HB

488

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

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State Capitol
Juneau, Alaska 99801-1182
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MEMORANDUM March 17, 2006

SUBJECT: Resources Committee amendment 8 to CSHB 488(RES), draft version "Y" (Work Order No. 24-GH2052\Y)

TO: Representative Jay Ramras
Representative Ralph Samuels
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

Tim Benintendi has provided copies of amendments adopted by the committee during yesterday's mark-up of the above-captioned bill.

To meet the direction set out in committee amendment 8 ("delete sections relating to transitional investment expenditures"), captioned as a conceptual amendment, unless someone gives me different guidance. to meet the committee's direction, I propose to delete

(1) AS 43.55.160(a)(3) [bill, page 17, lines 26 to the end of the sentence on line 28];

(2) all of AS 43.55.160(b)(2) [bill, page 18, lines 14 - 22]; and

(3) all of AS 43.55.160(g) and (h) [bill, page 21, line 25, through page 23, line 6].

The deletions will necessitate some internal renumbering or relettering.

If there are other provisions covered under the general direction that deserve attention or that were intended to be encompassed within the scope of committee amendment 8. please advise.

JBC:ljw
06-135.ljw

cc: Representative Mary Kapsner, amendment sponsor

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MEMORANDUM March 16, 2006

SUBJECT: Editorial amendments offered to CSHB 48(RES), draft version "Y" (Work Order No. 24-GH2052\Y.9)

TO: Representative Ralph Samuels
Representative Jay Ramras
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

Since I am not (yet) preparing a further committee substitute, Assistant Attorney General Rob Mintz and Department of Law Legislation Editor B.J. Jordan asked me to prepare and submit the enclosed for the House Resources Committee's consideration.

The amendment's first entry is made to conform exactly the language of proposed AS 43.55.011(f) to like references in subsections (a) and (e).

The second is necessary to limit the section reference to the specific subsection referenced later in paragraphs (1) and (2).

The third, omitting bill section 24 from the list of sections taking an immediate effective date, aligns the effective date of the text of the amendment made in that bill section to other provisions imposing the new production tax to be effective, under this version, on April 1, 2006.

JBC:med
06-222.med

Enclosure

24-GH2052\Y.9
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 4, line 9, following "for":

Insert "all"

Page 5, line 31:

Delete "**AS 43.55.011**"

Insert "**AS 43.55.011(a)**"

Page 30, line 22:

Delete "24,"

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MEMORANDUM March 16, 2006

SUBJECT: Amendments to CSHB 488(RES), draft version "Y"
(Work Order No. 24-GH2052\Y.4 - Y.7)

TO: Representative Jay Ramras
Representative Ralph Samuels
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

Dan Dickinson visited me this morning, bringing with him four "clean-up" amendments to the draft committee substitute supplied yesterday. Since I could not assure him that we could produce a new draft committee substitute incorporating the changes by the time of your scheduled early afternoon hearing, this memo transmits that material set out as four amendments.

In the main, the material tracks the language offered by Mr. Dickinson. However, in amendment Y.6, reference in material supplied by Mr. Dickinson to "sec. 16" seemed incorrect, and I renumbered; please check the references.

I told Dan that, in any final version of the committee substitute, the content of bill sections 29 - 31, amending various subsections of AS 43.55.201, would be brought together in just one bill section, and the content of bill sections 33 - 35, amending various subsections of AS 43.55.300, would be similarly treated.

JBC:med
06-221.med

Enclosures

24-GH2052\Y.4
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 21, lines 3 - 4:

Delete "any payment or credit"

Insert "certain payments or credits received by the producer, as provided in this subsection. If, during a month or, under (f) of this section, during a calendar year, a producer receives one or more payments or credits subject to this subsection and if either the total amount of the payments or credits exceeds the amount of the producer's lease expenditures or the producer does not have any lease expenditures, the producer shall nevertheless subtract the payments or credits from the lease expenditures or from zero, respectively, and the producer's adjusted lease expenditures for that month or calendar year are a negative number. The producer shall apply that negative number to the calculation made under (a) of this section. The payments or credits that a producer must subtract from the producer's lease expenditures, or from zero, under this subsection are payments or credits that"

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 24, lines 3 - 4:

Delete "may apply a tax credit against that liability under this section."

Insert "and, during the calendar year, has incurred a qualified capital expenditure, as that term is defined in AS 43.55.024, may apply a tax credit, in an amount that does not exceed the amount of that expenditure, against that liability under this section. An unused portion of a tax credit may be applied to the extent otherwise allowed under this section for one or more months during the same calendar year."

Page 24, lines 6 - 7:

Delete "before applications for any credits under this chapter"

Insert "for any month"

Page 24, line 23, following "qualified":

Insert "capital"

24-GH2052\Y.6
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 29, line 31, following "REGULATIONS":

Delete "."

Insert "AND RETROACTIVITY OF REGULATIONS. (a)"

Page 30, following line 3:

Insert a new subsection to read:

"(b) Notwithstanding any contrary provision of AS 44.62.240, a regulation adopted by the Department of Revenue to implement, interpret, make specific, or otherwise carry out the provisions of secs. 5, 6, 8 - 11, 13 - 15, 17 - 20, 22, and 25 - 41 of this Act may apply retroactively as of April 1, 2006, if the Department of Revenue expressly designates in the regulation that the regulation applies retroactively to that date."

24-GH2052\Y.7
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 29, lines 5 - 6:

Delete "the sections of this Act that are not effective April 1, 2006"

Insert "secs. 8 and 13 of this Act"

Page 29, lines 14 - 15:

Delete "the sections of this Act that are not effective April 1, 2006"

Insert "secs. 5 and 6 of this Act"

Page 29, line 17, following "Act,":

Insert "or AS 43.55.030(e), added by sec. 22 of this Act,"

Page 29, lines 18 - 19:

Delete "the sections of this Act that are not effective April 1, 2006"

Insert "secs. 20 and 22 of this Act"

24-GH2052\Y
Chenoweth
3/15/06

CS FOR HOUSE BILL NO. 483(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FOURTH LEGISLATURE - SECOND SESSION

BY THE HOUSE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): HOUSE RU ES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

"An Act repealing the oil production tax and gas production tax and providing for a production tax on oil and gas; relating to the relationship of that tax to other taxes, to the dates those tax payments and surcharges are due, to interest on overpayments of the tax, and to the treatment of the tax in a producer's settlement with the royalty owners; relating to flared gas, and to oil and gas used in the operation of a lease or property under the production tax; relating to the prevailing value of oil or gas under the production tax; providing for tax credits against the tax for certain expenditures and losses; amending the rates applicable to each of the two tax surcharges imposed on oil under the production tax that are used to support the oil and hazardous substance release prevention and response fund and relating to those surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, for

the tax; relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, as applicable to the administration of the tax; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the tax, and to the deposit of tax money collected by the Department of Revenue; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the production tax value of oil and gas for purposes of a tax on the production tax value of oil and gas; relating to the definitions of 'gas,' 'oil,' and certain other terms for purposes of the production tax, and as the definition of the term 'gas' applies in the Alaska Stranded Gas Development Act; making conforming amendments; making uniform throughout the state the deadline for certain exploration expenditures used as credits against the production tax on oil and gas produced from a lease or property in the state by extending to July 1, 2016, the deadline for those expenditures and limiting use of the resultant credits; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

INTENT OF SEC. 12 OF THIS ACT. It is the intent of the legislature through sec. 12 of this Act to confirm by clarification the long-standing interpretation of AS 43.55.020(f) by the Department of Revenue.

*** Sec. 2.** AS 43.05.230(f) is amended to read:

(f) A wilful violation of the provisions of this section **or of a condition imposed under AS 43.55.040(1)(B)** is punishable by a fine of not more than $5,000, or by imprisonment for not more than two years, or by both.

*** Sec. 3.** AS 43.20.031(c) is amended to read:

(c) In computing the tax under this chapter, the taxpayer is not entitled to

deduct any taxes based on or measured by net income. **The taxpayer may deduct the tax levied and paid under AS 43.55.**

*** Sec. 4.** AS 43.20.072(b) is amended to read:

(b) A taxpayer's business income to be apportioned under this section to the state shall be the federal taxable income of the taxpayer's consolidated business for the tax period, except that

(1) taxes based on or measured by net income that are deducted in the determination of the federal taxable income shall be added back; **the tax levied and paid under AS 43.55 may not be added back;**

(2) intangible drilling and development costs that are deducted as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) in the determination of the federal taxable income shall be capitalized and depreciated as if the option to treat them as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) had not been exercised;

(3) depletion deducted on the percentage depletion basis under 26 U.S.C. 613 (Internal Revenue Code) in the determination of the federal taxable income shall be recomputed and deducted on the cost depletion basis under 26 U.S.C. 612 (Internal Revenue Code); and

(4) depreciation shall be computed on the basis of 26 U.S.C. 167 (Internal Revenue Code) as that section read on June 30, 1981.

*** Sec. 5.** AS 43.55.011(a) is repealed and reenacted to read:

(a) There is levied on the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state less any oil and gas the ownership or right to which is exempt from taxation or constitutes a lessor's royalty interest under an oil and gas lease. The tax is equal to 20 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160.

*** Sec. 6.** AS 43.55.011 is amended by adding new subsections to read:

(e) There is levied on the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state the ownership or right to which constitutes a lessor's royalty interest under an oil and gas lease, except for oil and gas the ownership or right to which is exempt from taxation. The tax is equal to

five percent of the gross value at the point of production of the oil and gas. However, if the department determines that, for purposes of reducing the producer's tax liability under this subsection, the producer has received or will receive consideration from the lessor offsetting all or a part of the producer's royalty obligation, the tax under this subsection is equal to 20 percent of the gross value at the point of production of the oil and gas.

(f) In addition to the taxes levied under (a) and (e) of this section, for each month for which the oil price index determined under (g) of this section is greater than zero, there is levied upon the producer of oil or gas a tax for oil and gas produced during that month from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation. The tax is equal to .30 percent of the gross value at the point of production of the oil and gas multiplied by the oil price index as determined under (g) of this section.

(g) The oil price index for a month is the number equal to the average United States Gulf Coast price determined under (h) of this section for that month of West Texas Intermediate crude oil in dollars per barrel, less 50, except that, if the average price determined under (h) of this section is

(1) not more than $50 per barrel, the oil price index is zero; and

(2) more than $150 per barrel, the oil price index is 100.

(h) For purposes of (f) and (g) of this section, the department may calculate the average price or may, by regulation, specify the method by which the average price shall be calculated with reference to one or more published sources of price information. If, in the department's judgment, reliable published sources of price information on West Texas Intermediate crude oil cease, or appear likely to soon cease, to be available, or if, in the department's judgment, the price of West Texas Intermediate crude oil ceases, or appears likely to soon cease, to be a reliable indicator of the general price level of crude oils, the department shall, by regulation, specify a substitute formula for computing the oil price index. The substitute formula specified by the department under this subsection must bear, as nearly as is reasonably possible, the same relationship to the general price level of crude oils as did the United States Gulf Coast price of West Texas Intermediate crude oil.

* **Sec. 7.** AS 43.55.017(a) is amended to read:

(a) Except as provided in this chapter, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax **on** [UPON]

(1) producing oil or gas leases;

(2) oil or gas produced or extracted in the state;

(3) the value of intangible drilling and **development costs, as described in 26 U.S.C. 263(c) (Internal Revenue Code), as amended through January 1, 1974** [EXPLORATION EXPENSES].

* **Sec. 8.** AS 43.55.020(a) is repealed and reenacted to read:

(a) The tax levied under AS 43.55.011(a) shall be paid monthly. The tax, net of any credits applied under this chapter, is due on the last day of each calendar month on oil and gas produced from each lease or property during the preceding month. An unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent. An overpayment of tax for a month may be applied against the tax due for a later month. Notwithstanding any contrary provision of AS 43.05.280, interest on an overpayment is allowed only from a date that is 90 days after the statement required under AS 43.55.030(e) to be filed on or before March 31 of the year following the calendar year during which the oil and gas were produced is filed. However, interest is not allowed if the overpayment was refunded within the 90-day period.

* **Sec. 9.** AS 43.55.020(b) is amended to read:

(b) The production tax on oil **and** [OR] gas shall be paid by or on behalf of the producer.

* **Sec. 10.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner **for oil or gas that is taxable under AS 43.55.011,** the producer may deduct the amount of the tax paid on **taxable** royalty oil **and** [OR] gas, or may deduct **taxable** royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. **Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under AS 43.55.011 on taxable royalty oil and gas for a month other than oil or**

gas the ownership or right to which constitutes a lessor's royalty interest under an oil or gas lease is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the month multiplied by a figure that is a quotient, in which

(1) the numerator is the producer's total tax liability under AS 43.55.011(a) for the month of production; and

(2) the denominator is the total gross value at the point of production of the oil and gas taxable under AS 43.55.011(a) produced by the producer from all leases and properties in the state during the month.

*** Sec. 11.** AS 43.55.020(e) is repealed and reenacted to read:

(e) Gas flared, released, or allowed to escape in excess of the amount authorized by the Alaska Oil and Gas Conservation Commission is considered, for the purpose of AS 43.55.011 - 43.55.170, as gas produced from a lease or property. Oil or gas used in the operation of a lease or property in the state in drilling for or producing oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and Gas Conservation Commission to be waste, is not considered, for the purpose of AS 43.55.011 - 43.55.170, as oil or gas produced from a lease or property.

*** Sec. 12.** AS 43.55.020(f) is amended to read:

(f) If oil or gas is **not sold, or if oil or gas is** sold under circumstances where the sale price does not represent the prevailing value for oil or gas of like kind, character, or quality in the field or area from which the product is produced, the department may require the tax to be paid upon the basis of the value of oil or gas of the same kind, quality, and character prevailing during the calendar month of production for that field or area.

*** Sec. 13.** AS 43.55.020 is amended by adding new subsections to read:

(g) The tax levied under AS 43.55.011(e) and (f) shall be paid monthly and is due on the last day of each calendar month on oil and gas produced from each lease or property during the preceding month, and, if not paid before the end of the month in which it becomes due, the tax becomes delinquent.

(h) If less than 90 percent of the total tax levied under AS 43.55.011(a), (e), and (f) is paid when due under this section, a civil penalty of five percent of the

difference between the amount paid and 90 percent of the tax due shall be added to the tax. The amount shall be added irrespective of whether the underpayment is also subject to a penalty under AS 43.05.220. However, a penalty paid under this subsection may be credited against a penalty or penalties assessed under AS 43.05.220 with respect to the same underpayment, but the credit may not exceed the total amount of those penalties.

* **Sec. 14.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.024. Tax credits for certain losses and expenditures. (a) Notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the production tax value of oil and gas under AS 43.55.160(a), a producer or explorer that incurs a qualified capital expenditure may also elect to take a tax credit in the amount of 20 percent of that expenditure, unless a credit for that expenditure is taken under AS 43.55.025. A credit under this subsection may be applied only against a tax due under AS 43.55.011(a). For a calendar year for which the producer makes an election under AS 43.55.160(f), instead of taking a tax credit of 20 percent of each separate qualified capital expenditure after it has been incurred, a producer that incurs a qualified capital expenditure during that year and that wishes to apply a credit based on that expenditure against a tax due under AS 43.55.011(a) shall calculate and apply every month an annualized tax credit in an amount equal to one and two-thirds percent of the total qualified capital expenditures incurred during that year and for which the tax credit is taken for that year.

(b) A producer or explorer may elect to take a tax credit in the amount of 20 percent of a carried-forward annual loss. A credit under this subsection may be applied only against a tax due under AS 43.55.011(a). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b).

(c) A credit or portion of a credit under this section may not be used to reduce a person's tax liability under AS 43.55.011(a) for any month below zero, and any unused credit or portion of a credit not used under this subsection may be applied in a

later month.

(d) A person entitled to take a tax credit under this section that wishes to transfer the unused credit to another person or to obtain a refund under (f) of this section may apply to the department for a transferable tax credit certificate. An application under this subsection must be on a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 60 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) if the applicant is required under AS 43.55.030(e) to file a statement on or before March 31 of the year following the calendar year in which the qualified capital expenditures or carried-forward annual loss for which the credit was incurred, the date the statement was filed; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

(e) A person to which a transferable tax credit certificate is issued under (d) of this section may transfer the certificate to another person, and a transferee may further transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and notwithstanding any action the department may take with respect to the applicant under (g) of this section, the owner of a certificate may apply the credit or a portion of the credit shown on the certificate only against a tax due under AS 43.55.011(a). However, a credit shown on a transferable tax credit certificate may not be applied to reduce a transferee's total tax due under AS 43.55.011(a) on oil and gas produced during a calendar year to less than 80 percent of the tax that would otherwise be due without applying that credit, and any portion of a credit not used under this subsection may be applied in a later period.

(f) Under standards established in regulations adopted by the department and subject to appropriations made by law, the department, on the written application of

the person to whom a transferable tax credit has been issued under (d) of this section, shall issue a cash refund, in whole or in part, for the certificate if the department finds

(1) after investigation and audit of the tax credit claim by the department, the applicant is entitled to the credit to the extent of the refund amount;

(2) within 24 months after having applied for the transferable tax credit certificate, the applicant incurred a qualified capital expenditure or was the successful bidder on a bid submitted for a lease on state land under AS 38.05.180(f);

(3) the amount of the refund would not exceed the total of qualified capital expenditures and successful bids described in (2) of this subsection that have not been the subject of a finding made under this paragraph for purposes of a previous refund;

(4) the applicant does not have an outstanding liability to the state for unpaid delinquent taxes under this title; and

(5) the sum of the amount of the refund applied for and amounts previously refunded to the applicant during the calendar year under this subsection would not exceed $10,000,000.

(g) The issuance of a transferable tax credit certificate under (d) of this section does not limit the department's ability to later investigate or audit a tax credit claim to which the certificate relates or to adjust or deny the claim if the department determines that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011 - 43.55.170 is increased by the amount of the credit that exceeds that to which the applicant was entitled. That amount bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, an applicant that is an explorer is considered a producer subject to the tax levied under AS 43.55.011.

(h) The department may adopt regulations to carry out the purposes of this section, including prescribing reporting, record keeping, and certification procedures and requirements to verify the accuracy of credits claimed and to ensure that a credit is not used more than once, and otherwise implementing this section.

(i) A producer or explorer may not elect to take a tax credit under this section for a lease expenditure under AS 43.55.160 that is an expenditure incurred

(1) to acquire an asset (A) the cost of previously acquiring which was a lease expenditure under AS 43.55.160(c) or would have been a lease expenditure under AS 43.55.160(c) if it had been incurred on or after April 1, 2006; or (B) that has previously been placed in service in the state; an expenditure to acquire an asset is not excluded under this paragraph if not more than an immaterial portion of the asset meets a description under (A) or (B) of this paragraph; for purposes of this paragraph, "asset" includes geological, geophysical, and well data and interpretations; or

(2) for an extended period of disuse, dismantlement, removal, surrender, or abandonment of a well, facility, pipeline, platform, or other structure, or for the restoration of a lease, field, unit, area, or body of water in conjunction with an extended period of disuse, dismantlement, removal, surrender, or abandonment of a facility described in this paragraph.

(j) In this section, "qualified capital expenditure" means, except as otherwise provided in (i) of this section, an expenditure that is a lease expenditure under AS 43.55.160 and is

(1) incurred for geological or geophysical exploration; or

(2) treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and either is treated as a capitalized expenditure by the person incurring the expenditure or is eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal Revenue Code), as amended.

*** Sec. 15.** AS 43.55.025(a) is amended to read:

(a) Subject to the terms and conditions of this section, on oil and gas produced on or after July 1, 2004, from an oil and gas lease, or on gas produced from a gas only lease, a credit against the production tax due under **AS 43.55.011(a)** [THIS CHAPTER] is allowed for exploration expenditures that qualify under (b) of this section in an amount equal to one of the following:

(1) 20 percent of the total exploration expenditures that qualify only under (b) and (c) of this section;

(2) 20 percent of the total exploration expenditures for work performed before July 1, 2007, and that qualify only under (b) and (d) of this section;

(3) 40 percent of the total exploration expenditures that qualify under (b), (c), and (d) of this section; or

(4) 40 percent of the total exploration expenditures that qualify only under (b) and (e) of this section.

*** Sec. 16.** AS 43.55.025(b) is amended to read:

(b) To qualify for the production tax credit under (a) of this section, an exploration expenditure must be incurred for work performed on or after July 1, 2003, and before July 1, **2016** [2007], except that an exploration expenditure for a Cook Inlet prospect must be incurred for work performed on or after July 1, 2005, [AND BEFORE JULY 1, 2010, AND EXCEPT THAT AN EXPLORATION EXPENDITURE, IN WHOLE OR IN PART, SOUTH OF 68 DEGREES, 15 MINUTES, NORTH LATITUDE, AND NOT PART OF A COOK INLET PROSPECT MUST BE INCURRED FOR WORK PERFORMED ON OR AFTER JULY 1, 2003, AND BEFORE JULY 1, 2010,] and

(1) may be for seismic or geophysical exploration costs not connected with a specific well;

(2) if for an exploration well,

(A) must be incurred by an explorer that holds an interest in the exploration well for which the production tax credit is claimed;

(B) may be for either an oil or gas discovery well or a dry hole; and

(C) must be for goods, services, or rentals of personal property reasonably required for the surface preparation, drilling, casing, cementing, and logging of an exploration well, and, in the case of a dry hole, for the expenses required for abandonment if the well is abandoned within 18 months after the date the well was spudded;

(3) may not be for testing, stimulation, or completion costs; administration, supervision, engineering, or lease operating costs; geological or management costs; community relations or environmental costs; bonuses, taxes, or other payments to governments related to the well; or other costs that are generally recognized as indirect costs or financing costs; and

(4) may not be incurred for an exploration well or seismic exploration that is included in a plan of exploration or a plan of development for any unit on May 13, 2003.

*** Sec. 17.** AS 43.55.025(f) is amended to read:

(f) For a production tax credit under this section,

(1) an explorer shall, in a form prescribed by the department and within six months of the completion of the exploration activity, claim the credit and submit information sufficient to demonstrate to the department's satisfaction that the claimed exploration expenditures qualify under this section;

(2) an explorer shall agree, in writing,

(A) to notify the Department of Natural Resources, within 30 days after completion of seismic or geophysical data processing, completion of a well, or filing of a claim for credit, whichever is the latest, for which exploration costs are claimed, of the date of completion and submit a report to that department describing the processing sequence and providing a list of data sets available; if, under (c)(2)(B) of this section, an explorer submits a claim for a credit for expenditures for an exploration well that is located within three miles of a well already drilled for oil and gas, in addition to the submissions required under (1) of this subsection, the explorer shall submit the information necessary for the commissioner of natural resources to evaluate the validity of the explorer's claim that the well is directed at a distinctly separate exploration target, and the commissioner of natural resources shall, upon receipt of all evidence sufficient for the commissioner to evaluate the explorer's claim, make that determination within 60 days;

(B) to provide to the Department of Natural Resources, within 30 days after the date of a request, specific data sets, ancillary data, and reports identified in (A) of this paragraph;

(C) that, notwithstanding any provision of AS 38, information provided under this paragraph will be held confidential by the Department of Natural Resources for 10 years following the completion date, at which time that department will release the information after 30 days' public notice;

(3) if more than one explorer holds an interest in a well or seismic exploration, each explorer may claim an amount of credit that is proportional to the explorer's cost incurred;

(4) the department may exercise the full extent of its powers as though the explorer were a taxpayer under this title, in order to verify that the claimed expenditures are qualified exploration expenditures under this section; and

(5) if the department is satisfied that the explorer's claimed expenditures are qualified under this section, the department shall issue to the explorer a production tax credit certificate for the amount of credit to be allowed against production taxes due under **AS 43.55.011(a)** [THIS CHAPTER]; however, notwithstanding any other provision of this section, the department may not issue to an explorer a production tax credit certificate if the total of production tax credits submitted for Cook Inlet production, based on exploration expenditures for work performed during the period described in (b) of this section for that production, that have been approved by the department exceeds $20,000,000.

*** Sec. 18.** AS 43.55.025(h) is amended to read:

(h) A producer that purchases a production tax credit certificate may apply the credits against its production tax liability under **AS 43.55.011(a)** [THIS CHAPTER]. Regardless of the price the producer paid for the certificate, the producer may receive a credit against its production tax liability for the full amount of the credit, but for not more than the amount for which the certificate is issued. A production tax credit allowed under this section may not be applied more than once.

*** Sec. 19.** AS 43.55.025(i) is amended to read:

(i) For a production tax credit under this section,

(1) the amount of the credit that may be applied against the production tax for each tax month may not exceed the total production tax liability **under AS 43.55.011(a)** of the taxpayer applying the credit for the same month; and

(2) an amount of the production tax credit that is greater than the total tax liability **under AS 43.55.011(a)** of the taxpayer applying the credit for a tax month may be carried forward and applied against the taxpayer's production tax liability **under AS 43.55.011(a)** in one or more immediately following months.

*** Sec. 20.** AS 43.55.030(a) is amended to read.

(a) The tax shall be paid to the department and the person paying the tax shall file with the department at the time the tax is required to be paid a statement, under oath, on forms prescribed by or acceptable to the department, giving, with other information required, the following:

(1) a description of **each** [THE] lease or property from which the oil **and** [OR] gas **were** [WAS] produced, by name, legal description, lease number, or [BY] accounting **codes** [CODE NUMBERS] assigned by the department;

(2) the names of the producer and the person paying the tax;

(3) the gross amount of oil **and the gross amount of** [OR] gas produced from **each** [THE] lease or property, and the percentage of the gross amount **of oil and gas** owned by each producer for whom the tax is paid;

(4) the **gross** [TOTAL] value **at the point of production** of the oil **and of the** [OR] gas produced from **each** [THE] lease or property owned by each producer for whom the tax is paid; [AND]

(5) the name of the first purchaser and the price received for the oil **and for the** [OR] gas, **unless relieved from this requirement in whole or in part by the department; and**

(6) the producer's lease expenditures and adjustments as calculated under AS 43.55.160 [IF SOLD IN THE STATE].

*** Sec. 21.** AS 43.55.030(d) is amended to read:

(d) Reports by or on behalf of the producer are delinquent the first day following the day the tax is due. [EACH PRODUCER IS SUBJECT TO A PENALTY OF $25 A DAY FOR EACH LEASE OR PROPERTY UPON WHICH THE REPORT IS NOT FILED. THE PENALTY FOR FAILURE TO FILE A REPORT IS IN ADDITION TO THE PENALTY FOR DELINQUENT TAXES, AND IS A LIEN AGAINST THE ASSETS OF THE PRODUCER.]

*** Sec. 22.** AS 43.55.030 is amended by adding a new subsection to read:

(e) The person paying the tax under AS 43.55.011(a) shall file a statement on or before March 31 of a year showing any adjustments or corrections to the statements that were required under (a) of this section to be filed for the months of the preceding

calendar year during which the oil or gas was produced.

*** Sec. 23.** AS 43.55.040 is amended to read:

Sec. 43.55.040. Powers of Department of Revenue. Except as provided in AS 43.05.405 - 43.05.499, the department may

(1) require a person engaged in production and the agent or employee of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil or gas to furnish**, whether by the filing of regular statements or reports or otherwise,** additional information that is considered by the department as necessary to compute the amount of the tax**; notwithstanding any contrary provision of law, the disclosure of additional information under this paragraph to the producer obligated to pay the tax does not violate AS 40.25.100(a) or AS 43.05.230(a); before disclosing information under this paragraph that is otherwise required to be held confidential under AS 40.25.100(a) or AS 43.05.230(a), the department shall**

(A) provide the person that furnished the information a reasonable opportunity to be heard regarding the proposed disclosure and the conditions to be imposed under (B) of this paragraph; and

(B) impose appropriate conditions limiting

(i) access to the information to those legal counsel, consultants, employees, officers, and agents of the producer who have a need to know that information for the purpose of determining or contesting the producer's tax obligation; and

(ii) the use of the information to use for the purpose of determining or contesting the producer's tax obligation;

(2) examine the books, records, and files of such a person;

(3) conduct hearings and compel the attendance of witnesses and the production of books, records, and papers of any person; and

(4) make an investigation or hold an inquiry that is considered necessary to a disclosure of the facts as to

(A) the amount of production from any oil or gas location, or of a company or other producer of oil or gas; and

(B) the rendition of the oil and gas for taxing purposes.

*** Sec. 24.** AS 43.55.080 is amended to read:

Sec. 43.55.080. Collection and deposit of revenue. **Except as otherwise provided under art. IX, sec. 17, Constitution of the State of Alaska, the** [THE] department shall deposit in the general fund the money collected by it under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 25.** AS 43.55.135 is amended to read:

Sec. 43.55.135. Measurement. For the purposes of **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150], oil **is** [SHALL BE] measured in terms of a "barrel of oil" and gas **is** [SHALL BE] measured in terms of a "cubic foot of gas."

*** Sec. 26.** AS 43.55.150(a) is amended to read:

(a) For the purposes of **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150], the gross value **at the point of production is** [SHALL BE] calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation **are** [SHALL BE] the actual costs, except **when the**

(1) [WHEN THE] parties to the transportation of oil or gas are affiliated;

(2) [WHEN THE] contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation;

(3) [WHEN THE] method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

*** Sec. 27.** AS 43.55.150 is amended by adding a new subsection to read:

(d) Under regulations adopted by the department, the department may allow a producer, subject to limitations prescribed by the department as to the frequency of making elections, to elect prospectively to calculate the gross value at the point of production of oil or gas based in whole or part on

(1) a royalty value determined under a royalty settlement agreement between the producer and the state, with adjustments if appropriate;

(2) a formula prescribed by the department that uses, with adjustments if appropriate, a royalty value or valuation methodology accepted by the

(A) Department of Natural Resources under AS 38.05, in the case of oil and gas produced from a lease issued by the Department of Natural Resources or produced from a lease or property that is part of a unit approved by the Department of Natural Resources; or

(B) United States Department of the Interior under applicable federal oil and gas leasing statutes, in the case of oil and gas produced from a lease issued by the United States Department of the Interior that is not part of a unit approved by the Department of Natural Resources, or produced from a lease or property that is part of a unit approved by the United States Department of the Interior but not approved by the Department of Natural Resources; or

(3) another formula prescribed by the Department of Revenue that reasonably estimates a value for the oil or gas at a specific geographical location, such as the point of tender or delivery into a common carrier pipeline; the formula may use factors such as published price indices for oil or gas in or outside the state, quality differentials for oil or gas, transportation costs between markets, and inflation adjustments.

* **Sec. 28.** AS 43.55 is amended by adding new sections to article 1 to read:

Sec. 43.55.160. Determination of production tax value of oil and gas. (a) Except as provided in (f) of this section, for purposes of AS 43.55.011(a), the production tax value of the taxable oil and gas produced during a month is the total of the gross value at the point of production of the oil and gas taxable under AS 43.55.011(a) and produced by the producer from all leases or properties in the state, (1) less the producer's tax paid for the month under AS 43.55.011(f); (2) less the producer's lease expenditures for the month as adjusted under (e) of this section, and (3) to the extent allowed under (g) of this section and until the total amount of the producer's transitional investment expenditures has been deducted, less an amount equal to 1/84 of the producer's transitional investment expenditures. However, the production tax value calculated under this subsection may not be less than zero. If a producer does not produce taxable oil or gas during a month, the producer is considered to have generated a positive production tax value if the calculation

described in this subsection yields a positive number because the producer's adjusted lease expenditures for a month are less than zero as a result of the producer's receiving a payment or credit under (e) of this section or otherwise.

(b) For purposes of administration of (a) of this section,

(1) any adjusted lease expenditures that would otherwise be deductible in a month but the deduction of which would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero may be added to the producer's adjusted lease expenditures for one or more other months in the same calendar year; the total of any adjusted lease expenditures that are not deductible in any month during a calendar year because their deduction would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during one or more months to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.024(b);

(2) an amount of transitional investment expenditures that would otherwise be deductible in a month but the deduction of which would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero

(A) may be deducted in a later month during any calendar year to the extent allowed under (g) of this section, but not more than 1/84 of a producer's transitional investment expenditures may be deducted in any month;

(B) may not be used to establish a carried-forward annual loss under AS 43.55.024(b);

(3) an explorer that has taken a tax credit under AS 43.55.024(b) or that has obtained a transferable tax credit certificate under AS 43.55.024(d) for the amount of a tax credit under AS 43.55.024(b) is considered a producer, subject to the tax levied under AS 43.55.011(a), to the extent that the explorer generates a positive production tax value as the result of the explorer's receiving a payment or credit described in (e) of this section.

(c) For purposes of this section,

(1) a producer's lease expenditures for a period are the total costs upstream of the point of production of oil and gas that are incurred on or after April 1,

2006, by the producer during the period and that are direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas deposits located within the producer's leases or properties in the state or, in the case of land in which the producer does not own a working interest, direct, ordinary, and necessary costs of exploring for oil or gas deposits located within other land in the state; however, lease expenditures do not include the costs incurred to satisfy a work commitment under an exploration license under AS 38.05.132; in determining whether costs are direct, ordinary, and necessary costs of explo. ıg for, developing, or producing an oil or gas deposit located within a lease or property or other land in the state, the department shall give substantial weight to

(A) the typical industry practices and standards in the state and in the United States as to costs that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, not the operator, with substantial bargaining power; and

(B) the standards adopted by the Department of Natural Resources as to the costs, other than interest, that a lessee is allowed to deduct from revenue in calculating net profits under a lease issued under AS 38.05.180(f)(3)(B), (D), or (E);

(2) the Department of Revenue may authorize a producer, including a producer that is the operator, to treat as its lease expenditures under this section the costs paid by the producer that are billed to the producer by an operator in accordance with the terms of a unit operating agreement or similar operating agreement if the Department of Revenue finds that

(A) the pertinent provisions of the operating agreement are substantially consistent with the Department of Revenue's determinations and standards otherwise applicable under this subsection; and

(B) at least one working interest owner party to the agreement, other than the operator, has substantial incentive and ability to effectively audit billings under the agreement.

(d) For purposes of (c) of this section, "direct costs"

(1) includes

(A) an expenditure, when incurred, to acquire an item if the acquisition cost is otherwise a direct cost, notwithstanding that the expenditure may be required to be capitalized rather than treated as an expense for financial accounting or federal income tax purposes;

(B) payments of property taxes, sales and use taxes, motor fuel taxes, and excise taxes;

(C) a reasonable allowance, as determined under regulations adopted by the department, for overhead expenses directly related to exploring for, developing, and producing oil or gas deposits located within leases or properties or other land in the state;

(2) does not include

(A) depreciation or amortization;

(B) royalty payments for oil and gas;

(C) taxes based on or measured by net income;

(D) interest or other financing charges or costs of raising equity or debt capital;

(E) acquisition costs for a lease or property or exploration license;

(F) costs arising from fraud, wilful misconduct, or negligence;

(G) fines or penalties imposed by law;

(H) costs of arbitration, litigation, or other dispute resolution activities that involve the state or concern the rights or obligations among owners of interests in, or rights to production from, one or more leases or properties or a unit;

(I) donations;

(J) costs incurred in organizing a partnership, joint venture, or other business entity or arrangement;

(K) amounts paid to indemnify the state; the exclusion provided by this paragraph does not apply to the costs of obtaining insurance

or a surety bond from a third-party insurer or surety;

(L) surcharges levied under AS 43.55.201 or 43.55.300.

(e) A producer's lease expenditures must be adjusted by subtracting any payment or credit the producer receives for

(1) the use by another person of a production facility in which the producer has an ownership interest;

(2) a reimbursement or similar payment that offsets the producer's lease expenditures, including a payment from the state or federal government for reimbursement of the producer's upstream costs, including costs for gathering, separating, cleaning, dehydration, compressing, or other field handling associated with the production of oil or gas upstream of the point of production;

(3) the sale or other transfer of

(A) an asset, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of a lease expenditure or an expenditure that would be a lease expenditure if it were incurred on or after April 1, 2006; and

(B) oil or gas

(i) that is not considered produced from a lease or property under AS 43.55.020(e); and

(ii) the cost of acquiring which is a lease expenditure incurred by the person that acquires the oil or gas.

(f) In place of the adjusted lease expenditures for a month under (a) of this section, a producer may, at any time, elect to substitute, for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year.

(g) For purposes of this section,

(1) a producer's transitional investment expenditures are the sum of the expenditures the producer incurred on or after January 1, 2003, and before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, less the sum of the payments or credits the producer received before April 1, 2006, for the sale or other transfer of assets, including geological, geophysical, or well data or interpretations, acquired by the

producer as a result of expenditures the producer incurred before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, multiplied by

(A) 25 percent for expenditures incurred on or after January 1, 2003, and before January 1, 2004;

(B) 50 percent for expenditures incurred on or after January 1, 2004, and before January 1, 2005; and

(C) 75 percent for expenditures incurred on or after January 1, 2005, and before April 1, 2006;

(2) notwithstanding (1) of this subsection, an amount of transitional investment expenditures may not be deducted under (a) of this section for a month for which the average price of Alaska North Slope oil delivered on the United States West Coast, as determined under (h) of this section, is equal to or less than $40 a barrel, as adjusted for inflation under (h) of this section.

(h) The average price described in (g) of this section shall be an average, as calculated using a formula prescribed by the department by regulation, of published daily spot price assessments during the month for Alaska North Slope oil delivered on the United States West Coast. However, if the department determines that the daily assessments cease to be published throughout the calendar year or appear likely to soon cease to be published throughout the calendar year or that they cease to be reliable evidence of market conditions or appear likely to soon cease to be reliable evidence of market conditions, the department shall by regulation provide that the average price described in (g) of this section is the prevailing value of Alaska North Slope oil delivered on the United States West Coast as determined under regulations of the department implementing AS 43.55.020(f). For each year after 2006, the department shall adjust the reference price of $40 a barrel set out in (g) of this section for inflation. The dollar amount in (g) of this section changes according to and to the extent of changes in the Consumer Price Index for all urban consumers for the Anchorage Metropolitan Area compiled by the Bureau of Labor Statistics, United States Department of Labor (the index). The index for January of 2006 is the reference base index. If the index is revised, the percentage of change is calculated based on the

revised index. If a revision of the index changes the reference base index, a revised reference base index is determined by multiplying the reference base index applicable by the rebasing factor furnished by the United States Bureau of Labor Statistics. If the index is superseded, the index referred to in this section is the one represented by the United States Bureau of Labor Statistics as reflecting most accurately changes in the purchasing power of the dollar for Alaska consumers.

(i) The department shall specify or approve a reasonable allocation method for determining the portion of a cost that is appropriately treated as a lease expenditure under (c) of this section if a cost that would otherwise constitute a lease expenditure under (c) of this section is incurred to explore for, develop, or produce

(1) both an oil or gas deposit located within land outside the state and an oil or gas deposit located within a lease or property, or other land, in the state; or

(2) an oil or gas deposit located partly within land outside the state and partly within a lease or property, or other land, in the state.

(j) The department may adopt regulations that establish additional standards necessary to carrying out the purposes of this section.

(k) For purposes of AS 43.55.024(a) and (b) and only as to expenditures incurred to explore for an oil or gas deposit located within land in which an explorer does not own a working interest, the term "producer" in (b), (c), and (e) of this section includes "explorer."

(*l*) For purposes of this section,

(1) "explore" includes conducting geological or geophysical exploration, including drilling a stratigraphic test well, but the drilling of a stratigraphic test well qualifies under this paragraph only if the well's target zones are located in the state;

(2) "ordinary and necessary" has the meaning given "ordinary and necessary" in 26 U.S.C. 162 (Internal Revenue Code) and regulations adopted under that section;

(3) "stratigraphic test well" means a well drilled for the sole purpose of obtaining geological information to aid in exploring for an oil or gas deposit and the target zones of which are located in the state.

Sec. 43.55.170. Additional nontransferable credit. (a) For a month for which a producer's tax liability under AS 43.55.011(a) exceeds zero before application of any credits under this chapter, a producer that is qualified under (b) of this section may apply a tax credit against that liability under this section. The tax credit authorized by this subsection may be calculated and applied so that

(1) the producer's tax liability under AS 43.55.011(a) before applications of any credits under this chapter is not reduced below zero; and

(2) the total of the tax credits applied under this subsection during a calendar year does not exceed $10,000,000, except that the total of the tax credits applied under this subsection during calendar year 2016 does not exceed $2,500,000.

(b) On written application by a producer, including any information the department may require, the department shall determine whether the producer qualifies under this section for a calendar year. To qualify under this section, a producer must demonstrate that its operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer entity would not result in the division among multiple producer entities of any production tax liability under AS 43.55.011(a) that would be reasonably expected to be attributed to a single producer entity if the tax credit provision of (a) of this section did not exist.

(c) An unused tax credit or portion of a tax credit under this section is not transferable under AS 43.55.024(d) or refundable under AS 43.55.024(f), and may not be carried forward to or used in a later calendar year.

(d) The use of a tax credit under this section does not prevent a producer from taking a tax credit under AS 43.55.024(a) or 43.55.025 for the same qualified expenditure.

(e) A producer may not claim a credit under this section for a qualified capital expenditure incurred after March 31, 2016.

*** Sec. 29.** AS 43.55.201(a) is amended to read:

(a) Every producer of oil shall pay a surcharge of **$.01** [$.02] per barrel of oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation.

*** Sec. 30.** AS 43.55.201(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011 - 43.55.170,** [AS 43.55.011 - 43.55.150;] and is in addition to the surcharge imposed by AS 43.55.300 - 43.55.310.

*** Sec. 31.** AS 43.55.201(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 32.** AS 43.55.201 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

*** Sec. 33.** AS 43.55.300(a) is amended to read:

(a) Every producer of oil shall pay a surcharge of **$.04** [$.03] per barrel of oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation.

*** Sec. 34.** AS 43.55.300(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011 - 43.55.170,** [AS 43.55.011 - 43.55.150;] and is in addition to the surcharge imposed by AS 43.55.201 - 43.55.231.

*** Sec. 35.** AS 43.55.300(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 36.** AS 43.55.300 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

*** Sec. 37.** AS 43.55.900(6) is repealed and reenacted to read:

(6) "gas" means

(A) all natural, associated, or casinghead gas;

(B) all hydrocarbons that

(i) are recovered by mechanical separation of well fluids or by gas processing; and

(ii) exist in a gaseous phase at the completion of mechanical separation and any gas processing; and

(C) all other hydrocarbons produced from a well not defined as oil;

*** Sec. 38.** AS 43.55.900(7) is repealed and reenacted to read:

(7) "gross value at the point of production" means

(A) for oil, the value of the oil at the automatic custody transfer meter or device through which the oil enters into the facilities of a carrier pipeline or other transportation carrier in a condition of pipeline quality; in the absence of an automatic custody transfer meter or device, "gross value at the point of production" means the value of the oil at the mechanism or device to measure the quantity of oil that has been approved by the department for that purpose, through which the oil is tendered and accepted in a condition of pipeline quality into the facilities of a carrier pipeline or other transportation carrier or into a field topping plant;

(B) for gas, other than gas described in (C) of this paragraph, that is

(i) not subjected to or recovered by mechanical separation or gas processing, the value of the gas at the first point where the gas is accurately metered;

(ii) subjected to or recovered by mechanical separation but not gas processing, the value of the gas at the first point where the gas is accurately metered after completion of mechanical separation;

(iii) subjected to or recovered by gas processing, the value of the gas at the first point where the gas is accurately metered after completion of gas processing;

(C) for gas run through an integrated gas processing and gas

treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the value of the gas at the first point where gas processing is completed or where gas treatment begins, whichever is further upstream;

*** Sec. 39.** AS 43.55.900(10) is repealed and reenacted to read:

(10) "oil" means

(A) crude petroleum oil; and

(B) all liquid hydrocarbons that are recovered by mechanical separation of well fluids or by gas processing;

*** Sec. 40.** AS 43.55.900 is amended by adding new paragraphs to read:

(17) "explorer" means a person who, in exploring for new oil or gas reserves, incurs expenditures;

(18) "gas processing"

(A) means processing a gaseous mixture of hydrocarbons

(i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation;

(ii) for the purpose of extracting and recovering liquid hydrocarbons; and

(iii) upstream of any gas treatment and upstream of the inlet of any gas pipeline system transporting gas to a market;

(B) does not include gas treatment;

(19) "gas treatment"

(A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system; and

(B) includes incidentally removing liquid hydrocarbons from the gas.

*** Sec. 41.** AS 43.55.011(b), 43.55.011(c), 43.55.012(b), 43.55.013, 43.55.016, 43.55.025(k)(3), 43.55.900(1), 43.55.900(8), 43.55.900(11), 43.55.900(12), and

43.55.900(16) are repealed.

*** Sec. 42.** The uncodified law of the State of Alaska is amended by adding a new section to read:

APPLICABILITY. (a) Sections 5, 6, 8 - 11, 13, 14, 15, 17 - 20, 22, and 26 - 41 of this Act apply to oil and gas produced on or after April 1, 2006.

(b) Section 12 of this Act applies to oil and gas produced before, on, or after the effective date of sec. 12 of this Act.

*** Sec. 43.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITIONAL PROVISIONS. (a) Notwithstanding any contrary provision of AS 43.55.024(a), enacted by sec. 14 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "every month an annualized tax credit in an amount equal to one and two-thirds percent" in AS 43.55.024(a), enacted by sec. 14 of this Act, shall be replaced by the phrase "every month during the period April 1, 2006, through December 31, 2006, an annualized tax credit in an amount equal to 2.222 percent."

(b) Notwithstanding any contrary provision of AS 43.55.024(e), enacted by sec. 14 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "a calendar year" in AS 43.55.024(e), enacted by sec. 14 of this Act, shall be replaced by the phrase "the last nine months of the calendar year."

(c) Notwithstanding any contrary provision of AS 43.55.160(f), enacted by sec. 28 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year" in AS 43.55.160(f), enacted by sec. 28 of this Act, shall be replaced by the phrase "for each of the last nine months of 2006, one-ninth of the producer's adjusted lease expenditures for that nine-month period."

(d) Notwithstanding any contrary provision of AS 43.55.170(a), enacted by sec. 28 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the amount of "$10,000,000" in AS 43.55.170(a)(2), enacted by sec. 28 of this Act, shall be replaced by the amount "$7,500,000."

(e) For oil and gas produced before April 1, 2006, the provisions of AS 43.55, and regulations adopted under AS 43.55, that were in effect before April 1, 2006, and that were

applicable to the oil and gas continue to apply to that oil and gas.

(f) Notwithstanding any contrary provision of AS 43.55.020(a), as repealed and reenacted by sec. 8 of this Act, or of AS 43.55.020(g), as enacted by sec. 13 of this Act, for oil and gas produced on or after April 1, 2006, and before the first day of the first month that begins at least 180 days after the effective date of the sections of this Act that are not effective April 1, 2006,

(1) the amount of the taxes that would have been levied upon the producer under AS 43.55, as the provisions of that chapter read on March 31, 2006, is due on the last day of each calendar month on the oil and gas that was produced from each lease or property during the preceding month;

(2) the portion, if any, of the taxes levied under AS 43.55.011(a), as repealed and reenacted by sec. 5 of this Act, and under AS 43.55.011(e) and (f), as enacted by sec. 6 of this Act, that remains unpaid, net of any credits applied as allowed by law, is due on the last day of the second month that begins at least 180 days after the effective date of the sections of this Act that are not effective April 1, 2006.

(g) Notwithstanding any contrary provision of AS 43.55.030(a), as amended by sec. 20 of this Act, for oil and gas produced on or after April 1, 2006, and before the first day of the first month that begins at least 180 days after the effective date of the sections of this Act that are not effective April 1, 2006, the person paying the tax shall file with the Department of Revenue, at the time an amount of tax is due

(1) under (f)(1) of this section, the statement required under former AS 43.55.030(a), as that subsection read on March 31, 2006; and

(2) under (f)(2) of this section, the statement required under AS 43.55.030(e), enacted by sec. 22 of this Act.

(h) For purposes of taxes to be calculated and due under (f)(1) of this section and statements to be filed under (g)(1) of this section, regulations that were adopted by the Department of Revenue under AS 43.55, as the provisions of that chapter read on March 31, 2006, and that were in effect on that date apply to those taxes and statements.

*** Sec. 44.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: REGULATIONS. The Department of Revenue may proceed to adopt

regulations to implement the changes made by this Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not before the effective date of the law implemented by the regulation.

*** Sec. 45.** The uncodified law of the State of Alaska is amended by adding a new section to read:

REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the heading of

(1) AS 43.55 from "Oil and Gas Production Taxes and Oil Surcharge" to "Oil and Gas Production Tax and Oil Surcharge";

(2) article 1 of AS 43.55 from "Oil and Gas Properties Production Taxes" to "Oil and Gas Production Tax";

(3) AS 43.55.011 from "Oil production tax" to "Oil and gas production tax";

(4) AS 43.55.025 from "Tax credit for oil and gas exploration or gas only exploration" to "Alternative tax credit for oil and gas exploration or gas only exploration";

(5) AS 43.55.150 from "Determination of gross value" to "Determination of gross value at the point of production."

*** Sec. 46.** The uncodified law of the State of Alaska is amended by adding a new section to read:

CONDITIONAL RETROACTIVITY. If the sections of this Act that, under sec. 48 of this Act, are scheduled to take effect April 1, 2006, take effect on or after April 1, 2006, those sections of this Act are retroactive to April 1, 2006.

*** Sec. 47.** Sections 1 - 4, 7, 12, 16, 21, 23, 24, and 42 - 46 of this Act take effect immediately under AS 01.10.070(c).

*** Sec. 48.** Except as provided in sec. 47 of this Act, this Act takes effect April 1, 2006.

(AMENDS 'F')
(INVERSION 'Y')

H Res Notes HB 488
by R.P. SAMUELS

March 14, 2005

Notes re: Substantive Changes to HB488 by the House Resources Committee

1. Make tax rate progressive-

   Reasoning- The State should make more money at higher prices, and a larger percentage of the whole pie at extremely high prices. The Committee has increased the Governor's 20% tax rate to a progressive system. The 20% number will be in effect until the price of oil (West Texas Intermediate, WTI) reaches $50/barrel. After $50/barrel, the tax rate increases by .30% per $1.00 increase in the oil price (WTI). The rate caps at 50% at about $150.00/barrel, in case of a global oil shock. This makes the tax rate at $60.00/barrel 23.5%, and $70.00/barrel 26.5% and continues to escalate from there.

   We feel that this keeps investment opportunity in Alaska very strong, but balances it out by taking advantage of windfalls in high spikes of oil prices.

2. Reduce Transitional Money as deductible allowance- The Governor allowed five years of past investments to be deducted as costs. The rationale behind the transition provision was that investments made for the previous five years directly led to the production of oil that is now being taxed at a higher rate. The Committee feels that this rationale is partly true, but that a full five years of looking back is not appropriate. The cost recovery of the five years of investments has already been enhanced by extremely high oil prices. The Committee has replaced the 100% cost recovery of the previous five years with a

greatly scaled back program. The CS will allow 75% of 2005 expenditures, 50% of 2004 expenditures, and 25% of 2003 expenditures to be deducted as costs. The payback period of six years that was in the original legislation has been increased to seven years. The same caveat of oil prices being at least $40/barrel (ANS) before cost recovery is allowed remains the same. Additionally, the Committee has determined that the inflation indexing mechanism on the $40 price shall be in statute, not left up to regulators. This change reduces the amount of deduction allowed by industry from 5 billion to 2 billion and reduces the amount of the credit from approximately $1 billion to $300 million. Therefore, instead of the State absorbing $167 million annually in scheduled credits, the amount will be reduced to approximately $43 million per year.

3. Exploration enhancement- The SB 185 exploration tax credits of 40% will be extended 10 years. The Governor's credit rate of 20% remains intact. The Committee feels that this will significantly enhance explorers and independents. Department of Revenue has testified that exploration investment in new fields represents less than ten percent of all development and exploration investment dollars. The Committee wishes to emphasize exploration. As they do currently, the company will choose between which credit is most beneficial to them.

4. No credit for abandonment costs- The CS contains specific language that abandonment costs will not be eligible for tax credits.

5. Private Royalties- The CS sets private royalty oil severance tax rates at 5%.

6. AOGA technical changes- AOGA worked in conjunction with the Governor's office to suggest several technical changes and clarifications to the bill. Some of these changes are incorporated into the CS.

7. Contingency sur-charges- The CS will leave current statute in place, which makes a 5 cent/barrel sur-charge non-deductible and non-creditable. Currently, of the 5-cent/barrel charge, 2 cent/barrel is deposited into the Response Mitigation Account until the account reaches $50 million. After this, the 2-cent/barrel charge is suspended. The CS lowers this amount to one cent/barrel. The remaining 3-cent/barrel charge is deposited into Prevention Mitigation Account. The CS increases this to 4 cents/barrel, while dropping the Mitigation money to 1 cent/barrel, leaving the total sur-charge at 5 cents/barrel.

8. Effective date- CS changes the effective date of the bill from 1 July to 1 April, the start of the second calendar quarter. This will result in an almost immediate effective date and will gain the State over 200 million dollars in the current fiscal year.

9. Issues surrounding the $73 million allowance- The CS eliminates the 73 million annual dollar allowance, which resulted in a $14.6 million credit. Instead, the Committee implemented an annual direct tax credit, dollar for dollar, for the first $10 million worth of expenditures. The credit is annual, non-transferable, non salable and not eligible for carry forward. The credit can only be applied to the current year's severance tax. If there is no tax, the credit cannot be claimed. If a company has income but spends less than 10 million dollars, they can only claim credit up to amount that was spent.

10. Tax Credit Repurchase Program- To help protect explorers and new entrants to Alaska, the State will buy up to $10 million per year per company for credits at 100% of face value. Companies must show that an equivalent amount to the credit is being reinvested for exploration or lease purchases in Alaska.

11. Penalties on underpayment of less than 90% of monthly tax liability- The CS puts in place a 5% penalty for underpayment of the monthly severance tax bill for any amount below the 90% threshold. In addition, interest will be charged on any payment shortfall less than the full liability.

FOR VERSION (F)

CS for HB 488 (Res)
Suggested Inserts

March 14 2006

prepared by DAN DICKINSON and ROBERT MINTZ to Version 'F'

Insert 1 [*Sec 6 (page 4)]:

Alternatives:

Alternative 1: Restore previous language, with a single percentage applicable to all lessor royalty production.

The tax is equal to five percent of the gross value at the point of production of the oil and gas. However, if the department determines that, for purposes of reducing the producer's tax liability under this section, the producer has received or will receive consideration from the lessor offsetting all or a part of the producer's royalty obligation, the tax is equal to 20 percent of the gross value at the point of production of the oil and gas.

Alternative 2:

Except as otherwise provided under this subsection, the tax is equal to (1) five percent of the gross value at the point of production of the oil and gas for a lessor's royalty interest under an oil and gas lease that is in effect on the effective date of this section, or (2) seven and one-half percent of the gross value at the point of production of the oil and gas for a lessor's royalty interest under an oil and gas lease that takes effect after the effective date of this section. However, if the department determines that, for purposes of reducing a producer's tax liability under this section, the producer has received or will receive consideration from the lessor offsetting all or a part of the producer's royalty obligation, the tax is equal to 20 percent of the gross value at the point of production of the oil and gas.

Insert 2 [*Sec 6 (page 4)]:

(g) The oil price index for a month is the number equal to the average United States Gulf Coast price determined under (h) of this section for that month of West Texas Intermediate crude oil in dollars per barrel, less 50, except that, if the average price determined under (h) of this section is

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Insert 3 [*Sec 13 (page 7)]:

Alternative 1: Delete (h), because AS 43.05.220 already applies to any underpayment of tax, whether the underpayment is greater or less than 10 percent of what is due.

Alternative 2: If the intent is to provide a safe harbor from penalties under AS 43.55.220(a) or (b)(but not a safe harbor from interest) when a producer pays at least 90% of the tax levied under AS 43.55.011(a), change (h) to read as follows:

(h) Notwithstanding any contrary provision of AS 43.05.220, a producer that pays at least 90 percent of the tax levied under AS 43.55.011(a) when due is not liable for a penalty for underpayment of the tax under AS 43.55.220(a) **[or 43.55.220(b) or both, depending on the committee's preference]**.

Insert 4 [*Sec 14 (page 8)]:

(f) Under standards established in regulations adopted by the department and subject to appropriations enacted by law, the department, upon the written application of the person to whom a transferable tax credit certificate has been issued under (d) of this

section, will issue a cash refund in whole or in part for the certificate if the department finds that

(1) after investigation and audit by the department of the tax credit claim, the applicant is entitled to the credit to the extent of the refund amount;

(2) within 24 months after having applied for the transferable tax credit certificate, the applicant incurred a qualified capital expenditure or was the successful bidder on a bid submitted for a lease on state land under AS 38.05.180(f);

(3) the amount of the refund does not exceed the total of qualified capital expenditures and successful bids described in (2) of this subsection that have not been the subject of a comparison under this paragraph for purposes of a previous refund;

(4) the applicant has no outstanding liability to the state for unpaid delinquent taxes under this title; and

(5) the total amount refunded to the applicant during the calendar year under this subsection does not exceed $10,000,000.

Insert 5 [*Sec 18 (page 12)]:

(e) The person paying the tax levied under AS 43.55.011(a) shall file a statement...

Insert 6 [*Sec 24 (page 15)]:

Even if a producer produces no taxable oil or gas during a month, the producer is considered to have generated a positive production tax value if the calculation described

in this subsection yields a positive number because the producer's adjusted lease expenditures for a month are less than zero, as a result of the producer's receiving a payment or credit described in (e) of this section or otherwise. For purposes of this subsection, an explorer that previously took a tax credit under AS 43.55.024(b) or obtained a transferable tax credit certificate under AS 43.55.024(d) for the amount of a tax credit under AS 43.55.024(b) is considered a producer subject to the tax levied under AS 43.55.011(e) to the extent that the explorer generates a positive production tax value as the result of the explorer's receiving a payment or credit described in (e) of this section.

Insert 7 [*Sec 24 (page 17)]:

(A) an expenditure, when incurred, to acquire an item whose acquisition cost is otherwise a direct cost, notwithstanding that the expenditure may be required to be capitalized rather than expensed for financial accounting or federal income tax purposes;

Insert 8 [*Sec. 24 (page 20)]:

the drilling of a stratigraphic test well is considered geological exploration for an oil or gas deposit located within land in the state only if the well's target zones are located in the state.

Insert 9 [*Sec 24 (page 20)]:

Sec. 43.55.170. Additional nontransferable credit. (a) For a month for which a producer's tax liability under AS 43.55.011(a) exceeds zero before application of any credits under this chapter without regard to this section, a producer that is qualified under (b) of this section may apply a tax credit against that liability under this section. The tax credit authorized by this subsection may be calculated and applied so that

(1) the producer's tax liability under AS 43.55.011(a) before application of any credits under this chapter without regard to this section is not reduced below zero;

(2) the total of the tax credits applied under this subsection during a calendar year does not exceed $10,000,000; and

(3) the total of the tax credits applied under this subsection during calendar year 2016 does not exceed $2,500,000.

Insert 10 [*Sec. 24 (page 21)]:

(c) An unused tax credit or portion of a tax credit under this section is not transferable under AS 43.55.024(d) or refundable under AS 43.55.024(f) and may not be carried forward to or used in a later calendar year.

Insert 11 [*Sec. 24 (page 21)]:

(e) The use of a tax credit under this section does not bar the producer from taking a tax credit under AS 43.55.024(a) or AS 43.55.025 for the same qualified capital expenditure.

Insert 12 [*Sec 26 (page 21)]:

AS 43.55.201(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011 – 43.55.170** [AS 43.55.011 – 43.55.150]; and is in addition to the surcharge imposed by AS 43.55.300 – 43.55.310.

Insert 13 [*Sec 30 (page 22)]:

AS 43.55.300(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011 – 43.55.170** [AS 43.55.011 – 43.55.150]; and is in addition to the surcharge imposed by AS 43.55.201 – 43.55.231.

Insert 14 [*Sec. 39 (page 25)]

Additional transition provision in sec. 39:

(d) Notwithstanding any contrary provision of AS 43.55.170(a), enacted by sec. 24 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1,

2007, the amount "$10,000,000" in AS 43.55.170(a)(2), enacted by sec. 24 of this Act, shall be replaced by the amount "$7,500,000."

Insert 15 [*Sec 39 (page 25)]:

Additional transition provisions in sec. 39:

(f) Notwithstanding any contrary provision of AS 43.55.020(a), as repealed and reenacted by sec. 8 of this Act, or of AS 43.55.020(g), as enacted by sec. 13 of this Act, for oil and gas produced on or after April 1, 2006, and before the first day of the first month that begins at least 180 days after the effective date of this Act,

(1) the amount of the taxes that would have been levied upon the producer under AS 43.55, as that chapter existed on March 31, 2006, is due on the last day of each calendar month on oil and gas produced from each lease or property during the preceding month;

(2) the portion, if any, of the taxes levied under AS 43.55.011(a), as repealed and reenacted by sec. 5 of this Act, and under AS 43.55.011(e) and (f), as enacted by sec. 6 of this Act, that remains unpaid, net of any credits applied as allowed by law, is due on the last day of the second month that begins at last 180 days after the effective date of this Act.

(g) Notwithstanding any contrary provision of AS 43.55.030(a), as amended by sec. 16 of this Act, for oil and gas produced on or after April 1, 2006, and before the first day of the first month that begins at least 180 days after the effective date of this Act, the person paying the tax shall file with the department

(1) at the time an amount of tax is due under (f)(1) of this section, the statement required under AS 43.55.030(a), as that provision existed on March 31, 2006;

(2) at the time an amount of tax is due under (f)(2) of this section, the statement required under AS 43.55.030(e), added by sec. 18 of this Act.

(h) For purposes of taxes to be calculated and due under (f)(1) of this section, and statements to be filed under (g)(1) of this section, regulations that were adopted by the Department of Revenue under AS 43.55, as that chapter existed on March 31, 2006, and that were in effect on the day before the effective date of this Act, apply to those taxes and statements.

This version not released to the H. RES committee

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Chenoweth
3/14/06

Marking by DAN DICKINSON and ROBERT MINTZ.

CS FOR HOUSE BILL NO. 488(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FOURTH LEGISLATURE - SECOND SESSION

BY THE HOUSE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

"An Act repealing the oil production tax and gas production tax and providing for a production tax on oil and gas; relating to the relationship of that tax to other taxes, to the dates those tax payments and surcharges are due, to interest on overpayments of the tax, and to the treatment of the tax in a producer's settlement with the royalty owners; relating to flared gas, and to oil and gas used in the operation of a lease or property under the production tax; relating to the prevailing value of oil or gas under the production tax; providing for tax credits against the tax for certain expenditures, losses, and ~~surcharges~~; amending the rates applicable to each of the two tax surcharges imposed on oil under the production tax that are used to support the oil and hazardous substance release prevention and response fund and relating to those surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, for

the tax; relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, as applicable to the administration of the tax; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the tax, and to the deposit of tax money collected by the Department of Revenue; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the production tax value of oil and gas for purposes of a tax on the production tax value of oil and gas; relating to the definitions of 'gas,' 'oil,' and certain other terms for purposes of the production tax, ~~and as the definition of the term 'gas' applies in the Alaska Stranded Gas Development Act~~; making conforming amendments; making uniform throughout the state the deadline for certain exploration expenditures used as credits against the production tax on oil and gas produced from a lease or property in the state by extending to July 1, 2010, the deadline for those expenditures on leases or properties located north of 68 degrees, 15 minutes, North latitude; and providing for an effective date."

ask Chris.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. The uncodified law of the State of Alaska is amended by adding a new section to read:

INTENT OF SEC. 12 OF THIS ACT. It is the intent of the legislature through sec. 12 of this Act to confirm by clarification the long-standing interpretation of AS 43.55.020(f) by the Department of Revenue.

* Sec. 2. AS 43.05.230(f) is amended to read:

(f) A wilful violation of the provisions of this section **or of a condition imposed under AS 43.55.040(1)(B)** is punishable by a fine of not more than $5,000, or by imprisonment for not more than two years, or by both.

* Sec. 3. AS 43.20.031(c) is amended to read:

(c) In computing the tax under this chapter, the taxpayer is not entitled to deduct any taxes based on or measured by net income. **The taxpayer may deduct the tax levied and paid under AS 43.55.**

* Sec. 4. AS 43.20.072(b) is amended to read:

(b) A taxpayer's business income to be apportioned under this section to the state shall be the federal taxable income of the taxpayer's consolidated business for the tax period, except that

(1) taxes based on or measured by net income that are deducted in the determination of the federal taxable income shall be added back; **the tax levied and paid under AS 43.55 may not be added back;**

(2) intangible drilling and development costs that are deducted as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) in the determination of the federal taxable income shall be capitalized and depreciated as if the option to treat them as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) had not been exercised;

(3) depletion deducted on the percentage depletion basis under 26 U.S.C. 613 (Internal Revenue Code) in the determination of the federal taxable income shall be recomputed and deducted on the cost depletion basis under 26 U.S.C. 612 (Internal Revenue Code); and

(4) depreciation shall be computed on the basis of 26 U.S.C. 167 (Internal Revenue Code) as that section read on June 30, 1981.

* Sec. 5. AS 43.55.011(a) is repealed and reenacted to read:

(a) There is levied on the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state less any oil and gas the ownership or right to which is exempt from taxation or constitutes a lessor's royalty interest under an oil and gas lease. The tax is equal to 20 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160.

* Sec. 6. AS 43.55.011 is amended by adding new subsections to read:

(e) There is levied on the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state the ownership or right to which constitutes a lessor's royalty interest under an oil and gas lease, except for oil

and gas the ownership or right to which is exempt from taxation. For purposes of this subsection, for a lessor's royalty interest under an oil and gas lease

(1) that is in effect on the effective date of this section, the tax levied on the oil and gas is equal to five percent of the gross value at the point of production of the oil and gas; however, if the department determines that, for purposes of reducing the producer's tax liability under this paragraph, the producer has received or will receive consideration from the lessor offsetting all or a part of the producer's royalty obligation, the tax under this subsection is equal to 20 percent of the gross value at the point of production of the oil and gas; and

(2) other than an interest described in (1) of this subsection, the tax levied on the oil and gas is equal to a rate to be determined by the commissioner based on the gross value at the point of production.

(f) In addition to the taxes levied under (a) and (e) of this section, for each month for which the oil price index determined under (g) of this section is greater than zero, there is levied upon the producer of oil or gas a tax for oil and gas produced during that month from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation. The tax is equal to .30 percent multiplied by the oil price index as determined under (g) of this section.

(g) The oil price index for a month is the average United States Gulf Coast price for that month of West Texas Intermediate crude oil in dollars per barrel, less $50, except that, if the average price determined under this subsection is

(1) not more than $50 per barrel, the oil price index is zero; and

(2) more than $150 per barrel, the oil price index is 100.

(h) For purposes of (f) and (g) of this section, the department may calculate the average price or may, by regulation, specify the method by which the average price shall be calculated with reference to one or more published sources of price information. If, in the department's judgment, reliable published sources of price information on West Texas Intermediate crude oil cease, or appear likely to soon cease, to be available, or if, in the department's judgment, the price of West Texas Intermediate crude oil ceases, or appears likely to soon cease, to be a reliable indicator of the general price level of crude oils, the department shall, by regulation, specify a

Insert 1
alternative (1) or 2

of the gross value at the point of production of the oil and gas

Insert 2

substitute formula for computing the oil price index. The substitute formula specified by the department under this subsection must bear, as nearly as is reasonably possible, the same relationship to the general price level of crude oils as did the United States Gulf Coast price of West Texas Intermediate crude oil.

* Sec. 7. AS 43.55.017(a) is amended to read:

(a) Except as provided in this chapter, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax **on** [UPON]

(1) producing oil or gas leases;

(2) oil or gas produced or extracted in the state;

(3) the value of intangible drilling and **development costs, as described in 26 U.S.C. 263(c) (Internal Revenue Code), as amended through January 1, 1974** [EXPLORATION EXPENSES].

* Sec. 8. AS 43.55.020(a) is repealed and reenacted to read:

(a) The tax levied under AS 43.55.011(a) shall be paid ~~as set out in this subsection~~ Monthly. The tax, net of any credits applied under this chapter, is due on the last day of each calendar month on oil and gas produced from each lease or property during the preceding month. An unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent. An overpayment of tax for a month may be applied against the tax due for a later month. Notwithstanding any contrary provision of AS 43.05.280, interest on an overpayment is allowed only from a date that is 90 days after the statement required under AS 43.55.030(e) to be filed on or before March 31 of the year following the calendar year during which the oil and gas were produced is filed. However, interest is not allowed if the overpayment was refunded within the 90-day period.

* Sec. 9. AS 43.55.020(b) is amended to read:

(b) The production tax on oil **and** [OR] gas shall be paid by or on behalf of the producer.

* Sec. 10. AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner **for oil or gas that is taxable under AS 43.55.011,** the producer may deduct the amount of the tax paid on **taxable**

royalty oil and [OR] gas, or may deduct taxable royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under AS 43.55.011 on taxable royalty oil and gas for a month other than oil or gas the ownership or right to which constitutes a lessor's royalty interest under an oil or gas lease is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the month multiplied by a figure that is a quotient, in which

(1) the numerator is the producer's total tax liability under AS 43.55.011(a) for the month of production; and

(2) the denominator is the total gross value at the point of production of the oil and gas taxable under AS 43.55.011(a) produced by the producer from all leases and properties in the state during the month.

* Sec. 11. AS 43.55.020(e) is repealed and reenacted to read:

(e) Gas flared, released, or allowed to escape in excess of the amount authorized by the Alaska Oil and Gas Conservation Commission is considered, for the purpose of AS 43.55.011 - 43.55.170, as gas produced from a lease or property. Oil or gas used in the operation of a lease or property in the state in drilling for or producing oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and Gas Conservation Commission to be waste, is not considered, for the purpose of AS 43.55.011 - 43.55.170, as oil or gas produced from a lease or property.

* Sec. 12. AS 43.55.020(f) is amended to read:

(f) If oil or gas is not sold, or if oil or gas is sold under circumstances where the sale price does not represent the prevailing value for oil or gas of like kind, character, or quality in the field or area from which the product is produced, the department may require the tax to be paid upon the basis of the value of oil or gas of the same kind, quality, and character prevailing during the calendar month of production for that field or area.

* Sec. 13. AS 43.55.020 is amended by adding new subsections to read:

(g) The tax levied under AS 43.55.011(e) and (f) shall be paid monthly and is due on the last day of each calendar month on oil and gas produced from each lease or

property during the preceding month, and, if not paid before the end of the month in which it becomes due, the tax becomes delinquent.

~~(h) The penalty provisions of AS 43.05.220 apply to a producer who fails to pay at least 90 percent of the tax when due under (e) or (g) of this section.~~

Insert 3

Alternative 1 of 2 - need 3rd alt. - Rob

* Sec. 14. AS 43.55 is amended by adding a new section to read:

Sec. 43.55.024. Tax credits for certain losses and expenditures. (a) Notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the production tax value of oil and gas under AS 43.55.160(a), a producer or explorer that incurs a qualified capital expenditure may also elect to take a tax credit in the amount of 20 percent of that expenditure, unless a credit for that expenditure is taken under AS 43.55.025. A credit under this subsection may be applied only against a tax due under AS 43.55.011(a). For a calendar year for which the producer makes an election under AS 43.55.160(f), instead of taking a tax credit of 20 percent of each separate qualified capital expenditure after it has been incurred, a producer that incurs a qualified capital expenditure during that year and that wishes to apply a credit based on that expenditure against a tax due under AS 43.55.011(a) shall calculate and apply every month an annualized tax credit in an amount equal to one and two-thirds percent of the total qualified capital expenditures incurred during that year and for which the tax credit is taken for that year.

(b) A producer or explorer may elect to take a tax credit in the amount of 20 percent of a carried-forward annual loss. A credit under this subsection may be applied only against a tax due under AS 43.55.011(a). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's or explorer's adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b).

(c) A credit or portion of a credit under this section may not be used to reduce a person's tax liability under AS 43.55.011(a) for any month below zero, and any unused credit or portion of a credit not used under this subsection may be applied in a later month.

(d) A person entitled to take a tax credit under this section that wishes to

or to request a refund under (F) of this section

transfer the unused credit to another person may apply to the department for a transferable tax credit certificate. An application under this subsection must be on a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 60 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) if the applicant is required under AS 43.55.030(~~a~~)and (e) to file a statement on or before March 31 of the year following the calendar year in which the qualified capital expenditures or carried-forward annual loss for which the credit was incurred, the date the statement was filed; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

(e) A person to which a transferable tax credit certificate is issued under (d) of this section may transfer the certificate to another person, and a transferee may further transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and notwithstanding any action the department may take with respect to the applicant under (g) of this section, the owner of a certificate may apply the credit or a portion of the credit shown on the certificate only against a tax due under AS 43.55.011(a). However, a credit shown on a transferable tax credit certificate may not be applied to reduce a ~~producer's~~ transferee's total tax due under AS 43.55.011(a) on oil and gas produced during a calendar year to less than 80 percent of the tax that would otherwise be due without applying that credit, and any portion of a credit not used under this subsection may be applied in a later period.

~~(f) Under standards established in regulations adopted by the department, the commissioner may repurchase a transferable tax credit certificate issued under (d) of this section if~~ "WILL"

~~(1) within 24 months after the date of issuance of the tax credit~~

Insert 4

certificate, the person to whom the certificate was issued or any transferee of the certificate makes a qualified capital expenditure in this state or is the successful bidder on a bid submitted for a lease on state land under AS 38.05.180(f); and

(2) the expenditure made or bid submitted under (1) of this subsection is not less than the amount of the transferable tax credit certificate issued under (d) of this section.

(g) The issuance of a transferable tax credit certificate under (d) of this section does not limit the department's ability to later investigate or audit a tax credit claim to which the certificate relates or to adjust or deny the claim if the department determines that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011 - 43.55.170 is increased by the amount of the credit that exceeds that to which the applicant was entitled. That amount bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, an applicant that is an explorer is considered a producer subject to the tax levied under AS 43.55.011.

(h) The department may adopt regulations to carry out the purposes of this section, including prescribing reporting, record keeping, and certification procedures and requirements to verify the accuracy of credits claimed and to ensure that a credit is not used more than once, and otherwise implementing this section.

(i) A producer or explorer may not elect to take a tax credit under this section for a lease expenditure under AS 43.55.160 that is an expenditure incurred

(1) to acquire an asset (A) the cost of previously acquiring which was a lease expenditure under AS 43.55.160(c) or would have been a lease expenditure under AS 43.55.160(c) if it had been incurred on or after April 1, 2006; or (B) that has previously been placed in service in the state; an expenditure to acquire an asset is not excluded under this paragraph if not more than an immaterial portion of the asset meets a description under (A) or (B) of this paragraph; for purposes of this paragraph, "asset" includes geological, geophysical, and well data and interpretations; or

(2) for an extended period of disuse, dismantlement, removal, surrender, or abandonment of a well, facility, pipeline, platform, or other structure, or for the restoration of a lease, field, unit, area, or body of water in conjunction with an

extended period of disuse, dismantlement, removal, surrender, or abandonment of a facility described in this paragraph.

(j) In this section,

(1) "explorer" has the meaning given in AS 43.55.025;

(2) "qualified capital expenditure" means, except as otherwise provided in (i) of this section, an expenditure that is a lease expenditure under AS 43.55.160 and is

(A) incurred for geological or geophysical exploration; or

(B) treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and either is treated as a capitalized expenditure by the person incurring the expenditure or is eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal Revenue Code), as amended.

Consider def of explorer in 43.55.900 delete here and in 43.55.025(11)

* Sec. 15. AS 43.55.025(b) is amended to read:

(b) To qualify for the production tax credit under (a) of this section, an exploration expenditure must be incurred for work performed on or after July 1, 2003, and before July 1, 2016 [2007], except that an exploration expenditure for a Cook Inlet prospect must be incurred for work performed on or after July 1, 2005, [AND BEFORE JULY 1, 2010, AND EXCEPT THAT AN EXPLORATION EXPENDITURE, IN WHOLE OR IN PART, SOUTH OF 68 DEGREES, 15 MINUTES, NORTH LATITUDE, AND NOT PART OF A COOK INLET PROSPECT MUST BE INCURRED FOR WORK PERFORMED ON OR AFTER JULY 1, 2003, AND BEFORE JULY 1, 2010,] and

2016

Covers Nenana Basin w/o reference

(1) may be for seismic or geophysical exploration costs not connected with a specific well;

(2) if for an exploration well,

(A) must be incurred by an explorer that holds an interest in the exploration well for which the production tax credit is claimed;

(B) may be for either an oil or gas discovery well or a dry hole; and

(C) must be for goods, services, or rentals of personal property reasonably required for the surface preparation, drilling, casing, cementing, and logging of an exploration well, and, in the case of a dry hole, for the expenses required for abandonment if the well is abandoned within 18 months after the date the well was spudded;

(3) may not be for testing, stimulation, or completion costs; administration, supervision, engineering, or lease operating costs; geological or management costs; community relations or environmental costs; bonuses, taxes, or other payments to governments related to the well; or other costs that are generally recognized as indirect costs or financing costs; and

(4) may not be incurred for an exploration well or seismic exploration that is included in a plan of exploration or a plan of development for any unit on May 13, 2003.

* Sec. 16. AS 43.55.030(a) is amended to read:

(a) The tax shall be paid to the department and the person paying the tax shall file with the department at the time the tax ~~or a portion of the tax~~ is required to be paid a statement, under oath, on forms prescribed by or acceptable to the department, giving, with other information required, the following:

(1) a description of **each** [THE] lease or property from which the oil **and** [OR] gas **were** [WAS] produced, by name, legal description, lease number, or [BY] accounting **codes** [CODE NUMBERS] assigned by the department;

(2) the names of the producer and the person paying the tax;

(3) the gross amount of oil **and the gross amount of** [OR] gas produced from **each** [THE] lease or property, and the percentage of the gross amount **of oil and gas** owned by each producer for whom the tax is paid;

(4) the **gross** [TOTAL] value **at the point of production** of the oil **and of the** [OR] gas produced from **each** [THE] lease or property owned by each producer for whom the tax is paid; [AND]

(5) the name of the first purchaser and the price received for the oil **and for the** [OR] gas, **unless relieved from this requirement in whole or in part by the department; and**

N/A anymore

(6) the producer's lease expenditures and adjustments as calculated under AS 43.55.160 [IF SOLD IN THE STATE].

* Sec. 17. AS 43.55.030(d) is amended to read:

(d) Reports by or on behalf of the producer are delinquent the first day following the day the tax is due. ~~The provisions of AS 43.05.220 apply to reports that are not timely filed under this section.~~ [EACH PRODUCER IS SUBJECT TO A PENALTY OF $25 A DAY FOR EACH LEASE OR PROPERTY UPON WHICH THE REPORT IS NOT FILED.] ~~The penalty for failure to file a report is in addition to the penalty for delinquent taxes, and is a lien against the assets of the producer.~~

* Sec. 18. AS 43.55.030 is amended by adding a new subsection to read:

~~(e) In addition to other required information, the statement required to be filed~~ on or before March 31 of a year ~~must show~~ showing any adjustments or corrections to the statements that were required under (a) of this section to be filed for the months of the preceding calendar year during which the oil or gas was produced.

Insert 5

OK

* Sec. 19. AS 43.55.040 is amended to read:

Sec. 43.55.040. Powers of Department of Revenue. Except as provided in AS 43.05.405 - 43.05.499, the department may

(1) require a person engaged in production and the agent or employee of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil or gas to furnish, **whether by the filing of regular statements or reports or otherwise,** additional information that is considered by the department as necessary to compute the amount of the tax; **notwithstanding any contrary provision of law, the disclosure of additional information under this paragraph to the producer obligated to pay the tax does not violate AS 40.25.100(a) or AS 43.05.230(a); before disclosing information under this paragraph that is otherwise required to be held confidential under AS 40.25.100(a) or AS 43.05.230(a), the department shall**

(A) provide the person that furnished the information a reasonable opportunity to be heard regarding the proposed disclosure and the conditions to be imposed under (B) of this paragraph; and

(B) impose appropriate conditions limiting

(i) access to the information to those legal counsel, consultants, employees, officers, and agents of the producer who have a need to know that information for the purpose of determining or contesting the producer's tax obligation; and

(ii) the use of the information to use for the purpose of determining or contesting the producer's tax obligation;

(2) examine the books, records, and files of such a person;

(3) conduct hearings and compel the attendance of witnesses and the production of books, records, and papers of any person; and

(4) make an investigation or hold an inquiry that is considered necessary to a disclosure of the facts as to

(A) the amount of production from any oil or gas location, or of a company or other producer of oil or gas; and

(B) the rendition of the oil and gas for taxing purposes.

* Sec. 20. AS 43.55.080 is amended to read:

Sec. 43.55.080. Collection and deposit of revenue. Except as otherwise provided under art. IX, sec. 17, Constitution of the State of Alaska, the [THE] department shall deposit in the general fund the money collected by it under AS 43.55.011 - 43.55.170 [AS 43.55.011 - 43.55.150].

* Sec. 21. AS 43.55.135 is amended to read:

Sec. 43.55.135. Measurement. For the purposes of AS 43.55.011 - 43.55.170 [AS 43.55.011 - 43.55.150], oil is [SHALL BE] measured in terms of a "barrel of oil" and gas is [SHALL BE] measured in terms of a "cubic foot of gas."

* Sec. 22. AS 43.55.150(a) is amended to read:

(a) For the purposes of AS 43.55.011 - 43.55.170 [AS 43.55.011 - 43.55.150], the gross value at the point of production is [SHALL BE] calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation are [SHALL BE] the actual costs, except when the

(1) [WHEN THE] parties to the transportation of oil or gas are affiliated;

(2) [WHEN THE] contract for the transportation of oil or gas is not an

arm's length transaction or is not representative of the market value of that transportation;

(3) [WHEN THE] method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

* **Sec. 23.** AS 43.55.150 is amended by adding a new subsection to read:

(d) Under regulations adopted by the department, the department may allow a producer, subject to limitations prescribed by the department as to the frequency of making elections, to elect prospectively to calculate the gross value at the point of production of oil or gas based in whole or part on

(1) a royalty value determined under a royalty settlement agreement between the producer and the state, with adjustments if appropriate;

(2) a formula prescribed by the department that uses, with adjustments if appropriate, a royalty value or valuation methodology accepted by the

(A) Department of Natural Resources under AS 38.05, in the case of oil and gas produced from a lease issued by the Department of Natural Resources or produced from a lease or property that is part of a unit approved by the Department of Natural Resources; or

(B) United States Department of the Interior under applicable federal oil and gas leasing statutes, in the case of oil and gas produced from a lease issued by the United States Department of the Interior that is not part of a unit approved by the Department of Natural Resources, or produced from a lease or property that is part of a unit approved by the United States Department of the Interior but not approved by the Department of Natural Resources; or

(3) another formula prescribed by the Department of Revenue that reasonably estimates a value for the oil or gas at a specific geographical location, such as the point of tender or delivery into a common carrier pipeline; the formula may use factors such as published price indices for oil or gas in or outside the state, quality differentials for oil or gas, transportation costs between markets, and inflation adjustments.

* **Sec. 24.** AS 43.55 is amended by adding new sections to article 1 to read:

Sec. 43.55.160. Determination of production tax value of oil and gas. (a) Except as provided in (f) of this section, for purposes of AS 43.55.011(a), the production tax value of the taxable oil and gas produced during a month is the total of the gross value at the point of production of the oil and gas taxable under AS 43.55.011(a) and produced by the producer from all leases or properties in the state, (1) less the producer's tax paid for the month under AS 43.55.011(f); (2) less the producer's lease expenditures for the month as adjusted under (e) of this section, and (3) to the extent allowed under (g) of this section and until the total amount of the producer's transitional investment expenditures has been deducted, less an amount equal to 1/84 of the producer's transitional investment expenditures. However, the production tax value calculated under this subsection may not be less than zero.

clarifies deductibility p4, l 6 ; insert #6

(b) For purposes of administration of (a) of this section,

(1) any adjusted lease expenditures that would otherwise be deductible in a month but whose deduction would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero may be added to the producer's adjusted lease expenditures for one or more other months in the same calendar year; the total of any adjusted lease expenditures that are not deductible in any month during a calendar year because their deduction would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during one or more months to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.024(b);

(2) an amount of transitional investment expenditures that would otherwise be deductible in a month but whose deduction would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero

(A) may be deducted in a later month during any calendar year to the extent allowed under (g) of this section, but not more than 1/84 of a producer's transitional investment expenditures may be deducted in any month;

(B) may not be used to establish a carried-forward annual loss under AS 43.55.024(b).

(c) For purposes of this section,

(1) a producer's lease expenditures for a period are the total costs upstream of the point of production of oil and gas that are incurred on or after April 1, 2006, by the producer during the period and that are direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas ~~from~~ deposits located within the producer's leases or properties in the state or, in the case of land in which the producer does not own a working interest, direct, ordinary, and necessary costs of exploring for oil or gas deposits located within other land in the state; however, lease expenditures do not include the costs incurred to satisfy a work commitment under an exploration license under AS 38.05.132; in determining whether costs are direct, ordinary, and necessary costs of exploring for, developing, or producing an oil or gas ~~from a~~ deposit ~~of oil or gas~~ located within a lease or property or other land in the state, the department shall give substantial weight to

(A) the typical industry practices and standards in the state and in the United States as to costs that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, not the operator, with substantial bargaining power; and

(B) the standards adopted by the Department of Natural Resources as to the costs, other than interest, that a lessee is allowed to deduct from revenue in calculating net profits under a lease issued under AS 38.05.180(f)(3)(B), (D), or (E);

(2) the Department of Revenue may authorize a producer, including ~~the operator or a working interest owner~~ a producer that is the operator, to treat as its lease expenditures under this section the costs paid by the producer that are billed to the producer by an operator in accordance with the terms of a unit operating agreement or similar operating agreement if the Department of Revenue finds that

(A) the pertinent provisions of the operating agreement are substantially consistent with the Department of Revenue's determinations and standards otherwise applicable under this subsection; and

(B) at least one working interest owner party to the agreement,

other than the operator, has substantial incentive and ability to effectively audit billings under the agreement.

(d) For purposes of (c) of this section, "direct costs"

(1) includes

~~(A) outlays for capital assets;~~

(B) payments of property taxes, sales and use taxes, motor fuel taxes, and excise taxes;

(C) a reasonable allowance, as determined under regulations adopted by the department, for overhead expenses directly related to exploring for, developing, and producing oil or gas deposits located within leases or properties or other land in the state;

(2) does not include

(A) depreciation or amortization ~~of capital assets;~~

(B) royalty payments for oil and gas;

(C) taxes based on or measured by net income;

(D) interest or other financing charges or costs of raising equity or debt capital;

(E) acquisition costs for a lease or property or exploration license;

(F) costs arising from fraud, wilful misconduct, or negligence;

(G) fines or penalties imposed by law;

(H) costs of arbitration, litigation, or other dispute resolution activities that involve the state or concern the rights or obligations among owners of interests in, or rights to production from, one or more leases or properties or a unit;

(I) donations;

(J) costs incurred in organizing a partnership, joint venture, or other business entity or arrangement;

(K) amounts paid to indemnify the state; the exclusion provided by this paragraph does not apply to the costs of obtaining insurance or a surety bond from a third-party insurer or surety;

(wait)
Insert 7
?or in lieu of"

(L) surcharges levied under AS 43.55.201 or 43.55.300.

(e) A producer's lease expenditures must be adjusted by subtracting any payment or credit the producer receives for

(1) the use by another person of a production facility in which the producer has an ownership interest;

(2) a reimbursement or similar payment that offsets the producer's lease expenditures, including a payment from the state or federal government for reimbursement of the producer's upstream costs, including costs for gathering, separating, cleaning, dehydration, compressing, or other field handling associated with the production of oil or gas upstream of the point of production;

(3) the sale or other transfer of

(A) an asset, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of a lease expenditure or an expenditure that would be a lease expenditure if it were incurred on or after April 1, 2006; and

(B) oil or gas

(i) that is not considered produced from a lease or property under AS 43.55.020(e); and

(ii) the cost of acquiring which is a lease expenditure incurred by the person that acquires the oil or gas.

(f) In place of the adjusted lease expenditures for a month under (a) of this section, a producer may, at any time, elect to substitute, for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year.

(g) For the purposes of this section,

(1) a producer's transitional investment expenditures are the sum of the expenditures the producer incurred on or after January 1, 2003, and before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, less the sum of the payments or credits the producer received before April 1, 2006, for the sale or other transfer of assets, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of expenditures the producer incurred ~~on or after January 1, 2003~~

and before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, multiplied by

(A) 25 percent for expenditures incurred on or after January 1, 2003, and before January 1, 2004;

(B) 50 percent for expenditures incurred on or after January 1, 2004, and before January 1, 2005; and

(C) 75 percent for expenditures incurred on or after January 1, 2005, and before April 1, 2006;

(2) notwithstanding (1) of this subsection, an amount of transitional investment expenditures may not be deducted under (a) of this section for a month for which the average price of Alaska North Slope oil delivered on the United States West Coast, as determined under (h) of this section, is equal to or less than $40 a barrel, as adjusted for inflation under (h) of this section.

(h) The average price described in (g) of this section shall be an average, as calculated using a formula prescribed by the department by regulation, of published daily spot price assessments during the month for Alaska North Slope oil delivered on the United States West Coast. However, if the department determines that the daily assessments cease to be published throughout the calendar year or appear likely to soon cease to be published throughout the calendar year or that they cease to be reliable evidence of market conditions or appear likely to soon cease to be reliable evidence of market conditions, the department shall by regulation provide that the average price described in (g) of this section is the prevailing value of Alaska North Slope oil delivered on the United States West Coast as determined under regulations of the department implementing AS 43.55.020(f). For each year after 2006, the department shall adjust the reference price of $40 a barrel set out in (g) of this section for inflation. The dollar amount in (g) of this section changes according to and to the extent of changes in the Consumer Price Index for all urban consumers for the Anchorage Metropolitan Area compiled by the Bureau of Labor Statistics, United States Department of Labor (the index). The index for January of 2006 is the reference base index. If the index is revised, the percentage of change is calculated based on the revised index. If a revision of the index changes the reference base index, a revised

reference base index is determined by multiplying the reference base index applicable by the rebasing factor furnished by the United States Bureau of Labor Statistics. If the index is superseded, the index referred to in this section is the one represented by the United States Bureau of Labor Statistics as reflecting most accurately changes in the purchasing power of the dollar for Alaska consumers.

(i) The department shall specify or approve a reasonable allocation method for determining the portion of a cost that is appropriately treated as a lease expenditure under (c) of this section if a cost that would otherwise constitute a lease expenditure under (c) of this section is incurred to explore for, develop, or produce

(1) both an oil or gas deposit located within land outside the state and an oil or gas deposit located within a lease or property, or other land, in the state; or

(2) an oil or gas deposit located partly within land outside the state and partly within a lease or property, or other land, in the state.

(j) The department may adopt regulations that establish additional standards necessary to carrying out the purposes of this section.

(k) For purposes of AS 43.55.024(a) and (b) and only as to expenditures incurred to explore for an oil or gas deposit located within land in which an explorer, ~~as defined in AS 43.55.025,~~ does not own a working interest, the term "producer" in (b), (c) and (e) of this section includes "explorer."

(l) For purposes of this section,

(1) "explore" includes conducting geological or geophysical exploration, including drilling a stratigraphic test well;

(2) "ordinary and necessary" has the meaning given "ordinary and necessary" in 26 U.S.C. 162 (Internal Revenue Code) and regulations adopted under that section;

(3) "stratigraphic test well" means a well drilled for the sole purpose of obtaining geological information to aid in exploring for an oil or gas deposit and the target zones of which are located in the state, ~~the~~

Need def of exploration if not in AS 43.55.900

Insert 8

~~Sec. 43.55.170. Additional nontransferable credit. (a) For a month for which the net value of the taxable oil and gas produced during the month calculated under AS 43.55.160 exceeds zero, a producer that is qualified under (b) of this section may~~

Insert 9

reduce the net value by applying a tax credit for a qualified capital expenditure, as that term is defined in AS 43.55.024, if the qualified capital expenditure involved a payment made in this state and the claim of the credit is not taken under AS 43.55.024 or 43.55.025. The credit authorized by this subsection may be calculated and applied so that

(1) the net value for the month is not reduced below zero; and

(2) the total of the credits applied during the calendar year does not exceed $10,000,000.

(o) On written application by a producer, including any information the department may require, the department shall determine whether the producer qualifies under this section for a calendar year. To qualify under this section, a producer must demonstrate that its operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer entity would not result in the division among multiple producer entities of any ~~net value of taxable oil and gas, as determined~~ production tax liability under AS 43.55.~~160~~011(a), that would be reasonably expected to be attributed to a single producer entity if the ~~allowance~~ tax credit provision of (a) of this section did not exist.

~~(c) An unused allowance or portion of an allowance under this section is not transferable under AS 43.55.024(d), may not be carried forward to a later calendar year, and may not be used to establish a carried-forward annual loss under AS 43.55.024(b).~~

(d) A producer may not claim a credit under this section for a qualified capital expenditure incurred after March 31, 2016.

Insert 10

Insert 11

* Sec. 25. AS 43.55.201(a) is amended to read:

(a) Every producer of oil shall pay a surcharge of $.01 [$.02] per barrel of oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation.

~~* Sec. 26.~~ AS 43.55.201(b) is ~~amended~~ to read:

Insert 12

(b) The ~~surcharge~~ imposed by (a) of this section is in addition to the tax imposed by AS 43.55.011 and shall be paid in the [SAME] manner described in AS 43.55.020. ~~The surcharge~~ [AS THE TAX IMPOSED BY AS 43.55.011 -

~~43.55.150; AND] is in addition to the surcharge imposed~~ AS 43.55.300 - ~~43.55.310.~~

* Sec. 27. AS 43.55.201(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

* Sec. 28. AS 43.55.201 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

* Sec. 29. AS 43.55.300(a) is amended to read:

(a) Every producer of oil shall pay a surcharge of **$.04** [$.03] per barrel of oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation.

~~* Sec. 30. AS 43.55.300(b) is amended to read:~~

~~(b) The surcharge imposed by (a) of this section is in addition to~~ **the tax imposed by AS 43.55.011** and shall ~~be paid in the~~ [SAME] manner **described in AS 43.55.020. The surcharge** ~~[AS THE TAX IMPOSED BY AS 43.55.011 - 43.55.150; AND]~~ is in addition to the surcharge imposed by ~~AS 43.55.201 - 43.55.231.~~

Insert 13

* Sec. 31. AS 43.55.300(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

* Sec. 32. AS 43.55.300 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

* Sec. 33. AS 43.55.900(6) is repealed and reenacted to read:

(6) "gas" means

(A) all natural, associated, or casinghead gas;

(B) all hydrocarbons that

(i) are recovered by mechanical separation of well fluids or by gas processing; and

(ii) exist in a gaseous phase at the completion of mechanical separation and any gas processing; and

(C) all other hydrocarbons produced from a well not defined as oil;

* Sec. 34. AS 43.55.900(7) is repealed and reenacted to read:

(7) "gross value at the point of production" means

(A) for oil, the value of the oil at the automatic custody transfer meter or device through which the oil enters into the facilities of a carrier pipeline or other transportation carrier in a condition of pipeline quality; in the absence of an automatic custody transfer meter or device, "gross value at the point of production" means the value of the oil at the mechanism or device to measure the quantity of oil that has been approved by the department for that purpose, through which the oil is tendered and accepted in a condition of pipeline quality into the facilities of a carrier pipeline or other transportation carrier or into a field topping plant;

(B) for gas, other than gas described in (C) of this paragraph, that is

(i) not subjected to or recovered by mechanical separation or gas processing, the value of the gas at the first point where the gas is accurately metered;

(ii) subjected to or recovered by mechanical separation but not gas processing, the value of the gas at the first point where the gas is accurately metered after completion of mechanical separation;

(iii) subjected to or recovered by gas processing, the value of the gas at the first point where the gas is accurately metered after completion of gas processing;

(C) for gas run through an integrated gas processing and gas treatment facility that does not accurately meter the gas after the gas

processing and before the gas treatment, the value of the gas at the first point where gas processing is completed or where gas treatment begins, whichever is further upstream;

* Sec. 35. AS 43.55.900(10) is repealed and reenacted to read:

(10) "oil" means

(A) crude petroleum oil; and

(B) all liquid hydrocarbons that are recovered by mechanical separation of well fluids or by gas processing;

* Sec. 36. AS 43.55.900 is amended by adding new paragraphs to read:

(17) "gas processing"

(A) means processing a gaseous mixture of hydrocarbons

(i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation;

(ii) for the purpose of extracting and recovering liquid hydrocarbons; and

(iii) upstream of any gas treatment and upstream of the inlet of any gas pipeline system transporting gas to a market;

(B) does not include gas treatment;

(18) "gas treatment"

(A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system; and

(B) includes incidentally removing liquid hydrocarbons from the gas.

* Sec. 37. AS 43.55.011(b), 43.55.011(c), 43.55.012(b), 43.55.013, 43.55.016, 43.55.900(1), 43.55.900(8), 43.55.900(11), 43.55.900(12), and 43.55.900(16) are repealed.

* Sec. 38. The uncodified law of the State of Alaska is amended by adding a new section to read:

APPLICABILITY. (a) Sections 5, 6, 8 - 11, 13, 14, 16 - 18, and 20 - 37 of this Act

apply to oil and gas produced on or after April 1, 2006.

(b) Section 12 of this Act applies to oil and gas produced before, on, or after the effective date of sec. 12 of this Act.

* **Sec. 39.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITIONAL PROVISIONS. (a) Notwithstanding any contrary provision of AS 43.55.024(a), enacted by sec. 14 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "every month an annualized tax credit in an amount equal to one and two-thirds percent" in AS 43.55.024(a), enacted by sec. 14 of this Act, shall be replaced by the phrase "every month during the period April 1, 2006, through December 31, 2006, an annualized tax credit in an amount equal to 2.222 percent."

(b) Notwithstanding any contrary provision of AS 43.55.024(e), enacted by sec. 14 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "a calendar year" in AS 43.55.024(e), enacted by sec. 14 of this Act, shall be replaced by the phrase "the last nine months of the calendar year."

(c) Notwithstanding any contrary provision of AS 43.55.160(f), enacted by sec. 24 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year" in AS 43.55.160(f), enacted by sec. 24 of this Act, shall be replaced by the phrase "for each of the last nine months of 2006, ~~2.222 percent~~ one ninth of the producer's adjusted lease expenditures for that nine-month period."

Insert 14

e(d) For oil and gas produced before April 1, 2006, the provisions of AS 43.55, and regulations adopted under AS 43.55, that were in effect before April 1, 2006, and that were applicable to the oil and gas continue to apply to that oil and gas.

Insert 15

* **Sec. 40.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: REGULATIONS. The Department of Revenue may proceed to adopt regulations to implement the changes made by this Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not before the effective date of the law implemented by the regulation.

* **Sec. 41.** The uncodified law of the State of Alaska is amended by adding a new section to

read:

REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the heading of

(1) AS 43.55 from "Oil and Gas Production Taxes and Oil Surcharge" to "Oil and Gas Production Tax and Oil Surcharge";

(2) article 1 of AS 43.55 from "Oil and Gas Properties Production Taxes" to "Oil and Gas Production Tax";

(3) AS 43.55.011 from "Oil production tax" to "Oil and gas production tax";

(4) AS 43.55.025 from "Tax credit for oil and gas exploration or gas only exploration" to "Alternative tax credit for oil and gas exploration or gas only exploration";

(5) AS 43.55.150 from "Determination of gross value" to "Determination of gross value at the point of production."

* Sec. 42. The uncodified law of the State of Alaska is amended by adding a new section to read:

CONDITIONAL RETROACTIVITY. If the sections of this Act that, under sec. 44 of this Act, are scheduled to take effect April 1, 2006, take effect on or after April 1, 2006, those sections of this Act are retroactive to April 1, 2006.

* Sec. 43. Sections 1 - 4, 7, 12, 15, 19, 20, and 38 - 42 of this Act take effect immediately under AS 01.10.070(c).

* Sec. 44. Except as provided in sec. 43 of this Act, this Act takes effect April 1, 2006.

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
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MEMORANDUM March 14, 2006

SUBJECT: Draft CSHB 488(RES) (Work Order No. 24-GH205[redacted]

TO: Representative Jay Ramras
Representative Ralph Samuels
Co-Chairs of the House Resources Committee

FROM: Jack Chenowe[redacted]
Assistant Revisor

The changes set out in the accompanying draft are made to the bill as introduced. Please note --

The changes generally follow from the red line material prepared by Assistant Attorney General Rob Mintz, with the change made to the price index (proposed AS 43.55.011(g)), added as part of bill section 6, to follow your instruction to substitute a single .25 percent provision for the split index set out in the red-line.

In addition, the draft contains:

-- provisions eliminating the ninety percent payment/ten percent square up, substitution of language requiring payment in full; and, for failure to file or tender payment in full without justification, inclusion of language calling for a penalty comparable to tax penalties otherwise imposed under AS 43; you subsequently directed inclusion of a provision imposing a penalty for failure to pay or remit at least 90 percent of the tax due, a provision that is included as proposed AS 43.55.020(h), added as part of bill section 13;

-- inclusion of a five percent rate for private royalties on leases in effect on that provision's effective date (proposed AS 43.55.011(e)(1)), with the rate to be set at the commissioner of revenue's discretion (proposed AS 43.55.011(e)(2)); the latter provision, as set out, amounts to a standardless delegation of authority to an executive agency (a constitutional problem), and you should revisit it and provide necessary guidance as to how that rate should be calculated;

-- deletion of the surcharge credit provision, bill sections 25 and 29 of the administration's original bill;

-- inclusion of Representative Seaton's amendment A.2 adjusting the split of the nickel-per-barrel surcharge;

-- targeted amendments as submitted by the Alaska Oil & Gas Association that you have specifically approved for inclusion;

-- substitution of language referring to a specific consumer price index referencing changes occurring in the Anchorage CPI for all urban consumers.

From an earlier draft, the following have been incorporated into this "F" draft:

-- a progressive tax rate, with an index when prices exceed $50/barrel WTI; please be sure that the index limits, proposed AS 43.55.011(g), conform to your expectations [just so you understand my drafting of the provision, at $150/bbl, the index is calculated $150 - $50 = $100, or an index of 100; 100 x .30 = 30 that, when added to the base 20 percent of gross value, recovers at an effective rate of 50 percent];

-- transitional allowance adjustment: see proposed AS 43.55.160(g), added as part of bill section 14; the reference index is set in AS 43.55.160(h); adjustment of the transitional investment expenditures from six to seven years is addressed by amending the "1/72" fraction to substitute "1/84" in AS 43.55.160(a) and (b)(2)(A);

-- exploration enhancement, extending the authorized credits statewide to July 2010 -- see bill section 15;

-- disallowance of abandonment costs: see AS 43.55.024(i)(2), added by bill section 14;

-- private royalties set at five percent as to current (i.e. April 1, 2006) leases: see treatment of lessor's royalty interest, AS 43.55.011(e)(1);

-- effective date for provisions set to April 1, 2006: bill sections 42 and 44 address this change;

-- revision of the $73,000,000 allowance: language of the original version was deleted and proposed AS 43.55.170 substituted;

-- tax credit repurchase: see AS 43.55.024(f), added as part of bill section 14.

*

In addition, I've made other edits and modifications to conform the measure to the Legislative Drafting Manual. Look particularly at the handling of the exceptions to the definition of "qualified capital expenditure" with the additional material responsive to

your request to disallow "abandonment costs" for the credit allowed against the production tax value of the oil and gas.

JBC:ljw
06-126.ljw

Enclosure

24-GH205[redacted]
Chenoweth
3/14/06

CS FOR HOUSE BILL NO. 488(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FOURTH LEGISLATURE - SECOND SESSION

BY THE HOUSE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

"An Act repealing the oil production tax and gas production tax and providing for a production tax on oil and gas; relating to the relationship of that tax to other taxes, to the dates those tax payments and surcharges are due, to interest on overpayments of the tax, and to the treatment of the tax in a producer's settlement with the royalty owners; relating to flared gas, and to oil and gas used in the operation of a lease or property under the production tax; relating to the prevailing value of oil or gas under the production tax; providing for tax credits against the tax for certain expenditures, losses, and surcharges; amending the rates applicable to each of the two tax surcharges imposed on oil under the production tax that are used to support the oil and hazardous substance release prevention and response fund and relating to those surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, for

the tax; relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, as applicable to the administration of the tax; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the tax, and to the deposit of tax money collected by the Department of Revenue; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the production tax value of oil and gas for purposes of a tax on the production tax value of oil and gas; relating to the definitions of 'gas,' 'oil,' and certain other terms for purposes of the production tax, and as the definition of the term 'gas' applies in the Alaska Stranded Gas Development Act; making conforming amendments; making uniform throughout the state the deadline for certain exploration expenditures used as credits against the production tax on oil and gas produced from a lease or property in the state by extending to July 1, 2010, the deadline for those expenditures on leases or properties located north of 68 degrees, 15 minutes, North latitude; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

INTENT OF SEC. 12 OF THIS ACT. It is the intent of the legislature through sec. 12 of this Act to confirm by clarification the long-standing interpretation of AS 43.55.020(f) by the Department of Revenue.

*** Sec. 2.** AS 43.05.230(f) is amended to read:

(f) A wilful violation of the provisions of this section **or of a condition imposed under AS 43.55.040(1)(B)** is punishable by a fine of not more than $5,000, or by imprisonment for not more than two years, or by both.

*** Sec. 3.** AS 43.20.031(c) is amended to read:

(c) In computing the tax under this chapter, the taxpayer is not entitled to deduct any taxes based on or measured by net income. **The taxpayer may deduct the tax levied and paid under AS 43.55.**

*** Sec. 4.** AS 43.20.072(b) is amended to read:

(b) A taxpayer's business income to be apportioned under this section to the state shall be the federal taxable income of the taxpayer's consolidated business for the tax period, except that

(1) taxes based on or measured by net income that are deducted in the determination of the federal taxable income shall be added back; **the tax levied and paid under AS 43.55 may not be added back;**

(2) intangible drilling and development costs that are deducted as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) in the determination of the federal taxable income shall be capitalized and depreciated as if the option to treat them as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) had not been exercised;

(3) depletion deducted on the percentage depletion basis under 26 U.S.C. 613 (Internal Revenue Code) in the determination of the federal taxable income shall be recomputed and deducted on the cost depletion basis under 26 U.S.C. 612 (Internal Revenue Code); and

(4) depreciation shall be computed on the basis of 26 U.S.C. 167 (Internal Revenue Code) as that section read on June 30, 1981.

*** Sec. 5.** AS 43.55.011(a) is repealed and reenacted to read:

(a) There is levied on the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state less any oil and gas the ownership or right to which is exempt from taxation or constitutes a lessor's royalty interest under an oil and gas lease. The tax is equal to 20 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160.

*** Sec. 6.** AS 43.55.011 is amended by adding new subsections to read:

(e) There is levied on the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state the ownership or right to which constitutes a lessor's royalty interest under an oil and gas lease, except for oil

and gas the ownership or right to which is exempt from taxation. For purposes of this subsection, for a lessor's royalty interest under an oil and gas lease

(1) that is in effect on the effective date of this section, the tax levied on the oil and gas is equal to five percent of the gross value at the point of production of the oil and gas; however, if the department determines that, for purposes of reducing the producer's tax liability under this paragraph, the producer has received or will receive consideration from the lessor offsetting all or a part of the producer's royalty obligation, the tax under this subsection is equal to 20 percent of the gross value at the point of production of the oil and gas; and

(2) other than an interest described in (1) of this subsection, the tax levied on the oil and gas is equal to a rate to be determined by the commissioner based on the gross value at the point of production.

(f) In addition to the taxes levied under (a) and (e) of this section, for each month for which the oil price index determined under (g) of this section is greater than zero, there is levied upon the producer of oil or gas a tax for oil and gas produced during that month from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation. The tax is equal to .30 percent multiplied by the oil price index as determined under (g) of this section.

(g) The oil price index for a month is the average United States Gulf Coast price for that month of West Texas Intermediate crude oil in dollars per barrel, less $50, except that, if the average price determined under this subsection is

(1) not more than $50 per barrel, the oil price index is zero; and

(2) more than $150 per barrel, the oil price index is 100.

(h) For purposes of (f) and (g) of this section, the department may calculate the average price or may, by regulation, specify the method by which the average price shall be calculated with reference to one or more published sources of price information. If, in the department's judgment, reliable published sources of price information on West Texas Intermediate crude oil cease, or appear likely to soon cease, to be available, or if, in the department's judgment, the price of West Texas Intermediate crude oil ceases, or appears likely to soon cease, to be a reliable indicator of the general price level of crude oils, the department shall, by regulation, specify a

substitute formula for computing the oil price index. The substitute formula specified by the department under this subsection must bear, as nearly as is reasonably possible, the same relationship to the general price level of crude oils as did the United States Gulf Coast price of West Texas Intermediate crude oil.

*** Sec. 7.** AS 43.55.017(a) is amended to read:

(a) Except as provided in this chapter, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax **on** [UPON]

(1) producing oil or gas leases;

(2) oil or gas produced or extracted in the state;

(3) the value of intangible drilling and **development costs, as described in 26 U.S.C. 263(c) (Internal Revenue Code), as amended through January 1, 1974** [EXPLORATION EXPENSES].

*** Sec. 8.** AS 43.55.020(a) is repealed and reenacted to read:

(a) The tax levied under AS 43.55.011(a) shall be paid as set out in this subsection. The tax, net of any credits applied under this chapter, is due on the last day of each calendar month on oil and gas produced from each lease or property during the preceding month. An unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent. An overpayment of tax for a month may be applied against the tax due for a later month. Notwithstanding any contrary provision of AS 43.05.280, interest on an overpayment is allowed only from a date that is 90 days after the statement required under AS 43.55.030(e) to be filed on or before March 31 of the year following the calendar year during which the oil and gas were produced is filed. However, interest is not allowed if the overpayment was refunded within the 90-day period.

*** Sec. 9.** AS 43.55.020(b) is amended to read:

(b) The production tax on oil **and** [OR] gas shall be paid by or on behalf of the producer.

*** Sec. 10.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner **for oil or gas that is taxable under AS 43.55.011,** the producer may deduct the amount of the tax paid on **taxable**

royalty oil **and** [CR] gas, or may deduct **taxable** royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. **Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under AS 43.55.011 on taxable royalty oil and gas for a month other than oil or gas the ownership or right to which constitutes a lessor's royalty interest under an oil or gas lease is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the month multiplied by a figure that is a quotient, in which**

(1) the numerator is the producer's total tax liability under AS 43.55.011(a) for the month of production; and

(2) the denominator is the total gross value at the point of production of the oil and gas taxable under AS 43.55.011(e) produced by the producer from all leases and properties in the state during the month.

* **Sec. 11.** AS 43.55.020(e) is repealed and reenacted to read:

(e) Gas flared, released, or allowed to escape in excess of the amount authorized by the Alaska Oil and Gas Conservation Commission is considered, for the purpose of AS 43.55.011 - 43.55.170, as gas produced from a lease or property. Oil or gas used in the operation of a lease or property in the state in drilling for or producing oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and Gas Conservation Commission to be waste, is not considered, for the purpose of AS 43.55.011 - 43.55.170, as oil or gas produced from a lease or property.

* **Sec. 12.** AS 43.55.020(f) is amended to read:

(f) If oil or gas is **not sold, or if oil or gas is** sold under circumstances where the sale price does not represent the prevailing value for oil or gas of like kind, character, or quality in the field or area from which the product is produced, the department may require the tax to be paid upon the basis of the value of oil or gas of the same kind, quality, and character prevailing during the calendar month of production for that field or area.

* **Sec. 13.** AS 43.55.020 is amended by adding new subsections to read:

(g) The tax levied under AS 43.55.011(e) and (f) shall be paid monthly and is due on the last day of each calendar month on oil and gas produced from each lease or

property during the preceding month, and, if not paid before the end of the month in which it becomes due, the tax becomes delinquent.

(h) The penalty provisions of AS 43.05.220 apply to a producer who fails to pay at least 90 percent of the tax when due under (a) or (g) of this section.

* **Sec. 14.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.024. Tax credits for certain losses and expenditures. (a) Notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the production tax value of oil and gas under AS 43.55.160(a), a producer or explorer that incurs a qualified capital expenditure may also elect to take a tax credit in the amount of 20 percent of that expenditure, unless a credit for that expenditure is taken under AS 43.55.025. A credit under this subsection may be applied only against a tax due under AS 43.55.011(a). For a calendar year for which the producer makes an election under AS 43.55.160(f), instead of taking a tax credit of 20 percent of each separate qualified capital expenditure after it has been incurred, a producer that incurs a qualified capital expenditure during that year and that wishes to apply a credit based on that expenditure against a tax due under AS 43.55.011(a) shall calculate and apply every month an annualized tax credit in an amount equal to one and two-thirds percent of the total qualified capital expenditures incurred during that year and for which the tax credit is taken for that year.

(b) A producer may elect to take a tax credit in the amount of 20 percent of a carried-forward annual loss. A credit under this subsection may be applied only against a tax due under AS 43.55.011(a). For purposes of this subsection, a carried-forward annual loss is the amount of a producer's adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b).

(c) A credit or portion of a credit under this section may not be used to reduce a person's tax liability under AS 43.55.011(a) for any month below zero, and any unused credit or portion of a credit not used under this subsection may be applied in a later month.

(d) A person entitled to take a tax credit under this section that wishes to

transfer the unused credit to another person may apply to the department for a transferable tax credit certificate. An application under this subsection must be on a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 60 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) if the applicant is required under AS 43.55.030(a) and (e) to file a statement on or before March 31 of the year following the calendar year in which the qualified capital expenditures or carried-forward annual loss for which the credit was incurred, the date the statement was filed; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

(e) A person to which a transferable tax credit certificate is issued under (d) of this section may transfer the certificate to another person, and a transferee may further transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and notwithstanding any action the department may take with respect to the applicant under (g) of this section, the owner of a certificate may apply the credit or a portion of the credit shown on the certificate only against a tax due under AS 43.55.011(a). However, a credit shown on a transferable tax credit certificate may not be applied to reduce a producer's total tax due under AS 43.55.011(a) on oil and gas produced during a calendar year to less than 80 percent of the tax that would otherwise be due without applying that credit, and any portion of a credit not used under this subsection may be applied in a later period.

(f) Under standards established in regulations adopted by the department, the commissioner may repurchase a transferable tax credit certificate issued under (d) of this section if

(1) within 24 months after the date of issuance of the tax credit

certificate, the person to whom the certificate was issued or any transferee of the certificate makes a qualified capital expenditure in this state or is the successful bidder on a bid submitted for a lease on state land under AS 38.05.180(f); and

(2) the expenditure made or bid submitted under (1) of this subsection is not less than the amount of the transferable tax credit certificate issued under (d) of this section.

(g) The issuance of a transferable tax credit certificate under (d) of this section does not limit the department's ability to later investigate or audit a tax credit claim to which the certificate relates or to adjust or deny the claim if the department determines that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011 - 43.55.170 is increased by the amount of the credit that exceeds that to which the applicant was entitled. That amount bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, an applicant that is an explorer is considered a producer subject to the tax levied under AS 43.55.011.

(h) The department may adopt regulations to carry out the purposes of this section, including prescribing reporting, record keeping, and certification procedures and requirements to verify the accuracy of credits claimed and to ensure that a credit is not used more than once, and otherwise implementing this section.

(i) A producer or explorer may not elect to take a tax credit under this section for a lease expenditure under AS 43.55.160 that is an expenditure incurred

(1) to acquire an asset (A) the cost of previously acquiring which was a lease expenditure under AS 43.55.160(c) or would have been a lease expenditure under AS 43.55.160(c) if it had been incurred on or after April 1, 2006; or (B) that has previously been placed in service in the state; an expenditure to acquire an asset is not excluded under this paragraph if not more than an immaterial portion of the asset meets a description under (A) or (B) of this paragraph; for purposes of this paragraph, "asset" includes geological, geophysical, and well data and interpretations; or

(2) for an extended period of disuse, dismantlement, removal, surrender, or abandonment of a well, facility, pipeline, platform, or other structure, or for the restoration of a lease, field, unit, area, or body of water in conjunction with an

extended period of disuse, dismantlement, removal, surrender, or abandonment of a facility described in this paragraph.

(j) In this section,

(1) "explorer" has the meaning given in AS 43.55.025;

(2) "qualified capital expenditure" means, except as otherwise provided in (i) of this section, an expenditure that is a lease expenditure under AS 43.55.160 and is

(A) incurred for geological or geophysical exploration; or

(B) treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and either is treated as a capitalized expenditure by the person incurring the expenditure or is eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal Revenue Code), as amended.

*** Sec. 15.** AS 43.55.025(b) is amended to read:

(b) To qualify for the production tax credit under (a) of this section, an exploration expenditure must be incurred for work performed on or after July 1, 2003, and before July 1, **2010** [2007], except that an exploration expenditure for a Cook Inlet prospect must be incurred for work performed on or after July 1, 2005, [AND BEFORE JULY 1, 2010, AND EXCEPT THAT AN EXPLORATION EXPENDITURE, IN WHOLE OR IN PART, SOUTH OF 68 DEGREES, 15 MINUTES, NORTH LATITUDE, AND NOT PART OF A COOK INLET PROSPECT MUST BE INCURRED FOR WORK PERFORMED ON OR AFTER JULY 1, 2003, AND BEFORE JULY 1, 2010,] and

(1) may be for seismic or geophysical exploration costs not connected with a specific well;

(2) if for an exploration well,

(A) must be incurred by an explorer that holds an interest in the exploration well for which the production tax credit is claimed;

(B) may be for either an oil or gas discovery well or a dry hole; and

(C) must be for goods, services, or rentals of personal property reasonably required for the surface preparation, drilling, casing, cementing, and logging of an exploration well, and, in the case of a dry hole, for the expenses required for abandonment if the well is abandoned within 18 months after the date the well was spudded;

(3) may not be for testing, stimulation, or completion costs; administration, supervision, engineering, or lease operating costs; geological or management costs; community relations or environmental costs; bonuses, taxes, or other payments to governments related to the well; or other costs that are generally recognized as indirect costs or financing costs; and

(4) may not be incurred for an exploration well or seismic exploration that is included in a plan of exploration or a plan of development for any unit on May 13, 2003.

*** Sec. 16.** AS 43.55.030(a) is amended to read:

(a) The tax shall be paid to the department and the person paying the tax shall file with the department at the time the tax **or a portion of the ta..** is required to be paid a statement, under oath, on forms prescribed by or acceptable to the department, giving, with other information required, the following:

(1) a description of **each** [THE] lease or property from which the oil **and** [OR] gas **were** [WAS] produced, by name, legal description, lease number, or [BY] accounting **codes** [CODE NUMBERS] assigned by the department;

(2) the names of the producer and the person paying the tax;

(3) the gross amount of oil **and the gross amount of** [OR] gas produced from **each** [THE] lease or property, and the percentage of the gross amount **of oil and gas** owned by each producer for whom the tax is paid;

(4) the **gross** [TOTAL] value **at the point of production** of the oil **and of the** [OR] gas produced from **each** [THE] lease or property owned by each producer for whom the tax is paid; [AND]

(5) the name of the first purchaser and the price received for the oil **and for the** [OR] gas, **unless relieved from this requirement in whole or in part by the department; and**

(6) the producer's lease expenditures and adjustments as calculated under AS 43.55.160 [IF SOLD IN THE STATE].

*** Sec. 17.** AS 43.55.030(d) is amended to read:

(d) Reports by or on behalf of the producer are delinquent the first day following the day the tax is due. **The provisions of AS 43.05.220 apply to reports that are not timely filed under this section.** [EACH PRODUCER IS SUBJECT TO A PENALTY OF $25 A DAY FOR EACH LEASE OR PROPERTY UPON WHICH THE REPORT IS NOT FILED.] The penalty for failure to file a report is in addition to the penalty for delinquent taxes, and is a lien against the assets of the producer.

*** Sec. 18.** AS 43.55.030 is amended by adding a new subsection to read:

(e) In addition to other required information, the statement required to be filed on or before March 31 of a year must show any adjustments or corrections to the statements that were required under (a) of this section to be filed for the months of the preceding calendar year during which the oil or gas was produced.

*** Sec. 19.** AS 43.55.040 is amended to read:

Sec. 43.55.040. Powers of Department of Revenue. Except as provided in AS 43.05.405 - 43.05.499, the department may

(1) require a person engaged in production and the agent or employee of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil or gas to furnish, **whether by the filing of regular statements or reports or otherwise,** additional information that is considered by the department as necessary to compute the amount of the tax**; notwithstanding any contrary provision of law, the disclosure of additional information under this paragraph to the producer obligated to pay the tax does not violate AS 40.25.100(a) or AS 43.05.230(a); before disclosing information under this paragraph that is otherwise required to be held confidential under AS 40.25.100(a) or AS 43.05.230(a), the department shall**

(A) provide the person that furnished the information a reasonable opportunity to be heard regarding the proposed disclosure and the conditions to be imposed under (B) of this paragraph; and

(B) impose appropriate conditions limiting

(i) access to the information to those legal counsel, consultants, employees, officers, and agents of the producer who have a need to know that information for the purpose of determining or contesting the producer's tax obligation; and

(ii) the use of the information to use for the purpose of determining or contesting the producer's tax obligation;

(2) examine the books, records, and files of such a person;

(3) conduct hearings and compel the attendance of witnesses and the production of books, records, and papers of any person; and

(4) make an investigation or hold an inquiry that is considered necessary to a disclosure of the facts as to

(A) the amount of production from any oil or gas location, or of a company or other producer of oil or gas; and

(B) the rendition of the oil and gas for taxing purposes.

*** Sec. 20.** AS 43.55.080 is amended to read:

Sec. 43.55.080. Collection and deposit of revenue. Except as otherwise provided under art. IX, sec. 17, Constitution of the State of Alaska, the [THE] department shall deposit in the general fund the money collected by it under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 21.** AS 43.55.135 is amended to read:

Sec. 43.55.135. Measurement. For the purposes of **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150], oil **is** [SHALL BE] measured in terms of a "barrel of oil" and gas **is** [SHALL BE] measured in terms of a "cubic foot of gas."

*** Sec. 22.** AS 43.55.150(a) is amended to read:

(a) For the purposes of **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150], the gross value **at the point of production is** [SHALL BE] calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation **are** [SHALL BE] the actual costs, except **when the**

(1) [WHEN THE] parties to the transportation of oil or gas are affiliated;

(2) [WHEN THE] contract for the transportation of oil or gas is not an

arm's length transaction or is not representative of the market value of that transportation;

(3) [WHEN THE] method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

*** Sec. 23.** AS 43.55.150 is amended by adding a new subsection to read:

(d) Under regulations adopted by the department, the department may allow a producer, subject to limitations prescribed by the department as to the frequency of making elections, to elect prospectively to calculate the gross value at the point of production of oil or gas based in whole or part on

(1) a royalty value determined under a royalty settlement agreement between the producer and the state, with adjustments if appropriate;

(2) a formula prescribed by the department that uses, with adjustments if appropriate, a royalty value or valuation methodology accepted by the

(A) Department of Natural Resources under AS 38.05, in the case of oil and gas produced from a lease issued by the Department of Natural Resources or produced from a lease or property that is part of a unit approved by the Department of Natural Resources; or

(B) United States Department of the Interior under applicable federal oil and gas leasing statutes, in the case of oil and gas produced from a lease issued by the United States Department of the Interior that is not part of a unit approved by the Department of Natural Resources, or produced from a lease or property that is part of a unit approved by the United States Department of the Interior but not approved by the Department of Natural Resources; or

(3) another formula prescribed by the Department of Revenue that reasonably estimates a value for the oil or gas at a specific geographical location, such as the point of tender or delivery into a common carrier pipeline; the formula may use factors such as published price indices for oil or gas in or outside the state, quality differentials for oil or gas, transportation costs between markets, and inflation adjustments.

*** Sec. 24.** AS 43.55 is amended by adding new sections to article 1 to read:

Sec. 43.55.160. Determination of production tax value of oil and gas. (a) Except as provided in (f) of this section, for purposes of AS 43.55.011(a), the production tax value of the taxable oil and gas produced during a month is the total of the gross value at the point of production of the oil and gas taxable under AS 43.55.011(a) and produced by the producer from all leases or properties in the state, (1) less the producer's tax paid for the month under AS 43.55.011(f); (2) less the producer's lease expenditures for the month as adjusted under (e) of this section, and (3) to the extent allowed under (g) of this section and until the total amount of the producer's transitional investment expenditures has been deducted, less an amount equal to 1/84 of the producer's transitional investment expenditures. However, the production tax value calculated under this subsection may not be less than zero.

(b) For purposes of administration of (a) of this section,

(1) any adjusted lease expenditures that would otherwise be deductible in a month but whose deduction would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero may be added to the producer's adjusted lease expenditures for one or more other months in the same calendar year; the total of any adjusted lease expenditures that are not deductible in any month during a calendar year because their deduction would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during one or more months to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.024(b);

(2) an amount of transitional investment expenditures that would otherwise be deductible in a month but whose deduction would cause the production tax value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero

(A) may be deducted in a later month during any calendar year to the extent allowed under (g) of this section, but not more than 1/84 of a producer's transitional investment expenditures may be deducted in any month;

(B) may not be used to establish a carried-forward annual loss under AS 43.55.024(b).

(c) For purposes of this section,

(1) a producer's lease expenditures for a period are the total costs upstream of the point of production of oil and gas that are incurred on or after April 1, 2006, by the producer during the period and that are direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas from deposits located within the producer's leases or properties in the state or, in the case of land in which the producer does not own a working interest, direct, ordinary, and necessary costs of exploring for oil or gas deposits located within other land in the state; however, lease expenditures do not include the costs incurred to satisfy a work commitment under an exploration license under AS 38.05.132; in determining whether costs are direct, ordinary, and necessary costs of exploring for, developing, or producing an oil or gas from a deposit of oil or gas located within a lease or property or other land in the state, the department shall give substantial weight to

(A) the typical industry practices and standards in the state and in the United States as to costs that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, not the operator, with substantial bargaining power; and

(B) the standards adopted by the Department of Natural Resources as to the costs, other than interest, that a lessee is allowed to deduct from revenue in calculating net profits under a lease issued under AS 38.05.180(f)(3)(B), (D), or (E);

(2) the Department of Revenue may authorize a producer, including the operator or a working interest owner, to treat as its lease expenditures under this section the costs paid by the producer that are billed to the producer by an operator in accordance with the terms of a unit operating agreement or similar operating agreement if the Department of Revenue finds that

(A) the pertinent provisions of the operating agreement are substantially consistent with the Department of Revenue's determinations and standards otherwise applicable under this subsection; and

(B) at least one working interest owner party to the agreement,

other than the operator, has substantial incentive and ability to effectively audit billings under the agreement.

(d) For purposes of (c) of this section, "direct costs"

(1) includes

(A) outlays for capital assets;

(B) payments of property taxes, sales and use taxes, motor fuel taxes, and excise taxes;

(C) a reasonable allowance, as determined under regulations adopted by the department, for overhead expenses directly related to exploring for, developing, and producing oil or gas deposits located within leases or properties or other land in the state;

(2) does not include

(A) depreciation or amortization of capital assets;

(B) royalty payments for oil and gas;

(C) taxes based on or measured by net income;

(D) interest or other financing charges or costs of raising equity or debt capital;

(E) acquisition costs for a lease or property or exploration license;

(F) costs arising from fraud, wilful misconduct, or negligence;

(G) fines or penalties imposed by law;

(H) costs of arbitration, litigation, or other dispute resolution activities that involve the state or concern the rights or obligations among owners of interests in, or rights to production from, one or more leases or properties or a unit;

(I) donations;

(J) costs incurred in organizing a partnership, joint venture, or other business entity or arrangement;

(K) amounts paid to indemnify the state; the exclusion provided by this paragraph does not apply to the costs of obtaining insurance or a surety bond from a third-party insurer or surety;

(L) surcharges levied under AS 43.55.201 or 43.55.300.

(e) A producer's lease expenditures must be adjusted by subtracting any payment or credit the producer receives for

(1) the use by another person of a production facility in which the producer has an ownership interest;

(2) a reimbursement or similar payment that offsets the producer's lease expenditures, including a payment from the state or federal government for reimbursement of the producer's upstream costs, including costs for gathering, separating, cleaning, dehydration, compressing, or other field handling associated with the production of oil or gas upstream of the point of production;

(3) the sale or other transfer of

(A) an asset, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of a lease expenditure or an expenditure that would be a lease expenditure if it were incurred on or after April 1, 2006; and

(B) oil or gas

(i) that is not considered produced from a lease or property under AS 43.55.020(e); and

(ii) the cost of acquiring which is a lease expenditure incurred by the person that acquires the oil or gas.

(f) In place of the adjusted lease expenditures for a month under (a) of this section, a producer may, at any time, elect to substitute, for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year.

(g) For the purposes of this section,

(1) a producer's transitional investment expenditures are the sum of the expenditures the producer incurred on or after January 1, 2003, and before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, less the sum of the payments or credits the producer received before April 1, 2006, for the sale or other transfer of assets, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of expenditures the producer incurred on or after January 1, 2003,

and before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, multiplied by

(A) 25 percent for expenditures incurred on or after January 1, 2003, and before January 1, 2004;

(B) 50 percent for expenditures incurred on or after January 1, 2004, and before January 1, 2005; and

(C) 75 percent for expenditures incurred on or after January 1, 2005, and before April 1, 2006;

(2) notwithstanding (1) of this subsection, an amount of transitional investment expenditures may not be deducted under (a) of this section for a month for which the average price of Alaska North Slope oil delivered on the United States West Coast, as determined under (h) of this section, is equal to or less than $40 a barrel, as adjusted for inflation under (h) of this section.

(h) The average price described in (g) of this section shall be an average, as calculated using a formula prescribed by the department by regulation, of published daily spot price assessments during the month for Alaska North Slope oil delivered on the United States West Coast. However, if the department determines that the daily assessments cease to be published throughout the calendar year or appear likely to soon cease to be published throughout the calendar year or that they cease to be reliable evidence of market conditions or appear likely to soon cease to be reliable evidence of market conditions, the department shall by regulation provide that the average price described in (g) of this section is the prevailing value of Alaska North Slope oil delivered on the United States West Coast as determined under regulations of the department implementing AS 43.55.020(f). For each year after 2006, the department shall adjust the reference price of $40 a barrel set out in (g) of this section for inflation. The dollar amount in (g) of this section changes according to and to the extent of changes in the Consumer Price Index for all urban consumers for the Anchorage Metropolitan Area compiled by the Bureau of Labor Statistics, United States Department of Labor (the index). The index for January of 2006 is the reference base index. If the index is revised, the percentage of change is calculated based on the revised index. If a revision of the index changes the reference base index, a revised

reference base index is determined by multiplying the reference base index applicable by the rebasing factor furnished by the United States Bureau of Labor Statistics. If the index is superseded, the index referred to in this section is the one represented by the United States Bureau of Labor Statistics as reflecting most accurately changes in the purchasing power of the dollar for Alaska consumers.

(i) The department shall specify or approve a reasonable allocation method for determining the portion of a cost that is appropriately treated as a lease expenditure under (c) of this section if a cost that would otherwise constitute a lease expenditure under (c) of this section is incurred to explore for, develop, or produce

(1) both an oil or gas deposit located within land outside the state and an oil or gas deposit located within a lease or property, or other land, in the state; or

(2) an oil or gas deposit located partly within land outside the state and partly within a lease or property, or other land, in the state.

(j) The department may adopt regulations that establish additional standards necessary to carrying out the purposes of this section.

(k) For purposes of AS 43.55.024(a) and (b) and only as to expenditures incurred to explore for an oil or gas deposit located within land in which an explorer, as defined in AS 43.55.025, does not own a working interest, the term "producer" in (c) and (e) of this section includes "explorer."

(*l*) For purposes of this section,

(1) "explore" includes conducting geological or geophysical exploration, including drilling a stratigraphic test well;

(2) "ordinary and necessary" has the meaning given "ordinary and necessary" in 26 U.S.C. 162 (Internal Revenue Code) and regulations adopted under that section;

(3) "stratigraphic test well" means a well drilled for the sole purpose of obtaining geological information to aid in exploring for an oil or gas deposit and the target zones of which are located in the state.

Sec. 43.55.170. Additional nontransferable credit. (a) For a month for which the net value of the taxable oil and gas produced during the month calculated under AS 43.55.160 exceeds zero, a producer that is qualified under (b) of this section may

reduce the net value by applying a tax credit for a qualified capital expenditure, as that term is defined in AS 43.55.024, if the qualified capital expenditure involved a payment made in this state and the claim of the credit is not taken under AS 43.55.024 or 43.55.025. The credit authorized by this subsection may be calculated and applied so that

(1) the net value for the month is not reduced below zero; and

(2) the total of the credits applied during the calendar year does not exceed $10,000,000.

(b) On written application by a producer, including any information the department may require, the department shall determine whether the producer qualifies under this section for a calendar year. To qualify under this section, a producer must demonstrate that its operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer entity would not result in the division among multiple producer entities of any net value of taxable oil and gas, as determined under AS 43.55.160(a), that would be reasonably expected to be attributed to a single producer entity if the allowance provision of (a) of this section did not exist.

(c) An unused allowance or portion of an allowance under this section is not transferable under AS 43.55.024(d), may not be carried forward to a later calendar year, and may not be used to establish a carried-forward annual loss under AS 43.55.024(b).

(d) A producer may not claim a credit under this section for a qualified capital expenditure incurred after March 31, 2016.

*** Sec. 25.** AS 43.55.201(a) is amended to read:

(a) Every producer of oil shall pay a surcharge of **$.01** [$.02] per barrel of oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation.

*** Sec. 26.** AS 43.55.201(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to **the tax imposed by AS 43.55.011** and shall be paid in the [SAME] manner **described in AS 43.55.020. The surcharge** [AS THE TAX IMPOSED BY AS 43.55.011 -

43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.300 - 43.55.310.

*** Sec. 27.** AS 43.55.201(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 28.** AS 43.55.201 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

*** Sec. 29.** AS 43.55.300(a) is amended to read:

(a) Every producer of oil shall pay a surcharge of **$.04** [$.03] per barrel of oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation.

*** Sec. 30.** AS 43.55.300(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to **the tax imposed by AS 43.55.011** and shall be paid in the [SAME] manner **described in AS 43.55.020. The surcharge** [AS THE TAX IMPOSED BY AS 43.55.011 - 43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.201 - 43.55.231.

*** Sec. 31.** AS 43.55.300(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 32.** AS 43.55.300 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

*** Sec. 33.** AS 43.55.900(6) is repealed and reenacted to read:

(6) "gas" means

(A) all natural, associated, or casinghead gas;

(B) all hydrocarbons that

(i) are recovered by mechanical separation of well fluids or by gas processing; and

(ii) exist in a gaseous phase at the completion of mechanical separation and any gas processing; and

(C) all other hydrocarbons produced from a well not defined as oil;

*** Sec. 34.** AS 43.55.900(7) is repealed and reenacted to read:

(7) "gross value at the point of production" means

(A) for oil, the value of the oil at the automatic custody transfer meter or device through which the oil enters into the facilities of a carrier pipeline or other transportation carrier in a condition of pipeline quality; in the absence of an automatic custody transfer meter or device, "gross value at the point of production" means the value of the oil at the mechanism or device to measure the quantity of oil that has been approved by the department for that purpose, through which the oil is tendered and accepted in a condition of pipeline quality into the facilities of a carrier pipeline or other transportation carrier or into a field topping plant;

(B) for gas, other than gas described in (C) of this paragraph, that is

(i) not subjected to or recovered by mechanical separation or gas processing, the value of the gas at the first point where the gas is accurately metered;

(ii) subjected to or recovered by mechanical separation but not gas processing, the value of the gas at the first point where the gas is accurately metered after completion of mechanical separation;

(iii) subjected to or recovered by gas processing, the value of the gas at the first point where the gas is accurately metered after completion of gas processing;

(C) for gas run through an integrated gas processing and gas treatment facility that does not accurately meter the gas after the gas

processing and before the gas treatment, the value of the gas at the first point where gas processing is completed or where gas treatment begins, whichever is further upstream;

*** Sec. 35.** AS 43.55.900(10) is repealed and reenacted to read:

(10) "oil" means

(A) crude petroleum oil; and

(B) all liquid hydrocarbons that are recovered by mechanical separation of well fluids or by gas processing;

*** Sec. 36.** AS 43.55.900 is amended by adding new paragraphs to read:

(17) "gas processing"

(A) means processing a gaseous mixture of hydrocarbons

(i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation;

(ii) for the purpose of extracting and recovering liquid hydrocarbons; and

(iii) upstream of any gas treatment and upstream of the inlet of any gas pipeline system transporting gas to a market;

(B) does not include gas treatment;

(18) "gas treatment"

(A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system; and

(B) includes incidentally removing liquid hydrocarbons from the gas.

*** Sec. 37.** AS 43.55.011(b), 43.55.011(c), 43.55.012(b), 43.55.013, 43.55.016, 43.55.900(1), 43.55.900(8), 43.55.900(11), 43.55.900(12), and 43.55.900(16) are repealed.

*** Sec. 38.** The uncodified law of the State of Alaska is amended by adding a new section to read:

APPLICABILITY. (a) Sections 5, 6, 8 - 11, 13, 14, 16 - 18, and 22 - 37 of this Act

apply to oil and gas produced on or after April 1, 2006.

(b) Section 12 of this Act applies to oil and gas produced before, on, or after the effective date of sec. 12 of this Act.

*** Sec. 39.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITIONAL PROVISIONS. (a) Notwithstanding any contrary provision of AS 43.55.024(a), enacted by sec. 14 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "every month an annualized tax credit in an amount equal to one and two-thirds percent" in AS 43.55.024(a), enacted by sec. 14 of this Act, shall be replaced by the phrase "every month during the period April 1, 2006, through December 31, 2006, an annualized tax credit in an amount equal to 2.222 percent."

(b) Notwithstanding any contrary provision of AS 43.55.024(e), enacted by sec. 14 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "a calendar year" in AS 43.55.024(e), enacted by sec. 14 of this Act, shall be replaced by the phrase "the last nine months of the calendar year."

(c) Notwithstanding any contrary provision of AS 43.55.160(f), enacted by sec. 24 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year" in AS 43.55.160(f), enacted by sec. 24 of this Act, shall be replaced by the phrase "for each of the last nine months of 2006, 2.222 percent of the producer's adjusted lease expenditures for that nine-month period."

(d) For oil and gas produced before April 1, 2006, the provisions of AS 43.55, and regulations adopted under AS 43.55, that were in effect before April 1, 2006, and that were applicable to the oil and gas continue to apply to that oil and gas.

*** Sec. 40.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: REGULATIONS. The Department of Revenue may proceed to adopt regulations to implement the changes made by this Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not before the effective date of the law implemented by the regulation.

*** Sec. 41.** The uncodified law of the State of Alaska is amended by adding a new section to

read:

REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the heading of

(1) AS 43.55 from "Oil and Gas Production Taxes and Oil Surcharge" to "Oil and Gas Production Tax and Oil Surcharge";

(2) article 1 of AS 43.55 from "Oil and Gas Properties Production Taxes" to "Oil and Gas Production Tax";

(3) AS 43.55.011 from "Oil production tax" to "Oil and gas production tax";

(4) AS 43.55.025 from "Tax credit for oil and gas exploration or gas only exploration" to "Alternative tax credit for oil and gas exploration or gas only exploration";

(5) AS 43.55.150 from "Determination of gross value" to "Determination of gross value at the point of production."

*** Sec. 42.** The uncodified law of the State of Alaska is amended by adding a new section to read:

CONDITIONAL RETROACTIVITY. If the sections of this Act that, under sec. 44 of this Act, are scheduled to take effect April 1, 2006, take effect on or after April 1, 2006, those sections of this Act are retroactive to April 1, 2006.

*** Sec. 43.** Sections 1 - 4, 7, 12, 15, 19 - 21, and 38 - 42 of this Act take effect immediately under AS 01.10.070(c).

*** Sec. 44.** Except as provided in sec. 43 of this Act, this Act takes effect April 1, 2006.

LEGAL SERVICES

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MEMORANDUM March 9, 2006

SUBJECT: Initial draft CSHB 488(RES): notes to accompany the bill draft (Work Order No. 24-GH2052\G)

TO: Representative Ralph Samuels
Representative Jay Ramras
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

Transmitted with this memo is the very rough first draft of a committee substitute for the petroleum production tax bill. The draft is based on the notes you provided during our Tuesday morning meeting.

The draft does not address items identified as 2 (tax rate) and 9 (manner of determining gas valuation). My understanding is that details of each of these, including, particularly, the substitution of varying tax rates, remain under active consideration among committee members.

1. REDUCE "CLAWBACK" PROVISIONS: SUBSTITUTE RATES OF 75 PERCENT FOR 2005, 50 PERCENT FOR 2004, AND 25 PERCENT FOR 2003; SPREAD THE PAYBACK OVER 7 YEARS:

The transitional investment expenditures provision, AS 43.55.160(g) of the bill in the form as introduced, has been reworked and appears as AS 43.55.160(g)(1), at page 15 of the accompanying draft. The extended payback spread is addressed as replacement fractions "1/84" (instead of "1/72") [page 12, lines 5 and 23].

3. PER CONVERSATION AT OUR TUESDAY MORNING MEETING, REDUCE THE TAX CREDIT RATE TO 15 PERCENT:

Done: see amendments made in AS 43.55.024(a) and (b), added by bill section 13.

4. SUBSTITUTE AN APRIL 1, 2006, EFFECTIVE DATE:

Done: see in this draft bill section 40. A conditional retroactivity provision is provided against the likelihood that enactment will not occur before the date. When a final form of the House Resources Committee Substitute is agreed to, I will restate the conditional

retroactivity provision to identify specific bill sections. Additionally, within the text of the permanent and temporary law sections, references to "July 1, 2006" have been replaced by references to "April 1, 2006", and the temporary law provisions that base a calculation on a six-month adjustment have been recalculated to a nine-month adjustment.

5. ELIMINATE THE SPILL CONTINGENCY SURCHARGE AMENDMENTS:

Bill sections 25 and 29 of the original bill have been dropped from the committee substitute.

6. PROVIDE FOR "FULLY REFUNDABLE" TAX CREDITS THAT ARE IN ADDITION TO THE TRANSFERABLE FEATURE: WE AGREED IN CONVERSATION THAT THESE SHOULD BE DISCRETIONARY ("MAY REPURCHASE") RATHER THAN MANDATORY ("SHALL REPURCHASE"):

See proposed AS 43.55.160(f), a new subsection, beginning at the bottom of page 6 of the draft.

7. REWORK THE $73,000,000 EXEMPTION AS AN ADDITIONAL INVESTMENT TAX CREDIT FEATURE, WITH DIFFERENT CONSTRAINTS, TO OPERATE FOR 10 YEARS:

The material formerly set out in AS 43.55.160(i) and (j) has been dropped from that section, revised, and set out as a new section, AS 43.55.170. See if the material meets your expectations. A corresponding interim adjustment provision, bill section 36(d) of the original bill, has been deleted.

The treatment of this material as a credit (rather than as a reduction to the net value of oil) necessitated deletion of references to the material in former AS 43.55.160(i) and (j) as bearing on an authorized adjustment to the net value of oil. Please make sure that this is handled consistently with your expectations.

8. THE GAS TAX RATE:

No change in the material as introduced, per instruction.

10. THE PRIVATE ROYALTY ISSUE:

The first part of the Arctic Slope Regional Corporation's suggested amendment was used for the text of material to be found, in this draft, as AS 43.55.011(e), added as a new bill section 6, as related to the oil tax rate. Since the other portion of the ASRC amendment addressed settlement, a matter also addressed in AS 43.55.020(d), in the amendment of AS 43.55.020(d) made by bill section 10, assuming that the provisions would otherwise cover these so-called private royalties, I added the phrase "Except as to oil and gas for

which tax is payable under AS 43.55.011(e)," at the beginning of the principal amending language in that subsection. Again, please verify that this handling is responsive to the suggestion. Out of caution, in the material set out as AS 43.55.011(e), I inserted reference to "the owner of the land or interest in the land [that] is not the state" so that this provision would leave no argument that the reduced rate authorized in this subsection somehow might apply to a state-issued lease. You should review that as well.

For purposes of this draft, I used the ASRC's initial submission. Sara Gill has provided different language that I will incorporate into a subsequent draft.

*

In addition to the foregoing, I have made substantial edits to the text as submitted to conform to the drafting manual.

Someone should independently verify that the references to "2.222 percent" [page 21, lines 13 and 22] are accurate monthly adjustments to reflect the adjustment of the effective date from "July 1, 2006" (six months of the current calendar year) back to "April 1, 2006" (nine months of the current calendar year).

Finally, the bill title is a short form title intended only as working title for purposes of treating with any drafts. Again, when the committee has substantially settled on the content of the committee substitute, I will rewrite the title to more fully describe the measure's contents.

JBC:lmb
06-095.lmb

Enclosure

24-GH2052\3
Chenoweth
3/8/06

CS FOR HOUSE BILL NO. 488(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FOURTH LEGISLATURE - SECOND SESSION

BY THE HOUSE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

"An Act repealing the oil production tax and gas production tax and providing for a production tax on the net value of oil and gas, and making conforming amendments; amending the definition of 'gas' as it applies to the taxes described in this Act and as used in the Alaska Stranded Gas Development Act; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

INTENT OF SEC. 12 OF THIS ACT. It is the intent of the legislature through sec. 12 of this Act to confirm by clarification the long-standing interpretation of AS 43.55.020(f) by the Department of Revenue.

*** Sec. 2.** AS 43.05.230(f) is amended to read:

(f) A wilful violation of the provisions of this section **or of a condition imposed under AS 43.55.040(1)(B)** is punishable by a fine of not more than $5,000, or by imprisonment for not more than two years, or by both.

*** Sec. 3.** AS 43.20.031(c) is amended to read:

(c) In computing the tax under this chapter, the taxpayer is not entitled to deduct any taxes based on or measured by net income. **The taxpayer may deduct the tax levied and paid under AS 43.55.**

*** Sec. 4.** AS 43.20.072(b) is amended to read:

(b) A taxpayer's business income to be apportioned under this section to the state shall be the federal taxable income of the taxpayer's consolidated business for the tax period, except that

(1) taxes based on or measured by net income that are deducted in the determination of the federal taxable income shall be added back; **the tax levied and paid under AS 43.55 may not be added back;**

(2) intangible drilling and development costs that are deducted as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) in the determination of the federal taxable income shall be capitalized and depreciated as if the option to treat them as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) had not been exercised;

(3) depletion deducted on the percentage depletion basis under 26 U.S.C. 613 (Internal Revenue Code) in the determination of the federal taxable income shall be recomputed and deducted on the cost depletion basis under 26 U.S.C. 612 (Internal Revenue Code); and

(4) depreciation shall be computed on the basis of 26 U.S.C. 167 (Internal Revenue Code) as that section read on June 30, 1981.

*** Sec. 5.** AS 43.55.011(a) is repealed and reenacted to read:

(a) There is levied on the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation. The tax is equal to 20 percent of the net value of the taxable oil and gas as calculated under AS 43.55.160.

*** Sec. 6.** AS 43.55.011 is amended by adding a new subsection to read:

(e) Notwithstanding (a) of this section, the tax due by a producer under AS 43.55.011 - 43.55.170 on taxable oil or gas that is royalty due to the fee owner of the land, or of an estate in the land that is less than fee simple, from which the oil or

gas is produced, if the owner of the land or interest in the land is not the state, is five percent of the amount of the royalty paid to the owner by the producer, or five percent of the gross value of the royalty oil or gas at the point of delivery to the owner if the owner takes the royalty oil or gas in kind. The producer shall exclude from calculation of the tax due under (a) of this section the value of the oil and gas for which tax has been paid under this subsection.

*** Sec. 7.** AS 43.55.017(a) is amended to read:

(a) Except as provided in this chapter, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax **on** [UPON]

(1) producing oil or gas leases;

(2) oil or gas produced or extracted in the state;

(3) the value of intangible drilling and **development costs, as described in 26 U.S.C. 263(c) (Internal Revenue Code), as amended through January 1, 1974** [EXPLORATION EXPENSES].

*** Sec. 8.** AS 43.55.020(a) is repealed and reenacted to read:

(a) The production tax on oil and gas shall be paid as set out in this subsection. Ninety percent of the tax levied under AS 43.55.011, net of any credits applied under this chapter, is due on the last day of each calendar month on oil and gas produced from each lease or property during the preceding month. The remaining portion of the tax levied under AS 43.55.011, net of any credits applied under this chapter, is due on March 31 of the year following the calendar year during which the oil and gas were produced. An unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent. An overpayment of tax for a month may be applied against the tax due for a later month. Notwithstanding any contrary provision of AS 43.05.280, interest on an overpayment is allowed only from a date that is 90 days after the later of (1) March 31 of the year following the calendar year during which the oil and gas were produced; or (2) the date that the statement required under AS 43.55.030(a) and (e) to be filed on or before March 31 of the year following the calendar year during which the oil and gas were produced is filed. However, interest is not allowed if the overpayment was refunded within the 90-day period.

* **Sec. 9.** AS 43.55.020(b) is amended to read:

(b) The production tax on oil **and** [OR] gas shall be paid by or on behalf of the producer.

* **Sec. 10.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner **for oil or gas that is taxable under AS 43.55.011,** the producer may deduct the amount of the tax paid on **taxable** royalty oil **and** [OR] gas, or may deduct **taxable** royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. **Except as to oil and gas for which tax is payable under AS 43.55.011(e), unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid on taxable royalty oil and gas for a month is considered to be the quantity of that taxable royalty oil and gas produced during the month multiplied by the quotient of the producer's total tax liability for the month of production under AS 43.55.011 divided by the producer's total quantity of taxable oil and gas, other than royalty oil and gas, produced from all leases and properties in the state during the month. For purposes of the product calculated under this subsection, 6,000 cubic feet of gas is considered to be equivalent in amount to one barrel of oil.**

* **Sec. 11.** AS 43.55.020(e) is repealed and reenacted to read:

(e) Gas flared, released, or allowed to escape in excess of the amount authorized by the Alaska Oil and Gas Conservation Commission is considered, for the purpose of AS 43.55.011 - 43.55.170, as gas produced from a lease or property. Oil or gas used in the operation of a lease or property in the state in drilling for or producing oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and Gas Conservation Commission to be waste, is not considered, for the purpose of AS 43.55.011 - 43.55.170, as oil or gas produced from a lease or property.

* **Sec. 12.** AS 43.55.020(f) is amended to read:

(f) If oil or gas is **not sold, or if oil or gas is** sold under circumstances where the sale price does not represent the prevailing value for oil or gas of like kind, character, or quality in the field or area from which the product is produced, the department may require the tax to be paid upon the basis of the value of oil or gas of

the same kind, quality, and character prevailing during the calendar month of production for that field or area.

*** Sec. 13.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.024. Tax credits for certain losses and expenditures. (a) Notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the net value of oil and gas under AS 43.55.160(a), a producer or explorer that incurs a qualified capital expenditure may also elect to take a tax credit in the amount of 15 percent of that expenditure, unless a credit for that expenditure is taken under AS 43.55.025. A credit under this subsection may be applied only against a tax due under AS 43.55.011 - 43.55.170. For a calendar year for which the producer makes an election under AS 43.55.160(f), instead of taking a tax credit of 15 percent of each separate qualified capital expenditure after it has been incurred, a producer that incurs a qualified capital expenditure during that year and that wishes to apply a credit based on that expenditure against a tax due under AS 43.55.011 - 43.55.170 shall calculate and apply every month an annualized tax credit in an amount equal to one and one-fourth percent of the total qualified capital expenditures incurred during that year and for which the tax credit is taken for that year.

(b) A producer may elect to take a tax credit in the amount of 15 percent of a carried-forward annual loss. A credit under this subsection may be applied only against a tax due under AS 43.55.011 - 43.55.170. For purposes of this subsection, a carried-forward annual loss is the amount of a producer's adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b).

(c) A credit or portion of a credit under this section may not be used to reduce a person's tax liability under AS 43.55.011- 43.55.170 for any month below zero, and any unused credit or portion of a credit not used under this subsection may be applied in a later month.

(d) A person entitled to take a tax credit under this section that wishes to transfer the unused credit to another person may apply to the department for a transferable tax credit certificate. An application under this subsection must be on a

form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 60 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) if the applicant is required under AS 43.55.030(a) and (e) to file a statement on or before March 31 of the year following the calendar year in which the qualified capital expenditures or carried-forward annual loss for which the credit was incurred, the date the statement was filed; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a tax credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

(e) A person to which a transferable tax credit certificate is issued under (d) of this section may transfer the certificate to another person, and a transferee may further transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and notwithstanding any action the department may take with respect to the applicant under (g) of this section, the owner of a certificate may apply the credit or a portion of the credit shown on the certificate only against a tax due under AS 43.55.011 - 43.55.170. However, a credit shown on a transferable tax credit certificate may not be applied to reduce a producer's total tax due under AS 43.55.011 - 43.55.170 on oil and gas produced during a calendar year to less than 80 percent of the tax that would otherwise be due without applying that credit, and any portion of a credit not used under this subsection may be applied in a later period.

(f) Under standards established in regulations adopted by the department, the commissioner may repurchase a transferable tax credit certificate issued under (d) of this section if

(1) within 24 months after the date of issuance of the tax credit certificate, the person to whom the certificate was issued or any transferee of the certificate makes a qualified capital expenditure in this state or is the successful bidder

on a bid submitted for a lease on state land under AS 38.05.180(f); and

(2) the expenditure made or bid submitted under (1) of this subsection is not less than the amount of the transferable tax credit certificate issued under (d) of this section.

(g) The issuance of a transferable tax credit certificate under (d) of this section does not limit the department's ability to later investigate or audit a tax credit claim to which the certificate relates or to adjust or deny the claim if the department determines that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011 - 43.55.170 is increased by the amount of the credit that exceeds that to which the applicant was entitled. That amount bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, an applicant that is an explorer is considered a producer subject to the tax levied under AS 43.55.011.

(h) The department may adopt regulations to carry out the purposes of this section, including prescribing reporting, record keeping, and certification procedures and requirements to verify the accuracy of credits claimed and to ensure that a credit is not used more than once, and otherwise implementing this section.

(i) In this section,

(1) "explorer" has the meaning given in AS 43.55.025;

(2) "qualified capital expenditure"

(A) means, except as otherwise provided under (B) of this paragraph, an expenditure that is a lease expenditure under AS 43.55.160 and is

(i) incurred for geological or geophysical exploration; or

(ii) treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and either is treated as a capitalized expenditure by the person incurring the expenditure or is eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal Revenue Code), as amended;

(B) does not include an expenditure to acquire an asset (i) the cost of previously acquiring which was a lease expenditure under AS 43.55.160(c) or would have been a lease expenditure under AS 43.55.160(c) if it had been incurred on or after April 1, 2006; or (ii) that has previously been placed in service in the state; an expenditure to acquire an asset is not excluded under this subparagraph if not more than an immaterial portion of the asset meets a description under (i) or (ii) of this subparagraph; for purposes of this subparagraph, "asset" includes geological, geophysical, and well data and interpretations.

*** Sec. 14.** AS 43.55.030(a) is amended to read:

(a) The tax shall be paid to the department and the person paying the tax shall file with the department at the time the tax **or a portion of the tax** is required to be paid a statement, under oath, on forms prescribed by or acceptable to the department, giving, with other information required, the following:

(1) a description of **each** [THE] lease or property from which the oil **and** [OR] gas **were** [WAS] produced, by name, legal description, lease number, or [BY] accounting **codes** [CODE NUMBERS] assigned by the department;

(2) the names of the producer and the person paying the tax;

(3) the gross amount of oil **and the gross amount of** [OR] gas produced from **each** [THE] lease or property, and the percentage of the gross amount **of oil and of gas** owned by each producer for whom the tax is paid;

(4) the **gross** [TOTAL] value **at the point of production** of the oil **and of the** [OR] gas produced from **each** [THE] lease or property owned by each producer for whom the tax is paid; [AND]

(5) the name of the first purchaser and the price received for the oil **and for the** [OR] gas**, unless relieved from this requirement in whole or in part by the department; and**

(6) the producer's lease expenditures and adjustments as calculated under AS 43.55.160 [IF SOLD IN THE STATE].

*** Sec. 15.** AS 43.55.030(d) is amended to read:

(d) Reports by or on behalf of the producer are delinquent the first day

following the day the tax is due. [EACH PRODUCER IS SUBJECT TO A PENALTY OF $25 A DAY FOR EACH LEASE OR PROPERTY UPON WHICH THE REPORT IS NOT FILED. THE PENALTY FOR FAILURE TO FILE A REPORT IS IN ADDITION TO THE PENALTY FOR DELINQUENT TAXES, AND IS A LIEN AGAINST THE ASSETS OF THE PRODUCER.]

*** Sec. 16.** AS 43.55.030 is amended by adding a new subsection to read:

(e) In addition to other required information, the statement required to be filed on or before March 31 of a year must show any adjustments or corrections to the statements that were required under (a) of this section to be filed for the months of the preceding calendar year during which the oil or gas was produced.

*** Sec. 17.** AS 43.55.040 is amended to read:

Sec. 43.55.040. Powers of Department of Revenue. Except as provided in AS 43.05.405 - 43.05.499, the department may

(1) require a person engaged in production and the agent or employee of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil or gas to furnish**, whether by the filing of regular statements or reports or otherwise,** additional information that is considered by the department as necessary to compute the amount of the tax**; notwithstanding any contrary provision of law, the disclosure of additional information under this paragraph to the producer obligated to pay the tax does not violate AS 40.25.100(a) or AS 43.05.230(a); before disclosing information under this paragraph that is otherwise required to be held confidential under AS 40.25.100(a) or AS 43.05.230(a), the department shall**

(A) provide the person that furnished the information a reasonable opportunity to be heard regarding the proposed disclosure and the conditions to be imposed under (B) of this paragraph; and

(B) impose appropriate conditions limiting

(i) access to the information to those legal counsel, consultants, employees, officers, and agents of the producer who have a need to know that information for the purpose of determining or contesting the producer's tax obligation; and

(ii) the use of the information to use for the purpose of determining or contesting the producer's tax obligation;

(2) examine the books, records, and files of [SUCH] a person **described in (1) of this section**;

(3) conduct hearings and compel the attendance of witnesses and the production of books, records, and papers of any person; and

(4) make an investigation or hold an inquiry that is considered necessary to a disclosure of the facts as to

(A) the amount of production from any oil or gas location, or of a company or other producer of oil or gas; and

(B) the rendition of the oil and gas for taxing purposes.

* **Sec. 18.** AS 43.55.080 is amended to read:

Sec. 43.55.080. Collection and deposit of revenue. **Except as otherwise provided under art. IX, sec. 17, Constitution of the State of Alaska, the** [THE] department shall deposit in the general fund the money collected by it under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

* **Sec. 19.** AS 43.55.135 is amended to read:

Sec. 43.55.135. Measurement. For the purposes of **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150], oil **is** [SHALL BE] measured in terms of a "barrel of oil" and gas **is** [SHALL BE] measured in terms of a "cubic foot of gas."

* **Sec. 20.** AS 43.55.150(a) is amended to read:

(a) For the purposes of **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150], the gross value **at the point of production is** [SHALL BE] calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation **are** [SHALL BE] the actual costs, except **when the**

(1) [WHEN THE] parties to the transportation of oil or gas are affiliated;

(2) [WHEN THE] contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation;

(3) [WHEN THE] method of transportation of oil or gas is not

reasonable in view of existing alternative methods of transportation.

*** Sec. 21.** AS 43.55.150 is amended by adding a new subsection to read:

(d) Under regulations adopted by the department, the department may allow a producer, subject to limitations prescribed by the department as to the frequency of making elections, to elect prospectively to calculate the gross value at the point of production of oil or gas based in whole or part on

(1) a royalty value determined under a royalty settlement agreement between the producer and the state, with adjustments if appropriate;

(2) a formula prescribed by the department that uses, with adjustments if appropriate, a royalty value or valuation methodology accepted by the

(A) Department of Natural Resources under AS 38.05, in the case of oil and gas produced from a lease issued by the Department of Natural Resources or produced from a lease or property that is part of a unit approved by the Department of Natural Resources; or

(B) United States Department of the Interior under applicable federal oil and gas leasing statutes, in the case of oil and gas produced from a lease issued by the United States Department of the Interior that is not part of a unit approved by the Department of Natural Resources, or produced from a lease or property that is part of a unit approved by the United States Department of the Interior but not approved by the Department of Natural Resources; or

(3) another formula prescribed by the Department of Revenue that reasonably estimates a value for the oil or gas at a specific geographical location, such as the point of tender or delivery into a common carrier pipeline; the formula may use factors such as published price indices for oil or gas in or outside the state, quality differentials for oil or gas, transportation costs between markets, and inflation adjustments.

*** Sec. 22.** AS 43.55 is amended by adding new sections to article 1 to read:

Sec. 43.55.160. Determination of net value of oil and gas. (a) Except as provided in (f) of this section, for purposes of AS 43.55.011, the net value of the taxable oil and gas produced during a month is the total of the gross value at the point

of production of the oil and gas taxable under AS 43.55.011 and produced by the producer from all leases or properties in the state, (1) less the producer's lease expenditures for the month as adjusted under (e) of this section, and (2) to the extent allowed under (g) of this section and until the total amount of the producer's transitional investment expenditures has been deducted, less an amount equal to 1/84 of the producer's transitional investment expenditures. However, the net value calculated under this subsection may not be less than zero.

(b) In making the determination required by this section,

(1) any adjusted lease expenditures that would otherwise be deductible in a month but whose deduction would cause the net value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero may be added to the producer's adjusted lease expenditures for one or more other months in the same calendar year; the total of any adjusted lease expenditures that are not deductible in any month during a calendar year because their deduction would cause the net value calculated under (a) of this section of the taxable oil and gas produced during one or more months to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.024(b); and

(2) an amount of transitional investment expenditures that would otherwise be deductible in a month but whose deduction would cause the net value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero

(A) may be deducted in a later month during any calendar year to the extent allowed under (g) of this section, but not more than 1/84 of a producer's transitional investment expenditures may be deducted in any month;

(B) may not be used to establish a carried-forward annual loss under AS 43.55.024(b).

(c) For purposes of this section,

(1) a producer's lease expenditures for a period are the total costs upstream of the point of production of oil and gas that are incurred on or after April 1, 2006, by the producer during the period and that are direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas from deposits of oil or gas

located within the producer's leases or properties in the state or, in the case of land in which the producer does not own a working interest, direct, ordinary, and necessary costs of exploring for deposits of oil or gas located within other land in the state; however, lease expenditures do not include the costs incurred to satisfy a work commitment under an exploration license under AS 38.05.132; in determining whether costs are direct, ordinary, and necessary costs of exploring for, developing, or producing oil or gas from a deposit of oil or gas located within a lease or property or other land in the state, the department shall give substantial weight to

(A) the typical industry practices and standards in the state and in the United States as to costs that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, not the operator, with substantial bargaining power; and

(B) the standards adopted by the Department of Natural Resources as to the costs, other than interest, that a lessee is allowed to deduct from revenue in calculating net profits under a lease issued under AS 38.05.180(f)(3)(B), (D), or (E);

(2) the Department of Revenue may authorize a producer to treat as its lease expenditures under this section the costs paid by the producer that are billed to the producer by an operator in accordance with the terms of a unit operating agreement or similar operating agreement if the Department of Revenue finds that

(A) the pertinent provisions of the operating agreement are substantially consistent with the Department of Revenue's determinations and standards otherwise applicable under this subsection; and

(B) at least one working interest owner party to the agreement, other than the operator, has substantial incentive and ability to effectively audit billings under the agreement.

(d) For purposes of (c) of this section, "direct costs"

(1) includes

(A) outlays for capital assets;

(B) payments in lieu of property taxes;

(C) a reasonable allowance, as determined under regulations adopted by the department, for overhead expenses directly related to exploring for, developing, and producing oil or gas deposits located within leases or properties, or other land in the state;

(2) does not include

(A) depreciation or amortization of capital assets;

(B) royalty payments;

(C) taxes based on or measured by net income;

(D) interest or other financing charges or costs of raising equity or debt capital;

(E) acquisition costs for a lease or property or exploration license;

(F) costs arising from fraud, wilful misconduct, or negligence;

(G) fines or penalties imposed by law;

(H) costs of arbitration, litigation, or other dispute resolution activities that involve the state or concern the rights or obligations among owners of interests in, or rights to production from, one or more leases or properties or a unit;

(I) donations;

(J) costs incurred in organizing a partnership, joint venture, or other business entity or arrangement;

(K) amounts paid for purposes of indemnification.

(e) A producer's lease expenditures must be adjusted by subtracting any payment or credit the producer receives for

(1) the use by another person of a production facility in which the producer has an ownership interest;

(2) a reimbursement or similar payment that offsets the producer's lease expenditures, including any payment from the state or federal government for reimbursement of the producer's upstream costs, including costs for gathering, separating, cleaning, dehydration, compressing, or other field handling associated with

the production of oil or gas upstream of the point of production;

(3) the sale or other transfer of

(A) an asset, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of a lease expenditure or an expenditure that would be a lease expenditure if it were incurred on or after April 1, 2006; and

(B) oil or gas

(i) that is not considered produced from a lease or property under AS 43.55.020(e); and

(ii) the cost of acquiring which is a lease expenditure incurred by the person that acquires the oil or gas.

(f) In place of the adjusted lease expenditures for a month under (a) of this section, a producer may, at any time, elect to substitute, for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year.

(g) For the purposes of this section,

(1) a producer's transitional investment expenditures are the sum of the expenditures the producer incurred on or after January 1, 2003, and before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, less the sum of the payments or credits the producer received before April 1, 2006, for the sale or other transfer of assets, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of expenditures the producer incurred on or after January 1, 2003, and before April 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024, if they were incurred on or after April 1, 2006, multiplied by

(A) 25 percent for expenditures incurred on or after January 1, 2003, and before January 1, 2004;

(B) 50 percent for expenditures incurred on or after January 1, 2004, and before January 1, 2005; and

(C) 75 percent for expenditures incurred on or after January 1, 2005, and before April 1, 2006;

(2) notwithstanding (1) of this subsection, an amount of transitional

investment expenditures may not be deducted under (a) of this section for a month for which the average price of Alaska North Slope oil delivered on the United States West Coast, as determined under (h) of this section, is equal to or less than $40 a barrel, as adjusted for inflation under (h) of this section.

(h) The average price described in (g)(2) of this section shall be an average, as calculated using a formula prescribed by the department by regulation, of published daily spot price assessments during the month for Alaska North Slope oil delivered on the United States West Coast. However, if the department determines that the daily assessments cease to be published throughout the calendar year or appear likely to soon cease to be published throughout the calendar year or that they cease to be reliable evidence of market conditions or appear likely to soon cease to be reliable evidence of market conditions, the department shall by regulation provide that the average price described in (g)(2) of this section is the prevailing value of Alaska North Slope oil delivered on the United States West Coast as determined under regulations of the department implementing AS 43.55.020(f). For each year after 2006, the reference price of $40 a barrel set out in (g)(2) of this section shall be adjusted for inflation using an appropriate consumer price index published by the United States Bureau of Labor Statistics, as prescribed by the department by regulation.

(i) The department shall specify or approve a reasonable allocation method for determining the portion of a cost that is appropriately treated as a lease expenditure under (c) of this section if a cost that would otherwise constitute a lease expenditure under (c) of this section is incurred to explore for, develop, or produce

(1) both an oil or gas deposit located within land outside the state and an oil or gas deposit located within a lease or property, or other land, in the state; or

(2) an oil or gas deposit located partly within land outside the state and partly within a lease or property, or other land, in the state.

(j) The department may adopt regulations that establish additional standards necessary to carrying out the purposes of this section.

(k) For purposes of AS 43.55.024(a) and (b) and only as to expenditures incurred to explore for an oil or gas deposit located within land in which an explorer, as defined in AS 43.55.025, does not own a working interest, the term "producer" in

(c) and (e) of this section includes "explorer."

(*l*) For purposes of this section,

(1) "explore" includes conducting geological or geophysical exploration, including drilling a stratigraphic test well;

(2) "stratigraphic test well" means a well drilled for the sole purpose of obtaining geological information to aid in exploring for an oil or gas deposit, the target zones of which are located in the state.

Sec. 43.55.170. Additional nontransferable credit. (a) For a month for which the net value of the taxable oil and gas produced during the month calculated under AS 43.55.160 exceeds zero, a producer that is qualified under (b) of this section may reduce the net value by applying a tax credit for a qualified capital expenditure, as that term is defined in AS 43.55.024, if the qualified capital expenditure involved a payment made in this state and the claim of the credit is not taken under AS 43.55.024 or 43.55.025. The credit authorized by this subsection may be calculated and applied so that

(1) the net value for the month is not reduced below zero; and

(2) the total of the credits applied during the calendar year does not exceed $10,000,000.

(b) On written application by a producer, including any information the department may require, the department shall determine whether the producer qualifies under this section for a calendar year. To qualify under this section, a producer must demonstrate that its operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer entity would not result in the division among multiple producer entities of any net value of taxable oil and gas, as determined under AS 43.55.160(a), that would be reasonably expected to be attributed to a single producer entity if the allowance provision of (a) of this section did not exist.

(c) An unused allowance or portion of an allowance under this section is not transferable under AS 43.55.024(d), may not be carried forward to a later calendar year, and may not be used to establish a carried-forward annual loss under AS 43.55.024(b).

(d) A producer may not claim a credit under this section for a qualified capital expenditure incurred after March 31, 2016.

*** Sec. 23.** AS 43.55.201(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011, except that, notwithstanding any contrary provisions of AS 43.55.020(a), the full amount of the surcharge is due on the last day of each calendar month on oil produced from each lease or property during the preceding month. The surcharge** [AS 43.55.011 - 43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.300 - 43.55.310.

*** Sec. 24.** AS 43.55.201(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 25.** AS 43.55.201 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

*** Sec. 26.** AS 43.55.300(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011, except that, notwithstanding any contrary provisions of AS 43.55.020(a), the full amount of the surcharge is due on the last day of each calendar month on oil produced from each lease or property during the preceding month. The surcharge** [AS 43.55.011 - 43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.201 - 43.55.231.

*** Sec. 27.** AS 43.55.300(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.170** [AS 43.55.011 - 43.55.150].

*** Sec. 28.** AS 43.55.300 is amended by adding a new subsection to read:

(d) Oil not considered under AS 43.55.020(e) to be produced from a lease or property is not considered to be produced from a lease or property for purposes of this section.

*** Sec. 29.** AS 43.55.900(6) is repealed and reenacted to read:

(6) "gas" means

(A) all natural, associated, or casinghead gas;

(B) all hydrocarbons that

(i) are recovered by mechanical separation of well fluids or by gas processing; and

(ii) exist in a gaseous phase at the completion of mechanical separation and any gas processing; and

(C) all other hydrocarbons produced from a well not defined as oil;

*** Sec. 30.** AS 43.55.900(7) is repealed and reenacted to read:

(7) "gross value at the point of production" means

(A) for oil, the value of the oil at the automatic custody transfer meter or device through which the oil enters into the facilities of a carrier pipeline or other transportation carrier in a condition of pipeline quality; in the absence of an automatic custody transfer meter or device, "gross value at the point of production" means the value of the oil at the mechanism or device to measure the quantity of oil that has been approved by the department for that purpose, through which the oil is tendered and accepted in a condition of pipeline quality into the facilities of a carrier pipeline or other transportation carrier or into a field topping plant;

(B) for gas, other than gas described in (C) of this paragraph, that is

(i) not subjected to or recovered by mechanical separation or gas processing, the value of the gas at the first point where the gas is accurately metered;

(ii) subjected to or recovered by mechanical separation but not gas processing, the value of the gas at the first point where the gas is accurately metered after completion of mechanical separation;

(iii) subjected to or recovered by gas processing, the value of the gas at the first point where the gas is accurately metered after completion of gas processing;

(C) for gas run through an integrated gas processing and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the value of the gas at the first point where gas processing is completed or where gas treatment begins, whichever is further upstream;

*** Sec. 31.** AS 43.55.900(10) is repealed and reenacted to read:

(10) "oil" means

(A) crude petroleum oil; and

(B) all liquid hydrocarbons that are recovered by mechanical separation of well fluids or by gas processing;

*** Sec. 32.** AS 43.55.900 is amended by adding new paragraphs to read:

(17) "gas processing"

(A) means processing a gaseous mixture of hydrocarbons

(i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation;

(ii) for the purpose of extracting and recovering liquid hydrocarbons; and

(iii) upstream of any gas treatment and upstream of the inlet of any gas pipeline system transporting gas to a market;

(B) does not include gas treatment;

(18) "gas treatment"

(A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system; and

(B) includes incidentally removing liquid hydrocarbons from the gas.

*** Sec. 33.** AS 43.55.011(b), 43.55.011(c), 43.55.012(b), 43.55.013, 43.55.016, 43.55.900(1), 43.55.900(8), 43.55.900(11), 43.55.900(12), and 43.55.900(16) are repealed.

*** Sec. 34.** The uncodified law of the State of Alaska is amended by adding a new section to

read:

APPLICABILITY. (a) Sections 5, 8 - 11, 13, 14, 16, and 20 - 33 of this Act apply to oil and gas produced on or after April 1, 2006.

(b) Section 12 of this Act applies to oil and gas produced before, on, or after the effective date of sec. 12 of this Act.

*** Sec. 35.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITIONAL PROVISIONS. (a) Notwithstanding any contrary provision of AS 43.55.024(a), enacted by sec. 13 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "every month an annualized tax credit in an amount equal to one and two-thirds percent" in AS 43.55.024(a), enacted by sec. 13 of this Act, shall be replaced by the phrase "every month during the period April 1, 2006, through December 31, 2006, an annualized tax credit in an amount equal to 2.222 percent."

(b) Notwithstanding any contrary provision of AS 43.55.024(e), enacted by sec. 13 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "a calendar year" in AS 43.55.024(e), enacted by sec. 13 of this Act, shall be replaced by the phrase "the last nine months of the calendar year."

(c) Notwithstanding any contrary provision of AS 43.55.160(f), enacted by sec. 22 of this Act, for oil and gas produced on or after April 1, 2006, and before January 1, 2007, the phrase "for every month of a calendar year, one-twelfth of the producer's adjusted lease expenditures for the calendar year" in AS 43.55.160(f), enacted by sec. 22 of this Act, shall be replaced by the phrase "for each of the last nine months of 2006, 2.222 percent of the producer's adjusted lease expenditures for that nine-month period."

(d) For oil and gas produced before April 1, 2006, the provisions of AS 43.55, and regulations adopted under AS 43.55, that were in effect before April 1, 2006, and that were applicable to the oil and gas continue to apply to that oil and gas.

*** Sec. 36.** The uncodified law of the State of Alaska is amended by adding a new section to read:

TRANSITION: REGULATIONS. The Department of Revenue may proceed to adopt regulations to implement the changes made by this Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not before the effective date of the law

implemented by the regulation.

*** Sec. 37.** The uncodified law of the State of Alaska is amended by adding a new section to read:

REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the heading of

(1) AS 43.55 from "Oil and Gas Production Taxes and Oil Surcharge" to "Oil and Gas Production Tax and Oil Surcharge";

(2) article 1 of AS 43.55 from "Oil and Gas Properties Production Taxes" to "Oil and Gas Production Tax";

(3) AS 43.55.011 from "Oil production tax" to "Oil and gas production tax";

(4) AS 43.55.025 from "Tax credit for oil and gas exploration or gas only exploration" to "Alternative tax credit for oil and gas exploration or gas only exploration";

(5) AS 43.55.150 from "Determination of gross value" to "Determination of gross value at the point of production."

*** Sec. 38.** The uncodified law of the State of Alaska is amended by adding a new section to read:

CONDITIONAL RETROACTIVITY. If the sections of this Act that, under sec. 40 of this Act, are scheduled to take effect April 1, 2006, take effect on or after April 1, 2006, those sections of this Act are retroactive to April 1, 2006.

*** Sec. 39.** Sections 1 - 4, 7, 12, 15, 17, and 36 - 38 of this Act take effect immediately under AS 01.10.070(c).

*** Sec. 40.** Except as provided in sec. 39 of this Act, this Act takes effect April 1, 2006.

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: LL06-0052-DNR-O&G-02
() Publish Date:

Revision Date/Time (Note if correction):
Dept. Affected: Natural Resources

Title: Repealing the oil production tax and gas production tax etc.
RDU: Resource Development
Component: Oil & Gas Development

Sponsor: Rules by Request of Governor
Requester: Governor
Component No: 459

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )						

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2006) cost: 0.0
Mark this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

There is no anticipated fiscal impact for DNR associated with implementation of this legislation.

Prepared by: Bill VanDyke, Acting Director
Phone: 907-269-8800
Division: Oil & Gas
Date/Time: 2/15/2006
Approved by: Michael Menge, Commissioner
Date: 2/15/2006
Agency: Natural Resources

(Revised 9/7/2005 OMB)

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: 773060052
() Publish Date:

Revision Date/Time (Note if correction):
Dept. Affected: Revenue
Title: An Act Relating to the Production Tax on Oil and Gas
RDU: Tax and Treasury
Component: Tax
Sponsor: Rules Committee
Requester: Governor
Component No.: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	359.2	366.4	373.7	381.2	388.8	396.6
Travel						
Contractual	1,200.0	520.0				
Supplies	24.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous [OH office, etc]	18.0	18.0	18.0	18.0	18.0	18.0
TOTAL OPERATING	**1,601.2**	**904.4**	**391.7**	**399.2**	**406.8**	**414.6**
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )	*See analysis section*					

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	1,601.2	904.4	391.7	399.2	406.8	414.6
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	**1,601.2**	**904.4**	**391.7**	**399.2**	**406.8**	**414.6**

Estimate of any current year (FY2006) cost: 275.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time	4	4	4	4	4	4
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, property taxes, and an additional $73 million per year allowance for each producer. (The allowance can be no greater than the net value before the allowance.) The net income would be subject to a 20% tax, less a credit of 20% which applies to capital costs upstream of the point of production. In addition, there would be a deduction for capital costs incurred over the previous five years, which can be realized over the next six years, but only in years where the ANS price is over $40. It is estimated this would reduce revenues about $170 million in years when it was realized. In years where the ANS price is under $40 the deduction can be carried forward.

Prepared by: Robynn Wilson, Michael Williams, and Roger Marks
Phone: 269-1019
Division: Tax Division
Date/Time: 2/21/06 12:00 AM
Approved by: Jerry Burnett
Date: 2/21/2006
Agency: Department of Revenue

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. _____

ANALYSIS CONTINUATION

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo under various prices. They are predicated on the oil volumes in the Department of Revenue Fall 2005 Revenue Sources Book. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. They assume that seven producers utilize the full allowance. The status quo assumes the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- $100 mm/yr exploration
- $1/bbl on-going capital on all barrels
- $3.50/bbl developmental capital or /3 of existing conventional oil
- $8/bbl developmental capital on 2/3 of existing heavy oil
- $3.50/bbl developmental capital on new conventional oil
- $8/bbl developmental capital on new heavy oil
- $3/bbl operating cost on conventional oil
- $5/bbl operating cost on heavy oil

The following table shows the 2007-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a $40 price, and a $60 price. (Note that the status quo numbers are slightly different from what is reflected in the Fall 2005 Revenue Sources Book because of some minor changes in assumptions introduced since Fall 2005, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 3 additional positions for auditors: 1 O & G Specialist (Range 23), 1 O & G Revenue Auditor IV (Range 22), and 1 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax. In addition, we request 1 additional position for a Tax Tech III (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenses include $100,000 and $70,000 for programming in FY 07 and FY 08, respectively, $250,000 in each of FY 07 and FY 08 for help in writing regulations, and $850,000 and $200,000 in FY 07 and FY 08, respectively, for auditing costs related to the new transition rules. Supplies include computers and other supplies necessary for new positions.

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. _____

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

Fiscal Year	DOR Forecast	Status Quo Tax	Tax from Bill	Gain from Bill
2007	49.20	934	1,363	429
2008	40.95	697	915	217
2009	25.50	404	349	-55
2010	25.50	387	339	-48
2011	25.50	362	351	-11
2012	25.50	343	332	-10

Fiscal	Medium	Status Quo	Tax from	Gain from

Year	Price	Tax	Bill	Bill
2007	40.00	737	1,038	301
2008	40.00	679	1,031	353
2009	40.00	673	1,118	445
2010	40.00	646	1,106	460
2011	40.00	606	1,138	532
2012	40.00	576	1,112	536

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007	60.00	1,165	1,938	773
2008	60.00	1,069	1,917	848
2009	60.00	1,042	2,007	965
2010	60.00	1,003	1,992	989
2011	60.00	941	2,051	1,110
2012	60.00	896	2,014	1,117

Proposed Petroleum Production Tax (PPT)
Questions and Answers

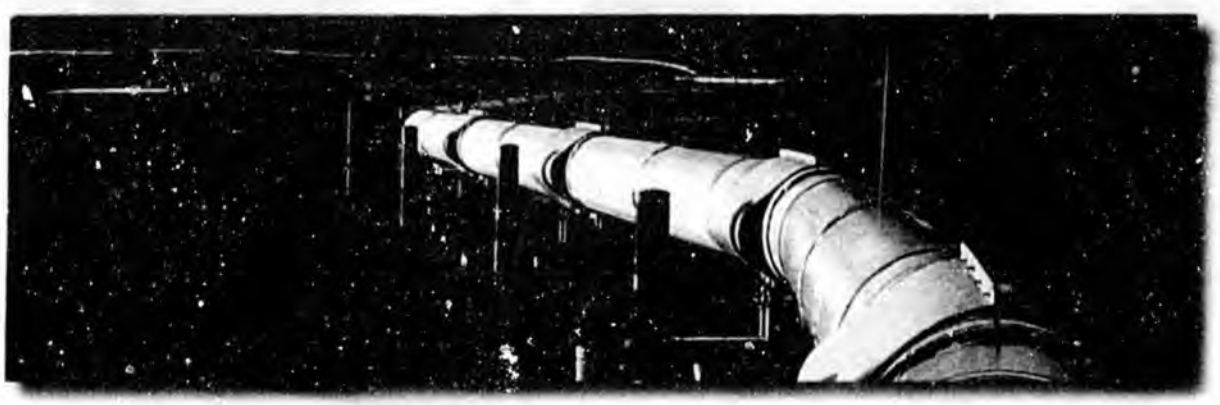
What is the new petroleum production tax?
The new petroleum production tax will change the existing oil taxation system in Alaska. The current production tax on oil is based on a percentage of the gross value of production. A new petroleum production tax would be based on a percentage of the net profit. The current production tax rate is driven by the Economic Limit Factor (ELF). This ELF-based system is no longer working for Alaska.The second largest oil field in the nation (Kuparuk) will no longer pay a production tax in the next year and Prudhoe Bay will pay a near zero production tax in 12 - 14 years.

Why is a new petroleum production tax a good idea?
The ELF-based oil production tax no longer works effectively for Alaska for three reasons:

1. Alaska is not getting its fair share of oil revenue under the ELF system compared to what the producers are paying in similar oil regimes around the world.
2. The current production tax provides few incentives for exploration, development and investment. The new oil production tax being proposed will provide significant new oil and gas exploration and investment incentives.
3. ELF will drop to near zero in 12 -14 years, meaning that Alaskans will receive no production tax revenue.

How would this new tax work?
The new tax system would be net cash flow driven. That is, it would be based on the difference between capital and operating expenditures and revenues as they occur annually. As a result, tax revenue would be lower when the initial large new capital outlays are made and higher as production responds to that investment and net cash flow becomes positive.

What are the tax rates?
The producers will pay a 20% tax rate with a 20% tradable capital investment tax credit. The bill also provides for a $73 million annual allowance to be used as an additional deduction as long as the allowance is not greater than the net value before the allowance. 20% of any carry-forward loss may also be taken as a tax credit.



Continued.-->

Is this tax designed to make the state more money?

Yes, when oil prices are above approximately $25 per barrel. Under the current system, when profits are high, they are being expatriated outside of Alaska because there is no tax incentive to invest in Alaska. However, when producers reinvest their profits here, or when prices are low because of low oil prices or high costs, it is possible that the state could see lower production tax revenue. More investment will lead to more barrels, more barrels will lead to more profits and more profits will lead to more taxes.



Why should the State change the oil tax?

Alaska should receive a fair share of the revenue generated from our natural resources. The current oil production tax does not provide Alaska the same level of revenue (also considering federal tax) that the producers are paying in similarly situated oil provinces around the world.

The new petroleum production tax would be a component of the fiscal stability offered to the producers who are proposing to build the gas pipeline. It is only fair that in exchange for fiscal stability on oil taxes that the state gets a fair share, similar to what the producers are paying elsewhere in the world, especially since fiscal stability increases the value of the leases that the producers hold.

What are the benefits of this tax?



A new petroleum production tax would ensure that Alaska gets a fair share of oil revenues compared to what the producers are paying in similar areas around the world. The structural tax change puts in place development incentives that encourages new and existing producers to invest their oil profits in finding and developing Alaska's oil and gas resources.

What about incentives for development?

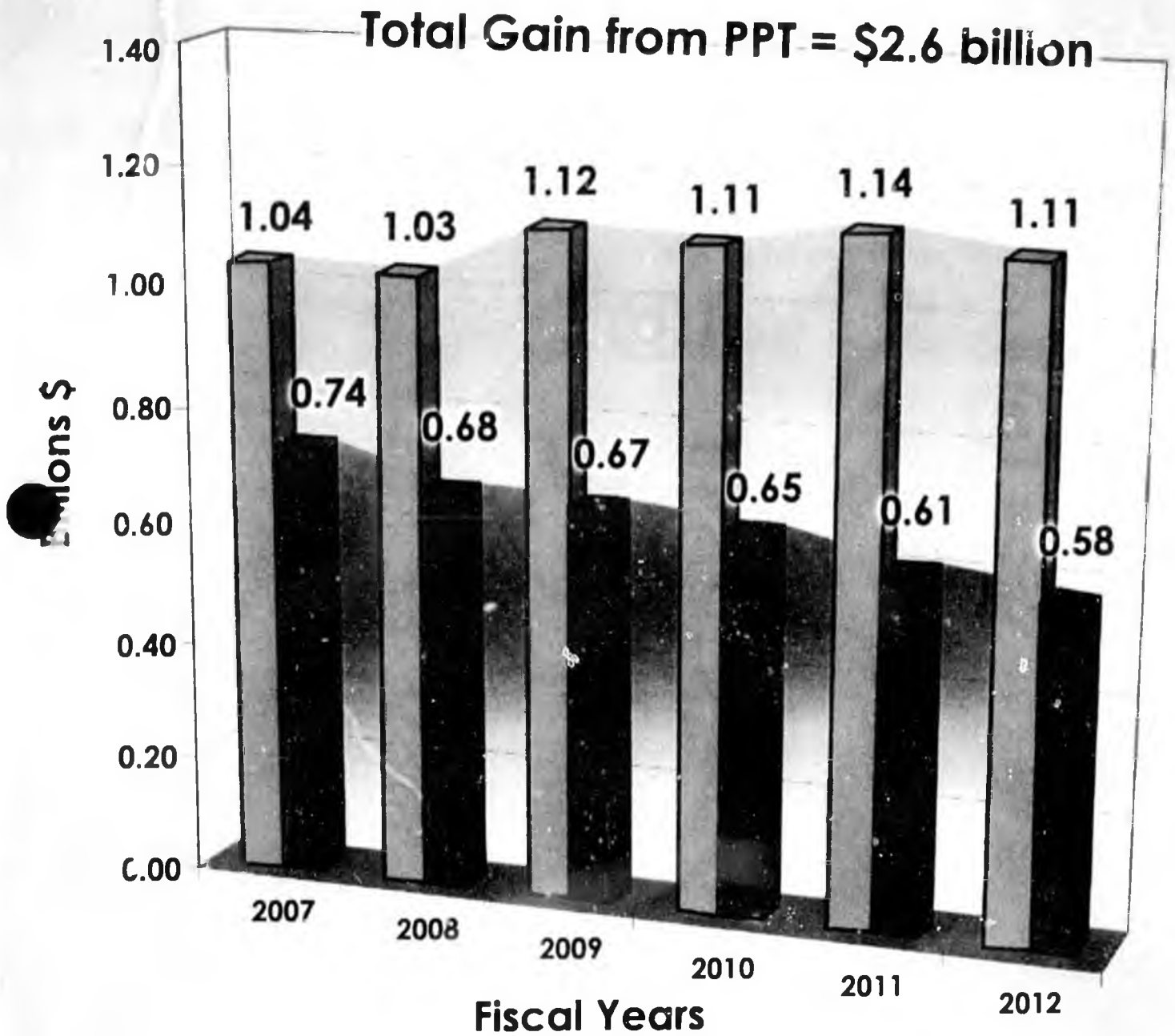
The bill creates new incentives for investment, exploration and development - a 20% tradable capital investment tax credit and a $73 million "standard deduction". The new incentives were included in the legislation because Prudhoe Bay is an aging field and other than ANWR, we are unlikely to find major new oil fields on state land on the North Slope. Explorers are more likely to find new fields in the 50 to 150 million barrel range. These explorers will need incentives to find and develop these expensive and smaller fields.

For Questions and Comments:

Chuck Logsdon
Gas Pipeline Negotiations Spokesman
907.269.7450

Becky Hultberg
Governor's Spokeswoman
907.465.3500

Oil Production Revenue Comparison
Current vs. Proposed (Billions $)

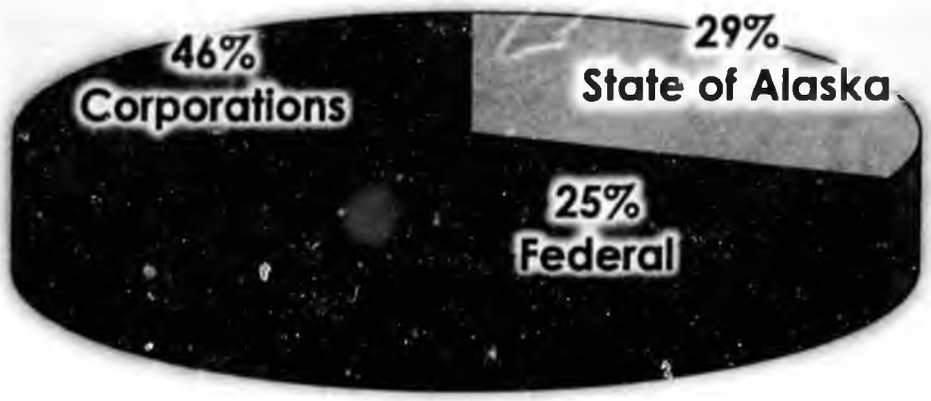


Proposed Petroleum Production Tax

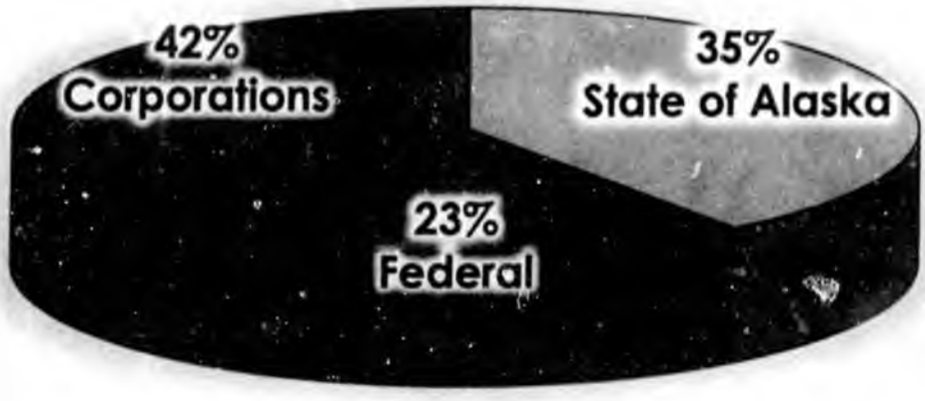
Current Oil Production Tax

Based on Fiscal Note at $40 per Barrel

Oil Resource Value Shares
Over Long Term (2006-2050)



Current System



PPT System

Production Tax, Royalties, Corporate Income Tax, Property Tax

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STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

February 21, 2006

The Honorable John Harris
Speaker of the House
Alaska State Legislature
State Capitol, Room 208
Juneau, AK 99801-1182

Dear Speaker Harris:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill relating to the oil and gas production tax.

This bill would eliminate the economic limit factor (ELF) from the determination of production tax, and would replace it with a more progressive and investment-friendly tax system.

Under current law, the tax imposed on oil or gas production generally is determined by multiplying the gross value at the point of production times the appropriate tax rate times the economic limit factor for that production.

The economic limit factor was intended to provide a proxy for costs. It is determined by a complex formula that uses as input the total production from, and productivity of, the wells in a field. The theory behind the economic limit is that a producer would not be taxed for production below the economic limit while still recovering costs. However, this has not worked well in recent practice. On the one hand, under current conditions, producers are allowed proxy costs several times their actual costs. On the other hand, a producer reinvesting its profits from Alaska production in exploration, production, or development in the state may receive little or no tax benefit compared to a producer who exports its profits and makes those same investments in another state or country.

As explained in more detail below, this bill introduces two important investment-friendly tax concepts in place of the economic limit factor.

- The tax proposed in the bill is based essentially on the cash flow from a lease, or the profit net of all qualified costs. Thus, a deduction is allowed for all upstream costs, including expenses and capital investment. In other words, the tax base is not gross value at the point of production but the net value. In addition, every producer is allowed an annual allowance of up to $73 million, so if a producer's cash flow is $73 million or less in a year, there would be no tax.
- A 20 percent tax credit is allowed for all the upstream capital investment, even if a deduction was taken for that investment as described above. Another credit is allowed for operating losses.

Because of this proposed switch from a gross to net basis, a higher tax rate is appropriate and this bill would raise the rate (before applying ELF) from the current 15 percent (or 12.25 percent for new production) to 20 percent. In addition, the minimum tax is repealed. Thus, as mentioned above, a company would incur a production tax liability only if it has positive cash flow from its Alaska production properties greater than $73 million a year.

Upstream Cost Deduction

The calculation of the net value of a producer's oil and gas starts with gross value, which is essentially unchanged from current law, with some streamlining. Direct lease costs, including both capital investment and operating costs are deducted from that gross value. If in any month the total cash flow is reduced to zero by those costs, remaining costs are carried forward to future months (or, if unused by the end of a calendar year, are translated into a credit applicable in future years). In addition, each producer is granted an allowance of up to $200,000 a day or $73 million a year. That is, if after calculating its net profit a producer still showed positive cash flows of $73 million or less, this allowance may be used to reduce that cash flow to zero (though again, not any lower). If the producer showed a positive cash flow of more than $73 million, the allowance would be used to reduce the taxable cash flow by $73 million. Finally, as a transition measure, for the first 72 months in which the Alaska North Slope oil spot price is above $40 a barrel, a producer is allowed to include in its upstream deduction a pro rata amount of capital costs incurred in the five years before the new production tax takes effect.

In the interests of streamlining and simplicity, the Department of Revenue is directed to take into account the kind of costs that an operator typically bills a working interest owner (and a working interest owner typically audits) and the Department of Natural Resources' net profit share lease regulations.

A number of indirect costs that may not be included in the calculation of direct lease costs are specified in the bill. Finally, the bill specifies that any deduction for lease expenses must be reduced by any reimbursements that a taxpayer receives from other taxpayers, say, for example, for use of facilities, or from the government where such payments are in the nature of field costs.

New Investment Credits

Two major new credits are provided for in the bill.

(1) A credit would be allowed against the production tax for 20 percent of any qualified investment, even though that same outlay may also be deductible in calculating taxable net value of the oil and gas. This credit and the exploration credits under AS 43.55.025 may not both be taken for the same expenditures. Qualified capital expenditures include outlays for new (or new-to-Alaska) assets that are treated as capital under the federal tax code, as well as geological and geophysical exploration costs and drilling costs that would be expensed under the federal tax code.

(2) A credit also would be allowed for 20 percent of any annual loss. Because the tax due can only be reduced to zero (and not below zero), mechanically this is the same as allowing unclaimed expense to be carried forward year to year, but for tax administration purposes it is preferable for carryforwards to be in the form of credits.

These credits would be non-refundable; that is, they could not be used to reduce a taxpayer's liability below zero. However, any credit not used in a given period could either be carried forward or sold to another taxpayer who might better be able to use it. Taxpayers who purchase credits may not use the credits to reduce their production taxes by more than 20 percent in any year.

In addition to the two major new credits, producers would be allowed to credit their oil conservation surcharge payments under AS 43.55 against the production tax.

Other Provisions

In providing for taxation of the net value of oil and gas, the bill also would preserve most of the current provisions on calculating gross value at the point of production, since this calculation is an intermediate step in calculating taxable net value. This approach has the benefit of conserving the body of regulations, interpretations, and case law that has developed over several decades. In the interest of fostering simplicity and efficiency, however, the bill would make a significant addition to the current provisions, authorizing the Department of Revenue to allow taxpayers, if appropriate, to rely on royalty settlement agreements with the Department of Natural Resources (DNR), or other royalty values or methodologies accepted by the DNR, or the United States Department of the Interior (in the case of some federal leases or units) or to use a simplifying formula approved by the Department of Revenue.

The bill would make several changes in current law to facilitate administration of the new production tax approach. The subjects addressed include tax returns and tax payment due dates, definitions of oil and gas and other terms, and treatment of private royalty oil and gas for production tax purposes. The bill clarifies how the Department of Revenue may disclose certain otherwise confidential information to taxpayers when the information affects their tax liabilities. Persons who violate the conditions of such disclosure would be subject to the same criminal penalties that currently apply to state employees who violate taxpayer confidentiality. The bill also simplifies the tax treatment of flared gas and extends to oil the current tax exemption for gas that is used on the lease.

The bill would make needed updates and clarifications to certain provisions of the production tax statute: confirming the Department of Revenue's long-standing application of the prevailing value concept to internal transfers of oil or gas, incorporating a necessary reference to the constitutional budget reserve fund regarding the department's disposition of revenue, and repealing a specific failure-to-file penalty that is superfluous in the light of the general penalty provisions of the revenue laws.

The proposed new production tax on net value, and related provisions of the bill, would apply prospectively, as of July 1, 2006. The bill has an immediate effective date for other purposes.

This bill will greatly improve Alaska's oil and gas tax system, encouraging investment in the state, making tax administration more predictable, better reflecting the variable economics of oil and gas development,

and providing Alaskans with a fairer share of the value of the oil and gas taken out of the ground in our state. I urge your prompt and favorable action on this legislation.

Sincerely yours,

Frank H. Murkowski
Governor

Enclosure

HB 488
"OIL AND GAS PRODUCTION TAX"
SECTIONAL ANALYSIS

Section 1: This section addresses the legislative intent of sec. 11 of the bill, which amends AS 43.55.020(f), a provision of the production tax statute. Section 1 explains that the intent is not to change the meaning or effect of that law but rather to confirm the meaning as it has long been interpreted by the Department of Revenue.

Sections 2 and 3: These sections amend provisions of the corporate income tax statute, AS 43.20, to ensure that the oil and gas production tax, as amended by this bill, is not treated the way an income tax is treated under that statute. Specifically, the amendments ensure that the production tax may be deducted, and that the production tax will not be added back to federal taxable income, for purposes of computing the corporate income tax.

Section 4: This section deals with criminal penalties for unauthorized disclosure of confidential tax records. Currently, AS 43.05.230(f) subjects current or former state officers, employees, and agents to fine or imprisonment for such disclosure. Section 4 would extend the criminal penalties to private persons who violate conditions imposed by the Department of Revenue limiting access to and use of certain confidential information related to the production tax.

Section 5: This section is one of the core provisions of the bill. It (together with the repealer provision, sec. 34) replaces the current production taxes on oil and gas with a single production tax on both oil and gas. The current taxes are generally based on a percentage of the *gross* value of oil or gas at the point of production As amended by sec. 5, the production tax is equal to 20 percent of the *net* value of oil and gas. Section 21 of the bill addresses how net value is determined.

Section 6: This section conforms certain existing statutory terminology to that used in the Internal Revenue Code and incorporates a definition that no longer needs to be located in a separate definitions section of the statute.

Section 7: This section deals with production tax payment due dates and interest. As under existing law, the production tax remains a monthly tax, but because a taxpayer's exact liability may be subject to adjustment in light of later information or events (such as capital investments), only 90 percent of the tax is initially due each month. The remainder is due when a "true-up" return is filed by March 31 of the next calendar year.

Sections 8, 18, 19, 22, 23, 26, 27, and 38: These sections are simply conforming amendments or updates to reflect current legislative language usage.

Section 9: This section deals with a producer's right to charge a private royalty owner for the share of production taxes attributable to royalty oil and gas. That right is recognized in existing law; what the section adds is a method of determining the royalty share of the taxes in the absence of an agreement between the producer and royalty owner to use a different method.

Section 10: This section expands the current production tax exemption for gas that is used in lease operations, to include oil that is used in lease operations. The section also simplifies the treatment of flared gas, which currently may be tax exempt, taxable, or both taxable and subject to a penalty, depending on why it is flared. Under this bill, gas whose flaring is authorized by the Alaska Oil and Gas Conservation Commission would be tax exempt; and otherwise it would be taxable.

Section 11: This section amends a provision of the production tax statute allowing the Department of Revenue to require production tax to be paid on the basis of the prevailing value of oil or gas. The section clarifies that the provision applies, not only where the sale price of oil or gas is sold differs from the prevailing value, but also where the oil or gas is not sold at all – for example, where it is refined by the company that produced it.

Section 12: This core section of the bill provides for two new types of tax credits that may be applied against the production tax. One is in the amount of 20 percent of capital expenditures for oil or gas exploration, development, or production. The other is in the amount of 20 percent of net losses from oil or gas exploration, development, or production that are carried forward from previous years. An unused credit may be sold to other producers by applying to the Department of Revenue for a transferable tax credit certificate. If the Department of Revenue later finds that the original producer's credit claim was invalid, it may assess a tax deficiency against that producer, but the purchaser of the certificate would still be able to rely on and use the certificate in full.

Sections 13 - 15: These sections update the statutory provisions that govern production tax returns, including requiring those returns to report on the costs that will be deductible under this bill for purposes of calculating taxable net value of oil and gas. The annual return that "trues up" prior year monthly returns must show any adjustments or corrections to those monthly returns. Section 13 repeals a $25 per day penalty for failure to file a production tax return, in light of the fact that there is a generally applicable late-filing penalty in the tax administration provisions of AS 43.

Section 16: This section clarifies that the Department of Revenue's power to obtain information relevant to determining taxes includes the power to require the filing of regular reports. The section also clarifies the statutory confidentiality restrictions on tax information, recognizing that the Department of Revenue may disclose such information to a taxpayer when it is necessary to compute that taxpayer's liability. In such

circumstances, the Department is required to impose appropriate limitations on which individuals may have access to the information and how the information may be used.

Section 17: This section amends the current requirement that production taxes be deposited in the general fund, to incorporate exceptions imposed under the constitutional budget reserve fund amendment.

Section 20: This section amends AS 43.55.150, which deals with determining the gross value at the point of production of oil and gas. The section authorizes the Department of Revenue to allow producers to calculate the gross value with a formula that uses a producer's royalty settlement agreement with the state, or a royalty value or valuation methodology accepted by the Department of Natural Resources or the United States Department of the Interior in certain cases, or another formula using such factors as published price indices.

Section 21: This section, a core provision of the bill, provides for the calculation of a producer's net value of taxable oil and gas. This calculation may include five steps. First, the gross value at the point of production of all of the producer's taxable oil and gas statewide is computed. Second, the producer's deductible costs of oil and gas exploration, development, and production – called adjusted lease expenditures -- in the state are totaled. Third, those costs are deducted from gross value. Fourth, a specified fraction of the producer's oil and gas capital investments during the five years before the new tax law takes effect may be deducted. Fifth, an allowance of up to $73 million, spread over a calendar year, may be deducted. In no case, however, may the net value calculation for oil and gas drop below zero; the section establishes rules for the treatment of unused deductions.

The section directs the Department of Revenue to give substantial weight, in determining deductible costs, to typical industry practices and standards as reflected in billable types of costs under joint operating agreements, and allows the Department of Revenue to authorize producers in appropriate circumstances to rely on billings under such agreements for production tax purposes. The section also provides examples of costs that are potentially deductible as "direct" costs and examples of costs that are not deductible because they are not "direct." Costs are required to be adjusted to account for reimbursements, asset sales, and other relevant producer receipts.

The section establishes limits on the deduction of previous capital investments, including a requirement that the West Coast price of Alaska North Slope oil must exceed $40 per barrel for the month. This figure is subject to future adjustment for inflation.

To benefit from an annual allowance of up to $73 million, a producer must qualify with the Department of Revenue. The qualification requirement is designed to prevent the proliferation of producer entities for tax avoidance purposes.

Sections 24 and 28: These sections provide that oil that is exempt from production tax because it is used in lease operations, is also exempt from the oil conservation surcharges under AS 43.55.

Sections 25 and 29: These sections allow a producer to take a credit against the production tax for the amount paid in oil conservation surcharges.

Sections 30 – 33: These sections change the existing statutory definitions of "oil," "gas," and "gross value at the point of production," and add new definitions for "gas processing" and "gas treatment." Under these definitions, gas processing is considered an operation upstream of the point of production for gas, and generally the line between what is oil and what is gas corresponds to what substances are in liquid form and what substances are in gaseous form, respectively, at the point of production.

Section 34: This section repeals provisions of the current oil and gas production taxes that will be obsolete under the new production tax. It also repeals definitions that will no longer be needed.

Sections 35 and 40: These sections specify that the new production tax provisions will take effect on July 1, 2006, and will apply to oil and gas produced on or after July 1, 2006. Section 11, the provision of the bill that confirms a long-standing agency interpretation of existing law, applies to oil and gas whenever produced.

Section 36: This section contains transition provisions that clarify how certain calendar year rules under the new production tax law will apply to the first half-year the law is in effect (i.e., the last six months of 2006). The section also provides that oil and gas produced before the new law takes effect will continue to be subject to the earlier production tax statute and regulations.

Section 37: This section contains another transition provision, authorizing the Department of Revenue to immediately develop and adopt implementing regulations so they can take effect at the time the new statutory provisions take effect.

Section 39: This section provides an immediate effective date for provisions of the bill that do not change the way the production tax is calculated, as well as the transition provision concerning regulations of the Department of Revenue.

Prepared by: Robert E. Mintz
Assistant Attorney General
Department of Law
February 21, 2006

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: LL06-0052-DNR-O&G-02
() Publish Date:

Revision Date/Time (Note if correction):
Dept. Affected: Natural Resources

Title: Repealing the oil production tax and gas production tax etc.
RDU: Resource Development
Component: Oil & Gas Development

Sponsor: Rules by Request of Governor
Requester: Governor
Component No.: 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )						

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Estimate of any current year (FY2006) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

There is no anticipated fiscal impact for DNR associated with implementation of this legislation.

Prepared by: Bill VanDyke, Acting Director
Phone 907-269-8800
Division: Oil & Gas
Date/Time 2/15/2006
Approved by: Michael Menge, Commissioner
Date 2/15/2006
Agency: Natural Resources

(Revised 9/7/2005 OMB)

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: 773060052
() Publish Date:

Revision Date/Time (Note if correction):
Dept. Affected: Revenue
Title: An Act Relating to the Production Tax on Oil and Gas
RDU: Tax and Treasury
Component: Tax
Sponsor: Rules Committee
Requester: Governor
Component No.: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	359.2	366.4	373.7	381.2	388.8	396.6
Travel						
Contractual	1,200.0	520.0				
Supplies	24.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous [OH office, etc]	18.0	18.0	18.0	18.0	18.0	18.0
TOTAL OPERATING	**1,601.2**	**904.4**	**391.7**	**399.2**	**406.8**	**414.6**
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )	***See analysis section***					

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	1,601.2	904.4	391.7	399.2	406.8	414.6
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	**1,601.2**	**904.4**	**391.7**	**399.2**	**406.8**	**414.6**

Estimate of any current year (FY2006) cost: 275.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time	4	4	4	4	4	4
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, property taxes, and an additional $73 million per year allowance for each producer. (The allowance can be no greater than the net value before the allowance.) The net income would be subject to a 20% tax, less a credit of 20% which applies to capital costs upstream of the point of production. In addition, there would be a deduction for capital costs incurred over the previous five years, which can be realized over the next six years, but only in years where the ANS price is over $40. It is estimated this would reduce revenues about $170 million in years when it was realized. In years where the ANS price is under $40 the deduction can be carried forward.

Prepared by: Robynn Wilson, Michael Williams, and Roger Marks
Phone: 269-1019
Division: Tax Division
Date/Time: 2/21/06 12:00 AM
Approved by: Jerry Burnett
Date: 2/21/2006
Agency: Department of Revenue

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. _____

ANALYSIS CONTINUATION

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo under various prices. They are predicated on the oil volumes in the Department of Revenue Fall 2005 Revenue Sources Book. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. They assume that seven producers utilize the full allowance. The status quo assumes the January 2005 ELF aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- $100 mm/yr exploration
- $1/bbl on-going capital on all barrels
- $3.50/bbl developmental capital on 2/3 of existing conventional oil
- $8/bbl developmental capital on 2/3 of existing heavy oil
- $3.50/bbl developmental capital on new conventional oil
- $8/bbl developmental capital on new heavy oil
- $5/bbl operating cost on conventional oil
- $5/bbl operating cost on heavy oil

The following table shows the 2007-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a $40 price, and a $60 price. (Note that the status quo numbers are slightly different from what is reflected in the Fall 2005 Revenue Sources Book because of some minor changes in assumptions introduced since Fall 2005, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 3 additional positions for auditors: 1 O & G Specialist (Range 23), 1 O & G Revenue Auditor IV (Range 22), and 1 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax. In addition, we request 1 additional position for a Tax Tech III (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenses include $100,000 and $70,000 for programming in FY 07 and FY 08, respectively, $250,000 in each of FY 07 and FY 08 for help in writing regulations, and $850,000 and $200,000 in FY 07 and FY 08, respectively, for auditing costs related to the new transition rules. Supplies include computers and other supplies necessary for new positions.

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. _____

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

Fiscal Year	DOR Forecast	Status Quo Tax	Tax from Bill	Gain from Bill
2007	49.20	934	1,363	429
2008	40.95	697	915	217
2009	25.50	404	349	-55
2010	25.50	387	339	-48
2011	25.50	362	351	-11
2012	25.50	343	332	-10

Fiscal	Medium	Status Quo Tax	Tax from	Gain from

Year	Price	Tax	Bill	Bill
2007	40.00	737	1,038	301
2008	40.00	679	1,031	353
2009	40.00	673	1,118	445
2010	40.00	646	1,106	460
2011	40.00	606	1,138	532
2012	40.00	576	1,112	536

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill
2007	60.00	1,165	1,938	773
2008	60.00	1,069	1,917	848
2009	60.00	1,042	2,007	965
2010	60.00	1,003	1,992	989
2011	60.00	941	2,051	1,110
2012	60.00	896	2,014	1,117

PROPOSAL FOR A PROFIT BASED PRODUCTION TAX FOR ALASKA

February 14, 2006

Dr. Pedro van Meurs

EXECUTIVE SUMMARY

The severance tax (production tax) of the State of Alaska has essentially remained unchanged since 1989. The current tax is based on a percentage of the gross revenues less the royalty. The percentage is adjusted with a formula (Economic Limit Factor or ELF), which for oil is based on field size and well productivity. This formula has served Alaska well for more than a decade. However, the economic framework on which the ELF formula was based is no longer realistic for North Slope conditions. As a result, based on the formula, the amount of tax will significantly decrease over the coming decade to a point were less than 20% of the oil is actually taxed. This is not in the interest of Alaska. Furthermore, the current ELF formula is not sensitive to variations in oil price creating significant losses for Alaska under current conditions. Also the production tax does not provide incentives to re-invest in Alaska.

It is suggested to repeal sections of the current act dealing with production tax (AS 43.55) and replace them with a profit based tax, the Profit based Production Tax ("PPT").

The profit based approach is a widely accepted international practice, including for instance Norway, the UK, Nigeria and Angola adopted this approach for the offshore. Alberta is using this approach to develop the oil sands.

The international competitive situation with respect to oil has changed drastically over the last two years. It is now apparent that there is strong upward pressure on the government take for oil. This is the result of many factors. Many of the oil producing nations had adopted in the past progressive fiscal systems which adjust the government take automatically upward in case of higher prices. Therefore, in these nations the average government take is now higher compared to two years ago.

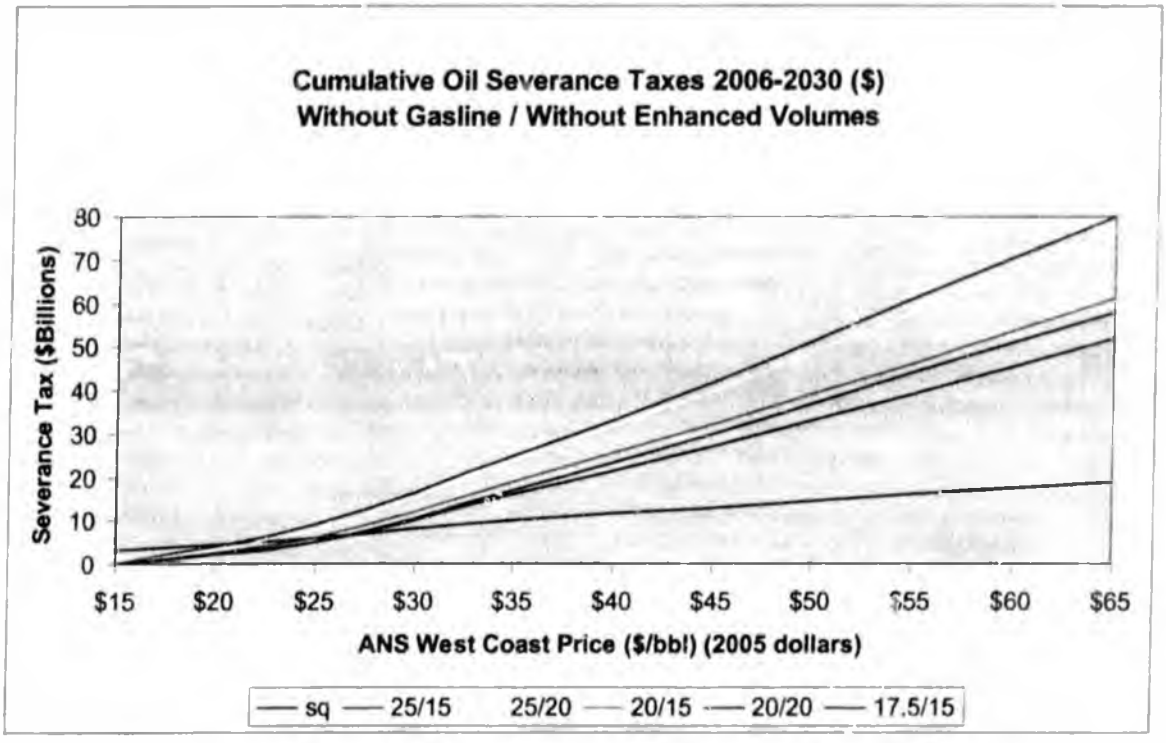
The higher oil prices are the result of difficulties in the supply of the strongly increasing world oil demand. Good exploration and development areas for oil are increasingly difficult to obtain. This puts now a premium on Alaska acreage for oil.

At the same time, new and aggressive players have entered world exploration and production. New companies from China, India, Russia, Latin America, Australia and Europe are willing to pay more for exploration and development acreage, driving up world wide government take.

All these factors make a re-evaluation of the production tax in Alaska highly desirable and appropriate at this moment. A much higher tax under average and high oil prices is justified.

Therefore, a PPT of 25% on the net revenues is proposed, with tax credits of 20% on all capital expenditures.

The Department of Revenue ("DOR") presented a number of alternative PPT's to the Alaska Legislature. The following graph from this presentation shows the cumulative revenues under various options based on existing production and modest new developments.



This graph shows how under the proposed PPT (25/20 in the graph) and at an average ANS price of $ 40 per barrel the cumulative production tax revenues over 25 years to Alaska will increase from the current estimate of $ 10 billion to about $ 30 billion. At $ 60 per barrel the cumulative revenues will increase to $ 70 billion. These revenues would be largely derived from existing production.

It is important to ensure that the new PPT encourages investment in Alaska.

On the North Slope smaller conventional oil fields and reservoirs are now the main target. Furthermore, heavy oil is an important new resource to Alaska. Improved technology may unlock billions of additional barrels of oil.

Therefore, tax credits are important to encourage such developments. A loss in any year can be converted in a tax credit by taking the 25% tax value. Therefore, in total, a credit of 45% can be obtained for new investments in Alaska.

Furthermore a tax free allowance of $ 73 million per year per company is proposed in order to ensure that small companies are not subject to tax and that new investors are provided with a strong incentive to invest in Alaska.

Under low prices and high costs the strong tax credits create a situation where there will be no PPT. Under high prices and low costs the PPT will be considerable. The PPT is therefore a progressive system.

The tax credits can be traded. Therefore investments in exploration, small and marginal fields or heavy oils will result in immediate credits even when the investor does not have prior income in Alaska. This will strongly attract new investors.

The PPT will be levied on a corporate basis. The tax credits and the profit based system ensures that when oil companies actively re-invest in Alaska the PPT payable will be less, even zero. When companies do not re-invest the PPT will be much higher.

As can be seen from the DOR graph, the PPT is primarily a tax on existing production. This tax is very significant under average or high prices.

However, with respect to production from new investments, the PPT can be negative or positive. On average, for large producers, the PPT payable will be zero on new small 50 million barrel fields on the North Slope at a WTI price of $ 30 per barrel. Under low prices and high costs, the tax credits are more than the tax that will be paid eventually and therefore the PPT will be "negative" (provided a company has PPT payable or can trade its credits). Under high prices and low costs, the tax credits will be less than the tax that will be paid eventually and therefore the PPT will be "positive".

There is, of course, a State wide "floor" of zero for the total PPT. Under low prices Alaska may not receive PPT at all. No matter how many tax credits a company has, the tax cannot be reduced below zero. Also there will be no trade in tax credits under low price conditions because all tax payers will have zero taxes.

Royalties, property taxes and state corporate income tax will not be affected by the PPT (other than that the PPT will be a deduction for federal income tax).

This report contains an in depth international comparative analysis which confirms that the proposed PPT is indeed more attractive to new investors than the current system.

A detailed rating was done to compare the attractiveness of the PPT with the current system in Alaska and eight other fiscal systems around the world: the UK, Norway, US Gulf of Mexico, Alberta oil sands, Nigeria, Russia and Azerbaijan.

The considerable increase in international competitiveness of the Alaska PPT for new investors can be studied from the following table. The best fiscal system would be rated 48 and the worst 480.

The Alaska Current system has an index of 363. The PPT would improve the index to 244.

COMPETITIVENESS INDEX

Hypothetical best	48	
US GOM	54	#1
UK	139	#2
Alberta-Oil Sands	163	#3
Nigeria	179	#4
Alaska PPT	244	#5
Angola	322	#6
Azerbaijan	329	#7
Alaska Current	363	#8
Norway	402	#9
Russia-Sakhalin	445	#10
Hypothetical worst	480	

The rating was done taking into account the low well head prices for Alaska crude oil. For instance, in the economic analysis it was assumed that in the US Gulf of Mexico producers will receive $ 7 per barrel more at the well head than in Alaska. Therefore, the rating fully accounts for the geographical disadvantage of Alaska.

The competitiveness also improves modestly for large existing producers which re-invest in Alaska. Such companies do not benefit from the tax free allowance upon re-investment. The large producers will in particular see an improvement in the rate of return on new investment.

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1. INTRODUCTION

1.1. Preliminary Comments

This report is a draft which reflects the analysis carried out at the request of the Governor of Alaska to review the severance tax for oil and gas. In a report which I prepared on June 15, 2003 it was concluded that deep revisions were necessary. Two options were considered over time:

- a revision of the ELF factors to make them more sensitive to price and the introduction of tax credits to create more incentive for re-investment, and
- a replacement of the current severance tax with a profits based tax.

The purpose of the 2003 review was to:

- Make this tax more effective in the light of changed economic and technical circumstances
- Make the tax more progressive and better linked to the profitability of the operations resulting in a more reasonable balance between government and petroleum industry over a wider range of economic circumstances
- Provide stronger incentives to re-invest in Alaska

This report constitutes therefore a follow up on the earlier reports.

The first question to be raised is whether changes in the severance tax would create an environment of fiscal instability that would undermine the confidence of the petroleum industry in Alaska.

1.2. Changing the Severance Tax

The Alaska severance tax is a tax of general application to the petroleum industry and can therefore be changed by the Legislature.

Many jurisdictions have taxes that are only or primarily related to petroleum or minerals. Examples are the PRT in the United Kingdom, the Hydrocarbon Tax in Norway, the PRRT in Australia , the SPT in Trinidad , the SRB in Thailand or the APT in Papua New Guinea.

The international practice is to change these type of resource based taxes only occasionally. Frequent changes in resource taxes create instability because this makes it difficult for the petroleum industry to undertake the long term planning that is required for decisions on exploration and oil and gas field development.

Nevertheless, the implicit understanding with respect to a resource tax is that such a tax can be modified occasionally where new conditions justify such a change, where governments want to

implement a new policy or where deficiencies in the structure of the tax make adjustment desirable.

Alaska has introduced changes to the severance tax in 1977 and in 1989. If Alaska were to implement another change during 2006, it would mean that this tax is being changed seventeen years since the last major change in this tax. This is a reasonable frequency of charge for a resource tax from an international perspective.

This then raises the issue as to whether there is a justification for adjustments to the Alaska severance tax.

Therefore the next section discusses why changes to the severance tax are appropriate.

1.3. ELF "design flaws" and technical and economic conditions on the North Slope.

When the recent ELF was introduced in 1989 it was from a fiscal perspective an advanced and modern feature.

The production tax (severance tax) for oil was based on a rate of 12.25% for the first five years of production of a field and 15% thereafter. The rate applies after the deduction of the royalty. A flat severance tax rate of this nature would be a severely regressive tax which would risk making smaller oil fields with modest well productivities uneconomic.

The ELF factor made this tax progressive with respect to field size and well productivity. This was achieved through multiplying the severance tax rate with the ELF factor, which varies between zero and one. Fields with high field and well productivities have a factor of close to one. Fields with low field and well productivities have a factor of close to zero. The formula is as follows:

$$ELF = \left[1 - \frac{(300 \times wells)}{volume} \right]^{\left[\left(\frac{150{,}000}{volume} \right)^{\wedge 1.53333} \right]}$$

"wells" is the number of producing wells in the field; "volume" is the total daily production for the field

This formula contemplates that a marginal oil well would produce 300 barrels per day and that therefore fields with wells that produce less should not be taxed. The field also considers that a 150,000 barrel field is a marginal field.

The ELF therefore encouraged the development of smaller and less prolific oil fields. Alaska has benefited from this concept, because it is likely that as a result of the introduction of the ELF a number of additional oil fields and satellites to existing fields have been developed which otherwise might not have been economic.

However, after the ELF has now been for 17 years in operation, five "flaws" have now been identified with the current ELF formula:

1. The ELF is no longer corresponding reasonably to oil field decline.
2. The ELF does not react reasonably to the current economics of field size and well productivity and the specific relief that is granted through the ELF does not seem appropriate for the circumstances.
3. The ELF does not relate rationally to incremental investments in oil field development, which now have become very important mode of operation in North Slope developments.
4. The ELF does not respond to higher or lower oil or gas prices.
5. The ELF does not provide an incentive for re-investment.

Following is a discussion of each of these five "flaws".

1.3.1. The ELF and field production decline

One issue relates to the decline of the ELF during the decline of production during the final phase of an oil field.

It is reasonable for the ELF to become gradually less if production declines in an oil field. Typically operating costs per barrel increase if production in an oil field declines. This is the result of the fact that some of the operating costs are fixed and therefore with declining production the costs per barrel go up. Also usually as the field production declines, gas and water production per barrel increase which means increased operating costs and sometimes additional facility requirements. For all these reasons it is reasonable to reduce the ELF gradually with declining field production.

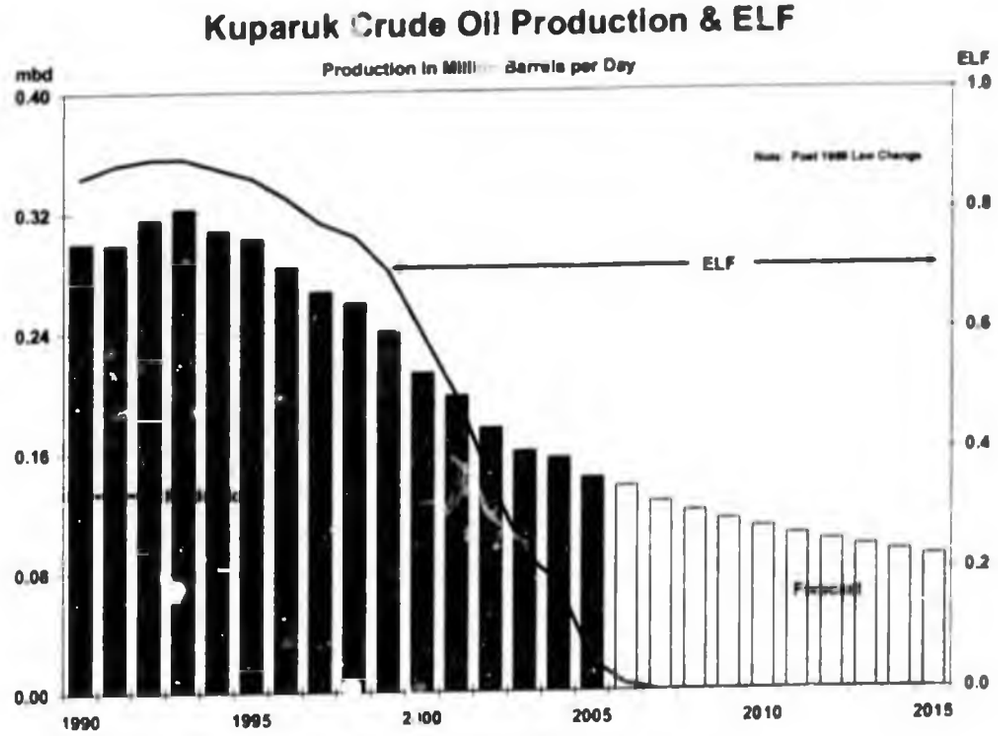
Once the field approaches the end of the field life, it is reasonable to reduce the ELF to zero. This will help prolong the economic life of the field. The current ELF formula achieves this result.

The main question is whether the current formula results in a reasonable decline of the ELF under declining production.

An important case is the Kuparuk field. In fiscal year 2000, this field produced 212,000 bopd. By the year 2011 it is estimated that the field will produce 98,000 bopd.

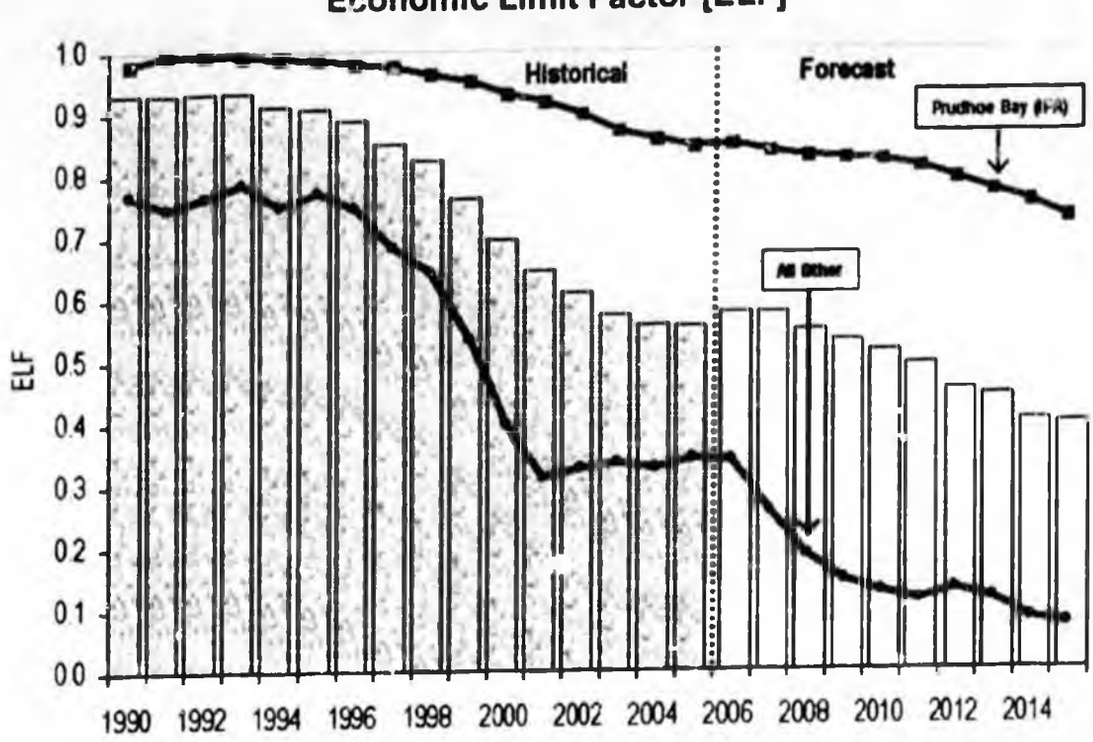
In the year 2000, the ELF on the field was 0.60. In March 2003 the same ELF factor was only 0.25. In the year 2007, the ELF will be 0.

Following is the anticipated graphs of production and ELF decline:



Therefore, the ELF reaches zero well before this is necessary as a result of the economic circumstances. This is unreasonable from a government perspective. Kuparuk is a world class and profitable oil field and there is no reason why Alaska should not receive production taxes from this field.

In general, the level of production tax will decline strongly due to a reduction of the ELF during the next decade as can be seen from the following graph:



The rapid decline of the ELF is not reasonable and unfair to Alaska, in particular under the current high oil prices. This aspect of the current production tax alone justifies a revision of the production tax.

1.3.2. General relationship between ELF and field and well production

The ELF formula is very sensitive to well productivity and has the following effects:

Well Prod bopd	Wells	Volume bopd	ELF
300	2000	600000	0.00
300	500	150000	0.00
1500	100	150000	0.80
1500	20	30000	0.07
6000	5	30000	0.55

It can be seen that a 150,000 bopd with 100 wells has an ELF of 0.8 and with 500 wells the ELF is down to zero. For a 30,000 bopd field, the ELF is 0.55 with 5 wells and 0.07 with 20 wells.

These relationships are no longer logical. The economics of a field is influenced by the number of wells. Obviously fields with more wells to achieve the same level of production typically require higher capital and operating costs. Nevertheless the relationship contained in the formula is extreme and no longer representative of current conditions.

In an oil field with declining production it is economic under current price conditions on the North Slope, to keep wells operating with well productivities that are well below 300 bopd. This automatically results in the rapid elimination of the ELF.

Also the strong sensitivity of the formula with respect to the number of wells provides an inducement to keep wells flowing that otherwise would be abandoned under normal economic circumstances. In other words producers would be able to manipulate the ELF downward with a "maximum number of flowing wells" strategy.

In 1989 a "marginal well" was set at 300 barrels per day. Today with $ 60 oil prices maintaining a 10 barrel a day well is economic. In effect, the higher the oil price the lower the production from a marginal well and therefore Alaska is very exposed to downward manipulation of the ELF under high oil prices.

Under current economic conditions the relationship between well productivity and the ELF is no longer in the interest of the State of Alaska.

1.3.3. ELF and incremental developments

A rather fundamental "design flaw" of the ELF relates to incremental developments.

Infill drilling in an existing field could result in significant increases in ELF if such wells have high well productivities for instance in case of horizontal wells. The incremental production would result in a very significant increase in ELF **for the whole field.** For economic purposes the increase in ELF on the whole field needs to be attributed to the economics of the incremental wells.

This means the incremental ELF could be very high and could exceed 1.00.

As a result is it unattractive for companies to increase production in existing fields in case the incremental wells would have a higher well productivity.

This problem is rather important since over the last ten years many satellite fields have been developed. It could be argued that these satellite fields really are economically part of the main field and should be counted as production of the main field. However, over the years the government has approved these satellites as separate developments until some modest adjustments were made as of January 1, 2005.

Therefore, if new wells are drilled in a satellite field the severance tax rate is 0%. If the same additional production is developed as part of the original field the incremental severance tax may be as higher than 15%.

The wide discrepancy of the incremental severance tax rate between a development in the same field and a satellite field is illogical from an economic perspective and it is a major deficiency of the current formula.

The developments on the North Slope during the last decade have resulted in new trends. These trends are:

- Exploration for and development of new "stand alone" fields with maximum field production rates in the 25,000 to 100,000 bopd range.
- Development of satellite fields with maximum production levels in the range of 5,000 to 50,000 bopd.
- A rapid decline in the production of the primary fields.

All these developments result jointly in a situation where the average ELF factor for the production of the total North Slope is declining very rapidly.

This sharp decline in the overall ELF for the North Slope area as a whole is not correlated with rapidly deteriorating economics and is therefore not a reasonable result from a government perspective.

There is ample justification to deal with the current deficiencies in the ELF formula and bring this formula more in balance with reasonable economic conditions and consequences.

1.3.4. The ELF and international oil prices.

A major deficiency of the ELF factor is that it does not deal with the oil price.

This means that when oil prices are low, the burden on the petroleum industry is very high, while in case of high oil prices, the burden is very modest.

As a result Alaska leaves considerable possible revenues "on the table" during high oil prices and burdens the oil industry unreasonably during low oil prices.

This means that the fiscal system of Alaska is regressive with price. The higher the oil price the lower the share is that the government receives from the operations. This is not logical. It is a very unbalanced situation.

Many other major oil exporting jurisdictions have fiscal systems that are more balanced. The government take either stays more or less the same with higher prices or actually increases.

The recent high oil prices and the recent developments in fiscal terms around the world create a significant new environment which justifies a re-evaluation of the ELF system. In the next chapter a more detailed review will be provided of this matter.

Given the extreme volatility of the oil price during the last decade and the volatility that can be expected during the next decade, the current ELF factor is not appropriate for the circumstances.

1.3.5. Re-investment under the Severance Tax

One of the most important characteristics of the severance tax is that it is essentially based on gross income (after deduction of royalty) rather than net income.

Many jurisdictions have resource taxes, production shares or participations that are based on net income. These features are often applied in addition to a royalty and corporate income tax.

Alaska is one of the few jurisdictions in the world that has a resource tax that is based on gross income.

The fact that most other jurisdictions have fiscal features that are based on net income means that exploration and development expenditures are deductible from gross income. Therefore, payments to government can be reduced by re-investing in the country, through the deductions that can be claimed.

The final result of such fiscal features is that companies that re-invest in the jurisdiction pay less to government than companies that take their profits out.

Such re-investment incentive does not exist in Alaska.

The result of this may be that companies are actually induced through the fiscal terms to take their profits out of Alaska for re-investment in other parts of the world.

Therefore, the current severance tax may not provide sufficient incentive to maintain or increase re-investment in the State.

As an illustration, the table below provides the net investment per dollar related to an exploration well:

Azerbaijan	$ 0.05
Canada, Northwest Terr	$ 0.10
Australia	$ 0.18
Norway	$ 0.22
Qatar	$ 0.22
Brunei	$ 0.25
Malaysia	$ 0.30
Canada, Nova Scotia	$ 0.35
Oman	$ 0.35

Venezuela – Orinoco Belt	$ 0.35
Indonesia	$ 0.38
Thailand	$ 0.45, less depending on level of production
Colombia	$ 0.45
Trinidad & Tobago	$ 0.45
Abu Dhabi	$ 0.50
Kazakhstan	$ 0.55, some agreements much less
Alberta	$ 0.58
China	$ 0.60, less depending on level of production
United Kingdom	$ 0.60
Sakhalin, Russia	$ 0.62, much less depending on level of production
US Gulf of Mexico	$ 0.65
Alaska - Current	**$ 0.65**

As can be seen, the Alaska net exploration costs are among the highest in the world and compare very poorly with other similar frontier areas such as the Canadian North West Territories or Offshore Nova Scotia.

2. NEW INTERNATIONAL TRENDS IN GOVERNMENT TAKE

(Note: parts of this chapter have been published earlier in the Oxford Energy Forum, Volume 63, November 2005)

In general it can be predicted that the higher oil prices will lead to upward pressure on the government take for oil and a stabilization of the government take for gas. It is also likely that governments will base their fiscal terms increasingly on sliding scales which are progressive with oil and gas prices.

2.1. Developments during the last two decades

Over the last twenty years the world arithmetic average government take for oil and for gas has typically declined, from high levels of about 75% during the energy crisis in the late 1970's to about 60% today.

The main reason for the decline of the average government take has been the relative "over supply" of exploration and development opportunities until recently. This was caused by two separate trends:

- new jurisdictions opening up for investment, and
- increased access to petroleum basins through improved technology.

The government take is determined by competition among governments. In essence, the government take is the "price" for the "petroleum properties" a government has available. A large increase in new opportunities creates a drop in "price". Governments were forced to lower government take in order to attract investment or maintain or expand petroleum production. The decline in government take has been stronger for gas than for oil due to the new pipeline and LNG opportunities and large volumes of "stranded" gas.

Since the early 1980's, important new acreage became available for petroleum exploration and production in the People's Republic of China, the former Soviet Union and Eastern Europe, Venezuela, Argentina, Brazil, Bolivia and Peru, Vietnam and Cambodia, and Saudi Arabia and Iran.

During the last two decades we have also seen many new investment opportunities as a result of improvements in technology. Companies now are able to develop oil and gas discoveries in 2000 meter water depth. New pipeline technology, including deep water pipelines, has resulted in connecting many new areas to markets, such as Algeria to Europe. LNG developments now make it possible to ship LNG from Qatar to East Asia.

This significant increase in new development opportunities has resulted in a gradual lowering of the government take during the last two decades.

2.2. Current Situation

This process is now coming to a halt. Except for Kuwait and Iraq, there are no important jurisdictions left in the world that can still be opened up. Most of the continental shelves and slopes are now accessible. Most petroleum basins in the world are now connected to markets through pipelines or LNG shipments. From now onwards, petroleum companies will be forced to "pick over" the existing acreage in order to identify new exploration and development targets.

At the same time a large number of new "buyers" of "petroleum properties" have come in the market. During the last two decades many new petroleum companies from China, Russia, Latin America, Europe, Asia and the Middle East have entered world petroleum exploration and development. Also many small Canadian, Australian and British companies have decided to go "international". These new investors bid aggressively in the available bidding rounds in order to acquire new acreage positions.

Will these new trends in conjunction with the high oil prices drive the government take back up?

2.3. Future

There are two types of fiscal systems with respect to high oil and gas prices:

- Systems that are progressive with price, whereby the government take adjusts upward automatically with higher prices, and
- Systems that are regressive of neutral with price, whereby the government take remains about the same or even declines somewhat with higher prices.

There are a considerable number of countries with progressive systems. There are two ways in which the upward adjustment in government take is taking place:

- *"One Way" adjustments.* These are systems that are based on cumulative profitability. In these systems a higher government take "locks in" once certain levels of IRR, Profitability ratios or cumulative revenues are being reached. In other words if the oil price would decline again, the government take will stay high. These jurisdictions include:
    - IRR based profit oil and gas shares such as in Angola, Russia and Azerbaijan and IRR based profit shares or taxes, such as in Saudi Arabia, the Canadian frontier areas, Australia and Kazakhstan.
    - Profit ratio based profit oil and gas shares in Libya, Qatar, Azerbaijan and India, profit ratio based royalties and taxes in Peru and Tunisia,
    - The PRT in Algeria.

- *"Two Way" adjustments.* These are systems that are based on price related formula or shares. In these systems the government take goes up when prices are high, but the take comes down when prices decline again. This is done through windfall profits taxes,

supplemental payments, uplifts or other mechanisms. Examples are the fiscal systems of Alberta, Colombia, Trinidad and Tobago, Malaysia, Pakistan, Thailand, Indonesia, East Timor, Norway and the Netherlands.

Certain countries have service contracts with fees which are not price sensitive, such as in Iran, Mexico and Venezuela. These countries receive the entire price upside.

As can be seen from the above list, there will be an automatic upward adjustment of government take in a large group of important petroleum producing countries as a result of higher oil and gas prices. In all countries this upward adjustment applies to oil as well as gas, except for Trinidad and Tobago and Qatar where it only applies to oil.

Price Upside Countries.

The countries with regressive or neutral fiscal systems are "price upside countries", where investors will earn a significant "wind fall" as a result of the price increases.

These countries can be divided in two groups:

- Countries with systems that primarily consist of royalties and corporate income tax. In almost all of these countries there are no fiscal stability provisions and therefore governments are free to impose new petroleum taxes.
- Countries with production sharing agreements whereby the percentage profit oil or gas to government is determined on production levels only, rather than certain formulas. Many of these contracts are subject to fiscal stability provisions.

Countries with royalty-tax systems include the United States (federal as well as state fiscal systems), certain provinces of Canada, the Venezuelan concessions, Argentina and Brazil, onshore Australia and the new licenses in the UK.

Countries with production level based production sharing agreements include Congo, Gabon, Egypt, Sudan, Yemen, Bangladesh, certain Indonesian contracts, Vietnam and China.

Trends

The oil supply shortage will induce many countries to have new bidding rounds for remaining acreage or acreage that is being relinquished. The high oil prices and the large number of new companies interested in acreage will result in high bids.

The high bids and the automatic upward adjustment of the government take in many jurisdictions with progressive systems creates a "competitive space" for price upside countries. It makes it easier for these countries to adjust their government take upward without becoming less competitive. This will have the following effects:

- In countries which are not subject to fiscal stability provisions, it can be expected that certain governments will review their fiscal terms in order to determine whether the government take should be adjusted upward through new or increased taxes.
- In countries with contracts that are subject to fiscal stability, it can be expected that a higher government take will be established for new model contracts. In some cases, governments may try to renegotiate certain production sharing contracts.
- Price upside countries will consider moving to price progressive fiscal systems.

Some nations are already in the process of reviewing or adjusting their fiscal terms. Venezuela cancelled the royalty holiday on heavy oil development and is currently trying to force investors into the new concession terms. Bolivia just introduced a new hydrocarbon law, which provides for a significantly higher government take. Trinidad and Tobago is reviewing its SPT terms. Kazakhstan is considering new fiscal terms with a very high government take. In the case of Bolivia and Kazakhstan the proposed increases are so strong that they may be counter-productive. Norway introduced a number of interesting small improvements in its fiscal terms, but this process may now come to a halt. Most recently in December 2005 the UK announced that it would increase its overall tax rate applicable to the petroleum industry from 40% to 50%.

Although it can be expected that the government take for oil will start to increase, the strong developments in gas pipeline and LNG technology are still creating significant new gas development opportunities. The ratio between world gas reserves and production is still 68 years and therefore there are considerable stranded gas reserves in nations which are still actively trying to market this gas. Following table[1] provides an overview of the major nations with stranded gas. In addition to the nations listed on the table there are six other nations with more modest gas reserves which are also actively trying to monetize their gas reserves, which are Vietnam, PNG, Peru, Yemen, Myanmar and Syria.

The possibility for still considerable supplies of gas, will depress the trend towards a higher government take. Therefore, the government take for gas may stabilize on average, with some countries leaving government take the same and other countries increasing or decreasing their take on gas.

[1] The table has been derived from the data of the Petroleum Encyclopedia, 2004.

WORLD GAS RESERVES AND PRODUCTION

	Reserves (Tcf)	Productio (Tcf)	Ratio years	
Canada	59	6.5	9.1	
USA	187	19.3	9.7	
Argentina	23	1.3	18.1	
Bolivia	**24**	**0.2**	**136.0**	**stranded gas**
Trinidad&Tobago	26	0.6	43.3	**stranded gas**
Venezuela	**148**	**1.0**	**155.3**	**stranded gas**
Netherlands	62	2.1	29.3	
Norway	75	2.3	32.7	
UK	22	3.6	6.1	
Iran	**940**	**2.3**	**409.7**	**stranded gas**
Iraq	**110**	**0.6**	**194.8**	**stranded gas**
Kuwait	**55**	**0.3**	**173.1**	
Oman	**29**	**0.5**	**54.8**	
Qatar	**910**	**1.0**	**888.9**	**stranded gas**
Saudi Arabia	**231**	**2.0**	**116.9**	
UAE	**212**	**1.6**	**130.6**	**stranded gas**
Algeria	**160**	**2.8**	**56.7**	**stranded gas**
Egypt	**59**	**0.8**	**72.7**	**stranded gas**
Libya	**46**	**0.2**	**217.2**	**stranded gas**
Nigeria	**159**	**0.6**	**250.2**	**stranded gas**
Azerbaijan	**30**	**0.2**	**170.0**	**stranded gas**
Kazakhstan	**65**	**0.4**	**153.4**	**stranded gas**
Russia	**1680**	**19.6**	**85.8**	**stranded gas**
Turkmenistan	71	1.8	40.2	**stranded gas**
Ukraine	**40**	**0.6**	**66.7**	
Uzbekistan	66	1.9	34.6	**stranded gas**
Australia	**90**	**1.2**	**72.8**	**stranded gas**
China	53	1.2	45.5	
India	30	1.0	30.4	
Indonesia	90	2.5	35.9	**stranded gas**
Malaysia	75	1.8	42.5	**stranded gas**
Pakistan	27	0.7	36.4	
Others	222	6.7	33.3	
Total	**6076**	**89.2**	**68.1**	

The speed with which these new trends will develop will depend in part on political developments which could create significant new opportunities, such as

- A stabilization of the security situation in Iraq and subsequent an opening of Iraq for new investment based on attractive contracts,
- The re-introduction of production sharing contracts in Russia.
- A strong opening of Mexico, in particular the deep water acreage.
- Resolution of political issues in Iran together with the introduction of more attractive upstream contracts.

However, none of these four above developments is expected to make a major impact during the next two years.

In general, it can therefore be concluded that it is clear that there is a new international environment with respect to the government take for oil. Previous competitive relationships have now been transformed in a new framework where it is obvious that there will be considerable upward pressure on government take for oil.

This matter justifies a review of the competitiveness of the severance tax in Alaska, in particular with respect to oil.

3. ECONOMIC ANALYSIS

3.1. Preliminary economic studies

During the last two years two broad alternative ways were evaluated to re-structure the severance tax:

- Modifications to the ELF structure, making the ELF more price sensitive and adjusting the ELF formula. This structure also included tax credits in order to encourage re-investment in the State.
- An new Petroleum Profits Tax ("PPT") regime, based entirely on profits and with tax credits in order to encourage re-investment in the State.

A complete study was done on the first option and was updated in the June 2003 report.

Subsequent, to the June 2003 report the Alaska Gas Project negotiations started and it was decided to first evaluate the result of these negotiations before finalizing the plans for a review of the severance tax.

However, during the last year the high oil prices made an acceleration of the severance tax review imperative. It was decided that the PPT concept was more desirable than revising the ELF.

Geological and technical conditions in Alaska have now become widely different. The Cook Inlet, Yukon Flats, North Slope and other regions reflect very different geological and technical environments. On the North Slope there are very different geological-technical conditions represented by conventional oil fields, gas condensate field, heavy oils, fields in state offshore waters, etc.

The strong increases in oil prices made it obvious that a profit based system was more appropriate on an Alaska wide basis than a more complex ELF concept. Conditions have become too variable and different in order to "capture" all variations in a simple ELF formula.

A profit based system also is a stronger basis for encouraging re-investment and attracting new investment.

For these reasons it was decided to go forward with the introduction of a PPT that would replace the current severance tax for oil and gas.

In this report, the development, the structure and the international competitiveness of the PPT will be evaluated. In particular, the attractiveness of the PPT to new investors will be dealt with.

A separate analysis has been prepared by the Department of Revenue which analyzes the impact of the PPT on overall State revenues, based on the various models in operation by the State. The results of this analysis were presented to the Alaska Legislature.

3.2. Economic assumptions

3.2.1. Cost and field size estimates

In order to test the economics of the PPT, six alternative exploration targets were evaluated, with the following targets:

- 50 million barrels – low well productivity
- 150 million barrels – low well productivity
- 500 million barrels - low well productivity

- 50 million barrels – high well productivity
- 150 million barrels – high well productivity
- 500 million barrels – high well productivity

The production levels and number of wells is of great importance for the ELF calculations. The following assumptions were made:

Field Size	Maximum production	Maximum number of wells	Number of wells at abandonment
(million barrels)	(barrels of oil per day)		
50	13,700	15	8
150	35,600	24	10
500	109,600	52	11
50	13,700	8	2
150	35,600	12	4
500	109,600	28	6

As can be seen the economic runs assume that there will be a considerable number of wells abandoned during the decline of the field. This maintains the ELF factor at a relative attractive level and production taxes will be relatively robust.

If it would have been assumed that few wells would be abandoned, the ELF factors would be substantially less during the decline phase.

It was assumed that the exploration program would have a 1:4 success ratio.

Cost assumptions were made which are reflective of the Alaska North Slope environment. Following are the cost assumptions for each of the six cases in total costs:

COST SCENARIOS
Total Costs

			DRY HOLE	FIELD#1 50MM-LOW	FIELD#2 150MM-LOW	FIELD#3 500MM-LOW	FIELD#4 50MM-HIGH	FIELD#5 150MM-HIGH	FIELD#6 500MM-HIGH
TOTAL OIL PRODUCTION		(MMbbls)	0.0	50.0	150.0	500.0	50.0	150.0	500.0
HIGH COSTS:									
TOTAL CAPEX	Exploration	(m$)	45	45	45	45	45	45	45
	Development	(m$)		375	900	2625	300	675	1500
TOTAL OPEX		(m$)		300.0	750.0	1875.0	225.0	525.0	1500.0
AVERAGE COSTS:									
TOTAL CAPEX	Exploration	(m$)	37.5	37.5	37.5	37.5	37.5	37.5	37.5
	Development	(m$)		312.5	750.0	2187.5	240.0	562.5	1250.0
TOTAL OPEX		(m$)		250.0	625.0	1562.5	187.5	437.5	1250.0
LOW COSTS:									
TOTAL CAPEX	Exploration	(m$)	30	30	30	30	30	30	30
	Development	(m$)		250.0	600.0	1750.0	200.0	450.0	1000.0
TOTAL OPEX		(m$)		200.0	500.0	1250.0	150.0	350.0	1000.0

Following are the per barrel costs:

COST SCENARIOS
Per barrel costs

			DRY HOLE	FIELD#1 50MM-LOW	FIELD#2 150MM-LOW	FIELD#3 500MM-LOW	FIELD#4 50MM-HIGH	FIELD#5 150MM-HIGH	FIELD#6 500MM-HIGH
TOTAL OIL PRODUCTION		(MMbbls)	0.0	50.0	150.0	500.0	50.0	150.0	500.0
HIGH COSTS:									
TOTAL CAPEX	Exploration	(m$)	45	45	45	45	45	45	45
	Development	($/bbl)		7.50	6.00	5.25	6.00	4.50	3.00
TOTAL OPEX		($/bbl)		6.00	5.00	3.75	4.50	3.50	3.00
AVERAGE COSTS:									
TOTAL CAPEX	Exploration	(m$)	37.5	37.5	37.5	37.5	37.5	37.5	37.5
	Development	($/bbl)		6.25	5.00	4.37	4.80	3.75	2.50
TOTAL OPEX		($/bbl)		5.00	4.17	3.12	3.75	2.92	2.50
LOW COSTS:									
TOTAL CAPEX	Exploration	(m$)	30	30	30	30	30	30	30
	Development	($/bbl)		5.00	4.00	3.50	4.00	3.00	2.00
TOTAL OPEX		($/bbl)		4.00	3.33	2.50	3.00	2.33	2.00

It was assumed that the exploration period would be 4 years and that production would start in year 7 of the cash flow.

Broad price sensitivity was done in the $ 10 - $ 60 per barrel range and more detailed analysis in the $ 22 - $ 40 per barrel range.

Escalation and inflation were assumed to be 2% per year.

All cash flows were done in nominal US dollars and all results in this report are expressed on this basis.

A differential of $ 7 per barrel was assumed between the WTI price and the well head price at the North Slope due to transportation and quality differentials.

3.2.2. Profitability indicators

All profitability indicators were calculated on nominal cash flows.

The following profitability indicators were used:

- The internal rate of return on a cash flow basis (IRR). This indicator illustrates how fast profits are being made and the attractiveness of the cash flow relative to the investment.
- The net present value discounted at 10% (NPV@10%). This indicator illustrates the present value of an investment. It is a good indicator of the total amount of profits that is being made with the venture.
- The expected monetary value at 10% (EMV@10%). This is the weighted average of the exploration investment discounted at 10% and the NPV@10%. A success ration of 1:4 was used. This indicator illustrates the attractiveness of the fiscal system for exploration. A high EMV@10% is obtained through a high NPV@10%, or low net exploration expenditures (for instance as a result of exploration tax credits).
- The undiscounted Government Take. This is a good indicator of percentage that the government receives of the long term pre-tax cash flow. The remaining cash flow is the Corporate Take. A low Government Take and high Corporate Take is attractive to companies, in particular on large fields, since it indicates a long and large undiscounted cash flow.

4. ANALYSIS OF THE PETROLEUM PROFITS TAX ("PPT")

(Note: After the initial scoping a PPT tax rate of 20% and a credit rate of 15% seemed a reasonable combination. Therefore much economic work was done on this combination. As a result of subsequent work it was concluded that a 25% tax rate and 20% tax credit rate is more in the interest of Alaska. Nevertheless in order to provide maximum information about the PPT it is desirable to leave the Chapters that were based on the 20% tax rate and 15% credit rate in the report. These are Chapters 4,5,6,7 and 8. Chapter 9,10 and 11 are based on the recommended fiscal terms.)

4.1. PPT terms of the 20/15 system.

Following is a description of the 20/15 option, which was used for much of the international comparative analysis.

The PPT is based on the yearly cash flow from oil and gas in Alaska of the tax payer (company). The PPT is therefore consolidated at the level of the company, not calculated on the basis of individual leases as is currently the case for the severance tax.

The PPT rate is 20% of the positive cash flow.

In order to calculate the Alaska cash flow for the company, the company takes all oil and gas gross revenues and deduct all lease expenditures, being capital and operating expenditures. These expenditures will be defined in more detail in the new PPT legislation. All expenditures are deducted in the year these costs are incurred for the full amount. In other words, it is not required to depreciate the capital expenditures.

If there is a negative cash flow, 20% of the "loss" can be converted to a tax credit against future PPT obligations. These tax credits can be traded with other companies.

Furthermore, there will be a 15% tax credit on all capital expenditures. These tax credits can also be traded.

In order to attract new investors and to protect the smaller companies in Alaska, there is a tax free allowance for the first $ 200,000 per day cash flow for a maximum of up to $ 73 million per year.

In other words if the positive cash flow is $ 40 million in a year, this amount will not be subject to tax. However, the $ 33 million difference between the $ 73 million maximum and the $ 40 million can not be used or carried forward. If the positive cash flow is $ 100 million per year, only $ 27 million will be subject to PPT.

If there would be a Stranded Gas Contract with the current Sponsors, and if this contract provides for taking tax gas in kind, than the respective provisions that would modify the general PPT law will be in the contract.

4.2. PPT analysis

The PPT payments depend on whether a field is developed while a company is benefiting in total or in part of the tax free allowance of up to $ 73 million. The economics will therefore be analyzed with and without the benefit of such allowance.

The large companies will receive the allowance, but most of their production operations under average oil prices will result in profits well above the $ 73 million and therefore new field investment will not benefit from this allowance.

The following table provides the general overview of all low and high well productivity cases that were studied for a $ 40 per barrel scenario for the first investment in Alaska which fully benefits from the $ 73 million tax free allowance.

PPT GOVERNMENT TAKE WITH $ 73 MILLION TAX FREE ALLOWANCE

		DRY HOLE	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
TOTAL OIL PRODUCTION	**(MMbbls)**	**0.0**	**50.0**	**150.0**	**500.0**	**50.0**	**150.0**	**500.0**
TOTAL GROSS REVENUES	**(m$)**	0.0	2115.2	6565.2	22620.3	2115.2	6565.2	22620.3
TOTAL CAPEX	**(m$)**	46.8	472.7	1075.5	3082.1	397.6	825.4	1789.9
TOTAL OPEX	**(m$)**	0.0	389.3	1018.1	2654.3	290.0	708.6	2107.2
DIVISIBLE INCOME	**(m$)**	**-46.8**	**1253.1**	**4471.5**	**16883.9**	**1427.5**	**5031.1**	**18723.2**
ROYALTIES	**(m$)**	0.0	264.4	820.6	2827.5	264.4	820.6	2827.5
PPT	**(m$)**	-16.4	-86.5	234.4	1884.4	-42.0	381.9	2443.4
PROPERTY TAXES	**(m$)**	0.0	28.3	86.3	292.3	28.3	86.3	292.3
STATE CORPORATE TAX	**(m$)**	-2.9	98.4	313.0	1116.7	111.3	351.8	1237.0
TOTAL ALASKA	**(m$)**	**-19.3**	**304.6**	**1454.4**	**6121.0**	**362.0**	**1640.7**	**6800.3**
FEDERAL INCOME TAX	**(m$)**	**-9.7**	**332.8**	**1058.7**	**3776.5**	**376.4**	**1189.7**	**4183.6**
GOVERNMENT INCOME	**(m$)**	**-28.9**	**637.4**	**2513.0**	**9897.5**	**738.4**	**2830.3**	**10983.8**
STATE TAKE:		**41.1%**	**24.3%**	**32.5%**	**36.3%**	**25.4%**	**32.6%**	**36.3%**
FEDERAL TAKE:		**20.7%**	**26.6%**	**23.7%**	**22.4%**	**26.4%**	**23.6%**	**22.3%**
GOVERNMENT TAKE:		**61.8%**	**50.9%**	**56.2%**	**58.6%**	**51.7%**	**56.3%**	**58.7%**

The table illustrates a number of issues. Is shows how there would be a very significant support for an exploration well or dry hole from government. The PPT losses than can be converted into credits, the investment credits and the benefit from state and federal tax deductions would be in total 61.8% of the cost of the dry hole.

On the small 50 million barrel fields the PPT is negative. This means that the company will not pay PPT because it is benefiting from the $ 73 tax free allowance, but the company can trade the loss credits and the investment credits and receive the benefits of the tax credits.

The table also shows how the PPT becomes quite substantial in case of a large field. The equivalent PPT rates are provided below. The equivalent PPT rates are the production tax rates that would equate to the PPT payments. For the 50 million barrel field these rates are negative.

	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
EQUIVALENT PPT RATES	-4.67%	4.08%	9.52%	-2.27%	6.65%	12.34%

The following table shows the results for a company who has already used its tax free allowance and considers reinvestment in new fields.

PPT GOVERNMENT TAKE FOR A COMPANY THAT HAS ALREADY USED ITS TAX FREE ALLOWANCE

		DRY HOLE	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
TOTAL OIL PRODUCTION	**(MMbbls)**	**0.0**	**50.0**	**150.0**	**500.0**	**50.0**	**150.0**	**500.0**
TOTAL GROSS REVENUES	**(m$)**	0.0	2115.2	6565.2	22620.3	2115.2	6565.2	22620.3
TOTAL CAPEX	**(m$)**	46.8	472.7	1075.5	3082.1	397.6	825.4	1789.9
TOTAL OPEX	**(m$)**	0.0	389.3	1018.1	2654.3	290.0	708.6	2107.2
DIVISIBLE INCOME	**(m$)**	**-46.8**	**1253.1**	**4471.5**	**16883.9**	**1427.5**	**5031.1**	**18723.2**
ROYALTIES	**(m$)**	0.0	264.4	820.6	2827.5	264.4	820.6	2827.5
PPT	**(m$)**	-16.4	121.2	551.6	2290.5	167.3	701.0	2852.2
PROPERTY TAXES	**(m$)**	0.0	28.3	86.3	292.3	28.3	86.3	292.3
STATE CORPORATE TAX	**(m$)**	-2.9	78.9	283.2	1078.5	91.6	321.8	1198.6
TOTAL ALASKA	**(m$)**	**-19.3**	**492.8**	**1741.7**	**6488.8**	**551.6**	**1929.7**	**7170.6**
FEDERAL INCOME TAX	**(m$)**	**-9.7**	**266.8**	**957.8**	**3647.5**	**309.9**	**1088.2**	**4053.6**
GOVERNMENT INCOME	**(m$)**	-28.9	759.6	2699.6	10136.3	861.5	3018.0	11224.2
STATE TAKE:		**41.1%**	**39.3%**	**39.0%**	**38.4%**	**38.6%**	**38.4%**	**38.3%**
FEDERAL TAKE:		**20.7%**	**21.3%**	**21.4%**	**21.6%**	**21.7%**	**21.6%**	**21.7%**
GOVERNMENT TAKE:		**61.8%**	**60.6%**	**60.4%**	**60.0%**	**60.3%**	**60.0%**	**59.9%**

It can be seen how the same exploration incentive is being provided. However, now the PPT on small fields is positive and generally the PPT is higher, resulting in a lower corporate income tax.

The equivalent PPT rates now range up to 14.41%. In other words under favorable field and price conditions the PPT is essentially restored to a situation that would be equivalent a PPT without ELF with the blended rate of 12.25% and 15%.

	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
EQUIVALENT PPT RATES	6.55%	9.60%	11.57%	9.04%	12.20%	14.41%

The equivalent rates also show how the PPT is progressive with field size and costs.

The same is true for prices.

Following table provides the equivalent rates based on WTI prices:

PPT EQUIVALENT RATES FOR PRODUCTION TAX

WTI	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
$20	-14.15%	-6.40%	-1.39%	-7.82%	0.21%	5.81%
$30	0.70%	5.08%	7.91%	4.28%	8.81%	11.98%
$40	6.55%	9.60%	11.57%	9.04%	12.20%	14.41%
$50	9.68%	12.02%	13.53%	11.59%	14.02%	15.71%
$60	11.62%	13.53%	14.75%	13.18%	15.15%	16.52%

As can be seen from the table, with a WTI price of $ 20 per barrel and a net back of $ 13 and costs of $ 13.50 per barrel as assumed for the 50 MM barrel case, the producer would sell his tax loss credits and his tax investment credits to others. It should be noted, however, that the PPT bill provides for the fact that the PPT cannot be negative, therefore, in a situation where all producers would have a loss in a year, the State would not be out of pocket on the PPT. There is no "negative" PPT on an Alaska wide basis.

At very high prices, the PPT would be equivalent to a 16.52% production tax without ELF.

It can be noted how the PPT is very progressive in terms of the production tax equivalent rate with field size, field costs and price for a situation where large producers have already used their tax free allowance.

The system is more progressive with field size as illustrated above, where the field is the first investment.

4.3. PPT payments

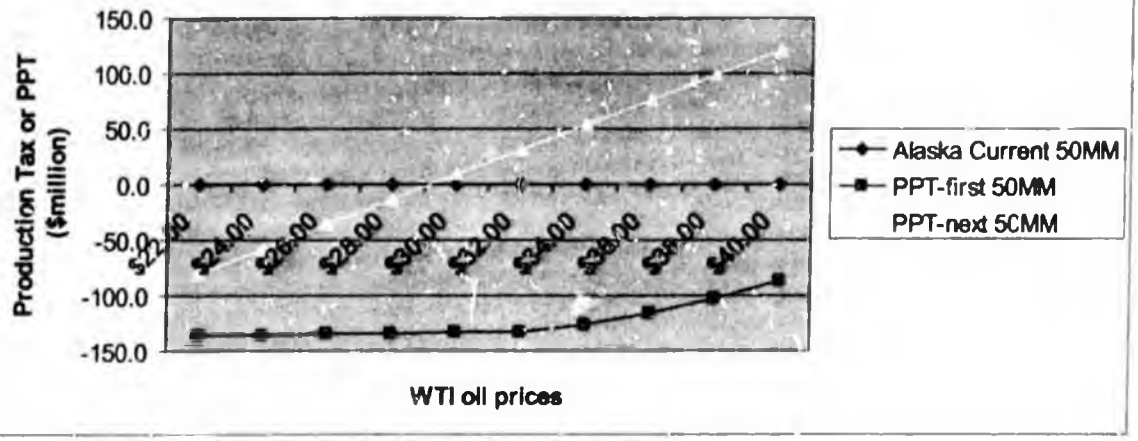
High Cost Fields

The following graphs illustrate the PPT payments relative to the current severance tax that would result under three cases:

- 50 million barrels, low well productivity, high costs
- 150 million barrels, low well productivity, high costs
- 500 million barrels, high well productivity, high costs

The economics with the tax free allowance is indicated as "First" in the graphs and without the tax free allowance as "Next".

Chart 4.1. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

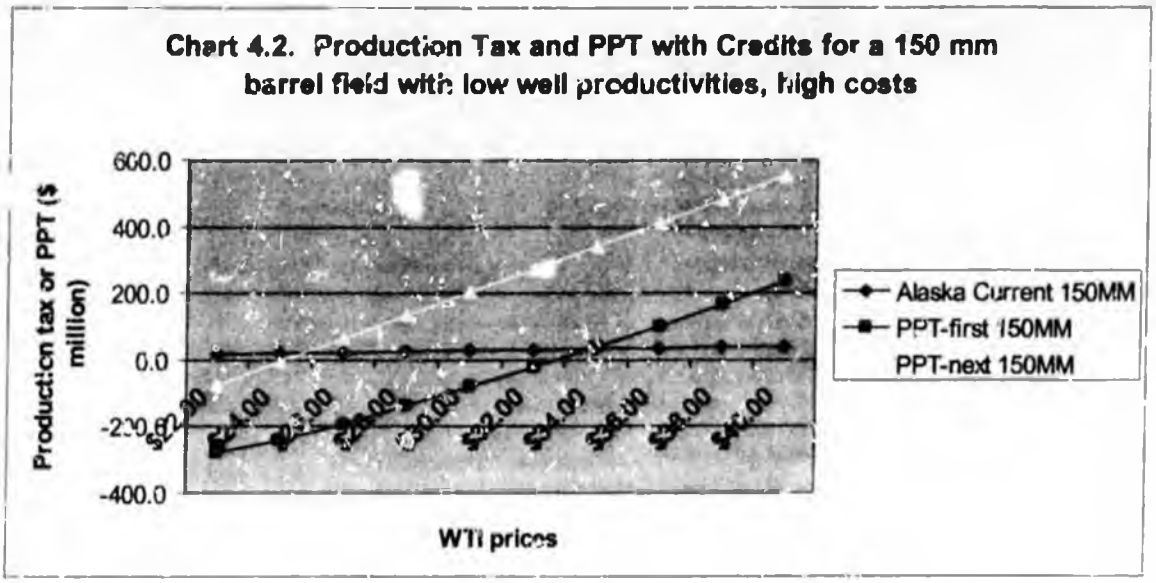


As can be seen from the 50 million barrel graph, a new investor or a small company developing a 50 million barrel field would not pay any PPT in the $ 22 - $ 40 per barrel price range. This is because the yearly tax free allowance would eliminate the obligation to pay taxes. However, such an investor would nevertheless receive the tax credits, whenever the cash flow is negative or as a result of his capital expenditures. These tax credits can be traded. Therefore, the new or small investors receives significant support through the PPT for such an investment.

Under the current severance tax system there is only an exploration tax credit which is being phased out (not included in this analysis). Therefore, the PPT is significantly more attractive to a new or small investor than the current severance tax with the ELF structure, despite the fact that under the current ELF there would be no severance tax payable on the 50 million barrel field.

A large oil company re-investing in a 50 million barrel field as provided in Chart 4.1 will find that for WTI prices below $ 29 per barrel the tax credits received under the PPT are higher an the PPT payable prior to tax credits and therefore PPT is "negative" and therefore this is better than the current severance tax. Over the $ 29 per barrel there is PPT payable and the system results therefore in more tax. Of course, these WTI benchmarks depend on the economic assumptions about capital and operating costs, production profiles, etc.

The 50 MM barrel high cost and low well productivity case is a very important benchmark for large producers because this is a fairly representative case of most of the incremental developments that may take place on the North Slope. This case will therefore see a significant improvement of overall economics while on average there is no increase in tax (assuming that large companies maintain a long term price forecast in the $ 25 to $ 30 range).



For the 150 million barrel field as assumed in our economic analysis a low amount of severance tax would be payable under the current system.

For a new investor, the cash flow under high prices would exceed the tax free allowance. Also the relative importance of tax credits is less. Therefore, PPT would be payable for WTI prices in excess of $ 33 per barrel. Below these prices the PPT would be less than the current system and would be negative.

A large oil company re-investing in a 150 million field would find a break-even point at a WTI price of $ 25 per barrel relative to the current system. Over this price the company would pay more tax.

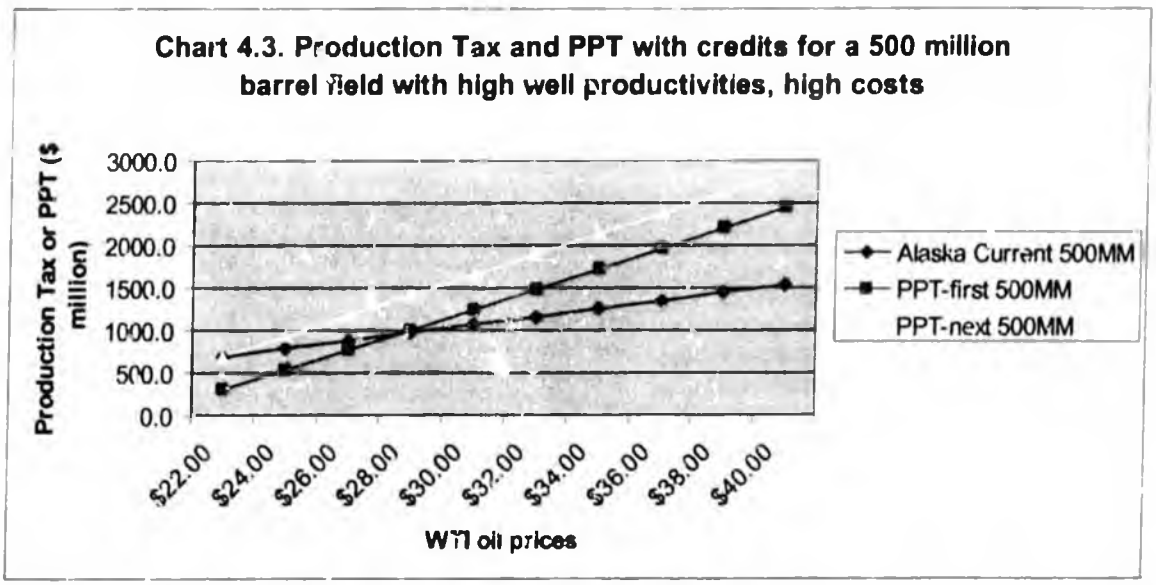


Chart 4.3 shows how for a 500 million barrel field with high well productivities, but high costs, the PPT results in more tax for a new investor at a break even WTI price of $ 29 per barrel and a large oil company would have a break even WTI price of $ 22 per barrel.

Lower Cost Fields

Because the FPT is profit sensitive and provides incentives through the tax credits, the break even WTI prices depend very much on cost assumptions. The graphs below show the same field 150 million barrel field of Chart 4.2, but now for lower costs.

Chart 4.4 shows how the WTI break even price for a new investor in a 150 million barrel field would drop from $ 33 to $ 31 per barrel, when average costs are being assumed. For a large company it drops from $ 25 to $ 22 per barrel.

Chart 4.4. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, average costs

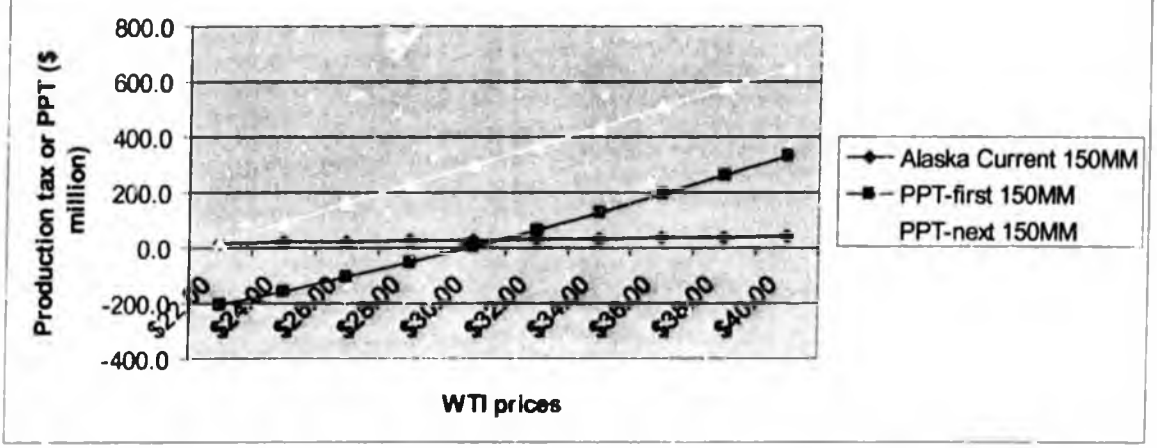
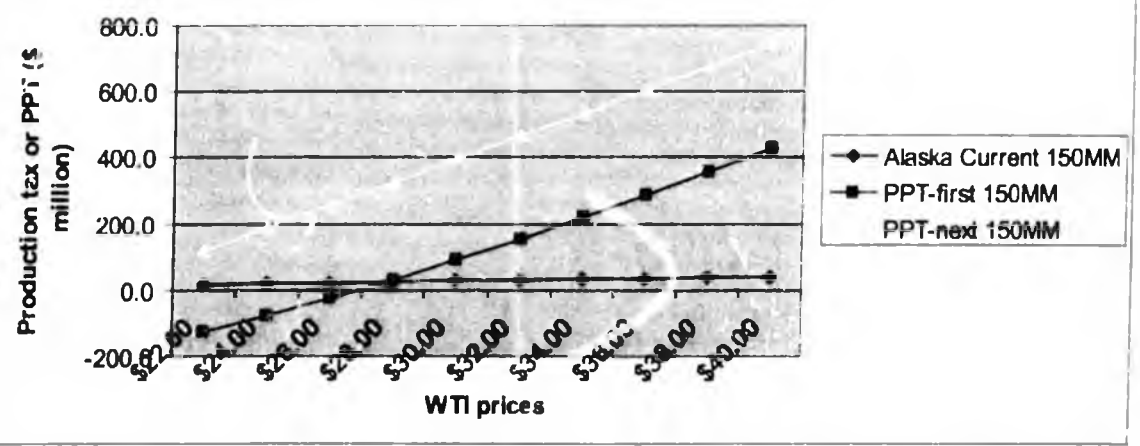


Chart 4.5. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, low costs



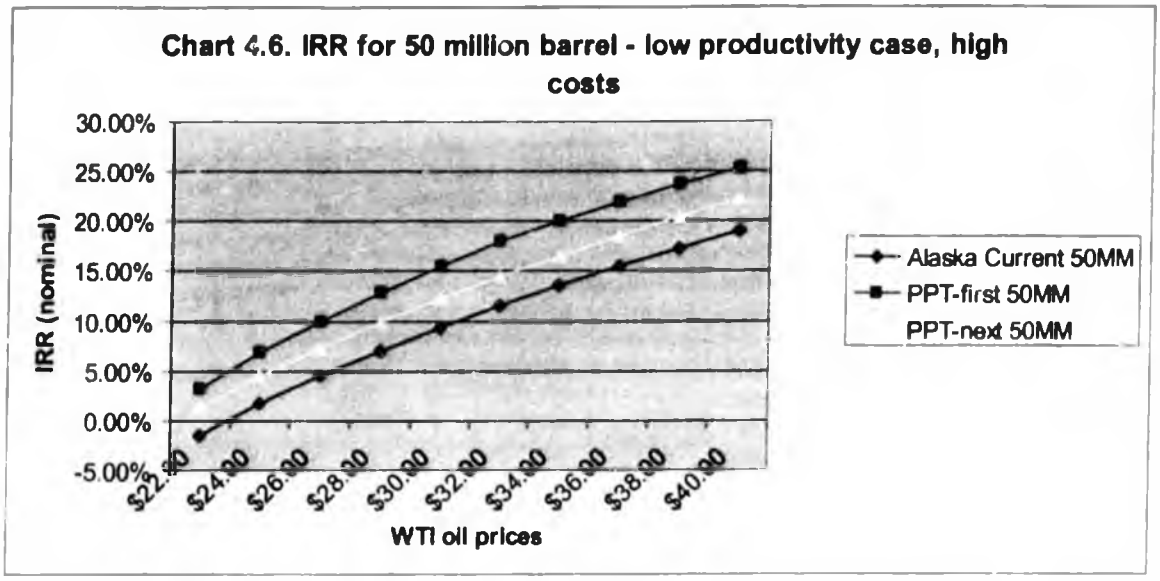
For low costs assumptions the WTI break even prices drop to $ 29 and $ 19 respectively as can be seen on Chart 4.5.

4.4. Investor economics

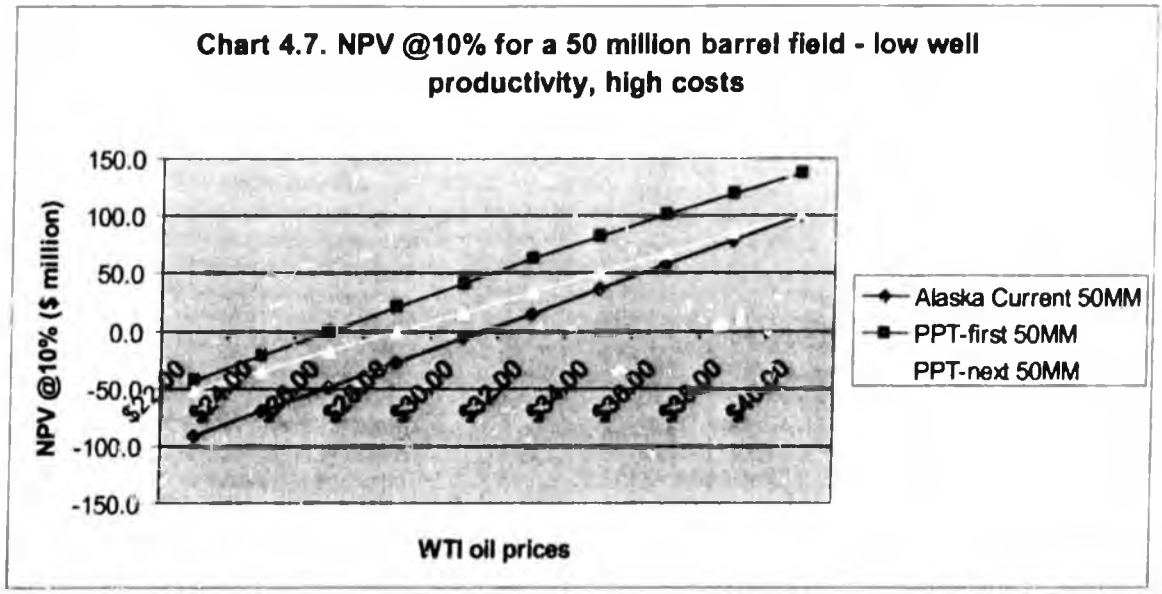
The investor economics are different depending on the field sizes.

50 million barrels

The following three graphs show the investor economics for the 50 million barrel field.



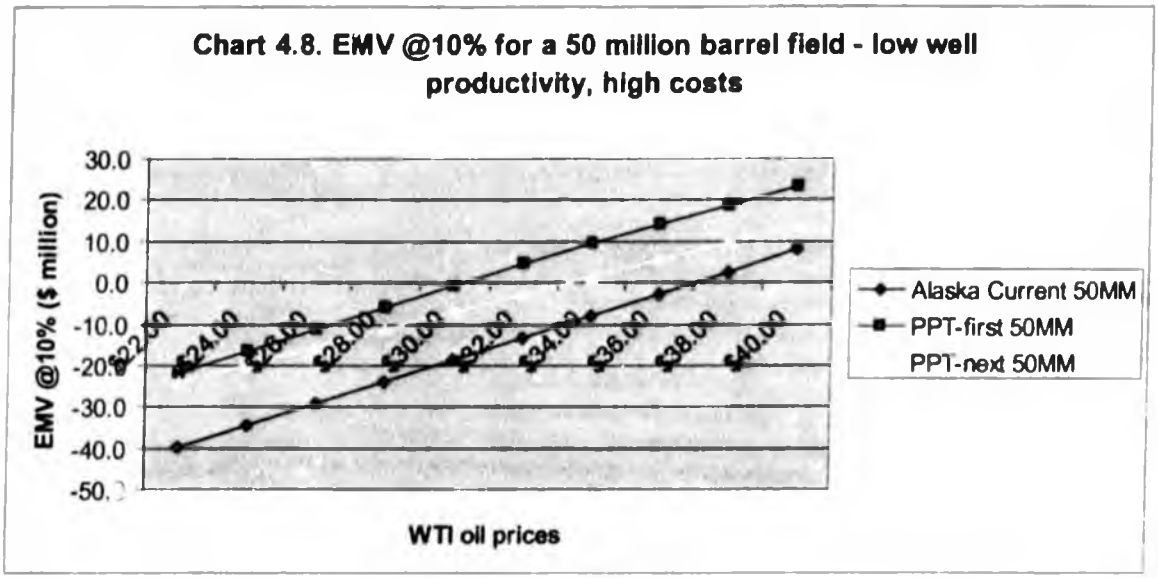
The IRR is much higher for the new investor or small investor and therefore small fields will become much more attractive targets. However, even for the large oil companies the IRR on small fields would improve considerably as a result of the tax credits, even if companies have already used their tax free allowance.



The NPV@10% is much better for new and small investors. For large companies, which have already used their tax free allowance, the NPV break even point is a WTI price of $ 40 per barrel.

For lower cost 50 million barrel fields the WTI break even prices for the NPV@10% are lower, as indicated in the small table below.

	First 50 million	Next 50 million
High Costs	< $ 60	$ 40
Average Costs	< $ 60	$ 35
Low Costs	<$ 50	$ 30



The EMV@10% is much better for small and new investors. For large oil companies who have already used their tax free allowance, the EMV has a break even price which is in excess of $ 50 per barrel. This indicates that even for large oil companies, small fields would be more attractive exploration targets up to rather high WTI price levels under the PPT.

For EMV@10% the WTI breakeven prices are lower under lower costs, but higher than the NPV values.

Generally, the PPT makes exploration for 50 million barrel fields and their development economically more attractive, in particular at low or average prices.

150 million barrels

For the 150 million barrel field with low well productivities and high costs, the IRR is always much better for a new or small investor and also for a large company.

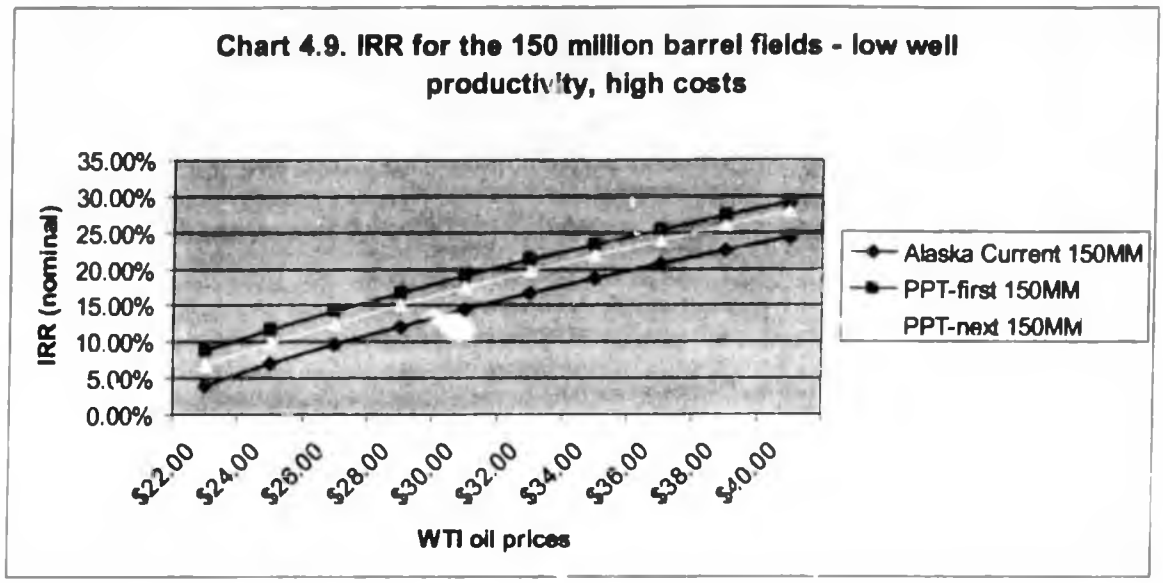
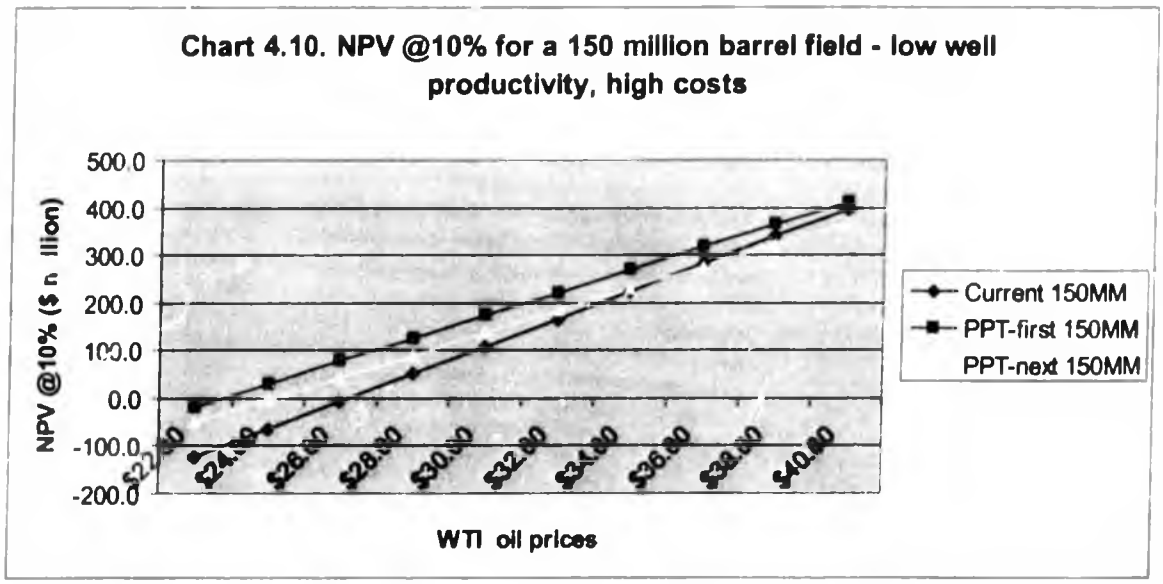
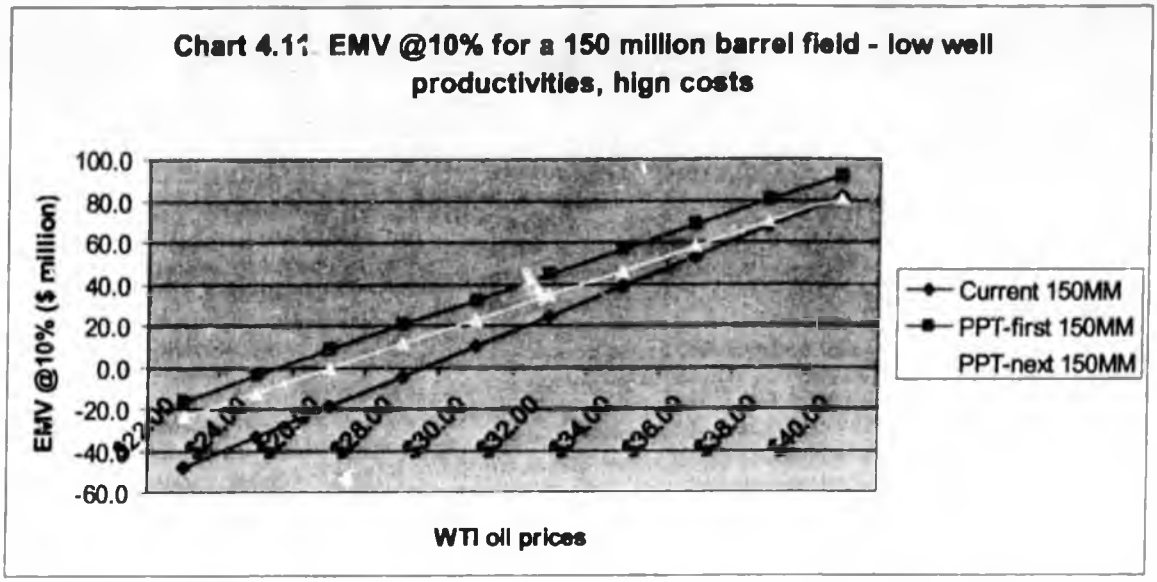


Chart 4.10 illustrates how also the NPV@10% for a 150 million fields for a new or small investor is better over $ 40 per barrel. The WTI break even point is about $ 35 per barrel for a large company, which has already used the tax free allowance.



The EMV@10% for a 150 million barrel field is better for a WTI price range of well over $ 40 per barrel. The WTI break even point for a large company is about $ 39 per barrel.

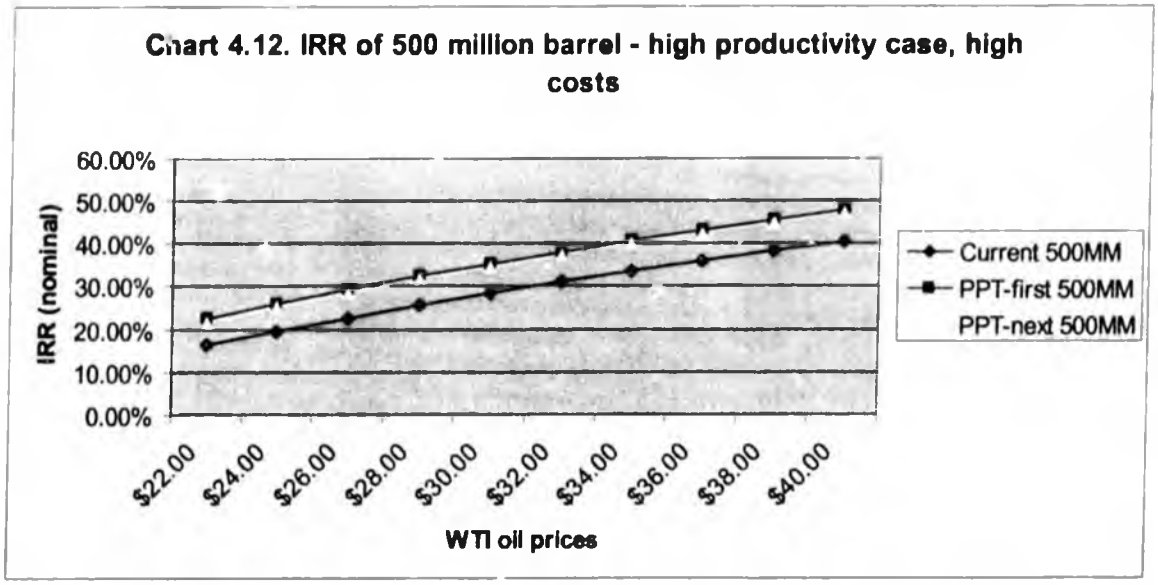


For the average and low cost scenarios, the break even points are somewhat less.

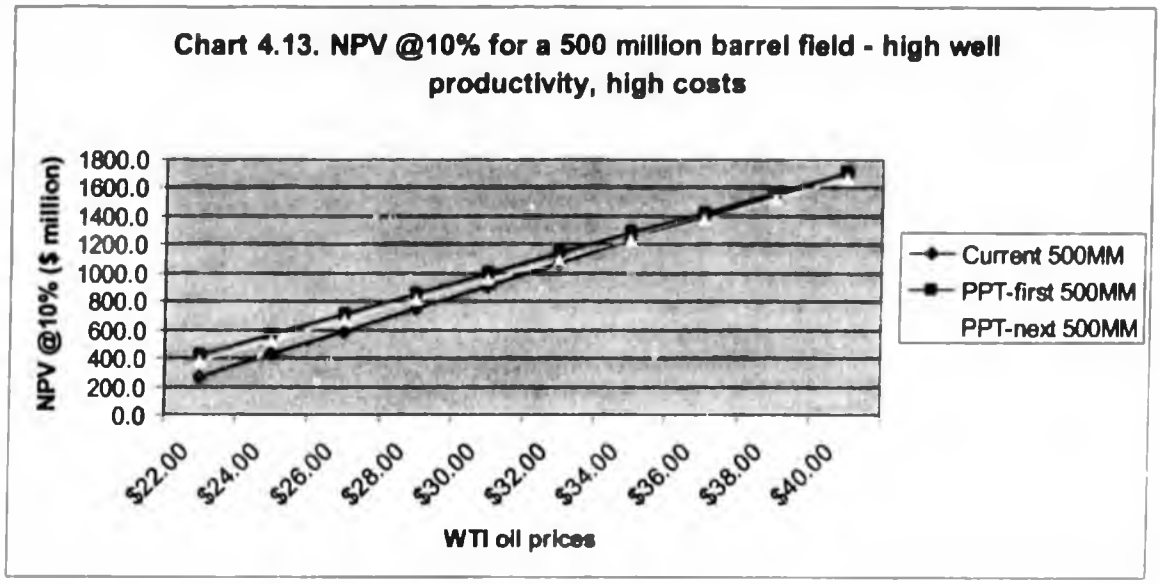
The analysis for the 150 million barrel field indicates that the economics of this field improves for both the new investor and large oil companies, in particular under low and average oil prices.

500 million barrels

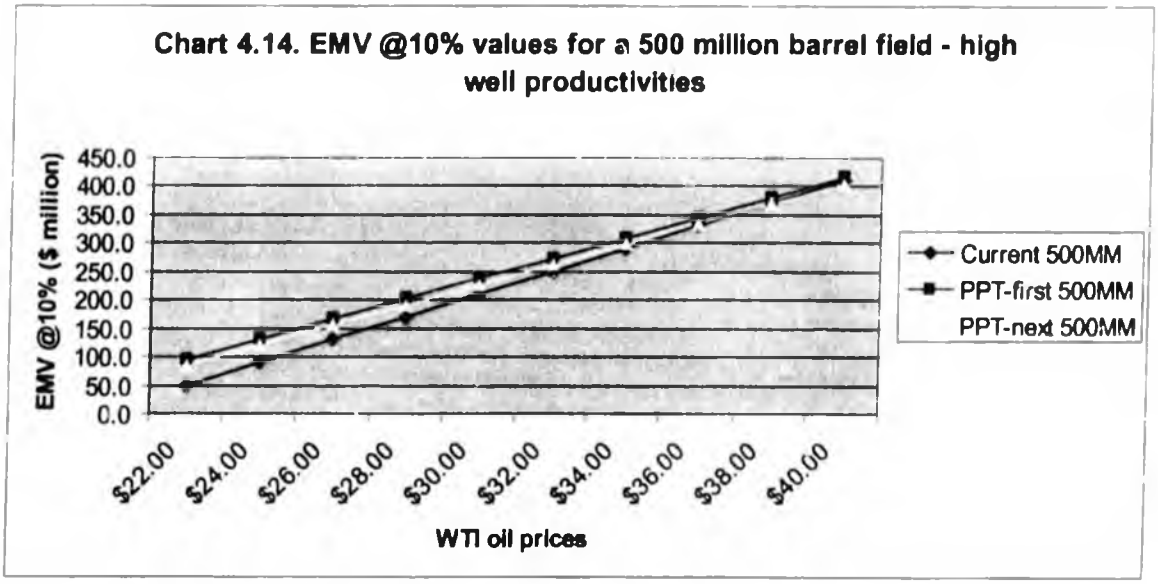
Even for a large field of 500 million barrels, the IRR improves considerably for both the new investor and a large company.



For the NPV@10% and EMV@10%, the WTI break even price for the 500 million barrel fields is about $ 40 per barrel for the new investor and $ 34 per barrel for a large company which already applied its tax free allowance.



For lower costs the break even prices for the NPV@10% and EMV@10% are somewhat lower. For the 500 million barrel, high well productivity, low cost case, the break even price of the NPV@10% is about $ 26 per barrel and for the EMV@10% about $ 28 per barrel for large companies.



It can be concluded that for a 500 million barrel field, the economics for new investors and large oil companies is better under the PPT, in particular for low prices.

Conclusion

In general it can be concluded that the PPT based on 20% tax and a 15% tax credit improves the IRR considerably of investments by new investors or large oil companies.

For targets in the 50 – 150 million barrel range, the NPV@10% and EMV@10% is typically better for new investors over a wide price range. For large oil companies, who have already used their tax free allowance, the NPV@ and EMV@10% is typically better for low and average prices.

For large targets, the NPV@10% and EMV@10% is typically better for low prices and for new investors also for average prices.

In general, the PPT will be a strong encouragement to invest for new investors or to re-invest for small investors since the profitability of ventures under the PPT well exceeds that of the current system.

For large companies with price expectations in the $ 25-$30 per barrel range, the PPT is more attractive from an IRR perspective and equally attractive from an NPV@10% or EMV@10% perspective than the current system. For small fields in the 50 million barrel class the tax is zero at the long term price range.

In general therefore the introduction of the PPT can be expected to result in a higher level of activity in the North Slope and other areas of Alaska.

5. ANALYSIS OF ALTERNATIVE PETROLEUM PROFITS TAX ("PPT") CONFIGURATIONS

(Note: After the initial scoping a PPT tax rate of 20% and a credit rate of 15% seemed a reasonable combination. Therefore much economic work was done on this combination. As a result of subsequent work it was concluded that a 25% tax rate and 20% tax credit rate is more in the interest of Alaska. Nevertheless in the interest of providing the maximum information about the PPT it was considered desirable to leave the Chapters that were based on the 20% tax rate and 15% credit rate in the report. These are Chapters 4,5,6,7 and 8. Chapter 9,10 and 11 are based on the recommended fiscal terms.)

5.1. PPT Rate

5.1.1. PPT income

Sensitivity analysis was done on the PPT rate. Rates from 10% to 30% were studied in detail. The following graphs show the results for the PPT income compared to the current severance tax for 10%, 20% and 30% PPT. These rates were analyzed in conjunction with a 15% tax credit on all capital. The negative cash flow credits were also adjusted to 10% of the negative cash flow, 20% and 30%.

For clarity, the $ 73 million yearly tax free allowance was not included in this analysis. The investment economics are therefore from the perspective of a re-investment by a large petroleum company who has already used the tax free allowance.

The following Charts 5.1, 5.2 and 5.3 show the PPT compared with the current severance tax for the three field combinations that were also displayed earlier in Chapter 4.

Chart 5.1. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

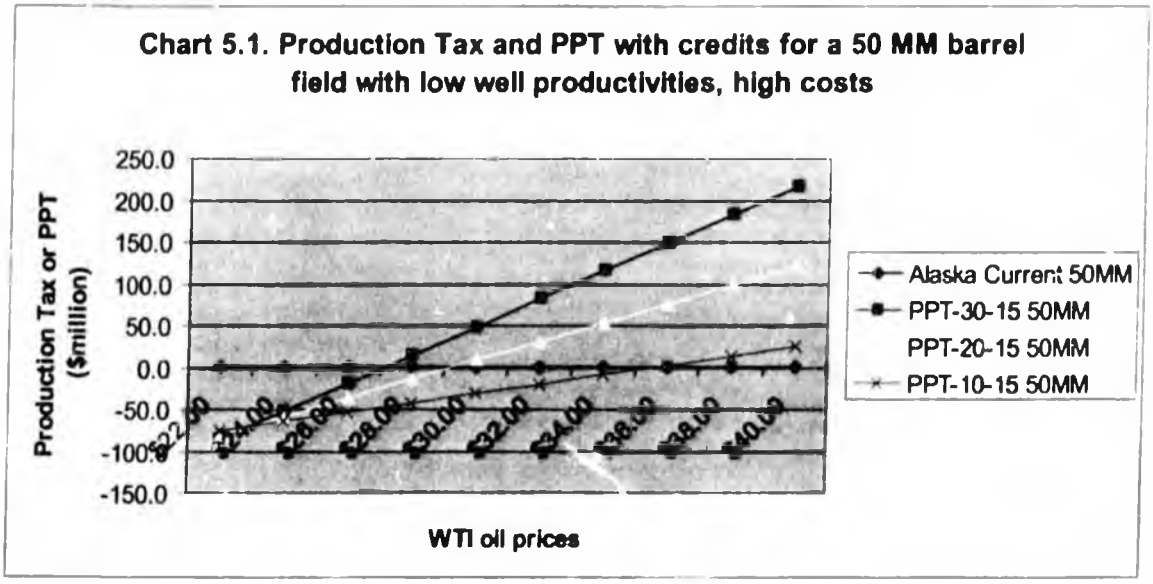


Chart 5.1 shows that a PPT of 10% would be less below WTI prices of $ 36 per barrel, a PPT of 20% would have a WTI break even point of $ 29 and a PPT of 30% a WTI break even point of $ 27 per barrel.

Chart 5.2. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, high costs

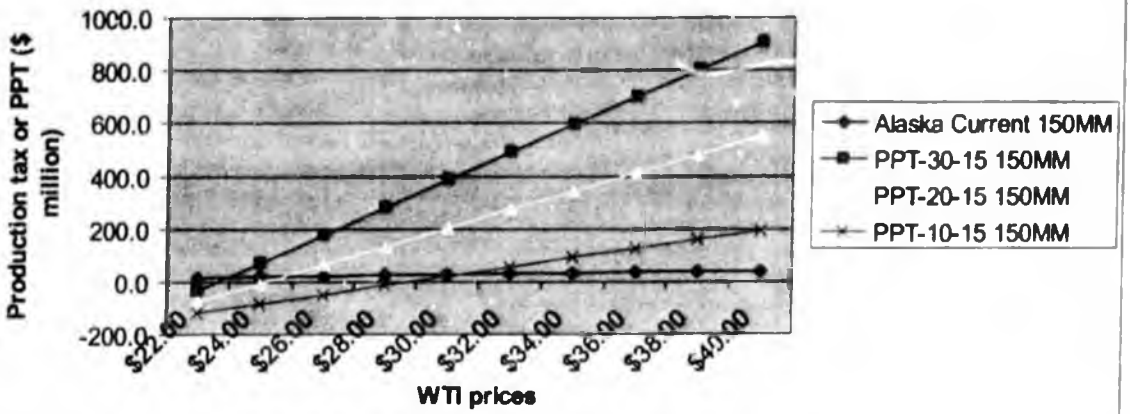


Chart 5.2 shows that a PPT of 10% would be less below WTI prices of $ 31 per barrel, a PPT of 20% would have a WTI break even point of $ 25 and a PPT of 30% a WTI break even point of $ 23 per barrel.

Chart 5.3. Production Tax and PPT with credits for a 500 million barrel field with high well productivities, high costs

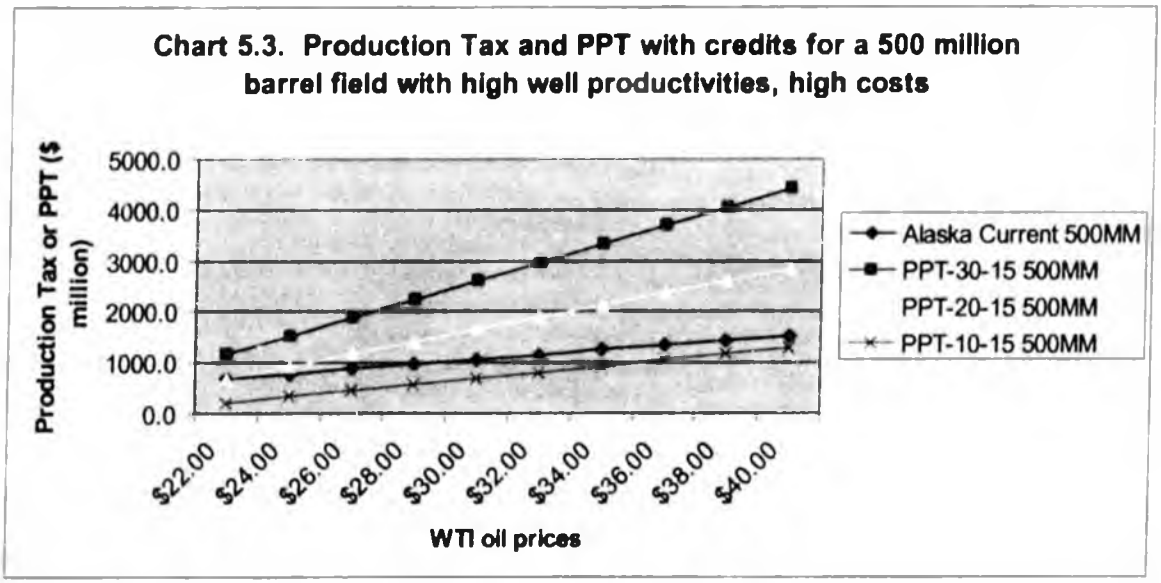


Chart 5.3 shows clearly that a 10% rate would result in less PPT than the current severance tax for the 500 million barrel field for the entire price range.

A PPT of 20% would have a break even point of $ 22 per barrel and a PPT of 30% would have a much lower break even point.

From these graphs it is clear that a PPT of 10% would be unattractive to Alaska. Both a PPT of 20% or 30% would be attractive and would under reasonable prices result in considerably more revenues for Alaska.

In chapter 8 the international competitiveness of the PPT with respect to re-investment will be analyzed and this analysis will conclude that a 30% rate would be too high.

The following graphs provide more detail for PPT rates between 15% and 20%.

Chart 5.4. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

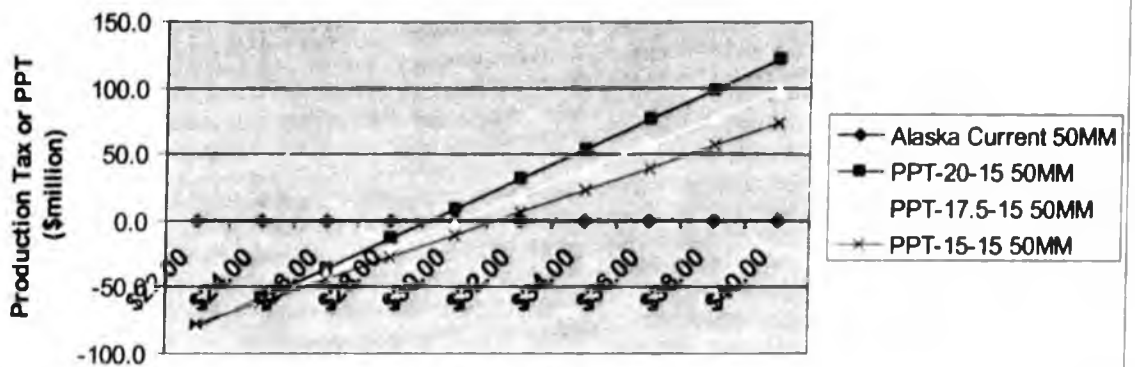
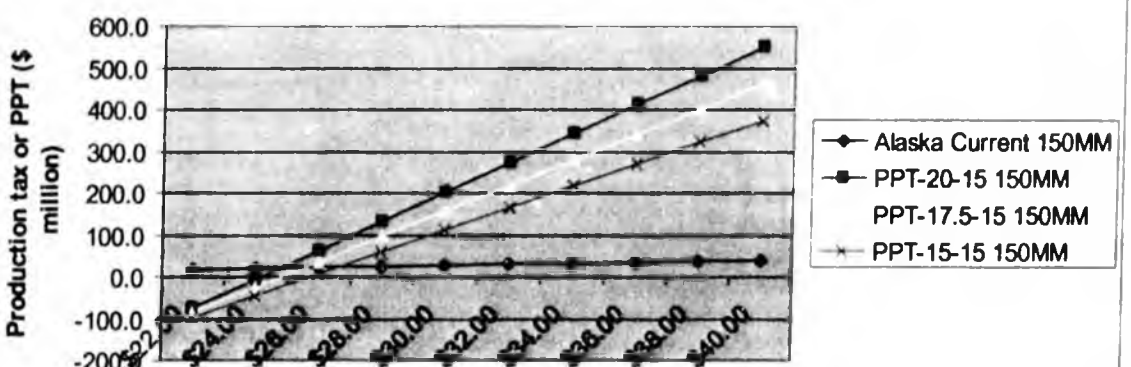
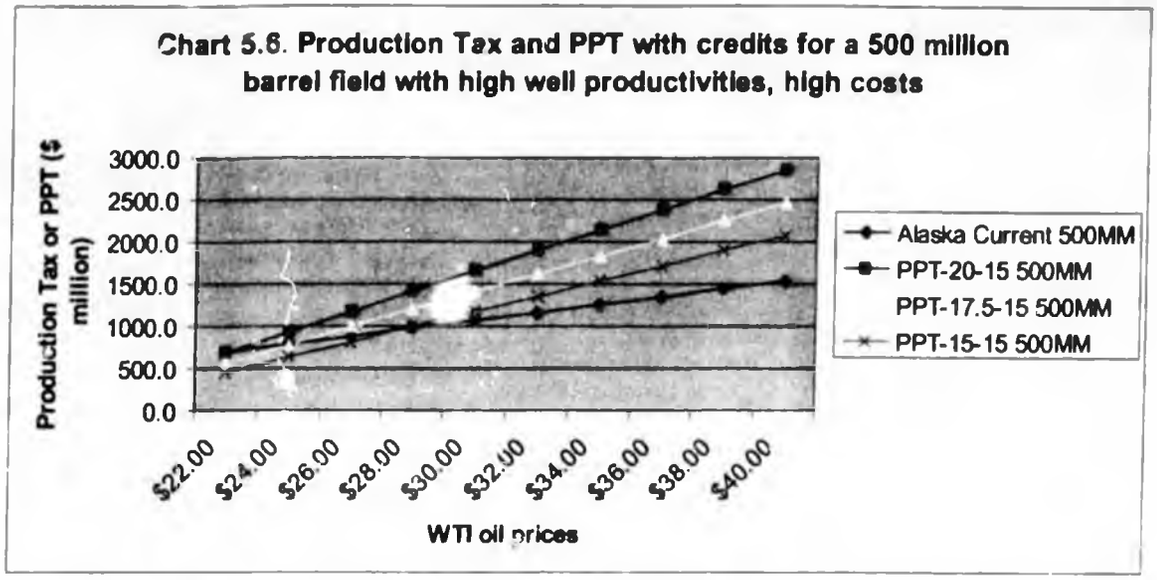


Chart 5.5. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, high costs





It can be seen how even a 15% rate would not provide a clear advantage to Alaska. The WTI break even points for the various fields are too high. The WTI range of $ 27 - $ 31 would expose Alaska too much to the possibility that PPT revenues would actually be less than the current severance tax under average price scenarios.

Only the 20% rate seems reasonable from an Alaska perspective. This rate has a WTI break even range of $ 22 - $ 29 per barrel.

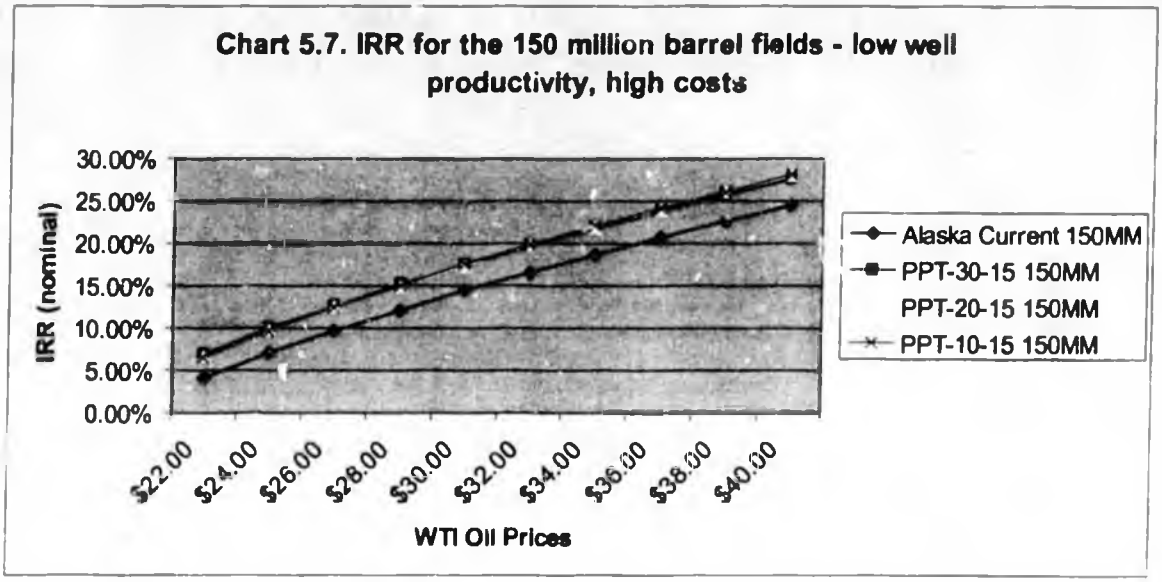
5.1.2. Impact on Investors

The following graphs are for the 150 million barrel field. However, the results for the other fields are similar in trend and nature.

Under all PPT rates the IRR is approximately the same and is much higher than the under the current severance tax. Whether the PPT rate is 30% or 10% results about in the same IRR. The reason is the fact that the negative cash flow losses can be converted into tax credits at the PPT rate and these credits can be traded. In other words the State of Alaska equally shares in the negative and positive cash flow. This creates a situation where the IRR is about the same for a high or low PPT rate. It should be remembered that the IRR is a profitability yardstick which measures the speed at which profits are being made, not the amount of profits.

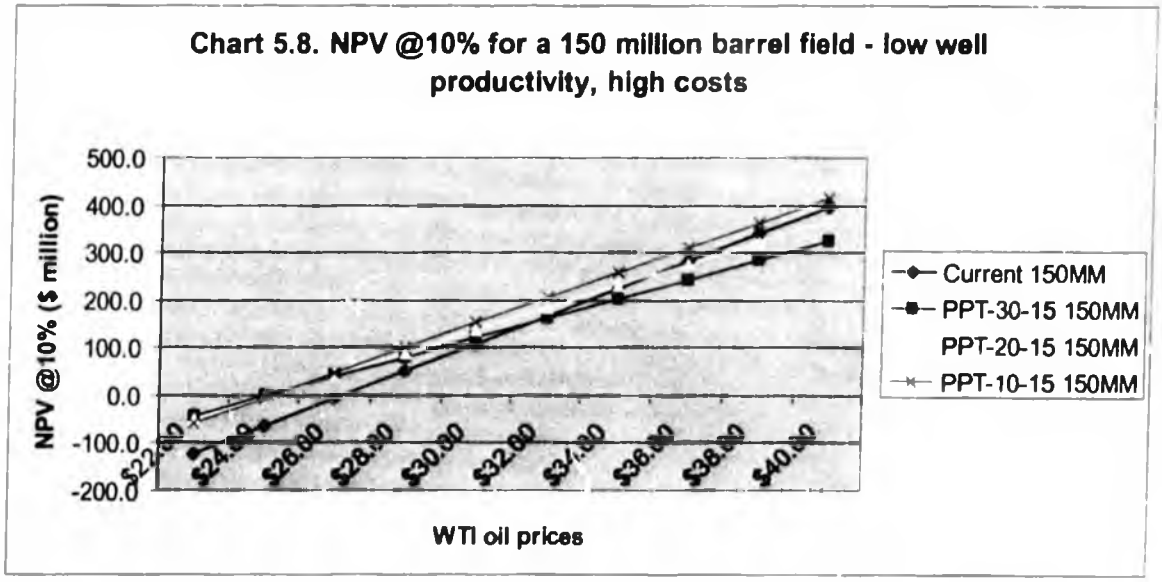
Additionally, there are the 15% tax credits on capital expenditures, which are unaffected by the PPT rate.

The IRR effect of different rates can be seen in Chart 5.7.



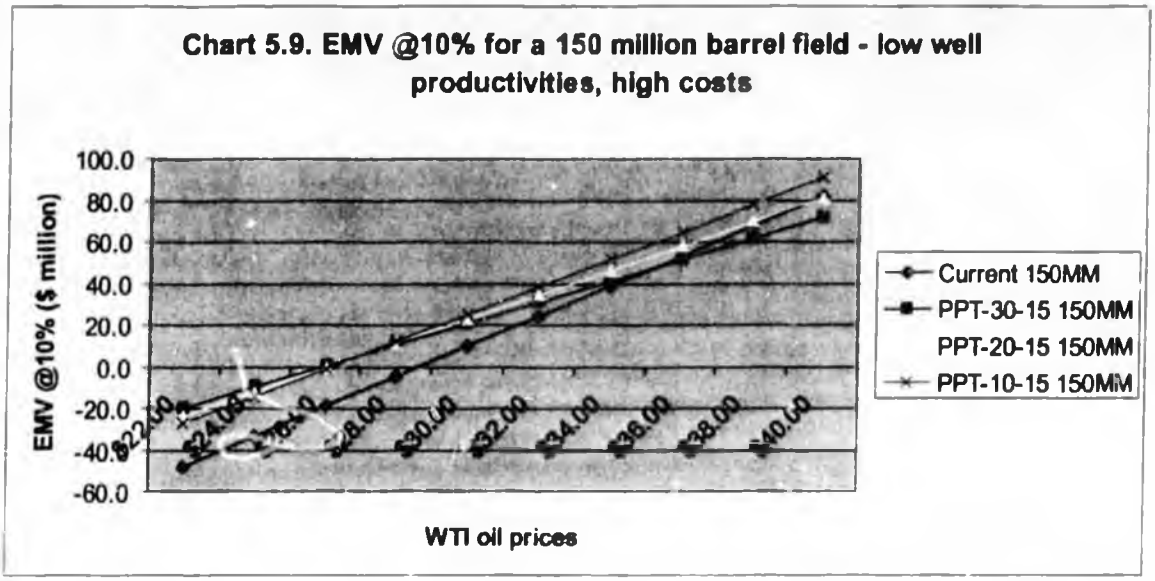
The NPV@10% nominal is, of course, affected by the PPT rate. As can be expected a PPT rate of 10% will result in a NPV@10% that is better than the current severance tax for the entire price range.

A PPT rate of 20% would result in a WTI price cross over point of US $ 35 per barrel and a PPT rate of 30% in a cross over point of US $ 32 per barrel.



Also on an EMV@10% basis, the PPT rate of 10% would be better than the current system for the entire price range used in this report.

The cross over points are a WTI price of US $ 39 per barrel for the 20% PPT and $ 35 for the 30% PPT.



Conclusion. From a large existing producer perspective the combination of a PPT rate of 10% and a tax credit rate of 15% would create economics that would be better than the current system for the entire price range. A 20% PPT rate would have a better IRR, but would have cross over points for the NPV@10% and EMV@10%, whereby at high prices, the current system would be more attractive.

5.2. Tax Credit Rate for Capital Expenditures

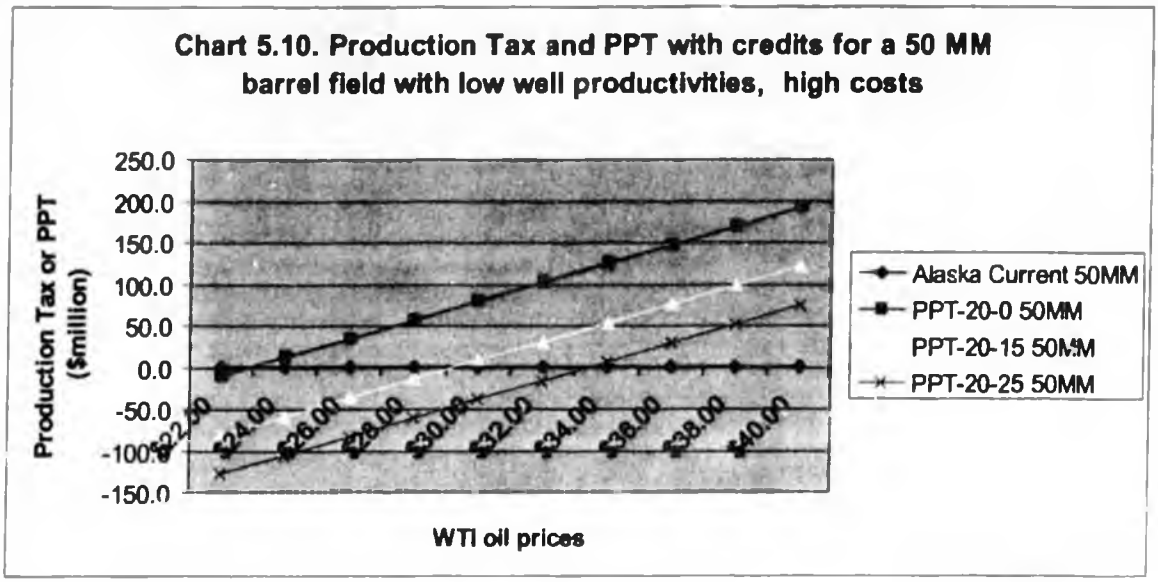
An important factor in the total package is the tax credit on capital expenditures. Therefore, a sensitivity analysis was done on this matter.

5.2.1. Impact on PPT

The impact of the tax credit on capital expenditures is independent of price. The tax credit is a fixed amount and depends on the level of capital expenditures, not the price. Therefore, in Chart 5.10 it can be noted that the PPT curves for the various levels of tax credit are parallel.

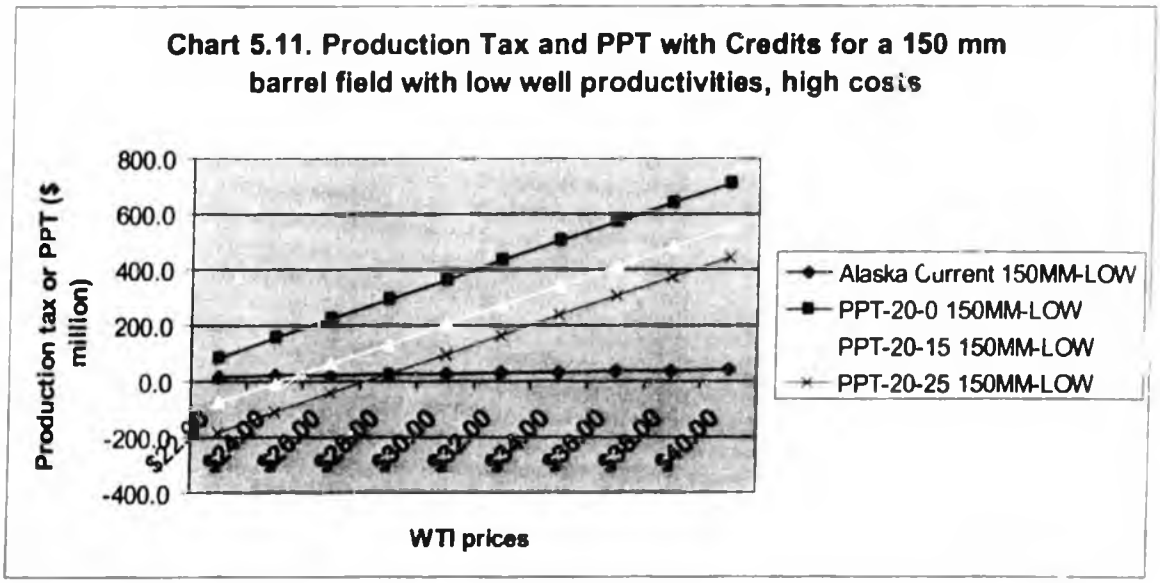
Chart 5.10 shows that above a WTI price of $ 22 per barrel, the PPT based on a 20% rate with no tax credits on capital expenditures would result in a significant level of PPT for a small field, compared with zero severance tax under the current system.

A PPT of 20% without tax free allowance and without a tax credit would therefore result in a rather negative impact on small companies and new investors. This was an important reason to consider the tax credits and the tax free allowance.



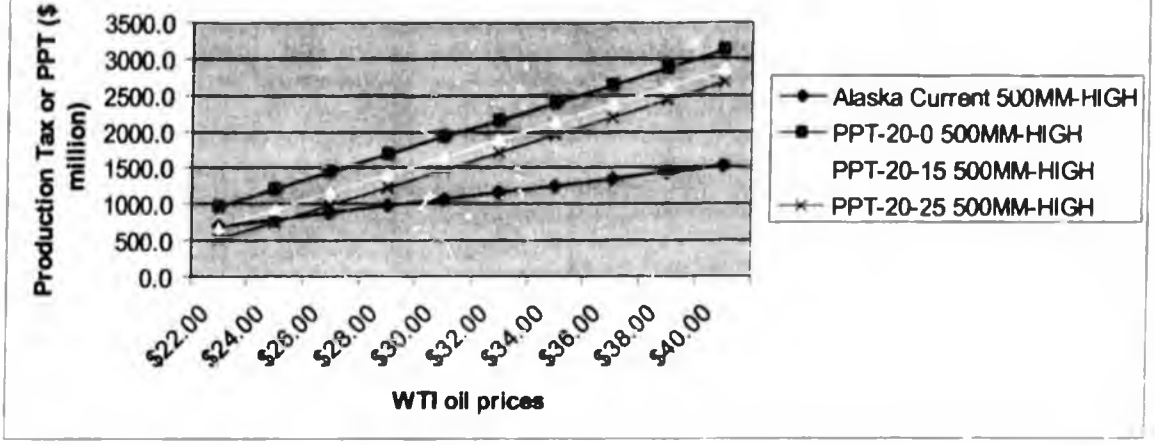
A PPT of 20% with a 15% tax credit results in a WTI break even point of $ 29 per barrel as previously discussed and a 25% tax credit results in a break even point of $ 34 per barrel for a 50 million barrel field.

For the 150 MM barrel field, as can be expected, a PPT of 20% without tax credit and without tax free allowance would result in considerably higher taxes over the entire $ 22 - $ 40 price range. The PPT with a 15% credit would result in a WTI break even price of $ 25 per barrel and a 25% credit would result in a break even price of $ 28 per barrel.



The results for the 500 million barrel field are similar, only the break even prices are lower. For a 15% tax credit the break even price would be $ 22 per barrel and a 25% credit it would be $ 24 per barrel.

Chart 5.12. Production Tax and PPT with credits for a 500 million barrel field with high well productivities, high costs

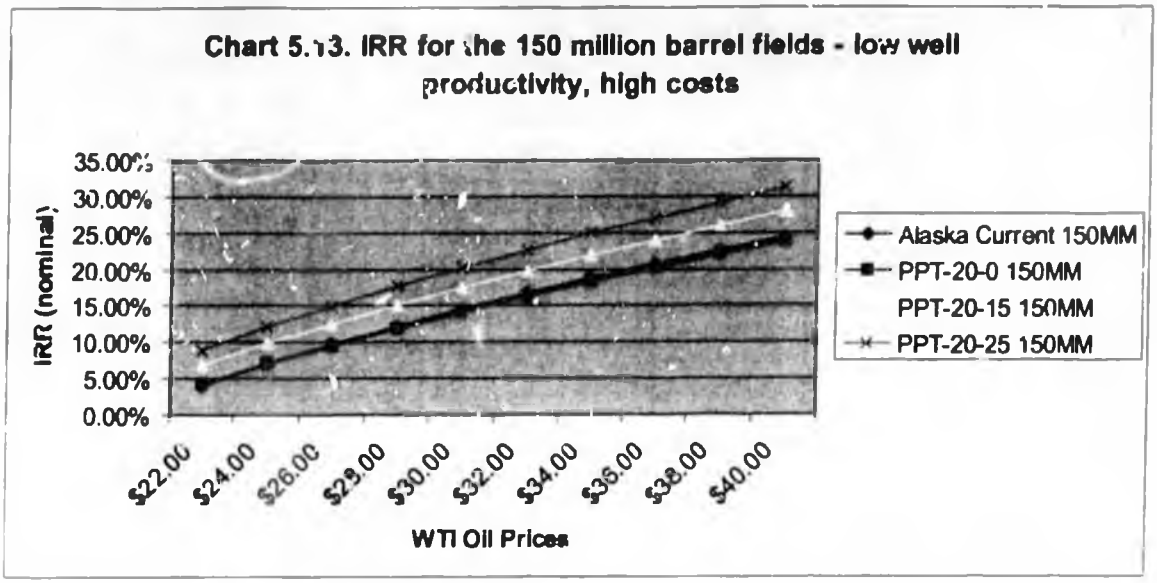


5.2.2. Impact on Investor Economics

The 150 million barrel field is again a good field to illustrate the overall investor economics. Based on this field size, a 20% PPT without tax credits and tax free allowance would result in about the same IRR as the current severance tax system.

It can be seen from Chart 5.13 that the boost in IRR is mainly created through the tax credits on capital expenditures. A tax credit of 15% significantly improves the IRR. A stronger improvement is obtained with a tax credit of 25%. The reason that the tax credits improve the IRR so significantly relates to the fact that the tax credits benefit the investor during the investment phase, early in the cash flow. Since the tax credits can be traded, this effect is the same for small and large companies.

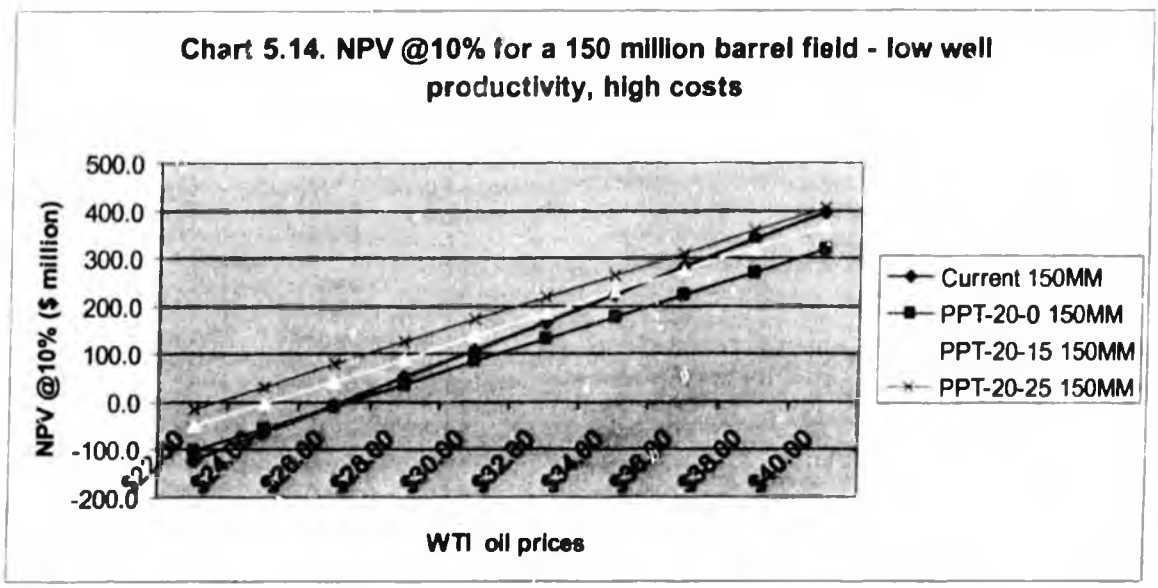
The overall improvement in IRR is an important feature for the world wide competitiveness of Alaska and therefore this is a powerful instrument to attract investment as can be seen from Chart 5.13.



The tax credits also play an important role with respect to the NPV@10%. If a 20% PPT would be introduced without tax credits and without tax free allowance, the result would be that the PPT would be less attractive over a WTI break even price of $ 24 per barrel.

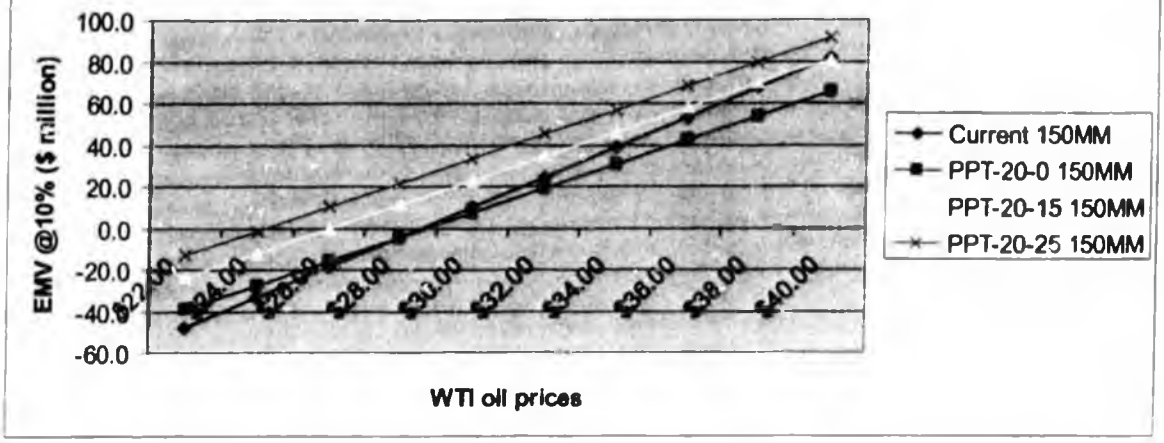
A tax credit of 15% moves the WTI break even price to $ 35 per barrel and a tax credit of 25% put is over the $ 40 per barrel level.

The tax credits therefore play a major role in creating a new fiscal package that results in higher taxes for Alaska above average price expectations, but at the same time encourages new investment.



The tax credits have even a more important impact on the EMV@10%, because these credits will also apply to the exploration phase. In case of a dry hole, the tax credit can be traded, in effect lowering the net costs of exploration. Therefore Chart 5.15 shows a significant impact on the EMV@15% of these credits. With no credits the break even price is about $ 28 per barrel. The break even price improves to $ 39 per barrel with a credit of 15% and well over $ 40 with a credit of 25%.

Chart 5.15. EMV @10% for a 150 million barrel field - low well productivities, high costs



The results of the analysis clearly indicate that a PPT without tax credits would be received unfavorably by investors.

At the same time a tax credit of 25% would make the fiscal system more attractive in the entire $ 22 - $ 40 price range. The introduction of such a strong tax credit would expose Alaska over time to the fact that PPT payments may decline over time, as fields become smaller and more costly. Tax payments may reduce strongly over time. This seems an incentive that is too strong and too risky for Alaska.

5.3. Tax Free Allowance

As was already concluded from Chart 5.10, even if a 15% tax credit would be adopted, small companies and new investors would still pay PPT over a WTI price of $ 29 per barrel. These companies would not pay severance tax at all on such small fields with under the current system. Therefore, a 20% PPT with a 15% tax credit may be considered unattractive by small companies, since it means that they may have to be PPT under high prices, even on small fields. Also for new investors, looking at modest oil field targets, the need to pay a PPT under high prices would be negative factor.

It is for this reason that an additional feature is recommended to protect the small companies and to encourage new investors more strongly. This feature is the tax free allowance on up to $ 73 million of cash flow per year.

Following is an analysis of this feature, with sensitivity to an allowance of $ 50 million per year and $ 100 million per year.

5.3.1. Impact on PPT

Chart 5.16 provides the PPT on a first 50 million barrel field with full application of the tax free allowance. The graphs shows clearly that for the price range of $ 22 - $ 40 per barrel the PPT would be negative. This is because there is no or little tax payable and the tax credits easily offset the tax that may have to be paid.

However, the graph also shows that for the $ 50 million allowance, the WTI break even price would be about $ 43 per barrel. Therefore under high oil prices, over $ 43 per barrel, small companies would still pay some PPT. This still may create some concern, when compared to the current severance tax.

As indicated above, economic analysis was also done for the price range $ 10 - $ 60 per barrel. This analysis indicates that the WTI break even point for $ 73 million tax free allowance would be $ 50 per barrel and for $ 100 million it would be $ 56 per barrel.

It should be noted that the tax free allowance would be applicable to all companies, the large and small ones. The DOR analysis, to be presented in a separate report, indicated that a $ 100 million allowance would reduce the overall Alaska PPT payable too much. Therefore, this level is too high.

For this reason the $ 73 million level was selected. Despite, the fact that small companies and new investors will pay some PPT when prices are over $ 50 per barrel on this 50 million barrel field, it should be noted that otherwise the tax credits they receive improve the economics considerably. Therefore, this seems a reasonable balance.

Chart 5.16. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

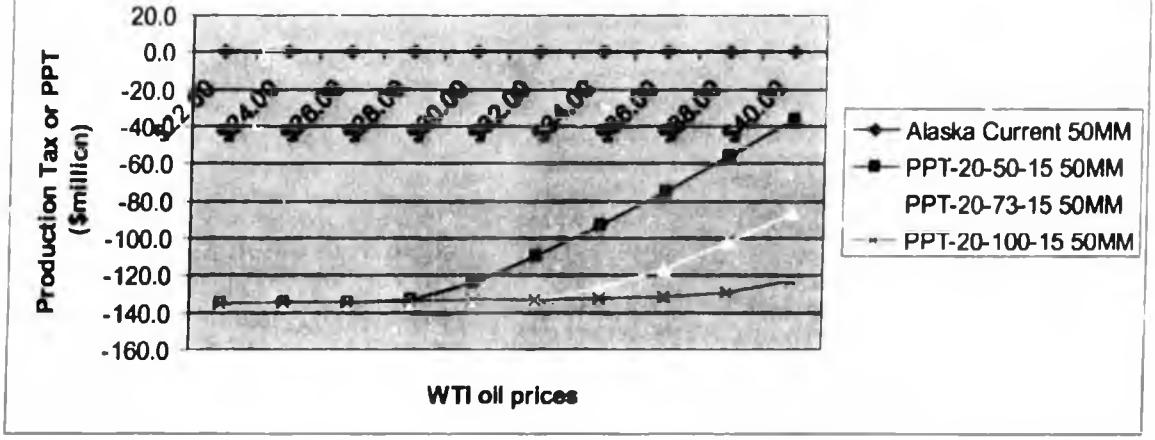


Chart 5.17 indicates that a $ 73 million tax free allowance would result in a significant reduction of PPT on the first 150 million barrel field as well, resulting in a very material improvement of economics. This means that some of the larger new companies may be interested in more actively considering Alaska for the new first investments.

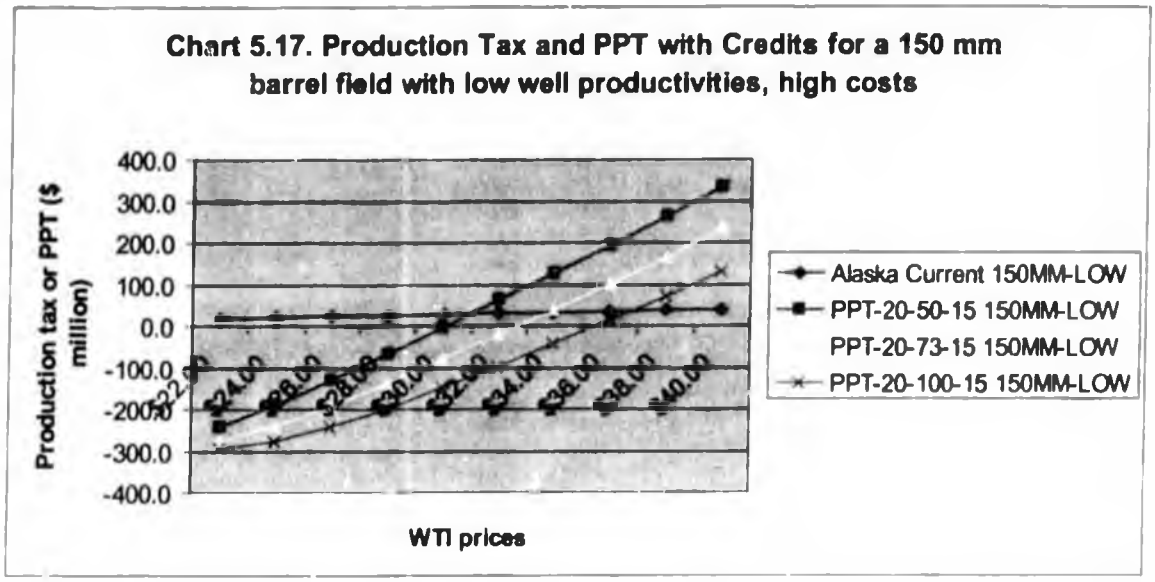
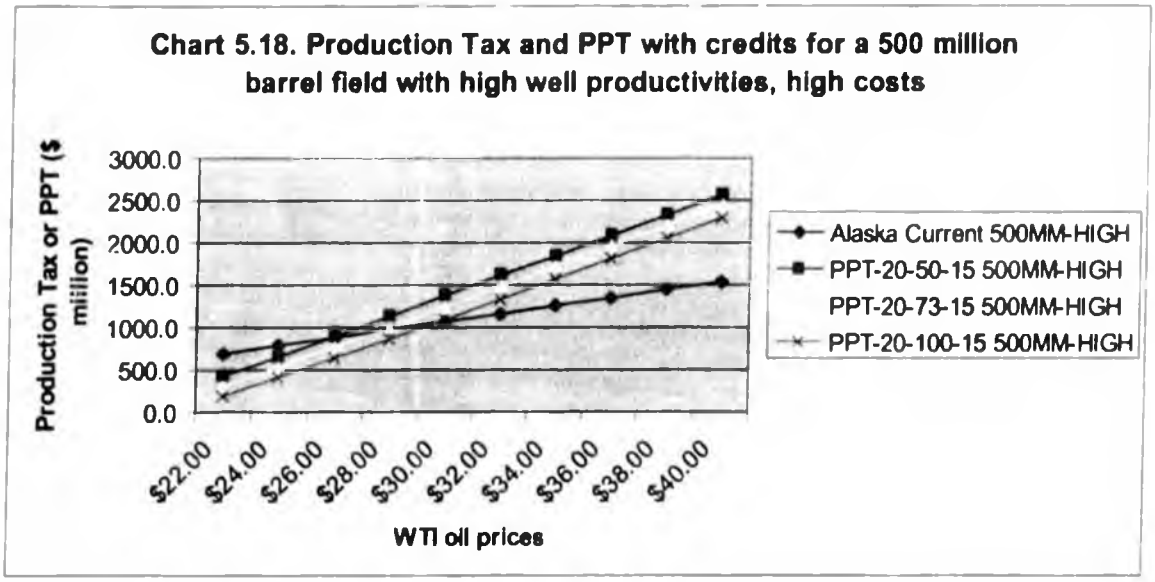


Chart 5.18 indicates that even on a $ 500 million target the tax free allowance will provide a material improvement in PPT for a new investor.



The $ 73 million tax free allowance will not only assist small companies, but will also attract new large potential producers to Alaska. The positive impact is material on investments in the first large fields.

5.3.2. Impact on investor economics

The following graphs relate to the 50 MM barrel field, which is the important field to evaluate the impact on small and new investors.

All the charts 5.19, 5.20 and 5.21 indicate that at low prices it makes no difference whether a tax free allowance of $ 50 million, $ 73 million or $ 100 million is applied, since in all cases $ 50 million is sufficient not to pay the PPT and the higher levels of tax free allowance have therefore no impact.

For higher prices the impact is rather modest. The reason is that the amount of profit subject to tax in all cases is modest. The tax free allowance therefore does not impact much on the traditional profitability indicators for the small 50 MM barrel field.

Chart 5.19. IRR for 50 million barrel - low productivity case, high costs

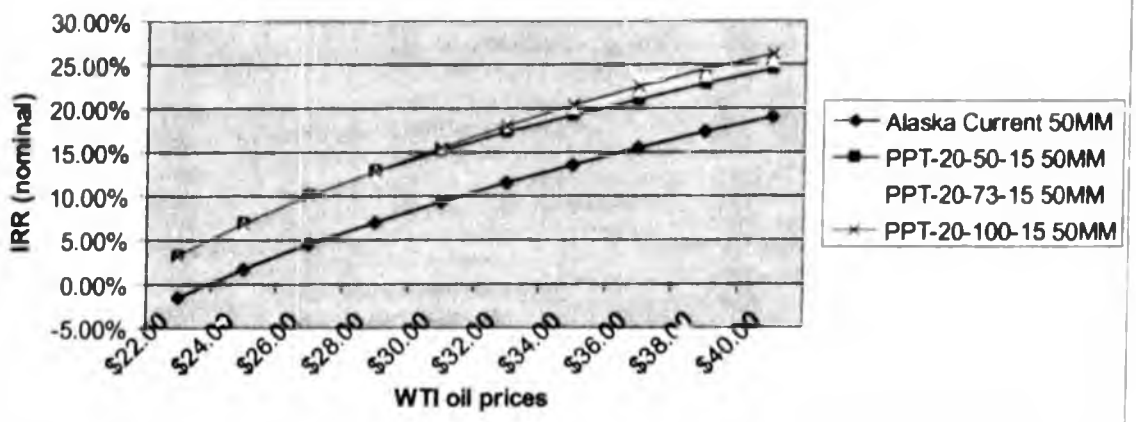
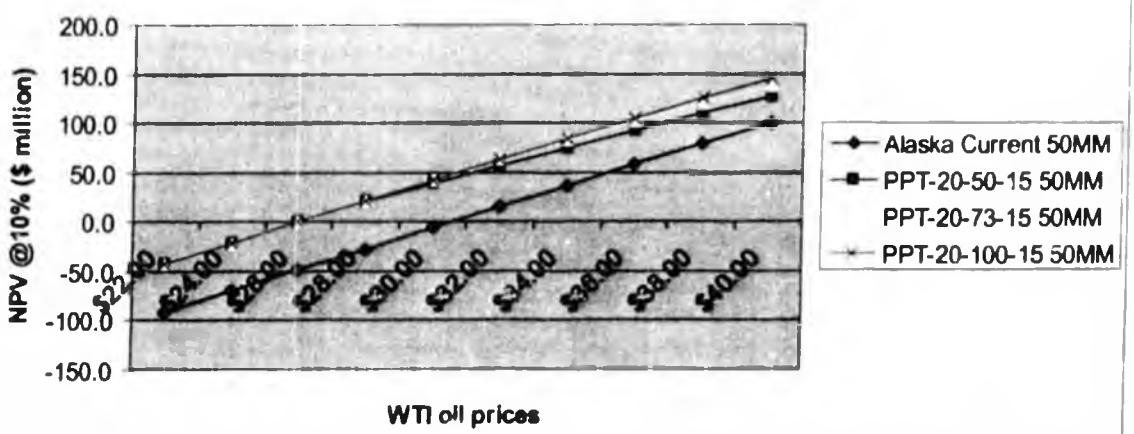
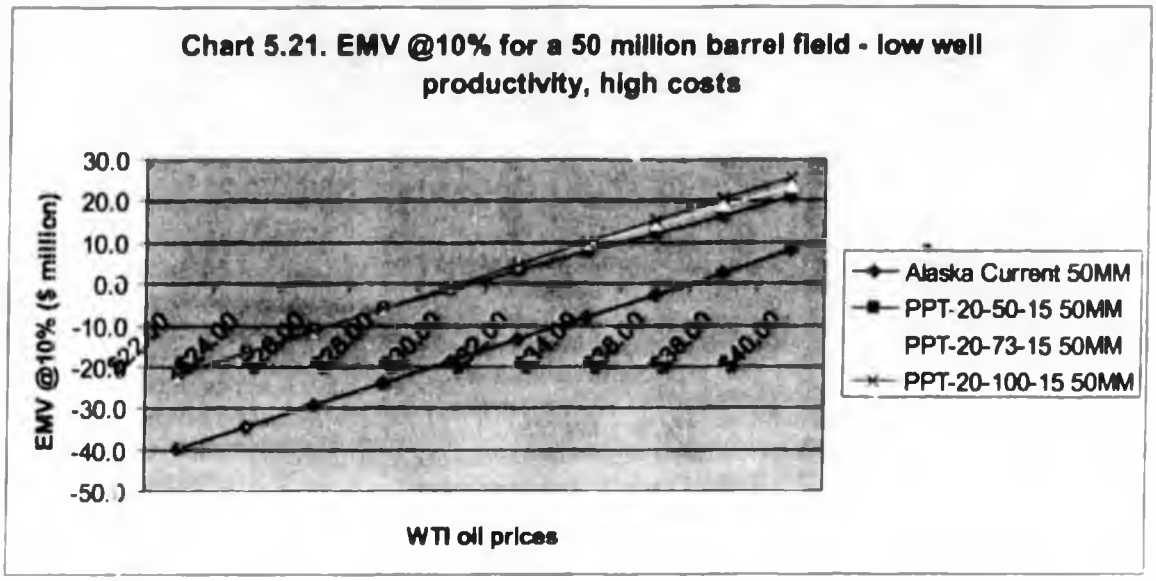


Chart 5.20 NPV @10% for a 50 million barrel field - low well productivity, high costs





With respect to small fields and tax free allowance in the range of $ 50 to $ 100 million is adequate. A level of $ 200,000 per day was selected because this is administratively easy and it is also material for larger fields, as was indicated above.

5.4. Other PTT variations

Other variations to the PPT were also considered, but are not recommended. Following is a listing of items that was considered.

Differential tax credit

Instead of a flat tax credit of 15%, it is possible to consider different levels of tax credits for different activities. For instance, development of conventional oil and gas could be a 10% credit, exploration could be a 15% credit and development of heavy oil a 20% credit. The advantage of this approach is that it makes the credit more targeted towards investments in opportunities that seem to justify such credits. The State of Alaska would therefore re-distribute the credit to "where it is most needed".

This approach is not recommended. The main reason is that it would be difficult to properly audit and verify all the different classes of capital expenditures. It could also lead to many disagreements among companies and the State of Alaska.

A more detailed analysis will be provided for Heavy Oils in Chapter 10.

Uplifts

Instead of tax credits it is possible to provide uplifts. Uplifts are extra deductions of capital expenditures. For a particular tax rate a particular level of uplift corresponds to a level of tax

credit. For instance, for a 20% PPT a 50% uplift would be equal to a 10% tax credit. Uplifts and tax credits can therefore be used in order to create identical economic effects. However, it would be more complicated to have separately uplifts and tax credits based on negative cash flows and allow both the uplifts and the tax credits to be traded. This would create confusion. So it seems easier to simply only adopt tax credits, which can then be traded without distinction.

Carry forwards

A similar issue is related to carry forwards. Instead of converting a negative cash flow into tax credits, it is possible to apply the more traditional way of permitting carry forwards. It is simpler to have both for the uplifts and the carry forwards, tax credits instead.

Minimum Tax

Considerable study was done of the possibility to have a minimum tax. During periods of low oil prices or periods of strong investment, the State of Alaska would always be assured of some type of minimum payment. This would have psychological-political value and would provide some assistance to State budgeting in case of such conditions.

In reality, the minimum tax is not very useful. It is fair to carry forward any minimum tax and offset such minimum taxes from the full PPT to be paid as soon as economic conditions improve. It is highly unlikely that strong investment would co-exist very long with sustained periods of low oil prices. Therefore, it is highly likely that periods of minimum tax would be of limited duration. Under these conditions, the minimum tax becomes really an interest-free loan of short duration. For the long term future of the State this is an irrelevant feature.

In addition, the minimum tax, when applied would complicate the tax credit system and the overall administration of the tax credits, which now would have to be split between tax credits that can be traded and tax credits as a result of minimum tax which cannot be traded. This is a complex system for a very modest purpose.

Furthermore, the minimum tax would interfere with the concept of a tax free allowance. It would mean that small companies and new investors would always pay the minimum tax. This seems contradictory to the objective of providing support for these investors.

For these reasons a minimum tax is not recommended.

6. ANALYSIS OF INTERNATIONAL COMPETITIVENESS OF THE PETROLEUM PROFITS TAX ("PPT")

(Note: After the initial scoping a PPT tax rate of 20% and a credit rate of 15% seemed a reasonable combination. Therefore much economic work was done on this combination. As a result of subsequent work it was concluded that a 25% tax rate and 20% tax credit rate is more in the interest of Alaska. Nevertheless in the interest of providing the maximum information about the PPT it was considered desirable to leave the Chapters that were based on the 20% tax rate and 15% credit rate in the report. These are Chapters 4,5,6,7 and 8. Chapter 9,10 and 11 are based on the recommended fiscal terms.)

The competitive level of PPT that can be sustained in Alaska depends very much on the international framework. As indicated in Chapter 2, this framework has changed rather drastically as a result of the high oil prices.

In this chapter a comparative analysis will be done of proposed PPT with fiscal systems of other countries. It is not possible to isolate the PPT for comparison. The total fiscal terms need to be compared. These total terms include the US Federal income tax.

Eight different fiscal systems were selected for the comparison. The fiscal systems were selected to present a reasonable distribution of high and low government take regimes around the world, in order to ensure that the total comparison reflects the world wide conditions. However, the eight specific areas were all selected based on the level of activity. All eight areas represent significant developments by large international oil companies, including the ones also operating in Alaska. Therefore, it is confirmed that these investment terms result in considerable activity in the particular areas.

The eight areas that were selected are:

- Norway
- UK
- US Gulf of Mexico
- Nigeria
- Alberta Oil Sands
- Angola
- Russia-Sakhalin
- Azerbaijan

6.1. Preliminary economic comments

The comparison will be made on the basis of the same fields as were provided in Chapter 3. These fields reflect a wide enough cost range to be relevant for international conditions. In order to provide an overview over the entire cost range the High Cost and the Low Costs scenario results will be compared. Also to test a large range, graphs for the 50 MM and 500 MM barrel fields will be provided.

A major difference between Alaska North Slope and most other jurisdictions in the world is that the net back value at the well head in Alaska North Slope is much lower than in most other jurisdictions, due to the high transport costs and a quality of crude oil that is less than WTI or Brent. Therefore, an international comparison has to take this difference into account.

Therefore all fiscal systems will be compared on the basis of the same WTI price. For each system an approximate net back will be included in the analysis. The net backs differentials relative to WTI are the following:

Jurisdiction	Net back differential
	($ per barrel)
Alaska-North Slope	$ 7
Norway	$ 1
UK	$ 1
US Gulf of Mexico – Deep water	0
Nigeria – Deep Water	$ 2
Alberta – oil sands	$ 2
Angola	$ 2
Russia-Sakhalin	$ 1
Azerbaijan	$ 6

First fiscal comparisons will be made between Alaska and each jurisdiction and in Chapter 6 subsequently an overall rating will be provided in Chapters 7 and 8.

The main emphasis in this report is an analysis of the attractiveness of Alaska to new investors. Therefore, for the analysis of the international competitiveness of the PPT the $ 73 million allowance will be included.

Also for convenience two fiscal systems are included in each graph. In order to make the graphs easier to analyze typically a system with a high government take and a low government take selected.

The main emphasis of the analysis will be on the $ 22 – $ 40 per barrel WTI price range. This is the long term price range which is still applied by most oil companies. As indicated in Chapter 3, these prices are escalated by 2% per year.

Some fiscal systems feature signature bonuses. These include Alaska, Canada, the US Gulf of Mexico, Angola, Russia, etc. For economic comparison, the signature bonuses were set at zero, since in all cases they are freely biddable or negotiable. Where there were specific requirements for social expenditures, such as in Russia, these expenditures were included in the fiscal terms.

6.2. Comparisons with other jurisdictions

Of course, the attractiveness of the petroleum resources of each country is different. International comparisons on the basis of the same standard fields do not reflect actual investment decisions of investors, which are based on specific prospects and projects in the various countries. These opportunities could be less attractive or more attractive than Alaska. The comparison in this chapter and the subsequent rating in the following chapters therefore serve only as a very general benchmarking of the attractiveness of Alaska terms.

6.2.1. Norway

The comparison between Alaska and Norway is relevant because Norway typically has a high cost environment. Also Norway has seen over the last decade a gradual outflow of capital from the major oil companies and therefore Norway has recently taken some steps to increase the interest of new investors. One of these measures was to provide new investors with a tax rebate equal to the tax value of their losses in case their operations in Norway would be unsuccessful. This is very similar to the proposed Alaska tax credit that can be traded for capital expenditures. Therefore, Norway and Alaska are considering the same type of policies in order to make their jurisdictions more attractive to new investors.

Norwegian terms. The terms of Norway are a basic 28% corporate income tax and a 50% hydrocarbon tax. The hydrocarbon tax has a 30% uplift which can be earned over a 4 year period. Furthermore, there are modest surface rentals. It is assumed that Norway would have a $ 6 per barrel advantage over Alaska North Slope at the well head.

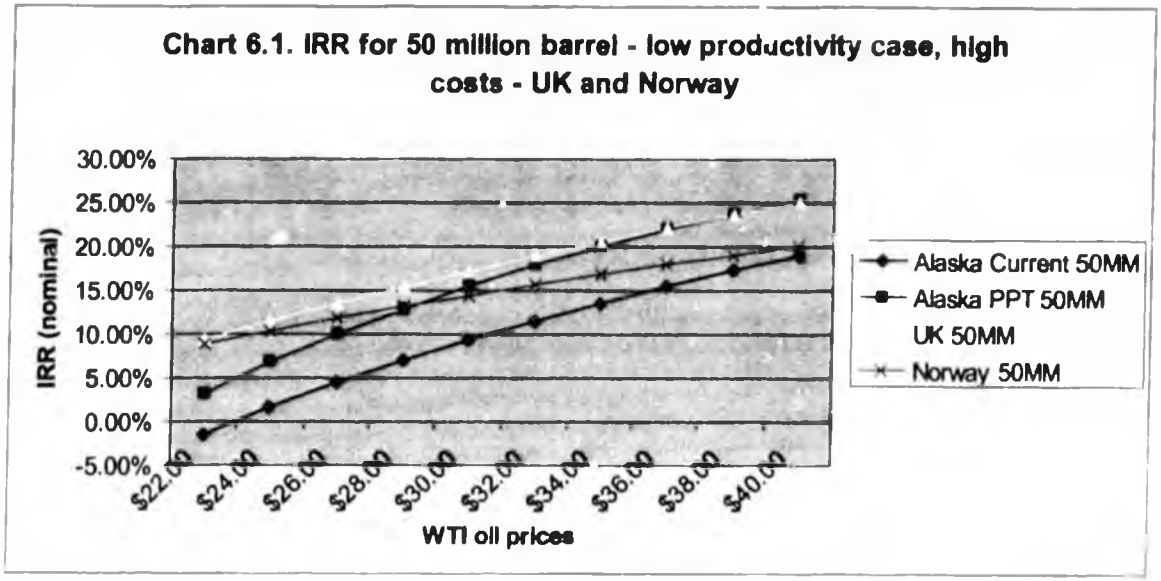
Norway does not provide fiscal stability on its terms.

50MM high cost

The following graphs display the economics for the UK and Norway for the 50 MM high cost field compared with fiscal conditions for a new investors in Alaska. In this section we will discuss the Norway results.

Chart 6.1. illustrates how the proposed PPT relative to the current severance tax will be a very material improvement relative to the Norwegian fiscal system with respect to the IRR. The WTI break even point with Norway was $ 42 per barrel under the current system and this is now

reduced to $ 28 per barrel under the PPT proposal. This means that the Alaska PPT terms are now more attractive than the Norwegian terms for prices over $ 28 per barrel. These terms are therefore considerably more competitive than the current severance tax with respect to the IRR.



The NPV@10% results show a similar pattern. The WTI break even oil price is $ 36 per barrel under the current severance taxes and would now be $ 28 per barrel.

The PPT would also improve the EMV results relative to Norway. With the current severance tax the WTI break even point would be $ 42 per barrel. However, with the new PPT the EMV@10% is better than Norway over $ 30 per barrel.

Chart 6.2. NPV @10% for a 50 million barrel field - low well productivity, high costs, UK and Norway

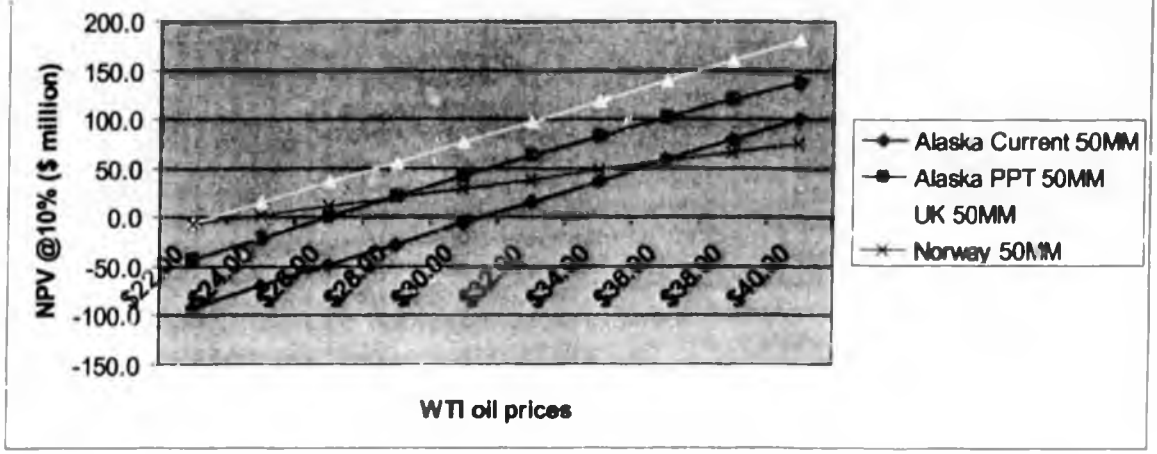
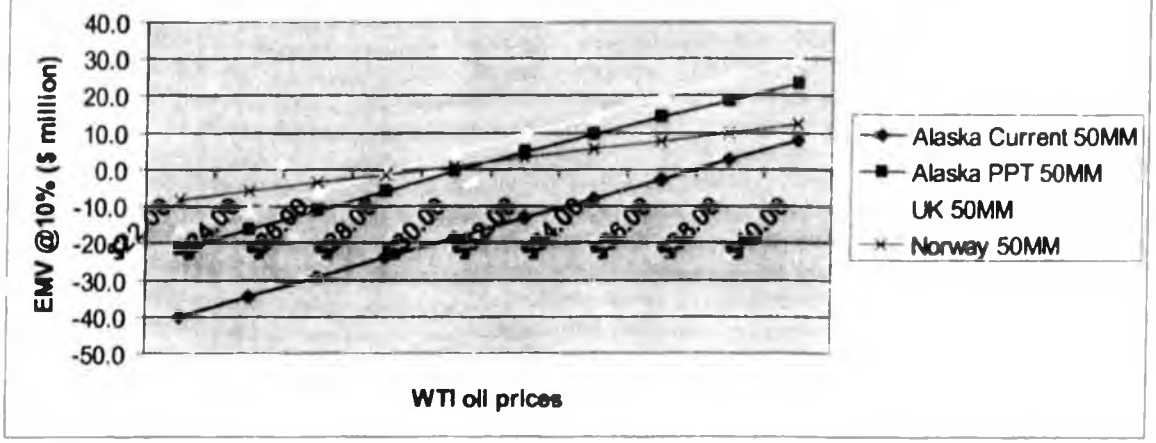
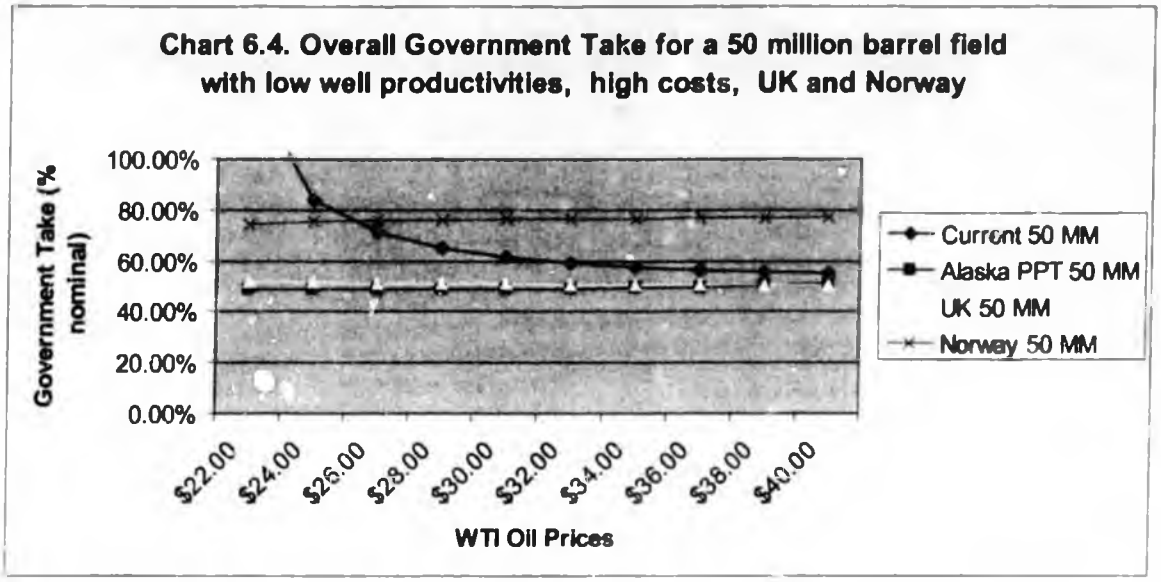


Chart 6.3. EMV @10% for a 50 million barrel field - low well productivity, high costs, UK and Norway

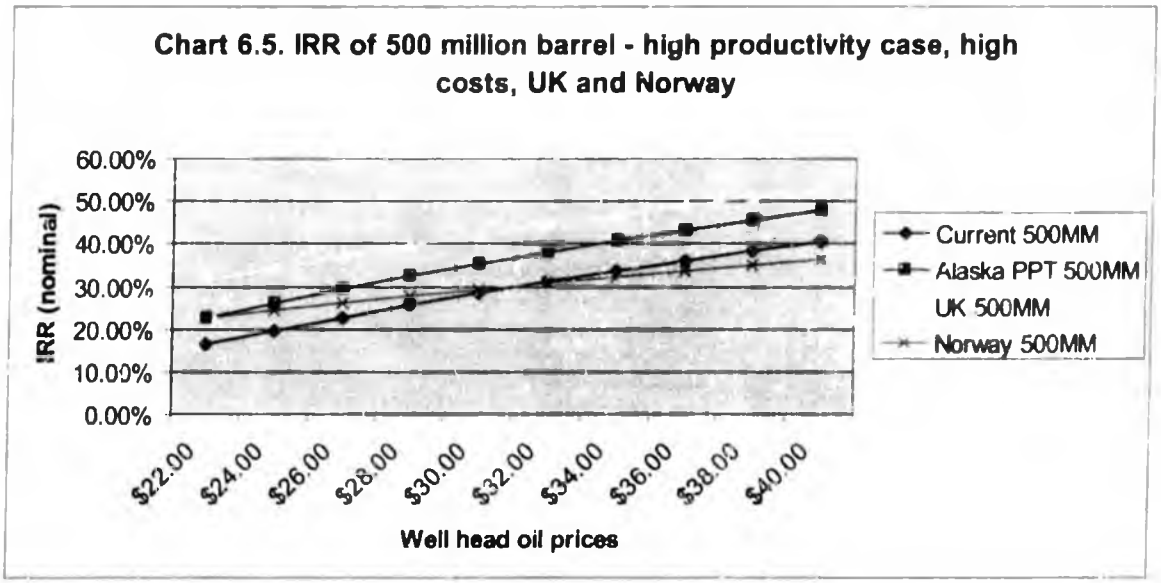


The proposed PPT **lowers** the overall Federal/Alaska government take for this field for new investors. This is because new investors receive the tax credits, but will actually not pay PPT on this field, because of the tax free allowance. This makes the overall government take attractive from an international perspective as can be seen by comparing this with the government take in Norway.



500MM high cost

Also for the IRR of a 500 MM barrel field the PPT system results in a very substantial reduction of the WTI break even points relative to Norway, making the Alaska PPT fiscal system much more competitive.



For the NPV@10% and EMV@10% there are significant improvements in the competitiveness with a lower WTI break even point for the PPT compared to the current severance tax. This is in part caused by the tax free allowance for new investors, which still has a significant impact even on the 500 MM barrel field.

Chart 6.6. NPV @10% for a 500 million barrel field - high well productivity, high costs, Uk and Norway

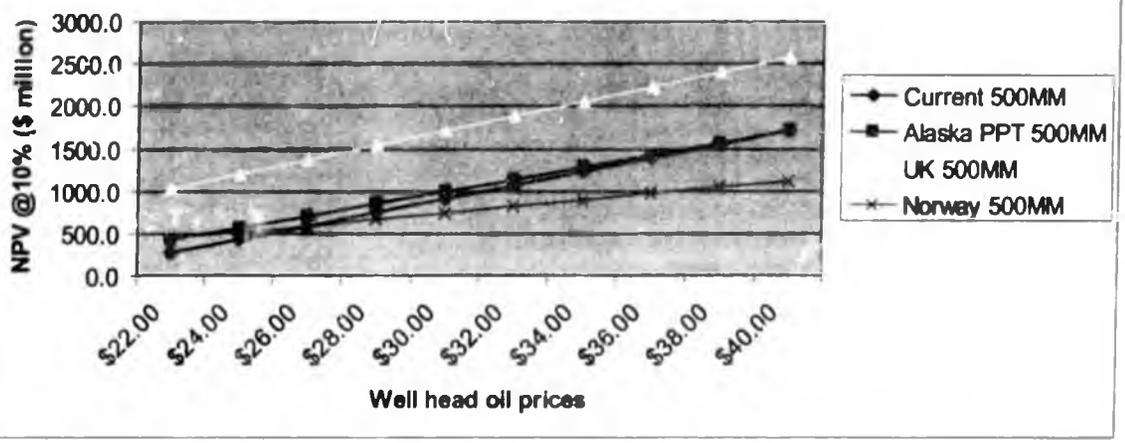


Chart 6.7. EMV @10% values for a 500 million barrel field - high well productivities, high costs, UK and Norway

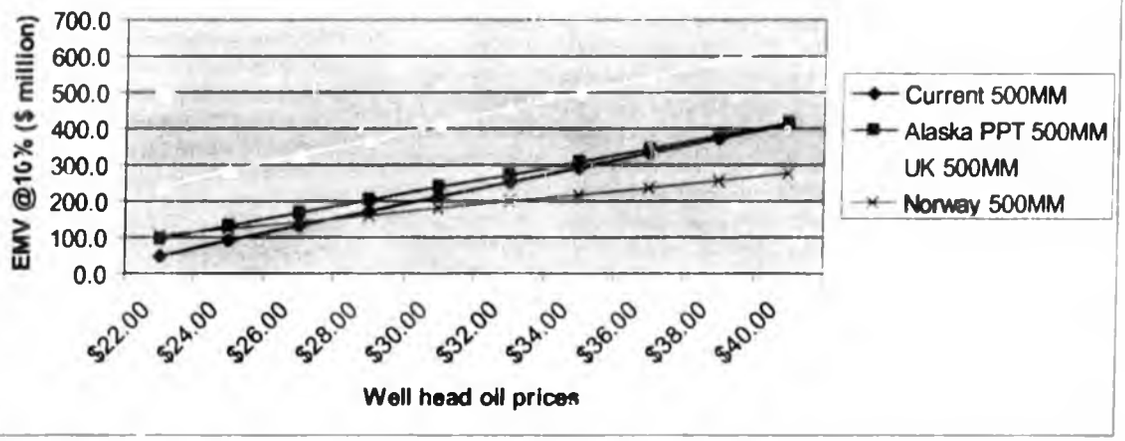
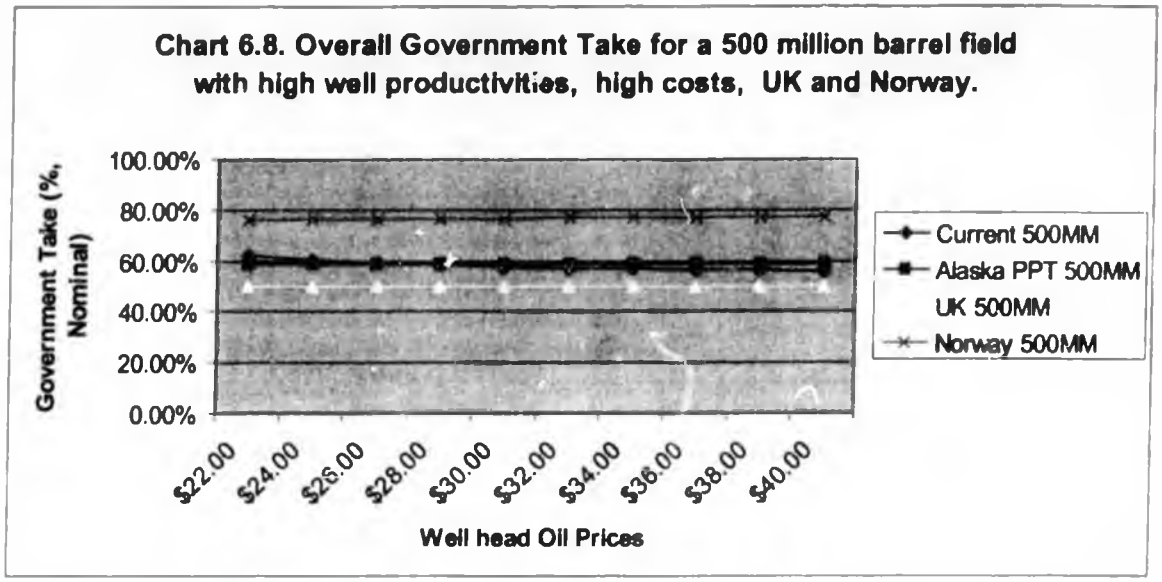
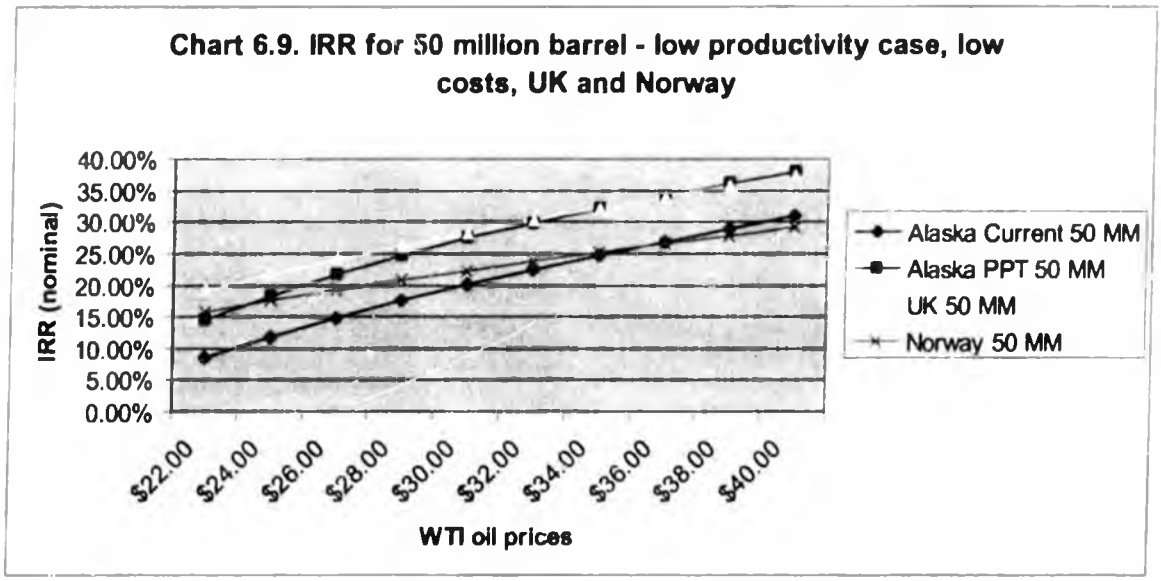


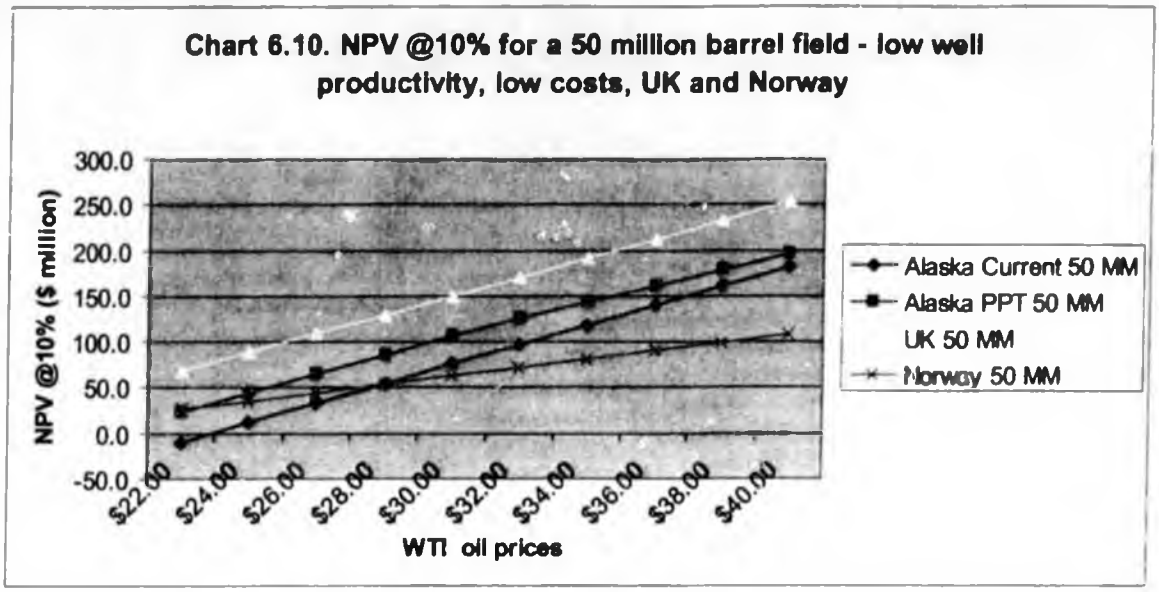
Chart 6.8 indicates that the overall government take for the 500 million barrel field is higher than for the 50 million barrel field as a result of the progressive nature of the PPT. Yet, this government take is still substantially less than the government take in Norway.



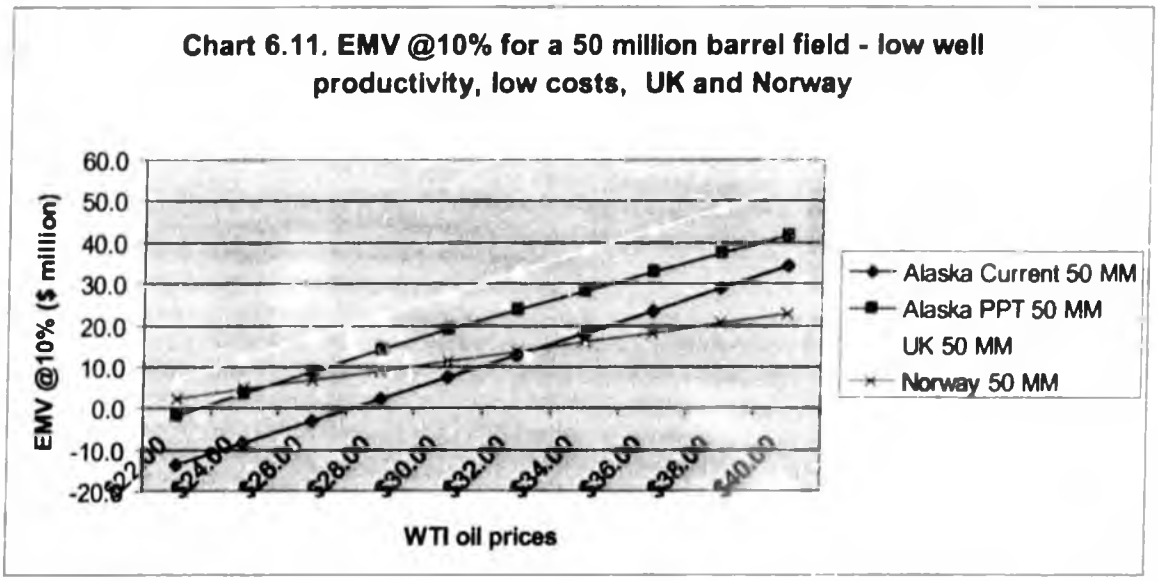
50MM low cost

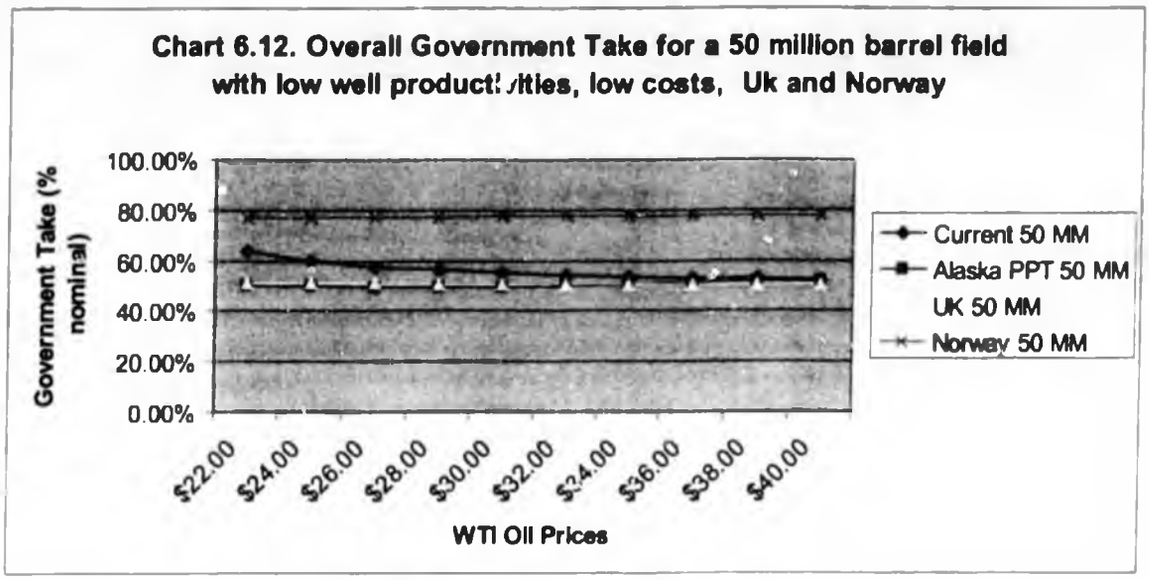
As can be observed in Charts 6.9, 6.10 and 6.11, the results for the low costs cases provide the same overall conclusion as those for the high cost cases. For all profitability indicators the WTI break even points for the new PPT are considerably below those of the current severance tax compared to Norway.





The government take results are also very similar to the 50 MM high cost case. A new investment in a 50 MM barrel field even with low costs, has a considerably lower government take than in Norway.





500 MM low cost

The results for the 500 MM low cost field are very similar to the 500 MM high cost field as can be seen from Charts 6.13, 6.14., 6.15 and 6.16.

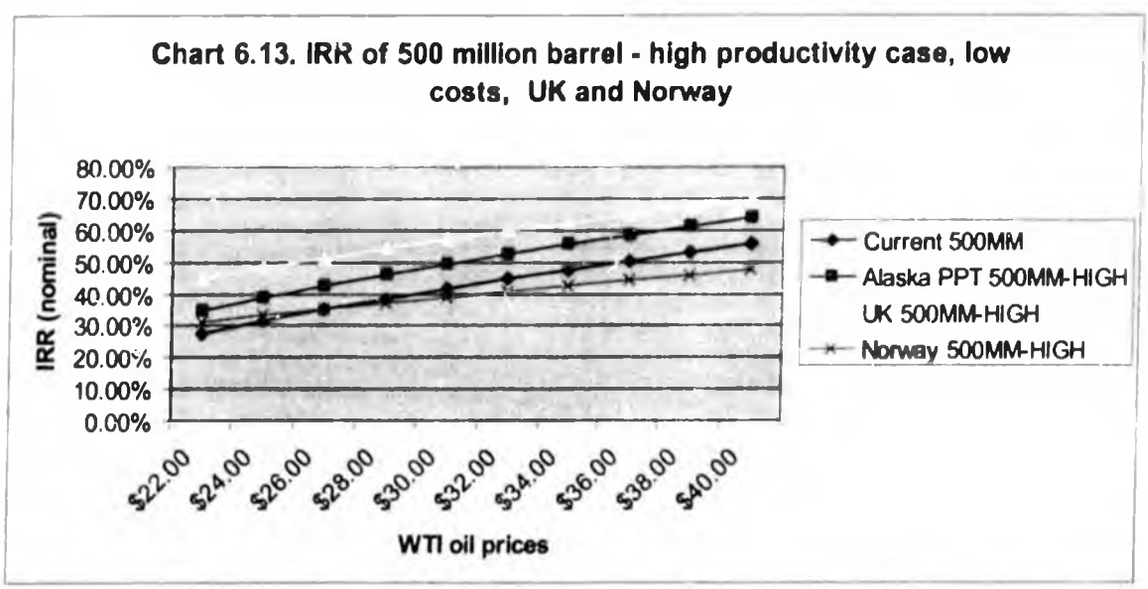


Chart 6.14. NPV @10% for a 500 million barrel field - high well productivity, low costs, Uk and Norway

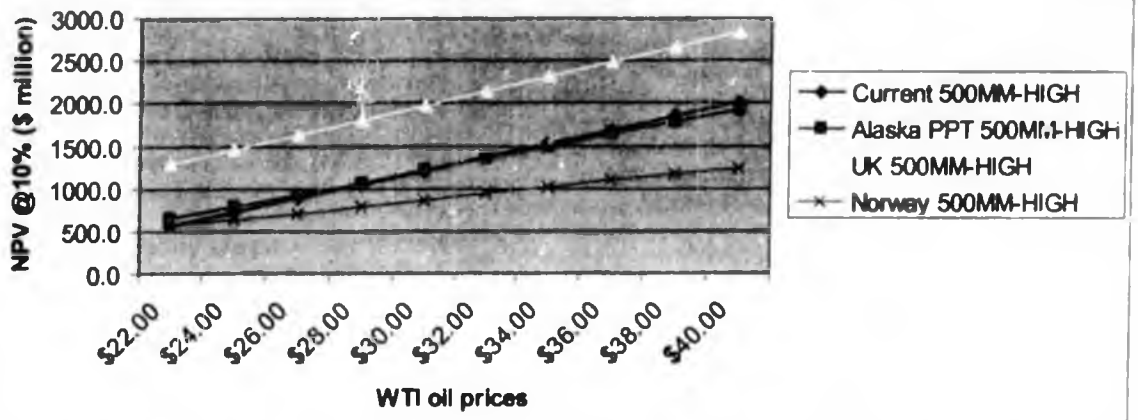
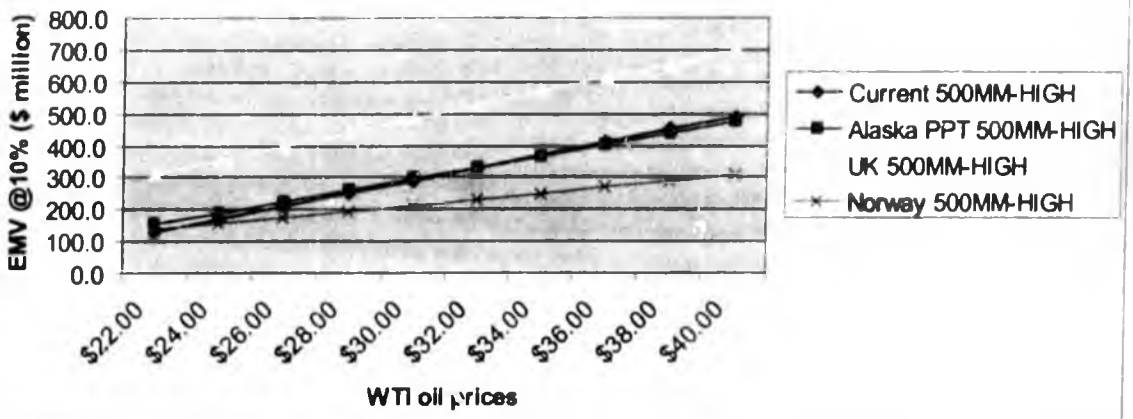
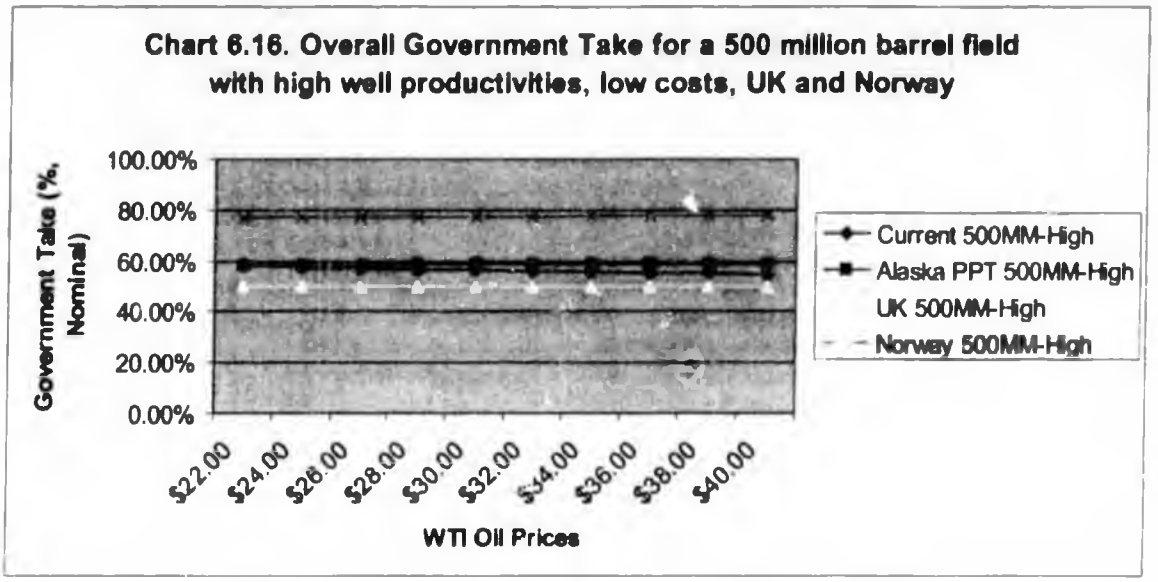


Chart 6.15. EMV @10% values for a 500 million barrel field - high well productivities, low costs, UK and Norway





Norway Conclusion. The PPT makes Alaska more competitive relative to Norway for new investors compared to the current production tax. Relative to Norway the PPT has attractive IRR results, also under high prices the NPV and EMV are better. The PPT is in particular more attractive for first investments in small fields.

6.2.2. UK

UK terms. The UK fundamentally changed its fiscal system in the North Sea in 1993 when it removed the Petroleum Revenue Tax and established that for new licenses the only applicable fiscal terms would be corporate income tax and some rentals. A surcharge was established for corporate income tax, creating a total rate of 40%. In December 2005 the UK proposed to increase the surtax, so that the total tax rate is now 50%. The UK change in fiscal terms is an important indication of the world wide trend to a higher government take.

It is assumed that the UK has a $ 6 per barrel advantage over Alaska North Slope at the well head.

The previous UK system was one of the most attractive in the world. With the increase in the surtax, the US Gulf of Mexico terms have clearly become more attractive. It should be noted, however, that the UK offshore went through a very rapid development in only four decades and that as a result the remaining prospects are small and marginal. As a result, even under these very favorable fiscal terms investors are looking abroad for new opportunities.

The UK does not provide fiscal stability on its terms.

Charts 6.1 through 6.4 show that for small high cost fields the PPT terms do not compare unfavorably with the UK terms. For high prices the IRR is the same. The NPV and EMV are somewhat less due to the much higher well head values in the UK. The government take is similar.

Tables 6.5 through 6.16 show that the UK has a more favorable fiscal system than Alaska under the proposed PPT terms for low cost fields and large fields.

UK Conclusion. The PPT terms would be less attractive than the fiscal terms for the UK. Nevertheless, the PPT would significantly reduce the gap in competition and the PPT compares relatively favorable for small high cost fields. Small high cost fields are typical for the North Sea today.

6.2.3. US – Gulf of Mexico – Deep water

The deep waters of the US Gulf of Mexico have been an area of intensive oil activity and therefore, the fiscal terms are attractive for the environment. The Gulf of Mexico is for US oil companies a direct alternative to Alaska. Therefore, this comparison is important.

US-Gulf of Mexico-Deep Water terms. The area has a favorable royalty regime of 12.5%. An initial royalty suspension volume of 87.5 million barrel equivalent of oil was assumed. Furthermore, the area is subject to the Federal corporate income tax, as well as rentals and bonuses. It is assumed that the US Gulf has a $ 7 per barrel advantage over Alaska North Slope at the well head.

The Federal Government of the United States does not provide fiscal stability on its terms.

50MM high cost

Charts 6.17 through 6.20 clearly indicate that for a 50 MM barrel high cost field the fiscal terms in the US Gulf of Mexico are considerably more attractive to investors, assuming the same costs conditions, than the proposed Alaska PPT terms. This is true in terms of IRR, NPV@10%, EMV@% and Undiscounted Government Take.

The relative attractiveness of the EMV@10% depends very much on the assumptions about bonuses in either the US Gulf of Mexico or Alaska. Bonuses influence these values considerably and therefore investor assumptions about the level of bonuses that may have to be paid has a large impact on the relative outcome.

However, it is also obvious from the graphs that the Alaska PPT is an important step in reducing the gap in competitiveness between the Gulf of Mexico and Alaska. Therefore, the Alaska PPT terms will increase interest of new US investors in Alaska.

Chart 6.17. IRR for 50 million barrel - low productivity case, high costs, US GOM and Nigeria

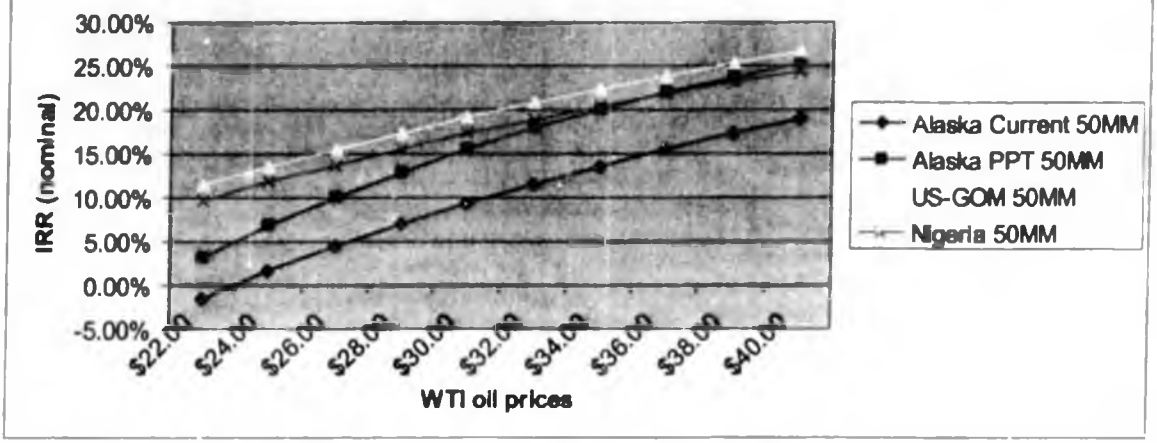


Chart 6.18. NPV @10% for a 50 million barrel field - low well productivity, high costs, US GOM and Nigeria

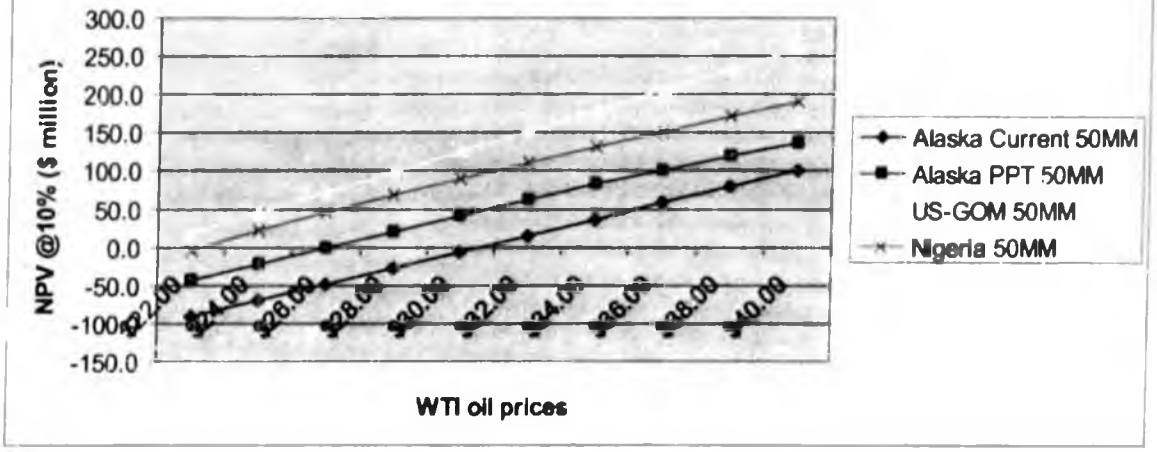


Chart 6.19. EMV @10% for a 50 million barrel field - low well productivity, high costs, US GOM and Nigeria

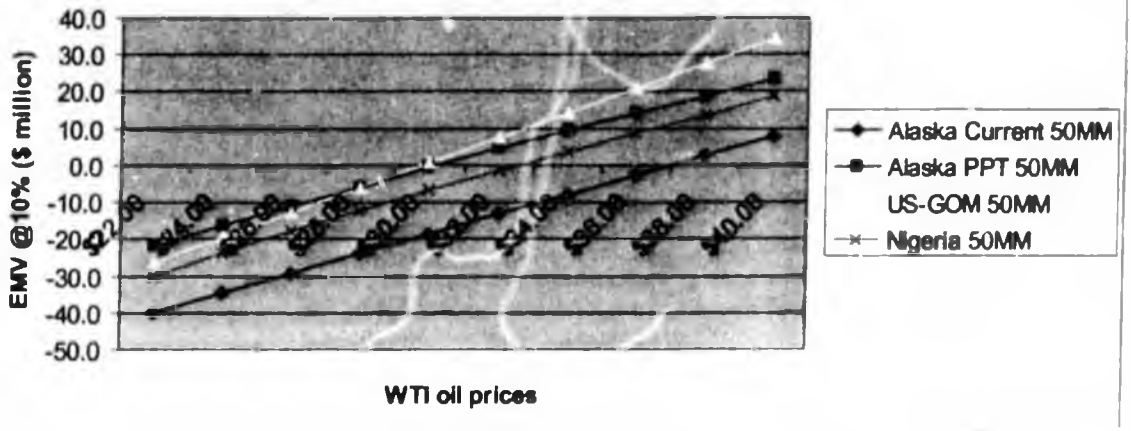
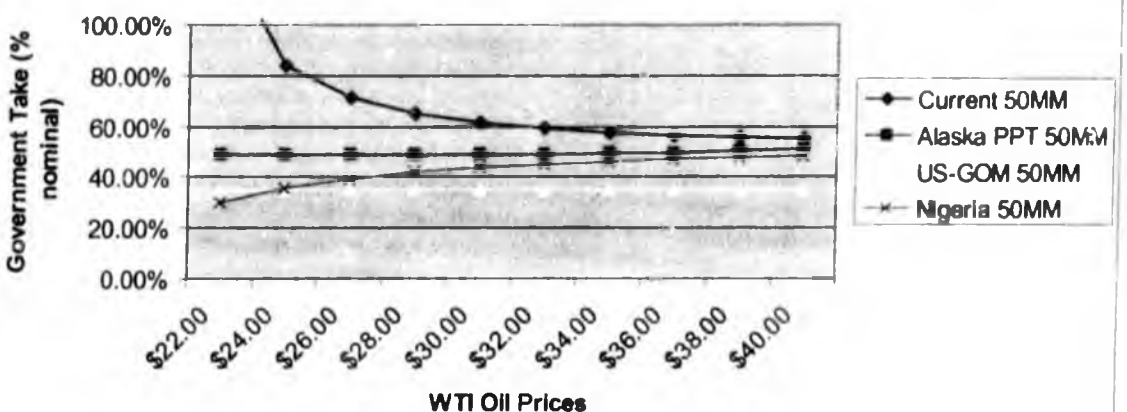


Chart 6.20. Overall Government Take for a 50 million barrel field with low well productivities, high costs, US GOM and Nigeria



500MM high cost

Charts 6.21 through 6.24 indicate that for a 500 MM barrel, high cost, field the fiscal terms for the US GOM are considerably more attractive than the Alaska PPT terms for new investors. The Alaska PPT terms narrow the gap somewhat relative to the current severance tax and therefore more interest from US investors can be expected.

Chart 6.21. IRR of 500 million barrel - high productivity case, high costs, US GOM and Nigeria

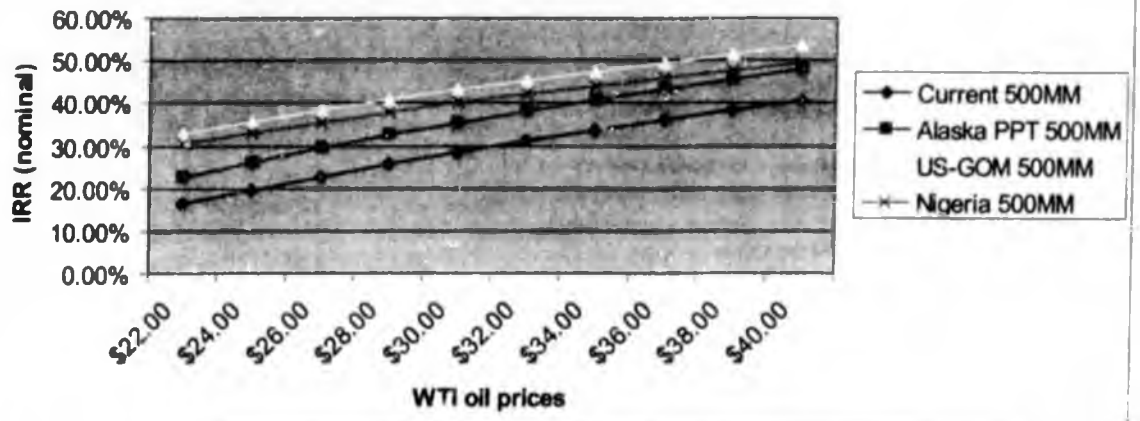


Chart 6.22. NPV @10% for a 500 million barrel field - high well productivity, high costs, US GOM and Nigeria

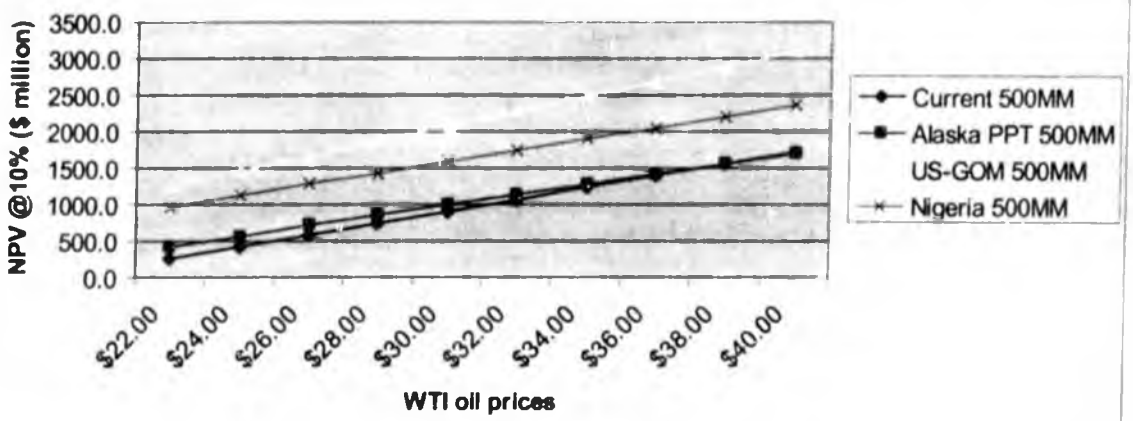


Chart 6.23. EMV @10% values for a 500 million barrel field - high well productivities, high costs, US GOM and Nigeria

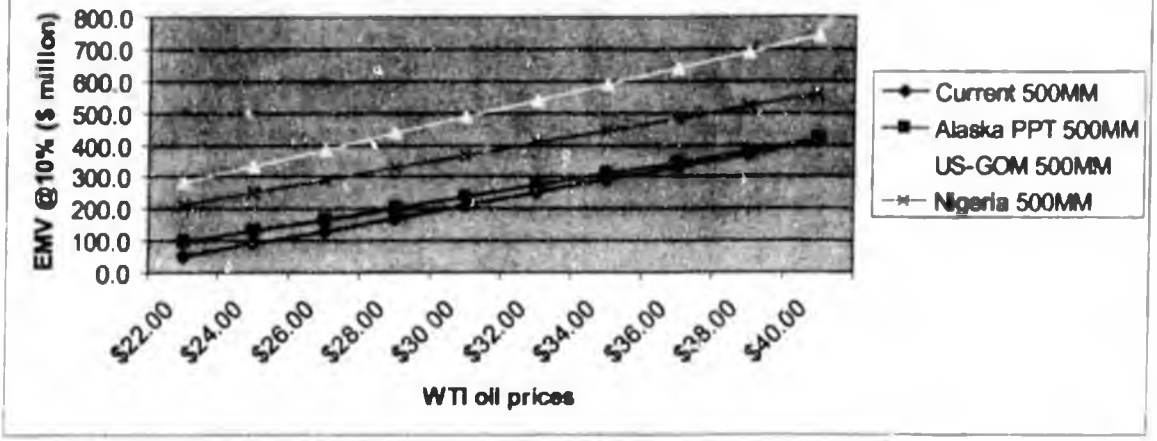
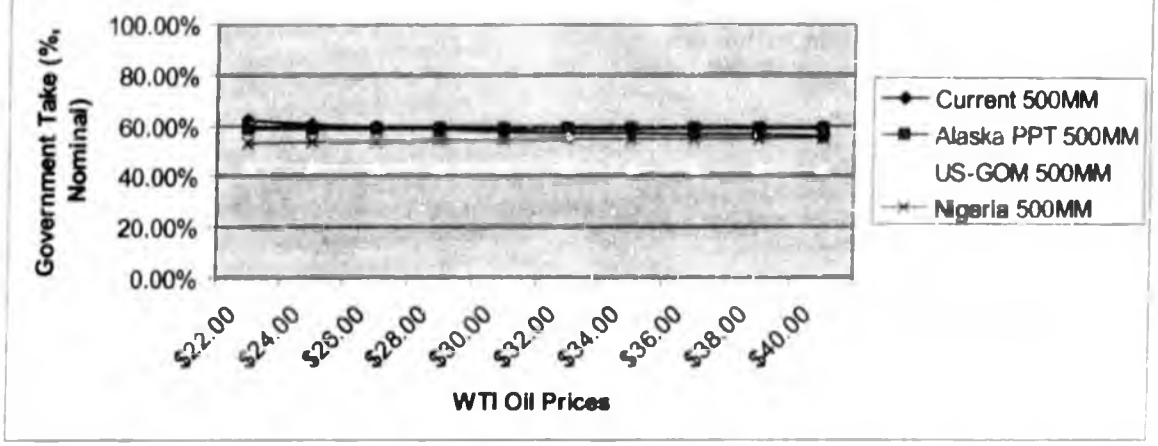


Chart 6.24. Overall Government Take for a 500 million barrel field with high well productivities, high costs, US GOM and Nigeria



50MM low cost

Charts 6.25 through 6.28 indicate that also for a 50 MM barrel low cost field the fiscal terms of the US Gulf of Mexico are much more attractive than the proposed Alaska PPT terms. However, also the PPT terms narrow the competitiveness gas with the US Gulf of Mexico.

Chart 6.25. IRR for 50 million barrel - low productivity case, low costs, US GOM and Nigeria

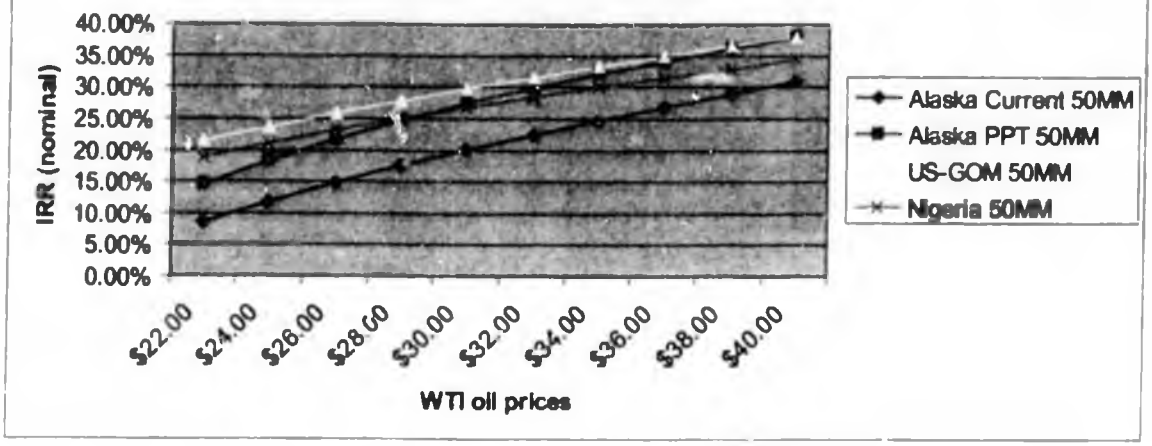


Chart 6.26. NPV @10% for a 50 million barrel field - low well productivity, low costs, US GOM and Nigeria

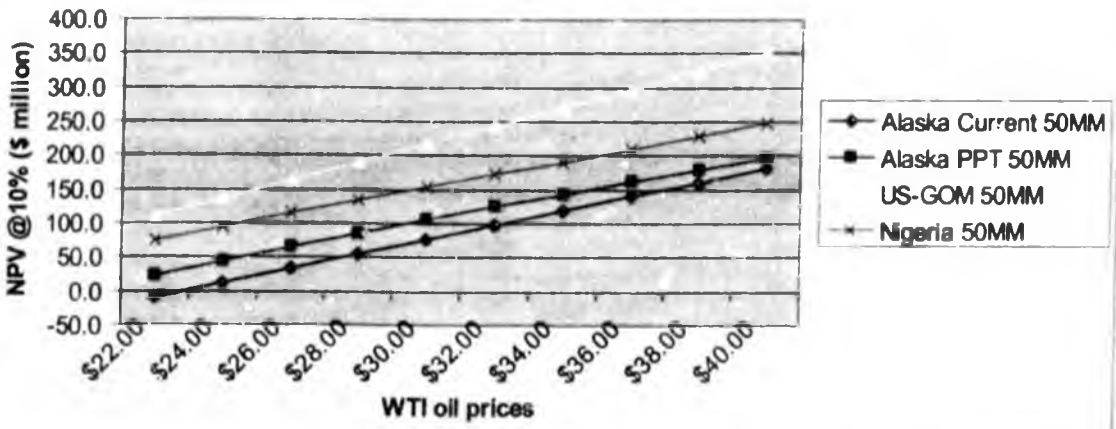


Chart 6.27. EMV @10% for a 50 million barrel field - low well productivity, low costs, US GOM and Nigeria

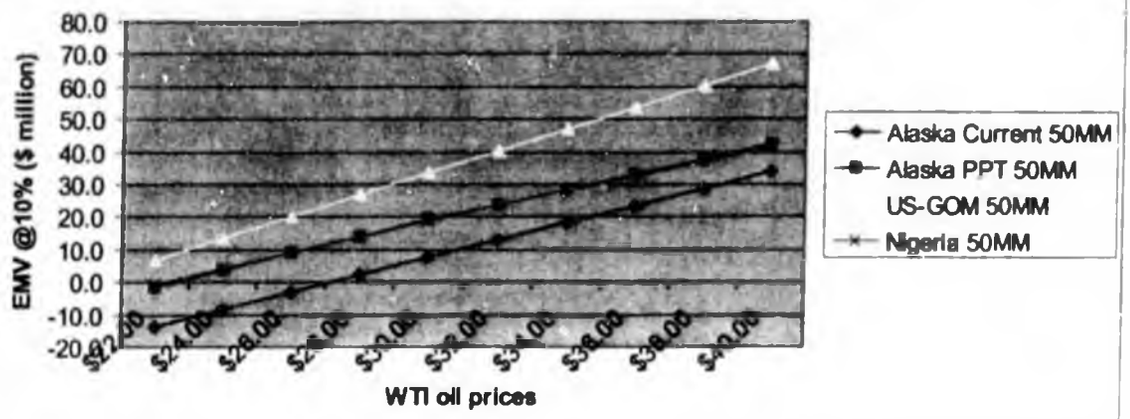
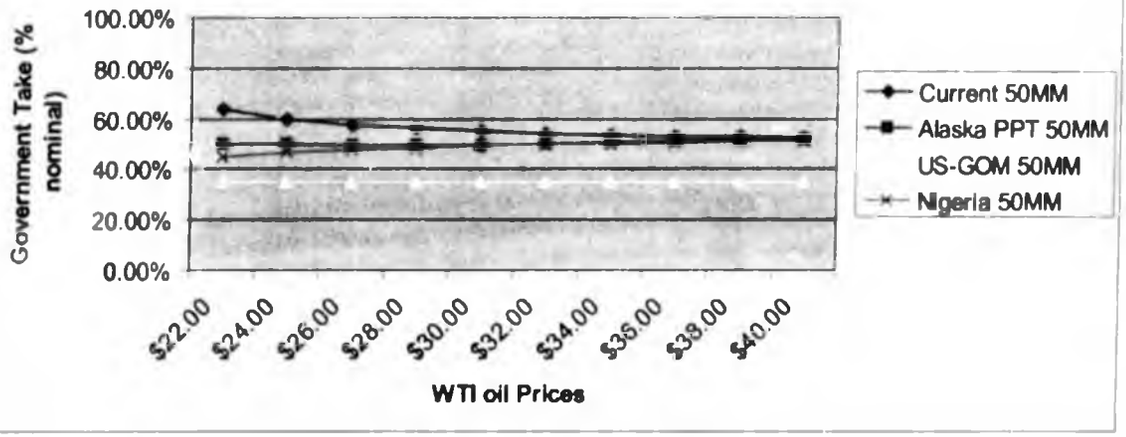


Chart 6.28. Overall Government Take for a 50 million barrel field with low well productivities, low costs, US GOM and Nigeria



500 MM low cost

For low cost 500 MM barrel fields, the fiscal terms of the US Gulf are clearly more attractive than the Alaska PPT terms for new investors as can be seen in Charts 6.29 through 6.32. Chart 6.29 indicates, however, the strong IRR characteristics that the Alaska PPT would have.

Chart 6.29. IRR of 500 million barrel - high productivity case, low costs, US GOM and Nigeria

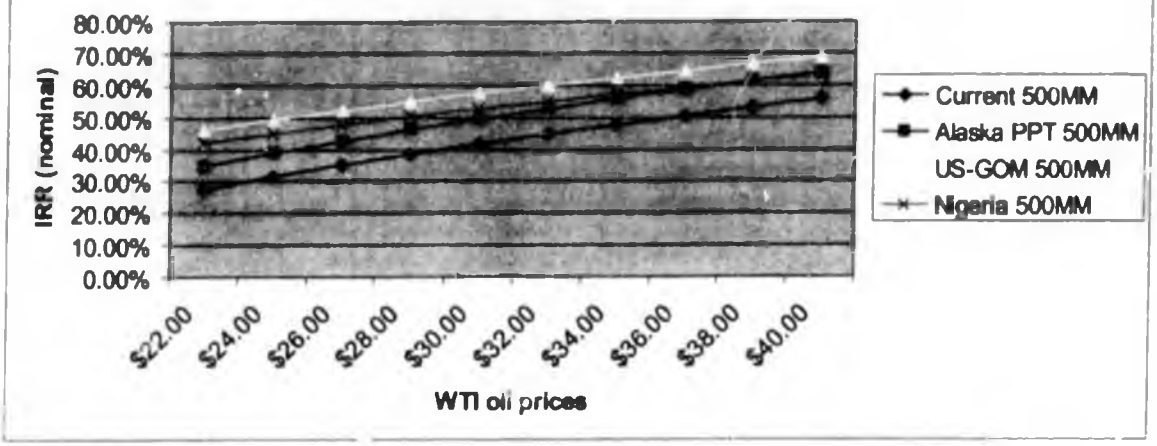


Chart 6.30. NPV @10% for a 500 million barrel field - high well productivity, low costs, US GOM and Nigeria

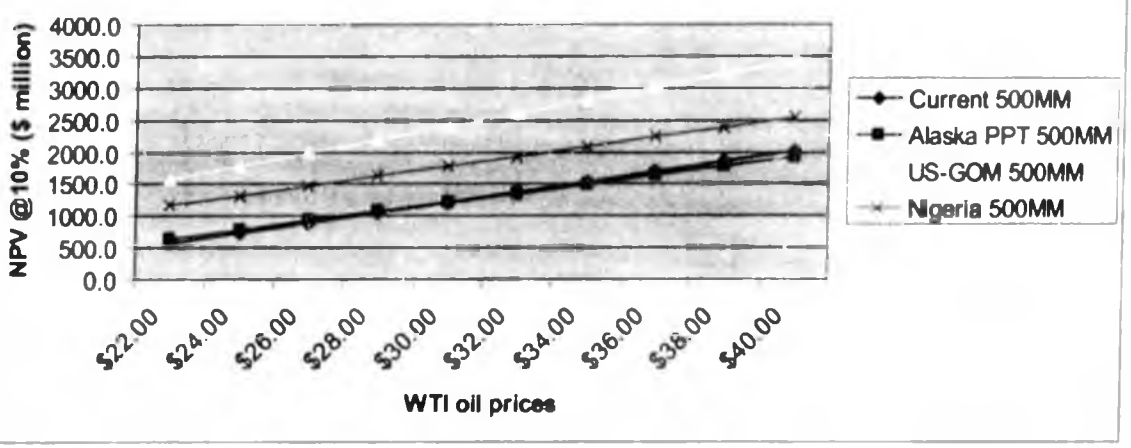


Chart 6.31. EMV @10% values for a 500 million barrel field - high well productivities, low costs, US GOM and Nigeria

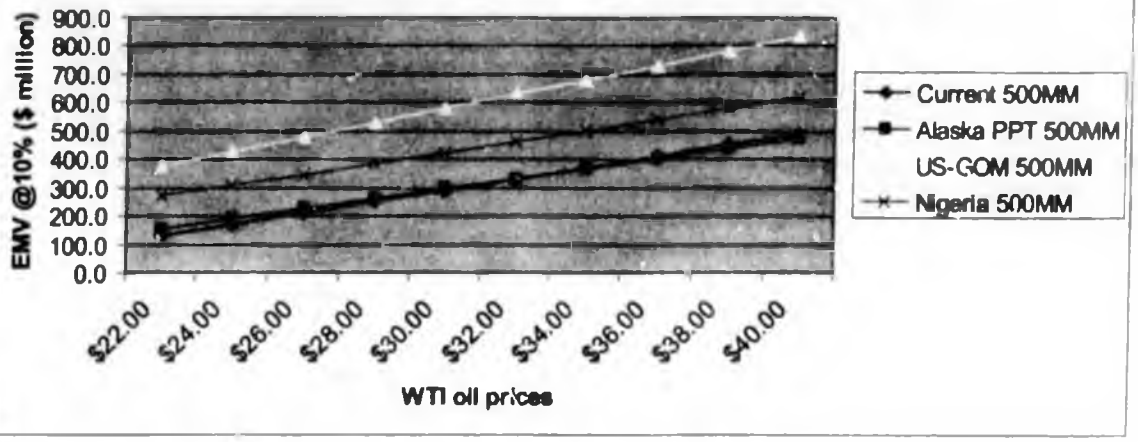
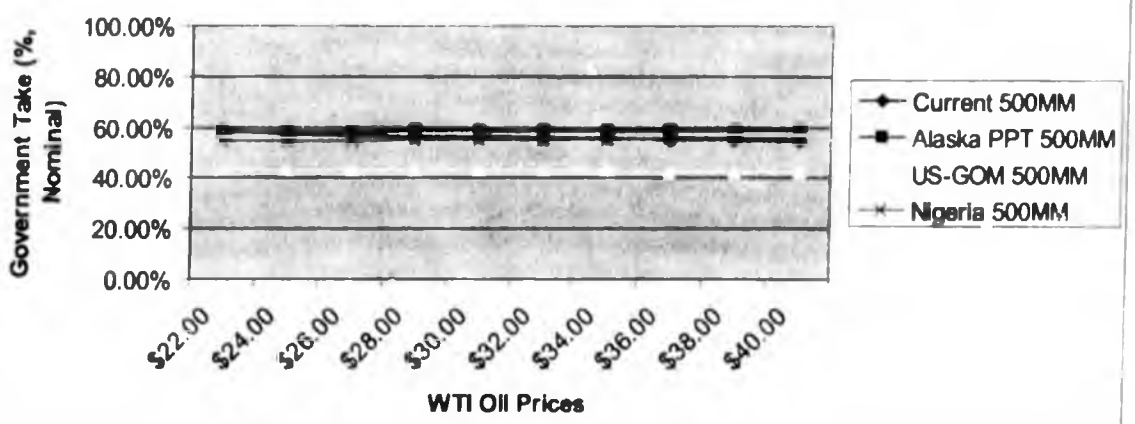


Chart 6.32. Overall Government Take for a 500 million barrel field with high well productivities, low costs, US GOM and Nigeria



US Gulf of Mexico Conclusion. The US Gulf of Mexico has a much more attractive fiscal system than Alaska. Also the value of oil at the well head is considerably higher. For these reasons the Alaska PPT would not be competitive with the US Gulf of Mexico. However, the Alaska PPT will help narrow the gap compared to the current severance tax.

6.2.4. Nigeria – Deep water

The deep waters in the offshore of Nigeria have experienced considerable activity during the last decade. This due to the relatively attractive terms that Nigeria is offering, which include a 0% royalty for very deep water in excess of 1000 meter water depth.

Nigeria-Deep water terms. The Nigerian terms are different from block to block, but following terms are representative of typical terms. These terms provide for a 50% corporate income tax, but with tax credits of 25% on capital expenditures. Furthermore, Nigeria has a production sharing agreement with a profit oil share ranging from 20% to 60% based on a sliding scale based on cumulative production, starting at 300 million barrels and going up to 2 billion barrels. It is assumed that Nigeria has a $ 5 per barrel advantage over Alaska North Slope at the well head.

Nigeria does not provide fiscal stability under its production sharing contracts, but Nigeria has traditionally negotiated MOU's with a typical duration of 10 years which may provide for some fiscal stability.

50 MM high cost

Fields of 50 MM barrels with high costs are not necessarily economic offshore Nigeria. However, fiscal conditions for larger fields up to 300 million barrels, which would be competitive, are the same and therefore this analysis can be used as a proxy for such fields.

Chart 6.17 illustrates how the Alaska PPT would compete well on the basis of IRR, with a cross over point of a WTI price of $ 34 under which Alaska terms would become more competitive.

Chart 6.18 shows how the NPV@10% would be less attractive, but the EMV@10% would be more attractive in Alaska. Much depends in this case on the ability to consolidate in Nigeria.

Chart 6.19 indicates how the government take in Nigeria for low prices is relative low due to the considerable tax credits, at higher prices the government take is only slightly less than in Alaska.

500 MM high cost

Charts 6.21 through 6.24 indicate how for high cost 500 MM barrel fields, Nigerian terms would be more attractive than the Alaska PPT for new investors. Nevertheless, the Alaska PPT narrows the competitive gap compared to the current severance tax.

50 MM low cost

The fiscal comparison for the 50 MM low cost field is similar to the 50 MM high cost field as is indicated in Charts 6.25 through 6.28. However, for the low cost field the EMV@10% values are equal in Nigeria and Alaska.

500 MM low cost

Charts 6.29 through 6.32 indicate that for 500MM low cost fields, Nigeria has typically much more attractive fiscal terms than the Alaska PPT.

Nigeria deep water Conclusion. Alaska competes relatively well with Nigeria on an IRR and EMV@10% basis, in particular for smaller fields, however, the NPV% is more attractive in Nigeria. Also the government take is less and the well head values are considerably higher. For these reasons the Alaska PPT would not be competitive with Nigeria, except for exploration investments in smaller fields.

6.2.5. Alberta – Oil Sands

The Alberta oil sands are the subject of major expansion and investment. This is in part due to an attractive fiscal regime offered by the Province of Alberta. The oil sands plants are often of a scale that is larger than oil field developments on the North Slope. Nevertheless, a fiscal comparison seems important since the Alberta oil sands form one of the most important upstream petroleum investment opportunities in North America. Therefore, for comparative purposes the 50 and 500 MM barrel field comparisons will be provided, in order to provide consistency in the analysis.

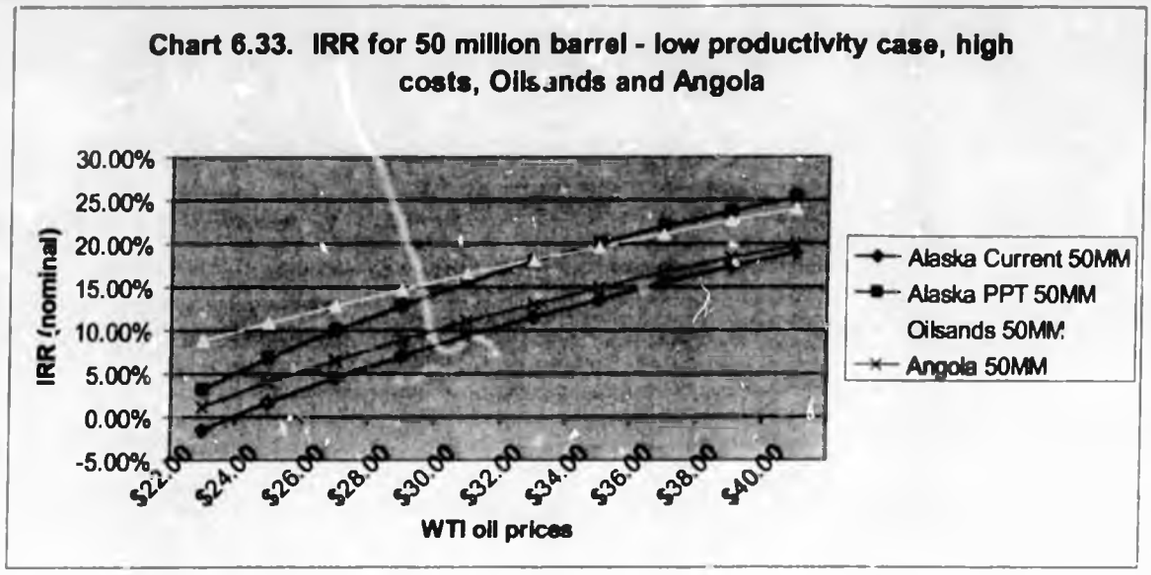
Also, of course, the oil sands have already been discovered. Therefore, the EMV analysis is only illustrative.

Alberta oil sand terms. The province requires a profit share of 25% after payout or a royalty of 1% whatever is the higher amount. Furthermore Alberta requires rentals and a bonus. The Federal Canadian/Alberta corporate income tax rate is 33.62%. It is assumed that the Alberta oil sand oil has an advantage of US $ 5 per barrel at the delivery point over Alaska North Slope crude.

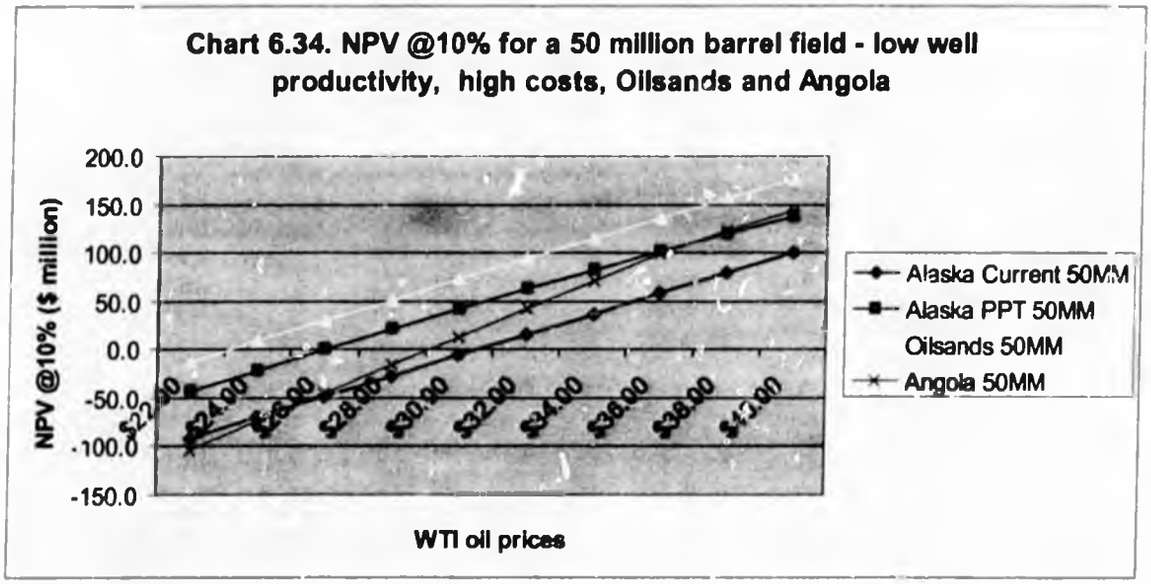
The province of Alberta and the Federal Government of Canada typically do not provide fiscal stability on their terms.

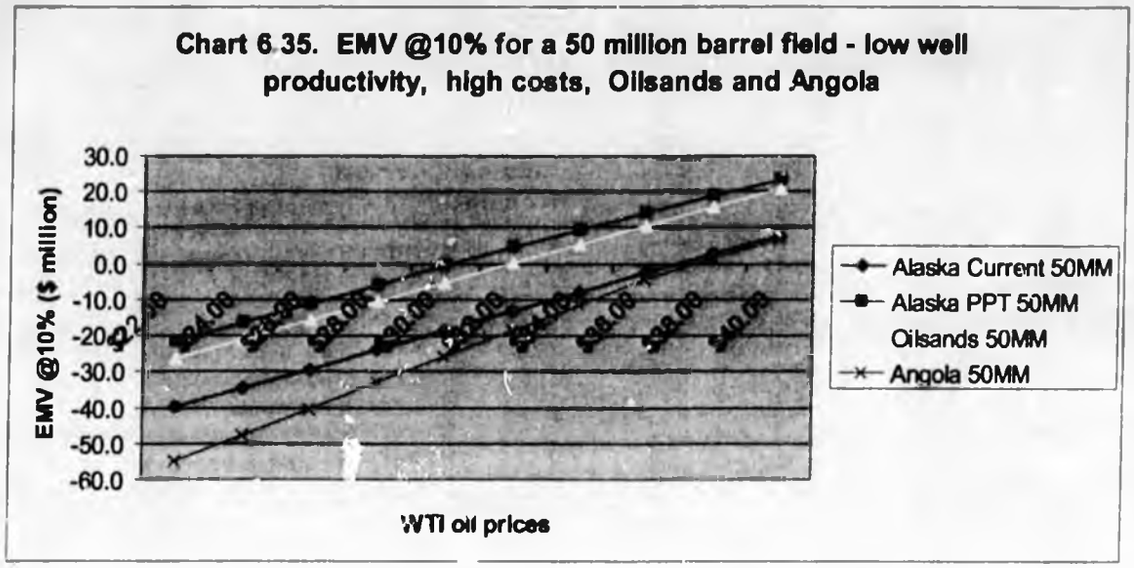
50 MM high cost

Chart 6.33 shows how the IRR for the Alaska PPT would be rather competitive with Alberta oil sands terms, despite the $ 5 per barrel advantage for the oil sands.

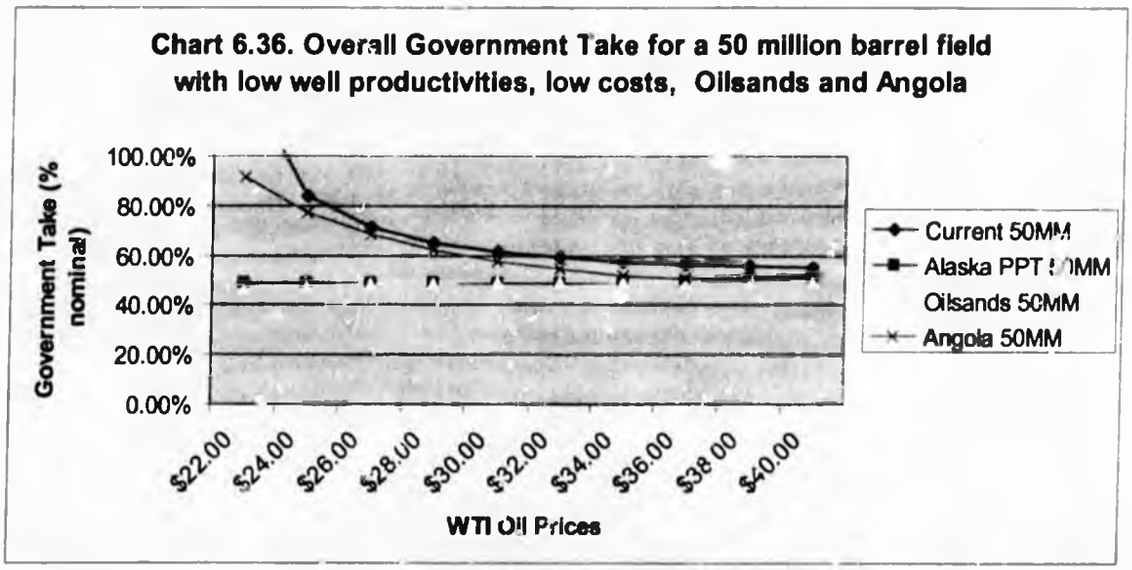


The NPV@10% is more favorable for the Alberta oil sands for the entire price range. The EMV@10% is less favorable, however, this depends primarily on the respective bonus assumptions.





The overall government take is remarkably similar. Therefore the better NPV@10% for the Alberta oil sands is primarily due to the higher net back value of the oil.



500 MM high cost

Charts 6.37 through 6.40 indicate how the Alberta oil sands economics are better for all indicators for the $ 22 - $ 40 per barrel price range. This is due to the lower government take and the higher net back.

Chart 6.37. IRR of 500 million barrel - high productivity case, high costs, Oilsands and Angola

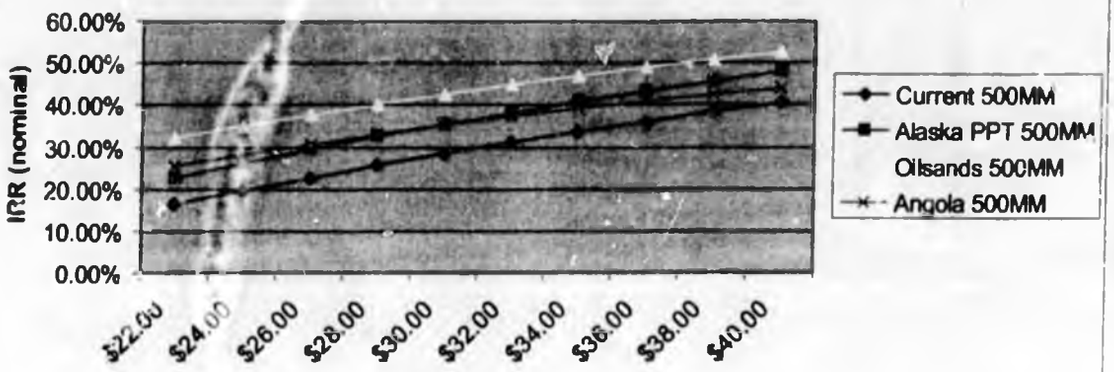
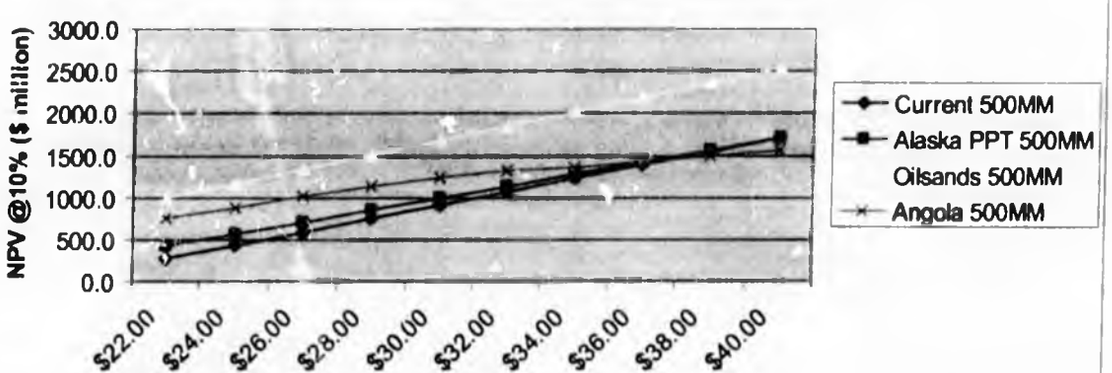
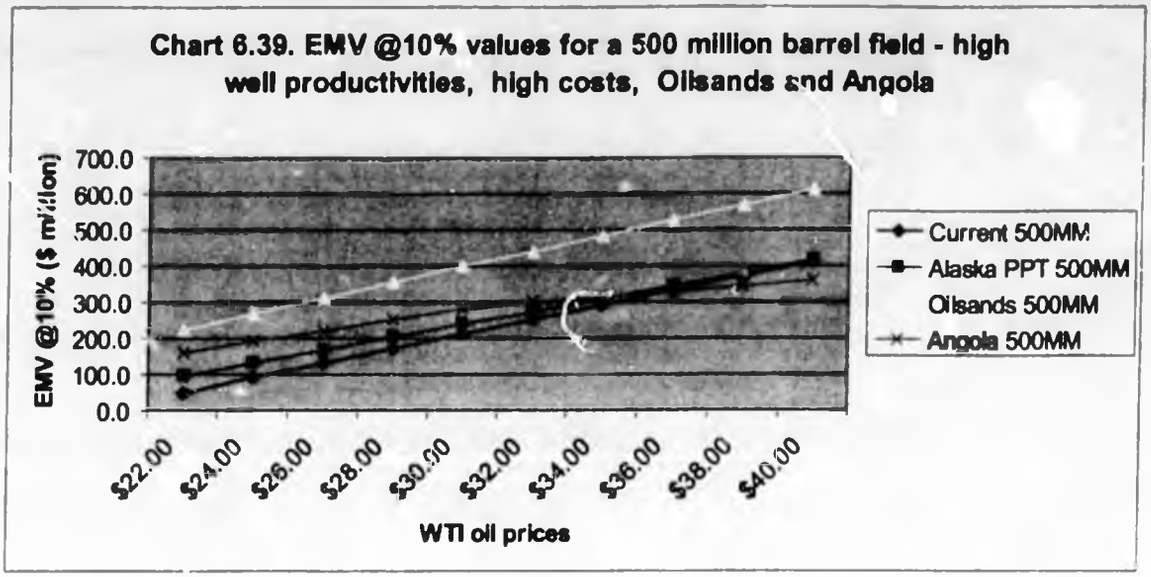
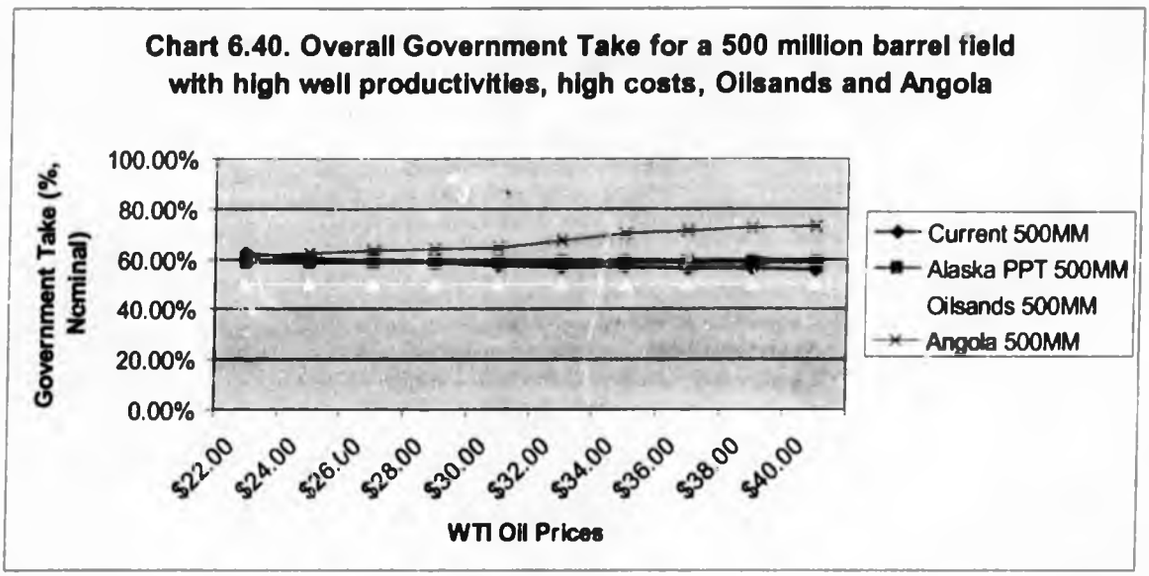


Chart 6.38. NPV @10% for a 500 million barrel field - high well productivity, high costs, Oilsands and Angola







50 MM low cost

Charts 6.41 through 6.44 indicate about the same economics as for the 50 MM high cost case. The IRR of the Alaska PPT compares rather favorable, the NPV@10% does not, the EMV@10% depends primarily on bonus assumptions and the government take is almost identical.

Chart 6.41. IRR for 50 million barrel - low productivity case, low costs, Oil sands and Angola

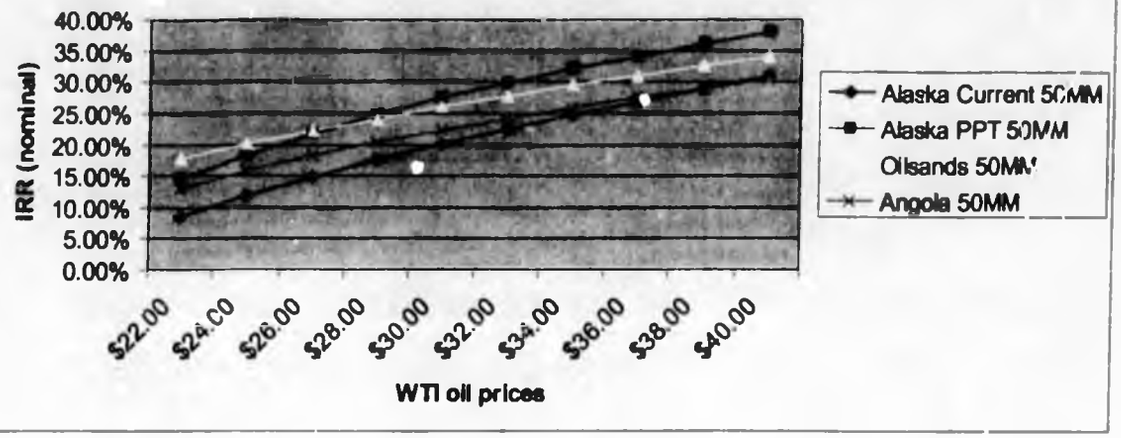
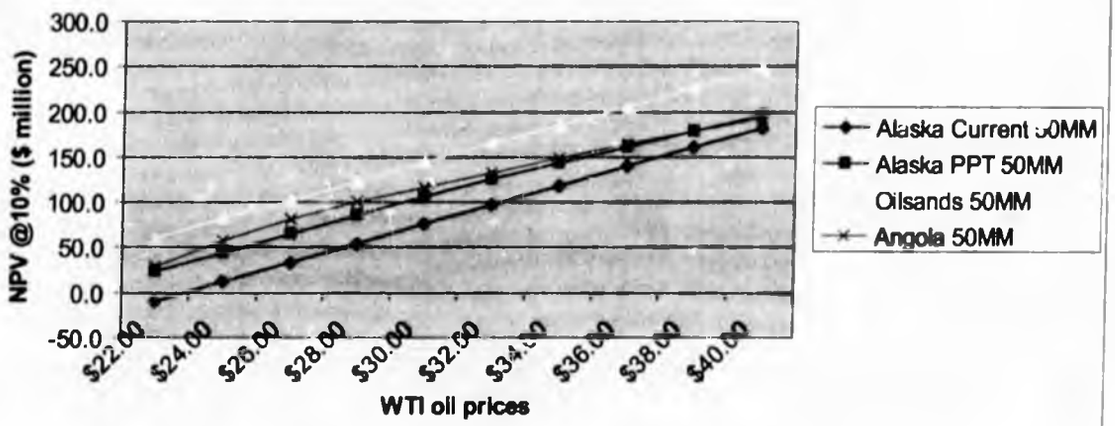
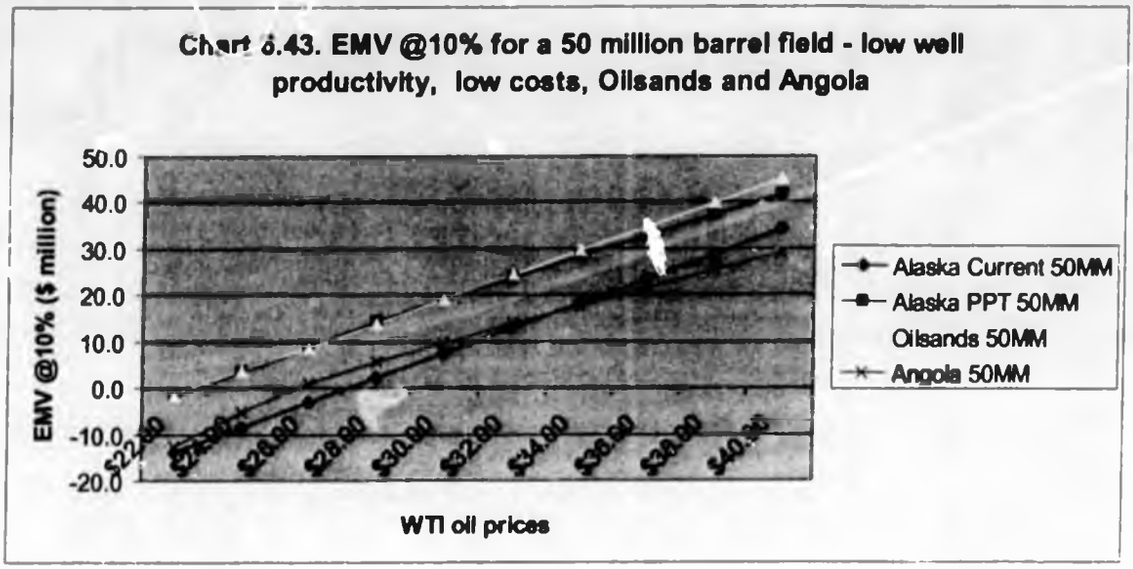
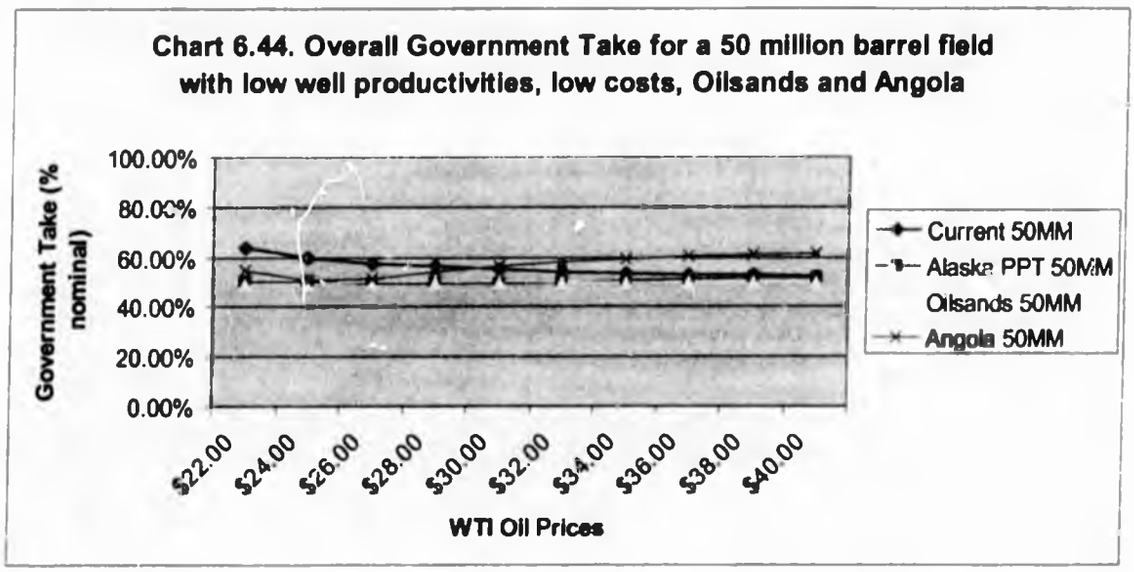


Chart 6.42. NPV @10% for a 50 million barrel field - low well productivity, low costs, Oil Sands and Angola







500 MM low cost

The 500 MM low cost case also indicates more favorable economics for the Alberta oil sands, primarily due to the higher net back and lower government take.

Chart 6.45. IRR of 500 million barrel - high productivity case, low costs, Oilsands and Angola

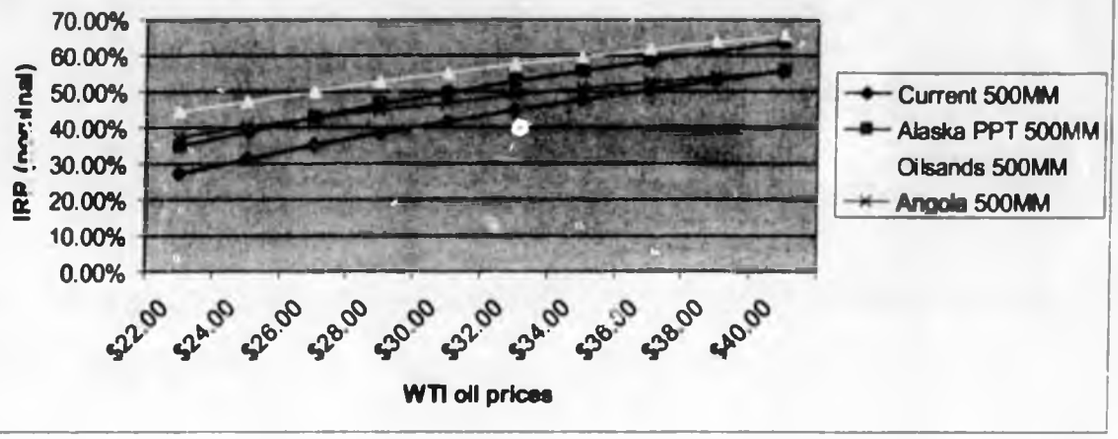


Chart 6.46. NPV @10% for a 500 million barrel field - high well productivity, low costs, Oilsands and Angola

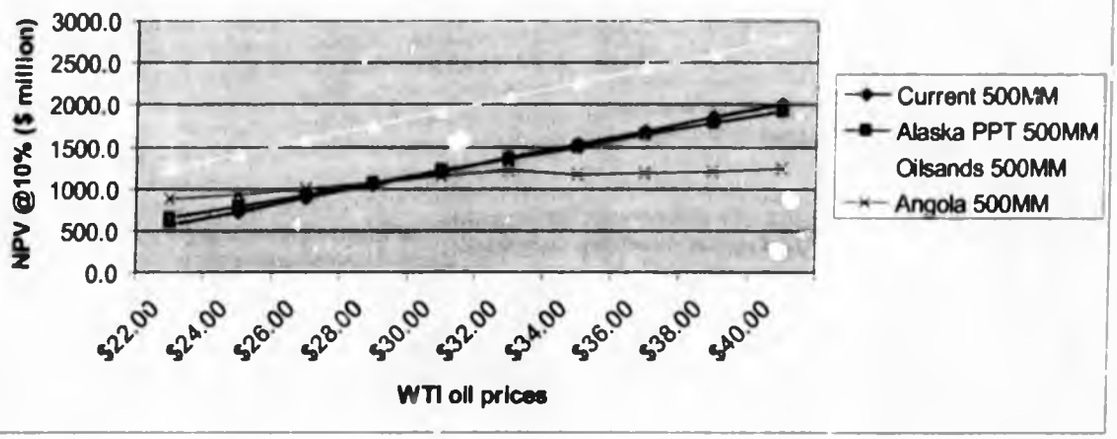


Chart 6.47. EMV @10% values for a 500 million barrel field - high well productivities, low costs, Oilsands and Angola

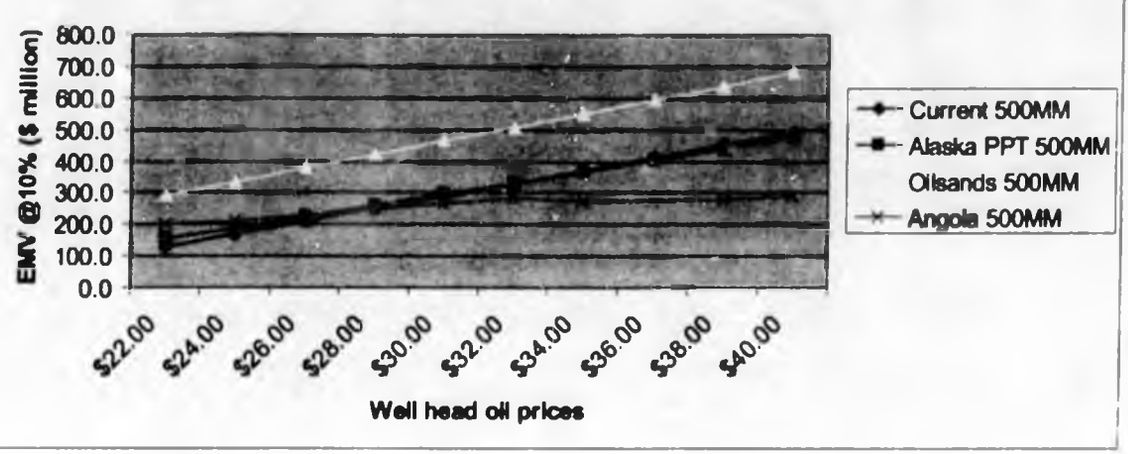
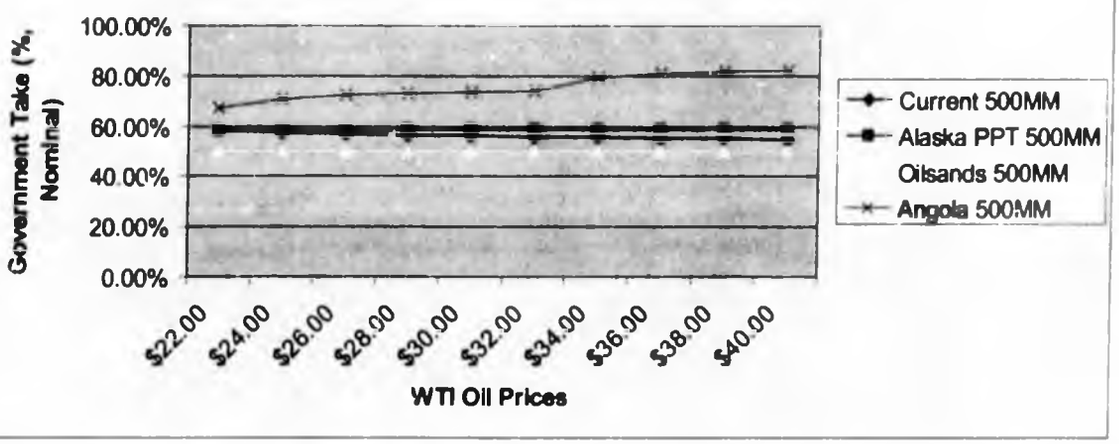


Chart 6.48 Overall Government Take for a 500 million barrel field with high well productivities, low costs, Oilsands and Angola



Alberta Oil Sands Conclusion. The Alberta Oil Sands fiscal terms are more favorable than those of the Alaska PPT because the government take for large fields is less and the net back value is higher. For small fields, Alaska PPT and EMV@10% compares relatively favorably.

6.2.6. Angola – Deep offshore

The Angola Deep offshore has been a prime area of development, in particular for large companies that work also in Alaska, such as BP and ExxonMobil. Angola has a rfather progressive system, which in particular under current high oil prices will result eventually in a high government take for most fields, if prices continue. As for Nigeria, in the deep waters offshore Angola, 50 MM barrel fields are not economic. However, for consistency such fields will be reviewed.

Angola terms. The Angolan terms are based on a production sharing agreement. These agreements are different from block to block. Following are representative terms. It is assumed that there is a cost oil limit of 50%. The profit oil is based on an IRR sliding scale and moves from 20% profit oil for government to 80% profit oil for government depending on profitability. There is a 45% uplift on capital expenditures. The corporate income tax is 50%. **It should be noted that very high bonuses were paid for the blocks offshore Angola.** A negative feature of the Angola system is that each development area is ring-fenced for production sharing and tax purposes. It is assumed that Angola has a $ 5 per barrel advantage relative to the Alaska North Slope at the well head.

Angola provides for near complete fiscal stability on its terms.

50 MM high cost

Charts 6.33 through 6.36 show some interesting features. The IRR for the Alaska PPT is much higher than for Angola. This is primarily due to the ring-fenced nature of the Angolan operations. The NPV@10% is higher than the Alaska Current system but less attractive than the Alaska PPT system. The EMV@10% is much better in Alaska, due to the possibility for consolidation in Alaska. The government take is regressive for the small field in the $ 22 - $ 40 price range, despite the progressive sliding scale and follows approximately the Alaska Current system. This is largely due to the cost oil limit.

500 MM high cost

For the 500 MM high the IRR is much better than the Alaska Current system, but straddles the Alaska PPT system. Both for the NPV@10% and the EMV@10% Angola is better than Alaska for low prices but worse than Alaska for high prices. This is due to the progressive nature of the Angolan system. The government take is about equal to Alaska for low prices, but becomes much higher for high prices.

50 MM low cost

The 50 MM low cost field provides for and IRR that is again between the Alaska Current and the Alaska PPT system. The NPV@10% is about equal to the Alaska PPT system. The EMV@10% is about equal to the Alaska Current system. The government take is higher for high prices.

500 MM low cost

The Angolan terms result in an IRR which is between the Alaska Current and Alaska PPT systems. The NPV@10% and EMV@10% become much less at high prices. The government take is considerably higher across the board.

Angola Deep Water Conclusion. The Alaska PPT terms are generally competitive with Angolan terms. The IRR is generally more attractive for the PPT despite the lower net backs. The Alaska PPT is more attractive for larger fields and for high prices. Angola is more attractive for low prices and small fields.

6.2.7. Russia - Sakhalin

The Russia-Sakhalin developments have been very important over the last decade. ExxonMobil and Shell have large projects in Sakhalin. The Sakhalin projects relate to developments of both oil and gas. The projects are very large scale and the fiscal systems that were negotiated for these contracts reflect the nature of these activities. The Sakhalin terms are based on production sharing contracts.

Russia – Sakhalin terms. The Sakhalin terms include a 6% royalty, a 32% corporate income tax and a production sharing agreement based on an after tax rate of return based sliding scale. There is no cost oil limit under the contract. The sliding scale moves the profit oil share earned by the government upward in three steps based on the real after tax rate of return. The steps are as follows:

Up to 17.5% IRR	- 10% to government
Up to 24% IRR	- 50% to government
Over 24% IRR	- 70% to government

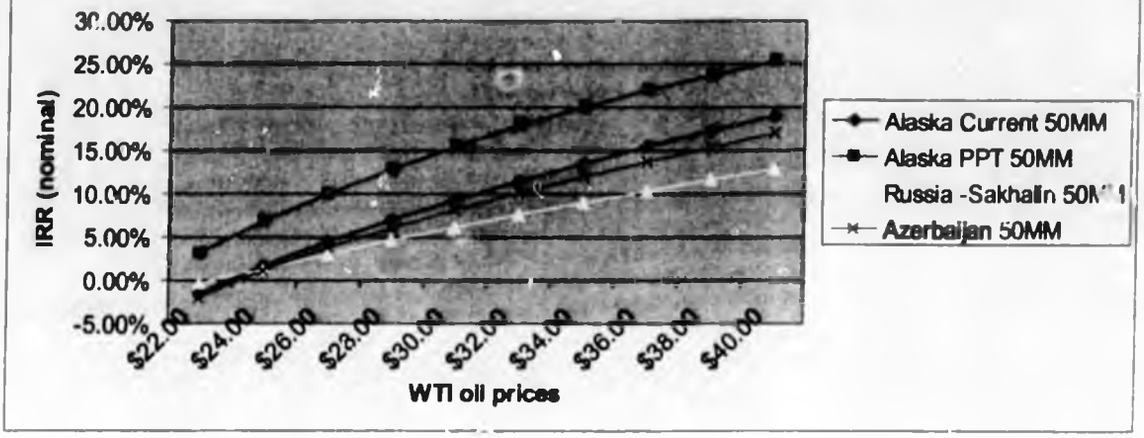
It should be noted that a high bonus was paid on the Sakhalin contract, in the Shell contract this was a $ 55 million bonus. As states previously this bonus is not taken into consideration. The Sakhalin project involved considerable expenditures for local costs. These costs have been included.

Russia provides for a high degree of fiscal stability on its production sharing contracts.

50 MM high cost

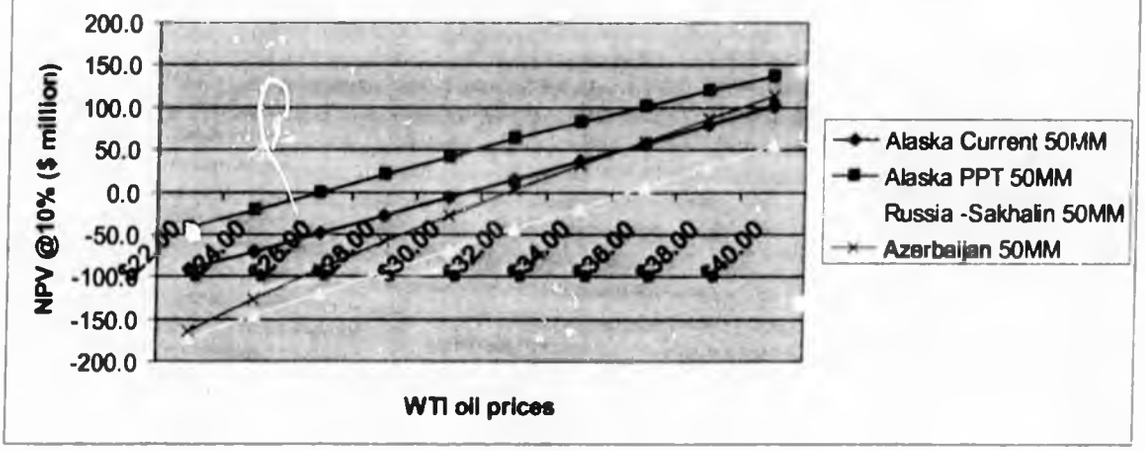
Chart 6.49 shows how the Sakhalin contracts have a rate of return that is much less than the Alaska Current system and the Alaska PPT. This is in part due to the high social expenditures required during the construction phase. For very low prices, Alaska Current becomes less attractive because of the low net back values.

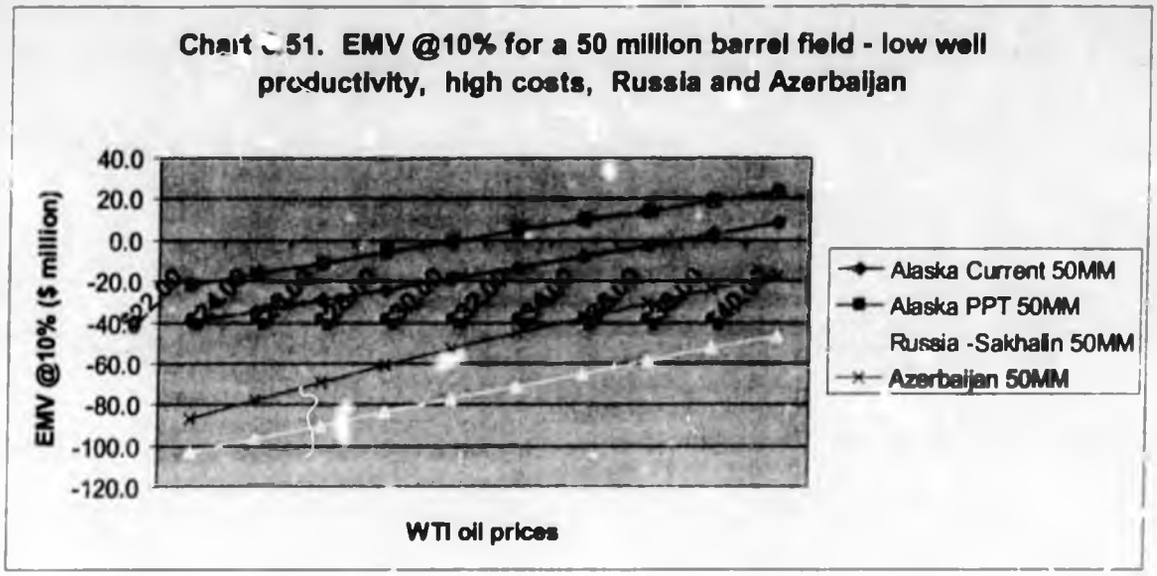
Chart 6.49. IRR for 50 million barrel - low productivity case, high costs, Russia and Azerbaijan



The NPV@10% and the EMV@10% are substantially less favorable than Alaska.

Chart 6.50. NPV @10% for a 50 million barrel field - low well productivity, high costs, Russia and Azedrbaijan





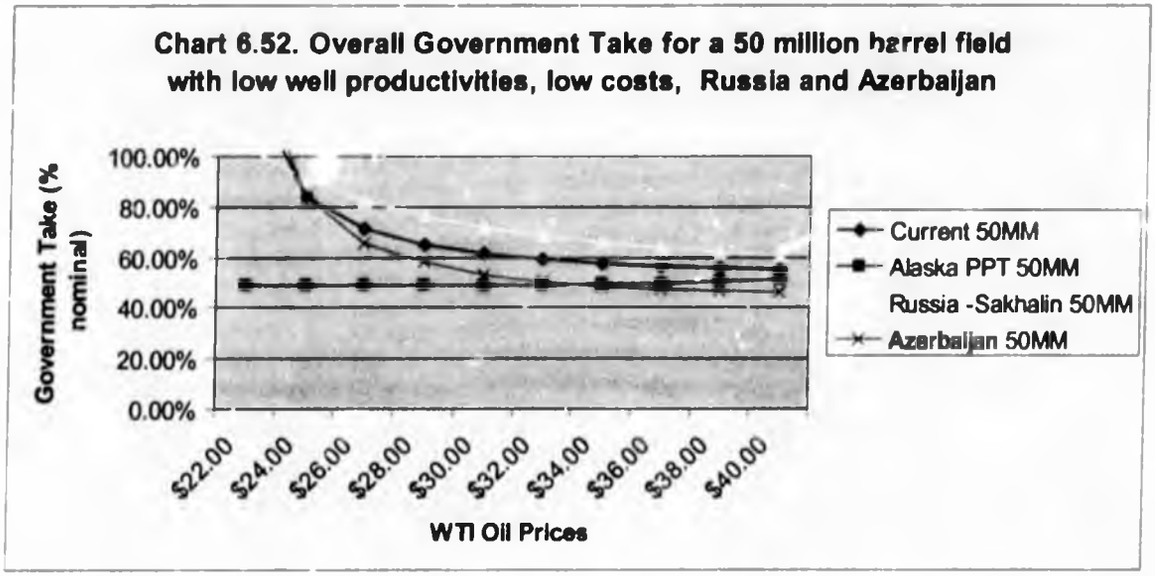


Chart 6.52 shows how the Russian system for small fields is rather regressive, primarily due to the high social expenditures. The Russion system is not designed for small fields.

500 MM high cost

Charts 6.53 through 6.56 indicate how the high government take over high rates of return result in a much flatter IRR, NPV and EMV curve than for Alaska. For large fields, Alaska is less attractive than Russia at low prices, but at higher prices Alaska becomes rapidly more attractive.

Chart 6.53. IRR of 500 million barrel - high productivity case, high costs, Russia and Azerbaijan

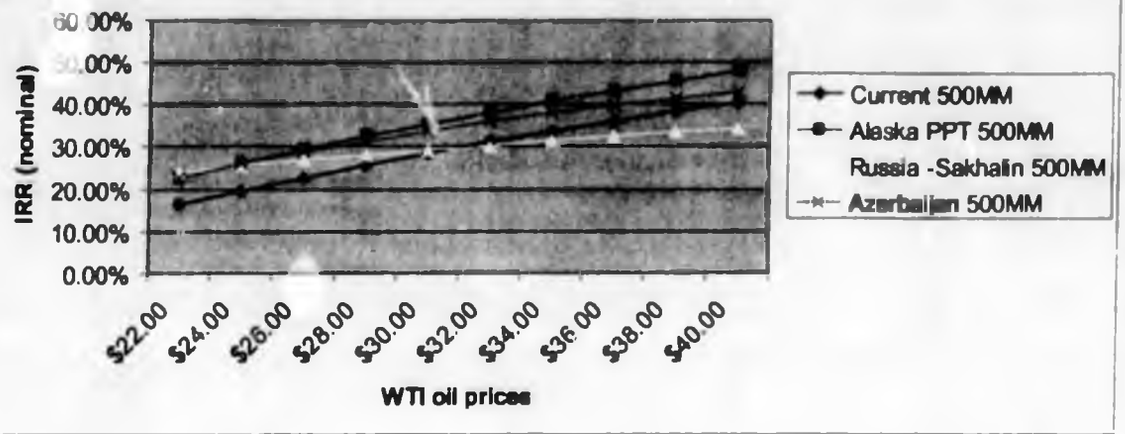
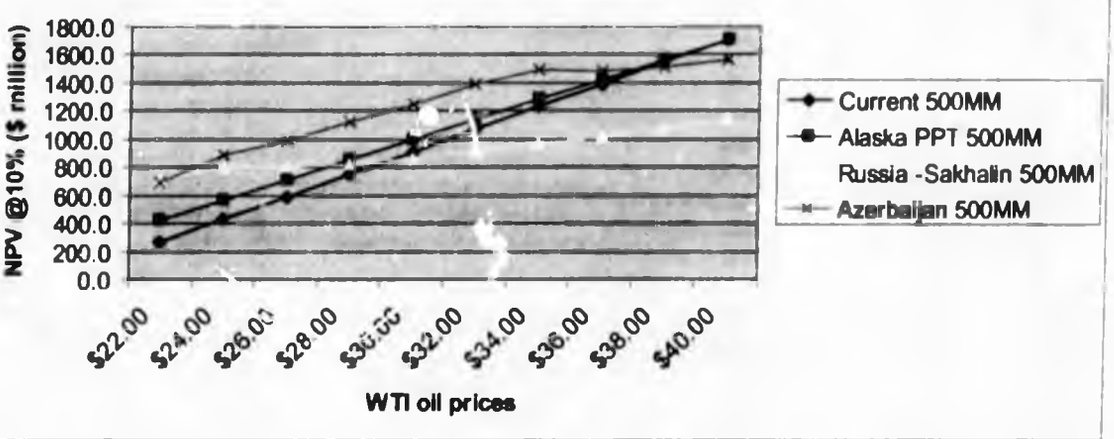
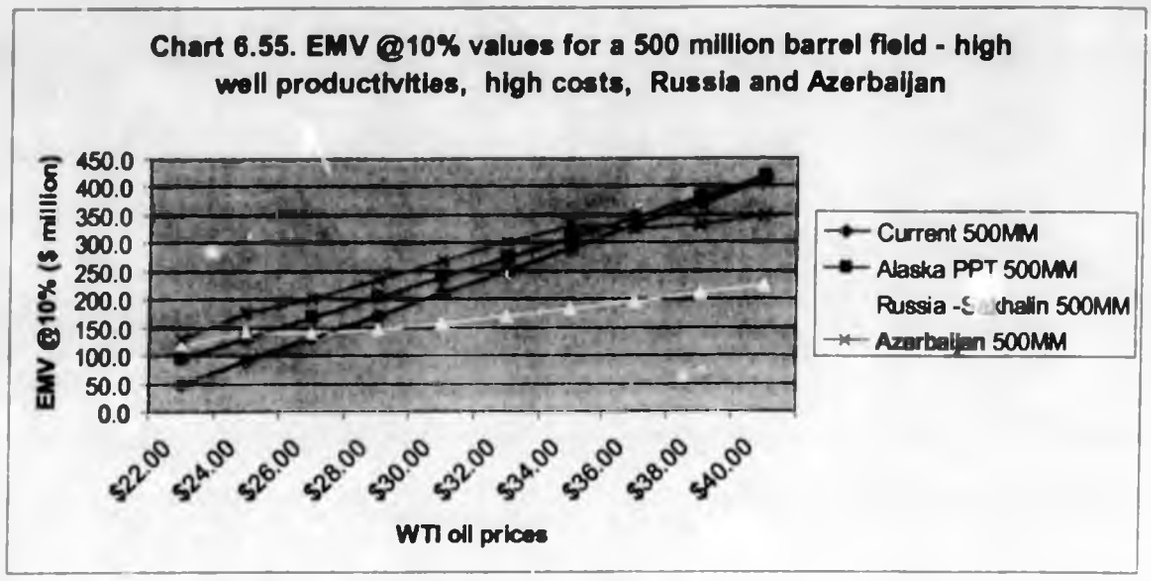
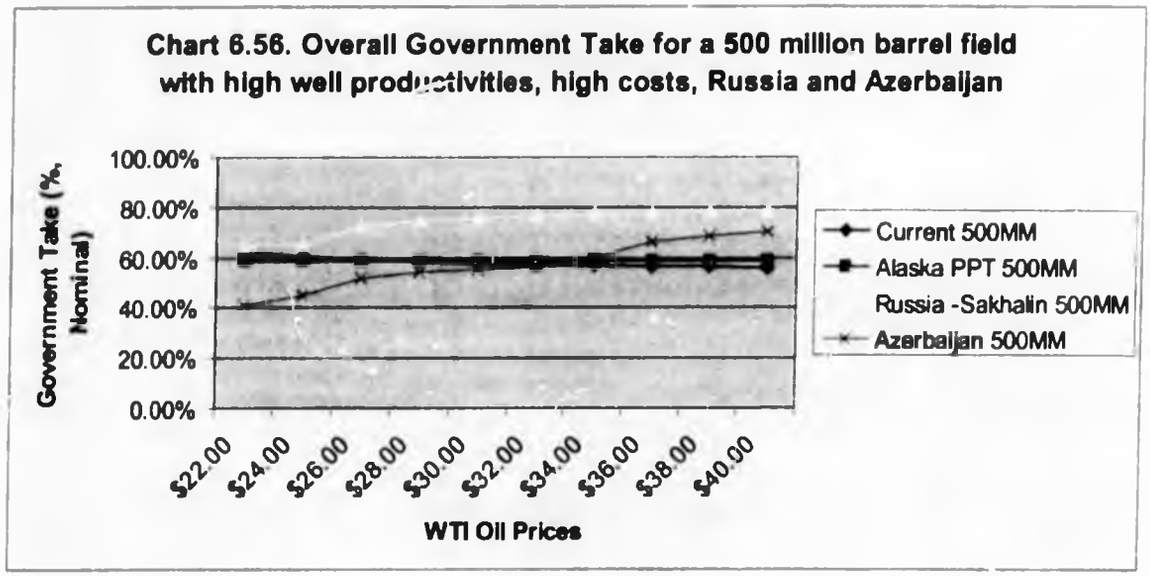


Chart 6.54. NPV @10% for a 500 million barrel field - high well productivity, high costs, Russia and Azerbaijan





The strongly progressive Russian system is clearly illustrated in Chart 6.56.



50 MM low cost

Charts 6.57 through 6.60 indicate about the same economics as for the 50 MM high cost case. The Russian system is clearly less attractive than the Alaska system for small fields, whether it is the current system of the PPT. Also the system is regressive.

Chart 6.57. IRR for 50 million barrel - low productivity case, low costs, Russia and Azerbaijan

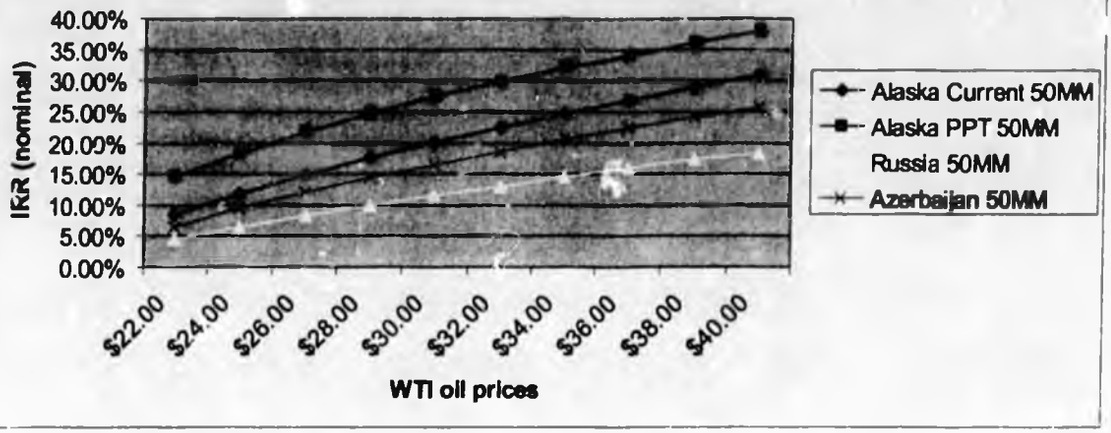


Chart 6.58. NPV @10% for a 50 million barrel field - low well productivity, low costs, Russia and Azerbaijan

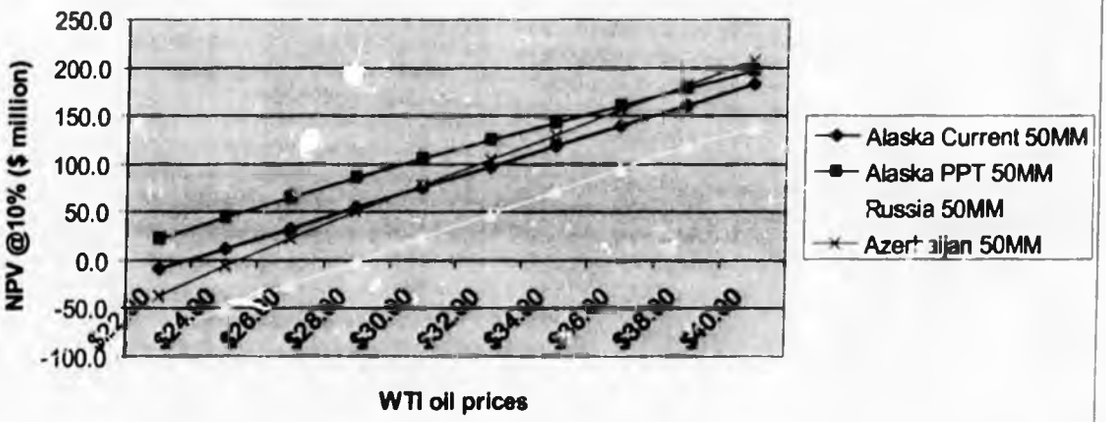


Chart 6.59. EMV @10% for a 50 million barrel field - low well productivity, low costs, Russia and Azerbaijan

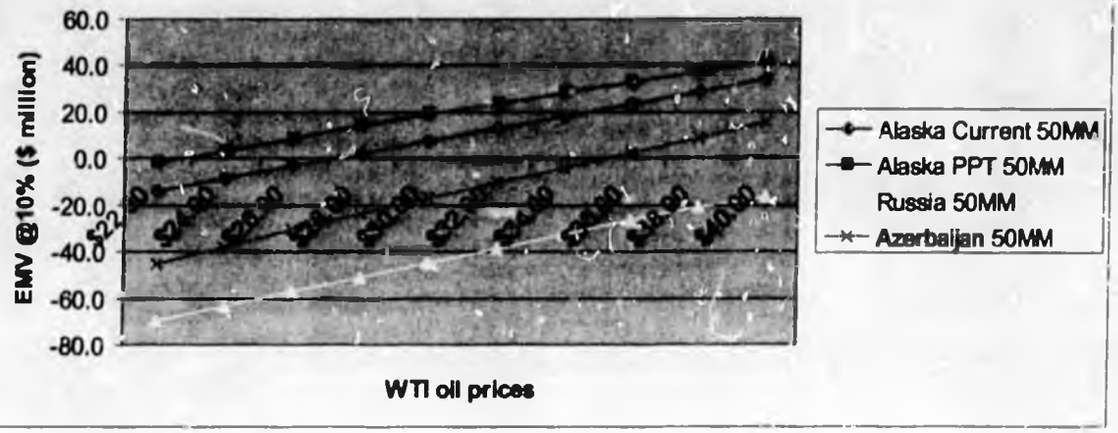
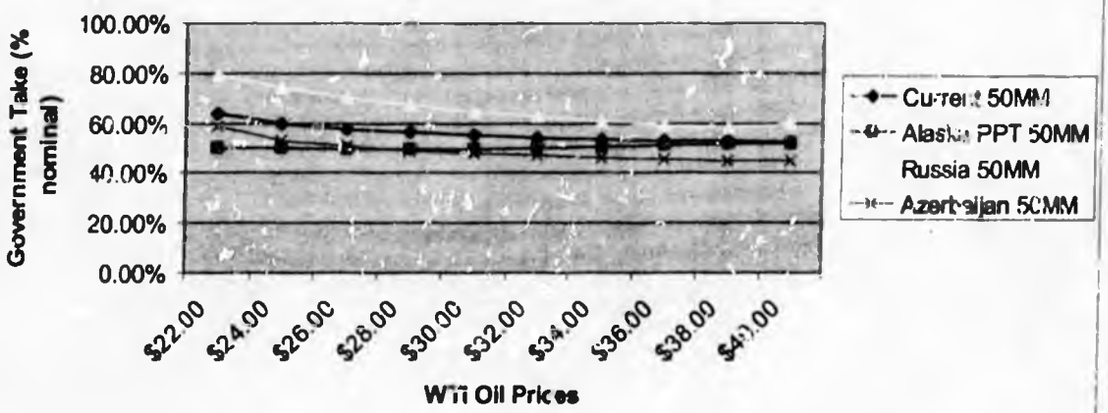


Chart 6.60. Overall Government Take for a 50 million barrel field with low well productivities, low costs, Russia and Azerbaijan



500 MM low cost

Charts 6.61 through 6.64 indicates how the Russian system is much less attractive than the Alaska system for the low cost case. This is because the low cost result in a situation where the rate of return benchmarks are reached earlier in time and therefore the profit oil shares for the government increase more rapidly.

Chart 6.61. IRR of 500 million barrel - high productivity case, low costs, Russia and Azerbaijan

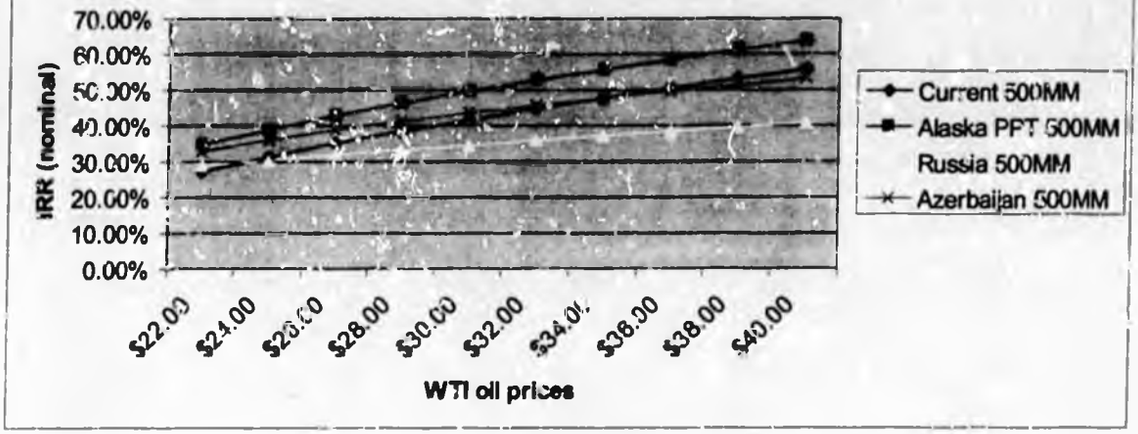


Chart 6.62 NPV @10% for a 500 million barrel field - high well productivity, low costs, Russia and Azerbaijan

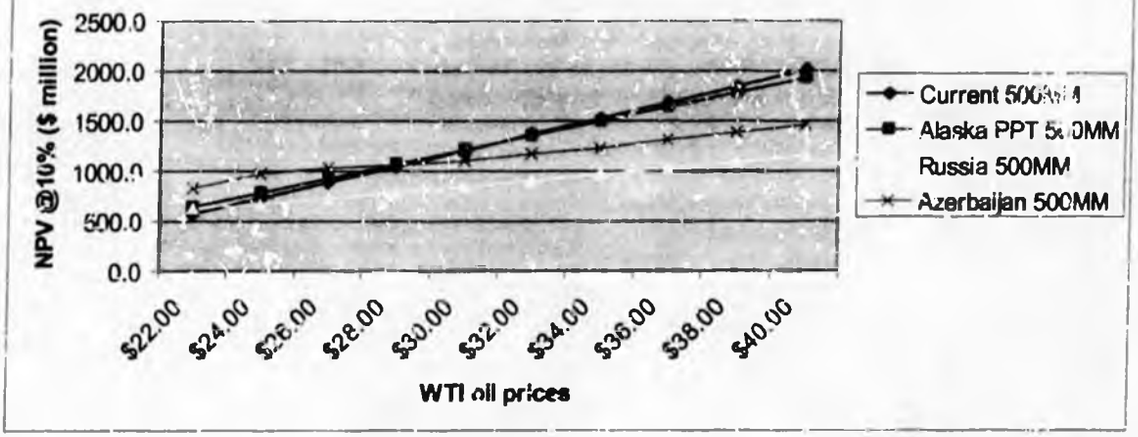


Chart 6.63. EMV @10% values for a 500 million barrel field - high well productivities, low costs, Russia and Azerbaijan

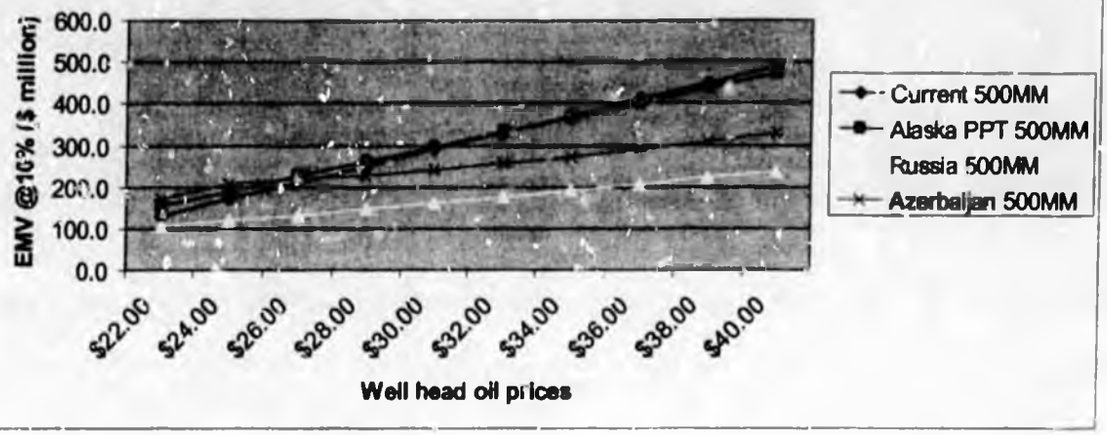
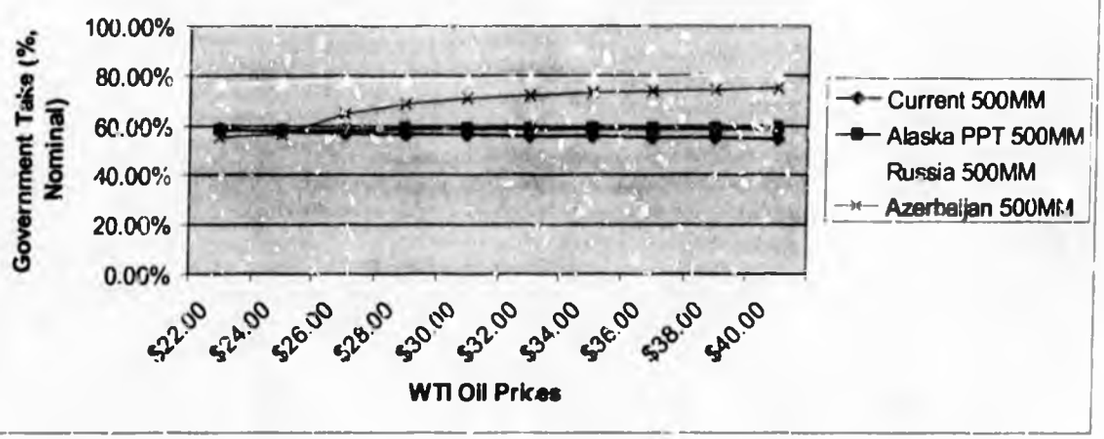


Chart 6.64 Overall Government Take for a 500 million barrel field with high well productivities, low costs, Russia and Azerbaijan



Russia-Sakhalin Conclusion. The Russian system is designed for large fields and is not attractive for small fields compared to Alaska. In general, under average or high oil prices and low costs, the rate of return based system creates conditions of a high government take in Russia. This makes Alaska more competitive. The PPT increases the competitiveness relative to Russia.

6.2.8. Azerbaijan

Azerbaijan represents a very important new oil development for the petroleum industry. Just as Alaska, Azerbaijan has to export its crude through long distance and costly pipeline systems and therefore the net back price for its crudes is relatively low. It is therefore an important country to compare with. Azerbaijan concludes its terms through production sharing agreements.

Azerbaijan terms. Azerbaijan does not have royalties. There is a 25% corporate income tax. Furthermore there is a production sharing arrangements. The cost oil limit is 50% for capital expenditures. Operating costs are not subject to the limit. The profit oil is based on an IRR based sliding scale which related to a real after tax IRR. This sliding scale is based on the pipeline transport costs. Higher transport costs result in a lower scale. It is assumed here that the transport costs are in excess of $ 4 per barrel. For these costs, the following scale of profit oil to government is being used:

Up to a real IRR of 16.75%	- 20% profit oil to government
Up to a real IRR of 24.75%	- 50% profit oil to government
Over a real IRR of 24.75%	- 75% profit oil to government

The national oil company SOCAR participates for 20% in the venture, but this is almost on a "straight up" basis and therefore this is participation is not included in the government take.

There was a bonus of $ 120 million on the project. However, that bonus is excluded for analysis as explained in the beginning of this Chapter. A sequence of social expenditures was included.

Azerbaijan provides near absolute fiscal stability on its fiscal terms.

50 MM high cost

Chart 6.49 shows how the IRR and NPV@10% in Azerbaijan is generally worse than the Alaska Current system and in particular relative to the Alaska PPT. But the Alaska PPT is fare more favorable than Azerbaijan.

The EMV@10% is far less favorable in Azerbaijan, due to the ring-fenced nature of the production sharing agreement and the social expenditures.

The government take in Azerbaijan for small high cost fields is regressive, because the higher benchmarks on the IRR sliding scale do not click in.

500 MM high cost

For a high cost field, the IRR feature works rather favorable under low prices (with very low netbacks). Therefore, IRR is between the PPT and the Alaska Current system. The NPV@10% and the EMV@10% are actually more favorable under low prices than the Alaska PPT due to the relatively low government take at low prices, but these indicators become more favorable for Alaska at higher prices..

As can be seen from Chart 6.56 the government take is rather progressive. It is less than Alaska for low prices and becomes about higher than Alaska at high prices for this large field.

50 MM low cost

The 50 MM low cost field has about the same characteristics as the high cost field. The NPV performance worse than the PPT and has a cross over with the Alaska Current system.

500 MM low cost

Under low cost conditions, the government take under the Azerbaijan terms becomes strongly progressive. Therefore, compared to the high cost case, the IRR, NPV@10% and EMV@10% all become considerable less than the PPT for high prices.

Azerbaijan conclusion. The system is strongly progressive with costs and prices. Therefore under cost and high price conditions the PPT is far more favorable than the system in Azerbaijan for investors. Under low prices and high costs, the system in Azerbaijan is more favorable. It should be noted that the production sharing contract was designed for large fields.

7. INTERNATIONAL RATING OF THE ALASKA PETROLEUM PROFITS TAX ("PPT")

(Note: After the initial scoping a PPT tax rate of 20% and a credit rate of 15% seemed a reasonable combination. Therefore much economic work was done on this combination. As a result of subsequent work it was concluded that a 25% tax rate and 20% tax credit rate is more in the interest of Alaska. Nevertheless in the interest of providing the maximum information about the PPT it was considered desirable to leave the Chapters that were based on the 20% tax rate and 15% credit rate in the report. These are Chapters 4,5,6,7 and 8. Chapter 9,10 and 11 are based on the recommended fiscal terms.)

7.1. Introduction

This chapter contains an rating analysis of the Alaska PPT in order to evaluate in more detail the actual improvement in competitiveness that this fiscal change would create.

The rating is done by comparing in detail the economic results of the 8 world fiscal systems evaluated in Chapter 6.

The same fields will be used for the rating analysis, based on the high and the low cost cases. However, three of the fields were selected for the analysis:

- 50 MM barrels with low well productivities
- 150 MM barrels with low well productivities
- 500 MM barrels with high well productivities

The rating is done for two price levels:

- a WTI price of $ 26 per barrel
- a WTI price of $ 36 per barrel

These two levels reflect approximately the long term average price range that some oil companies may use to evaluate opportunities in Alaska. Large international major oil companies may still use lower prices in the $ 25 to $ 30 price range, but many of the large and medium sized oil companies have now shifted to higher levels of long term price expectation. Therefore, this price range may be representative of possible new investors in Alaska.

The rating will be based on the PPT for new investors, which means including the tax free allowance.

The same weighting was given to the 50 MM, 150 MM and 500 MM fields. This implies that the distribution of field sizes will be logarithmic. In other words a typical distribution is ten 50 MM barrel fields, about three 150 MM barrel fields and one 500 MM barrel field. This is a fairly representative distribution for the North Slope.

7.2. IRR rating

Table 7.1 and 7.2 summarize the IRR results that were obtained for the 10 fiscal systems.

Table 7.1

IRR	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	4.54%	15.47%	9.69%	20.67%	22.76%	36.00%
Alaska PPT	9.98%	21.96%	14.35%	25.44%	29.38%	43.29%
Norway	11.75%	17.98%	15.38%	21.47%	26.06%	33.54%
UK	13.50%	22.17%	18.81%	28.12%	37.13%	48.90%
US GOM	15.51%	23.84%	21.04%	30.47%	38.26%	49.52%
Nigeria	13.73%	21.76%	19.12%	27.99%	35.45%	45.82%
Alberta-Oil Sands	12.84%	21.21%	19.07%	28.50%	37.75%	48.91%
Angola	6.46%	16.68%	13.08%	22.80%	30.67%	40.80%
Russia-Sakhalin	3.02%	10.30%	12.69%	20.40%	26.98%	32.49%
Azerbaijan	3.79%	13.72%	11.21%	21.84%	28.71%	39.85%

Table 7.2

IRR	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	14.75%	26.91%	19.92%	32.93%	35.07%	50.47%
Alaska PPT	21.63%	34.06%	25.25%	38.45%	42.70%	58.54%
Norway	19.22%	26.48%	22.79%	30.17%	35.20%	44.27%
UK	23.99%	34.01%	30.16%	41.32%	51.42%	64.73%
US GOM	25.83%	34.93%	32.83%	43.48%	52.26%	64.49%
Nigeria	23.13%	31.51%	29.49%	39.30%	47.59%	59.20%
Alberta-Oil Sands	22.15%	31.09%	29.74%	40.20%	50.07%	61.77%
Angola	18.26%	27.44%	24.39%	34.47%	42.38%	52.36%
Russia-Sakhalin	8.21%	15.91%	19.70%	25.58%	31.90%	38.34%
Azerbaijan	11.95%	22.34%	20.70%	31.69%	38.90%	49.49%

Tables 7.3 and 7.4 rank these results from "1" to "10". In other words the highest IRR is number "1" and the lowest IRR is number "10"

The total ranking for the IRR is done by simply adding the ranking numbers. The last column in table 7.4 provides the total for the high and the low cases. The lower the number the more attractive the fiscal system is for investors.

The competitiveness index for the IRR indicates the relative competitiveness of the 10 fiscal systems related to each other, based on 6 fields for the high and low cost scenarios. If the IRR rates best in all 10 of them, the index is 12 (1 x 6 x 2 = 12). If the system rates worst in all of them, the index is 120 (10 x 6 x 2 = 120).

The US Gulf of Mexico is the most attractive system with a number 13. The Russia-Sakhalin agreement is the least attractive system with a number 116. The Alaska Current system is the next least attractive with a score of 100. The Alaska PPT improves the number to 58. In other words with respect to the IRR, the Alaska PPT improves the competitive position from a # 9 ranking for the current severance tax to a # 5 ranking among 10 fiscal systems. This means that the PPT improves the Alaska terms considerably from an IRR point of view.

Table 7.3

IRR	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	10	9	10	8	53
Alaska PPT	6	3	6	5	6	5	31
Norway	5	6	5	8	9	9	42
UK	3	2	4	3	3	3	18
US GOM	1	1	1	1	1	1	6
Nigeria	2	4	2	4	4	4	20
Alberta-Oil Sands	4	5	3	2	2	2	18
Angola	7	7	7	6	5	6	38
Russia-Sakhalin	10	10	8	10	8	10	56
Azerbaijan	9	9	9	7	7	7	48

Table 7.4

IRR	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	7	9	7	9	7	47	100
Alaska PPT	5	2	5	5	5	5	27	58
Norway	6	8	7	9	8	9	47	89
UK	2	3	2	2	2	1	12	30
US GOM	1	1	1	1	1	2	7	13
Nigeria	3	4	4	4	4	4	23	43
Alberta-Oil Sands	4	5	3	3	3	3	21	39
Angola	7	6	6	6	6	6	37	75
Russia-Sakhalin	10	10	10	10	10	10	60	116
Azerbaijan	9	9	8	8	7	8	49	97

7.3. NPV @10% rating

Tables 7.5 through 7.8 provide the same analysis for the NPV@10%. It can be seen how the Alaska Current system would rank # 8 and the Alaska PPT would rank # 7 under the 10 fiscal systems. The relative competitiveness improvement of the PPT relative to the Current System is moderate for the PPT. This is caused by the fact that the government take under high prices is higher for the PPT.

Table 7.5
NPV @10%

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	-48.6	57.8	-7.1	281.2	589.0	1390.5
Alaska PPT	-0.1	101.5	78.6	317.6	711.1	1423.9
Norway	11.0	56.5	90.4	214.9	590.9	970.4
UK	35.5	139.0	220.5	503.5	1365.4	2228.0
US GOM	71.4	205.8	322.6	677.8	1667.2	2685.6
Nigeria	45.3	151.0	245.7	519.0	1273.8	2045.1
Alberta-Oil Sands	30.3	135.5	220.0	504.3	1338.6	2201.0
Angola	-45.2	98.6	97.1	391.2	1003.0	1420.6
Russia-Sakhalin	-119.8	5.7	95.6	366.0	797.5	1023.3
Azerbaijan	-91.5	59.3	38.4	409.1	990.2	1476.6

Table 7.6
NPV @10%

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	33.2	139.7	172.9	461.2	885.4	1687.0
Alaska PPT	64.9	161.2	211.0	447.8	928.7	1638.9
Norway	44.5	90.0	163.2	287.7	709.3	1088.8
UK	109.1	212.5	381.8	664.8	1628.0	2490.6
US GOM	163.5	297.8	522.4	877.6	1993.5	3012.0
Nigeria	114.0	210.0	381.0	641.2	1465.5	2232.0
Alberta-Oil Sands	102.6	206.2	372.3	655.6	1580.3	2439.5
Angola	81.3	164.1	290.3	493.5	991.6	1176.3
Russia-Sakhalin	-25.9	95.5	260.0	379.8	729.2	1026.7
Azerbaijan	22.2	155.6	256.8	511.3	1023.5	1312.7

Table 7.7
NPV @10%

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	10	9	9	8	52
Alaska PPT	6	5	8	8	8	6	41
Norway	5	9	7	10	10	10	51
UK	3	3	3	4	2	2	17
US GOM	1	1	1	1	1	1	6
Nigeria	2	2	2	2	4	4	16
Alberta-Oil Sands	4	4	4	3	3	3	21
Angola	7	6	5	6	5	7	36
Russia-Sakhalin	10	10	6	7	7	9	49
Azerbaijan	9	7	9	5	6	5	41

Table 7.8

NPV @10%	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	8	9	7	8	5	45	97
Alaska PPT	6	6	8	8	7	6	41	82
Norway	7	10	10	10	10	9	56	107
UK	3	2	2	2	2	2	13	30
US GOM	1	1	1	1	1	1	6	12
Nigeria	2	3	3	4	4	4	20	36
Alberta-Oil Sands	4	4	4	3	3	3	21	42
Angola	5	5	5	6	6	8	35	71
Russia-Sakhalin	10	9	6	9	9	10	53	102
Azerbaijan	9	7	7	5	5	7	40	81

7.4. EMV @10% rating

Tables 7.9 through 7.12 provide the analysis for the EMV@10%. From an EMV perspective, the Alaska current system would rank # 8 and the Alaska PPT would rank # 5. The EMV improvement for the PPT is due to a large extent to the tax credits which have a significant impact on the EMV. The PPT improvement therefore is very significant for explorers.

Table 7.9

EMV @10%	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	-29.3	-2.7	-18.9	53.2	130.1	330.5
Alaska PPT	-11.2	14.2	8.5	68.3	166.6	344.8
Norway	-3.7	7.6	16.1	47.2	141.2	236.1
UK	-6.0	19.9	40.3	111.0	326.5	542.2
US GOM	-12.7	20.9	50.1	138.9	386.2	640.8
Nigeria	-17.8	8.6	32.3	100.6	289.3	482.1
Alberta-Oil Sands	-15.7	10.6	31.7	102.8	311.4	527.0
Angola	-40.4	-4.5	-4.9	68.7	221.6	326.0
Russia-Sakhalin	-90.1	-58.7	-36.2	31.4	139.2	195.7
Azerbaijan	-68.9	-31.2	-36.4	56.2	201.5	323.1

Table 7.10
EMV @10%

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	-3.1	23.5	31.8	103.9	209.9	410.3
Alaska PPT	8.8	32.9	45.3	104.5	224.8	402.3
Norway	6.8	18.2	36.4	67.6	173.0	267.9
UK	17.3	43.2	85.5	156.2	397.0	612.7
US GOM	20.0	53.6	109.7	198.5	477.5	732.1
Nigeria	9.1	33.1	75.8	140.9	347.0	538.6
Alberta-Oil Sands	8.8	34.7	76.2	147.1	378.2	593.0
Angola	0.9	21.6	53.1	103.9	228.5	274.6
Russia-Sakhalin	-56.9	-26.5	14.6	44.5	131.9	206.3
Azerbaijan	-30.8	2.6	27.9	91.5	219.5	291.8

Table 7.11
EMV @10%

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	7	7	8	8	10	6	46
Alaska PPT	3	3	6	6	7	5	30
Norway	1	6	5	9	8	9	38
UK	2	2	2	2	2	2	12
US GOM	4	1	1	1	1	1	9
Nigeria	6	5	3	4	4	4	26
Alberta-Oil Sands	5	4	4	3	3	3	22
Angola	8	8	7	5	5	7	40
Russia-Sakhalin	10	10	9	10	9	10	58
Azerbaijan	9	9	10	7	6	8	49

Table 7.12
EMV @10%

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	6	8	7	8	5	42	88
Alaska PPT	5	5	6	5	6	6	33	63
Norway	6	8	7	9	9	9	48	86
UK	2	2	2	2	2	2	12	24
US GOM	1	1	1	1	1	1	6	15
Nigeria	3	4	4	4	4	4	23	49
Alberta-Oil Sands	4	3	3	3	3	3	19	41
Angola	7	7	5	6	5	8	38	78
Russia-Sakhalin	10	10	10	10	10	10	60	118
Azerbaijan	9	9	9	8	7	7	49	98

7.5. Government Take rating

Tables 7.13 through 7.16 show the attractiveness of the government take to investors. In this case, of course, the lower the government take is the more attractive the fiscal system is for investors. So here a "1" is given for the lowest government take and an "10" is provided for the highest government take.

The Alaska current system ranks # 7. Alaska needs a somewhat better government take in order to compensate for the low net back.

The PPT for new investors, with the tax free allowance, would on an overall basis be slightly less because of the government take improves strongly on small fields and higher government take on large fields. Therefore the Alaska PPT would rate # 6. On an overall basis the government take improvement is very modest.

Table 7.13

Gov Take	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	71.03%	56.57%	61.48%	54.67%	59.25%	56.37%
Alaska PPT	48.80%	49.70%	53.98%	55.73%	58.54%	58.64%
Norway	75.65%	76.74%	75.17%	76.33%	76.43%	76.97%
UK	51.25%	50.67%	50.50%	50.30%	50.15%	50.10%
US GOM	35.16%	35.13%	41.41%	40.40%	43.91%	43.27%
Nigeria	39.27%	46.92%	45.97%	49.82%	53.66%	54.74%
Alberta-Oil Sands	48.60%	49.53%	49.13%	49.70%	49.86%	49.98%
Angola	68.24%	50.31%	53.43%	58.26%	63.10%	71.29%
Russia-Sakhalin	82.36%	63.79%	54.26%	59.16%	72.42%	77.81%
Azerbaijan	65.76%	47.07%	44.81%	41.94%	51.62%	66.24%

Table 7.14

Gov Take	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	57.70%	53.13%	55.54%	52.52%	57.00%	55.23%
Alaska PPT	49.66%	51.00%	54.39%	55.93%	58.30%	58.51%
Norway	77.13%	77.47%	76.59%	77.09%	77.08%	77.38%
UK	50.90%	50.55%	50.41%	50.26%	50.14%	50.09%
US GOM	35.14%	35.12%	40.24%	39.76%	43.16%	42.79%
Nigeria	47.64%	50.58%	50.23%	51.99%	54.87%	55.47%
Alberta-Oil Sands	49.76%	49.98%	49.81%	49.97%	50.01%	50.10%
Angola	51.17%	60.31%	59.41%	63.53%	72.15%	80.94%
Russia-Sakhalin	70.12%	59.47%	58.68%	69.84%	78.00%	79.51%
Azerbaijan	50.60%	45.56%	42.90%	53.99%	64.20%	73.44%

Table 7.15

Gov Take	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	9	6	7	5	43
Alaska PPT	4	5	7	7	6	6	35
Norway	9	10	10	10	10	9	58
UK	5	7	5	5	3	3	28
US GOM	1	1	1	1	1	1	6
Nigeria	2	2	3	4	5	4	20
Alberta-Oil Sands	3	4	4	3	2	2	18
Angola	7	6	6	8	8	8	43
Russia-Sakhalin	10	9	8	9	9	10	55
Azerbaijan	6	3	2	2	4	7	24

Table 7.16

Gov Take	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	7	7	5	5	4	36	79
Alaska PPT	3	6	6	7	6	6	34	69
Norway	10	10	10	10	9	8	57	115
UK	6	4	5	3	3	2	23	51
US GOM	1	1	1	1	1	1	6	12
Nigeria	2	5	4	4	4	5	24	44
Alberta-Oil Sands	4	3	3	2	2	3	17	35
Angola	7	9	9	8	8	10	51	94
Russia-Sakhalin	9	8	8	9	10	9	53	108
Azerbaijan	5	2	2	6	7	7	29	53

7.6. Overall rating

It can be seen from the previous tables that the Alaska PPT strongly boosts the IRR and the EMV@10%. The NPV@10% is less strongly affected but the Alaska PPT still provides an improvement. The Government Take is about the same for new investors because it improves significantly for small fields for new investors but is higher on large fields.

Despite the relatively modest government take compared Norway and Angola, the Alaska PPT does not rate that well on an NPV@10% basis due to the low net back prices.

The reason therefore that the Alaska current system rates # 8 economically is because of the low net back prices.

Therefore, the current severance tax and the proposed Alaska PPT need to accommodate the low net back through a generally modest government take compared to world wide standards. Compared to some other high cost environments in North America the government take is tougher.

Table 7.17 provides the overall ranking. The table summarizes the results for the four variables. The overall ranking of the Alaska PPT would be # 5 compared with # 8 for the current system. It can be seen how there is a considerable reduction in number from 364 to 272.

This indicates that the improvement in competitiveness of the Alaska PPT is considerable for new investors. It should result in attracting new entrants to Alaska.

Table 7.17
Overall

	IRR Subtotal	NPV Subtotal	EMV Subtotal	GOV TAKE Subtotal	SUM TOTAL	Ranking
Alaska Current	100	97	88	79	364	#8
Alaska PPT	58	82	63	69	272	#5
Norway	89	107	86	115	397	#9
UK	30	30	24	51	135	#2
US GOM	13	12	15	12	52	#1
Nigeria	43	36	49	44	172	#4
Alberta-Oil Sands	39	42	41	35	157	#3
Angola	75	71	78	94	318	#6
Russia-Sakhalin	116	102	118	108	444	#10
Azarbaijan	97	81	98	53	329	#7

The following table summarizes the total competitiveness index from attractive to unattractive for new investors in Alaska.

Table 7.18
COMPETITIVENESS INDEX

Hypothetical best	48	
US GOM	52	#1
UK	135	#2
Alberta-Oil Sands	157	#3
Nigeria	172	#4
Alaska PPT	272	#5
Angola	318	#6
Azerbaijan	329	#7
Alaska Current	364	#8
Norway	397	#9
Russia-Sakhalin	444	#10
Hypothetical worst	480	

8. COMPETITIVENESS AND THE PPT RATE

(Note: After the initial scoping a PPT tax rate of 20% and a credit rate of 15% seemed a reasonable combination. Therefore much economic work was done on this combination. As a result of subsequent work it was concluded that a 25% tax rate and 20% tax credit rate is more in the interest of Alaska. Nevertheless in the interest of providing the maximum information about the PPT it was considered desirable to leave the Chapters that were based on the 20% tax rate and 15% credit rate in the report. These are Chapters 4,5,6,7 and 8. Chapter 9,10 and 11 are based on the recommended fiscal terms.)

8.1. Introduction

As was illustrated in Chapter 4, a new investor will not be concerned about the PPT rate for small fields because of the tax free allowance. The new investor will receive the tax credits for negative cash flow and for capital expenditures on the small field, but will typically not pay PPT unless oil prices are very high. Therefore, small companies and new investors in small fields will not be concerned about the PPT rate.

The PPT rate will be mainly a concern for existing larger oil companies. It is therefore important to analyze the international economic competitiveness with respect to the PPT rate for a situation where companies have already used their tax free allowance and are re-investing in Alaska. Such re-investments should be attractive from an international perspective, otherwise there is not an increased incentive to re-invest in Alaska.

An important Alaska PPT concept is that large oil companies that actively re-invest in Alaska should be rewarded with better economics. Large oil companies that are largely in a "harvest" mode and re-direct their Alaska profits in other jurisdictions, should pay a higher tax.

A PPT rate that is too high might discourage re-investment if the overall economic rating becomes unattractive. In order to review the effect of a high PPT rate, an analysis was done of various rates.

In this chapter the analysis will be provided for PPT rates of 30%, 25% and 20% in order to evaluate the economics from this perspective.

Following is the same competitiveness analysis as done in Chapter 7 for the proposed PPT for new investors, but now for re-investment by oil companies which have already used their tax free allowance.

8.2. Results of the analysis

8.2.1. IRR results

The IRR results show the IRR is not very different depending on the PPT rate, for the 30%, 25% and 20% cases (indicated in the table as PPT-30, PPT-25 and PPT-20). The reason is that both the negative as well as the positive cash flows are subject to the PPT rate and therefore, a higher rate also results in higher tax credits for negative cash flows.

Table 8.1

IRR	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	4.54%	15.47%	4.54%	20.67%	22.76%	36.00%
PPT-20	7.33%	18.56%	12.54%	23.97%	28.61%	42.61%
Norway	11.75%	17.98%	15.38%	21.47%	26.06%	33.54%
UK	13.50%	22.17%	18.81%	28.12%	37.13%	48.90%
US GOM	15.51%	23.84%	21.04%	30.47%	38.26%	49.52%
Nigeria	13.73%	21.76%	19.12%	27.99%	35.45%	45.82%
Alberta-Oil Sands	12.84%	21.21%	19.07%	28.50%	37.75%	48.91%
Angola	6.46%	16.68%	13.08%	22.80%	30.67%	40.80%
Russia-Sakhalin	3.02%	10.30%	12.69%	20.40%	26.98%	32.49%
Azerbaijan	3.79%	13.72%	11.21%	21.84%	28.71%	39.85%
PPT-30	7.58%	18.62%	12.61%	23.80%	28.22%	41.96%
PPT-25	7.45%	18.59%	12.57%	23.89%	28.43%	42.30%

Table 8.2

IRR	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	14.75%	26.91%	19.92%	32.93%	35.07%	50.47%
PPT-20	17.82%	30.38%	23.19%	36.73%	41.66%	57.75%
Norway	19.22%	26.48%	22.79%	30.17%	35.20%	44.27%
UK	23.99%	34.01%	30.16%	41.32%	51.42%	64.73%
US GOM	25.83%	34.93%	32.83%	43.48%	52.26%	64.49%
Nigeria	23.13%	31.51%	29.49%	39.30%	47.59%	59.20%
Alberta-Oil Sands	22.15%	31.09%	29.74%	40.20%	50.07%	61.77%
Angola	18.26%	27.44%	24.39%	34.47%	42.38%	52.36%
Russia-Sakhalin	8.21%	15.91%	19.70%	25.58%	31.90%	38.34%
Azerbaijan	11.95%	22.34%	20.70%	31.69%	38.90%	49.49%
PPT-30	17.89%	30.30%	23.04%	36.35%	41.03%	56.90%
PPT-25	17.86%	30.34%	23.12%	36.55%	41.36%	57.35%

Even without specific rating analysis, it can be seen how the IRR results for all PPT rates are generally more attractive than the Current system. This is because of the tax credits on negative cash flow and on capital expenditures, which are important during the first part of the cash flow.

8.2.2. NPV@10% results

The NPV@10% results are sensitive to the PPT rate as can be seen in Tables 8.3 and 8.4. The lower the PPT rate, the more attractive the NPV@10%. As can be expected for the large fields and under high prices is the PPT 30% system less attractive than the Current system, in view of the fact that the 30% takes away considerable positive cash flow.

Table 8.3

NPV @10%	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	-48.6	57.8	-7.1	281.2	589.0	1390.5
PPT-20	-17.7	67.5	43.3	276.3	668.6	1378.8
Norway	11.0	56.5	90.4	214.9	590.9	970.4
UK	35.5	139.0	220.5	503.5	1365.4	2228.0
US GOM	71.4	205.8	322.6	677.8	1667.2	2685.6
Nigeria	45.3	151.0	245.7	519.0	1273.8	2045.1
Alberta-Oil Sands	30.3	135.5	220.0	504.3	1338.6	2201.0
Angola	-45.2	98.6	97.1	391.2	1003.0	1420.6
Russia-Sakhalin	-119.8	5.7	95.6	366.0	797.5	1023.3
Azerbaijan	-91.5	59.3	38.4	409.1	990.2	1476.6
PPT-30	-14.3	60.3	39.6	243.5	586.5	1207.9
PPT-25	-16.0	63.9	41.5	259.9	627.5	1293.3

Table 8.4

NPV @10%	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	33.2	139.7	172.9	461.2	885.4	1687.0
PPT-20	40.7	125.9	172.5	405.4	883.6	1593.3
Norway	44.5	90.0	163.2	287.7	709.3	1088.8
UK	109.1	212.5	381.8	664.8	1628.0	2490.6
US GOM	163.5	297.8	522.4	877.6	1993.5	3012.0
Nigeria	114.0	210.0	381.0	641.2	1465.5	2232.0
Alberta-Oil Sands	102.6	206.2	372.3	655.6	1580.3	2439.5
Angola	81.3	164.1	290.3	493.5	991.6	1176.3
Russia-Sakhalin	-25.9	95.5	260.0	379.8	729.2	1026.7
Azerbaijan	22.2	155.6	256.8	511.3	1023.5	1312.7
PPT-30	36.4	111.0	152.1	355.9	774.1	1395.5
PPT-25	38.6	118.4	162.3	380.7	828.9	1494.7

8.2.3. EMV@10% results.

Also with respect to the EMV@10% the PPT rate is important. Generally, the higher the PPT rate, the less attractive the exploration for the field. An exception is the small field under low prices. In fact in this case the PPT 30% indicates the least unattractive results. This is because the exploration costs are also subject to the tax credit. With a PPT of 30% the tax credit is more and therefore, the net costs of an expioratory dry hole is less.

Table 8.5
EMV @10%

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	-29.3	-2.7	-18.9	53.2	130.1	330.5
PPT-20	-15.6	5.7	-0.3	57.9	156.0	333.6
Norway	-3.7	7.6	16.1	47.2	141.2	236.1
UK	-6.0	19.9	40.3	111.0	326.5	542.2
US GOM	-12.7	20.9	50.1	138.9	386.2	640.8
Nigeria	-17.8	9.6	32.3	100.6	289.3	482.1
Alberta-Oil Sands	-15.7	10.6	31.7	102.8	311.4	527.0
Angola	-40.4	-4.5	-4.9	68.7	221.6	326.0
Russia-Sakhalin	-90.1	-58.7	-36.2	31.4	139.2	195.7
Azerbaijan	-68.9	-31.2	-36.4	56.2	201.5	323.1
PPT-30	-13.0	5.6	0.5	51.4	137.2	292.5
PPT-25	-14.3	5.7	0.1	54.7	146.6	313.1

Table 8.6
EMV @10%

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	-3.1	23.5	31.8	103.9	209.9	410.3
PPT-20	2.8	24.1	35.7	93.9	213.5	391.0
Norway	6.8	18.2	36.4	67.6	173.0	267.9
UK	17.3	43.2	85.5	156.2	397.0	612.7
US GOM	20.0	53.6	109.7	198.5	477.5	732.1
Nigeria	9.1	33.1	75.8	140.9	347.0	538.6
Alberta-Oil Sands	8.8	34.7	76.2	147.1	378.2	593.0
Angola	0.9	21.6	53.1	103.9	228.5	274.6
Russia-Sakhalin	-56.9	-26.5	14.6	44.5	131.9	206.3
Azerbaijan	-30.8	2.6	27.9	91.5	219.5	291.8
PPT-30	2.8	21.5	31.7	82.7	187.2	342.6
PPT-25	2.8	22.8	33.7	88.3	200.4	366.8

8.2.4. Government Take results

The most negative factor of a high PPT of 30% for large oil companies with large operations in Alaska would be the resulting high government take, which means losses on undiscounted cash. This is unattractive from a long term perspective. This is clearly illustrated in the following two tables. The higher the PPT rate, the higher the government take (which means a correspondingly lower corporate take) and the less attractive the field economics are to the investors.

Table 8.7

Gov Take	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	71.03%	56.57%	61.48%	54.67%	59.25%	56.37%
PPT-20	65.10%	61.07%	62.92%	60.71%	61.12%	60.14%
Norway	75.65%	76.74%	75.17%	76.33%	76.43%	76.97%
UK	51.25%	50.67%	50.50%	50.30%	50.15%	50.10%
US GOM	35.16%	35.13%	41.41%	40.40%	43.91%	43.27%
Nigeria	39.27%	46.92%	45.97%	49.82%	53.66%	54.74%
Alberta-Oil Sands	48.60%	49.53%	49.13%	49.70%	49.86%	49.98%
Angola	60.24%	50.31%	53.43%	58.26%	63.10%	71.29%
Russia-Sakhalin	82.36%	63.79%	54.26%	59.16%	72.42%	77.81%
Azerbaijan	63.76%	47.07%	44.81%	41.94%	51.62%	66.24%
PPT-30	68.00%	65.41%	66.85%	65.30%	65.76%	65.00%
PPT-25	66.55%	63.24%	64.88%	63.00%	63.44%	62.57%

Table 8.8

Gov Take	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	57.70%	53.13%	55.54%	52.52%	57.00%	55.23%
PPT-20	61.84%	60.34%	61.33%	60.19%	60.61%	59.90%
Norway	77.13%	77.47%	76.50%	77.09%	77.08%	77.38%
UK	50.90%	50.55%	50.41%	50.26%	50.14%	50.09%
US GOM	35.14%	35.12%	40.24%	39.76%	43.16%	42.79%
Nigeria	47.64%	50.58%	50.23%	51.99%	54.87%	55.47%
Alberta-Oil Sands	49.76%	49.98%	49.81%	49.97%	50.01%	50.10%
Angola	51.17%	60.31%	59.41%	63.53%	72.15%	80.94%
Russia-Sakhalin	70.12%	59.47%	58.68%	69.84%	78.00%	79.51%
Azerbaijan	50.60%	45.56%	42.90%	53.99%	64.20%	73.44%
PPT-30	66.07%	65.02%	65.83%	64.99%	65.41%	64.84%
PPT-25	63.95%	62.68%	63.58%	62.59%	63.01%	62.37%

8.3. Rating

The rating will be done separately for the 8 fiscal systems, comparing a PPT of 30%, 25% and 20% with the other 7 fiscal terms, including the Current System.

The PPT 30% will be shown in detail. Subsequently, the summary results of the PPT of 25% and 20% will also be provided.

8.3.1. Rating of the PPT of 30%

Following are all the tables for the PPT rating of 30%.

Table 8.9

IRR	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	10	9	10	8	53
PPT-30	6	5	8	5	7	5	36
Norway	5	6	5	8	9	9	42
UK	3	2	4	3	3	3	18
US GOM	1	1	1	1	1	1	6
Nigeria	2	3	2	4	4	4	19
Alberta-Oil Sands	4	4	3	2	2	2	17
Angola	7	7	6	6	5	6	37
Russia-Sakhalin	10	10	7	10	8	10	55
Azerbaijan	9	9	9	7	6	7	47

Table 8.10

IRR	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	7	9	7	9	7	47	100
PPT-30	7	5	6	5	6	5	34	70
Norway	5	8	7	9	8	9	46	88
UK	2	2	2	2	2	1	11	29
US GOM	1	1	1	1	1	2	7	13
Nigeria	3	3	4	4	4	4	22	41
Alberta-Oil Sands	4	4	3	3	3	3	20	37
Angola	6	6	5	6	5	6	34	71
Russia-Sakhalin	10	10	10	10	10	10	60	115
Azerbaijan	9	9	8	8	7	8	49	96

Table 8.11
NPV @10%

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	10	8	9	7	50
PPT-30	6	6	8	9	10	8	47
Norway	5	9	7	10	8	10	49
UK	3	3	3	4	2	2	17
US GOM	1	1	1	1	1	1	6
Nigeria	2	2	2	2	4	4	16
Alberta-Oil Sands	4	4	4	3	3	3	21
Angola	7	5	5	6	5	6	34
Russia-Sakhalin	10	10	6	7	7	9	49
Azerbaijan	9	7	9	5	6	5	41

Table 8.12
NPV @10%

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	7	8	7	7	5	42	92
PPT-30	7	8	10	9	8	7	49	96
Norway	6	10	9	10	10	9	54	103
UK	3	2	2	2	2	2	13	30
US GOM	1	1	1	1	1	1	6	12
Nigeria	2	3	3	4	4	4	20	36
Alberta-Oil Sands	4	4	4	3	3	3	21	42
Angola	5	6	5	6	6	8	36	70
Russia-Sakhalin	10	9	7	8	9	10	53	102
Azerbaijan	9	5	6	5	5	6	36	77

Table 8.13
EMV @10%

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	7	7	8	7	10	5	44
PPT-30	4	6	6	8	9	8	41
Norway	1	5	5	9	7	9	36
UK	2	2	2	2	2	2	12
US GOM	3	1	1	1	1	1	8
Nigeria	6	4	3	4	4	4	25
Alberta-Oil Sands	5	3	4	3	3	3	21
Angola	8	8	7	5	5	6	39
Russia-Sakhalin	10	10	9	10	8	10	57
Azerbaijan	9	9	10	6	6	7	47

Table 8.14
EMV @10%

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	5	7	6	7	5	38	82
PPT-30	6	7	8	8	8	6	43	84
Norway	5	8	6	9	9	9	46	82
UK	2	2	2	2	2	2	12	24
US GOM	1	1	1	1	1	1	6	14
Nigeria	3	4	4	4	4	4	23	48
Alberta-Oil Sands	4	3	3	3	3	3	19	40
Angola	7	6	5	5	5	8	36	75
Russia-Sakhalin	10	10	10	10	10	10	60	117
Azerbaijan	9	9	9	7	6	7	47	94

Table 8.15
Gov Take

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	7	8	6	6	5	40
PPT-30	6	9	9	9	8	6	47
Norway	9	10	10	10	10	9	58
UK	4	6	5	5	3	3	26
US GOM	1	1	1	1	1	1	6
Nigeria	2	2	3	4	5	4	20
Alberta-Oil Sands	3	4	4	3	2	2	18
Angola	7	5	6	7	7	8	40
Russia-Sakhalin	10	8	7	8	9	10	52
Azerbaijan	5	3	2	2	4	7	23

Table 8.16
Gov Take

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	7	6	6	5	5	4	33	73
PPT-30	8	9	9	8	7	6	47	94
Norway	10	10	10	10	9	8	57	115
UK	5	4	5	3	3	2	22	48
US GOM	1	1	1	1	1	1	6	12
Nigeria	2	5	4	4	4	5	24	44
Alberta-Oil Sands	3	3	3	2	2	3	16	34
Angola	6	8	8	7	8	10	47	87
Russia-Sakhalin	9	7	7	9	10	9	51	103
Azerbaijan	4	2	2	6	6	7	27	50

As can be seen from the above eight tables, in general the PPT 30% rates favorably compared to the Current System with respect to the IRR, but rates unfavorably with respect to NPV@10% and the EMV@10% and rates very unfavorably with respect to the Government Take.

The following two summary tables illustrate how on balance the PPT has about the same competitiveness rating as the Current Systems in total.

A PPT rate of 30% would not improve the competitiveness of Alaska for re-investmen. by large companies which have already used their tax free allowance. Therefore this rate would be too high.

Table 8.17
Overview

	IRR Subtotal	NPV Subtotal	EMV Subtotal	GOV TAKE Subtotal	SUM TOTAL	Ranking
Alaska Current	100	92	82	73	347	#8
PPT-30	70	96	84	94	344	#7
Norway	88	103	82	115	388	#9
UK	29	30	24	48	131	#2
US GOM	13	12	14	12	51	#1
Nigeria	41	36	48	44	169	#4
Alberta-Oil Sands	37	42	40	34	153	#3
Angola	71	70	75	87	303	#5
Russia-Sakhalin	115	102	117	103	437	#10
Azerbaijan	96	77	94	50	317	#6

Table 8.18
COMPETITIVENESS INDEX

Hypothetical best	48	
US GOM	51	#1
UK	131	#2
Alberta-Oil Sands	153	#3
Nigeria	169	#4
Angola	302	#5
Azerbaijan	317	#6
PPT-30	344	#7
Alaska Current	347	#8
Norway	388	#9
Russia-Sakhalin	438	#10
Hypothetical worst	480	

8.3.2. Rating of the PPT of 25%

Comparing Table 8.19 with 8.17 it can be seen how the PPT of 25% improves with respect to the NPV@10% and EMV@10%. This results in an overall better rating of the PPT at 25%. Which is now slightly more attractive than the Current system, as can be seen from Table 8.20. Nevertheless the competitive position is still close to the Current System based on a tax credit of 15%.

Table 8.19

Overview	IRR Subtotal	NPV Subtotal	EMV Subtotal	GOV TAKE Subtotal	SUM TOTAL	Ranking
Alaska Current	100	93	84	73	350	#8
PPT-25	70	93	79	92	334	#7
Norway	88	104	83	115	390	#9
UK	29	30	24	48	131	#2
US GOM	13	12	14	12	51	#1
Nigeria	41	36	48	44	169	#4
Alberta-Oil Sands	37	42	40	34	153	#3
Angola	71	70	76	88	305	#5
Russia-Sakhalin	115	103	118	103	439	#10
Azerbaijan	96	77	94	51	318	#6

Table 8.20
COMPETITIVENESS INDEX

Hypothetical best	48	
US GOM	51	#1
UK	131	#2
Alberta-Oil Sands	153	#3
Nigeria	169	#4
Angola	305	#5
Azerbaijan	318	#6
PPT-25	334	#7
Alaska Current	350	#8
Norway	390	#9
Russia-Sakhalin	439	#10
Hypothetical worst	480	

Subsequent to these results, a further rating was done on a 25% tax rate and a 20% tax credit. This rating resulted in a rather attractive rating as will be discussed in Chapter 9.

8.3.3. Rating of the PPT of 20%

Comparing Tables 8.21 and 8.19, the NPV@10% and EMV@10% improve further relative to the Current System. Also the Government Take difference in rating is now less. This now results in a much better rating for the PPT with 20% relative to the Current System.

Table 8.21

Overview	IRR Subtotal	NPV Subtotal	EMV Subtotal	GOV TAKE Subtotal	SUM TOTAL	Ranking
Alaska Current	100	93	87	73	353	#8
PPT-20	70	91	72	89	322	#6
Norway	88	105	83	115	391	#9
UK	29	30	24	48	131	#2
US GOM	13	12	14	12	51	#1
Nigeria	41	36	48	44	169	#4
Alberta-Oil Sands	37	42	40	34	153	#3
Angola	71	70	77	89	307	#5
Russia-Sakhalin	115	103	118	104	440	#10
Azerbaijan	96	78	97	52	323	#7

The competitiveness index for a PPT of 20% shows some considerable improvement over the Current System.

In this case much depends on how investors attribute weight to the various factors. If a low government take is considered very important, a PPT of 20% may be considered still less attractive. If on the other hand the IRR and EMV@10% are considered important the PPT of 20% offers a better deal than the Current System.

On average the improvement in competitiveness of the PPT-20 is enough to ensure that the behavior of large producers will not be negatively impacted relative to the current situation. Large producers may maintain operations unchanged or may accelerate their investments, in particular in exploration, while smaller producers will find a considerable incentive to invest and explore.

It should be noted that the competitive position depends considerably on price levels. As can be seen from Charts 6.6, 6.38 and 6.54, the PPT improves the competitive position for new investors rapidly under high prices relative to Norway, Angola, Russia-Sakhalin and Azerbaijan. The same would be true for a wide variety of other fiscal systems in the world which are progressive, as discussed in Chapter 2. Therefore, as long as WTI long term price

predictions of investors are $ 30 per barrel or higher, considerable interest can be expected for investment in Alaska by such investors.

Table 8.22
COMPETITIVENESS INDEX

Hypothetical best	**48**	
US GOM	**51**	**#1**
UK	**131**	**#2**
Alberta-Oil Sands	**153**	**#3**
Nigeria	**169**	**#4**
Angola	**307**	**#5**
PPT-20	**322**	**#6**
Azerbaijan	**323**	**#7**
Alaska Current	**353**	**#8**
Norway	**391**	**#9**
Russia-Sakhalin	**440**	**#10**
Hypothetical worst	**480**	

9. FURTHER RATING BASED ON HIGHER TAX CREDIT RATES.

9.1. Introduction

The DOR model indicated that the overall revenues to the State were primarily determined by the tax rate. Higher tax credits result only in a modest reduction of these overall revenues. This required a new look at the PPT tax rate and tax credit rate. Therefore, more sensitivity analysis was done on higher tax rates with higher tax credit rates. This indicated that a 25% tax rate with a 20% tax credit was a better combination for the State. The rating analysis for new investors also indicated that such a system would be even more attractive for new investors. This chapter discusses the rating of this new package for new investors.

9.2. IRR rating

Table 9.1 and 9.2 summarize the IRR results that were obtained.

Table 9.1

IRR	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	4.54%	15.47%	9.69%	20.67%	22.76%	36.00%
Alaska PPT	12.16%	24.58%	16.18%	27.40%	30.95%	45.01%
Norway	11.75%	17.98%	15.38%	21.47%	26.06%	33.54%
UK	13.50%	22.17%	18.81%	28.12%	37.13%	48.90%
US GOM	15.51%	23.84%	21.04%	30.47%	38.26%	49.52%
Nigeria	13.73%	21.76%	19.12%	27.99%	35.45%	45.82%
Alberta-Oil Sands	12.84%	21.21%	19.07%	28.50%	37.75%	48.91%
Angola	6.46%	16.68%	13.08%	22.80%	30.67%	40.80%
Russia-Sakhalin	3.02%	10.30%	12.69%	20.40%	26.98%	32.49%
Azerbaijan	3.79%	13.72%	11.21%	21.84%	28.71%	39.85%

Table 9.2
IRR

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	14.75%	26.91%	19.92%	32.63%	35.07%	50.47%
Alaska PPT	24.39%	36.99%	27.37%	40.74%	44.53%	60.49%
Norway	19.22%	28.48%	22.79%	30.17%	35.20%	44.27%
UK	23.99%	34.01%	30.16%	41.32%	51.42%	64.73%
US GOM	25.63%	34.93%	32.83%	43.48%	52.26%	64.49%
Nigeria	23.13%	31.51%	29.49%	39.30%	47.59%	59.20%
Alberta-Oil Sands	22.15%	31.09%	29.74%	40.20%	50.07%	61.77%
Angola	18.26%	27.44%	24.39%	34.47%	42.38%	52.36%
Russia-Sakhalin	8.21%	15.91%	19.70%	25.58%	31.90%	38.34%
Azerbaijan	11.95%	22.34%	20.70%	31.69%	38.90%	49.49%

As can be seen by comparing this table with the one in Chapter 7, the 20% tax credit has a very favorable impact on the rate of return.

Tables 9.3 and 9.4 rank these results again from "1" to "10".

Table 9.3
IRR

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	10	9	10	8	53
Alaska PPT	5	1	5	5	5	5	26
Norway	6	6	6	8	9	9	44
UK	3	3	4	3	3	3	19
US GOM	1	2	1	1	1	1	7
Nigeria	2	4	2	4	4	4	20
Alberta-Oil Sands	4	5	3	2	2	2	18
Angola	7	7	7	6	6	6	39
Russia-Sakhalin	10	10	8	10	8	10	56
Azerbaijan	9	9	9	7	7	7	48

Table 9.4

IRR	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	7	9	7	9	7	47	100
Alaska PPT	2	1	5	3	5	4	20	46
Norway	6	8	7	9	8	9	47	91
UK	3	3	2	2	2	1	13	32
US GOM	1	2	1	1	1	2	8	15
Nigeria	4	4	4	5	4	5	26	46
Alberta-Oil Sands	5	5	3	4	3	3	23	41
Angola	7	6	6	6	6	6	37	76
Russia-Sakhalin	10	10	10	10	10	10	60	116
Azerbaijan	9	9	8	8	7	8	49	97

It can be seen how the overall IRR ranking improves from 58 on Table 7.4 to 46 on the above table. By international standards the IRR would be highly attractive for small and new investors.

9.3. NPV @10% rating

Tables 9.5 through 9.8 provide the same analysis for the NPV@10%. It can be seen how the NPV@10% only modestly improves relative to table 7.8 from 82 to 79.

Table 9.5

NPV @10%	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	-48.6	57.8	-7.1	281.2	589.0	1390.5
Alaska PPT	14.0	111.4	103.0	328.9	707.4	1376.5
Norway	11.0	56.5	90.4	214.9	590.9	970.4
UK	35.5	139.0	220.5	503.5	1365.4	2228.0
US GOM	71.4	205.8	322.6	677.8	1667.2	2685.6
Nigeria	45.3	151.0	245.7	519.0	1273.8	2045.1
Alberta-Oil Sands	30.3	135.5	220.0	504.3	1338.6	2201.0
Angola	-45.2	98.6	97.1	391.2	1003.0	1420.6
Russia-Sakhalin	-119.8	5.7	95.6	366.0	797.5	1023.3
Azerbaijan	-91.5	59.3	38.4	409.1	990.2	1476.6

Table 9.6

NPV @10%	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	33.2	139.7	172.9	461.2	885.4	1687.0
Alaska PPT	74.2	167.9	222.0	445.2	903.1	1568.9
Norway	44.5	90.0	163.2	287.7	709.3	1088.8
UK	109.1	212.5	381.8	664.8	1628.0	2490.6
US GOM	163.5	297.8	522.4	877.6	1993.5	3012.0
Nigeria	114.0	210.0	381.0	641.2	1465.5	2232.0
Alberta-Oil Sands	102.6	206.2	372.3	655.6	1580.3	2439.5
Angola	81.3	164.1	290.3	493.5	991.6	1176.3
Russia-Sakhalin	-25.9	95.5	260.0	379.8	729.2	1026.7
Azerbaijan	22.2	155.6	256.8	511.3	1023.5	1312.7

Table 9.7

NPV @10%	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	10	9	9	7	51
Alaska PPT	5	5	5	8	8	8	39
Norway	6	9	8	10	10	10	53
UK	3	3	3	4	2	2	17
US GOM	1	1	1	1	1	1	6
Nigeria	2	2	2	2	4	4	16
Alberta-Oil Sands	4	4	4	3	3	3	21
Angola	7	6	6	6	5	6	36
Russia-Sakhalin	10	10	7	7	7	9	50
Azerbaijan	9	7	9	5	6	5	41

Table 9.8

NPV @10%	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	8	9	7	8	5	45	96
Alaska PPT	6	5	8	8	7	6	40	79
Norway	7	10	10	10	10	9	56	109
UK	3	2	2	2	2	2	13	30
US GOM	1	1	1	1	1	1	6	12
Nigeria	2	3	3	4	4	4	20	36
Alberta-Oil Sands	4	4	4	3	3	3	21	42
Angola	5	6	5	6	6	8	36	72
Russia-Sakhalin	10	9	6	9	9	10	53	103
Azerbaijan	9	7	7	5	5	7	40	81

9.4. EMV @10% rating

Tables 9.9 through 9.12 provide the analysis for the EMV@10%. Relative to Table 7.12, it can be seen how the EMV improved from 63 to 56. This indicates that the 25% tax rate resulting in a 25% loss carry forward credit plus the 20% investment credit rate, would be an unusual strong incentive to explore in Alaska.

Table 9.9

EMV @10%	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	-29.3	-2.7	-18.9	53.2	130.1	330.5
Alaska PPT	-5.9	19.2	16.3	72.8	167.4	334.7
Norway	-3.7	7.6	16.1	47.2	141.2	236.1
UK	-6.0	19.9	40.3	111.0	326.5	542.2
US GOM	-12.7	20.9	50.1	138.9	386.2	640.8
Nigeria	-17.8	8.6	32.3	100.6	289.3	482.1
Alberta-Oil Sands	-15.7	10.6	31.7	102.8	311.4	527.0
Angola	-40.4	-4.5	-4.9	68.7	221.6	326.0
Russia-Sakhalin	-90.1	-58.7	-36.2	31.4	139.2	195.7
Azerbaijan	-68.9	-31.2	-36.4	56.2	201.5	323.1

Table 9.10

EMV @10%	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	-3.1	23.5	31.8	103.9	209.9	410.3
Alaska PPT	12.3	35.7	49.2	105.0	219.5	385.9
Norway	6.8	18.2	36.4	67.6	173.0	267.9
UK	17.3	43.2	85.5	156.2	397.0	612.7
US GOM	20.0	53.6	109.7	198.5	477.5	732.1
Nigeria	9.1	33.1	75.8	140.9	347.0	538.6
Alberta-Oil Sands	8.8	34.7	76.2	147.1	378.2	593.0
Angola	0.9	21.6	53.1	103.9	228.5	274.6
Russia-Sakhalin	-56.9	-26.5	14.6	44.5	131.9	206.3
Azerbaijan	-30.8	2.6	27.9	91.5	219.5	291.8

Table 9.11
EMV @10%

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	7	7	8	8	10	6	46
Alaska PPT	2	3	5	5	7	5	27
Norway	1	6	6	9	8	9	39
UK	3	2	2	2	2	2	13
US GOM	4	1	1	1	1	1	9
Nigeria	6	5	3	4	4	4	26
Alberta-Oil Sands	5	4	4	3	3	3	22
Angola	8	8	7	6	5	7	41
Russia-Sakhalin	10	10	9	10	9	10	58
Azerbaijan	9	9	10	7	6	8	49

Table 9.12
EMV @10%

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	6	8	7	8	5	42	88
Alaska PPT	3	3	6	5	6	6	29	56
Norway	6	8	7	9	9	9	48	87
UK	2	2	2	2	2	2	12	25
US GOM	1	1	1	1	1	1	6	15
Nigeria	4	5	4	4	4	4	25	51
Alberta-Oil Sands	5	4	3	3	3	3	21	43
Angola	7	7	5	6	5	8	38	79
Russia-Sakhalin	10	10	10	10	10	10	60	118
Azerbaijan	9	9	9	8	7	7	49	98

9.5. Government Take rating

Tables 9.13 through 9.16 show the attractiveness of the government take to investors. In comparison with Table 7.16 the government take is actually more attractive in the rating despite the higher tax rate. The rating drops from 69 to 63. This is directly due to the fact that on the 50 MM barrel field the tax credits are very important and actually lower the government take.

Table 9.13
Gov Take

	50MM $26 high	50MM $36 high	150MM $26 high	150MM $36 high	500MM $26 high	500MM $36 high
Alaska Current	71.03%	56.57%	61.48%	54.67%	59.25%	56.37%
Alaska PPT	42.26%	47.64%	51.84%	55.92%	59.64%	60.36%
Norway	75.65%	76.74%	75.17%	76.33%	76.43%	76.97%
UK	51.25%	50.67%	50.50%	50.30%	50.15%	50.10%
US GOM	35.16%	35.13%	41.41%	40.40%	43.91%	43.27%
Nigeria	39.27%	46.92%	45.97%	49.82%	53.66%	54.74%
Alberta-Oil Sands	48.60%	49.53%	49.13%	49.70%	49.86%	49.98%
Angola	68.24%	50.31%	53.43%	58.26%	63.10%	71.29%
Russia-Sakhalin	82.36%	63.79%	54.26%	59.16%	72.42%	77.81%
Azerbaijan	65.76%	47.07%	44.81%	41.94%	51.62%	66.24%

Table 9.14
Gov Take

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low
Alaska Current	57.70%	53.13%	55.54%	52.52%	57.00%	55.23%
Alaska PPT	47.29%	50.29%	54.02%	56.78%	59.79%	60.43%
Norway	77.13%	77.47%	76.59%	77.09%	77.08%	77.38%
UK	50.90%	50.55%	50.41%	50.26%	50.14%	50.09%
US GOM	35.14%	35.12%	40.24%	39.76%	43.16%	42.79%
Nigeria	47.64%	50.58%	50.23%	51.99%	54.87%	55.47%
Alberta-Oil Sands	49.76%	49.98%	49.81%	49.97%	50.01%	50.10%
Angola	51.17%	60.31%	59.41%	63.53%	72.15%	80.94%
Russia-Sakhalin	70.12%	59.47%	58.68%	69.84%	78.00%	79.51%
Azerbaijan	50.60%	45.56%	42.90%	53.99%	64.20%	73.44%

Table 9.15
Gov Take

	50MM $26 high	50MM $36 high	150MM $26 hign	150MM $36 high	500MM $26 high	500MM $36 high	Subtotal
Alaska Current	8	8	9	6	7	5	**43**
Alaska PPT	3	4	6	7	6	6	**32**
Norway	9	10	10	10	10	9	**56**
UK	5	7	5	5	3	3	**28**
US GOM	1	1	1	1	1	1	**6**
Nigeria	2	2	3	4	5	4	**20**
Alberta-Oil Sands	4	5	4	3	2	2	**20**
Angola	7	6	7	8	8	8	**44**
Russia-Sakhalin	10	9	8	9	9	10	**55**
Azerbaijan	6	3	2	2	4	7	**24**

Table 9.16
Gov Take

	50MM $26 low	50MM $36 low	150MM $26 low	150MM $36 low	500MM $26 low	500MM $36 low	Subtotal	TOTAL for high and low
Alaska Current	8	7	7	5	5	4	36	72
Alaska PPT	2	4	6	7	6	6	31	63
Norway	10	10	10	10	9	8	57	115
UK	6	5	5	3	3	2	24	52
US GOM	1	1	1	1	1	1	6	12
Nigeria	3	6	4	4	4	5	26	46
Alberta-Oil Sands	4	3	3	2	2	3	17	37
Angola	7	9	9	8	8	10	51	95
Russia-Sakhalin	9	8	8	9	10	9	53	108
Azerbaijan	5	2	2	6	7	7	29	53

9.6. Overall rating

It can be seen in comparing with the tables in Chapter 7 that that the Alaska PPT with a 25% tax rate and 20% tax credit rate strongly boosts the IRR and the EMV@10%. The NPV@10% is less strongly affected but the Alaska PPT still provides an improvement. The Government Take also shows a slight improvement on small fields.

Table 9.17 provides the overall ranking. Relative to a 20/15 system the 25/20 system improves the competitiveness index improves from 272 to 244.

This indicates that the improvement in competitiveness of the Alaska PPT with a 25% tax rate and 20% tax credit rate is more attractive to new and small investors than the option to have a 20% tax rate and 15% tax credit rate.

Table 9.17
Overall

	IRR Subtotal	NPV Subtotal	EMV Subtotal	GOV TAKE Subtotal	SUM TOTAL	Ranking
Alaska Current	100	96	88	79	363	#8
Alaska PPT	46	79	56	63	244	#5
Norway	91	109	87	115	402	#9
UK	32	30	25	52	139	#2
US GOM	15	12	15	12	54	#1
Nigeria	46	36	51	46	179	#4
Alberta-Oil Sands	41	42	43	37	163	#3
Angola	76	72	79	95	322	#6
Russia-Sakhalin	116	103	118	108	445	#10
Azerbaijan	97	81	98	53	329	#7

The following table summarizes the total competitiveness index from attractive to unattractive for new investors in Alaska.

Table 9.18
COMPETITIVENESS INDEX

Hypothetical best	**48**	
US GOM	**54**	**#1**
UK	**139**	**#2**
Alberta-Oil Sands	**163**	**#3**
Nigeria	**179**	**#4**
Alaska PPT	**244**	**#5**
Angola	**322**	**#6**
Azerbaijan	**329**	**#7**
Alaska Current	**363**	**#8**
Norway	**402**	**#9**
Russia-Sakhalin	**445**	**#10**
Hypothetical worst	**480**	

9.7. Tide water analysis

9.7.1. New Investors

An important issue is whether the 25% tax rate and 20% tax credit rate would be a reasonable system from an overall word wide government take point of view.

In order to analyze this matter it is important to "filter out" the low net back value of the Alaska crude oil.

This can be done by taking the transport costs of $ 5 per barrel and converting this to an equivalent government take. At $ 40 per barrel there is really no difference between an extra 12.5% royalty on tide water or the lower net back. In other words it is possible to analyze Alaska by simply not deducting the $ 5 transport charge, but instead assuming that the royalty is 25%. Based on this high royalty, the overall government take can then easily be compared with other countries. In other words it is the same as placing the Alaska North Slope in Texas and assuming a 25% royalty.

The following table displays these "tide water" government takes for the high cost scenarios.

Table 9.19.
Undiscounted Government Take on "tide water" basis of the 25% tax and 20% tax credit system
High Cost Scenarios (with low and high well productivities)

	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
$22.00	65.57%	65.25%	68.32%	62.77%	63.59%	67.52%
$24.00	63.37%	64.95%	68.09%	61.60%	63.72%	67.41%
$26.00	62.01%	64.90%	67.94%	60.78%	63.90%	67.32%
$28.00	61.08%	64.92%	67.82%	60.18%	64.02%	67.26%
$30.00	60.40%	64.92%	67.73%	60.04%	64.14%	67.23%
$32.00	60.00%	64.94%	67.66%	60.11%	64.28%	67.21%
$34.00	59.92%	65.00%	67.59%	60.24%	64.42%	67.18%
$36.00	60.07%	65.07%	67.54%	60.38%	64.57%	67.16%
$38.00	60.31%	65.15%	67.48%	60.54%	64.72%	67.15%
$40.00	60.58%	65.26%	67.42%	60.72%	64.86%	67.13%

The table shows how the overall government take would range from about 60% to 67%. This is a world average government take. The table shows how the government take would be rather progressive with field size for a new investor. This is primarily due to the tax free allowance of $ 73 million and the tax credits. Otherwise the government take is relatively flat with price, because the progressive PPT compensates for the regressive royalties and property taxes.

A very important question is whether the Alaska resource base is sufficiently attractive to have a 60 – 67% government take. It is therefore interesting to search for jurisdictions with similar government takes. The Van Meurs Corporation rating of 2001 can be used in this respect. A search of this data base indicates that the following jurisdictions would have a government take in this range for approximately a $ 30 price level:

- Denmark
- Albania
- Azerbaijan, some onshore PSC's
- Newfoundland offshore
- British Columbia onshore
- Nova Scotia offshore
- Trinidad and Tobago
- Guatemala
- Peru
- Jordan
- Egypt Deep Water
- Nigeria, about 500 m water depth
- Cote d'Ivoire
- Cambodia
- Joint Development Area between Thailand and Malaysia
- Thailand offshore
- Nepal
- Bangladesh
- Timor Gap (joint offshore area between Australia and East Timor)

It would be difficult to argue that all or most of the above areas would have more attractive petroleum resource conditions than Alaska in terms of costs, oil field sizes or exploratory risk. In fact it can be easily seen that most areas would have less attractive resource conditions.

Therefore, Alaska would compete very well with these areas on the basis of a "tide water" government take of 60% - 67%.

In summary the overall Federal and Alaska government take that results from a PPT with a 25% tax rate, a 20% tax credit rate and a 73 million tax free allowance would clearly be attractive to new and small investors.

9.7.2. New Investors

The following table shows the same results for large producers which cannot benefit on an incremental basis from the tax free allowance.

Table 9.20.
Undiscounted Government Take on a "tide water" basis of the 25% tax and 20% tax credit system
High Cost Scenarios (with low and high well productivities)
Undiscounted Government Take

	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
$22.00	79.29%	74.47%	71.92%	74.41%	71.42%	70.47%
$24.00	76.39%	73.16%	71.19%	73.08%	70.79%	70.03%
$26.00	74.60%	72.23%	70.64%	72.15%	70.32%	69.69%
$28.00	73.37%	71.55%	70.22%	71.47%	69.95%	69.42%
$30.00	72.49%	71.02%	69.88%	70.94%	69.65%	69.20%
$32.00	71.81%	70.60%	69.61%	70.52%	69.40%	69.01%
$34.00	71.29%	70.25%	69.38%	70.18%	69.20%	68.85%
$36.00	70.86%	69.97%	69.19%	69.90%	69.03%	68.71%
$38.00	70.51%	69.73%	69.03%	69.67%	68.88%	68.59%
$40.00	70.22%	69.52%	68.88%	69.47%	68.75%	68.49%

As can be seen, the "tide water" government take would range from about 68% to 75%.

The following jurisdictions would be in this range:

- Albania onshore
- Turkmenistan
- Azerbaijan, some onshore PSC's
- Alberta Conventional Oil
- Newfoundland – Hibernia
- Venezuela Heavy Oil (prior to the recently imposed increased take)
- Trinidad and Tobago
- Egypt Onshore
- Egypt Gulf of Suez
- Syria

- Yemen, revised PSC terms
- Equatorial Guinea
- Cameroon
- Congo – offshore
- Namibia
- Nigeria – shallow water
- Indonesia – general frontier terms
- Vietnam
- China offshore
- Thailand onshore
- Myanmar
- India

Most of these jurisdictions would have a resource attractiveness that is less than Alaska. Therefore, Alaska seems very well competitive with these areas.

9.7.3. Conclusion

It can be concluded that the 25% tax rate and 20% credit rate would be competitive from an international point of view and the overall government take would be similar to countries that have an equal or lesser resource quality. Therefore this is a fair and reasonable system.

10. ANALYSIS OF POSSIBLE HEAVY OIL INCENTIVES

10.1. Introduction

Heavy oils and viscous medium gravity oils play an important role in the future of Alaska. These resources are relatively expensive and in some cases not economic.

The potential of these oils is very considerable. The following table displays the two broad types of heavy oils that are available on the North Slope.

Table 10.1

	"West Sak"	"Ugnu"
Gravity (API)	14 - 26	8 - 15
Viscosity	"Olive Oil"	"Molasses"
Oil in Place (billion bbls)	6 - 12	16-24
Recoverable	10% - 25%	4% - 8%
Recoverable Oil (billion bbls)	1 - 3	0.5 - 2
Current Fields	West Sak, Orion Polaris, Milne Schrader	none

For simplicity the heavy oils will be grouped as "West Sak" and "Ugnu". The West Sak group stands for a variety of heavy oils from different fields and reservoirs. Ugnu is largely from the Ugnu reservoir. The Ugnu reservoir is typically shallower than the West Sak Group of reservoirs.

In the Alaska Arctic shallow reservoirs are relatively cold, which in turn creates problems with viscosity. Therefore, in general, the shallower the reservoirs are, the more viscous the oil is and the more difficult the oil is to produce.

Apart from the heavy oils, there is relatively viscous medium gravity oil present in some fields, such as the Polaris field. Similar reservoirs will for simplicity called "Polaris" type crudes.

Heavy oils are difficult to produce because of their viscosity.

The importance of these resources to Alaska can not be under-estimated as can be seen from the large possible recoverable resource estimates. It is not impossible that over the next three decades as much as 4 billion barrels will be produced.

Because of the high costs to produce heavy oils and the large potential resource base on the North Slope it is important to evaluate whether special incentives relative to the terms proposed in Chapter 9 might result in an accelerated development.

Therefore, special incentives were analyzed in terms of lower tax rates and/or lower tax credit rates.

The special incentives were analyzed separately for "West Sak" and "Ugnu" reservoirs.

10.2. Net back value

An important reason why heavy oils are less attractive to produce is because these crude oils sell for a lower price in the market.

Some of the Kern River heavy crude oils of California have a gravity of 14 degrees API. Currently, these crude oils sell at about $ 10 to $ 12 less than WTI crude.

It should be noted, however, that this quality differential is sensitive to the oil prices. Typically, when the WTI price goes down the quality differential becomes less. Heavy oils produce large volumes of heavy fuel oil or so-called bunker fuel. This is fuel used for marine transportation, for heating in industrial processes as well as power generation. At low oil prices, heavy fuel oil becomes more competitive with other energy sources, such as coal and gas. This reduces the quality differential. It is difficult to make exact estimates of this.

However, the following table illustrates the assumptions that were made about the quality plus transport differential differentials between WTI and the well head values at the North Slope for heavy oils.

The average gravity for West Sak was assumed to be 19 degrees API and for Ugnu it was assumed 14 degrees API.

Table 10.2
WELL HEAD VALUES

WTI	West Sak Diff	West Sak Well head	Ugnu Diff	Ugnu Well head
$20.00	$9.00	**$11.00**	$10.00	**$10.00**
$25.00	$9.00	**$16.00**	$11.00	**$14.00**
$30.00	$10.00	**$20.00**	$12.00	**$18.00**
$35.00	$10.00	**$25.00**	$12.00	**$23.00**
$40.00	$10.00	**$30.00**	$13.00	**$27.00**
$45.00	$11.00	**$34.00**	$13.00	**$32.00**
$50.00	$11.00	**$39.00**	$13.00	**$37.00**
$55.00	$11.00	**$44.00**	$14.00	**$41.00**
$60.00	$12.00	**$48.00**	$14.00	**$46.00**
$65.00	$12.00	**$53.00**	$15.00	**$50.00**
$70.00	$12.00	**$58.00**	$15.00	**$55.00**
$75.00	$12.00	**$63.00**	$15.00	**$60.00**

10.3. Field and cost assumptions

In order to do economic analysis certain assumptions were made about the fields and the costs.

A 100 million barrel field was assumed, which would be developed with an equal number of water injectors and producers. The wells would be horizontal multilateral wells. At initial maximum production the the number of producers was assumed to be 17 for West Sak and 34 for Ugnu. The total number of wells was assumed to be 32 and 64.

A relatively aggressive production and abandonment program was assumed with a total field life of 23 years.

Each producers and injector was assumed to be $ 5 million. In addition facilities costs were assumed. This brings the total capital expenditure costs to $ 8 per barrel for West Sak and $ 12 per barrel for Ugnu.

The following table provides the overview of these assumptions.

Table 10.3
Technical and Economic Assumptions

	West Sak	Ugnu
Field size (million barrels)	100	100
Maximum production (bopd)	16,500	16,500
Producers at maximum production	17	34
Injectors at maximum production	17	34
Maximum producers	32	64
Maximum injectors	32	64
Total wells at abandonment	30	60
Duration of production (years)	23	23
Costs per producer and injector ($ million)	5	5
Exploration ($ million)	30	30
Total well costs ($ million)	320	640
Total facilities costs ($ million)	450	530
Total Capex per barrel	8	12
Total Opex per barrel	6	7

Based on all these data it is possible to calculate WTI break even prices for the various North Slope crude oils. For information a typical Prudhoe Bay and Polaris were also included. Quality differentials were based on the above table on the basis of $ 40 per barrel WTI for simplicity.

Table 10.4 shows these break even prices for new investments with respect to four different types of crudes on the North Slope.

Table 10.4
BREAK EVEN WTI PRICE

	Prudhoe Bay	"Polaris"	"West Sak"	"Ugnu"
API		23	19	14
WTI quality diff	$2.00	$3.00	$5.00	$8.00
Transport	$5.00	$5.00	$5.00	$5.00
Capital Costs	$4.00	$6.00	$8.00	$12.00
Operating Costs	$3.00	$4.00	$6.00	$7.00
Subtotal	$14.00	$18.00	$24.00	$32.00
Property tax	$0.50	$0.50	$0.50	$0.50
Royalty (12.5%)	$16.57	$21.14	$28.00	$37.14

These break even prices show that the economics of the Polaris, West Sak and Ugnu type crudes is primarily determined by the oil price projections and cost assumptions.

If long term oil price projections of the major and large oil companies shift upwards and further technological developments shift the costs downward than heavy oils of the West Sak and even Ugnu types may come in economic range.

The economics are only modestly affected by fiscal terms. No matter what fiscal incentives are provided, under current conditions of typical long term price forecasts Ugnu developments are uneconomic.

To a lesser degree the same is true for West Sak. With respect to "West Sak" much, however, depends on the detailed circumstances.

The developments of Polaris, Orion and Milne Schrader are economic under current conditions, as is evidenced by the investments that are being made in these fields by the major oil companies. It should be noted that these developments are typically taking place in deeper and therefore "warmer" reservoirs which are less viscous. Also the crude oils are lighter than for the West Sake economics to be discussed below.

An important aspect is that the current field developments are taking place in areas where oil production is already taking place and where therefore facilities costs are less because existing facilities can be used. All that is required is some upgrades of these facilities.

However, it is important to stimulate small possible independent developments outside the area which is currently controlled by the major oil companies. Therefore, the West Sak and Ugnu economics will be studied on the basis that new facilities will be required.

10.4. Fiscal incentives

In principle, fiscal incentives could be provided by offering a lower tax rate and higher tax credit rate for heavy oils.

The economic analysis of heavy oil economics is based on large producer economics, which means without taking into account the $ 73 million tax free allowance.

In order to evaluate fiscal incentives two different alternative fiscal packages were evaluated:

- a 20% tax rate with a 25% tax credit, and
- a 15% tax rate with a 25% tax credit.

It should be noted that under the Current System, the ELF would be essentially 0. This is due to the small field size. Despite the relatively attractive well productivities at maximum production, the small field size creates a very high exponent which brings the ELF to near 0.

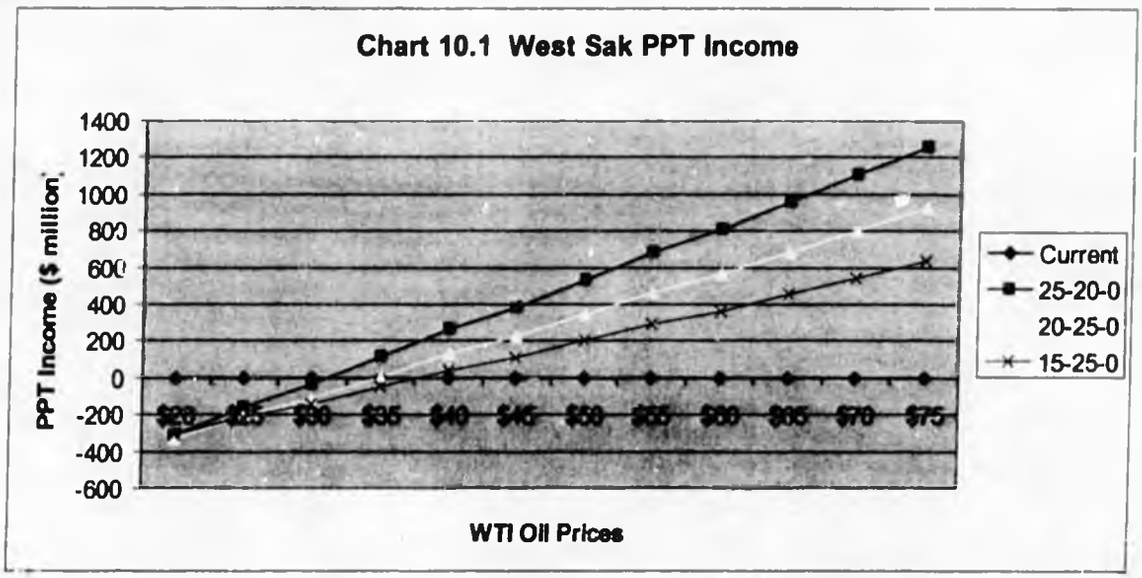
10.5. West Sak economics

Chart 10.1 indicates how the PPT would vary considerably with the fiscal terms.

At a WTI of $ 20, the project would run a severe loss and therefore the investor would be able to recover 45% of this loss under the systems with a 25% tax rate and 20% tax credit rate or 20% tax rate and a 25% tax credit rate.

With a 15% tax and a 25% tax credit, the recovery would be 40%.

The results of the loss carry forward credits and the tax credits is that the PPT would be negative. For the three fiscal systems it would be about $ 300 million negative. This means that the investor can trade his tax credits to other producers. It should be noted that under such low prices, all producers will have a negative PPT and therefore the tax credits can not be taken against PPT payable. In Chapter 11 the DOR results will be presented which illustrate that the PPT credits are really capped by this mechanism.



Of course, under such low prices, investors would not invest further in heavy oil and therefore, it is unlikely that many fields would create such a loss. Only fields for which the development was started under much higher long term oil price predictions would be caught in this situation.

All three fiscal options provide therefore considerable downside price protection for heavy oil projects and will therefore be a significant stimulus for such developments. From an Alaska perspective, the 25/20 system would have a WTI cross over point of $ 32 per barrel. The other two fiscal options would have higher cross over points: the 20/25 system would have a $ 35 per barrel cross over and the 15/25 system a $ 38 cross over.

Under high prices, the government revenues are substantially more for the 25/20 options as can be expected. The 20/25 and 15/25 options do not seem to provide a reasonable balance between downside and upside from a government perspective. The downside price risk to government of being faced with a negative PPT is not adequately compensated by the upside benefits of a high PPT in case of high prices.

This matter can be studied in more detail in Chart 10.2, which displays the overall Alaska income (State and municipalities). This chart shows at about $ 23 per barrel the total government take from the project becomes negative. As explained before, this risk would only related to heavy oil projects that were started under high oil forecast but would then be faced with low prices.

The graph clearly shows that under downside conditions the State of Alaska would provide very considerable price support and therefore a significant reward to Alaska is also reasonable in case prices are high. Therefore the 25/20 system is the best. It provides strong downside risk protection for heavy oil projects, but at the same time rewards Alaska with significant revenues if prices are high.

Chart 10.3 shows how all fiscal options result in a very considerable improvement of the IRR for all price levels. This constitutes major support for heavy oil developments. Under the current system a nominal IRR of 15% would be obtained under a WTI price of $ 42 per barrel. Under any of the PPT proposals this price level shifts down to $ 37 per barrel.

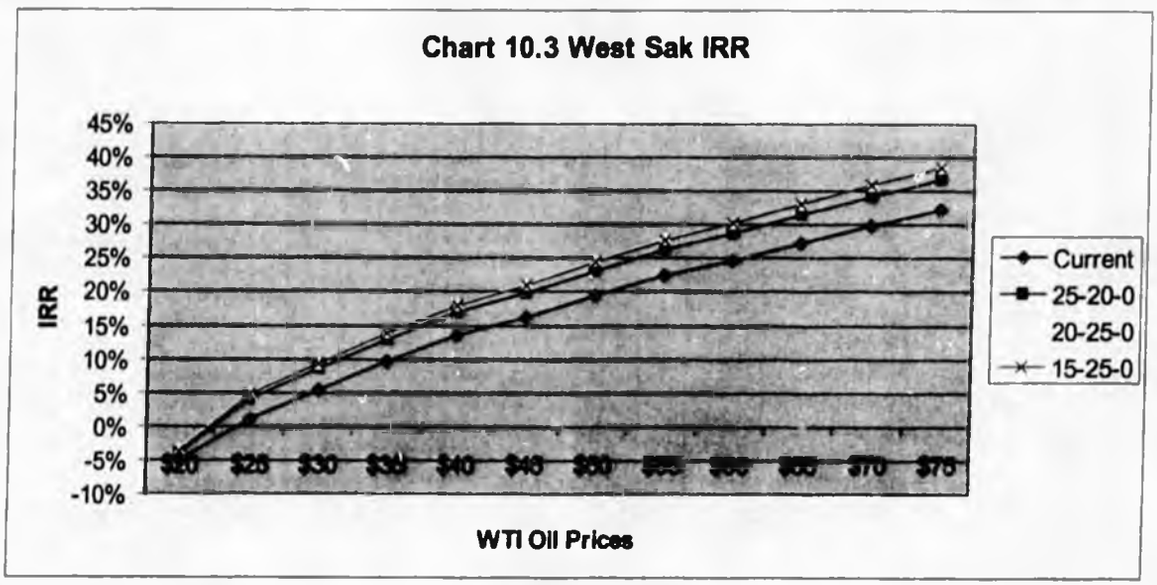
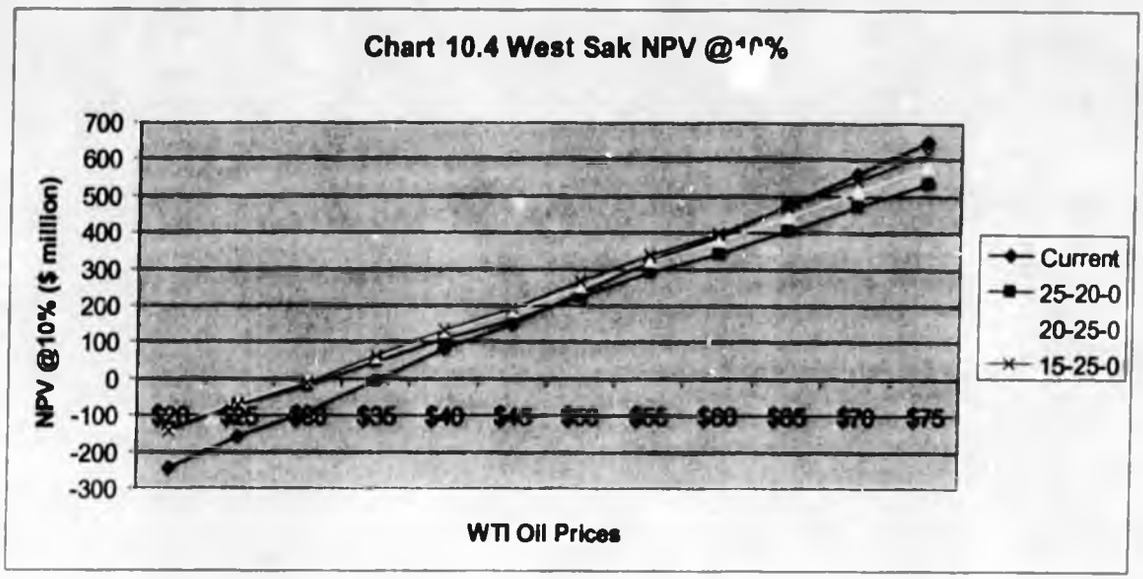


Chart 10.4 shows how the NPV@10% would also improve the economics of the heavy oil projects considerably in the current long term price forecast range of major and large oil companies of $ 25 to $ 35 per barrel. The break even point at an NPV@10% of zero is shifted down from $ 35 to $ 30 per barrel.



At about $ 50 per barrel the NPV@10% values are about the same for the Current system and the three PPT alternatives. At high prices the higher tax rate of 25% starts to "bite" and therefore the NPV becomes less for the 25/20 system. However, the total NPV is extremely attractive at these price levels and therefore the progressive nature of the 25/20 system does not affect in a serious negative way investment decisions.

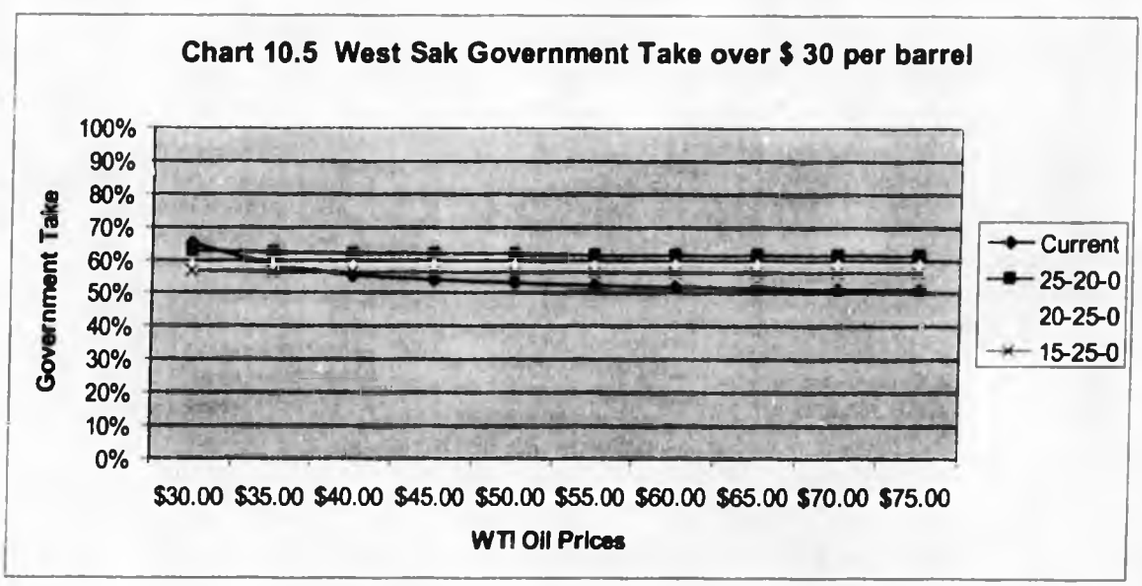


Chart 10.5 illustrates the overall combined government take of Alaska and the Federal Government. The progressive nature of the PPT turns the current regressive system of Alaska in a neutral system. The regressive royalties and property taxes are balanced by the progressive PPT. Therefore the PPT creates an overall flat government take over $ 30 per barrel. This is the price level at which the project has a positive NPV@10%.

Obviously, the 25/20 results in the highest government take and the 15/25 system in the lowest.

Conclusion. The fiscal proposal of a 25% tax rate and a 20% credit rate will provide a strong stimulus for heavy oil developments through the considerable downside price risk protection this system provides and the significant improvement in IRR and NPV@10% under current long term price projections. There is no need for further incentives. Such incentives would unreasonably lower the revenues of Alaska for no significant added benefit in economic stimulus.

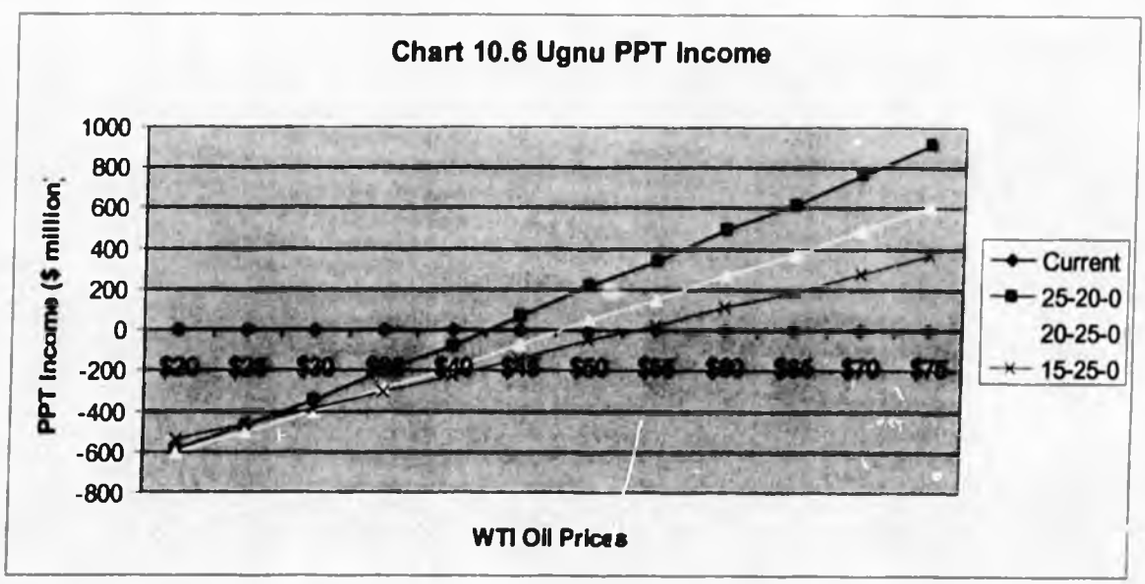
10.6. Ugnu economics

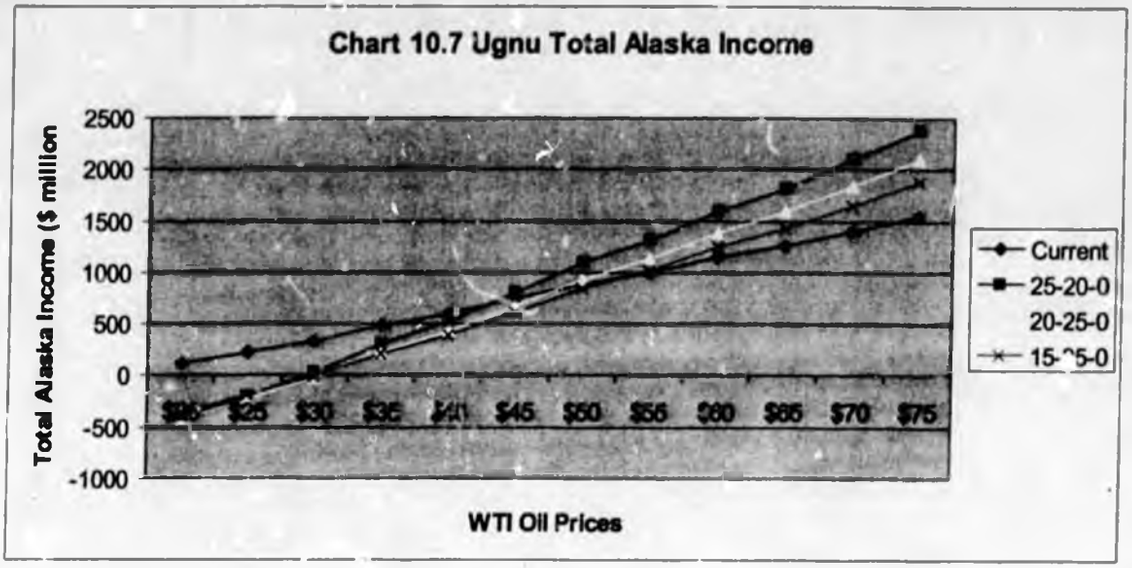
As was discussed earlier, the Ugnu reservoirs are currently uneconomic. In order to become economic perceptions of long term oil prices have to shift upward and further technology has to shift the development costs downward.

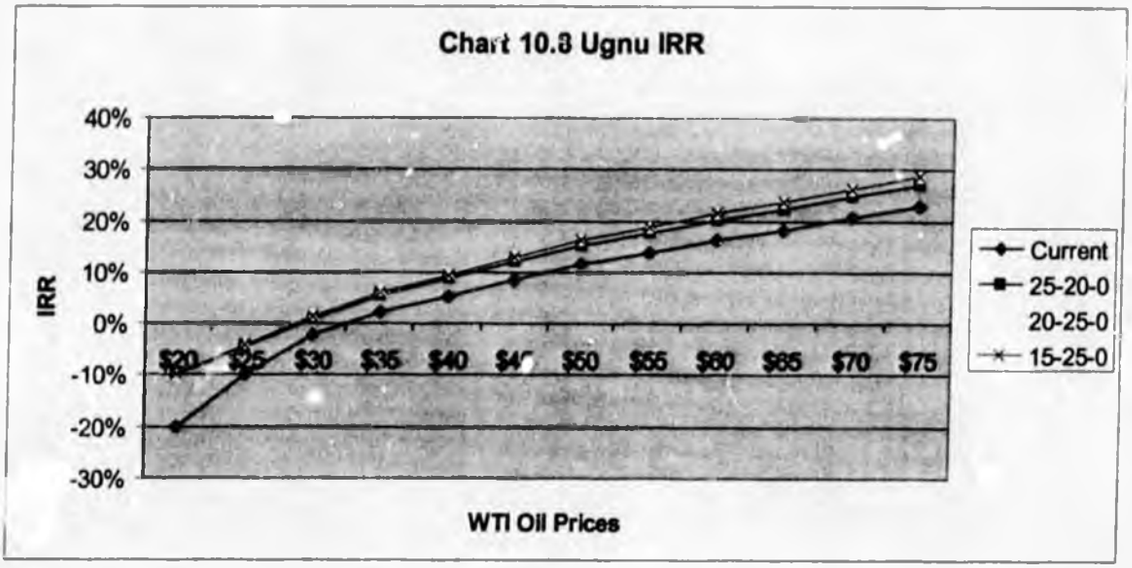
Therefore, the following economic analysis does not represent conditions that could occur today.

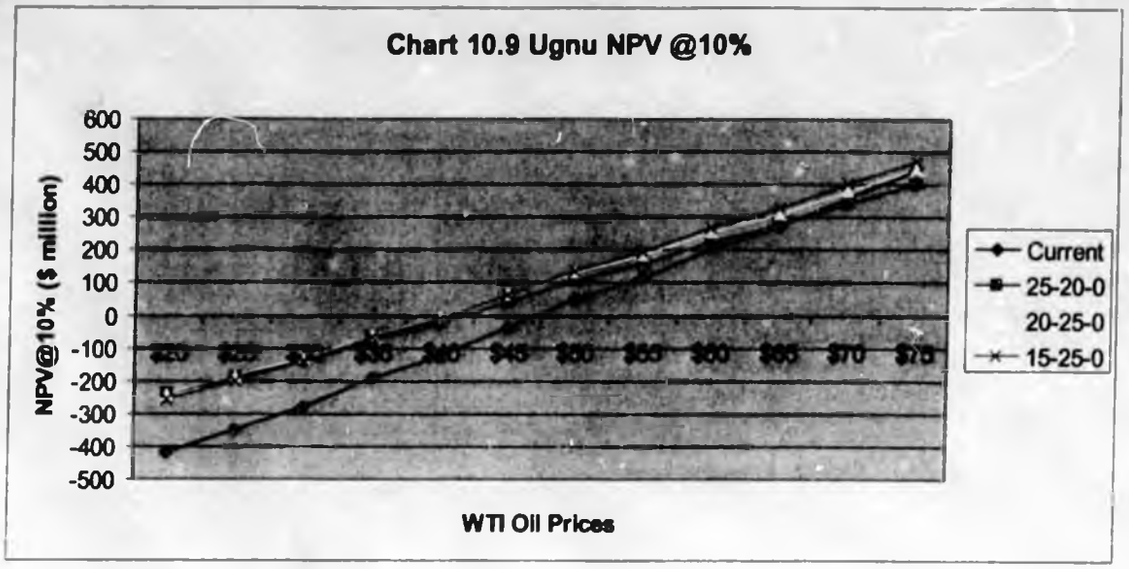
However, if in the future prices shift up and costs shift down, it would represent a case where despite these developments, the oil price would crash and the investor would incur significant cost overruns.

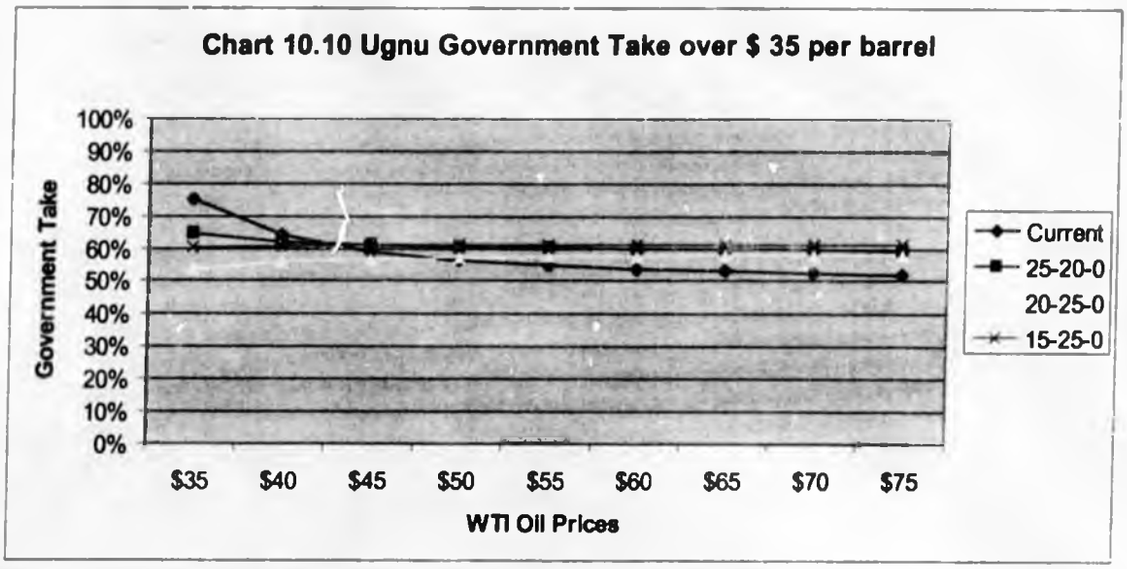
The following tables provide the overview of the economics.




Chart 10.7 Ugnu Total Alaska Income
Total Alaska Income ($ million
2500
2000
1500
1000
500
0
-500
-1000
$25
$30
$45
$50
$55
$70
$75
WTI Oil Prices
Current
25-20-0
20-25-0
15-^5-0


Chart 10.8 Ugnu IRR
IRR
40%
30%
20%
10%
0%
-10%
-20%
-30%
$20
$25
$30
$35
$40
$50
$55
$60
$65
$70
$75
WTI Oil Prices
Current
25-20-0
20-25-0
15-25-0





As can be seen from the above graphs, the results are very similar as the West Sak economics.

However, as can be expected the downside price protection is even stronger. The State would be rather exposed under low prices and cost overruns.

Despite the PPT, Ugnu developments remain clearly uneconomic and therefore such developments cannot be expected.

However, the PPT would bring the day closer that Ugnu developments may take place and it might also encourage the development of some small pilot projects in order to evaluate whether costs can be reduced with new technology.

Even more than for West Sak, the higher government take under the 25/20 system under high prices seems justified.

11. REVIEW OF THE RECOMMENDED PROFIT SHARING PRODUCTION TAX

11.1. Description of recommended profit sharing production tax

It may be useful to provide a review of the economics of the recommended profit sharing production tax ("PPT").

The PPT would have the following features:

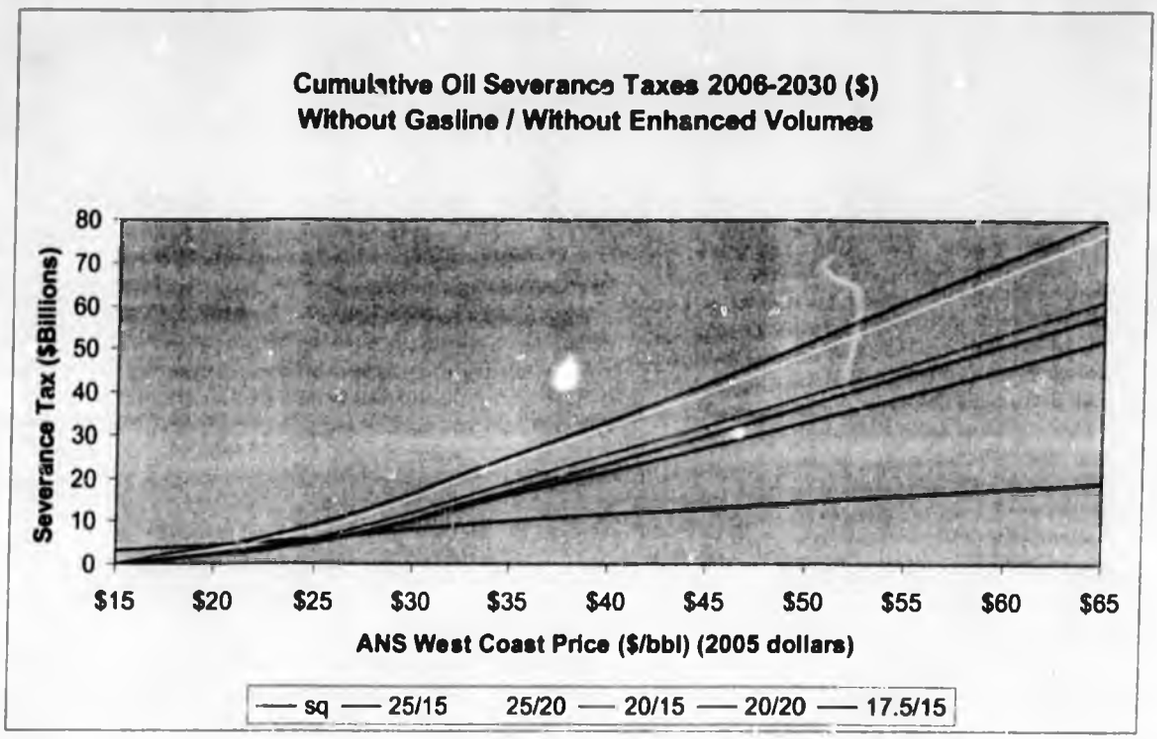
- The tax would be a monthly tax on net revenues. The net revenues will be determined as the gross revenues at the point of production less lease expenditures and exploration costs. Capital expenditures can be fully deducted in the year these costs are incurred.
- The PPT will be a consolidated tax on all net revenues of the corporation with respect to Alaska petroleum production and exploration.
- The tax rate will be 25%.
- Losses can be carried forward indefinitely, but the tax payer can obtain a certificate for a tax credit for 25% of the amount of the loss. Such certificates can be traded. This means that 25% of the loss can be recovered in the year following the year in which the expenditures were incurred.
- Furthermore, there will be a tax credit of 20% on all qualified capital expenditures. These are typically all expenditures which are capital for IRS purposes, intangible drilling expenditures and exploration expenditures, including geological and geophysical costs.
- Up to $ 73 million per year will be tax free. However, if the net revenues are less, the tax free amount is equal to the net revenues. This means that small producers will not pay tax.

11.2. Rationale for the selection of 25/20.

Various options were studied and selected. The selection of the 25% tax rate and 20% credit rate was largely based on the results of the DOR model, which indicated that the tax rate is the most important determinant of the Alaska government revenues. The tax credit rate is a lesser factor.

Following are some of the results of the study.

The following graph illustrates the cumulative revenues to the State from the production tax for a conservative scenario involving a remaining production of 5.8 billion barrels of oil for different price levels.



The graph illustrates how the 25/20 (25% tax and 20% tax credits) scenario generates considerably more revenues for the State than the 20/15 scenario. The tax credits play a relatively minor role in the reduction of the State revenues. It means that relative to the scenario of 20/15 which was the main focus of the earlier studies, the 25/20 scenario:

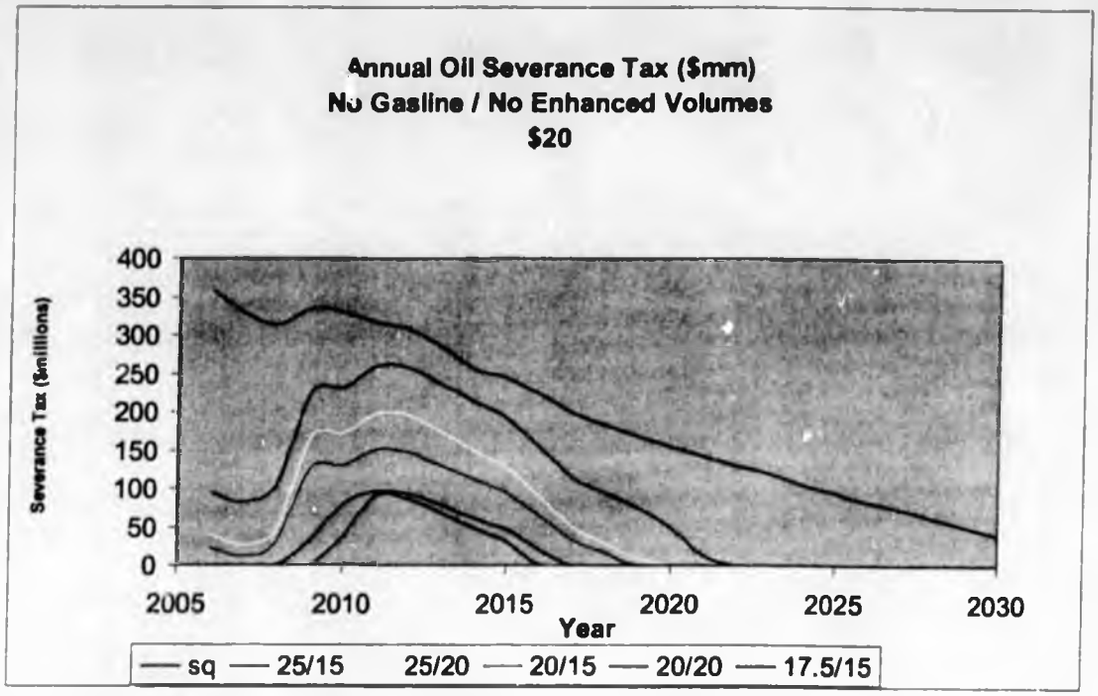
- Is a more progressive system
- Results in more revenues for the State
- Results in a stronger stimulus for re-investment
- Creates a better protection of marginal fields.

The stronger credits were a concern, since at low prices, it could lead to a more rapid erosion of the government revenues.

The following graph shows the year to year revenues under an ANS price of $ 20 per barrel.

The graph shows how for a tax rate of 25%, a tax credit of 20% compared to 15% indeed results in lower revenues. However, the entire revenues of Alaska would be very modest and therefore, even if extraordinary tax credits would occur as a result of major earlier investments, the exposure of the State to income loss is not more than a maximum of about $ 200 million per year around the year 2010. Compared with the billions that might result under high prices, this seems very much an acceptable exposure.

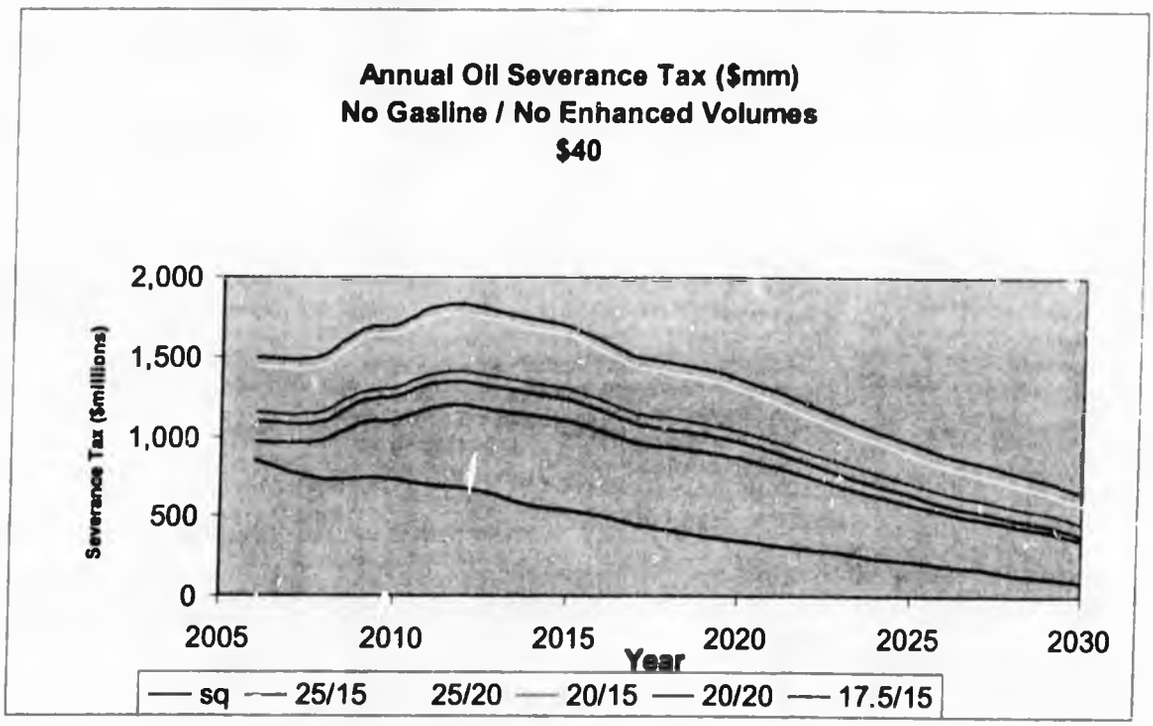
For this reason, the DOR study indicated that the income loss exposure as a result of higher than expected investment and low prices is modest. This resulted in the conclusion that a 25/20 combination is better for the State than the 20/15 combination.

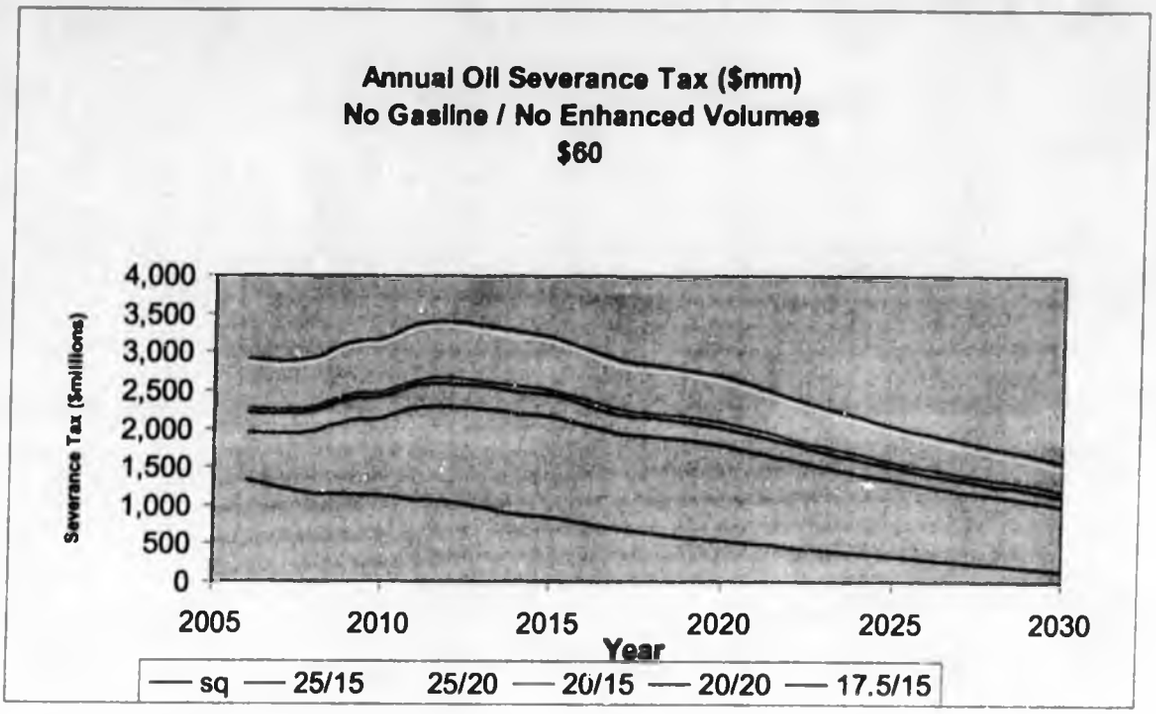


The "negative PPT's" which were identified in the previous chapters are really capped by the fact that the overall PPT will be low anyway under an ANS price of $ 20 per barrel and therefore these negative PPT cannot really be traded to a large extent under these conditions. Since PPT credits can only be taken against PPT payable this creates an automatic protection for Alaska.

Under low prices the royalties, property taxes and state corporate income tax remain unaffected.

Of course under high prices the income to the State of the new PPT is very considerable as can be seen from the following two graphs.





11.3. PPT income on new investments

11.3.1. Field size and price sensitivity

The following graphs show the PPT income for the 25-20-73 scenario and the 25-20-0 scenario. This means the 25% PPT with a 20% tax credit, with or without the $ 73 million tax free allowance. The scenario with the tax free allowance illustrates the economics of a first investor or small company. The scenario without the tax free allowance illustrates the economics of a large producing company.

Chart 11.1. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

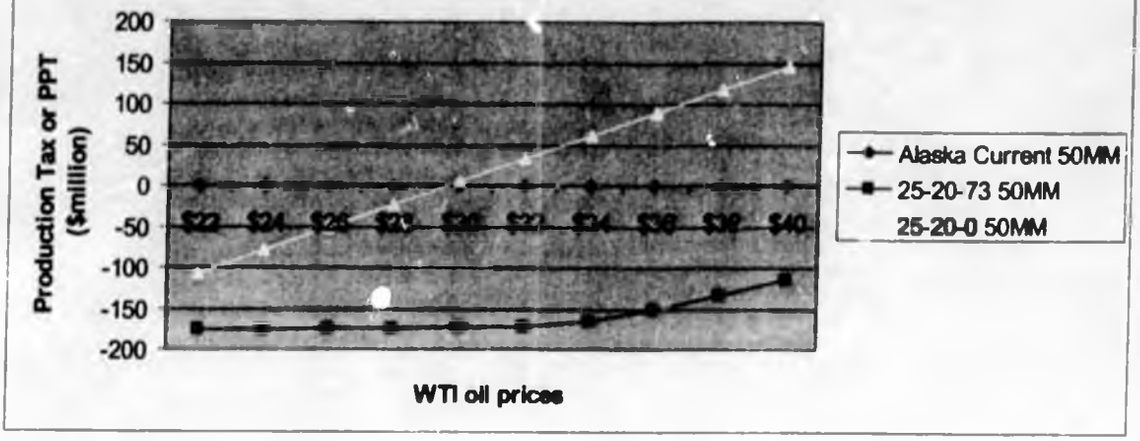
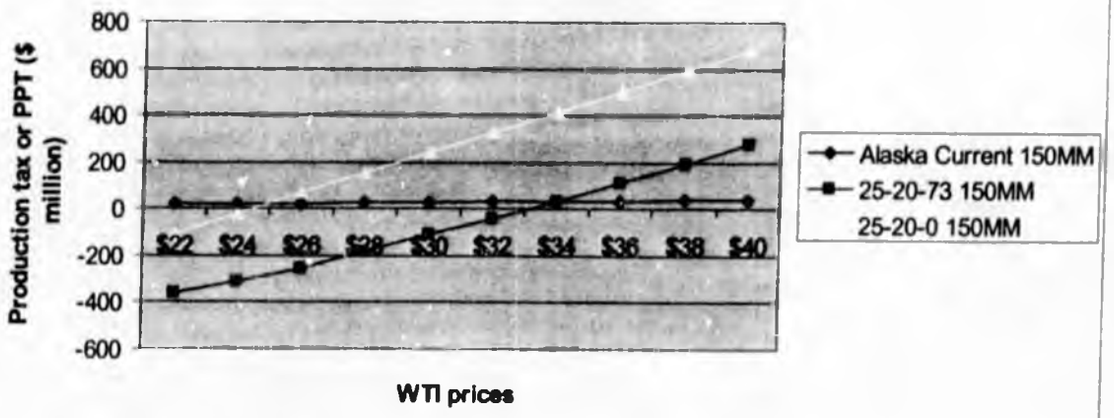
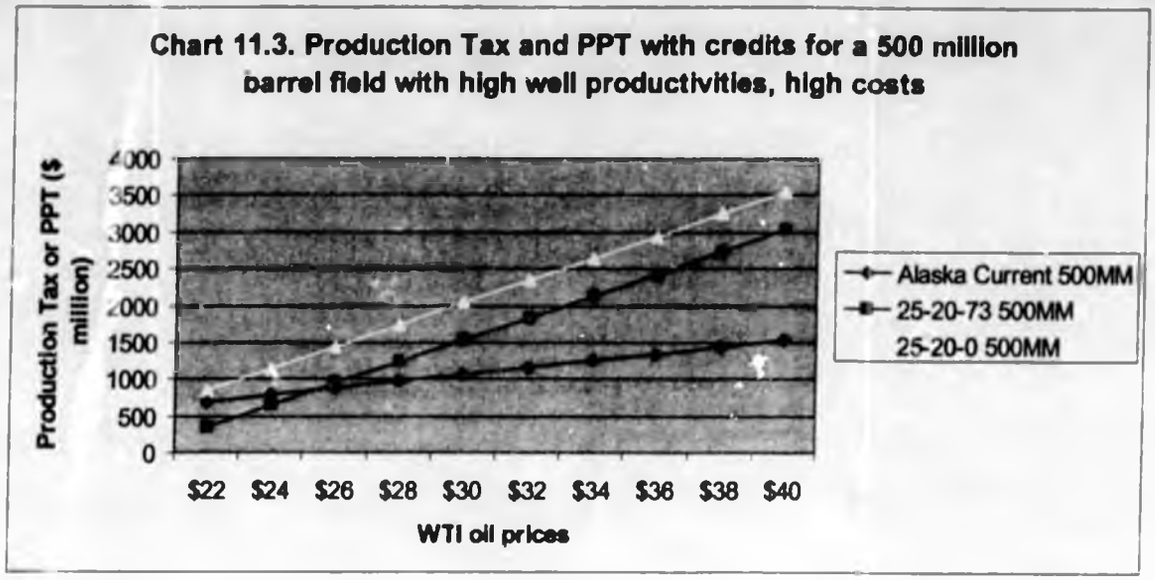


Chart 11.2. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, high costs





The results of the charts are very similar to charts 4.1 through 4.3.

For first investors there will be tax credits, but no tax on a 50 million barrel field. On the 150 million and 500 million fields first investors will pay tax over $ 34 and $ 26 per barrel respectively. Below these levels the undiscounted value of the tax credits will exceed the tax payable and a "negative PPT" is created. The degree to which these negative PPT's can be traded depends on the availability of buyers for these credits.

The current large producers will have a zero PPT on a high cost 50 million barrel field at a WTI price of about $ 30 per barrel. Below this price there is a negative PPT because of the significant tax credits. These credits can be used against the PPT payable. Above this price there is a positive PPT.

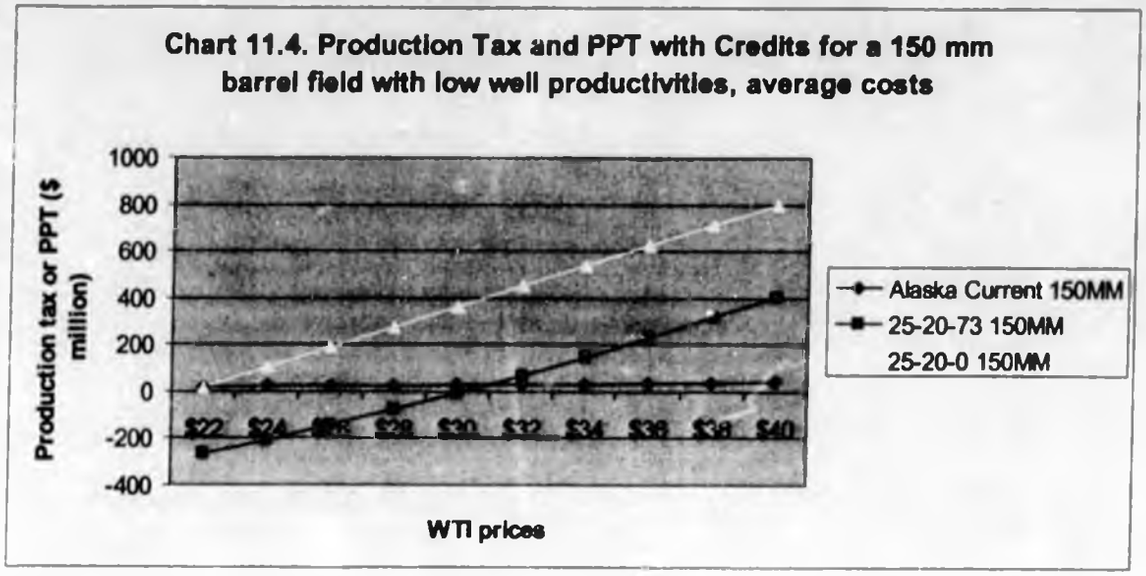
For larger fields which were assumed to be less costly per barrel, the break even price is less.

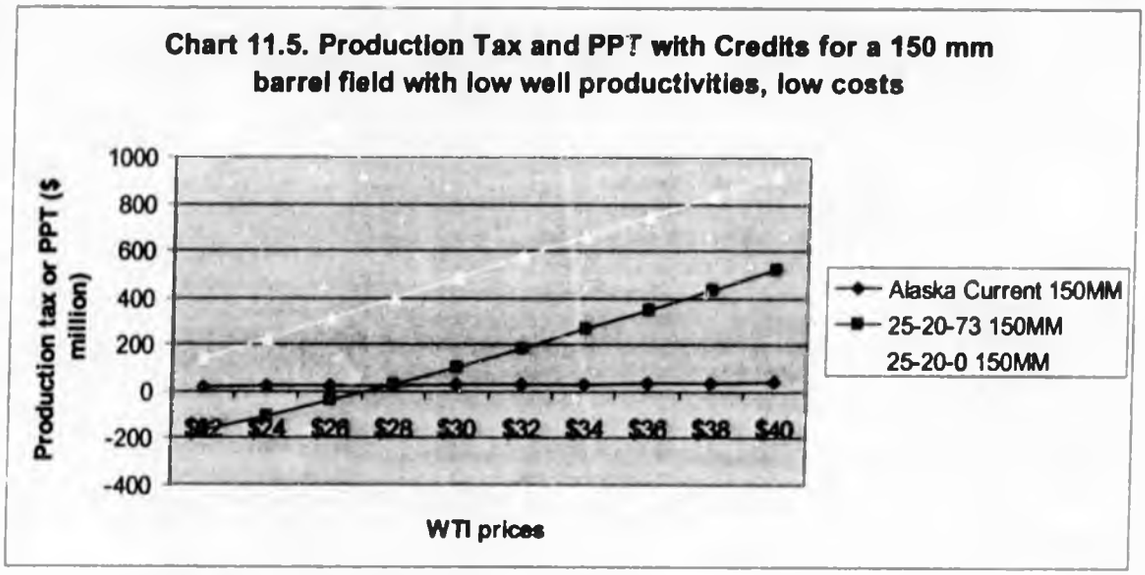
11.3.2. Cost sensitivity

The following two charts show the same 150 million barrel field, but with lower costs.

As can be easily seen the WTI break even point shifts to lower levels as a result. In other words, the effect of lower costs is:

- A lower WTI break even price
- A higher tax
- A lesser probability for "negative PPT" and a higher probability for "positive PPT".





11.3.3. Conclusion

As can be clearly seen from the information in this chapter so far, the PPT is primarily a tax on existing production in terms of additional revenues for the State under average or high prices.

With respect to production from fields as a result of new investments, the PPT modifies the overall corporate PPT payable either negative or positive. Under low prices and high costs, the PPT lowers the overall PPT payable, with a State wide "floor" of zero. Under high prices and low costs, the PPT increases the overall PPT payable.

11.4. Profitability of new investments

11.4.1. Profitability Indicators

The following graphs repeat the graphs shown in Chapter 4 for high cost conditions.

Charts 11.6, 11.9 and 11.12 show clearly that irrespective of field size, costs or prices, the PPT system improves the rate of return (IRR) of the investments considerably.

Charts 11.7, 11.10 and 11.13 show how the NPV@10% at low prices is always favorably affected by the PPT. At higher prices, the NPV is less attractive as a result of the higher tax rate, but the level of NPV is under these conditions very attractive in any case.

Charts 11.8, 11.11 and 11.14 show how the EMV@10% is more favorable over a wide low and average price range. This indicates that the PPT will stimulate exploration considerably.

Chart 11.6. IRR for 50 million barrel - low productivity case, high costs

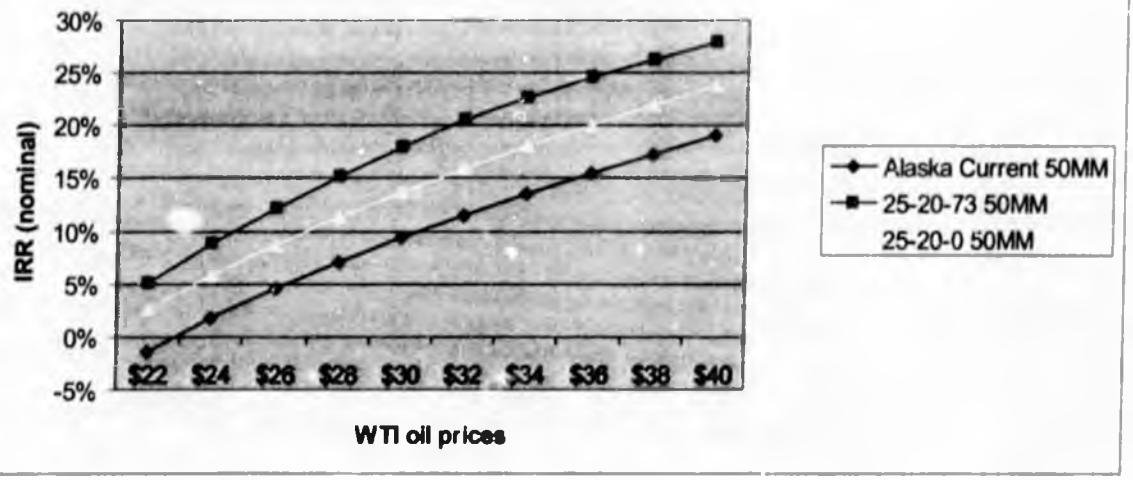


Chart 11.7. NPV @10% for a 50 million barrel field - low well productivity, high costs

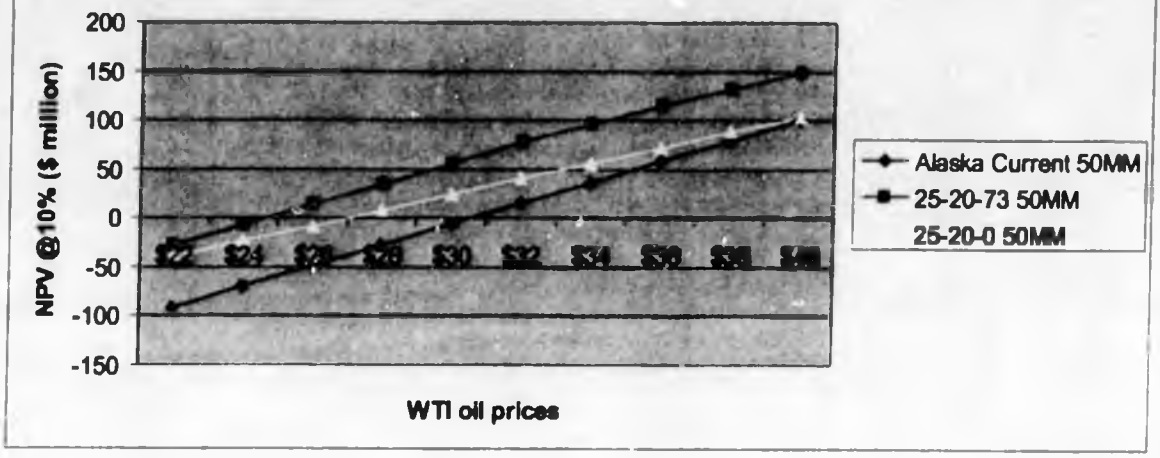


Chart 11.8. EMV @10% for a 50 million barrel field - low well productivity, high costs

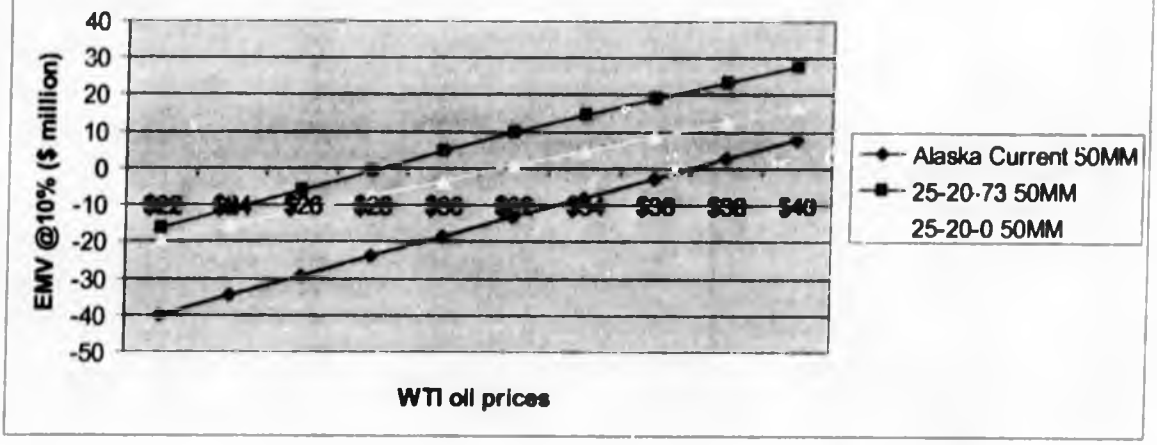


Chart 11.9. IRR for the 150 million barrel fields - low well productivity, high costs

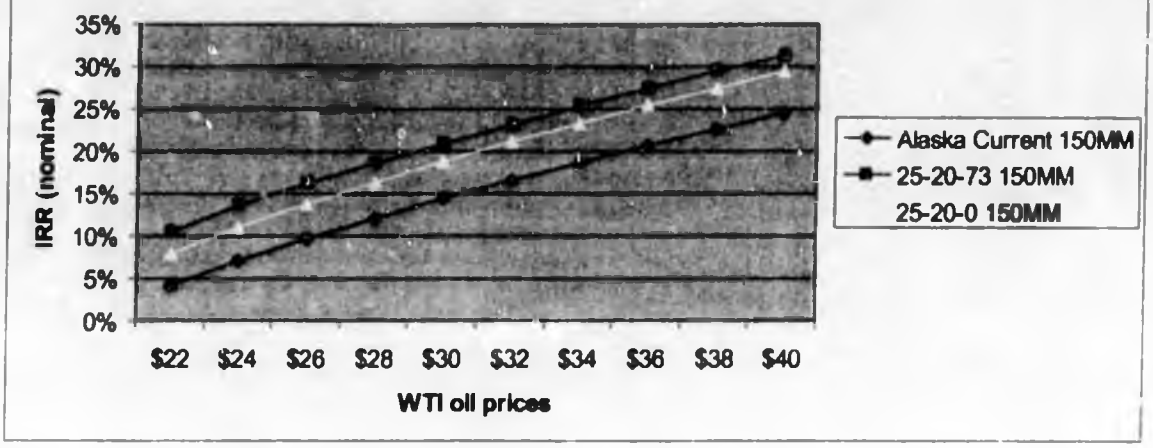


Chart 11.10 NPV @10% for a 150 million barrel field - low well productivity, high costs

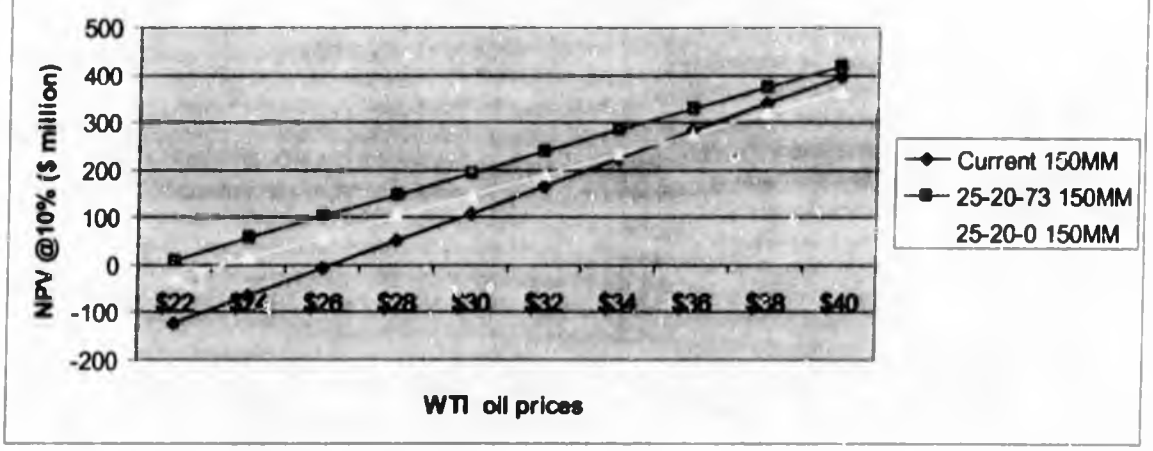


Chart 11.11. EMV @10% for a 150 million barrel field - low well productivities, high costs

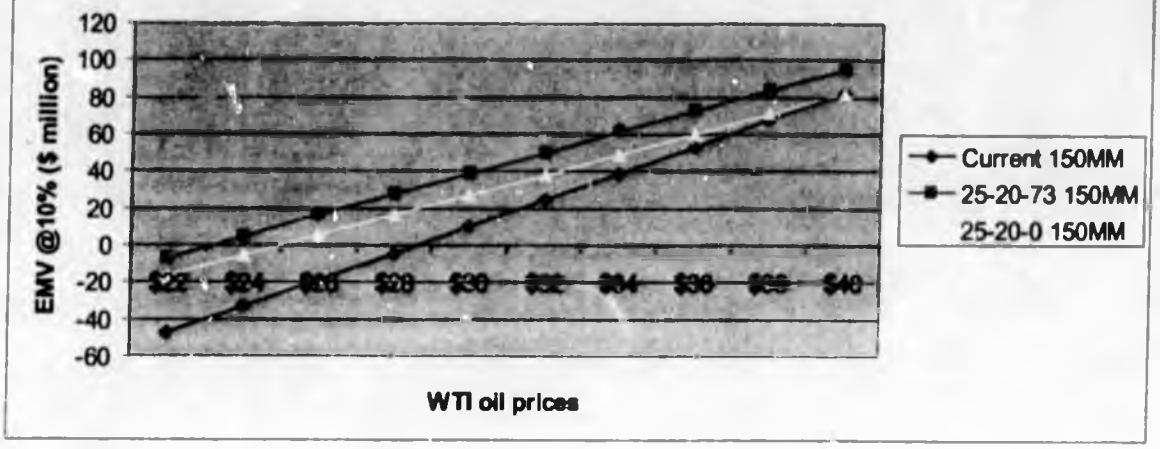
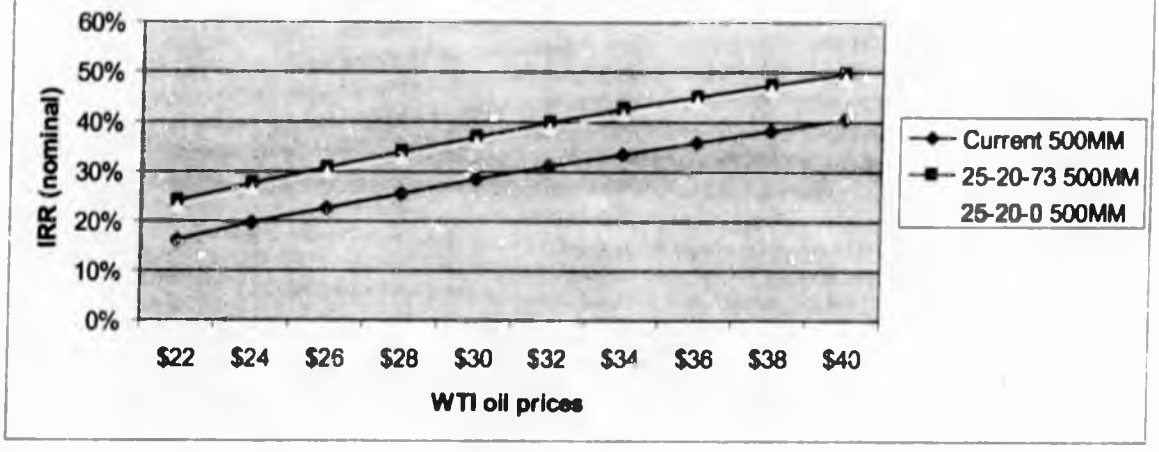
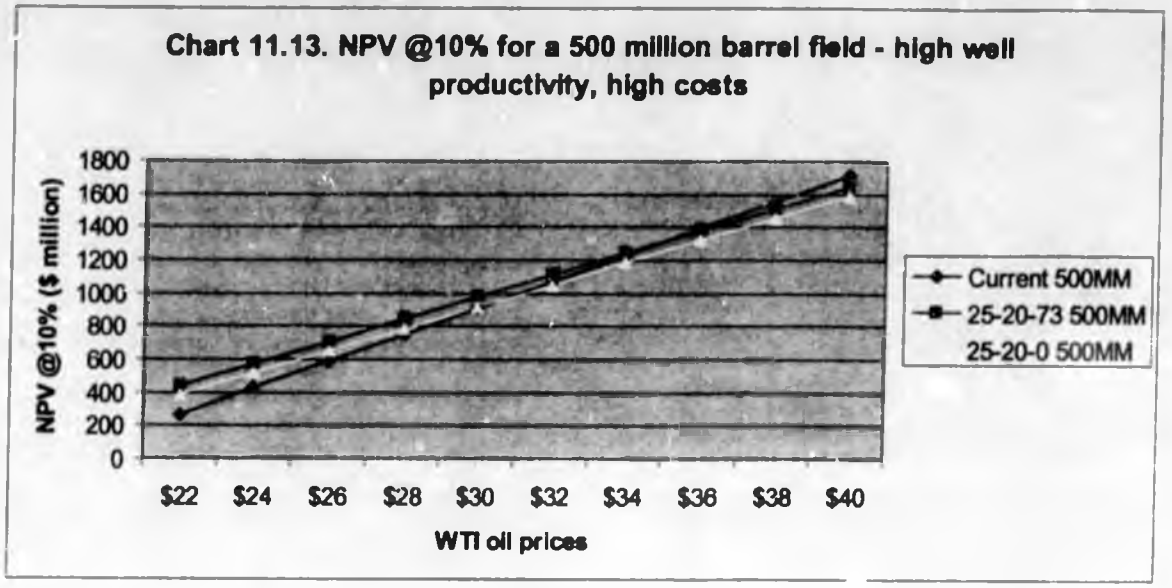
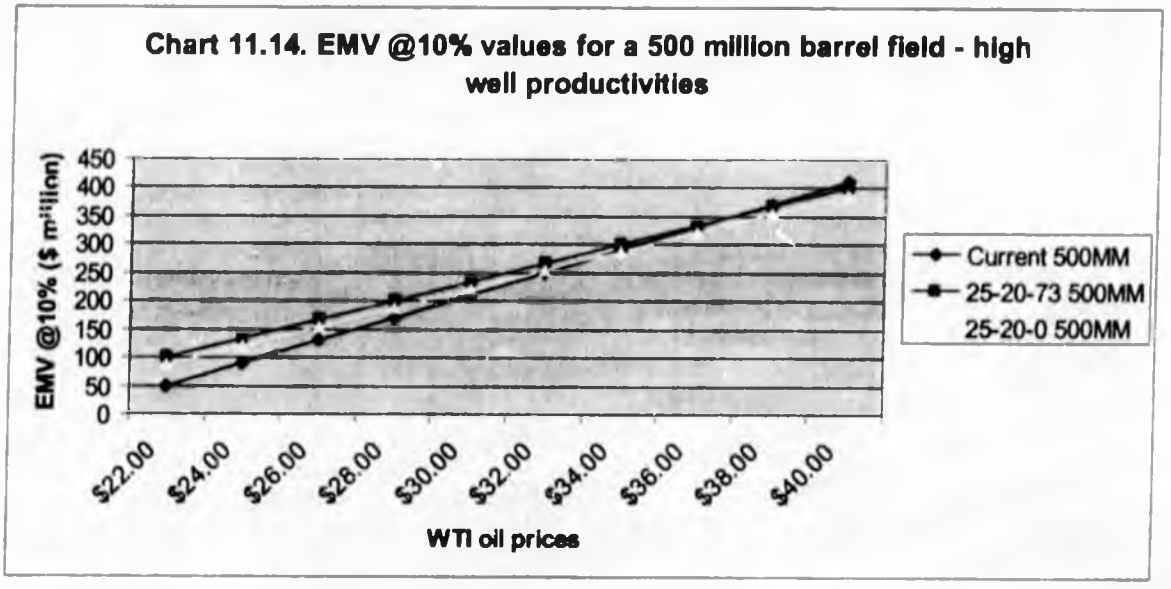


Chart 11.12. IRR of 500 million barrel - high productivity case, high costs







11.4.2. Government Take

The following three charts provide for the overall Federal and Alaska government take.

It can be seen how in all cases the current regressive system is converted to a neutral or even somewhat progressive system, whereby the regressive royalty and production tax are compensated by the progressive PPT.

The government take is typically less than the current system at low prices and for small and high cost fields and is more than the current system at high prices and low cost.

Chart 11.15. Overall Government Take for a 50 million barrel field with low well productivities

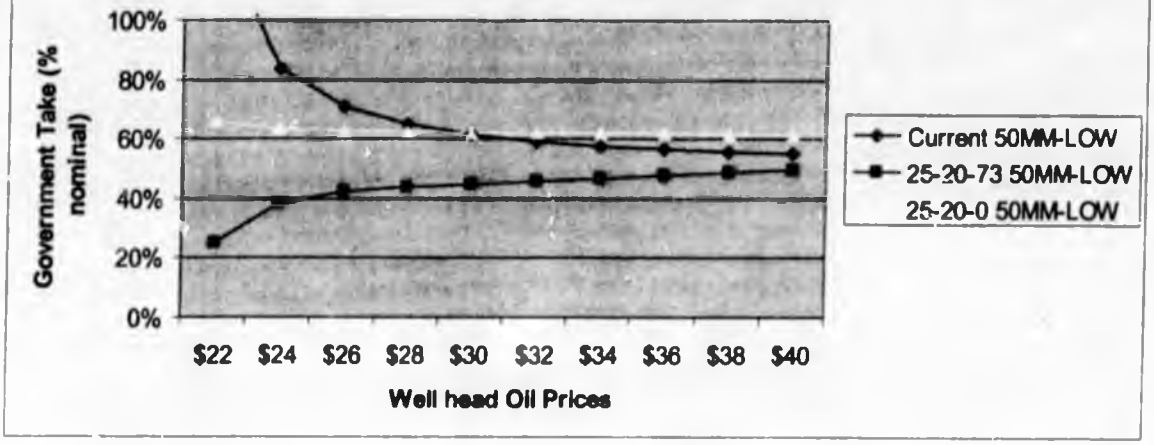
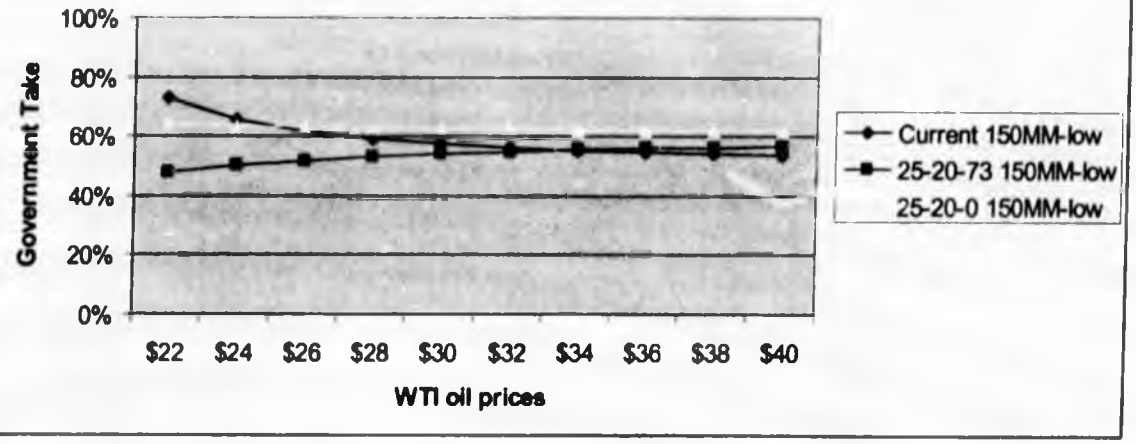
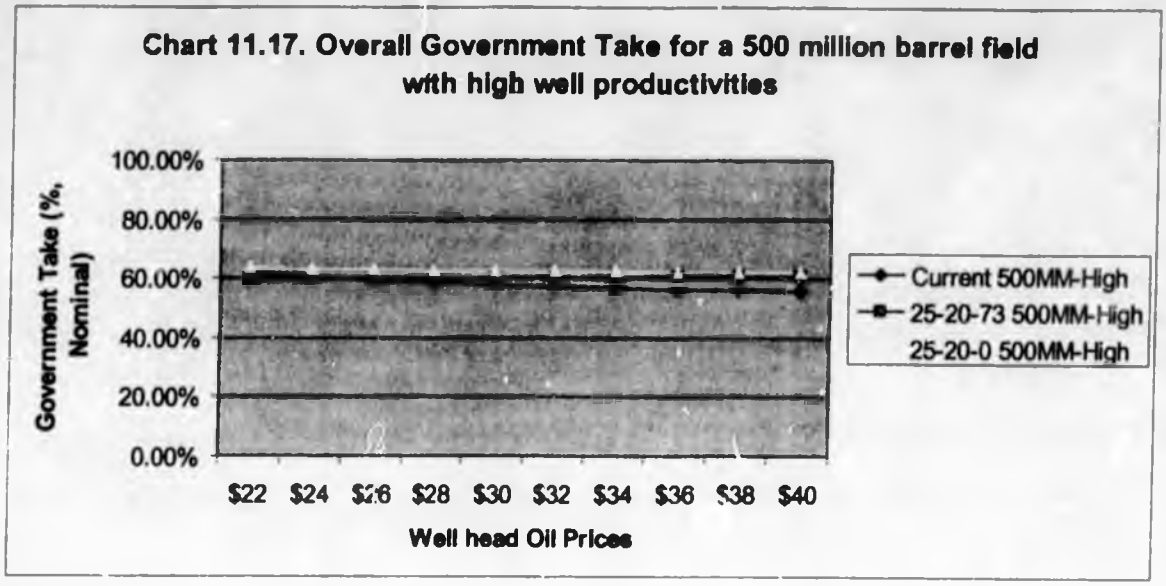


Chart 11.16. Overall government take for a 150 mm barrel field with low well productivities





11.4.3. Conclusion

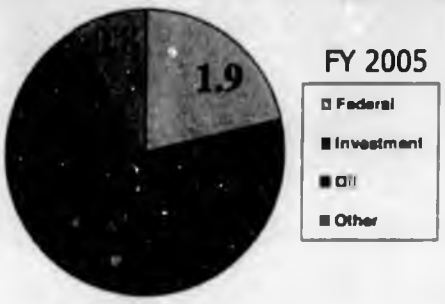
The recommended PPT system will strongly encourage new investment through a higher rate of return and a better overall project value at low or average prices. The system also strongly encourages exploration. The overall government take is either less or more depending on the price and cost conditions.

Proposed Production Tax

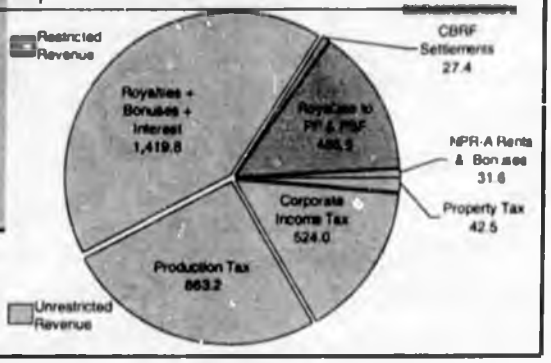
Alaska State Legislature
Senate & House of Representatives
Resources Committees

Dan E. Dickinson, CPA
February 22, 2006

Unrestricted & Restricted Revenue
$ 8.9 Billion



FY 2005 Petroleum Revenue
$ Million



Alaska Oil Production



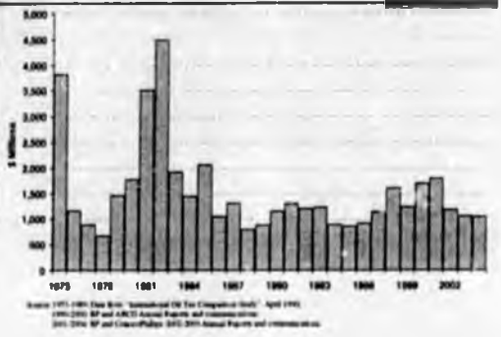
ANS West Coast Price & Oil Production



Status Quo Issues

- Revenues
- Investment
- Production
- Revenues

Capital Spending on ANS Wells, Field Facilities & Exploration



1. How the World Works (2005)

	Volume		$ Million
Destination Value at Market	330	$43.43	$14,332
Less Tankering & Pipelines	330	$ 4.51	($1,488)
Gross Value at Point of Production	330	$38.92	$12,844
Less Upstream Costs			
Operating:		$ 3.33	
Capital and Exploration:		$ 3.18	
Total	330	$ 6.52	($2,150)
Net Value at Point of Production	330	$32.40	$ 10,694

2. Current Production Tax

	$ Million
Gross Value at Point of Production	$12,843.60
Royalty Rate	0.875
Value Net of Royalty	$11,238.15
Tax Rate	0.15
ELF Rate	0.55
Tax (current)	$ 927.15

3. Proposed Production Tax (PPT)

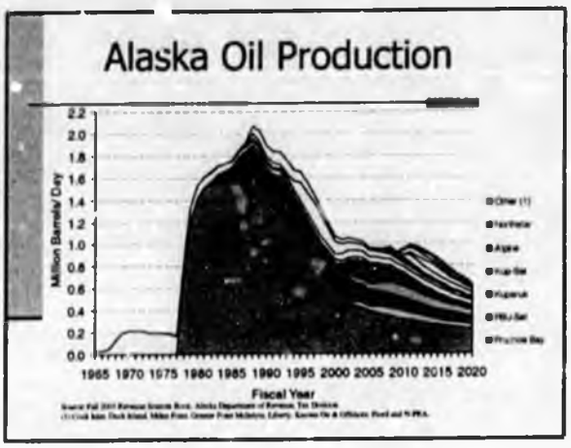
	$ Million
Value Net of Royalty	$11,238.2
Less Upstream Cost Deductions	($ 2,150.0)
Taxable Value at Point of Production	$ 9,088.2
	.20
Tax Prior to Credits	$ 1,817.6
Credits (1,050 * 2)	($210.0)
Proposed Production Tax	$ 1,607.6

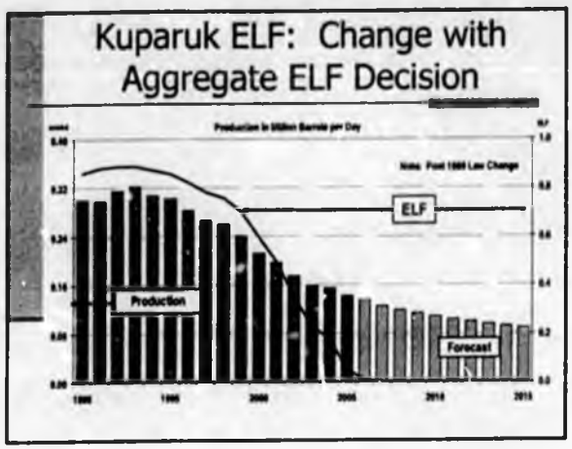
4. PPT with Investment

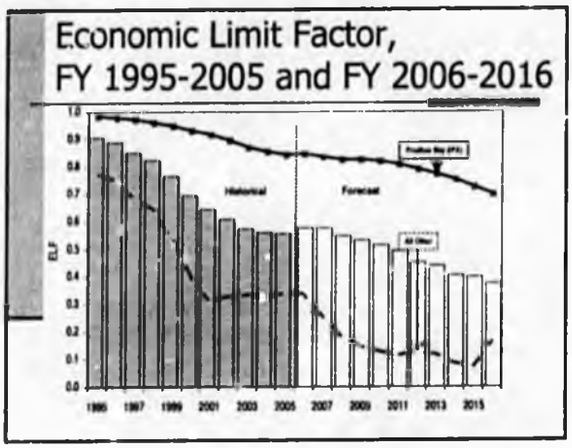
	$ in Billion
Production Tax Net of Royalty	$11,238.2
Less Upstream Cost Deductions	($ 3,850.0)
Taxable Value at Point of Production	$ 7,388.2
Times Tax Rate	.20
Tax Prior to Credits	$ 1,477.2
Credits (1,050+1,700)*.2	($550.0)
Proposed Production Tax	$ 927.6

5. Implicit Cost From Proxy

	$ in Billion
Production Tax Net of Royalty	$11,238.15
Less Implicit Costs from Proxy	($ 5,057.00)
	$ 6,181.00
Tax Rate	0.15
Same Production Tax	$ 927.15


Alaska Oil Production
Million Barrels/Day
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
1965 1970 1975 1980 1985 1990 1995 2000 2005 2010 2015 2020
Fiscal Year


Kuparuk ELF: Change with Aggregate ELF Decision
ELF
Production
Forecast


Economic Limit Factor,
FY 1995-2005 and FY 2006-2016
ELF
Historical
Forecast
1995 1997 1999 2001 2003 2005 2007 2009 2011 2013 2015

PPT REVENUE STUDIES

Presentation to
House & Senate Resources

Alaska Department of Revenue
Tax Division
February 23, 2006

1

OVERVIEW

- Description of tax
- Description of model
- Long-term cumulative revenues
- Annual revenues
- Corporate take

2

PPT

- Start with ***WELLHEAD VALUE*** (market value less transportation)
- Subtract ***UPSTREAM COSTS*** (capital, operating, royalties, property tax)
- Subtract additional **STANDARD ALLOWANCE** of $73 million
- This is ***TAXABLE INCOME***
- Multiply taxable income by ***TAX RATE***
- This is the ***TAX BEFORE CREDITS***
- Credits are capital costs multiplied by ***CREDIT RATE***
- This is subtracted from the tax before credits to yield the ***PPT PAID***

3

PPT Example

- 20 million barrels @ $50/bbl ANS West Coast = MARKET VALUE of $1,000 million
- $2/bbl shipping + $3/bbl TAPS = $5/bbl = $100 million
- WELLHEAD VALUE = $900 million
- UPSTREAM COST = Capital + Operating + Royalty + Property Tax = $300 million
- STANDARD ALLOWANCE of $73 million
- TAXABLE INCOME = $900 - $300 - $73 = $527 million
- If TAX RATE = 20%, TAX BEFORE CREDITS = 20% X $527 = $105 million
- If capital = $200 million and the CREDIT RATE = 20%, credit = $40 million
- PPT PAID = $105 - $40 = $65 million

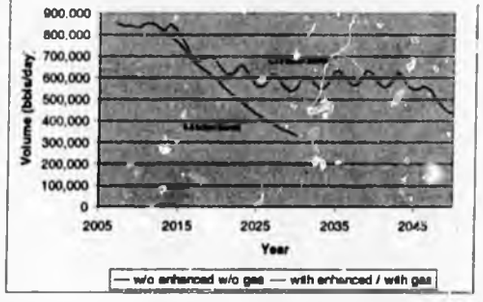
4

Volume Scenarios

- No enhanced volumes / No gasline
  - Totals 5.5 billion barrels through 2030
    - Including 0.8 billion barrels of heavy oil
      - No additional heavy oil at prices under $30
- Gasline and enhanced volumes
  - Totals 10.5 billion barrels through 2050
    - Includes additional 3.2 billion barrels conventional
      - 700 million barrels not stemming from gasline
    - Including additional 1.8 billion barrels heavy oil
      - No additional heavy oil at prices under $30

5

Figure 1
Volume Scenarios



6

Costs and Prices

- Costs
  - $100 mm/yr exploration through 2040
  - $1/bbl on-going capital on all barrels
  - $3.50/bbl developmental capital on 2/3 of existing conventional oil
  - $8/bbl developmental capital on 2/3 of existing heavy oil
  - $3.50/bbl developmental capital on new conventional oil
  - $8/bbl developmental capital on new heavy oil
  - $3/bbl operating costs on conventional oil
  - $5/bbl operating costs on heavy oil
- Costs and prices are real $2005 dollars
- Heavy oil discounted 8% for quality

7

Cumulative Revenues

- Without enhanced volumes / without gasline (through 2030)
- With enhanced volumes / with gasline (through 2050)
  - Does not include gasline severance taxes
  - Includes gasline costs

8

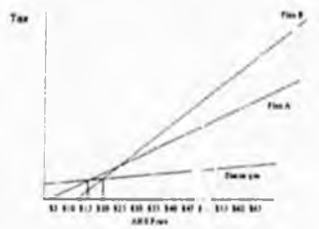
Figure 2A
Cumulative Oil Severance Taxes, 2007-2030
(Billions of 2006 Dollars)
Low Volume Scenario



Total revenues $2 billion less to $26 billion more than status quo

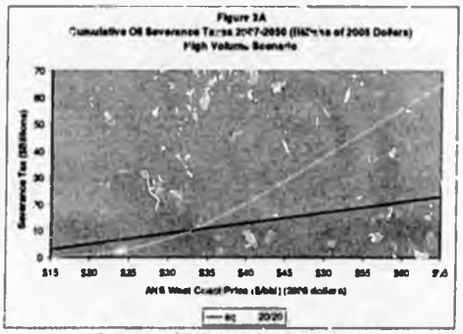
9

Figure 2B
Crossover Point and Slope



10

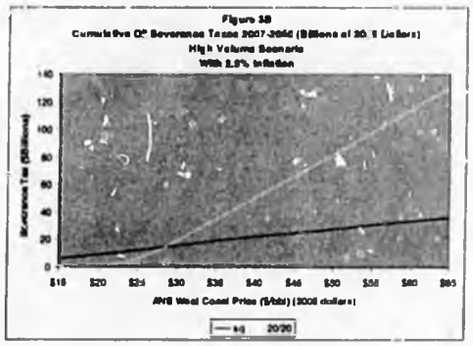
Figure 3A
Cumulative Oil Severance Taxes 2007-2050 (Billions of 2006 Dollars)
High Volume Scenario



Total revenues $3 billion less to $42 billion more than status quo

11

Figure 3B
Cumulative Oil Severance Taxes 2007-2050 (Billions of 2006 Dollars)
High Volume Scenario
With 2.5% Inflation

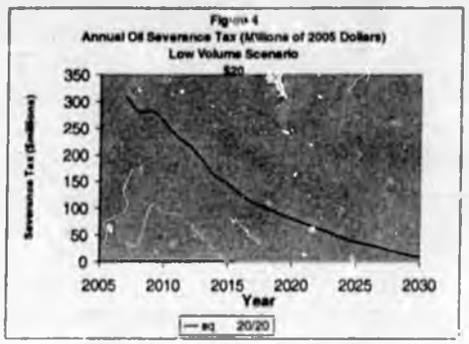


12

Annual Revenues

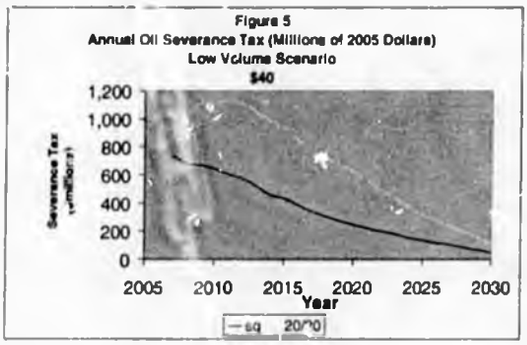
- Without enhanced volumes / without gasline (through 2030)
  - $20
  - $40
  - $60
- With gasline / with enhanced volumes (through 2050) (does not include gasline severance taxes; includes gasline costs)
  - $20
  - $40
  - $60

13



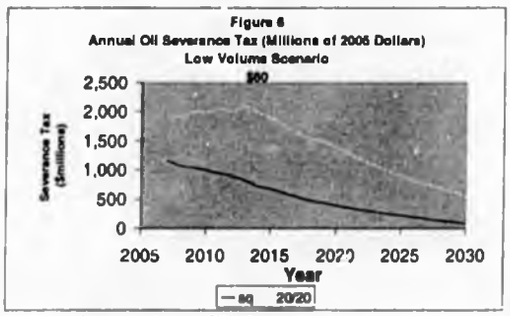
Average annual revenues $100 million less than status quo

14



Average annual revenues $330 million more than status quo

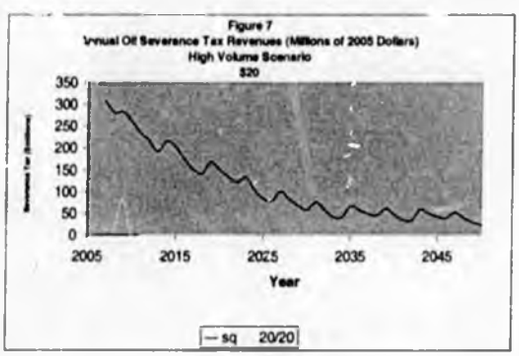
15



Average annual revenues $800 million more than status quo

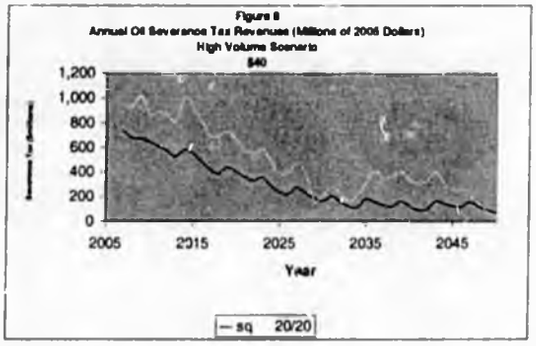
This is equivalent to total State Gasline revenues at a $4.70/mmbtu market price

16



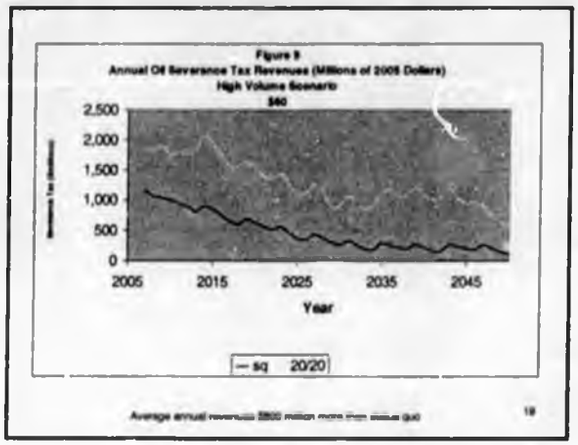
Average annual revenues $110 million less than status quo

17



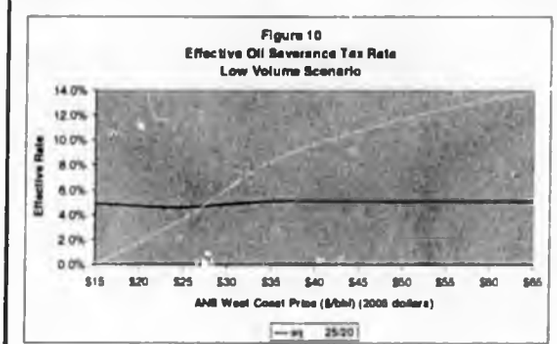
Average annual revenues $180 million more than status quo

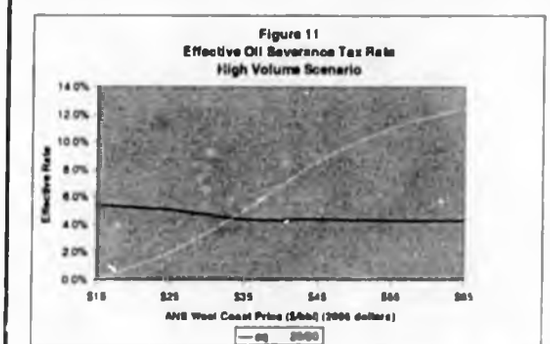
18



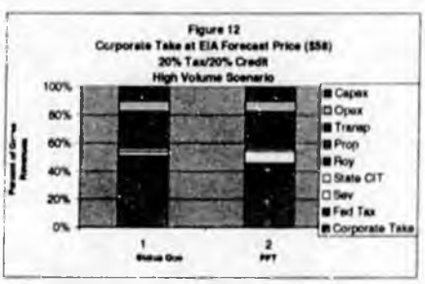
Effective Tax Rate

- Without enhanced volumes / without gasline
- With enhanced volumes / with gasline





Conclusion: Corporate Take



Corporate take goes from
33% to 30% of gross income
46% to 44% of economic rent

State take goes from
17% to 22% of gross income
25% to 32% of economic rent

Petroleum Profits Tax (PPT)

Overview

Alaska Department of Revenue
Before the Alaska State Legislature

Robynn J. Wilson

Problems with Current Production Tax

- No incentive in tax system to reinvest in Alaska
- Low take (internationally) at high prices, high take at low prices
- Maturing of North Slope leads to declines in tax revenue

Components of PPT

- Tax Base
- Rate
- Incentive Credits
- Base Allowance
- Transition Provision

Gross vs. Net

Current Tax on Gross	
Value at wellhead	$50.00
Times: tax rate	15%
Tax before ELF	$7.50

PPT on Net	
Value at wellhead	$50.00
Less:	
Lease op exps	(12.50)
Net taxable	$37.50
Times: tax rate	20%
Tax before credits	$7.50

Tax Base

Gross value at point of production

Less: Lease expenditures
- operating costs
- capital expenditures
- allowance for overhead

Non-deductible expenses

- Depreciation
- Royalty payments
- Taxes based on net income
- Interest & financing charges
- Lease acquisition costs
- Other costs

Determining value under current system

West coast value

$



2/22/06 7

Gross Value under PPT

Producer can elect to use:

- . oyalty value
- DOR formula that estimates a value at a specific location such as point of delivery into a common carrier pipeline

2/22/06 8

Tax Rate 20%

of **Net** Profits

Incentive Credits

- **20%** of qualified capital expenditures
- May be taken on:
  - Exploration costs
  - Capital costs **incurred on lease**
- Credits are transferable

2/22/06 10

How are losses handled?

Gross value	$50.00
less:	
Lease op exps	(12.50)
Capital exp's	(60.00)
Net loss (NOL)	($22.50)

2/22/06 11

Net Operating Losses (NOL's)

- Can be converted to Credits
- 20% of loss

2/22/06 12

Base Allowance

- $73 million deduction
- Available to each corporation
- Cannot reduce taxable income below zero

Other provisions

- Monthly return filing
- 90% payment safe harbor
- Yearly true-up on 3/31
- Effective date 7/1/06

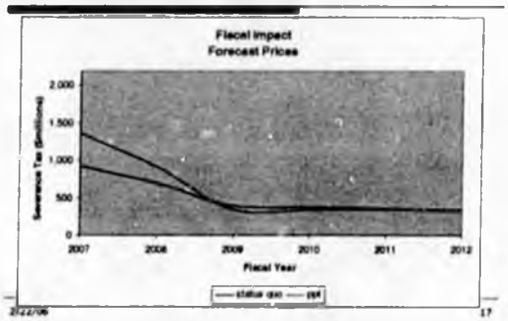
Transition Provisions

- Allows cost recovery of assets placed in service 7/01—6/06
- Deduction of 1/6 of cost in each of 6 transition years
- Deduction available only when average price of oil exceeds $40

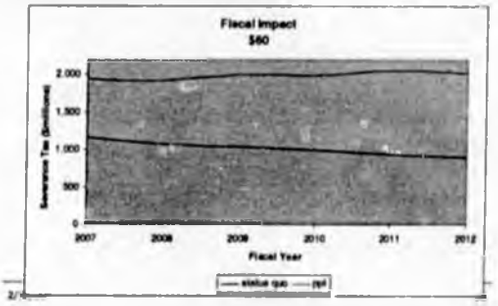
Revenue

- Additional revenue from PPT will depend primarily on two factors:
  - Price of oil/gas
  - Producer investment in the state

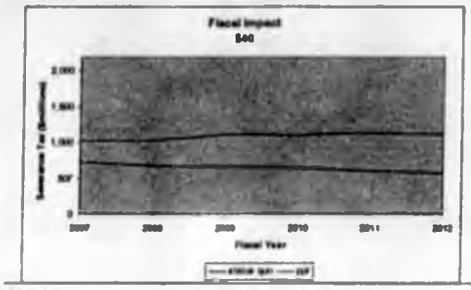
Incremental Revenue based on DOR Forecast:



Incremental Revenue based on $60 oil



Incremental Revenue based on $40 oil:



PPT: A Tax for Alaska's Future

Glossary of Terms Related to the Production Profit Tax

Capitalize.

1. In an accounting sense, the periodic expensing (amortization) of capital costs through depreciation or depletion.
2. To convert an (anticipated) income stream to a present value by dividing by an interest rate, as in the dividend discount model.
3. To record capital outlays as additions to asset value rather than as expense.

Generally, expenditures that will yields benefits to future operations beyond the accounting period in which they are incurred are capitalized-that is, they are depreciated at either a statutory rate or a rate consistent with the useful life of the asset.

Cash Flow

1. Net income plus depreciation, depletion, and amortization and other non-cash expenses. Usually synonymous with cash earnings and operating cash flow.
2. An analysis of all the changes that affect the cash account during an accounting period.

Dollars–of–the Day

A term usually associated with cost estimates that indicate the effects of anticipated inflation have been taken into account. For example, if a well costs $5 million right now in "today's dollars" (the opposite of dollars-of-the day), than the cost of the well two years from now might be estimated at $5.51 million in dollars-of-the-day assuming a 5% inflation factor. Also called *escalated dollars*.

Dutch Disease

The adverse results of large-scale positive shock to a single sector of a nation's economy, so named because of the problems associated with large-scale development of the Groningen Gas field in the Netherlands in the 1970s. Typically the sector of economy that is booming causes widespread inflation and other sectors, particularly agriculture, suffer from inability to attract workers. The drastic increase in foreign exchange can cause problems with local currencies and fiscal and monetary problems can occur without proper management.

Equity Oil

Usually this term refers to oil or revenues after cost recovery (or cost oil). It is also referred to as profit oil or share oil-terms that are most often associated with PSCs. Generally speaking, the analog to equity oil in a concessionary system would be pretax cash flow. Like pretax cash flow, equity oil may also be subject to taxation.

Expense

1. In a financial sense, a non-capital cost associated most often with operations or production.
2. In accounting, costs incurred in a given accounting period as expenses and charged against revenues. To expense a particular cost is to charge it against income during the accounting period in which it was spent. The opposite would be to capitalize the cost and charge it off through some depreciation schedule.

Exploratory Well

A will drilled in an unproved area. This can include: (1) a well in proved area seeking a new reservoir in a significantly deeper horizon, (2) a well drilled substantially beyond the limits of exiting production. Exploratory wells are defined partly by distance from proved production and by degree of risk associated with the drilling. Wildcat wells involve a higher degree of risk than exploratory wells.

Fiscal System

Technically, the legislated taxation structure for a country including royalty payments. In popular language, the term includes all aspects of contractual and fiscal elements that make up a given government-foreign oil company relationship.

Government Take

The total government share of profit oil or revenues not associated with cost recovery. Same as government after-tax equity split and government marginal take.

Heavy Oil

A type of crude oil which is very viscous and does not flow easily. There is no one definition, and may be characterized as having an American Petroleum Institute [API] gravity less than 20°.The common characteristics properties are the following:

- High specific gravity
- Low hydrogen to carbon ratios
- High carbon residues and
- High contents of asphaltenes, heavy metal, sulphur and nitrogen

Incentives

Fiscal or contractual elements emplaced by host government that make petroleum exploration or development more economically attractive includes such things as:

- Royalty Holidays
- Tax holidays
- Tax credits
- Reduced government participation
- Lower government take
- Investment credits/uplifts
- Accelerated depreciation

Intangible Drilling and Development Costs (IDCs)

Expenditures for wages, transportation, fuel, fungible supplies used in drilling and equipping wells for production.

Intangibles

All intangible assets such as goodwill, patents, trademarks, unamortized debts discounts, and deferred charges.

Investment Credit

A fiscal incentive where the government allows a company to recover an additional percentage of tangible capital expenditure. For example, if a contractor spent $10 million on expenditures eligible for a 20% investment credit, than the contractor would actually be able to recover $12 million through cost recovery (see Uplift). These incentives can be taxable. Sometime the investment credit is mistakenly referred to as an investment tax credit.

Netback

Many royalty calculations are based upon gross revenues from some point of valuation, usually the last value off of a production platform or at the boundary of a field or license area. The point of sale, however, may be different than the point of valuation. The statutory royalty calculation may allow the transportation costs from the point of valuation to the point of sale to be deducted. This is called *netback formula*.

Operating Profit (or Loss)

The difference between business revenues and the associated costs and expenses exclusive of interest or other financing expenses, and extraordinary items, or ancillary activities. Synonymous with net operating profit (or loss), operating income (or loss), and net operating income (or loss).

Production Sharing Agreement

This (PSA) is the same as a Production Sharing Contract (PSC). While at one time this term was quite common, it is use less frequently now, and the term *Production Sharing Contract* is becoming more common.

Production Sharing Contract

A contractual agreement between a contractor and a host government whereby the contractor bears all exploration costs and risks and development and production costs in return for a stipulated share of the production resulting from this effort.

Progressive Taxation

Where tax rates increase as the basis to which the applied tax increases. Or where tax rates decrease as the basis decreases. The opposite of regressive taxation.

Severance Tax

A tax on the removal of minerals or petroleum from the ground, usually levied as a percentage of the gross value of the minerals removed. The tax can also be levied on the basis of so many cents per barrel or per million cubic feet of gas.

Tax

A compulsory payment pursuant to the authority of a government. Fines, penalties, interest, and customs duties are not taxes.

Working Interest

The percentage of interest ownership a company (or government) has in joint venture, partnership, or consortium. The expense-bearing interest of various working-interest owners during exploration, development, and production operations my change at certain stages of a contract or license. For example, a partner with a 20% working interest in a concession may be required to pay 30% of exploration costs but only a 20% share of development costs. With government participation, the host government usually pays no exploration expenses by pays prorated development and operating costs and expenses.

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: CS for HB 488(RES)
() Publish Date:

Revision Date/Time (Note if correction):
Dept. Affected: Revenue
Title: An Act Relating to the Production Tax on Oil and Gas
RDU: Tax and Treasury
Component: Tax
Sponsor: Rules Committee
Requester: Governor
Component No.: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Personal Services	359.2	366.4	373.7	381.2	388.8	396.6
Travel						
Contractual	400.0	370.0				
Supplies	24.0					
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous [OH office, etc]	18.0	18.0	18.0	18.0	18.0	18.0
TOTAL OPERATING	**801.2**	**754.4**	**391.7**	**399.2**	**406.8**	**414.6**
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )	***See analysis section***					

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	801.2	754.4	391.7	399.2	406.8	414.6
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type–Do not abbreviate)						
TOTAL	**801.2**	**754.4**	**391.7**	**399.2**	**406.8**	**414.6**

Estimate of any current year (FY2006) cost: 275.0
Check this box (X) if funding for this bill is included in the Governor's FY 2007 budget proposal:

POSITIONS

Full-time	4	4	4	4	4	4
Part-time						
Temporary						

ANALYSIS: *(Attach a separate page if necessary)*

Relative to Status Quo

This bill would amend the oil and gas production tax by basing the tax on the net value of the oil and gas. The net value is the wellhead value (net of royalty) less all qualified lease expenditures, including capital and operating costs, property taxes. The net income would be subject to a 20% tax, less a credit of 20% which applies to capital costs upstream of the point of production.There would also be a progressive surcharge based on .3% of the difference between actual West Texas Intermediate (WTI) oil price and $50 applied to the gross value at the point of production. There would be no surcharge when the WTI price was under $50. The surcharge would also be considered a deductible lease expenditure. There would be an additional annual credit per company of up to the lesser of actual net income or $12 million per year. In addition, as a transition provision, there would be a deduction for capital costs incurred over the 3 month period January through March 2006, which can be realized over the 9 month period April

Prepared by: Robynn Wilson, Michael Williams, and Roger Marks
Phone 269-1019
Division: Tax Division
Date/Time 3/24/06 2:00 PM

Approved by: Jerry Burnett
Date 3/25/2006
Agency: Department of Revenue

(Revised 9/7/2005 OMB)

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for HB 488 (RES)

ANALYSIS CONTINUATION

through December 2006. It is estimated this would reduce revenues about $50 million total over that 9 month period. Finally, the conservation surcharge on oil is decreased from 2 cents/bbl to 1 cent/bbl, while the additional conservation surcharge on oil is increased from 3 cents to 4 cents. The net impact of this, assuming that the oil and hazardous substance release prevention account is at capacity, would be a 1 cent/bbl increase in revenues.

The bill would be effective April 1, 2006.

Relative to Governor's Bill

The Governor's bill had no progressive surcharge. There was an deductible allowance of up to $73 million of net income per company per year. There was a transition provision where all qualified capital expenditures incurred between July 1, 2001 through July 1, 2006 would be deductible over six years. The 3 cent additional conservation surcharge on oil would have been a credit against the oil tax.

The bill would have been effective July 1, 2006.

The figures in the table below reflect the revenues that would be received from the bill relative to the status quo under various prices. Columns 1-3 reflect the original fiscal note for the bill. Columns 4-5 reflect adjustments to the original fiscal note to reflect net adjustments in state corporate income tax from changes in the severance tax, the recognition of the credit for the additional conservation surcharge on oil, the re-assessment of the number of full allowances from 7 company equivalents to nine, and minor model changes.Columns 6-8 reflect changes from converting from the Fall 2005 Department of Revenue Source Book data to Spring 2006. The volumes for the last quarter have been adjusted to reflect short-term adjustments resulting from the North Slope oil spill in March. Finally, Columns 9-11 reflect the House Resources CS. The figures reflect North Slope activity; the impact on Cook Inlet is expected to be modest. The status quo assumes the January 2005 BP.F aggregation decision by the Department of Revenue for Prudhoe Bay continues.

The cost assumptions are as follows:

- $100 mm/yr exploration
- $1/bbl on-going capital on all barrels
- $3.50/bbl developmental capital on 2/3 of existing conventional oil
- $8/bbl developmental capital on 2/3 of existing heavy oil
- $3.50/bbl developmental capital on new conventional oil
- $8/bbl developmental capital on new heavy oil
- $3/bbl operating cost on conventional oil
- $5/bbl operating cost on heavy oil

The table shows the 2006-2012 receipts from the bill, sensitive to different oil prices. These include the Department of Revenue forecast, a $40 price, and a $60 price. (Note that the status quo numbers are slightly different from what is reflected in the Spring 2006 Revenue Sources Book because of volume adjustments from the oil spill, and because of some differences between what some taxpayers actually remit and what is ultimately expected to be collected.)

Operating expenditures include costs for 3 additional positions for auditors: 1 O & G Specialist (Range 23), 1 O & G Revenue Auditor IV (Range 22), and 1 O & G Revenue Auditor III (Range 20). These positions would be used to fulfill additional audit responsibilities inherent in a net profits tax. In addition, we request 1 additional position for a Tax Tech III (Range 14) to process additional information and tax returns that will be required, and additional credit applications anticipated. Personal Services reflect a 2% yearly increase.

Contractual expenses include $100,000 and $70,000 for programming in FY 07 and FY 08, respectively, and $300,000 in each of FY 07 and FY 08 for help in writing regulations. Supplies include computers and other supplies necessary for new positions.

See Page 3 for revenue estimates

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for HB 488 (RES)

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

GOVERNOR'S BILL
ORIGINAL FISCAL NOTE

GOVERNOR'S BILL
WITH CORPORATE INCOME TAX,
CONSERVATION SURCHARGE
NINE COMPANY ALLOWANCES
MINOR MODEL CHANGES

Fiscal Year	DOR Forecast	Col. 1 Status Quo Tax	Col. 2 Tax from Bill	Col. 3 Gain from Bill	Col. 4 Tax from Bill	Col. 5 Gain from Bill
2006	na	na	na	na	na	na
2007	$49.20	934	1,363	429	1,317	383
2008	$40.95	697	915	217	876	179
2009	$25.50	404	349	-55	320	-84
2010	$25.50	387	339	-48	310	-77
2011	$25.50	362	351	-11	319	-43
2012	$25.50	343	332	-10	300	-42

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill	Tax from Bill	Gain from Bill
2006	na	na	na	na	na	na
2007	$40.00	737	1,038	301	997	260
2008	$40.00	679	1,031	353	988	309
2009	$40.00	673	1,118	445	1,070	397
2010	$40.00	646	1,106	460	1,058	411
2011	$40.00	606	1,138	532	1,086	480
2012	$40.00	576	1,112	536	1,059	483

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill	Tax from Bill	Gain from Bill
2006	na	na	na	na	na	na
2007	$60.00	1,165	1,938	773	1,879	714
2008	$60.00	1,069	1,917	848	1,855	786
2009	$60.00	1,042	2,007	965	1,939	897
2010	$60.00	1,003	1,992	989	1,923	921
2011	$60.00	941	2,051	1,110	1,977	1,036
2012	$60.00	896	2,014	1,117	1,939	1,043

FISCAL NOTE

STATE OF ALASKA
2006 LEGISLATIVE SESSION

BILL NO. CS for HB 488 (RES)

ANALYSIS CONTINUATION (MILLIONS OF 2005 DOLLARS)

GOVERNOR'S BILL
CHANGES FROM FALL 2005 FORECAST
TO SPRING 2006 FORECAST

Fiscal Year	DOR Forecast	Col. 6 Status Quo Tax	Col. 7 Tax from Bill	Col. 8 Gain from Bill	Col. 9 Status Quo Tax	Col. 10 Tax from Bill	Col. 11 Gain from Bill
2006	na	na	na	na	262	517	255
2007	$53.60	989	1,514	526	989	1,825	836
2008	$46.90	759	1,136	377	759	1,318	558
2009	$25.50	355	302	-52	355	323	-32
2010	$25.50	315	283	-32	315	304	-11
2011	$25.50	281	291	10	281	312	31
2012	$25.50	271	291	20	271	312	41

Fiscal Year	Medium Price	Status Quo Tax	Tax from Bill	Gain from Bill	Status Quo Tax	Tax from Bill	Gain from Bill
2006	na	na	na	na	174	227	53
2007	$40.00	708	978	270	708	967	259
2008	$40.00	655	953	298	655	974	319
2009	$40.00	631	1,021	390	631	1,042	411
2010	$40.00	582	990	408	582	1,011	429
2011	$40.00	544	1,012	468	544	1,033	489
2012	$40.00	536	1,021	485	536	1,042	506

Fiscal Year	High Price	Status Quo Tax	Tax from Bill	Gain from Bill	Status Quo Tax	Tax from Bill	Gain from Bill
2006	na	na	na	na	275	572	297
2007	$60.00	1,120	1,840	720	1,120	2,380	1,260
2008	$60.00	1,032	1,786	754	1,032	2,350	1,318
2009	$60.00	978	1,848	871	978	2,421	1,443
2010	$60.00	901	1,800	899	901	2,366	1,465
2011	$60.00	842	1,841	999	842	2,414	1,572
2012	$60.00	831	1,861	1,029	831	2,438	1,606

INCLUDES VOLUMES, PRICE, TAPS, MARINE, UPSTREAM, WELLS

SPRING 2006 VOLUMES FOR THE LAST QUARTER OF FY 2006 HAVE BEEN REDUCED TO REFLECT SHORT TERM ADJUSTMENTS FROM THE NORTH SLOPE OIL SPILL

PETROLEUM PRODUCTION TAX

Presentations to the Senate Resources Committee and to the House Resources Committee

February 23, 2006

FISCAL SYSTEM OF ALASKA

The fiscal system applicable to oil and gas of Alaska consists primarily of four components:

- Royalties
- Production tax (severance tax, "ELF")
- Property tax
- State corporate income tax

Additionally, there is federal corporate income tax.

This presentation is about the international competitive aspects of the proposed petroleum production tax.

In international comparisons always the entire State and Federal package together is compared.

PETROLEUM PRODUCTION TAX

The most recent proposal for the petroleum production tax is as follows:

Tax rate: 20%

Tax credit rate: 20%

Tax free allowance: Up to $ 73 million

Capex clawback: 20% of capex over last 5 years

PETROLEUM PRODUCTION TAX

The presentation is primarily aimed at the discussion of my PPT report. The preparation of the report started in July 2005 and continued until February 14th this month.

Until early January 2006, I recommended a system with a 20% tax and 15% tax credit based on the international competitiveness analysis.

As a result of the economic analysis done in DOR in January 2006, and input from various other consultants, I amended my recommendation to a 25% tax rate and 20% tax credit rate.

Therefore, the report contains chapters about 20/15 and 25/20. Sensitivity analysis was done on other combinations.

The 20/20 concept and the capex clawback were adopted after the finalization of this report. However, from an international perspective of competitiveness, all these options are rather close and therefore the general conclusions of the report remain valid for the 20/20 concept as well.

PETROLEUM PRODUCTION TAX

The report contains the following chapters:

Executive Summary

1. Introduction
2. New international trends in government take
3. Economic analysis
4. Analysis of the 20/15 PPT
5. Analysis of alternative PPT's
6. International competitiveness of the 20/15 PPT
7. International rating of the 20/15 PPT
8. Competitiveness and PPT rate
9. International rating of the 25/20 PPT
10. Heavy Oil Incentives
11. Review of 25/20 PPT

PETROLEUM PRODUCTION TAX

COST SCENARIOS
Per barrel costs

			DRY HOLE	FIELD#1 50MM-LOW	FIELD#2 150MM-LOW	FIELD#3 500MM-LOW	FIELD#4 50MM-HIGH	FIELD#5 150MM-HIGH	FIELD#6 500MM-HIGH
TOTAL OIL PRODUCTION		(MMbbls)	0.0	50.0	150.0	500.0	50.0	150.0	500.0
HIGH COSTS:									
TOTAL CAPEX	Exploration	(m$)	45	45	45	45	45	45	45
	Development	($/bbl)		7.50	6.00	5.25	6.00	4.50	3.00
TOTAL OPEX		($/bbl)		6.00	5.00	3.75	4.50	3.[illegible]0	3.00
AVERAGE COSTS:									
TOTAL CAPEX	Exploration	(m$)	37.5	37.5	37.5	37.5	37.5	37.5	37.5
	Development	($/bbl)		6.25	5.00	4.37	4.80	3.75	2.50
TOTAL OPEX		($/bbl)		5.00	4.17	3.12	3.75	2.92	2.50
LOW COSTS:									
TOTAL CAPEX	Exploration	(m$)	30	30	30	30	30	30	30
	Development	($/bbl)		5.00	4.00	3.50	4.00	3.00	2.00
TOTAL OPEX		($/bbl)		4.00	3.33	2.50	3.00	2.33	2.00

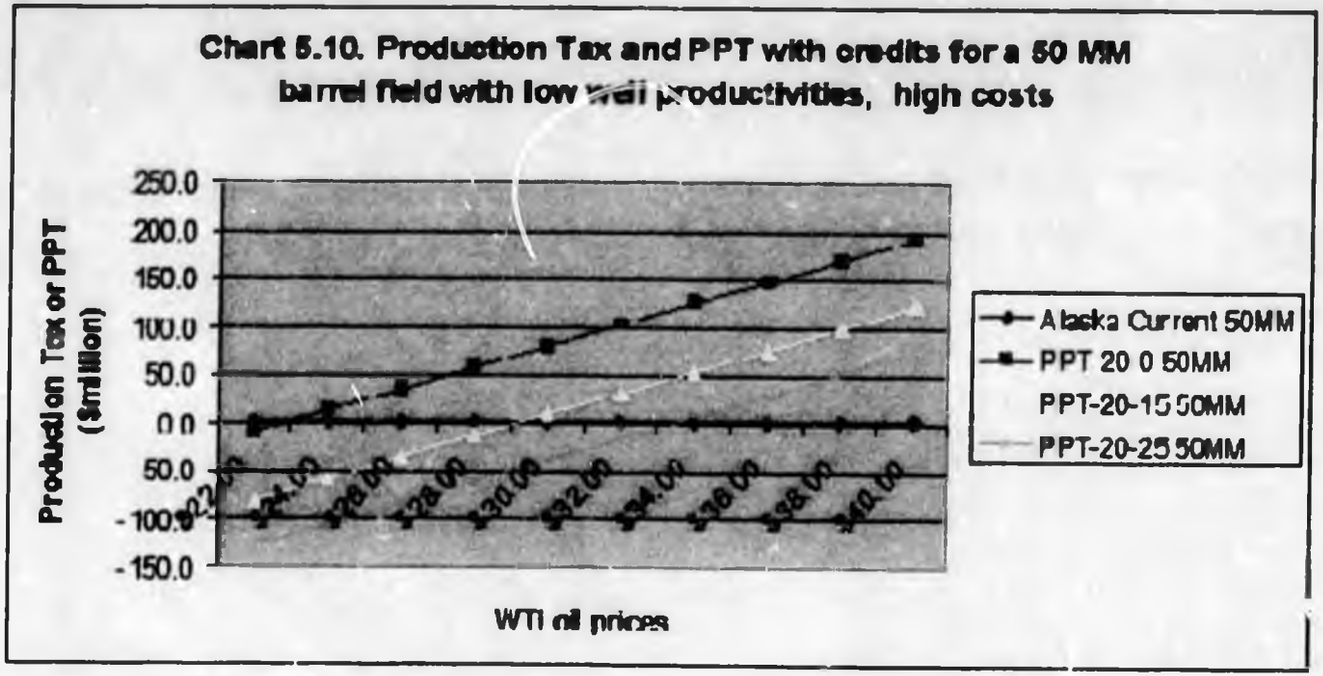
The main focus of the economic work was on high cost fields of 50 million and 150 million barrels, since these field types represent North Slope conditions.

PETROLEUM PRODUCTION TAX

20/20 PPT $ 40 CASE HIGH COSTS	DRY HOLE	50 MM	150 MM	500 MM
ROYALTIES	0.0	264.4	820.6	2827.5
PPT	-18.7	-110.1	180.6	1730.3
PROPERTY TAXES	0.0	28.3	86.3	292.3
STATE CIT	-2.6	100.6	318.1	1131.2
FEDERAL CIT	-8.9	340.3	1075.8	3825.5
ALASKA GOVERNMENT TAKE	45.6%	22.6%	31.4%	35.4%
FEDERAL GOVERNMENT TAKE	19.1%	27.2%	24.1%	22.7%
TOTAL	64.7%	49.8%	55.5%	58.1%

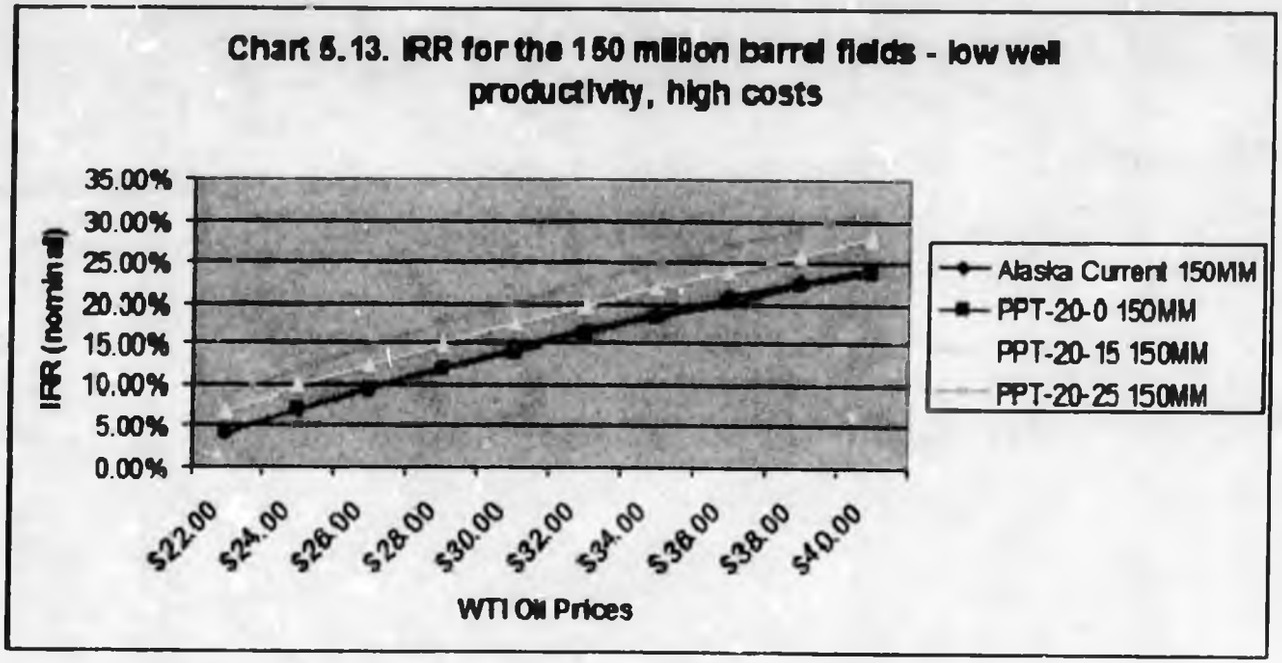
The 20/20 PPT provides for a progressive system for new investors, with a negative PPT on small fields to encourage investment.

PETROLEUM PRODUCTION TAX



For small fields, the tax credits have a considerable impact on the break even point. Graph illustrates PPT for large producers

PETROLEUM PRODUCTION TAX



The level of tax credit is the main determinant of the rate of return. The higher the tax credits the higher the rate of return.

PPT AND COMPETITION

The competitive position of the Alaska system was analyzed using the same field sizes and applying international terms. Eight fisc[illegible]ystems were analyzed. They all reflect areas in the world where currently considerable investment is taking place:

- Norway
- UK
- US Gulf Coast
- Alberta Oil Sands
- Nigeria
- Angola
- Russia-Sakhalin
- Azerbaijan

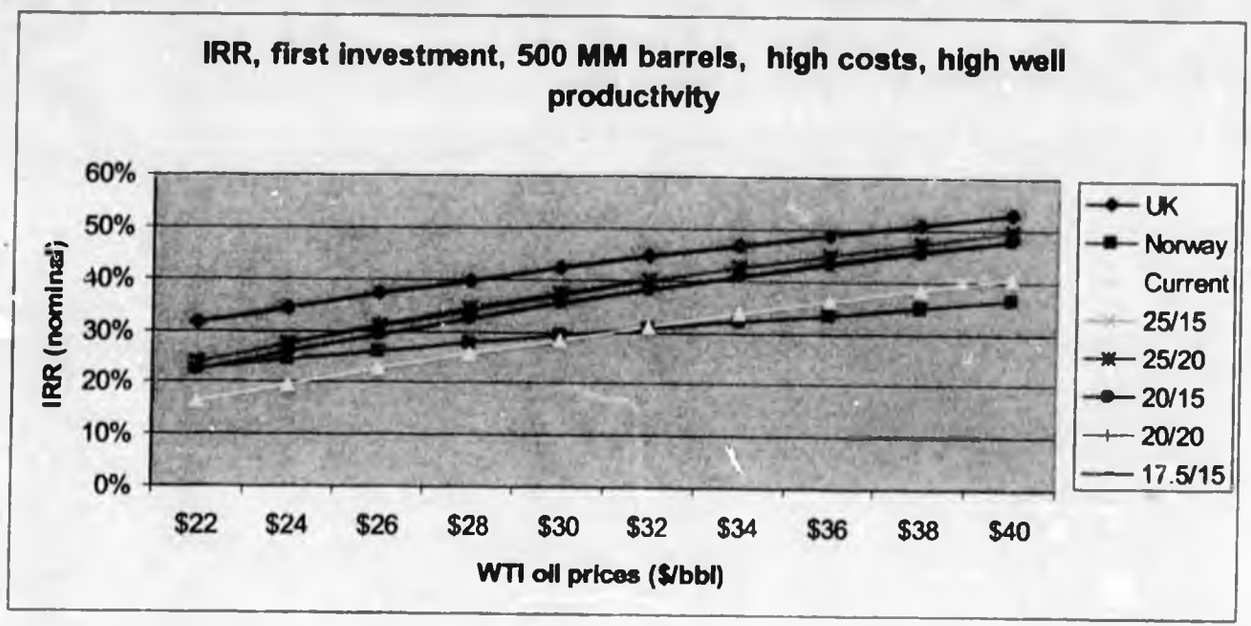
PETROLEUM PRODUCTION TAX

Jurisdiction	Net back differential
	($ per barrel)
Alaska-North Slope	$ 7
Norway	$ 1
UK	$ 1
US Gulf of Mexico – Deep water	0
Nigeria – Deep Water	$ 2
Alberta – oil sands	$ 2
Angola	$ 2
Russia-Sakhalin	$ 1
Azerbaijan	$ 6

The international comparison was corrected for the low net back of Alaska crude oil.

PPT AND COMPETITION

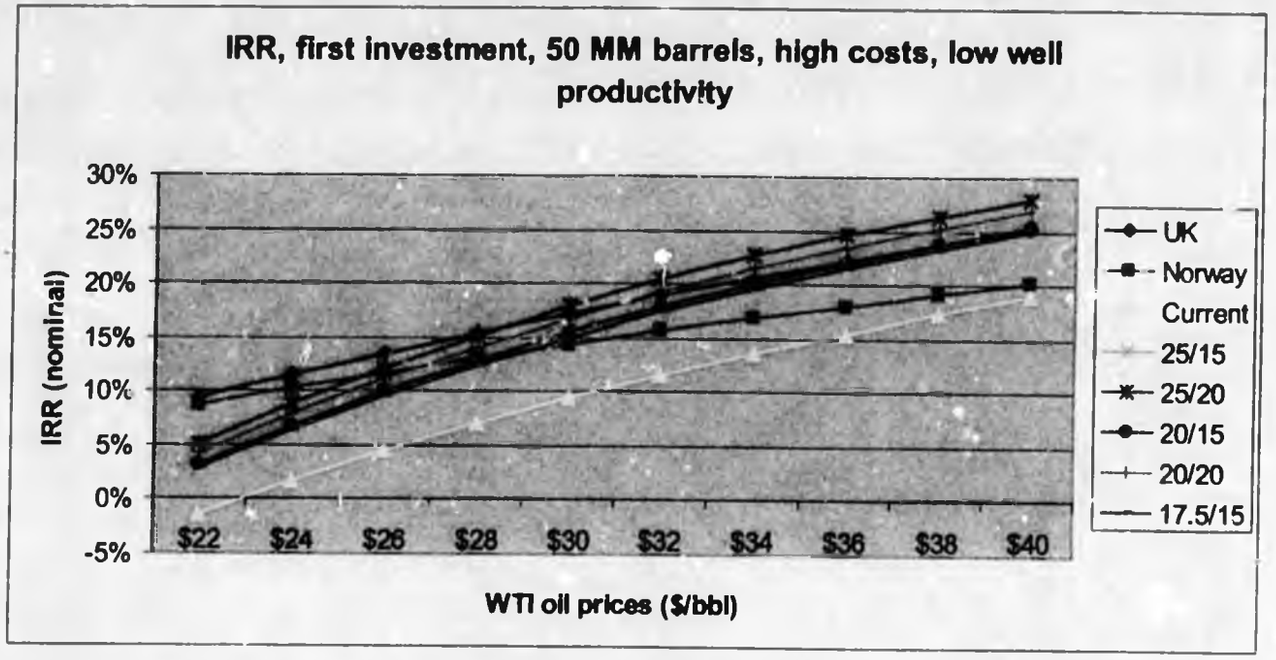
First Investment in 500 MM barrel field



The PPT creates a very material improvement in IRR relative to Norway and UK, for a first investment in a large field.

PPT AND COMPETITION

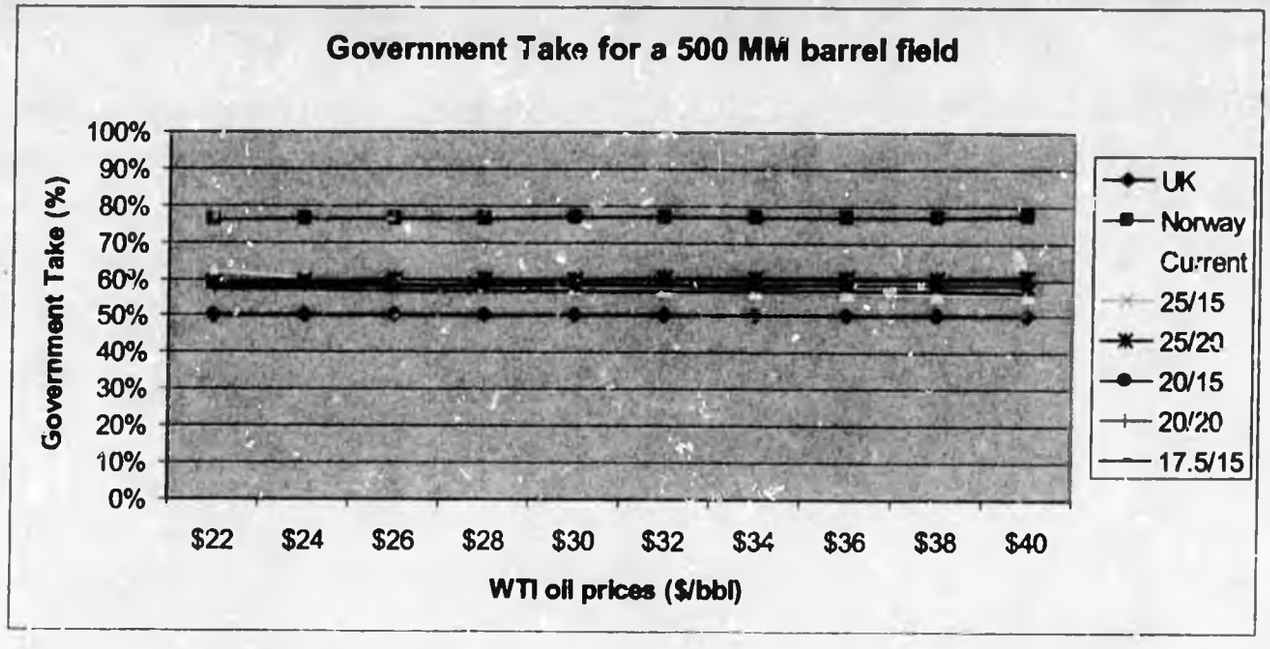
First Investment in 50 MM barrel field



The PPT creates a very significant improvement in IRR relative to Norway and UK, for a first investment in a small field.

PPT AND COMPETITION

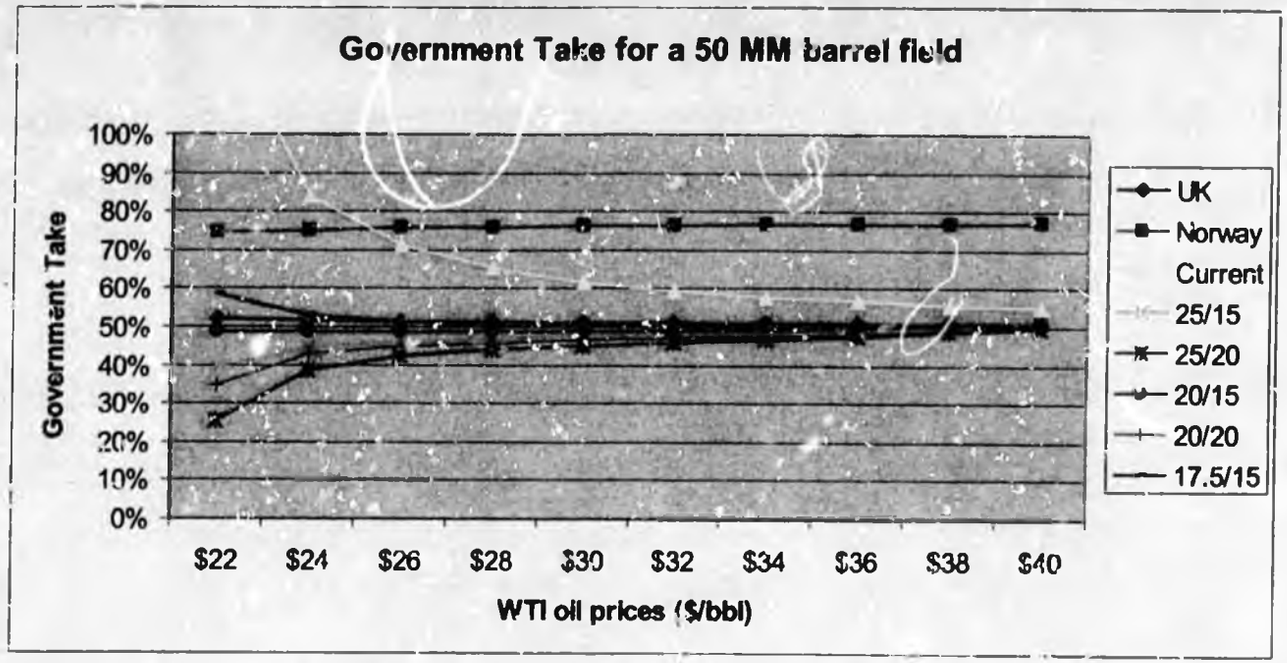
First Investment in 500 MM barrel field



The PPT provides for a modest total government take for each of the five options, in order to compensate for the low net back prices and high costs.

PPT AND COMPETITION

First Investment in 50 MM barrel field



For first investors or small producers there is a reduction of government take compared to the Current System. The regressive nature of the government take is removed for each of the five options.

PPT and competition

A competitiveness index was prepared by evaluating 48 economic yardsticks for 10 fiscal terms.

If a fiscal system was the best in all of them the rating was 48. If the system was the worst in all of them the rating was 480

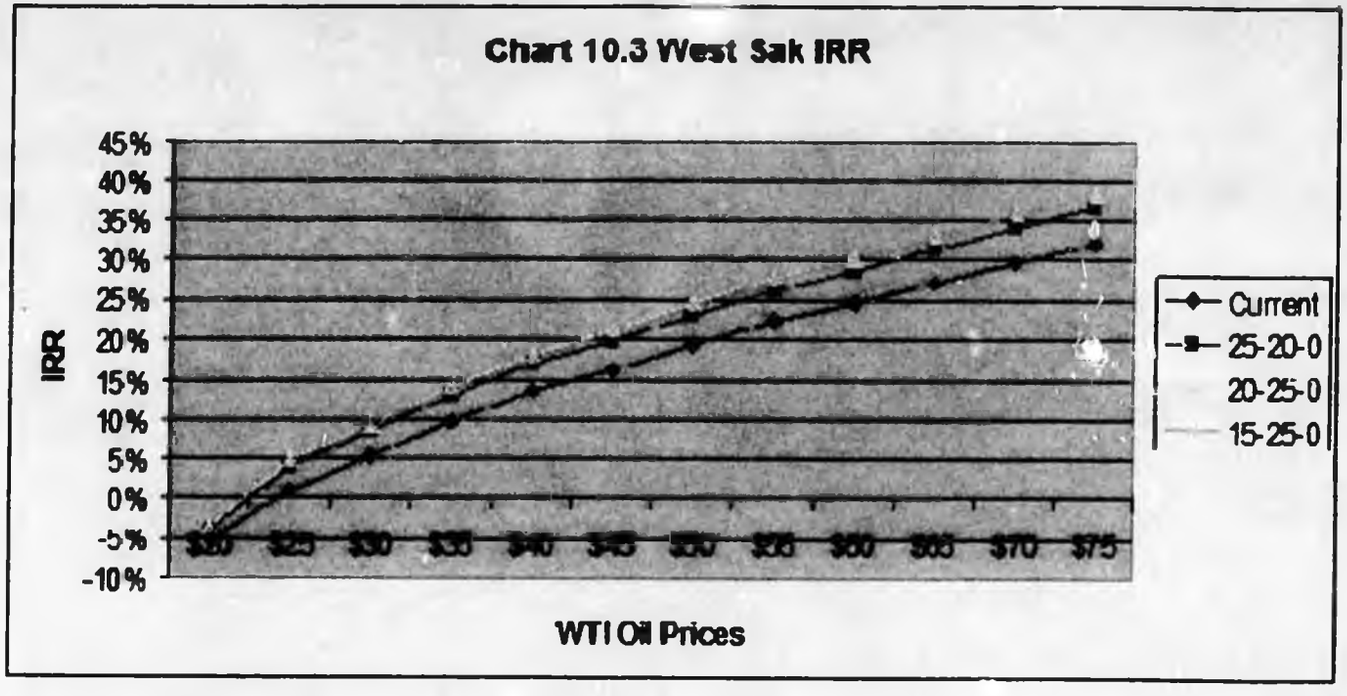
PPT and competition

RATING 20/15	
US GOM	52
UK	135
Alberta-Oil Sands	157
Nigeria	172
Alaska PPT	272
Angola	318
Azerbaijan	329
Alaska Current	364
Norway	397
Russia-Sakhalin	444

RATING 25/20	
US GOM	54
UK	139
Alberta-Oil Sands	163
Nigeria	179
Alaska PPT	244
Angola	322
Azerbaijan	329
Alaska Current	363
Norway	402
Russia-Sakhalin	445

The rating of 25/20 was better than 20/15, because tax credits are very important in international rating. The system 20/20 would rate somewhat more attractive to investors than 25/20, but not significantly more

PPT AND HEAVY OIL



The tax credit system will strongly enhance the rate of return on heavy oil projects, because the higher capital requirements will automatically result in more credits. The graph, however, also shows that it is not necessary to have very high credits of 25%.

Conclusion

The 20/20 proposal results in very competitive terms from an international perspective for new investors as well as for existing petroleum companies.

The system will therefore result in more investment in Alaska, while at the same time creating much higher revenues, primarily from existing production and under average and high prices also from new production.

Petroleum Profits Tax (PPT)

Overview

Alaska Department of Revenue
Before the Alaska State Legislature

Robynn J. Wilson

Problems with Current Production Tax

- No incentive in tax system to reinvest in Alaska
- Low take (internationally) at high prices, high take at low prices
- Maturing of North Slope leads to declines in tax revenue

Components of PPT

- Tax Base
- Rate
- Incentive Credits
- Base Allowance
- Transition Provision

Gross vs. Net

Current Tax on Gross	
Value at wellhead	$50.00
Times: tax rate	15%
Tax before ELF	$7.50

PPT on Net	
Value at wellhead	$50.00
Less:	
Lease op exps	(12.50)
Net taxable	$37.50
Times: tax rate	20%
Tax before credits	$7.50

Tax Base

Gross value at point of production

Less: Lease expenditures

- operating costs
- capital expenditures
- allowance for overhead

Non-deductible expenses

- Depreciation
- Royalty payments
- Taxes based on net income
- Interest & financing charges
- Lease acquisition costs
- Other costs

Determining value under current system





West coast value



$

Gross Value under PPT

Producer can elect to use:

- Royalty value
- DOR formula that estimates a value at a specific location such as point of delivery into a common carrier pipeline

Tax Rate 20%

of **Net** Profits

Incentive Credits

- **20%** of qualified capital expenditures
- May be taken on:
  - Exploration costs
  - Capital costs **incurred on lease**
- Credits are transferable

How are losses handled?

Gross value	$50.00
less:	
Lease op exps	(12.50)
Capital exp's	(60.00)
Net loss (NOL)	($22.50)

Net Operating Losses (NOL's)

- Can be converted to Credits
- 20% of loss

Base Allowance

- $73 million deduction
- Available to each corporation
- Cannot reduce taxable income below zero

Other provisions

- Monthly return filing
- 90% payment safe harbor
- Yearly true-up on 3/31
- Effective date 7/1/06

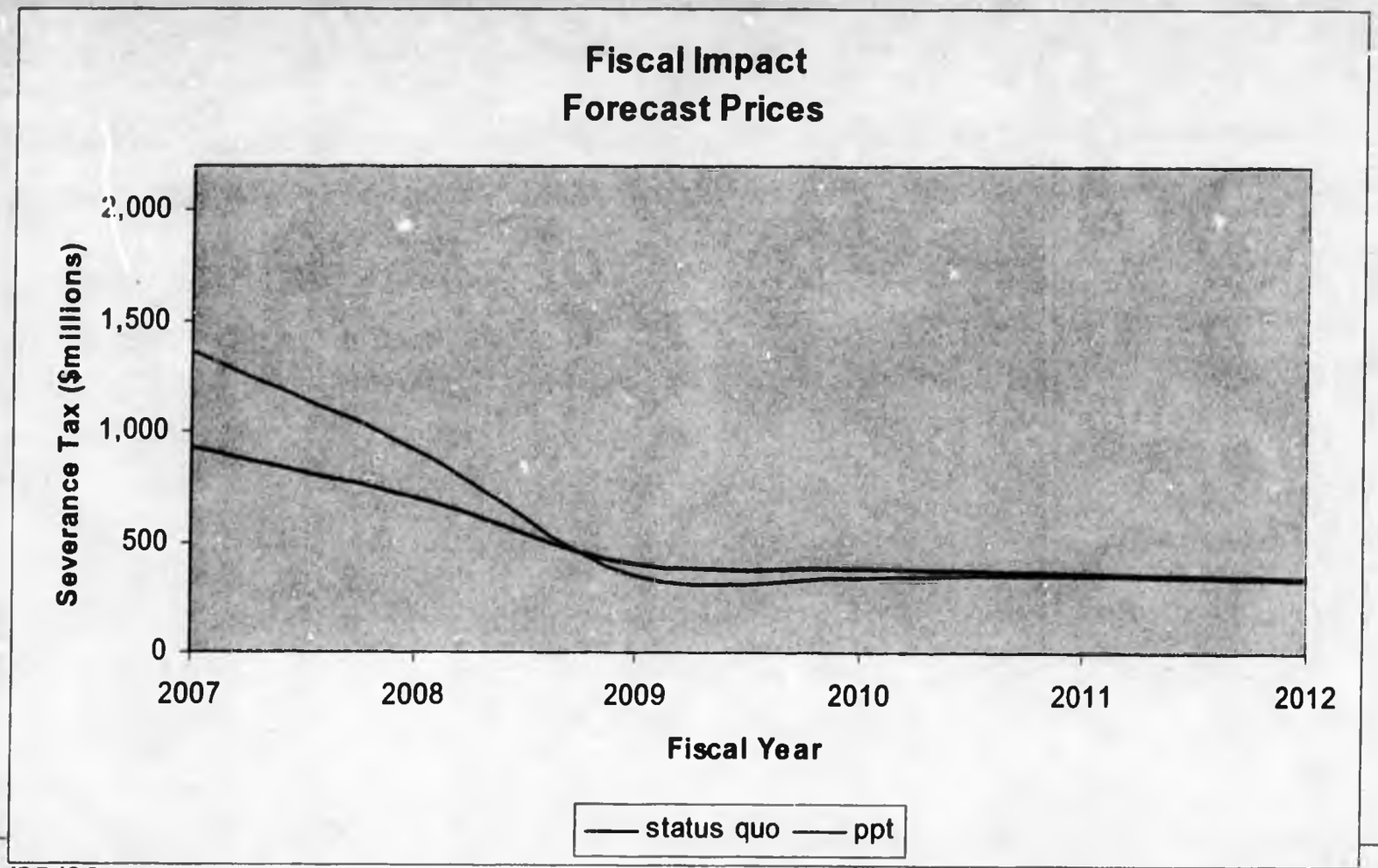
Transition Provision

- Allows cost recovery of assets placed in service 7/01—6/06
- Deduction of 1/6 of cost in each of 6 transition years
- Deduction available only when average price of oil exceeds $40

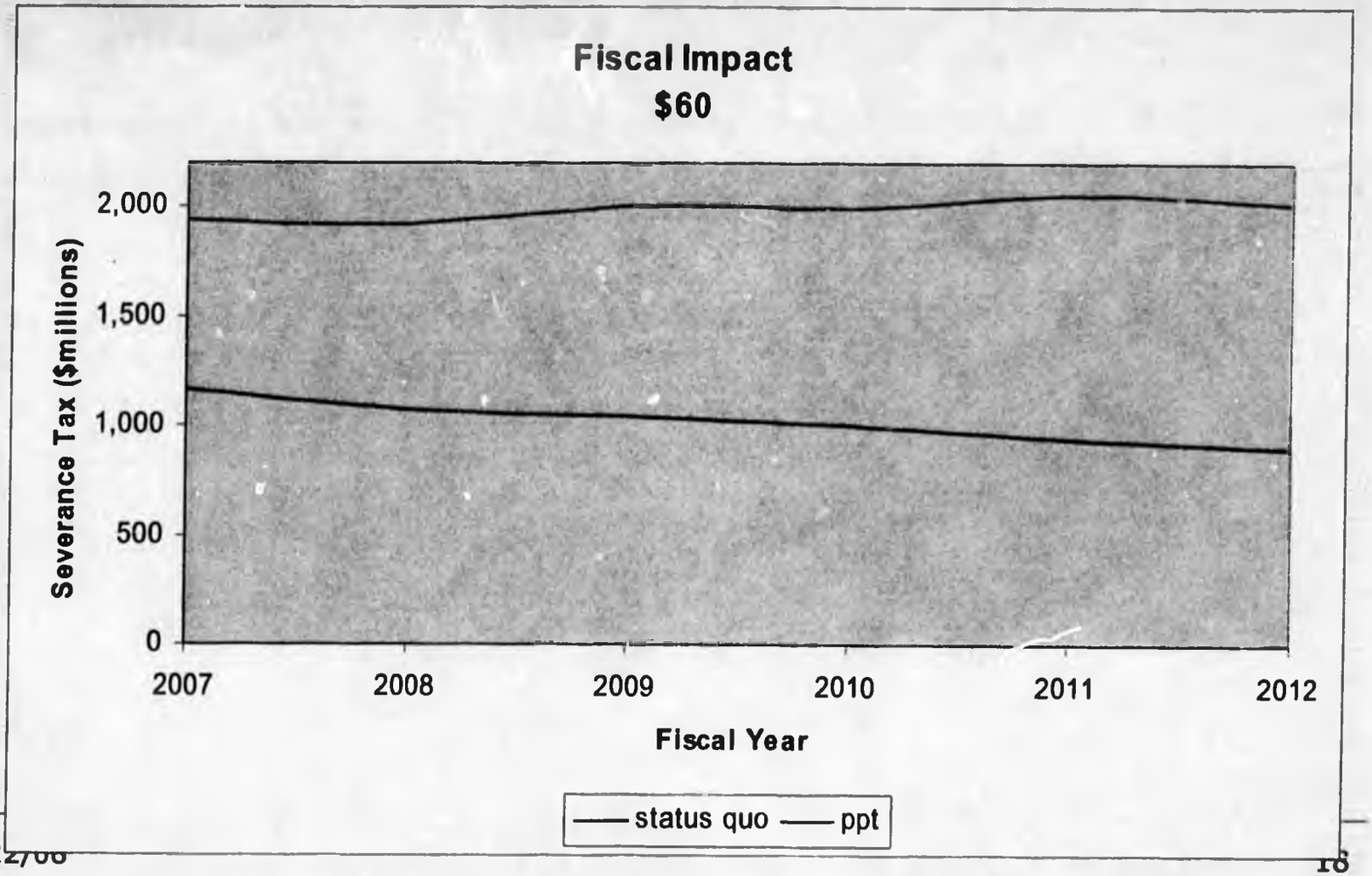
Revenue

- Additional revenue from PPT will depend primarily on two factors:
  - Price of oil/gas
  - Producer investment in the state

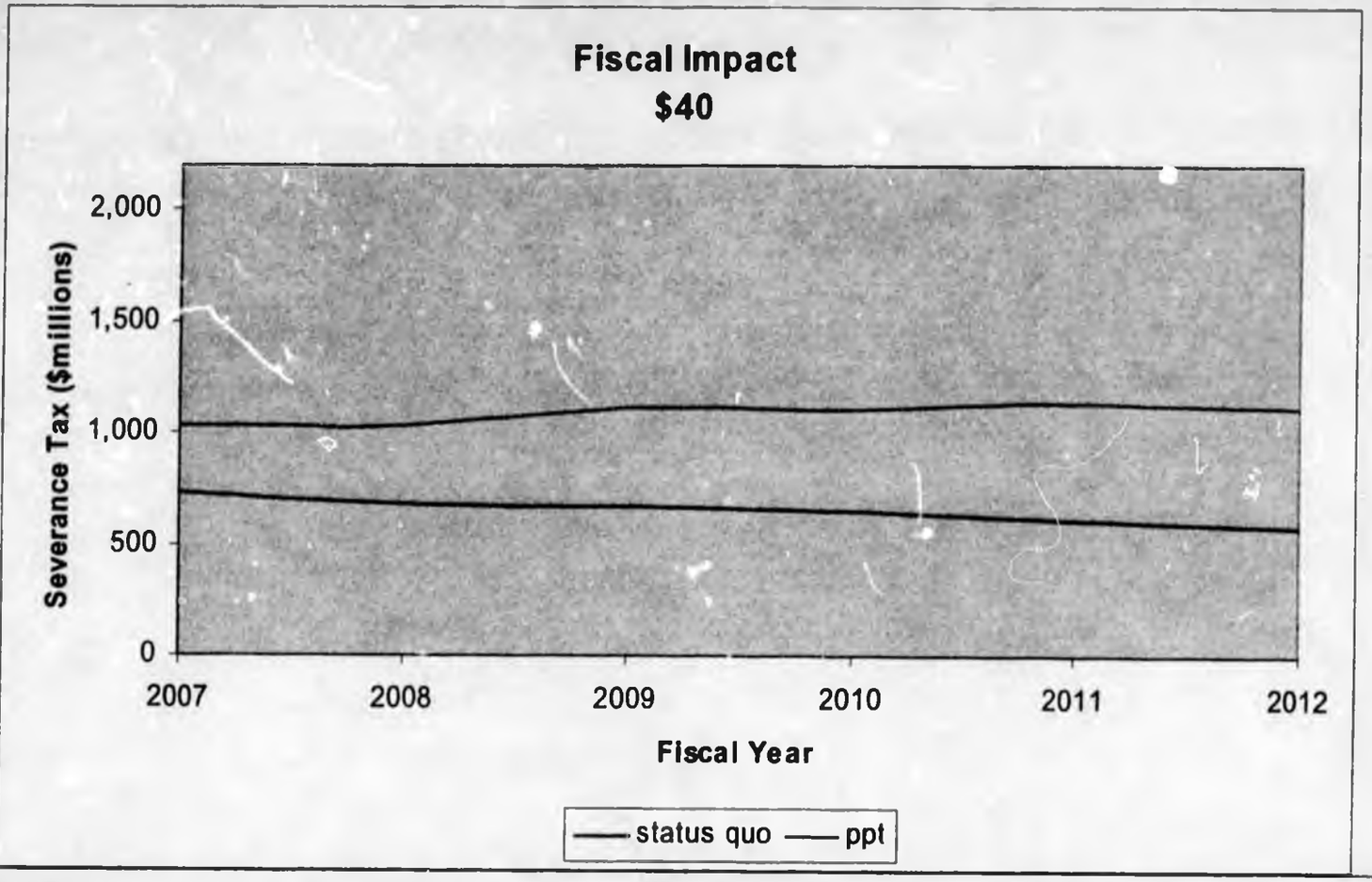
Incremental Revenue based on DOR Forecast:



Incremental Revenue based on $60 oil



Incremental Revenue based on $40 oil:



PPT: A Tax for Alaska's Future



BP Presentation on Proposed PPT

Alaska State Legislature
House & Senate Resource Committees
28th February 2006

Introduction – Ken Konrad

My name is Ken Konrad. I am Vice President, Gas for BP Alaska. We are here today to talk to you about the proposed PPT legislation – HB488 / SB305. I will make a few opening comments and then turn things over to Angus Walker and our PPT team.



- How we got here
- Current realities of the Alaska North Slope
- Global perspective
- Impact of PPT on BP Alaska

Ken Konrad — Gas Vice President BP Alaska
Angus Walker — Commercial Vice President BP Alaska
Ray Hall — Senior Tax Economist BP Group
Tom Williams — Alaska Tax Counsel BP Alaska

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How we got here

Last week, after more then two years of negotiations, and a lot of hard work on all sides, we reached a very finely balanced agreement with the administration on a predictable and durable Fiscal Contract with Alaska. The Fiscal Contract will establish clear rules governing payments-in-lieu of taxes we would make to the State, including a PPT payment incorporated by reference from this legislation. Once ratified, the Fiscal Contract will enable a gas pipeline to advance in partnership with the State as an equity participant.

Much of what is contained in the PPT legislation was born in part out of the Fiscal Contract negotiations we've been in with the administration. I thought it would be useful to share an overview as to how and why we arrived at this point given that many of the discussions to date have been confidential as stipulated in the SGDA.

Mother Nature - oil and gas are unavoidably linked

Oil and gas form together when plants (and dinosaurs) are buried deep beneath the Earth's surface and, under great heat and pressure, are transformed into oil and gas.

The oil and gas co-exist in the same underground reservoirs, they are produced together through the same wells, flow together through the same flowlines and are processed together in the same facilities. Some fields have more oil than gas and some fields have more gas than oil or condensate. But it is exceedingly rare that one is produced without the other.

Because oil and gas co-exist physically, and are produced together through the same investments made in wells and facilities, they are also linked economically.

This inextricable physical and economic linkage is widely recognized by both governments and investors around the world.

North American royalty contracts cover both oil and gas. Internationally, production sharing contracts include terms for both oil and gas. General oil and gas tax laws across the U.S. and internationally always address both oil and gas.

Governments want to know how much money they will receive from oil and gas production. Similarly, investors need to know how much they will pay governments when oil and gas is produced and sold and make their investment decisions accordingly.

The economic linkage of oil and gas is particularly acute here in Alaska when considering a gas pipeline given the unique operating challenges on the North Slope and the criticality of economies of scale.

Oil Decline - additional oil investment needed to support ANS gas development

We, the producers and the State, currently have a problem. ANS oil production has been declining for over 15 years and *has been on an unsustainable trajectory*. Investment by all of industry has been insufficient to limit decline.

Unless we, and here I mean the entire industry in partnership with the State, are able to maintain economic levels of oil production to support and maintain vital North Slope infrastructure for many decades to come, a gas project can't be successful – it simply cannot be burdened with the cost of uneconomic oil production.

Investors need confidence that the fiscal regime will be sufficiently competitive to attract the enormous amounts of additional capital needed to maintain economic levels of ANS oil production for decades. Providing this confidence benefits both the State and investors against our common enemy – *production decline*.

Building a gas pipeline is effectively a commitment by the major producers to maintain vital North Slope infrastructure for another 40-50 years – This is a daunting challenge.

- Will there be enough investment to stem the long term decline in ANS production?
- Will there be sufficient oil production to keep the unit costs of operating TAPS at an economically viable level?
- Will there be sufficient oil production to cover the operating and maintenance investment costs of operating aging production facilities?

The answer can be yes. We know the oil is up there. Billions of barrels of oil that might otherwise be left behind in producing fields can be accessed. Viscous oil in and around existing infrastructure that was discovered decades ago holds promise. Exploration near existing fields and beyond in areas like NPRA may have potential.

But it is all very difficult. ANS production is declining for a reason – not for lack of oil, but for a lack of profitable ways to extract it. The totality of industry costs and taxes are high. But, we do believe with the right technology and the right fiscal regime, these historically unprofitable investments can be made viable so industry can convert resources into production to sustain ANS infrastructure.

This is why oil taxation policy should *appropriately balance risks and rewards* to enable this additional investment. Even prior to this proposed tax increase, investment has been insufficient to prevent ongoing production decline. The legislature needs to very carefully consider the impacts of a very large tax increase on future investment and long term production.

This is an important decision. And it should not and cannot be a shortsighted decision based on next year's budget or political calculus – this is our collective future.

Are we feeding or starving the golden goose? Will North Slope investment increase or decrease as a result of significantly higher taxes? Will the long term decline in oil production increase or decrease as a result?

What are the knock-on revenue effects on royalty, State Corporate Income Tax, and AVT taxes if investment is impacted? Is a high tax rate at modest prices appropriate?

The evolution of PPT and the Fiscal Contract negotiations

There has been a lot of speculation and innuendo about positions taken by both sides through the negotiation on the PPT. Unfortunately, this appears to be driving perceptions about what the tax rate should be rather than what is right for Alaska and what is right for industry.

I'd like to briefly give you an overview of how the PPT negotiation unfolded to hopefully clear the air and help us focus directly on the real issues at hand.

Since the onset of the fiscal contract negotiations, and indeed years before, BP has sought to make clear the importance of having a competitive and durable fiscal platform for both oil and

gas to underpin a massive gas investment. Including both in the Fiscal Contract is important for two fundamental reasons among others.

First, it provides confidence that the level of taxation will be competitive to enable the additional investments needed to mitigate the ongoing decline in ANS oil production so vital infrastructure can be maintained for another 40-50 years.

Second, it protects us from after the fact tax increases on our business after a gas pipeline has been built and we have no choice but to pay and produce regardless. This is what happened as TAPs entered service some 30 years ago.

In summary, both a competitive and durable oil tax regime are essential and should align well with State goals.

In the summer of 2005, the administration advised us that although they respected the importance to investors of having competitive and durable rules for both oil and gas in the Fiscal Contract, they did not see the ELF regime as properly suited as a long term solution. The concern being the tax base underpinning ELF was declining with time.

The concept of a PPT type structure was proposed by the administration to fix the so called ELF problem. We responded to the administration that if populated with balanced numbers, the PPT could be a viable long term structure with potentially positive attributes for both the State and industry.

In this regard we agreed to move off our preferred position which was to simply utilize the existing ELF based system for the duration of the fiscal contract and consider the PPT structure.

At that time, the mutually agreed goals of both sides for the PPT included:

1. all barrels should be subject to taxation
2. provide the State a balanced and proportionate share of the price / profit upside
3. stimulate additional investment critical to reduce long term production decline

Proposals were discussed intermittently through yearend and it was clear that there was a significant difference of opinion as to what numbers would create a balanced PPT that met these goals.

During that time, the State initially proposed and held to a 20% tax rate. The Sponsor Group had proposed a tax rate of 12.5% which we estimated would have increased State revenues by hundreds of millions of dollars per year at current prices and tens of billions of dollars over the long term relative to ELF. It would also have, we believe, stimulated more investment, more jobs and most critically more long term production.

On Saturday, February 18th, following a long and at times difficult negotiation, we were able to agree and conclude the gas portion of the Fiscal Contract with the State. The following day, we made another PPT proposal for the State to consider in advance of the planned executive meeting, including our Chief Executive, Dr. Tony Hayward.

This proposal made a very substantial move towards the administration's position while providing more support for investors at low to moderate prices where everyone agrees Alaskan investments are extremely challenged.

On Monday morning, February 20th, the Governor outlined to Dr. Hayward and the other executives his 20 / 20 PPT proposal. The proposal we had made to the administration the day before was rejected.

BP has agreed with the Governor that we will not oppose the rates and figures in the proposed PPT legislation before you today. Our Chief Executive and others have made the extremely difficult decision to accept the Governor's terms as a means to finalize a Fiscal Contract. We do believe that this PPT is at the far outer fringe of what should be seen as a reasonable or plausible range of outcomes.

We also need to be very frank with this legislature by saying upfront that we do not believe the 20% rate will maximize investment or in turn maximize long term production. Although the PPT structure has significant merit, and we support it, the overall size of the tax increase outweighs, we believe, the other benefits and goes well beyond optimum.

I hope this context has been helpful. We genuinely hope that this bill can be progressed in a thoughtful and objective manner. Alaska is at a crossroads.

I'll now turn things over to Angus Walker and our PPT team.

Introduction – Angus Walker

I am Angus Walker and I am the Commercial Vice President of BP Alaska.

I would like to start by thanking this Committee for this opportunity to provide testimony on the very important matter of House Bill 488 / Senate Bill 305

We recognise that between PPT and in due course the Gas Fiscal Contract you have decisions to make of great importance for the future of Alaska. We respect the responsibility that the Legislature has to do the right thing for Alaska and hope that we can inform those decisions through our testimony.

I would like to introduce my associates –

Ray Hall: Senior Tax Economist with BP Group in London

An economist by background, Ray has worked with BP since 1988, initially in commercial roles but latterly as a senior adviser on fiscal issues. Ray has held positions in organizations outside of BP including the United Kingdom Offshore Operators Association (UKOOA) and the International Association of Oil & Gas Producers (OGP). His most recent focus areas have been UK, Norway, Egypt and Trinidad.

Tom Williams: Tax Counsel for BP Alaska

It is particularly appropriate to have Tom here. He was Commissioner of Revenue for Governor Hammond and is widely recognised as the creator of ELF.

Our testimony will be in three parts, all of which are directly relevant to PPT and the issues before you:

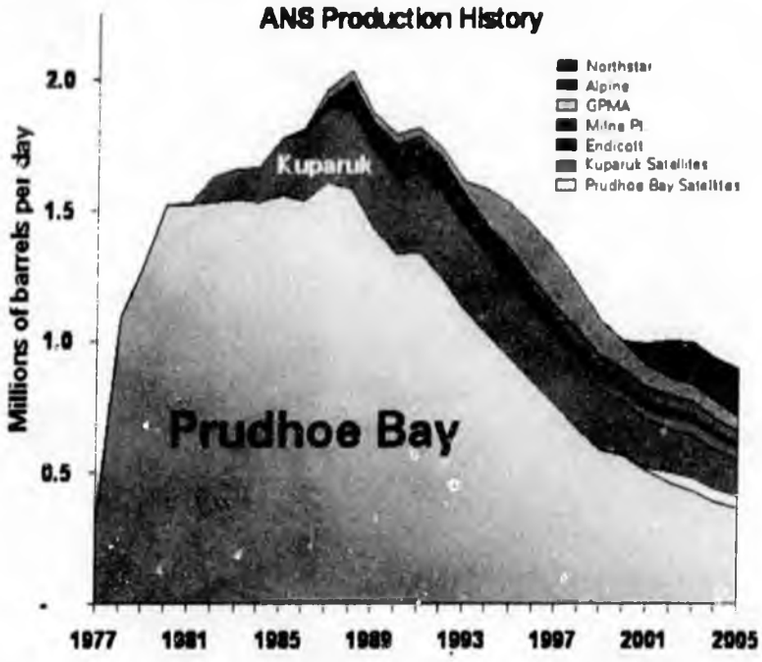
- I will start by describing the current realities of our business and the remaining resources of the North Slope
- Ray will provide a global perspective by comparing fiscal regimes in a selection of the countries in which we do business
- I will conclude by describing the impact of this PPT legislation on BP's business in Alaska

It should be noted that since BP only has leases on the North Slope and in the Beaufort Sea, our remarks will be confined to that business and not other basins like the Cook Inlet in which we do not participate.

Current realities of the Alaska North Slope

Alaska North Slope: The Current Reality

bp



- **Production declining at 6%**
- **ELF has stimulated additional investment through low tax rates**

We're looking at a profile of historical production from 1977 through 2005. The North Slope has produced over 15 billion barrels of oil to date, and while we look back with envy at the days of peak production it is clear that the business today is very different than it was 20 years ago.

To date BP has invested $24 billion to create the Alaska business we have today. We have paid over $32 billion of tax to the State of Alaska and $24 billion of tax to the federal government.

In total we estimate that the North Slope participants have generated $120 billion in taxes for Alaska & the Federal Government since first production in 1977. In addition, as an industry, we generate more than 34,000 jobs in Alaska every year.

But the harsh reality is that since production peaked in 1988, production has declined at an average 6%.

What this doesn't show is the underlying decline which would have occurred without the tens of billions of dollars industry has invested to stem decline. Natural decline of these fields is around 15%. As an industry we've managed to stem that decline to, on average, 6% over the last ten years by investing between 1 and 1.5 billion dollars a year in the North Slope business.

ELF has worked as intended

Each of the small wedges on this production profile represents the contribution from one of the North Slope's smaller fields. Many of these fields would not have been developed without ELF. And yes, whilst much but not all of this production pays Production Tax, it <u>all</u> pays property tax, royalty and state income tax and helps keeps TAPS operational and economic.

ELF <u>has and continues to</u> encourage investment in these small or less productive fields, and has played a significant role in stemming overall North Slope decline.

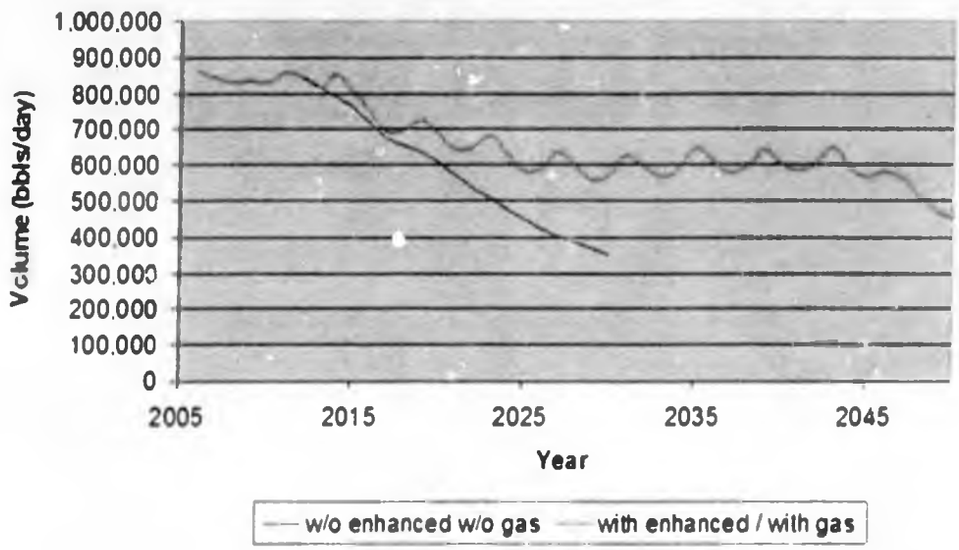
However, we recognise that ELF was designed as a surrogate for profitability and while it has been effective it is not perfect in today's price environment. And it is for that reason that we are supportive of adopting the PPT structure proposed by the Administration.

One of the most important issues for this committee to consider is the impact PPT will have on the decline of the Alaska North Slope.

DOR Scenarios

bp

Figure 1
Volume Scenarios



Source DOR Testimony PPT Analysis020106 (DOR) ppt

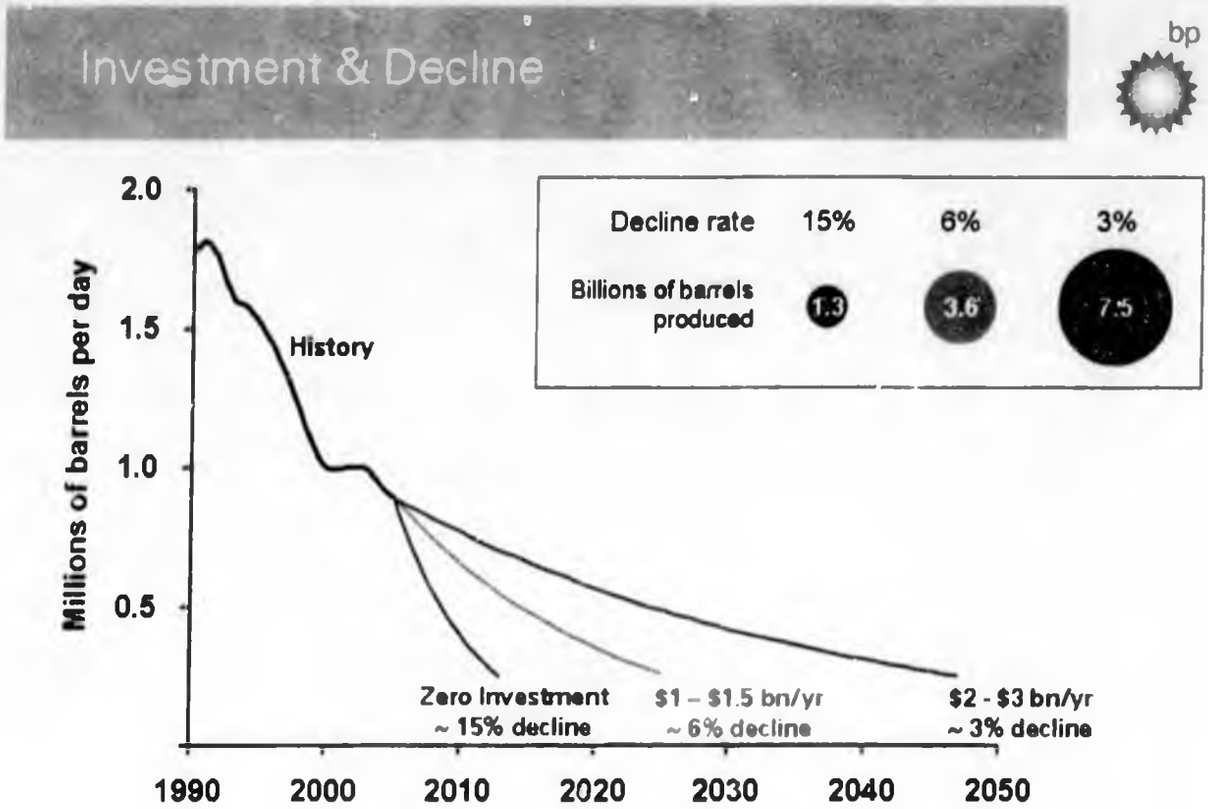
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You will recognise the above slide from Roger Marks' presentation last week. It shows two forecasts of future production – the lower blue forecast represents a future without gas, the upper pink line represents a future where the oil business is revitalised by gas.

We agree that the futures with and without Gas look very different. A future without Gas is very much shorter and far less exciting than a future with gas!

But, for Gas to work, it must be built on the foundations of a healthy oil business, a business which must remain healthy for 45 years.

So what will it take to keep the oil business healthy?



We share the challenge of keeping Alaska competitive

The simple answer is to stem decline.

The black line on this chart shows the history of North Slope production. The coloured lines look forward to the future.

With no investment the natural decline of the fields would be the lower red line and with in 10 years the business would be gone.

With the current levels of investment of $1-1.5 billion / year) (which assumes the current tax regime), history tells us that decline will be around six percent per year. With that trajectory we can expect the business to last around 25 years, but nowhere near long enough to enable gas.

In order to enable gas we must reduce the rate of decline even more. 3% decline would require twice as much capital as is being spent today ($2 - $3 bn dollars per year). That is $20 to $30 billion dollars over the next decade alone. Alaska must compete to attract these dollars!

We share the challenge of keeping Alaska competitive: the State's part is to maintain stability and keep Alaska attractive to investors; our part is to provide the technology, innovation and investment.

The tax regime you approve will directly impact how attractive Alaska is and what the future decline will be. It is in the interest of all (industry and Alaska) that we focus on growing the pie rather than taking an increasing share of a declining pie.

So where will we find all this oil to stem decline?

The good news for Alaska is that we have a huge resource base!

Alaska has lots of oil and gas!

bp

		Billion barrels equivalent
Produced		**15**
Known Remaining		**17.5**
Developed	- Light	3.5
	- Viscous	0.3
Undeveloped	- Light	4
	- Viscous	0.7
	- Heavy	3
	- Gas	6
Yet to Find (Exploration)		**5**

Recoverable Resource



Source DOR / USGS / BP

To date we have produced 15 billion barrels, but there are 17.5 billion barrels remaining that we already know about, 3.8 billion barrels of which have been developed to date.

The remaining 14 billion barrels consists of:

3.5 billion bbls of light oil remaining in the existing reservoirs
1 billion bbls of viscous oil which we have started to produce
3 billion bbls of heavy oil lying in shallow formations below the permafrost
6 billion bbls of gas which we are working so hard to get to market

The scale of this known resource greatly exceeds that expected from future exploration. Future discoveries are expected to be of the order of 50-150 million barrels. It's not to say you should stop exploring, but you cannot rely on exploration to stem the decline of the North Slope.

While BP isn't exploring in the conventional sense, we are adding barrels. We're not only looking at develop our share of the 17.5 billion barrels, but we're looking to make it even bigger.

To put that in perspective, every time we increase the recovery efficiency by just 1% we access an additional 600 million barrels (400 mmbbls light oil and an additional 200 mmbbls heavy oil)..... Every 1% is equivalent to another Alpine!

It is for this reason we're investing in technology. We're exploring within our existing fields.

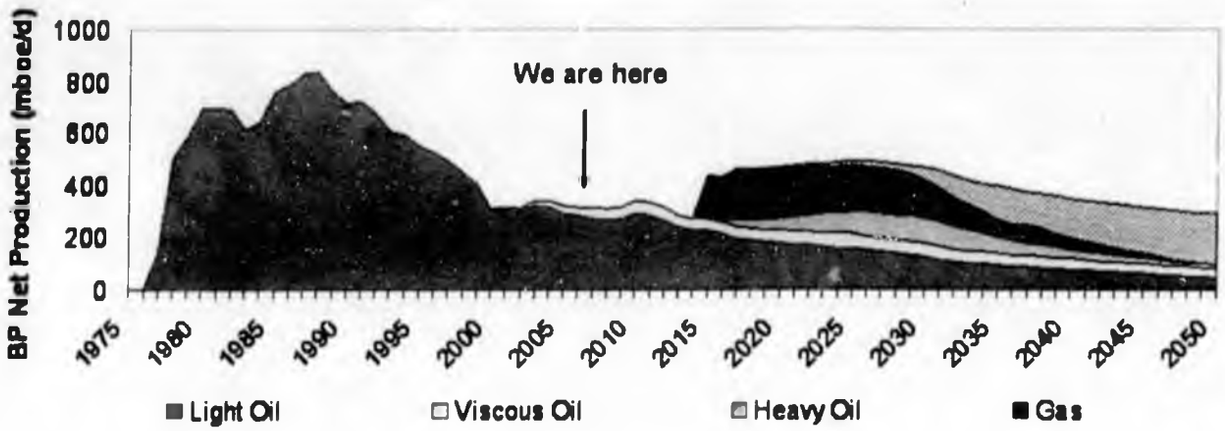
One example is that we're spending in excess of $100 million implementing innovative technology to increase recovery at Endicott. If we're successful at Endicott it could add hundreds of millions of barrels of production across the North Slope. (Another Alpine?)

To develop the 14 billion barrels we know about would require well in excess of $100 billion. And that kind of investment can only come from the Major oil companies of the world a fact supported by Pedro Van Meurs testimony. It thus mystifies us why so much of the testimony given to this Committee by Pedro Van Meurs focussed on the impact of PPT on new entrants when the future of the North Slope is dependant on making Alaska attractive to Major oil companies.

This is the reality of our business and the reality of the North Slope today.

It's the reality we encourage you to look at as you consider House Bill 488 / Senate Bill 305.

A 50 year vision



This is the graphic we use when we describe our vision for our business in Alaska.

It shows BP's production both historical and future. A few points we always make when we talk to this are:

a) The future will be very different to the past.
b) Three businesses built on top of each other all of which must be healthy.
c) We face enormous challenges in creating this future
d) Attractive and stable fiscal terms are key to making this happen, without it our vision will not come true.

I will now hand over to Ray Hall, who is going to provide a global perspective after which I will describe the impact of PPT on BP's business in Alaska.

Global Perspective

Refer to Raymond Hall's slides
[2006-02-28 BP Testimony - Global Perspective.pdf]

Impact of PPT on BP in Alaska

Much of the analysis presented to this comn.ittee has been based on specific cases – (50, 150, 500 mmbbl fields). These are of course academic examples and what I will do is to clarify the impact of implementing PPT on BP's business in Alaska.

I will do this through the lens of Government take.

Government Take

bp

$$\textbf{Government Take} = \frac{\textbf{Total Taxes}}{\textbf{(Total Taxes + Industry Profit)}}$$

Government Take in Alaska comprises 5 elements:-

- Royalty
- Production Tax
- Property Tax
- Income Tax

State Taxes

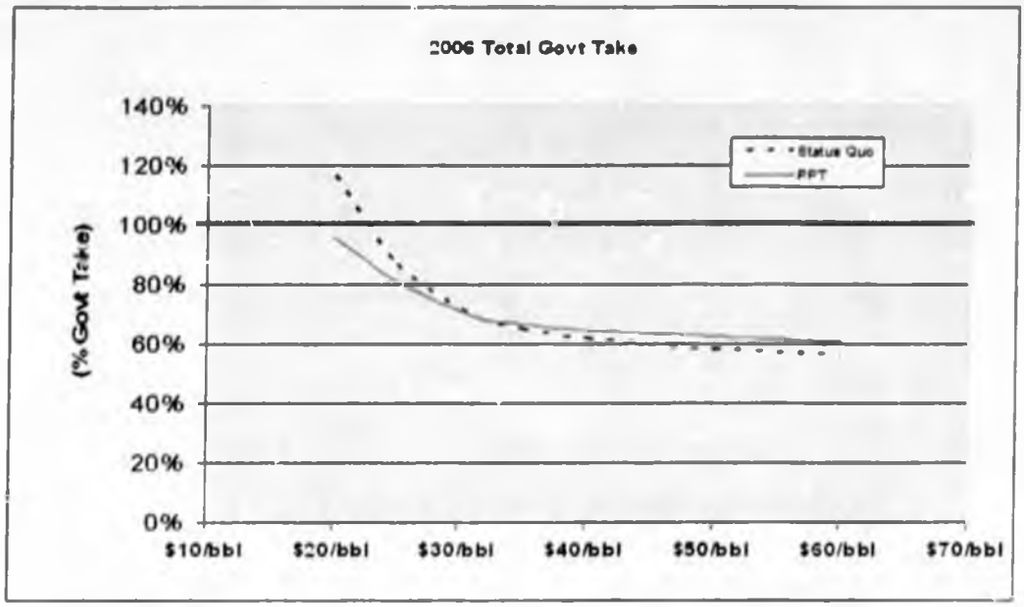
- Federal Income Tax

Federal Taxes

Government take is the percentage of total profit which is taken by government (in this case both State & Federal) with the remaining being the profit which goes to the investor.

Government Take is made up of a total of five elements: State income tax, property tax, royalties, production tax, and Federal income tax. The Investor's take is the investor's profit.

PPT Impacts on BP Alaska
Government Take vs. Price



- ***Government Take extremely high at low & medium prices***
- ***Investors must make a reasonable return at medium to high prices for Alaska to be attractive***

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This chart shows the total Government take at different oil prices for the current Elf based system and PPT.

That's the real Government take on BP's business in Alaska.

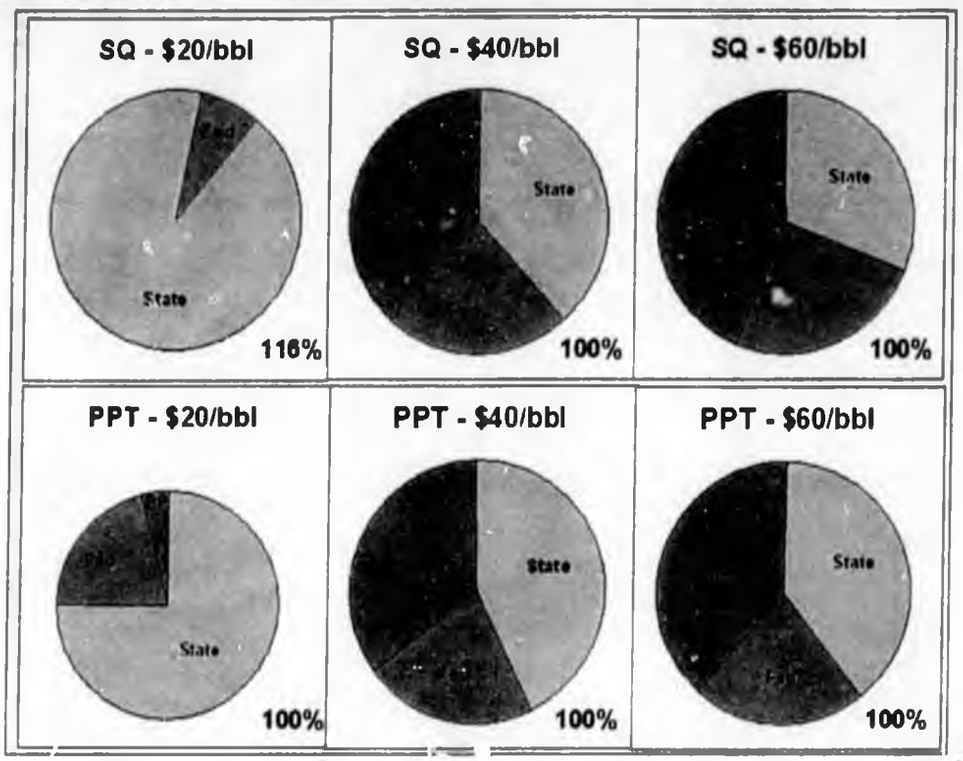
The first point to note is that at low prices we do not make a profit. We make a loss. But regardless we continue to pay Royalty, Property Taxes and State income tax, which results in a government take of greater than 100%.

Under PPT, the Government take is around 70% at the moderately high price of $30 / bbl. This is very high & especially considering the very high cost of doing business in Alaska.

We absolutely must make a good profit in Alaska when prices are high. We make no profit when prices are low. Alaska is a price play and if you take away the upside price incentive then there is no reason for us to be here.

Alaska is a mature business with a challenged resource. In our opinion you should be concerned about overtaxing the industry rather than undertaxing it.

PPT Impacts
Government Take (%)



Here we can see the split between State, Federal and BP take under the current regime and PPT at low, medium and high prices.

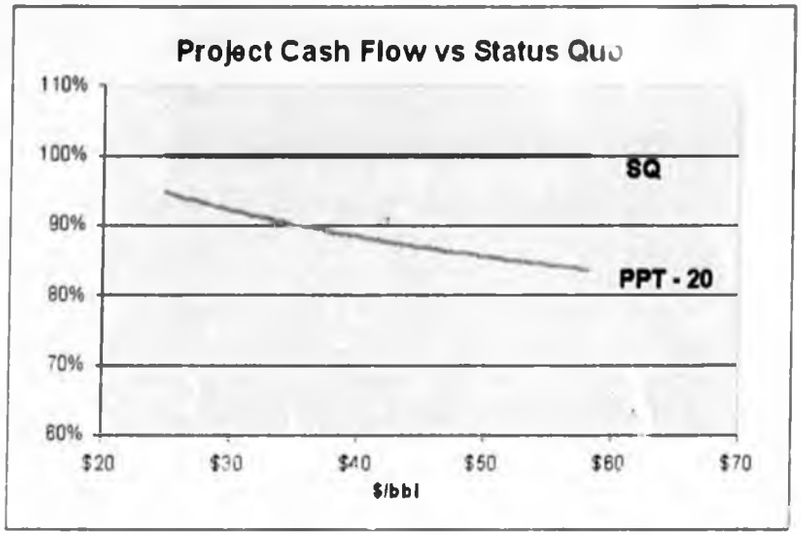
The left hand pies illustrate the problem for BP at low prices. Under the current system BP makes a loss at $20 / bbl.

At $60 / bbl the current system provides a higher % to the industry than to the State, but that is not new news. Alaska's fiscal system was designed to protect the state at low prices and compensate the industry at high prices. That is the nature of a regressive tax regime.

Under PPT, we would make an extremely modest profit at $20. At $40 the state gets a considerably higher share than BP. At $60 the State's and BP's take is balanced.

Introduction of PPT squeezes our profit at higher prices, and let's not forget we make the investments, we take the risks and absolutely we have to make a good profit at high prices for Alaska to be attractive.

PPT Impacts
Project Cash Flow



- ***Rate of Return improves, but it's only one measure***
- ***Project Cash is lower at all prices***

So what about future investments? We agree with Pedro Van Meurs, PPT will tend to increase the rate of return on many new projects, but we look at many metrics when making decisions about investing (Net Present Value (NPV), Net Income, and cash flow per barrel are but a few examples).

This graphic shows how PPT (20/20) impacts a new investment.

Rate of return is increased due to the positive impact of the capital credits on the upfront investment, but

Total return to the investor (after tax cash flow) is decreased due to the increased state take. This project takes the same effort / capacity to execute regardless of the tax regime. Increasing State take reduces total returns to investors making investments less attractive.

It is thus our sincere belief that the best result for Alaska is to implement a Petroleum Production Tax with a tax rate less than the 20% proposed by the Administration.

I would like to leave with you the key messages from this testimony.

PPT: Key Messages

bp

- **Decline is a problem**
  Alaska has been in decline because profitability has been insufficient to attract capital, not due to a lack of resources
- **Large increases in investment are required**
  To stem ongoing decline and attract the required investment ($50 - $100bn), PPT must work for the major investors
- **Capital is mobile**
  International investment flows to basins where it can earn a profit
- **Profit-based taxes are superior to revenue-based taxes**
  The PPT structure has merit and could serve Alaska well for the long term
- **Higher taxes means less investment**
  The 20% rate is very high and will not maximize investment and production
- **Oil needs Gas . . . and Gas needs Oil**
  For Gas to work, the Oil business must be healthy

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On behalf of BP I would like to thank you for this opportunity to testify and wish you well with your deliberations.

We will of course be available to provide further testimony as appropriate.



Alaska fiscal regime in global context

Raymond Hall, BP

February 2006

Outline

bp

Fiscal regime principles

Regime comparisons ***(detailed)***

- ***UK***
- ***Norway***
- ***Gulf of Mexico (deep water)***
- Alberta heavy oil
- US oil states

Key points for regime comparisons

1. Basin maturity, resource quality and policy objectives
2. Higher tax burden generally equates to less investment
3. Lowering tax rate generally equates to more investment

Design attributes of upstream fiscal regimes



Equitable: to investors and government

- Government should have adequate control over their resources
- Investor's profit potential should be consistent with the risk it bears and its resource commitment

Simple : to understand and administer

Stable: to protect economics of committed investments

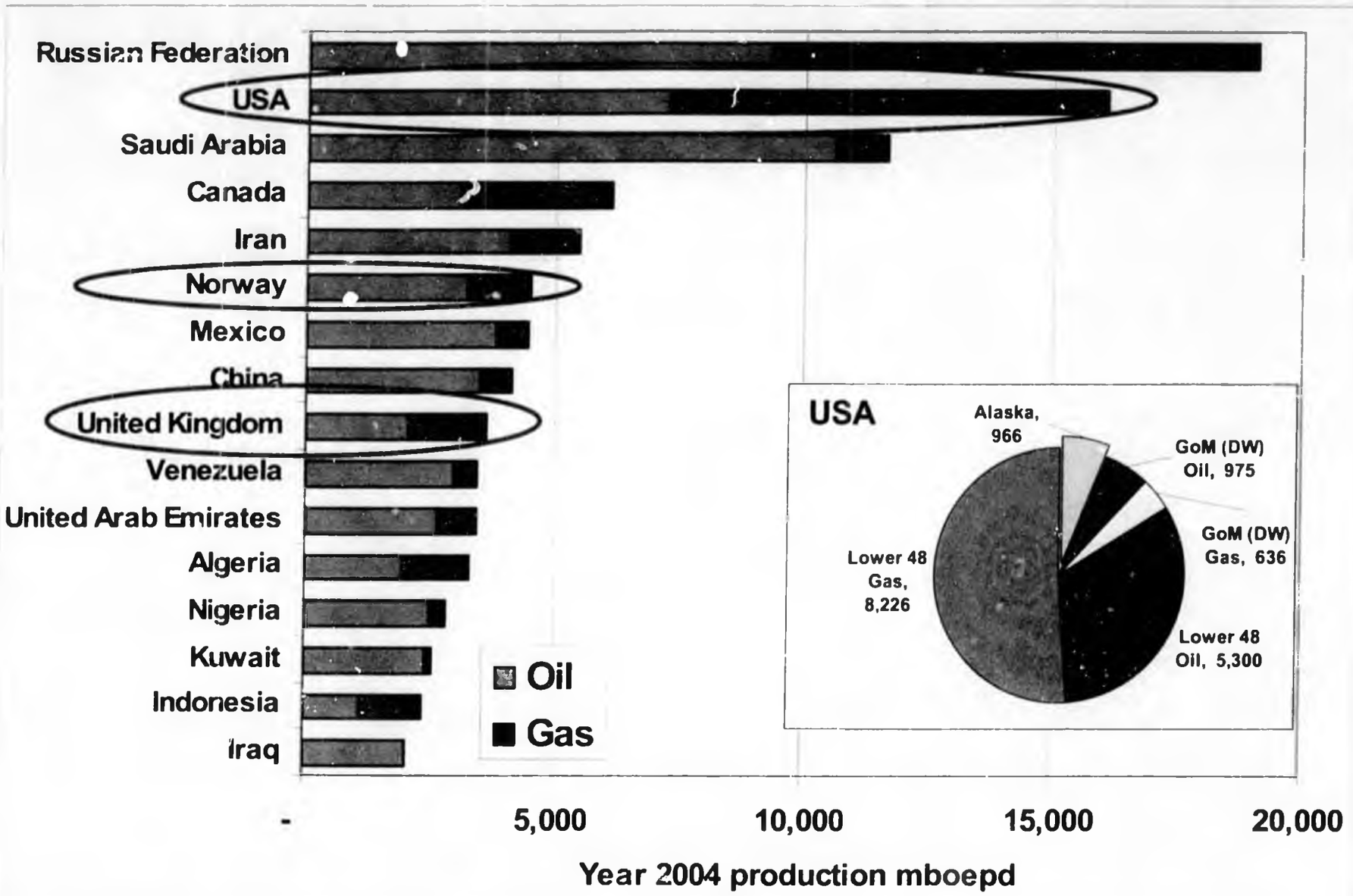
Profit related: tax levied on profits not revenues

Competitive

- Reflects maturity, geology & cost structure

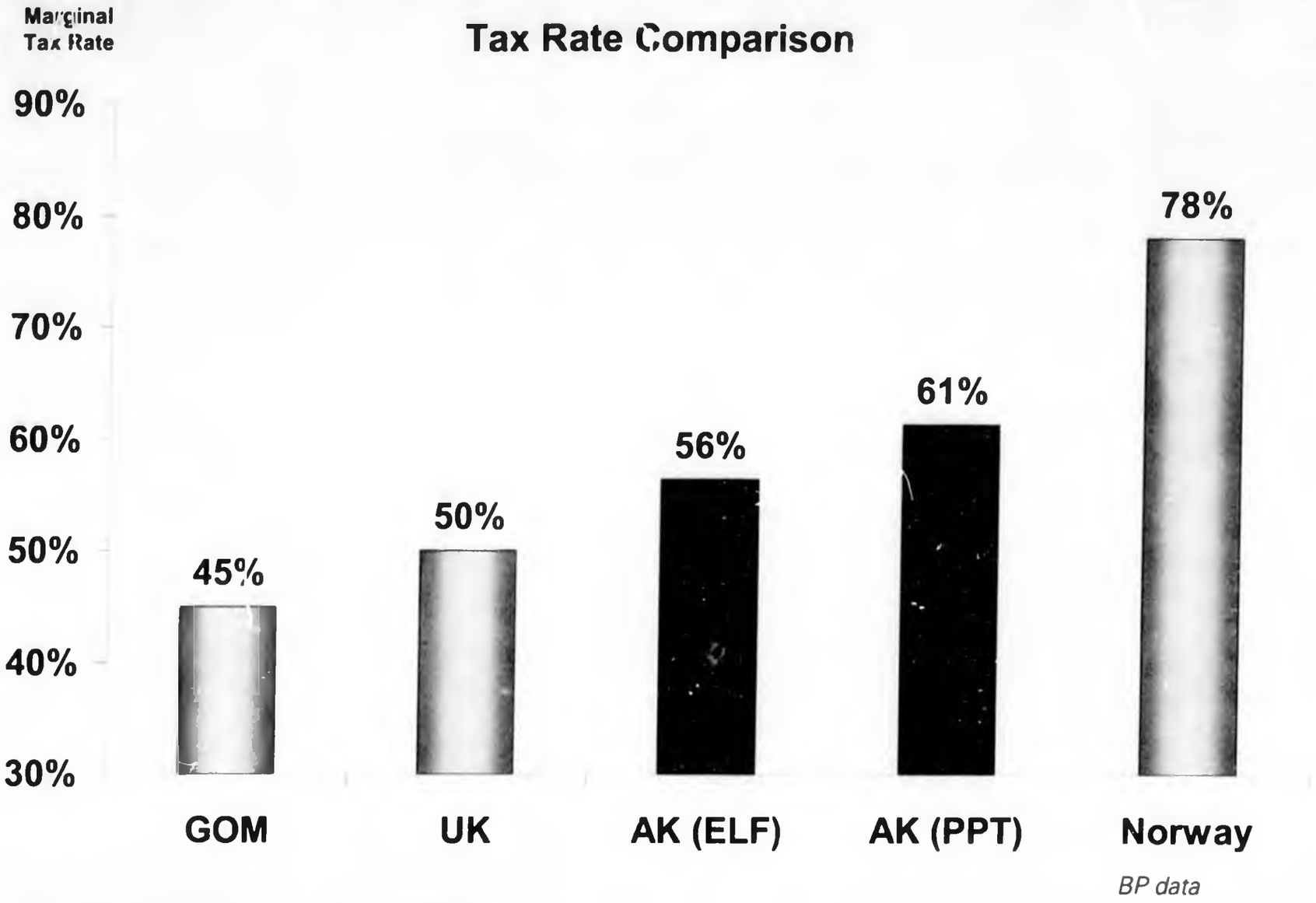
Efficient

Leading Global Producing Countries 2004



Source : BP Statistical review 2004

Fiscal Regimes



BP data

Note: UK rate 40% prior to 1/1/2006

Trend to profit based taxes

bp

UK

- Royalty: Rate of 12.5% (now abolished)
  - ✓ Abolished for **new** developments from 1983
  - ✓ Abolished for **all** developments from 2003

Norway

- Royalty : Rate in range 8% to 16% (now abolished)
  - ✓ Abolished for **new** developments in 1986
  - ✓ Abolished on **all gas** production in 1992
  - ✓ Phased out for **all oil** fields by 2006

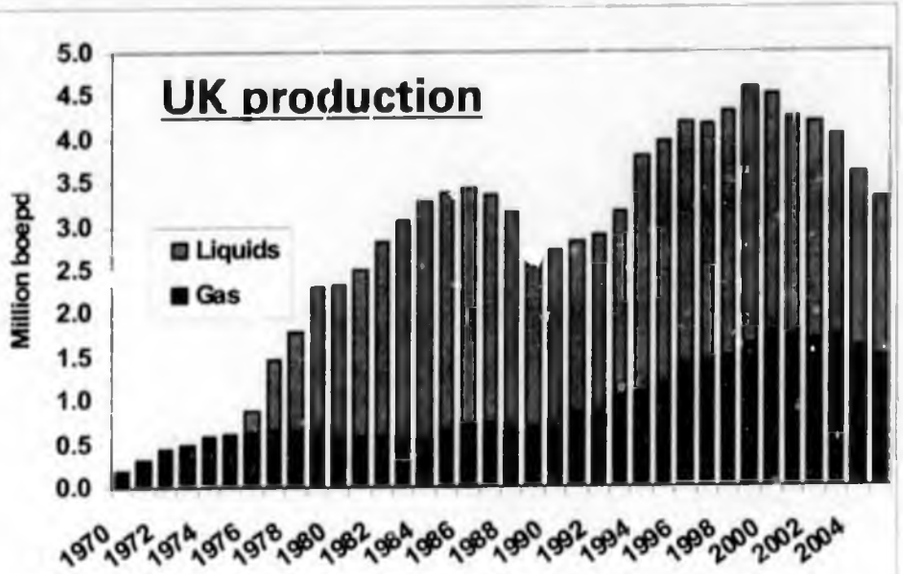
Gulf of Mexico (GOM)

- Royalty : Rate of 12.5% to 16.7%
  - ✓ Rate varies with water depth and cumulative production
  - ✓ Above 400 metres water depth rate is 12.5% maximum
  - ✓ Up to first 88 million bbs of production is Royalty exempt

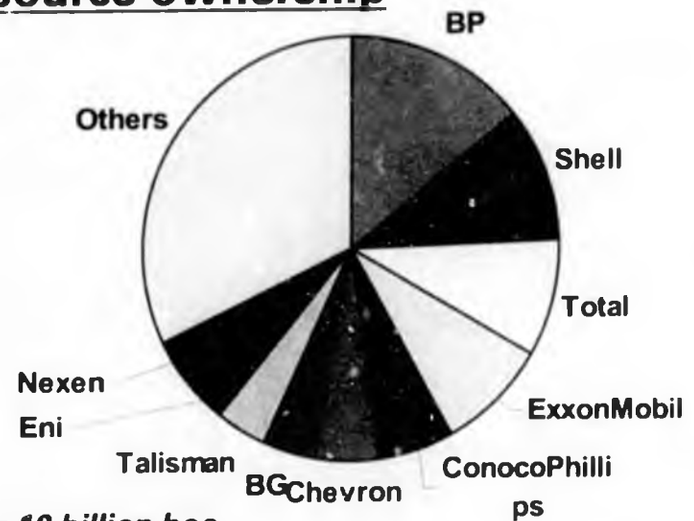
UK a mature basin facing many challenges

Policy objectives

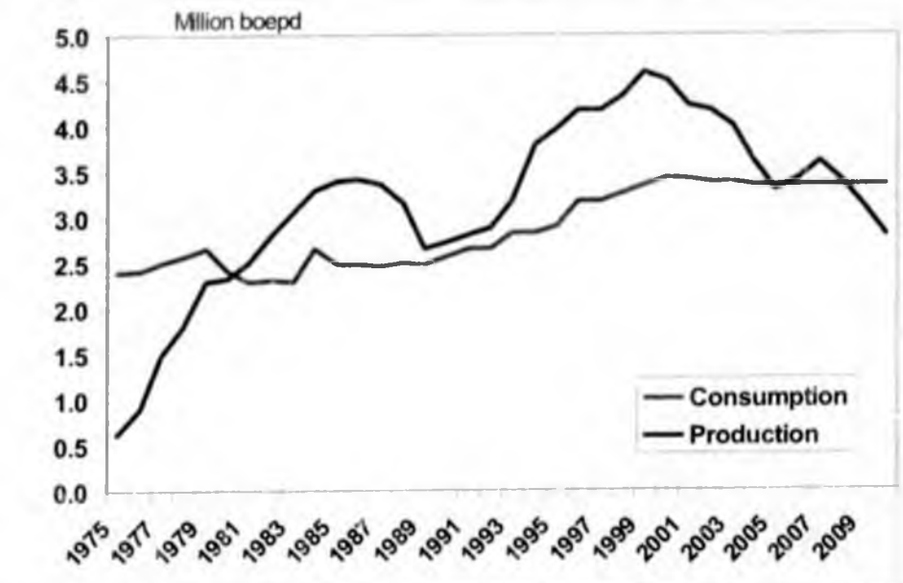
- Prolong self sufficiency
- Sustain competitive fiscal regime to
  - ✓ Maximize recovery
  - ✓ Encourage exploration
  - ✓ Encourage diversity (142 licensees)
  - ✓ Prolong infrastructure longevity
- Current challenges
  - ✓ Rapid production decline
  - ✓ Small opportunities
  - ✓ Recent Tax increase eroded confidence



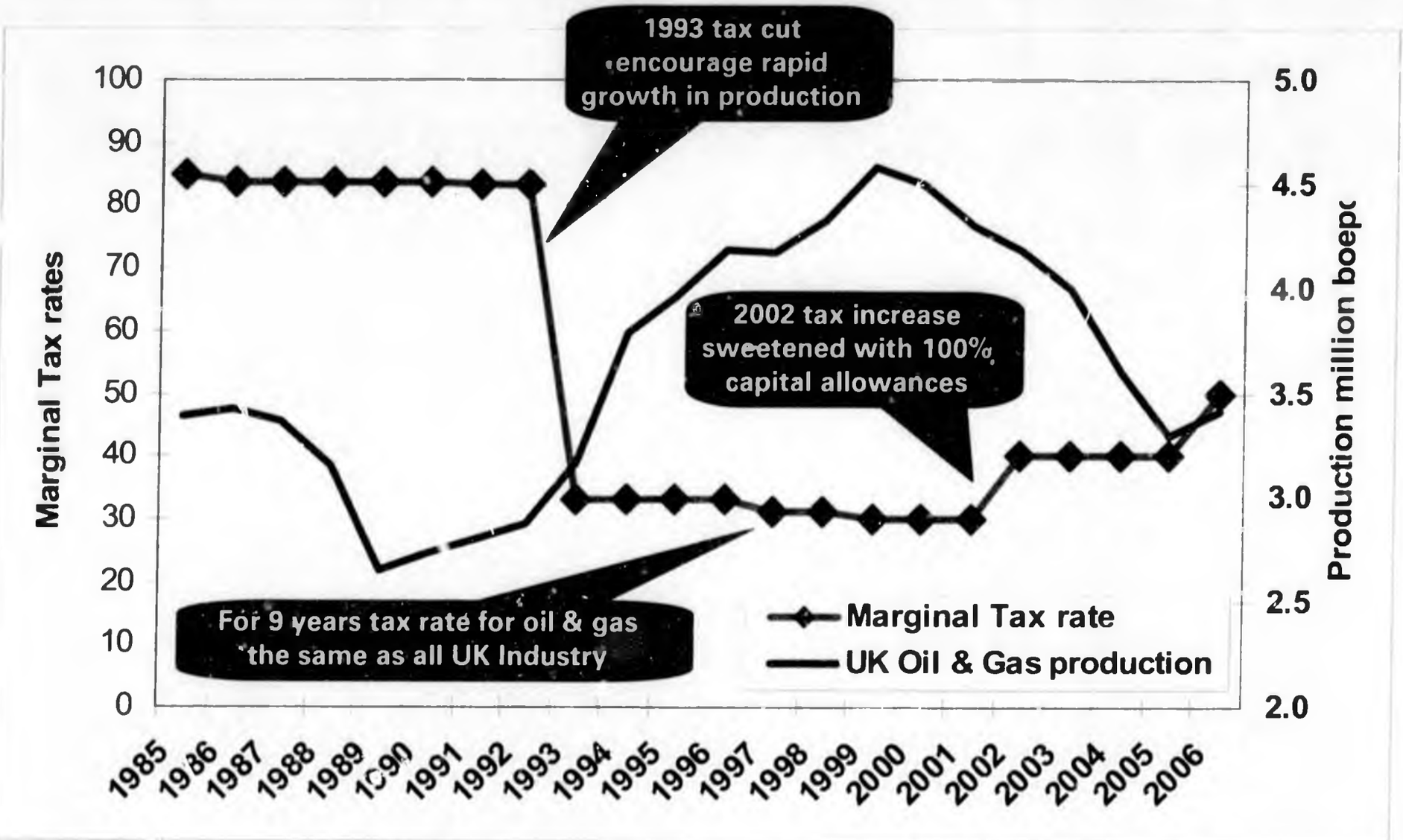
Resource ownership



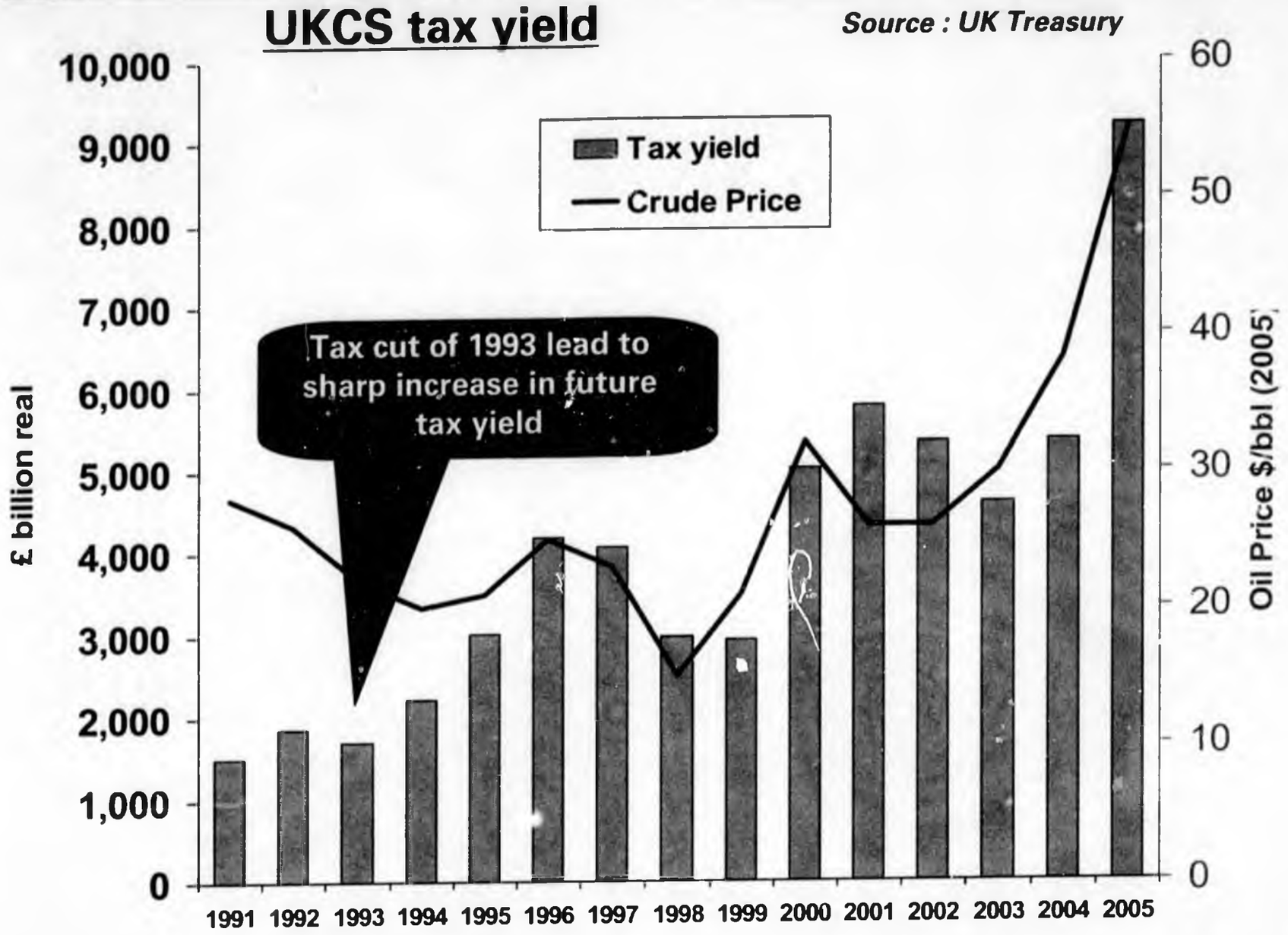
Total = 10 billion boe



.... But lowering tax rates will encourage investment



..... and increases tax yield



Norway less mature with much potential

Less mature than UK

- Produced 1/3 of resources
- UK produced over half

Strong state control

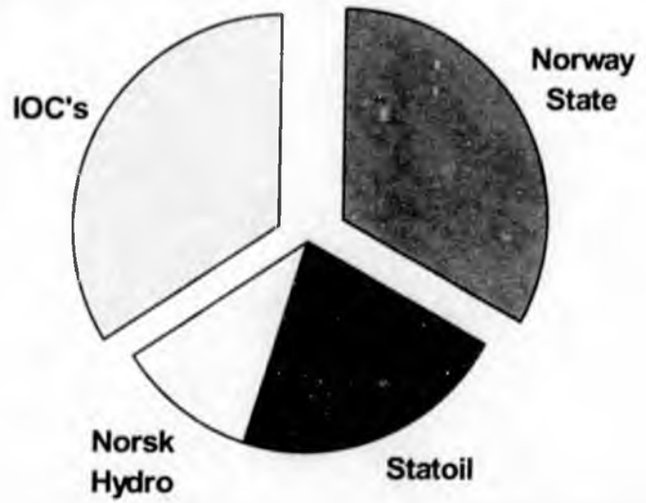
- State owns 1/3 directly
- Large equity in 2 largest players

Blessed with many giant fields

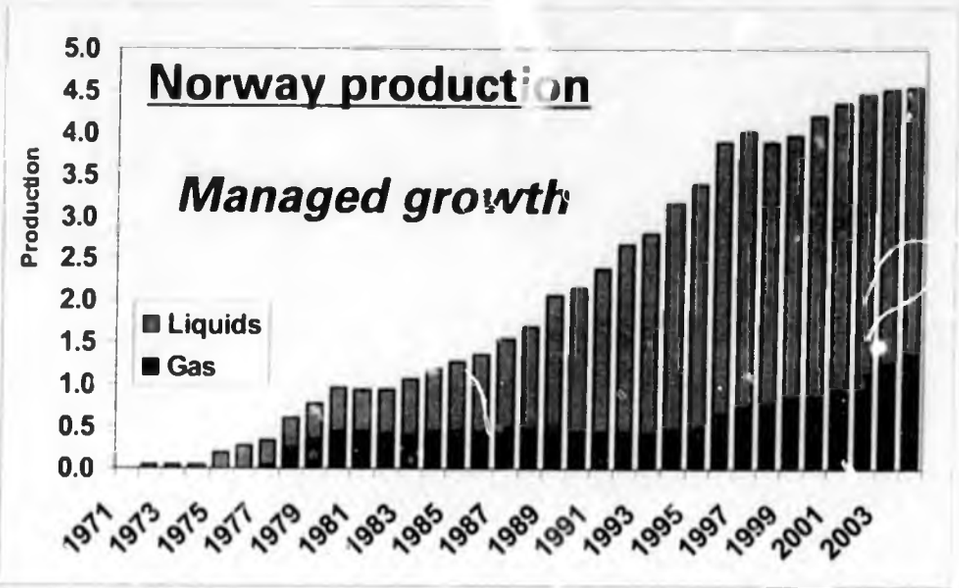
- 5 largest fields in North sea
- 11 of the 14 largest

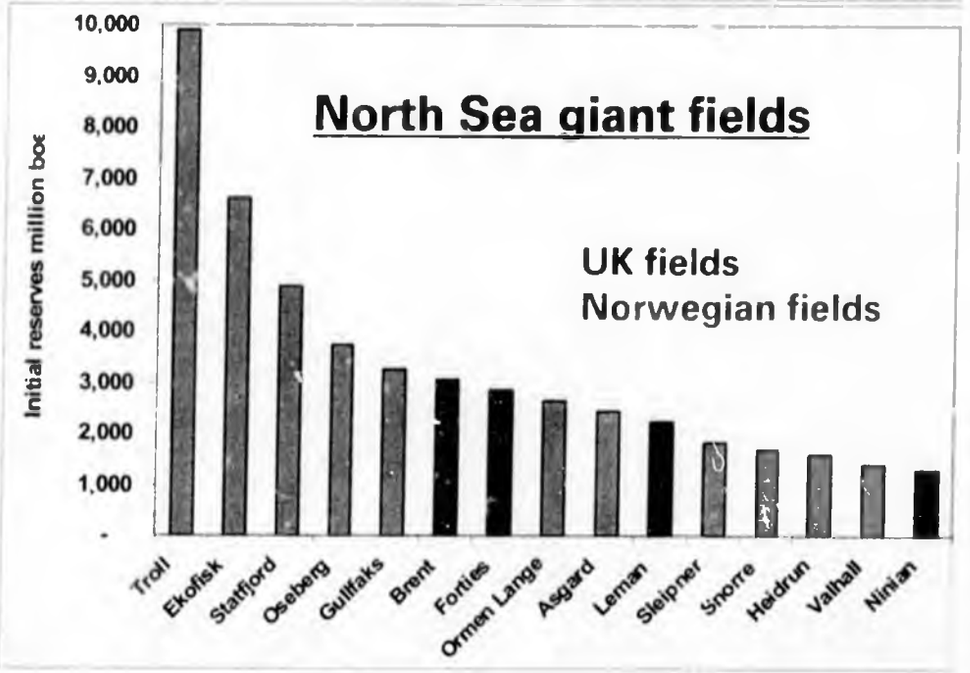
Close to European markets

Resource ownership

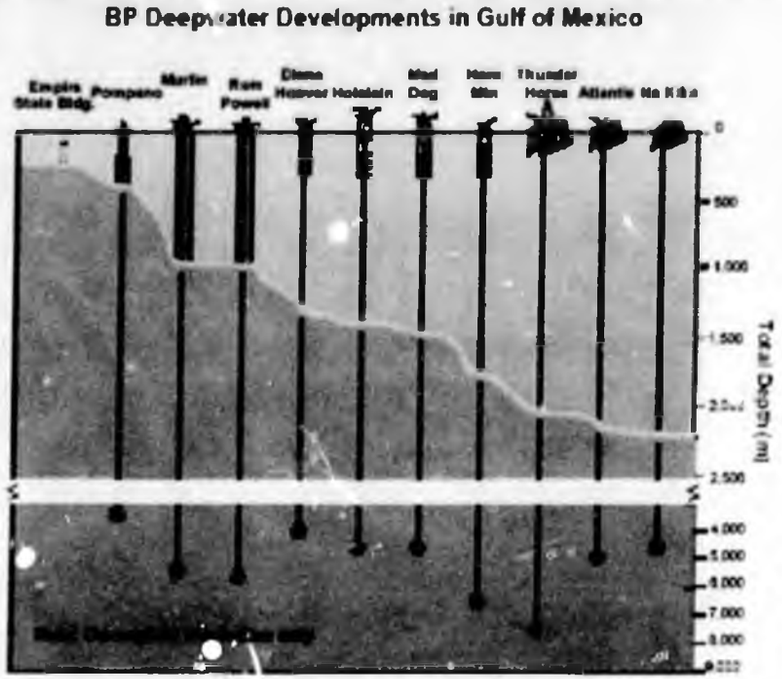


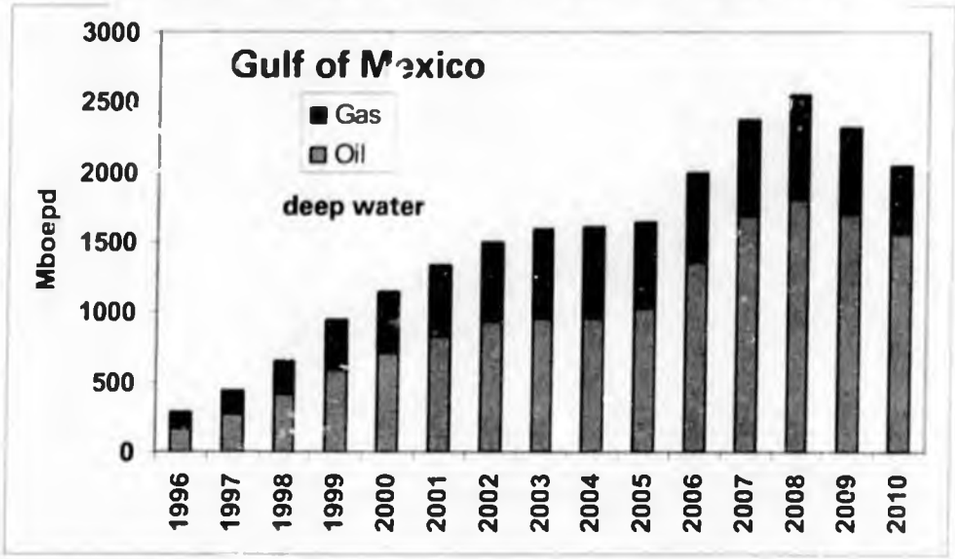
Total = 27 billion boe





Gulf of Mexico (DW)....lessons for all





Most active global exploration basin 1993-2004

- Highest E & A spend
- 2nd highest discovered volumes

Rapid growth in production

- Despite challenging deep water environment

Enabling factors

- Extension of existing Industry
- High volumetric potential
- **Competitive and stable fiscal regime**
- Close to markets
- Deployment of new technologies

Represents growing share of US production

- 10% in 2004
- Helps US Energy security

Alberta Heavy oil

Investment boom underway

- **Capex increasing up to $10 billion p.a**
- **Alaska flat circa $1 billion p.a**

Enabling fiscal regime

- **Key reform in 1995**
  - ✓ **1% Royalty until project payout**
  - ✓ **25% after payout**
  - ✓ **Federal and State tax of 39%**

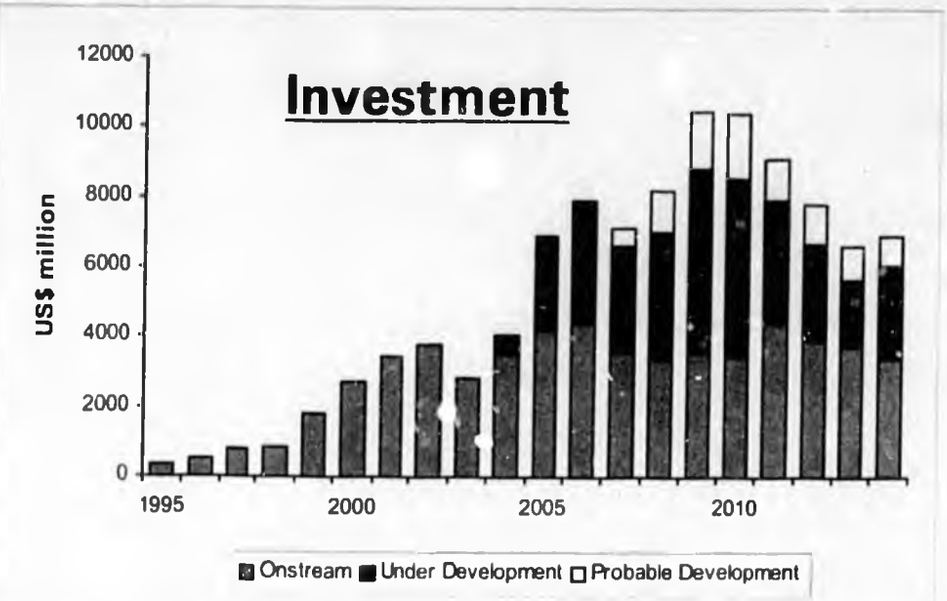
Marginal tax rates

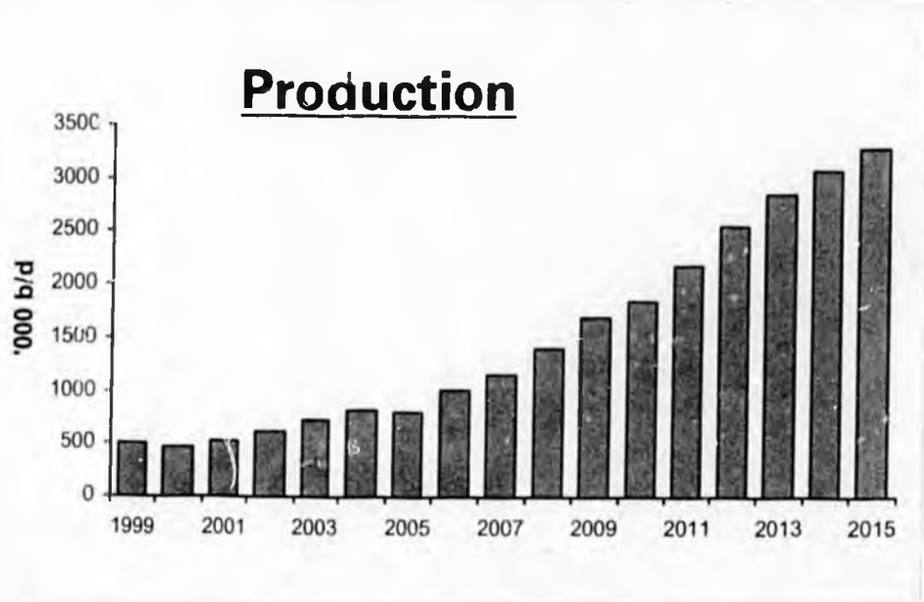
- **39% pre payout**
- **54% post payout**

Above rates will decline by 4% through 2007

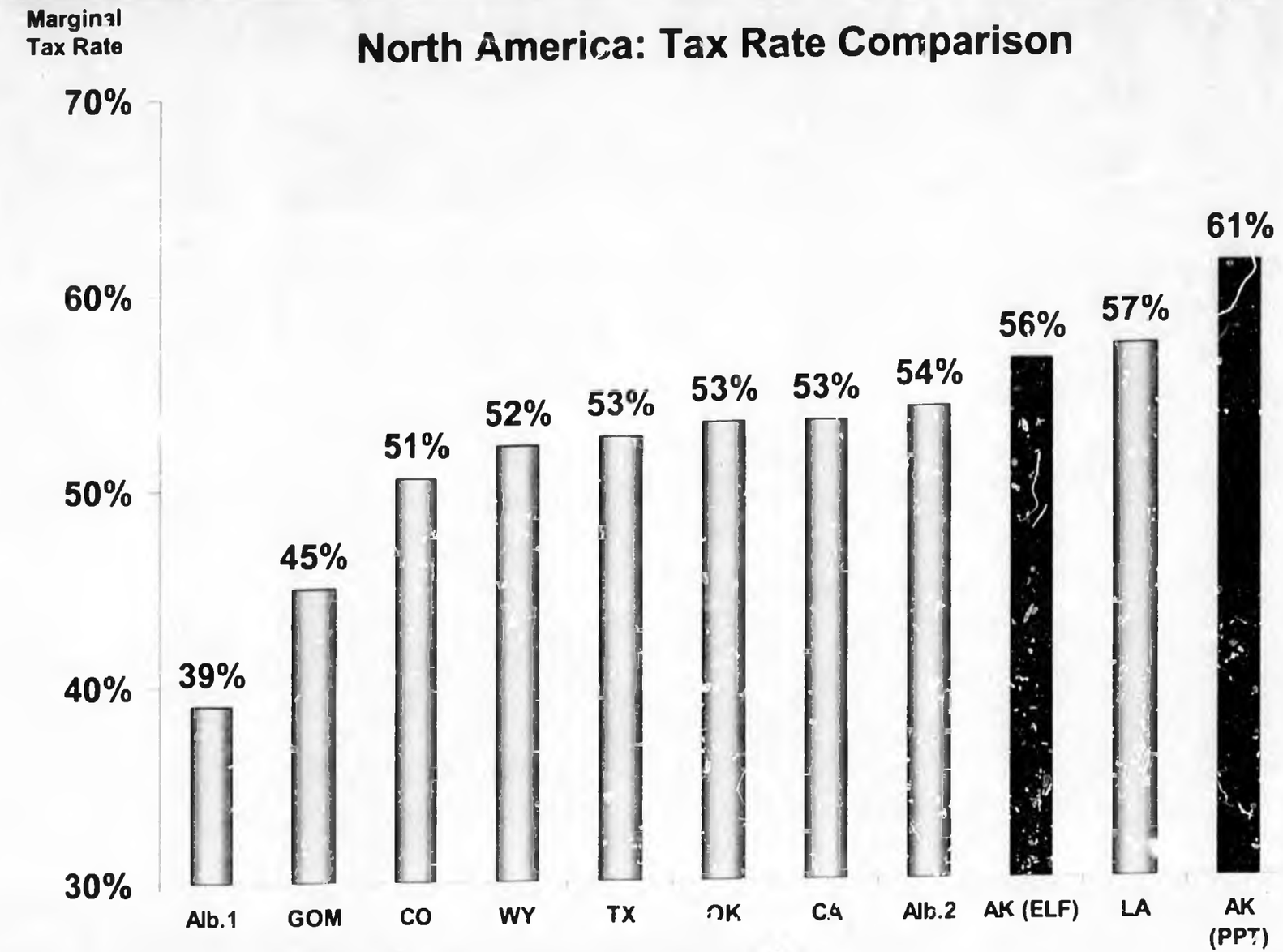
- **via phased reduction in Federal tax rates**

Source: Wood MacKenzie





Selected Fiscal Regimes in North America



**Alb: ALBERTA HEAVY OIL – pre and post-payout*

BP data

Summary – Alaska in Global Context

Regime comparison context is vitally important

- Basin maturity, resource quality, risk-reward relationship, cost environment, market considerations and policy objectives

Clear cause & effect relationship between fiscal policy & basin activity

- Higher tax burden equates to less investment
- Lower tax burden equates to more investment

UK experience, Gulf of Mexico, Alberta Heavy oil

2/24/2006

The Petroleum Production Tax (PPT) legislation currently under consideration by the State Legislature is part an agreement between the sponsor group (BP, ExxonMobil & ConocoPhillips) which covers fiscal terms for both oil and gas. The agreement represents a finely balanced package that will support the producers strategy to develop the massive oil and gas resources on the North Slope. It is a big milestone in delivering that strategy to the future of oil and gas in Alaska. Any further tax increase will jeopardize that future.

Points to consider -

- The Governor and producers have worked well over a year to reach this finely balanced agreement. Please don't mess this up.
- Alaska has abundant natural resources, but they are challenged by cost and geography
- The producers are working hard to apply innovative technologies to bring Alaska's oil and gas resources to energy consumers.
- These investments mean jobs for Alaskans and revenue for the state.
- But those investments won't happen if Alaska has a weak investment climate
- Alaska's fiscal policies should encourage investment and focus on growing the pie rather than taking an increased share of a shrinking pie.
- The rules of the game need to be clear and lasting. Big investments won't happen if taxes are too high, or if the rules can be changed once investments are made.
- We are on the brink of something very big: a fiscal contract that creates a healthy oil and gas business for generations to come.
- This delicately balanced legislation can help deliver that future, and I support this legislation as drafted because it enables a gas project to move ahead.
- New developments like the Ooguruk needed royalty relief to move forward, but also require infrastructure of the majors. The existing business must be healthy to provide this sort of development opportunity.
- Alaska's oil business must be healthy for gas to work.

Respectfully Yours,

James Gilbert
9201 Main Tree Dr.
Anchorage, AK. 99507

And

35290 King Salmon Ave.
Funny River, AK.

Role of the Alaska Oil and Gas Conservation Commission in Establishing an Allowable Gas Offtake Rate for North Slope Gas Sales

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The AOGCC has a very important role in this process – to protect the public's interest by preventing waste and encouraging maximum recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas production rates should be allowed from Prudhoe Bay and other North Slope oil fields. Considering only the laws of science, these decisions are very simple; to prevent waste and maximize hydrocarbon recovery, produce all of the oil in a reservoir first and then "blow down" its gas cap only when there is no commercially recoverable oil left. However, as is typical of just about anything Alaskan, many other factors will – and should – play an important part in reaching the best decisions for maximizing total hydrocarbon recovery and deriving maximum economic benefit for the citizens of Alaska.

Before considering other factors, it is essential first to understand the science. Extracting gas from an oil field like Prudhoe Bay triggers a series of events. First, the pressure in the gas cap decreases and becomes lower than the pressure in the oil-bearing part of the reservoir. As driven by the laws of physics, the reservoir then works to get back to equilibrium, i.e., the same pressure throughout. To do this, some oil, which is at a higher pressure, moves up into the lower pressure gas cap and the pressure in the oil-bearing part of the reservoir drops. This process continues as the pressure throughout the reservoir equalizes at a lower pressure than before. And as more gas is withdrawn, the process repeats, causing more oil to move into the gas cap and also causing the reservoir pressure to decrease further.

Both the movement of oil into the gas cap and the decrease in reservoir pressure jeopardize oil reserves.

Let's look at movement of oil into the gas cap first. Think about what happens when you drain the oil from your car or when you pour cooking oil into a measuring cup. When you empty the container, some of the oil sticks to it and will not come off. That is what happens to oil when it moves into the gas cap, a part of the reservoir that has never contained oil but has always only held gas. However, because that container is porous rock rather

than glass or plastic, the amount of oil that sticks is much greater. The previously "dry" reservoir rock becomes coated with oil. Although some of this oil can be produced, a substantial portion (in some fields over 20 to 30 percent) sticks to the rock and will never come out. In short, producing gas without replacing the gas cap fluids will cause some oil to stick to the reservoir rock and result in a decrease of ultimate recovery of oil.

Now let's look at decreasing reservoir pressure. Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids – both the active product and the carrier gas -- are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen. Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir. Typically operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they "blow down" the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oil field this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to suck water up a straw than it is molasses.

In summary, looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercial oil remaining to be produced WILL cause a portion of the oil resources to be lost and, thus, it is always best to keep the gas in an oil reservoir until no more commercially recoverable oil remains. Only then should the gas cap be "blown down."

The explanation above assumes that all of the gas can be recovered after all of the oil has been produced, and for most Lower 48 scenarios this is a reasonable assumption. However, for the North Slope there will be a trade-off between leaving black oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors.

For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas production. As this infrastructure ages, two things happen: 1) the cost to operate the equipment increases, and 2) components break and must be repaired or replaced. The later in time the gas is produced the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas will be left stranded.

The minimum rate at which TAPS can operate will also impact the balance between losing oil and stranding gas. Although the gas will have its own line which will operate independently of TAPS, continued operation of the TAPS line will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical.

These and other factors will complicate the gas off take rate and timing decisions for North Slope fields. The AOGCC must balance black oil recovery optimization with gas recovery optimization to insure maximum total hydrocarbon recovery, and this will be no trivial task.

Tim Benintendi

From: Kevin Brown [kevin.brown@gci.net]

Sent: Saturday, February 25, 2006 2:58 PM

To: Sen. Ben Stevens; Sen. Gary Stevens; Sen. Johnny Ellis; Sen. Con Bunde; Sen. John Cowdery; Sen. Bettye Davis; Sen. Fred Dyson; Sen. Kim Elton; Sen. Hollis French; Sen. Lyda Green; Sen. Gretchen Guess; Sen. Lyman Hoffman; Sen. Charlie Huggins; Sen. Albert Kookesh; Sen. Donny Olson; Sen. Ralph Seekins; Sen. Bert Stedman; Sen. Gene Therriault; Sen. Gary Wilken; Rep. Tom Anderson; Rep. Ethan Berkowitz; Rep. Mike Chenault; Rep. Sharon Cissna; Rep. John Coghill; Rep. Harry Crawford; Rep. Eric Croft; Rep. Nancy Dahlstrom; Rep. Jim Elkins; Rep. Richard Foster; Rep. Les Gara; Rep. Berta Gardner; Rep. Carl Gatto; Rep. Max Gruenberg; Rep. David Guttenberg; Rep. John Harris; Rep. Mike Hawker; Rep. Jim Holm; Rep. Reggie Joule; Rep. Mary Kapsner; Rep. Mike Kelly; Rep. Beth Kerttula; Rep. Vic Kohring; Rep. Pete Kott; Rep. Gabrielle LeDoux; Rep. Bob Lynn; Rep. Lesil McGuire; Rep. Kevin Meyer; Rep. Carl Moses; Rep. Mark Neuman; Rep. Kurt Olson; Rep. Jay Ramras; Rep. Norman Rokeberg; Rep. Woodie Salmon; Rep. Paul Seaton; Rep. Bill Stoltze; Rep. Bill Thomas; Rep. Bruce Weyhrauch; Rep. Peggy Wilson; Sen. Tom Wagoner; Rep. Ralph Samuels

Subject: Fw: HB488 &SB 305 PPT

Attachments: K.Brown Comments HB488 & SB 305.doc

Dear Alaska Legislator,

My comments represent my personal views. They are a bit long, but I hope you can review them before you vote on or ammend the very important PPT bill.

Sincerely,

Kevin Brown

Anchorage, Alaska

To the honorable chairmen:
Thomas Wagoner
Ralph Samuels

Comments from Alaskan, Kevin Brown

Re: HB 488 & SB 305 before the Legislature

Thank you for the opportunity to share my views regarding the bills under consideration.

Background
I'm transplanted, but have spent the majority of my life in Alaska, 29 years. My wife and I have six children ranging from 10 to 23 years old. My son graduates as a mechanical engineer this spring and hopes to return home to find work supporting the design and construction of the gas line. As a proud dad, I am very excited for him and those of his generation that will help deliver this building block of Alaska's fiscal future.

It is in this frame of mind I write to you. You and your colleagues in state leadership are trusted to secure this project for Alaska and our country. I am pleased that the State has reached agreement with the major producers. Soon, we can begin the engineering and planning that will take us to the point where we all celebrate the first sections of pipe being laid in Alaskan and Canadian soil. I implore you to do your part in assuring that politics does not impede this process.

Gas line
As to the pipeline project, please let reason prevail. There is only one proposal that has been evaluated in detail and explained. Also, that project's sponsors have the technical and financial capacity to deliver a thirty billion dollar project. Yes $30 billon! TAPS was estimated at less than $1 billion and exceeded $9 billion.

I'd ask that you not tolerate the distractions caused by ill conceived alternatives or misguided sentiment around all Alaska anything. The shortest distance to the market is a "straight line." I suggest it is time "all Alaskans get it" and "our leaders help us get on with it."

The deal
As I understand it, the Legislature has two steps before it votes for the gas contract itself. The first step is to create an oil production tax framework that can be added to the gas contract. In my view, this is an incredibly important step and I sympathize with producers. Please pass something they can support.

Prudence(what is being asked for is reasonable)

It is unreasonable to expect these companies to invest $30 billion without due diligence. Alaskan lessons can be attributed to numerous rule revisions, challenges and actions of DOR, DNR and RCA. Also, consider TAPS owners who have paid and fought to defend their tariff settlement ever sense oil began flowing. I would certainly ask for tax-rule clarity before I invested $30 billion. From the State's perspective I can think of more than 30 billion reasons to grant it.

Why are oil terms important? The oil business and gas business are the same business. God placed the oil and gas together; the same wells penetrate the same formations; gas and oil will flow to the same facilities; the same people, systems and processes will prepare the products for shipment; and, the companies running it all will report combined financial results to their shareholders. Gas will only work if built upon the foundation of a profitable oil business.

Bad timing (they could not have picked a worse time to ask for fiscal certainty- $60+/bbl)
We have been blessed and cursed with 18 months of extremely high oil prices. We've been blessed with additional revenues from royalty, severance tax and state income tax. And, we have been cursed with a lack of fiscal discipline, increased spending and a lust for our industry's profits. Is it right to participate in the upside? Yes; but Alaska must be careful not to bite the hand that feeds us, or worse yet, make Alaska less attractive for investment than it already is. Yes, they are making a lot of money. But, no one is asking how much Coke made selling sugar water last year. No one seems to remember Alaska at $10/bbl. And, I don't hear anyone talking about how these companies need good times to pay for the bad times. In the bad times (moderate to low prices), Alaska's amalgamation of taxes (royalty, severance, state income, property, environmental, federal income) cause the combined government share of revenues to exceed 100%. The PPT proposal does not eliminate this effect.

So, from producer's perspective, could you think of a worse time to negotiate a fiscal contract? And, recognizing this, isn't it all the more important that the legislature demonstrate constraint and wisdom while designing the new PPT? I'm confident that you can and I trust you will.

So here we are:
HB 488 & SB 305
This important decision affects the future of oil and gas, Alaska's future. The Legislature's decisions will be of immense benefit or detriment to Alaska. This is where I begin to worry a bit.

In general, I worry that a short-sighted grab for increased revenue may put the gas project at risk and also begin to put the Alaska industry into an unhealthy downward spiral.

The PPT method is a definite improvement over the old severance tax system. My issue is that the proposed 20% rate is too high and some of the other bells and whistles seem purely political; as, it is difficult to see how they add production or revenue to the State. The most obvious is the "give-away" in the form of a $73 million exemption. No company needs this if the rate is lowered and the credits raised. Revenue exemptions will not generate additional investment, but they will produce unwanted consequences. Low tax and attractive investment credits will attract investment. And, Alaska needs a lot more than historical levels to stop decline.

High investment credits can be made "safe" for the state with creation of simple deductibility limits (carry forwards) based on price. For example, have investment credits put in carried forward status unless oil is above $35 per bbl. Such limits will provide for a minimum tax during moderate and low price cycles. Further, if these key terms are

adjusted (tax rate□ - credit rate□), you may improve the balance enough to make an effective date of January 1 and a shorter transition term agreeable.

Alaska's resource quality and costs will determine our attractiveness for investment. Alaska has a cost disadvantage as Dr van Meurs illustrates; however, van Meurs doesn't realize that this disadvantage widens every year. Also, as ANS crude quality changes with increased viscous production, one may expect that market differentials would grow – another burden on the cost side. These "givens" must be considered collectively with the total government take to understand Alaska's competitiveness. Even at $60 per barrel this represents another 10% to 15% of disadvantage, or taken another way, add 10% to 15% before you compare Alaska tax burden to other regimes that are close to the market and have a product comparable to WTI.

Two last general points related to what Dr. van Meurs' testimony and analysis miss.

1. Given Alaska resource quality, our main competition is for development dollars with mature areas of North America and the United Kingdom and with booming and highly competitive areas like deep water Gulf of Mexico.
2. Alaska currently only has one market to sell its crude, the US West Coast. If the market changes, transportation costs increase and so does our competitive gap.

Analysis Paralysis, I've been watching gavel to gavel and I am concerned about the mind numbing presentations by DOR and state consultants. I actually feel for you as a simple concept has become incredibly confusing. The other problem with much of the work is that it does not focus on the real application of the tax (current producing ANS assets) and the taxes probable adverse impacts. These producing assets are life blood of this state.

Dr. van Meurs analysis

- his model assumptions do not reflect Alaska business
- understates tax and over emphasizes "first investment", "small players" and "incremental IRR"
- takes your eye's off the real ball – the $billions of increases you have been shown = $billions of decreases to investors and increased burdens on mature, declining and already high cost businesses
- tax will cause decline rate to increase – less production

DOR's analysis

- understates tax and exaggerates the $/bbl crossover point because they include gas development costs as a deduction in the oil PPT – the explanation I have heard is evasive and misses the point
- overestimates production in all cases (this is historically consistent with DOR track record)

Here is the simple equation neither DOR nor van Meurs has shared with you*(and likely other consultants hired by the Legislature to support tax increases):*

- More tax equals less investment
- Less investment equals less production
- Less production equals higher costs
- Higher cost equals a less competitive Alaska
- Less competitive equals even-less investment

- Even-less investment equals even-less production
- Even-less production equals **death spiral**

PPT proposal, Please consider

- Report by Dr. van Meurs has over 130 of pages of analysis supporting a structure where the tax rate is between 13% and 20%, includes a warning that 30% is too high and has two sections with a conclusion that a 25% tax rate is appropriate(?). The report is incongruent. (Does "best" mean "highest" in Dutch?)
- The emphasis on small players is noble, but no real reason to give a $73 million revenue exemption to anyone. Revenue exemptions won't add one barrel of production and will cost the state money. This provision will lead to poor behaviors and unintended consequences. If you need a revenue exemption, the rate is too high.
- Too many misleading graphs in van Meurs report. Where is the analysis of business being taxed: Prudhoe, Kuparuk, Milne, Alpine, Northstar & Satellites? Taxes have consequences and retrospective tax increases on sunken investment cause companies to readjust their view of regime risk.
- If Alaska wants to grow the business, consider a lower rate and higher credit. I've watched the discussion go from "ELF doesn't work" where the effective production tax rate is currently ~6%, to "how about 20, 25, 30, 35%??" This type of dialog is irresponsible. Please do your part in regaining balance. In other parts of the world, they have abolished royalties to help tail end production. We are talking about significantly raising taxes????
- Alaska needs major companies to increase their investment above historical levels. Increased oil prices have been helping. Will increased taxes?
- Alaska needs to attract other major companies (eg. Shell ...). Will provisions tailored to small players do this? The majors provide the niche for small players like Kerr McGee and Pioneer.
- If the base business is healthy, new players, large and small alike, will add value, but no free rides are necessary (e.g.$73 m exemption). A balanced system with a competitive rate and attractive credits will do.
- It seems reasonable for the companies to expect their return on recent investment ("claw back").

In summary

- The proposed rate of 20% is too high
- Consultants are confusing your decision with distorted analysis
- 25% rate announced just prior to agreement seems odd. *Weren't we all waiting to hear the outcome of a negotiation? How is it there was an announcement just prior to the final negotiation?*
- A reading of van Meurs report leaves you questioning the validity of his rate recommendation. *Are there previous drafts? Did DOR edit their consultant's report?*
- Must consider potential impact to base business and potential risk of downward spiral.
- Tax rate should be adjusted downward and credits upward.
- $73 million revenue exemption is a political-giveaway, adds no value to the state and should be dropped
- All modifications by Legislature should improve terms for existing business and represent terms which producers will support, paste into their gas line contract, and produce forward momentum on securing Alaska's oil and gas future

Finally, a little back seat driving (my day on the state Legislature)

1. Make improvements to PPT that the producers will support. These terms should increase state revenue when prices are up, create much more incentive for investment, provide some protection when prices are down, and secure the gas contract.

   a. Rate based upon oil price $/bbl

i. Below 30 per barrel	PPT – 0%	Credit – 25% carry forward
ii. Between 30 and 60 $35/bbl)	PPT – 15%	Credit – 25% (usable >
iii. Between 60 and 90 $35/bbl)	PPT – 20%	Credit – 25% (usable >
iv. Greater than 90 $35/bbl)	PPT – 30%	Credit – 25% (usable >
v. challenged viscous oil $35/bbl)	PPT- same	Credit – 30% (usable >

   b. Eliminate $73 million revenue exemption – PPT is good for small and large alike
   c. Limit "claw-back" to three years (usable above $40/bbl)
   d. Use credit and deduction carry forwards (without interest) to provide for minimum tax during moderately low oil price, but let companies recover during higher price cycles (this will continue to encourage more investment when prices are down).
   e. Legislature develop fiscal discipline to save excesses so we do not grow the fixed cost of running Alaska and make the whole system unstable with bulging state budgets.

I hope you will consider these views as my family's future rides on our getting this right.

Sincerely,

Kevin Brown
Anchorage, Alaska
February 25, 2006

Deborah Vogt
P.O. Box 675
Haines, AK 99827
(907) 766-3849

Testimony – Joint House/Senate Resource Committees
House Bill 488 / Senate Bill 305
February 25, 2006

Good Morning. Thank you for the opportunity to testify on this important bill

My name is Deborah Vogt and I live in Haines.

I served for five years as the Deputy Commissioner for the Dept of Revenue. I retired from that position in 1999; before that, I was an assistant attorney general for many years, and much of my practice was with oil and gas tax matters. I was the lead attorney for the state in the litigation challenging the separate accounting income tax; I mention that because in many ways this legislation is much closer to an income tax than a traditional severance tax.

It is great that the administration has recogized the defects in our current oil and gas tax structure, with the problems with the ELF being the most fundamental of those defects at this point in time. I am gratified to see the Governor bring a bill before this body, and I urge you to give it your most serious consideration. Having listened in on the hearings the last several days, I believe you are doing that. In my view, this is the most important topic over which you have real control that will probably come before in your careers. In many ways, the long term economic future of the state rests in your hands.

Specifically, then, with reference to House Bill 488: In short, I think it is a good fundamental approach, but with a seriously flawed execution. Certainly, an oil tax system in which the producers can recover their sunk costs before they pay taxes is a modern, and – as Dr. Van Meurs has testified – a common approach throughout the world.

However, **this** bill does not protect the interests of Alaskans. It gives far too much away, and unnecessarily so. I sit on the local municipal assembly here in Haines, and I am acutely aware of how much the state's reduction in municipal revenue sharing, coupled with the high cost of heating oil for schools and municipal buildings, has challenged local governments' ability to make ends meet, or in some cases, even stay open for business.

Any of you who operate a business can imagine the incredible benefit of not only being able to expense, in the first year, any capital expenditure that you make, but also getting a dollar-for-dollar credit for a portion of that expenditure. If I ran a dry cleaning business, and bought a new delivery truck for $50,000, I could not only deduct the ENTIRE $50,000 from my income that year (or carry forward a loss) but I would also receive a credit against my tax liability of $10,000. If I didn't have enough tax liability to offset the credit, I could SELL the credit. These provision of the production tax bill make it very competitive in the international arena.

If the bill stopped right there, I think we'd have a generous, competitive piece of legislation, so long as the tax rate were appropriate. But the bill goes on to grant what I believe are totally unnecessary give-aways to the taxpayers.

Examples include: the $73,000,000 tax-free allowance that every taxpayer gets, whether it needs it or not, and whether it invests that money in Alaska or not. I really cannot see the advantage of handing $73 million tax free dollars to a company, like Exxon, that has declared profits of $39 billion dollars unless it is developing something new in Alaska. These dollars don't have to be spent in Alaska; they can be spent to develop oil fields anywhere on earth. This is an overbroad and unnecessary provision; Roger Marks testified yesterday that the provision will cost the state about $40 million annually. Surely all the creative minds there in Juneau could design a provision that tailored an allowance like that to new development. There are a thousand ways to do it.

Second, the so-called "claw-back" provisions are just a give-away. These expenditures were not made with the thought that they would be recovered in this manner. This whole bill is about incentives; it is impossible to "incent" (a new word I learned this week) activities that took place half a decade ago. This provision, Marks testified, will cost the state $170 million for the next six years, if this bill is passed. If you don't want those dollars, let me tell you that the municipalities will take them!!! This provision should be deleted.

A much less expensive give-away, but still one that is unnecessary and should be recognized, is the repeal of the conservation surcharge of $.05 / bbl. (now divided into 2 cents and 3 cents) Thankfully, we have not had another major oil spill since the Exxon Valdez; but this is a giveaway we don't need to make. I don't, buy the way, see a fiscal note from the DEC on this provision.

The change from the Governor's original proposal of a January 1, 2006 effective date to a July 1 date, which took place after the Governor's meeting with the industry, is a give-away of a half a billion dollars (at the 20% tax rate now in the bill). I've litigated effective date (or more precisely, applicability date) provisions, and Assistant Attorney General Mintz was certainly right yesterday when he testified that the courts generally uphold these provisions. This tax greatly resembles an income tax, and in my experience, an income tax law almost always applies throughout a calendar year. It is very very common for such a provision to relate back to the beginning of the tax year. As I recall, the separate accounting income tax was enacted back to January 1 of 1978; its repeal

applied to an entire tax year. These sort of provisions have been litigated; I don't know of a case where a court has thrown out an applicability section in a tax case which goes back less than a full year. The January 1, 2006 date should be restored..

Much of this is no doubt dwarfed by the rate that is included in the legislation. Again, this rate changed from 25% to 20% after the Governor sat down behind closed doors with the industry. The Governor's own fiscal note projects that, at the 20% rate, this tax is better than the status quo for ONLY TWO YEARS, using the DOR's current long term price projections. Granted, most of us think, and we certainly all hope, that the long term price of oil will be above $25.50; but that is what they are projecting, and unless they revise that number, it makes sense to use it.

Certainly, a tax structure that plunges to worse than what we have now at a $25 / bbl price of oil is absurd. Clearly, at $25.00 oil, the companies are making plenty of money; the DOR's numbers show that if the price were $25 during FY 07, they'd clear $1.7 billion under the current tax structure, and the state would take in about the same amount. But under the bill you have before you, the state would lose the entire severance tax component of that amount, or about $400 million dollars. That's overly generous; we hope we don't see that price of oil any time soon, but if we did, your constituents would have good reason to be upset with you.

What's the right rate?? Certainly, the 25% originally proposed by the governor would be better. Dr. Van Meurs' study is based on this rate, and shows that Alaska would be very competitive internationally at this rate. I hope you take this question very very seriously and make the best deal for Alaskans. Have a special session if you need to, nothing could be more important. Hire you own international expert to advise you; hire two. Take your time.

An important part of that analysis should be the comparative share of the economic rents of production that are realized by the state and industry. Roger Mark's "Figure 12" shows those comparative amounts for $58/bbl oil at the 20% tax rate. The corporate share is 44%, and the state's share is 32%. Historically, policy makers since the 70's have thought that the industry and the state should enjoy an equal share. You should certainly request that DOR provide similar charts at various rates, and I'd recommend you adopt the rate that shows state and industry shares about equal. I would not be surprised if that rate were more like 30% than 20%. Find a system that doesn't tube to zero when the industry is still making significant money; find a system that gives the state an equal share of its natural resource wealth.

Thanks for the opportunity to testify; I wish you well in this endeavor.

Written Testimony of Adam M. Pener, Chief Operating Officer
Conflict Securities Advisory Group, Inc.
Submitted to the Alaska House State Affairs Committee
February 27, 2006

Introduction

Thank you Mr. Chairman and Members of the Committee for this opportunity to submit written testimony regarding Alaska House Concurrent Resolution 27. By way of background, I am Chief Operating Officer of Conflict Securities Advisory Group, Inc. (CSAG), a Washington, DC-based independent research provider that specializes in identifying and assessing U.S. and foreign publicly traded companies that have business activities in or with Iran, North Korea, Sudan, Syria and Libya.

To my knowledge, CSAG's *Global Security Risk Monitor* (Monitor) online database of public companies with such business ties is the only one of its kind. Our clients include the U.S. Securities and Exchange Commission (SEC), the Department of Defense and the Department of State and leading public pension systems such as the $85 billion New York City Employees Retirement Systems, the Missouri State Employees Retirement System and the Office of Arizona State Treasurer David Petersen. Numerous asset management firms, mutual fund providers and universities also utilize CSAG's products and services.

As a private, for-profit and impartial research firm, CSAG neither supports nor opposes HCR 27. Likewise, our firm, as a matter of corporate policy, does not take a position on how our data should be used by clients. Rather, CSAG seeks to provide impartial information that allows investors and their asset managers to conduct expanded due diligence in the area of global security risk.[1]

Over the past year, investors and state legislatures have increasingly sought to restrict investment in companies with ties to Sudan and/or other terrorist-sponsoring states. In a number of such cases, CSAG's research has been employed by asset management firms to comply with these new restrictions on a cost-effective basis.

I have submitted to the Committee a detailed Product Overview that describes our qualifications, provides additional background on our firm and global security risk and describes our research methodology and verification processes. More information on CSAG as well as a "Free Trial" of our database can be found at www.conflictsecurities.com.

Testimony Content

CSAG believes that its extensive experience in helping pension systems and asset management firms comply with legislative requirements, investment mandates and corporate governance initiatives will assist the Committee in its deliberations with respect to HCR 27. At the request of the Committee, I am pleased to offer testimony that will:

[1] CSAG was established following a determination by the SEC in May 2001 that corporate ties to U.S.-sanctioned countries, including U.S. State Department-designated terrorist-sponsoring states, can be material to investors. This new risk category was termed "global security risk," or the risk to a company's share value and corporate reputation stemming from its business activities in or with terrorist-sponsoring states. The majority of CSAG's clients use the data to identify portfolio companies that may be exposed to global security risk and to help assess such risks.

1. Address the issue of whether data is available that would allow the Alaska Permanent Fund (APF) and Alaska State Pension Investment Board (ASPIB) to comply with HCR 27;
2. Provide a cost estimate for implementation; and
3. Address, to the best of our ability, the issue of "divestment costs" (i.e., prospective portfolio losses associated with divesting from companies with ties to Iran or North Korea).

Before continuing, I should note that CSAG's experiences in this field have netted results that differ from those anticipated in Ms. Achee's testimony. I hope that Ms. Achee, the Committee and the Alaska Permanent Fund will accept my apology in advance if any of these differences were a result of my inability to articulate properly the capabilities of our firm and CSAG's pricing models during my call with her of Wednesday, February 21.

List of Companies

In the event that APF and ASPIB are required to screen out companies with business activities in Iran or North Korea, the question has been raised as to how the Funds could identify the relevant companies.

I respectfully disagree with APF's suggestion that the Federal Government, via the SEC -- rather than private research firms -- should be looked to as a source to identify and publish a list of companies that have business ties to terrorist-sponsoring states. The SEC and the Treasury Department -- in public statements and letters to public pension systems -- have made clear that the government cannot, and will not, provide a list of companies that do business in terrorist-sponsoring states. There are several reasons why the government has been firm on this matter.

Legality of Operations

The USG can (and does) provide investors with a "do not buy" list of companies that have engaged in **illegal** activity. The vast majority of companies with ties to Iran, North Korea and other terrorist-sponsoring states, however, maintain such operations legally. The U.S. government, including the SEC, cannot and does not provide lists of companies that are not in violation of any law.

This is likely why U.S. Treasury Spokesman Taylor Griffen, in response to pension system requests for a government-identified list of these companies, stated in an Associated Press article dated July 8, 2003: "[Divesting from companies with ties to terrorist-sponsoring states is] not a question of regulation, but of policy, and we would leave that for the states to decide." (See Attachment 1.)

Global Security Risk

While pension systems can legally invest in these companies, such investments can still introduce risk to the investor. In that connection, it is the job of the federal government to ensure that companies disclose all activities that could put the investor at risk (usually via public filings).

It is not the responsibility of the federal government, however, to provide a list of companies that may be risky investments. SEC Deputy Director Shelley Parratt said as much in a letter to Nick

Maiale, Chairman of the Pennsylvania State Employee's Retirement System (PSERS) dated July 28, 2004 (see Attachment 2):

> "It would be inappropriate for [the SEC] to publish a list of companies whose securities might be deemed to involve terrorism-related investment risk without publishing corresponding lists for every other possible type of investment risk."

This unwillingness of the government to identify companies exposed to risk might help explain why the SEC looks, in large part, to CSAG to make these identifications through a subscription to our aforementioned *Monitor* product.

Values Based Investing

As Mr. Griffen and Ms. Parratt make clear, it is not possible for the government to provide a list of companies that have legal ties to terrorist-sponsoring states. It is likewise restricted from providing a list of companies that may be exposed to global security risk.

Interestingly, HCR 27 speaks to neither the legality of these investments nor the risk factors they involve. Rather, the Alaska Resolution reflects the fact that some investors that business activities in terrorist sponsoring states run counter to their personal values or beliefs, or that of their constituencies. This is commonly referred to as "values-based investing." For example, some investors choose to avoid investing in companies that promote tobacco, gambling, firearms or alcohol – *not because it is illegal or risky to invest in such companies*, but because the investor is seeking to align their personal values with their financial goals.

This "values-based investing" question lies at the heart of HCR 27. Apparently, some state legislators believe that Alaskans simply do not want to invest in companies with business ties to Iran or North Korea.

This position is, again, perfectly within the rights of the investor or, in this case, the state of Alaska. For example, some states and public pension systems restrict investments in companies that produce tobacco products. Others will not invest in companies that fail to meet certain labor rights standards. **However, it is important to note that in no case, will the USG tell an investor whether or not to establish such "values-based" investment restrictions or provide a list of such companies.**

As Ms. Parratt goes on to say in the aforementioned letter,

> "It would also be inappropriate for [the SEC] to engage in any activity that might be construed as providing investment advice."

[We probably need a summary b-4 transitioning here...] To summarize, HCR 27 seeks to assess whether Alaskans want to invest in companies that operate in Iran or North Korea.

Finally, the APF has correctly pointed out that companies such as CSAG do not promote the use of their data as a "divestment list." As noted above, our firm believes that advocacy of any type runs counter to our corporate mandate to provide impartial, independent data to our clients. Moreover, our list is designed to be a comprehensive research tool that includes information on a variety of

corporate ties to Iran and North Korea. Whether such ties meet Alaska's threshold for disinvestment should be up to the state and its Funds to determine.

To be clear, CSAG has not designed its research or products for any predetermined use by its clients. Accordingly, subscribers are welcome to use our products in any way they deem indicated – including to develop screens or implement a divestment policy.

The bottom line is that CSAG has extensive experience in helping clients comply with divestment policies and similar investment restrictions. We are confident that our firm could likewise work with the State of Alaska, its public pension systems and its asset managers to help meet their needs.

Cost of Data

Naturally, there would be modest costs involved should APF and ASPIB decide to identify or screen out companies that do business in Iran and North Korea.

- Our standard subscription is $15,000 per year to access the full *Monitor* database and research. This option is widely used by clients that wish to use our product to enhance their due diligence process and have comprehensive information on the business activities of publicly traded companies in Iran, North Korea, Sudan, Syria and Libya.

- If the Committee (or APF and ASPIB) wanted to determine how many APF and ASPIB holdings would be affected by the HCR 27 restrictions, CSAG could provide a "Certification Report," including sample company profiles, for $3,500.

In the event that APF and ASPIB establish investment restrictions on companies with business ties to Iran and/or North Korea, implementation could be approached in several ways. For example, the Funds could allow their asset managers to comply independently with state law by purchasing their choice of research products – which is the process being employed by Illinois.

Based on our understanding of the concerns raised by APF and ASPIB regarding how a Iran and North Korea screen would be implemented, CSAG believes the more "top-down" approach described below might guarantee a higher level of uniformity in the data used by asset managers.

In this "top-down" approach, CSAG could work with APF and ASPIB to configure a custom screen for Iran- and North Korea-linked companies to comply with Alaska. The custom screen would involve the formulation and maintenance of a "do not buy" list based on CSAG's research. This single, statewide list would then be available to asset managers for the consistent application of state law. For example:

- The Funds would review CSAG's data and establish a "do not buy" list of companies that meets Alaska's specifications. (Please note that such a list could exclude companies that, for example, only have humanitarian ties to these countries.)

- Determine an agreed price point for CSAG to provide the Alaska custom screen to all APF and ASPIB asset managers, including regular updates of the list.

- Managers that are already subscribers to CSAG's *Monitor* product would be able to employ the Alaska screen at no cost.
- The Alaska Funds would have access to the custom screen at no cost to assist the process of overseeing their managers.

While I cannot provide a firm price point for such a custom screen at this time, I am confident CSAG would be able to execute this proposed process for substantially less than the APF-estimated price tag of between $207,000 and $585,000 annually.

Specifically, I would estimate that CSAG's custom screen proposal for Alaska would be priced between $1,500 and $3,000 annually, per manager. The exact price point would depend on the number of asset management firms that would require ongoing access to the custom screen. Naturally, the cost-per-manager to access the screen decreases as the number of managers using the service increases.

Accordingly, I would anticipate the entire set of deliverables described in this implementation scenario to cost *Alaska asset managers* cumulatively some $75,000 - $100,000 per year. Interestingly, in the event that Alaska's asset managers were required to implement a screen, the cost estimates I have provided would likely represent less than one quarter of one percent of the APF's FY06 budget for asset managers (i.e., based on APF's estimates, asset managers will collectively receive $46.6 million from Alaska in 2006, while having to budget only $100,000 to comply with HCR 27).

Finally, the APF stated in its testimony that the costs associated with this type of screen will be passed back from the asset manager to the pension funds. Again, this has not been our experience. For example, in the case of Sudan divestment legislation in Oregon and Illinois, it was stipulated that the costs of setting up screens were to be borne by the asset manager. In working with Illinois asset managers, I have received no indication that these firms planned to, in effect, charge their pension system clients for minor expenses incurred in establishing a Sudan screen.

The Performance Costs of Divestment

On Sunday, February 19, the *New York Times* ran an article on the Illinois divestment legislation (see Attachment 3). Despite the fact that the legislation affects some 10 public pension systems with more than $120 billion in assets under management – as well as over 150 asset managers ranging in size from small, local firms to some of the biggest names in the business – the *Times* article made no mention of any financial losses incurred by Illinois pension systems as a result of this policy.

Practical experience also casts doubt with respect to anticipated losses stemming from divestment of a relatively small number of companies. Specifically, CSAG's data is licensed by The Roosevelt Investment Group (Roosevelt), a New York-based asset management firm. Roosevelt uses CSAG's database to exclude from of its Bull Moose Growth Fund all companies identified by CSAG as having business ties to any terrorist-sponsoring states. Not only has Roosevelt been able to avoid losses since employing its screen, but it has outperformed the S&P 500 by a substantial margin.

Oregon likewise does not expect to lose money in employing a Sudan screen for its public funds. According to a recent Socialfunds.com article (see Attachment 4),

> "Oregon law goes a step further than Illinois law, requiring institutional investors' asset managers to prevent negative financial impacts on the portfolio when divesting. 'What I'm hearing from [asset management firms], though, is that this is not very difficult --they've been able to reposition their portfolios without a lot of adverse impact,' Ms. Ivy [of Institutional Shareholder Services] concluded."

None of this is to suggest the APF's assessment is misguided. There may be performance losses associated with implementing a screen. However, it is important to note that the SEC has determined that companies that do certain types of business in terrorist-sponsoring states could face new material risks. This is likely why Missouri Treasurer Sarah Steelman recently made clear that her state should seek to protect the *investments* of Missourians when assessing corporate ties to terrorist-sponsoring countries: "We can and must develop and adopt a real policy that protects our citizens and our investments."

The fact of the matter is that Alaska could take significant losses by holding companies that are exposed to global security risk, just as easily as the state could experience performance losses from restricting such holdings.

Conclusion

In closing, I would note that Alaska is not alone in considering this issue. In addition to three states that have already enacted legislation that establishes investment restrictions on companies with business activities in Sudan, published reports indicate that as many as five states are expected to introduce divestment legislation this spring targeting companies that do business in any terrorist-sponsoring state.

Should Alaska choose to restrict APF and ASPIB from investing in companies with ties to Iran and North Korea, it is my view and experience that CSAG could help the Funds develop and implement such a screen on a cost-effective and relatively non-disruptive basis.

I would be pleased to discuss this matter further with the Committee and/or Alaska's Funds. Also, I would recommend that the Committee look to the following experts and public officials for additional information on those matters raised in my testimony:

1. **New York City Comptroller William Thompson:** Comptroller Thompson can be reached via Pat Doherty, 212-669-2651 or pdohert@comptroller.nyc.gov

2. **Missouri Treasurer Sarah Steelman**: Treasurer Steelman can be reached through Mark Mathers (see below).

3. **Nell Minow**, Expert on Corporate Governance and President of The Corporate Library, nminow@thecorporatelibrary.com.

4. **Mark Mathers,** Director of Investments for the State of Missouri and Board Member for the Missouri Investment Trust, 573-751-8530 Mark.Mathers@treasurer.mo.gov.

5. **Steven Schoenfeld**,** Chief Investment Strategist for Quantitative Investments for Northern Trust, .

6. **Tony Malaj**, Chief of Staff for Arizona Treasurer David Petersen, 602-604-7809 or tonym@treasury.state.az.us.

** As noted in the attached *New York Times* article, Mr. Schoenfeld is responsible for implementing six "Sudan-Free" indices for Northern Trust that already have over $8 billion in assets under management – mainly from Illinois pension systems that are required to divest from companies operating in Sudan. CSAG has spoken with Mr. Schoenfeld and received no indication that Northern Trust's "Sudan-Free" indices are experiencing sub-standard performance.

Mr. Schoenfeld is one of the country's leading thinkers on indexed funds and should be able to shed additional light on whether divestment and/or the development of "Iran- and North Korea-Free" indices would have the negative financial impact predicted by the APF in its testimony.

Tim Benintendi

From: JRWINTHER@aol.com
Sent: Monday, February 27, 2006 8:36 AM
To: Rep. Ralph Samuels
Subject: SB305 Testimony
Attachments: SB305--JRWTESTIMONY--2-25-2006.doc

Rep. Samuels,

Enclosed is my testimony I did via telephone at the Saturday hearing.

It is important to for the small independent oil companies that the $73M deduction and the tax credits stay in the bill.

John Winther

MR. CHAIRMAN, MEMEBERS OF THE COMMITTEE

THANK YOU FOR THE OPPORTUNITY TO TESTIFY ON SB 305.

FOR THE RECORD, MY NAME IS JOHN WINTHER AND I RESIDE IN PETERSBURG.

MY PRIMARY BUSINESS IS FISHING, BUT I AM ASLO AN OWNER OF TWO INDEPENDENT OIL COMPANIES THAT OWN ACREAGE ON THE NORTH SLOPE WITH HOPES OF BECOMING A PRODUCER.

IN 1997, DALE LINDSEY, MYSELF AND SEVERAL OTHERS FOUNDED WINSTAR PETROLEUM IN 1997. WE SUCESSFULLY BID ON LEASES TOTALING ABOUT 20,000 ACRES OVER THE NEXT SEVERAL YEARS.

IN 2002 DALE LINDSEY, JIM WEEKS AND I STARTED ANOTHER COMPANY CALLED UNLTRASTAR EXPLORATION. WE CURRENTLY HOLD 4700 ACRES NORTH SLOPE .

DALE AND I WERE INSTRUMENTAL IN GETTING THE PROVISIONS IN THE CHARTER FOR DEVELOPMENT THAT IS IN THE MERGER AGREEMENT BETWEEN BP AND ARCO. I CAN SAY WITH OUT THESE PROVISIONS IN THE CHARTER FOR DEVELOPMENT, THERE WOULDN'T BE ANY OPPORTUNITY FOR AN INDEPENDENT ON THE NORTH SLOPE TODAY. THE KEY PROVISIONS WERE ACCESS TO THEIR FACILITIES ON REASONABLE TERMS, THE MAJORS HAD TO PURCHASE UP 5000 BBL/DAY OF PRODUCTION, THEY WERE REQUIRED TO SELL SEISMIC TO AN INDEPENDENT, AND THERE WAS A BINDING ARBITRATION CLAUSE IN THE EVENT TERMS AND CONDITIONS CANNOT BE AGREED.

DALE AND I ALSO WENT TO WASHINGTON DC ON OUR OWN TO COMMENT ON THE MERGER AND PARTLY BECAUSE OF OUR EFFORTS, THE ARCO ASSETS IN ALASKA HAD TO BE SOLD OFF. THIS LED TO PHILLIPS COMING TO ALASKA. WE FELT THERE HAS TO BE THREE MAJORS ON THE SLOPE TO ENSURE COMPETITION.

WE ARE UNIQUE IN THAT I BELIEVE WE ARE THE ONLY ALASKAN OWNED INDEPENDENT OIL COMPANY TO EVER DRILL A WELL ON THE NORTH SLOPE. WE DID THIS IN 2003 ON A LEASE WE OWNED NORTH OF OLIKTOK POINT. WE CONTRACTED WITH CONOCCO TO DRILL AND IF WE WERE SUCESSFUL, TO DRILL ANOTHER WELL AND OPERATE THE WELLS. I WISH I COULD SAY WE STRUCK OIL, BUT ALL WE FOUND WAS WATER.

WHILE WE WERE DISAPPOINTED, WE WEREN'T DISCOURAGED AND BEGAN NEGOIATING WITH BP TO DRILL A WELL FOR US AT PT MCINTIRE. WE

EXPECT TO COMPLETE THESE NEGOIATIONS IN TIME TO DRILL A WELL LATER THIS YEAR.

I AM HERE TO SUPPORT SB305. WHILE THERE ARE MANY PARTS TO THIS BILL, I SUPPORT WHAT TO ME IS THE MAJOR PARTS OF THE BILL THAT IS THE 20% TAX LISTED IN SECTION 5 ON PAGE 2 OF THE BILL, THE $73 M DEDUCTION AND THE TAX CREDIT PROVISIONS THAT ARE ALSO IN THE BILL.

I SEE THAT THERE IS SOME SUPPORT IN THIS LEGISLATURE FOR RAISING THE 20% TAX ON OIL AND GAS PRODUCTION. I URGE YOU TO LEAVE THIS AS NEGOIATED BY GOVERNOR MURKOWSKI.

RAISING THIS TAX IS GOING TO DISCOURAGE EXPLORATION AND DEVELOPMENT BY THE MAJORS.

BEFORE BECOMING INVLOVED IN THE OIL INDUSTRY, I DIDN'T REALLY UNDERSTAND MUCH ABOUT BIG OIL, OTHER THAT THEY MADE HUGE MONEY AND PUMPED LOT OF OIL, AT LEAST THAT IS WHAT I THOUGHT.

AFTER DEALING WITH THEM, I HAVE A BETTER UNDERSTANDING ON HOW THEY WORK AND WHY THEY DO THINGS THE WAY THEY DO.

I THINK THE MOST IMPORTANT THING TO REMEMBER IS THEY HAVE MORE OPPORTUNITIES TO DRILL FOR OIL AROUND THE WORLD THEN THEY HAVE THE MONEY FOR SO THEY HAVE TO PICK AND CHOOSE THEIR PROJECTS. IT IS A WELL KNOWN FACT THAT ALASKA IS THE MOST COSTLY PLACE TO DO BUSINESS, BUT IT IS ALSO THE MOST POLITICALLY STABLE OIL SUPPLY FOR THE UNITED STATES IN THE WORLD. WHILE WE MAY THINK ALASKA IS A PLACE THEY MUST DO BUSINESS, I DOUBT THEY THINK THAT WAY. THIS 20% IS WHAT THEY HAVE AGREED TO AND I THINK IT SHOULD NOT BE RAISED.

WE WHO WERE IN ALASKA KNOW WHAT KIND OF ECONOMY WE HAD BEFORE OIL AND IT WASN'T WHAT YOU CALL ROBUST. I THINK THE STATE BUDGET IN 1967 OR 68 WAS $98M.

OUR PRODUCTION IS DECLINING EVERY YEAR SO WHY DISCOURAGE DEVELOPMENT BY INCREASING THIS 20% TAX?

THE $73M DEDUCTION IS SOMETHING THAT HEAVILY FAVORS THE INDEPENDENTS AND REALLY DOESN'T DO MUCH FOR THE MAJORS BECAUSE OF THEIR HIGH PROFITS SO, I URGE YOU TO KEEP THIS IN THE BILL ALONG WITH THE TAX CREDITS.

IN CLOSING, SOME OF MY REMARKS MAY SOUND LIKE I'M SPEAKING FOR THE MAJORS, BUT I'M NOT. HAVING NEGOIATED WITH THEM TO DRILL A WELL FOR US, I LEARNED A LOT ABOUT THEM AND I RESPECT THE WAY THEY DO BUSINESS. AT 20% ALASKA, IS GOING TO DO VERY WELL AND TRYING TO GET MORE MAY WORK BUT YOU MAY HAVE DISGRUNTLED MAJORS WHICH IN THE LONG RUN ISN'T GOOD. AGAIN I URGE YOU TO SUPPORT AND APPROVE THE KEY PROVISIONS OF THIS BILL.

Tim Benintendi

From: Jim Sykes [jsykes@ak.net]
Sent: Monday, February 27, 2006 12:47 PM
To: Sen. Tom Wagoner; Rep. Jay Ramras; Rep. Ralph Samuels
Subject: Info for Oil tax hearings
Attachments: WorldOilCompare.pdf

Dear Resource Committee Chairs,

This is a resend. I wasn't sure if you received the chart I had sent in advance of my testimony on Saturday. My intent was to allow every member of the respective committees to have a copy. I'm not sure my original email was received, so I'm just sending it again so that it can be shared with all members.

It begs the question whether Alaska is getting a fair return on it's nonrenewable resources. This and other indicators point to a "no" answer. So, as the oil tax structure is considered for revision, we need to figure out what is fair, how we're going to get it and how we will monitor and maintain a fair and transparent process. Since I did not prepare comments for the testimony I gave, I will forward some specific questions and concerns that deserve further consideration.

Thank you. If you have any further questions, please call anytime.

Jim Sykes 745-6962

----- Original Message -----
From: Jim Sykes
To: Senator_Thomas_Wagoner@legis.state.ak.us ; Representative_Jay_Ramras@legis.state.ak.us ; Representative_Ralph_Samuels@legis.state.ak.us
Sent: Saturday, February 25, 2006 9:15 AM
Subject: Info for Oil tax hearings

Dear Senator Wagoner, Representative Ramras and Representative Samuels,

Please print the attachment (in color if possible) and distribute to all members of the respective Resource Committees.

It basically shows that Alaska is near the bottom of the world's oil producing regions in getting a share of economic rent for oil. It is very relevant to the discussions at hand. If you have any questions please call.

Thank you.

Jim Sykes 745-6962

How Alaska's oil tax policies compare to other countries around the world.

Government Participation = Government taking an ownership position in a development venture.

Effective royalty rate = All combined guaranteed returns subject only to fluctuation in the price of oil. Not sharing in risks of loss.

Government Take = Total percent of revenue taken from production, regardless of whether it was a tax, a royalty, a risk sharing production contract, risk service contract or some other method of taking revenue.

PSCs = Production Sharing Contracts.

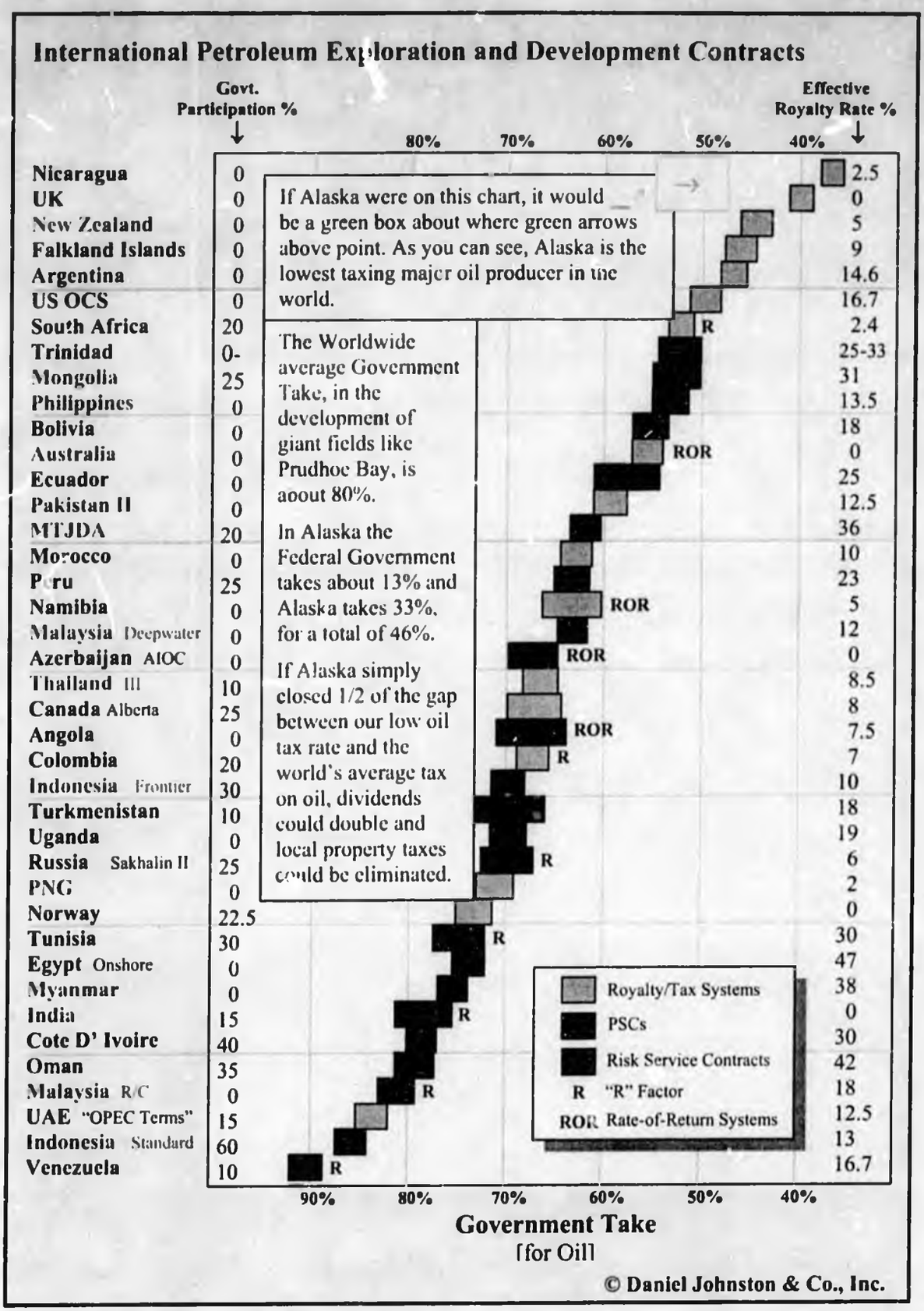


Figure 5. Chart reprinted with permission; with Definitions and Alaska statistics added by Ray Metcalfe.

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The oil companies want you to believe that Alaskan oil is more expensive to produce. **That is misleading for two reasons. (1.)** When we are talking about sharing the wealth, we are talking about how we share the money left over **after** all production expenses are paid. What's our fair share? How does Alaska compare to the rest of the world? **(Reason #2.)** Due to the size of the field, Prudhoe Bay enjoys a among the lowest pre-barrel production costs in the world. The low cost of producing giant oil fields is why "Government Take" for giant fields averages 80% around the world; everywhere but Alaska. In Alaska, it's about 46%. (See the chart for details) To Alaska, that's about three billion dollars per year in services, dividends and Permanent Fund savings that we don't get.

Out of the hundreds of wells in production throughout Alaska, Alaska has only one well in production which was leased on terms bearing any resemblance to world market values.

Leased in 1982 and in production on the North Slope for nearly 20 years now, it is:
State of Alaska Department of Natural Resources Lease # 312828

DUCK ISLAND UNIT-PORTION OF TRACT 15, FILE: ADL 312828.

ITS LEASE TERMS ARE: ROYALTY SHARE % TO ALASKA = 20%
PLUS NET PROFIT SHARE % TO ALASKA = 79.593500%

The balance of the **net profit share** from Duck Island is retained by British Petroleum, who spends millions every year to convince you and your legislators that they couldn't possibly operate a well in Alaska under such circumstances.

If Duck Island weren't profitable, it wouldn't be in production.

Contrary to popular opinion, Alaska's percent of retention of profits from the production of its oil is among the lowest in the world. Alaska's Legislators and Governor have given tax break after tax break to the oil companies who fund their campaigns. Consequently we now have wells in production producing as little as 9% in total returns (government take) to the State of Alaska. Returns so low they wouldn't even fit on the chart showing how Alaska compares to other countries.

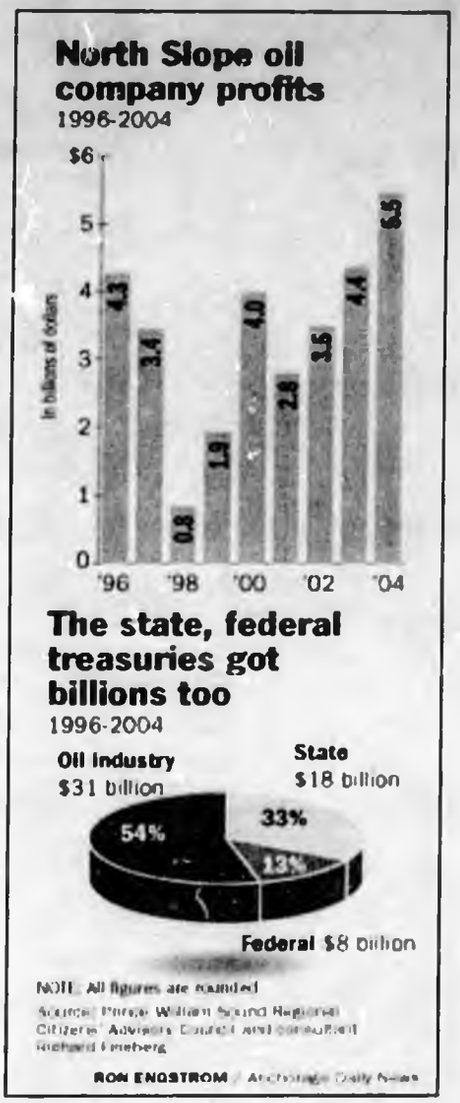
If Alaska simply closed 1/2 of the gap between our low oil tax rate and the world's average tax on oil, dividends could double and local property taxes could be eliminated.

Giant oil companies with refineries and retail facilities are constantly searching the world for giant oilfields. They do so to insure uninterruptible long-term supplies.

Selling refined products is by far the most profitable part of being in the oil business and consequently, oil companies are far more concerned about uninterruptible long-term supplies than they are with Alaska's rate of taxation. If this were not so, BP would not now be investing its exploration dollars in Venezuela, the country with the highest oil taxes in the world. Please note Venezuela on the chart comparing Alaska to other countries

Giant oil companies won't stay a day longer if we give them our last barrel of oil for free. Alaska's best chance for a bright future is to wrestle control of our resources back from the oil giants while there is still enough oil left to make a difference.

Ray Metcalfe
RayinAK@aol.com





The Associated Press

A gas station in Stockbridge, Ga., posted prices for gasoline from $5.87 to $6.07 per gallon Wednesday.

Anchorage Daily News, Sept. 1, 2005

Emily Stancliff

From: Kirby Koy [kirbykoy@gmail.com]
Sent: Monday, February 27, 2006 9:32 AM
Subject: Oil & Gas Employee - Opportunity to Testify
Attachments: MRK - CV.doc

Dear Representative,

I am currently on a leave of absence from BP where I have worked for over ten years in Alaska and abroad on various business development projects - all from the position of strategy development, partner negotiations, economic valuation, long term planning and capital allocation. I am well versed in how major oil companies make economic decisions and how they choose to make capital investments. Specifically, I worked for two years developing BP's economics and basic strategy for a pipeline development to market natural gas from the north slope.

This week the oil companies will be testifying regarding the oil tax proposed by the Governor. I would like to offer to testify and provide the opportunity for the committee to hear from someone who has worked for and understands the oil company perspective, but isn't tied to toting the company line. Specific points I would make are:

- The premise of the Governor's oil tax plan is reasonable: more progressive, based on profits, investment incentive. However,
- Investment decisions are usually made assuming oil prices of between $20-$30/bbl. In this range is where Alaska needs to be competitive relative to other regions and where the greatest tax breaks should be focused. The tax proposal gives the largest tax break relative to the current system at oil prices between $16-$20/bbl. The mechanisms should be adjusted to raise this to be between $20-$30/bbl.
- High oil price (above $30/bbl) is incentive enough to invest. Investment incentives above this price should be eliminated or phased out.
- The tax as proposed gives too much of a tax break, relative to the current tax structure, at low oil prices and shares in too little of the upside on the high side. Because companies look at oil prices between $20-$30/bbl when making investments, it is possible to flatten out the tax break in the low oil price world and increase the tax take in the high oil price world without impacting investment.
- Given long term oil prices average between $15-$20/bbl more times than not the oil price will be in the range where Alaska is earning fewer dollars relative to the current system instead of in the high oil price range where Alaska earns relatively more tax dollars. The structure as proposed is therefore more risky for the State.
- Oil taxes and investment in a gas pipeline are not related other than by the oil companies to minimize their oil taxes. The decision to invest in a gas pipeline is an incremental investment decision not impacted by oil production and each company will make the decision to invest in a gas pipeline based on the economics of gas solely and without regard to the oil business.

Best Regards,
Mike Koy
1-907-250-7169

Michael Ronald Koy

Address: 5901 Greece Circle
Anchorage, Alaska 99516

Home: 907-250-7169
Email: kirbykoy@gmail.com

SUMMARY OF QUALIFICATIONS

Business Development Manager with more than ten years experience preparing business strategies and plans; conducting and leading economic and investment valuations; managing third party relationships; working in operational and corporate head-office environments and leading multi-disciplinary/muli-cultural teams. Industry experience includes oil & gas exploration and manufacturing: both domestic and international.

WORK EXPERIENCE

BP Exploration (Alaska), Inc., Anchorage, Alaska **2004-2005**

Business Development Manager **GPB Performance Unit**

- Lead long term planning process for Performance Unit (PU)
- Lead/support 3rd party negotiations with partners/state
- Restructuring PU capital governance framework to align with Alaska Business Unit (BU) and Segment frameworks
- Lead development of economic valuations related to new business development opportunities
- Develop and lead methods for efficiently managing over $900million in annual capital and expense expenditures

BP International, plc., London, England **2001-2004**

Planning Manager **TNK-BP Business Unit**

- Lead long term planning process for Strategic Performance Unit (SPU)
- Monitor TNK-BP's performance and long term expectations, provide challenge where appropriate and report clearly and meaningfully to Business Unit Leader, Group Vice-Presidents (GVP) and Managing Directors with an objective perspective developed via rigorous analysis/interpretation of management information
- Communicate Business Unit performance to Group Planning and other stakeholders within BP
- Maintain required networks/relationships with extended team members (BP Finance, M&A, Tax, Legal, HSE), Planning & Performance Management (PPM) and Investor Relations
- Interface with TNK-BP Managing Directors to:
  - Develop appropriate context and understanding of business environment within TNK-BP and Russia
  - Understand and challenge, when necessary, performance
  - Participate in framing of work products in order to gain a better understanding of the business and increase performance
- Support SPU leader and BP's TNK-BP Board members as required

Project Manager **Mergers & Acquisitions**

Integral part of three person team responsible for managing investment bank relationships, coordinating work product development for numerous work groups, negotiating and supporting Group GVP through internal BP approval process, related to $16bn merger creating the TNK-BP joint venture.

Project Leader **BP Finance**

Responsible for positioning concepts with BP Sr. management and within the Financial Skills framework, developing training materials, acting as BP expert through leading analysis and training the BP Group how to recognize and value optionality inherent within real assets. Projects involved with included: Kovykta gas pipeline, Alaska gas pipeline, miscible injection vs NGL sales, LNG shipping, Indonesian gas and Gulf of Mexico value chain.

BP Exploration (Alaska), Inc., Anchorage, Alaska **1998-2001**

Sr. Commercial Analyst **Alaska Gas Business Unit**
Developed an integrated economic model to evaluate the many related facets of a scheme to commercialize 35+ tcf of gas from the North Slope of Alaska which was used to align technical and commercial work focus. Worked with BP Finance and BP Pipelines to develop innovative ways to finance and structure pipeline investment.

Commercial Manager **Alaska Gas Business Unit**
Managed commercial team responsible with commercializing 35+ tcf of gas from the North Slope of Alaska.

Commercial Analyst **Management Team**
Recruited to a small team to complete economic evaluations and asset reviews, consistent with regional and globally stated objectives, in support of BP negotiations with Exxon and Arco/Phillips to align Prudhoe Bay Unit equity interests. Commercial lead during negotiations which ultimately aligned Prudhoe Bay Unit equity interests and the deepening of BP's in Pt. Thompson.

Commercial Analyst **Prudhoe Bay Asset**
Worked with the Operations Team to identify marginal operating costs and potential facility consolidations. Negotiated yearly overhead allocations with partners resulting in a perpetual $500,000 per year savings to BP.

BP Developments Australia Limited, Inc., Melbourne, Australia **1996-1998**

Commercial Analyst **Papua New Guinea Team**
Developed unique methods for creating an integrated gas project attractive to project sponsors, prospective buyers, host-governments and project area landowners. Defined project structure, financing and fiscal package that produced the highest sustainable value to the project sponsors while meeting the objectives of all parties involved.

Commercial Analyst **North West Shelf ("NWS") Team**
Supported Sr. Commercial Analyst during pre-investment valuation of NWS liquefied natural gas (LNG) project expansion (US$1.25 billion investment). In addition, I filled the lead commercial role during the 1996 and 1997 exploration access valuations and was an integral member of team developing BP's regional and NWS development strategies.

BP Exploration (Alaska), Inc., Houston, Texas **1996-1996**

Commercial Analyst **Prudhoe Alignment Team**
Integral part of a four member team representing BP during Federal Energy Regulatory Commission (FERC) and Alaska Public Utilities Commission (APUC) arbitration and depositions. I worked with external consultants and BP specialists to develop BP's settlement proposal that was ultimately adopted and approved by the FERC.

BP Exploration (Alaska), Inc., Anchorage, Alaska **1995-1995**

Commercial Analyst Intern **Planning & Commercial Team**
Worked with consultants to develop portions of a pan-BP Alaska economic model. Completed in two weeks what was expected to take three months. Balance of time was utilized developing test cases for the model, writing parts of the users manual and assisting the Planning Team organize regional inputs for the yearly planning cycle.

EDUCATION

Colorado School of Mines - Golden, Colorado
Master's of Science degree in Mineral Economics
Graduated: December 1995 GPA: (4.0/4.0)

Purdue University - West Lafayette, Indiana
Bachelors of Science degree in Mechanical Engineering
Graduated: May 1992 GPA: (3.2/4.0)

INTERESTS

mountaineering, rock/ice climbing, jogging, weight lifting, hiking, reading and writing

Emily Stancliff

From: Jim Sykes [jsykes@ak.net]
Sent: Monday, February 27, 2006 12:47 PM
To: Sen. Tom Wagoner; Rep. Jay Ramras; Rep. Ralph Samuels
Subject: Info for Oil tax hearings
Attachments: WorldOilCompare.pdf

Dear Resource Committee Chairs,

This is a resend. I wasn't sure if you received the chart I had sent in advance of my testimony on Saturday. My intent was to allow every member of the respective committees to have a copy. I'm not sure my original email was received, so I'm just sending it again so that it can be shared with all members.

It begs the question whether Alaska is getting a fair return on it's nonrenewable resources. This and other indicators point to a "no" answer. So, as the oil tax structure is considered for revision, we need to figure out what is fair, how we're going to get it and how we will monitor and maintain a fair and transparent process. Since I did not prepare comments for the testimony I gave, I will forward some specific questions and concerns that deserve further consideration.

Thank you. If you have any further questions, please call anytime.

Jim Sykes 745-6962

----- Original Message -----
From: Jim Sykes
To: Senator_Thomas_Wagoner@legis.state.ak.us ; Representative_Jay_Ramras@legis.state.ak.us ; Representative_Ralph_Samuels@legis.state.ak.us
Sent: Saturday, February 25, 2006 9:15 AM
Subject: Info for Oil tax hearings

Dear Senator Wagoner, Representative Ramras and Representative Samuels,

Please print the attachment (in color if possible) and distribute to all members of the respective Resource Committees.

It basically shows that Alaska is near the bottom of the world's oil producing regions in getting a share of economic rent for oil. It is very relevant to the discussions at hand. If you have any questions please call.

Thank you.

Jim Sykes 745-6962

How Alaska's oil tax policies compare to other countries around the world.

Government Participation = Government taking an ownership position in a development venture.

Effective royalty rate = All combined guaranteed returns subject only to fluctuation in the price of oil. Not sharing in risks of loss.

Government Take = Total percent of revenue taken from production, regardless of whether it was a tax, a royalty, a risk sharing production contract, risk service contract or some other method of taking revenue.

PSCs = Production Sharing Contracts.

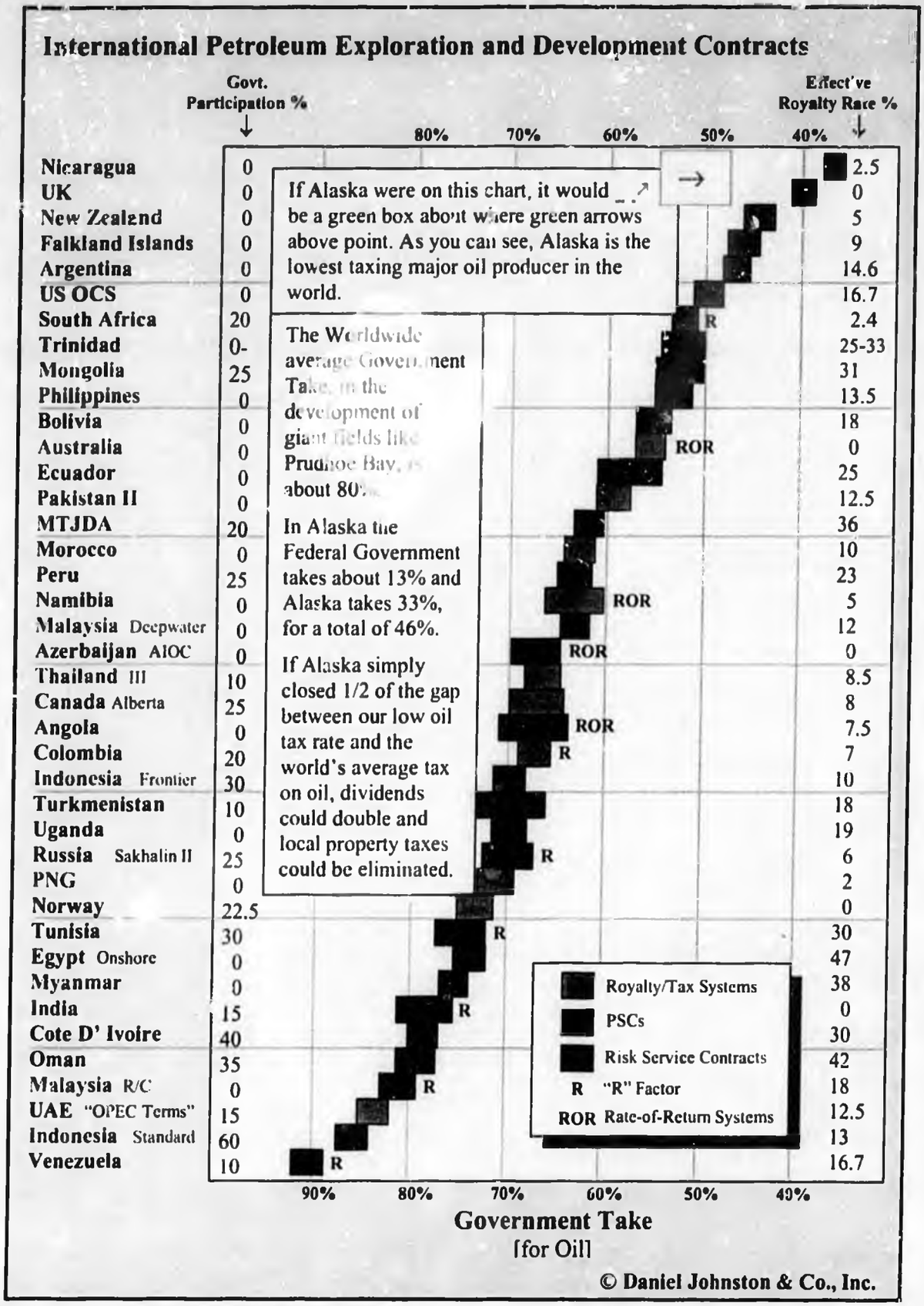


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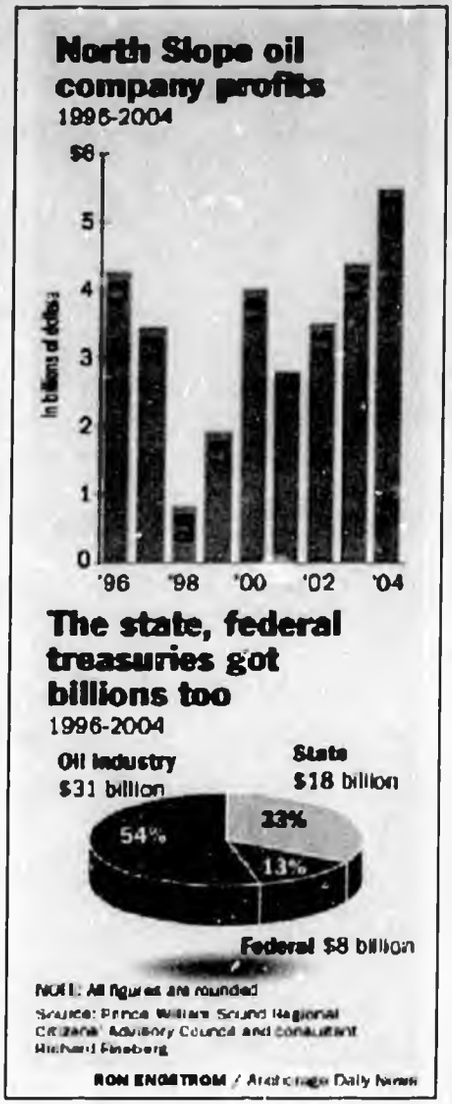
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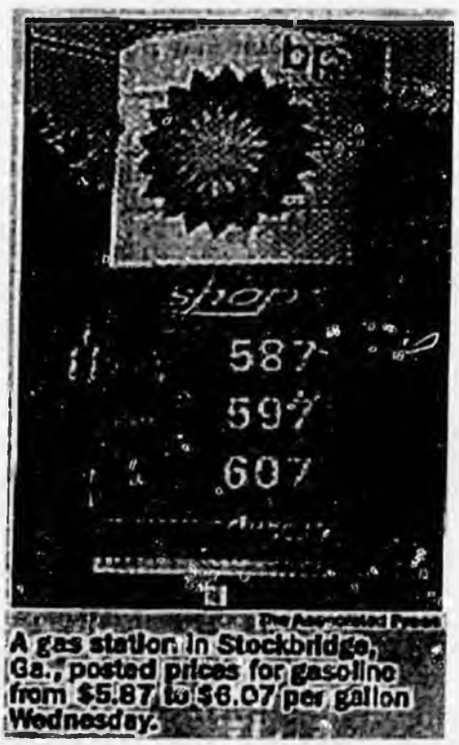
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Ray Metcalfe
RayinAK@aol.com





The Associated Press
A gas station in Stockbridge, Ga., posted prices for gasoline from $5.87 to $6.07 per gallon Wednesday.

Anchorage Daily News, Sept. 1, 2005

Bonnie Robson
Oil & Gas Attorney and Consultant
408 West 11th Avenue
Anchorage, Alaska 99501

February 27, 2006

This memorandum begins with a general discussion of the workings of HB 488 and SB 305, the House and Senate versions of the Governor's bill repealing and replacing Alaska's tax on oil and gas production. It then identifies and discusses three issues raised by legislators in hearings on the bill. For each of the three issues raised by legislators, this memorandum suggests potential amendments to the Governor's bill to address concerns voiced by legislators.

General Discussion of the Workings of the PPT

The Governor's proposed legislation is referred to as the "petroleum production tax" or "PPT." The PPT taxes net profits at the point of production. Net profits are calculated by starting with gross profits at the point of production, then subtracting capital and operating expenses incurred upstream of the point of production. The first $73 million in net profits per producer per year is exempt from taxation, with net profits in excess of $73 million per producer per year treated as taxable income.

After subtraction of the first $73 million in net profits, the remaining net profits, or taxable income, is multiplied by the 20% tax rate to arrive at a producer's initial tax liability. This initial tax liability may be further reduced by the application of tax credits, which may be applied dollar-for-dollar against the initial liability. Tax credits are available for 20% of losses as calculated annually at the point of production and 20% of capital expenses incurred upstream of the point of production.[1] Also, the value of tax credits purchased from those without sufficient net profits to fully utilize their own losses and credits may be applied to reduce a producer's initial tax liability. And while a producer's own tax losses and capital expense tax credits can be used to reduce its tax liability as low as $0, tax losses and capital expense tax credits purchased from others cannot reduce a producer's tax payments to the State below 80% of the amount the producer calculated before application of losses and credits purchased from third parties.

An example of the workings of the PPT for an individual producer is set forth in the following table:

[1] For certain exploration capital expenditures incurred anywhere in the State during the first year of the PPT or south of 68 degrees, 15 minutes North latitude during the first four years of the PPT, an explorer or producer may take tax credits of up to 40% in lieu of the PPT's 20% tax credit for same exploration capital expenditures. As a result, the value provided by the State for these expenditures may rise to a total of 60% of the expenditures.

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Example of Workings of PPT for Individual Producer

Gross value at point of production	$1,000,000,000
- Capital expenses	$ 350,000,000
- Operating expenses	$ 50,000,000
= Net profits (net value at point of production)	$ 600,000,000
- $73,000,000 annual profits exemption	$ 73,000,000
= Taxable income	$ 527,000,000
X 20% tax rate	$ 105,400,000
Initial tax liability, before credits	$ 105,400,000
- Producer's own capital expense tax credits ($350,000,000 x 20% = $70,000,000)	$ 70,000,000
= Tax liability after application of producer's own credits	$ 35,400,000
Maximum usage of purchased tax credits ($35,400,000 x 20% = $7,080,000)	$ 7,080,000
Amount producer pays State, if max. credits purchased	$ 28,320,000

1. Tax deductions, losses, and credits are of greater value to established major producers than to those the State seeks to attract: explorers, small producers, and new entrants.

The PPT is intended to bring explorers and new producers to the State of Alaska. Yet explorers and new producers will want to know that they can compete with existing, major producers on equal footing. This has not always been the case in the past. For example, explorers, potential new entrants, and those leaving the State after determining that they cannot compete have complained that the tariffs for transportation of oil through the Trans Alaska Pipeline System (TAPS) have exceeded just and reasonable rates, to the disadvantage of those without an ownership interest in TAPS. The problem with excessive TAPS tariffs, they argue, is compounded by the fact that the overages they must pay are paid to their competitors, since those that own TAPS are also the largest explorers and producers in this State.

Explorers, small producers, and potential new entrants may argue that the PPT's mechanisms for monetizing losses and tax credits exacerbates an uneven playing field in much the same way as do TAPS tariffs. Their argument may be expressed as follows: Those testifying before the legislature on behalf of the Administration have stated that major, existing producers will be able to immediately take full advantage of tax credits generated from their own activities—they can use 100 cents of every dollar, without limit. These same witnesses have acknowledged that transferable tax credits available through existing programs typically sell for $0.90 on the dollar, and one should expect no more with the PPT. Further, they have revealed that the price offered by major, existing producers to explorers, small producers, and new entrants for the latter's transferable tax credits could be substantially less than $0.90 on the dollar in the event of low oil prices, which are apt to trigger the Section 12(e) percentage limit on use of transferable or purchased tax credits.

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The Administration seems to agree, then, that tax credits available to explorers, small producers, and new entrants will be worth no more than $0.90 on the dollar, and possibly substantially less, even though those credits cost the State the full dollar, and major existing producers can take full advantage of 100 cents on the dollar. This inequity in value of tax credits is compounded by the fact that $0.10 or more of every dollar in tax credits made available because of expenditures by the explorers, small producers, and new entrants will, in fact, be paid over to their competitors—the major, existing producers who buy their tax credits at a discount.

Administration witnesses have justified the PPT's approach to delivering value on two grounds. First, they state—correctly—that if the State was left to fund direct payments for the credit amounts through annual appropriations, in an era of low oil prices the legislature might fail or refuse to do so. Second, they state—also correctly—that the percentage limit on use of transferable tax credits protects the State's treasury. However, there may be an alternative or supplemental approach that accounts for the Administration's concerns in a fashion less likely to increase the disparity between major, existing producers and the explorers, small producers, and new entrants.

Undoubtedly, the Administration, all explorers, and all producers would rather not count on affirmative funding actions by future legislatures to assure that parties are rewarded for incurring expenses related to Alaska's upstream exploration, development, and production. However, HB 488 and SB 305 could be amended to recognize that future legislatures may choose to take affirmative funding actions, and only if they do not will the system of automatic transferable tax credits come into play. As a consequence, at least in robust years the State would be more apt to fund directly what it is going to pay for one way or another, and thus fully reward explorers, small producers, and new entrants for their own expenditures, rather than aggravating uncompetitive conditions.

Additionally, the bill could be amended so that in lean years the explorers, small producers, and new entrants are not "limited-out" while the major, existing producers take full value for their expenditures. While a limit is desirable to protect the public treasury, the limit could be more equitably formulated. For example, a threshold for minimum payments or maximum credits could be established, then credits could be prioritized so that they are not all taken in a year when the State cannot afford it, but some portion of everybody's credits roll forward into more lucrative years. For example, the PPT as currently drafted puts a 20% value on all capital and operating expenses incurred upstream of the point of production, which is taken either as a deduction from gross profits or as a loss; it puts an additional 20% value on the very same capital expenses, which value is taken as a capital expense tax credit. Rather than allowing a major, existing producer to take 100% of both forms of value during a lean year while an explorer, small producer, and new entrant takes little or none, instead deductions and losses could be taken first by all players, and some portion or all of every player's capital expense tax credits could be rolled forward into future tax years if the pre-determined overall limit on credits came into play.

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Also, if tax credits that must be bought and sold to be monetized are to play a continuing role in PPT, the legislature may want to consider establishing a minimum price that must be paid to buy these tax credits—say $0.95 cents on the dollar. Even at $0.95 cents on the dollar, the $0.05 amount ought to be sufficient "free money" to entice a major, existing producer to still buy transferable tax credits, yet the floor price will protect explorers, small producers, and new entrants from larger and potentially anti-competitive erosions in the value of their credits.

If the bill's language on tax credits is not amended, disparate treatment of existing, major productions and explorers, small producers, and new entrants may become the rule, as can be seen from the example of the workings of the PPT set forth on page 2. There the producer with $1 billion in net income can fully utilize its own deductions and credits by taking deductions of $400,000,000, which carry a cash value of $80,000,000, and credits of $70,000,000, for a combined tax savings in the year at issue of $150,000,000, while explorers, small producers, and new entrants that must rely on the very same producer to monetize their tax credits can only sell that producer credits with a total value of 1/20th that amount—just over $7,000,000. As a result, their credits may sell into a constrained market at substantially less than $0.90 on the dollar or be rolled forward into future years, with their time value significantly eroded.

2. The $73,000,000 tax free allowance was devised to protect those that do not currently pay taxes; its phase-out would prevent an abrupt imposition of taxes on those formerly untaxed, yet discourage multiplication of amounts escaping taxation.

The PPT allows each producer to take its first $73,000,000 in net profits each year tax-free. The Administration has explained this tax-free allowance by stating that a producer generating revenues from a 5,000 barrel/day field should not have to pay taxes when oil is selling for $53/bbl on the West Coast and its net profits at the point of production total $40/bbl. One could question this rationale, and further ask about the implications of a $73,000,000 per producer per year tax-free allowance on the public psyche when and if Alaskans are asked to start paying state income taxes on their own, substantially smaller net incomes.

Perhaps a better rationale for the $73,000,000 per producer per year tax-free allowance is that it is intended to allow those that currently pay little or no state productions taxes to continue paying little or no state production taxes, and thus avoid the abrupt imposition of taxes. However, as currently formulated, the tax-free allowance benefits major, existing producers as well, even though they proposed its elimination. Furthermore, with time, the tax-free allowance encourages the proliferation of new entities for the sole purpose of multiplying income escaping taxation.

When considering whether the $73,000,000 tax-free allowance is necessary to blunt the imposition of taxes on smaller players, it is important to note that, unlike the current system, at all oil and gas prices the PPT already taxes only the profitable, and further includes substantial credits for capital expenditures, which credits effectively permit a percentage of net profits to escape taxation. Thus, the impacts on a small player have already been softened even without the $73,000,000 tax-free allowance, in a way they would not have happened with other possible changes to the State's production tax regime, such as a simple repeal of the economic limit factor (ELF). Still, if legislators choose to leave the tax-free allowance in place in light of expenditures made by industry with the expectation of lower taxes, the tax-free allowance could be phased out. Phasing out could be accomplished by reducing the allowance each year for a period of

years or simply sun-setting the full allowance a number of years hence. In either case, the largest value of the allowance would be received in the early years of the new tax regime, and thus substantially improve a producer's net present value calculations (whereas allowances to be received in years after a possible sunset date would be of lesser value—and a lesser loss—to producers).

If the tax-free allowance is to be phased out, a phase out over five years may discourage the proliferation of entities created or entering Alaska for no reason other than multiplication of income escaping taxation, whereas a phase out over a longer period (such as ten years) may mean that multiplication is still worthwhile and can be accomplished without clearly triggering the Department of Revenue's ability to aggregate taxpayers under Section 21(j) of the bill.

3. The PPT may obligate the State to pay up to 40% of abandonment costs, even for fields with little in net profits left to garner.

Through the PPT the State conveys value—either as a deduction, loss, or transferable tax credit—equal to 20% of all operating costs and 40% of all capital costs incurred upstream of the point of production. In exchange, the State receives 20% of all taxable net income earned upstream of the point of production from and after July 1, 2006. The State's 20% share of net profits and obligation to "pay" 20-40% of costs applies to all oil and gas fields throughout the state—whether on state, federal, or private lands, and without regard to the stage of field life. Thus, for fields past their prime, and even for fields where production has ceased but abandonment has not been completed, as well as for wells, facilities, and fields abandon during the five year "look-back" period for transition expenses, the State through the PPT is undertaking to "pay" (through deductions and credits) up to 40% of abandonment costs, though those costs currently fall exclusively upon oil and gas companies that undoubtedly accounted for their obligation to cover such costs in years past when deciding whether to invest in particular fields. As a consequence, the PPT's treatment of abandonment expenses may result in a huge and disproportionate liability for the State where it currently has none.

There a number of ways in which the legislature could change the treatment of abandonment expenses by amending HB 488 and SB 305. First, abandonment expenses could be disallowed when calculating deductions, losses, and tax credits. Alternatively, abandonment expenses could be prorated, based on the number of barrels of oil (or barrel-equivalents in the case of gas) produced before the effective date of the PPT and the number produced thereafter. Additionally, since the Internal Revenue Code or the PPT's definition of "qualified capital expenses" may allow producers (and former producers) to claim that some or all abandonment expenses are capital expenses subject to a 40% benefit, the PPT could be amended to limit producer benefits at State expense to 20%—that is, require all abandonment costs to be treated as operating costs for purposes of the PPT.

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Conclusion

This memorandum does not attempt to identify or address all issues surrounding HB 488 and SB 305, the petroleum production tax legislation introduced by the Governor. Rather, it selects three concerns raised by legislators, discusses them, and provides suggestions on how these concerns could be met through amendments to the proposed legislation. If legislators are interested in further pursuing the possibility of one or more of the amendments mentioned, I recommend that Administration personnel be included in the drafting process to assure that there is no unintended damage to the overall regime of taxation. Also, I would be happy to assist in drafting or reviewing any such changes to the language of the bills.

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Preliminary Analysis of Alaska Oil Production Tax
February 27, 2006

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Introduction.

Legislation has been introduced that would revamp Alaska's oil production tax from a severance based tax based on the amount of oil produced, to a net profits based tax. The discussion is a preliminary analysis of the proposed legislation from a tax law perspective.

Most states impose a severance tax on minerals extracted, based on a fixed value per unit of minerals removed from the earth, or a percentage of the gross value. The principal advantage of a traditional severance tax is its simplicity and ease of administration. The oil company determines how much oil it produces, and pays the tax based on the per unit or percentage tax rate. The oil production tax proposed in the bill would calculate the net profit inherent in oil that is produced. The net profit is determined as the gross value of the oil produced during the month, less the production costs. Accordingly, the proposed bill would add a level of complexity not present in the existing tax. There are two principal disadvantages of this added complexity: (1) It allows oil companies more opportunities to plan their production activities in a way to minimize the net profits; and (2) It will require increased resources to the Department of Revenue to administer and enforce the tax.

Nature of the Proposed Tax.

The oil tax, as noted, is not a traditional severance tax, because it is not based on the value of the oil produced (although this is the starting point). Although Texas allows a deduction for natural gas marketing costs in calculating its gas severance tax, this deduction is designed to tax all gas on an equal footing even if it must be transported a further distance from the wellhead and is not considered a net profits tax. With this exception, we are unaware of any severance tax that is determined by deducting any cost (and the Texas deduction is not a production cost).

The proposed oil production tax is not really an income tax because the oil is taxed when it is pumped out of the ground, not necessarily when sold. However, it shares many characteristics of an income tax because the tax is determined on the gross value oil produced, less the production costs. Although the oil is a fungible commodity, easily sold on world markets, it nevertheless does not result in the recognition of gross income for federal income tax purposes until it is sold on the market, so it is not technically an income tax.

The tax also bears some resemblance to a tax on tangible personal property (i.e., the value of the oil produced), but a tangible personal property tax is imposed on the fair market value of an asset, with no deduction for costs.

This tax has a strong resemblance to a value added tax. Value added tax ("VAT") is the norm in the European Union. It imposes a tax by the value added at each stage of the production of a product. Since the proposed oil production tax is determined as the difference between the value of the oil produced and the value of the oil in the ground, the net difference is in effect the value added as a result of the production efforts of the oil companies, and therefore has the primary earmarks of a value added tax.

Apportionment of Tax.

The oil production tax bill does not apportion the tax on the proportion of the activities in Alaska to all production activities. Although a pure severance tax is not required to be apportioned, there is the potential that a value added tax might be challenged on constitutional grounds if it is not apportioned. As noted below, any such potential challenge can be preempted by Congress.

In order for a state tax that is imposed on a foreign corporation to be valid under the commerce clause of the U.S. Constitution, it must not discriminate against interstate commerce and must be fairly apportioned. It is possible that a corporation subject to the oil production tax might challenge the tax based on the argument that it is not fairly apportioned to the company's activities inside and outside Alaska. Although a pure severance tax based on the gross value of oil extracted should not have to be apportioned, because the tax base is determined on the number of barrels extracted, the determination of the net profits under the proposed tax takes into consideration activities that might occur outside of the state. Therefore, this might open the door to a challenge that the oil production tax violates the commerce clause requirement that the tax be fairly apportioned.

Michigan has had a value added tax - known as the Single Business Tax ("SBT") - since 1976. The SBT is apportioned based on a standard apportionment formula used by many states to calculate income tax liability based on the proportion of (sales, assets and payroll in the state over total sales, assets and payroll). An auto parts manufacturer based in Ohio challenged the SBT as violating the commerce clause, arguing that the tax was not fairly apportioned (Trinova Corporation v. Michigan 498 U.S. 358 (1991)). The Supreme Court upheld the SBT, holding that it was fairly apportioned. This case, however, raises the issue that a value added tax must be apportioned.

The Supreme Court has also ruled that a typical severance tax must satisfy the fair apportionment test in order to satisfy the requirements of the commerce clause. Commonwealth Edison Company v. Montana 453 U.S. 609 (1981). The court upheld the Montana coal severance tax, as being fairly apportioned, because the tax was a percentage of the value of the coal taken and therefore, was in proper proportion to the company's activities in the state.

Because the proposed oil production tax adds to the traditional severance tax calculation the determination of a company's cost to produce the oil, this could cause a disgruntled oil company, or possibly just a disgruntled citizen to challenge the tax based on the argument that the tax is not fairly apportioned. Since there is no other similar oil production tax that calculates net profits, it is difficult to predict how such a challenge would be greeted by the courts. This could create a level of uncertainty that could hinder the state's efforts to use the tax as a mechanism to help build the much needed gas pipeline.

One sure fix to this potential "fair apportionment" problem would be for the United States Congress to pass legislation authorizing a state to impose an oil production tax based on net profits like the proposed oil production tax. Since Congress has the power to regulate interstate commerce (as discussed more thoroughly below in the discussion on the tax credit), such federal legislation would cut short any potential challenge based on a commerce clause argument. Because of the important national energy security policy that would be advanced by the construction of a natural gas pipeline to bring domestic energy to American markets, Congress might be inclined to adopt such legislation.

Tax Credit-Constitutional Concern.

The 20% tax credit set out in Section 43.55.024 is a typical state tax incentive to encourage economic development.

Unfortunately, the legality of these tax incentives has been successfully challenged in Ohio, and the United States Supreme Court may soon decide the viability of these programs. The forthcoming Supreme Court decision, might invalidate the economic development tax incentives offered by states around the U.S. Such an adverse decision might invalidate the proposed Alaska tax credit.

The Ohio Case. The Supreme Court will review an appeals court case that declared illegal Ohio's corporate income tax credit for the purchase of new equipment - designed as an incentive for companies to expand investment in the state. The Ohio tax credit is very similar to the proposed Alaska tax credit.

The Ohio case, Cuno v DaimlerChrysler, involved incentives taken advantage of by DaimlerChrysler to build a plant in Toledo, Ohio. DaimlerChrysler was entitled to the Ohio investment tax credit for the purchase of equipment for the plant. In addition, as allowed by Ohio law, the City of Toledo granted a property tax abatement for the equipment purchased for the plant. The total incentives package was valued at $ 280 million. These substantial tax benefits were obviously a critical aspect of DaimlerChrysler's decision to build the plant in Toledo.

Individual taxpayers from Ohio and Michigan brought a legal action challenging the legality of these tax incentives in Cuno. The trial court dismissed the action. and the plaintiffs appealed to the Sixth Circuit Court of Appeals.

On Appeal, the Sixth Circuit ruled that the tax credit component of the Ohio tax incentive program for equipment purchases was illegal, as a violation of the commerce clause of the United States constitution. DaimlerChrysler appealed the case to the United States Supreme Court, which agreed to review this case.

The Commerce Clause. The Sixth Circuit found that the tax credit component of the Ohio program is illegal because it violates the commerce clause of the constitution. The commerce clause reserves to Congress all power to regulate interstate commerce. This is the provision of the constitution that creates the authority of the federal government to regulate all aspects of commerce. The commerce clause also prohibits states from putting up barriers to interstate commerce. One state can not create trade barriers to regulate the importation of goods from another state, either by regulation or tariffs. For example, a state can not impose a tax at a lower rate for products manufactured within its borders than for products made elsewhere. The plaintiffs in Cuno argued that the commerce clause prohibition against burdening business activity in another state by imposing a higher tax rate also prohibits Ohio from favoring investment within its borders. The Sixth Circuit agreed with this argument, concluding that the commerce clause prohibits a state from adopting tax incentives that favor investment in its state.

If the Supreme Court agrees with the Sixth Circuit Court that the Ohio tax credit violates the commerce clause, then the proposed Alaska tax credit would likely be invalid.

Possible Supreme Court Outcomes. The Supreme Court will hear oral arguments in Cuno on March 1, 2006. There are several possible outcomes when the Supreme Court decides this case.

The Court might very well decline to make any decision for now based on procedural grounds. The Court has asked the parties to file briefs based on the issue of "standing."Only someone who is directly effected by an act has the standing to file litigation in the courts. The plaintiffs in Cuno are individual taxpayers from Ohio and Michigan. The question that the Supreme Court wants them to address is whether an individual taxpayer has the standing to challenge the Ohio tax incentives. It is quite possible that the Supreme Court might rule that the harm suffered by these individual taxpayers as a result of these tax incentives is so indirect and tenuous that they do not have standing to bring this action. In such an event the entire case would be thrown out, and the Sixth Circuit decision would have no force or effect, at least for the time being. If this happens, then the plaintiffs in Cuno have indicated that they will take their case to the state courts, and litigate in that forum. If and when this happens, the entire process would start over, and presumably the case might again make it back to the Supreme Court. This process would likely take several years, leaving the final result up in the air.

The Supreme Court might decide to return this case back to the trial court for a determination of facts as to whether the Ohio tax incentives actually caused DaimlerChrysler to open the plant in Ohio, rather than in some other state. Because the trial court dismissed the case in its early stages, this evidence was not fully developed. By

sending this case back for a trial, the record would be more fully developed. It is possible that DaimlerChrysler was not swayed by the available tax benefits in making its decision to invest in Ohio. If so, this would likely end up back in the Supreme Court, a process that would also take several years.

The Supreme Court might decide to overrule the Sixth Circuit, and say that these tax incentives do not violate the commerce clause. This should return everything back to the status quo, and the proposed Alaska tax credit would likely be safe from the argument that it violates the commerce clause.

Finally, the Supreme Court might decide to affirm the Sixth Circuit, which would put an end to all similar tax incentive programs, including the proposed Alaska tax credit.

Intervention by Congress. Because the constitution gives to Congress the sole power to regulate interstate commerce, Congress has the authority to deal with the issue of state economic development tax subsidies. Accordingly, Congress has the power to fix the Sixth Circuit ruling. Even if the Supreme Court decides to uphold the Sixth Circuit, Congress has the power to statutorily overrule the Supreme Court. In fact, legislation has been introduced in both the House (H.R. 2471) and the Senate (S 1066) that would do just that - allow states to offer this type of tax subsidy. Accordingly, if these federal bills are adopted by Congress, and signed by the President, this would immunize the proposed Alaska tax credit from a potential commerce clause challenge. As such, the state should champion these bills in Congress if it intends to move forward with the tax credit for investment in Alaska.

Tax Credit- Transferability.

The bill would create Section 43.55.024(d) which would allow a taxpayer who has earned a tax credit to sell any unused tax credits, with the consent of the Department of Revenue. The problem with the sale of state tax credits is that they are frequently result in a sale at a deep discount (this is a major issue with state film production tax credits allowed by many states). This is not a desirable result because the state is paying 100 cents on the dollar for every dollar of tax credit, but the company that made the investment in the state is only getting a fraction of this amount. The difference - the "tax credit transfer profit" - goes to the companies that purchase the credit at a discount and the middlemen tax credit brokers who put the buyer and seller together.

Although the big oil companies will clearly be able to use all of the tax credits they earn, the exploration and development companies are less likely to be able to use up all of the credits that they earn. If the exploration companies sell their unused tax credits at a discount to the oil companies, then the oil companies (and any middlemen brokers) would recognize a significant benefit.

There are two potential fixes to this problem. The first would be to allow the tax credit as a credit against any other Alaska tax. This way, if an exploration company did not have

any oil production tax liability to use up the tax credit, it could at least use the tax credit to offset other Alaska tax obligations.

The second alternative would be for the state to "buy back" any unused credits at a modest discount. For example, say that a company could redeem unused tax credits at a 10% discount, so that if a company had $1 million in unused credits, it could sell these unused credits to the Department of Revenue for $900 thousand. In this way, it would be the state of Alaska that would gain the benefit of a 10% discount, not the oil companies who would purchase the credits at a discount. This would allow a market to develop for these tax credits at a reasonable discount. A company would not sell its tax credits to an oil company for 85 cents on the dollar if it can sell the unused credits back to the state of Alaska for 90 cents on the dollar.

Limitation on Carry Forward Tax Credit.

Section 43.55.04(c) allows a carry forward of the unused credit to a later month. This appears to allow a carry forward of any unused credit in a later month without any time limitation. The legislature might want to consider placing an outside time limitation.

Most corporate tax benefits that can be carried forward if they are unable to be used in the year earned have a limit to the number of years to which they can be carried forward. There are sound administrating reasons to place a limit on the number of years that carry forwards should be allowed. For example, tax examinations are much more difficult if the auditor has to look back to events generating the credit that occurred several years earlier. It also creates state budgeting complexities.

Outlay for Capital Expenditures - - Stock of Companies.

The direct expense deduction for outlays for capital expenses is quite broad, and it is not clear if it is intended that this deduction be allowed for the acquisition of the stock of another company that is involved with exploration development or production of oil or gas in Alaska. If this is the intention, then this should be expanded to prevent a direct cost expense if the Company merely purchases a related company from a common parent corporation.

For example, if the development subsidiary purchased the stock of a development subsidiary from the common parent corporation, the purchase price should not be allowed as a direct cost.

If it is not the intent of the legislature to allow a direct cost deduction for the purchase of the stock of a company, then this should be expressly stated.

Outlays for Capital Expenses - Related Party Transaction.

If an asset is purchased from a related company, and the company pays an amount that is greater than its fair market value, then the direct cost should be limited to the fair market value.

Subtraction from Direct Costs - Ownership Interests.

Section 43.55.160(e)(1) requires a company to subtract from direct costs the amount received from another company for the use of production facilities in which the taxpayer has an ownership interest. This should be broadened to include net payments received for the use of production facilities in which the taxpayer has a management agreement where the management fee is determined by the income received.

Subtraction from Direct Costs - Credits and Reimbursements.

Section 43.55.160(e)(2) requires a company to subtract from direct costs the amount of credits and reimbursements received from state and local governments for the company's upstream costs. This provision does not expressly state that this applies to tax credits, including the proposed oil and gas production tax credit. It is also not clear if this would apply to property tax exemptions. If it is the intent of the Legislature that tax credits and property tax exemptions should be subtracted from direct costs, then this should be expressly set out.

Subtraction from Direct Costs - Recapture of Outlays for Capital Assets.

Section 43.55.160(c) would allow a company to deduct its direct costs incurred in the exploration, development and production of oil and gas in calculating its net profit for purposes of the oil production tax. The term "direct cost" includes outlays for capital assets. There is a recapture provision in Section 43.55.160(e)(3)(A), which requires a company to subtract from direct costs the amount it receives from the sale or transfer of an asset that it previously deducted as a "direct cost". This rule is designed to prevent a company from churning assets merely to generate "direct cost deductions". For example, if a company purchases a piece of equipment for $1 million in June which would generate a direct cost deduction, and then sells it in July for $1 million, the amount received from the sale would be deducted in calculating its direct costs for July. In order to avoid manipulation of the intent and policy behind this rule, the concept should be expanded as follows:

(a) Related Party Transactions. If a company sells an asset to a related company for less than fair market value, then the amount it must subtract from its direct costs should be the fair market value of the asset.

(b) Removal of Asset From Alaska. If an asset that was purchased is subsequently removed from Alaska to be used by the Company elsewhere, this should be treated as a sale by the Company at its fair market value, so that it would be deducted from the Company's direct costs in the month that it was removed from Alaska. Otherwise a

company might attempt to enhance its deductions merely by purchasing assets for use in Alaska, and later moving it to another state or country for use there.

(c) Wash Sales. It is possible that a Company might attempt to increase its direct costs by selling an asset that it purchased prior to July 1, 2006, and purchasing an identical asset in order to generate a direct cost deduction. Since the asset that was sold was purchased prior to July 1, 2006, the amount received from the sale would not be deducted from direct costs, but the purchase of the identical replacement asset would be included in direct costs, thereby reducing tax liability without actually incurring any real direct cost. In order to prevent this type of manipulation, the recapture provision should be expanded to require the direct costs to be reduced by the amount received from the sale of an asset purchased prior to July 1, 2006 where a similar replacement asset is purchased.

Exemption for Small Producers.

Section 43.55.160(i) and (j) provides an exemption for smaller producers. In order to qualify for this exemption, a smaller producer must demonstrate that it is not owned by a single producer entity. This would prevent a large oil company from setting up numerous subsidiaries so that the oil produced by the subsidiaries would be exempt under the small producer exemption.

Large oil companies might try to circumvent this by banding together to form jointly owned enterprises. For example, if four oil companies each own 25% of several production companies, the bill should be clarified to make clear that such smaller production companies would not be eligible for this exemption, even though the ownership can not be attributed to a single large oil company.

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Testimony Regarding HB 488 and SB 305, a
Petroleum Production Tax Bill

Brian Wenzel, Marianne Kah, Darren Jones
ConocoPhillips

Before the
House Resources Committee &
Senate Resources Committee
February 27, 2006

Mr. Chairman, members of the committee:

Good afternoon. My name is Brian Wenzel, and I am the Vice President, Finance and Administration, for ConocoPhillips Alaska. With me today are Marianne Kah, Chief Economist for ConocoPhillips globally, and Darren Jones, Vice President, Commercial Assets Alaska. Thank you for allowing ConocoPhillips the opportunity to present testimony on HB 488 / SB 305, a bill designed by the Administration to replace the current production tax system.

ConocoPhillips is proud of its 45 year long history (through ARCO and Phillips Petroleum) here in Alaska. We have been actively exploring and developing oil and gas since the early 50's and have been a producer for 49 years. ConocoPhillips is the State's leading oil producer, its leading explorer, and its leading champion for the gas pipeline. ConocoPhillips is also the leading investor in Alaska. We are committed to Alaska and this year alone we are reinvesting over $700 million on Alaska capital projects, most in our core legacy fields but also in bringing on new developments.

Over the past 10 years we have invested over $5.8 billion in capital and $6.8 billion in expense dollars in the State. We are among the State's largest employers of Alaskans and we pay more to the state ($1.6 B) than any other entity.

We can't talk about ConocoPhillips in Alaska without talking about our employees. We have approximately 1000 employees in the state and approximately 90% of them are Alaskan residents and proud of it. They are competent, motivated, and active in the communities. They care about Alaska, and they believe that the work they do makes Alaska a better place to live. They see themselves as playing an important part in building Alaska's future. And, through contractors, subcontractors and support industries, we directly and indirectly generate employment for thousands of additional Alaskans.

The past, present, and future for ConocoPhillips and the State of Alaska are inextricably linked. As we move forward as partners for perhaps the next 50-100 years, we believe there must be a mutual recognition of, and respect for, the interests of each. We have to try, together, to answer the question—how do we balance the factors that affect each of our interests in a way that makes us both successful—so that over time we are both better off than if we single-mindedly tried to pursue our individual short-term interests? That is the balance the Governor's bill tries to strike.

Unfortunately, the balance in the bill is decidedly in the favor of the State and at the expense of established investors. We believe the Governor's bill sets an aggressive level of State take, when that take is considered in conjunction with our corporate income tax obligations to the State, our

property tax obligations to the State, our property, sales and other tax obligations to the State's municipalities, our royalty obligations to the State, the various oil and gas tax surcharges imposed by the State, and the sundry additional fees and costs paid as part of the permitting process whenever we attempt to move forward with development. All of which, of course, is on top of our corporate income tax obligations to the Federal government attributable to our activities in the State. It is no surprise that this layer upon layer of governmental take inevitably has a negative impact on the level of investment here, and, commensurately, the level of job creation and job growth in the State. As taxes increase, it is difficult to see how investment in Alaska will not be effected.

On the other hand, we realize that the legislature cannot adopt a tax policy that is concerned exclusively with maximizing the robustness of the State's economy and the participants in that economy. The government is charged with providing certain essential services to its citizens and those essential services cost money. And, if the State cannot pay, or chooses not to pay, for those services from the proceeds of the sale of its resources—that is, the royalty proceeds from its oil and gas—then it must turn to its sovereign taxing power to obtain the revenues to pay for those services.

While we support passage of this bill, we do so reluctantly. The bill reflects a significant tax increase on our company, and on the industry, at a time when the government is enjoying a large budget surplus. We believe the tax rate set in the bill is too high to guarantee the State's goal of increasing investment over the long term, and it punishes companies that have made long term investments that are returning dividends to the State in the form of

jobs, royalties, corporate income taxes and property taxes. We would, in fact, oppose this bill except for the fact that it has enabled all parties to come together in support of a contract under the Stranded Gas Development Act that will move the gas pipeline project to the next phase of development. Advancing the gas pipeline project has been, and continues to be, one of ConocoPhillips' top priorities.

With that introduction, I would like to start off by discussing some of ConocoPhillips' long term investments in Alaska, the role they have played in minimizing North Slope production decline and the impact that ELF has had on these developments.

As I mentioned, ConocoPhillips is Alaska's leading producer and explorer. Since 1989, we have been involved with the exploration and development of fourteen satellites (six of these since 2001). These satellites were predominately marginal developments, the 50 to 150 million barrel type that the State is targeting with this legislation, that were able to be developed as a result of the favorable fiscal treatment given under ELF.

Development of these satellites played a significant role in reducing North Slope decline and enabling more than 1.9 billion barrels of additional oil to be produced compared to predictions back in 1989, when the Economic Limit Factor was first introduced. This is equivalent to discovering a Kuparuk-size field and has added more than $5 billion in revenues to the State of Alaska. In addition to our active satellite developments, we continued to actively explore, drilling more that 40 exploration and appraisal wells in the last 5 years and are committed to continue exploring in the State

and developing future successes. As we look back, in general the ELF structure did what it was intended to do and enabled ConocoPhillips to continue exploration, pursue heavy oil, develop marginal satellite fields and maintain in-field drilling programs. It increased the barrels in the pipeline and the state government was able to collect the royalties, the corporate income taxes, the property taxes, and the various fees and surcharges that go along with these developments; the federal government collected its share; and most important, Alaska's economy was able to grow.

We understand the State's view on the limitations of the current ELF-based severance tax system, particularly at high prices. We also understand that there is no such thing as a perfect tax system. However, we believe that there can be such a thing as a wise and enduring tax policy. We believe a production tax, such as the one the Governor has proposed, that is intended to reflect profits from that production and includes incentives to encourage investment in the future and fair transition provisions that recognize the costs of the investments already made, is such a policy.

Nevertheless, HB 488 / SB 305 as proposed will result in an average of $1 billion per year in additional State revenue at today's prices, even with significant industry investment levels. This unprecedented increase will more than double existing severance tax payments.

With that backdrop, Marianne and I would like to give you ConocoPhillips' perspective in several key areas:

- A balanced fiscal structure is critical for both oil and gas future investment,

- Future of oil production in Alaska is primarily dependent on existing fields
- HB 488 / SB 305 differentially and adversely impacts our legacy production from existing fields
- A significant transition plan is necessary to allow equitable conversion to a new production tax system
- The new PPT will impact Alaska's global competitiveness for investment

Balanced Fiscal Structure: There have been many questions about the relationship of the Governor's oil tax proposal to the fiscal contract negotiations under the Stranded Gas Development Act. As you know the fundamental purpose of the Stranded Gas Development Act was to encourage new investment to develop the State's stranded gas resources by establishing fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows.

Unfortunately, the line between "oil" and "gas" is not clear-cut. Oil and gas exist together in reservoirs; the wells we drill produce both; many of the investments necessary to develop gas will help develop oil as well. Ultimately, this means that the "fiscal certainty" provided by the State under the SGDA could be inadequate if it only applied to gas.

The Administration recognized the need for the Legislature to approve any agreement that included fiscal certainty for oil but was unwilling to consider fiscal certainty on oil under the terms of the current production tax statute. It was, however, willing to propose to the legislature a new oil tax that could

become part of a fair and durable fiscal regime for both oil and gas. But the Administration's position was clear: the new production tax had to stand on its own. In other words, it had to represent something the legislature itself would accept as wise tax policy even in the absence of a deal on the natural gas pipeline.

For our part, this oil tax increase—on average, $1 billion per year for the industry at today's prices—is not something ConocoPhillips would have found acceptable if we didn't think it would result in progress—and, ultimately, an agreement to move forward—on the gas pipeline project.

So, once again, the proposed oil tax increase by the Administration is a balance. On the one hand, it provides a foundation for fiscal stability for the oil and gas-related businesses of the Producers in Alaska. This stability is essential to facilitate future investment, including investment in the development of a gas pipeline project. On the other hand, the Producers must pay substantially more taxes than they would under the current regime.

Future Oil Production: I would like to move on to talk briefly on the future of oil production in Alaska. Even with the proposed incentives, the State's consultant acknowledges that production resulting from wildcat exploration, will only play a small role in increasing revenues under the PPT. The core legacy fields such as Prudhoe and Kuparuk will still produce over 80% of the total North Slope production in 2015, providing the base infrastructure on which these smaller fields will depend.

The already discovered heavy oil resource will play a much more significant role in the future of the North Slope However, the State's consultant acknowledged that technology limitations and development costs will constrain heavy oil production in the near term, and it could be many years before this resource reaches its production potential. Yet, this heavy oil resource base is huge; published data suggests that in-place volumes are greater than 20 billion barrels. This is a key resource for Alaska, and the legislature should consider a structure that will best enable its development. The technology required to develop this resource will require huge expenditures. Therefore, heavy oil should be given differential consideration in the form of a lower tax rate or additional credits to develop.

Impact on legacy production: The bill has been designed to encourage new investors to come to Alaska. We fully support the arrival of new players and believe they can be beneficial to both the State and the Industry. Indeed, we have already made partners of several of them. However, the terms that will attract new investors also come with a cost.

Under the Governor's proposal the tax increase mainly targets the large legacy production assets (Prudhoe and Kuparuk) and will result in one of the highest, if not the highest severance tax burden of anywhere in the United States. This is an unprecedented fiscal increase on those who invested tens of billions of dollars to develop the North Slope and stayed in Alaska through difficult times, including periods of very low oil prices. We believe such an increase could undermine investor confidence in Alaska.

As we have discussed, the huge rate increase reflected in this bill is

something that ConocoPhillips supports with great reluctance. We should acknowledge that the State is currently enjoying a budget surplus and if one were to consider moving to a profits tax that collected the same amount that is collected today under current law, the PPT rate would be approximately 13% vs the 20% in the proposed bill.

Nevertheless, the legislature has fielded many questions over the last week some of which suggest that a tax rate of 20% is too low and that 25% would be more appropriate. Anytime the government raises taxes it is taking away money from the private sector that could be used for reinvestment and continued job growth. While it is obvious that higher rates would negatively affect the oil and gas industry, we also believe that those higher rates would not be in the long-term best interest of the State.

New field sizes in Alaska are small and arctic operating and development costs are high. We therefore spend a lot of time and resources assessing the upside potential and the downside risk. When we invest, we fully understand that there is a chance that we may not get a return on the investment, but also acknowledge that results could exceed expectations; hopefully we are right more than we are wrong. As we bear the greatest risk, it is fair that we should be appropriately rewarded. We acknowledge that the presence of tax credits reduces the downside risk for investors, but conversely higher tax rates significantly reduce the upside potential.

To attract investors, the State needs to set an appropriate risk/reward balance. If the credits are too high, the state will take too much downside risk, if the tax rate is too high, investors see insufficient upside potential and

look for better opportunities elsewhere. As we have mentioned before, with the high field costs and limited exploration prospectivity, investors in Alaska need upside potential. Moving upwards from 20% will seriously disrupt this risk/reward balance.

Getting the right balance between the tax rate and the credits for reinvestment is critical to future resource development in Alaska. The balance provided in this bill, while incorporating a significant tax increase, reflects, as we've said, a balance we are willing to reluctantly accept. Changes, even small ones will impact this balance and will cause investors to re-evaluate potential investments. Twenty percent can be implemented; but, the question you have to wrestle with is, with a rate that high, are you really going to get the level of long-term investment you desire.

Transition Plan: Under the bill, a fraction of a producer's expenditures on exploration, appraisal, and development capital incurred over the past five years may be deducted for purposes of calculating the producer's monthly profit tax obligation. ConocoPhillips supports this plan as it provides an equitable transition to the new tax system and is an essential piece of the overall balance reflected in the bill.

The Fiord field was discovered in 1992 (prior to the discovery of the Alpine Field). It was not possible to develop this small field by itself and it is only with the expansion of the Alpine facilities in 2004 that it is now possible to develop this satellite.

The project kicked off in 2003 and when faced with ELF aggregation, was in

jeopardy of not moving forward. In 2005, the Department of Revenue provided ConocoPhillips with a letter ruling stating that Fiord would be treated as stand-alone satellite and not be aggregated with Alpine for severance tax purposes. As a small satellite, Fiord would have a low ELF and hence pay little severance tax. Once this decision was received from the DOR, ConocoPhillips and its partners sanctioned the project.

Fiord will be an 18 well, roadless satellite with first production in late third or fourth quarter this year. Drilling will continue in 2007 and 2008 and production will peak at around 17,000 bpd. Total capital costs are expected to be around $300MM. While oil and gas prices have significant increased over the past few years, we are also seeing dramatically increased labor and material costs. On this project alone, we expect the costs be $30MM more than originally sanctioned.

The majority of the costs associated with developing Fiord will have been expended prior to the bill becoming effective. Without the Transitional Investment Expenditure plan, only costs associated with the 2007 and 2008 winter drilling programs would be eligible for PPT deductions and credits. As previously discussed, the project was sanctioned (based on the letter ruling from the DOR) assuming that the field would pay full state corporate income tax, royalty and property tax, but little or no severance tax. However, under the new bill, the development would now be subject to the 20% PPT rate. Without the transition plan, the increase in fiscal terms will result in a reduction of over $100MM in gross value and a 6% reduction in IRR at a $40 ANS West Coast Price.

ConocoPhillips is currently working on two other satellites in addition to Fiord. These are Nanuq, due to start up in late 2006, and West Sak IJ, which came on line in late 2005. All of these projects will have similar value loss impacts without the transition plan. In addition there are several other projects undertaken over the last few years which are now almost fully developed and will have value eroded as a result of the PPT.

In order to ensure that these past investments are equitably treated, a transition plan is essential.

I would now like to ask Marianne Kah to spend a few moments discussing how this proposed tax change might impact Alaska's competitiveness from the perspective of a global investor.

Good afternoon. I am Marianne Kah, the Chief Economist for ConocoPhillips in Houston. Thank you for providing me the opportunity to discuss how this proposed tax change might impact Alaska's competitiveness from the perspective of a global investor.

First, let me say that I appreciate the difficulty of your position. Many factors have to be considered by a government in choosing an appropriate tax rate for an industry as complex as the oil and gas industry. Cost structure, prospectivity, potential field size, reservoir quality, regulatory constraints, and the desired level of investment are perhaps but a few of the factors that have to be considered. Moreover, how these factors interrelate is not always obvious or easy to predict. Nevertheless, I will discuss several of

these factors and try to give you information that I hope will be helpful and relevant to your deliberations.

With that said, let me turn to some things that may be important to your decision and that I can illustrate with some slides.

Global Total Cost per Barrel: This slide shows for Alaska and other locations average capital and operating costs on a per dollar per BOE basis over the last decade. You can see that Alaska has higher capital and operating costs than other regions. Cost needs to be taken into account when setting the tax take. The countries with the lowest costs can afford to have higher tax rates while remaining competitive. Similarly, higher cost countries need to offset these conditions with lower tax takes.

In addition, with higher taxes there is actually less of an incentive for companies to control costs so you can say that higher taxes lead to higher costs.

Alaska – High Cost, High Tax: My next slide, shows the total costs as a function of government take for about 50 countries/states in the world. This data was taken from the Wood Mackenzie 2004 "Global Oil and Gas Risks and Reward Study". As can be seen, there are inverse relationships between Government take and Total Costs. Alaska under the ELF is shown as the Green Box and the peer companies referenced by the State's consultant in his PPT report are annotated and shown as red data points. As can be seen, Alaska under ELF is on the same trend line as many of the countries used by the consultant for his competitive analysis in his PPT report and is in the

"High Cost-Low Tax" quadrant. Based on his analysis, Government Take under PPT will go up about 6%. Alaska's position on the charts under PPT is shown high-lighted with a circle in the upper right-hand quadrant. Using the new Government take figures estimated by the State's consultant, Alaska has now shifted from the original trend line and moved into the high cost-high tax quadrant.

It is interesting to note that peer areas (according to the consultant's competitive analysis) such as the Gulf of Mexico and UK North Sea (even adjusted for the recent tax increase) are still significantly more favorable investment regimes. The high cost in the Arctic and the types of fields that are likely to be found suggest that the proposed fiscal regime could detract, rather than encourage, significant additional investment.

Global Average Commercial Discovery Size: My next slide shows the average commercial discovery size in Alaska versus various countries around the world. Areas with high prospectivity can generally assess higher tax rates, while maintaining investment. The Alaska North Slope, however, has limited prospectivity as compared to many parts of the world that we are exploring. Tax rates need to reflect that.

The State's consultant assessed the competitiveness of Alaska's tax rates by comparing tax rates of different regimes around the world. He assessed the impact on investor net present value using similar sized fields in all locations. That is not the way investors look at it. When we compare investments in Russia versus Alaska, for example, we compare the prospects of finding a very large field with very high tax rates in Russia versus finding

a much smaller field with lower tax rates in Alaska. The greater prospectivity in Russia may compensate for the higher tax rates. Thus, it is not meaningful to compare the competitiveness of Alaskan tax terms with Russia's terms or those in Azerbaijan and Angola at the same field sizes.

Norwegian Crude Production: The State's consultant has stated that Norway is comparable to Alaska in its wealth of natural resources and should be an analogue for Alaska. I don't believe that it is a good analogue because Norway has a lower cost structure and better prospectivity than Alaska. However, Norway has significantly higher taxes than Alaska. I don't believe that the Norwegian tax model is a helpful comparison for Alaska because as shown in this slide, Norwegian crude production has declined by 17% since 2001 despite the high oil prices we have seen in recent years. Thus, I would assert that Norway is not getting sufficient investment since its tax regime isn't in line with its cost and prospectivity position.

Petroleum Industry Re-Investment Rates: Investors most need stable fiscal terms with tax rates that are commensurate with the cost structure and size of the opportunity. Alaska's tax regime has offered that in the past and that is why we have found Alaska to be an attractive place to invest.

With the recent tax increases we have seen in a few locations around the world, I have become concerned that global tax takes are reaching a point where private companies are finding it challenging to invest. I believe that is one of the main reasons why petroleum industry re-investment rates, including those of independents, have not completely followed the rise up in

crude prices.

Of course, there are several other reasons why we haven't seen a greater spending response thus far -- the expectation that prices will cycle down to more "normal" levels and a lag time in developing new projects to invest in. But I firmly believe that tax rates around the world are also playing a key role. I also believe that re-investment rates could be lagging due to fear that governments will change tax rates after investments are made. Longer term, I am concerned that private oil companies will not be able to invest in conventional oil under terms being offered and will be forced to invest in alternative energy supplies with more favorable tax terms.

Cost of Capital: Another concern from a major oil company's point of view is the bias in the proposed tax regime change in favor of new versus legacy investors. There is a common misperception that small and medium-sized petroleum companies have lower return requirements than the majors. I would like to point out that the independent petroleum companies as a group, for example, have a higher cost of capital than the supermajors, and they should therefore have higher return requirements. Companies of all sizes who have not maintained adequate returns for their shareholders are no longer with us today.

I would also imagine that independents will also be comparing Alaska's tax rates to those in the Gulf of Mexico, United Kingdom and Canadian oil sands, where they have been frequent investors. The State's consultant concludes that tax rates in these locations are more competitive than the existing and proposed tax rates in Alaska.

If countries have high tax rates, it is possible that only government-controlled oil companies with different objectives, like energy security, will be willing to invest.

There is another concern created by the bias in favor of new versus legacy investors. This bias creates the potential of having a large number of small players active in the environmentally sensitive North Slope. The costs associated with the environmental protections that companies like ConocoPhillips insist on and are demanded by federal, state, and local governments are significant. This level of environmental sensitivity may be new to many of these smaller players.

Majors Offer Important Benefits: ConocoPhillips has been a long-term investor in Alaska and we want to make the case for why our company, along with other majors, should continue to have a significant role in the state.

We have the size and financial strength to carry out projects of any size. We have the skills to manage large and complex projects and we have substantial experience in developing projects and operating in Arctic conditions. ConocoPhillips, in particular, has substantial experience in heavy oil production and has leading coking technology to process heavier crudes. We are also the second largest refiner in the United States so we have the ability to upgrade our numerous refineries to process additional heavy crude oil. We also have strong commercial acumen and access to markets, which allows us to design projects to maximize the value of the

resource. For example, ConocoPhillips is the second largest gas marketer in the United States. And we have strong risk management skills. Finally, we have a long-term investment horizon. That means that we invest year in and year out and won't leave when market conditions get rough.

Majors Have Great Spending Capability: The last point I wanted to make about why major oil companies should be viewed as desirable investors is our great investment capability. This chart shows the three-year average total upstream spending in billions of dollars of the majors versus various independent petroleum companies. We can and would like to bring a lot of investment dollars into this state provided the terms are competitive. The tax proposal as introduced is the upper bound of what we believe is reasonable given the totality of the deal.

Thank you for your attention.

Thank you Marianne

Bill Language:

Prior to some concluding remarks, I would like to note that we have identified some suggested changes in language to improve or clarify the intent of the bill. Among other things, these changes concern how eligible deductions and credits are identified and how the value at the point of production should be calculated. We are developing proposed language to reflect these changes and hope to offer this language to you shortly.

Finally, we would like to summarize several key messages.

One, the proposed tax results in a more than doubling of the effective tax rate over the current system. In isolation, we would not view this change as reasonable, fair or appropriate, particularly given the state's current budget surplus. However, as a foundation for oil and gas fiscal stability that facilitates future investment in Alaska, the balance proposed in this bill is something ConocoPhillips will reluctantly support.

Two, the North Slope has a huge heavy oil resource that is already significantly disadvantaged from a technology, quality and cost perspective; incentivizing this resource will be key to increasing production levels in Alaska.

Three, a transition plan from the current production tax system to the next is essential to ensure equitable treatment of our legacy investments. Many of these investments were associated with the development of marginal assets that were justified on the basis of ELF. Qualifying these legacy investments for deduction against PPT is an essential part of the balance reflected in the bill.

Four, the tax rate proposed in the bill pushes Alaska into a high cost/high tax bracket as compared to many regimes around the world. This will affect the risk/reward balance that companies will evaluate before deciding to invest here. Before you accept the rate reflected in the Governor's bill, you must be comfortable with the potential risks to future investment that such a high rate imposes.

I would like to reiterate that Alaska and ConocoPhillips are aligned as partners on many important goals:

- increasing investment in Alaska;
- increasing Alaska's oil and gas production,
- increasing Alaska's competitive position, and
- developing long-term relationships with proven partners for long-term, mutual benefit.

In closing, many factors have to be considered by a government in choosing an appropriate tax rate for an industry as complex as the oil and gas industry. Cost structure (including distance to market), prospectivity, potential field size, reservoir quality, regulatory constraints, and the desired level of investment are perhaps but a few of the factors that have to be considered. Today, Alaska is challenged in each of these areas and the fiscal regime needs to recognize this.

Thank you for considering our views.

ALASKA STATE LEGISLATURE

SENATE RESOURCES COMMITTEE
Senator Tom Wagoner, Chair
State Capitol, Room 427
Juneau, AK 99801-1182

HOUSE RESOURCES COMMITTEE
Rep. Ralph Samuels, Co-Chair
State Capitol, Room 126
Juneau, AK 99801-1182

Rep Jay Ramras, Co-Chair
State Capitol, Room 104
Juneau, AK 99801-1182

Official Business

DATE: February 28, 2006
TO: Commissioner Bill Corbus & Commissioner-Select Menge
FROM: Senate & House Resources Committee
RE: Questions on PPT Legislation

We have listed the questions we have heard both during the committee process and also during subsequent discussions. Please provide your responses, at your very earliest convenience, in writing. We anticipate your appearance again before the committees perhaps as early as Wednesday, March 1.

To the extent that information requests are confidential information, please provide them as separate documents so we will be able to keep them distinguished from open, public information.

We understand that you are working on the first three questions, per the memo from R. Wilson on 2-27-06, and will also be providing tax calculations with the following assumptions: Gross value =60.00; Opex= 15.00; and Capez = 10.00.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production), by company.

2. How are mob, demob, and platform abandonment costs treated - as tax credits or deductions?

3. Is there a "rating" for political stability – or one that reflects instability?

4. What loss of revenue is incurred by moving the effective date from Jan 1, 2006 to July 1, 2006 on both 20/20 and on 25/20?

5. Section 9 – what amount is involved in this section.

6. Was there consideration of phasing out the $73 million deduction over a certain period of time?

7. Of the current 14 producers in Alaska, which would pay a severance tax after employing the proposed $73 million standard deduction?

Committee Staff: Mary Jackson (907) 465-4907 telephone (907) 465-4779 fax

8. Which other tax regimes – worldwide - have a progressivity structure?

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

11. Provide information on the effect of previous incentives – the costs.

12. What is the rational for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

13. Why should Point Thomson be incentivised?

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

15. What steps must be taken to make the tax credits refundable rather than transferable?

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

17. Does the limit on transferable tax credits in section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the legislation on the State's legal position in past agreements, current disputes, or future disputes?

19. Have you asked the Department of Law to review this legislation in light of the 6th Circuit Court of Appeals' decision in Cuno v DaimlerChrysler that is now pending before the United States Supreme Court?

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

21. Have any of the definitions in sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

31. How will Net Profit Share Leases be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

Thank you for your efforts in this regard.

Senator Tom Wagoner , Chair
Senate Resources Committee

Rep. Ralph Samuels, Co-Chair
House Resources Committee

Rep. Jay Ramras, Co-Chair
House Resources Committee

MEMORANDUM DEPARTMENT OF REVENUE

Tax Division

TO: Senator Thomas Wagoner
Chairman, Senate Resources Committee

FROM: Robynn J. Wilson
Director, Tax Division

RE: Outstanding Questions on PPT (SB 305)

DATE: February 27, 2006

During the hearings on February 22—24, 2006, I have noted the following outstanding questions from your committee members. Please let me know if there are additional questions.

Senate Resources

1. Is it possible to revise Dr. Van Meuers' country rankings to include risk?

2.. Show tax calculation with the following assumptions:

gross value	$60
opex	15
capex	10

4. Which companies have made what investments on the North Slope in the last 5 years? (This question will be answered within the constraints of confidentiality requirements.)

5. Are costs to demobe wells a capital expenditure for purposes of the PPT?

SENATOR KIM ELTON

SB 305 Oil and Gas Severance Tax

1. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

2. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

3. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

4. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

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SENATOR_KIM_ELTON@LEGIS.STATE.AK.US

SB305: Oil and Gas Severance Tax

Is current production tax deductible from corporate tax? If not, is this impact in the models presented by the Administration?

Referring to section five, what oil and gas is exempt from taxation – just what is discussed in section 10?

Referring to section six, will there be any impact to current state taxes or municipality taxes from this change?

Why was the payment for taxes and surcharges changed from the 20th day to the last day of the month? What is the economic impact of this change?

Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

What are the penalties for under-payment when sure-up is more than ten percent of the taxes owed?

Referring to section 10, why does the AOGC role change from focusing on excess needed for safety reasons to whatever they determine to be waste. Does this provision provide more power to the AGOC on what is included/excluded for taxation?

Why does it seem the credits and incentive are on production along with exploration if our focus is to provide incentives for exploration?

Can the carry-forward amount be used for a credit for more than the first year after the loss?

Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Why not use GAP accounting rules versus set up or our system of defining revenues and expenses?

Which credits can be applied to multiple years?

Can a tax credit be sold in any year or just the year after it was accrued?

What is the estimated economic impact to the state of the ability to sell tax credits?

Referring to section 16, what is current system and why do we need this change in confidentiality.

In what circumstances would oil and gas taxes go straight into the CBR?

Referring to section 18 and 19, why change from shall to is?

Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

Section 21, page 13, line 8 – why is this clause constrained by Dec 1, 2005

Section 21, provision (h), which US CPI does the Administration plan on using?

Are the current oil conservation surcharges deductible from any other taxation? If not, what is the policy reason to make them a credit in SB305 and what is the economic impact?

February 28, 2006

TESTIMONY OF RICHARD OWEN

HB 488 / SB 305 TO THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

AND SENATE RESOURCE COMMITTEE

FEBURARY 28, 2006

Mr. Chairman, members of the committee

Good afternoon. My name is Richard Owen and I am the Production Manager for ExxonMobil in Alaska and a vice president of ExxonMobil Alaska Production. Along side me, to assist in addressing any questions that you may have, are Marty Massey and Dan Seckers. Marty Massey is ExxonMobil's Joint Interest Manager for the U.S. and is leading our Alaska Gas Pipeline Project fiscal contract negotiations. Dan Seckers is our Tax Counsel responsible for Alaska.

I am here today, at your request, to offer ExxonMobil's thoughts and concerns about HB 488/SB 305. If this measure was simply a tax increase, ExxonMobil would actively oppose it. At current prices, we expect ExxonMobil's production tax payments would increase by $50-$100 million per year. However, we are prepared to move forward under the proposed system since it balances revenues to the State and producers across a range of oil prices, provides incentives for new investment, and includes a transition provision for recent investments. Most importantly for ExxonMobil, the PPT proposal provides a predictable and durable tax system which, along with the appropriate gas pipeline fiscal

contract terms, will allow the Alaska Natural Gas Pipeline project to move forward to the next phase.

As far as specific concerns about this bill, they center around whether the high tax rate and resulting increase in taxes will hinder full development of the remaining oil resources on the North Slope. I'll expand on this concern during my testimony. Before I make further comment on the PPT bill, I would like to give a brief overview of ExxonMobil's presence in Alaska and review how the current ELF system has benefited both industry and the State of Alaska.

ExxonMobil in Alaska

ExxonMobil has had a presence in Alaska for over a half century, investing more than 11 billion dollars in the State's economy. Our activities date back to 1954 when we conducted a comprehensive study of the territory's oil and gas potential. Over the years, we explored most of the major hydrocarbon plays in Alaska including: the Gulf of Alaska; St. George and Navarin Basins; the Norton Sound; the Beaufort Sea; the Cook Inlet; and of course, the North Slope where we were a participant in the 1968 Prudhoe Bay State #1 discovery well. We are proud of the role our company has played in Alaska through: exploration; initial field developments; construction of TAPS; development of new technology; and the promotion of efficient reservoir management practices.

Currently, ExxonMobil has working interests in Prudhoe Bay, Kuparuk, Endicott and Granite Point. We are the operator of the Point Thomson Unit, and the largest interest

holder in the Prudhoe Bay field. Our current working interest oil production is approximately 180,000 B/D *(Note: EMWI; 159,000 EMNI)* and we are the largest owner of discovered gas resource. Our production from Alaska represents approximately 4% of ExxonMobil's worldwide oil and gas production. Our Alaskan production is primarily from Prudhoe Bay and near-by satellite fields. Prudhoe Bay, along with Point Thomson, h[illegible] significant remaining potential but it comes at higher cost and risk.

Historical Context

One of ExxonMobil's objectives in both the gas pipeline fiscal contract negotiation and the debate on oil taxes has been to reduce the risk associated with fiscal changes by working with the State of Alaska to establish a predictable and durable fiscal environment in which to make long term investment decisions. To that end, any change in the fiscal regime for oil has a direct impact on how we view the stability of the Alaskan fiscal environment, which in turn, impacts how we evaluate ongoing investment decisions.

We understand the State's desire to obtain additional tax revenue at higher prices. One of the most challenging tasks that the Legislature can undertake is how to change the oil tax system without damaging the industry. As Governor Murkowski has correctly stated on many occasions, the North Slope is one of the most expensive places in which our industry operates. Tax systems need to be carefully designed to ensure that the desired objectives are achieved and that any change does not result in unintended consequences, such as reduced investments and lower reserve recovery.

One of the many questions that we are asked is, why are ExxonMobil and other Producers seeking durability and predictability for oil in parallel with negotiating a fiscal contract for a gas pipeline? The answer is fairly simple, the gas on the North Slope is contained in the same reservoirs as the oil and is produced through the same facilities. For a gas project to be viable, we need the fields that produce both oil and gas to be viable, underpinned by predictable and durable fiscal terms. A commitment of billions of dollars to build the natural gas pipeline requires confidence that the base oil business will remain healthy for the long-term.

Existing System – ELF

With that context in mind, I'd like to make a few comments about the current oil production severance tax system – the Economic Limit Factor or ELF and, in particular, how it has been effective at encouraging investment and mitigating production decline. The ELF was designed to allow the State to increase the production tax while not stifling investment in marginal fields. The ELF scaled down the production tax rate when a field became more marginal, reducing the economic limit to which a field could be produced and ultimately allowing more reserves to be recovered. The 1989 ELF amendment significantly increased the production tax on Prudhoe Bay and Kuparuk, while providing an incentive to encourage the development of smaller fields. That 1989 amendment worked as intended, with many small and marginal fields coming on stream over the past 17 years. The ELF lowered the tax rate on those fields, supporting their commercial viability.

contribute substantial amounts to the State in royalties, property taxes and income taxes, and in jobs for Alaskans.

Over the past five years, we and other working interest owners have also extended the primary Prudhoe Bay enhanced oil recovery (EOR) technology to the some of these satellite fields. Since 1998, ExxonMobil has invested over $30 million in tertiary recovery projects at Point McIntyre, Eileen West End, and Borealis which are expected to produce an additional 60 million barrels gross. While tertiary projects recover additional oil, the production profile results in a slower oil recovery and longer payout periods. These satellite EOR projects are in the early stages of development. The major investments have been made, but the oil production benefits will not be received until many years out. The ELF provision of the existing production severance tax made these economically challenged projects commercially viable.

Taken together, the recent Prudhoe Bay satellite and EOR development projects developed over 560 million barrels gross. While the resulting State's production tax under ELF was relatively minor, the State's royalty oil would total 70 million barrels, which at today's oil price is worth roughly $4 billion. Bottom line, the ELF system has worked well for industry and the State of Alaska by encouraging significant new investment.

However, it is also recognized that ELF can be considered a somewhat regressive system in that it does not reflect "profitability" or "cost" in the division of gross revenue between

the State and the producers as oil prices rise and fall. The assumption that a well is marginal at 300 BOPD does not necessarily hold in the current high oil price environment, yet this assumption typically contributes to a reduced ELF factor based on the current formula. As a global oil and gas producer, ExxonMobil operates across a wide array of fiscal systems. It is most important that the system recognize the quality of the resources so that the potential developments will be commercially viable and attract capital. When I say the quality of resource, I mean: the size and nature of the oil and gas reservoirs, the cost and technology required to develop those reservoirs, the distance to market, as well as the tax and royalty system that applies including the long-term stability of that system. Countries that are experiencing significant industry investment have achieved the proper balance in their fiscal regimes.

Alaska Remaining Oil Resource Base

ExxonMobil's assessment of the remaining oil resource suggests future growth opportunities will come from: complex enhanced oil recovery (EOR) projects; development of smaller, more marginal oil accumulations; and the innovative development of viscous and heavy oil resources. These opportunities will require the development and application of new technology, higher unit development costs, and more complex operations to deliver a given production rate. These resources are much lower in quality as compared to Prudhoe Bay and Kuparuk, though they face the similar challenges associated with arctic conditions and distance to market.

Therefore, as stated earlier, we are concerned that the Administration's proposal is weighted towards a higher tax which may prevent some of Alaska's challenged resources from being developed.

PPT Proposal - Overview

I would now like to make some comments on the Administration's PPT proposal. This proposal represents a tax based on profits which results in a sharing of the risks and the rewards across a range of prices. The State will receive a higher share of the revenues when prices are high and will accept lower taxes during periods of low prices. The proposal moves from the regressive ELF system to a progressive system. ExxonMobil affiliates have significant experience in profit-based progressive systems around the world and they work well, as long as they have properly taken into account the nature of resource base – which I mentioned earlier.

Let me discuss some of the key features of the PPT proposal:

PPT System: Transition

This bill represents a major step-change in Alaska's current production tax system. The bill appropriately addresses this step-change by including a transition plan so that recent investment decisions are not adversely impacted. The bill provides a transition allowance over the next six years based on capital investments made in the last five years. We believe this transition plan is appropriate because the benefits from these recent investments have not yet been fully received. Oil and gas companies invest large sums of

money years ahead of first production and are at risk for price, development cost, production rates and ultimate reserve recovery. In most cases it takes many years, often more than five years, for a return on oil or gas investment to occur.

For example, satellite and tertiary recovery investment decisions during the last five years were made under the ELF structure anticipating a lower tax relative to that proposed under the PPT bill. The State appropriately provided this incentive so that these challenged and costly projects would be commercially viable. It is not appropriate to suddenly increase taxes on these investments without providing some form of consideration. The transition provision recognizes that past investments were made under the ELF structure and somewhat reduces the increased tax treatment to which these projects will now be subjected. To avoid penalizing these recent investments, the transition provisions included in this bill are essential.

PPT System: Tax Rate and Investment Tax Credits

As I have said, we are concerned the 20% tax rate as proposed will not support the growth opportunities remaining on the North Slope which I've described as primarily: complex enhanced oil recovery projects; development of small oil accumulations; and innovative development of viscous and heavy oil resources – these opportunities have challenged economics. While the investment tax credits of 20% will enhance the present value economics of new investments, the 20% tax rate will result in lower overall cash flow. The impact on all economic parameters must be carefully weighed before a decision to progress an investment is made. The combination of a 20% credit along with

a 20% tax rate may not be adequate to support development of all of the remaining opportunities.

It is with this in mind that we strongly recommend that the legislature not increase the proposed tax rate or reduce the proposed tax credits.

PPT System: Valuation from Royalty Settlement Methodology

This bill addresses many of the longstanding issues that have divided the State and the industry over the years. For example, too many years and too much money have been spent in disputes over how to value a single barrel of crude oil or a single molecule of gas. It made little sense in the past and it makes little sense today for the State to have separate divisions determining the value of oil and gas – one for royalty and one for taxes. There is only one value in the market place. HB 488/SB 305 allows the State to value a producer's oil and gas using the producer's royalty settlement agreement, which was negotiated with, and approved by, the Department of Natural Resources. This will provide certainty to a producer on the value on which to pay its royalty and production taxes and will reduce the administrative and audit costs to both the State and the industry.

PPT Proposal - Conclusion

Under current prices, ExxonMobil and industry will pay more in taxes as compared to the current production tax system. However, as I said in my opening comments we need predictably and durability under which to gauge investment decisions. No one wants to invest money in a project only to have the rules changed, reducing the attractiveness of

the investment. The transition provision is an important feature of the bill necessary to provide relief for the abrupt change caused by the new PPT system.

The Administration decided to weight the proposal to a higher tax which may make it difficult to progress the remaining future development opportunities. It is most important that the quality of the resources be factored into the design of the tax system. Given our view of the resources, we would not support a higher tax rate or lower credits than proposed in the bill.

HB 488/SB 305 seeks to balance revenues to the State and the producers across a range of oil prices and provides incentives for new investments, which is a clear objective of the State of Alask

And most importantly for ExxonMobil, we believe the new system, coupled with appropriate gas pipeline fiscal contract terms, will lead to a predictable and durable tax system, which will enable the Alaska Gas Project to move forward to the next phase. Pote tial changes to the features of the PPT bill must be carefully considered to avoid upsetting the balance contained within the bill.

In conclusion, this bill is important for Alaska and the Producers. It is one part – a very important part – of a series of related issues that the legislature will need to address to ultimately provide the necessary fiscal environment to stimulate oil production and to progress the Alaska Gas Pipeline Project.

The Fiscal Contract that is being finalized under the authority of the Stranded Gas Development Act will incorporate this PPT legislation by reference in order to provide fiscal stability. We are currently working with the Administration on how best to incorporate this bill into the fiscal contract.

The Fiscal Contract will soon be released for public and legislative comment. Following the regular session, we understand the Governor will call a special session so the Legislature can vote on the contract. For that reason it is important that HB 488/SB 305 be enacted in its present form prior to that special session.

ExxonMobil has been in Alaska for over 50 years. Our future business plans show our continued activity in Alaska for at least the next fifty years. We are on the verge of taking the next step to commercialize Alaska's North Slope gas and I ask you to support the Administration's efforts in this regard.

Thank you again Mister Chairman for the opportunity to testify today.

MR. PAT FOLEY
PIONEER NATURAL RESOURCES

March 1, 2006

Representative Ralph Samuels and other members of the House Resources Committee

Thank you for the opportunity to share Pioneer's views regarding HB 488 eliminating the current severance tax system and replacing it with a Profit Sharing Production Tax.

Pioneer began its investment in Alaska in early 2003 with the drilling of 3 exploration wells in the shallow waters of the Beaufort Sea. Pioneer significantly expanded its Alaskan inventory at the October 2003 Alaska State Lease Sale where it was the largest participant and successful bidder on approximately 150,000 acres. We opened an office in Anchorage in early 2004 and now employ 26 persons in Alaska. In 2004, Pioneer concluded exploration agreements with ConocoPhillips and Anadarko across a vast portion of NPR-A. In 2005, Pioneer acquired a 10 percent working interest and the option to acquire up to an additional 40 percent working interest and possibly succeed ConocoPhillips as the operator of the Cosmopolitan Unit located in the Cook Inlet. Pioneer has significantly invested in the state and has assembled a substantial portfolio with an interest in approximately 1.6 million acres of leasehold.

On February 6, 2006, Pioneer announced that it approved and is commencing the development of the Oooguruk field on the North Slope of Alaska. Pioneer is the operator of the field, which is in the shallow waters of the Beaufort Sea approximately eight miles northwest of the Kuparuk River Unit. Pioneer has commenced operations to install an offshore gravel drilling and production site and we expect to complete gravel hauling activities by the end of winter. Following construction of the gravel drilling and production, a subsea flowline and facilities will be installed during 2007 to carry produced three-phase liquids to existing onshore processing facilities at the Kuparuk River Unit. Pioneer plans to drill approximately 40 horizontal wells to develop 50 million to 90 million barrels of estimated gross oil resources. Total gross capital to be invested in drilling and facilities is expected to range from $450 million to $525 million. The wells are expected to be brought on production as drilling progresses, with peak

rates of approximately 15,000 to 20,000 barrels of oil per day expected by 2010.

For independent companies like Pioneer, the challenges to building a business in Alaska are formidable. The remaining North Slope resources are nothing like the billion barrel fields that opened the Slope. The new wave of developers are working to commercialize: a) smaller, lower quality oil reservoirs, b) viscous oil resources, c) remote resources in NPRA, the foothills and offshore and d) natural gas resources, which will not have a market until the next decade. All of these resources are challenging to commercialize, but it is a challenge that must be met to insure new sources of supply for the state.

The North Slope is one of the highest cost areas in the world. Remote geography translates to some of the highest capital, lease operating and product transportation costs in the world. Additionally, North Slope projects have comparatively long cycles times. From buying a lease to selling oil takes 5 to 10 years depending upon drilling success and distance to existing infrastructure.

The largest challenge independents face on the North Slope is arguably uncertainty. To be successful, we must properly assess and make provision for a number of uncertainties related to exploration risk, future oil and gas prices, fiscal policy, regulatory processes and access to infrastructure.

The long cycle times for Alaska projects require that we make our investment decisions based upon a long term price projection. Although current prices exceed $50 per barrel, the 10 year average price for North Slope crude is approximately $25 per barrel. For Pioneer's Alaska projects, the price of oil in 2006 is irrelevant. The prevailing price in the next two decades will determine future cash flow for new projects.

Accurate assessment of risk is critical to the success of an exploration portfolio. Will the value of the fields we ultimately discover offset the cost of dry holes, land, seismic data and development costs? For many of the remote exploration areas in Alaska, it is difficult to project acceptable full cycle returns. In 2003, the state initiated exploration incentive credits for certain qualifying exploration expenditures. These incentives encouraged Pioneer to invest significantly in infrastructure challenged areas such as NPR-A.

When Pioneer was considering its first investments in Alaska, state officials were promoting the resource merits of Alaska basins. Alaska certainly contains world class petroleum systems. Additionally, the officials promoted the fiscal policy including the ELF formula and exploration incentives. Under the ELF formula, only very large new fields would pay severance tax and qualifying exploration expenditures in remote areas would receive exploration incentive credits at either a 20 or a 40% rate. With this fiscal system in place, Pioneer invested heavily in the state over the last several years. When we learned that a new severance tax policy was under development, we were quite concerned that any new system would be detrimental to our future investments and a departure from the fiscal system promoted to the independents by the state.

We recognize that the existing severance tax policy, as it applies to the large fields on the North Slope, is likely not sustainable and we are pleased that the proposed PPT taxes profits rather than revenues. Given that the state collects royalties right off the top, it makes sense that any additional government take should be assessed after costs have been recovered. This concept is important to the smaller, lower productivity and remote resources which are critical to future production growth. Although the proposed production tax rate of 20% is quite large when layered upon the other burdens of royalty, ad valorem tax, state income tax and federal income tax, the impact of the large tax rate is tempered by the allowance of cost recovery, investment tax credits and the proposed taxable income threshold.

Pioneer is pleased to see the provision included in the proposed legislation regarding the deductibility of transitional capital. The provision serves to compensate those companies, including Pioneer, who have made significant capital investments over the past five years based upon the fiscal terms in place at that time.

We have reviewed the testimony of the administration and agree that the PPT, as proposed, will provide incentives for new investment by all companies. Economic metrics for new investments will improve under the PPT versus existing tax law. This should encourage the development of marginal fields and will reduce the minimum economic size for exploration prospects, thus prompting more exploration and increasing the chances of finding commercial-sized fields. In addition, it should encourage re-investment in existing fields. We believe the PPT as proposed will entice

more companies to Alaska and increase competition. More companies and more ideas will lead to smarter field development methods, smarter drilling and production equipment, which will further reduce the minimum economic size of exploration prospects and grow the resource pie.

The tradable tax credits are a particularly effective incentive for the exploration and development of new resources. Under the proposed PPT, the higher risk, higher cost and long project cycle times associated with new resource exploration and development are partially offset by the ability to monetize these credits shortly after investment. In an exploration portfolio, the large majority of projects are not successful resulting in a total loss from all lease acquisition, seismic and drilling costs. The tradable tax credits would lessen the negative financial consequences of the inevitable dry holes explorers will drill.

A significant concern to Pioneer is the potential for a lack of liquidity for the tradable tax credits. Pioneer's outlook is to continue with very large capital expenditures in the state over the next several years. With only a handful of very large producers as potential buyers for the credits, and the proposed limit that a company may utilize purchased credits to offset no more than 20% of its tax, we are concerned that the market for the credits may not be competitive. New investors could face selling credits at a discount to tax payers who would in turn cash them in to the state at full value. We appreciate that a buyer of tax credits should recover its transaction costs, but we are concerned that the required discount might be substantially greater. We respectfully ask the legislature to consider implementing refundable credits with appropriate limitations to protect the state's cash flow in the event of low oil prices. The program could provide that credits be refunded at a modest discount to face value. This would allow the State, and not a third party producer, to benefit from any discount that a seller would be willing to accept.

We believe that the PPT as proposed improves Alaska's competitive position with respect to other investment opportunities around the world. Mr. Van Meurs' testimony indicated that the proposed PPT would improve Alaska's competitiveness versus a number of mostly large, international investment opportunities around the world. To attract companies of Pioneer's size and smaller, we believe that Alaska must effectively compete with U.S. lower 48 opportunities as well. With higher prevailing natural gas prices in the lower 48, gas resource plays (tight sands, shales and coalbed

methane) are attracting huge amounts of capital due to the relatively low risk, low cost and short project cycle time relative to exploration. The size of some of these resources is quite large resulting in increased competition in the U.S. for independent's capital. If Alaska wants to improve its competitive position and attract new investors, we believe that the legislature should take great care in making changes to the administration's proposal that would make it less competitive.

For new investors to Alaska, particularly smaller companies, exempting the first $73 million of cash flow from taxation is a valuable feature of the PPT. The obstacles to new investors are high. Most new investment opportunities in Alaska are either small, infrastructure challenged, risky (exploration) or some combination of these factors. New investors are also handicapped by not owning the existing infrastructure and they lack the economies of scale enjoyed by the large operators. To be an effective operator in the state requires a huge commitment in highly compensated personnel to effectively navigate the regulatory and operational challenges that are unique to Alaska. Under existing law, it is unlikely that an explorer would pay significant production tax unless a huge field was discovered. A number of new companies were recruited to Alaska by the state and made substantial investments based on the existing tax law. Under the proposed PPT, exempting the first $73MM of cash flow from taxation will help deliver an investment climate more consistent with the system that initially encouraged Pioneer to explore in Alaska and will help offset the high "start-up" costs.

In general, we believe the proposed PPT is a balanced program with appropriate incentives to encourage new investment in the state. We encourage the legislature to carefully evaluate the proposal and take care to insure that it results in fiscal policy that makes Alaska more competitive. We also respectfully request your consideration to make the tax credits in this bill refundable to allow the new investors the full intended advantage of the tax credit program. Thank you for this opportunity to express Pioneer Natural Resource's views on HB 488.

Pioneer Natural Resources Alaska, Inc.

Testimony of James C. Weeks
On HB 488
Oil and Gas Production Tax
Alaska State House Resources Committee

01 March, 2006

Mr. Chairman, distinguished members of the House Resources Committee. My name is Jim Weeks, and I am here today representing UltraStar Exploration LLC, a very small all Alaskan owned independent explorer, with strategically located leases on the North Slope. UltraStar is based i Anchorage, with offices at 3111 C Street, Suite 500. The Company was formed in 2002 by me, John Winther, and Dale Lindsey, for the primary purpose of exploring and developing leases on the North Slope. UltraStar is 100% owned by Alaskans. I am Managing Member, and moved to Anchorage in 1984 with ARCO, and have had a presence here ever since. Dale, whom most of you know, was born and raised and still lives in Seward. John, whom most of you also know, was born in Fairbanks and raised in Juneau. He currently lives in Petersburg. Thanks for the invitation to testify on this important legislation.

First of all, I'd like to commend the Governor and members of the Administration for addressing this issue, and your Committee for the timely and thorough review it is being given. During the last several days, I've listened to a lot of testimony on the proposal. Some witnesses wanted the Committee to delay decisions on this issue. There should be no delay, nor should there be a rush. This is a very important piece of legislation, and you need to get it right, less it results in un-expected and/or un-desired outcomes. You are doing it right, giving the bill a thorough and fair hearing in a timely fashion.

I will now offer a few specific comments on the bill. You've heard lots of testimony supporting the 20-20 tax and exploration/development incentive split, and the arguments in favor of these provisions have been articulated very thoroughly and clearly, and I certainly cannot embellish on them, so I won't even attempt to. I'll just add UltraStar's strong support for the positions of the existing producers and independents and explorers on these issues.

John Winther testified to the Joint House and Senate Committee hearing last Saturday, echoing UltraStar's support for the 20/20 provisions, and the $73 million deduction allowance in the bill. Since then, we've learned that the $73 million allowance, granted to all companies in Alaska regardless of the size of their cash flow streams, may be a difficult pill for you and your colleagues to swallow. Thus, you may want to eliminate it from the bill. I encourage you not to jettison it entirely, but consider an alternative that will provide incentives for exploration and development of smaller fields.

It's generally agreed that the big Prudhoe Bay and Kuparuk sized fields have been found. The big structures have been drilled, and what remains are 10-100 million barrel accumulations. These are modest by North Slope standards, but can add up to significant amounts of oil and related economic activity. The stock market rewards reserve replacement. The current producers are huge, publicly traded companies that have become so large that their reserve replacement needs cannot be met by chasing small satellites on the North Slope. For instance, ExxonMobil produces 20 million barrels in 10 days. We'd do jumping jacks in downtown Juneau if we found that much oil on our leases.

But smaller accumulations can be attractive to small independents like us, provided the right incentives. Rather than the $73 million allowance for all companies, I suggest you consider establishing a ceiling above which larger companies would not get the $73 million allowance, and below which smaller companies would . There is precedent for this in the "Charter for Development", a 1999 agreement between the State, BP and ConocoPhillips that made the combination of ARCO and BP possible. There are many provisions in the Charter, but one of them requires BP and ConocoPhillips to give preferential treatment to small producers, called "qualified producers". The Charter defines qualified producers as those with worldwide assets of less than $1 billion dollars, and establishes 5000 barrels per day as a maximum amount of crude oil that a qualified producer can produce to receive the preferential treatment. I realize that the provisions of the Charter were developed for a different purpose, but certainly it distinguished between "little guys", and "big guys", and established a maximum production level for which the benefits apply. Whether $1 billion dollars or 5000 barrels per day are the appropriate ceilings for the PPT is subject to more debate, but such a two-tiered approach will accomplish what I believe you want: to provide incentive for entry by small newcomers without giving an un-deserved windfall to the established players. Please don't throw the baby out with the bathwater by eliminating the $73 million allowance altogether.

My last issue is pretty specific, but could be significant for small independents. It regards the exclusion of "amounts paid for purposes of indemnification." on line 15 of page 14 of the bill. Small independents like UltraStar will need to indemnify facility owners and operators who will process our oil through their facilities. We will need to purchase real, third party, arms length insurance to satisfy these requirements. We will also need insurance to meet the bonding and financial responsibility requirements of the Departments of Natural Resources and Environmental Conservation, and the Alaska Oil and Gas Conservation Commission. Depending upon the circumstances, membership in an oil spill clean up cooperative may also be required. All these costs can broadly be characterized as costs for the purposes of indemnification, and could arguably be excluded when direct costs are calculated, as defined at line 21 on page 13.

Nearly 15 percent of the cost of the Winstar exploration well at Oliktok Point in 2003 was for insurance premiums, so these indemnification costs can be

significant for the little guy, and should clearly be deductible to determine direct costs. In his letter transmitting this legislation to this committee, the Governor said that a number of indirect costs are listed in the bill, and are to be excluded from the calculation of direct costs. Indemnification is one of the indirect costs listed. Trust me, Mr. Chairman, there was nothing indirect about the $370,000 check I wrote for the insurance premium on our last well. The money went directly from our bank account into theirs. I urge you to clarify your intent on this issue, and allow real, invoice supported, arms length indemnification costs to be included.

Thanks for the opportunity to testify at this important proceeding.

James D. Weeks
Managing Member
UltraStar Exploration LLC
907-258-2969

Chevron

Chevron
Testimony on SB 305 & HB 488

John P. Zager
General Manager – Alaska Area

Juneau, Alaska
March 1, 2006

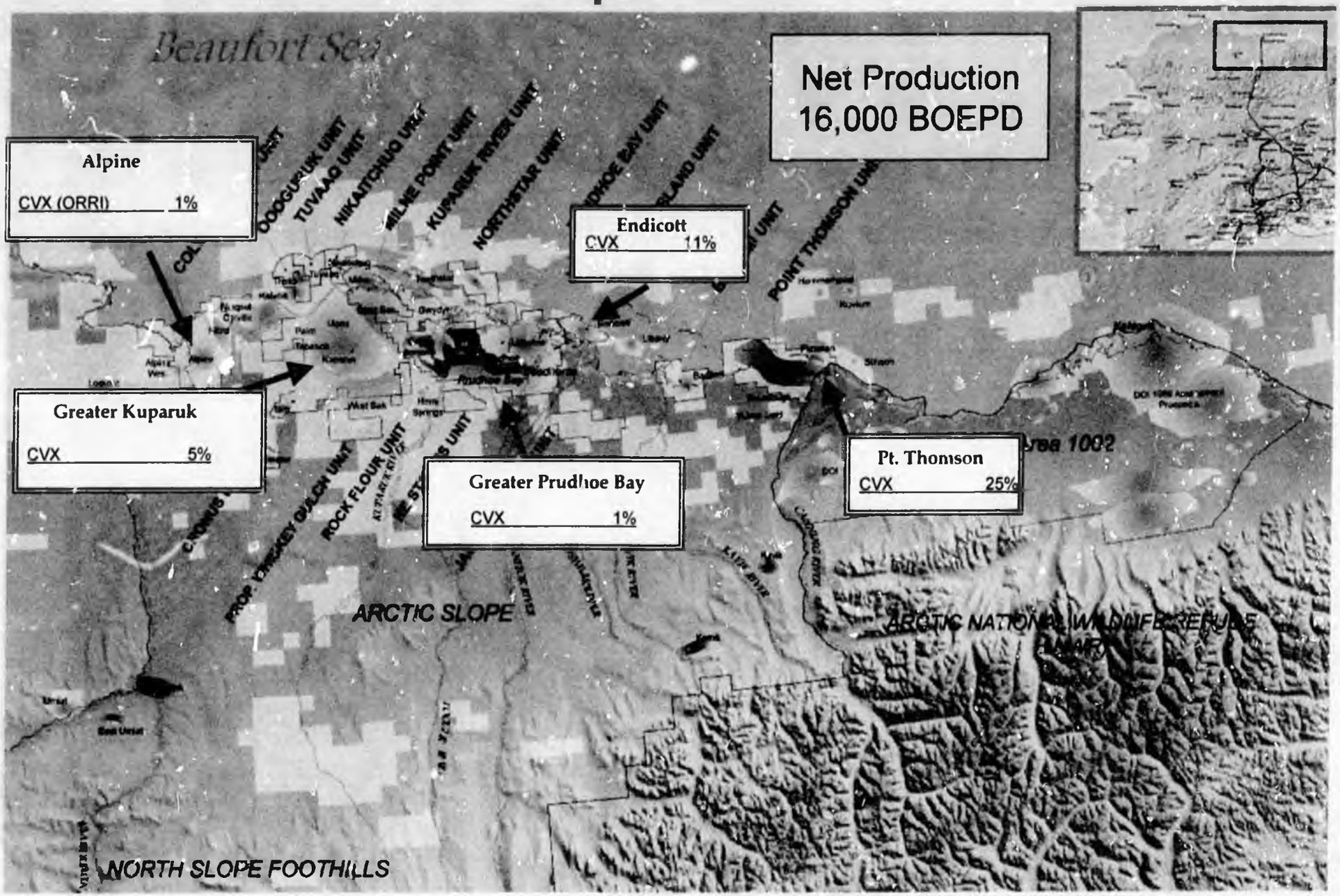
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Chevron's Alaska Presence

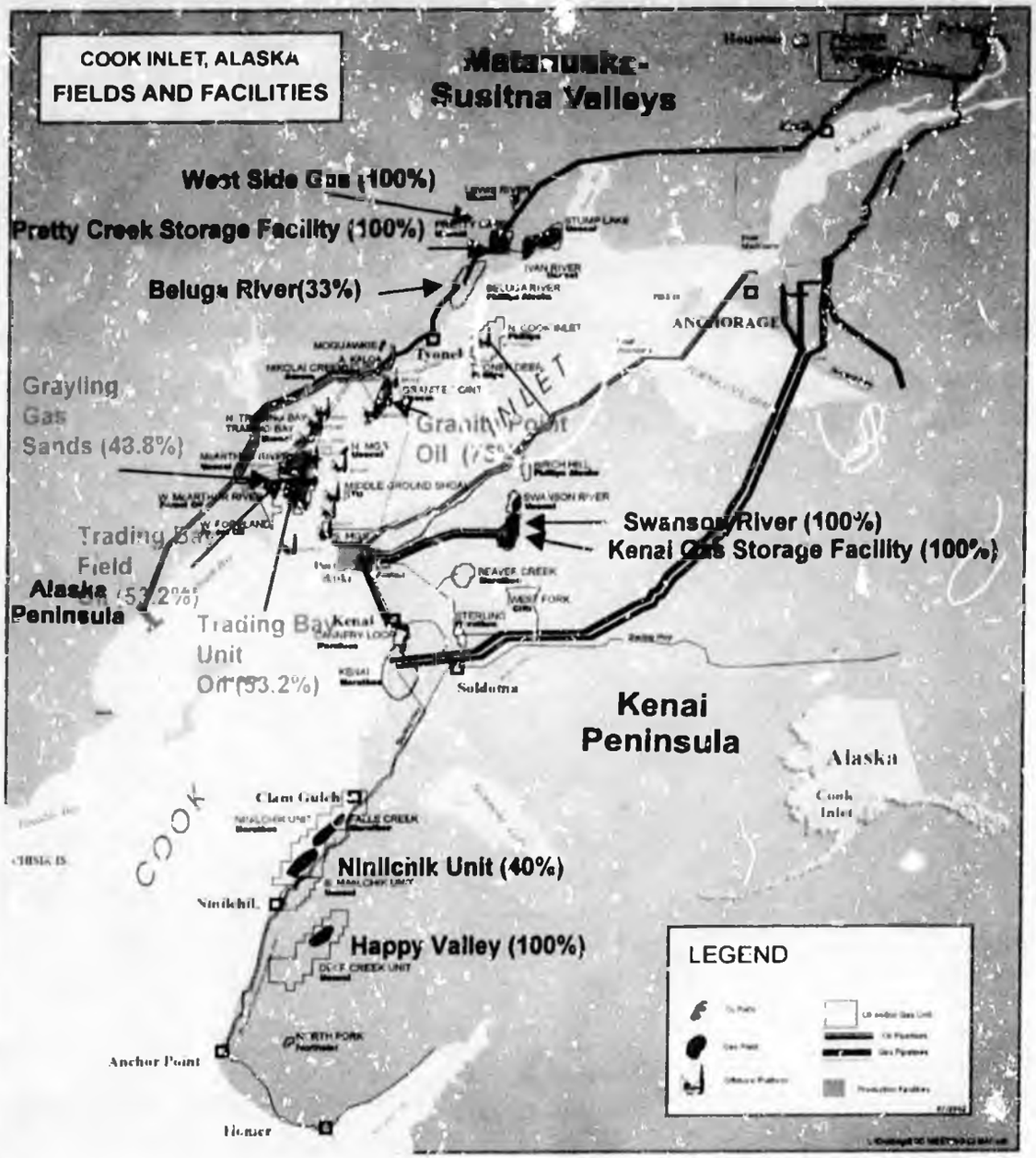
- Current Asset base is formed by combination of heritage Chevron and Unocal assets
  - Both companies have been active in Alaska for many years
- 4th largest producer in state
- 3rd largest operator
- 382 employees or full time contractors
  - 272 on the Kenai Peninsula
  - Payroll of >$45 million
- Key customers: Tesoro, Enstar, Chugach Electric, Agrium, Aurora
- Chevron is the only producer in the state with a relative balance of assets in the Cook Inlet and on the North Slope
  - Both production streams are large enough to trigger PPT
- Chevron's Cook Inlet offshore assets are uniquely positioned to suffer from the proposed PPT

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Alaska North Slope Fields



Cook Inlet - CVX Asset Description



Cook Inlet Offshore :

- 3 fields (all op.)
- 10 Platforms
- 145 wells
- 2 onshore plants
- 42 mile PL
- 10,900 BOEPD

Cook Inlet Onshore :

- 8 fields (6 op.)
- 60 wells
- 2 gas storage fields
- WI% in 4 PLs
- 14,100 BOEPD

Net Production

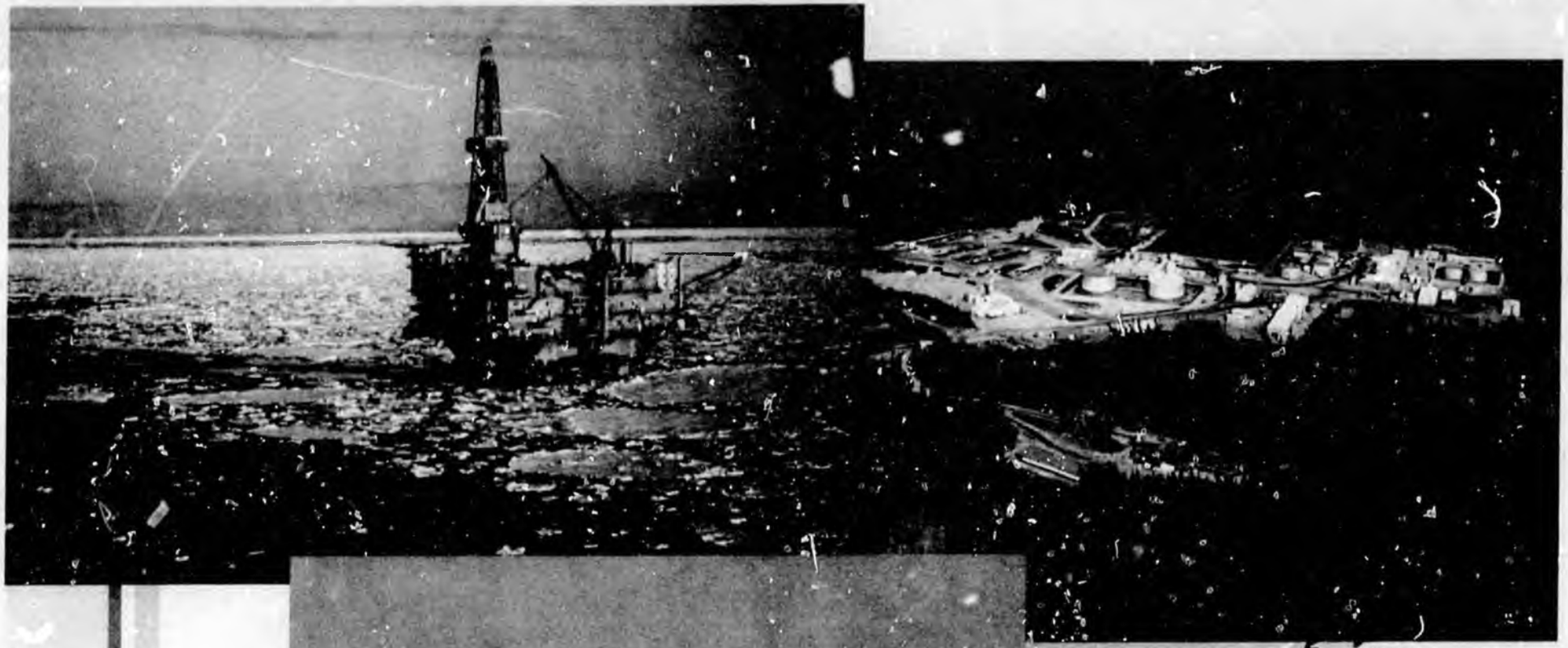
Offshore Oil
6,300 BOPD

Gas
112 MMCFPD

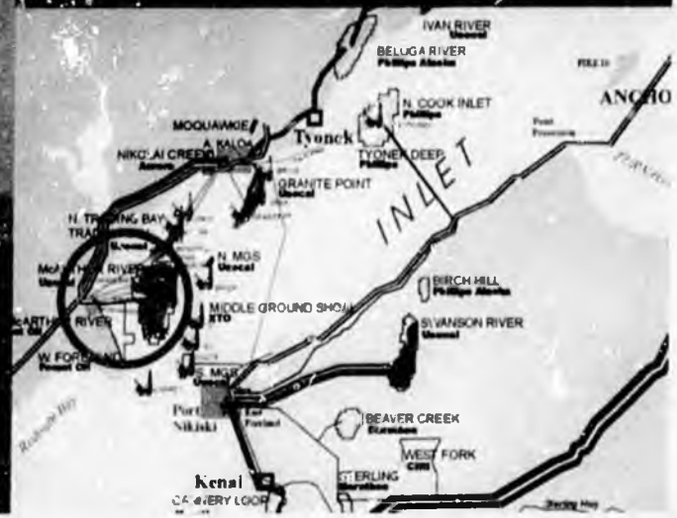
25,000 BOEPD

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Trading Bay Unit





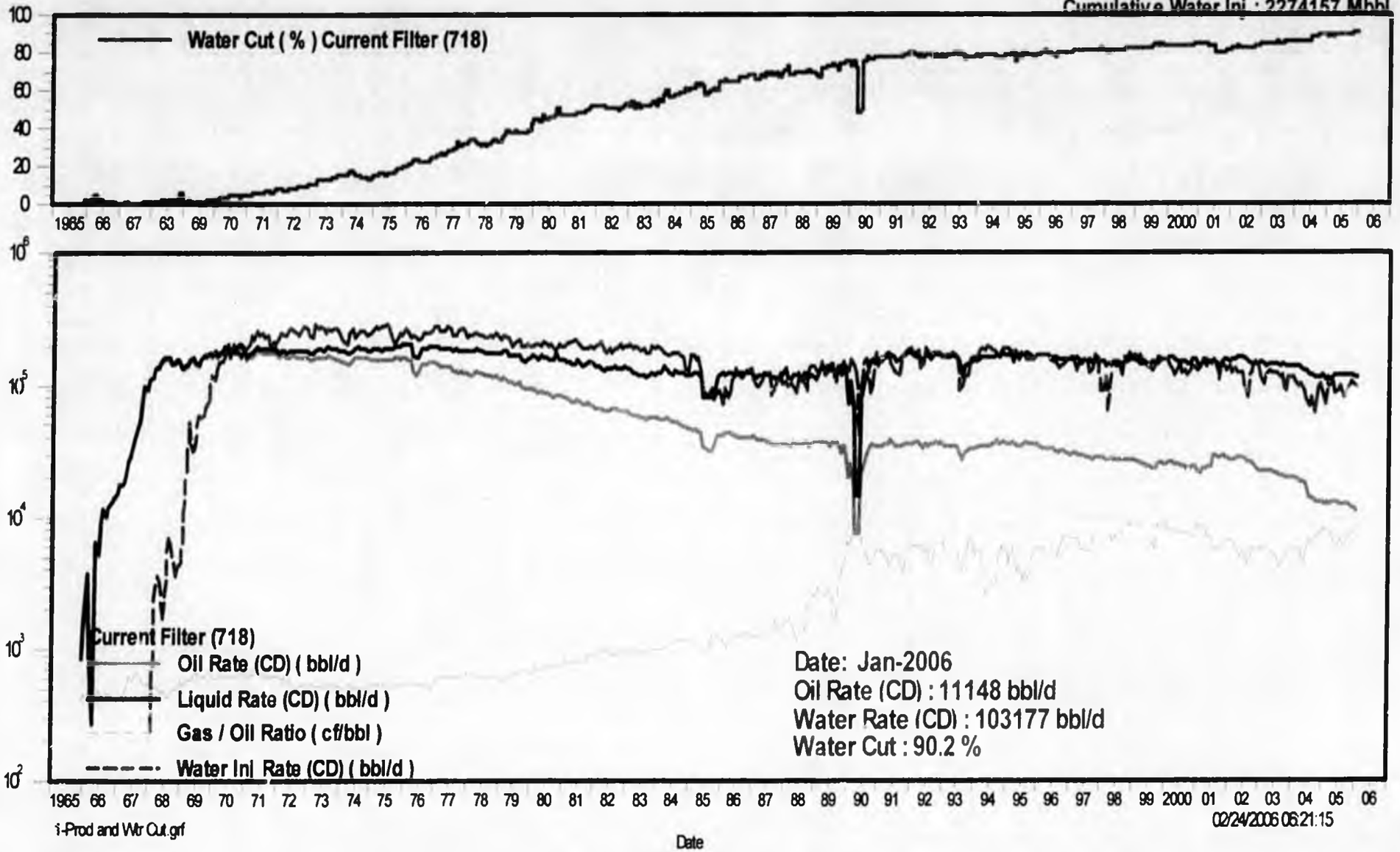


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Cook Inlet Offshore

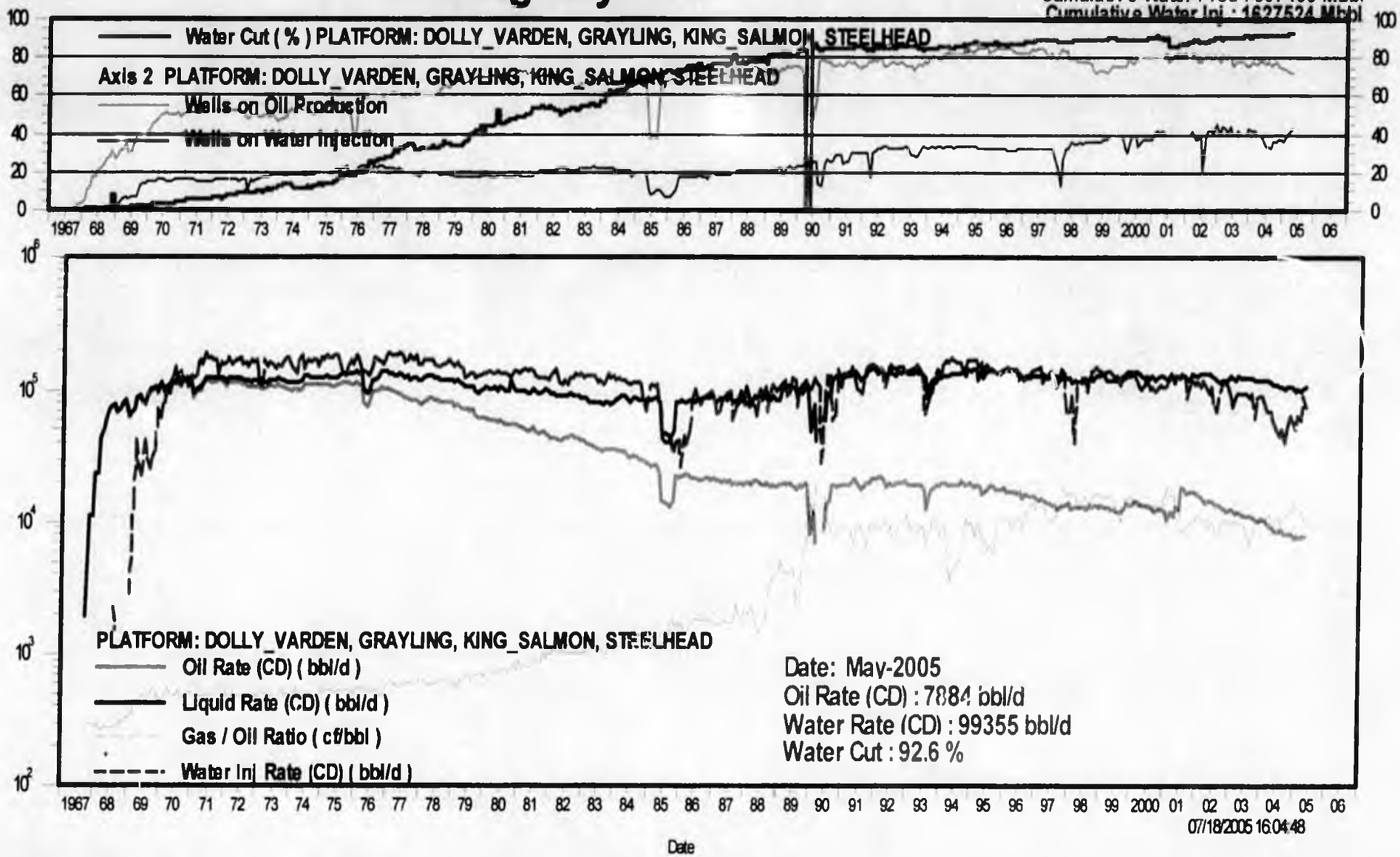
Chevron

Cumulative Oil Prod : 1030570 Mbbl
Cumulative Gas Prod : 1587463 MMcf
Cumulative Water Prod : 1117781 Mbbl
Cumulative Water Inj : 2274157 Mbbl



Trading Bay Unit

Cumulative Oil Prod : 618928 Mbbl
Cumulative Gas Prod : 1266687 MMcf
Cumulative Water Prod : 897435 Mbbl
Cumulative Water Inj : 1627524 Mbbl



Cook Inlet Offshore Oil

- Cook Inlet Oil is very high cost
  - Direct lift cost $20 - $25 per BOE
  - Currently breakeven on Cash Flow @ ~ $30/BOE
  - Currently breakeven on Earnings @ ~ $45/BOE
  - Further production declines will raise breakeven prices
- Significant operational risks
  - Two platforms are currently shut-in
  - Must maintain critical mass of operations
- Cook Inlet Offshore cannot afford an additional tax burden

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Chevron Cook Inlet Strategic Study

- August 10, 2005 Chevron acquires Unocal
  - Much speculation about Cook Inlet asset fit in Chevron Portfolio
- October 2005 – January 2006 – Strategy work completed
  - Determine that there are incremental investment opportunities in the Cook Inlet although they are in the lowest quartile of Chevron's investment portfolio, many other projects did not make the cut
- February 2006 – Great news - announce decision that Chevron will retain all Cook Inlet assets with the intent to begin a multiyear investment program
  - Chevron will retain the current office locations

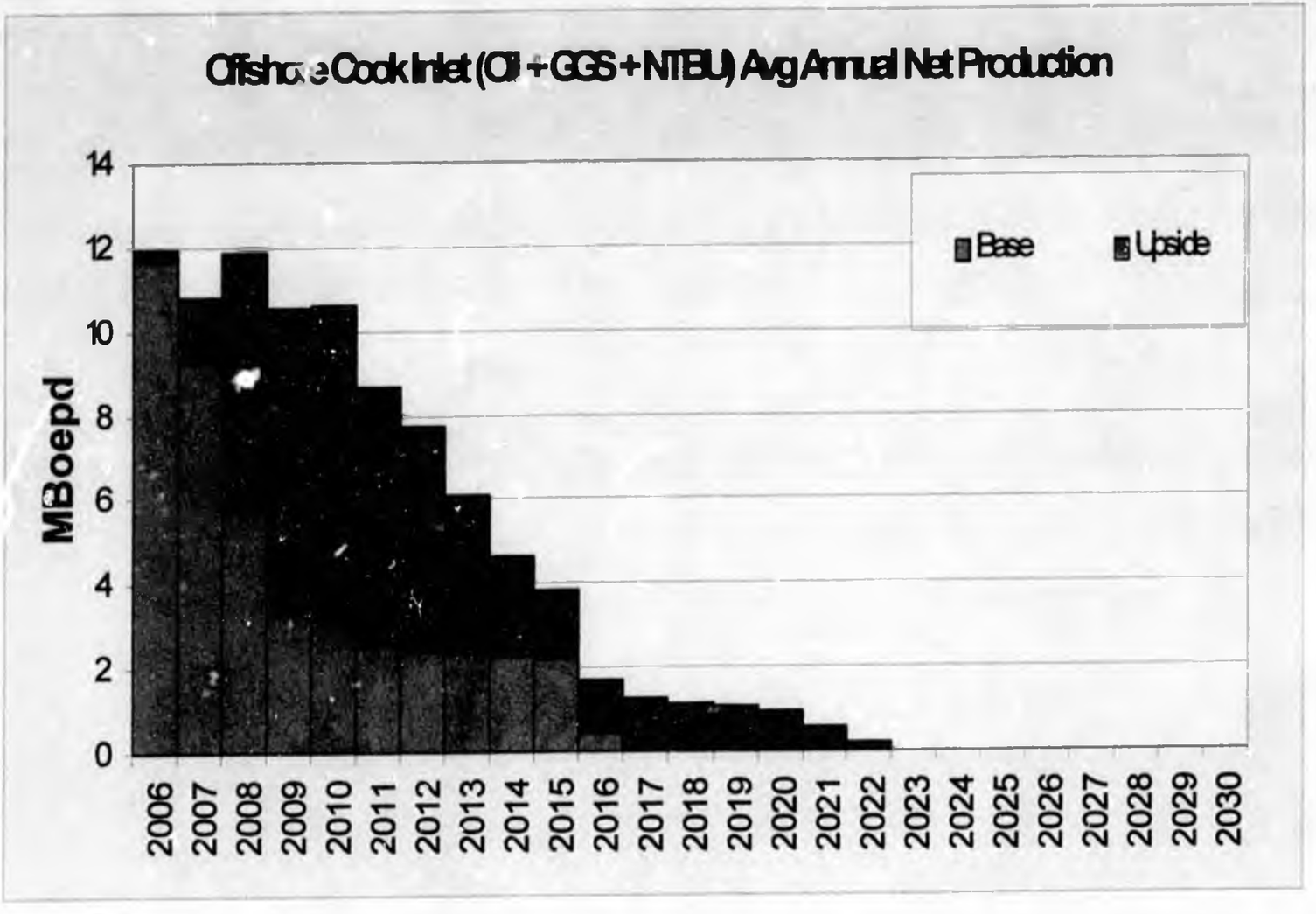
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Great news, so what's the problem?

- The Cook Inlet reinvestment program was evaluated using the current severance tax assumptions (zero severance tax)
- When modeled under the proposed PPT the economics on some projects are degraded, some projects are improved, overall poorer economics for the program
  - Will cause investment decision to be reconsidered
  - Enhanced PPT terms could significantly expand the list of economic projects in the investment program
  - Misalignment with joint venture properties

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Cook Inlet Production Forecast with Four Year Capital Plan



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Reasons to Spur Cook Inlet Investment



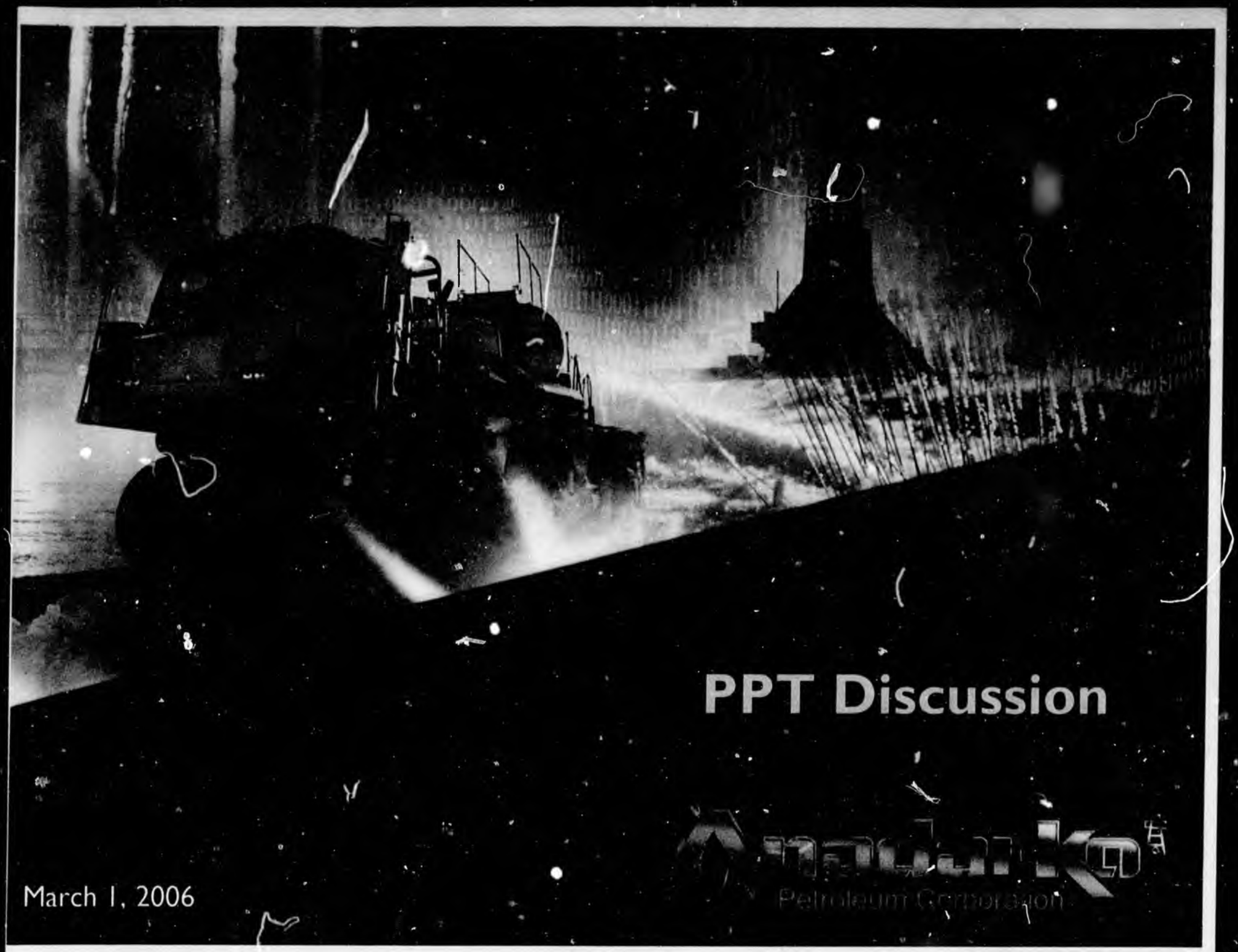
- Gas is running out
  - Home heating, electrical generation, industrial consumption
  - Additional gas supply is critical to state's economy
- Oil redevelopment will maintain and add new jobs and will extend field life
- New exploration efforts could add new fields
- Currently a lack of significant exploration
  - Last Cook Inlet lease sale was poorly attended

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Summary

- We will support the bill and the key terms as written with the following stipulations:
  - Cook Inlet must be treated differently
    - Re-apply $73 million exemption
    - PPT rates – consider lowering the tax rate and/or increase the capital credit
- Recommend inclusion of an additional 5% capital credit (20/25) for heavy oil or tertiary recovery (CO2) projects statewide
- Need absolute clarity on terms and definitions
- Chevron has been in Alaska for many years and intends to continue an active exploration and production operation in the state if a sound and stable fiscal regime can be offered

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PPT Discussion

March 1, 2006

Petroleum Corporation

Overview of Anadarko Petroleum

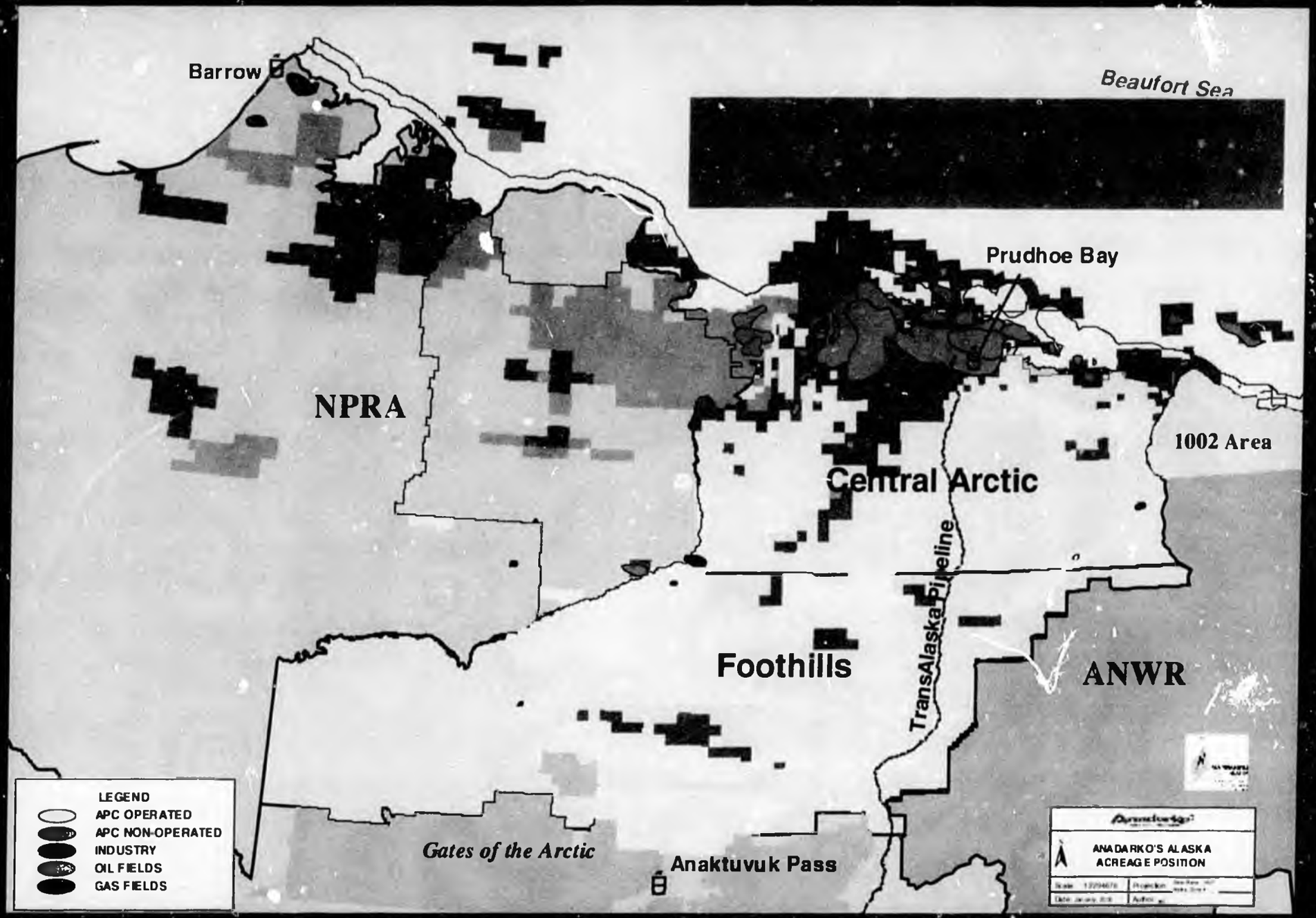


ANADARKO HQ
Houston, Texas

Alaska
Mackenzie Delta
Faroe Islands
Canada
Onshore U.S.
Gulf of Mexico
Tunisia
Algeria
Georgia Black Sea
Qatar
Venezuela
W. Africa
Indonesia

Exploration Areas
Producing Areas

Anadarko's Alaska Acreage Position



Alaska Opportunities

- World class petroleum basin
- Significant remaining resource potential
- Legacy type prospectivity (i.e. Anchor Fields)
- Favorable political environment
- Abundant new entrants/partnering opportunities

Alaska Challenges

- Maturing basin/materiality
- High costs
- Lack of infrastructure and competition
- Limited access to facilities and pipelines
- Extremely long lead-time exploration
- Seasonal drilling & regulatory timing requirements
- Lack of gas market

How about PPT?

Administration did a good job balancing issues and priorities

- *State vs. Companies*
- *Companies vs. State*
- *Companies vs. Companies*

ARCHIVED

New Small Oil Development

Ultimate recovery is 47 million barrels.

Peak oil production rate is 15,000 BOPD.

Capital expenditure is 316 million dollars.

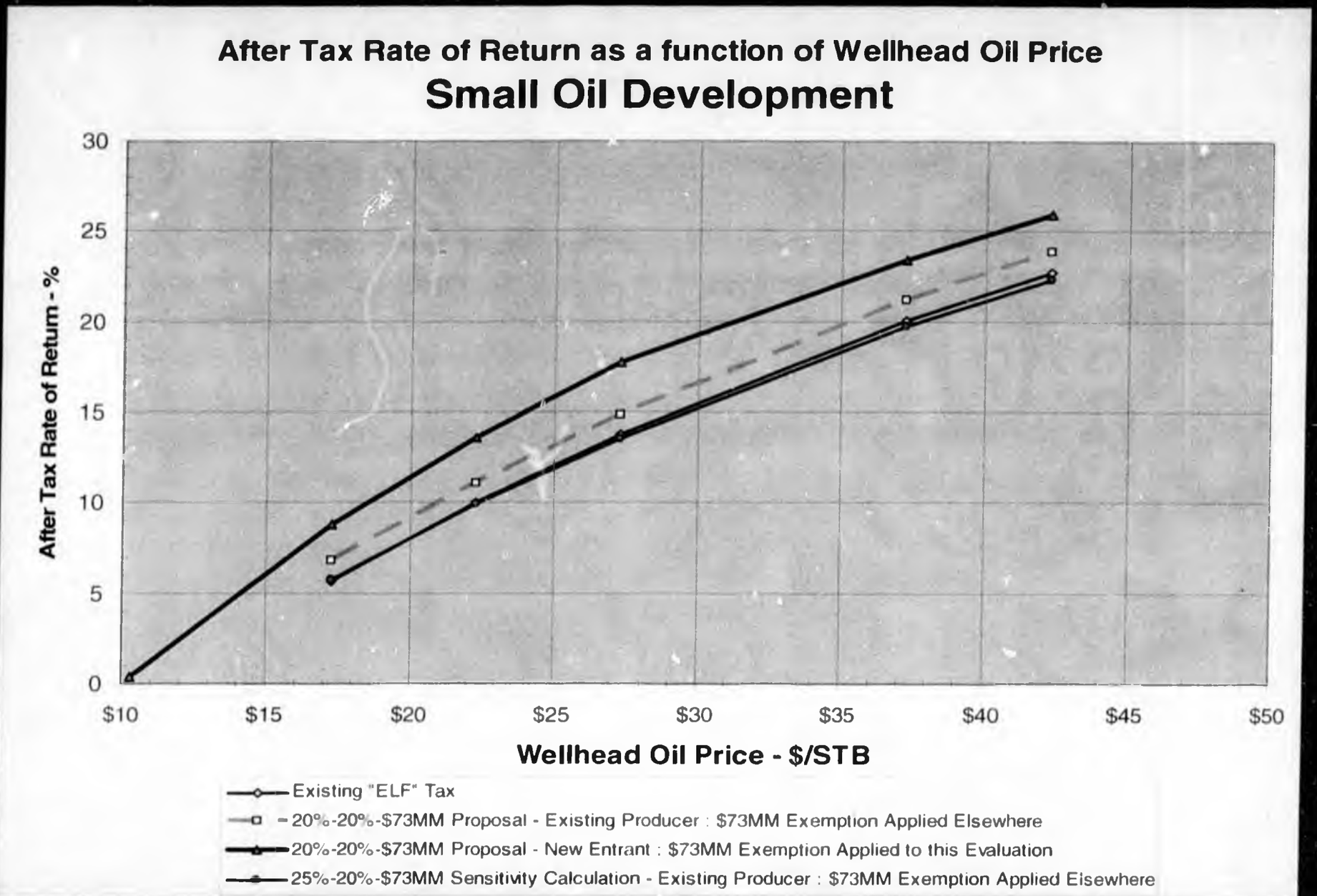
Timing from discovery to first production is 6 years.

The development concept is a satellite to an existing oil field. The satellite has a separate ELF calculation from the existing oil field.

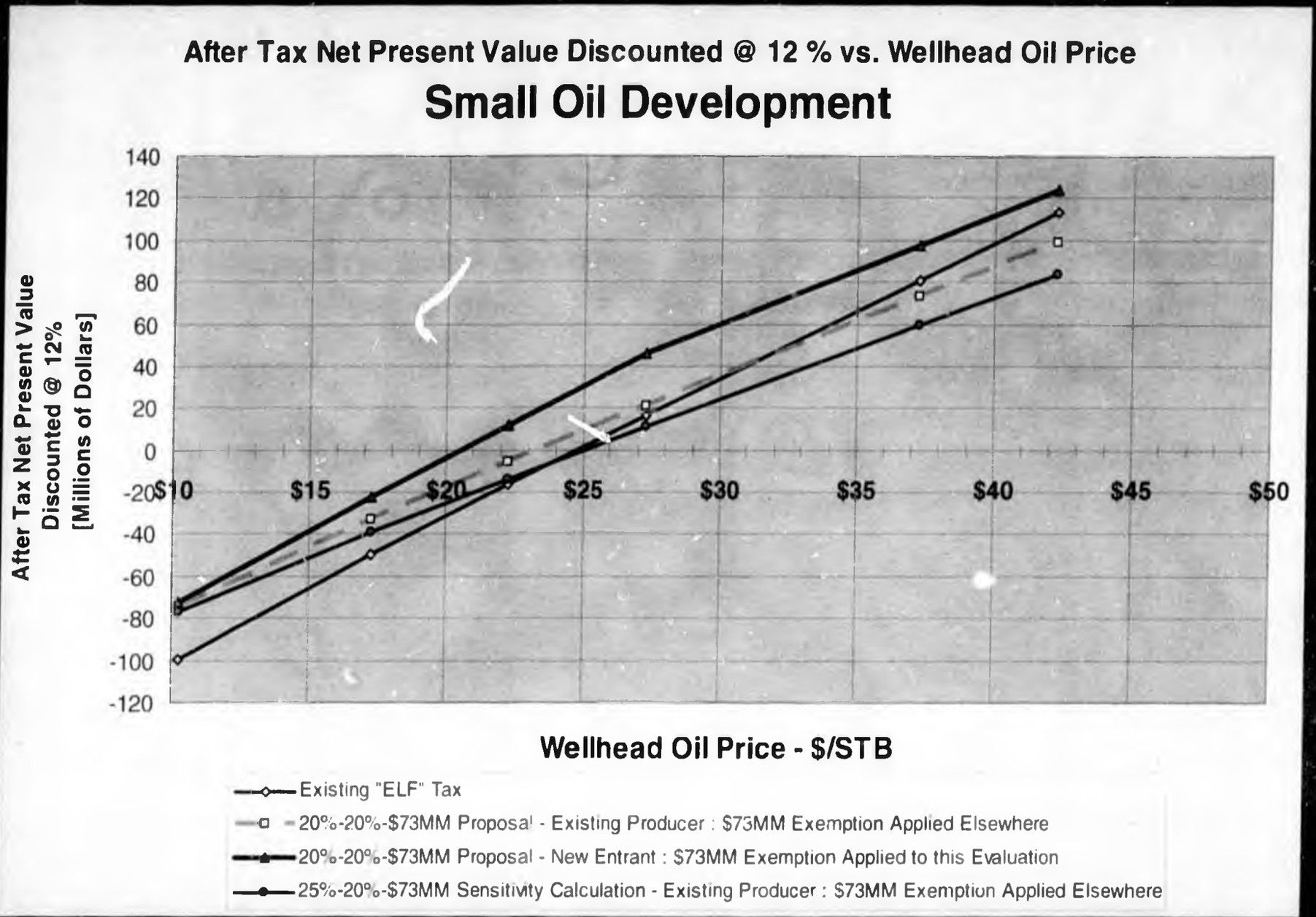
The satellite field pays an oil processing charge to the existing facility of $5.00 per barrel. This is treated as a deduction to the wellhead price.

The royalty is 12.5%.

Small Oil Development- Rate of Return



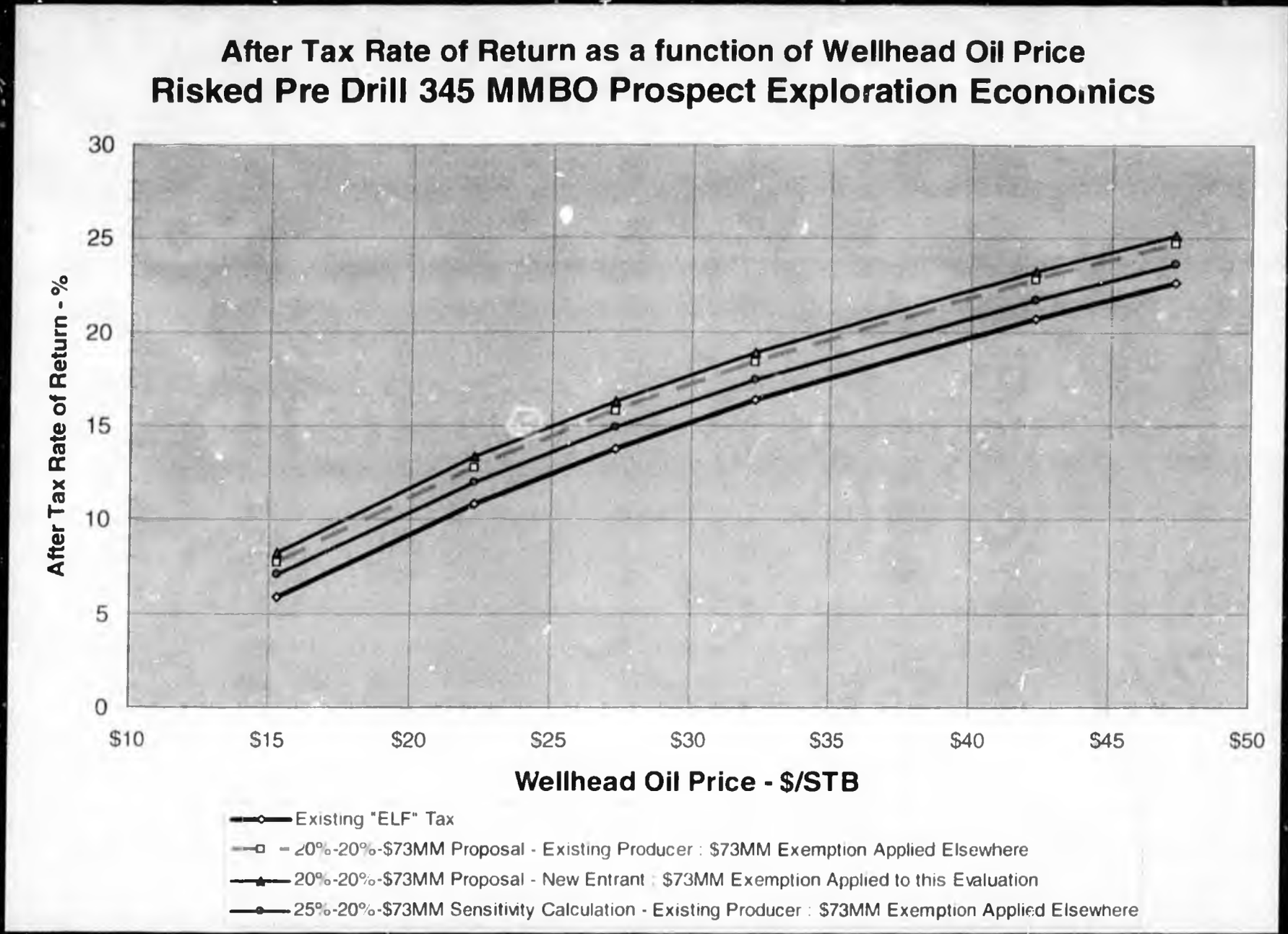
Small Oil Development- Net Present Value



Risked Exploration Economics for Oil Prospect

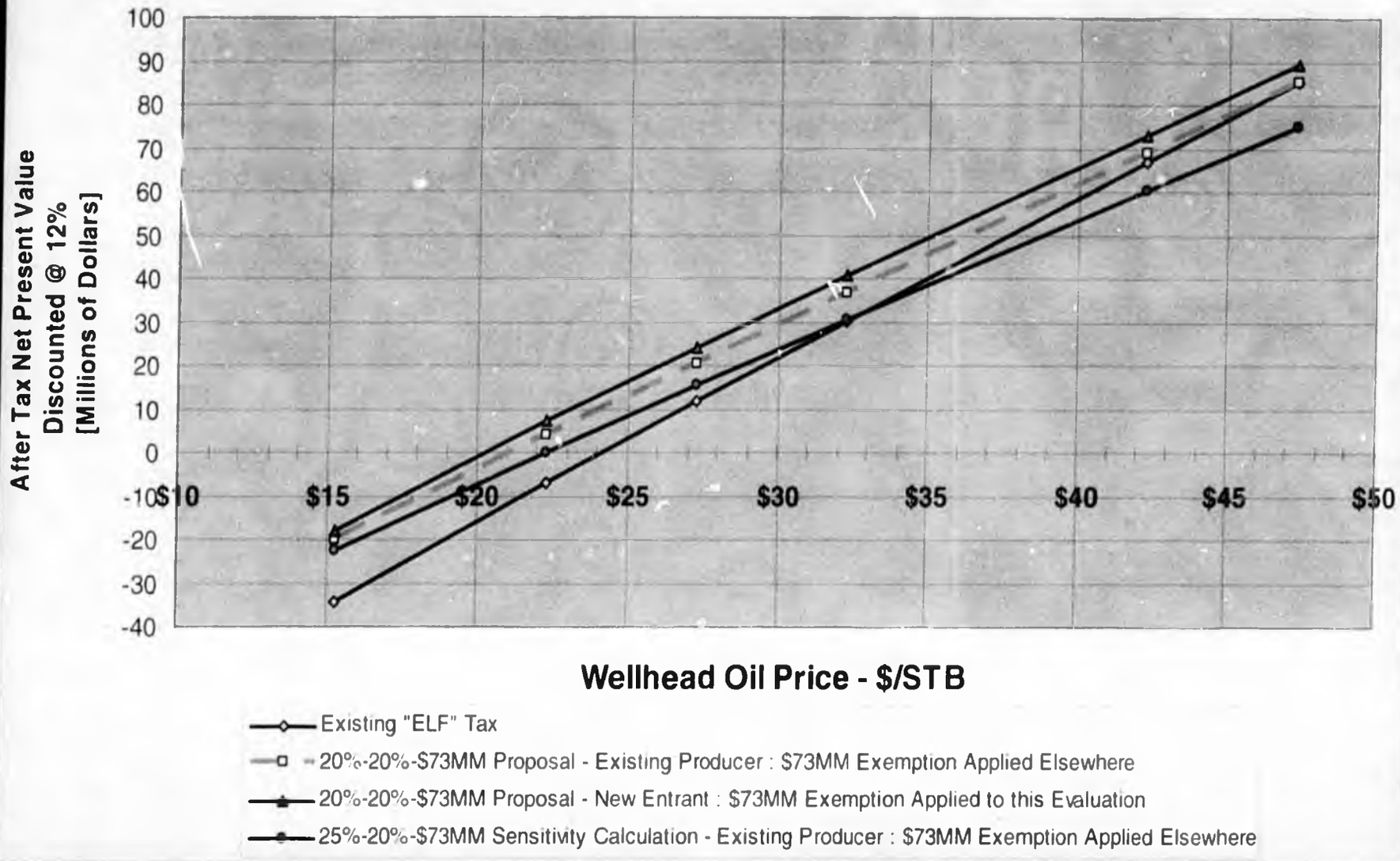
- Commercial chance of success is 15% at a $32/Bbl wellhead oil price
- Mean commercial prospect size is 345 million barrels
- Capital expenditure is 1.1 billion dollars
- The peak production rate is 55,000 BOPD
- Royalty is 12.5%

Medium Oil Prospect- Risked Rate of Return



Medium Oil Prospect- Risked Net Present Value

After Tax Net Present Value Discounted @ 12 % vs. Wellhead Oil Price
Risked Pre Drill 345 MMBO Prospect Exploration Economics

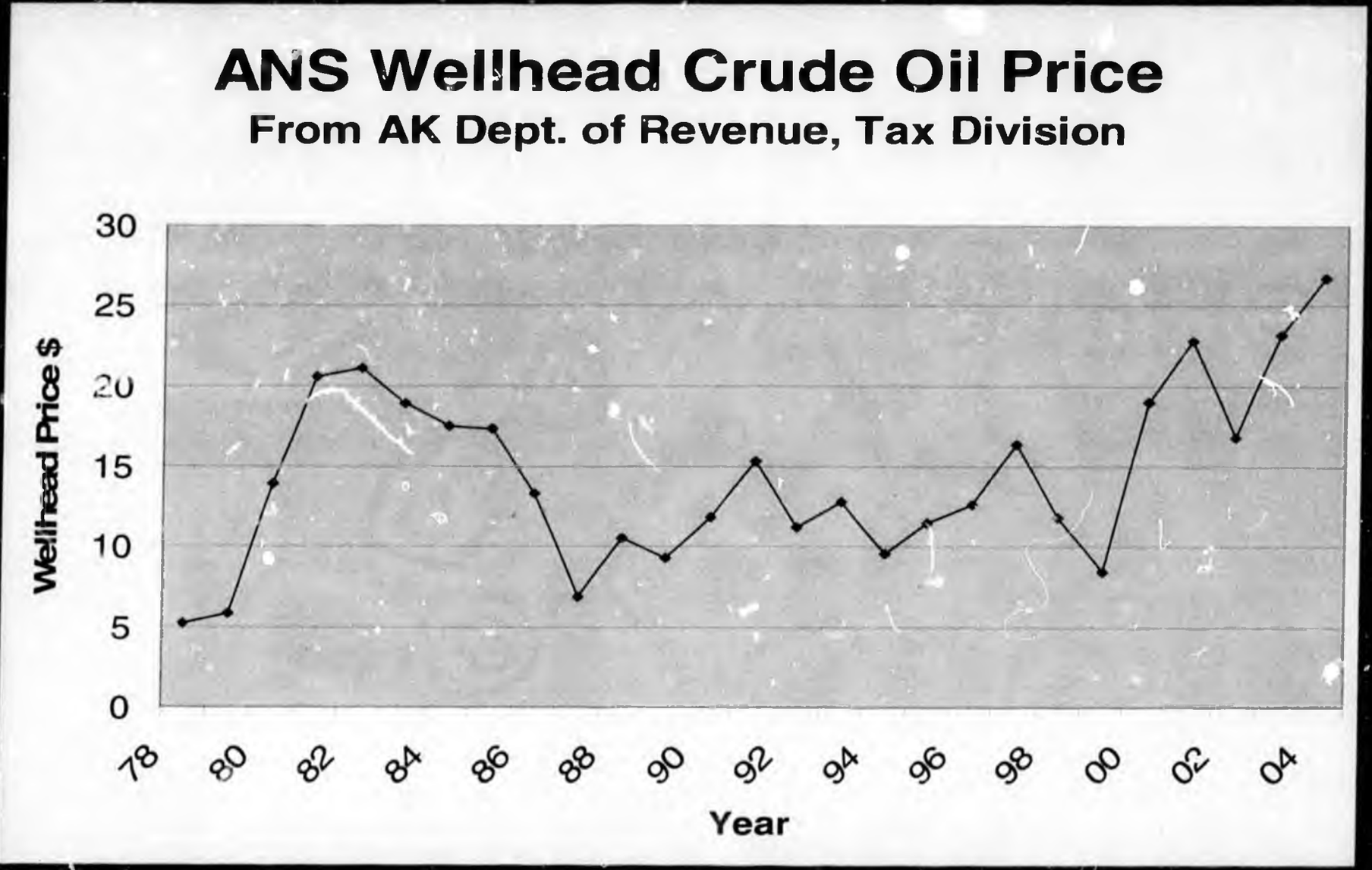


Issues

- Look back's looking bad
- Price is King
- Independents are sensitive
- $73 million is $73 million right?
- Credits that aren't
- Be careful what you ask for
- Should you know?
- Let's talk

AZADARKO

Historic Alaska North Slope Crude Prices



This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that its goals will be achieved. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this release. While Anadarko makes these forward-looking statements in good faith, neither Anadarko nor its management can guarantee that the anticipated future results will be achieved. Anadarko discloses proved reserves that comply with the SEC's definitions. Additionally, Anadarko may disclose estimated reserves, which the SEC guidelines do not allow us to include in filings with the SEC. See Additional Factors Affecting Business in the Management's Discussion and Analysis (MD&A) included in the company's Annual Report on Form 10-K.

Testimony of James D. Weeks
On HB 488
Oil and Gas Production Tax
Alaska State House Resources Committee

01 March, 2006

Mr. Chairman, distinguished members of the House Resources Committee. My name is Jim Weeks, and I am here today representing UltraStar Exploration LLC, a very small all Alaskan owned independent explorer, with strategically located leases on the North Slope. UltraStar is based in Anchorage, with offices at 3111 C Street, Suite 500. The Company was formed in 2002 by me, John Winther, and Dale Lindsey, for the primary purpose of exploring and developing leases on the North Slope. UltraStar is 100% owned by Alaskans. I am Managing Member, and moved to Anchorage in 1984 with ARCO, and have had a presence here ever since. Dale, whom most of you know, was born and raised and still lives in Seward. John, whom most of you also know, was born in Fairbanks and raised in Juneau. He currently lives in Petersburg. Thanks for the invitation to testify on this important legislation.

First of all, I'd like to commend the Governor and members of the Administration for addressing this issue, and your Committee for the timely and thorough review it is being given. During the last several days, I've listened to a lot of testimony on the proposal. Some witnesses wanted the Committee to delay decisions on this issue. There should be no delay, nor should there be a rush. This is a very important piece of legislation, and you need to get it right, less it results in un-expected and/or un-desired outcomes. You are doing it right, giving the bill a thorough and fair hearing in a timely fashion.

I will now offer a few specific comments on the bill. You've heard lots of testimony supporting the 20-20 tax and exploration/development incentive split, and the arguments in favor of these provisions have been articulated very thoroughly and clearly, and I certainly cannot embellish on them, so I won't even attempt to. I'll just add UltraStar's strong support for the positions of the existing producers and independents and explorers on these issues.

John Winther testified to the Joint House and Senate Committee hearing last Saturday, echoing UltraStar's support for the 20/20 provisions, and the $73 million deduction allowance in the bill. Since then, we've learned that the $73 million allowance, granted to all companies in Alaska regardless of the size of their cash flow streams, may be a difficult pill for you and your colleagues to swallow. Thus, you may want to eliminate it from the bill. I encourage you not to jettison it entirely, but consider an alternative that will provide incentives for exploration and development of smaller fields.

It's generally agreed that the big Prudhoe Bay and Kuparuk sized fields have been found. The big structures have been drilled, and what remains are 10-100 million barrel accumulations. These are modest by North Slope standards, but can add up to significant amounts of oil and related economic activity. The stock market rewards reserve replacement. The current producers are huge, publicly traded companies that have become so large that their reserve replacement needs cannot be met by chasing small satellites on the North Slope. For instance, ExxonMobil produces 20 million barrels in 10 days. We'd do jumping jacks in downtown Juneau if we found that much oil on our leases.

But smaller accumulations can be attractive to small independents like us, provided the right incentives. Rather than the $73 million allowance for all companies, I suggest you consider establishing a ceiling above which larger companies would not get the $73 million allowance, and below which smaller companies would . There is precedent for this in the "Charter for Development", a 1999 agreement between the State, BP and ConocoPhillips that made the combination of ARCO and BP possible. There are many provisions in the Charter, but one of them requires BP and ConocoPhillips to give preferential treatment to small producers, called "qualified producers". The Charter defines qualified producers as those with worldwide assets of less than $1 billion dollars, and establishes 5000 barrels per day as a maximum amount of crude oil that a qualified producer can produce to receive the preferential treatment. I realize that the provisions of the Charter were developed for a different purpose, but certainly it distinguished between "little guys", and "big guys", and established a maximum production level for which the benefits apply. Whether $1 billion dollars or 5000 barrels per day are the appropriate ceilings for the PPT is subject to more debate, but such a two-tiered approach will accomplish what I believe you want: to provide incentive for entry by small newcomers without giving an un-deserved windfall to the established players. Please don't throw the baby out with the bathwater by eliminating the $73 million allowance altogether.

My last issue is pretty specific, but could be significant for small independents. It regards the exclusion of "amounts paid for purposes of indemnification." on line 15 of page 14 of the bill. Small independents like UltraStar will need to indemnify facility owners and operators who will process our oil through their facilities. We will need to purchase real, third party, arms length insurance to satisfy these requirements. We will also need insurance to meet the bonding and financial responsibility requirements of the Departments of Natural Resources and Environmental Conservation, and the Alaska Oil and Gas Conservation Commission. Depending upon the circumstances, membership in an oil spill clean up cooperative may also be required. All these costs can broadly be characterized as costs for the purposes of indemnification, and could arguably be excluded when direct costs are calculated, as defined at line 21 on page 13.

Nearly 15 percent of the cost of the Winstar exploration well at Oliktok Point in 2003 was for insurance premiums, so these indemnification costs can be

significant for the little guy, and should clearly be deductible to determine direct costs. In his letter transmitting this legislation to this committee, the Governor said that a number of indirect costs are listed in the bill, and are to be excluded from the calculation of direct costs. Indemnification is one of the indirect costs listed. Trust me, Mr. Chairman, there was nothing indirect about the $370,000 check I wrote for the insurance premium on our last well. The money went directly from our bank account into theirs. I urge you to clarify your intent on this issue, and allow real, invoice supported, arms length indemnification costs to be included.

Thanks for the opportunity to testify at this important proceeding.

James D. Weeks
Managing Member
UltraStar Exploration LLC
907-258-2969

STATE OF ALASKA
DEPARTMENT OF
REVENUE

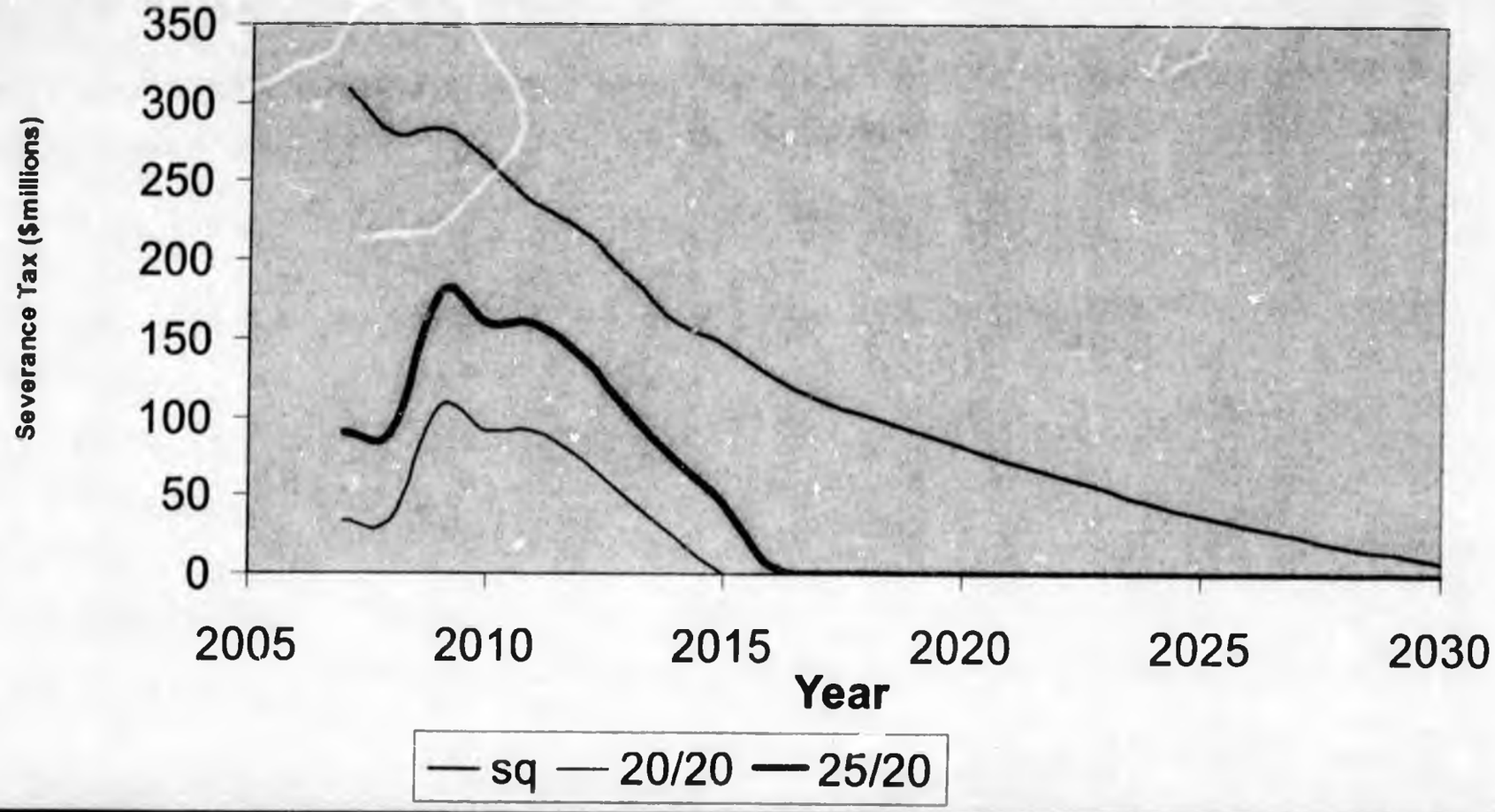
Responses to Committee Questions

Today's PPT Charts

- Comparisons to 20/20 PPT
  - PPT 25/20
  - PPT 30/20
  - PPT 30/15
- ANS Crude Oil Prices
  - $20
  - $40
  - $60

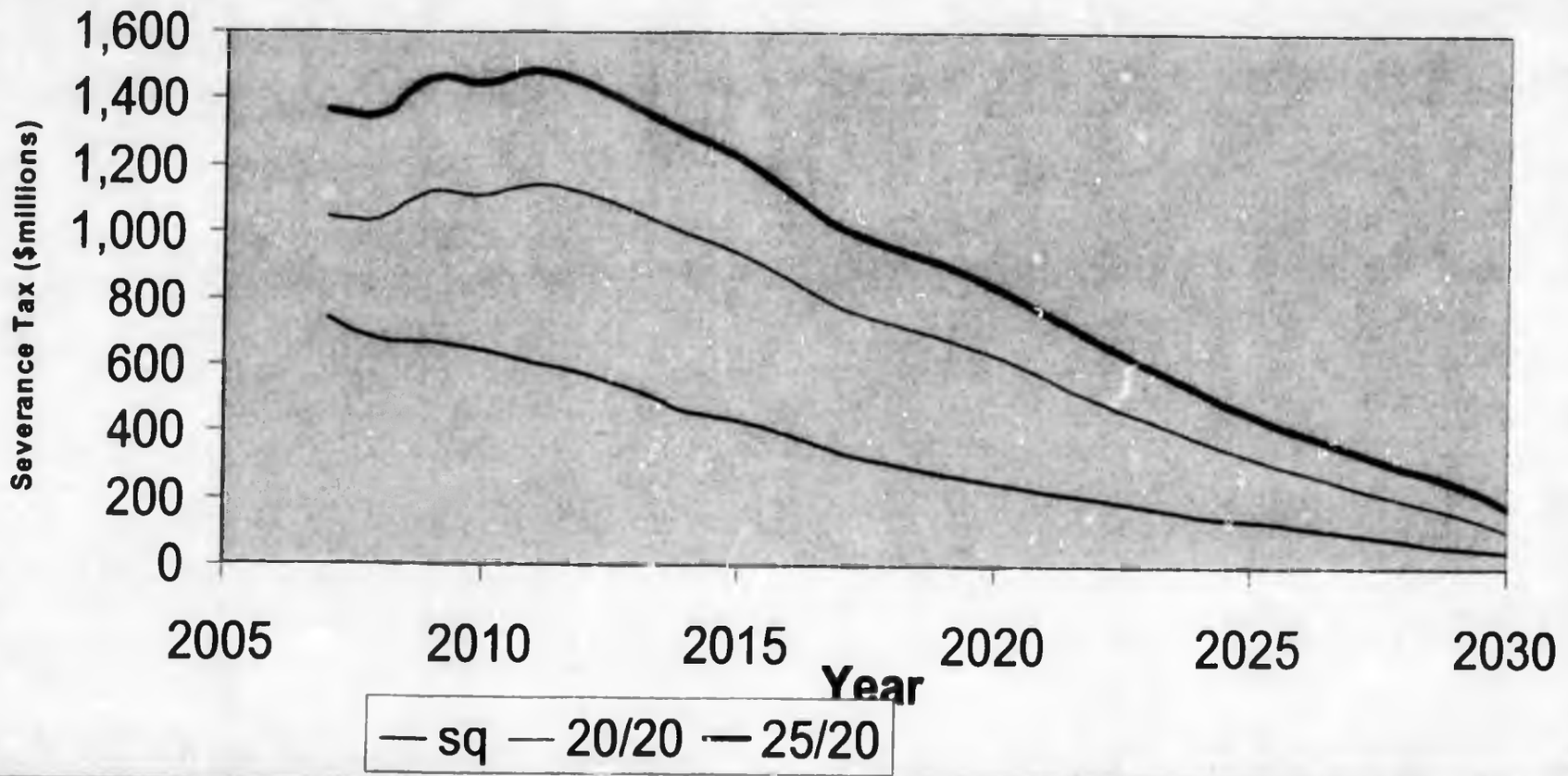


Figure 4a
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



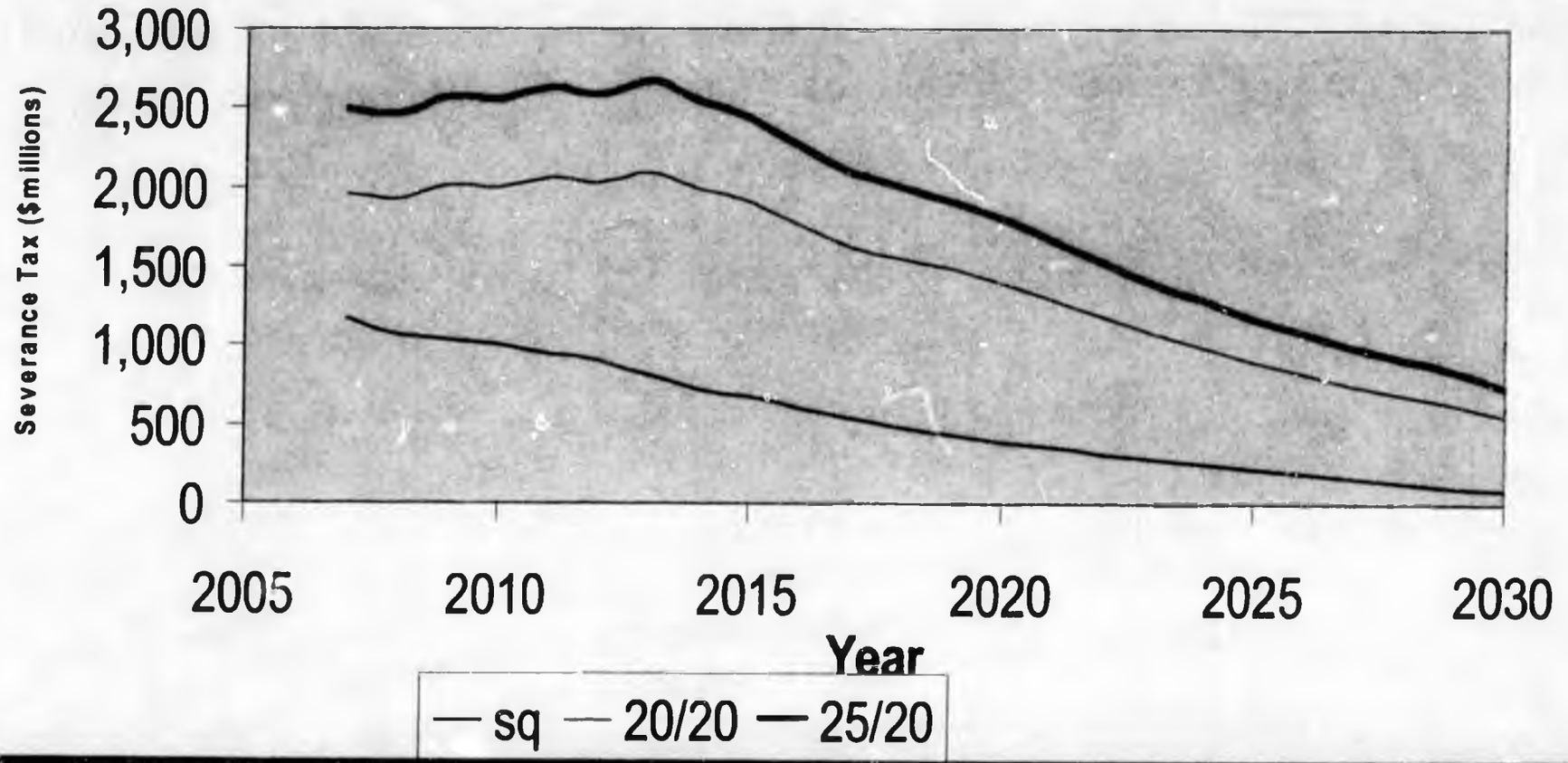
PPT 25/20 - Average annual revenues $80 million less than status quo & $20 million more than 20/20

Figure 5a
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



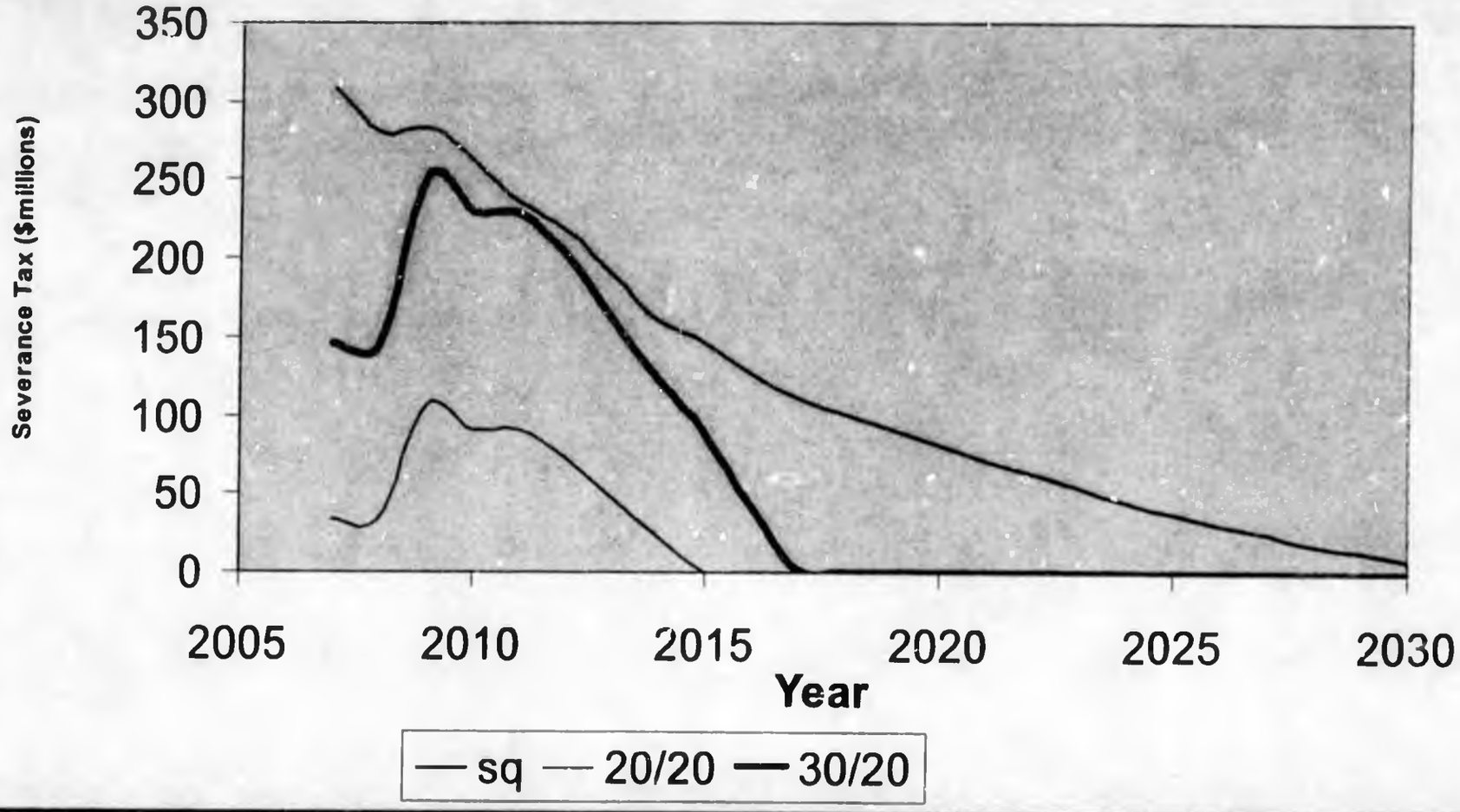
PPT 25/20 - Average annual revenues $565 million more than status quo and $220 million more than 20/20

Figure 6a
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



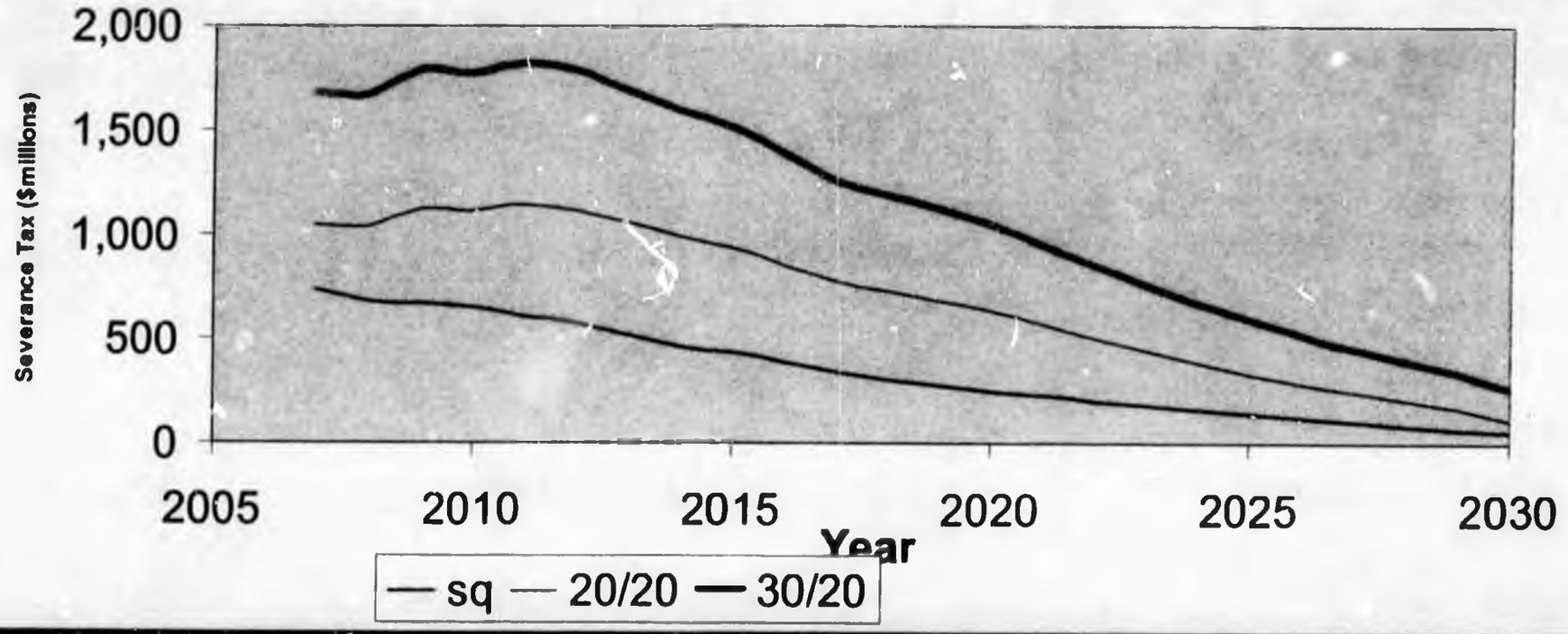
PPT 25/20 - Average annual revenues $1,300 million more than status quo & $400 million more than 20/20.

Figure 4b
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



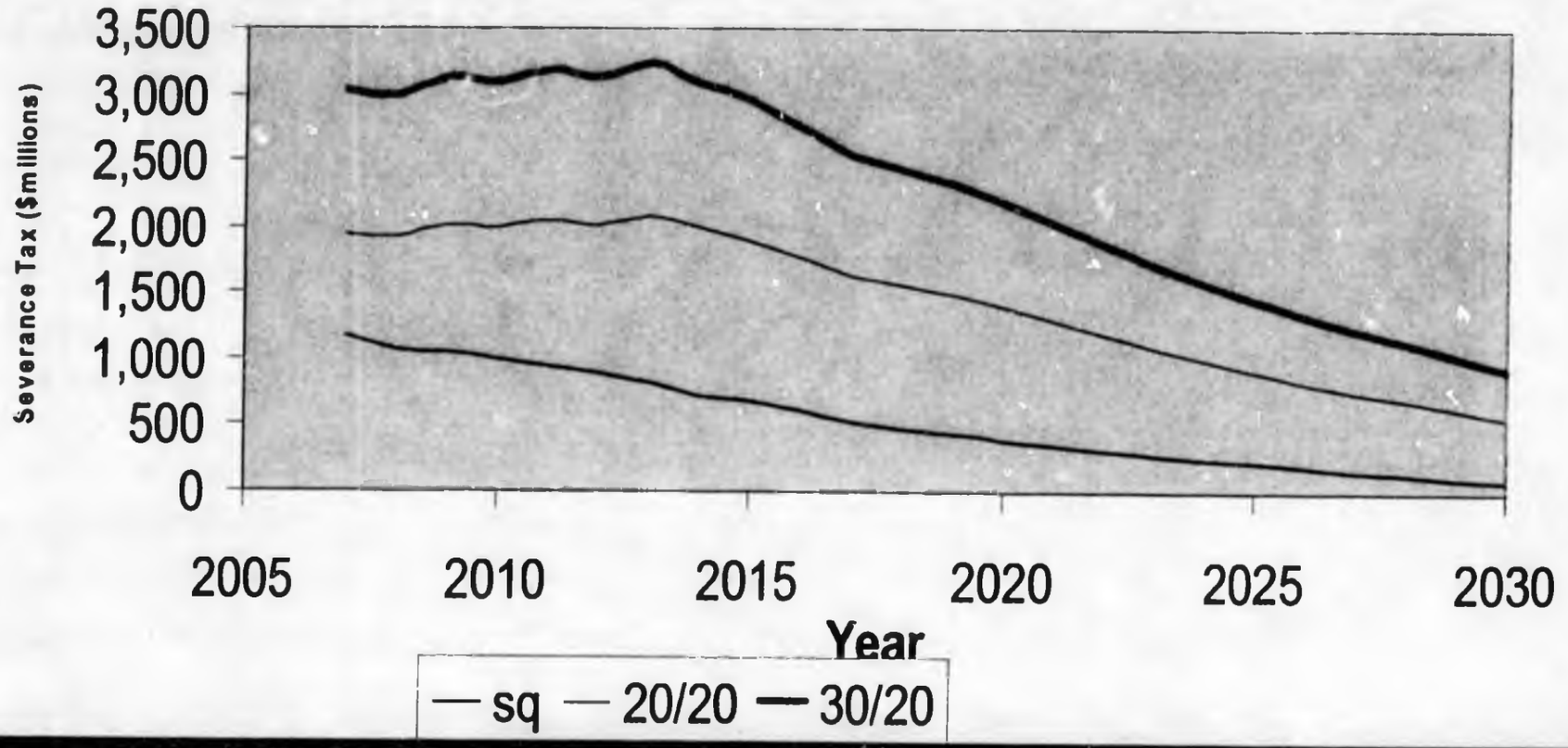
PPT 30/20 - Average annual revenues $55 million less than status quo and $45 million more than 20/20

Figure 5b
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



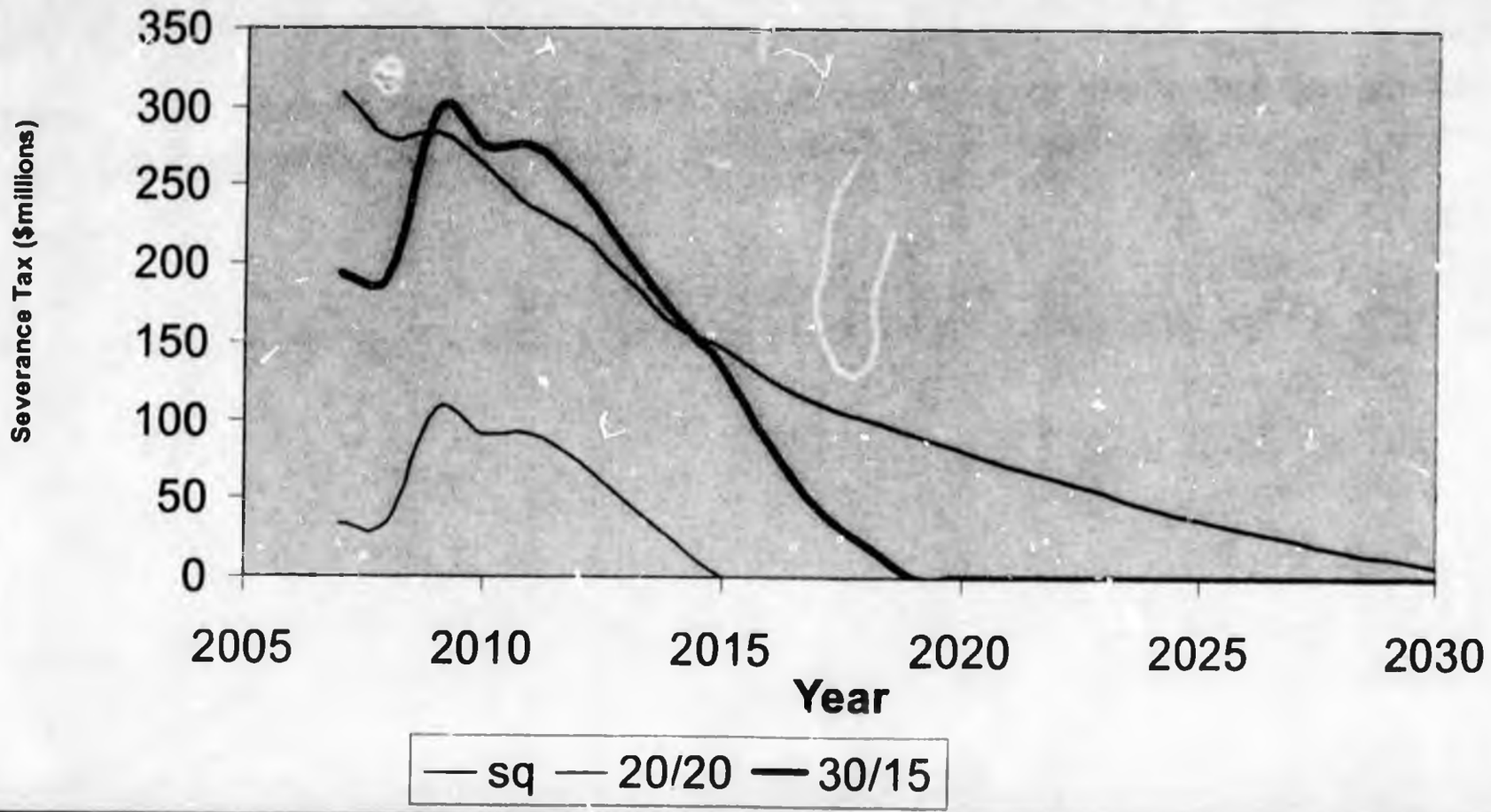
PPT 30/20 - Average annual revenues $790 million more than status quo and $440 million more than 20/20

Figure 6b
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



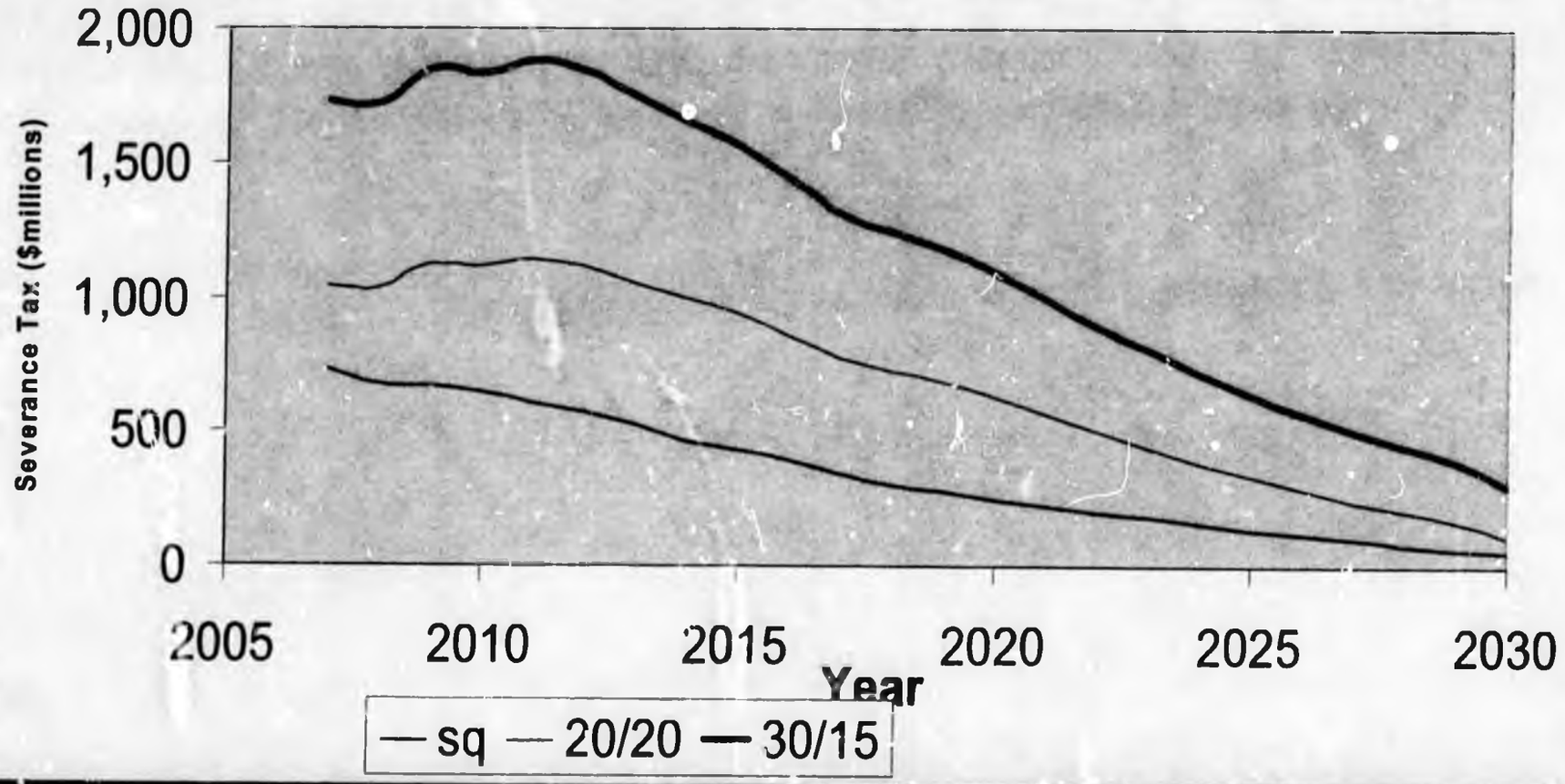
PPT 30/20 - Average annual revenues $1,730 million more than status quo and $820 million more than 20/20

Figure 4c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



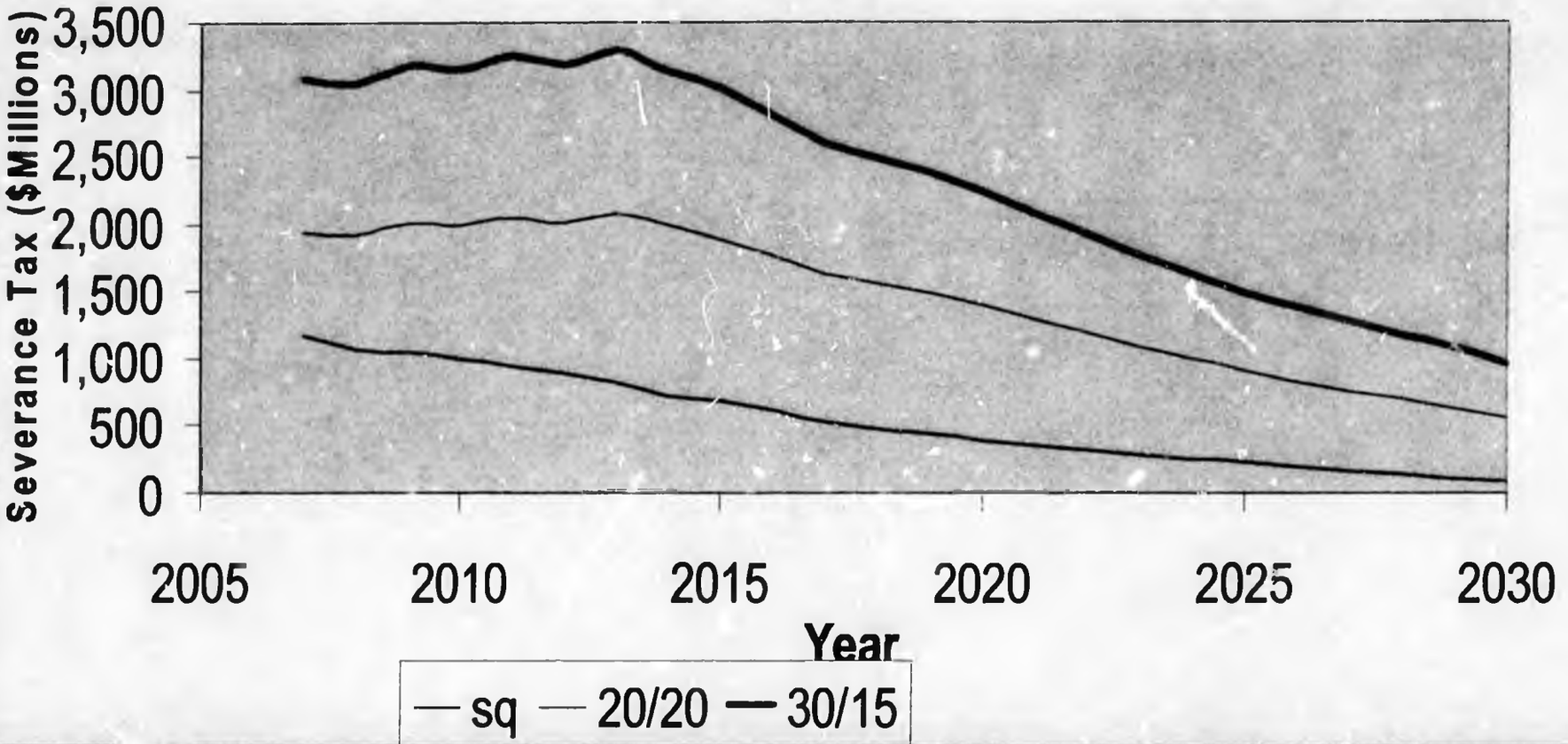
PPT 30/15 - Average annual revenues $35 million less than status quo and $70 million more than 20/20

Figure 5c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



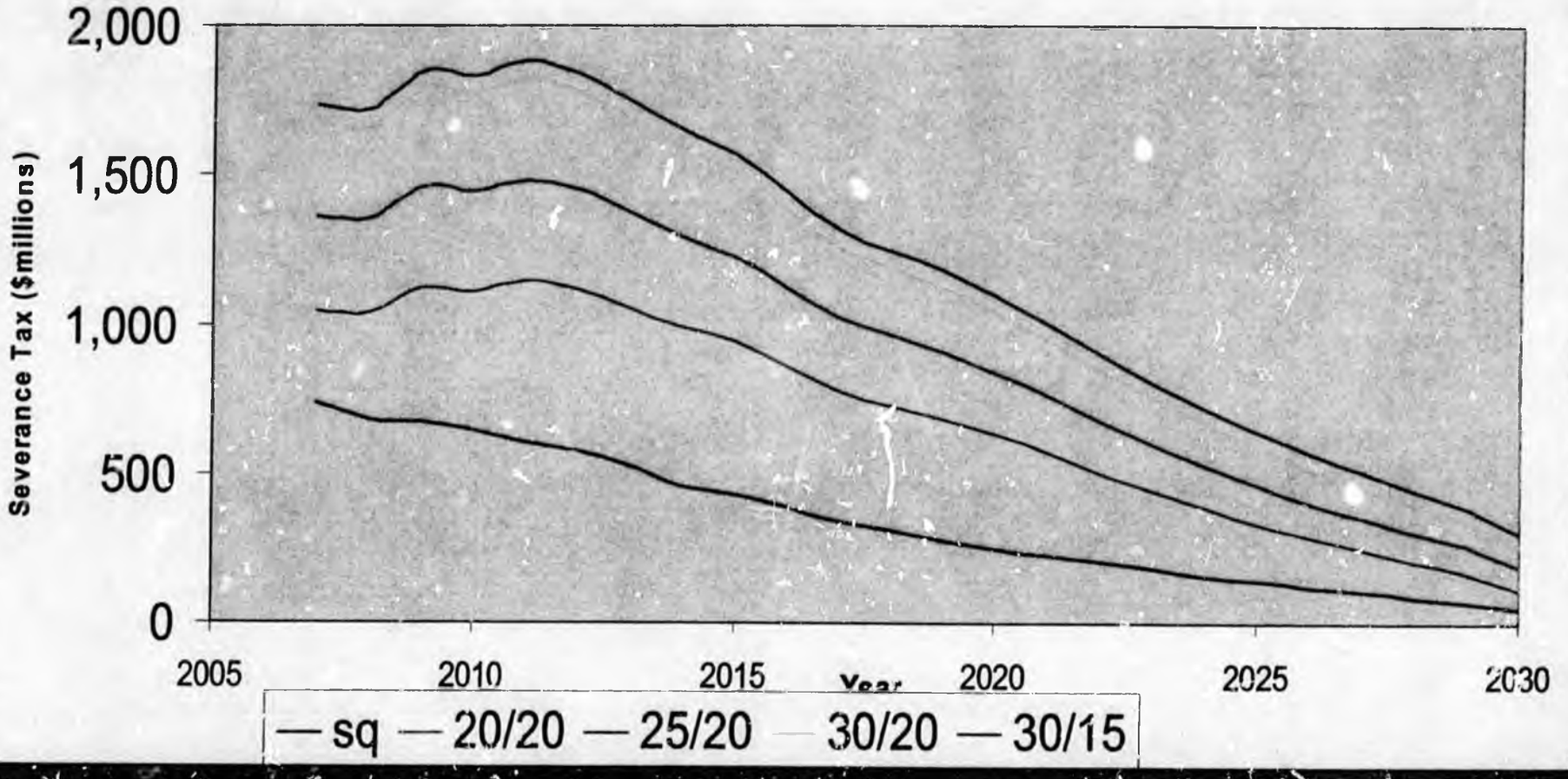
PPT 30/15 - Average annual revenues $840 million more than status quo and $500 million more than 20/20

Figure 6c
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60



PPT 30/15 - Average annual revenues $1,780 million more than status quo & $870 million more than 20/20

Figure 7
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40





STATE OF ALASKA
DEPARTMENT OF
REVENUE

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March 2, 2006

The House and Senate Resource Committees have conducted a number of hearings on HB 488 and SB 305, the Governor's bill repealing Alaska's current tax on oil and gas production and replacing it with a new petroleum profits tax, or "PPT." In the course of those hearings legislators have raised concerns about multiple issues, including certain terms appearing throughout the bill, which terms are defined in Sections 30-33 of the proposed legislation. Those terms and the potential for litigation and gaming they present are discussed in this memorandum.

Potential Ambiguities In Terms Used In The PPT and Consequent Opportunities for Disputes and Gaming

The PPT taxes the value of oil and gas at the "point of production." In calculating taxable value at the point of production, a producer is allowed to deduct capital and operating expenses incurred upstream of the point of production. Additionally, the very same expenses—to the extent they meet the PPT's rather broad definition of "qualified capital expenses"—garner a 20% tax credit, which may be either applied dollar-for-dollar against a producer's tax liability or sold for profit. And any net losses upstream of the point of production also earn a 20% tax credit that can be sold. Since both capital expense tax credits and loss tax credits attributable to operations upstream of the point of production can be liquidated at state expense, even in the absence of tax liability, both those that have a positive tax liability and those that do not have great interest in identifying the "point of production."

The "point of production" has been a subject of intense dispute between the State and its oil and gas lessees for many years. At various times the parties have argued that the point of production falls anywhere from the point at which oil and gas exits the wellbore to the point at which it is "in marketable condition," "of pipeline quality," and entering the Trans Alaska Pipeline System (TAPS) or other oil pipeline leaving the oil and gas unit of origin for market. These disputes have arisen with regard to both the State's royalty share of production (which compensates the State as landowner for its mineral interest) and the State's production tax on all oil and gas production occurring within its borders (whether on lands owned by the State or not).

Generally, oil and gas lessees have argued that the "point of production" is as far upstream as possible—preferably the wellbore. Conversely, the State has argued that the "point of production" is as far downstream as possible—where it leaves the Prudhoe Bay, Kuparuk River, or other unit of origin by pipeline for market. Producers have pushed the point upstream to minimize their royalty and production tax obligations while the State has pushed the point downstream to maximize the royalties and production taxes it collects and avoid issues about the allocation of costs accumulating between the wellbore and unit boundary.

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With the PPT one cannot assume that the producers always will be best served by pushing the point of production upstream and the State best served by pushing the point downstream. For example, an explorer or producer that incurs costs and earns tax credits in a year where it does not have taxable income would prefer that the point of production be moved downstream—at least for that year—to maximize its capital expense tax credits and loss tax credits. Additionally, if the "point of production" for the Pt. Thomson Unit is not at the wellbore but downstream at the unit boundary at the time that field is being developed, under the PPT the State will, effectively, "pay" for 40% of the surface facilities as those expenses are incurred, an outcome producers are certain to favor. However, a producer's financial interest in having the "point of production" pushed upstream or downstream may change for reasons currently unknown to legislators. For example, in a version of the PPT that predated its introduction as legislation, gasline-related capital expenditures incurred downstream of the point of production but upstream of a 2.0 bcfd (or larger) pipeline leaving the state were eligible for a 35% tax credit. While this credit has been removed from the PPT as introduced, we do not know whether it has been included in the gasline contract tentatively reached between the executive branch and producers BP, ConocoPhillips, and Exxon Mobil; if so, it may create an incentive for producers to push the point upstream for a 35% tax credit when they otherwise would have preferred to push it downstream for a 20% tax credit.

The PPT legislation could be amended in an effort to reduce the potential for disputes about the location of the point of production and the allocation of costs incurred upstream and downstream of the point of production. However, as HB 488 and SB 305 now stand, a lawyer working for an oil and gas lessee is given considerable leeway in arguing the point upstream or downstream, and an accountant working for an oil and gas lessee may divvy up costs in a way that a state auditor finds difficult to untangle. Using the Prudhoe Bay Unit as an example, and with regard to gas only, here is why:

Under the PPT there are four different categories of places that may qualify as a point of production for some portion of Prudhoe Bay gas. Factors that influence identification of the point of production for any given gas molecule include whether it is recovered by mechanical separation or gas processing and if it is metered between "gas processing" and "gas treatment." Under the PPT as proposed, the greatest potential for abuse appears to exist for gas run through an integrated "gas processing" and "gas treatment" facility, and the new Gas Treatment Plant planned for Prudhoe Bay may be just such a facility. "Gas processing" is defined to include processing of a gaseous mixture of hydrocarbons for the purpose of extracting and recovering liquid hydrocarbons, where upstream of any gas treatment. "Gas treatment" includes "conditioning gas" and removing non-hydrocarbon substances, as well as incidental removal of liquid hydrocarbons. Ambiguity arises for several reasons. First, "gas treatment" includes "conditioning gas," which is not defined, and one could argue that anything done to take gas from its condition in the reservoir to the conditions it must meet to be placed in a pipeline leaving the state constitutes "conditioning gas." Second, "gas treatment" also includes removing non-hydrocarbon substances from gas, but some non-hydrocarbon substances—like water and sediment—will be largely removed at the Flow Stations and Gathering Centers just downstream of Prudhoe's wellbores, while other non-hydrocarbon substances—such as carbon dioxide and hydrogen sulfide—will be removed in a new GTP, which will be downstream not only of the wellbores, but also the Flow Stations, Gathering Centers, Central Gas Facility (CGF), and most if not all other Prudhoe Bay Unit surface facilities.

Given these logistics and definitions, the Prudhoe Bay Unit operator, with the concurrence of other Prudhoe Bay producers, could attempt to game the system as follows. If the producers chose to push the point of production upstream, the unit operator court run all gas destine for the gas pipeline through the new GTP, making sure not to meter it at a point between the processing and treatment equipment located within the GTP, and claim that "gas treatment" begins, and hence the "point of production" is located, far upstream at the Flow Stations and Gathering Centers where water and sediment are removed. To push the point of production downstream under otherwise identical circumstances, the Prudhoe Bay Unit operator could simply install a meter between the "processing" and "treatment" equipment located within the GTP, and that meter would become the "point of production" under the definitions proposed in the PPT.

Moreover, Prudhoe Bay could become an auditing quagmire if gas recovered by mechanical separation as well as gas recovered without either mechanical separation or gas processing bypasses the processing equipment in the GTP, so that there is a multitude of "points of production" for bits and pieces of the gas originating from the Prudhoe Bay Unit. In that event, the costs of the Unit would be divvied up in accounting and audits necessary only for production tax purposes, and the State would not benefit from the adverse interests of individual lessees or joint interest accounting in the ways discussed by the executive branch when testifying in support of the PPT; it would be left on its own to defend its own interests, which would be adverse to those of the producers.

Arguably, there are other ambiguities in the definitions contained in the PPT. For example, if the point of production is pushed upstream at Prudhoe Bay to the Flow Stations and Gathering Centers and a hydrocarbon that was natural, associated, or casinghead gas is in gaseous phase at one of these facilities but is subsequently recovered in the CGF or new GTP as a liquid, one might argue that "gas" does not become "oil" for production tax purposes downstream of the point of incidence for the tax. This argument becomes more likely if gas is selling for less than oil on a barrel-equivalent basis, as is frequently the case.

The definitions of "point of production," "gas processing," and "gas treatment" are troubling for other reasons. Typically, one thinks of "gas processing" as occurring downstream of the "point of production," unless it is necessary to put gas in marketable condition, in which case it may occur upstream of the point of production, but, as to any governmental share, it is unlike other costs of production in that it is at the government's expense. Yet with the PPT it appears that the executive branch intends gas processing to occur upstream of the point of production, with room for a producer to argue the opposite. Also, frequently "gas treatment" is used in industry to refer to gas handling upstream of the point of production, but with the PPT my guess is that the executive branch intends it to most often or always occur downstream of the point of production. There is danger in using terms regularly used by industry in a manner atypical of industry usage—anyone that chooses to start a dispute has been provided by the PPT with ammunition to do so. Further, typical industry usage may be obscured by atypical application in the PPT, to the potential disadvantage of the State in collecting the royalties it is due based on value at the "point of production."

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Please be aware that with the memorandum I am not representing that the arguments advanced for alternative constructions of terms found in the PPT are the best or "winner" arguments. Rather, the point is that there is room for an interested party to argue that the proposed statutory language is ambiguous, and argue they will, if history is any indication. In fact, there may be too much money riding on one possible outcome for a producer to pass up the opportunity for argument, even if only to later settle somewhere between a better state position and a tenuous producer position.

Possible Approaches to Minimizing Ambiguities and Unintended Consequences

There are a number of possible approaches to mitigate the likelihood and unintended consequences of disputes over the location of the "point of production" and what is meant by "gas processing," "gas treatment," "oil," and "gas." Seven are set forth below:

1. At a minimum, the executive branch and the producers should be asked to go on record in writing in legislative proceedings on the PPT to specifically identify agreed-upon "points of production" for oil and for gas in each of the existing oil and gas units, both for facilities now in existence and for those planned for the future.

2. If the arguable ambiguities identified in this memorandum are brought to the attention of the executive branch, its personnel may come up with their own thoughts on how to "clean-up" the language or may be able to convince legislators that there is no room to argue ambiguity.

3. Legislators may want to ask the executive branch whether its proposed gasline contract will include tax credits for gasline-related capital expenditures, especially those that might influence a producer's desire to move the point of production upstream or downstream.

4. As long as the possibility for disputes over definitions remain, the State may want to retain the few advantages it has in multimillion dollar disagreements with some of the largest, most resourceful, and brightest companies in the world. Those advantages include the ability to set and change rules by regulation, the authority to decide disputes in the first instance by an agency hearing officer, and the jurisdiction of Alaska courts to hear those disputes on appeal, giving deference to agency decisions. If the executive branch is thinking of surrendering these advantages in a gasline contract and the legislature would prefer that the executive branch not, the legislature may want to include language to that effect in any PPT bill passed.

5. Legislators may want to consider a different point of production than that proposed by the executive branch. For example, the point of production could be as discussed by outside counsel for the executive branch in a memorandum dated January 5, 2005 and as found by Judge Compton in an April 1979 decision regarding the State's royalty share under state oil and gas leases. Both Judge Compton and the State's legal counsel have identified the point of production—at least for royalty purposes—as the point where oil is in "merchantable condition" and "metered ... for removal from the unit." More specifically, the point of production for oil could be at the entry of an oil pipeline leaving a unit and the point of production for gas could be at the entry of a gas pipeline leaving a unit, with a requirement in both instances that the oil or gas be in marketable condition and of pipeline quality, though fine-tuning would be needed to address situations where both oil and gas leave a unit in a single multi-phase pipeline, with

treatment that is normally considered part of the process of production occurring off-unit, as might be the case with offshore units or development at Pt. Thomson. Of course, use of the definitions discussed in this paragraph would require the executive branch, producers, and legislators to revisit the cost of the PPT's tax credits, which would increase if the point of production is moved downstream of where it would otherwise fall under the PPT's current definitions.

6. The legislature may want to include language in any legislation passed stating that the definitions used in the PPT are not "fair-game" for use in royalty disputes between the State and producers, at least if the final version of these definitions are in conflict with the principles discussed by Judge Compton in his April 1979 decision and the State's outside counsel in its January 2005 memorandum.

7 Legislators may want to address whether expenses related to experimental facilities for gas-to-liquids are eligible for the deductions and tax credits provided by the PPT. As the PPT now reads, a producer using Alaska as its site for a gas-to-liquids experimental plant may have the State "paying" for up to 40% of the experimental plant as long as one can argue that it is upstream of the "point of production," even if the producer intends to use gas-to-liquids technology in other parts of the world and not in Alaska, and there is little or no taxable production generated by the plant.

If legislators are interested in pursuing these or other ideas for minimizing the possibility of disputes and gaming as a result of terms defined in Sections 30-33 of HB 488 and SB 305, I would be happy to assist in that effort by drafting or reviewing language that could be proposed as an amendment to the PPT.

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March 2, 2006

Senator Tom Wagoner, Chair
Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801

Rep. Ralph Samuels, Co-Chair
House Resources Committee
State Capitol, Room 126
Juneau, AK 99801

Rep. Jay Ramras, Co-Chair
House Resources Committee
State Capitol, Room 104
Juneau, AK 99801

Re: Questions on PPT Legislation (SB 305, HB 488)

Dear Senator Wagoner and Representatives Samuels and Ramras,

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings.

Received 2/28/06, 12:00 p.m.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production), by company.

The Department of Revenue model uses $1 billion per year as capital costs, so for the transitional period, there would be about $5 billion. This annual costs are based on compilations of historical data. The attached excel files outlines public data regarding investments.

2. How are mob, demob, and platform abandonment costs treated—as tax credits or deductions?

Mobilization costs are capitalized for federal tax purposes, as Intangible Drilling Costs. As such, they are a capitalized expenditure for PPT purposes, and therefore are deductible and creditable. We understand that demobilization and abandonment expenditures are both expensed as incurred. This would mean that these costs are deductible, but would not generate a credit.

3. Is there a "rating" for political stability – or one that reflects instability?

We do not have any information on a quantification of the risk of political stability.

4. What loss of revenue is incurred by moving the effective date from Jan 1, 2006 to July 1, 2006 on both 20/20 and on 25/20?

Using a combination of our spring forecast and YTD actuals, the average ANS price between January 1, 2006 and July 1, 2006 was $58.62.

- The loss of revenue using the 20/20 system would be about $480 mm in additional tax.
- The loss of revenue using the 25/20 system would be about $770 mm in additional tax.

5. Section 9 – what amount is involved in this section?

A very small amount, probably no more than 1% of total state revenue from oil and gas. It is limited to three areas: [1] Alpine and its satellites; [2] the National Petroleum Reserve Alaska; and [3] Cook Inlet.

6. Was there consideration of phasing out the $73 million deduction over a certain period of time?

No, it was not considered.

7. Of the current 14 producers in Alaska, which would pay a severance tax after employing the proposed $73 million standard deduction?

With the merger of Chevron and Unocal, there are now 13 producers in Alaska. Of the 13 producers, BP, ConocoPhillips and ExxonMobil will pay severance tax at most price levels after employing the $73 million standard deduction. At high oil and gas prices, and given our cost assumptions, Anadarko and ChevronUnocal will also pay severance tax after deducting the $73 million dollar allowance, given the production volumes reported publicly by those companies.

8. Which other tax regimes – worldwide - have a progressivity structure?

TO BE PROVIDED

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

We do not have information on the number of private royalty owners in Alaska, which would include private oil and gas leases that are not in production. Homesteads staked under certain (but not all) federal homestead laws included oil and gas rights, and any of the owners of such parcels might enter into an oil and gas lease.

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

This question appears to query the relationship between tax under the status quo, the PPT, and the gas line contract terms. At this time, gas line contract terms are not public information.

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) total $104. 8 million and claimed credits total $33. 6 million [see table below]. A claim was received by the Department of Revenue last week, thus the totals has been updated from the $95.5 million and $29.0 million figures previously provided.

12. What is the rational for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

The rationale is that the incentives have the potential to result in higher severance taxes; taxes that are assessed on any oil or gas production within Alaska's sovereign territory. Given the overall economic benefit of increased production of oil and gas (and particularly gas in the Cook Inlet where significant private lands occur), an incentive for exploration and development even in the event that a field would pay no taxes after incentives makes sense.

13. Why should Point Thomson be incentivised?

We believe the development of Pt. Thomson may be critical for the development of the gasline. Accordingly, incentivizing Pt. Thomson may well incentivize the gasline

Pt Thomson is particularly problematic for two reasons. First, it is a high cost field since it is a high pressure gas condensate reservoir and second we do need the gas reserves to underpin the gas pipeline economics. By providing incentives, the goal would be two fold. First any incentive to encourage Pt. Thomson improves the economics of the gas pipeline. Second, incentives may encourage early production of the liquids which requires expensive infrastructure to handle the high pressure production.

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

We're not clear whether this question seeks more explanation of the definitions in the bill or is requesting that we consider modifying those definitions. Please clarify. Regarding past litigation, in general the point of production and the definitions of oil and gas have not been major subjects of litigation under the production tax statute. In contrast, there has been considerable litigation of related concepts, though not necessarily the phrase "point of production," in the royalty context.

In the tax context, there was at least one dispute decided at the internal DOR appeal stage relating to point of production, but most of the controversy in this area played out in the development of regulations defining "gas processing plant," rather than litigation. The use of the term "gas processing" in the bill is consistent with existing department regulations, but under current law gas processing generally is considered an activity occurring downstream of the point of production, while under the bill it is considered an activity occurring upstream of the point of production.

15. What steps must be taken to make the tax credits refundable rather than transferable?

This would require a language change to Section 12 at Sec. 43.55.024(d) and (e). We are available to work with drafters on the exact wording.

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

Section 21 (Sec. 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are deductible. Sec. 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Sub-section (d) provides clarification for items that are not clear, such as "payments made in lieu of property taxes."

17. Does the limit on transferable tax credits in section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

Section 12 (Sec. 43.55.024(e)) limits the amount of tax that can be reduced through purchased credits. There is no limit on credits utilized by a taxpayer that were generated by that same taxpayer.

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the

legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel(not all of them) have been consulted and such assessments have been discussed but have not generally been generated in formal written form.

19. Have you asked the Department of Law to review this legislation in light of the 6th Circuit Court of Appeals' decision in Cuno v DaimlerChrysler that is now pending before the United States Supreme Court?

The Department of Law has examined this question. As a Sixth Circuit decision, it has no direct precedence for Alaska. It is currently before the U.S. Supreme Court and many analysts believe that it will not be sustained in its current form.

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

It appears that this question relates to the transition provision in Section 21 (Sec. 43.55.160(g)) which allows a deduction for capital expenditures made over the last five years, deductible over the next six years. The capital expenditures that qualify for transitional treatment are the same type of expenditures that qualify for ongoing credits. These are defined in Section 12 (Sec. 43.55.024(h)). These expenditures include exploration expenses and those expenditures that are capitalized for federal tax purposes. Exploration expenses include geological and geophysical exploration. Expenditures capitalized for federal tax purposes include intangible drilling costs. The capitalized expenditures are subject to a variety of useful lives under federal and state income rules. See Question 60 below.

21. Have any of the definitions in sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

See question 18 above.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

TO BE PROVIDED

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

This term only appears in the definition of "oil." It was not in the old definition, nor the new definition of "gas." The standard for "pipeline quality" has not changed under the bill. The standard is based on a series of court cases.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

TO BE PROVIDED

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

See Question 2 for deductibility of abandonment costs. With regard to costs, we are aware of no field having ever been abandoned in Alaska, and so we do not have any empirical data on costs.

27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

TO BE PROVIDED

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

Five [5] exploration wells per year are included in the model. The Department of Revenue assumes $100 million is spent on exploration per year. With average costs of $20 million dollars per well, this comes out to five [5] wells per year. Delineation wells are separate and included under development expenditures. The model assumes there are four [4] finds of large oil accumulations – reserves in place that would be on the order of 500 million barrels. There are four [4] relatively small fields that are characterized as being "heavy" oil. These fields would pay no production tax under the current system because their Economic Limit Factor [ELF] would be zero [0.0]. We did not include a "success rate" in our model.

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

TO BE PROVIDED

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

See Attachments A1 and A2. These tables contain effective tax rates since 1986 for all Alaskan fields on gross value at the point of production. The effective tax rate shown on these tables is the ELF x 12.25% for the first five years of production, and ELF x 15% thereafter. We note the effective rate varies between 15.0%, for Prudhoe Bay through 1987 (when the so-called "rounding rule" rounded the ELF up to 1), and 0.0% for a number of fields for a number of years.

31. How will Net Profit Share Leases be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

TO BE PROVIDED

Received 2/28/06, 2:30 p.m.

32. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

In the gasline contract the state has indeed proposed taking deliveries of gas in place of a production tax; this is not reflected in the PPT bill which will stand on its own, gasline or no. Under the PPT, if the producers sell gas, those revenues would be part of the net profit calculation. Under the gasline, they would not. Instead the state would receive a percentage of the gas, which it would monetize thought marketing. Note that the costs of developing (for example Pt Thomson) or running (for example Prudhoe Bay) a field that produces both oil and gas would go into calculating the oil profits for the PPT.

33. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

See question 20.

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

Sale of credits under SB185 do not effect the ability of the seller to claim those credits as Transitional Investment Expenditures (that is to qualify for the claw back.)

35. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

Without getting into price sensitive forecast, or the confidential draft gas contract, we can make the following observations about the comparison: The upstream costs are covered in the PPT, so the difference could be as simple as;

(a) under the PPT, a taxpayer would pay 20% of the gross value at the point of production, that is sales revenues less the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale would be paid to the state. (without taking into account the effect of the $73 million dollar allowance).

(b) Under the gas contract, the state will receive some percentage of the gas, and then pay the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale. If the state owns part of the pipeline, then the state will also receive that portion of the tariff which is profit accruing to the owner.

36. Is current production tax deductible from corporate tax? If no, is this impact in the models presented by the Administration?

Yes, current production is deductible from corporate tax.

37. Referring to Section five, what oil and gas is exempt from taxation—just what is discussed in Section 10?

The oil and gas royalty amounts paid to the state and federal government are exempt. (AS 43.55.900 (13) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state.")

Section 10 simplifies treatment of flared gas. Under current law there are three categories of gas – gas used in production operations which is exempt from tax, gas produced in excess of that needed for safety purposes which is taxable, and gas flared beyond the amount authorized for safety which is taxed and subject to a penalty. Currently there is no 'free use of oil' to produce more oil in statute. The bill

exempts from tax any oil or gas used in production operations, unless the Alaska Oil and Gas Conservation Commission determines that it was waste (instead of used to produce salable hydrocarbons), in which case it is taxed.

38. Referring to Section six, will there be any impact to current state taxes or municipality taxes from this change?

No, there should be no impact to current state or municipal taxes. This language change simply makes the description of Intangible Drilling Costs consistent with Internal Revenue Code language, which is how this item is interpreted currently.

39. Why was the payment for taxes and surcharges changed from the 20th day to the last day of the month? What is the economic impact of this change?

There is no economic impact and this just clears up current language. Under AS 43.55.020, payment for the tax is "due" on the 20th, however, the tax is not "delinquent" until the last day of the month. The significance of this is that according to AS 43.05.225 interest is assessed only when a tax "becomes delinquent." Thus this bill makes the due date the end of the month and in section 7 establishes that "an unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent."

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

TO BE PROVIDED

41. What are the penalties for under-payment when sure-up is more than ten percent of the taxes owed?

If the taxpayer does not pay 90%, then interest will be due on the difference between the tax paid and the 90% amount.

42. Referring to Section 10, why does the AOGC [Alaska Oil and Gas Conservation Commission] role change from focusing on excess needed for safety reasons to whatever they determine to be waste? Does this provision provide more power to the AOGC on what is included/excluded for taxation?

Under current law, as applied by DOR regulation, the categories of flared gas recognized by DOR are different from (although related to) the categories recognized by AOGCC. The bill will simplify the categorization and harmonize it completely with AOGCC's. This simply creates one standard administered by AOGCC, in place of two standards administered by two agencies.

43. Why does it seem the credits and incentive [sic] are on production along with exploration if our focus is to provide incentives for exploration?

(The bill is based on the expectation that investment, both exploration and in existing fields, will increase production.

44. Can the carry-forward amount be used for a credit for more than the first year after the loss?

Yes, the credit carry-forwards can be used indefinitely. There is no time limit on the credit carryforwards.

45. Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Expenses are allowable only if they are "upstream" costs. A gas line is "downstream" and so would not be a deductible expense.

46. Why not use GAP [sic] accounting rules versus set up or our [sic] system of defining revenues and expenses?

GAAP (Generally Accepted Accounting Principles) are useful for determining whether an item of expenditure can be classified as an "expense." GAAP does not differentiate between expenses incurred specific to a lease and those expenses that are indirect to a lease. For example, GAAP does not distinguish between wages paid to a lease-based worker, and an employee in the home office.

47. Which credits can be applied to multiple years?

There is no time limit for credit carryforwards under the bill, nor for the optional credit codified in 43.55.025. However, any dollar of investment can only generate one credit, and that credit can only be used once.

48. Can a tax credit be sold in any year or just the year after it was accrued?

Once the credit has been turned into a Credit Certificate, it can be sold at any time. A person can apply for a Credit Certificate at any time, but the bill allows the Dept. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, Sec. 43.55.024(g))

49. What is the estimated economic impact to the state of the ability to sell tax credits?

TO BE PROVIDED

50. Referring to Section 16, what is current system and why do we need this change in confidentiality?

The bill codifies current practice embodied in regulations in our treatment of taxpayer information. The only change here is that the bill makes clear that any person receiving information released under current department practices, is subject to the same criminal penalties that apply to a state employee.

The current confidentiality law is very general in its exception language – information must be kept confidential "except in connection with official investigations or proceedings . . . ." The Department believes that current law does allow disclosure under the circumstances specified in the bill, but there has been some question about that, and it would be desirable to clarify the meaning of the law, as the bill does. In addition, there is the new provision on penalties, referred to above.

51. In what circumstances would oil and gas taxes go straight into the CBR.

Additions to the CBRF (Constitutional Budget Reserve Fund) are made for any oil and gas taxes collected in resolution of a dispute. That means that amounts collected because of an audit assessment, or subsequent settlement, are additions to the CBRF.

52. Referring to Section 18 and 19, why change from shall to is?

This change is made in accordance with the state style manual.

53. Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

The bill does not directly allow a taxpayer to elect alternative methods, it just allows the Department to authorize use of an alternative method. The election referred to would be an election between using an alternative method or just calculating gross value according to the usual rules – NOT an election among several different alternative methods. In implementing this provision, the Department will no doubt develop criteria for when a particular alternative method would be appropriate. I don't think we can predict now whether there might be circumstances under which more than one alternative method might be appropriate and under which the Department would authorize a taxpayer to elect among several alternative methods.

54. Section 21, page 1, line 8—why is this clause constrained y Dec. 1, 2005?

TO BE PROVIDED

55. Section 21, provision (h), which US CPI does the Administration plan on using?

This would be established by regulation. The Department has not evaluated the various CPI's at this time.

56. Are the current oil conservation surcharges deductible from any other taxation? If no, what is the policy reason to make them a credit in SB 305 and what is the economic impact?

Yes, current oil conservation surcharges are deductible from corporate income tax.

Other Questions

57. Do any other state taxes have a "standard deduction"?

a. Seafood Marketing Assessment (ASMI) tax is imposed only on processors/exporters that process or export fisheries resources with a value of $50,000 or more in a calendar year. AS 16.51.120(g).

b. Mining License Tax is not imposed when net income is less than $40,000 in a fiscal year. AS 43.65.010(c).

c. Gaming tax exempts gross receipts of less than $20,000 from paying the additional fee under AS 05.15.020(b).

d. Alaska's Estate Tax follows federal rules, but the most recent exemption (Fy05) included estates valued at under $1.5M.

58. How many NPSL's (Net Profit Share Leases) are in the state, and how much are they paying in royalties?

Out of 19 NPSL's, seven are paying royalties. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was $81M. Total receipts from NPSL's from 2001—2005 were $254M.

Out of 19 NPSL's, seven are paying net profit share payments *(in addition to royalties and production taxes)*. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was $81M. Total NPS receipts from NPSL's from 2001—2005 were $254M. Net profit share payments are not deductible for PPT purposes nor for the current production tax. Royalties and production taxes are deductible for NPS purposes.

Royalties, however, are paid on net profit share leases according to each individual lease contract. For example, one NPS lease in Duck Island Unit has a twenty percent (20%) royalty rate. Other NPS leases may have the standard royalty rate of 12.5% or another, negotiated royalty rate. Royalties and production taxes are due from a net profit share lease as long as there is production, even when there is no net profit share payment from the property.

Attached is an Xcel table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease. (See Attachment B)

59. What are the depreciable lives for O & G equipment for federal and state income tax purposes?

	Federal	Alaska
Equipment for exploration and production including drilling, gathering pipelines, pumping equipment, separation equipment, certain platforms	7	11
Offshore drilling	5	6
Pipelines, excluding gathering and transmission lines	15	17.5
Vessels, barges, other water transportation equipment	10	14.5

60. Please provide the tax calculation under the bill, with the following assumptions:

--Gross value	$60M
--Opex	15M
--Capex	10M

Gross value	$60M
Less: Opex	(15)
Capex	(0)
Tentative net profit Before standard deduction	$35M
Less: standard deduction*	(35)
Net Taxable income	$ 0

Tax	$ 0
Capital investment credit available for carryforward (20% of $10M)	$5M

* this calculation assumes that taxpayer has not reached $73M limit for the standard deduction.

61. Are net profit lease payments included as a direct cost under 43.55.160?

Net proft share payments under NPSL's (Net Profit Share Leases) would not be deductible lease expenditures because they are in the nature of lease acquisition costs. Lease acquisition costs are not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

62. Are lease bonus payments eligible for capital credit under 43.55.024 and/or are they included as a direct cost under 43.55.160?

Lease bonus payments are neither deductible nor eligible for capital credits. Lease bonus payments are in the nature of lease acquisition costs which are specifically not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

63. How are payments for "spec 3D" handled? Are they credit eligible under 43.55.024 or only allowed as deductions under 43.55.160?

We understand "spec 3D" to be certain seismic exploration costs. Exploration costs are allowed as deductions under Section 21 of the bill (Sec. 43.55.160(c)). Such costs are also eligible for credits under Section 12 (Sec. 43.55.024) by reference to definition of "qualified capital expenditure" at Sec. 43.55.024(h).

64. Please explain the taxation or exemption of royalties.

Public royalties (paid to federal or state jurisdictions) never enter into the base of gross value. This is so because AS 43.55.011(a) levies the tax on oil except oil the "ownership or right to which is exempt from taxation." This phrase is then defined in AS 43.55.900(13) as follows:

"any ownership interest of the federal government or the state."

These sections are not changed in the bill.

Because the bill changes the tax to a tax on net profits, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21

(Sec. 43.55.160(d)(2)(B)). Royalties paid to state and federal jurisdictions cannot be deducted because they are not included in the starting "gross value." Private royalties cannot be deducted because the related production is subject to tax.

65. Under Section 21 (Sec. 43.55.160(d)), "direct costs... include..." Does the word "include" serve to restrict the list of allowable expenses to only those items included below in (A)—(C)?

No, Sec. 43.55.160(d) provides additional clarification for the general rule stated at sub-section (c). Sub-section (c) provides the general rule that lease costs are deductible. Sub-section (d) addresses only those items that may have been questionable under the general rule. Additionally, we note that under AS 01.10.040(b):

"When the words 'includes' or 'including' are used in a law, they shall be construed as though followed by the phrase 'but not limited to.'"

Questions Received 3/1/06 12:00 a. m.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO_2 re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

TO BE PROVIDED

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant gax benefits ever be realized?

TO BE PROVIDED

68. How is it possible that any corporation gets triple the sale price for a commodity, having invested capital at the expected lower returns, and then maintains that they need a claw back provision? Why should we offer it?

TO BE PROVIDED

69. Please show us an international competitiveness rank and score for PPT under the following tax/credit scenarios, both overall and for new producers:

a. 30/15
b. 30/20
c. 25/20
d. 20/20

TO BE PROVIDED

70. Please present Mr. Marks' charts on pages 14-16 to show the difference between a PPT and status quo, annually under the following PPT plans at $20, $40, and $60/bbl:

a. 25/20
b. 30/20
c. 30/15

TO BE PROVIDED

71. Please show the corporate take chart on page 24 of Mr. Marks' presentation given the following tax/credit scenarios:

a. 25/20
b. 30/20
c. 30/15

TO BE PROVIDED

72. Please show the price point where DOR estimates corporate profit margins hit 15% and 20%.

TO BE PROVIDED

Attachment A1 (Question 30)

Effective Tax Rates, North Slope by Field, FY86 - FY05

	Prudhoe Bay	Midnight Sun	Polaris	Orion	Aurora	Borealis					
FY86	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.07%	0.00%	0.00%	0.00%	0.00%
FY87	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.47%	0.00%	0.00%	0.00%	0.00%
FY88	12.66%	0.00%	0.00%	0.00%	0.00%	0.00%	8.33%	0.00%	0.00%	0.00%	0.00%
FY89	12.33%	0.00%	0.00%	0.00%	0.00%	0.00%	8.71%	0.00%	0.00%	0.00%	0.00%
FY90	14.71%	0.00%	0.00%	0.00%	0.00%	0.00%	12.89%	0.00%	0.00%	0.00%	0.00%
FY91	14.91%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	0.00%	0.00%	0.00%	0.00%
FY92	14.90%	0.00%	0.00%	0.00%	0.00%	0.00%	13.33%	0.00%	0.00%	0.00%	0.00%
FY93	14.85%	0.00%	0.00%	0.00%	0.00%	0.00%	13.34%	0.00%	0.00%	0.00%	0.00%
FY94	14.81%	0.00%	0.00%	0.00%	0.00%	0.00%	13.09%	0.00%	0.00%	0.00%	0.00%
FY95	14.76%	0.00%	0.00%	0.00%	0.00%	0.00%	12.85%	0.00%	0.00%	0.00%	0.00%
FY96	14.67%	0.00%	0.00%	0.00%	0.00%	0.00%	12.35%	0.00%	0.00%	0.00%	0.00%
FY97	14.59%	0.00%	0.00%	0.00%	0.00%	0.00%	11.72%	0.00%	0.00%	0.00%	0.00%
FY98	14.44%	0.00%	0.00%	0.00%	0.00%	0.00%	11.38%	0.00%	0.00%	0.00%	0.00%
FY99	14.23%	0.00%	0.00%	0.00%	0.00%	0.00%	10.53%	0.00%	0.00%	0.87%	0.00%
FY00	13.96%	0.00%	0.00%	0.00%	0.00%	0.00%	8.97%	0.00%	0.00%	0.58%	0.00%
FY01	13.76%	0.00%	0.00%	0.00%	0.00%	0.00%	7.40%	0.00%	0.00%	0.05%	0.00%
FY02	13.44%	0.13%	0.00%	0.00%	0.00%	0.96%	5.29%	0.00%	0.00%	0.52%	0.00%
FY03	13.05%	0.10%	0.00%	0.00%	0.00%	1.40%	3.44%	0.00%	0.00%	1.22%	0.00%
FY04	12.82%	0.00%	0.00%	0.00%	0.00%	1.03%	2.70%	0.00%	0.00%	0.84%	0.00%
FY05	12.65%	4.43%	4.43%	3.63%	3.62%	3.69%	0.76%	0.00%	0.00%	0.15%	0.00%

Note: The effective tax rate for Midnight Sun, Polaris, Orion, Aurora, Pt. McIntyre, and Borealis for FY 05 reflects 5 months' effect of the aggregation decision effective Feb. 1, 2005.

Attachment A2 (Question 30)

	Milne Point	[redacted]	[redacted]	Lisburne	Point Mcintyre	Niakuk	West Beach	NPRB	Alpine	Northstar
FY86	2.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY87	0.62%	0.00%	0.00%	4.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY88	0.00%	8.17%	0.00%	7.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY89	0.00%	12.25%	0.00%	6.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY90	0.00%	10.37%	0.00%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY91	0.00%	9.44%	0.00%	0.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY92	0.00%	9.51%	0.00%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY93	0.00%	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY94	0.00%	11.53%	0.00%	0.00%	7.28%	1.56%	0.00%	0.00%	0.00%	0.00%
FY95	0.00%	11.30%	0.00%	0.00%	11.30%	6.15%	0.00%	0.00%	0.00%	0.00%
FY96	0.00%	10.39%	0.00%	0.00%	11.60%	1.76%	0.00%	0.00%	0.00%	0.00%
FY97	0.29%	7.10%	0.00%	0.00%	11.63%	1.51%	0.00%	0.00%	0.00%	0.00%
FY98	0.46%	4.54%	0.00%	0.00%	11.29%	0.89%	0.00%	0.00%	0.00%	0.00%
FY99	0.64%	1.29%	0.00%	0.00%	11.75%	0.70%	0.00%	0.00%	0.00%	0.00%
FY00	0.38%	0.73%	0.00%	0.00%	9.45%	1.32%	0.00%	0.00%	0.00%	0.00%
FY01	0.16%	0.13%	0.00%	0.00%	6.47%	0.17%	0.00%	0.00%	4.24%	0.00%
FY02	0.02%	0.02%	0.00%	0.00%	3.10%	0.15%	0.00%	0.00%	10.76%	5.14%
FY03	0.00%	0.01%	0.00%	0.00%	2.40%	0.02%	0.00%	0.00%	10.50%	10.59%
FY04	0.00%	0.00%	0.00%	0.00%	1.63%	0.00%	0.00%	0.00%	10.33%	10.37%
FY05	0.00%	0.00%	0.00%	0.00%	4.78%	0.00%	0.00%	0.00%	10.17%	10.18%

Attachment B (Question 58)

By: G. Rogers, March 1, 2006, source DNR

NPS LEASES, NPS RATES & ROYALTY RATES & STATUS

	Unit - lease number	Royalty Rate	NPS Rate	NPS Status
	Duck Island			
1	312828	20%	79.5935%	in payout
2	312834	20%	48.8703%	in payout
	Milne Point			
3	355016	12.5%	40.0000%	in payout
4	355017	12.5%	40.0000%	in payout
5	355018	12.5%	30.0000%	in payout
6	355021	12.5%	30.0000%	in payout
7	388235	12.5%	30.0000%	in payout
	Kuparuk River			
8	355023	12.5%	30.0000%	not in payout
9	355024	12.5%	30.0000%	not in payout
10	355030	12.5%	30.0000%	not in payout
11	355032	12.5%	30.0000%	not in payout
	Colville River			
12	364470	12.5%	30.0%	non producing
13	364471	12.5%	30.0%	non producing
14	364472	12.5%	30.0%	non producing
15	364477	12.5%	30.0%	non producing
16	364478	12.5%	30.0%	non producing
	Point Thompson Unit			
17	312866	20%	52.352%	non producing
18	343109	12.5%	40%	non producing
19	343110	12.5%	40%	non producing
20	343111	12.5%	40%	non producing
21	343112	closed	closed	non producing

Average Effective Tax Rates, Low Volume Scenario, No Gasline

	$20/bbl	$40/bbl	$60/bbl
Status Quo	4.1	4.5	4.4
PPT 20/20	0.55	9.7	13.0
PPT 25/20	1.2	12.4	16.7
PPT 30/20	1.8	15.5	20.5
PPT 30/15	2.5	16.3	21.0

Cumulative Severance Tax Revenues, Low Volume Scenario, No Gasline

	$20/bbl	$40/bbl	$60/bbl
Status Quo	2,959	8,211	12,870
PPT 20/20	498	16,458	34,649
PPT 25/20	1,041	21,782	44,521
PPT 30/20	1,614	27,107	54,393
PPT 30/15	2,133	28,317	55,603

KEN THOMPSON
PRESENTATION 3-2-06

Comments On SB 305 and HB 488 Oil and Gas Production Tax
By Ken Thompson, Managing Director of AVCG/Brooks Range Petroleum

Personal Background

For the record, my name is Ken Thompson. I reside at 12031 Lilac Drive, Anchorage, Alaska. I am the Managing Director of Alaska Venture Capital Group, or AVCG LLC, an independent oil exploration company with a focus on the North Slope of Alaska. AVCG is a consortium of 15 independent oil and gas companies and individuals from Kansas and me as an owner/investor from Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with offices in Anchorage.

AVCG LLC has been very active in the past six North Slope areawide lease sales and we have acquired over 160,000 acres of exploration leases in five exploration prospect areas, including new acreage we acquired earlier this morning in the NS lease sale. Our exploration strategy is to explore in the central part of the North Slope for fields in the 25-100+ million barrels range, fields that may be too small for the giant producers but fields that can be produced profitably by smaller companies like ours. We believe there are hundreds of millions if not billions of barrels of oil left on the North Slope in smaller fields of this size.

Our company is excited to report that the first exploration well AVCG will participate in with an ownership interest should have started drilling last night...the Cronus exploration well about 10 miles southwest of the Kuparuk Field, operated by Pioneer Natural Resources. We plan two exploration wells next winter and two the winter after that. With success, we will continue exploring and producing.

My comments today represent the perspectives of a small, independent exploration company. Having said this, many of you also know me as the past President of ARCO Alaska, Inc. I also served as Executive Vice-President for ARCO and head of global oil and gas exploration for ARCO. I do have exploration and production experience in over 20 countries throughout the world, so I'll also share my perspective in how I see the new production profits tax bill in the context of competitiveness in the world.

Introduction

- In my first week as President of ARCO Alaska in June, 1994, our ARCO staff reviewed state policies with me to educate me about the oil and gas industry in Alaska. One of the items they reviewed with me was the production tax and the complicated policy of ELF. Our government affairs personnel told me that ELF was in jeopardy...that the production property tax was going to be changed. That did produce uncertainty in our project economics forecast. Every year since then, production taxes and the ELF have been topics...and uncertainty remains. Sixteen years have passed since that meeting, and every year, I hear discussion about production taxes, ELF, and the imminent

threat of change. I welcome change and I say, "It's time to put the new system into effect and let's get on with it."

- Our company, AVCG, supports the proposed production tax changes provided the most important terms remain as written.
- Alaska has long been challenged to be competitive with fiscal regimes in other countries that offer competing projects; as an Alaskan, I'm excited to see the State ensure that our State's new oil tax regime is more like that in other countries...a progressive, profit sharing type structure versus a regressive, straight tax on gross revenues.
- The State will "share the gain" at high oil prices, but will likewise "share the pain" at lower oil prices...this helps small investors like AVCG/Brooks Range Petroleum limit our downside risk in the event of price collapse. And we think it is fair to share our upside profits with the State at a 20% tax rate; the State owns the land and the oil...we realize that we only lease it and we do have implied covenants to be fair with the State.
- At this point, I would like to answer three questions from my perspective: 1) Is this new production tax good or bad for industry; 2) what three things should not be changed; and 3) what three things should be changed?

Is This New Production Tax Proposal Good Or Bad For Industry?

- Both...for a small explorer startup company like AVCG LLC with about 160,000 acres under lease for oil exploration on the North Slope, the exploration economics with the proposal are favorable with an improvement in the rate of return. Near-term cash flow because of the investment tax credits is higher which improves the return on investment. But cash flow is lower a few years after new production startup as the State shares a higher share of the profits than what it currently does. We think the State taking 20% of the upside profits is fair, and we recommend the tax rate stay at 20%...the old 80/20 rule has proven to be a good one over time. Keep in mind the State will also still receive a 12.5-16.67% royalty share of all oil and gas revenues on State leases, oil and gas property taxes, corporate income taxes, and other revenues, in addition to the production profits tax.
- A key part of the bill is the investment tax credit, and AVCG plans to use that....our only area of exploration investment is Alaska and we do plan to return a large share of our future production cash flow back into exploration and development only in this state so we can grow to a sizeable company...the tax credit creates a clear incentive for us to do that rather than take the money outside.
- For a large major producer who is planning to make large capital investments on the oil side or in the gas pipeline, the bill could possibly be favorable for them as well when all is said and done.
- For any producer – large or small - who is not planning to make large capital investments but plans to send cash flow outside without a high re-investment plan in Alaska, this bill is likely not good for that type of company in Alaska.

What three things should not be changed?

- I "panicked" when I saw the profit tax reported at 25%...this takes too large a chunk of positive cash flow away from small companies - or really companies of any size - and our company sees this as cash flow that could be re-invested into new exploration prospects and new oil leases. I started warming up to the bill only when the tax rate was changed to 20%...then the AVCG economics started showing sufficient improvement in capital investment rates of return for us to attract new capital from partners or investors. When the tax rate changed from 25% to 20%, I crossed over from opposition to support of this proposal.
- It is essential to keep the 20% investment tax credit. This will help us in attracting new capital from AVCG partners or equity investors for new exploration and development. With a tax credit of 20% and re-deployment of the tax savings back into our exploration in the State, we can essentially drill an extra exploration well for each five exploration wells we currently have budgeted.
- It is essential to keep the $73,000,000/year operating cash flow "standard tax deduction" before production taxes are paid, at least for smaller producers. At a $40/bbl oil price, this equates as a production tax exemption for the first 5,000 net barrels per day to encourage new producers. As our company is risking a lot of money currently with no revenues whatsoever and with our first revenues to possibly occur only 3-4 years from now, I cannot emphasize how important having such an exemption is while we get our feet on the ground to eventual financial strength. Having said this, I do suggest, however, that this "pill might be easier swallowed" if the exemption were simply changed to read "there is an exemption for the first 5,000 net barrels of oil per day;" this certainly sounds better to the general public and is much easier to understand than saying, "there is an exemption for the first $73,000,000 of profits." This also implies that for larger companies, with say 300,000 barrels of oil production currently on the North Slope, they only get an exemption for the first 5,000 barrels per day...they still have to pay production profits tax on the other 295,000 barrels per day.

<u>What three things should be changed in the bill?</u>

- The bill allows for the investment tax credits to be sold to others in industry if a new explorer – like AVCG - does not yet have oil production revenues to use the credits. While this sounds good, in practical application these credits can only be sold to a few buyers...basically the major three oil producers who will literally set the market for these credits and the value they will receive when sold. With limited buyers, our company estimates the credits might be sold at only 70-75% on the dollar. This disadvantages new explorers...the majors get 100% of their credits while the new explorer must sell at 70-75% of value only to then see the major producers take 100% of the acquired tax credit against their production tax bill. It is suggested that the State consider establishing a pool of dollars from the production profits taxes taken in to buy the tax credits from small explorers. This makes sense...the State would not be giving up anything because the major producers would otherwise use the credits to reduce their tax bill and reduce revenue to the State....but using this approach,

the small explorer could turn around and re-invest the State-refunded credit into new leases, seismic or exploration drilling. In fact, the State might want to stipulate that if the State refunded the tax credits to a company, that company must use it for exploration or development. Our company would support such a concept. Explorers who don't want to do this option and re-invest in the State but just want the cash value of the credit could sell to the majors at 70-75% if they prefer that option.

- The section in the bill on "determination of net value of oil and gas" listed direct costs that could be deducted from gross oil revenues to calculate a profit, or "net value of oil and gas" to then be taxed at the 20% tax rate. For a new explorer in Alaska, the startup costs in the State can be very substantial, particularly for smaller players. This can include high costs for bonding, participation in the oil spill consortium Alaska Clean Seas, indemnification insurance, etc. These types of costs should be clearly mentioned in the bill as deductible.
- Again, we hope the $73,000,000 "standard tax deduction" remains. But I certainly have seen that this item is a "hot button" to certain legislators. But I urge you that while you may be angry with certain large producers, please do not loose sight of how important this could be to a startup company like ours trying to establish a foothold in Alaska and someday contribute substantial oil revenues to the State. As an alternative, however, to the $73,000,000 profits exemption, we offer that the State might choose to use an approach that the State has already approved in the 1999 "Charter for Development of the Alaskan North Slope" between the State of Alaska, BP and ARCO. In that charter, there was a section entitled "Purchases From Qualified Producers" that guaranteed that BP and ARCO (now ConocoPhillips) would agree to offer to purchase any "qualified producer's" crude oil so that new entrants or small producers would not be disadvantaged in marketing their oil. In that section there was a clear definition of a protected "small producer"...actually, the Charter called such a company a "qualified producer." I quote from the Charter: a "qualified producer" means an entity with assets of less than $1 billion (worldwide) which produces not more than 10,000 barrels of gross working interest ANS liquid hydrocarbons per day." Again, we hope the deduction provision remains in the bill. If there is opposition in the end, AVCG does hope the small companies are protected in some way; perhaps an innovation such as using the Charter guidelines may help.

That concludes my remarks. I tried to share the perspective of an independent exploration company that only invests in Alaska. I have shared the three things our company would not change in this bill and the three things we would change. All in all, I am optimistic that this bill with some tweaking could help AVCG/Brooks Range Petroleum attract new partners and new capital to Alaska, increase our exploration budget, and establish us as an important oil producer someday.

Thank you for this opportunity to make comments.

Ken Thompson

ConocoPhillips

March 3, 2006

The Honorable Ralph Samuels
Alaska House of Representatives
Alaska State Capitol, Room 126
Juneau, AK 99801-1182

The Honorable Tom Wagoner
The Alaska Senate
Alaska State Capitol, 427
Juneau, AK 99801-1182

Dear Sirs:

I wanted to thank you again for the opportunity to express ConocoPhillips' views on HB 488/SB 305. During my testimony, there was some additional information requested by the committee members. This information is provided below:

House Resources Committee

1. (Rep. Berkowitz) What are your profit numbers for the last 10 years? How much of these are from your heavy oil investments?

   Listed below are the publicly reported earnings for ConocoPhillips' operations in Alaska for the years 2000-2005 as reported in our Annual Reports. Earnings from heavy oil investments are not reported publicly. Unfortunately, ARCO did not separate out Alaska earnings data in their annual reports, so the figures for the years prior to Phillips Petroleum's acquisition of ARCO Alaska may not be disclosed.

	ConocoPhillips Alaska Operations					
	9 Months					
	2000	**2001**	**2002**	**2003**	**2004**	**2005**
Exploration and Production Earnings $MM	$700	$677	$673	$1,079	$1,665	$2,410
Other Earnings $MM (TAPS/Polar/LNG)	$129	$189	$197	$366	$167	$142
Total COP Alaska Earnings $MM	$829	$866	$870	$1,445	$1,832	$2,552

2. (Rep. Gatto) What is your public rate of return on investments for recent years (past 2 annual filings)?

   Our Annual Report does include our corporate return on capital employed (ROCE) at a corporate level. The ConocoPhillips return on capital employed in 2004 was 15.2% and in 2003, the return on capital employed was 9.8% (GAAP

ROCE). The ConocoPhillips 2005 Annual Report has not been published as of this date.

3. **(Rep. Berkowitz) What would be the decline in effective tax rate as a result of removing the Oil Spill 470 fund (AS 43.55.201)?**

   The conservation surcharge on oil has not been removed from the statute and must be paid by a producer of oil. The proposed legislation will allow this surcharge to be applied as a credit against the producer's taxes due. At a surcharge of $0.03-$0.05/bbl. this credit amounted to approximately $3.4 MM for COP in 2005 and has essentially no impact on the effective tax rate at today's prices.

4. **(Rep. Ramras) What is the depreciation mix of the $700MM (this year's capital spend)? (e.g., 5-yr, 10-yr, etc.)**

   For 2005, ConocoPhillips Alaska's reported capital expenditures were $746.2MM. A large portion of the assets have not yet been placed in service so no depreciation has occurred. Once the equipment is placed in service, it will be depreciated at IRS depreciation schedules for federal taxation purposes. The $746.2MM can be broken down into these types of assets:

   Field Life 2% Leasehold Costs
   - *Costs which are depreciated on a per unit of production basis over the life of the fields*

   7-10 Years 62% Lease and Well Equipment (L&W)
   - *Are tangible costs such as tankers, casing, tubing, wellheads, separators and producing equipment necessary to serve the well (tanks, flowlines etc)*

   5 Years 11% Intangible Drilling Costs (IDC) - Capitalized
   - *Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value*

   Immediate 25% Intangible Drilling Costs (IDC) - Expensed
   - *Costs of drilling wells such as labor, location preparation costs, rig mobilization, drilling costs, completion costs, which generally have no salvage value*

5. **(Rep. Kerttula) What would be the production tax on Fiord under the current ELF formula?**

   Fiord is expected to startup in the fourth quarter of 2006. In order to make the project economically viable, ConocoPhillips sought and obtained a letter from the Department of Revenue stating that Fiord would not be aggregated with Alpine for calculation of severance tax; hence, initial Fiord production would have an effective ELF severance rate of 0%. The ELF tax rate is currently expected to be

1.76% in 2007, and the total projected production would result in ELF production tax payments of just under $20MM over the next 10 years at today's prices. This figure, of course, does not include royalties, State corporate income taxes, state and local property taxes, the oil and gas conservation surcharge, or federal corporate income taxes attributable to the Fiord project.

6. (Rep. Samuels) What have been your abandonment expenses over the transition period?

   Abandonment expenditures are treated as expense rather than capital expenditures and thus do not result in tax credits under the proposed PPT production tax system. Our abandonment expenditures from 2001 to 2005 totaled $33.7 MM. However, none of these expenditures would be counted as capital or included in the *transitional investment expenditures* under the proposed PPT HB 488. On a go-forward basis, we do experience limited abandonment expenditures each year for activities such as plugging and abandoning old wells and some gravel removal and restoration (e.g., $12.6 MM in aggregate in 2005). However, these expenses, like our expenses for 2001 through 2005, are all anticipated to be operating costs that are not eligible for the capital credit. In addition, the bulk of the abandonment dollars would occur at the end of field life, when we expect limited, if any, production or revenue which will leave the production tax deductions associated with these expenditures with limited or no value.

Senate Resources Committee

1. (Sen. Stevens) Please break down the 2005 capital expenditures into exploration, development, and production expenditures?

   In 2005, ConocoPhillips reported capital expenditures of $746.2 MM. Approximately, 67% was associated with development activities, 13% on production maintenance activities and 2% on exploration. The remaining 18% was associated with marine, pipeline and acquisition expenditures.

If you have any questions regarding this information, you may contact me at 907-265-1650 or make arrangements through our Juneau office at 907-586-3680.

Sincerely,

Brian R. Wenzel
Vice President, Finance & Administration
ConocoPhillips Alaska

Alaska State Public Opinion Message System:

Rep Ralph Samuels's office

Filter applied is: All

Messages About

There are 14 messages about this subject

Save all messages about
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Sort messages by: District or Date or Last_Name or <Subject>

Messages

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:39 about *Oil & Gas*

Message:

Taxes before gasline contract, weird! Most of you know that Pedro vanMeurs said for Governor Murkowski in Anchorage that just because the oil companies sign a gasline contract the contract is not going to obligate the oil companies to construct a gasline.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Go to Main Menu | Go to Search Page

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:43 about *Oil & Gas*

Message:

Why are you buying a pig in a poke when you are not allowed to even see the poke let alone the pig? What harm could it do to at least see the gasline contract?

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:46 about *Oil & Gas*

Message:

The gasline contract contains provisions that allow the oil companies to just quit in 3 or 4 years after signing the gasline contract. After that they have to offer a reason like they do not think the gasline is in their best interest.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:48 about *Oil & Gas*

Message:

Do you often buy pigs in pokes for your own business when you are not even allowed to see the poke? Then why are you conducting the States business in a manner that you would not tolerate in your own business.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mc utcheon
Po Box 101838
Anchorage 99510-1838

Fairbanks Daily News-Miner

Tax credit ruling could hurt gas line negotiations
By SAM BISHOP News-Miner Washington Bureau

Friday, March 03, 2006 - WASHINGTON--The U.S. Supreme Court may rule this year on the constitutionality of a tax credit similar to the one that Gov. Frank Murkowski wants to offer oil companies for in-state investments, according to a lawyer who analyzed Murkowski's proposal for the Alaska Legislature.

If the court rejects the tax credit, it could eliminate one plank of the package with which Murkowski hopes to lure oil companies into building a pipeline to bring Alaska North Slope natural gas to market, according to Marvin Kirsner, a tax lawyer with Greenberg Traurig in Boca Raton, Fla.

Oil company executives, testifying before legislators Tuesday in Juneau, declined to say whether any changes in that package might doom the gas line.

"It's too early to draw that conclusion," said Becky Hultberg, the governor's spokeswoman, on Thursday.

The Supreme Court on Wednesday heard oral arguments in the case on which the tax credit's future may hinge.

The case began when some Ohio residents sued over tax credits their state gave DaimlerChrysler Corp. for building a Jeep assembly plant. A district court rejected the citizens' argument, but an appeals court reversed the decision.

DaimlerChrysler appealed to the nation's high court, which agreed to hear the case.

The Ohio residents say their state's tax credit violates the U.S. Constitution. The constitution gives Congress the power to regulate interstate commerce, so courts have frequently prohibited states from taking actions that might limit such commerce, Kirsner said in an interview Wednesday.

The Ohio taxpayers argue that their state's tax credit improperly burdens interstate commerce because the credits are available only to companies that spend money in Ohio.

Murkowski's proposed tax credit is similar to the Ohio credit, Kirsner said.

At Wednesday's court hearing, Justices Antonin Scalia and David Souter offered comments indicating they didn't buy the constitutional argument.

Companies are free to invest elsewhere, Souter observed. "That's not discrimination, that's free choice," he said.

Scalia said fights over whether to offer such tax credits should be decided by politicians, not judges.

Members of Ohio's delegation in the U.S. Senate and House, who are nevertheless worried about the

court challenge, filed legislation last year to give states the authority to offer such tax credits.

Nothing in the constitution prohibits Congress from extending such authority; states are on less certain legal territory if they try it themselves, Kirsner said.

That legislation may get a boost if the Supreme Court rules in favor of the Ohio taxpayers, Kirsner said, because thousands of similar tax credits are offered across the country.

"I have the feeling that Congress will have no choice," he said, if the court rejects the tax credits.

In his analysis, Kirsner suggested the state put its shoulder behind the legislation in Congress.

Murkowski's proposed tax credit would let oil companies deduct up to 20 percent of the value of any in-state investment from their taxable income in Alaska. They would also get a $73 million standard deduction for any such investment.

Hultberg, Murkowski's spokeswoman, said the administration is considering Kirsner's analysis.

"It is one issue that one consultant has raised, so we're going to look into it," she said.

State Sen. Gene Therriault, R-North Pole, said he had discussed the issue with oil company representatives. They were aware of the Supreme Court case but did not express any serious concern about it, Therriault said Wednesday.

Washington, D.C., reporter Sam Bishop can be reached at (202) 662-8721 or sbishop@newsminer.com . The Associated Press contributed to this article.

Alaska's Proposed Production Tax

"PPT 20/20%"

SB 305/HB 488

Issues for Discussion and Further Research

Daniel Johnston

Juneau, Alaska
6 March, 2006

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Daniel Johnston & Co., Inc. — Founded in 1985

Services include:

Consulting – (Similar to this work)
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  - **Supreme Court – India**
  - **International Court of Justice**
  - **High Court – Wellington, New Zealand**
  - **Brussels, London, USA, etc**

In the past 15 years my work has been fairly equally divided between oil companies and governments. Further information is provided at the end of this report.

Mineral resources are a gift from God

I dedicate this work to the current and future generations of Alaskans and to my family.

May God bless us all.

Daniel Johnston
6 March, 2006

PPT 20/20% Analysis and Discussion

My mandate:

Analysis, Research, Discussion, Recommendations

Help design a Fair System

Nobody Wants a Punitive Arrangement.

Future Generations will ask:

(1) Did we design the system right with the best information, tools, and resources available to us?

(2) Did we negotiate effectively and from a position of strength? If not did we do the best we could with what we had?

(3) Did we manage to strengthen or undermine the bargaining position for future generations?

Remember, the whole world is watching and we will continue to be observed and judged for years to come.

Warning:

Before we go further I must point out that I have had barely one month to address and/or prepare for many of these complex issues, the situation, the proposal, the SB 305/HB 488 Bills, and all that goes with it (travel, meetings, hearings, analysis and everything). I need more time.

I cannot claim to have exercised due diligence on a variety of matters in the little time I have had so far — there is too much at stake. More work must be done.

I do believe that even this preliminary assessment of the proposed tax regime (PPT 20/20%) can help facilitate discussion and foster an understanding of the key issues and concerns. This report is provided in conjunction with my testimony on 6 March, 2006. The appropriate context for any statements here must include my oral testimony.

I have never submitted a such a large and complex document to the kind of scrutiny I expect this one to undergo with so little time, under such pressure, and with so much at stake.

The testimony from various oil companies occupied an immense amount of time while I was preparing this report but I believe I was obligated to observe those hearings. Much of that testimony was helpful to me. Responding to some of the remarks I believe is mandatory and is included in this preliminary analysis.

I appreciate the assistance from personnel with the Legislature and the Administration particularly Dr. van Meurs and Dr. Roger Marks, and the Econ One consultants. I appreciate that no one has pressured me to lean one way or the other – this is important.

This report should be viewed as a preliminary indication of things I intend to address in detail when I have had sufficient time to finalize my research and review the results of economic modeling that is being performed as I write this report.

I reserve the right to correct, amend, change and/or add to this preliminary report.

Daniel Johnston
6 March, 2006

CONCLUSIONS

1. **Alaska has every right to change the system.**
   - a) Alaska is not the only region considering or making changes these days.
   - b) Alaska may have more justification to change than most:
     - (1) Because of the ordinary regressive effect of the royalty,
     - (2) the ordinary regressive effect of a severance tax,
     - (3) the inefficiencies of ELF's field production rate element
     - (4) the inefficiencies of ELF's daily well production rate element

2. **The new system should increase revenues to the State of Alaska <u>and</u> enhance exploration activity.**
   - a) These sound like mutually exclusive objectives. Not necessarily.
   - b) Increasing taxes on existing production is relatively inelastic.
   - c) Incentives like those proposed (credits) can work well for exploration.

3. **The new system should be a well designed <u>modern</u> system.**
   - a) PPT 20/20% would just bring Alaska up to the end of the last century.
   - b) The system should be flexible, progressive, simple, and transparent.

4. **Trying to craft one system to fit all situations here may be impossible.**
   - a) Like trying to design a saddle for your horse that must also fit your dog.
   - b) Exploration is extremely different than production from existing fields.
   - c) With the Legacy Fields like Prudhoe Bay there is little margin for error. Getting it wrong by even 1 or 2 percentage points of Government Take will be measured in the hundreds of millions of dollars.
   - d) Margin for error with exploration terms is not nearly as critical.

5. **The Producers want "fiscal certainty".**
   - a) For the pipeline I don't blame them and it may simply be required. But Alaska must be extremely careful - it is not a simple matter.
   - b) For the oil tax law I don't blame them – but it is not as critical. Companies operate regularly with much less certainty than is being demanded.
   - c) For everything to be "linked" — does Alaska want to be the pioneer on this risky and extremely unusual proposal? Its an issue of sovereignty.

6. **Much of the debate here regarding oil revolves around Government Take. With the gas pipeline project a Government Take statistic is much less meaningful. The time will come to address this issue and it is critical.**

7. **Crafting language to avoid "leakage" deserves appropriate terms on the front end — get the deal right.**

8. **There are several issues of critical importance that I have not had time yet to address in a way they deserve. These include:**

   a) **Relinquishment provisions. In Alaska companies have the right to hold acreage in ways that would astonish most other countries. It has placed Alaska in a difficult position—an issue of sovereignty.**
   b) **Abandonment provisions (site restoration, cleanup, dismantlement) need work. Big difference between existing and future facilities.**
   c) **The proposed "Linkage" with the gas pipeline deal is extremely disconcerting. The risks associated with this unique situation are immense.**

Other perspectives on ELF:

Alignment of Interests – not good. We know that.

First of all the tax is based on production not profits (i.e. regressive)

Reference:

The Indonesian Story: the DMO Holiday! Separate field status
(Definition of a Field)

The California Story: the Cunningham Field story
(Production per well)

The State lost in 2 ways: lower royalty AND lower taxes

If the system is going to be changed then: what criteria?

The system must be progressive

There must be a fair division of profits

There must be no unhealthy dis-incentives

Hopefully, the new system will be simple and transparent

One critical issue centers on whether or not raising (or lowering) taxes has an effect on investment activity in the petroleum sector.

Every Country is Unique — Is Alaska More Unique?

Boundary Conditions

- **Land-locked – High Transportation costs**
- **Arctic – high cost**
- **Field size distribution expectations relative to Arctic conditions**

Concerns

- **Need for fiscal certainty for Gas Pipeline (?)**
- **Issues of sovereignty**

Objectives

- **Fix Elf – Obtain a fair share of profits – Nothing punitive**
- **Craft a "modern" state-of-the-art system**
- **Magnify exploration activity**

Policy

- **Provide fiscal certainty?**
- **Take greater risk?**

Strategy

- **Reduce exploration risk exposure for oil companies**
- **Craft a progressive tax**

Tactics

- **Allocation mechanisms**

Fiscal System Analysis and Design – Things to Consider

This table is relatively self-explanatory but notice that Government Take has a broad context within which it fits as far as Contract Terms (using the term broadly) are concerned. When evaluating Alaska's position with respect to other elements it stacks up fairly well. This area/discussion deserves further examination.

The Balance Sheet

Prospectivity	Contract Terms
? Expected Field Size Distributions	? Type of System
? Petrophysical characteristics	PSC, Service Agreement, Royalty/Tax System
Porosity, Permeability, Saturations, etc	? Signature Bonus
Stratigraphy, Age, Depths, Thicknesses	? Work Program Seismic + Drilling
? Well Deliverability	$, Timing, Relinquishment, Guarantees
? Estimated Success Probability	? Royalty
Source, Seal, Reservoir, Migration, etc	? Cost Recovery Limit
? Oil vs Gas – Fluid Properties	? Effective Royalty Rate
API Gravity, Wax, H_2S etc	? Government Take
? Data Quality and Quantity	? Government Participation
? Exploration Drilling Costs	? Entitlement
? Post Discovery Costs	? Cost Savings Index
Development Drilling	? Ringfencing
Production Facilities	? "Crypto" Taxes
Transportation Costs	? Other (Lots of strange things)
Operating Costs	? Contract Stability
? Water Depth and Climate	? Allocation System
? Political Risk	

From: Johnston Course Materials.

Choosing the Appropriate Peer Group

Every mention of the UK in this debate mentions a Government Take of 50%.

Perhaps a better comparison for Prudhoe Bay would be the Brent or Forties Oil Fields. These fields pay a 50% Petroleum Revenue Tax (PRT) in addition to the 50% Corporate Tax, i.e. they have a Government Take or Effective Tax Rate of 75%.

Why has nobody mentioned the 75% Government Take in the UK?

As far as the choice of peer group is concerned, there is much work needed. Picking a peer group for Alaskan exploration (future) is one thing. Picking a peer group that fits both exploration and the Legacy Fields is quite another matter. I agonize over this.

The <u>problem</u> of "HOW" to calculate Government Take regardless of the peer group is quite another matter. And it is a huge issue.

Will increasing tax rates reduce investment in Alaska?

I believe there is strong evidence that producing activities are relatively unaffected by changes in tax rates unless they are dramatic.

The issue of industry response to changes in tax rate was addressed by BP (discussed in the following pages).

Do credits work?

I believe that "incentives" like the "credits" proposed can work quite well. I have experienced it.

In fact my inclination at this time is that we could enhance credits for exploration — still looking into that but supporting information is being generated and some follows.

The information that follows is preliminary. Gathering this information was prompted by remarks by the Producers and struck me as odd and inconsistent with my experience. I have had less than 5 very busy days to respond to this BUT it is critical. Alaskans don't want to lose jobs.

The producers say that a dramatic reduction in Government Take spurred investment activity in the UK in 1993. I disagree. There should be sufficient information to make an informed opinion even though my historical expenditure and drilling data comes from graphs (UKOOC) that had to be "reduced". Further work is required here. See below:

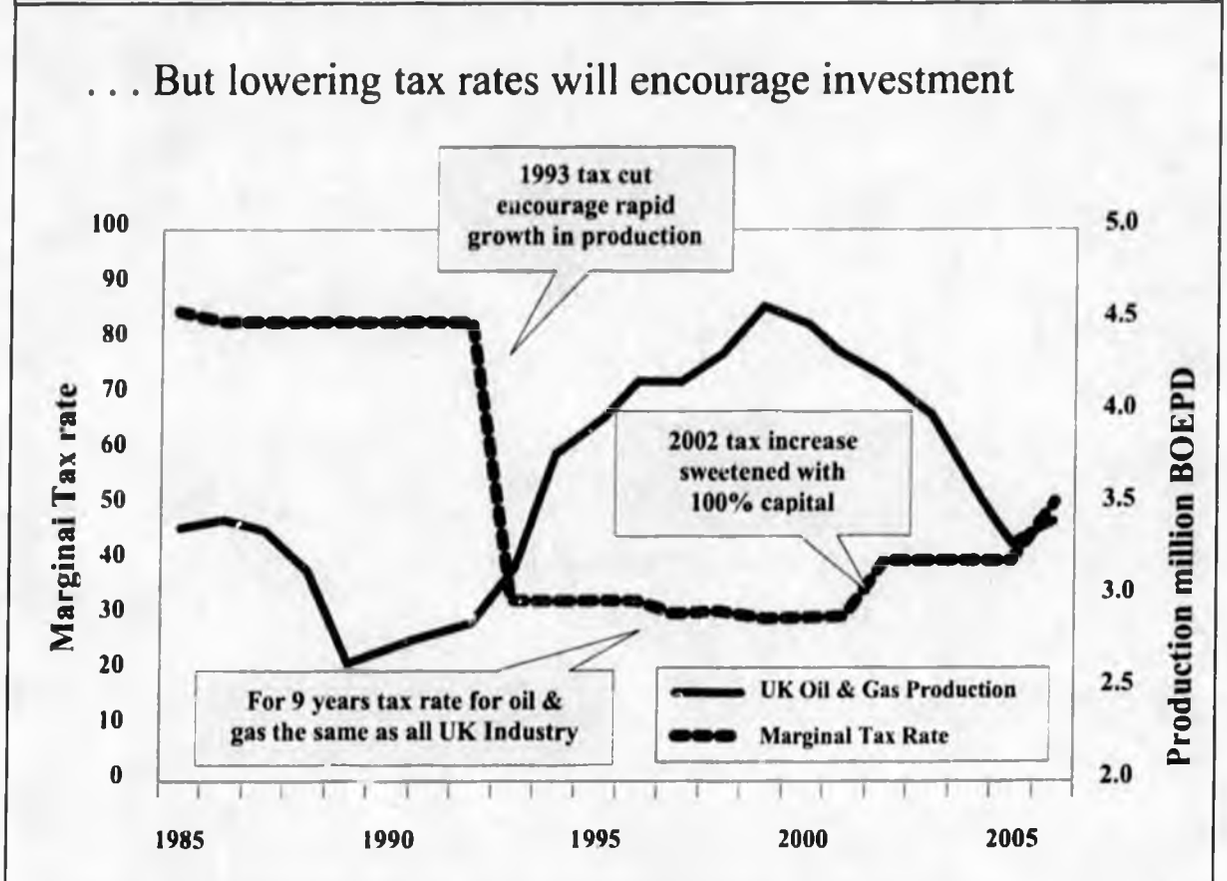
BP Graph of Production vs. Tax Rate

The graph below is not a fair representation of what the result of lowering the tax rate in 1993 was. In fact exploration expenditures went down significantly in 1994 and development expenditures did not go up (see following page). They went down but not as dramatically as exploration expenditures.

I think every Alaskan should consider this carefully and compare it to the data on the following page.

I experienced the "boom" in the mid-1980s in the UK sector of the North Sea that resulted from incentives provided that were very similar to the "credits" proposed here in Alaska. The increase in production was the result of exploration that occurred years before the 1993 reduction in taxes as one would expect. I do not see how it could be possible for industry to gear up and respond as quickly as this graph would suggest.

Please consider my work on the following page with caution. I had very little time to respond to this graph on such short notice with the busy schedule here in Juneau. With a bit more work we can verify — it is so important.



Source: BP presentation to Alaska Legislature 28 February, 2006 (page 8)

UK Petroleum Taxation History

					Marginal Take		Brent	Annual (£MM)	
					Old	New	Price	Expenditures (1)	
Year	Royalty	SPD	PRT	CT	Fields	Fields	$/BBL	Expl.	Dev.
1974	12.5%			52%	58%	58%		1,625	3,625
1975	12.5		45	52	76.9	76.9		1,750	6,813
1976	12.5		45	52	76.9	76.9		1,375	8,875
1977	12.5		45	52	76.9	76.9		1,500	7,750
1978	12.5		45	52	76.9	76.9		1,000	7,375
1979	12.5		60	52	83.2	83.2		750	6,750
1980	12.5		70	52	87.4	87.4		1,063	6,688
1981	12.5	20	70	52	90.3	90.3		1,375	6,875
1982	12.5	20	75	52	91.9	91.9		2,000	6,688
1983			75	50	87.5	87.5		2,125	6,250 Ring fence dropped in
1984			75	45	86.3	86.3		2,875	6,375 1980s for the PRT. When?
1985			75	40	85.0	85.0	28.43	2,813	5,500
1986			75	35	83.8	83.8	14.44	2,000	4,563 Price Crash
1987			75	35	83.8	83.8	18.42	1,438	3,688
1988			75	35	83.8	83.8	14.88	1,938	3,750 Piper Alpha Disaster (2)
1989			75	35	83.8	83.8	18.21	1,875	3,500
1990			75	35	83.8	83.8	23.79	2,375	4,125
1991			75	34	83.5	83.5	20.06	2,750	6,125
1992			75	33	83.3	83.3	19.31	2,000	6,250
1993			50*	33	66.5	33	17.04	1,625	5,063 Tax Rate Drops
1994			50*	33	66.5	33	15.87	1,188	4,750
1995			50*	33	66.5	33	17.00	1,375	5,500
1996			50*	33	66.5	33	20.61	1,313	5,313
1997			50*	33	66.5	33	19.19	1,438	5,063
1998			50*	33	66.5	33	12.84	875	5,938 Price Crash
1999			50*	31	65.5	31	17.83	500	5,563
2000			50*	31	65.5	31	28.55	375	3,125
2001			50*	30	65.0	30	24.43	438	3,875
2002			50*	40	70.0	40	24.86	375	3,875
2003			50*	40	70.0	40	28.79	313	3,563
2004			50*	40	70.0	40	38.30	344	3,188
2005			50*	50	75.0	50	53.73		

* New fields receiving development approval after 16 March 1993 exempt from PRT. Also, these take statistics ignore the effect of "uplifts" on the PRT.

SPD = Supplementary Petroleum Duty
PRT = Petroleum Revenue Tax
CT = Corporate Tax

(1) Derived from UKOOC graph – it was all I had at the moment. If anybody has the correct information I would appreciate it.

(2) Industry spent an extra £5 Billion for new safety equipment in the UK North Sea I have subtracted £1,000 Million per year for the 5 years following the disaster (my estimate)

The actual investment activity contradicts the theme that production after 1993 was strongly influenced by the tax reduction. Notice, there was a "boom" in the 1980s.

UK Drilling Activity History — Wells Drilled per year

This data was "reduced" from a graph from another UKOOC document and generated at 1:AM March 6, 2006. It begs verification and "real data" but I believe it confirms the fallacy of the claim that the reduction of Government take from around 85% to 33% enhanced investment activity in the UK in 1993.

More work needs to be done but it is clear to me that something is wrong with the conclusions drawn by BP regarding the 1993 fiscal event.

Year	Exploration	Appraisal	Development	Total
1974	67	33	19	119
1975	81	38	19	138
1976	58	28	52	138
1977	67	39	92	198
1978	38	25	92	155
1979	34	16	97	147
1980	31	22	117	170
1982	48	27	131	206
1983	69	44	111	223
1981	78	52	92	222
1984	108	78	102	288
1985	94	66	128	288
1986	73	41	81	195
1987	70	64	123	258
1988	94	86	159	339
1989	95	91	150	336
1990	163	66	122	350
1991	108	81	142	331
1992	75	58	161	294
1993	52	59	158	269
1994	63	38	197	297
1995	61	38	239	338
1996	72	41	256	369
1997	63	34	253	350
1998	47	33	272	352
1999	16	19	222	256
2000	27	33	213	272
2001	25	36	275	336
2002	16	31	258	305

Risk vs. Reward and the PPT Credit plan (Careful: more work needed here)

One critical aspect of the PPT is the fact that it was designed in part to encourage exploration by providing Credits and allowing companies to sell (or trade) them and any Tax Loss Carry Forwards. This aspect should be particularly appealing to explorers. It reduces their risk. But by reducing exploration risk the State takes on added risk. Consistent with basic onomic theory and extremely common industry rhetoric there should be commensurate potential for reward or a greater share of the "upside" for the State if it takes on added risk. As proposed the PPT places greater risk on the State without compensation on the reward side of the equation.

Examples of situations where countries exposed themselves on the "risk side" of the equation. Below I show for every dollar ($1.00) of exploration capital how much each party was exposed to:

	Company Exposure	Gvt. Exposure	Gvt. Take	
Indonesia Grass-roots oil **Exploration**	**$1.00**	**0¢**	**N/A**	Standard contract for
Indonesia Second-stage oil **Exploration**	**15¢**	**85¢**	**85%**	Standard contract for
Norway Grass-roots Exploration	**22¢**	**78¢**	**78%**	**Fairly new** (circa 2004)
UK (Circa mid-1980s) **Grass-roots** (1) **Exploration**	**25¢**	**?**	**85%**	Company exposure may have been less than 25¢ on the dollar
Canada	**20¢**	**?**	**?**	**PIP Grants** (2) (circa 1980±)
Alaska PPT 20/20% Without $73 MM Allowance	**39¢**	**AK & Fed**	**Depends**	

These things can work quite well. Another example might be the credits for coal-bed methane in the lower 48 in the mid 1990s (as I recall). Worth further examination.

Summary of Key Fiscal Elements of PPT 20/20%

The 5 Main Components of PPT (*Translated* from Robynn Wilson presentation 22 Feb., 2006)

(I am going to try and cast this in "my" words)

(1)	**PPT Rate**	**20%**
	PPT Base	**Company Cash Flow**
(2)	**Tax Credit Rate**	**20%**
	Tax Credit Base	**Capital Expenditures**
(3)	**TLCF or Net Operating Loss**	

"Negative Cash flow can also be converted in(to) a tax credit by taking the 20% tax value of these yearly losses." (PVM 26 Jan., 2006)

"A loss in any year can be converted in a tax credit by taking the 25% tax value. Therefore, in total, a credit of 45% can be obtained for new investments in Alaska." (PVM 14 Feb., 2006)

This language confused me a bit at first but if this thing wasn't "tradeable" it would behave just like a typical tax deduction – nothing cruel and unusual about it. If for example Alaska simply added a 20% tax without the credits, costs would be deductible and ultimately the State would pay for 20% because of the tax deductibility of the costs. It is called a "credit", I believe, because of the ability to "trade" it. It behaves though, like an ordinary deduction.

(4)	**Base Allowance Rate**	**$73 MM Deduction ("Standard Deduction")**
	Base Allowance Base	**Same as PPT base "deductible" for PPT calculation purposes**
(5)	**Transition Provision**	**Past Capital Expenditures from July 2001 to June 2006 to be amortized over 6 years (72 months)**

Summary of Key Fiscal Elements of PPT 20/20%

The proposed structure shifts some of the risk from the industry to the State of Alaska. Furthermore the "shift" is multi-dimensional:

(1) By shifting the tax base from "net production" to "profits"
(2) By providing a "liberal" definition of "profit" i.e. no depreciation
(3) By applying a 20% credit on capital expenditures (exploration AND development)
(4) By allowing credits to be traded
(5) By allowing TLCFs to be traded
(6) By providing the $73 MM "allowance"
(7) An added virtue of many of these elements is: There is no ringfence!

The question is: "If the State of Alaska is taking on more risk will it see more potential "upside" as is so common in the industry.

What do I think about the $73 MM Allowance?

(1) It is the most difficult and awkward of all.

(2) If Alaska simply MUST (for some legal or political reason) design a "one-size-fits-all" system then what are ya gonna do?

It is like designing one saddle that has to work on every farm animal on the farm.

Either this or something like it is required to distinguish legacy production at Prudhoe Bay and Kuparuk from frontier exploration.

What do I think about the "Lookback" provision?

(1) This provision is difficult for me but it does have some basis in economic logic.

(2) From a "fairness" point of view there is support.

However this same logic (fairness) provokes the question of whether or not a lookback should be provided to the Alaskans who have certainly lost because of ELF.

It is an important issue and deserves further consideration, more than I have given it so far.

This table illustrates the hierarchy of arithmetic one would expect in any given accounting period but is based on "full cycle" revenues and costs over the life of a field. It shows here that while the official PPT tax rate is 20% the actual rate is 7%. The "Tidewater Approach" treats transportation costs like a "tax" which places Alaska exploration on a more equal footing with other regions.

The "assumptions" used in this flow diagram are for illustration purposes only – not meant to be representative of my opinion about prices or costs.

PPT 20/20% System

20 MMBBLS of Oil at $50/BBL ANS West Coast Price

Oil Company Share		Alaska and Federal Gvt. Share
	$1,000 MM Gross Revenues	
	- 100 Taps $3/BBL + Shipping $2/BBL	
	$900 Gross Revenues at Wellhead	
	- 113 Royalty 12.5%	→ $113 Royalty
	$787	
$400 ← Assumed Costs ($10/BBL Capex + $10/BBL Opex)	Deductions	→ $10 AK Property Tax ($0.50/BBL)
	$377 Company Cash Flow	
	- 73 Allowance	
	$304 PPT Tax Base	
	- 61 20% PPT (before credit)	
	+ 40 Credit	
	- 21	→ $21 Net PPT (Note: effectively 7%)
	$356 Company pre-Fed Tax Cash Flow ($377-21)	($21/377)
$210 ←	- 146 41% Fed + AK Tax	→ $146
	$210 Co. after-tax C/F	
$610	Division of Gross Revenues	$290
42% [$210/(1,000 – 100 – 400)]	Take	58% [$290/(1,000 – 100 – 400)]
35% [$210/(1,000 – 400)]	Take "Tidewater Approach"	65% [($290 + 100)/(1,000 – 400)]

The credit system qualifies for a 20% credit on the capital expenditure. I assume $200 MM Capex out of the $400 MM.

(Credit = .20 * $200 = $40)

Note: The "lookback" element is not included.

Also: All $ figures are in Millions except per-barrel (BBL) figures.

Example Take Calculations — Regressiveness and Marginal Take

This exercise is used to illustrate two key points: First, why royalties are regressive, and second; the logic behind a "Marginal Take" statistic. "Marginal Take" or Marginal Government Take is typically not exactly the same as ordinary "Government Take". I believe the BP representatives use this statistic in this way. So we are not all exactly speaking the same language. We need to work on that.

A simple royalty/tax system with a 15% royalty and a 50% tax is used to illustrate this. Notice when oil prices increase from $20.00/BBL to $60.00/BBL (going from A to B) everybody makes more money BUT the government share of profits (Take) goes down. Example C examines separately what happens "at the margin" it focuses on just the "windfall" profits i.e. the difference between $20.00/BBL and $60.00/BBL.

Government Take

Example: Effect of Price Increase and "Windfall of $40/BBL"

A	B	C	
		"Windfall"	
Gvt. Take	Gvt. Take	Marginal Take	
$20.00	$60.00	$40.00	Gross Revenues
3.00	9.00	6.00	15% Royalty
17.00	51.00	34.00	Net (Revenues)
- 8.00	- 8.00	- 0.00	Operating + Capital Costs
9.00	43.00	34.00	Taxable Income
- 4.50	-21.50	17.00	Taxes 50%
4.50	21.50	17.00	Contractor Cash Flow
38%	41%	43%	Contractor Take
63%	59%	58%	Government Take

Variations on Government Take Calculation

This exercise is used to illustrate that there is added dimension to the problem mentioned in the previous graph i.e. there are more problems than just the difference between "Marginal Take" and ordinary "Government Take".

This time a royalty/tax system with a 15% royalty and a 50% tax is used but the system also has a 30% Government Participation element. The Wood Mackenzie report that ConocoPhillips referenced does not include the effects of Government Participation.

This is very important. The reason is because PPT 20/20% has many of the characteristics of Government Participation. In fact from an oil company point of view PPT 20/20% has many of the beneficial aspects of Government Participation without many of the painful aspects.

Government Takes

WoodMac ConocoPh Gvt. Take	Johnston Gvt. Take	BP Marginal Take	
$40.00	$40.00	$40.00	Gross Revenues
- 6.00	- 6.00	- 6.00	15% Royalty
34.00	34.00	34.00	Net (Revenues)
- 8.00	- 8.00	- 0.00	Operating + Capital Costs
26.00	26.00	34.00	Taxable Income
- 13.00	- 13.00	- 13.00	Taxes 50%
13.00	13.00	21.00	Contractor Group Cash Flow
- .00	- 3.90	- 6.30	Government 30% Participation
13.00	12.10	14.70	Taxable Income
40.6%	37.8%	36.75%	Contractor Take

Wood Mackenzie treatment of Government Participation

Global Oil & Gas Risks & Rewards — Wood Mackenzie – Nov. 2004

GOGRR Methodology Full Cycle Costs & Economics
(From page 9, "Tab" #9 "Methodology")

> In calculating the Government Take, we have included all elements of the fiscal regime, such as royalty, income tax, PSC profit shares and additional profits taxes. We have not, however, included any cash flow that would be derived by the government (or NOC) having an equity interest in a field.

Emphasis added. No explanation is given as to why this element is excluded.

PSC = Production Sharing Contract
NOC = National Oil Company

Administration and Dr. van Meurs treatment of Government Take

From the Administration's "Proposal for a Profit Based Production Tax for Alaska" February 14, 2006, Dr. Pedro van Meurs (page 103)

6.2.8 Azerbaijan

"The national oil company SOCAR participates for 20% in the venture, but this is almost on a "straight up" basis and therefore this participation is not included in the government take."

I agree with this approach because of the fact that SOCAR "pays its way" from day-one i.e. as Dr. van Meurs points out "straight up" (kind of like Norway) or sometimes we call it "heads up".

However, most of the time Government Participation is not "heads up" yet Wood Mackenzie excludes all forms of Government Participation.

If Government Participation were so painless as to ignore it in the Government Take calculations then why do oil companies hate it so?

The implications are huge.

Take Calculations With & Without Factoring-in Participation

Without factoring-in the Government Participation element the universe of fiscal terms is distorted by around 5 percentage points Government Take. Alaska looks "worse" than it should if this element is excluded.

The example below shows for a "world average" system with government participation of 13.5% (which should be close to World Average for all systems) how different the Take statistics look regarding this issue of Government Participation.

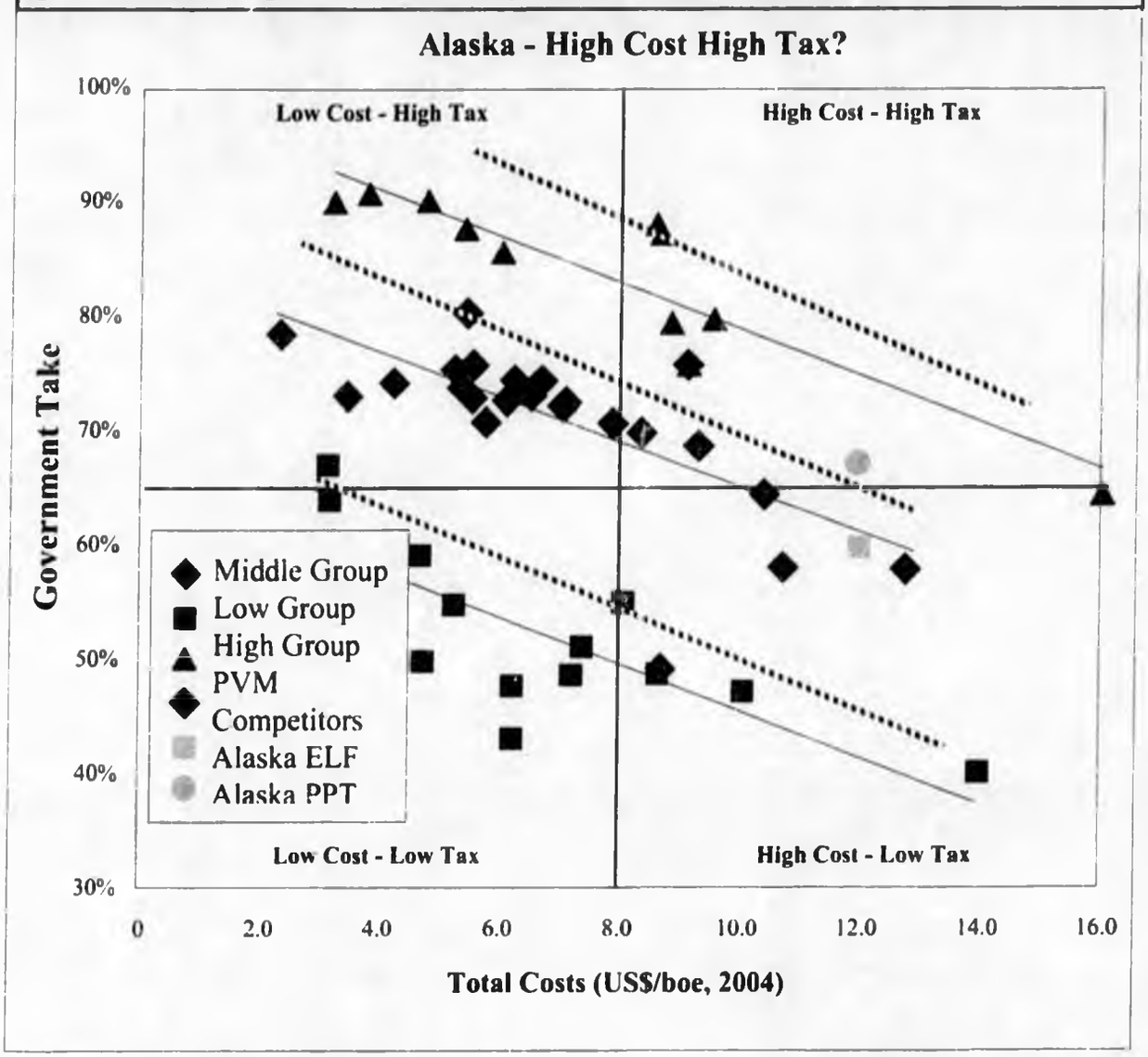
This is important because at $40.00/BBL oil price and $10.00/BBL costs with say 800,000 BOPD of production profits are $24 MM/day or $8.76 Billion per year. Just a 1% point difference in government take can represent around $87 MM per year. We must be extremely careful with our choice of a peer group, particularly for the legacy assets at Prudhoe Bay and Kuparuk.

World Average Government Takes
With and Without Government Participation

Gvt. Take With	Gvt. Take Without	With or Without factoring-in Gvt. Participation
$40.00	$40.00	Gross Revenues $/BBL
- 2.80	- 2.80	7% Royalty
37.20	37.20	Net (Revenues)
- 12.00	- 12.00	Operating + Capital Costs (30% of Gross Revenues)
25.20	25.20	Profits
- 13.90	- 13.90	Profits-based Levies 55% (Taxes and Production Sharing)
11.30	11.30	Contractor Group Cash Flow
- 1.53	- 0	Government 13.5% Participation
9.77	11.30	Cash Flow
35%	40%	Company Take

ConocoPhillips Government Take, Cost, and Tax Graph

I had a little difficulty re-creating the graph (from the ConocoPhilips presentation Feb 27, pg 19) based on the Wood Mackenzie 2004 "Global Oil and Gas Risk and Reward Study". It uses Government Take statistics that do not include "Government participation". The red dashed lines which I have added show (somewhat) how the "trend lines" might look if this element was included. This requires further consideration I am just trying to show what to expect. The real work has not been done yet. However factoring in Government Participation should make a difference of about 5 percentage points of Government take. Notice they are not parallel to the original lines in the report – much depends on costs and prices etc. And typically the governments with high take are more likely to have a participation option.



These lines represent what the picture might look like had the Wood Mackenzie report referenced by ConocoPhillips had included "Government Participation"

Government Participation (from my course materials)

Many systems provide an option for the national oil company to participate in development projects. Under most government participation arrangements, the contractor bears the cost and risk of exploration and if there is a discovery the government backs-in for a percentage. In other words the government is *carried through exploration*. This is fairly common and automatically assumed whenever some percentage of government participation is quoted.

Technically the government through the NOC is carried through "commerciality". Commerciality is usually downstream by a well or two from the actual discovery well. The contract clause that deals with the requirement for delineation/appraisal wells following a discovery is referred to as the "commerciality clause". The government agent usually the NOC must decide whether to exercise their right to "back-in" after the discovery has been appraised—the "commerciality point".

Over 40% of the counties have the option to back-in at the point of commerciality.

The key aspects of government participation are:

- What percentage participation? (Most range from 10% to 51%) (Average is around 30%)
- When does the government back in? (Usually at commerciality)
- How much participation in management? (Large range)
- What costs will the government bear? (Usually their pro rata share of costs)
- How does government fund its share of costs? (Often out of up to a certain % of Government's share of production)
- Does government reimburse its share of "Past Costs"? (Half do – half don't)

The financial effect of a government partner is similar to that of any working interest partner with a few *large* exceptions. First, the government is usually *carried* through the exploration phase and may or may not reimburse the contractor for past exploration costs. Second, the government contribution to capital and operating costs is normally paid out of production. Finally, the government is seldom a silent partner.

In Colombia the government has the right to take up to 50% working interest and will reimburse the contractor up to 50% of any *successful* exploratory wells. In China the government participation is 51%. This usually defines the upper limit of direct government involvement.

Contractors prefer no government participation. This is not totally selfish, but stems from a desire for efficiency as well as economy. Joint operations of any sort, especially between diverse cultures can have a negative impact on operational efficiency. This is particularly true when the interests of government and an oil company can be so polarized.

Government participation analysis controversy

One of the more controversial aspects of fiscal system analysis is the treatment of the government participation or the back-in option. Some analysts believe it is not appropriate to view this element of a system as a rent extraction mechanism. The argument goes like this:

> **Government take as a result of equity participation by government is really a government equity return, directly paid for by government, rather than a form of government take. Hence, comparing government take statistics by excluding government equity participation is probably a more accurate representation of levels of take.**

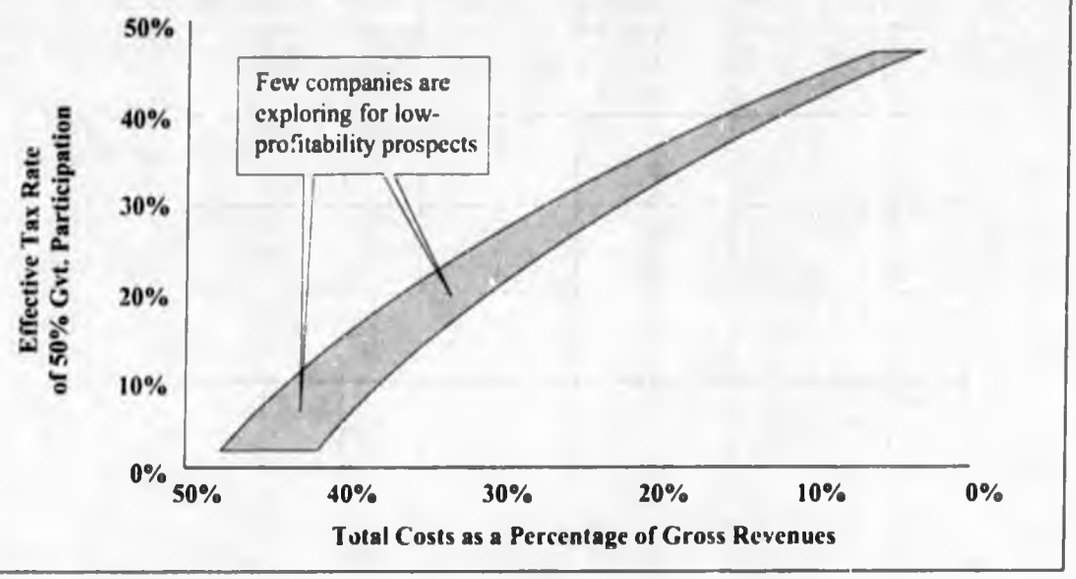
Following this logic, the government take calculation for the Libyan licenses would ignore much of the government production share – the 50% for which it pays its way on development and operating costs. This would yield a government take of only around 50% - very good terms indeed, but misleading.

Conceptually, there is certainly a difference between say a 50% profits-based tax and a government back-in option of 50%—both of which will guarantee the government an added 50% share of profits. An oil company would happily avoid both. From a purely financial point of view, companies will certainly prefer 50% government participation to a 50% tax because, with participation, after the NOC backs-in, it "pays its way". Just how different the financial impact is between a 50% tax and a 50% back-in depends on profitability. As profitability increases the back-in or participation element takes on more of the characteristics of a pure tax or a royalty depending on the point at which the government takes its share of production. While it is conceptually a bit abstract, as costs relative to gross revenues approach zero (the ultimate in profitability) the back-in begins to take on all of the characteristics of a tax, or in the case of EPSA IV, a royalty. Thus, the less profitable a venture is, the less painful the government participation element is. Either way though, both taxes and/or participation options cause the contractor financial pain to various degrees. Comparing two fiscal systems on the basis of government take alone then is not a perfect comparison if one system has participation and the other does not. This highlights one of the key weaknesses of government take statistics. However, to simply ignore the participation element would also be a misrepresentation. When comparing fiscal terms for exploration rights it is not appropriate to exclude or ignore the participation element as the argument above suggests.

From: "Impressive Libya licensing round contained tough terms, no surprises", Daniel Johnston, Oil & Gas Journal, April 18, 2005, pp. 29-37.

Government Participation "Painometer"

This graph shows that the relative financial pain caused by typical Government Participation (the "back-in") depends upon profitability [measured here in terms of Total Costs (Capex and Opex) divided by Gross Revenues]. For example when costs as a percentage of gross revenues are 20% a tax of 33% would have reduced contractor NPV (discounted 12.5%) by the same amount as a 50% Government Participation.



From: David Johnston speech, Libreville, Gabon January, 2006

Explanation of "Total Costs as a Percentage of Gross Revenues":

(1) Assume Oil prices are expected to average $50.00/BBL

(2) Capex and Opex are expected to average $4.00/BBL each = $8.00/BBL total

(3) Therefore total Costs as a Percentage of Gross Revenues = 16% ($8.00/$50.00)

This metric by-the-way, accommodates simultaneously both variations in price as well as cost.

Total Costs as a Percentage of Gross Revenues during the 1980s and 1990s average around 30 to 40% so from this perspective costs are about half what they were before.

Efficiency and Flexibility in Fiscal System Design

When I talk about a "Progressive System" I am talking about efficiency and flexibility. It goes to the heart of taxation theory and the issue of fairness.

The guiding lights of fiscal system design are: Efficiency and Flexibility. These elements are not mutually exclusive.
Theoretically, an efficient, flexible contract is a more stable contract.

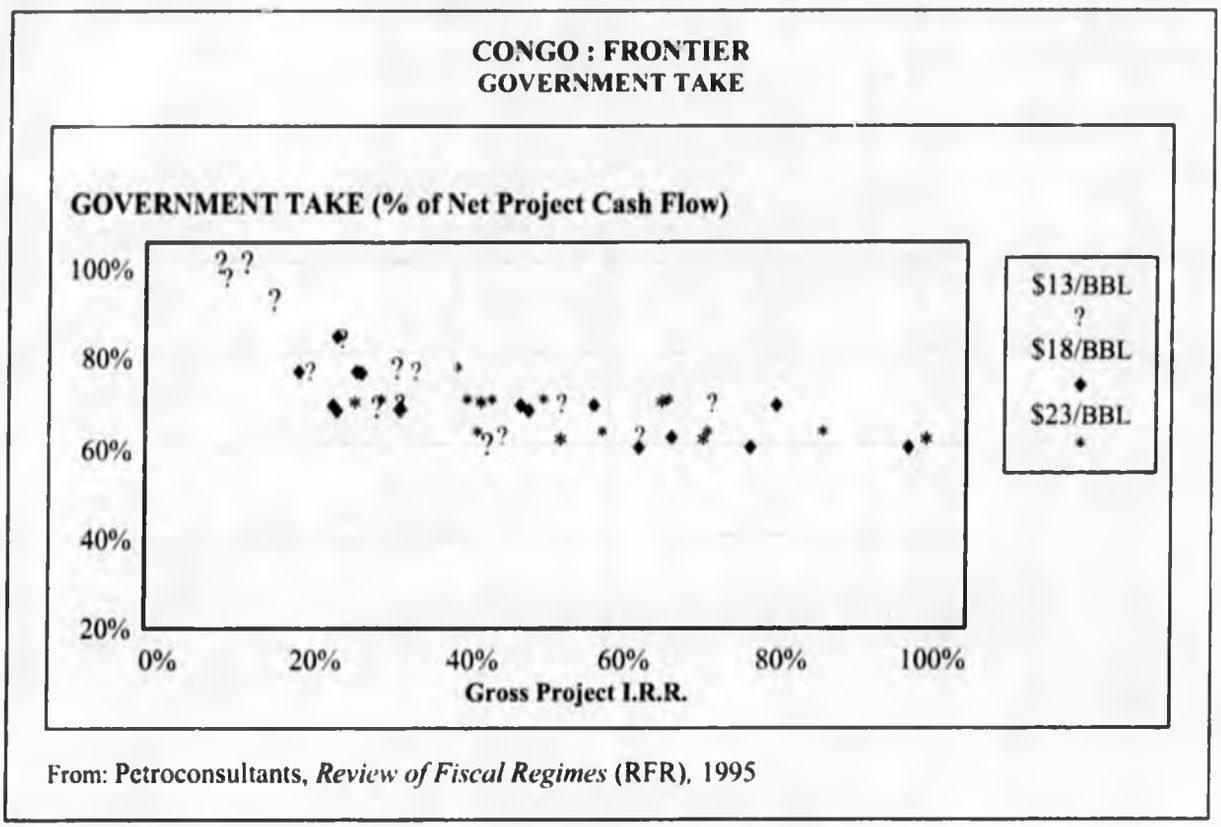


From: "International Petroleum Fiscal Systems and Production Sharing Contracts" Course Workbook, Johnston 2005, (pg 13)

Typical Regressive System & the Regressive Signature

This graph shows a typical "regressive signature" characteristic of most petroleum fiscal systems today. As profitability goes up, Government Take goes down. (However, most countries are re-thinking their position just like Alaska is.) The regressiveness is magnified when time-value-of-money is factored-in. Approximately 70% of the systems worldwide exhibit this kind and degree of aggressiveness. Today most countries like this one wish they had a progressive system. In the late 1990s around 65% of the countries were regressive.

Typically a company like Petroconsultants (below) would run economics (cash flow analysis) on 5 different field sizes, three different cost scenarios (high, average, low) and 3 different price scenarios (below). The resulting take statistics of these 45 permutations would be plotted on a graph like this.



From: Petroconsultants, *Review of Fiscal Regimes* (RFR), 1995

Regional Distribution of Petroleum Fiscal Systems

	Royalty/Tax Systems		Production Sharing Systems		Service Agreements
Africa **38**	C. Af. Rep. • Chad Congo (Z) Ghana • Madagascar Mali Morocco Namibia • Niger	Nigeria (Off) Senegal • Seychelles Sierra Leone Somalia S. Africa ♦ Tunisia (Old) ♦	Algeria ♦ Angola •+ Benin Cameroon ♦ Congo (Br.) Cote D'Ivoire Egypt Eq. Guinea • Ethiopia Gabon Gambia • Kenya	Liberia Libya ♦ Madagascar ♦ Mozambique Nigeria (DW) Sudan Tanzania • Togo Tunisia (New) ♦ Uganda • Zambia	Nigeria (JVs)
Europe **20**	Australia Bulgaria Czech Rep. Denmark France Greece • Hungary Ireland	Italy Netherlands Norway Poland ♦ Portugal Romania ♦ Spain UK	Albania ♦ Malta Poland Turkey		
Far East **23**	Australia • Brunei Korea S. Nepal New Zealand	Pakistan (On) PNG • Thailand + Timor Gap B	Bangladesh Cambodia China India ♦♦ Indonesia Laos Malaysia ♦ +	Mongolia MTJDA Myanmar Pakistan (Off) Timor Gap A Vietnam	Philippines
Former Soviet Union **7**	Russia +		Azerbaijan ♦♦ Georgia Kazakhstan • Kyrghyzstan	Russia • Turkmnistan ♦ Uzbekistan	
Latin America **23**	Argentina Bolivia Brazil Colombia ♦ +	Costa Rica Falkland Is. Paraguay Tr&To (On)	Belize Cuba Guatemala Guyana Jamaica	Nicaragua Panama ♦ Tr&To(Off) ♦+ Uruguay	Chile Honduras Ecuador Panama Haiti Peru ♦ Venezuela ♦♦
Middle East **18**	Abu Dhabi Ajman Dubai Fujairah	Neutral Zone Sharjah Turkey	Bahrain Iraq Jordan Libya	Oman Qatar ♦ Syria Yemen	Iran Kuwait (OSA) Saudi Arabia
North America **2**	Canada • United States				
Total 131	**58**		**63**		**11**

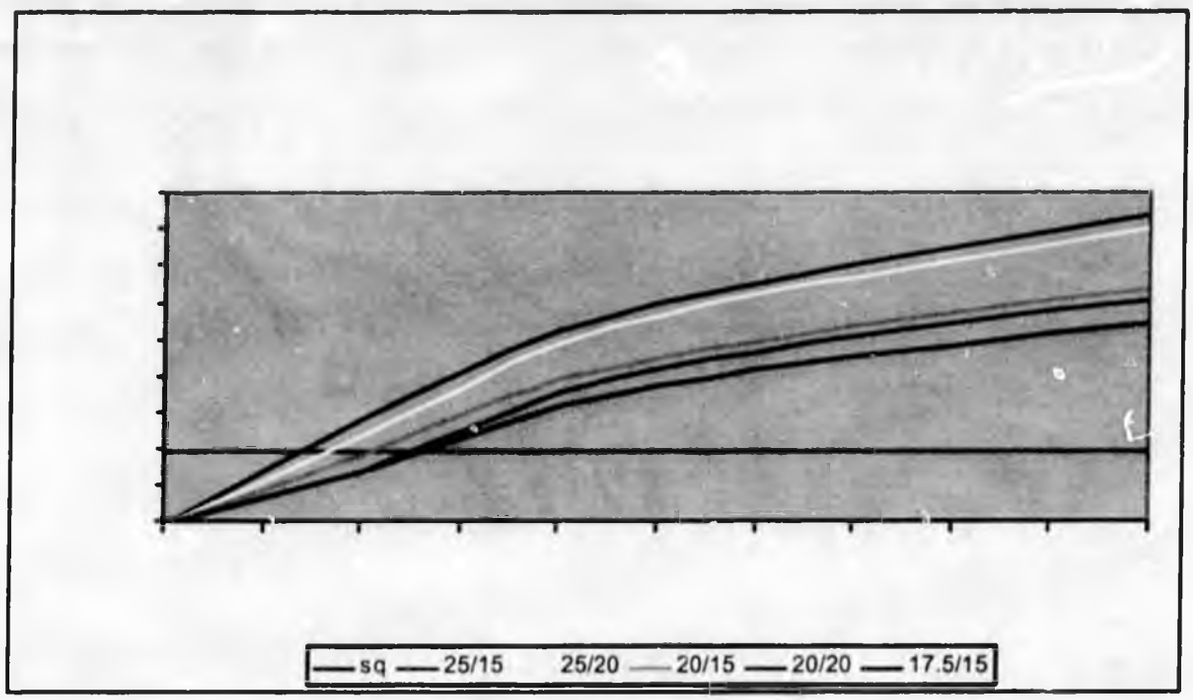
- **ROR Systems**
- ♦ **"R" factor**
- **+ Price-based formulas**

These are the systems that are most likely to be progressive.

Adapted from: Course Workbook, Johnston

Effective Oil Severance Tax Rate

The following graphs from Dr. van Meurs and Dr. Roger Marks are helpful and I find myself regularly referring back to them so I include them here for convenience. They may be out of date soon and I am still reviewing the assumptions and methodology.



From: PPTAnalysis020106.ppt Roger Marks

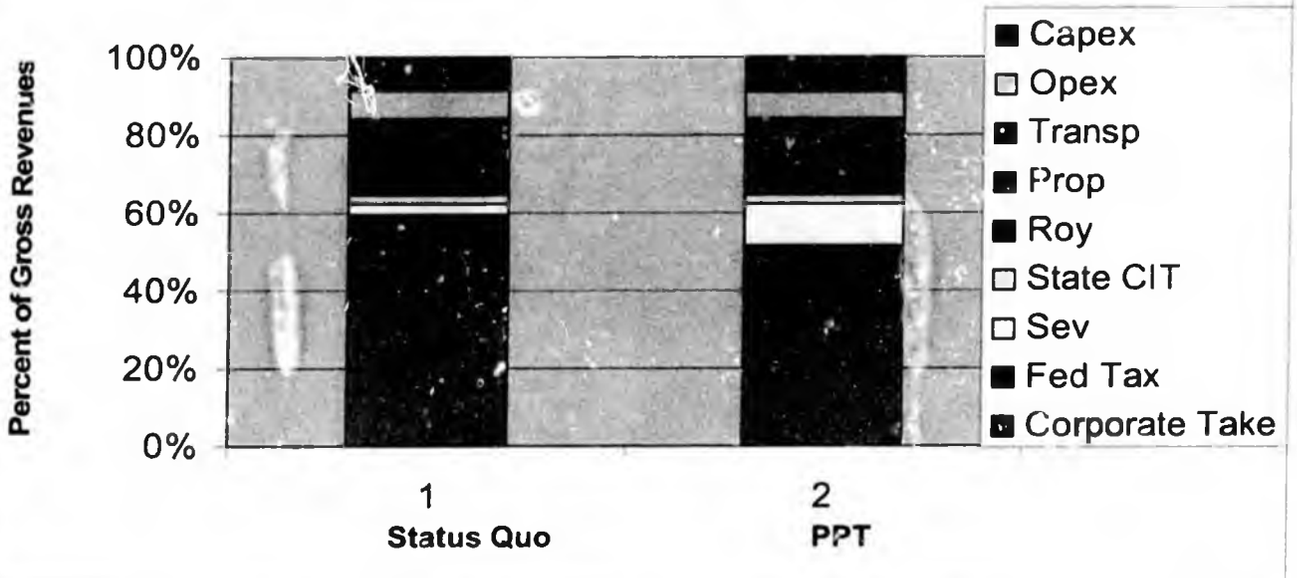
Estimated EFFECTIVE PPT RATES (from the graphs above)		
	$40/BBL	**$60/BBL**
Status Quo	**4%**	**4%**
25%/20% PPT as Proposed	**11.5%**	**15%**
Negotiated 20%/20% + Look-back	**< 8%**	**< 11%**
I assumed the "look-back" amounted to $1 Billion over 6 years = -$167 MM/year		

Government Take at $58 per BBL increases 14% with PPT 20/15%

I used this graph to illustrate that with this particular scenario i.e. 20/15% (like so many others) severance tax increase only results in an overall increase of Government Take of 14% (7 point increase from 49%). The Government Take statistic is the only reasonable barometer to use when discussing a change in terms. To say that the Severance tax increased by 100% or 200% is not fair or appropriate.

It brings to mind the famous "Panna-Mukta" dispute in India, which I will explain in my testimony.

Figure 12
Corporate Take at EIA Forecast Price ($58)
20% Tax/15% Credit
With Gasline & Enhanced Volumes

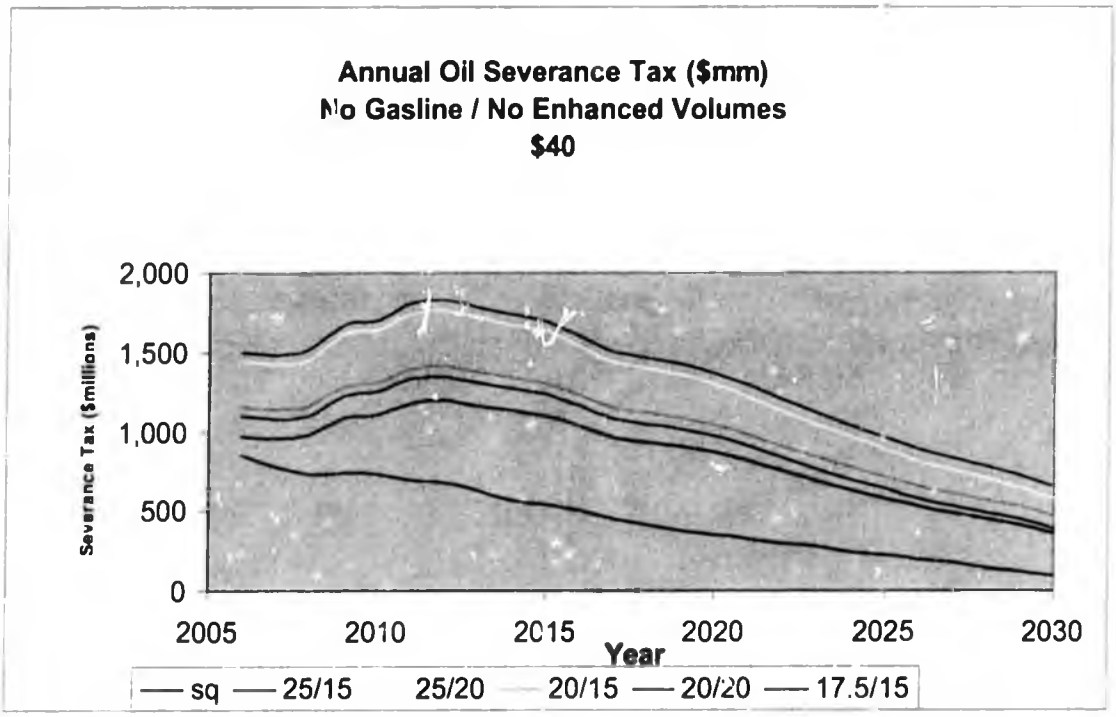


"Corporate take goes from 39% to 33% of gross revenues, or from 51% to 44% of the economic rent."

From: PPTAnalysis020106.ppt Roger Marks

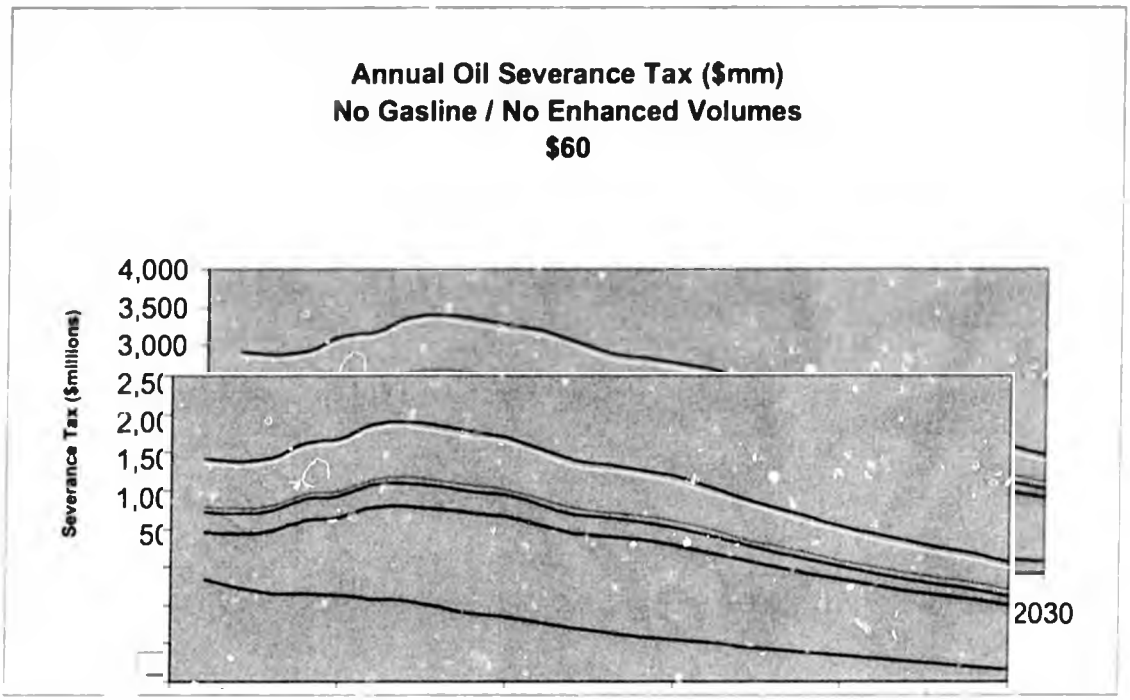
Note: Government Take goes from 49% to 56% an increase of 14%

Annual Oil Severance Tax - $40 per BBL



From: van Meurs 14 February, 2006 Report (pg 154-155)

Annual Oil Severance Tax - $40 per BBL



Estimated Near-term ALASKA ANNUAL REVENUES		
	$40/BBL	**$60/BBL**
Status Quo	**$ 800 MM**	**$1,200 MM**
25%/20% PPT as Proposed	**$ 1,500 MM**	**$2,900 MM**
Negotiated 20%/20% + Lookback	**$1,200 MM** **- 167 MM** **$1,033 MM**	**$2,300 MM** **- 167 MM** **$2,133 MM**
I assumed the "lookback" amounted to $1 Billion over 6 years = -$167 MM/year		

Industry Statistics - Handle with care!

When designing exploration terms the margin for error is not so critical i.e. plus or minus 5% or so depending on a variety of other factors such as the means by which a country allocates licenses or projects. However, with the Legacy Fields on the North Slope it is very different. There are millions of dollars per year represented by each percentage point of Government Take.

Important: The following statistics are "dated". We will discuss what has happened in the past few years. Also, most contract analysis in the past and now has focused on exploration projects not development type projects.

Database Table 7

World Petroleum Fiscal System Statistics

	PSCs	World Average	Royalty/Tax Systems
Number of Systems	72	136	64
Government Take	70%	65%	59%
Gvt. Participation			
Systems with Gvt. Participation (%)	36 (50%)	65 (48%)	29 (46%)
% Participation in those Systems with Gvt. Participation	25%	27%	30%
Royalty	5%	7%	8%
Effective Royalty Rate	23%	17%	8%
Ringfenced Systems	75%	55%	30%
Lifting Entitlement	63%	77%	92%
Savings Index	39¢	47¢	56¢
Cost Recovery Limit (PSCs only)	65%	N/A	N/A
Systems with ROR features or "R" factors	17%	21%	25%

From: "International Petroleum Fiscal Systems Database" PennWell Books (2002), Johnston

Weaknesses of Government Take

Before we press on, it is important to discuss the fact that Government Take is not a perfect statistic. We will have a difficult time ignoring it because it is an important metric but it can be more meaningful if we are aware of both the strengths and weaknesses

Weaknesses of the Government take statistic:

- Does not adequately capture signature bonuses
  Unless analysis addresses both present value and risk — its an accuracy vs precision thing.
- Does not address "how" Government takes (such as front-end-loading)
  The companion statistic "ERR" helps here.
- Says nothing of timing and time value of money (unless "discounted")
- It's macroeconomic scope is too narrow
  Does not measure all of the means by which Gvt. benefits i.e. **Gross Benefits**
  Such things as jobs.
- Says nothing of ringfencing (the ability to tax deduct costs incurred in one area against other license areas.
- Does not measure contract or system stability
- Reserve/lifting entitlements and "ownership" not accounted for
- Does not differentiate between diverse work program provisions
- By definition "Crypto taxes" don't get captured
- It is not relevant in some important situations Government take for exploration may not be the same statistic for development (the Gvt. participation thing)

From: "International Petroleum Fiscal Systems and Production Sharing Contracts" Course Workbook 2006, Johnston

More "dated" Industry Statistics - Handle with care!

Database Table 8 Fiscal System Statistics – for the more Prospective Countries 20th Percentile			
	PSCs	Average	Royalty/Tax Systems
Number of Systems	19	25	6
Government Take	78%	79%	80%
Gvt. Participation			
Systems with Gvt. Participation (%)	12 (63%)	17 (68%)	5 (83%)
% Participation in those Systems with Gvt. Participation	28%	32%	42%
Royalty	5%	6.8%	11%
Effective Royalty Rate	29%	24.5%	11%
Ringfenced Systems	90%	76%	33%
Lifting Entitlement	55%	63%	89%
Savings Index	30¢	31¢	37¢
Cost Recovery Limit (PSCs only)	6?%	N/A	N/A
Systems with ROR features or "R" factors	26%	24%	16%

From: "International Petroleum Fiscal Systems Database" PennWell Books (2002), Johnston

More "Dated" Industry Statistics - Handle with care!

World Fiscal Terms – Regular and Special Situations			
	Government Take	**Effective Royalty Rate**	**Comment**
World Average for Oil (Includes all types of contracts: exploration, development, rehabilitation, EOR, heavy oil)	**65%**	**20%**	
World Average for Gas	**56%**	**15%**	Many contracts have a "gas clause"
Frontier Terms	**56-60%**	**15%**	
Heavy Oil Terms	**50%**	**10%**	These are still fairly rare
Deepwater Terms	**58%**	**13%**	

From: "International Petroleum Fiscal Systems and Production Sharing Contracts" (2006) Course Materials, Johnston

More "Dated" Industry Statistics - Handle with care!

Average State Take for Deepwater Projects

From: Petroconsultants "Review of Petroleum Fiscal Regimes (Oil) 1997."

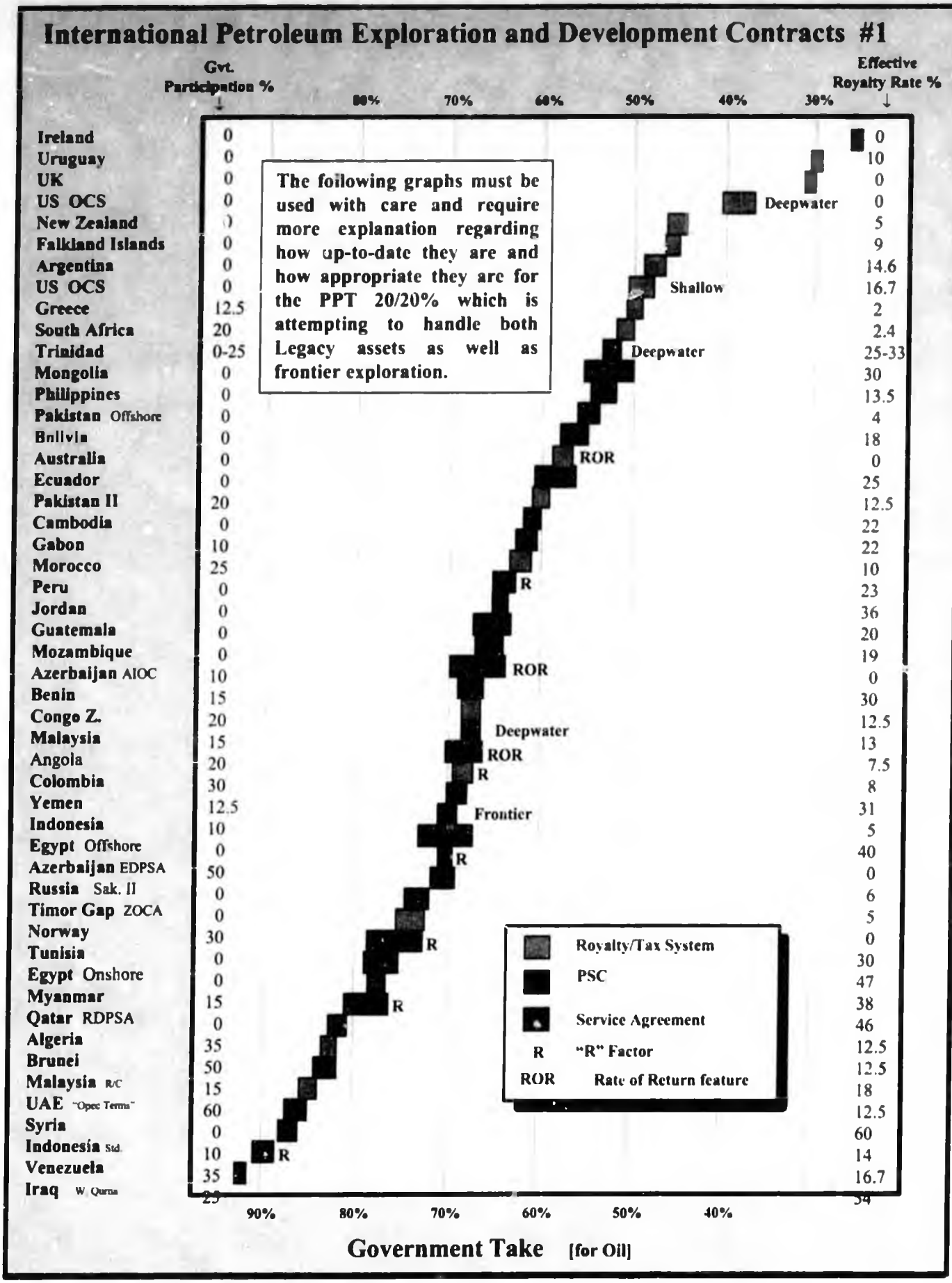
	Marginal Fields	Economic Fields	Upside Fields
UK	33.4%	33.0%	33.0%
USA (OCS)	46.1	41.4	37.1
Cote d' Ivoire	50.9	49.2	46.8
Nigeria	53.1	57.8	58.5
Thailand	53.3	54.7	50.5
Angola	56.2	52.6	64.8
Gabon	56.6	52.6	50.0
Congo	67.6	61.4	58.6
Indonesia	74.2	72.4	71.3
Malaysia	78.2	74.1	71.3
Average Deepwater	57.0	54.9	54.2
World Average (116 Fiscal Regimes)	69.9	65.1	63.9
Breakdown (From RFR 1995)			
72% Regressive	76.2	68.4	65.3
5% Neutral	56.5	55.8	55.7
23% Progressive	62.8	67.4	72.2

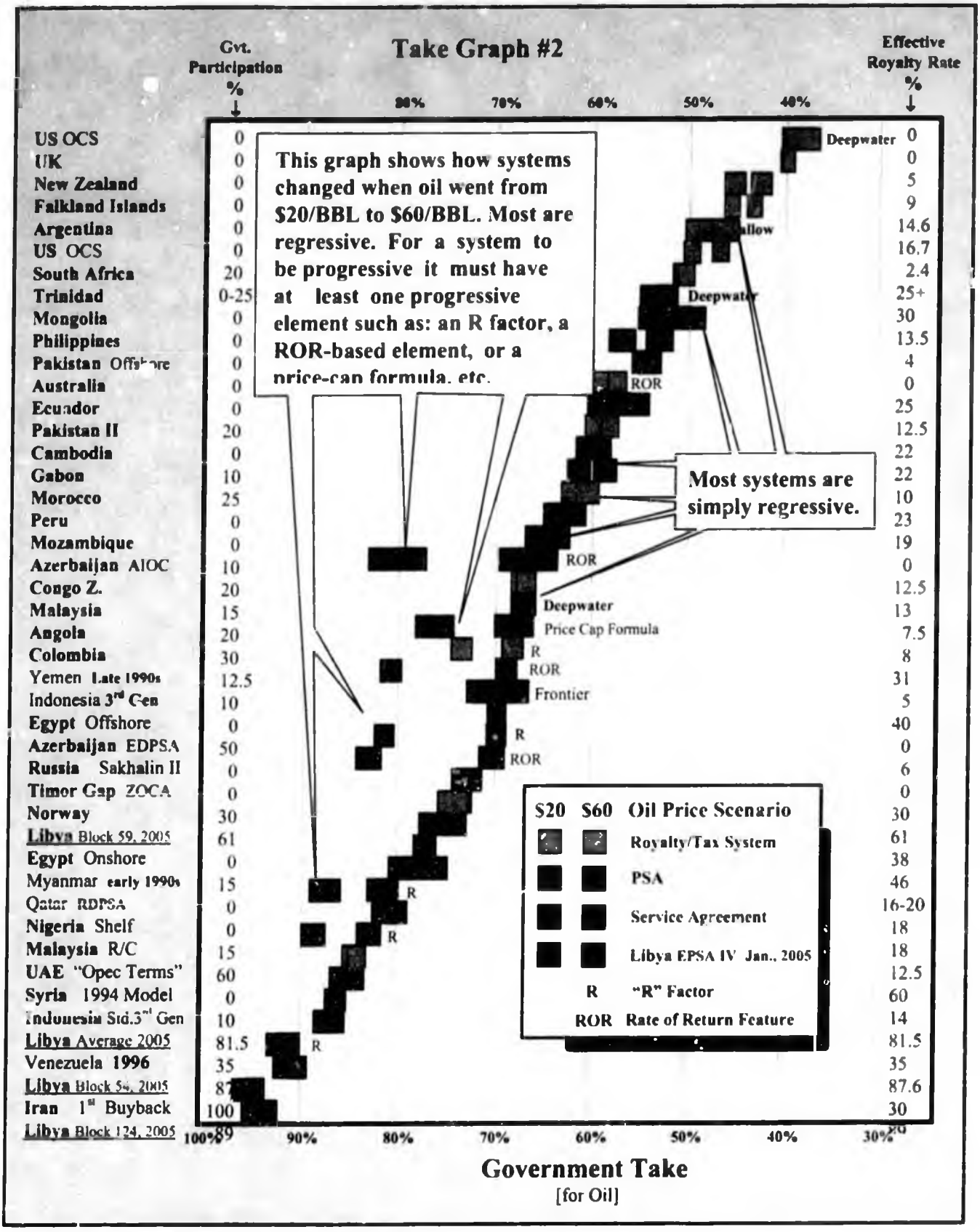
Average State Take (Peer Group Comparison)

From: Graham Kellas - Petroconsultants
"New Fiscal Incentives encouraging Global Push Into Deepwater Plays"
The American Oil & Gas Reporter - Special Report: April, 1997 (pg 47-50)

	Marginal Fields	Economic Fields	Upside Fields
20 Largest Producing Regimes	80.0%	74.6%	72.7%
30 Significant Producing Regimes	73.4%	66.7%	67.7%
66 Frontier Regimes	65.3%	60.5%	59.5%

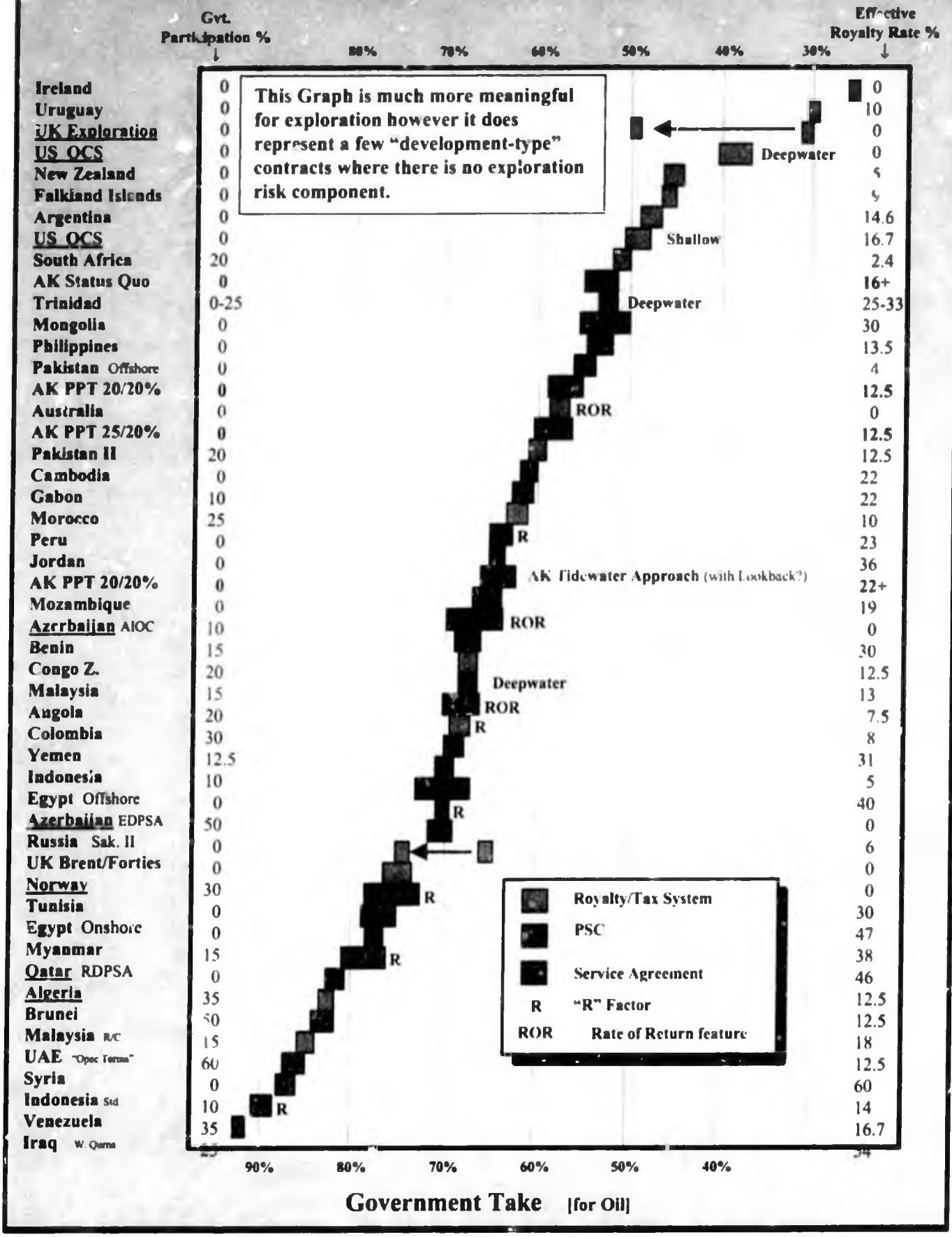
International Petroleum Exploration and Development Contracts #1



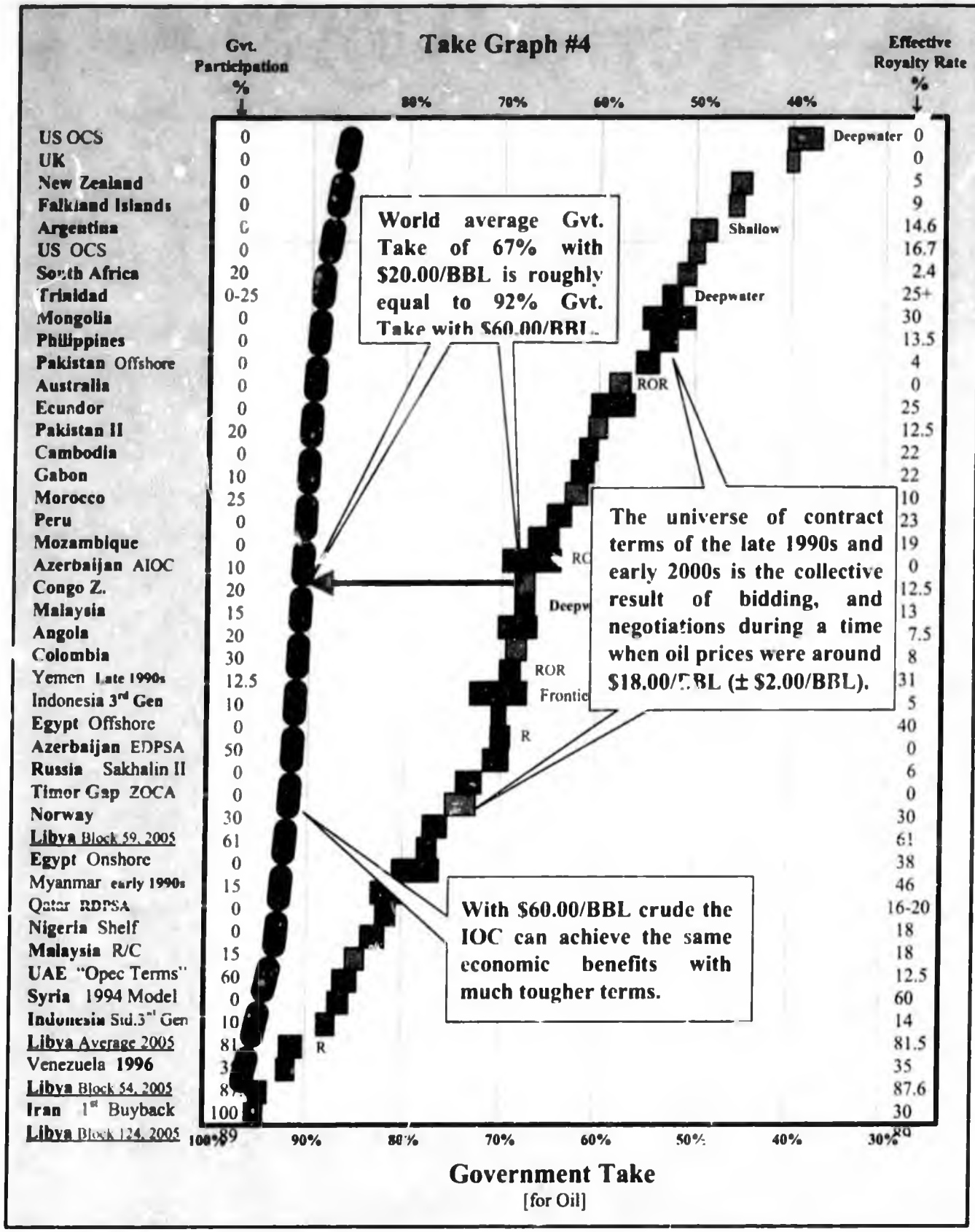


Difference between $20/BBL and $60/BBL

International Petroleum Exploration and Development Contracts #3



	Gvt. Participation %	Effective Royalty Rate %
Ireland	0	0
Uruguay	0	10
UK Exploration	0	0
US OCS	0	0
New Zealand	0	5
Falkland Islands	0	5
Argentina	0	14.6
US OCS	0	16.7
South Africa	20	2.4
AK Status Quo	0	16+
Trinidad	0-25	25-33
Mongolia	0	30
Philippines	0	13.5
Pakistan Offshore	0	4
AK PPT 20/20%	0	12.5
Australia	0	0
AK PPT 25/20%	0	12.5
Pakistan II	20	12.5
Cambodia	0	22
Gabon	10	22
Morocco	25	10
Peru	0	23
Jordan	0	36
AK PPT 20/20%	0	22+
Mozambique	0	19
Azerbaijan AIOC	10	0
Benin	15	30
Congo Z.	20	12.5
Malaysia	15	13
Angola	20	7.5
Colombia	30	8
Yemen	12.5	31
Indonesia	10	5
Egypt Offshore	0	40
Azerbaijan EDPSA	50	0
Russia Sak. II	0	6
UK Brent/Forties	0	0
Norway	30	0
Tunisia	0	30
Egypt Onshore	0	47
Myanmar	15	38
Qatar RDPSA	0	46
Algeria	35	12.5
Brunei	50	12.5
Malaysia R/C	15	18
UAE "Opec Terms"	60	12.5
Syria	0	60
Indonesia Std	10	14
Venezuela	35	16.7
Iraq W. Qurna	25	34



What terms wouid yield the same economic benefit at $60/BBL?

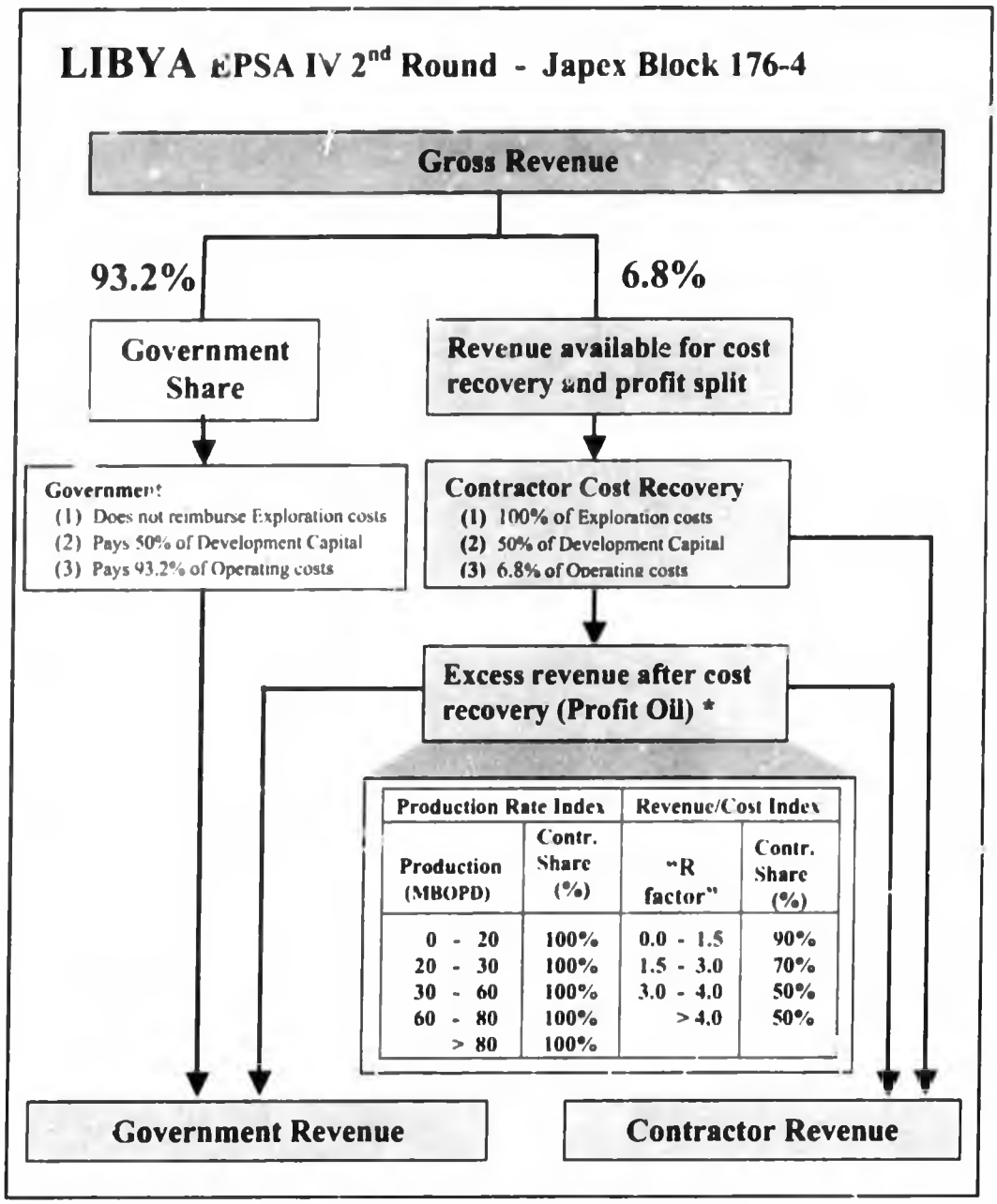
Contract Duration

This graph is provided in response to a statement made by one of the oil company representatives claiming that typical contract term, or duration, was 50-60 years. That is not consistent with my experience. The implications are heavy.

Examples of Contract Duration Worldwide

Province/Block	Exploration Years	Production Years
Abu Dhabi	3 + 2 + 2	33
Ajman	4 + 2 + 2	35
Albania	2 + 3 + 1.5	24
Algeria	5 + 2	15 - 30
Algeria	5 + 2	20 - 25
Australia	6 + 5	42
Beliz	8	25
Benin	4 + 2 + 2	25 + 10
Bolivia		30 Max
Brunei	8	38 + 30
Brunei Offshore	17	40 + 30
Cambodia	3 + 2 + 1	22
Congo Br.	4 + 3 + 3	30
Congo Br.	10	30
Cote d'Ivoire	2 + 2 + 2	25
Czech Rep.	4 + 4	20
Dubai	3 + 2 + 3	35
Ecuador	4 + 2	22
Egypt	8	20
France	5 + 5 + 5	5 + 5 + 5
Gabon Deepwater	5 + 3	10 + 5 + 5
Gabon	3 + 2 + 2	25
Ghana	7	18 (25 Total)
Guyana	4 + 3 + 3	25 + 5
Honduras	4 + 2	20 + 5
Hungary	2 + 2 + 1	25
India	3 + 2 + 2	25 + 5
Indonesia	3	20
Liberia	3 + 3	25 + 10
Madagascar	8	15 + 5
Malaysia	3 + 2 2 + 2 Dev	15
Malaysia R/C	5	29 Total
Netherlands	10	40
Nigeria	3 + 3 + 4	20
Oman	2 + 2 + 2	20 + 10
Peru	7	30
Poland	3 + 3	20 + 5 + 5
Rep. of Guinea	5	21 (Maz 25)
Senegal	3 + 2 + 2	25 + 10
South Africa	4 + 3 + 3	as long as is profitable
Syria	3 + 2 + 1	20 + 10
Vietnam	3 + 1 + 1	20 (total not to exceed 25)
Zambia	8	25
Average/Typical	3 + 2.5 + 2 (7.5)	25

Lybia's Latest License round - Mechanics



EPSA IV Terms – Flow Diagram * **Assumed P/O split** (not known yet)

The Expected value (EV) formula

This is the basic equation of modern day risk analysis. The rule is: If expected value is positive then the reward outweighs the risk. Companies try to choose investment opportunities that maximize expected value.

Expected value = Reward * SP - Risk capital * (1-SP)

Where:

Risk capital =	Costs associated with testing a prospect. Typically consists of dry hole costs, geological/geophysical costs, and possibly a signature bonus.
Reward =	Present value of possible successful exploration efforts based upon discounted cash flow analysis of a hypothetical discovery typically discounted at (or close to) corporate cost of capital. [see tables T 1.3 and T 1.4]
SP =	Probability of success (Likelihood of actually making a discovery – Estimated by geotechnical personnel.)
1 – SP =	Probability of failure (Likelihood of drilling a dry hole and losing the risk capital).

This formula provides the cornerstone of risk analysis. The rule is that if EV is positive, then the risk-weighted reward outweighs the risk-weighted cost of failure.

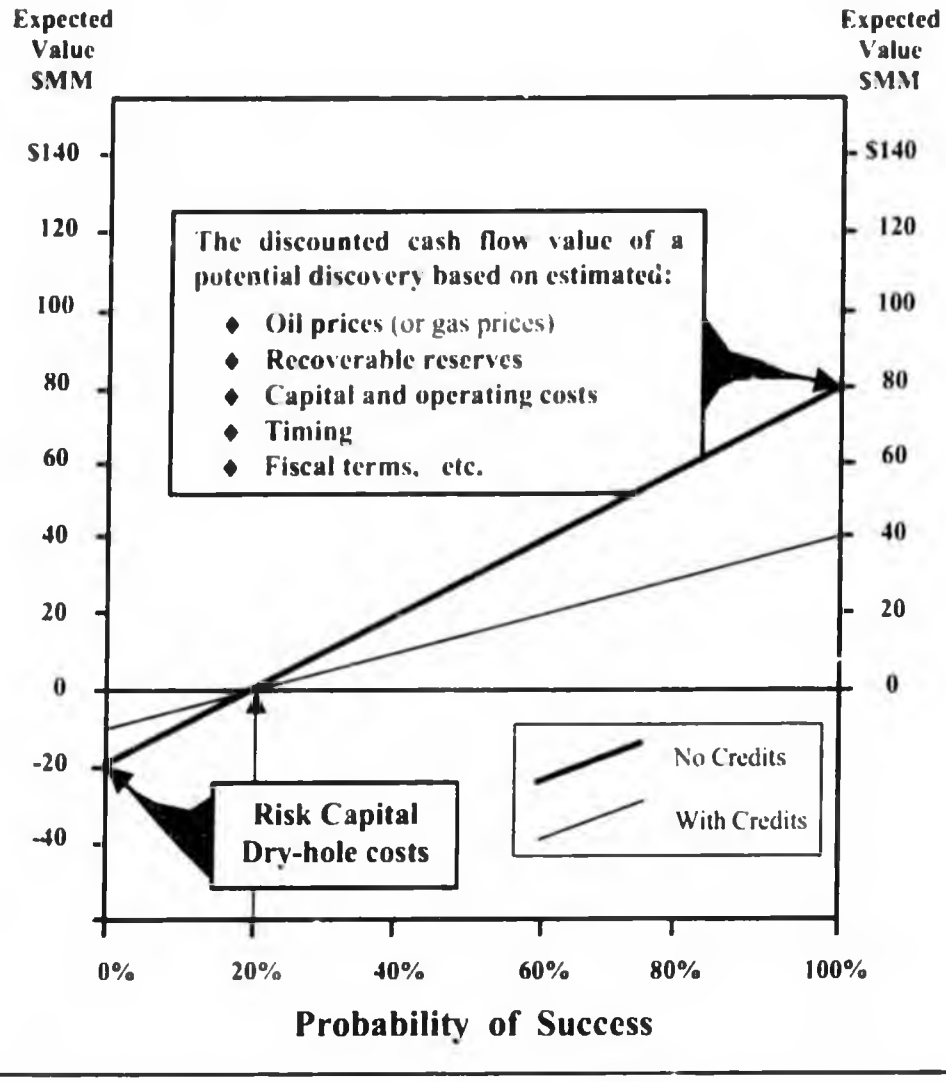
The expected value formula, whether it is used directly or indirectly (gut feel), provides the basis for billions of dollars of exploration investments. It is normally more complex with the common practice in the industry of using multiple outcomes (at least 3) on the "reward side" of the equation.

Expected Value

Assume: (1) dry-hole cost (risk capital) is $20 MM
(2) estimated probability of success is 20%
(3) a potential prospect would have to be worth $80 MM to the Company before they could even consider risking their capital drilling it.

This might correspond to say a 200 MMBBL prospect, i.e. "exploration threshold field size". Therefore prospects must be larger than 200 MM.

A credit arrangement like the one in-place now (not PPT 20/20%) reduces the "risk exposure" by 50%. Companies can justify smaller prospects (about half the size). The question is: With a credit system addressing the "risk side" of the equation what can be done on the "reward side" without destroying the incentive. The explorers in Alaska are close to the edge at even $40/BBL. Much to discuss.



BP Presentation on Proposed PPT (28 February, 2006)

"Because oil and gas co-exist in the same underground reservoirs, they are produced together through the same investments made in wells and facilities, they are also linked economically.

This inextricable physical and economic linkage is widely recognized by both governments and investors around the world.

North American royalty contracts cov · both oil and gas. Internationally, production sharing contracts include terms for both oil and gas. General oil and gas tax laws across the U.S. and internationally always address both oil and gas.

Governments want to know how much money they will receive from oil and gas production. Similarly, investors need to know how much they will pay governments when oil and gas is produced and sold and make their investment decisions accordingly."

From: page 2 starting at paragraph 4 (emphasis added)

Contrast this with a common and typical "gas clause" found in many countries – in this case Angola.

Non-associated Gas: if non-associated natural gas is found, Sonangol and the contractor have 36 months, or such longer period as may be agreed upon, after the discovery date to agree terms under which it might be developed, whether for oil field operations, domestic consumption or export.

If no agreement is reached within that time, Sonangol may develop the discovery for its own account. Sonangol may agree for the contractor to opt back into the discovery, with reimbursement of Sonangol's expenses plus 1,000% of such expenses.

(This is like a "sole risk" provision)

Ringfencing

The issue of recovery or deductibility of costs is further defined by the revenue base from which costs can be deducted. Ordinarily all costs associated with a given block or license must be recovered from revenues generated within that block. The block is "ringfenced." This element of a system can have a huge impact on the recovery of costs of exploration and development. Indonesia requires each contract to be administered by a separate new company. This restricts *consolidation* or effectively erects a ringfence around each license area.

Some countries will allow certain classes of costs associated with a given field or license to be recovered from revenues from another field or license. India allows exploration costs from one area to be recovered out of revenues from another, but development costs must be recovered from the license in which those costs were incurred.

From the government perspective any consolidation or allowance for costs to cross a ringfence means that the government may in effect subsidize unsuccessful operations. This is not a popular direction for governments because of the risky nature of exploration. However, to allow exploration costs to *cross the fence* can be a strong financial incentive for the industry.

The importance of risk dollars has already been demonstrated. If a country with an effective tax burden of 50% allowed exploration costs to be deducted across license boundaries then the industry would be drilling with 50¢ dollars. It would cut the risk in half. From the perspective of the development engineer, it has little meaning unless development and operating costs are also allowed to cross. Dropping or loosening the ringfence can provide strong incentives, especially to companies that have existing production and are paying taxes.

In the early 1980s exploration in the UK sector of the North Sea reached record levels (due to changes resulting from the 1983 budget). This is because the government allowed exploration costs to cross the ringfence as deductions against the 75% PRT tax on older fields. This created a huge exploration incentive for any company paying PRT taxes. Some of the larger companies had substantial unused tax cover, and smaller companies did not have enough. The smaller companies purchased what came to be known as "Forties Units" to take advantage of the exploration relief provided by the hole in the ringfence. These "units" were a quarter of a 1% working interest in the British Petroleum operated Forties field which during that time was producing in excess of 160,000 BOPD. By late 1984 BP's Forties field had gained 22 new owners all with shares of less than 2%. A dozen companies owned only a 0.25% working interest "unit". The dynamics of ringfencing can be spectacular. The UK sector of the North Sea became the hottest offshore province in the world. By 1993 when the PRT was abolished, few fields were actually paying PRT. (Notice: This section comes straight from my course materials. Considering the intensity of the oil tax negotiations in Alaska I am researching this further as of 4 March, 2006 DJ).

- **Trinidad** decided to ringfence their deepwater license round in order to maintain a level playing field.

- This is also the kind of thing found in countries where there are different terms for oil vs gas. **Indonesia** does not allow costs from gas developments to be recovered from oil fields.

- **Colombia** is supposedly not ringfenced but unsuccessful exploration costs *within* a license area are not deductible unless they can be shown to have contributed in some way to the ultimate discovery.

- **New Zealand** considered having the potential of a ringfence within a ringfence like that in Colombia (above). But decided it would be too hard to "sell".

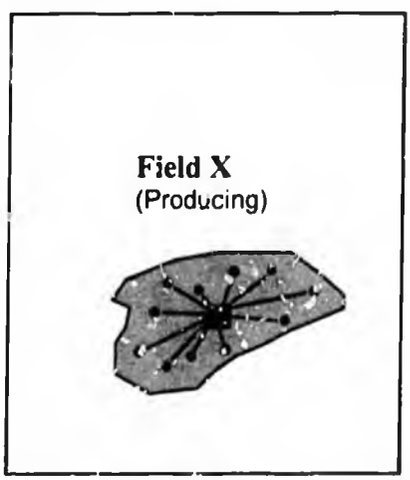
- Lack of a ringfence = Government as silent partner in exploration.
  Some say "widows and orphans as silent partner".
  Some use the word "subsidize" in this context (See Norway below).

- **Norway** has no ring fence. But that is not all. If a company drills a dry exploration well **the government will reimburse** 78% of the costs just as if the company had production against which it could deduct the expenses. This is very unusual!

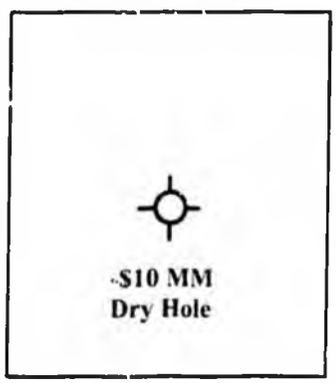
Most countries "ringfence" their acreage – that is, they do not allow consolidation.

Assuming Company X drills a dry hole in Block B. With typical ringfencing the company would not be able to take the $10 MM loss and apply it to production/revenues in Block A for cost recovery purposes or as deductions for tax calculation purposes.

Block A – Company X

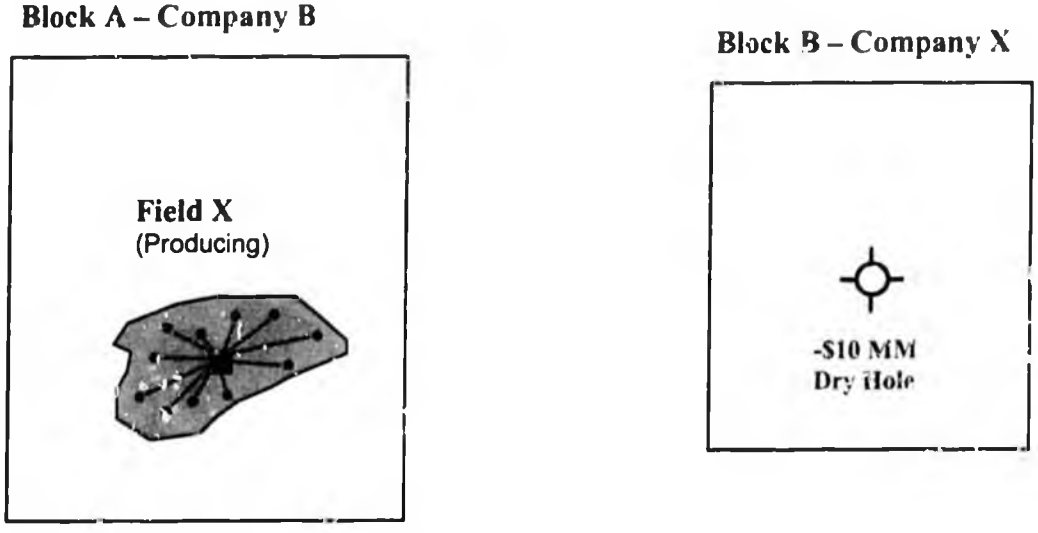


Block B – Company X



ALASKA PPT 20/20% Approach

Assume Company X drills a dry hole in Block B. With the PPT 20/20% system the Company X would be able to take the $10 MM loss and effectively apply it to production/revenues in Block A with Company B as deductions for (PPT) tax calculation purposes and it would be able to sell its 20% tax credit to Company B.



Alaska's Severance Taxes (also referred to as Production Taxes) **and The Economic Limit Factor (ELF)**

Severance taxes are a function of field vintage

Severance tax rate on Oil	
1st 5 years of production	12.5%
After 5 years	15%
(for fields in production after 1981)	
Fields in production prior to 1981	15%
There is a minimum tax of	$0.80/bbl
Severance tax on Gas	
Fields in production prior to 1981	10%
There is a minimum tax of	$0.64/Mcf

The Severance Tax was also a function of ELF, which was designed to differentiate the tax rate on the new super giant Prudhoe Bay oilfield and old declining fields in Cook Inlet.

Severance Tax paid = Severance Tax * ELF (even if severance tax is at minimum)
ELF Formula for Oil

ELF = (1 – (300/PPW))^((150,000/TP)^1.5333)

Where PPW = avg production/well/day in a field
TP = avg daily production from a field

Note: ELF was born in 1977, the same year the 800 mile TAP was completed.
If average production/well/day in a field is < 300 bbls, ELF = zero, no severance taxes are due.
300 bbls/day was considered breakeven for a North Slope well at that time. And it appears that the breakeven calculation assumed considerable infrastructure costs associated with new fields and wells.

Voodoo Economics?

Psychologists wear thin on lawmakers

By Doug Robarchek
Knight-Ridder Newspapers

Do you get the feeling that when psychologists testify in court as "expert witnesses," there's the odor of voodoo about them?

New Mexico State Sen. Duncan Scott thinks so. He proposed amending a bill so that psychologists would be required to wear cone-shaped wizard hats with stars and lightning bolts on them when they testify, according to the Western Journalism Center in Fair Oaks, California.

The amendment also would have required psychologists to wear long beards and carry wands in court. The bailiff would have been ordered to dim the courtroom lights and strike a Chinese gong during testimony.

What's more — we love this — the bill passed both houses of the New Mexico legislature.

Unfortunately, the governor vetoed it.

Distributed by Knight-Ridder Tribune News Wire

Dallas Morning News – 27 January, 1997

Daniel Johnston

Daniel Johnston lives and works out of his home in the New Hampshire countryside. He and his wife Jill have 6 children.

Daniel has 27 years experience in the petroleum industry, For 21 years he has been an independent financial consultant to the international petroleum industry. He has worked for 22 governments and most of the major and largest independent international oil companies. His consulting work focuses on the accounting, economic, and financial aspects of international petroleum exploration, contract negotiations, and petroleum fiscal system analysis and design.

He has testified as a financial expert witness in/and-or involving disputes in India, Australia, Russia, Turkmenistan, China, Yemen, California, Gabon, the Czech Republic, Equatorial Guinea, Indonesia, Kazakhstan, Myanmar, Texas, Timor Gap, Brussels, Wellington, Vienna, The Hague, and Vietnam.

He has a Bachelor of Science Degree in Geology from Northern Arizona University where he currently sits on the Advisory Council for the College of Arts and Sciences. He also has an M.B.A. (Finance) from the University of Texas at Austin.

He has published numerous articles and lectures worldwide on the subjects of: Economics and Risk Analysis; Petroleum Fiscal Systems; and Financial Analysis. Over 3,700 delegates from IOCs and NOCs from 60 countries have taken his courses.

He is author of

"**Production Sharing Agreements**" University of Dundee-Scotland (1994)
"**Oil Company Financial Analysis in Nontechnical Language**" PennWell (1992),
"**International Petroleum Fiscal Systems and Production Sharing Contracts**" (1994),
"**International Oil Company Financial Management in Nontechnical Language**" (1998)
"**International Petroleum Fiscal Systems Analysis**" **Database** (2001) PennWell
"**Maximum Efficient Production Rate**" (2002) University of Dundee (With David Johnston)
"**Economic Modeling and Risk Analysis Handbook**" (2002) U. of Dundee (With D. Johnston)
"**International Exploration Economics, Risk and Contract Analysis**" PennWell (2003)
"**Introduction to Oil Company Financial Statement Analysis**" PennWell (2005)

He is a column editor for the Petroleum Accounting and Financial Management Journal (PAFMJ) published by the Institute of Petroleum Accounting at the University of North Texas. He is also a charter member of the editorial board of Global Energy Outlook, published by Gordon Moody.

Daniel is an Honorary Lecturer at the University of Dundee, Scotland where he teaches public and industry courses and graduate seminars each May.

March 14, 2005
Notes re: Substantive Changes to HB488 by the House Resources Committee

1. Make tax rate progressive-

   Reasoning- The State should make more money at higher prices, and a larger percentage of the whole pie at extremely high prices. The Committee has increased the Governor's 20% tax rate to a progressive system. The 20% number will be in effect until the price of oil (West Texas Intermediate, WTI) reaches $50/barrel. After $50/barrel, the tax rate increases by .30% per $1.00 increase in the oil price (WTI). The rate caps at 50% at about $150.00/barrel, in case of a global oil shock. This makes the tax rate at $60.00/barrel 23.5%, and $70.00/barrel 26.5% and continues to escalate from there.

   We feel that this keeps investment opportunity in Alaska very strong, but balances it out by taking advantage of windfalls in high spikes of oil prices.

2. Reduce Transitional Money as deductible allowance- The Governor allowed five years of past investments to be deducted as costs. The rationale behind the transition provision was that investments made for the previous five years directly led to the production of oil that is now being taxed at a higher rate. The Committee feels that this rationale is partly true, but that a full five years of looking back is not appropriate. The cost recovery of the five years of investments has already been enhanced by extremely high oil prices. The Committee has replaced the 100% cost recovery of the previous five years with a

greatly scaled back program. The CS will allow 75% of 2005 expenditures, 50% of 2004 expenditures, and 25% of 2003 expenditures to be deducted as costs. The payback period of six years that was in the original legislation has been increased to seven years. The same caveat of oil prices being at least $40/barrel (ANS) before cost recovery is allowed remains the same. Additionally, the Committee has determined that the inflation indexing mechanism on the $40 price shall be in statute, not left up to regulators. This change reduces the amount of deduction allowed by industry from 5 billion to 2 billion and reduces the amount of the credit from approximately $1 billion to $300 million. Therefore, instead of the State absorbing $167 million annually in scheduled credits, the amount will be reduced to approximately $43 million per year.

3. Exploration enhancement- The SB185 exploration tax credits of 40% will be extended 10 years. The Governor's credit rate of 20% remains intact. The Committee feels that this will significantly enhance explorers and independents. Department of Revenue has testified that exploration investment in new fields represents less than ten percent of all development and exploration investment dollars. The Committee wishes to emphasize exploration. As they do currently, the company will choose between which credit is most beneficial to them.

4. No credit for abandonment costs- The CS contains specific language that abandonment costs will not be eligible for tax credits.

5. Private Royalties- The CS sets private royalty oil severance tax rates at 5%.

6. AOGA technical changes- AOGA worked in conjunction with the Governor's office to suggest several technical changes and clarifications to the bill. Some of these changes are incorporated into the CS.

7. Contingency sur-charges- The CS will leave current statute in place, which makes a 5 cent/barrel sur-charge non-deductible and non-creditable. Currently, of the 5-cent/barrel charge, 2 cent/barrel is deposited into the Response Mitigation Account until the account reaches $50 million. After this, the 2-cent/barrel charge is suspended. The CS lowers this amount to one cent/barrel. The remaining 3-cent/barrel charge is deposited into Prevention Mitigation Account. The CS increases this to 4 cents/barrel, while dropping the Mitigation money to 1 cent/barrel, leaving the total sur-charge at 5 cents/barrel.

8. Effective date- CS changes the effective date of the bill from 1 July to 1 April, the start of the second calendar quarter. This will result in an almost immediate effective date and will gain the State over 200 million dollars in the current fiscal year.

9. Issues surrounding the $73 million allowance- The CS eliminates the 73 million annual dollar allowance, which resulted in a $14.6 million credit. Instead, the Committee implemented an annual direct tax credit, dollar for dollar, for the first $10 million worth of expenditures. The credit is annual, non-transferable, non salable and not eligible for carry forward. The credit can only be applied to the current year's severance tax. If there is no tax, the credit cannot be claimed. If a company has income but spends less than 10 million dollars, they can only claim credit up to amount that was spent.

10. Tax Credit Repurchase Program- To help protect explorers and new entrants to Alaska, the State will buy up to $10 million per year per company for credits at 100% of face value. Companies must show that an equivalent amount to the credit is being reinvested for exploration or lease purchases in Alaska.

11. Penalties on underpayment of less than 90% of monthly tax liability- The CS puts in place a 5% penalty for underpayment of the monthly severance tax bill for any amount below the 90% threshold. In addition, interest will be charged on any payment shortfall less than the full liability.

PRESENTATION ON ALASKA PPT

to House Resources Committee
March 13, 2006

Analysis of PPT

Barry Pulliam

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ONE

Econ One Research, Inc.

- An economic research and consulting firm with offices in California (Los Angeles and Sacramento) and Texas (Houston and Austin)
- We provide consulting services in various industries, including petroleum and natural gas, regulated utilities, electricity, telecommunications and computer software
- We have worked for:
  - A number of state governments on energy-related matters, including the States of Alaska, California, Hawaii, Louisiana, New Mexico, New York, and Texas
  - Federal government agencies, including the Department of Justice, the Federal Trade Commission, the Department of the Interior, and the President's Council of Economic Advisors
  - A number of foreign countries and international agencies, including the World Bank, Mexico, Nigeria, Turkey, and Tanzania on matters related to economic development and privatization of state-owned utilities
  - A number of companies in the petroleum and natural gas industries, including BP, Occidental Petroleum, ANR Pipeline, Koch Gateway Pipeline, Sempra Energy, KN Energy Corp., Lyondell-CITGO Refining, Total Petrochemicals U.S.A., Panhandle Eastern Corp., and ONEOK, Inc.

ONE

Barry Pulliam

- Senior Economist with Econ One Research, Inc.
- Masters Degree in Economics from the Claremont Graduate School, with 17 years of experience consulting in the petroleum and natural gas industries
- Has consulted with or served as an economic expert for the State of Alaska on a number of occasions, including:
  - Several severance tax matters involving the valuation of crude oil
  - Operation of the TAPS Quality Bank in proceedings before the FERC and Alaska PUC
  - Merger and antitrust investigations
  - Recent arbitration between State and ExxonMobil involving crude oil royalties
- Consulted with the States of California, New Mexico, Texas, and Louisiana on economic issues related to the petroleum industry
- Consulted with federal government agencies, including the Department of the Interior and the Federal Trade Commission
- Co-author of two recent studies prepared for the Alaska Department of Natural Resources related to natural gas markets and royalty valuation issues

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Dr. Anthony Finizza

- Economist working in conjunction with Econ One Research, Inc.
- Ph.D. in Economics and Finance from the University of Chicago with over 30 years of experience working in the petroleum industry
- Chief Economist for ARCO from 1975 to 1998
- At ARCO, Dr. Finizza was in charge of petroleum price forecasting for the company's Long Range Planning Process and conducted scenario-planning exercises with senior management responsible for investment decisions
- Consulted with the California Energy Commission, the State of Hawaii, and the International Hydrogen Infrastructure Group (a consortium of private companies and the U.S. Department of Energy) on energy-related matters
- Currently teaches forecasting and modeling at the University of California, Irvine
- Published articles in *Business Economics*, *The Journal of Corporate Renewal*, and *The International Journal of Forecasting*
- Senior Fellow with the U.S. Association for Energy Economics
- Former President of the International Association for Energy Economics

ONE

Oil Price Issues

Conclusions/Observations Regarding Oil Price Forecasts

- Producers are using $40 as a planning base case with $30 as a stress price case. Majors may be using a slightly lower price range than independents, but are moving their views up.
  - This range may actually be lower than their best estimate, but is consistent with their "prudent" planning approach
  - This range is consistent with recent observed oil asset purchases
- This range is consistent with publicly available forecasts although the recent EIA AEO 2006 is above this range. (~$54)
- What really matters is what forecasts are the "risk takers" using?
- Forecasters have been humbled (and will continue to be humbled) by their forecasts

Oil Price Outlook

- **Factors Suggesting Continued Higher Prices (short-term)**
  - Strong oil demand, especially in China and rest of Asia
  - Growing Gap Between Global Demand and Global Non-OPEC Supply
    - Non-OPEC oil supply cannot keep up with growing world demand permitting increase in OPEC's market power
- **Factors Opposing Higher Oil Prices (long-term)**
  - Conventional oil faces threat from alternative sources of liquids when prices are high
    - Tar Sands: economic at ~$20-30 oil
    - Coal Liquids: economic above $30/bbl
    - Shale Oil: economic above $45-50/bbl
  - Penetration of Alternative Transportation Vehicles
    - Oil's key position in the transportation market will be eroded by Hybrid vehicles, Grid-Connected Hybrid vehicles, Fuel Cell Vehicles
  - A $10/bbl difference in oil prices is an $73B additional consumer costs per year

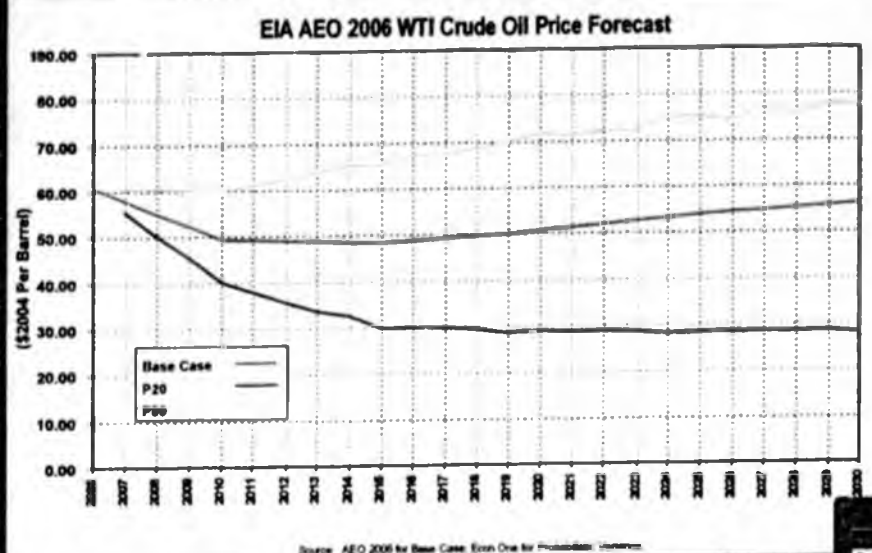
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Oil Price Forecasts

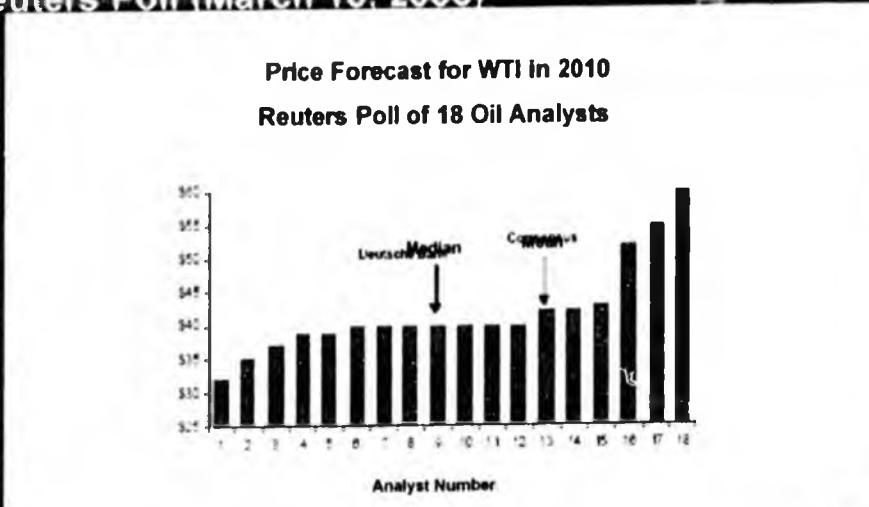
- **EIA's Annual Energy Outlook (AEO) – January 2006**
  - Forecast of oil prices (through 2030, converted to WTI by Econ One)
  - Include Alternative scenarios, probabilistic forecasts developed by Econ One
- **International Energy Agency (Paris) – 2005**
- **Reuters Poll of 18 Oil Analysts for WTI in 2010 (March 2006)**
- **NYMEX Futures market**
  - WTI oil contract traded since early 1980s

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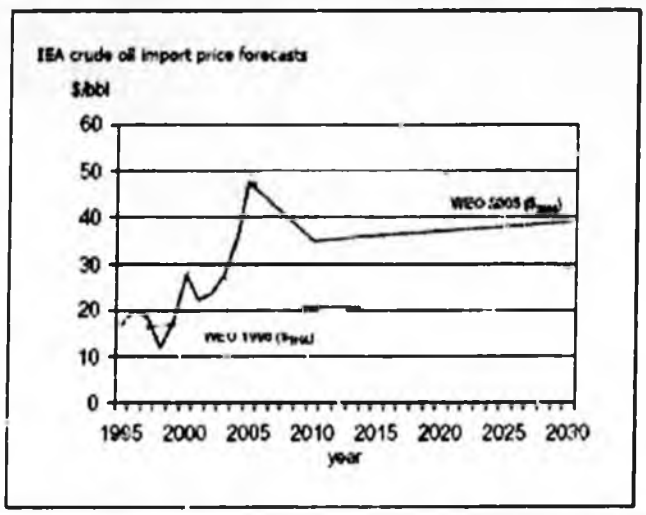
Oil Price Outlook – EIA Annual Energy Outlook 2006



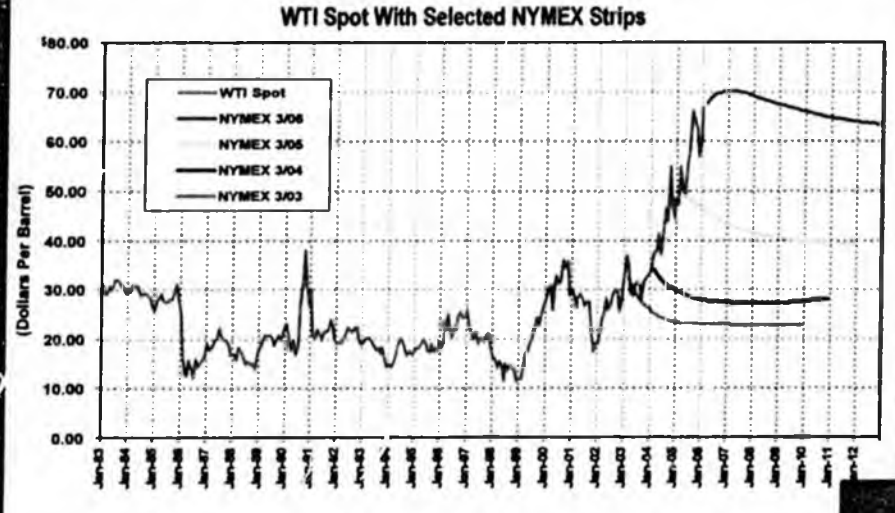
Alternative Oil Price Forecasts – Reuters Poll (March 10, 2006)



IEA (2005) Oil Price Forecasts



WTI Prices: History and Market Forecast



Producer View of Future Oil Prices

- Producers have been "burned" by forecasts of high oil prices in the past
- Producers will test their projects against a price path that is below their "Most Likely" view
  - They use the "official price view" as a speed limit to signal caution
  - By "high-grading," they will have a suite of projects resilient to price risk
  - Their price view lags the current market price by as much as 5-7 years as prices rise, and by 2 years as prices fall.
  - Current view might be: $35-40/barrel
  - Producers will also "stress" test their projects at $30/barrel
- The consequences of error are not symmetrical
  - If a producer underestimates the future path of prices, they will not undertake high risk projects and their returns will skyrocket (the current situation relative to a few years ago)
  - If a producer overestimates the future path of prices, they will be scorned by Wall Street and investors (their position in the late 1990s)
  - They will "miss" opportunities, but these misses will not be fully "penalized" by the market

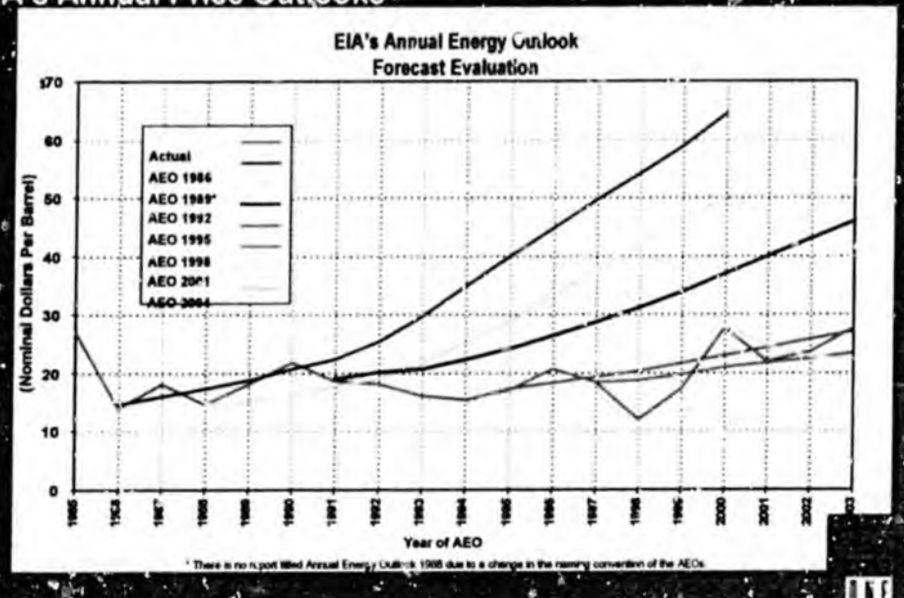
Imputed Oil Company Price Views

- Marubeni acquisition (2/23/06) of Pioneer GOM assets: ~ $40
- Norsk Hydro acquisition (9/19/05) of Spinnaker Exploration: ~$35
- Statoil acquisition (4/28/05) of EnCana's Deepwater GOM: ~ $30

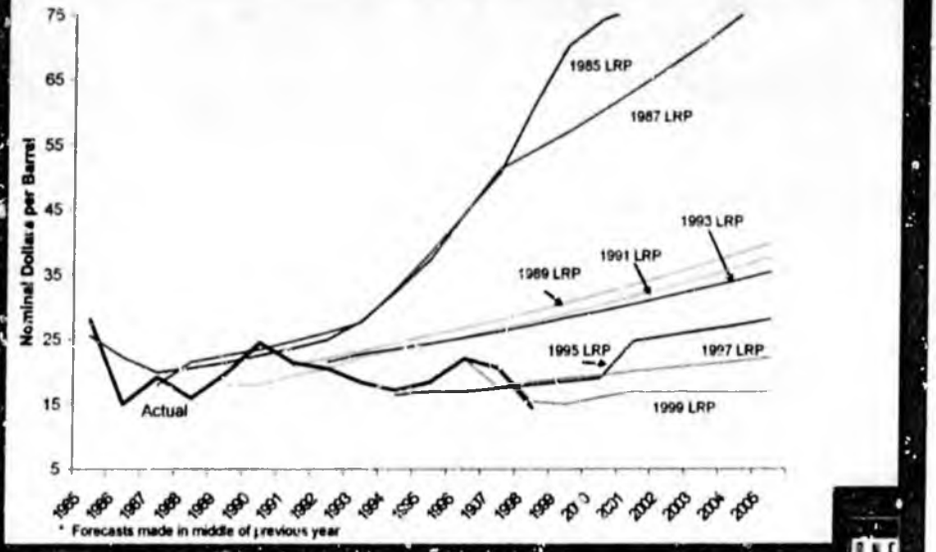
Some Examples of Humbling Oil Price Forecasting

- **Energy Administration Administration (US DOE)**
- **A Private Oil Company**
- **Polls of "experts" – Society of Petroleum Evaluation Engineers**

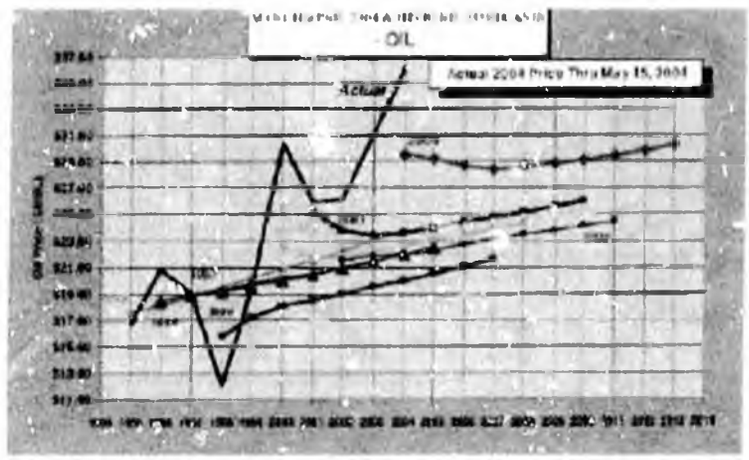
EIA's Annual Price Outlooks



Outlooks From An Oil Company

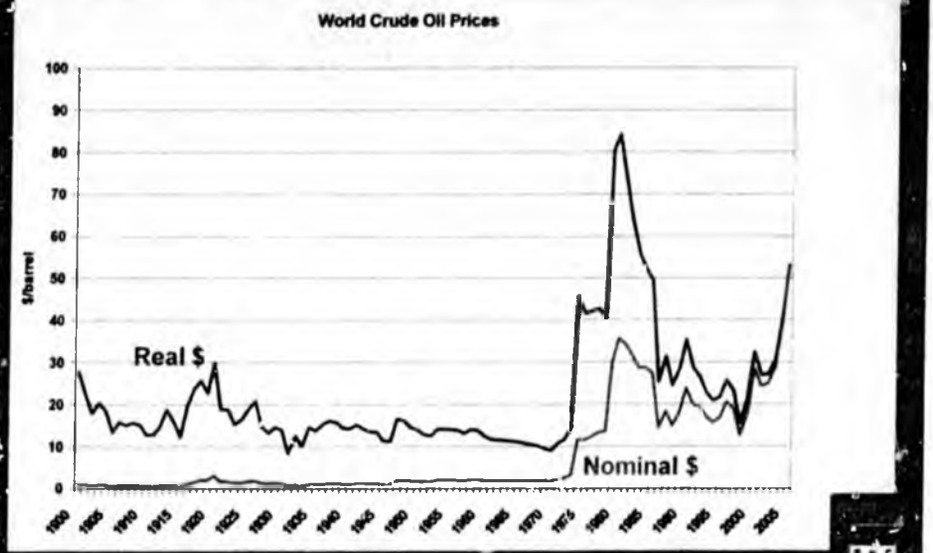


SPEE Annual Delphi Poll

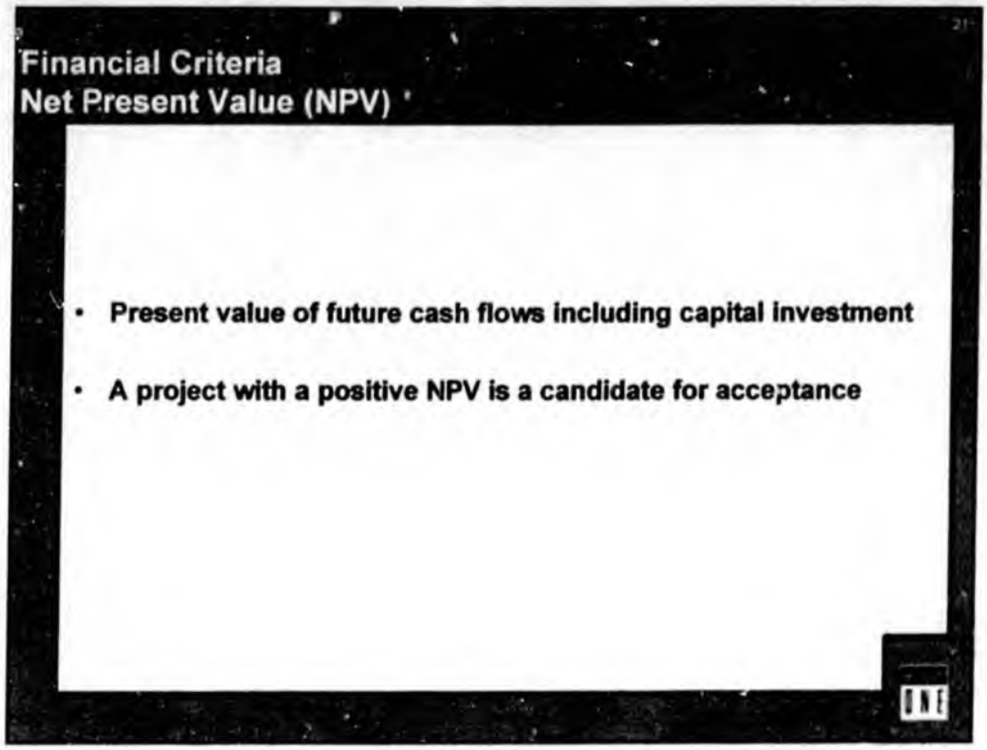


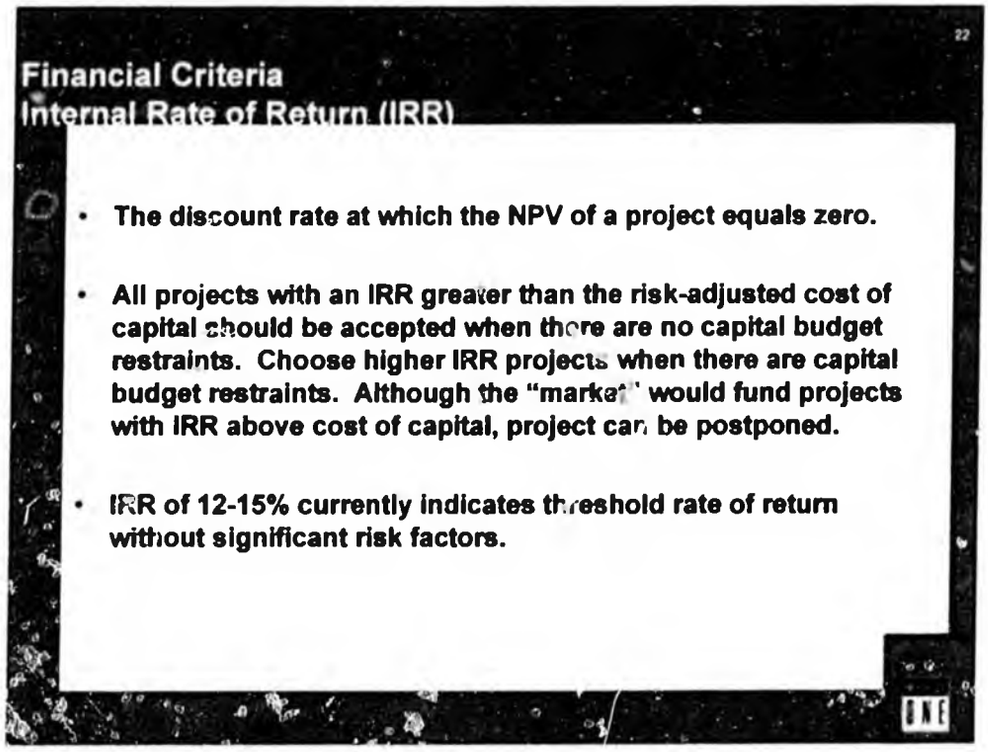
Source: Society of Petroleum Evaluation Engineers (SPEE)

Historical Crude Oil Prices



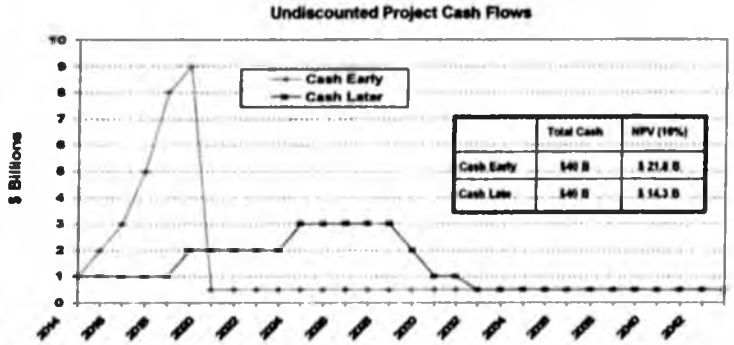
Investment Decision-Making by Oil and Gas Companies


Financial Criteria
Net Present Value (NPV)
• Present value of future cash flows including capital investment
• A project with a positive NPV is a candidate for acceptance


Financial Criteria
Internal Rate of Return (IRR)
• The discount rate at which the NPV of a project equals zero.
• All projects with an IRR greater than the risk-adjusted cost of capital should be accepted when there are no capital budget restraints. Choose higher IRR projects when there are capital budget restraints. Although the "market" would fund projects with IRR above cost of capital, project can be postponed.
• IRR of 12-15% currently indicates threshold rate of return without significant risk factors.

Financial Criteria
Cash (Undiscounted)

- Not used as key investment metric
- Often used to view size of project in presentations to sovereign governments
- Antithetical to discounted cash flow analysis
  - Suffers from failure to reward cash early
  - E.g. Cash flows below are equivalent, but not in discounted terms



Economics of New Fields

Prudhoe Bay Discovery Well - 1967



Conclusions/Observations Regarding Exploration Impacts

- Without ANWR opening, expectation of large oil discoveries are unlikely, due to the Field Size Distribution of remaining economic reserves
- At low prices, 25/20 helps explorer more than 20/20
- Incentives are required at low prices (say, $73 M, although alternative approaches could work as well)
- At low prices, 20/20 and 25/20 preferred over SQ, in order to incent exploration
- Under either a 20/20 or 25/20 program, remaining reserves are economic, except for low prices (<$30?)

Stylized Lifecycle of New Field



Exploration and Appraisal Period — 4 years

Development Capital — 3 years

Production Phase — 5-20+ years

Economic Limit

Comparison of Reserves – Central North Slope vs. ANWR

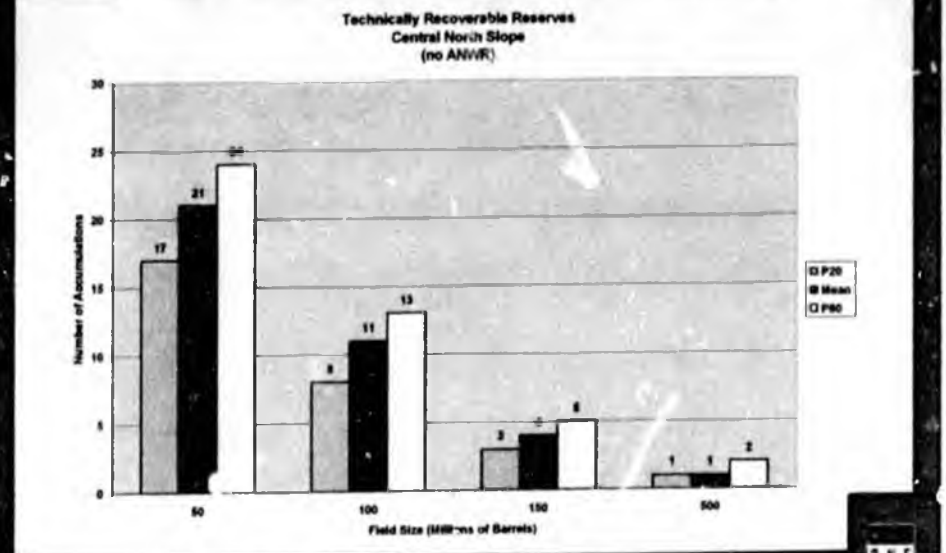
Undiscovered Technically Recoverable Oil Reserves

	Central North Slope	ANWR
Mean Estimate of Reserves (Billions of barrels)	4.0	10.4
Amount in Fields Over 1 B Barrels	0%	22%
Amount in Fields Over 500 M Barrels	2%	43%
Amount in Fields Smaller than 64 M Barrels	51%	1%

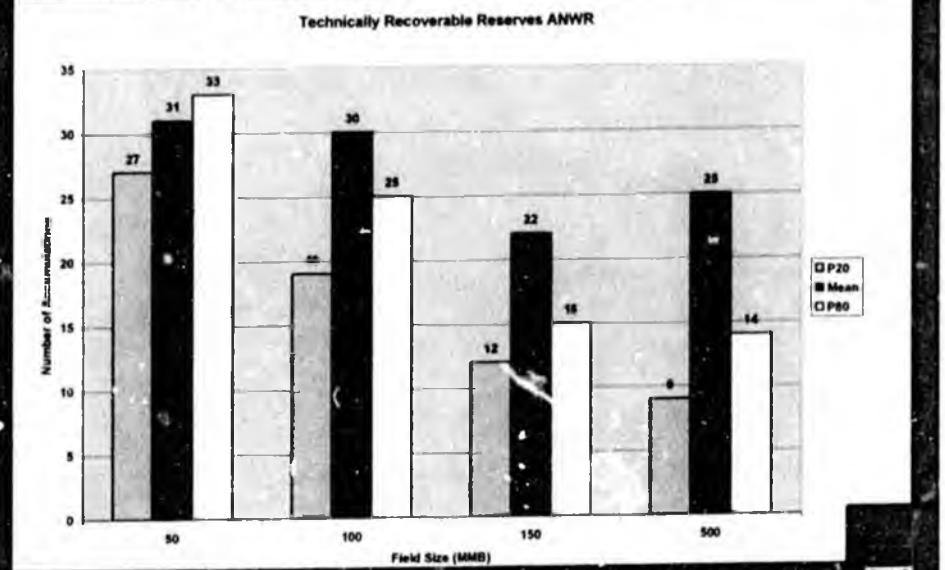
Note: Not all these reserves are economic

Source: USGS

Size Distribution of Undiscovered Fields in Central North Slope

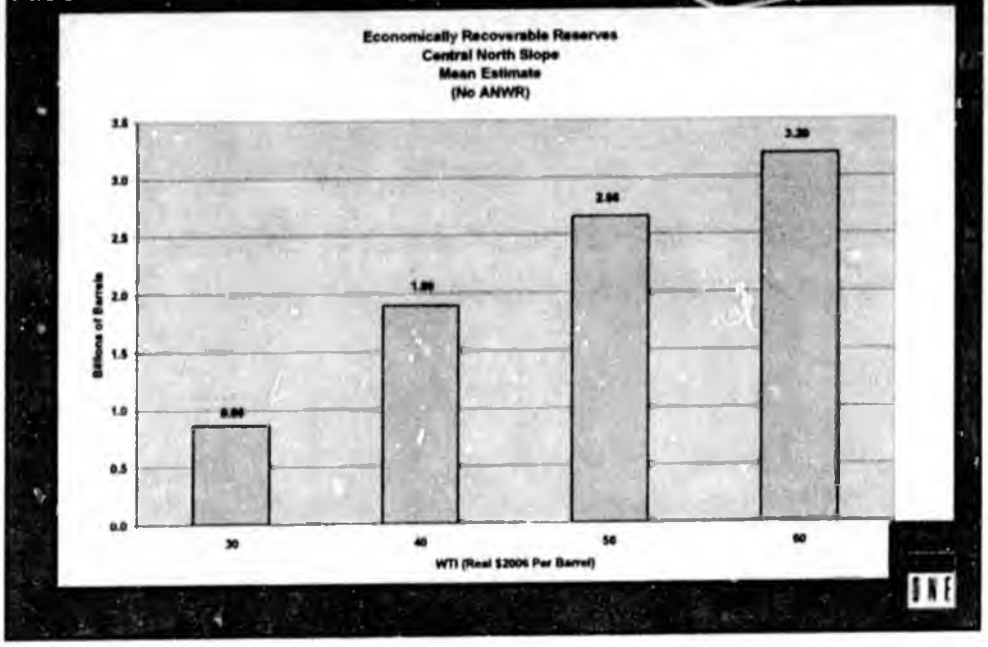


Size Distribution of Undiscovered Fields – ANWR

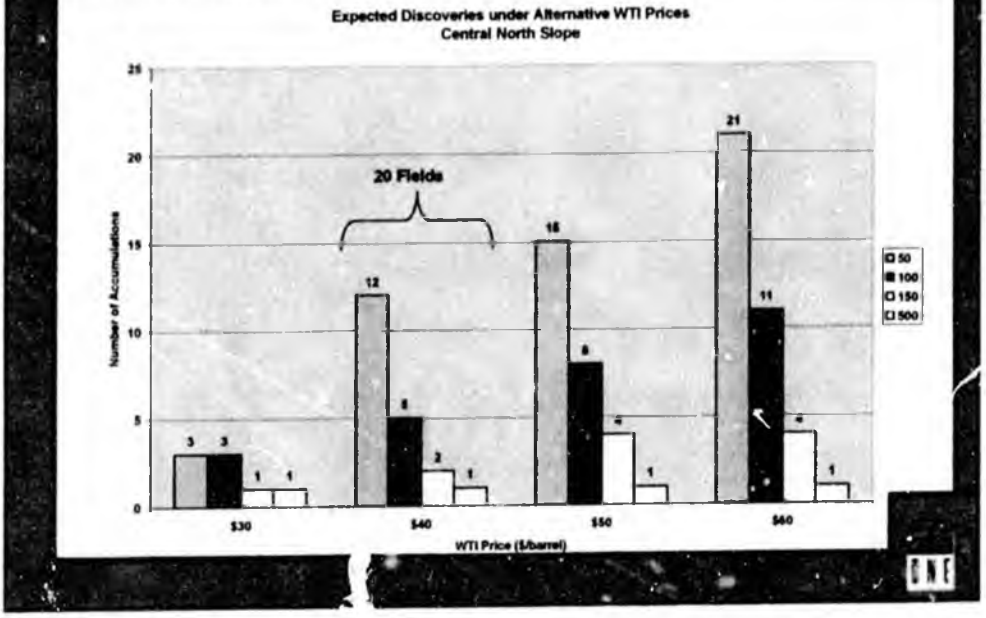


10 Billion Barrels of Technically Recoverable Oil Reserves in ANWR

Economic Oil Reserves in Central North Slope Alaska At Alternative Prices



Expected Discoveries Under Alternative Prices

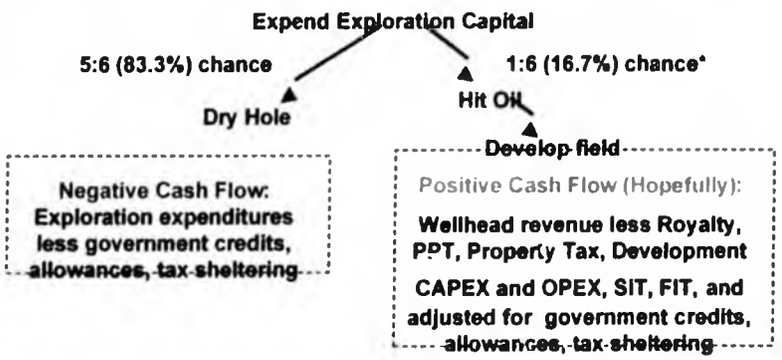


Likely Distribution of New Field Discoveries

Size of Field	Percent
50 MMB	60%
100 MMB	25%
150 MMB	10%
500 MMB	5%

How An Explorer Will Look At The Exploration Proposition

- Calculate the Net Present Value of all outcomes, weighted by the expectation of the outcome
- EMV= NPV (a successful development project) x (Chance of hitting oil) less NPV (cash flow from undertaking exploration)



Schematic of Cash Flows For This Example

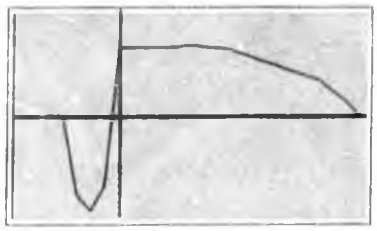
Cash Flow From Exploration

100% **of Time**



Cash Flow From Development and Production

16.7% **of Time**



Avoiding Gambler's Ruin

- **Say the chance of drilling a successful well is 1-in-6, or .167**
- **An explorer will want to mitigate the risk of failure by drilling more wells. (Possibly shared.)**
- **The chance of failure with one well is .833 (=1-.167). The chance of failure with a 6 well program is .334 (=.833^6)**
- **An explorer can drill six wells with an** expected number of successful wells = 1.0

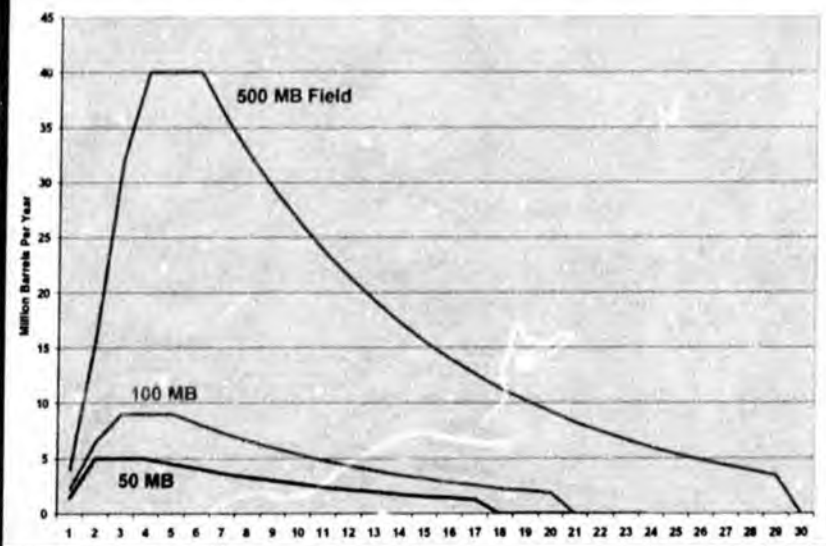
No. of Successes	Chance	Expected Value
0	.3341	0
1	.4019	.4019
2	.2015	.4030
3	.0538	.1614
4	.0081	.0324
5	.0007	.0033
6	.0001	.0078
	Total	1.000

Illustration of A Failed Exploration Program – 1 Well

A One Well Dry Hole Program at $20 Million

	20/20	25/20	SQ
Year			
1	-2.4	-2.3	-3.1
2	-2.3	-2.2	-3.1
3	-2.3	-2.2	-3.2
4	-7.8	-7.4	-10.3
Total Producer Cash Flow	-14.8	-14.2	-19.8
Producer NCF NPV10	-11.1	-10.7	-14.9

Oil Production Profiles



Economics of an 6-Well Exploration Program
50 MM Field (High Cost, Low Productivity)

Without $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	-37.0	-35.7	-79.2
$ 40	44.9	41.1	23.1
$ 50	120.9	110.5	125.5
	State Revenues ($M) NPV10		
$ 30	0.0	-2.1	69.0
$ 40	64.8	71.1	100.4
$ 50	139.2	156.2	131.8

Economics of an 6-Well Exploration Program
50 MM Field (High Cost, Low Productivity)

With $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	43.2	6.0	79.2
$ 40	79.2	22.8	23.1
$ 50	158.8	157.0	125.5
	State Revenues ($M) NPV10		
$ 30	36.0	50.6	69.0
$ 40	10.3	2.0	100.4
$ 50	77.2	78.8	131.8

Economics of an 6-Well Exploration Program

Without $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30			-34.9
$ 40			148.3
$ 50			331.6
	Explorer IRR		
$ 30			9.9
$ 40			14.9
$ 50			21.1
	State Revenues ($M) NPV10		
$ 30			139.2
$ 40			200.6
$ 50			281.9

Economics of an 6-Well Exploration Program

Without $73 M Allowance

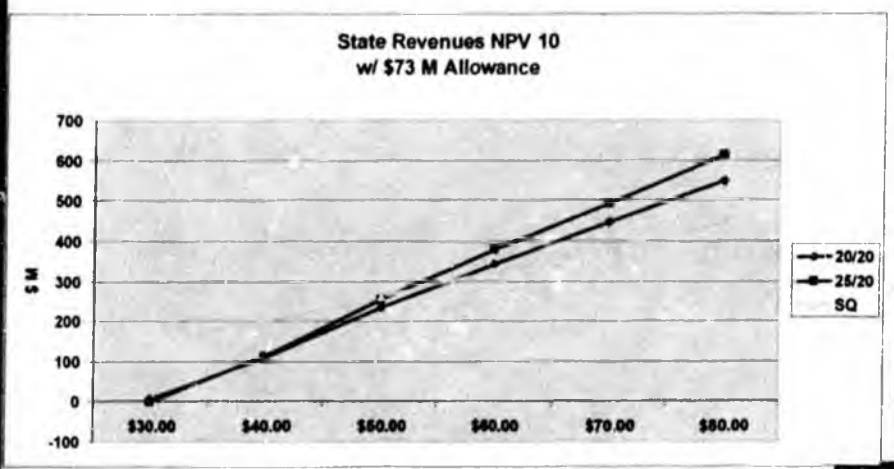
	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	-5.4	3.3	-34.9
$ 40	140.7	138.9	148.3
$ 50	284.1	261.7	331.6
	Explorer IRR		
$ 30	10.3	10.2	9.9
$ 40	17.4	16.9	14.9
$ 50	22.8	22.5	21.1
	State Revenues ($M) NPV10		
$ 30	51.2	54.1	139.2
$ 40	165.7	183.4	200.6
$ 50	296.0	327.5	264.9

Economics of an 6-Well Exploration Program

With $73 M Allowance

	Explorer NCF NPV10		
Price (Real $2006)	20/20	25/20	SQ
$ 30	32.6	37.7	-34.9
$ 40	184.5	182.4	148.3
$ 50	323.5	311.0	331.6
	Explorer IRR		
$ 30	11.7	12.0	9.9
$ 40	18.5	18.7	14.9
$ 50	23.9	24.0	21.1
	State Revenues ($M) NPV10		
$ 30	6.2	-2.2	139.2
$ 40	108.9	112.3	200.6
$ 50	232.6	253.0	261.9

State Revenues (NPV10) From Example Exploration Program

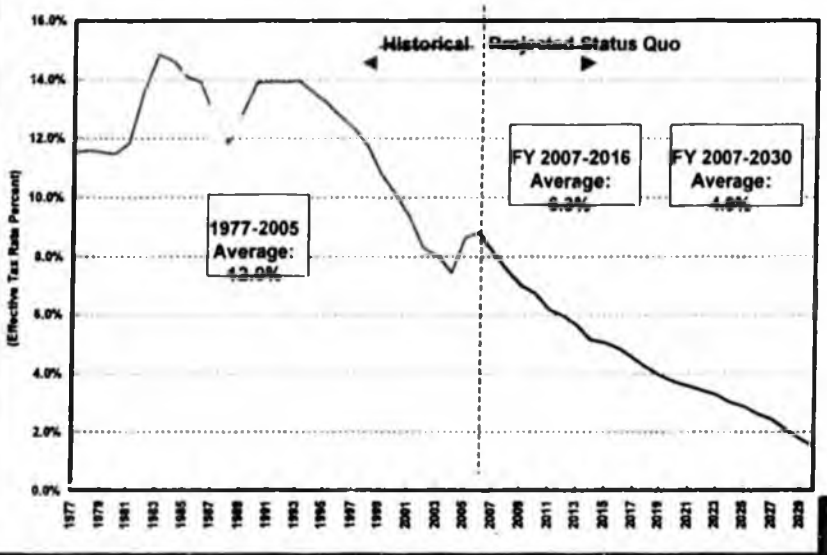


Conclusions/Observations Regarding Exploration Impacts

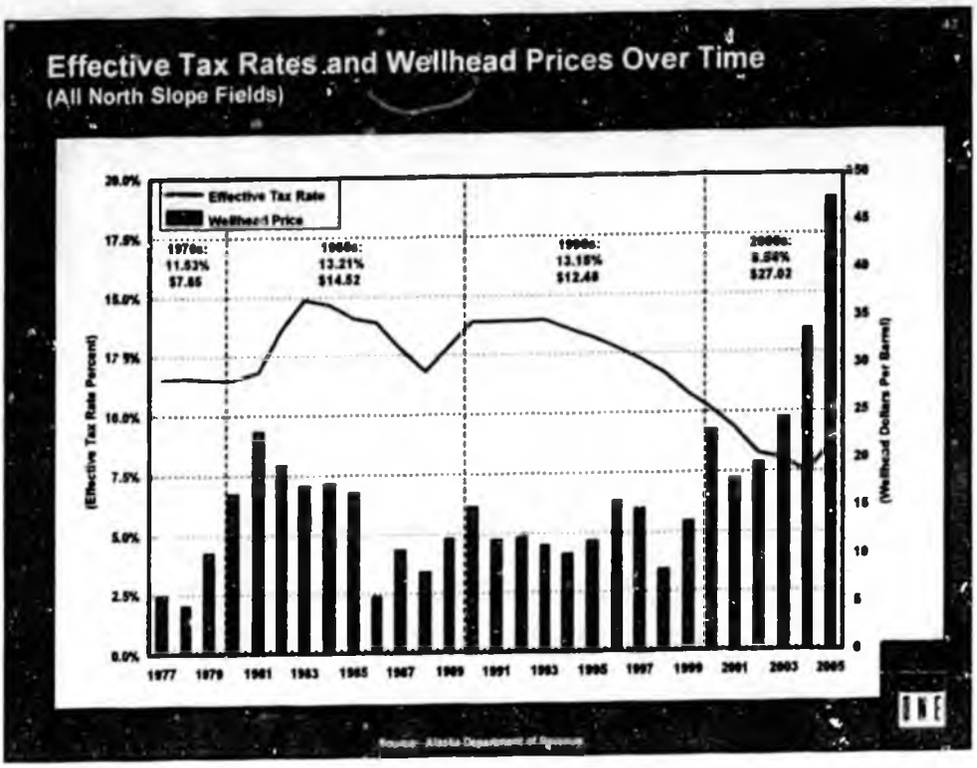
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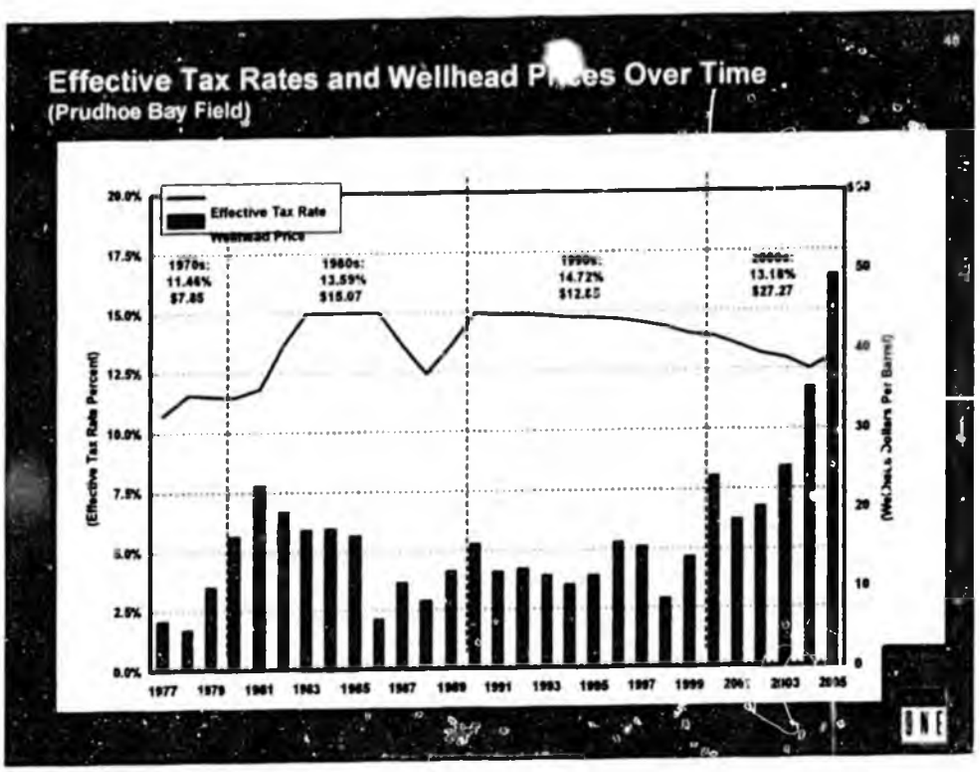
EIA

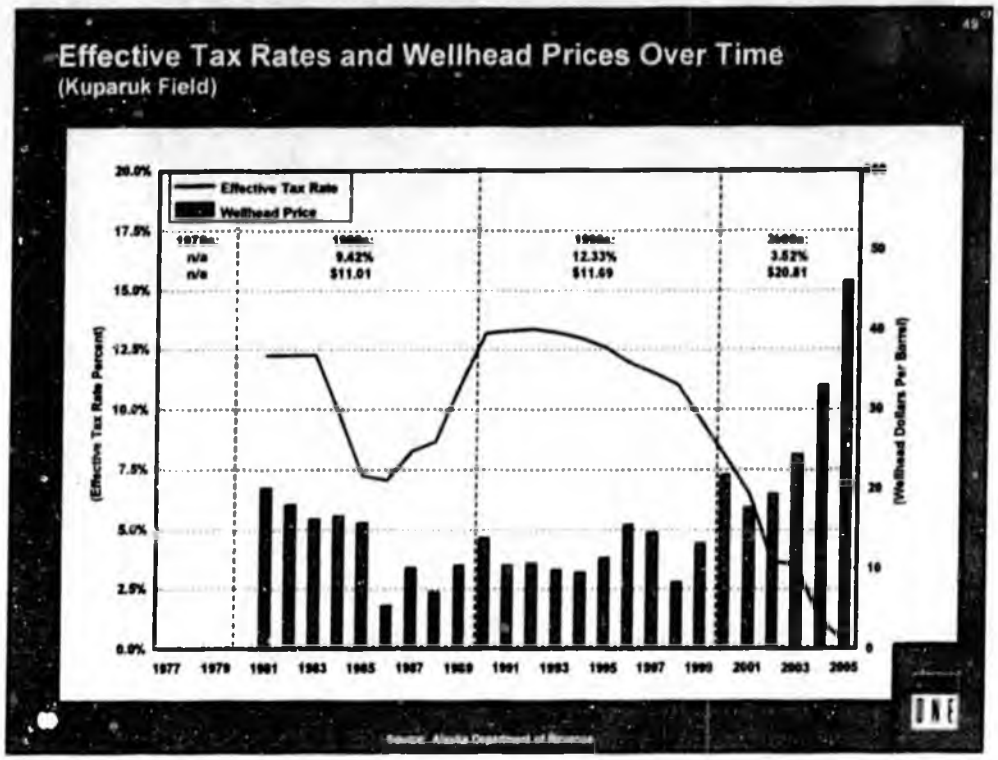
Effective Severance Tax Rates Over Time

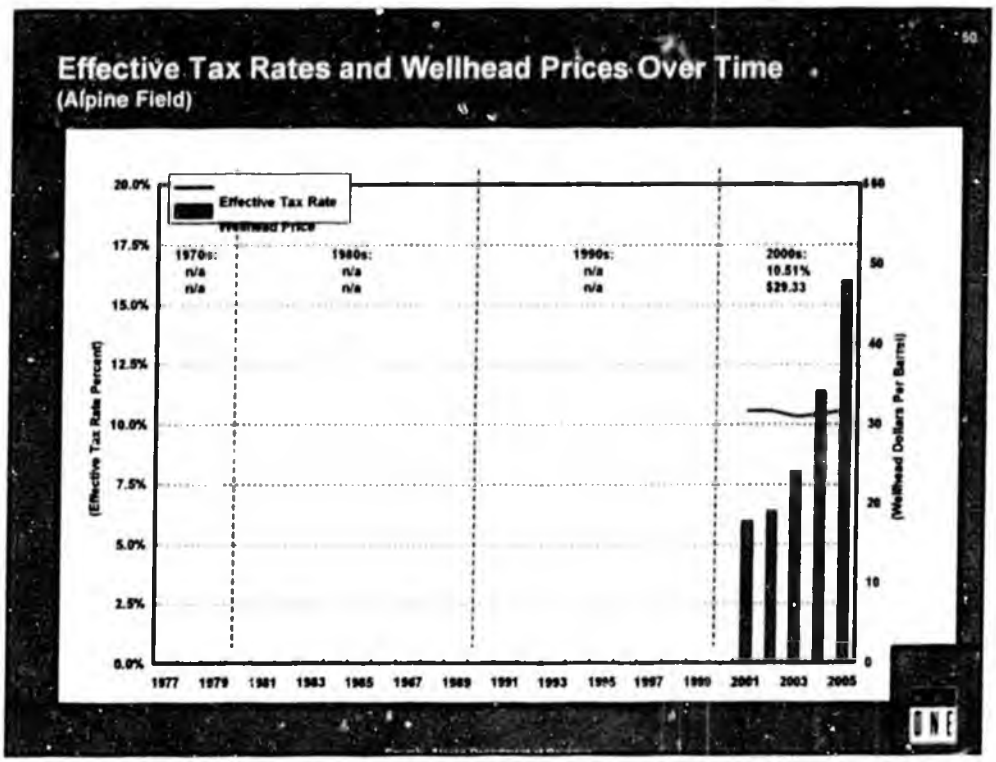


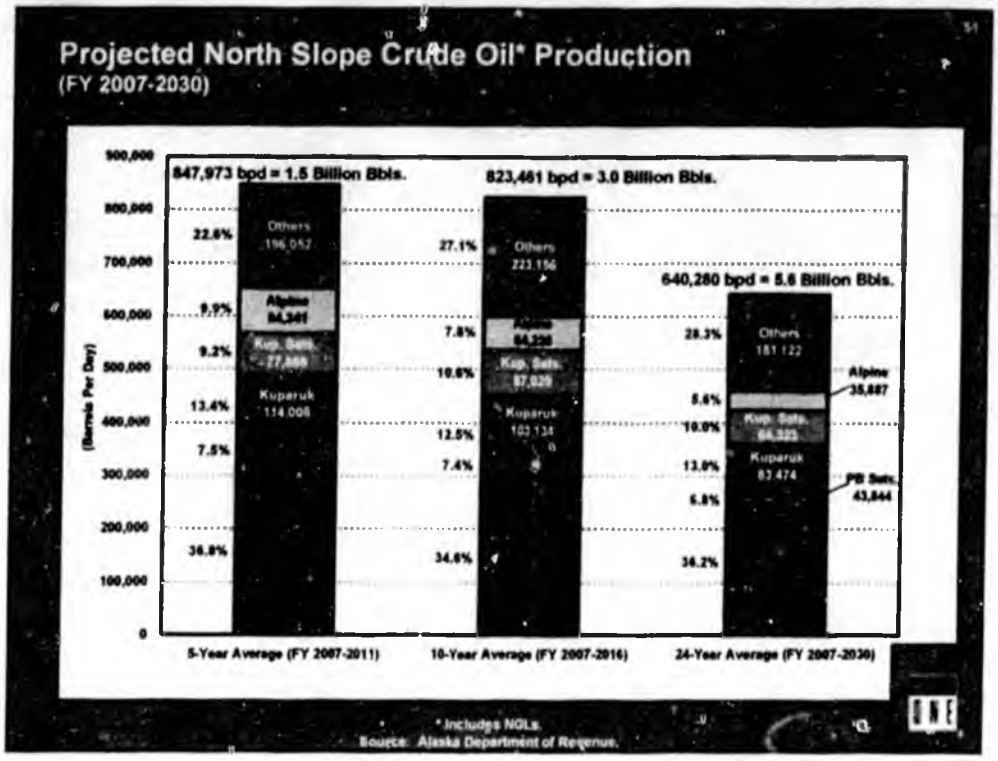
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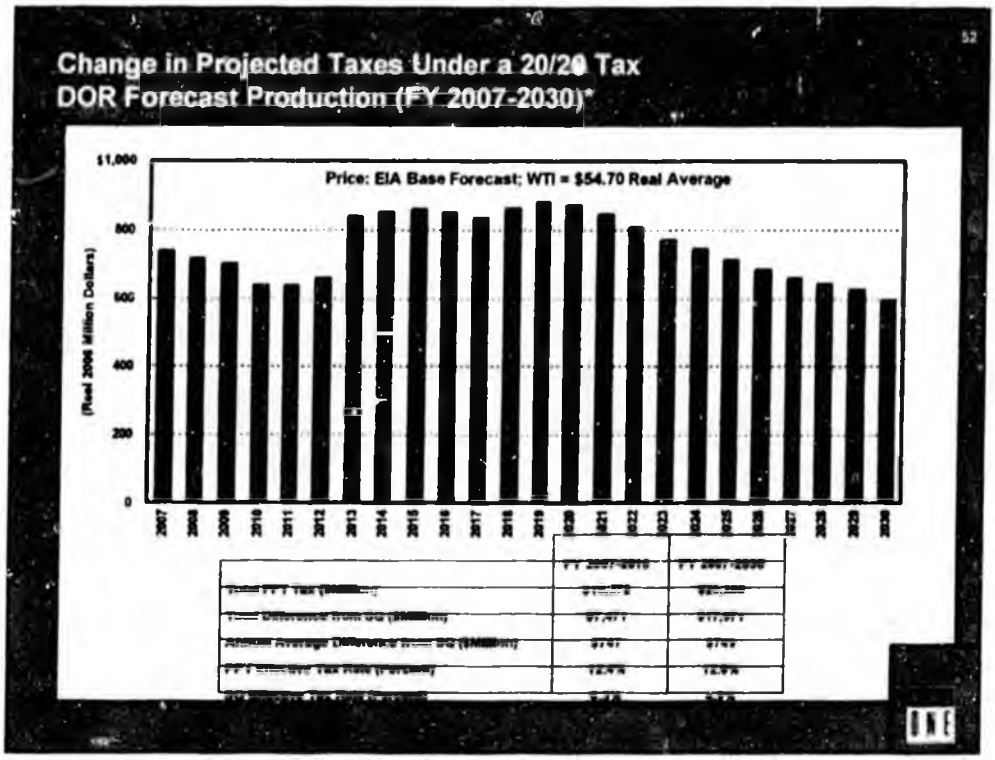

Effective Tax Rates and Wellhead Prices Over Time
(All North Slope Fields)
Effective Tax Rate
Wellhead Price
1970s:
11.53%
$7.85
1980s:
13.21%
$14.52
1990s:
13.18%
$12.48
2000s:
8.56%
$27.02
(Effective Tax Rate Percent)
(Wellhead Dollars Per Barrel)
20.0%
17.5%
15.0%
12.5%
10.0%
7.5%
5.0%
2.5%
0.0%
50
45
40
35
30
25
20
15
10
5
0
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005


Effective Tax Rates and Wellhead Prices Over Time
(Prudhoe Bay Field)
Effective Tax Rate
1970s:
11.46%
$7.85
1980s:
13.59%
$15.07
1990s:
14.72%
2000s:
13.18%
$27.27
(Effective Tax Rate Percent)
20.0%
17.5%
15.0%
12.5%
10.0%
7.5%
5.0%
2.5%
0.0%
50
40
30
20
10
0
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999

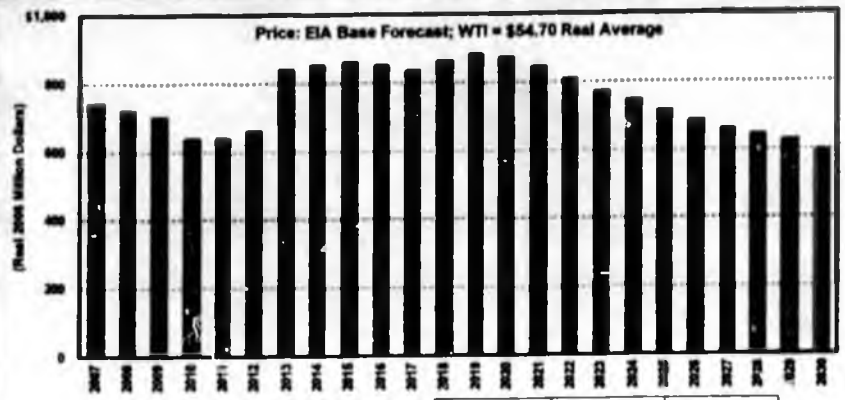

Effective Tax Rates and Wellhead Prices Over Time
(Kuparuk Field)
Effective Tax Rate
Wellhead Price
1970s:
n/a
n/a
1980s:
9.42%
$11.01
1990s:
12.33%
$11.69
2000s:
3.82%
$20.81
(Effective Tax Rate Percent)
(Wellhead Dollars Per Barrel)
20.0%
17.5%
15.0%
12.5%
10.0%
7.5%
5.0%
2.5%
0.0%
50
40
30
20
10
0
1977 1979 1981 1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005
Source: Alaska Department of Revenue


Effective Tax Rates and Wellhead Prices Over Time
(Alpine Field)
Effective Tax Rate
Wellhead Price
1970s:
n/a
n/a
1980s:
n/a
n/a
1990s:
n/a
n/a
2000s:
10.51%
$29.33
(Effective Tax Rate Percent)
(Wellhead Dollars Per Barrel)
20.0%
17.5%
15.0%
12.5%
10.0%
7.5%
5.0%
2.5%
0.0%
50
40
30
20
10
0
1977 1979 1981 1983 1985 1987 1989 1991 1993 1995 1997 1999 2001 2003 2005


Projected North Slope Crude Oil* Production
(FY 2007-2030)
847,973 bpd = 1.5 Billion Bbls.
823,461 bpd = 3.0 Billion Bbls.
640,280 bpd = 5.6 Billion Bbls.
(Barrels Per Day)
Others
Alpine
Kup. Sats.
Kuparuk
Alpine 35,887
PB Sats. 43,844
5-Year Average (FY 2007-2011)
10-Year Average (FY 2007-2016)
24-Year Average (FY 2007-2030)
* Includes NGLs.
Source: Alaska Department of Revenue.


Change in Projected Taxes Under a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*
Price: EIA Base Forecast; WTI = $54.70 Real Average
(Real 2006 Million Dollars)

Change in Projected Taxes Under a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030	1H 2006
Total PPT Tax ($Million)	$15,272	$29,255	$1,127
Total Difference from SQ ($Million)	$7,471	$17,871	$476
Annual Average Difference from SQ ($Million)	$747	$749	n/a
PPT Effective Tax Rate (Percent)	12.4%	12.6%	15.2%
SQ Effective Tax Rate (Percent)	6.3%	4.9%	8.8%

ANE

* Calculated from July 2006, includes 6-year transition and $75 Million exemption, volumes per DOR Fall 2006 Forecast with Original projection

Change in Projected Taxes Under a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*

	EIA WTI Price Forecast: Base	Low	High	Fixed $40 Price	FY2007-2016 Breakeven	FY2007-2030 Breakeven
Average WTI Price in Real 2006 Dollars	$54.70	$35.40	$72.00	$40.00	$36.30	$26.60
FY 2007-2016						
Total PPT Tax (Million 2006$)	$15,272	$8,788	$21,158	$8,888	$3,635	-
Total Difference from Status Quo (Million 2006$)	$7,471	$3,614	$11,888	$3,434	$0	-
Annual Average Difference from Status Quo (Million 2006$)	$747	$361	$1,188	$343	$0	-
PPT Effective Tax Rate (Percent)	12.4%	10.3%	13.6%	10.2%	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.3%	6.3%	6.3%	-
FY 2007-2030						
Total PPT Tax (Million 2006$)	$29,255	$12,788	$44,738	$16,230	-	$5,293
Total Difference from Status Quo (Million 2006$)	$17,871	$4,824	$30,282	$8,317	-	$0
Annual Average Difference from Status Quo (Million 2006$)	$749	$201	$1,261	$347	-	$0
PPT Effective Tax Rate (Percent)	12.6%	8.7%	14.5%	10.0%	-	5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	5.0%

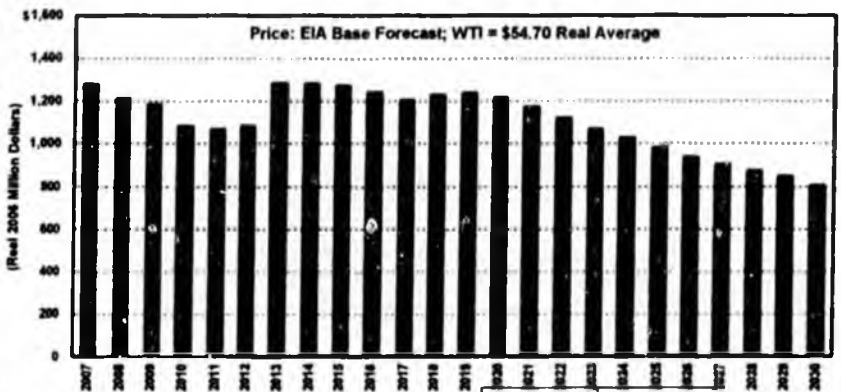
ANE

Change in Projected Taxes Under a 20/20 Tax with Costs Increased by 20% DOR Forecast Production (FY 2007-2030)*

	EIA WTI Price Forecast: Base	Low	High	Fixed $40 Price	FY2007-2016 Breakeven	FY2007-2030 Breakeven
Average WTI Price in Real 2006 Dollars	$54.70	$35.40	$72.00	$40.00	$34.60	$32.50
FY 2007-2016						
Total PPT Tax (Million 2006$)	$13,888	$8,328	$18,688	$7,418	$4,579	-
Total Difference from Status Quo (Million 2006$)	$6,469	$2,145	$10,210	$1,000	$0	-
Annual Average Difference from Status Quo (Million 2006$)	$646	$214	$1,022	$107	$0	-
PPT Effective Tax Rate (Percent)	11.3%	6.8%	13.9%	6.0%	3.7%	-
Status Quo Effective Tax Rate (Percent)	6.3%	0.5%	8.2%	0.3%	0.3%	-
FY 2007-2030						
Total PPT Tax (Million 2006$)	$36,888	$18,070	$41,888	$13,480		$6,159
Total Difference from Status Quo (Million 2006$)	$16,227	$3,139	$27,911	$5,888	-	$0
Annual Average Difference from Status Quo (Million 2006$)	$634	$86	$1,148	$232	-	$0
PPT Effective Tax Rate (Percent)	11.0%	6.0%	13.0%	5.0%	-	4.9%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	4.9%

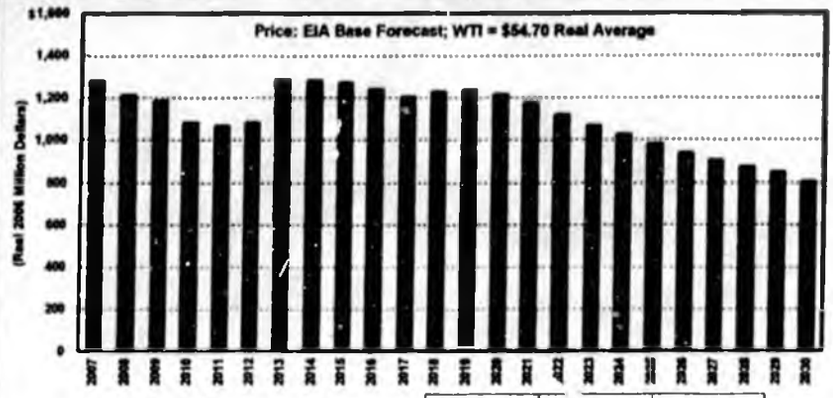
* Calculated from July 2006 decline & year transition and $73 Million assumption, optimism per DOR Fall 2006 Forecast with Ongoing projection

Change in Projected Taxes Under a 25/20 Tax DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030
Total PPT Tax ($Million)	$13,888	$36,888
Total Difference from SQ ($Million)	$11,388	$20,969
Annual Average Difference from SQ ($Million)	$1,197	$1,199
PPT Effective Tax Rate (Percent)	19.9%	10.9%
Status Quo Effective Tax Rate (Percent)	6.3%	4.9%

Change in Projected Taxes Under a 25/20 Tax .DOR Forecast Production (FY 2007-2030)*

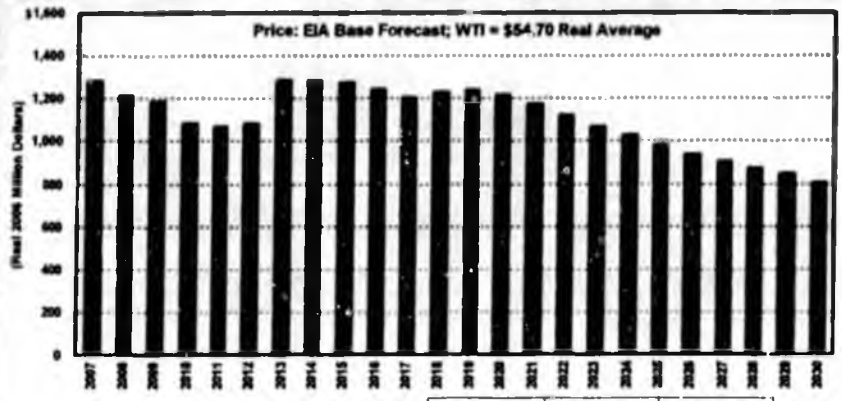


	FY 2007-2016	FY 20[illegible] 1030	1H 2006
Total PPT Tax ($Million)	$19,769	$37,840	$1,432
Total Difference from SQ ($Million)	$11,968	$26,555	$782
Annual Average Difference from SQ ($Million)	$1,197	$1,106	n/a
PPT Effective Tax Rate (Percent)	16.0%	16.4%	19.4%
SQ Effective Tax Rate (Percent)	8.3%	4.9%	8.8%

Change in Projected Taxes Under a 25/20 Tax DOR Forecast Production (FY 2007-2030)*

	EIA WTI Price Forecast: Base	Low	High	Fixed $40 Price	FY2007-2016 Breakeven	FY2007-2030 Breakeven
Average WTI Price in Real 2006 Dollars	$54.70	$35.40	$72.00	$40.00	$27.10	$26.10
FY 2007-2016						
Total PPT Tax (Million 2006$)	$19,769	$12,915	$27,126	$11,789	$3,382	-
Total Difference from Status Quo (Million 2006$)	$11,968	$6,740	$17,656	$6,335	$0	-
Annual Average Difference from Status Quo (Million 2006$)	$1,197	$674	$1,766	$633	$0	-
PPT Effective Tax Rate (Percent)	16.0%	13.5%	17.7%	13.6%	8.3%	-
Status Quo Effective Tax Rate (Percent)	8.3%	8.5%	8.2%	8.3%	8.3%	-
FY 2007-2030						
Total PPT Tax (Million 2006$)	$37,840	$17,228	$57,193	$21,558	-	$4,671
Total Difference from Status Quo (Million 2006$)	$26,555	$6,295	$42,717	$13,645	-	$0
Annual Average Difference from Status Quo (Million 2006$)	$1,106	$357	$1,780	$569	-	$0
PPT Effective Tax Rate (Percent)	16.4%	11.7%	18.5%	13.3%	-	5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	5.0%

Change in Projected Taxes Under a 25/20 Tax DOR Forecast Production (FY 2007-2030)*



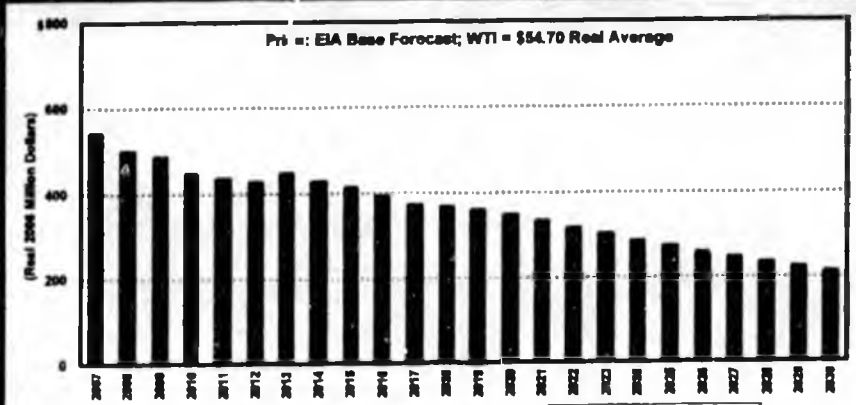
	FY 2007-2016	FY 2007-2030	1H 2006
Total PPT Tax ($Million)	$19,769	$37,840	$1,532
Total Difference from SQ ($Million)	$11,968	$26,685	$782
Annual Average Difference from SQ ($Million)	$1,197	$1,106	n/a
PPT Effective Tax Rate (Percent)	16.0%	16.4%	19.4%
SQ Effective Tax Rate (Percent)	6.3%	4.9%	8.8%

* Calculated from July 2006; includes 5-year transition and $73 Million exemption; assumes per DOR Fall 2006 forecast with Gaffney production

Change in Projected Taxes Under a 25/20 Tax DOR Forecast Production (FY 2007-2030)*

	EIA WTI Price Forecast: Base	Low	High	Fixed $40 Price	FY2007-2016 Breakeven	FY2007-2030 Breakeven
Average WTI Price in Real 2006 Dollars	$54.70	$35.40	$72.00	$40.00	$27.10	$26.10
FY 2007-2016						
Total PPT Tax (Million 2006$)	$19,769	$12,915	$27,126	$11,769	$3,382	-
Total Difference from Status Quo (Million 2006$)	$11,968	$6,740	$17,656	$6,335	$0	-
Annual Average Difference from Status Quo (Million 2006$)	$1,197	$674	$1,766	$633	$0	-
PPT Effective Tax Rate (Percent)	16.0%	13.9%	17.7%	13.9%	6.3%	-
Status Quo Effective Tax Rate (Percent)	6.3%	6.5%	6.3%	6.3%	6.3%	-
FY 2007-2030						
Total PPT Tax (Million 2006$)	$37,840	$17,226	$67,183	$21,506	-	$4,671
Total Difference from Status Quo (Million 2006$)	$26,685	$6,268	$42,717	$13,645	-	$0
Annual Average Difference from Status Quo (Million 2006$)	$1,106	$387	$1,780	$566	-	$0
PPT Effective Tax Rate (Percent)	16.4%	11.7%	18.5%	13.3%	-	5.0%
Status Quo Effective Tax Rate (Percent)	4.9%	5.4%	4.7%	4.9%	-	5.0%

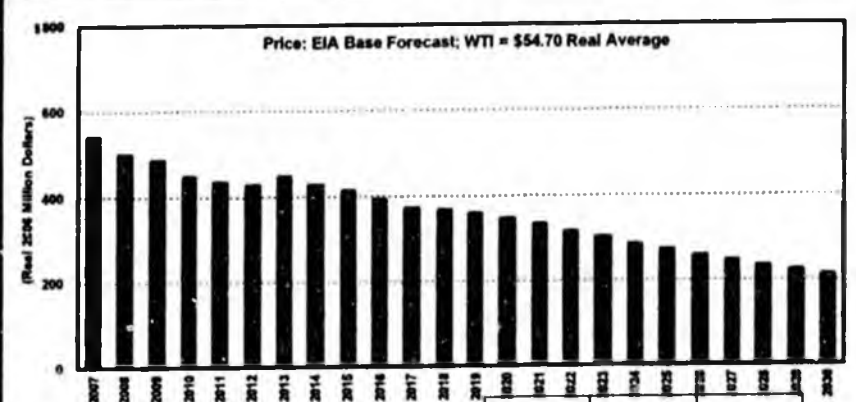
Difference in Projected Taxes Between a 25/20 and a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



	FY 2007-2016	FY 2007-2030
Total 25/20 PPT Tax ($Million)	$119,799	$37,840
Total Difference from 20/20 PPT Tax ($Million)	$4,487	$8,584
Annual Average Difference from 20/20 PPT Tax ($Million)	$449	$368
20/20 PPT Effective Tax Rate (Percent)	16.0%	16.4%
25/20 PPT Effective Tax Rate (Percent)	12.6%	12.6%

* Calculated from July 2006, including 5-year transition and $72 billion assumption; volumes per DOR Fall 2006 Forecast with Objective production

Difference in Projected Taxes Between a 25/20 and a 20/20 Tax DOR Forecast Production (FY 2007-2030)*



Difference in Projected Taxes Between a 25/20 and a 20/20 Tax
DOR Forecast Production (FY 2007-2030)*

	EIA WTI Price Forecast			Fixed	FY2007-2016	FY2007-2030
	Base	Low	High	$40 Price	Breakeven	Breakeven
Average WTI Price in Real 2006 Dollars	$54.70	$35.40	$72.00	$40.00	-	-
FY 2007-2016						
Total 25/20 PPT Tax (Million 2006$)	$18,799	$12,915	$27,126	$11,789	-	-
Total Difference from 20/20 PPT Tax (Million 2006$)	$4,497	$3,126	$5,998	$2,901	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006$)	$450	$313	$597	$290	-	-
25/20 PPT Effective Tax Rate (Percent)	16.6%	13.6%	17.7%	13.6%	-	-
20/20 PPT Effective Tax Rate (Percent)	12.4%	10.3%	13.8%	10.2%	-	-
FY 2007-2030						
Total 25/20 PPT Tax (Million 2006$)	$37,640	$17,226	$57,193	$21,558	-	-
Total Difference from 20/20 PPT Tax (Million 2006$)	$8,564	$4,462	$12,455	$5,328	-	-
Annual Average Difference from 20/20 PPT Tax (Million 2006$)	$358	$186	$519	$222	-	-
25/20 PPT Effective Tax Rate (Percent)	16.4%	11.7%	18.5%	13.3%	-	-
20/20 PPT Effective Tax Rate (Percent)	12.6%	8.7%	14.5%	10.0%	-	-

*Calculated from July 2006, includes 6-year transition and $73 Million exemption, volumes per DOR Fall 2006 Forecast with Ooguruk projection

Projected Government Takes
DOR Forecast Production (FY 2007-2030)*

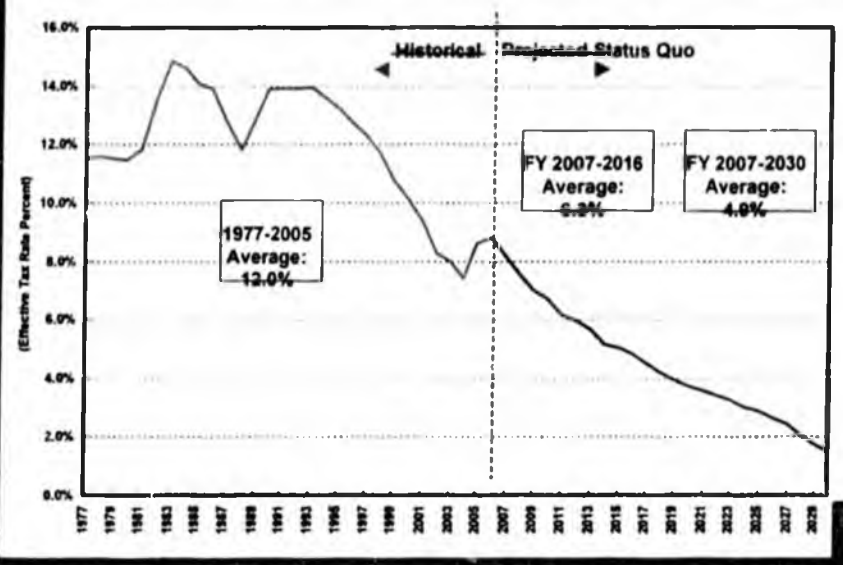
	Total Government Take (Percent)				Alaska Take (Percent)			
	EIA WTI Price Forecast			Fixed	EIA WTI Price Forecast			Fixed
	Base	Low	High	$40 Price	Base	Low	High	$40 Price
Average WTI Price in Real 2006 Dollars	*$54.70*	*$35.40*	*$72.00*	*$40.00*	*$54.70*	*$35.40*	*$72.00*	*$40.00*
FY 2007-2016								
Status Quo	**53.3%**	55.0%	52.4%	55.5%	**24.8%**	26.9%	23.7%	27.2%
20/20 PPT	**57.2%**	57.6%	57.1%	58.2%	**30.9%**	30.9%	31.0%	31.5%
25/20 PPT	**58.6%**	59.0%	59.6%	60.6%	**34.5%**	34.5%	34.8%	35.1%
FY 2007-2030								
Status Quo	**51.9%**	54.7%	50.6%	53.7%	**23.4%**	27.2%	22.0%	25.7%
20/20 PPT	**56.9%**	57.1%	56.9%	57.3%	**31.2%**	30.9%	31.3%	31.3%
25/20 PPT	**58.3%**	59.3%	58.3%	59.7%	**34.8%**	34.3%	35.2%	34.9%

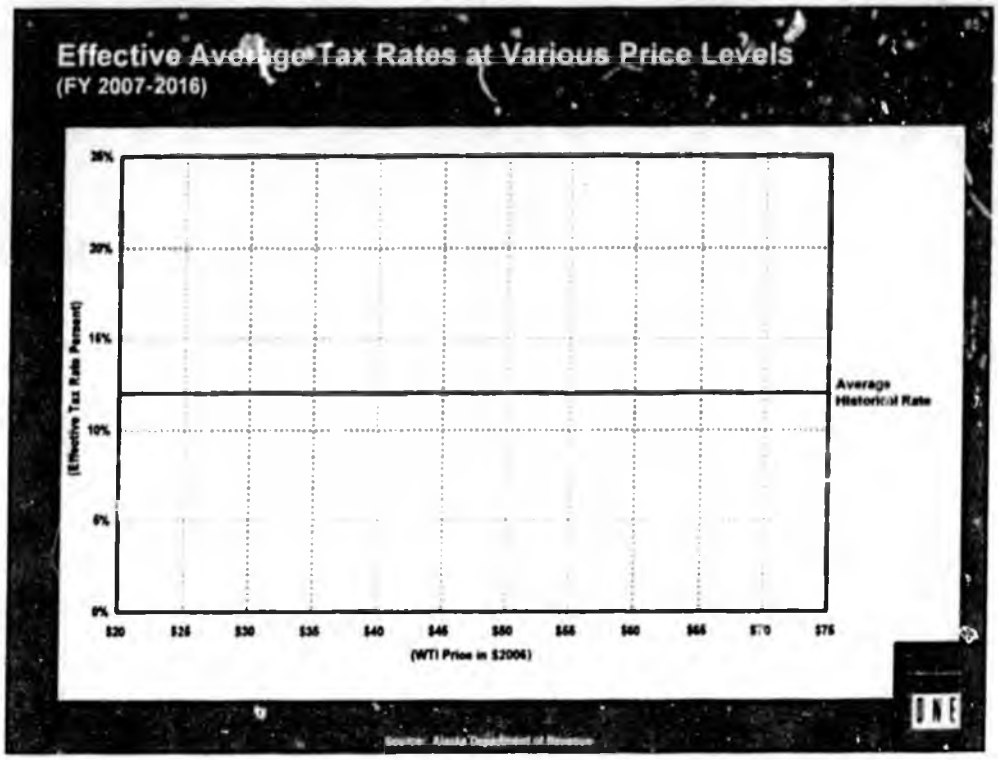
Projected Annual Average Taxes at Various Tax Rates and Prices
DOR Forecast Production (FY 2007-2030)*

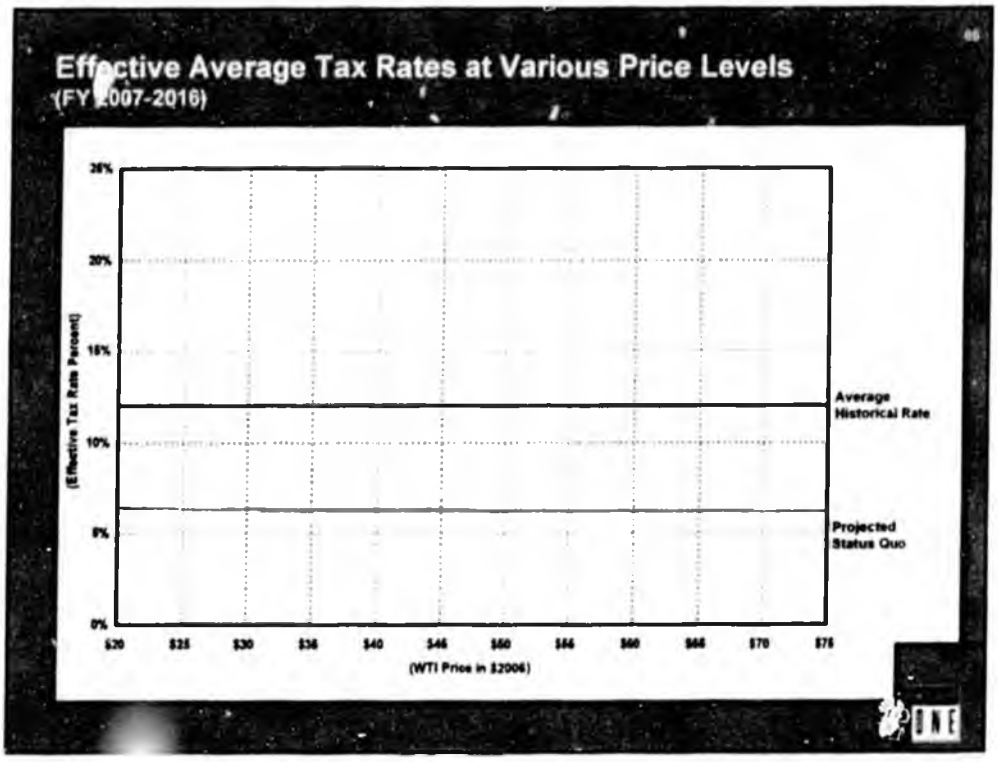
WTI Price	20/20	21/20	22/20	23/20	24/20	25/20	Change Per % Increase in Tax Rate	Change Per % Increase in Credit Rate
	(Million 2005 Dollars)							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
FY 2007-2016								
$40	$[illegible]	$[illegible]	$1,034.8	$1,082.8	$1,130.9	$1,178.9	$58.0	($13.6)
$45	$1,149.5	$1,220.6	$1,291.6	$1,362.7	$1,433.7	$1,504.8	$71.1	($13.6)
$50	$1,490.2	$1,494.3	$1,578.4	$1,662.5	$1,746.6	$1,830.7	$84.1	($13.6)
$55	$1,671.0	$1,768.1	$1,865.2	$1,962.4	$2,059.5	$2,156.6	$97.1	($13.6)
$60	$1,831.7	$2,041.9	$2,152.1	$2,262.2	$2,372.4	$2,482.6	$110.2	($13.6)
Change Per Dollar Increase in WTI Price	$82.1	$84.8	$87.4	$90.0	$92.6	$95.2		
FY 2007-2030								
$40	$678.3	$720.7	$765.1	$809.5	$853.9	$898.3	$44.4	($10.0)
$45	$878.9	$933.5	$988.0	$1,042.5	$1,097.1	$1,151.6	$54.5	($10.0)
$50	$1,081.6	$1,146.3	$1,211.0	$1,275.6	$1,340.3	$1,405.0	$64.7	($10.0)
$55	$1,284.3	$1,359.1	$1,433.9	$1,508.7	$1,583.5	$1,658.3	$74.8	($10.0)
$60	$1,487.0	$1,571.9	$1,656.9	$1,741.8	$1,826.7	$1,911.7	$84.9	($10.0)
Change Per Dollar Increase in WTI Price	$40.5	$42.0	$44.0	$46.0	$48.0	$50.7		

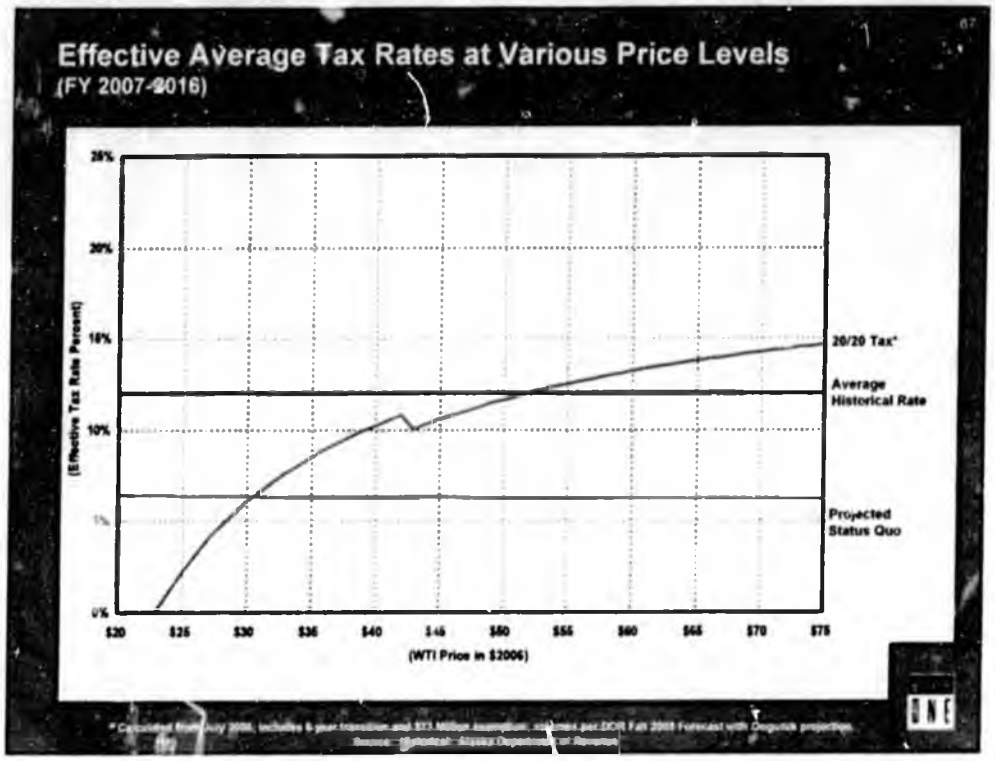
* Calculated from July 2006, $73 Million exemption; does not include transition volumes per DOR Fall 2006 Forecast with Ongaack projection

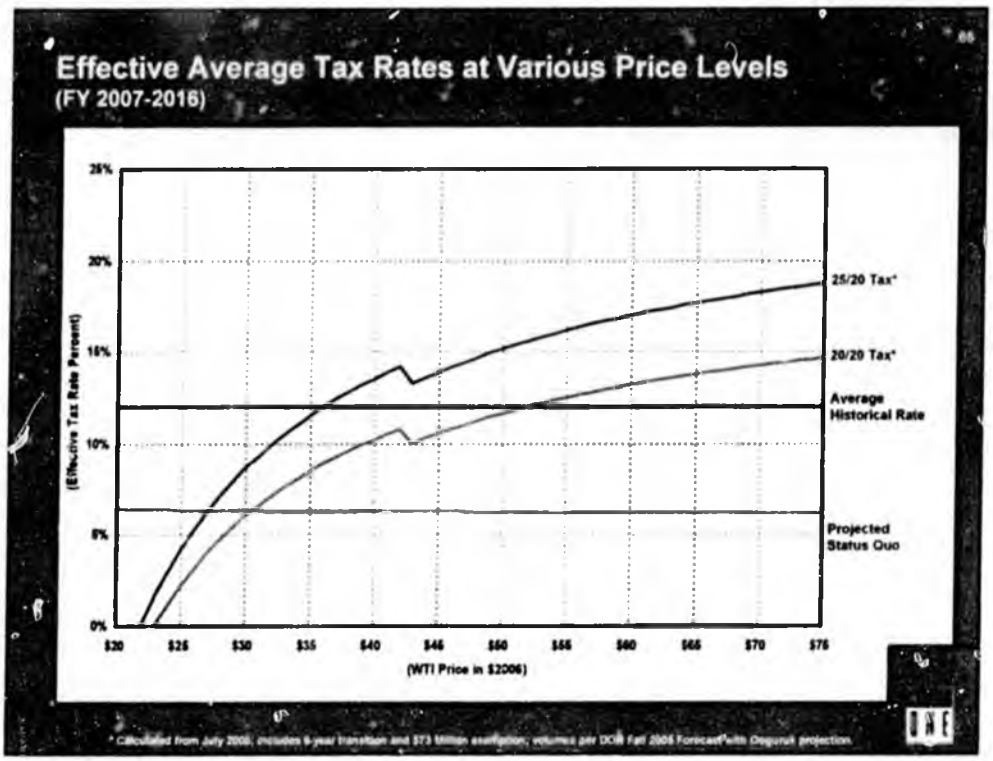
Effective Severance Tax Rates Over Time




Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
35%
30%
15%
10%
5%
0%
(Effective Tax Rate Percent)
Average
Historical Rate
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
ANE


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
35%
30%
15%
10%
5%
0%
(Effective Tax Rate Percent)
Average
Historical Rate
Projected
Status Quo
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
ANE


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
20/20 Tax*
Average Historical Rate
Projected Status Quo


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
25%
20%
15%
10%
5%
0%
(Effective Tax Rate Percent)
$20
$25
$30
$35
$40
$45
$50
$55
$60
$65
$70
$75
(WTI Price in $2006)
25/20 Tax*
20/20 Tax*
Average Historical Rate
Projected Status Quo

Example of Tax with Sliding Scale

Assumptions: 0.25% per dollar over $45/barrel WTI (threshold);
$55/barrel WTI price;
$47/barrel ANS wellhead price;
20/20 PPT.

- Sliding Scale Tax in Addition to PPT, and Deductible Against PPT
- If WTI is <= Threshold price (e.g., $45): No Additional Tax
- If WTI is > Threshold price: Additional Tax Equals 0.25% Per Dollar Over Threshold x Gross Wellhead Value

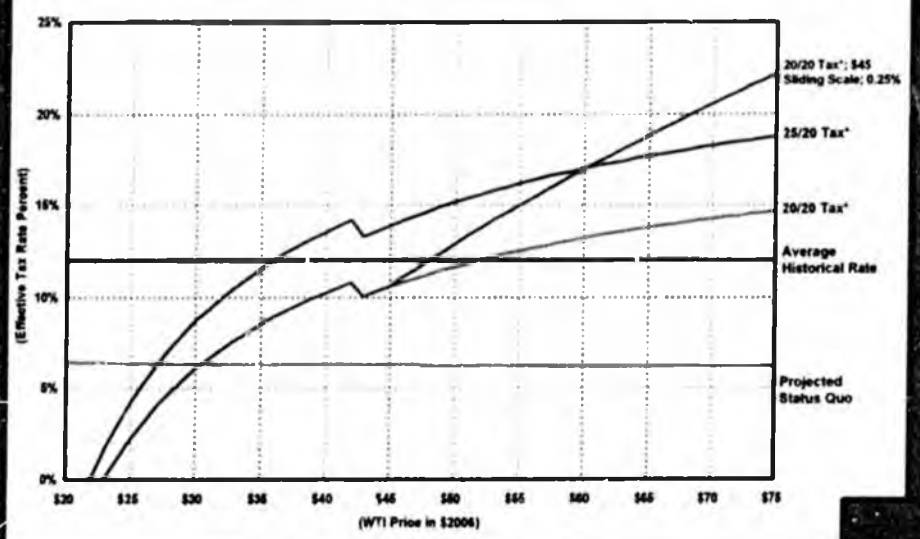
Additional Tax = (WTI Price - Threshold) x Increment Rate x ANS Wellhead Price x (1 - PPT Tax Rate)

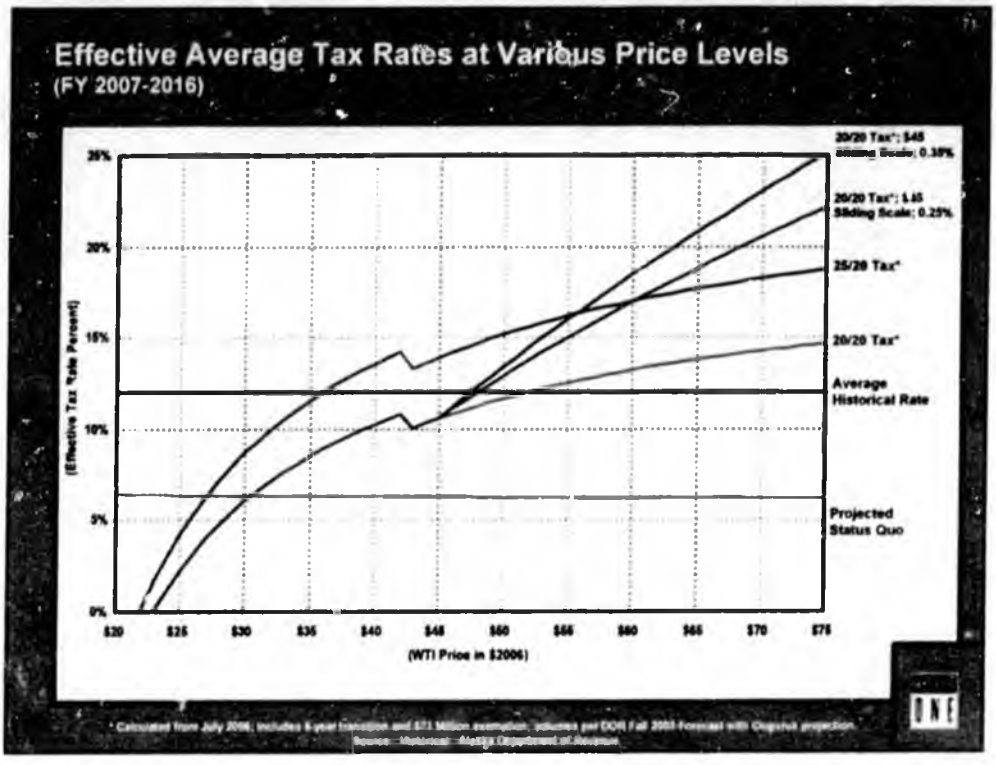
= ($55 - $45) x 0.25% x $47 x (1 - 20%)

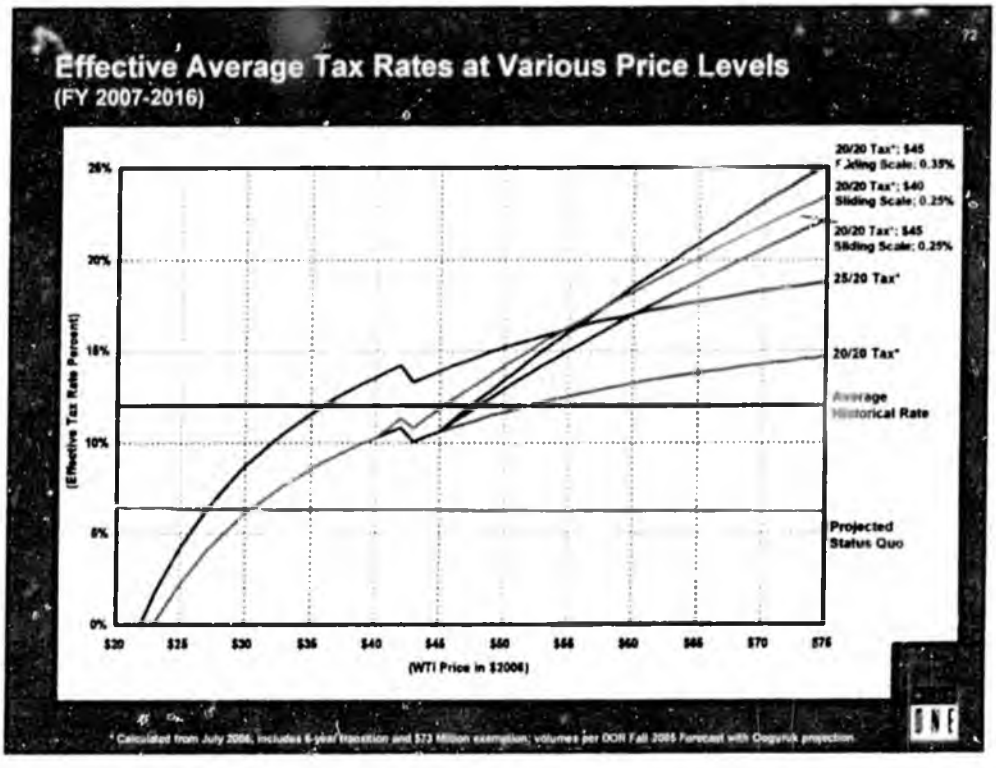
= 2.5% x $47 x 80%

= $0.94

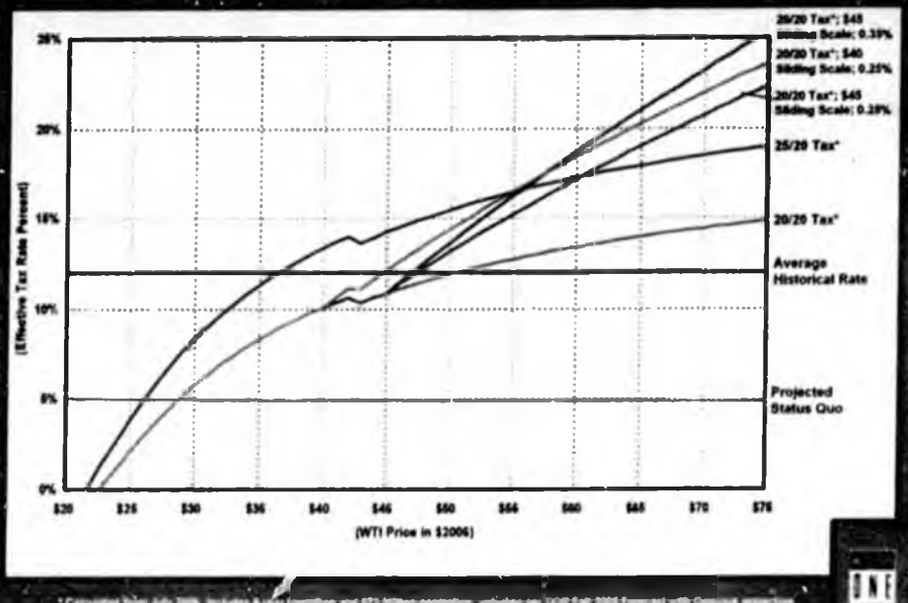
Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)




Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
20/20 Tax*; $45
20/20 Tax*; $40
Sliding Scale; 0.25%
25/20 Tax*
20/20 Tax*
Average
Historical Rate
Projected
Status Quo
(Effective Tax Rate Percent)
(WTI Price in $2006)
$20 $25 $30 $35 $40 $45 $50 $55 $60 $65 $70 $75
0% 5% 10% 15% 20% 25%


Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)
20/20 Tax*; $45
Sliding Scale; 0.25%
25/20 Tax*
20/20 Tax*
Projected
Status Quo
(Effective Tax Rate Percent)
(WTI Price in $2006)
$20 $25 $30 $35 $40 $45 $50 $55 $60 $65 $70 $75
0% 5% 10% 15% 20% 25%

Effective Average Tax Rates at Various Price Levels
(FY 2007-2030)



* Calculated from July 2006. Includes 4-year incentive and 0% trigger assumptions, consistent with DOR Fall 2006 Forecast with Graduate projections.
Source: Hornaday - Alaska Department of Revenue

Projected Effective Tax Rates with Sliding Scale Tax
DOR Forecast Production (FY 2007-2030)*

WTI Price ($ 2006)	Status Quo	20/20	20/20 with sliding Scale Tax: $35 Threshold Price 0.20% Increment	$35 Threshold Price 0.25% Increment	$35 Threshold Price 0.30% Increment	$35 Threshold Price 0.35% Increment	$40 Threshold Price 0.20% Increment	$40 Threshold Price 0.25% Increment	$40 Threshold Price 0.30% Increment	$40 Threshold Price 0.35% Increment
					(Percent)					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
$30	4.9%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%
$40	4.9%	10.0%	11.0%	11.3%	11.5%	11.8%	10.0%	10.0%	10.0%	10.0%
$50	4.9%	11.9%	14.9%	15.7%	16.4%	17.2%	13.9%	14.4%	14.9%	15.4%
$60	4.9%	13.4%	16.4%	19.7%	20.9%	22.2%	17.4%	18.4%	19.4%	20.4%
$70	4.9%	14.5%	21.5%	23.2%	25.0%	26.7%	20.5%	22.0%	23.5%	25.0%
$80	4.9%	15.2%	24.2%	26.5%	28.7%	31.0%	23.2%	25.2%	27.2%	29.2%

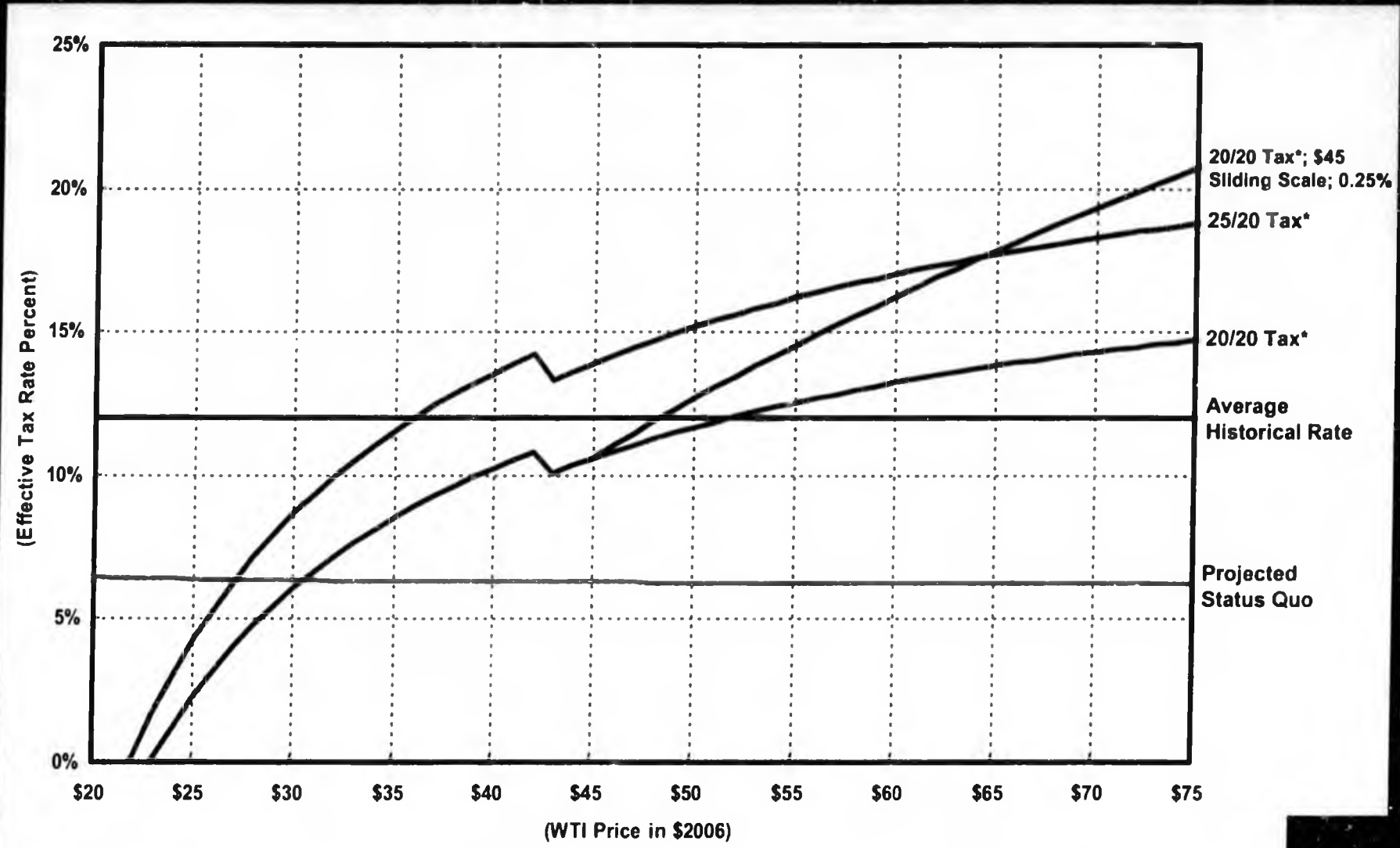
WTI Price ($ 2006)	25/20	20/20 with Sliding Scale Tax: $45 Threshold Price 0.20% Increment	$45 Threshold Price 0.25% Increment	$45 Threshold Price 0.30% Increment	$45 Threshold Price 0.35% Increment	$50 Threshold Price 0.20% Increment	$50 Threshold Price 0.25% Increment	$50 Threshold Price 0.30% Increment	$50 Threshold Price 0.35% Increment
				(Percent)					
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
$30	8.3%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%
$40	13.3%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
$50	15.5%	12.9%	13.2%	13.4%	13.7%	11.9%	11.9%	11.9%	11.9%
$60	17.3%	16.4%	17.2%	17.9%	18.7%	15.4%	15.9%	16.4%	16.9%
$70	18.8%	19.5%	20.7%	22.0%	23.2%	18.5%	18.5%	20.5%	21.5%
$80	19.4%	22.2%	24.0%	25.7%	27.5%	21.2%	22.7%	24.2%	25.7%

Projected Government Takes with Sliding Scale Tax
DOR Forecast Production (FY 2007-2030)*

WTI Price ($ 2006)	Status Quo	2020	2020 with Sliding Scale Tax: $30 Threshold Price 0.20% Increment	$30 Threshold Price 0.25% Increment	$30 Threshold Price 0.30% Increment	$30 Threshold Price 0.35% Increment	$40 Threshold Price 0.20% Increment	$40 Threshold Price 0.25% Increment	$40 Threshold Price 0.30% Increment	$40 Threshold Price 0.35% Increment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
$30	57.0%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
$40	53.7%	57.3%	58.0%	58.2%	58.4%	58.6%	57.3%	57.3%	57.3%	57.3%
$50	52.3%	56.8%	58.9%	59.4%	59.9%	60.4%	58.2%	58.5%	58.8%	59.2%
$60	51.9%	56.8%	60.0%	60.8%	61.6%	62.4%	59.4%	60.0%	60.7%	61.3%
$70	50.8%	56.8%	61.2%	62.1%	63.3%	64.4%	60.6%	61.9%	62.4%	63.3%
$80	50.6%	56.8%	62.3%	63.7%	65.0%	66.4%	61.7%	62.9%	64.1%	65.3%

WTI Price ($ 2006)	2020	2020 with Sliding Scale Tax: $40 Threshold Price 0.20% Increment	$40 Threshold Price 0.25% Increment	$40 Threshold Price 0.30% Increment	$40 Threshold Price 0.35% Increment	$50 Threshold Price 0.20% Increment	$50 Threshold Price 0.25% Increment	$50 Threshold Price 0.30% Increment	$50 Threshold Price 0.35% Increment
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
$30	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
$40	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%
$50	58.3%	57.6%	57.7%	57.9%	58.1%	58.8%	58.8%	58.9%	58.8%
$60	58.3%	58.8%	58.3%	58.7%	60.2%	58.1%	58.5%	58.8%	59.1%
$70	58.3%	59.9%	60.7%	61.5%	62.3%	59.3%	59.9%	60.6%	61.2%
$80	58.4%	61.1%	62.1%	63.2%	64.3%	60.5%	61.4%	62.3%	63.2%

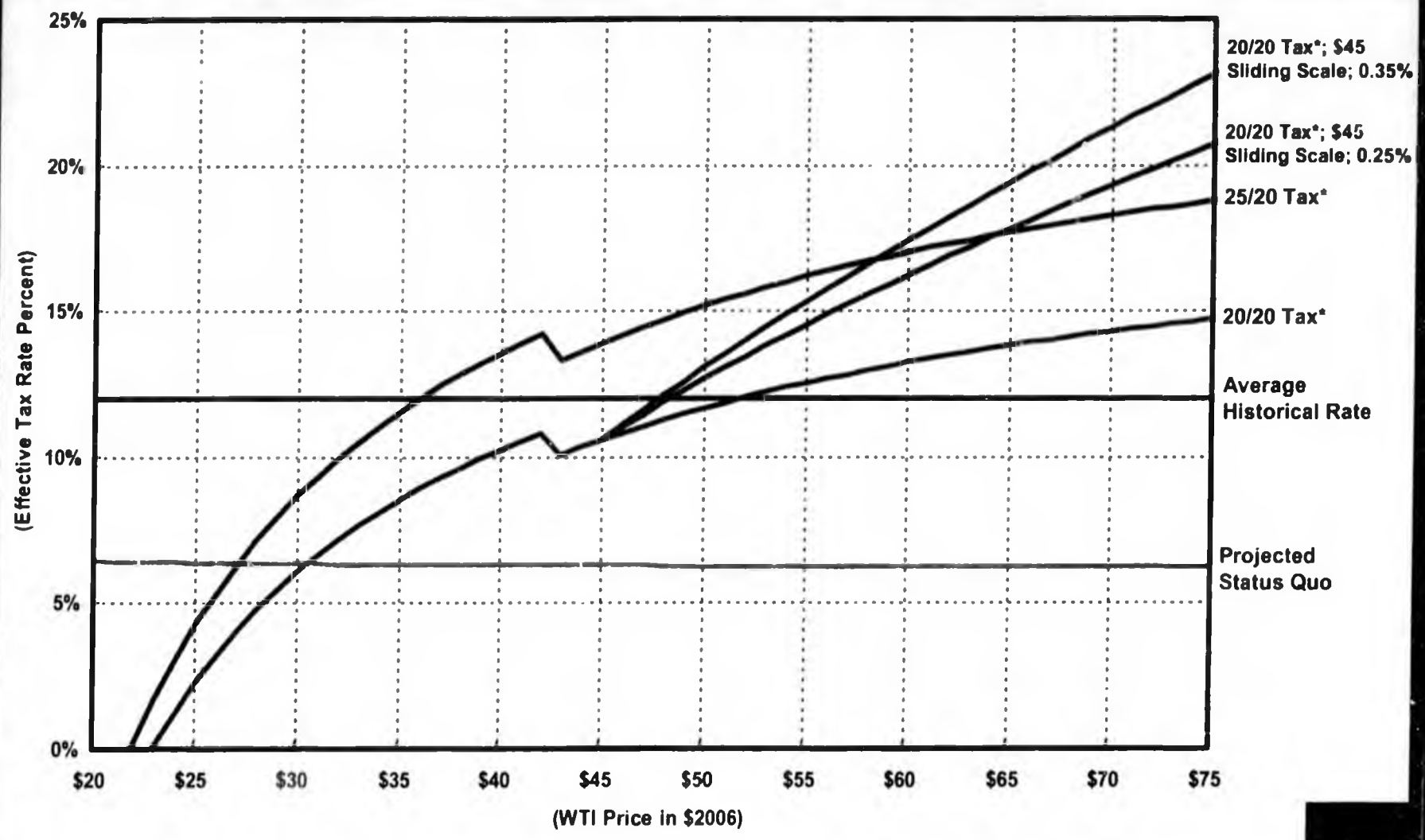
Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)



econ ONE

* Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.
Source: Historical: Alaska Department of Revenue.

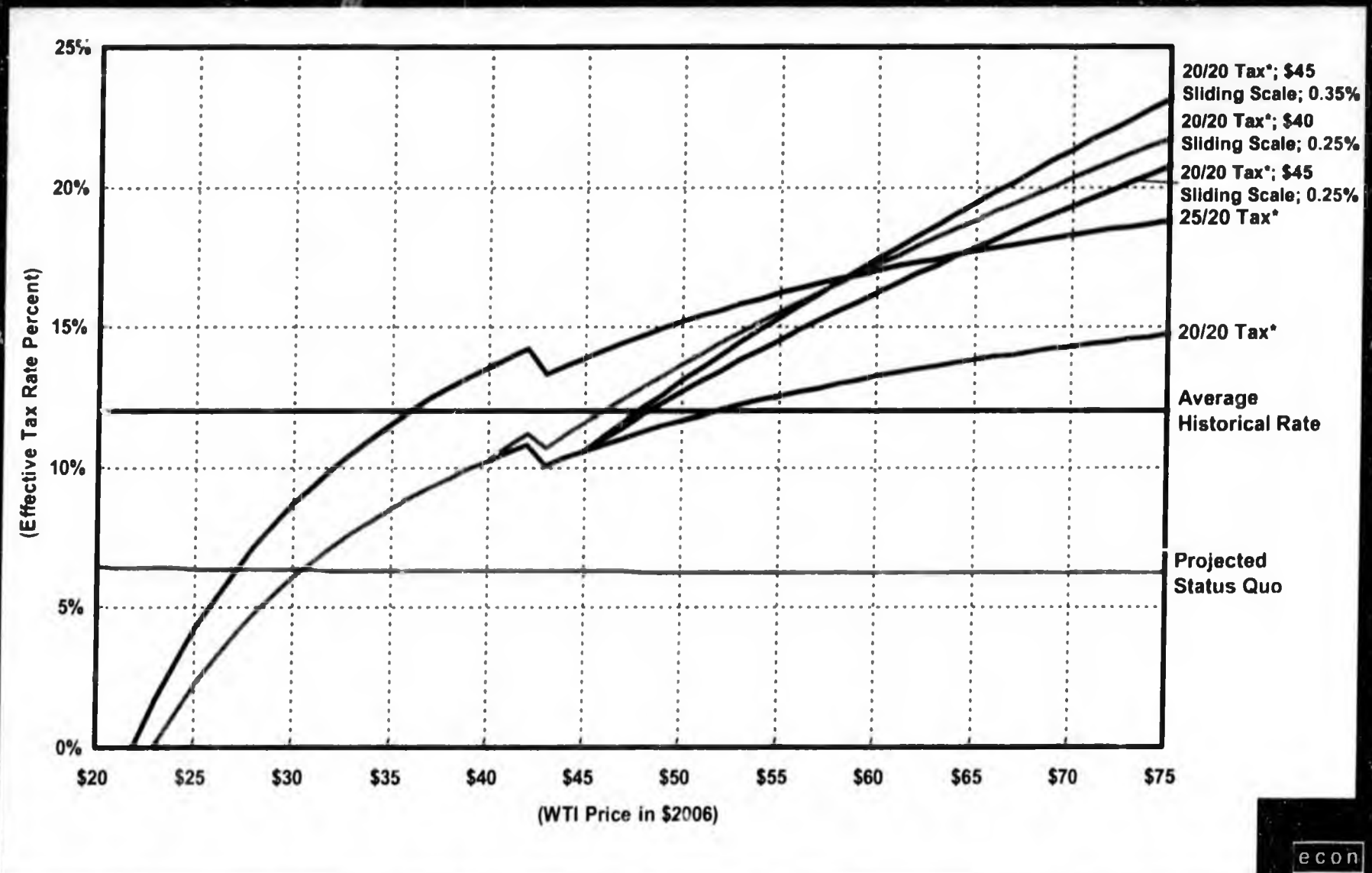
Effective Average Tax Rates at Various Price Levels
(FY 2007-2016)



econ ONE

* Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.
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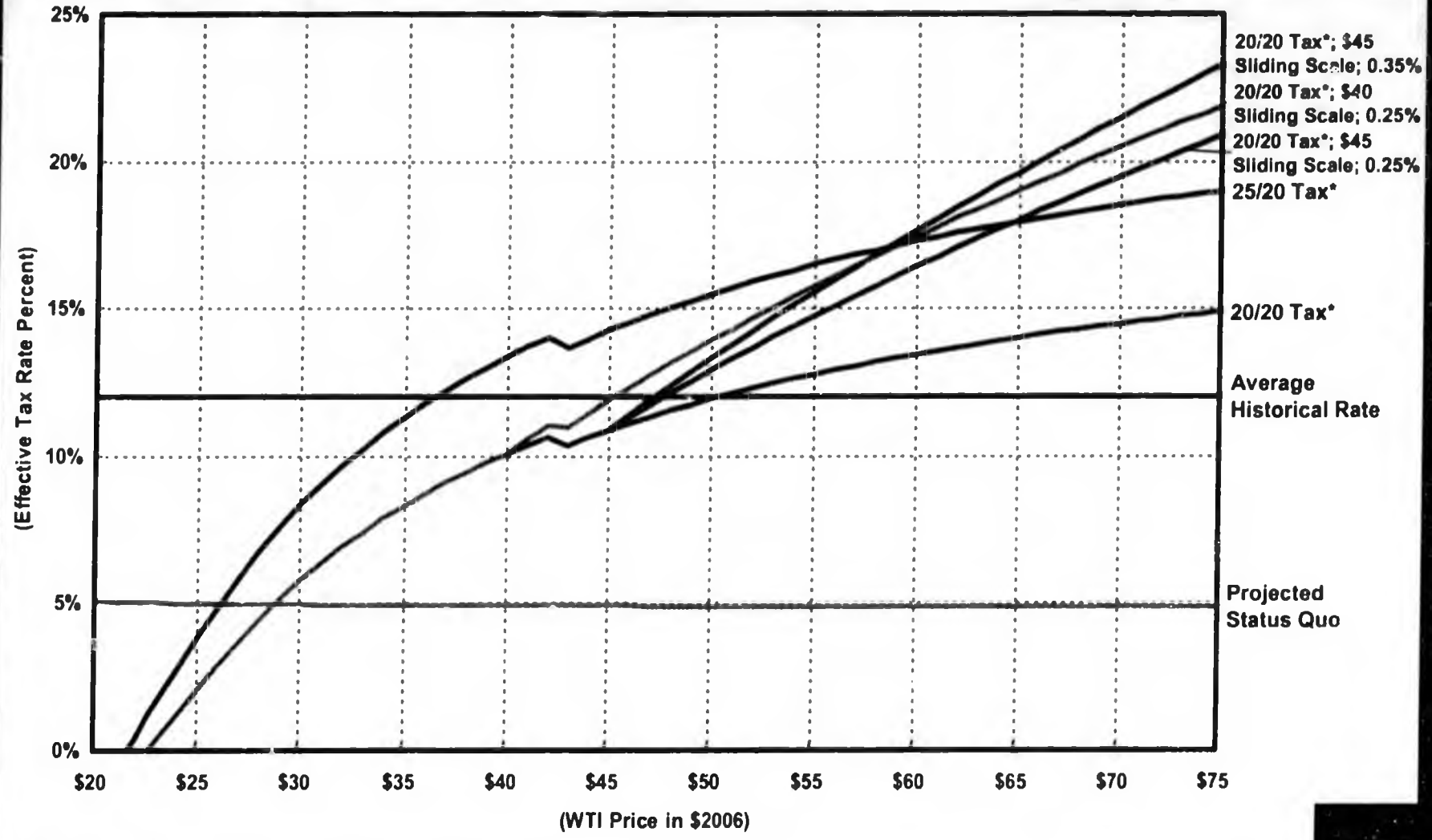
Effective Average Tax Rates at Various Price Levels
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* Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.
Source: Historical: Alaska Department of Revenue.

Effective Average Tax Rates at Various Price Levels
(FY 2007-2030)



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* Calculated from July 2006; includes 6-year transition and $73-Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.
Source: Historical: Alaska Department of Revenue.

Projected Government Takes with Sliding Scale Tax
DOR Forecast Production (FY 2007-2030)*

WTI Price ($ 2006)	Status Quo	20/20	20/20 with Sliding Scale Tax: $35 Threshold Price 0.20% Increment	$35 Threshold Price 0.25% Increment	$35 Threshold Price 0.30% Increment	$35 Threshold Price 0.35% Increment	$40 Threshold Price 0.20% Increment	$40 Threshold Price 0.25% Increment	$40 Threshold Price 0.30% Increment	$40 Threshold Price 0.35% Increment
					(Percent)					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
$30	57.0%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
$40	53.7%	57.3%	57.9%	58.0%	58.2%	58.3%	57.3%	57.3%	57.3%	57.3%
$50	52.3%	56.9%	58.5%	58.9%	59.3%	59.7%	58.0%	58.2%	58.5%	58.7%
$60	51.5%	56.9%	59.4%	60.0%	60.7%	61.3%	58.9%	59.4%	59.9%	60.4%
$70	50.9%	56.9%	60.3%	61.2%	62.0%	62.9%	59.8%	60.6%	61.3%	62.0%
$80	50.6%	56.9%	61.2%	62.3%	63.4%	64.5%	60.7%	61.7%	62.7%	63.6%

WTI Price ($ 2006)	25/20	20/20 with Sliding Scale Tax: $45 Threshold Price 0.20% Increment	$45 Threshold Price 0.25% Increment	$45 Threshold Price 0.30% Increment	$45 Threshold Price 0.35% Increment	$50 Threshold Price 0.20% Increment	$50 Threshold Price 0.25% Increment	$50 Threshold Price 0.30% Increment	$50 Threshold Price 0.35% Increment
				(Percent)					
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
$30	59.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%	57.7%
$40	59.7%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%	57.3%
$50	59.3%	57.4%	57.6%	57.7%	57.8%	56.9%	56.9%	56.9%	56.9%
$60	59.3%	58.4%	58.8%	59.2%	59.5%	57.9%	58.1%	58.4%	58.7%
$70	59.3%	59.3%	59.9%	60.6%	61.2%	58.8%	59.3%	59.8%	60.3%
$80	59.4%	60.2%	61.1%	61.9%	62.8%	59.8%	60.5%	61.2%	61.9%

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*Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.

Projected Effective Tax Rates with Sliding Scale Tax
DOR Forecast Production (FY 2007-2030)*

WTI Price ($ 2006)	Status Quo	20/20	20/20 with Sliding Scale Tax: $35 Threshold Price, 0.20% Increment	$35 Threshold Price, 0.25% Increment	$35 Threshold Price, 0.30% Increment	$35 Threshold Price, 0.35% Increment	$40 Threshold Price, 0.20% Increment	$40 Threshold Price, 0.25% Increment	$40 Threshold Price, 0.30% Increment	$40 Threshold Price, 0.35% Increment
			(Percent)							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
$30	4.9%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%
$40	4.9%	10.0%	10.8%	11.0%	11.2%	11.4%	10.0%	10.0%	10.0%	10.0%
$50	4.9%	11.9%	14.3%	14.9%	15.5%	16.1%	13.5%	13.9%	14.3%	14.7%
$60	4.9%	13.4%	17.4%	18.4%	19.4%	20.4%	16.6%	17.4%	18.2%	19.0%
$70	4.8%	14.5%	20.1%	21.5%	22.9%	24.3%	19.3%	20.5%	21.7%	22.9%
$80	4.8%	15.2%	22.4%	24.2%	26.0%	27.8%	21.6%	23.2%	24.8%	26.4%

WTI Price ($ 2006)	25/20	20/20 with Sliding Scale Tax: $45 Threshold Price, 0.20% Increment	$45 Threshold Price, 0.25% Increment	$45 Threshold Price, 0.30% Increment	$45 Threshold Price, 0.35% Increment	$50 Threshold Price, 0.20% Increment	$50 Threshold Price, 0.25% Increment	$50 Threshold Price, 0.30% Increment	$50 Threshold Price, 0.35% Increment
		(Percent)							
	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
$30	8.3%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%
$40	13.3%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
$50	15.5%	12.7%	12.9%	13.1%	13.3%	11.9%	11.9%	11.9%	11.9%
$60	17.3%	15.8%	16.4%	17.0%	17.6%	15.0%	15.4%	15.8%	16.2%
$70	18.5%	18.5%	19.5%	20.5%	21.5%	17.7%	18.5%	19.3%	20.1%
$80	19.4%	20.8%	22.2%	23.6%	25.0%	20.0%	21.2%	22.4%	23.6%

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* Calculated from July 2006; includes 6-year transition and $73 Million exemption; volumes per DOR Fall 2005 Forecast with Ooguruk projection.

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March 13, 2006

Senator Tom Wagoner, Chair
Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801

DRAFT

Rep. Ralph Samuels, Co-Chair
House Resources Committee
State Capitol, Room 126
Juneau, AK 99801

Rep. Jay Ramras, Co-Chair
House Resources Committee
State Capitol, Room 104
Juneau, AK 99801

Re: Questions on PPT Legislation (SB 305, HB 488)

Dear Senator Wagoner and Representatives Samuels and Ramras,

Thank you for the opportunity to respond to questions posed during (and following) recent committee hearings. This letter incorporates the answers presented during testimony which was based on our interim draft reports dated March 2 and March 7, 2006, and provides additional information not previously available. In addition, this letter expands some of the answers in response to followup questions posed during the hearings. We have included a substantial number of attachments which are indexed to the question number. Lastly, we have included an index, by topic, which should prove helpful.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production).

The Department of Revenue model uses $1 billion per year as capital costs, so for the transitional period, there would be about $5 billion. This annual costs are based on compilations of historical data.

(millions)	Exploration	Dev. & Production*	Total
2001	152	1,636	1,788
2002	125	1,054	1,180
2003	90	970	1,060
2004	67	980	1,047

* We do not have information on the split between development and production expenditures.

Although we have not completed this work, we have some evidence about costs in 2005 and the first half of 2006 and it appears they will continue the downward trend seen in the four years presented.

DRAFT

2. How are mobilization, demobilization, and platform abandonment costs treated—as tax credits or deductions?

Mobilization costs are capitalized for federal tax purposes, as Intangible Drilling Costs. As such, they are a capitalized expenditure for PPT purposes, and therefore are deductible and creditable. We understand that demobilization and abandonment expenditures are both expensed as incurred. This would mean that these costs are deductible, but would not generate a credit.

3. Is there a "rating" for political stability – or one that reflects instability?

We do not have any information on a quantification of the risk of political stability.

4. What loss of revenue is incurred by moving the effective date from Jan 1, 2006 to July 1, 2006 on both 20/20 and on 25/20?

Using a combination of our spring forecast and YTD actuals, the average ANS price between January 1, 2006 and July 1, 2006 was $58.62.

- The loss of revenue using the 20/20 system would be about $480 mm in additional tax.
- The loss of revenue using the 25/20 system would be about $770 mm in additional tax.

5. Section 9 – what amount is involved in this section?

A very small amount, probably no more than 1% of total state production of oil and gas. Currently it is limited to Alpine and its satellites and Cook Inlet, though production expected soon from the NPRA will also have private leasehold interest.

6. Was there consideration of phasing out the $73 million allowance over a certain period of time?

No, it was not considered.

7. Of the current 14 producers in Alaska, which would pay a severance tax after employing the proposed $73 million standard allowance?

DRAFT

With the merger of Chevron and Unocal, there are now 13 producers in Alaska. Of the 13 producers, BP, ConocoPhillips and ExxonMobil will pay severance tax at most anticipated price levels after employing the $73 million standard allowance. At high oil and gas prices, and given our cost assumptions, Anadarko, Marathon, and ChevronUnocal will also pay severance tax after deducting the $73 million dollar allowance, given the production volumes reported publicly by those companies.

8. Which other tax regimes – worldwide - have a progressivity structure?

Note: this question answers progressivity generally, but see definition at Question 91.

Progressive features are relatively common around the world. Following is a list of the main fiscal regimes with such features. "Old" features are defined as features that have been in existence for more than 20 years. "New" less than 20 years.

There is a wide variety of systems that are progressive with the level of well production or field production. These systems are not included in the list.

Country	Region/Type	Feature	Oil/Gas	Old/New
Canada	NWT	IRR based profit sharing royalty	Both	Old
	Newfoundland	IRR based profit sharing royalty	Oil	Old
	Nova Scotia	Payout based profit sharing royalty	Both	New
	Alberta	Production/Price	Oil	Old

		sensitive royalty		
	Alberta	Price Sensitive royalty	Gas	Old
	Alberta oil sands	IRR based profit sharing royalty	Oil	Old
Colombia		Price sensitive windfall profits tax	Oil	New
Venezuela	Conventional Oil	IRR based profit share	Oil	New
Peru		R-factor royalty	Both	New
Bolivia		Profit sensitive Surcharge with uplifts	Both	New
Trinidad & Tobago	Conventional Oil	Supplemental Petroleum Tax, Price sensitive	Oil	New
	Deep water	Production/Price sensitive profit oil/gas shares	Both	New
Norway		Uplifts on Hydrocarbon Tax	Both	Old
UK	Old licenses	Uplifts and Oil Allowance on PRT	Both	Old
Denmark		Uplifts on Hydrocarbon Tax	Both	Old
The Netherlands		Uplifts on Special Profit share	Both	Old
Algeria		Cumulative Revenue sensitive PRT and uplifts	Both	New
Tunisia		Sliding scale taxation	Both	New
Libya		R-factor based profit oil splits	Oil	Old
Nigeria		Uplifts and tax credits	Oil	Old
Angola		IRR based profit oil shares	Oil	New
Qatar		R-factor based profit oil shares	Oil	New
Saudi Arabia		IRR based corporate income tax rates	Gas	New
Iran		Buy Back contracts	Both	New
Pakistan	Offshore	Price Sensitive Windfall profits tax	Both	New
India		R-factor based profit oil shares	Both	New
Thailand		Profit sensitive SRB	Both	New
Malaysia		Price sensitive windfall profits tax	Both	Old

DRAFT

Indonesia		Uplifts	Both	Old
Australia	Offshore	IRR based PRRT	Both	Old
PNG		IRR based APT	Both	Old
Russia	Sakhalin	IRR based profit oil shares	Both	New
Kazakhstan	Tengiz	IRR based profit share	Oil	New
	General	New models with variety of progressive features	Oil	New
Azerbaijan	AIOC	IRR based profit oil share	Oil	New
	Other	R-factor based profit oil shares	Oil	New

DRAFT

9. How many private royalty owners are there in Alaska – all areas, not just the North Slope (i.e., Nenana Basin, Kenai Peninsula, native corporation holdings, etc).

We do not have information on the number of private royalty owners in Alaska, which would include private oil and gas leases that are not in production. Homesteads staked under certain (but not all) federal homestead laws included oil and gas rights, and any of the owners of such parcels might enter into an oil and gas lease.

10. Provide a graph showing the status quo, the PPT, and the gas line contract terms.

This question appears to query the relationship between tax under the status quo, the PPT, and the gas line contract terms. At this time, gas line contract terms are not public information.

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) total $104.8 million and claimed credits total $33.6 million [see table below]. A claim was recently received by the Department of Revenue, thus the totals has been updated from the $95.5 million and $29.0 million figures previously provided.

Exploration Production Tax Credit Program Summary, AS 43.55.025
As of February 28, 2006

	No. of Projects	Claimed Expenses	Claimed Credits
FY 04, 05			
Audited & issued:	7		
N. Slope wells		$51,050,000	$13,308,000
Cook Inlet wells		$ 3,430,000	$ 392,000
Cook Inlet seismic		$ 3,178,000	$ 1,085,000
Audits In progress:	5		
N. Slope wells		$26,615,000	$10,646,000
N. Slope seismic		$ 7,957,000	$ 3,182,000
Other - seismic		$ 3,295,000	$ 1,318,000
Other - wells		$ 9,286,000	$ 3,714,000
Total	12	$104,811,000	$ 33,646,000

DRAFT

12. What is the rational for offering the same amount of credits for non-state lease lands where the state receives no royalty tax benefit – was there discussion of a reduction in the credit to offset this?

The rationale is that the incentives have the potential to result in higher severance taxes. taxes that are assessed on any oil or gas production within Alaska's sovereign territory. Given the overall economic benefit of increased production of oil and gas (and particularly gas in the Cook Inlet where significant private lands occur), an incentive for exploration and development even in the event that a field would pay no taxes after incentives makes sense.

13. Why should Point Thomson be incentivised?

We believe the development of Pt. Thomson may be critical for the development of the gasline. Accordingly, incentivizing Pt. Thomson may well incentivize the gasline

Pt. Thomson is particularly problematic for two reasons. First, it is a high cost field since it is a high pressure gas condensate reservoir and second we do need the gas reserves to underpin the gas pipeline economics. By providing incentives, the goal would be two-fold. First any incentive to encourage Pt. Thomson improves the

economics of the gas pipeline. Second, incentives may encourage early production of the liquids which requires expensive infrastructure to handle the high pressure production.

14. Can you provide better definitions for "point of production" and "oil" and "gas" and has the State litigated these terms?

DRAFT

We're not clear whether this question seeks more explanation of the definitions in the bill or is requesting that we consider modifying those definitions. Please clarify. Regarding past litigation, in general the point of production and the definitions of oil and gas have not been major subjects of litigation under the production tax statute. In contrast, there has been considerable litigation of related concepts, though not necessarily the phrase "point of production," in the royalty context.

In the tax context, there was at least one dispute decided at the internal DOR appeal stage relating to point of production, but most of the controversy in this area played out in the development of regulations defining "gas processing plant," rather than litigation. The use of the term "gas processing" in the bill is consistent with existing department regulations, but under current law gas processing generally is considered an activity occurring downstream of the point of production, while under the bill it is considered an activity occurring upstream of the point of production.

15. What steps must be taken to make the tax credits refundable rather than transferable?

This would require a language change to Section 12 at Sec. 43.55.024(d) and (e). We are available to work with drafters on the exact wording.

16. On Page 13, line 24 of the bill, what does "payment in lieu of" tie into for oil?

Section 21 (Sec. 43.55.160(d)(1)(B)) clarifies that payments in lieu of property taxes are deductible. Sec. 43.55.160(c) presents the general rule that lease expenditures are deductible. Lease expenditures would include property taxes. Sub-section (d) provides clarification for items that are not clear, such as "payments made in lieu of property taxes."

17. Does the limit on transferable tax credits in section 12 (subsection (e)) limit the amount of tax credits that a single taxpayer can take against their own production tax in a single year?

Section 12 (Sec. 43.55.024(e)) limits the amount of tax that can be reduced through purchased credits. There is no limit on credits utilized by a taxpayer that were generated by that same taxpayer.

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel (not all of them) has been consulted and such assessments have been discussed but have not generally been generated in formal written form.

DRAFT

Did such advice result in any changes to the legislation?

The bills reflect discussions with counsel that took place during the drafting process, so in that sense such advice did affect the legislation.

19. Have you asked the Department of Law to review this legislation in light of the 6th Circuit Court of Appeals' decision in Cuno v Daimler Chrysler that is now pending before the United States Supreme Court?

The Department of Law has examined this matter. The court decision calls into question, under the Commerce Clause of the United States Constitution, investment tax credit provisions that are found in state tax laws throughout the country. However, the decision's applicability to tax credits under a production tax, rather than an income tax, is not clear. In any event, the decision is currently being reviewed by the United States Supreme Court, and we should learn within the next several months whether it will be sustained.

20. Please provide information regarding the expenditures that will qualify for the transition credits—including the depreciation method chosen under the federal and state income tax systems.

It appears that this question relates to the transition provision in Section 21 (Sec. 43.55.160(g)) which allows a deduction for capital expenditures made over the last five years, deductible over the next six years. The capital expenditures that qualify for transitional treatment are the same type of expenditures that qualify for ongoing credits. These are defined in Section 12 (Sec. 43.55.024(h)). These expenditures include exploration expenses and those expenditures that are capitalized for federal tax purposes. Exploration expenses include geological and geophysical exploration. Expenditures capitalized for federal tax purposes include intangible drilling costs.

The capitalized expenditures are subject to a variety of useful lives under federal and state income tax rules. See Question 59 below.

21. Have any of the definitions in Sections 30-33 been the subject of disputes with tax and/or royalty payers in the past? To the extent they have, please provide the definitions the state asserted in those disputes.

See question 18 above.

22. Please provide an identification of the point of production at each unit in the state under existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

For crude oil, the point of production will not change under our proposal. It will remain the point where the oil is first metered and measured in a condition of pipeline quality. Note that certain oil used on the lease will no longer be taxable under the proposed production tax reforms, but that is not a point of production issue. As examples, the points of production for oil are and will be the LACT (lease automatic transfer custody) meters at the inlets to TAPS (for Prudhoe Bay) the Kuparuk Pipeline (for Kuparuk) and onshore production facilities for the Cook Inlet platforms.

DRAFT

What is of more interest is the point of production for gas. At Prudhoe Bay, while the point of production for most gas is the inlet to the Central Gas Facility (CGF), there are other potential points of production for other gas uses. For example, in the separation facilities, gas is taken right out of the flow stream and burned in that facility (however this gas is not taxable under the free use of gas rules.) For taxable gas, the ***inlet*** to the CGF is generally the point of production for all gas that emerges from the CGF, including the ngls.

This compares to other gas plants that are or have been operating at Kuparuk, Endicott, Lisburne or in the Cook Inlet. For these plants, (and for the gas plant at Prudhoe prior to the construction of the CGF in 1986) the point of production for gas will be the ***outlet*** where the facility is tied to a sales or other line that take the gas off the unit. Why? Volatile liquid hydrocarbons are extracted from a gaseous fluid at these plants, and these liquid hydrocarbons are stabilized by putting them back into the well fluid stream. This stream of well fluids run through primary separation again, where some of the hydocarbons will become gas and some will become oil. In other words the gas plant still had not separated the molecules that will end up as crude oil and the molecules that will end up as gas. Only after the fluid has moved beyond the line running back to primary separation can it be considered produced gas. Incidentally, this is why the CGF is the only gas

processing plant known in Alaska. Because gas processing must be downstream of the point of production, these gas plants are not gas processing plants.

The producers have argued in the cases that resolved this issue that it was a "gotcha". They argued that by spending a few million dollars and making their gas plants suboptimal and stabilizing the volatile hydrocarbon liquids in the produced oil stream instead of the well fluid stream, the point of production would move upstream to the inlet to the gas plants and the gas plants would become fully deductible downstream gas processing plants. This proposal makes that argument moot.

23. Please provide an identification of 'gas treatment' and 'gas processing' facilities in the state under the existing statutes, regulations, agreements, and court decisions. Provide the same under the definition as proposed.

DRAFT

To date in administering the tax, there are no gas treatment facilities on the North Slope. The only gas processing plant currently in the state is the Central Gas Facility (CGF).

Under the proposed definitions, plants removing CO_2 and H_2S from gas for delivery to a sales line – which in the sponsor group proposal is assigned to a new Gas Treatment Plant (GTP)--would be a new Gas Treatment Plant. The CGF would remain a processing plant. All other gas exiting plants would remain upstream production facilities rather than gas processing plants.

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

The current production tax statute taxes the "gross value at the point of production" of oil and gas. The quoted phrase was enacted in 1977 and replaced the previous statutory phrase "gross value at the well." This change was aimed at ensuring that costs of production operations downstream of the well would not be deductible in calculating the taxable value of oil or gas; rather, taxable value would be calculated at the point that production is complete.

In the case of oil, "gross value at the point of production" was defined as the value of oil where it is metered "in a condition of pipeline quality," and "pipeline quality" was defined as "good and merchantable condition." This definition essentially adopts commercial standards of marketability for oil. HB 488 and SB 305 would simplify and shorten the definition of gross value at the point of production for oil but do not materially change it. In addition, the definition of "oil" is broadened to include liquid hydrocarbons recovered by gas processing in the case of leases or properties whose production is subject to gas processing. The bottom line is that the point of production under these bills would still be the point where oil is metered in a

condition of pipeline quality, and "pipeline quality" would mean the same thing it has always meant under the production tax statute.

In the case of gas, neither the existing statute nor the new bills use the phrase "pipeline quality" or "good and merchantable condition" with respect to gross value at the point of production. Rather, the statutory definitions of "gross value at the point of production" for gas, as interpreted and clarified by the Department's regulations, 15 AAC 55.900(a)(6)(B) and (C), focus on where gas is accurately metered after separation from oil. The new bills retain this concept but, in effect, expand "separation" to include gas processing, so that in the case of leases or properties whose production is subject to gas processing, the point of production for gas recovered by gas processing is the point where it is metered downstream of the processing.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

DRAFT

a. North Slope:

While there is much that is parallel in the calculation of gross value at the wellhead between royalty and tax, many differences have developed. Both start with destination value in the market, and then subtract the tankering, pipeline and other costs to arrive at a well head value. The Department of Revenue's (DOR) valuation for tax comes from statute and regulation. The Department of Natural Resources' (DNR) valuation for royalty comes from lease contracts supplemented by Royalty Settlement Agreements (RSAs) which set forth different methods for each large North Slope producer.

Destination value, for DOR, is what the oil was sold for, or when the oil is not sold or is sold for a below-market price, the so called prevailing value or spot price. Destination value for DNR is a formula driven by the ANS or a basket of similar crudes.

From the destination value, each method subtracts marine transportation costs, TAPS costs (including tariffs, losses and quality bank changes from mid-point refineries), feeder line costs (including tariffs, losses and quality bank differences), and other miscellaneous costs. DOR deducts the costs specific to each taxpayer, while for royalty, some of the RSAs have formulaic deductions and others use the royalty payer's actual cost. In addition, DNR subtracts field costs for most DL-1 lease form leases on the North Slope whereas DOR does not.

The differences between wellhead values narrow across time. The average difference for the period FY00 through December 2005 is 3.9%. However, the average

difference for the last 12 months was 6.1% while the average difference for FY00 through FY03 was 3.0%.

The critical point is that DOR uses actual proceeds, and only resorts to Prevailing Value when the conditions of 020 (f) are met, thereby taxing on the higher of proceeds or Prevailing Value. For each of the three producers, DNR uses a single destination formula based on spot prices, not actual proceeds.

b. Cook Inlet

In the Cook Inlet, the Oil ELF has been at zero for quite some time so there is no developed DOR methodology. Instead, it would be appropriate to compare Department of the Interior royalty methodology with DNR methodology.

26. Will abandonment costs be eligible for deductions or credits under the legislation? If so, what estimates of the timing and costs of those activities does the Department project?

See Question 2 for deductibility of abandonment costs. With regard to costs, we are aware of no field having ever been abandoned in Alaska, and so we do not have any empirical data on costs.

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27. How will AS 43.55.160(j) protect the State from a proliferation of corporate entities and/or companies claiming the tax free allowance?

Sec. 43.55.160(j) does not restrict the number of companies entering the market that would utilize the standard allowance. However, this section requires that the Department of Revenue evaluate each company claiming the deduction, on an annual basis, to determine if the company qualifies for the deduction. This section goes on to require the company to show that it has not split operations into multiple entities in order to gain usage of multiple $73M deductions, when only one deduction should have been granted.

28. Provide the number of exploration and delineation wells estimated to be drilled over the first ten years of your economic models. Include the technical and economic success rates projected in the modeling.

Five [5] exploration wells per year are included in the model. The Department of Revenue assumes $100 million is spent on exploration per year. With average costs of $20 million dollars per well, this comes out to five [5] wells per year. Delineation wells are separate and included under development expenditures. The model assumes there are four [4] finds of large oil accumulations – reserves in place that would be on the order of 500 million barrels. There are four [4] relatively small fields that are

characterized as being "heavy" oil. These fields would pay no production tax under the current system because their Economic Limit Factor [ELF] would be zero [0.0]. We did not include a "success rate" in our model

29. Provide estimates for undiscovered resources in Alaska. Include the breakdown between technically recoverable and economically recoverable resources to the extent possible.

Resources estimated are those that would enter the Trans Alaska Pipeline System [TAPS] north of the Brooks Range. These include estimates of recoverable oil from the National Petroleum Reserve – Alaska [NPRA], the Central North Slope, the Beaufort Sea and the Alaska National Wildlife Refuge [ANWR]. Estimates are presented in terms of barrels of technically and economically recoverable reserves. Technically recoverable estimates are mean estimates. Economic recovery is based upon the Department of Revenue [DOR] long term forecast of Alaska North Slope [ANS] crude oil delivered on the west coast at $25.50 per barrel in nominal terms. For purposes of analysis, all economically recoverable oil is presumed to be produced by 2046 [within 45 years]. Estimates are obtained from United State Federal government sources – the United States Geological Service [USGS], the Minerals Management Service [MMS] and the Energy Information Administration [EIA].

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	Oil		
	Technically	**Economically**	**Natural Gas**
NPRA	10.6 Bbl	2.95 Bbl	59.7 Tcf
Central North Slope	3.98 Bbl	0.88 Bbl	35 Tcf
Beaufort Sea	6.94 Bbl	1.79 Bbl	Remainder plus existing PBU
ANWR	10.40 Bbl	4.21 Bbl	
Total	**32.38 Bbl**	**9.83 Bbl**	**200 Tcf +**

- **NPRA** – The entire area is estimated to contain 10.6 billion barrels of technically recoverable oil. Economically recoverable reserves consist of 2.95 billion barrels of oil.[1] (U.S. Geological Survey, 2002, Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA), USGS Fact Sheet 045-02, Table 3 and Figure 7)

- **Central North Slope** – The technically recoverable yet-to-be-discovered barrels of oil are estimated at 3.98 billion. Economically recoverable reserves are set at 0.88 billion barrels (USGS, 2005, Economics of Undiscovered Oil and Gas in the Central North Slope, Alaska, Open-File Rpt 2005-1276, Table 5).

[1] Economically recoverable estimates were based on 2001 dollars so that $23.50 equates to approximately $25.50 in 2005 dollars.

- **Beaufort Sea** – There are 6.94 billion barrels of oil technically recoverable. Economically recoverable reserves during the period under consideration are set at 1.79 billion barrels, the mean estimate at lower oil prices. (Mineral Management Service, Beaufort Sea Planning Area Oil and Gas Lease Sales 186, 195, and 202 OCS FEIS, 2003, MMS 2003-001, Appendix B, Table B-1)

- **ANWR** – There are 10.4 billion barrels of technically recoverable oil. Economically recoverable reserves consist of 4.21 billion barrels. (Energy Information Administration, Analysis of Oil and Gas Production in the Arctic National Wildlife Refuge, March 2004, pg 5 and Table 1)

- **Natural Gas** – Most natural gas that is technically recoverable is considered economically recoverable provided there is a means of transmission to market. Assuming gas flow through a pipeline beginning in 2015, the period through 2046 production totals 49.6 trillion cubic feet. Best estimates of natural gas reserves on the north slope far exceed this amount and include: proven reserves – 35 trillion cubic feet within Prudhoe Bay Field, Pt. Thomson, and other fields (EIA, March 2004), NPRA - 59.7 trillion cubic feet (USGS Fact Sheet 045-02); and, together with ANWR and offshore undiscovered reserves totals above 200 trillion cubic feet (USGS, Conventional Natural Gas Resource Potential, Alaska North Slope, 2004, Rpt 2004-1440).

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The studies also set ranges for technically recoverable oil with a 5% and 95% confidence interval. These wide ranges are presented below. Economically recoverable oil volumes will vary by price of oil. However, higher valued oil will also be higher cost oil to produce with each increase in price resulting in increased volume strictly related to the cost of production.

Range of Technically Recoverable Oil

	5th Percentile	Mean	95th Percentile
NPRA	5.90 Bbl	10.6 Bbl	13.20 Bbl
Central North Slope	2.87 Bbl	3.98 Bbl	5.85 Bbl
Beaufort Sea	3.56 Bbl	6.94 Bbl	11.84 Bbl
ANWR	5.70 Bbl	10.40 Bbl	16.00 Bbl

30. Provide a historical analysis of the effective tax rate on each field in production on the North Slope over the past twenty years.

See attachment section, indexed by question number. These tables contain effective production oil tax rates since 1986 for all Alaskan fields on gross value at the point of production on non-royalty volumes. The effective tax rate shown on these tables is the ELF x 12.25% for the first five years of production, and ELF x 15% thereafter. We note the effective rate varies between 15.0%, for Prudhoe Bay through 1987

(when the so-called "rounding rule" rounded the ELF up to 1), and 0.0% for a number of fields for a number of years.

31. How will Net Profit Share Leases (NPSL's) be affected by this legislation? Will the gross costs of exploration and development go into the Development Account—or those costs net of the credits and deductions?

Production taxes are currently deductible for NPSL purposes. This legislation does not intended to change the deductibility of the production tax, nor does it change how costs are accounted for within the Development Account. However, the Department of Natural Resources (DNR) is currently examining whether or not the PPT tax credits would be income for NPS purposes, whether the PPT per se may an allowed deduction. DNR may be able to add additional information.
Also see Question 58.

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32. It's been reported that the gas line contract will propose the state take its gas production tax share in the form of gas. How does that work in this bill?

In the gasline contract the state has indeed proposed taking deliveries of gas in place of a production tax; this is not reflected in the PPT bill which will stand on its own, gasline or no. Under the PPT, if the producers sell gas, those revenues would be part of the net profit calculation. Under the gasline, they would not. Instead the state would receive a percentage of the gas, which it would monetize through marketing. Note that the costs of developing (for example Pt Thomson) or running (for example Prudhoe Bay) a field that produces both oil and gas would go into calculating the oil profits for the PPT.

33. Of the pre-PPT credit provisions (or claw back), what is the cost to the state for legacy fields and what is the cost to the state for frontier regimes?

The assumption made for this request is that the Pre-PPT cost claw-back will be the last adjustment made to the tax. All other deductions and credits allowed under the PPT will have been exercised.

There was approximately $4.8 billion of capitalized investment made by the industry during in the period 2001 through 2006.

Using the Department of Revenue price forecast, which has prices falling, and remaining below $40 after 2008:

Legacy Field Owners: $416.9 million

Frontier Field Owners: None. Due to no production or the inability to generate revenues sufficient to have a tax liability after other deductions or credits are taken.

Assuming a flat price of $45 for 2007-2050:

Legacy Field Owners: $1.232 billion
Frontier Field Owners: $0.020 billion
Total $1.252 billion
The major owners will recover all of their pre-PPT investment by 2011.

Assuming a flat price of $60 for 2007-2050:

Legacy Field Owners: $1.234 billion
Frontier Field Owners: $0.018 billion
Total $1.252 billion

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

a. Only 2 credits that have been issued have been sold to another party.

b. The Division will first obtain a waiver of confidentiality from the seller allowing the Division to confirm the credit amount to the prospective purchaser. Once sold, the Division makes the transfer and issues a new credit certificate to the purchaser upon receipt of documentation and confirmation of the transaction from the seller of the credit. The credit exists as an electronic entry in a Division database, therefore only the Division can make the actual transfer of the credit in that database. A new certificate is entered in the database to the purchaser and the old certificate is marked as transferred and its balance is zeroed out. The Division then notifies both the purchaser and the seller, in writing, of the completed transfer of the credit, at which time the purchaser may then apply the credit to its own production tax liability. When a credit is applied to a tax liability by a producer, the Division then verifies the holder and amount of the claimed credit against the credit certificates in the database.

35. If we have a gas pipeline in 2015, what will the ELF tax "take" be on North Slope gas and what will the "take" be under the PPT? What will the "take" be under PPT if we take gas in lieu of the production tax (the take would, I assume be the day-to-day value of the gas less the state's cut in selling the gas on the marketplace)?

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Without getting into price sensitive forecast, or the confidential draft gas contract, we can make the following observations about the comparison: The upstream costs are covered in the PPT, so the difference could be as simple as;

(a) under the PPT, a taxpayer would pay 20% of the gross value at the point of production, that is sales revenues less the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale would be paid to the state. (without taking into account the effect of the $73 million dollar allowance).

(b) Under a gas contract as now contemplated, the state would receive some percentage of the gas, and then pay the tariff charged by the Gas Treatment Plant and the tariff between the North Slope and the point of sale. If the state owns part of the pipeline, then the state will also receive that portion of the tariff which is profit accruing to the owner.

36. Is current production tax deductible from corporate tax? If no, is this impact in the models presented by the Administration?

Yes, current production is deductible from corporate income tax.

37. Referring to Section five, what oil and gas is exempt from taxation—just what is discussed in Section 10?

The oil and gas royalty amounts paid to the state and federal government are exempt. AS 43.55.900 (13) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state."

Section 10 simplifies treatment of flared gas. Under current law, there are three categories of gas – gas used in production operations which is exempt from tax, gas produced in excess of that needed for safety purposes which is taxable, and gas flared beyond the amount authorized for safety which is taxed and subject to a penalty. Currently there is no "free use of oil" to produce more oil in statute. The bill exempts from tax any oil or gas used in production operations, unless the Alaska Oil and Gas Conservation Commission determines that it was waste (instead of used to produce salable hydrocarbons), in which case it is taxed.

38. Referring to Section six, will there be any impact to current state taxes or municipality taxes from this change?

No, there should be no impact to current state or municipal taxes. This language change simply makes the description of Intangible Drilling Costs consistent with Internal Revenue Code language, which is how this item is interpreted currently.

39. Why was the payment for taxes and surcharges changed from the 20th day to the last day of the month? What is the economic impact of this change?

There is no economic impact and this just clears up current language. Under AS 43.55.020, payment for the tax is "due" on the 20th, however, the tax is not "delinquent" until the last day of the month. The significance of this is that according to AS 43.05.225, interest is assessed only when a tax "becomes delinquent." Thus this bill makes the due date the end of the month and in Section 7 establishes that "an unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent."

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

a. Net profits systems in the world typically work on the basis of three different concepts:

(a) monthly payments based on actual production, revenues and expenditures, without an annual true-up, as is the case in most production sharing agreements
(b) yearly payments based on a yearly return, filed within a few months after the year, without a need for monthly payments on account, as is the case for the Thai SRB, for instance. This means there is only a single annual payment.
(c) Yearly payments based on a yearly return, filed within a few months after a calendar year or a lease/contract year, with monthly payments on account. In this last case, the monthly payments could be based on:
    a. Estimates for each month, as for instance with the Nova Scotia profit sharing royalty. These estimates can be challenged by government and different estimates may be required.
    b. Payments based on a mixture of actual information from the previous month and estimates, such as in Algeria
    c. Corporate income tax style procedures, whereby payments are based on taxes paid in the prior year (Norway for the Hydrocarbon Tax).

The 90% rule proposed for Alaska is unique. The overall economic impact would depend on the taxpayers' cost estimates for each month. We expect that taxpayers will experience underpayments in some months, but will experience overpayments (because of estimates used) in other months. In addition, falling production amounts, or unforeseen costs will serve to likely create overpayments in later months. Overall, we do not expect any material net economic impact.

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41. What are the penalties for under-payment when sure-up [true-up] is more than ten percent of the taxes owed?

If the taxpayer does not pay 90%, then interest will be due on the difference between the tax paid and the 90% amount.

42. Referring to Section 10, why does the AOGC [Alaska Oil and Gas Conservation Commission] role change from focusing on excess needed for safety reasons to whatever they determine to be waste? Does this provision provide more power to the AOGC on what is included/excluded for taxation?

Under current law, as applied by DOR regulation, the categories of flared gas recognized by DOR are different from (although related to) the categories recognized by AOGCC. The bill will simplify the categorization and harmonize it completely with AOGCC's. This simply creates one standard administered by AOGCC, in place of two standards administered by two agencies.

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43. Why does it seem the credits and incentive [sic] ar on production along with exploration if our focus is to provide incentives for exploration?

The bill is based on the expectation that investment, both exploration and in existing fields, will increase production.

44. Can the carryforward amount be used for a credit for more than the first year after the loss?

Yes, the credit carryforwards can be used indefinitely. There is no time limit on the credit carryforwards.

45. Is it the case that any allowable expenses for the exploration, development, or production of gas can be deducted from oil revenues in determining net value? If so, could the expenses of a gas line be included in these deductible expenses?

Expenses are allowable only if they are "upstream" costs. A gas line is "downstream" and so would not be a deductible expense.

46. Why not use GAP [sic] accounting rules versus set up or our [sic] system of defining revenues and expenses?

GAAP (Generally Accepted Accounting Principles) are useful for determining whether an item of expenditure can be classified as an "expense." GAAP does not differentiate between expenses incurred specific to a lease and those expenses that are indirect to a lease. For example, GAAP does not distinguish between wages paid to a lease-based worker, and an employee in the home office.

47. Which credits can be applied to multiple years?

There is no time limit for credit carryforwards under the bill, nor for the optional credit codified in AS 43.55.025. However, any dollar of investment can only generate one credit, and that credit can only be used once.

48. Can a tax credit be sold in any year or just the year after it was accrued?

Once the credit has been turned into a Credit Certificate, it can be sold at any time. A person can apply for a Credit Certificate at any time, but the bill allows the Department. of Revenue a period of time in which to issue the Credit Certificate. (See Section 12, Sec. 43.55.024(g))

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49. What is the estimated economic impact to the state of the ability to sell tax credits?

We believe the economic impact on the state will be positive as the credits will cause additional exploration, investment and development in the state creating jobs and demands for local goods and services. We believe there will also be a positive impact on the state treasury, and that while the cost of the credits will be considerable as discussed below, a better comparison is total revenue collected with the incentive driven investment and with the incentive driven investment. Because we don't know exactly how much investment will occur as a consequence of these credits (and because without having some certainty about that number, comparing two sets of revenues from two different sets of volumes can become an exercise in wishful thinking, the rest of this answer focuses on the narrow question of the cost to the states PPT collections from the credits

In short, the proposed twenty percent capital credit against production tax would result in total credits of between $5,369.9 and $12,506.0 million depending on whether there are additional major (Alpine like) fields discovered on the ANS and whether or not a gas line is built triggering additional discovery and development (the gas line itself will have no effect on the PPT credits). These will amount to between 25.0% and 37.4%, respectively, of total pre credit PPT owed. Transferable credits, presuming that 95% of production is by major three companies but only 75% of credits are generated by them, result in an overall cost to the State of financing these credits of between $1,342.5 and $3,126.5 million.

Background

Permitting transferability of ta.. credits provides a strong economic incentive for full use of the credits. Credits accruing to companies with insufficient offsetting revenues would be more likely to be used rather than banked or lapsed. This will result in less production tax revenue to the State.

Capital credits as proposed in the Governor's PPT are equal to 20% of capital expenditures for a year (Sec. 12, AS 43.55.024(a)). They may be used in the year of expenditure, carried forward to following years, or transferred (they are fungible). If transferred, the credit can not lower a production tax rate below 80% of what it would otherwise be (AS 43.55.024(e)). These credits will have market value that would not exceed their face value, and will frequently be less than face value. A company generating them but unable to use them faces a choice – use them in some following year (if they have taxable income), or sell them for a discount. The value to the purchaser is in the size of the discount they get in the purchase.

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Each company that conducts exploration or development work within the State will accrue capital credits. However, only those with production tax obligations will be able to deduct a credit. In orde.: to determine production tax obligation, each company will deduct from gross revenues operating costs, capital costs, and other costs of operations. From this net amount each company will have a$73 million allowance that effectively exempt that much net production income from the PPT. Analysis indicates that at anything but high prices, only three companies will have significant production tax liabilities remaining following these deductions and exemptions.

During FY06, three oil companies (BP, ConocoPhillips, ExxonMobil) account for 95% of oil production on the ANS. Future production modeling is based on known reserves and these three companies continuing to account for this level of ownership.

The capital credit system is designed to provide incentives to invest in infrastructure and exploration. Taken with the $73 million allowance, it particularly encourages companies which do not already have a major presence in Alaska. To the extent this system is successful, the major three companies will see a decrease in their share of production. However, without modeling ownership percentages, it is not possible to accurately estimate who will be spending what and selling credits to whom. Therefore, we assume in our modeling that all capital credits will be generated generally as they would be now.

In order to estimate the capital credits, it is necessary to estimate total oil and gas development spending in Alaska. This is problematic in that a successful program will incentivize more exploration and development and therefore more spending both on the North Slope and elsewhere in the State.

Capital costs for the ANS are modeled based on the following cost assumptions: $100 million per year in exploration expenditures through either TAPS closure 2030 (without gasline); $1.00 per barrel in ongoing capital costs; and, $3.50 per barrel in capital costs for conventional oil and $8.00 per barrel in capital costs for heavy oil, both taken across 100% of barrels in new fields and 2/3s of barrels in existing fields. There are four scenarios: with and without additional large finds and with and without a gas line. The four capital cost totals are:

	Millions of Dollars	
ANS – Oil	Without Gas Line	With Gas Line
Without Finds	$23,796.6	$32,688.1
With Finds	$51,543.8	$55,462.2

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Gas related capital costs in the ANS are accrued only to the scenarios that include a gas line. These total $4,701 million per scenario.

Capital costs for Cook Inlet (and by proxy, the rest of the State other than North Slope) are modeled to be $3.051 billion through 2050. This is based on capital costs of $4.00 per barrel of oil and $0.50 per Mcf of gas as forecast to be produced through 2050 in the Spring RSB.

Taking ANS oil, Cook Inlet (and the remainder of the state), and ANS gas capital expenditures together results in a range of investment until 2050 of between $26,849.4 and $62,530.0 million. The twenty percent credit would amount to between $5,369.9 and $12,506.0 million.

The total production tax owed the State prior to credits is modeled using a constant $40 per barrel ANS west coast price. Depending on the scenario, this results in total production taxes of $21,488.4 to $33,416.6 million. The total credits amount to between 25.0% (no gas line and no finds) to 37.4% (gas line with finds) of the total production tax owed.

Scenario	ANS Explore	ANS Oil Ongoing	ANS Oil Develop	ANS Gas	C.I.	Total Capital Costs	20% Credit	Production Tax	Credit % of Prod Tax
w/Gas w/o Finds	$3,500.0	$7,096.5	$22,091.7	$4,017.0	$3,050.8	$39,755.9	$7,951.2	$22,007.6	36.1%
w/Gas w/Finds	$3,500.0	$10,468.1	$41,494.1	$4,017.0	$3,050.8	$62,530.0	$12,506.0	$33,416.6	37.4%
w/o Gas w/o Finds	$2,000.0	$5,543.5	$16,255.1		$3,050.8	$26,849.4	$5,369.9	$21,488.4	25.0%
w/o Gas w/Finds	$3,500.0	$9,674.0	$38,369.9		$3,050.8	$54,594.6	$10,919.0	$32,388.1	33.7%

Sensitivity analysis was run with 95% production by major three companies and both 95% and 75% of credits owned by majors. In both cases all credits were usable. The largest State exposure to transferability of credits is when there is this wide distribution, i.e. when 95% of the production comes from the three majors. In that case, between $1,342.5 and $3,126.5 million in credits are transferred, depending on scenario.

50. Referring to Section 16, what is current system and why do we need this change in confidentiality?

The bill codifies current practice embodied in regulations in our treatment of taxpayer information. The only change here is that the bill makes clear that any person receiving information released under current department practices, is subject to the same criminal penalties that apply to a state employee.

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The current confidentiality law is very general in its exception language – information must be kept confidential "except in connection with official investigations or proceedings . . . ." The Department believes that current law does allow disclosure under the circumstances specified in the bill, but there has been some question about that, and it would be desirable to clarify the meaning of the law, as the bill does. In addition, there is the new provision on penalties, referred to above.

51. In what circumstances would oil and gas taxes go straight into the CBR?

Additions to the CBRF (Constitutional Budget Reserve Fund) are made for any oil and gas taxes collected in resolution of a dispute. That means that amounts collected because of an audit assessment, or subsequent settlement, are additions to the CBRF.

52. Referring to Section 18 and 19, why change from "shall" to "is"?

This change is made in accordance with the state style manual.

53. Why does the bill offer multiple methods to determine gross value? Who will choose a methodology?

The bill does not directly allow a taxpayer to elect alternative methods: it just allows the Department to authorize use of an alternative method. The election referred to would be an election between using an alternative method or just calculating gross value according to the usual rules – NOT an election among several different

alternative methods. In implementing this provision, the Department will no doubt develop criteria for when a particular alternative method would be appropriate. It is difficult to predict now whether there might be circumstances under which more than one alternative method might be appropriate and under which the Department would authorize a taxpayer to elect among several alternative methods.

54. Section 21, page 13, line 8— why is this clause constrained by Dec. 1, 2005?

This constraint is intended to avoid industry creating new industry practices in allocating expenses, the sole purpose of which is to structure practices so as to purposefully avoid taxation. This was the date when the bill was being drafted.

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55. Section 21, provision (h), which US CPI [Consumer Price Index] does the Administration plan on using?

This would be established by regulation. The Department has not evaluated the various CPI's at this time.

56. Are the current oil conservation surcharges deductible from any other taxation? If no, what is the policy reason to make them a credit in SB 305 and what is the economic impact?

Yes, current oil conservation surcharges are deductible from corporate income tax.

57. Do any other state taxes have a "standard allowance"?

a. Seafood Marketing Assessment (ASMI) tax is imposed only on processors/exporters that process or export fisheries resources with a value of $50,000 or more in a calendar year. AS 16.51.120(g). However, note that if value exceeds $50,000, then tax is imposed on the entire amount.

b. Mining License Tax is not imposed when net income is less than $40,000 in a fiscal year. AS 43.65.010(c). However, note that if net income exceeds $40,000, then tax is imposed on the entire amount.

c. Gaming tax exempts gross receipts of less than $20,000 from paying the additional fee under AS 05.15.020(b).

d. Alaska's Estate Tax follows federal rules, but the most recent exemption (Fy05) included estates valued at under $1.5M.

58. How many NPSL's (Net Profit Share Leases) are in the state, and how much are they paying in royalties?

Out of 19 NPSL's, seven are paying net profit share payments *(in addition to royalties and production taxes in cases of a positive ELF)*. These seven include five in the Milne Point Unit, and two in the Duck Island Unit, and they began paying in 2001. The total of NPSL payments received in calendar year 2005 was $81M. Total NPS receipts from NPSL's from 2001—2005 were $254M. Net profit share payments are not deductible for PPT purposes nor for the current production tax. Royalties and production taxes are deductible for NPS purposes.

Royalties, however, are paid on net profit share leases according to each individual lease contract. For example, one NPS lease in Duck Island Unit has a twenty percent (20%) royalty rate. Other NPS leases may have the standard royalty rate of 12.5% or another, negotiated royalty rate. Royalties and production taxes are due from a net profit share lease as long as there is production, even when there is no net profit share payment from the property.

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Attached is a table of producing and non-producing NPS leases showing the lease number, the net profit share rate and the royalty rate for each lease.

Also see Question 31.

59. What are the depreciable lives for Oil & Gas equipment for federal and state income tax purposes?

	Federal	Alaska
Equipment for exploration and production including drilling, gathering pipelines, pumping equipment, separation equipment, certain platforms	7	11
Offshore drilling	5	6
Pipelines, excluding gathering and transmission lines	15	17.5
Vessels, barges, other water transportation equipment	10	14.5

60. Please provide the tax calculation under the bill, with the following assumptions:

--Gross value	$60M
--Opex	15M
--Capex	10M

Gross value	$60M
Less: Opex	(15)
Capex	(10)
Tentative net profit Before standard allowance	$35M
Less: standard allowance*	(35)
Net Taxable income	$ 0
Tax	$ 0
Capital investment credit available for carryforward (20% of $10M)	$2M

* this calculation assumes that taxpayer has not reached $73M limit for the standard allowance.

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61. Are net profit lease payments included as a direct cost under Sec. 43.55.160?

Net profit share payments under NPSL's (Net Profit Share Leases) would not be deductible lease expenditures because they are in the nature of lease acquisition costs. Lease acquisition costs are not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

62. Are lease bonus payments eligible for capital credit under 43.55.024 and/or are they included as a direct cost under 43.55.160?

Lease bonus payments are neither deductible nor eligible for capital credits. Lease bonus payments are in the nature of lease acquisition costs which are specifically not deductible per Section 21 (Sec. 43.55.160(d)(2)(E)).

63. How are payments for "spec 3D" handled? Are they credit eligible under 43.55.024 or only allowed as deductions under 43.55.160?

We understand "spec 3D" to be certain seismic exploration costs. Exploration costs are allowed as deductions under Section 21 of the bill (Sec. 43.55.160(c)). Such costs are also eligible for credits under Section 12 (Sec. 43.55.024) by reference to definition of "qualified capital expenditure" at Sec. 43.55.024(h).

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64. Please explain the taxation or exemption of royalties.

Public royalties (paid to federal or state jurisdictions) never enter into the base of gross value. This is so because AS 43.55.011(a) levies the tax on oil except oil the "ownership or right to which is exempt from taxation." This phrase is then defined in AS 43.55.900(13) as follows:

"any ownership interest of the federal government or the state."

These sections are not changed in the bill.

Because the bill changes the tax from a tax on gross value to a tax on net profits, it is necessary to specify deductions. Royalties are specifically disallowed as a deduction under Section 21 (Sec. 43.55.160(d)(2)(B)). Royalties paid to state and federal jurisdictions cannot be deducted because they are not included in the starting "gross value." Private royalties cannot be deducted because the related production is subject to tax.

65. Under Section 21 (Sec. 43.55.160(d)), "direct costs... include..." Does the word "include" serve to restrict the list of allowable expenses to only those items included below in (A)—(C)?

No. As provided under AS 01.10.040(b), "When the words 'includes' or 'including' are used in a law, they shall be construed as though followed by the phrase 'but not limited to.'"

There are specific reasons why each of the enumerated categories of costs is set out in AS 43.55.160(d)(1). "Outlays for capital assets" is set out to avoid any doubt that the bill intends to deviate from the usual principle that capital expenditures are recovered over time through depreciation allowances. Instead, under the bill, the entire outlay for an allowable capital expenditure is potentially deductible when incurred. (Correspondingly, AS 43.55.160(d)(2)(A) makes clear that "depreciation or amortization of capital assets" is *not* deductible.)

"Payments in lieu of property taxes" is set out to clarify that when a producer makes payments that are the equivalent of property taxes; those payments are deductible just as property taxes themselves are deductible.

"A reasonable allowance . . . for overhead expenses . . . " is set out to implement a policy decision that a certain amount of overhead expenses should be deductible even though "overhead" is often not considered a "direct" cost.

Just as the enumeration in AS 43.55.160(d)(1) is not intended to be an exhaustive list of direct costs for purposes of AS 43.55.160(c), neither is the enumeration in AS 43.55.160(d)(2) intended to be an exhaustive list of costs that are *not* direct costs for purposes of AS 43.55.160(c). Some of the items listed in AS 43.55.160(d)(2) are set out to implement policy decisions that certain types of costs should not be deductible whether or not they might ordinarily be considered "direct" costs; other items are set out simply for clarity, or to avoid any potential disputes over deductibility of categories that past experience indicates may be prone to controversy.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO_2 re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

At Prudhoe Bay about 8.5 billion cubic feet of gas a day is reinjected into the field for pressure maintenance. After stripping out certain hydrocarbon liquids, CO_2 is reinjected along with the other hydrocarbons (and non-hydrocarbons). When an export line is built on the North Slope, the CO_2 will be stripped (in "gas treatment"), and there is some question about what will happen with that CO_2, whether it will be treated as waste, or whether it will be treated as a by-product.

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant gas benefits ever be realized?

Assume 20 new companies suddenly showed up on the North Slope and each qualified for the $73 million dollar allowance. A total of $1.4 billion in profits would be sheltered from taxes. If these companies had simply purchased their way in, then taxes would be lower by $280 million (20% of 1.4 billion) than they would be otherwise. At current prices, or say even at $40 oil, this could be a material portion (though not all) of the tax.

If that is the future of the North Slope and the sell off was for business purposes, the legislature may choose to act and make it less attractive to new firms coming in. If these were tax motivated sales, we hope the powers of the commissioner that are built into the bill would prevent the new entrants from using the $73 million allowance

68. How is it possible that any corporation gets triple the sale price for a commodity, having invested capital at the expected lower returns, and then maintains that they need a claw back provision? Why should we offer it?

a. The first part of this question appears to be intended to be answered by oil companies.

b. We should offer a transition deduction because we are converting from a tax on gross, to a tax on net profit. When measuring net profit, it is necessary to allow deductions, not only for current expenses, but also a deduction for the capital investment that is generating the profit. For new assets acquired after the PPT is in effect, a full deduction for the cost the capital investment is allowed in the year acquired. Assets acquired within the last five years are currently producing net income, and a deduction should be allow d for, in effect, depreciation on those assets.

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69. Please show us an international competitiveness rank and score for PPT under the following tax/credit scenarios, both overall and for new producers:

a. 30/15
b. 30/20
c. 25/20
d. 20/20

The following tables are a competitiveness index overview for a number of alternative fiscal options. The methodology of determining the competitiveness index has been described earlier in my February 14, 2006 report.

Four fiscal options were evaluated:

- 20% tax rate 20% tax credit rate
- 25% tax rate 20% tax credit rate
- 30% tax rate 20% tax credit rate
- 30% tax rate 15% tax credit rate

Furthermore these four scenarios were evaluated under two corporate alternatives:

- Investment is a re-investment by a large producer which has already used its corporate tax free allowance
- Investment is a first investment with full use of the $ 73 million tax free allowance

Large Producer Economics

The tax rate is an important economic factor for the large producers.

This can be studied in the following three tables. These tables display the competitiveness at a WTI price of $ 26 per barrel and at $ 36 per barrel. The two indexes are then added up to provide the total index.

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$26	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	196	193	192	191
Alaska PPT	154	158	162	177
Norway	182	181	180	175
UK	68	68	68	68
US GOM	27	27	27	26
Nigeria	80	80	80	80
Alberta-Oil Sands	80	80	80	80
Angola	151	151	150	146
Russia-Sakhalin	214	214	214	212
Azerbaijan	168	168	167	165

$36	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	161	158	157	156
Alaska PPT	147	153	160	166
Norway	214	214	214	213
UK	63	63	63	63
US GOM	25	25	25	25
Nigeria	92	92	90	89
Alberta-Oil Sands	74	74	74	73
Angola	160	158	157	156
Russia-Sakhalin	226	226	224	224
Azerbaijan	158	157	156	155

TOTAL	20-20-0	25-20-0	30-20-0	30-15-0
Alaska Current	357	351	349	347
Alaska PPT	301	311	322	343
Norway	396	395	394	388
UK	131	131	131	131
US GOM	52	52	52	51
Nigeria	172	172	170	169
Alberta-Oil Sands	154	154	154	153
Angola	311	309	307	302
Russia-Sakhalin	440	440	438	436
Azerbaijan	326	325	323	320

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The $ 26 per barrel table shows how the PPT is more attractive than the Alaska current system under any combination. This is due to the fact that the current system is very front end loaded and regressive.

Therefore at low prices the current Alaska fiscal system is rather unattractive in a world wide comparison. This is the reason for the low level of activity on the North Slope during the last two decades. It is also the reason why the PPT will provide significant encouragement for investment for companies with conservative long term price forecasts.

Many large and major companies, however, are now moving to a long term price forecast in the range of $ 30 - $ 40 per barrel. This makes the $ 36 per barrel rating an important rating.

At $ 36 per barrel the PPT is clearly more attractive than the current system under the 20-20 scenario.

Under the 25-20 scenario the PPT is only marginally better than the current system. This is consistent with the opinions expressed by Anadarko and the major oil companies that a 25-20 system would not lead to more investment. However, it is also my opinion that 25-20 will not result in a significant drop in investment by large producers. I believe that the level of investment by large producers will stay about the same.

The 30-20 system is marginally less attractive than the current system and could therefore result in a drop in investment in my view.

The 30-15 system would be more unattractive and would under a $ 36 per barrel price forecast result in a considerably less attractive system with very likely a substantial drop in investment. It is for this reason that I did not recommend a 30% tax rate.

The Total Rating reflects the combination of the $ 26 and $ 36 per barrel ratings.

New Investor Economics

The following three tables show the same ratings but now for first investors which can fully benefit from the $ 73 million allowance.

DRAFT

$26	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	198	199	196	197
Alaska PPT	130	124	126	135
Norway	185	188	189	186
UK	70	72	72	71
US GOM	27	27	27	27
Nigeria	82	83	83	82
Alberta-Oil Sands	84	84	85	84
Angola	157	156	156	153
Russia-Sakhalin	217	217	217	216
Azerbaijan	170	170	169	169

$36	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	165	164	163	162
Alaska PPT	119	120	121	130
Norway	214	214	214	214
UK	67	67	67	66
US GOM	26	27	29	27
Nigeria	96	96	93	91
Alberta-Oil Sands	79	79	79	78
Angola	167	166	164	162
Russia-Sakhalin	228	228	228	228
Azerbaijan	159	159	159	159

TOTAL	20-20-73	25-20-73	30-20-73	30-15-73
Alaska Current	363	363	359	359
Alaska PPT	249	244	247	265
Norway	399	402	403	400
UK	137	139	139	137
US GOM	53	54	56	54
Nigeria	178	179	176	173
Alberta-Oil Sands	163	163	164	162
Angola	324	322	320	315
Russia-Sakhalin	445	445	445	444
Azerbaijan	329	329	328	328

The three tables show that both for the $ 26 and $ 36 price levels the PPT for any tax rate and credit rate combination is significantly more attractive than the current system. The $ 73 million tax free allowance is therefore very important in order to encourage new investment.

It can be seen how the rating "wobbles" from 249 at 20-20 to 244 at 25-20 and 247 at 30-20. This is due to the fact that for new investors a higher tax rate is actually more attractive for the 50 million barrel field since they receive a higher tax credit for the loss carry forward, but do not have to pay the tax. For the 500 million barrel case, a higher tax rate is less attractive. These two effects offset each other in the rating.

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It can also be seen how the tax credit of 20% is far more attractive to new investors than the 15% tax credit.

Overview

The expected level of investment as a result of the four fiscal options can therefore be summarized as follows:

	20-20	25-20	30-20	30-15
Large Producers	More	Same	Less	Much less
New Investors	More	More	More	More

70. Please present Mr. Marks' charts on pages 14-16 to show the difference between a PPT and status quo, annually under the following PPT plans at $20, $40, and $60/bbl:

a. 25/20
b. 30/20
c. 30/15
d. 15/20
e. 25/25
f. 15/25
g. 22.5/22.5
h. A summary chart showing all above scenarios at $40
i. A chart showing the effect of an incremental change of 1% in tax rate and credit.
j. A summary table showing the effective tax rate for all scenarios.

Please see attachment section, indexed by question number.

71. Please show the corporate take chart on page 24 of Mr. Marks' presentation given the following tax/credit scenarios:

a. 25/20
b. 30/20
c. 30/15
d. 15/20
e. 25/25
f. 15/25
g. 22.5/22.5

Please see attachment section, indexed by question number.

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72. Please show the price point where DOR estimates corporate profit margins hit:

a. 15%
b. 20%.

Please see attachment section, indexed by question number.

73. Will the new confidentiality provisions extend to or have an effect on any other taxes besides the production tax?

The general confidentiality requirements for all taxes are contained in AS 43.05.230. The new confidentiality language added by Secs. 4 and 16 of the bill applies only to information relating to the oil and gas production tax, not other taxes. This is because:

(1) AS 43.55.040(1) addresses information "necessary to compute the amount of the tax," and the phrase "the tax" is used throughout AS 43.55 as referring only to the production tax; and

(2) AS 43.55.040(1) deals only with information obtained from persons "engaged in production," or their agents, and with purchasers "of oil or gas," and with owners of a "royalty interest in oil or gas."

74. Model the Cook Inlet gas producers (presumably including their CI oil production, but do not include NS production from Chevron, Forest, Phillips or Exxon): Are their taxes going up or going down in the future.

Assuming that all provisions of the proposed PPT are in place (that is, the $73M deduction and the credits), and assuming that gas prices rise gradually to Henry Hub levels ($7-$9/Mcf), and that companies in the future maintain current levels and market shares of production in Cook Inlet, most likely Marathon, Chevron/Unocal,

and ConocoPhillips will see their severance tax liability increased, based on their Cook Inlet production alone. If however, gas prices stay low ($3/Mcf), these companies will not see an increase in their severance tax burdens under the PPT, and in fact, will probably pay less under the PPT system than under the ELF tax system.

75. Same as Question 74, except apply retroactively, with and without $73M allowance

We applied the PPT retroactively to Cook Inlet oil and gas production in fiscal years 03, 04, and 05. During those years, the prices received for natural gas were extremely low, with average wellhead prices of less than $3 per Mcf. We believe that producers will gradually see increased prices for Cook Inlet gas over time, and for that reason, this analysis is of limited use.

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Under the current tax system, severance tax collections for the three fiscal years used in this analysis were as follows: FY03--$23M; FY04--$24.7; FY05--$24.4.

Without the $73M allowance, and based on Cook Inlet production alone, Chevron/Unocal, Marathon, and ConocoPhillips would have seen moderate increases in their severance tax liability under the PPT in FY03-05. Aurora, and Municipal Light and Power (assuming they pay taxes), would have owed about the same amount as under the current severance tax system.

With the $73M allowance, and with all credits of the PPT in place, none of the companies would have had to pay severance tax under the PPT in FY03-05, based on their Cook Inlet production alone. Many companies paid some tax in FY03-05 under the current system, and this would represent a reduction for them.

76. Model a newcomer to the Cook Inlet that explores for, finds, develops and sells gas. What will their taxes look like under the status quo and the PPT?

It is impossible to answer this question with any accuracy because of the numerous assumptions one would have to make. Generally, a newcomer to Cook Inlet would spend at least a couple of years exploring for gas, and during this time, would presumably not produce any gas and in fact may not realize any income from these operations. So for the years of exploring, the newcomer would not pay any tax under either the status quo or the PPT system.

Under the PPT system, the newcomer would have earned capital credits in the first couple of years that they can either hold or sell, as well any loss carryforwards they may have accrued. Most investors would probably choose to monetize the credits or losses immediately, as this would increase the net present value of their investment. Under the current system, the newcomer would have no such opportunity and would not be able to take any credits until production begins (assuming the newcomer

would be eligible for the credit under AS 43.20.043). This credit is currently available for 10% of exploration costs.

After all credits have been used or monetized, the PPT system continues to allow a $73 million standard allowance per year. Therefore, the newcomer would not have to pay tax under the PPT if his net income was less than $73 million. The current system may require the payment of severance tax, depending on the productivity of the wells and the price paid for natural gas, without regard to the newcomer's income. Once production has reached a fairly high level, and if gas prices were high, there is a chance that the PPT system would create higher severance tax liabilities for the newcomer than the current system.

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77. How much gas was flared so as to trigger taxes and/or penalties in recent years?

During FY 2005, 351,000 Mcf of gas was flared that was considered gross taxable production. Of that, only 120,000 Mcf was from fields with a positive ELF and subject to tax. During the same period 31,000 Mcf was flared and considered waste and subject to both tax and penalty.

78. Could we look at (1) a standing offer to purchase tax credits for 10% of their face value – with the implication that the department could treat that as a receipts funded program so that the legislature would not have to authorize the purchase amount and (2) "Alaska bucks" – ie allow credit certificates to be used in lease sales or other lease acquisition activities as cash – or even at 110% of face value.

We assume this means a 10% discount from face value, or 90% of which is where the one set of credits traded. As this market is created by the state, and is driven by state restrictions, it is not out of line for the state to become a price maker in the market as well. It is the legislators' call to make tax receipts program. Among the considerations the legislature might bring to this is how much of tax receipts they wish to make program receipts, and are they willing to buy back $100 million plus, in credits if a major investment (say at Pt. Thomson) were followed by a radical price correction lasting over a year.
Again – this is a policy call about how far the state wants the effects of the investment credits to run; we believe the governor has made a balanced set of calls. Do we want them to both lower and distort our bidding lease sale markets? Does the state really want to have to reaudit what the money it hands out in credits is spent? Do we want to create advantages to for foils who have a history here of at least a year of investment and loss over folks considering entering the market? Before the Department undertakes further modeling on these matters it would help to get clearer insight into the outcome hoped for by the legislature.

79. Could we draft up alternative standards for the anti-hiving provision so the legislature can choose.

A possible alternative might be along these lines:

> "The department will disallow an allowance deduction if it finds that a benefit attributable to a producer's allowance is shared with or enjoyed by another producer."

This concept might be more effective if it were adopted as a supplement to, rather than a substitute for, the current language in proposed AS 43.55.160((j). For example, the new language could be added to proposed AS 43.55.160(i), as follows:

> (i) For a month for which the net value of the taxable oil and gas produced during the month calculated under (a) of this section exceeds zero, a producer that is qualified under (j) of this section may reduce the net value by deducting an allowance in an amount calculated such that (1) the net value for the month is not reduced below zero; and (2) the total of the allowances deducted for all months during the calendar year does not exceed $73,000,000. However, the department will disallow an allowance deduction if it finds that a benefit attributable to a producer's allowance is shared with or enjoyed by another producer. An unused allowance or portion of an allowance under this subsection may not be carried forward to a later calendar year or used to establish a carried-forward annual loss under AS 43.55.024(b).

80. When the 1989 ELF change was enacted, was it retroactive and were there transition provisions?

The 1989 ELF changes were made retroactive to January1, 1989, and applied to oil produced after December 31, 1988. There was a transition provision to the effect that tax payable as a result of the retroactive changes would be due on the 20th day of the calendar month following the effective date of the Act. (The effective date of the Act was August 6, 1989.)

81. Please provide the 20/20 modeling.

The PPT model is very large and complicated (nearly 5.5 megabytes over 38 worksheets). Its complexity is exacerbated by the inclusion of the gasline model and the proposed negotiated gasline fiscal terms. It also includes confidential producer data.

Moreover, it is our experience that when models become this large and this complicated, it is practically impossible for an outsider to use the model because of all the interdependencies. Nevertheless, we are absolutely dedicated to the goal

where legislators are comfortable with the mechanics of the tax and the model and its results. Accordingly, we are willing to work with any legislator to that end.

82. Under the new gas and oil definitions what will the net change to the spill fee be? In other words, looking at FY 2005, how much, if any (a) oil did we tax for its use in production operations and (b) how many ngls were put in TAPs?

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During FY 2005 tax was collected on 1,222,400 barrels of crude oil used in production operations. During FY 2005 16,445,000 barrels of NGLs were put in TAPS.

83. Please model the smaller interests and their sale of credits and estimate the price at which those credits will no longer have a market among the big three.

See Question 49.

84. If aggregation at Prudhoe Bay had been implemented on July 1, 2001 [the start of the claw back period], how much more would the State have received between then and the actual aggregation date?

The State would have received $430.4M additional revenue. See estimates below:

ANS Oil Severance Tax
With and without aggregation of
PBU
FY2001 thru Jan 2005 Production

FY	No Agg	With Agg	Delta
2001	667.1	713.1	46.0
2002	444.5	501.2	56.7
2003	549.6	644.4	94.8
2004	594.5	720.4	125.9
2005	465.9	572.9	107.0
	2721.6	3152.0	430.4

Note: Estimate with Aggregation assumes all taxpayers are paying under the aggregated Elf

85. Why are the status quo lines in the three graphs presented by Ms. Wilson flat once the forecast price effect is adjusted for? Wouldn't falling production and ELF move those down?

The status quo drops from $378 mm in 2009 to $291 mm in 2012. It looks flat because of the scale on the graph.

86. What will the actual cost to the investor be for these upstream investments, and what is the total government underwriting, state and federal, all tax types included. Is it different for large companies and small companies?

After state and federal tax the investor would bare about 38% of the marginal capital. There is no reason to think it would differ appreciably between large and small investors.

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87. Lord Browne famously said two years ago that any profits over $20 a barrel were being returned to shareholders as they weren't needed in BP's business. What tax rate, credit rate would be needed to have a cross over [unspecified period] at $20 [presumably Brent].

With a 20% credit it would take a tax rate of about 36% to effect a crossover at $20 Brent, based on our low-volume scenario. With a high-volume scenario, the tax rate would be about 51%. These calculations were made using our standard assumptions, as outlined in the fiscal note.

88. Please explain how the conservation surcharge is affected by oil price and what effect this bill has on the surcharge.

a. The conservation surcharge is a 3 cent per barrel charge on all oil produced less royalty barrels, so therefore it is not sensitive to price.

b. There will be changes in the quantity of oil subject to both production tax and conservation surcharges under the bill. One change will be positive, one negative. The positive change is that natural gas liquids extracted by gas processing and blended in the TAPS stream that are now taxed as gas, will be treated as oil under the bill. The negative change is that oil that is used in lease operations will not be taxed or subject to surcharge under the bill. Oil may be used to make fuel for lease operations and perhaps used for other production purposes. The overall result is an expected increase of the total surcharge amount of $444,000 per year, based on FY 2005 amounts. (See Question 82.)

The bill should not affect the assessment or collection of the surcharge, other than the quantity-of-oil effects described above. Any surcharge paid will be allowed to be credited against production taxes, but that would only reduce the amount of tax collected, not the amount of surcharges collected.

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89. Why are we including gas in the PPT calculation?

The bill includes gas in the PPT calculations because it is a stand-alone bill. The bill does not require implicitly or explicitly that a Stranded Gas Contract be subsequently concluded. Therefore, a PPT law would be entirely functional in case a Stranded Gas Contract is not presented to the Legislature or in case the Legislature rejects such a Contract.

The ELF system for gas is "broken". Just as the ELF is "broken" for oil, the gas ELF does not encourage reinvestment and it is not sensitive to price.

It should be noted that under high gas prices the Alaska State take for gas would increase significantly relative to the status quo. This would be beneficial in case significant gas reserves would be developed outside the scope of the Stranded Gas Development Act.

The inclusion of gas in the PPT is therefore a strong incentive for producers to conclude a Stranded Gas Contract that is in the interest of the State of Alaska. Including gas in the PPT enhances the bargaining position of the State for a good Stranded Gas Contract.

90. Please show the cumulative production tax from 2007—2030 under the PPT given the following tax/credit scenarios:

a. 25/20
b. 30/20
c. 30/15
d. 15/20
e. 25/25
f. 15/25
g. 22.5/22.5
h. A summary chart showing all above scenarios
i. A summary table showing all above scenarios

Please see attachment section, indexed by question number.

91. What is the meaning of the term "progressive tax"?

According to *Black's Law Dictionary* (2004), a progressive tax is

"A tax structured so that the effective tax rate increases more than proportionately as the tax *base* increases..."

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This is consistent with taxation and economics literature.[2] In other words, a progressive tax is any tax in which the rate increases as the amount subject to taxation increases. If a tax is levied on "net income", then a progressive tax scheme will increase the tax rate based on increasing levels of net income. If a tax is levied on "gross income", then a progressive tax scheme will increase the tax rate based on increasing levels of gross income.

92. What is the meaning of the term "proportional tax"?

According to Black's Law Dictionary, a proportional tax is:

"A tax whose rate remains fixed regardless of the amount of the tax base."

Black's equates a "proportional tax" with the term "flat tax." Thus, a proportional tax is neutral since the relative share does not change with amount.

93. What is the meaning of the term "marginal tax rate"?

According to WG&L Tax Dictionary (2004), a marginal tax rate is:

"The rate of tax applied to the last dollar of the tax base."

Therefore, if a tax is based on net income, a marginal tax rate is measured based on the last dollar of net income. This is most often found in income tax law such as AS 43.20.011 where the top marginal rate is 9.4% and this tax rate is applied to amounts of Alaska corporate taxable income over $90,000.

94. What is the meaning of the term "effective tax rate"?

In general, whenever there are several factors at play this measure cuts through all their effects, and typically divides the tax paid by some measure.

For an income tax, the effective tax rate is normally expressed as the actual income tax paid divided by taxable income, expressed as a percentage. For example:

[2] See WG&L Tax Dictionary written by Richard A. Westin (2004), and Principles of Microeconomics written by Karl E. Case and Ray C. Fair (1989).

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Gross income	$100
Less: deductions	(90)
Net income	$ 10
Tax at 20%	$ 2
Less: credits	(1)
Tax due	$ 1

In this example, the effective tax rate is 10%, which compares the $1 tax due with the taxable income of $10.

In Question 30, the effective production tax rate was the percentage of gross revenue, without taking into account exploration credits.

95. Please differentiate the definition of "exploration," "development," and "production."

According to FASB (Financial Accounting Standards Board) Current Text Section Oi5, Oil and Gas Producing Activities (as of January 1, 2000):

a. Exploration involves identifying areas that may warrant examination and examining specific areas that are considered to have prospects of containing oil and gas reserves. Exploration costs include drilling exploratory wells and exploratory-type stratigraphic test wells. Principal types of exploration costs include costs of topographical, geological, and geophysical studies.

b. Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas. These costs include such things as expenditures to gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, road building, power lines, drilling and equipping development well; platforms; casing; tubing; pumping equipment; and the wellhead assembly.

c. Production involves lifting the oil and gas to the surface, gathering and field storage. Production costs are those costs incurred to operate and maintain wells and related equipment and facilities, such as labor to operate the wells, repairs and maintenance, and materials, supplies, and fuel consumed to operate wells.

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I hope that this information is helpful. Please let us know if you would like any additional information. Thank you for the opportunity to be of assistance.

Sincerely,

Robynn J. Wilson

Robynn J. Wilson
Director, Tax Division
Department of Revenue

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Letter to Senator Wagoner and Representatives Samuels and Ramras
March 13, 2006

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Tax Rate, Marginal	92
Transitional Adjustment	1, 20, 33, 68, 80
Undiscovered Resources	29
Value	25, 53

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Question 30—Table A

Effective Tax Rates, North Slope by Field, FY86 - FY05

	Prudhoe Bay	Midnight Sun	Polaris	Orion	Aurora	Borealis					
FY86	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.07%	0.00%	0.00%	0.00%	0.00%
FY87	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.47%	0.00%	0.00%	0.00%	0.00%
FY88	12.66%	0.00%	0.00%	0.00%	0.00%	0.00%	8.33%	0.00%	0.00%	0.00%	0.00%
FY89	12.33%	0.00%	0.00%	0.00%	0.00%	0.00%	8.71%	0.00%	0.00%	0.00%	0.00%
FY90	14.71%	0.00%	0.00%	0.00%	0.00%	0.00%	12.89%	0.00%	0.00%	0.00%	0.00%
FY91	14.91%	0.00%	0.00%	0.00%	0.00%	0.00%	13.19%	0.00%	0.00%	0.00%	0.00%
FY92	14.90%	0.00%	0.00%	0.00%	0.00%	0.00%	13.33%	0.00%	0.00%	0.00%	0.00%
FY93	14.85%	0.00%	0.00%	0.00%	0.00%	0.00%	13.34%	0.00%	0.00%	0.00%	0.00%
FY94	14.81%	0.00%	0.00%	0.00%	0.00%	0.00%	13.09%	0.00%	0.00%	0.00%	0.00%
FY95	14.76%	0.00%	0.00%	0.00%	0.00%	0.00%	12.85%	0.00%	0.00%	0.00%	0.00%
FY96	14.67%	0.00%	0.00%	0.00%	0.00%	0.00%	12.35%	0.00%	0.00%	0.00%	0.00%
FY97	14.59%	0.00%	0.00%	0.00%	0.00%	0.00%	11.72%	0.00%	0.00%	0.00%	0.00%
FY98	14.44%	0.00%	0.00%	0.00%	0.00%	0.00%	11.38%	0.00%	0.00%	0.00%	0.00%
FY99	14.23%	0.00%	0.00%	0.00%	0.00%	0.00%	10.53%	0.00%	0.00%	0.87%	0.00%
FY00	13.96%	0.00%	0.00%	0.00%	0.00%	0.00%	8.97%	0.00%	0.00%	0.58%	0.00%
FY01	13.76%	0.00%	0.00%	0.00%	0.00%	0.00%	7.40%	0.00%	0.00%	0.05%	0.00%
FY02	13.44%	0.13%	0.00%	0.00%	0.00%	0.96%	5.29%	0.00%	0.00%	0.52%	0.00%
FY03	13.05%	0.10%	0.00%	0.00%	0.00%	1.40%	3.44%	0.00%	0.00%	1.22%	0.00%
FY04	12.82%	0.00%	0.00%	0.00%	0.00%	1.03%	2.70%	0.00%	0.00%	0.84%	0.00%
FY05	12.65%	4.43%	4.43%	3.63%	3.62%	3.69%	0.76%	0.00%	0.00%	0.15%	0.00%

Note: The effective tax rate for Midnight Sun, Polaris, Orion, Aurora, Pt. McIntyre, and Borealis for FY 05 reflects 5 months' effect of the aggregation decision effective Feb. 1, 2005.

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Question 30—Table B

	Milne Point	Endicott	Eider	Lisburne	Point McIntyre	Niakuk	West Beach	NPRS	Alpine	Northstar
FY86	2.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY87	0.62%	0.00%	0.00%	4.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY88	0.00%	8.17%	0.00%	7.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY89	0.00%	12.25%	0.00%	6.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY90	0.00%	10.37%	0.00%	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY91	0.00%	9.44%	0.00%	0.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY92	0.00%	9.51%	0.00%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY93	0.00%	11.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FY94	0.00%	11.53%	0.00%	0.00%	7.28%	1.56%	0.00%	0.00%	0.00%	0.00%
FY95	0.00%	11.30%	0.00%	0.00%	11.30%	6.15%	0.00%	0.00%	0.00%	0.00%
FY96	0.00%	10.39%	0.00%	0.00%	11.60%	1.76%	0.00%	0.00%	0.00%	0.00%
FY97	0.29%	7.10%	0.00%	0.00%	11.63%	1.51%	0.00%	0.00%	0.00%	0.00%
FY98	0.46%	4.54%	0.00%	0.00%	11.29%	0.89%	0.00%	0.00%	0.00%	0.00%
FY99	0.64%	1.29%	0.00%	0.00%	11.75%	0.70%	0.00%	0.00%	0.00%	0.00%
FY00	0.38%	0.73%	0.00%	0.00%	9.45%	1.32%	0.00%	0.00%	0.00%	0.00%
FY01	0.16%	0.13%	0.00%	0.00%	6.47%	0.17%	0.00%	0.00%	4.24%	0.00%
FY02	0.02%	0.02%	0.00%	0.00%	3.10%	0.15%	0.00%	0.00%	10.76%	5.14%
FY03	0.00%	0.01%	0.00%	0.00%	2.40%	0.02%	0.00%	0.00%	10.50%	10.59%
FY04	0.00%	0.00%	0.00%	0.00%	1.63%	0.00%	0.00%	0.00%	10.33%	10.37%
FY05	0.00%	0.00%	0.00%	0.00%	4.78%	0.00%	0.00%	0.00%	10.17%	10.18%

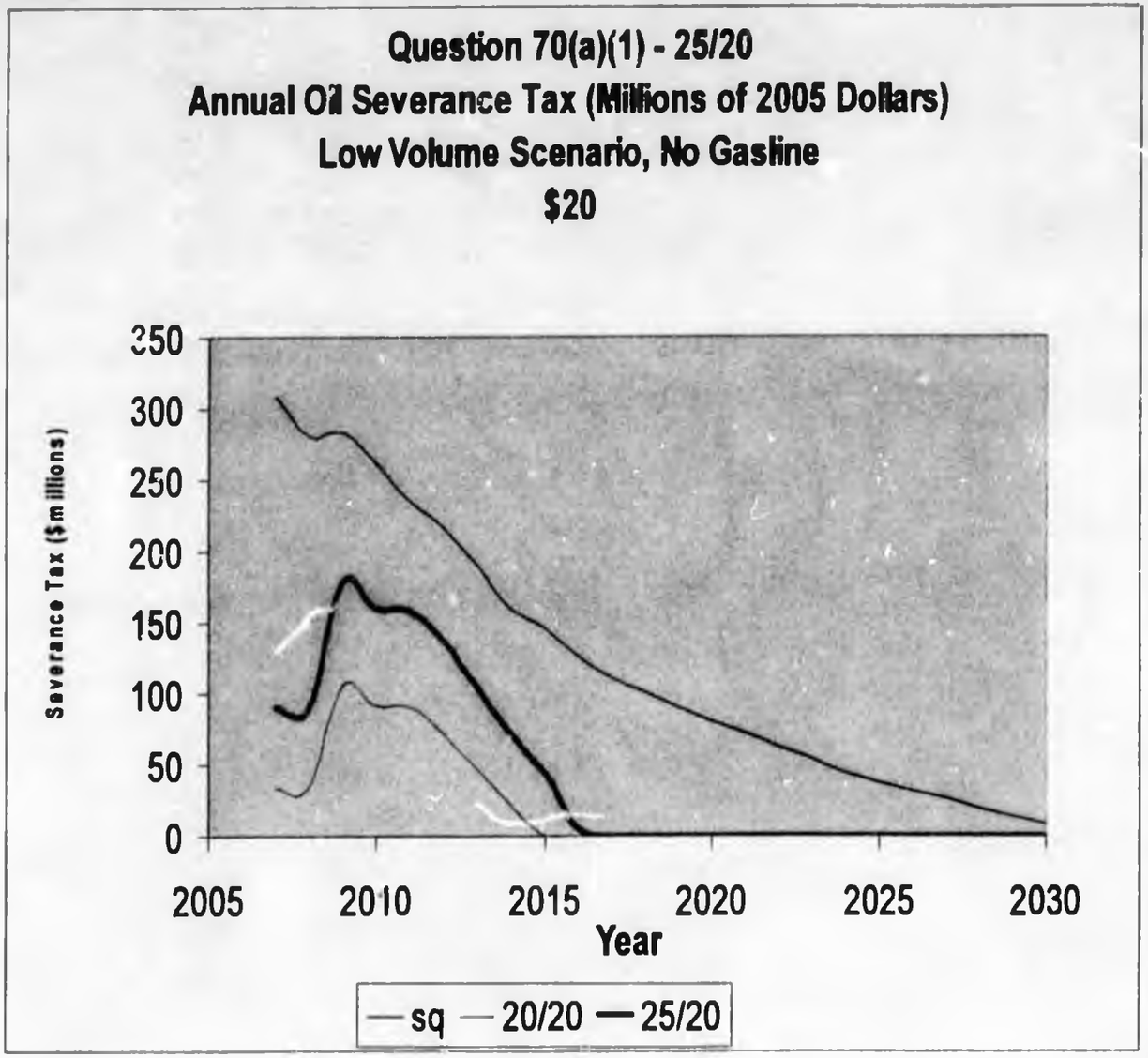
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Question 58

By: G. Rogers, March 1, 2006, source DNR

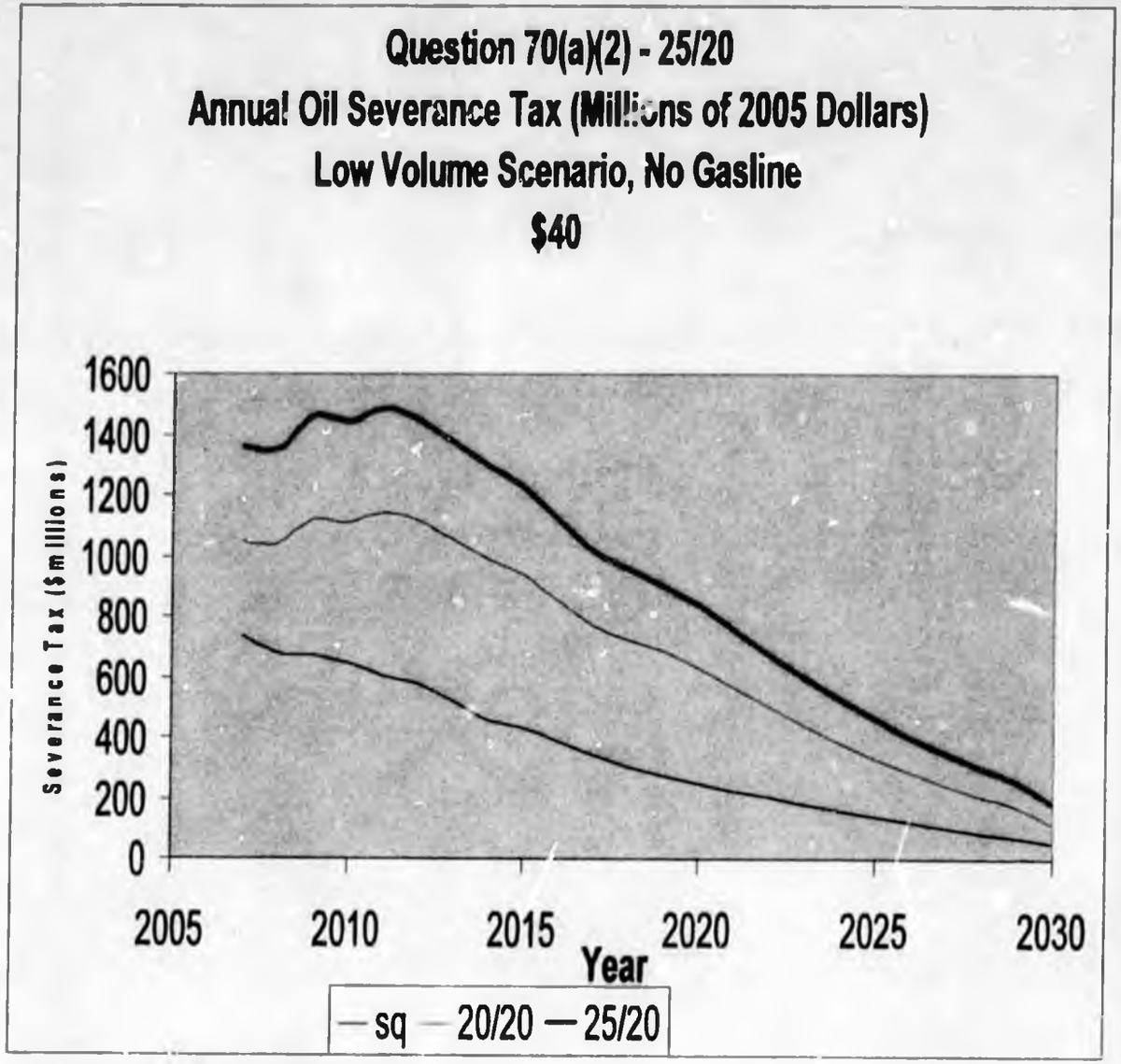
NPS LEASES, NPS RATES & ROYALTY RATES & STATUS

	Unit - lease number	Royalty Rate	NPS Rate	NPS Status
	Duck Island			
1	312823	20%	79.5935%	in payout
2	312834	20%	48.8703%	in payout
	Milne Point			
3	355016	12.5%	40.0000%	in payout
4	355017	12.5%	40.0000%	in payout
5	355018	12.5%	30.0000%	in payout
6	355021	12.5%	30.0000%	in payout
7	388235	12.5%	30.0000%	in payout
	Kuparuk River			
8	355023	12.5%	30.0000%	not in payout
9	355024	12.5%	30.0000%	not in payout
10	355030	12.5%	30.0000%	not in payout
11	355032	12.5%	30.0000%	not in payout
	Colville River			
12	364470	12.5%	30.0%	non producing
13	364471	12.5%	30.0%	non producing
14	364472	12.5%	30.0%	non producing
15	364477	12.5%	30.0%	non producing
16	364478	12.5%	30.0%	non producing
	Point Thompson Unit			
17	312866	20%	52.352%	non producing
18	343109	12.5%	40%	non producing
19	343110	12.5%	40%	non producing
20	343111	12.5%	40%	non producing
21	343112	closed	closed	non producing



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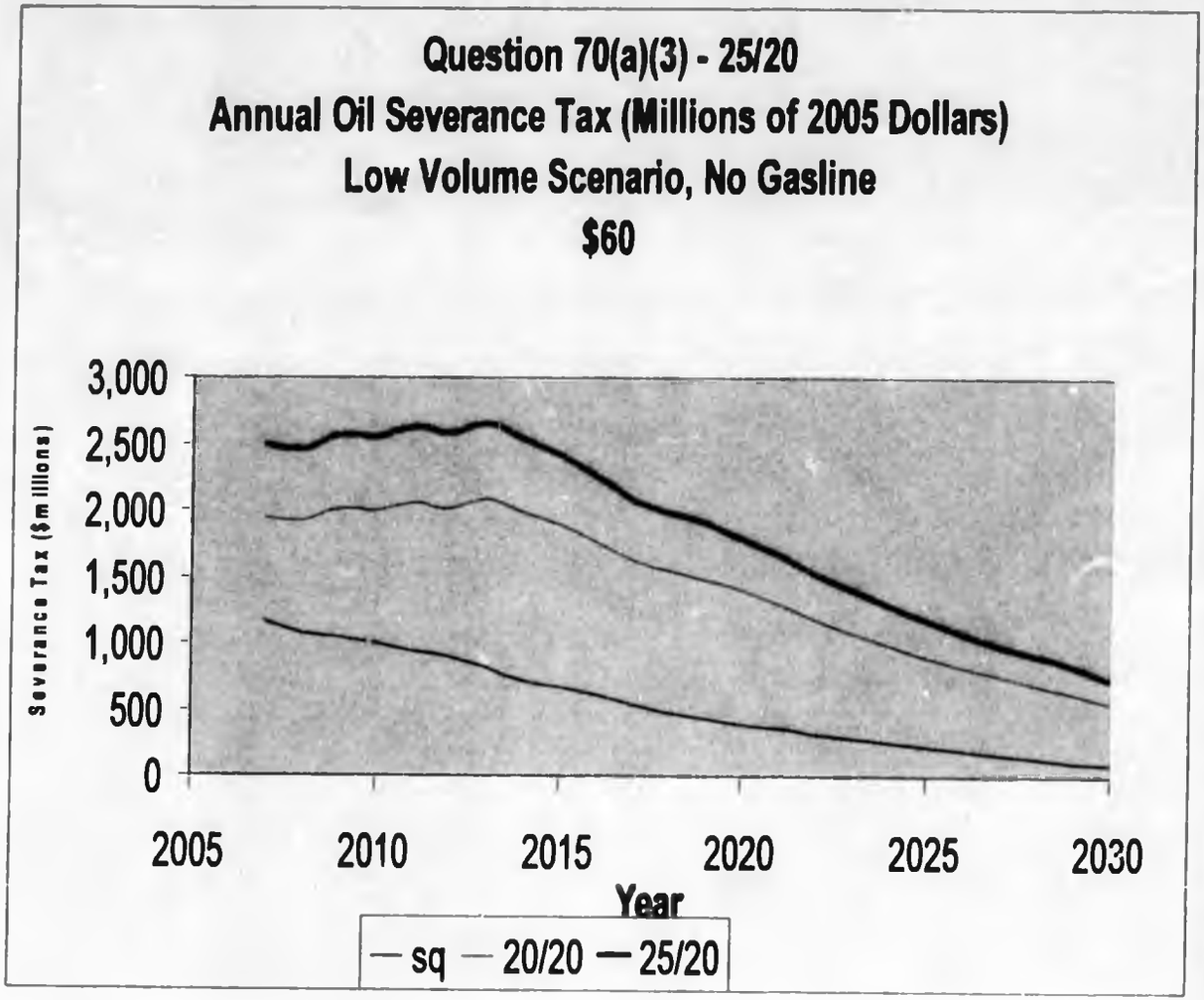
Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/20
2007	309	34	90
2008	280	34	89
2009	283	106	179
2010	262	91	160
2011	235	90	159
2012	216	73	137
2013	190	47	104
2014	159	22	72
2015	146	0	44
2016	126	0	6
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	1,041



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Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/20
2007	737	1,045	1,361
2008	679	1,038	1,352
2009	673	1,124	1,459
2010	646	1,112	1,444
2011	606	1,143	1,483
2012	576	1,117	1,450
2013	523	1,056	1,373
2014	459	992	1,293
2015	431	937	1,224
2016	388	853	1,119
2017	340	770	1,014
2018	306	726	958
2019	275	683	904
2020	248	629	837
2021	224	586	756
2022	201	499	673
2023	180	439	597
2024	156	384	528
2025	138	332	462
2026	119	284	402
2027	103	243	349
2028	83	204	301
2029	67	169	256
2030	52	113	186
Totals	8,211	16,458	21,782

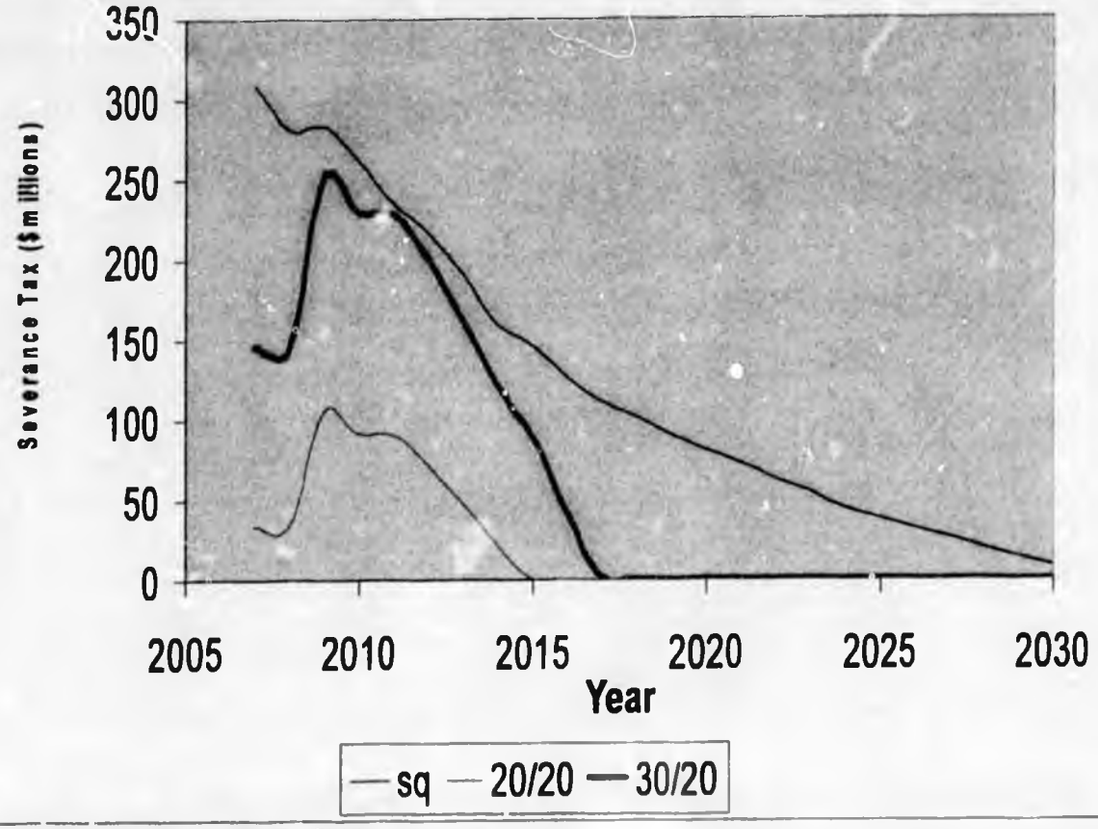
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/20
2007	1,165	1,945	2,486
2008	1,069	1,924	2,459
2009	1,042	2,013	2,570
2010	1,003	1,998	2,551
2011	941	2,056	624
2012	896	2,019	2,578
2013	815	2,088	2,664
2014	716	1,987	2,537
2015	674	1,898	2,425
2016	607	1,761	2,254
2017	533	1,625	2,082
2018	480	1,552	1,991
2019	432	1,483	1,905
2020	390	1,396	1,795
2021	353	1,292	1,664
2022	318	1,181	1,526
2023	286	1,081	1,400
2024	248	990	1,285
2025	219	903	1,176
2026	191	824	1,077
2027	165	755	990
2028	134	691	910
2029	108	632	836
2030	85	555	739
Totals	12,870	34,649	44,521

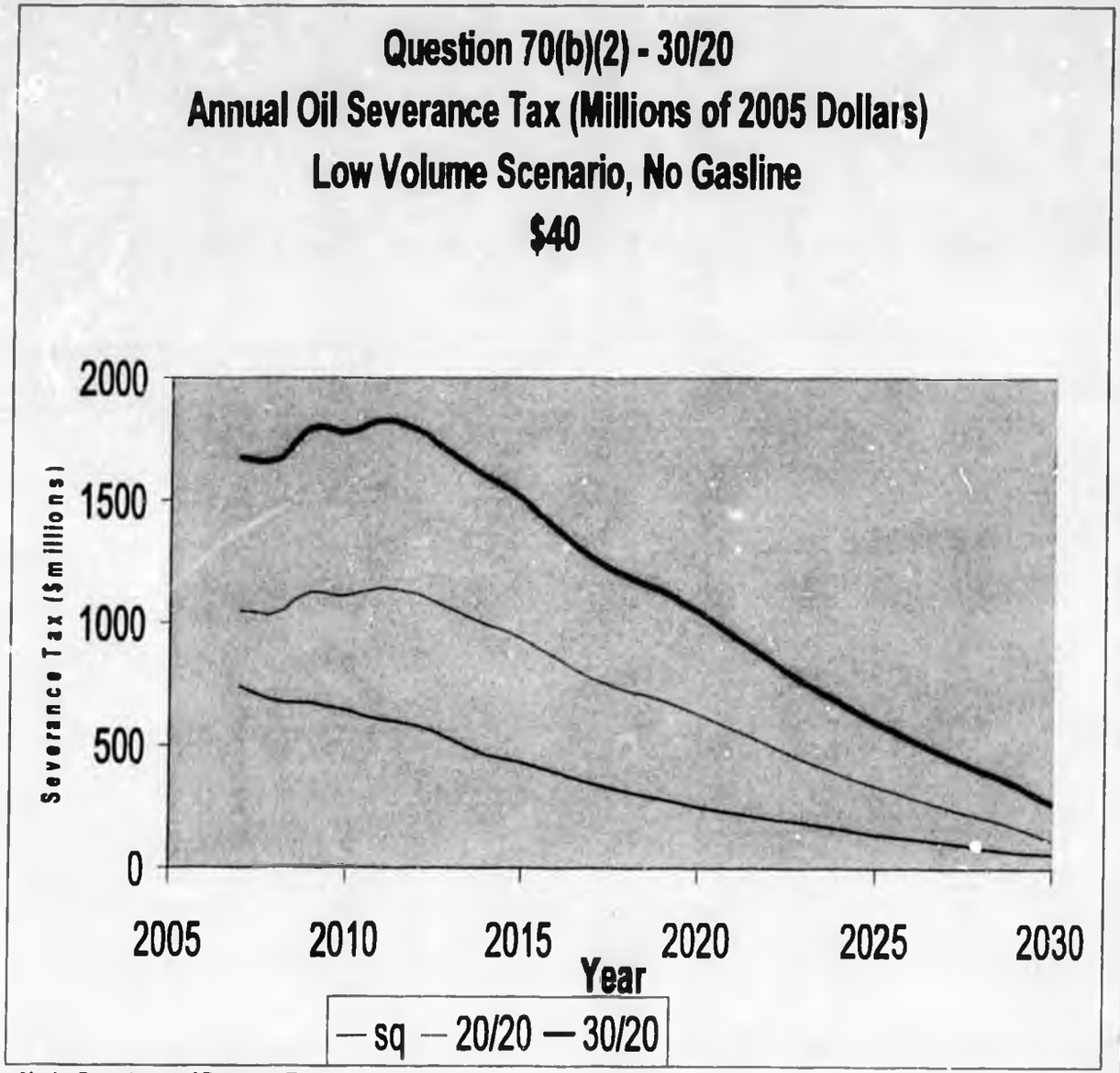
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Question 70(b)(1) - 30/20
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/20
2007	309	34	146
2008	280	34	144
2009	283	106	252
2010	262	91	229
2011	235	90	228
2012	216	73	201
2013	190	47	161
2014	159	22	122
2015	146	0	89
2016	126	0	42
2017	111	0	1
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	1,614

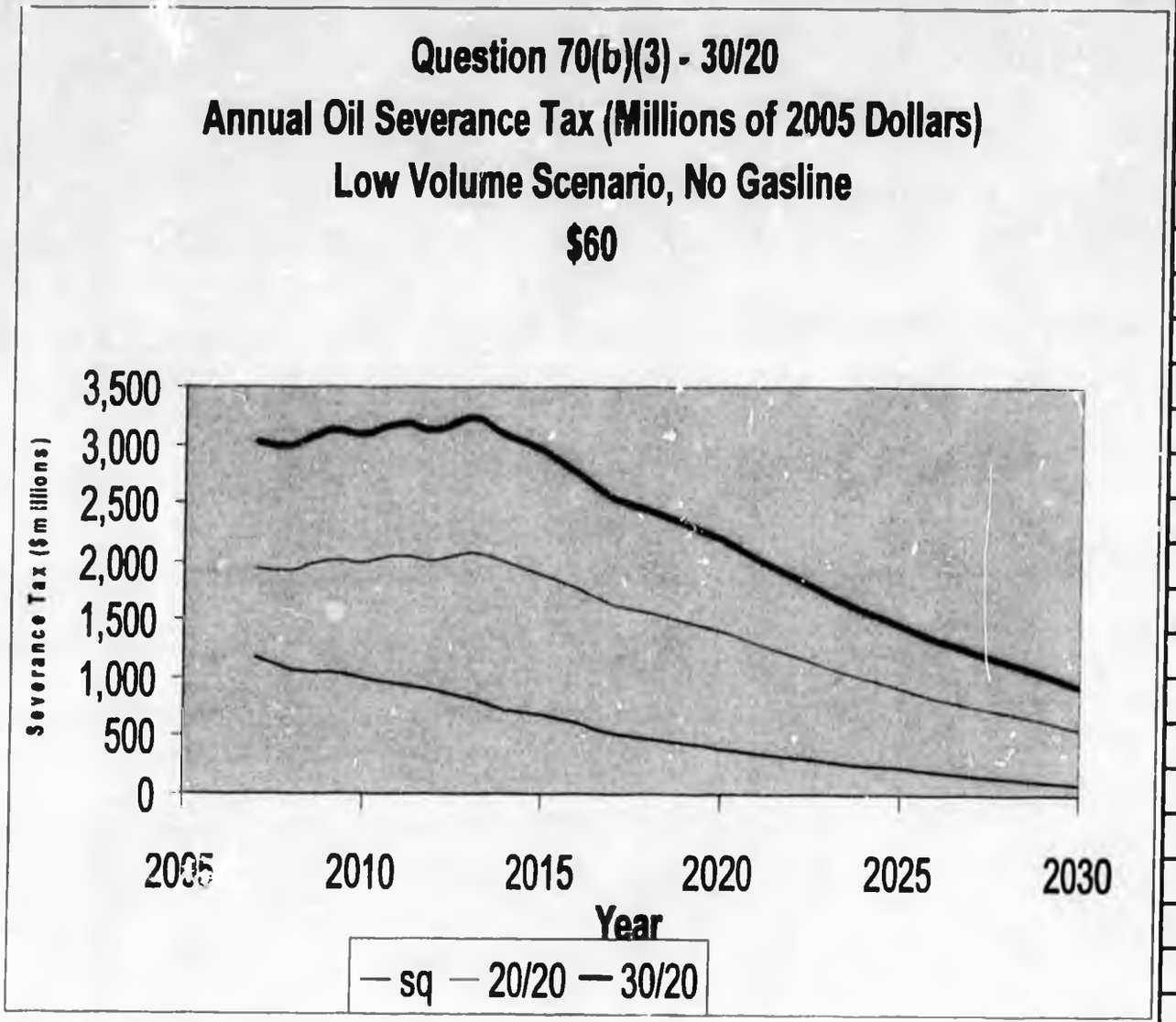


Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/20
2007	737	1,045	1,677
2008	679	1,038	1,585
2009	673	1,124	1,794
2010	646	1,112	1,776
2011	606	1,143	1,823
2012	576	1,117	1,784
2013	523	1,056	1,691
2014	459	992	1,595
2015	431	937	1,511
2016	388	853	1,384
2017	340	770	1,258
2018	306	726	1,191
2019	275	683	1,125
2020	248	629	1,044
2021	224	566	947
2022	201	499	846
2023	180	439	755
2024	156	384	671
2025	138	332	592
2026	119	284	520
2027	103	243	456
2028	83	204	398
2029	67	169	344
2030	52	113	260
Totals	8,211	16,458	27,107

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Question 70(b)(3) - 30/20
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$60

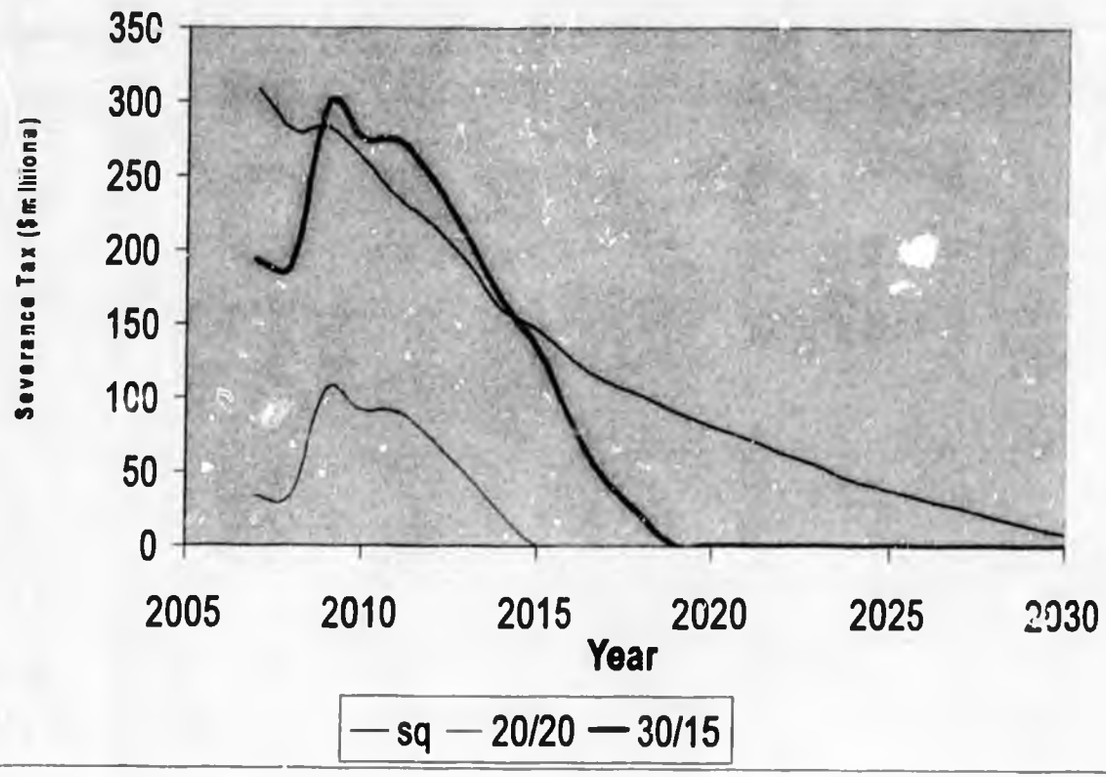


Alaska Department of Revenue, Tax Division
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/20
2007	1,165	1,945	3,026
2008	1,089	1,924	2,994
2009	1,042	2,013	3,127
2010	1,003	1,998	3,104
2011	941	2,055	3,183
2012	896	2,019	3,136
2013	815	2,088	3,240
2014	716	1,987	3,087
2015	674	1,898	2,952
2016	607	1,761	2,746
2017	533	1,625	2,539
2018	480	1,552	2,430
2019	432	1,483	2,326
2020	390	1,396	2,194
2021	353	1,292	2,037
2022	318	1,181	1,870
2023	286	1,081	1,719
2024	248	990	1,580
2025	219	903	1,448
2026	191	824	1,330
2027	165	755	1,225
2028	134	691	1,129
2029	108	632	1,039
2030	85	555	922
Totals	12,870	34,649	54,393

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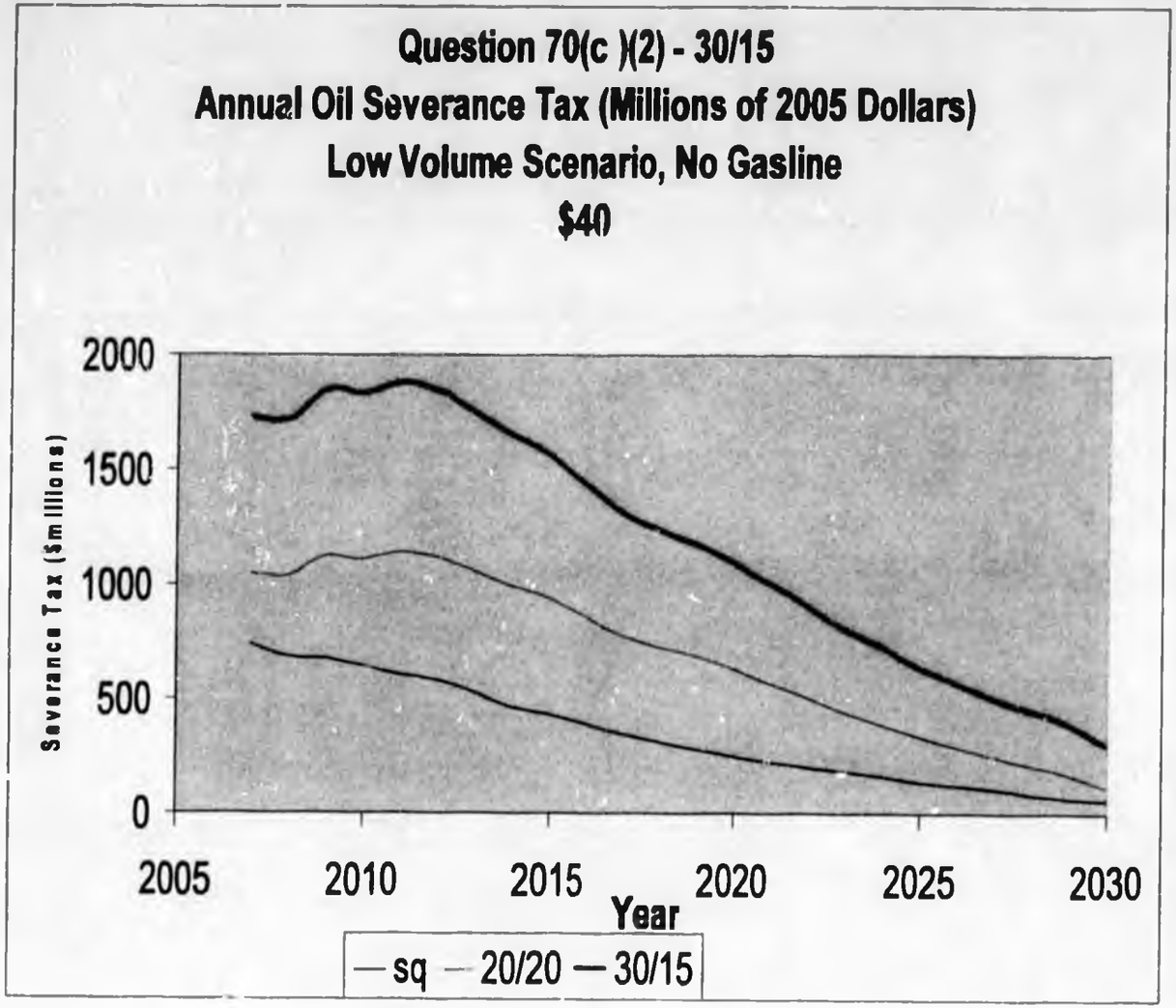
Question 70(c)(1)- 30/15
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$20



Alaska Department of Revenue. Tax Division
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/15
2007	309	34	193
2008	280	34	191
2009	283	106	298
2010	262	91	275
2011	235	90	274
2012	216	73	247
2013	190	47	206
2014	159	22	167
2015	146	0	133
2016	126	0	85
2017	111	0	44
2018	101	0	21
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	2,133

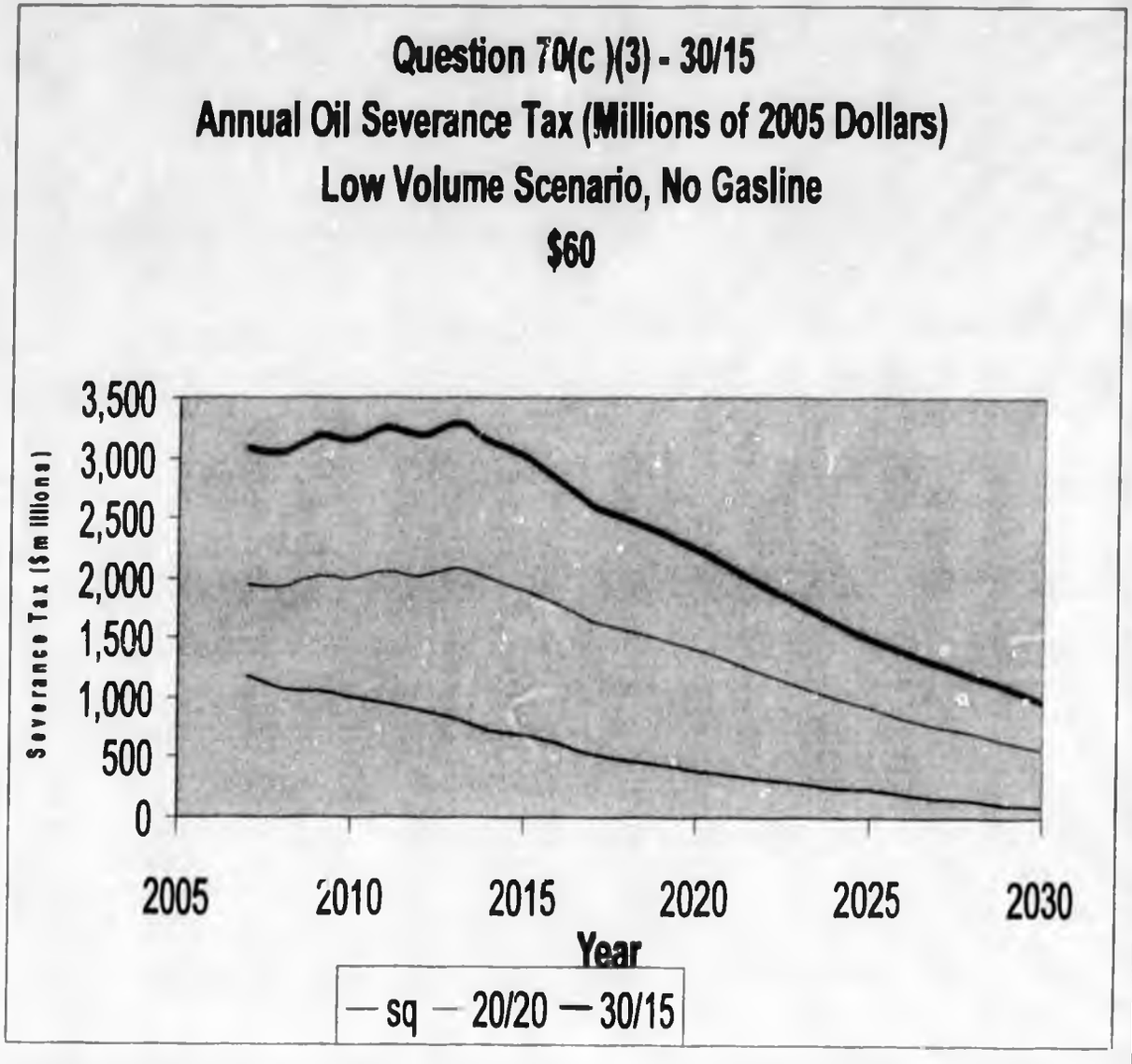
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/15
2007	737	1,045	1,731
2008	679	1,038	1,719
2009	673	1,124	1,848
2010	646	1,112	1,830
2011	606	1,143	1,878
2012	576	1,117	1,838
2013	523	1,056	1,745
2014	459	992	1,648
2015	431	937	1,564
2016	388	853	1,436
2017	340	770	1,309
2018	306	726	1,241
2019	275	683	1,176
2020	248	629	1,094
2021	224	566	997
2022	201	499	895
2023	180	439	803
2024	156	384	719
2025	138	332	639
2026	119	284	567
2027	103	243	503
2028	83	204	444
2029	67	169	389
2030	52	113	305
Totals	8,211	16,458	28,317

Alaska Department of Revenue, Tax Division
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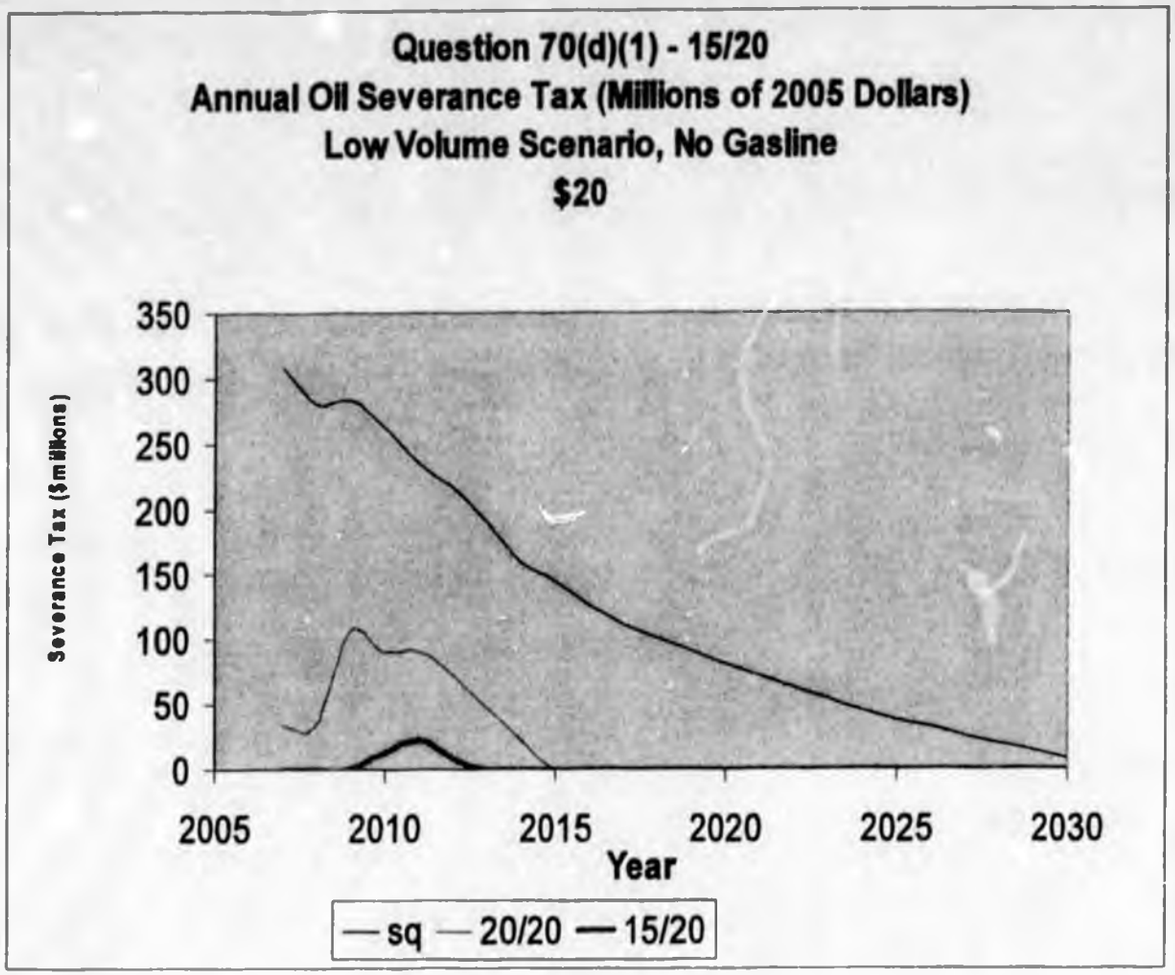
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Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	30/15
2007	1,165	1,945	3,081
2008	1,069	1,924	3,048
2009	1,042	2,013	3,181
2010	1,003	1,998	3,158
2011	941	2,056	3,247
2012	896	2,019	3,191
2013	815	2,088	3,293
2014	716	1,987	3,140
2015	674	1,898	3,005
2016	607	1,761	2,798
2017	533	1,625	2,590
2018	480	1,552	2,481
2019	432	1,483	2,376
2020	390	1,396	2,244
2021	353	1,292	2,086
2022	318	1,181	1,918
2023	286	1,081	1,767
2024	248	990	1,628
2025	219	903	1,496
2026	191	824	1,376
2027	165	755	1,271
2028	134	691	1,175
2029	108	632	1,085
2030	85	555	968
Totals	12,870	34,649	55,603

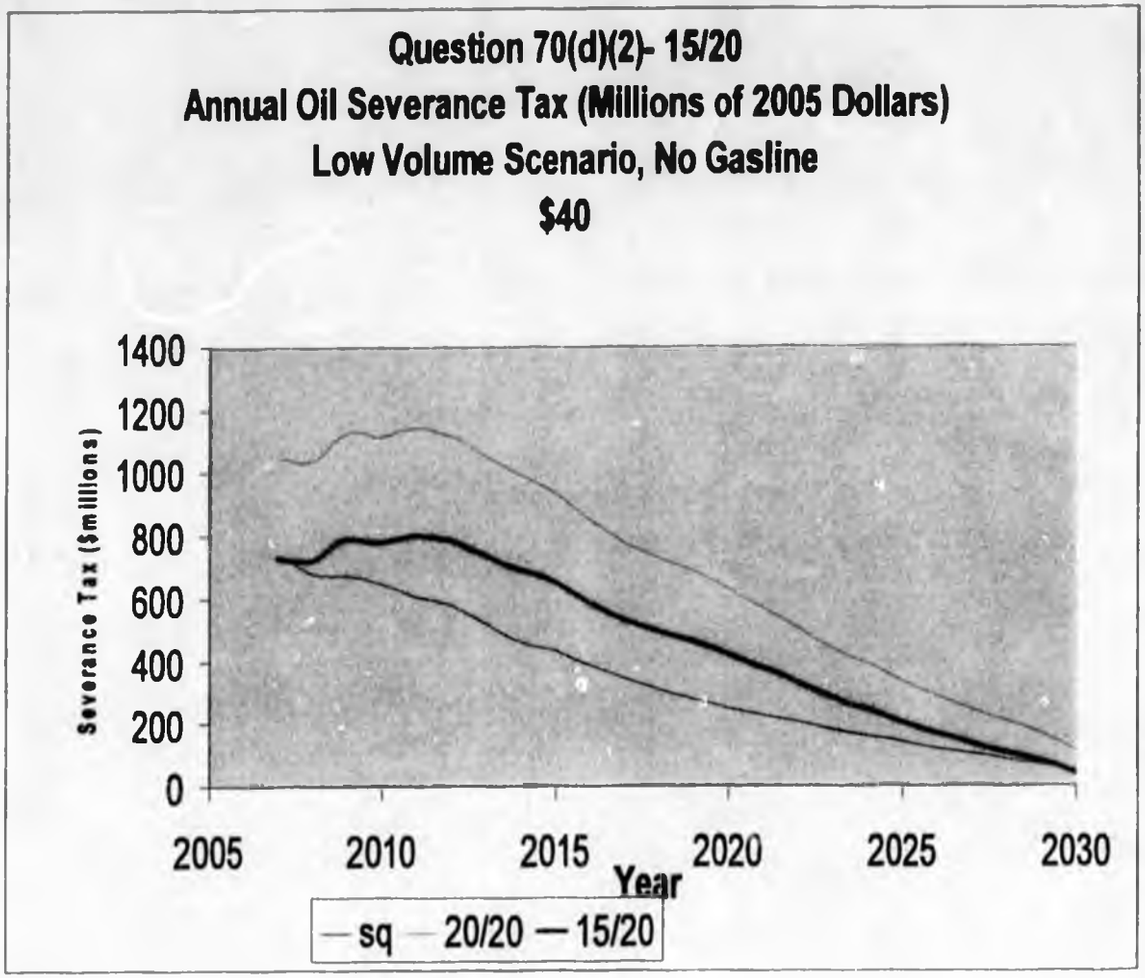
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/20
2007	309	34	0
2008	280	34	0
2009	283	106	0
2010	262	91	13
2011	235	90	22
2012	216	73	9
2013	190	47	0
2014	159	22	0
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	43

Alaska Department of Revenue, Tax Division
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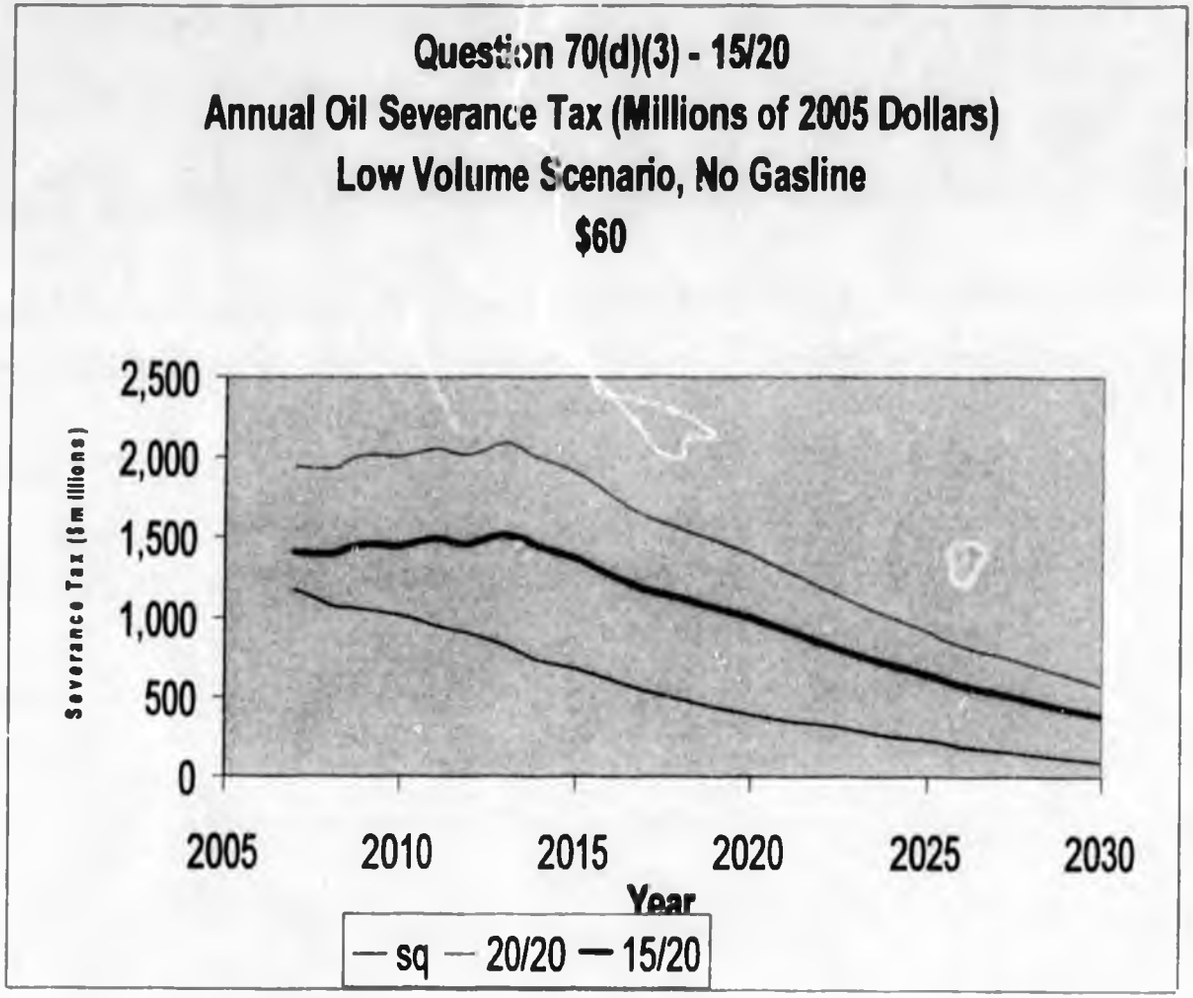
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/20
2007	737	1,045	730
2008	679	1,038	725
2009	673	1,124	789
2010	646	1,112	780
2011	606	1,143	803
2012	576	1,117	783
2013	523	1,056	738
2014	459	992	691
2015	431	937	650
2016	388	853	588
2017	340	770	527
2018	306	726	494
2019	275	683	462
2020	248	629	422
2021	224	566	375
2022	201	499	326
2023	180	439	281
2024	156	384	240
2025	138	332	202
2026	119	284	167
2027	103	243	136
2028	83	204	107
2029	67	169	81
2030	52	113	39
Totals	8,211	16,458	11,134

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

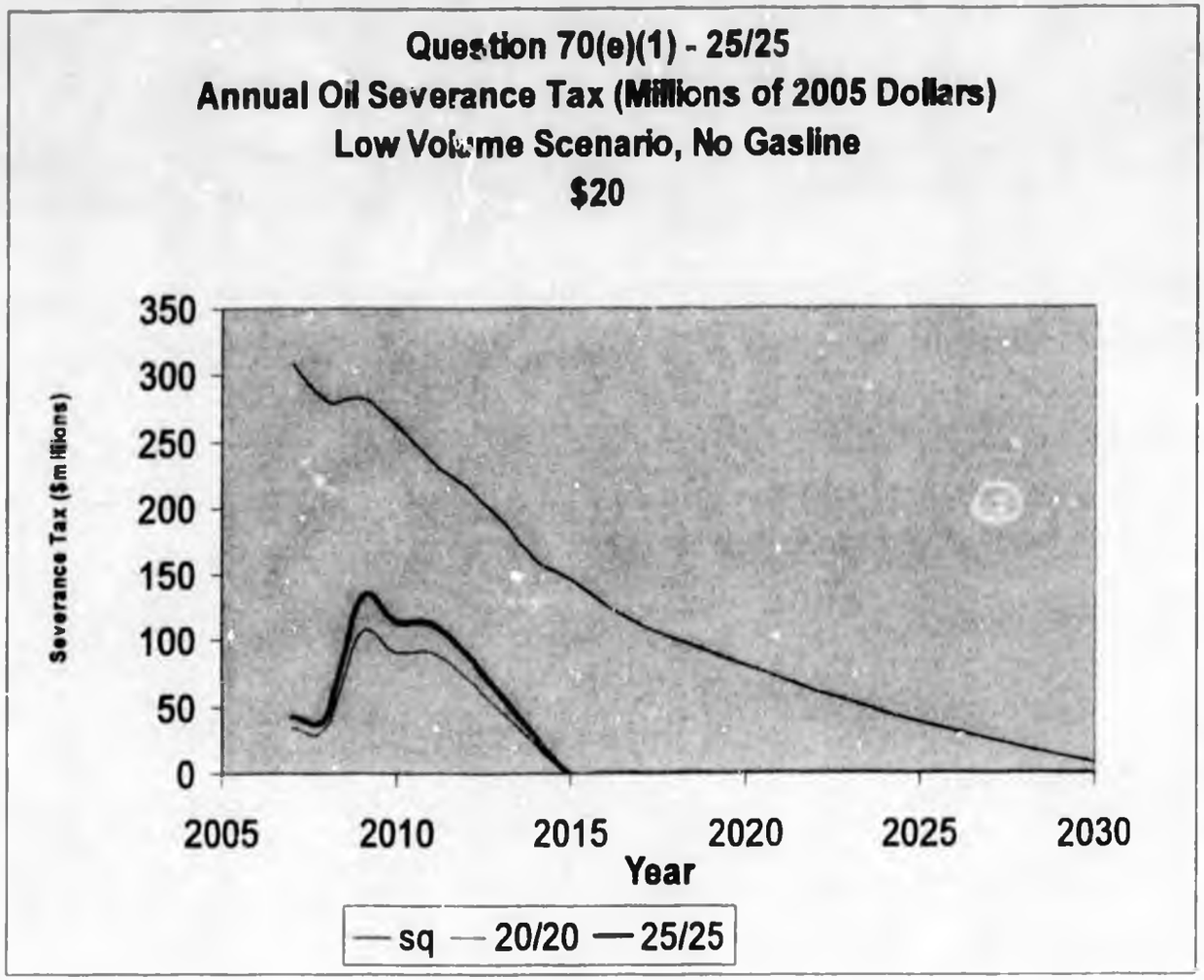
DRAFT



Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/20
2007	1,165	1,945	1,405
2008	1,069	1,924	1,389
2009	1,042	2,013	1,455
2010	1,003	1,998	1,444
2011	941	2,056	1,488
2012	896	2,019	1,460
2013	815	2,088	1,512
2014	716	1,987	1,437
2015	674	1,898	1,370
2016	607	1,761	1,269
2017	533	1,625	1,167
2018	480	1,552	1,113
2019	432	1,483	1,062
2020	390	1,396	997
2021	353	1,292	920
2022	318	1,181	837
2023	286	1,081	763
2024	248	990	695
2025	219	903	630
2026	191	824	571
2027	165	755	520
2028	134	691	473
2029	108	632	428
2030	85	555	371
Totals	12,870	34,649	24,777

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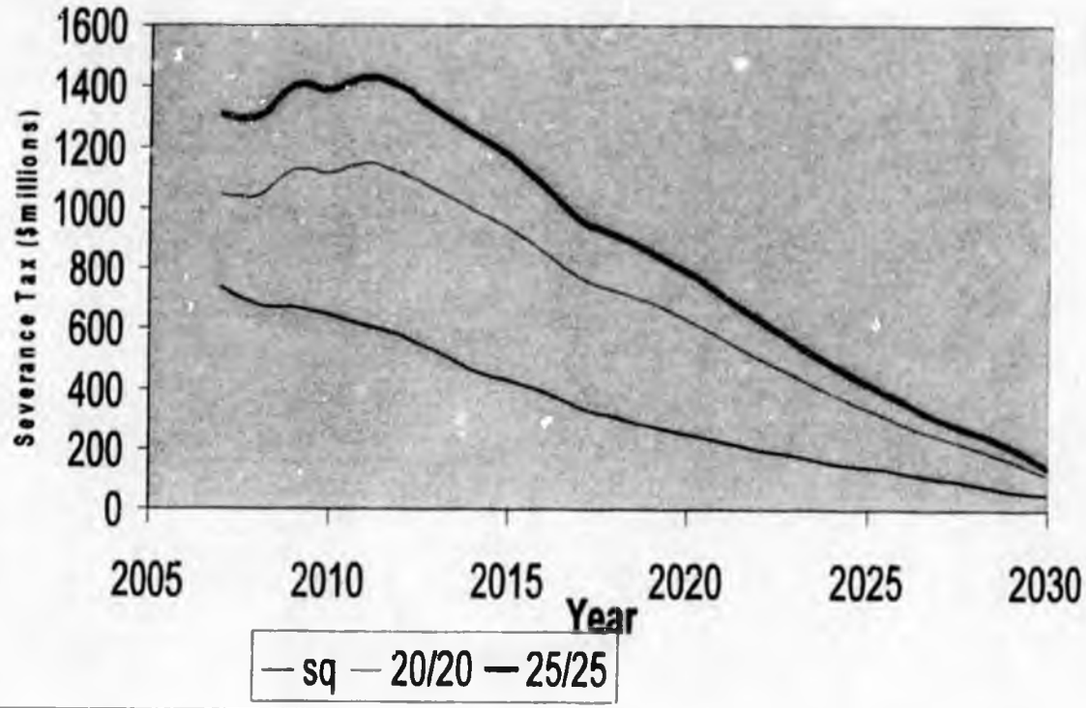
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/25
2007	309	34	43
2008	280	34	42
2009	283	106	133
2010	262	91	114
2011	235	90	113
2012	216	73	91
2013	190	47	59
2014	159	22	27
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	622

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

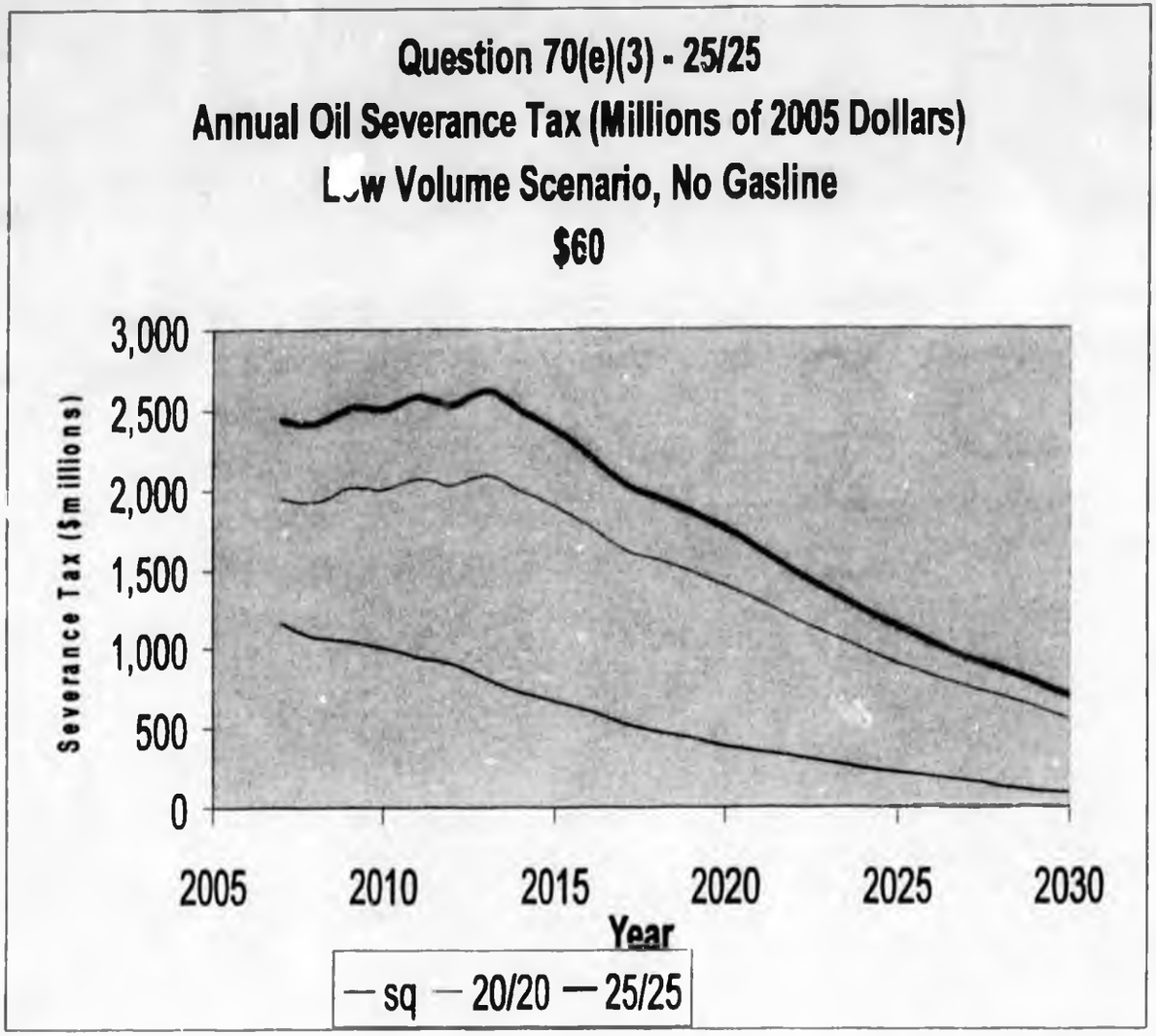
Question 70(e)(2) - 25/25
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/25
2007	737	1,045	1,307
2008	679	1,038	1,298
2009	673	1,124	1,405
2010	646	1,112	1,390
2011	606	1,143	1,429
2012	576	1,117	1,396
2013	523	1,056	1,319
2014	459	992	1,240
2015	431	937	1,171
2016	388	853	1,067
2017	340	770	963
2018	306	726	908
2019	275	683	854
2020	248	629	787
2021	224	566	707
2022	201	499	624
2023	180	439	549
2024	156	384	480
2025	138	332	415
2026	119	284	355
2027	103	243	303
2028	83	204	256
2029	67	169	211
2030	52	113	141
Totals	8,211	16,458	20,572

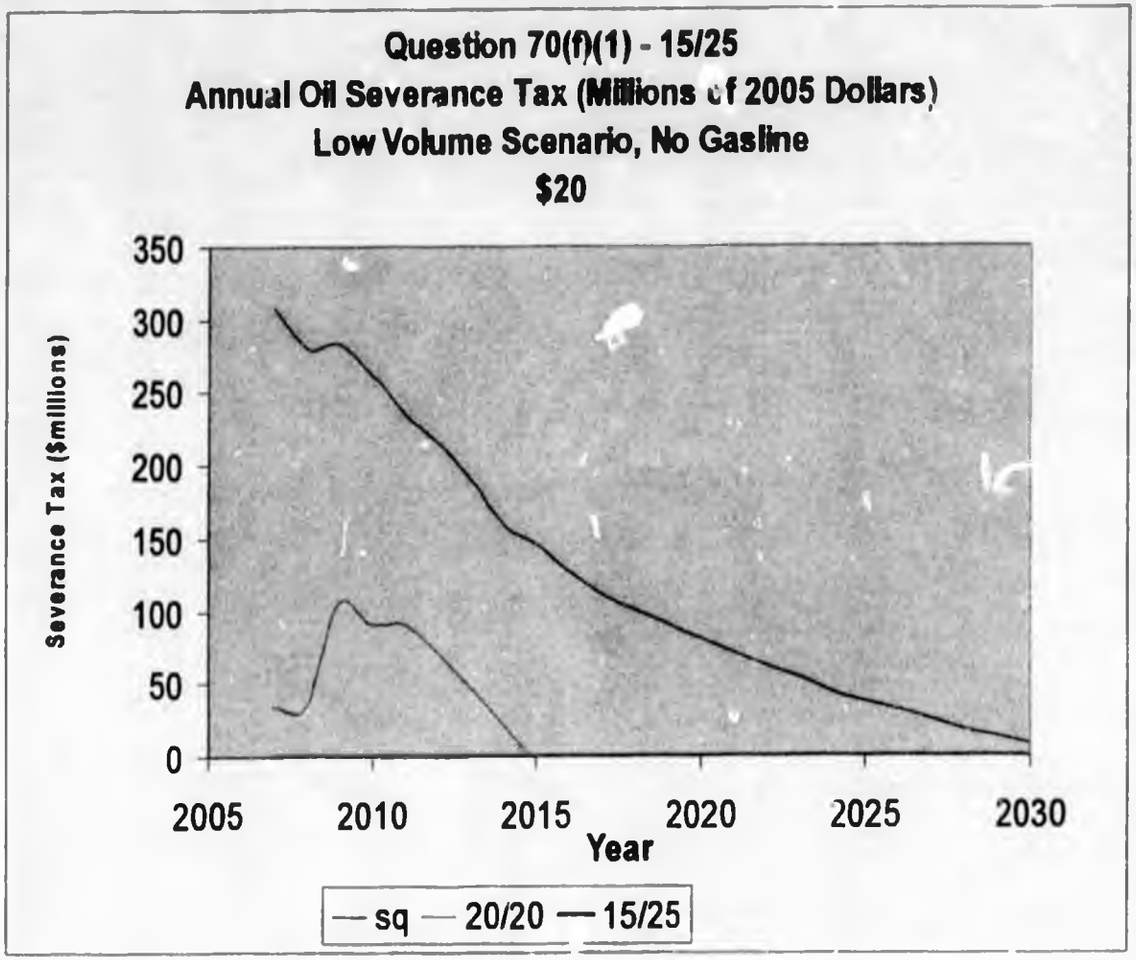
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Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	25/25
2007	1,165	1,945	2,432
2008	1,069	1,924	2,405
2009	1,042	2,013	2,516
2010	1,003	1,998	2,497
2011	941	2,056	2,570
2012	896	2,019	2,523
2013	815	2,088	2,610
2014	716	1,987	2,483
2015	674	1,898	2,372
2016	607	1,761	2,202
2017	533	1,625	2,031
2018	480	1,552	1,940
2019	432	1,483	1,854
2020	390	1,396	1,745
2021	353	1,292	1,615
2022	318	1,181	1,477
2023	286	1,081	1,352
2024	248	990	1,238
2025	219	903	1,128
2026	191	824	1,030
2027	165	755	944
2028	134	691	864
2029	108	632	790
2030	85	555	693
Totals	12,870	34,649	43,311

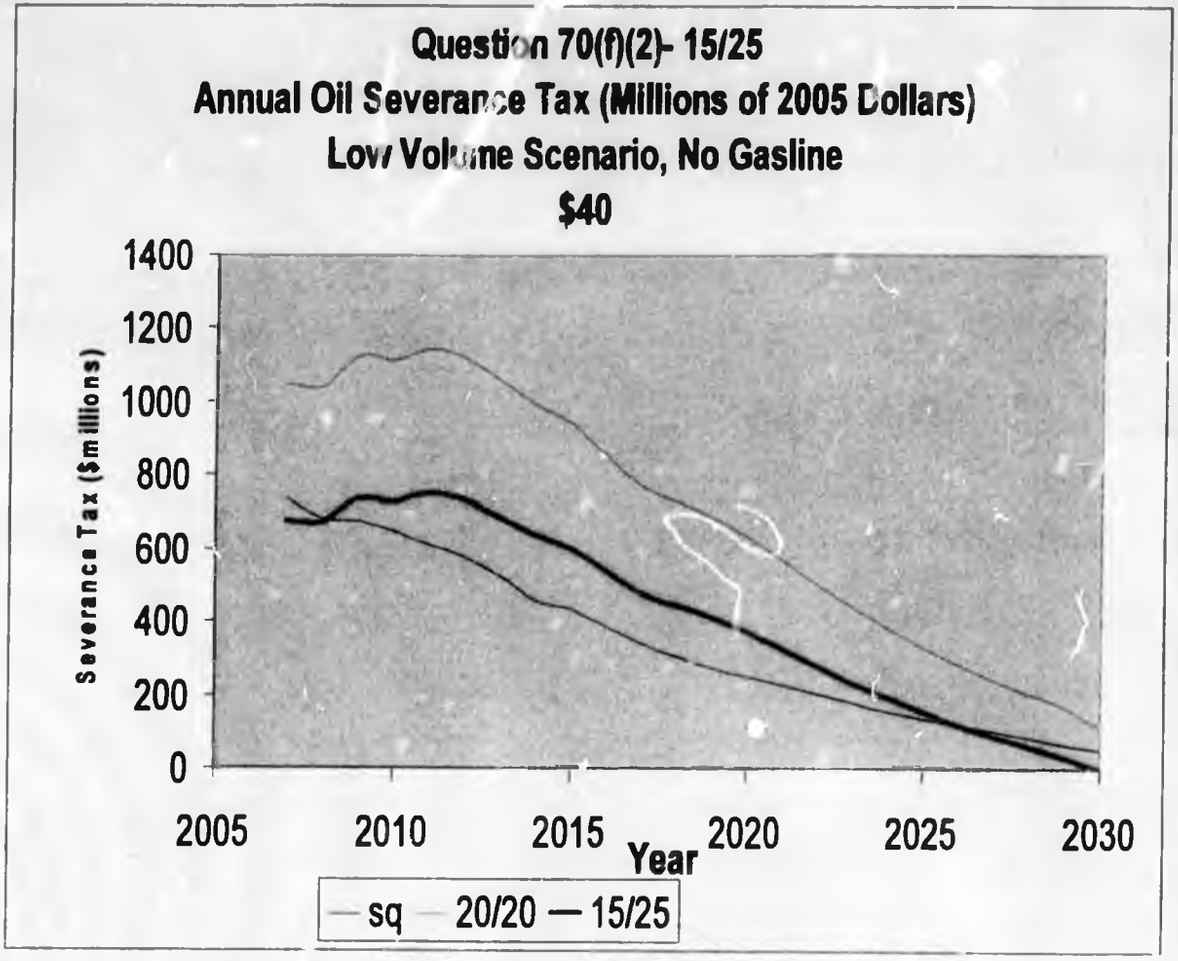
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/25
2007	309	34	0
2008	280	34	0
2009	283	106	0
2010	262	91	0
2011	235	90	0
2012	216	73	0
2013	190	47	0
2014	159	22	0
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	0

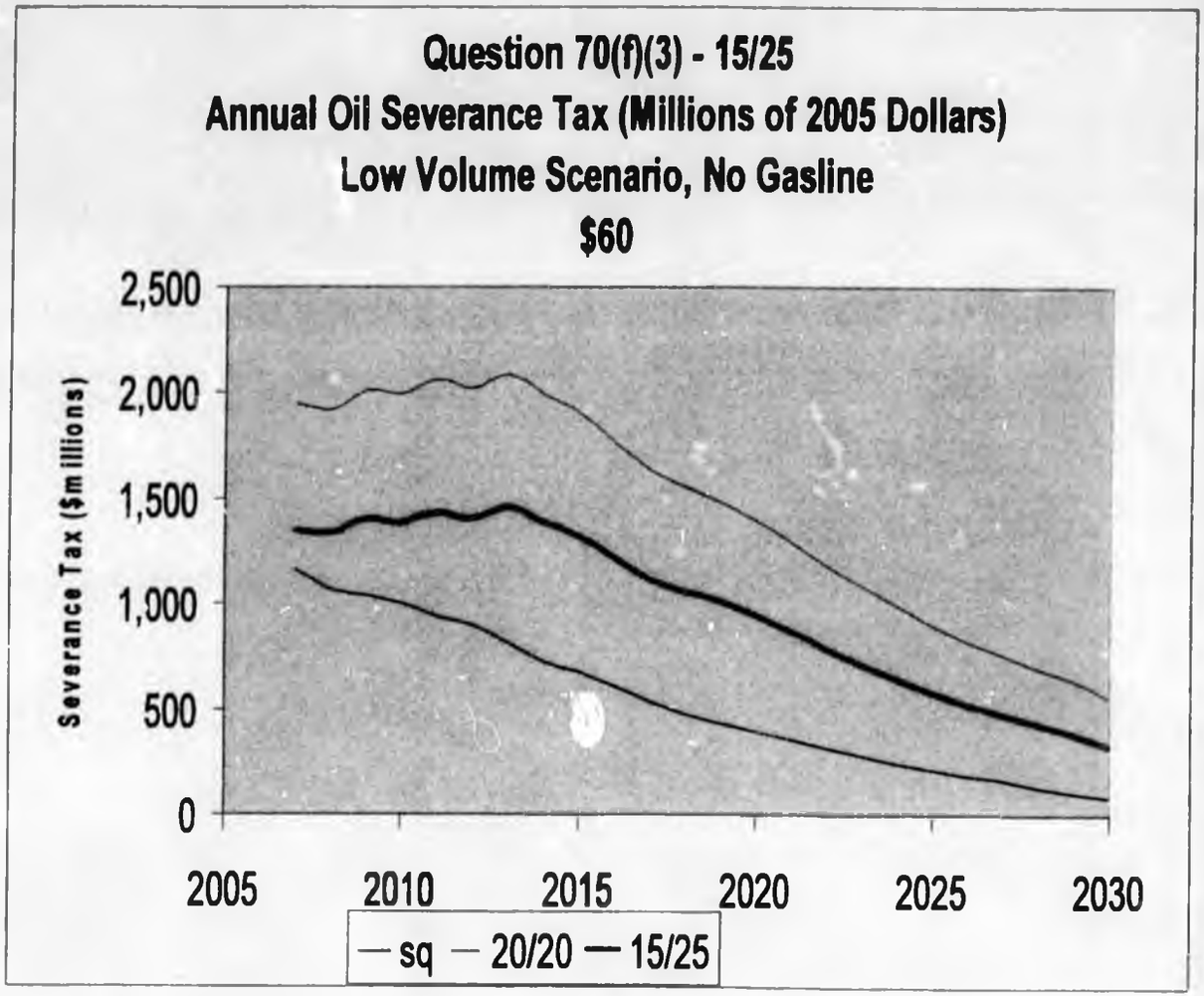
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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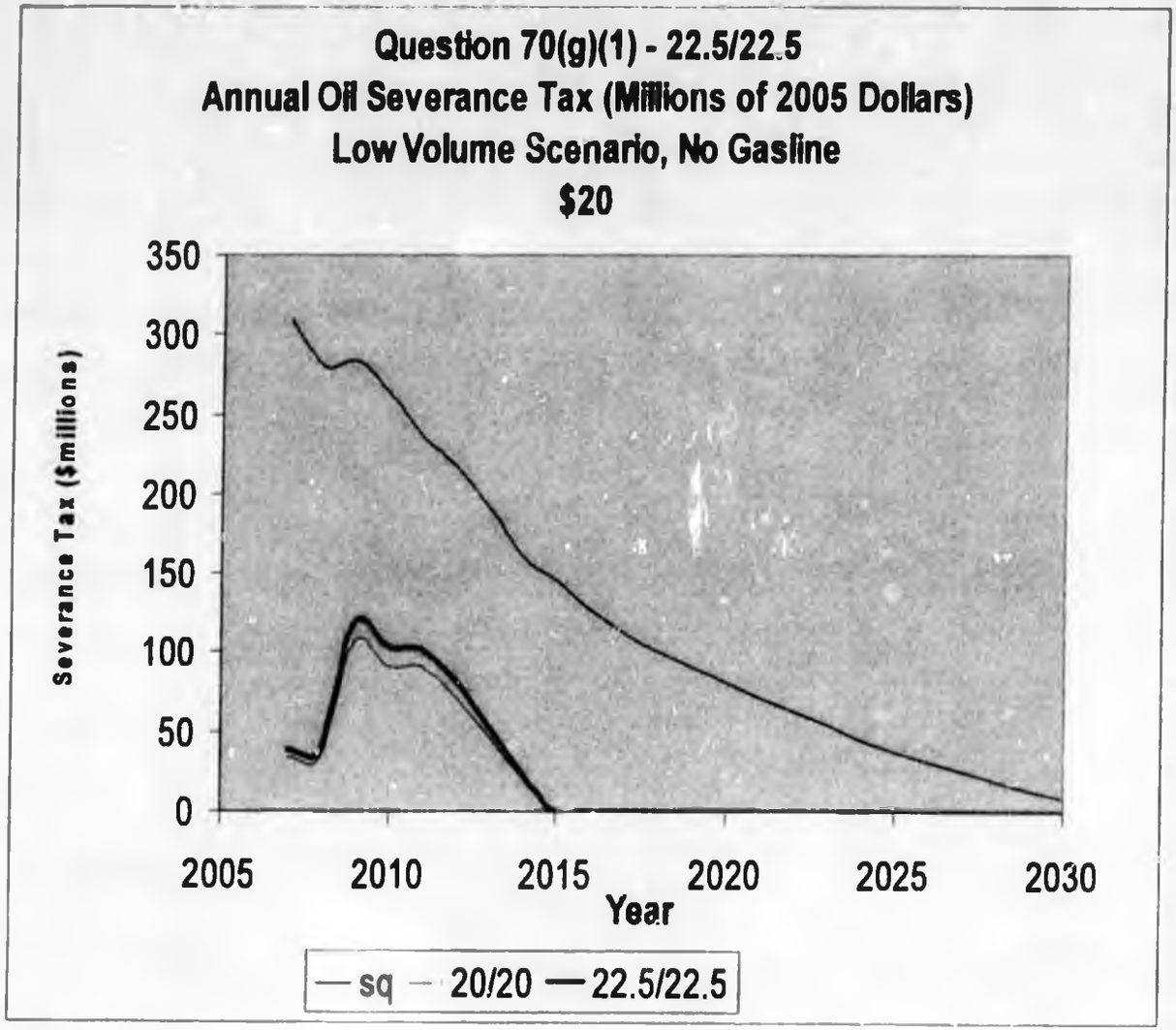
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/25
2007	737	1,045	676
2008	679	1,038	671
2009	673	1,124	735
2010	646	1,112	726
2011	606	1,143	748
2012	576	1,117	729
2013	523	1,056	684
2014	459	992	638
2015	431	937	597
2016	388	853	536
2017	340	770	475
2018	306	726	443
2019	275	683	411
2020	248	629	372
2021	224	566	326
2022	201	499	277
2023	180	439	233
2024	156	384	193
2025	138	332	154
2026	119	284	120
2027	103	243	89
2028	83	204	62
2029	67	169	35
2030	52	113	0
Totals	8,211	16,458	9,930



Annual Oil Severance Tax ($Millions)			
	sq	20/20	15/25
2007	1,165	1,945	1,351
2008	1,069	1,924	1,335
2009	1,042	2,013	1,401
2010	1,003	1,998	1,390
2011	941	2,056	1,433
2012	896	2,019	1,405
2013	815	2,088	1,458
2014	716	1,987	1,384
2015	674	1,898	1,318
2016	607	1,761	1,217
2017	533	1,625	1,116
2018	480	1,552	1,063
2019	432	1,483	1,012
2020	390	1,396	947
2021	353	1,292	870
2022	318	1,181	789
2023	286	1,081	715
2024	248	990	647
2025	219	903	583
2026	191	824	525
2027	165	755	474
2028	134	691	427
2029	108	632	383
2030	85	555	325
Totals	12,870	34,649	23,567

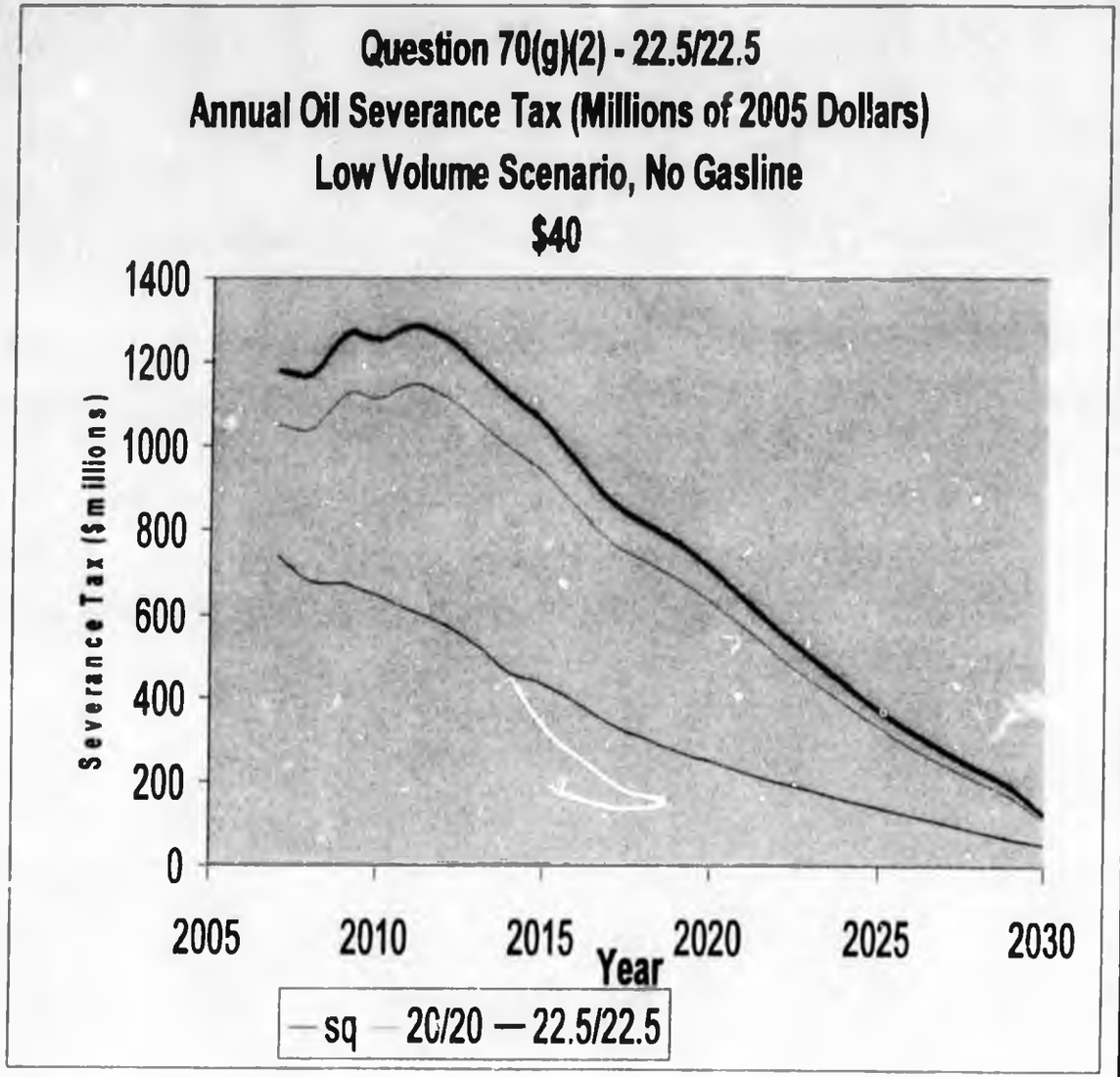
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



Annual Oil Severance Tax ($Millions)			
	sq	20/20	22.5/22.5
2007	309	34	38
2008	280	34	38
2009	283	106	119
2010	262	91	103
2011	235	90	102
2012	216	73	82
2013	190	47	53
2014	159	22	25
2015	146	0	0
2016	126	0	0
2017	111	0	0
2018	101	0	0
2019	91	0	0
2020	81	0	0
2021	72	0	0
2022	63	0	0
2023	54	0	0
2024	45	0	0
2025	38	0	0
2026	31	0	0
2027	26	0	0
2028	19	0	0
2029	14	0	0
2030	9	0	0
Totals	2,959	498	560

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

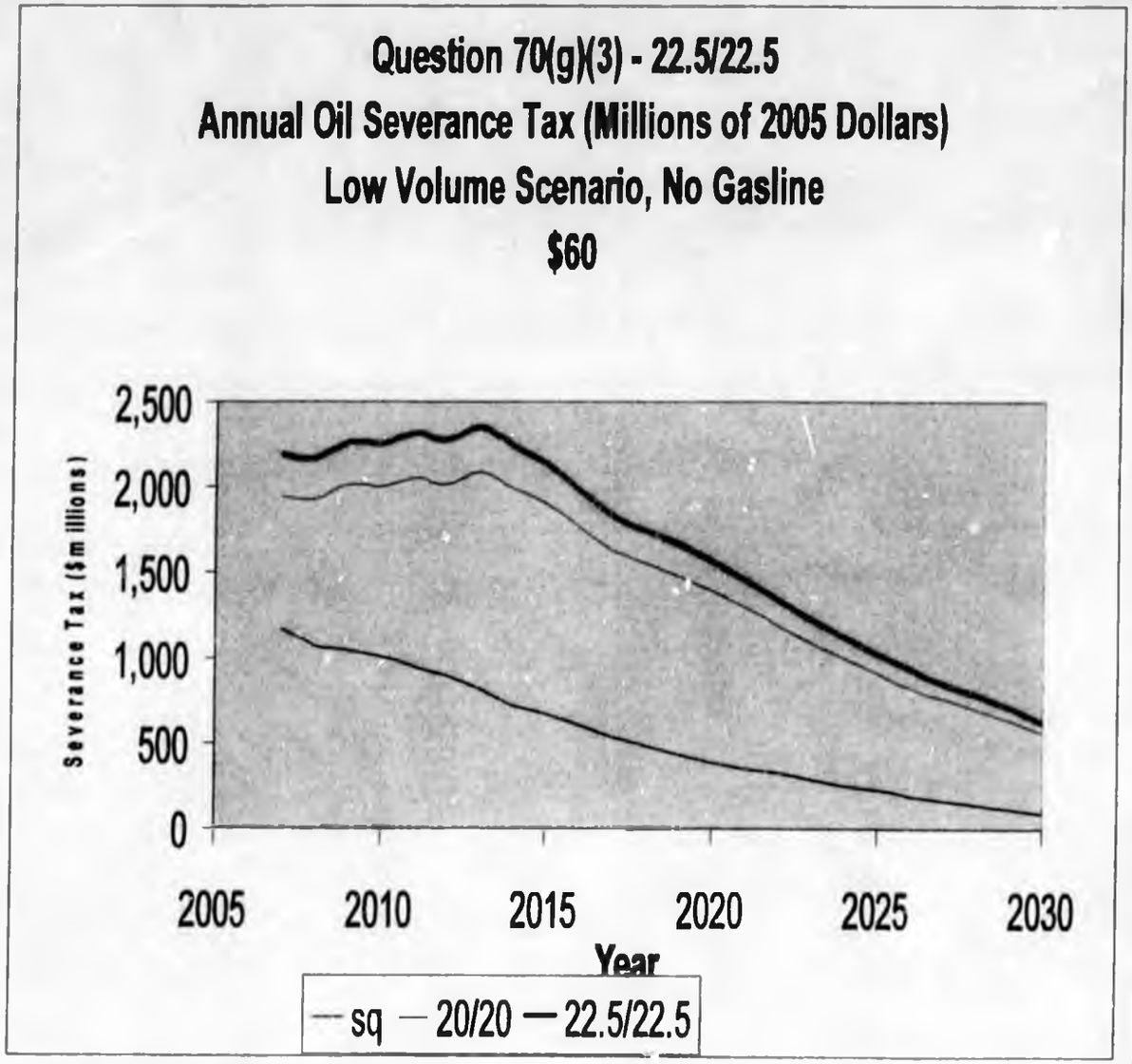
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Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Annual Oil Severance Tax ($Millions)			
	sq	20/20	22.5/22.5
2007	737	1,045	1,176
2008	679	1,038	1,168
2009	673	1,124	1,264
2010	646	1,112	1,251
2011	606	1,143	1,286
2012	576	1,117	1,256
2013	523	1,056	1,187
2014	459	992	1,116
2015	431	937	1,054
2016	388	853	960
2017	340	770	867
2018	306	726	817
2019	275	683	768
2020	248	629	708
2021	224	566	636
2022	201	499	562
2023	180	439	494
2024	156	384	432
2025	138	332	373
2026	119	284	320
2027	103	243	273
2028	83	204	230
2029	67	169	190
2030	52	113	127
Totals	8,211	16,458	18,515

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Alaska Department of Revenue, Tax Division
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Annual Oil Severance Tax ($Millions)			
	sq	20/20	22.5/22.5
2007	1,165	1,945	2,188
2008	1,069	1,924	2,165
2009	1,042	2,013	2,264
2010	1,003	1,998	2,247
2011	941	2,056	2,313
2012	896	2,019	2,271
2013	815	2,086	2,349
2014	716	1,987	2,235
2015	674	1,898	2,135
2016	607	1,761	1,981
2017	533	1,625	1,828
2018	480	1,552	1,746
2019	432	1,483	1,669
2020	390	1,396	1,571
2021	353	1,292	1,453
2022	318	1,181	1,329
2023	286	1,081	1,217
2024	248	990	1,114
2025	219	903	1,016
2026	191	824	927
2027	165	755	849
2028	134	691	778
2029	108	632	711
2030	85	555	624
Totals	12,870	34,649	38,980

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Question 70(h)(1)
Annual Oil Severance Tax (Millions of 2005 Dollars)
Low Volume Scenario, No Gasline
$40

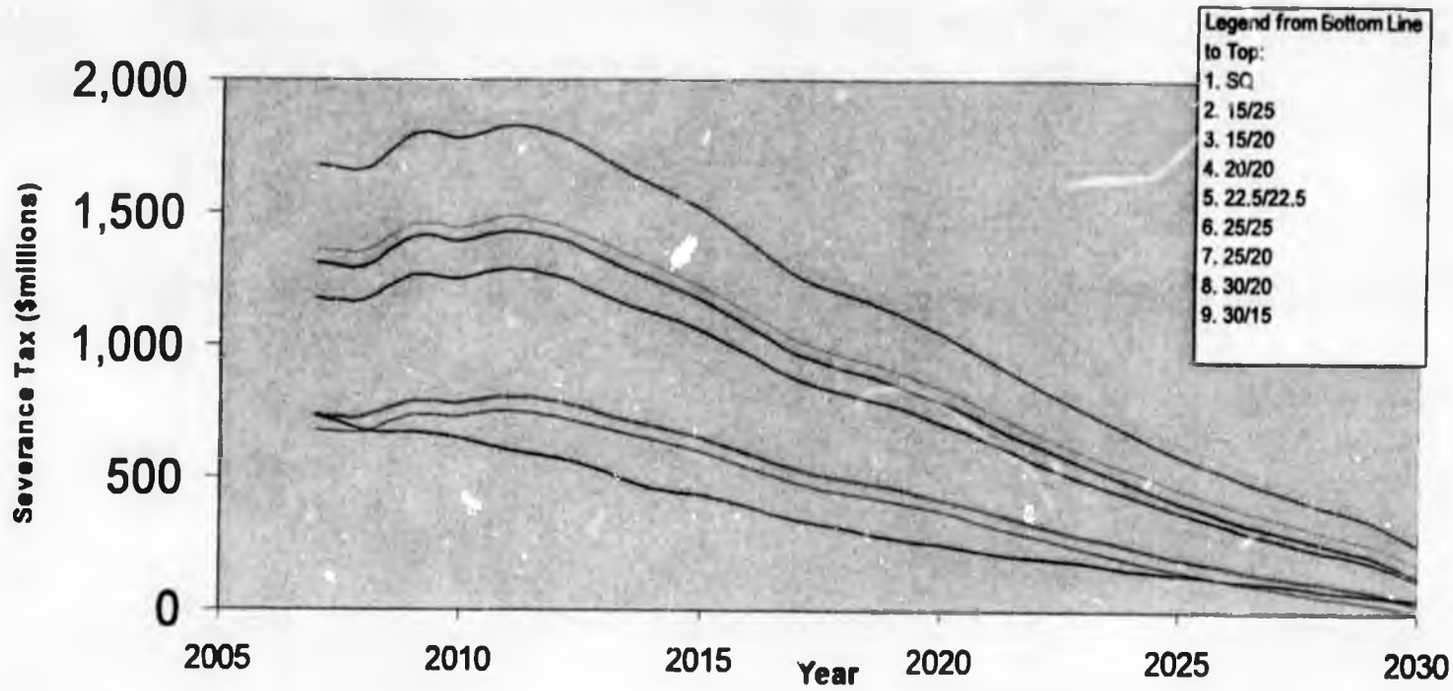
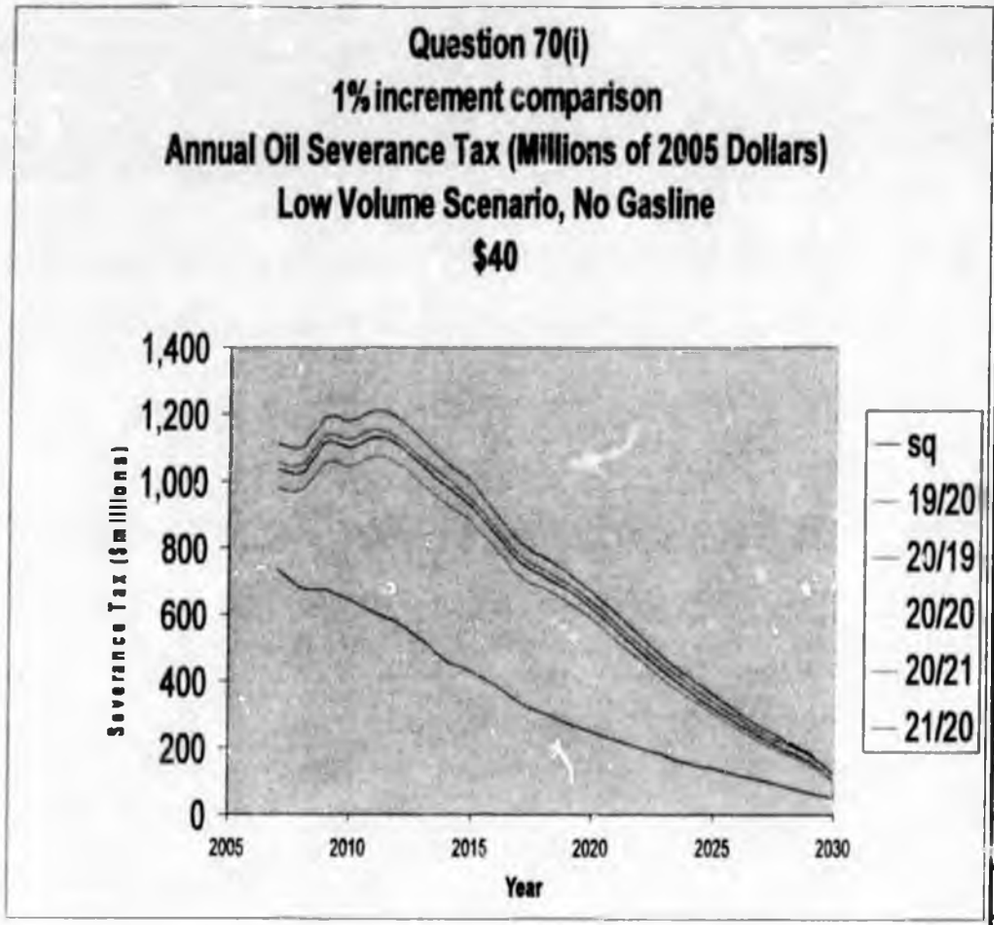


Table with Values on Next Slide

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Question 70(h)(2) Tabla: Annual Oil Severance Tax ($Millions), $40/bbl									
Fiscal Yr	sq	15/25	15/20	20/20	22.5/22.5	25/25	25/20	30/20	30/15
2007	737	676	730	1,045	1176	1307	1,361	1,677	1731
2008	679	671	725	1,038	1168	1298	1,352	1,665	1719
2009	673	735	789	1,124	1264	1405	1,459	1,794	1848
2010	646	726	780	1,112	1251	1390	1,444	1,776	1830
2011	606	748	803	1,143	1286	1429	1,483	1,823	1878
2012	576	729	783	1,117	1256	1396	1,450	1,784	1838
2013	523	684	738	1,056	1187	1319	1,373	1,691	1745
2014	459	638	691	992	1116	1240	1,293	1,595	1648
2015	431	597	650	937	1054	1171	1,224	1,511	1564
2016	388	536	588	853	960	1067	1,119	1,384	1436
2017	340	475	527	770	867	963	1,014	1,258	1309
2018	306	443	494	726	817	908	958	1,191	1241
2019	275	411	462	683	768	854	904	1,125	1176
2020	248	372	422	629	708	787	837	1,044	1094
2021	224	326	375	566	636	707	756	947	997
2022	201	277	326	499	562	624	673	846	895
2023	180	233	281	439	494	549	597	755	803
2024	156	193	240	384	432	480	528	671	719
2025	138	154	202	332	373	415	462	592	639
2026	119	120	167	284	320	355	402	520	567
2027	103	89	136	243	273	303	349	456	503
2028	83	62	107	204	230	256	301	398	444
2029	67	35	81	169	190	211	256	344	389
2030	52	0	39	113	127	141	186	260	305
Totals	8,211	9,930	11,134	16,458	18,515	20,572	21,782	27,107	28,317

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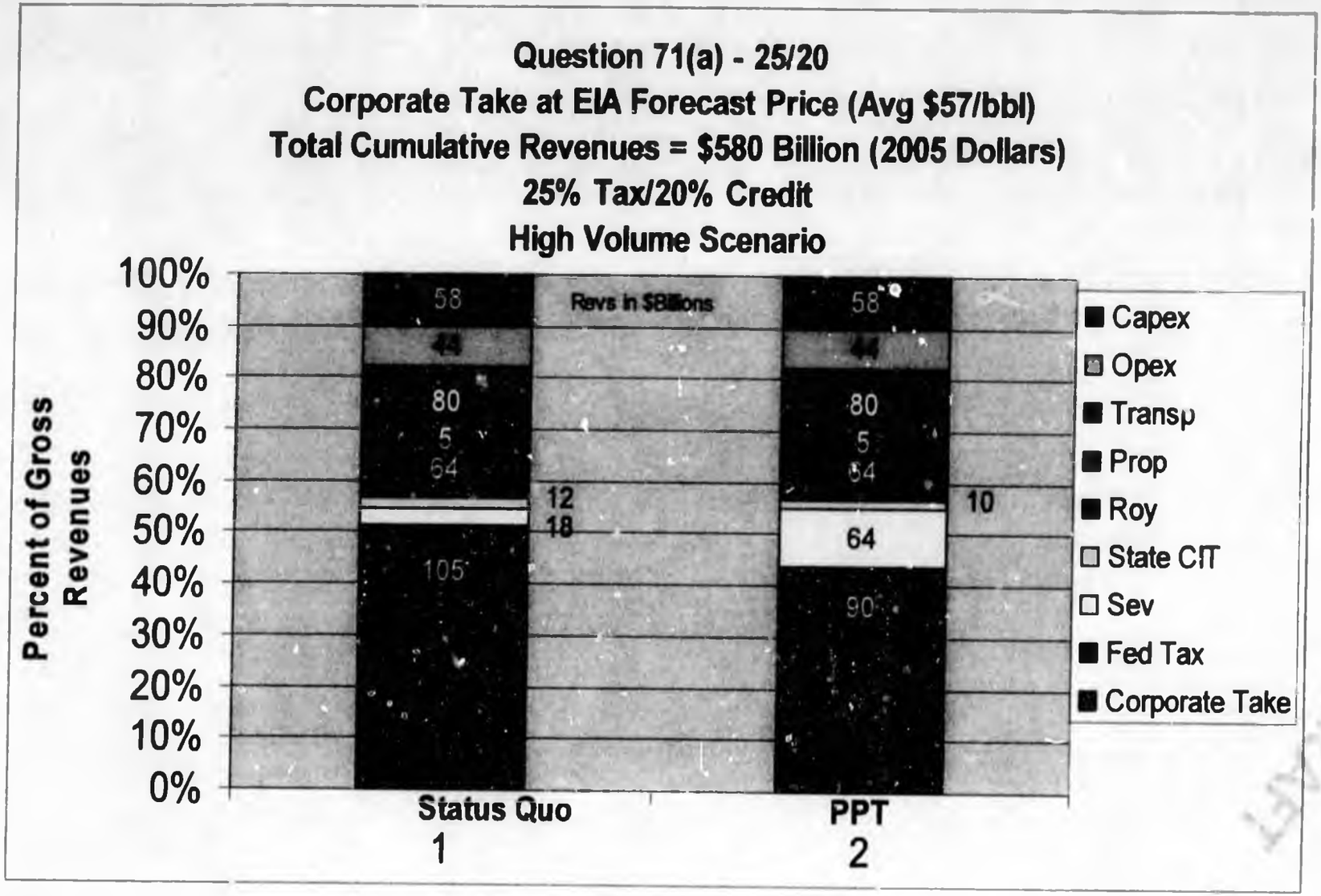
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

Question 70 - Annual Oil Severance Tax ($Millions)						
	sq	19/20	20/19	20/20	20/21	21/20
2007	737	982	1,056	1,045	1035	1109
2008	679	975	1,049	1,038	1027	1101
2009	673	1,057	1,135	1,124	1113	1191
2010	646	1,045	1,123	1,112	1101	1178
2011	606	1,075	1,154	1,143	1132	1211
2012	576	1,050	1,127	1,117	1106	1183
2013	523	992	1,066	1,056	1045	1119
2014	459	932	1,003	992	982	1052
2015	431	879	947	937	926	994
2016	388	800	864	853	843	906
2017	340	722	781	770	760	819
2018	306	680	736	726	716	772
2019	275	639	693	683	673	727
2020	248	588	639	629	619	671
2021	224	527	576	566	556	604
2022	201	465	509	499	489	534
2023	180	407	449	439	429	471
2024	156	355	394	384	375	413
2025	138	306	341	332	322	358
2026	119	261	294	284	275	308
2027	103	221	252	243	233	264
2028	83	185	214	204	195	224
2029	67	151	178	169	159	186
2030	52	98	122	113	104	127
Totals	8,211	15,393	16,700	16,458	18,515	20,572

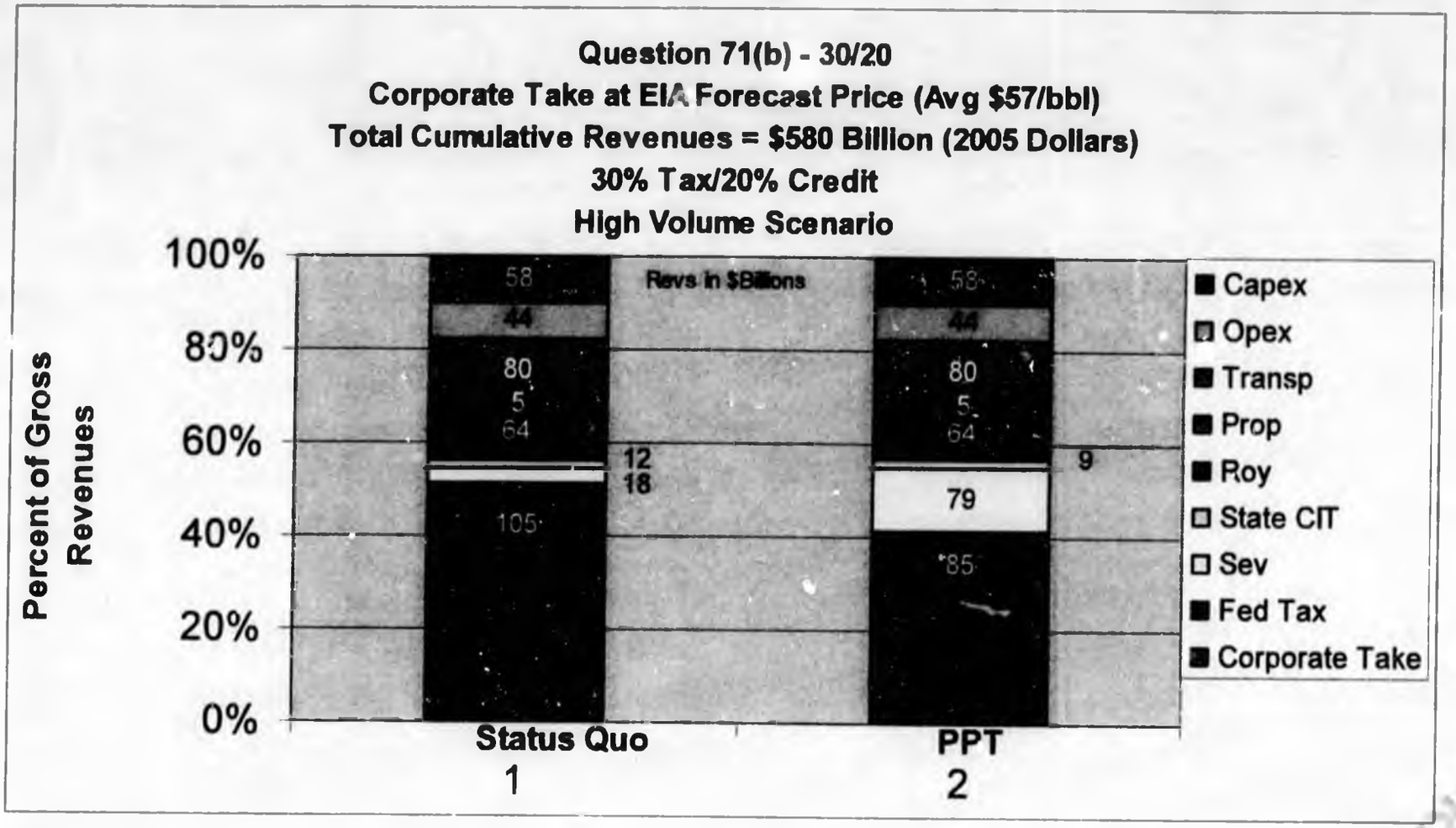
Question 70(j) - Average Effective Tax Rates*, Low Volume Scenario, No Gasline			
Tax Rate/Credit Rate	$20/bbl	$40/bbl	$60/bbl
Status Quo	4.1%	4.5%	4.4%
PPT 20/20	0.6%	9.3%	13.0%
PPT 25/20	1.2%	12.4%	16.8%
PPT 30/20	1.8%	15.5%	20.5%
PPT 30/15	2.5%	16.3%	21.0%
PPT 15/20	0.1%	6.2%	9.2%
PPT 25/25	0.7%	11.6%	16.3%
PPT 15/25	0.0%	5.4%	8.7%
PPT 22.5/22.5	0.6%	10.4%	14.6%
PPT 19/20	0.4%	8.6%	12.3%
PPT 20/19	0.7%	9.4%	13.1%
PPT 20/21	0.5%	9.1%	12.9%
PPT 21/20	0.7%	9.9%	13.8%

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*Average Effective Tax Rate = Severance Tax divided by Gross Wellhead Value Less Royalty

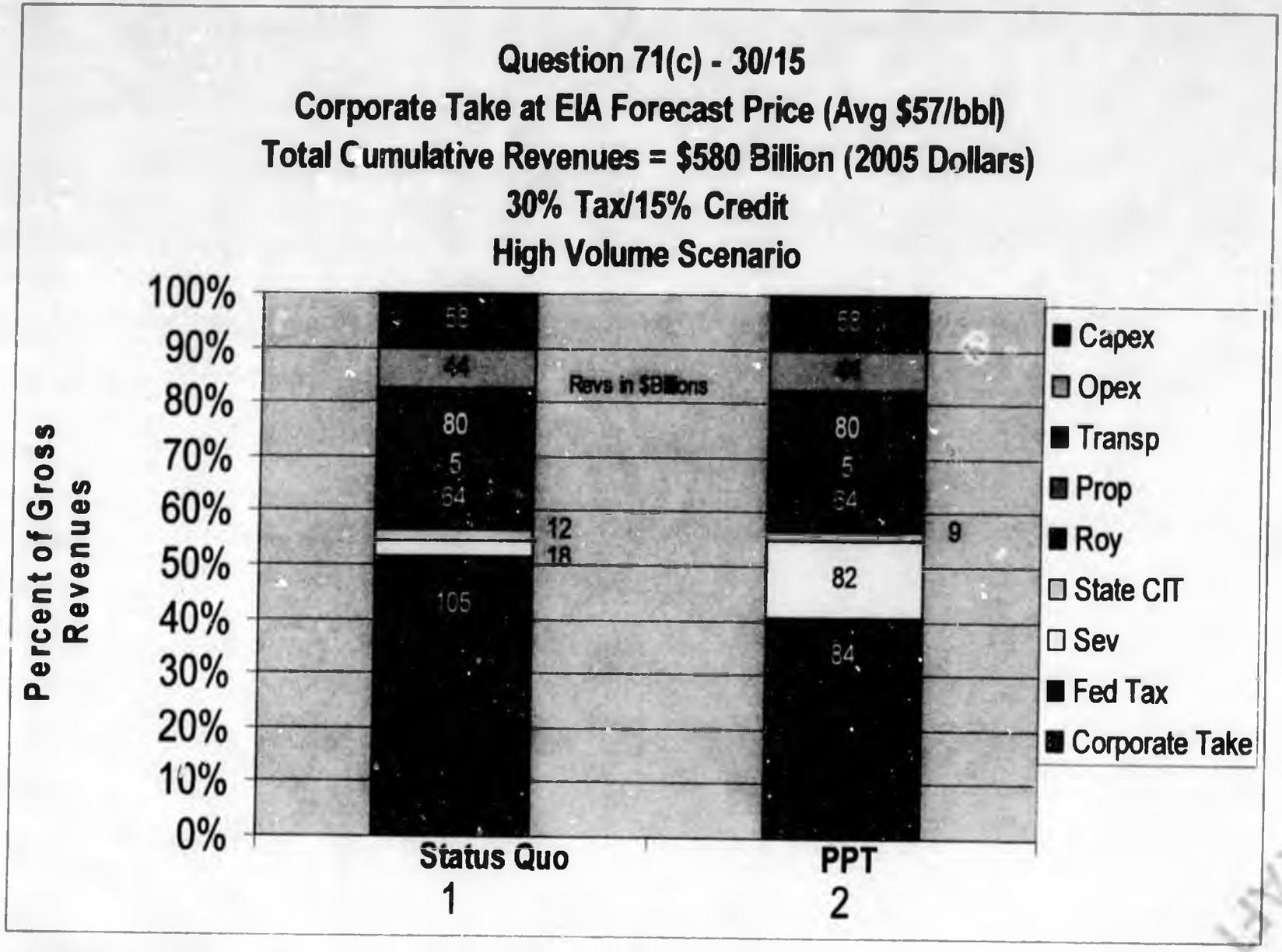


Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006



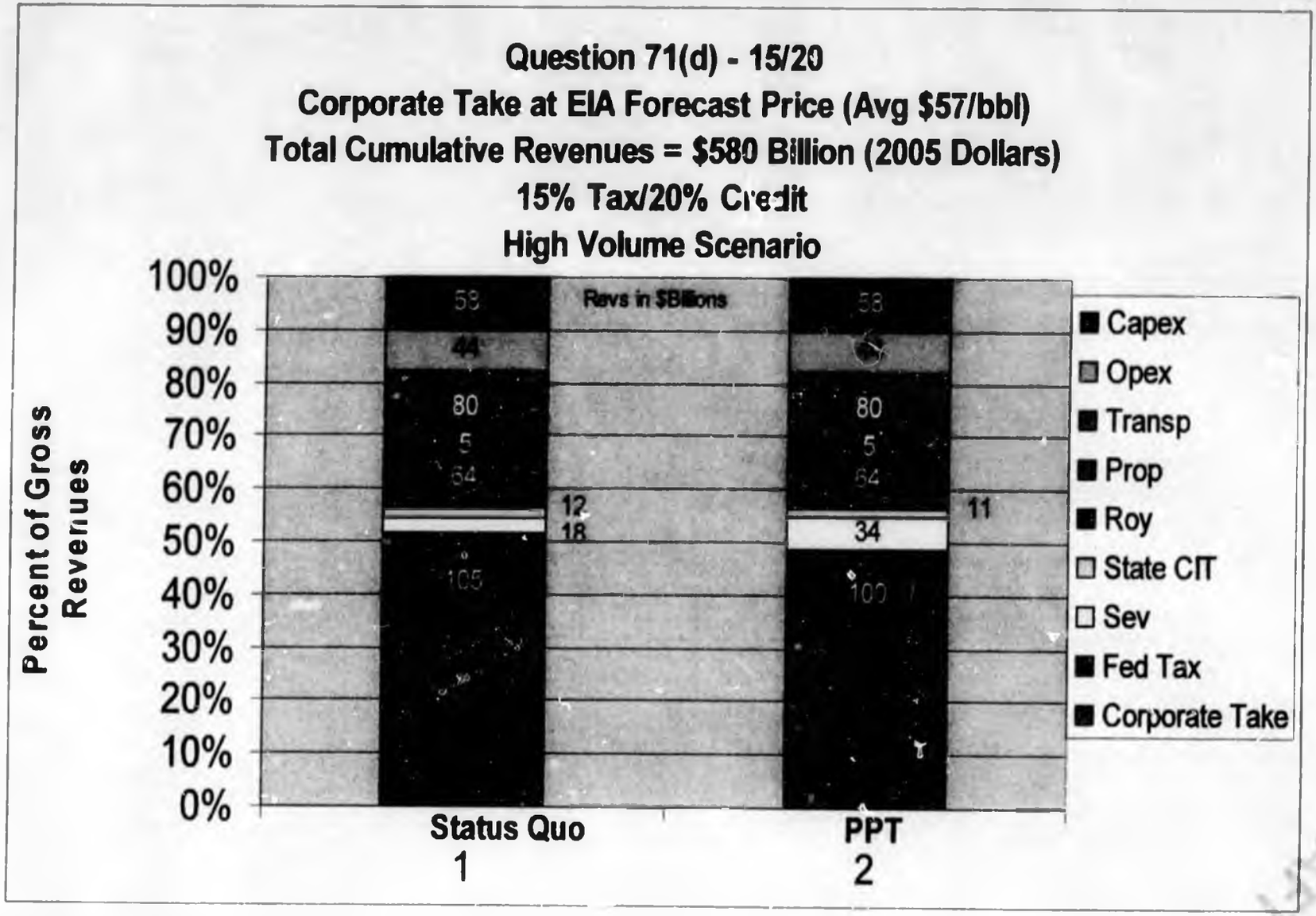
Alaska Department of Revenue, Tax Division
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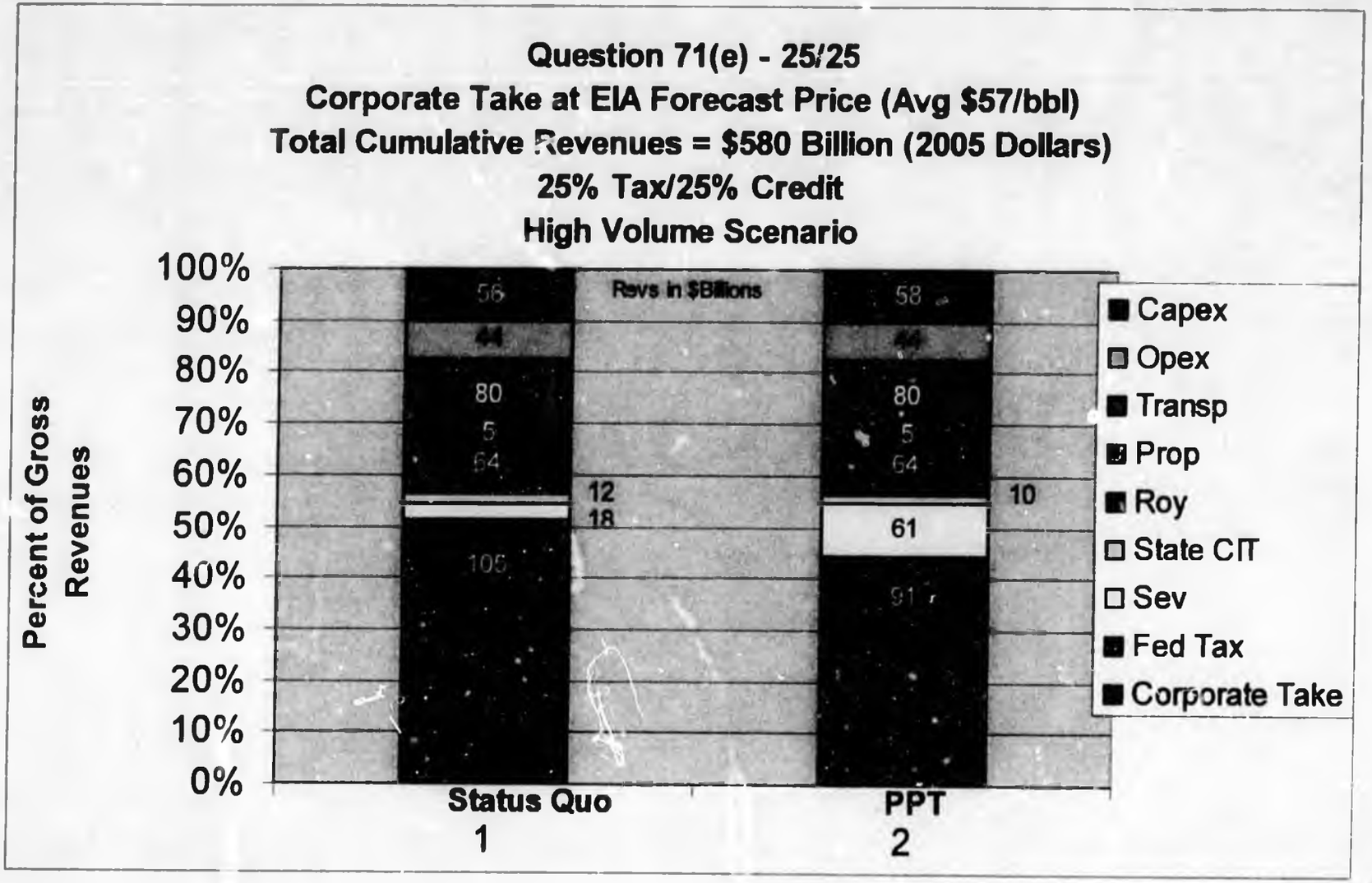
Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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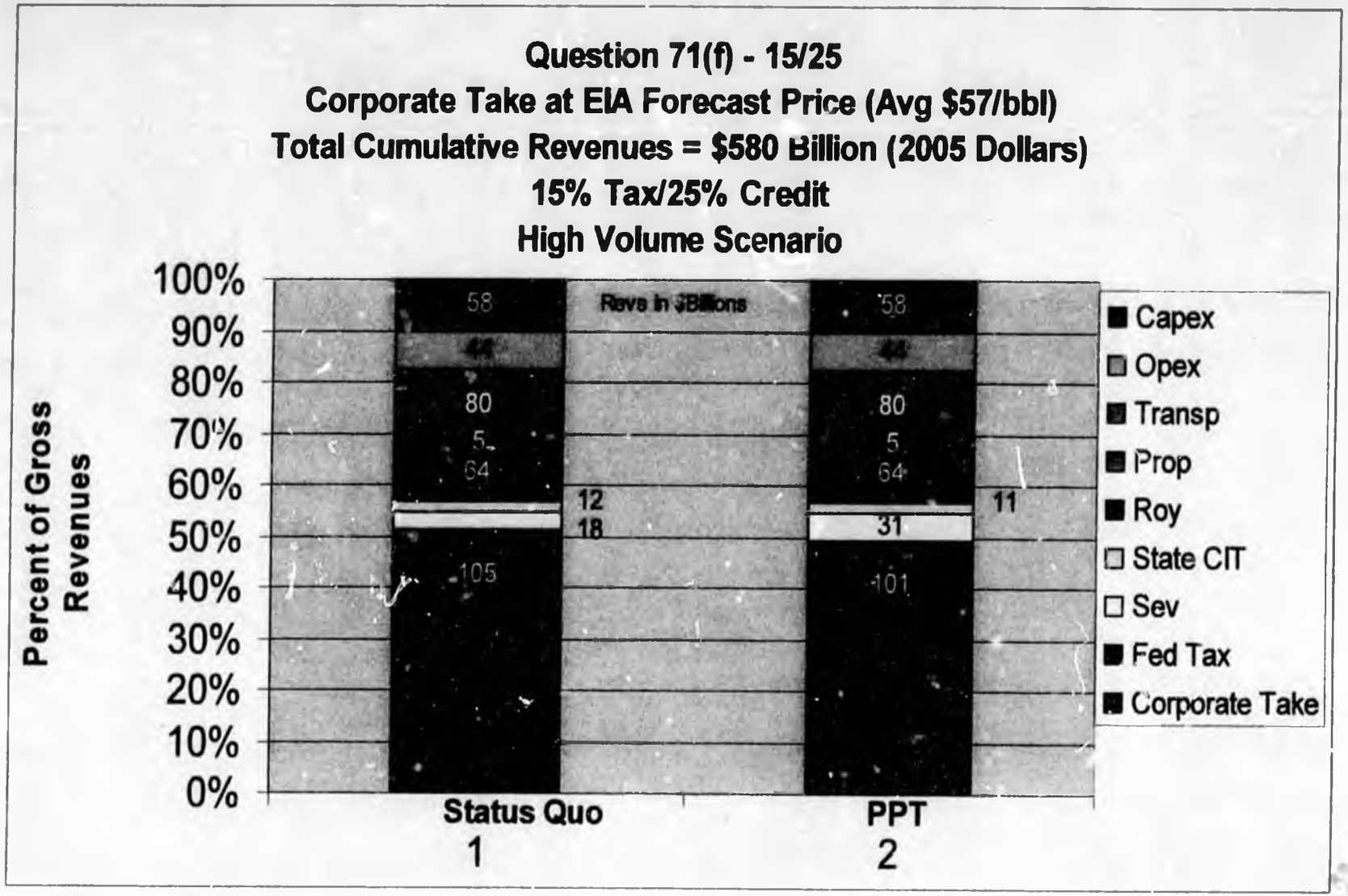
Alaska Department of Revenue, Tax Division
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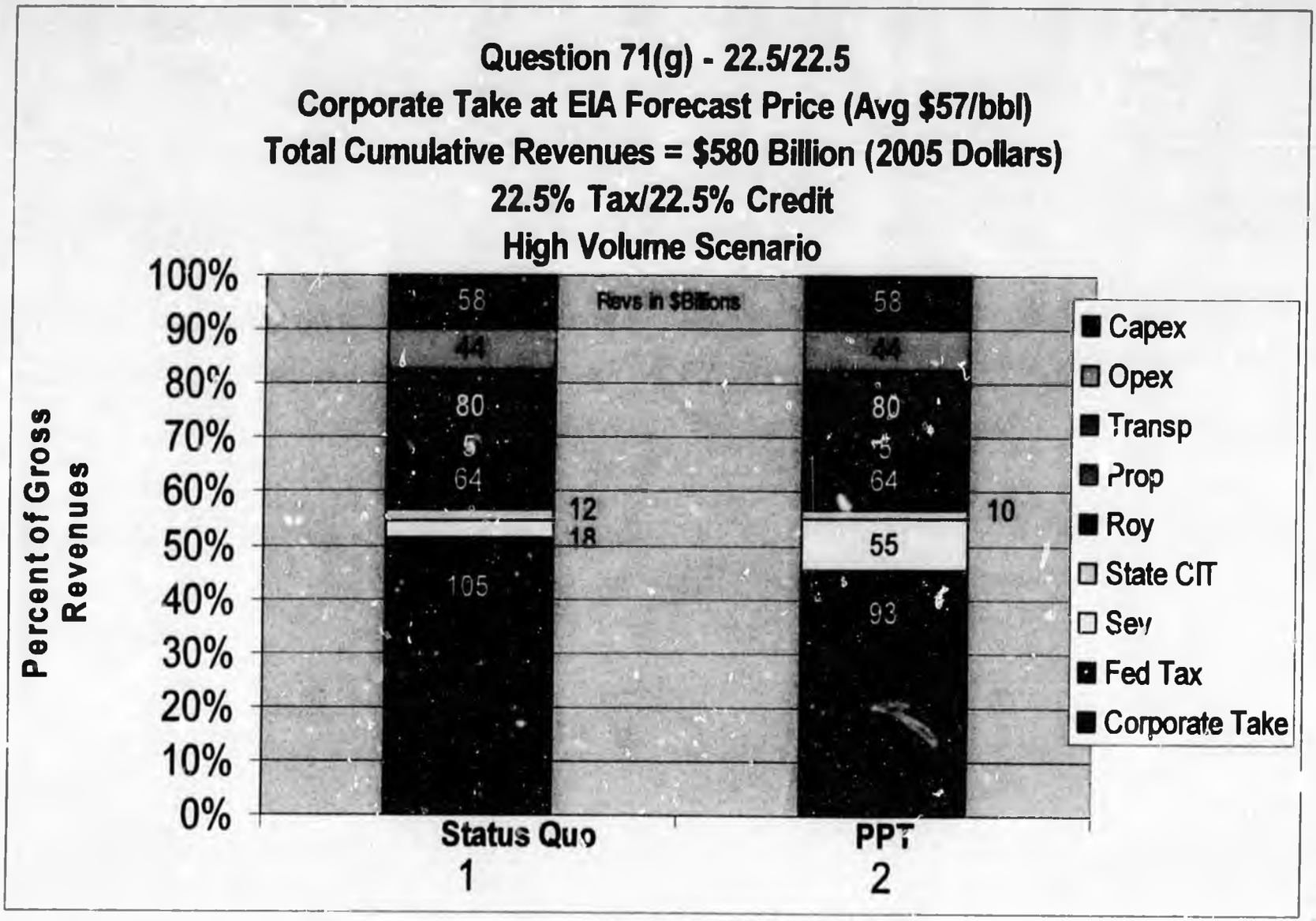
Alaska Department of Revenue, Tax Division
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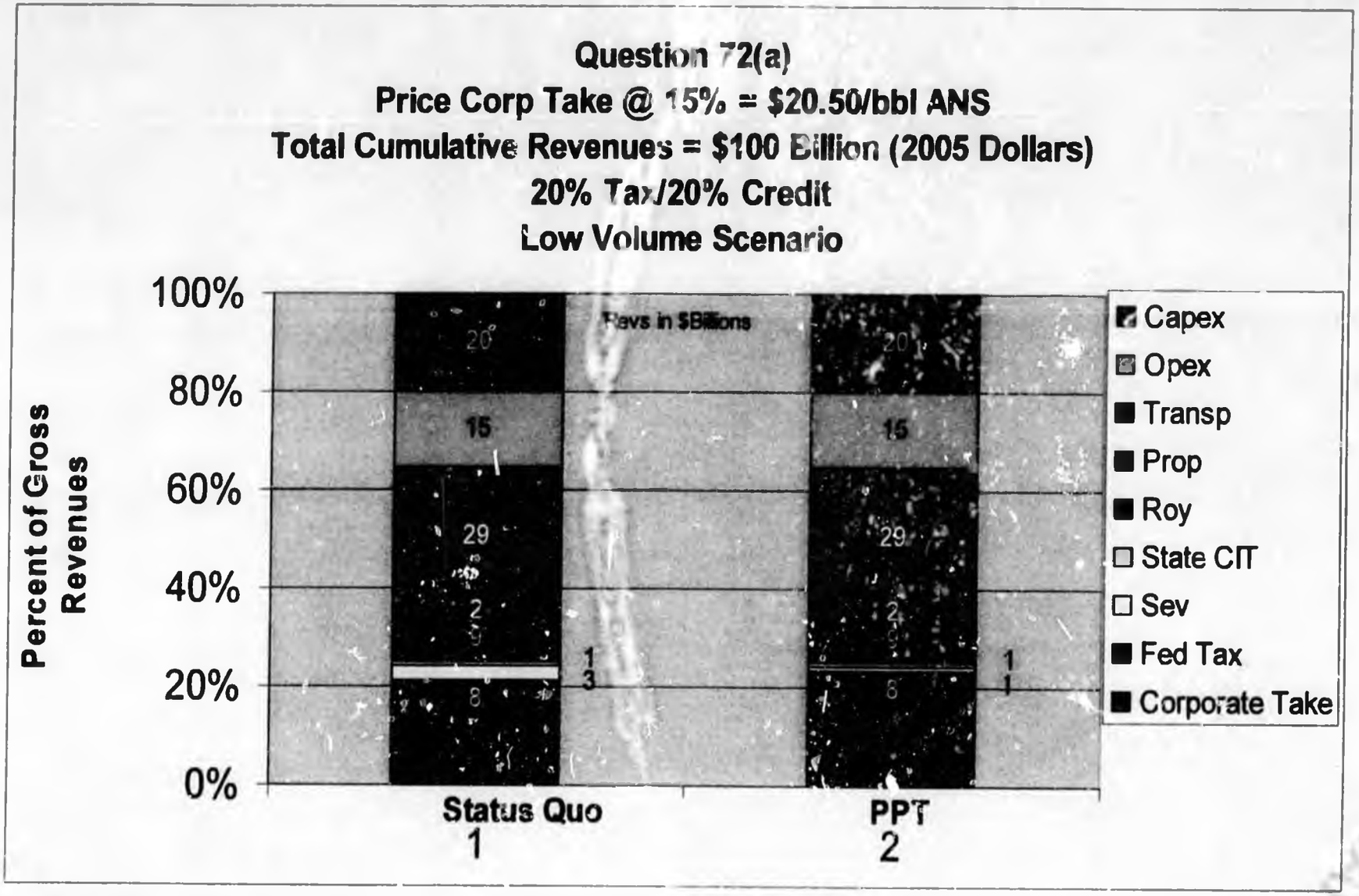
Alaska Department of Revenue, Tax Division
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Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

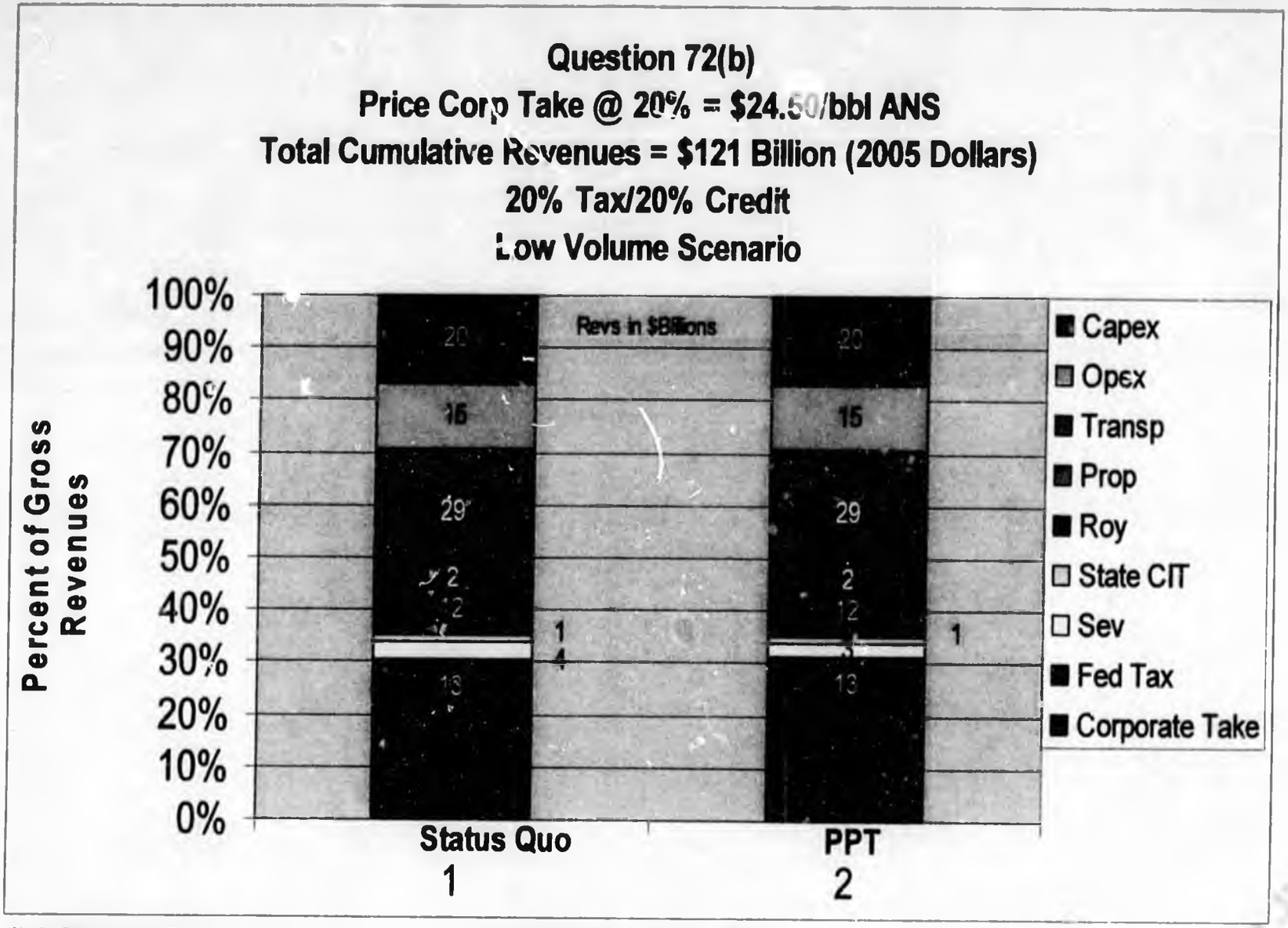
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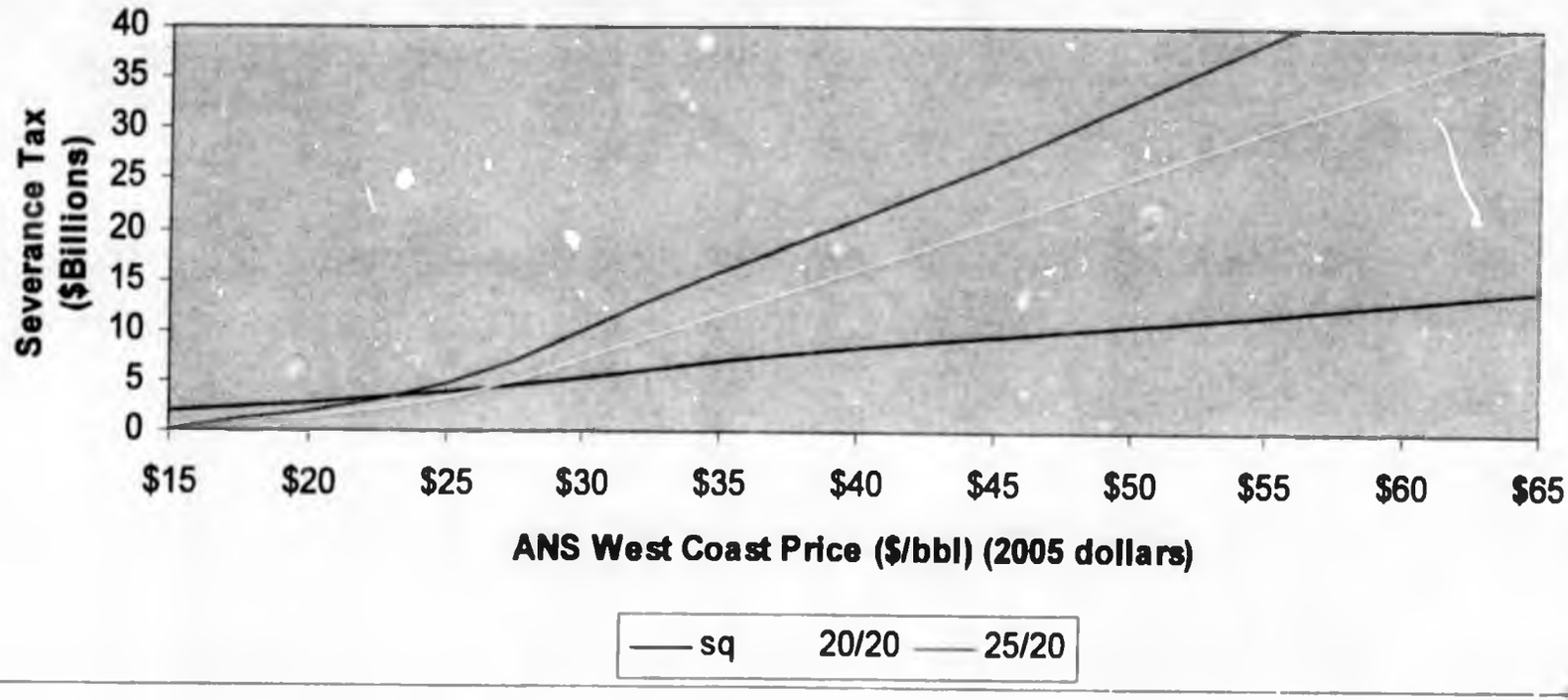


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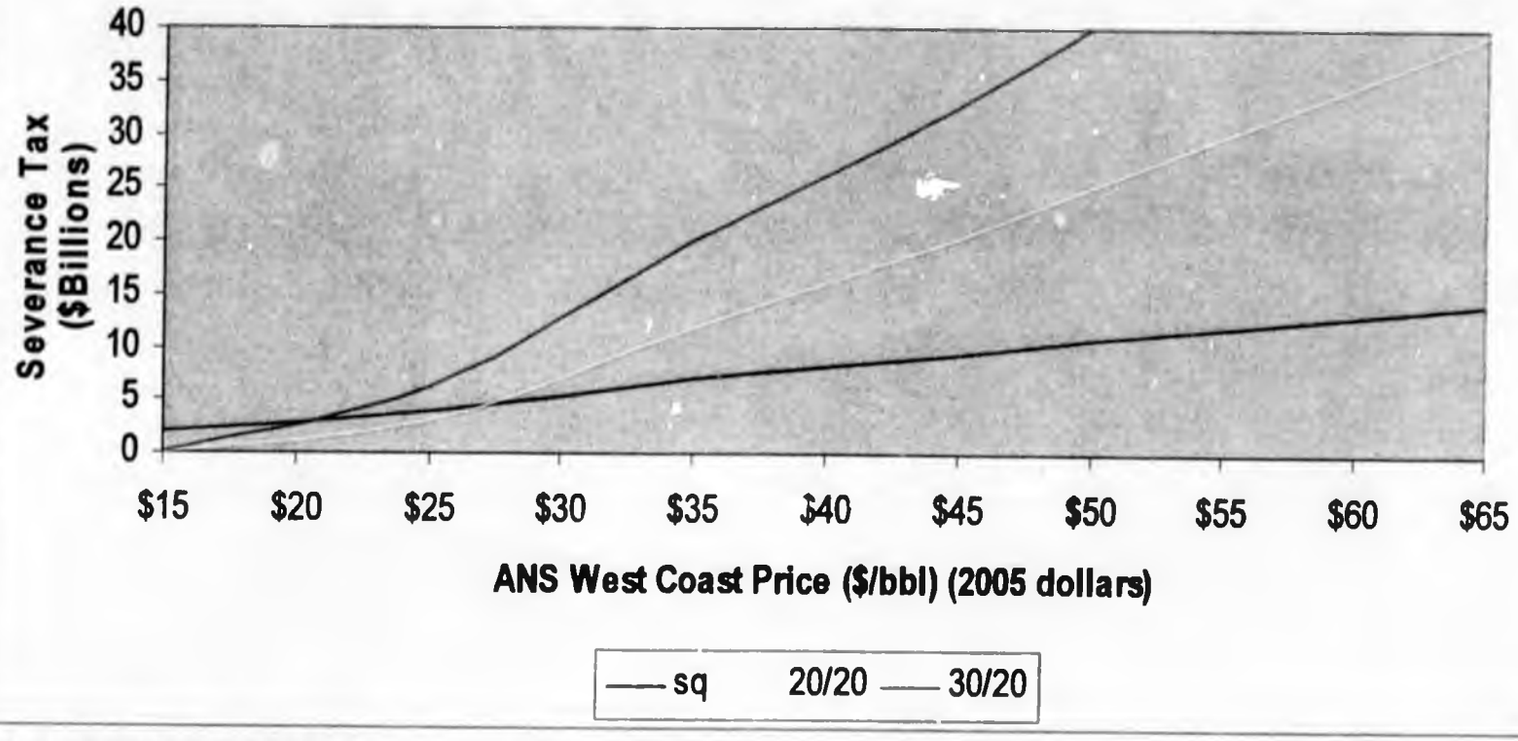
Question 90(a) - 25/20
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



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Alaska Department of Revenue, Tax Division
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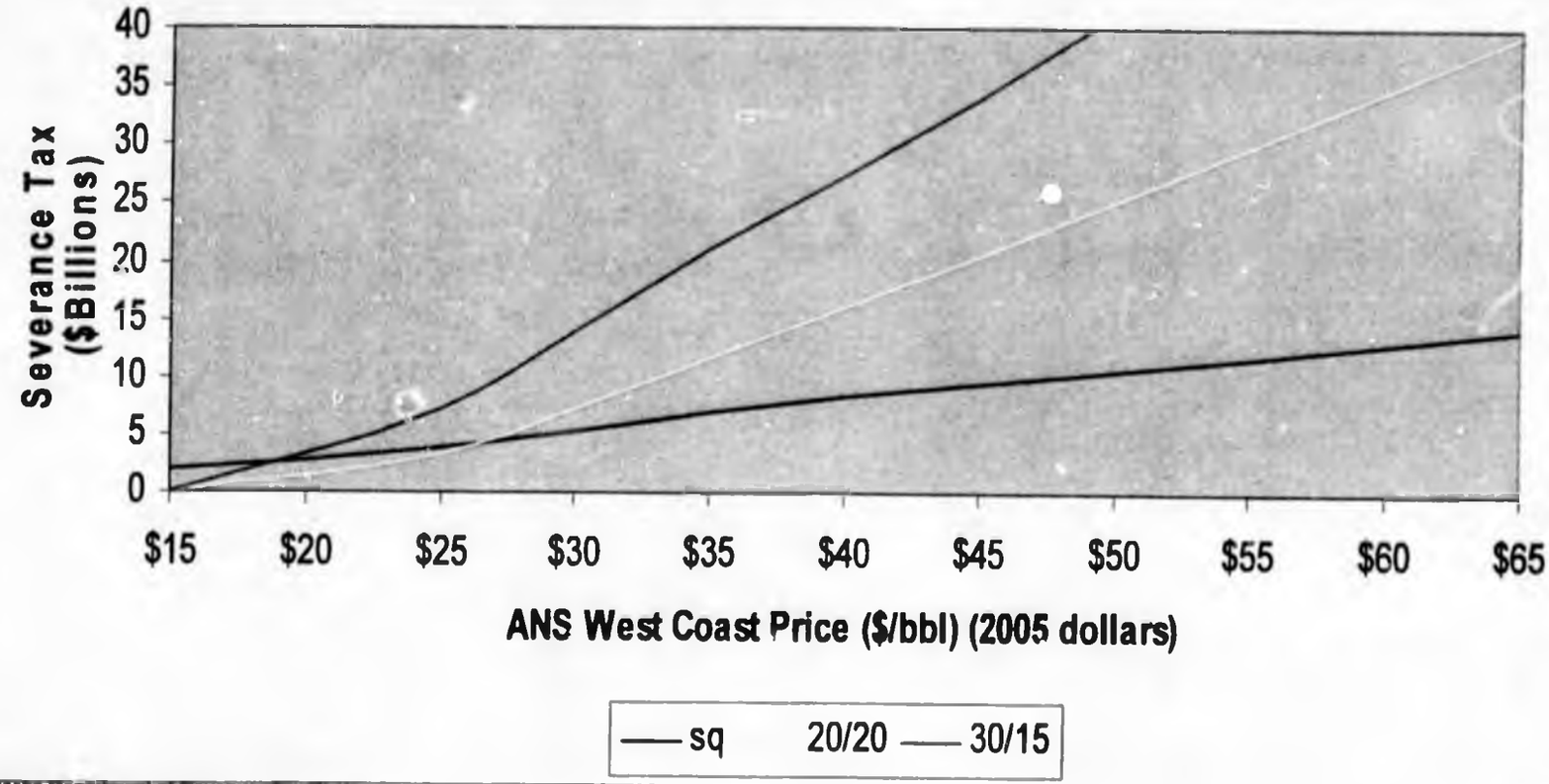
Question 90(b) - 30/20
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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Question 90(c) - 30/15
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario

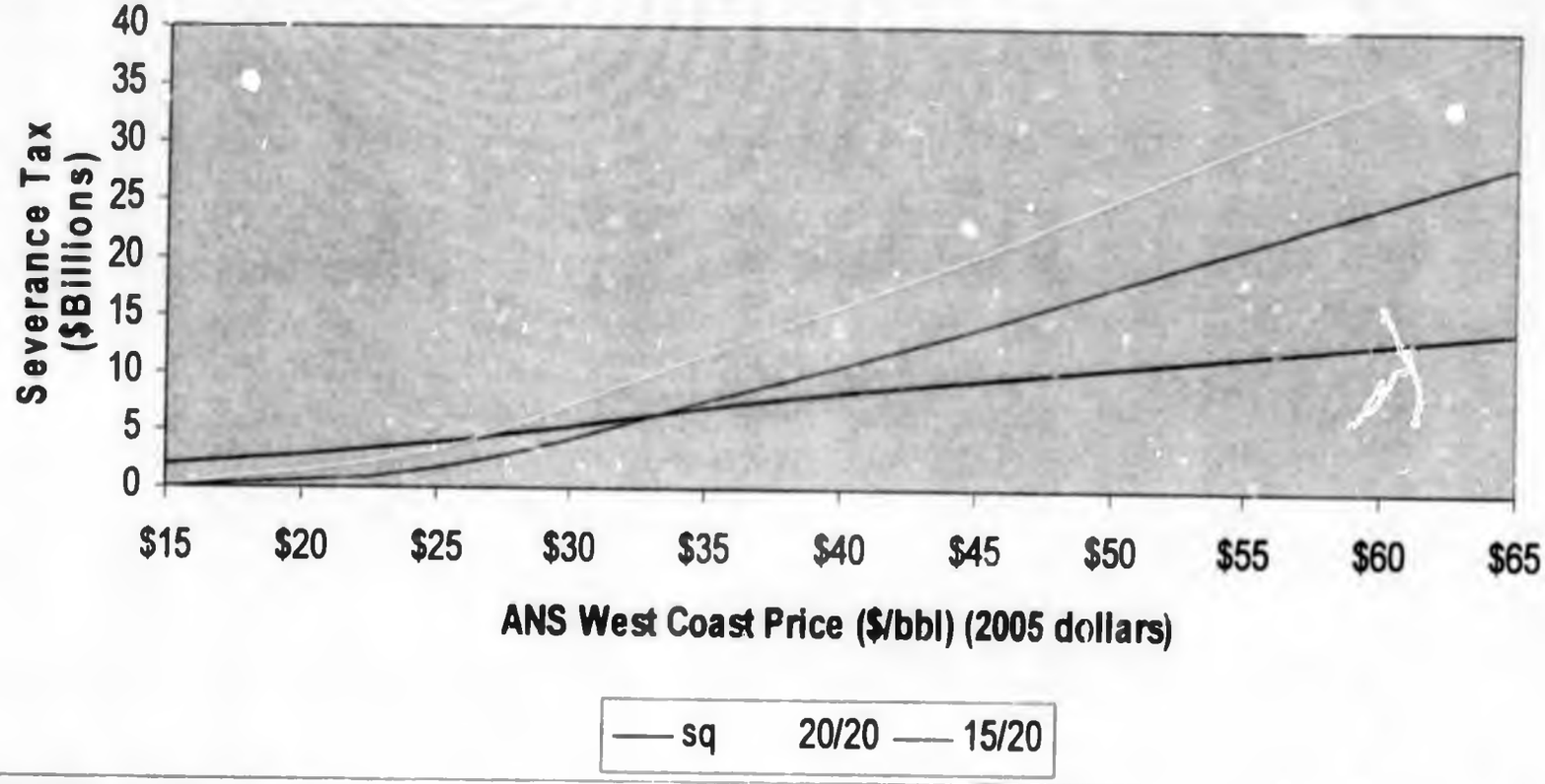


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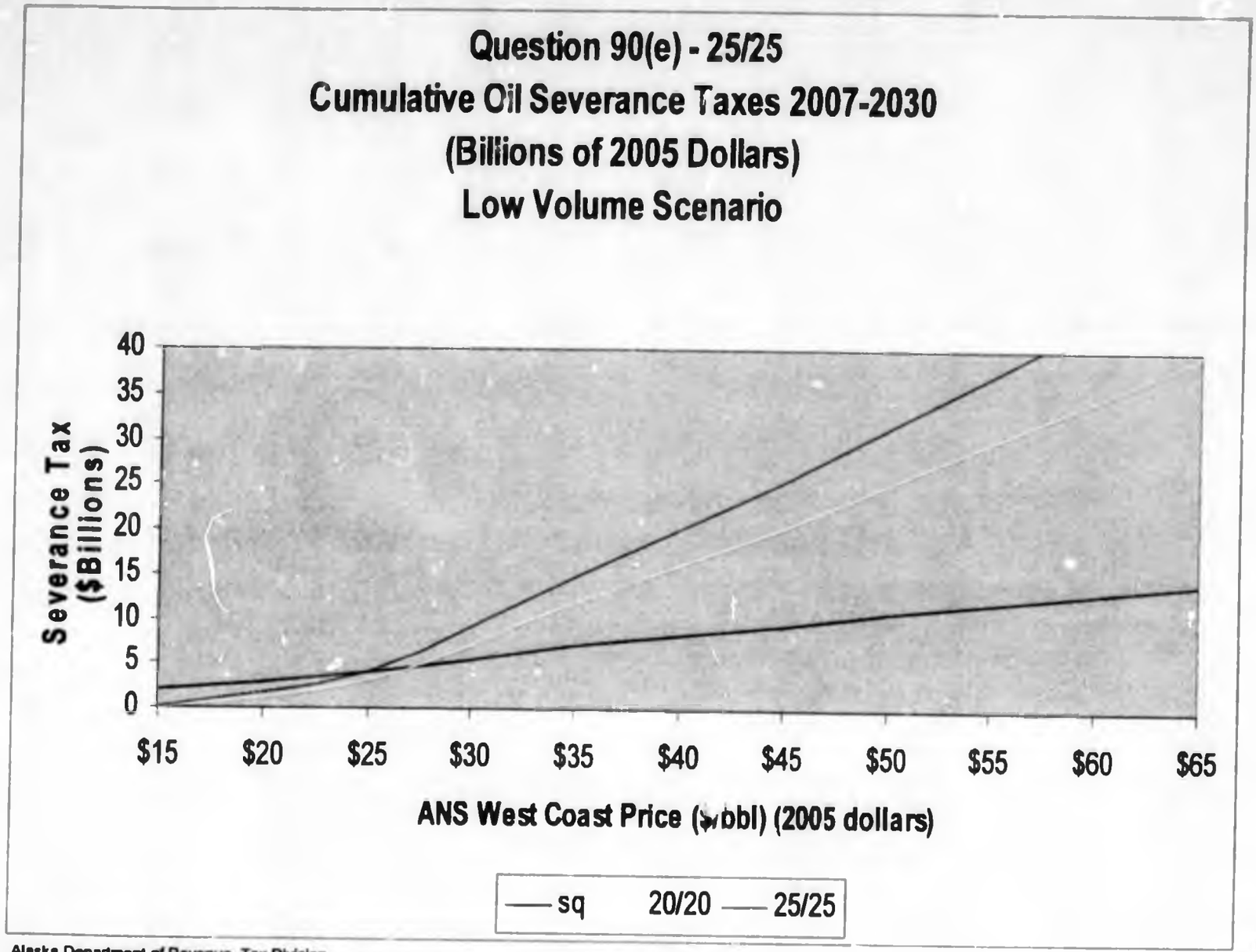
Question 90(d) - 15/20
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)

Low Volume Scenario



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

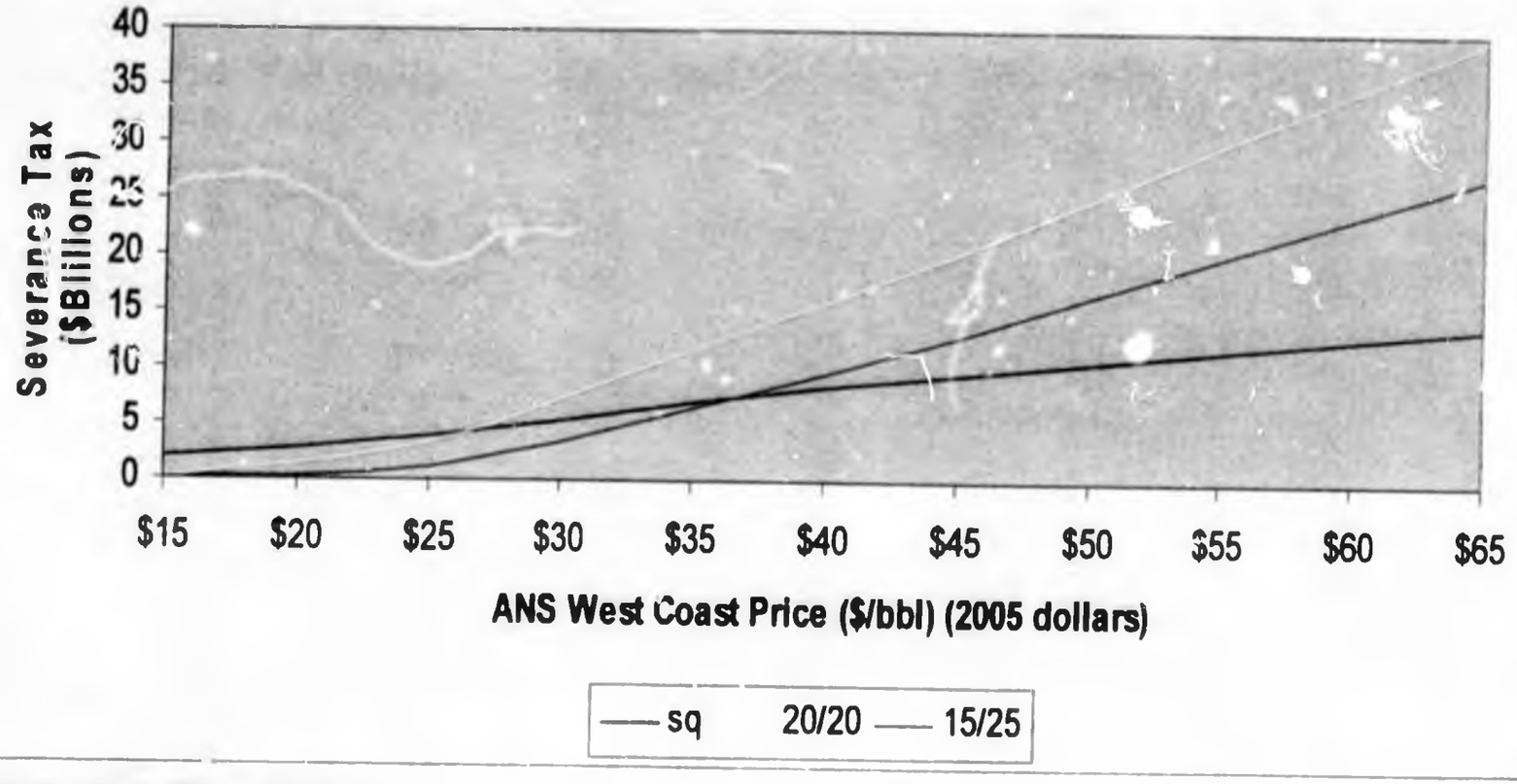
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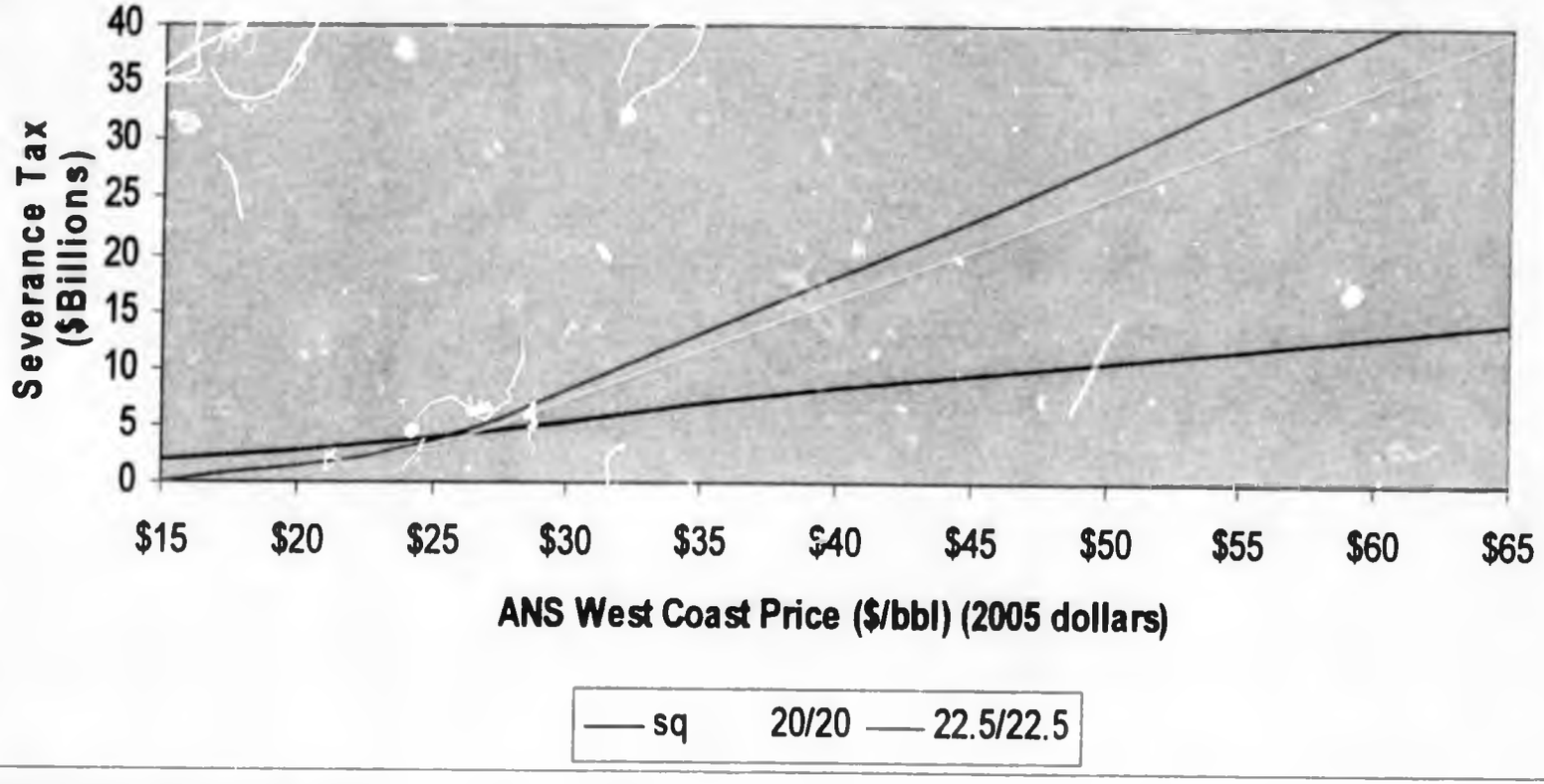
Question 90(f) - 15/25
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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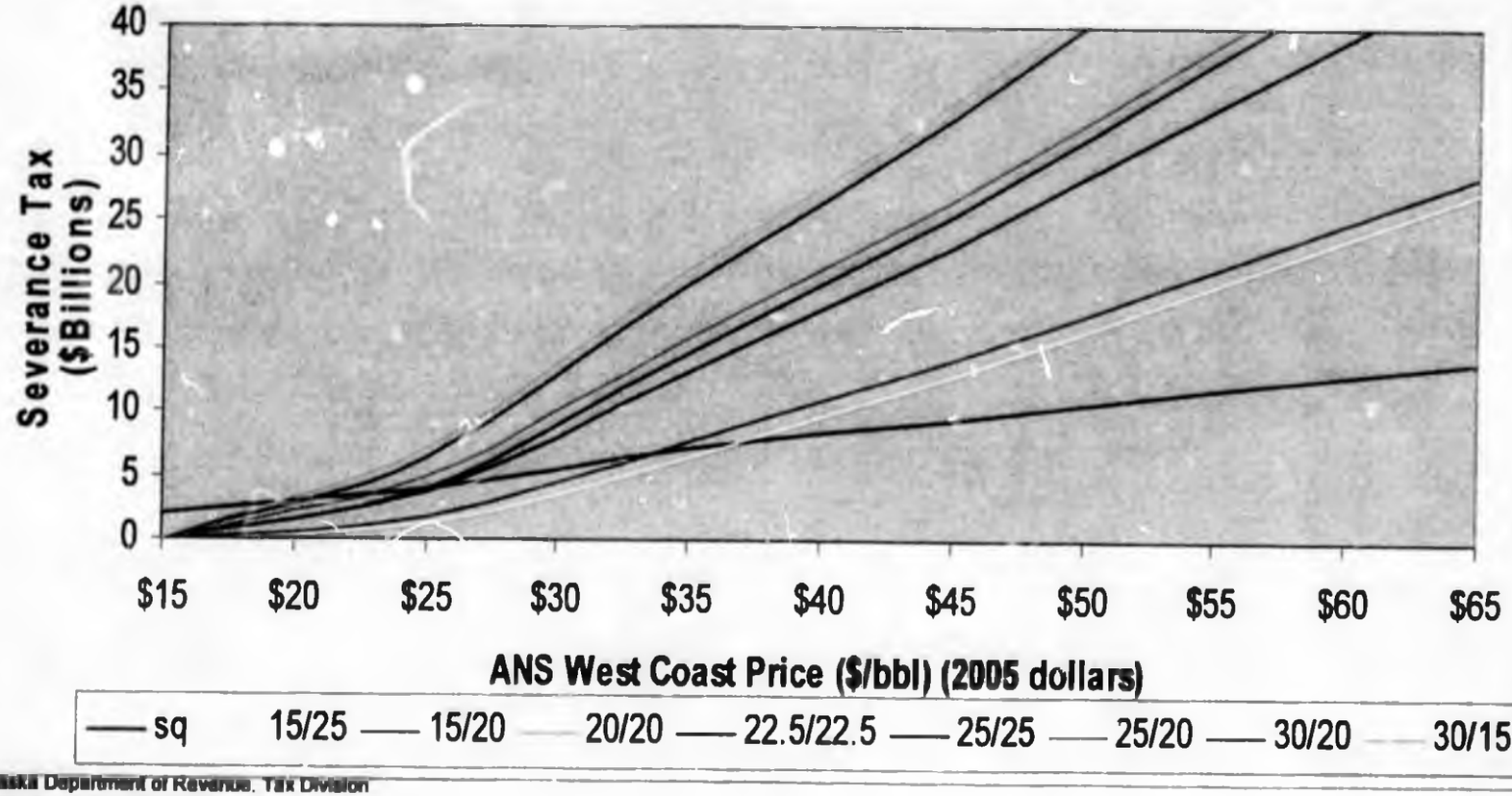
Question 90(g) - 22.5/22.5
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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Question 90(h)
Cumulative Oil Severance Taxes 2007-2030
(Billions of 2005 Dollars)
Low Volume Scenario



Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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Question 90(i) - Cumulative Severance Tax Revenues, Low Volume Scenario, No Gasline (in Millions of Dollars)			
Tax Rate/Credit Rate	$20/bbl	$40/bbl	$60/bbl
Status Quo	2,959	8,211	12,870
PPT 20/20	498	16,458	34,649
PPT 25/20	1,041	21,782	44,521
PPT 30/20	1,614	27,107	54,393
PPT 30/15	2,133	28,317	55,603
PPT 15/20	43	11,134	24,777
PPT 25/25	622	20,572	43,311
PPT 15/25	-	9,930	23,567
PPT 22.5/22.5	560	18,515	38,980
PPT 19/20	399	15,793	32,674
PPT 20/19	580	16,700	34,891
PPT 20/21	424	16,216	34,407
PPT 21/20	605	17,523	36,623

Alaska Department of Revenue, Tax Division
ATTACHMENT 03/13/2006

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Chevron

Chevron - Alaska Area

Testimony on HB 488

John P. Zager
General Manager



March 15, 2006

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General Comments on CS

- Previous Testimony by Chevron
  - Cook Inlet must be treated differently than the North Slope
  - Do not pull all of the "levers" in the same direction
  - Keep it as simple as possible
- We find none of this counsel retained in the CS

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Comments on Substantive Changes

- Make tax rate progressive
  - Very complex to track (daily?)
  - Why pegged to WTI?
    - What about ANS? What about Gas?
  - The price step up *is not* inflated
  - Taking away the "windfalls", no matter how you couch it, lowers expected value to investors
  - A move against industry

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Comments on Substantive Changes

- Reduce Transitional Money as Deductible Allowance
  - Reduces Chevron's annual deduction by >80%
  - The $40 indexing price *is* inflated
  - Another move against industry

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Comments on Substantive Changes

- Exploration Enhancement
  - Reducing capital credit to 20% is not encouraging exploration
    - We run full cycle economics to justify an exploration program
  - Dramatically shifts the balance of new taxes and investment incentives
  - Another move against industry

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Comments on Substantive Changes

- No Credit for Abandonment
  - Inclusion would encourage timely abandonment of operations
  - State has benefited from the assets for many years, it is a legitimate cost of production
  - Another move against industry

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Comments on Substantive Changes

- Private Royalties
  - No comment
- AOGA technical changes
  - Let's get it right
- Contingency surcharge
  - Another move against industry
- Effective Date
  - Another move against industry

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Comments on Substantive Changes

- Issues surrounding the $73 million allowance
  - Another move against industry
- Tax Credit Repurchase Program
  - Helps a few, but not Chevron
- Penalties on underpayment of less than 90% of monthly tax liability
  - 5% is punitive
  - Need market based interest rate
  - Another move against industry

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Biggest Disappointment of All

- The unique value and challenged position of the Cook Inlet is not recognized
- Revisions as proposed significantly lowers the economics of capital investments in the Cook Inlet
  - Puts Chevron's four year capital program in serious jeopardy
  - Without capital McArthur River Field is gone in ~4 years
  - Critical mass is gone - Cook Inlet oil industry shrivels and dies
  - Industry produces out remaining proven gas reserves

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Final Score

State	Industry
8	C

This bill has gone from being somewhat balanced and thus having the "reluctant support" of industry, to one that is lopsided in favor of the state, and is therefore one that Chevron cannot support.

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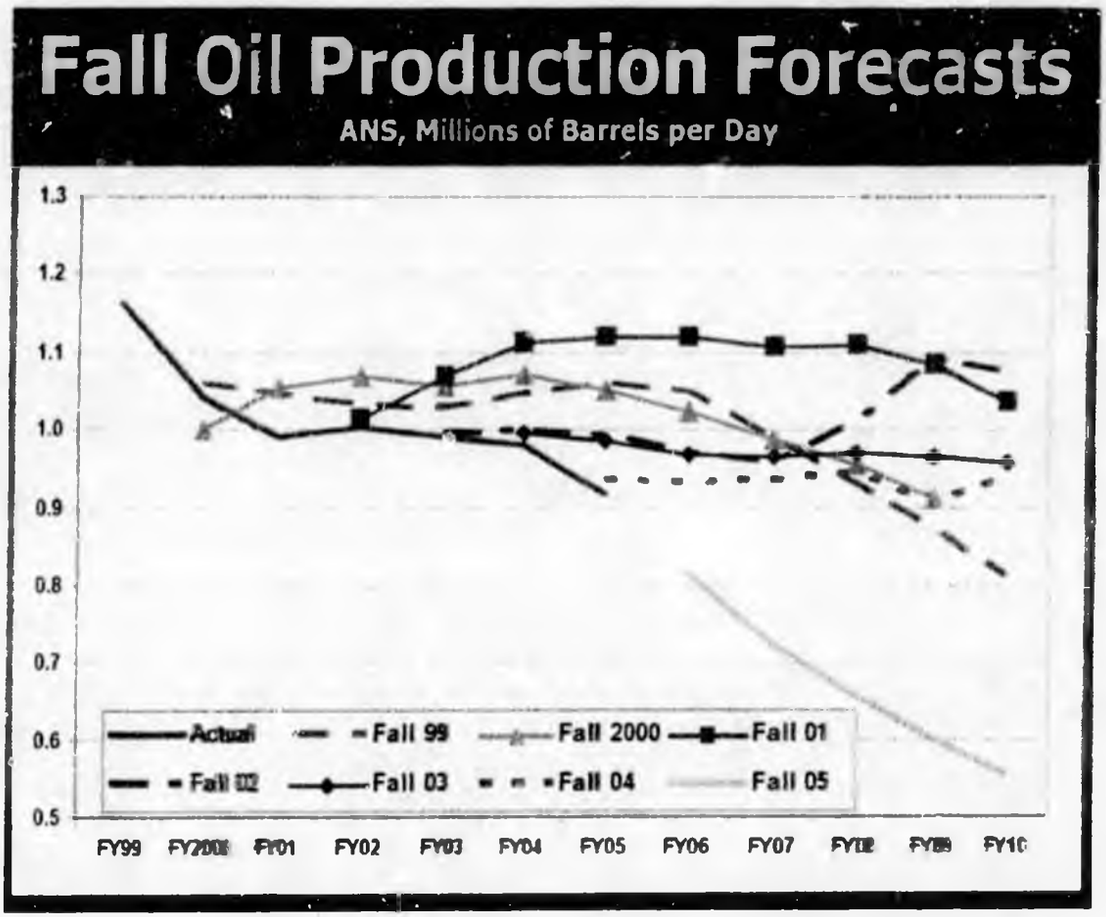
BP Presentation on House Bill 488 (PPT)

Alaska State Legislature
House Resource Committee
15th March 2006

I am Angus Walker and I am the Commercial Vice President of BP Alaska. Alongside me today is Tom Williams, Tax Counsel for BP Alaska.

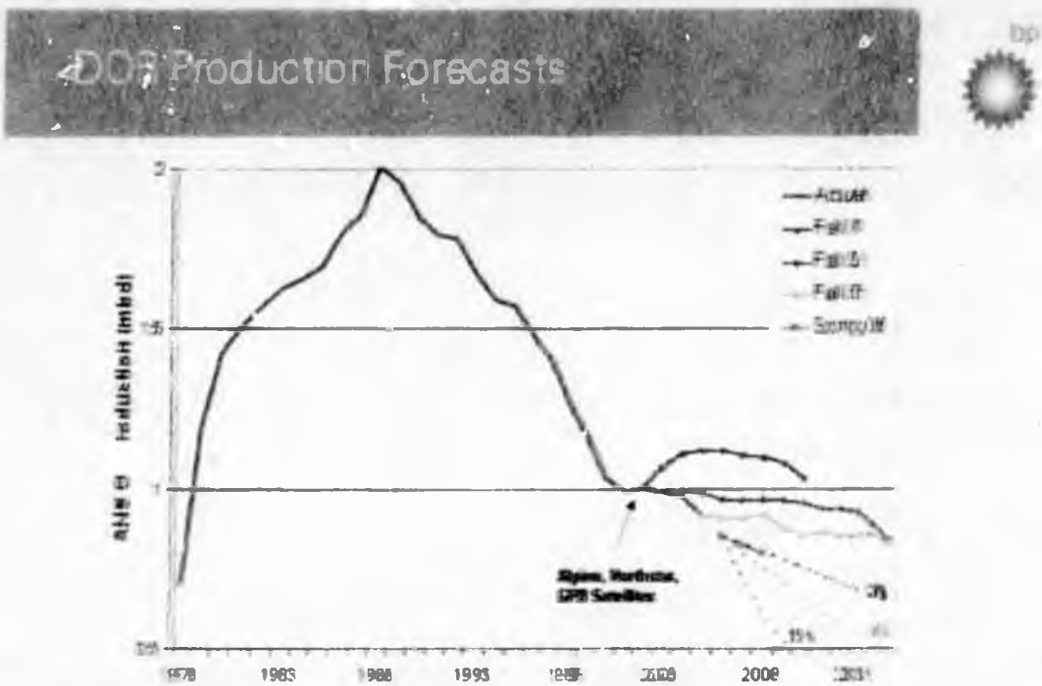
I would like to start by thanking this Committee for the opportunity to provide further testimony on House Bill 488 / Senate Bill 305.

I will not repeat our previous testimony, but will build upon some key issues raised and provide our view of the substantive changes this Committee is considering to House Bill 488.



One of the key moments in recent testimony was the slide Michael Williams presented showing the Department of Revenue forecasts of oil production made each year going back to 1999. In red is the actual production.

Whilst there's a lot of detail on this slide, it highlights the challenge of accurately forecasting production. Since 1999, both Industry and DOR have consistently overestimated production and have annually revised production forecasts down significantly. This is of great concern to us as it should be to you. A one hundred thousand barrel per day drop in production represents a drop in state revenue of around $500 million per year at current prices.



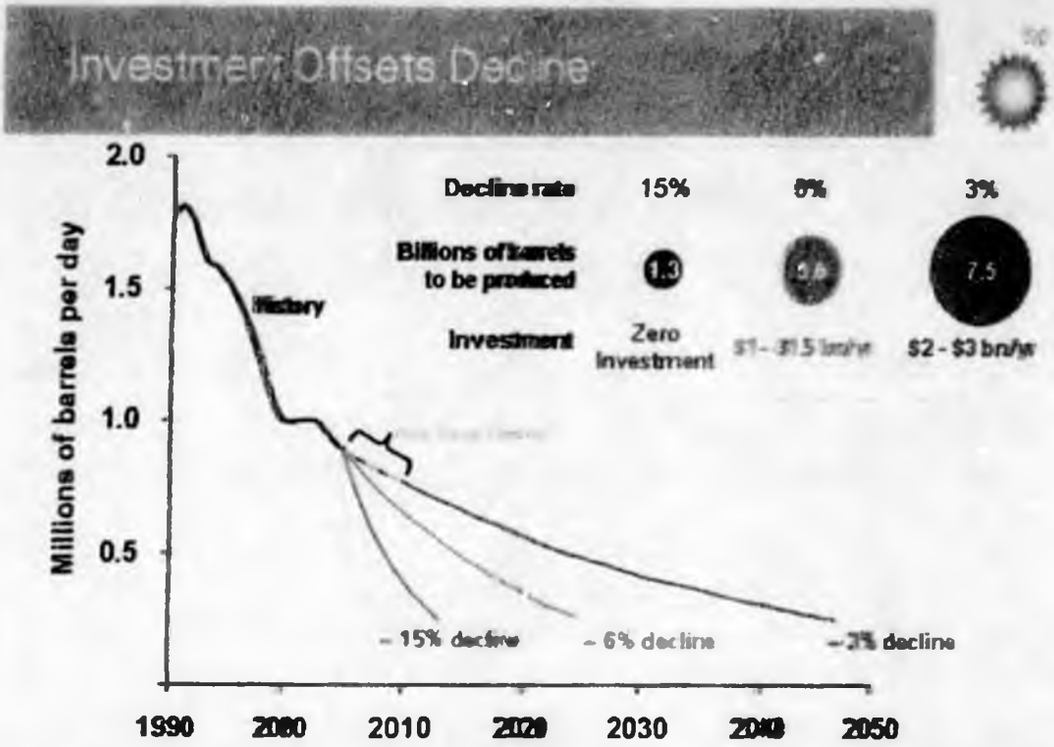
- **Historical basin decline has been around 6% per year**
- **Flattening of production from 2002-2004 due to Alpine & Northstar**
- **Decline since 2004 has mirrored historical basin decline**

This chart shows a subset of the DOR forecasts from 2001, 2003, 2005, along with the latest view of the Spring 2006 forecast, against actual production in red. The dashed lines describe the trajectories of a 3%, 6% and 15% decline.

Whilst development of Alpine, Northstar, and the Prudhoe Bay Satellites between 2000 and 2002 successfully flattened North Slope production for a number of years, 2005 saw decline return to the 6% rate that has characterized this basin in the past. Unfortunately for all of us, there are no more fields of Alpine or Northstar's magnitude waiting to be developed.

Investment & Decline

You will recognise the following slide from my presentation two weeks ago when I outlined the current reality of the North Slope oil business.



DOR Spring Forecast cannot be met without significant additional investment
The vast majority of that investment must be made in existing fields

With no investment the natural decline of the fields would be the lower red line. With the current levels of investment ($1-1.5 bn / year) that decline will be around six percent per year. The latest DOR 2006 Spring forecast translates into an approximate 3% decline.

However, the 3% decline cannot be met without significant additional investment, in the order of 2 to 3 billion dollars per year. Unless those investments are made, history will repeat itself, decline will continue at the current rate, and the DOR will be revising its production forecast down yet again.

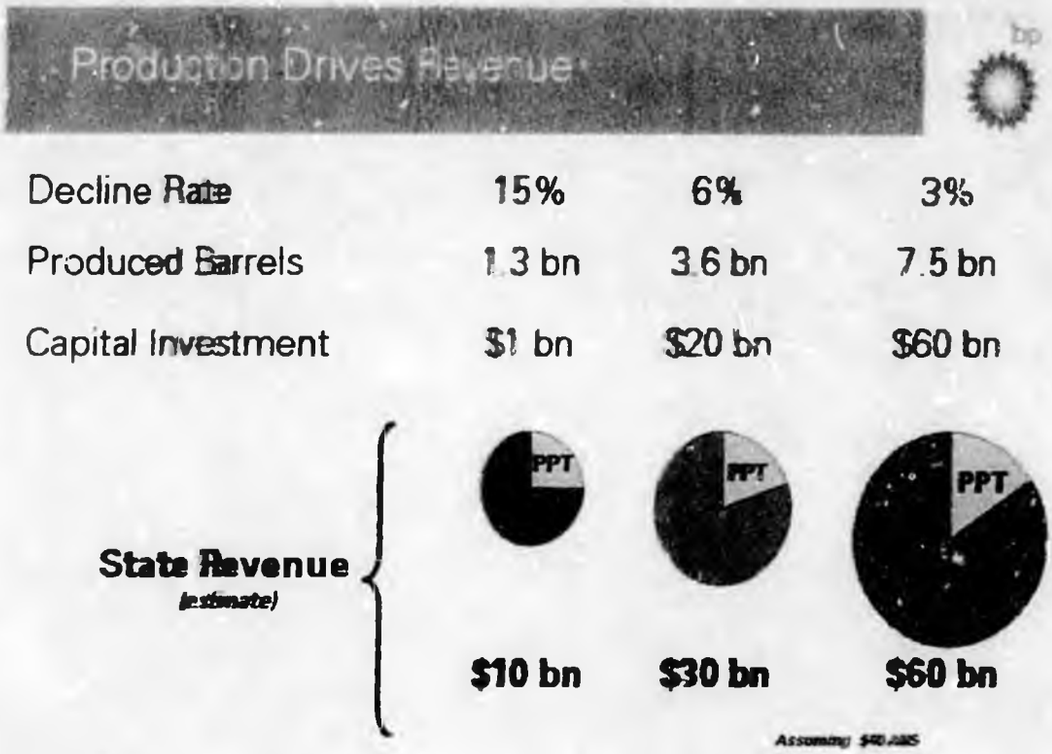
The real question for you to be asking industry and the consultants is "what would it take to double investment in the Alaska North Slope?"

Encouraging new exploration is good but it is a fact, acknowledged by all who have testified, that the resources expected to be discovered through exploration will likely be significantly less than the resources we already know about. It is investment in these known resources that offers the greatest chance of stemming the decline of ANS production. As you look at incentives for exploration you must not overlook incentives for investments which are more likely to succeed.

Decline Scenarios & State Revenues

The tax regime you approve will directly impact how attractive Alaska is for investment and that will translate into what the future decline will be. It is in the interest of all (industry and Alaska) that we focus on growing the pie rather than increasing state take from a declining pie.

The following slide is an attempt to show how growing the pie by incentivizing investment is in the best interest of the state over the long term.



Maximizing State Revenue means maximizing Production

I'd like to draw your attention to the capital investments necessary in each scenario and an estimate of the total state revenue. **The highest state revenue is derived from the scenario which delivers the greatest production regardless of what severance tax (PPT) you collect.** You could collect zero severance tax (PPT) and this would be a better outcome for the State than one where you collect a high severance tax (PPT) and have less resource development.

The size of the pie is the most important consideration. **Maximizing the value of resources for Alaskans means maximizing state revenue by maximizing production. Resources left in the ground are simply a wasted opportunity.**

This should be the focus of our deliberations.

US Marginal Rates

The good news for Alaska is that there is a huge known resource base on the North Slope.

The bad news is that it going to be ***technically difficult*** to extract that resource out of the ground. Every barrel gets more difficult.

Alaska is already ***one of the most expensive places in the world to produce oil and gas***.

Assuming the new 20/20 PPT is put in place, Alaska would also become the area with the ***highest marginal tax rate*** in the US. Needless to say this introduces one more barrier to attracting investment. **The incorporation of yet higher tax rates at higher prices is yet another take from industry and creates a bizarre fiscal regime, being regressive at low prices and progressive at high prices, thus reducing space for industry and creating yet more barriers to attracting investment.**



Alaska will have the highest marginal tax rate

To maximize the value of the resources in the ground, the legislature should be focussed on maximizing North Slope production by attracting investment. The priority for the state of Alaska should be to encourage investments to help industry develop those known resources, not to make it more difficult and risky than it already is.

UK – a role model for attracting investment



"Ordinary measures of Government take throughout the 1990's made the United Kingdom government appear rather crazy and irresponsible. The "gross benefits" to the UK Government go way beyond direct tax revenues and royalties received from the upstream sector of the petroleum industry. **The economic impact of the industrial hyperactivity in the UK sector of the North Sea, a direct result of the "lenient" terms of the 1990's, is difficult to measure.** Furthermore, the activity in the UK started in the late 1980's and early 1990's when the UK Government dropped the ring fence for the 75% PRT before Government take, as it is ordinarily measured, was drastically reduced. **The UK offshore became the most active offshore province in the world. Reducing the Government take in the following years managed to sustain that boom.** Activity and employment in the British petroleum sector is healthy and mature."

Daniel Johnston

23 Oct 2002, Washington DC
Petroleum Tax Design

You have heard much over the recent weeks about the impacts of reducing taxes in the UK. The UKCS has been our backyard for many years and we couldn't agree more with Daniel Johnston that reducing taxes firstly created and subsequently sustained an economic boom. The UK's decision to reduce Government Take led to a significant increase in activity in the North Sea, more production, higher revenues for the Government and a ripple effect throughout the whole economy.

The actions of the UK during the 1980's and 1990's provide an excellent role model for any Government hoping to attract investment.

Let us please not forget the urgent need to turn decline and attract significantly more capital (about twice what is being spent today) to the North Slope.

In order to maximise the value of Alaska's resources we believe you should be adopting tax rates lower than those proposed by the Governor. In so doing you would maximize investment, maximize production and maximize jobs for Alaskans. You would also take an important step towards creating a healthy oil business which will be the foundation for gas.

We recognize the burden on your shoulders in making these decisions. There are many people advising you to increase taxes, which will indeed increase state revenue, but for how long? One year? Two years?.....but at what cost to future production?

The substantive changes you are considering making to House Bill 488 are yet more takes from industry over and above the Governor's bill and we cannot support them:

Our key objections to the proposed changes are:-

1. The proposed progressive tax system is inappropriate given Alaska's circumstances:
   a. challenged resource base
   b. high cost environment
   c. distance to market
   d. regressive nature of the rest of the fiscal regime
   e. urgent need to attract very large amounts of capital to stem decline

2. Almost every proposed change in this CS amounts to an increase in take on the industry from the previous proposal. These changes represent a significant increase in tax across the board and will not help attract the additional investment required to stem decline of the ANS.

3. The change in the effective date means this tax will be implemented before it is enacted by the legislature.

4. The transition provisions, included for good reason in the Governor's bill, have been significantly reduced making the implementation unfair on historic investors.

5. The penalty and interest proposed under note 11 are inappropriate.

6. At the time of writing this testimony, we have not yet seen the CS or which of AOGA's proposed changes have been adopted.

I would like to leave you with the key messages from this testimony.

Key Messages



- Production is declining
- To maximize State revenue we must increase investment to reduce decline
- Alaska will have the highest tax rate and the highest cost structure in the US
- The proposed amendments to HB 488 will not maximize the benefits to Alaskans from the State's resources (oil or gas)
- The UK is a great role model for reducing taxes to increase investment, production and revenue

We believe the proposed amendments to HB 488, if enacted, would be a serious mistake for Alaska and we urge you not to adopt them.

In any event, we will continue to participate fully in the legislative process and will be urging the legislature not to enact the substantive changes being considered by this Committee, but to enact instead a bill close in structure to the original Bill, but with tax levels lower than the 20% first proposed.

On behalf of BP I would like to thank you for this opportunity to testify.

TALISMAN
ENERGY

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Good afternoon co-Chairman Samuels and Ramras, Committee Members. My name is Tim England. I am Senior Manager, Global New Ventures for Talisman Energy Inc., which is the group in Talisman that searches for exploration opportunities internationally. I led the entry into Alaska for Talisman in 2003. With me today are my colleagues Rod Wade, General Manager, International Operations, and Jon Handforth, International Operations Commercial Analyst.

This afternoon I would like to provide you with a brief description of Talisman Energy, our current activity in Alaska, through our FEX L.P subsidiary, and the potential impact of changing the Alaska fiscal regime on our future investments in Alaska

Talisman is a Canadian independent company with production and exploration activity around the world. We have an enterprise value of US $23 billion, and have a capital investment program in the order of US $3 to 4 billion per year. We currently produce and/or explore in North America, the North Sea (UK and Norway), Malaysia, Vietnam, Indonesia, Australia, Trinidad, Peru, Colombia, Qatar, Algeria, Tunisia, Gabon and Romania.

We are a new player in Alaska. We entered in 2003 and have since invested over US $30 million in land and over US $100 million in drilling and seismic acquisition. The wells we are drilling in Alaska have cost in the order of $30 to 35 million each. Due to the remoteness of our exploration activity and other factors, a commercial discovery would take 5 to 10 years to put on production, that is, it would take a long time from initial investment to begin to recoup the investment. The front-end investment in exploration is risky and, or course, comes with no guarantees for returns.

Our decision to enter Alaska was based on the current fiscal regime continuing for the duration of our activity in Alaska. Talisman accepts the risks associated with commodity price volatility as well as the risks of rising and changing costs. But fiscal stability is important if we are to successfully manage these risks

The proposed fiscal changes will have several predictable impacts from the perspective of explorers in Alaska such as Talisman: first, many exploration ventures which were economic under the previous fiscal regime will no longer meet our economic hurdles for investment (even after taking the proposed incentives into consideration); second, investment proposals for Alaska will not be able to compete as effectively with investment proposals in other countries and jurisdictions; and third, bonus bids paid for

land will be reduced. Increasing the tax/royalty take after initial investments have been made does not bode well to promoting a stable environment for future commitments.

In summary, Talisman is a global oil and gas producer who has made a significant exploration investment in the last three years and has plans to invest heavily in the near-term. Alaska is a high-risk, high-cost exploration area. If Alaska taxes and royalties are increased, potential resources that would have been economic to explore for under the existing fiscal regime would have to be larger to attract investment dollars. In the exploration business one thing is sure: the chance of finding larger potential resources is much less than smaller potential resources. If Alaska taxes and royalties are increased, attracting investment dollars to Alaska in competition with other jurisdictions will be, simply put, more difficult. If Alaska taxes and royalties are increased, more oil will be left in the ground.

If increasing exploration activity in order to add production for the future benefit of the Alaska people is an objective of the Alaskan government, Talisman submits that the proposed increases in the tax and royalty structure will not serve this objective well.

In closing, Talisman would like to express our appreciation for the opportunity to address the House Resources Committee this afternoon.

March 15, 2006

Testimony before the House Resources Committee offered by:

J. Patrick Foley
Manager – Land & External Affairs
Pioneer Natural Resources Alaska, Inc.

Representative Ralph Samuels and other members of the House Resources Committee:

Thank you for the opportunity to share Pioneer's views regarding **HB 488**.

Pioneer is a relatively new investor in the State of Alaska and we appreciate the opportunity to participate in this process.

A member of this Committee wisely stated in previous hearings on this matter, that when considering changes to the existing tax system, the Legislature could shoot a little high or shoot a little low, this committee chooses to shoot a little low and leave a vibrant industry left to invest in the State. Pioneer believes that the Committee has missed the mark in the suggested changes to HB 488 that may likely appear in the Committee Substitute.

1. The proposed changes to the tax rate structure and the reduction in the value of the exemption do not create the same investor friendly climate that the administrations' original legislative proposal intended.

2. The progressive tax rate structure fails to take into account the fact that at higher oil prices the investors' costs increase dramatically. In 2005 Pioneer's costs to drill development wells in the lower 48 increased by 50%. Additional cost

increase will be experienced in 2006. The Industry's profit margin does not directly widen with price increase.

3. The 10 extension to the EIC program created by SB 185 is helpful, but in a rather limited way. The 40% credit rate that applies to certain investments translates to an effective credit of closer to 30% due to the exclusive of certain costs that are not eligible for the calculation of credits. A more effective tool to mitigate the effects of the high tax rate would be to increase the credit percentage rate under the PPT, which applies to both exploration as well as development.

4. The offer to buy annually up to $ 10 MM in credits from each company is helpful, but again, in only a modest way. This would help small explorers, but would not have big impact on those that develop the successful exploration results. Pioneer will spend roughly $100MM each year for the next two years at Oooguruk alone. 2008 and 2009 will likely see capital investment of roughly $50MM or more at Oooguruk. This development program, combined with a robust exploration program, will develop credits well in excess of the $10MM considered by the Committee's purchase proposal. Pioneer's excess credits must be sold into the market at an unknown discount. A standing offer to purchase all available credits at a fixed discount would better ensure Pioneer's ability to timely monetize its earned credits and enjoy more fully their intended benefit. Additionally, an expansion of the pool into which credits could be sold and utilized would be helpful. Specifically, we ask the Committee to consider a modification that would allow the credits to be used to offset any income taxes paid in the State of Alaska. This would expand the pool of potential buyers beyond the oil industry large producers.

5. If the bill must have a progressive tax rate structure and if oil price is used to benchmark rate changes, the price should

include an inflation adjustment to make the real dollar value derived from that price have equivalent purchasing power that exists today. We would also suggest that the trigger points be tied to an ANS West Coast price rather that WTI, to be consistent with proposed Sections 53.55.160(g) and (h) that relate to transitional capital.

Thank you for the opportunity to express Pioneer's views on the proposed changes to HB 488

TESTIMONY OF RICHARD OWEN

ON PROPOSED CSHB 488 TO THE HOUSE RESOURCES COMMITTEE

March 15, 2006

Mr. Chairman, Members of the Committee:

Good afternoon. My name is Richard Owen and I am the Production Manager for ExxonMobil in Alaska and Vice President of ExxonMobil Alaska Production.

I am here today to express ExxonMobil's concerns with the proposed Committee Substitute to HB 488. On February 28, I testified about our key concerns with HB 488 as originally proposed. While we have not yet seen the substitute bill, we have been made aware of the key changes being considered by this Committee. These changes exacerbate the concerns I described on February 28. Specifically, I will make comments on two areas: the proposal to change the tax rate; and the proposal around reduced transition provisions.

HB 488, as originally proposed, represented a dramatic tax increase on the industry. As I previously testified, we expressed concern that the higher tax rate included in the bill could prevent some of Alaska's challenged resources from being developed. We understand the Committee is now considering even higher tax rates.

Too high a tax rate discourages investment. Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for

upside potential through a variety of factors, such as increased production or higher prices. When you cap or limit the benefit that Companies can achieve from the upside factors, you reduce the attractiveness of those investment opportunities. The proposal to increase the already high base tax rate as prices increase does reduce or limit the upside potential and will result in Companies recalibrating investment decisions. Reduced investment will result in reduced resource recovery, diminished state revenues and fewer employment opportunities, with a resultant negative impact on the state's economy.

ExxonMobil is concerned with the significant change from the ELF based system to the PPT system and the need for sufficient transition provisions to mitigate the adverse impact on recent investments. We understand the Committee is considering reducing those transition provisions. While the benefits from a typical oil and gas investment take many years to be realized, the Administration's proposed five year transition into the higher tax PPT system represented a reasonable transition. The Committee Substitute's proposed transition provisions do not sufficiently address the significant increase in tax burden these past investments will now have to bear.

Despite our concerns with HB 488 as originally proposed, we are prepared to move forward under that system since it sought to provide a balance of revenues to the state and producers across a range of oil prices, provided sufficient incentive for producers to undertake exploration and development risks, and included reasonable transition provisions for past investments. And, most importantly for ExxonMobil, oil fiscal contract terms consistent with the Administration's proposal would provide the predictability and durability necessary to advance the gas project to the next phase.

It is important that the quality of the resources, the risks undertaken by a producer, and the impact on the state's overall investment climate be factored into the design of the tax system. While industry needs predictably and durability under which to gauge investment decisions, the attractiveness of that predictably and durability is lost if it comes at too high a cost.

As I mentioned earlier, the Committee's proposed substitute exacerbates our key concerns regarding both tax rates and transition provisions. We urge this Committee to support HB 488 as originally proposed.

Thank you again Mr. Chairman for the opportunity to testify today.

Testimony Regarding the Committee Substitute for HB 488,

a Petroleum Production Tax Bill

Brian Wenzel

ConocoPhillips Alaska

Before the

House Resources Committee

March 15, 2006

Co-Chairmen Samuels and Ramras, members of the committee:

Good afternoon. My name is Brian Wenzel, and I am the Vice President, Finance & Administration, for ConocoPhillips Alaska.

I would like to present ConocoPhillips' views on this committee's proposed changes to HB 488. Based on the *Substantive Changes* document

handed out yesterday at the meeting of this committee, the Committee Substitute (CS) you are working on is going to have a negative impact on the attractiveness of Alaska for ConocoPhillips' investment dollars. ConocoPhillips absolutely opposes this CS and any proposal that increases our industry's taxes beyond the $1 billion per year proposed by the Governor. The proposal before us today increases oil taxes by an annual average of $1.8 billion – if today's prices continue, this is $18 billion over the next 10 yrs. The approach reflected in this Committee Substitute is clearly to maximize short term State revenue while putting at risk long term production, State revenue, jobs for Alaskans and growth of the private sector. The CS you are considering destroys the balance in the original bill.

We realize you have come to this conclusion after listening to the advice of various consultants. If we understand your consultants' testimony, they are suggesting that you can jettison the balance of the original proposal and adopt an approach like that reflected in the CS with no adverse consequence on investment. Indeed, they suggest you will actually increase investment in the State by doing so.

We also have hired a number of consultants and will use their input as we lay out for the House and Senate Finance committees the same points we were unsuccessful in demonstrating to you. However, at the end of the day

neither your consultants nor ours must make or live with the decision currently before the Alaska State Legislature. Similarly, none of these consultants ever has, or ever will, make an investment decision on behalf of ConocoPhillips. To the extent your consultants are telling you that the CS you are considering will not have a negative effect on ConocoPhillips' investment decisions going forward, I can tell you they are 100% wrong.

Taking billions of dollars from our industry will have a negative impact on investment. Taking away a significant portion of the upside potential in a basin with lead times (from initial investment to first production) of a decade or more, in an area with low prospectivity and higher costs than almost anywhere in the world, will negatively affect investment – and consequently, production, state revenues and jobs. This is a natural consequence of a action you are taking.

Moreover, the negative effect on our decision-making, and on the decision-making of others, will not result just from the increased tax burden you are seeking to impose. There is also the question of our and others' confidence in the future investment climate in the State. Adverse changes in the key parameters of the originally proposed bill will result in a fundamental shift in the balance of risks and rewards for investments in Alaska. Unreasonable changes like those imbedded in the CS will cause not

only ConocoPhillips but also other investors to question *not whether, but when,* Alaska will again change its fiscal regime and impose unfair and unreasonable burdens on those who have taken great risks and invested billions to help develop the State's resources.

It is irrelevant whether that future change will be in the State's production tax, its property tax, its corporate income tax or in the creation of some entirely new tax. The point is that investors will now need to consider another significant risk in making their economic decisions in Alaska – the risk that Alaska will not approach future fiscal policy changes in a reasonable manner that recognizes the commitment and contribution of companies like ConocoPhillips.

As an example of the type of thinking that will negatively affect potential future investors' view of Alaska, ConocoPhillips received a letter this morning from Representative Gara and Senator French concerning our recent media ads. If you haven't already received a copy of the letter, I am happy to share it with you. This letter suggests that somehow private sector company profits are bad, that the State government has not shared in the benefit of higher oil prices, and that our commitment and long term investment in Alaska, one of the largest for our company anywhere in the world, is essentially irrelevant. We disagree with each of those suggestions.

The antipathy toward industry expressed in this letter is what concerns us most about the current debate on oil taxes - it has become for some an exercise in seeing how much the State can take from the private sector for no reason other than to simply take more.

Unfortunately, this CS seems structured to take more from the very industry participants that are most committed to Alaska's future.

According to the Substantive Changes document, you have changed nearly every key parameter in the original bill in a one-sided way that benefits the State and is at the expense of ConocoPhillips and the other major North Slope producers. You have destroyed the balance previously represented in the bill.

Through the CS, you propose to further increase the PPT tax rate on the industry via a surcharge at high prices – in effect a windfall profits tax. At current prices the additional surcharge will more than triple, the effective tax rate over the current system. This is essentially another $1B per year at today's prices on top of the average $1 billion already raised by the original proposal. This change is neither fair nor reasonable to current investors and will be viewed as unfair and unreasonable by potential future investors.

You have severely reduced the intended transition plan such that investors with large, recent capital investment projects (which haven't even begun producing yet) are penalized for apparently investing in Alaska *too early* and being *too optimistic* about the future of Alaska. I want to emphasize this point ...this CS penalizes the very companies that have been investing, creating jobs and building the resource base in the State.

You have extended the current statutory exploration tax credits available to explorers, but as one of the few companies who have actually applied for credits under the current statute, our experience is that, in fact, current regulation effectively reduces the value of these credits to 70% or less of their stated value. Further, these credits only affect about 4% of the DOR's expected future sources of production and investment in Alaska.

You have reduced by over 30% the effective value of the base allowance which is intended to encourage small explorers and new entrants.

You have moved the effective date of this bill back to a date that is completely impractical -- the necessary regulations, procedures and

computer systems can not possibly be adopted and put in place by April 1st of this year which means that production tax payers in Alaska will have to guess at their tax liability and make un-supported payments of tax in an uncertain attempt to avoid punitive interest costs.

And, you have suggested a punitive interest penalty rate of 5% on top of a statutory tax rate of 11%.

In our view, these changes from the original bill are completely inconsistent with the goals of a fair and reasonable fiscal policy, increased long-term investment in Alaska and a vibrant, secure Alaska oil industry. We urge you to reconsider the long-term impact of this bill on the future of the State Alaska. We urge you *not* to move this bill out of Committee until it can be re-crafted with a more balanced, long-term perspective.

Thank you for considering our views.

March 16, 2006, Written Comments To The House Resources Committee
Response To The Committee's List Of Changes Dated March 14, 2006
By Ken Thompson

Personal Background

For the record, my name is Ken Thompson. I reside in Anchorage, Alaska. I am the Managing Director of Alaska Venture Capital Group, or AVCG LLC, an independent oil exploration company with a focus on the North Slope of Alaska. AVCG is a consortium of 15 independent oil and gas companies and individuals from Kansas and me as an owner/investor from Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with offices in Anchorage. I am the former President of ARCO Alaska, Inc.

AVCG LLC has been very active in the past six North Slope (NS) areawide lease sales and we have acquired over 160,000 acres of exploration leases in five exploration prospect areas, including new acreage we acquired in the recent March 1, 2006, NS lease sale. Our exploration strategy is to explore in the central part of the North Slope for fields in the 25-100+ million barrels range, fields that may be too small for the giant producers but fields that can be produced profitably by smaller companies like ours. We believe there are hundreds of millions if not billions of barrels of oil left on the North Slope in smaller fields of this size and these fields near infrastructure can be brought on more quickly. Our first exploration well in partnership with Pioneer Natural Resources – the Cronus #1 – is currently drilling about 10 miles southwest of the large Kuparuk Field.

Let me focus my comments on the March 14, 2006, document written by the House Resources Committee listing 11 changes being considered after many hearings and debates.

AVCG Owners' Perspectives

First, let me say that while I am Managing Director of AVCG LLC, our other owners disagree strongly that any change should be made to the 20/20 PPT formula. The 20% PPT tax rate and the 20% credit originally presented in the Governor's bill should be the tax rate and credit enacted. The AVCG owners representing 15 new exploration investors in Alaska are concerned enough that the current system is being revised after they have made almost $10 million investment in North Slope leases and other costs and are planning a 3-year $46 million exploration program with our first well now drilling. Quite honestly, the AVCG owners listened in disbelief when I told them the production profits tax rate being considered by the House Resources Committee could escalate at high oil prices to 50% in addition to the 12.5-16.7% royalty, the ad valorem property tax, the 3-9% corporate income tax, the ongoing annual lease bid amounts and the rentals expenditures, and the Federal income tax rates averaging 20-35% of taxable income. It all adds up, and AVCG Owners are saying, "enough is enough."

My Personal Perspective

Now let me shift gears in my written comments to you. Because I could not get buy-in for any alternatives from the AVCG owners except the 20/20 case, I have decided to speak out alone. As an Alaskan, I am concerned and feel I must try to share a personal perspective trying to balance what is best for my continued involvement in spending my family's personal money for exploration on the North Slope in balance with how the State must change its system to be competitive in the world and realize more government share at high prices like so many other countries are doing.

I realize by stepping out like this, I could jeopardize my management status with AVCG and perhaps even jeopardize how I am viewed by the major oil companies and my friends in the independent company sector. But I have taken such personal risks in the past, and I don't mind doing so again today to simply do what I think is the right thing to do regardless of others' opinions. I often do not "run with the herd."

So, let me turn my attention to the March 14, 2006, document prepared by the House Resources Committee and let me share my perspective on the 11 suggested changes to the original HB 488. Again, my views are not supported by AVCG owners; rather they are my personal views.

1) Make Tax Rate Progressive

When the Governor's office first announced a 25% tax rate then amended that to 20%, I could see the move by legislators to somehow bridge the gap from 20% to 25%. However, the approach being currently considered by the House Resources Committee based on the outside consultants work of last week is simply too complex and will be arduous to implement. I think – and perhaps all of you think – the Federal tax code is too complex....the changes to HB488 are also too complex and will lead to different interpretation, "gamesmanship" possibly by some companies because of the unwieldy progressive tax structure formula, and future costly lawsuits when the State disagrees with a company's calculations. And the number of accountants to keep track of these complexities on both sides will balloon! I urge you to simplify, simplify simplify...yet still have some progression that you seem set on.

For my company which drills the smaller traps that may add up over time, we do not have a lot of upside potential in seeing these smaller fields grow much larger over time. So our main upside is in oil price escalation to offset exploration risks and to offset the cycles of oil prices downward, a reality over time for any commodity. I find it disturbing – and personally unfair – that the Committee has tax rates going as high as 50% at high prices. I found it so interesting to see the Econ1 consultants and consultant Daniel Johnston saying the government should take more and more at high prices when not one member of the Committee asked them a very important question they should have been asked: "how much are you investing in Alaska?" I was shocked to see that these consultants, when calculating the future revenues to

the State at various escalating rates, used the same oil production curves. In reality, less capital will be spent by industry at exorbitant tax rates (tax rates above 25% when coupled with all other payments such as royalty, corporate income tax, ad valorem tax, lease costs and rentals, etc.). With less capital spending, the production curve will be lower...an increasingly higher tax rate may not in the end yield the forecasted revenues for the State.

On a related note, our company plans to go into the private or public equity markets to raise funds and capital for any future development. Such equity investors invest in the oil markets to be exposed to crude price upside. When they look at investments all over the world, and see that Alaska could tax at a 50% rate at much higher crude prices, they will place their capital elsewhere to continue their exposure to higher crude in investments without alternative taxing structures such as the Lower 48 states, the Gulf of Mexico deep water with royalty relief, or other countries. The consultants did not address this issue that I face month in and month out...the private and public equity markets and the desire for such investors to fully benefit from upside commodity price swings without hedging or excessive, escalated taxation.

I could not believe the consultants did not show capital spending elasticity graphs from different countries. They did you a disservice by not doing so. Their work showed a biased perspective in my opinion; if they get the House Resources Committee to adopt a complex progressive tax rate structure the consultants will feel they have been successful...but not one of these consultants will be around to defend their views in the future when capital spending does decline at exorbitantly high and unfair tax rates above the 25% level.

Bottomline: there is a point of unfair taxation which causes rebellion as our early settlers in America experienced first hand!

My first suggestion to the progressive tax dilemma: the cap on the tax rate should be capped at the 25% level...continue to keep in mind added to this at high prices will be the 12.5-16.7% royalty, ad valorem taxes, corporate income taxes, Federal income taxes, etc.

Secondly, I do not think the "trigger point" that increases the PPT tax rate from 20% should be based on West Texas Intermediate (WTI) oil price. The "trigger point" should be when a company's average realized wellhead price in Alaska exceeds $50 per barrel. Some say lower, but I do think there is strong merit that those who have invested and taken exploration risk and exposure to low prices should be able to benefit from increased profits at higher prices..."share the pain, share the gain"...to this $50/barrel wellhead level. However, I personally am fine with the State increasing the tax rate eventually to a cap of 25% when wellhead prices exceed $50/ barrel. Having said this, you need to know that I do not know anyone else in industry who thinks this; everyone I know continues to press the 20/20 formula.

Why should you tie the PPT calculation to a company's realize wellhead price? In reality on the North Slope, not one company sees WTI prices. Every crude oil in Alaska is different in quality with viscous crude receiving less and oil produced from wells farther away from infrastructure receiving less wellhead value due to higher shipping costs. Conversely, oil in the Cook Inlet is close to actual refining or on the water to ship out of state and thus realizes on average much higher wellhead value than most North Slope crude oils, a substantial plus to Cook Inlet operators who face higher operating costs with maturing fields. Our company's crude when discovered on the North Slope will be farther west, and when we have to transport the oil via the major producers' gathering system lines to TAPS pump station #1, we will pay the majors a certain tariff of $0.50-1.00/barrel or more, giving us a lower wellhead value for our crude while they make a profit on shipping in their crude lines. The majors further make profits from tariffs for shipping down TAPS and in their marine tankers.

So I ask, why should the tax rate increase with WTI price when there is such a variance in crude oil pricing factors on the Slope at the wellhead affecting each field's economics and economic limit differently? The production profits tax rate should not go up at the same time for those who produce viscous crude or oil from a farther distance as compared to those who have good quality oil right next to the TAPS line. If there is a "trigger point", it should be one based on a company's average monthly realized wellhead price for production.

My second suggestion to the progressive tax dilemma: the "trigger point" should be $50 per barrel realized wellhead price based on a monthly average and not based on $50 WTI, thus allowing explorers and producers to share in the upside profits at prices to this level with no higher burden than the 20% PPT tax rate (plus burden of royalty, corporate income tax, ad valorem tax, Federal tax, etc.).

Thirdly on this issue, let me address a way to transition from the 20% tax rate to the 25% tax rate without getting too complicated. I found the formula suggested by the consultants with the incremental rate being calculated dollar by dollar and based on revenues, not profits, to be unfair. This wasn't a production profits tax change, but really – in a way – a change to increase the royalty rate on production, in my view. Bottomline: keep the production profits tax rate simply that...a tax on production profits. Having the PPT at higher prices being a mixture of taxation of profits and a separate incremental tax on incremental revenues is unwieldy and an accounting nightmare.

A third suggestion to the progressive tax dilemma: Keep the production profits tax simply that...a tax on production profits, and not an underhanded way to further burden gross revenues...that is done through the royalty rate on leases at lease sales.

Lastly let me address a simpler way of getting the progressive rate from 20% to 25% without the dollar to dollar treatment complexity and without the complexity of taxing

production profits while also incrementally and differentially taxing gross revenues one more time.

A fourth and final suggestion to the progressive tax dilemma to simplify, simplify, simplify is the following production profits tax schedule that everyone could understand and implement with the State realizing upside at higher prices yet not too much upside is taken away from explorers/producers:

Up to monthly average wellhead price of $50/barrel for a company:	**PPT rate of 20%**
When monthly average wellhead price is between $50-75/barrel:	**PPT rate of 22.5%**
When monthly average wellhead price exceeds $75/barrel:	**PPT rate of 25%**

By the way, if the State were to pass a complex, unwieldy production profits tax like that one proposed by last week's consultants and favored by some on the Resources Committee with escalating production profits tax rates of up to 50%, I predict Alaska will make the cover of the industry-wide influential magazine "The Oil and Gas Journal" and perhaps even a cover spot in the "Wall Street Journal." And I don't mean this media coverage in a positive way…I think all in industry will say the State is taking advantage of industry at high prices. Whether or not industry makes money or not and good, solid returns is not the issue with such extremes…the perceived fairness of taxation in a high cost, remote area like Alaska is the issue. Keep in mind that America's early settlers were still taking money home to their families…it was just the tax rate from England had crossed the point of fairness not from England's perspective but from the settlers' perspectives. And rebellion began!

Now, let me move the discussion forward to the second item on the list of 11 House Resources Committee changes.

2) <u>Reduce Transitional Money As Deductible Allowance</u>

I think this compromise to a four-year staged and tiered "look back" is fair. You are right…many investments made over 2001-2005 were based on oil prices of $20-40+/barrel and actual prices have been much higher with all companies – and the State - obtaining more cash flows than predicted when originally approved.

3) <u>Exploration enhancement</u>

Thank you very much for extending the SB 185 exploration tax credits for the next 10 years.

4) <u>No credit for abandonment costs</u>

I would prefer that abandonment costs would be eligible for tax credits; these costs are a cost of doing business and an essential part of a field development's

expenditures for the life of a field. Having such credits may expedite more timely abandonment of wells and facilities rather than wells and facilities being "mothballed" or simply shut-in for longer periods of time while operators postpone abandonment and delay expenditures that, in some cases, may indeed be needed sooner.

5) Private royalties

I believe overriding royalties should also just have the burden of a 5% tax rate. I understand that ASRC was a big driver in seeing this lower tax rate for "private royalties." While some ASRC royalties are indeed "private royalties" where they have owned subsurface lease rights and leased land out to explorers/developers keeping a straight royalty, I do believe that ASRC and a few other Alaska Native Corporations have acquired "overriding royalties" in production by virtue of demanding overriding royalties in subsurface oil production in exchange for granting use of their surface rights and surface access. I think it would be fair to them – and to any company owning overriding royalties – that the tax rate is only 5%.

Commonly, even an overriding royalty owner that has "farmed out" their leases to others to drill due to high perceived risk would be taxed at 20% and not be able to receive the benefits of investment capital credits even though they may have made substantial investments in lease bonuses, lease rentals and seismic before they converted their working interest to an overriding royalty interest. A lower rate of 5% even for overriding royalties would be appropriate.

6) AOGA Technical Changes

I have not reviewed the AOGA technical changes, so could not address those.

7) Contingency Surcharges

Surcharges are just one more example that government take in Alaska is comprised of many different components – royalty, corporate income tax, ad valorem tax, lease bonuses, lease rental payments, etc. – emphasizing that the production tax is not the sole source of revenue to the State off oil production.

8) Effective Date

The State has made far more money at high prices than anyone ever dreamed. The State had, in a way, received a rich windfall at high oil prices. The change in the production profits tax is controversial in its own right. I would not dare "pour salt in the wound" by making the tax effective on April 1, 2006, but allow the transition as originally planned to a July 1, 2006, date. This will also give all of us time to hire additional accountants to do the monthly, complex filings!

9) Issues Surrounding The $73 Million Allowance

I would prefer the $73,000,000 annual allowance, but accept the $50,000,000 annual allowance as a reasonable compromise...provided the above amended PPT tax rate schedule listed above with a trigger point at $50 wellhead price and capped at 25% is concurrently amended.

I do think it is wise to convert this for communication purposes to the public as a $10 million credit. I also remain supportive of expressing this as a 5,000 barrels of oil per day allowance if you have to go that way for buyin in the Legislature and with the public.

10) Tax Credit Repurchase Program

Thank you for this approach. Our company would be willing to return these funds to purchase leases, run seismic and drill wells to find us both some more oil!

11) Penalties On Underpayment Of Less Than 90% Of Monthly Tax Liability

This is understandable and helps enforcement. But this is yet another reason to keep the original implementation date at July 1, 2006, to help all in industry get ready for the increased accounting workload and avoid wrong filings of this new system.

Concluding Remarks

The above comments are my personal views offered with a hope there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices. Many – if not most – in industry would disagree with some – if not all – my personal views expressed above. But I did feel compelled at this point to "tell it like it is" from my perspective.

Respectfully submitted by:

Ken Thompson

Passed

1

24-GH2052\Y.4
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 21, lines 3 - 4:

Delete "any payment or credit"

Insert "certain payments or credits received by the producer, as provided in this subsection. If, during a month or, under (f) of this section, during a calendar year, a producer receives one or more payments or credits subject to this subsection and if either the total amount of the payments or credits exceeds the amount of the producer's lease expenditures or the producer does not have any lease expenditures, the producer shall nevertheless subtract the payments or credits from the lease expenditures or from zero, respectively, and the producer's adjusted lease expenditures for that month or calendar year are a negative number. The producer shall apply that negative number to the calculation made under (a) of this section. The payments or credits that a producer must subtract from the producer's lease expenditures, or from zero, under this subsection are payments or credits that"

Passed #2

24-GH2052\Y.5
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 24, lines 3 - 4:

Delete "may apply a tax credit against that liability under this section."

Insert "and, during the calendar year, has incurred a qualified capital expenditure, as that term is defined in AS 43.55.024, may apply a tax credit, in an amount that does not exceed the amount of that expenditure, against that liability under this section. An unused portion of a tax credit may be applied to the extent otherwise allowed under this section for one or more months during the same calendar year."

Page 24, lines 6 - 7:

Delete "before applications for any credits under this chapter"

Insert "for any month"

Page 24, line 23, following "qualified":

Insert "capital"

#3

passed

24-GH2052\Y.6
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 29, line 31, following "REGULATIONS":

Delete "."

Insert "AND RETROACTIVITY OF REGULATIONS. (a)"

Page 30, following line 3:

Insert a new subsection to read:

"(b) Notwithstanding any contrary provision of AS 44.62.240, a regulation adopted by the Department of Revenue to implement, interpret, make specific, or otherwise carry out the provisions of secs. 5, 6, 8 - 11, 13 - 15, 17 - 20, 22, and 25 - 41 of this Act may apply retroactively as of April 1, 2006, if the Department of Revenue expressly designates in the regulation that the regulation applies retroactively to that date."

passed

4

24-GH2052\Y.7
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 29, lines 5 - 6:

Delete "the sections of this Act that are not effective April 1, 2006"

Insert "secs. 8 and 13 of this Act"

Page 29, lines 14 - 15:

Delete "the sections of this Act that are not effective April 1, 2006"

Insert "secs. 5 and 6 of this Act"

Page 29, line 17, following "Act,":

Insert "or AS 43.55.030(e), added by sec. 22 of this Act,"

Page 29, lines 18 - 19:

Delete "the sections of this Act that are not effective April 1, 2006"

Insert "secs. 20 and 22 of this Act"

passed # 7

24-GH2052\Y.9
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488(RES), Draft Version "Y"

Page 4, line 9, following "for":

Insert "all"

Page 5, line 31:

Delete "**AS 43.55.011**"

Insert "**AS 43.55.011(a)**"

Page 30, line 22:

Delete "24,"

passed

5

3-16-06

AMENDMENT

OFFERED IN THE HOUSE
TO: CSHB 488 (RES)

BY REPRESENTATIVE OLSON

Page 4, line 9:
delete "or gas" "and gas"

Page 4, line 10
delete "and gas"

Page 4, line 12
delete "and gas"

failed #6

24-GH2052\F.1
Chenoweth
3/15/06

AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE KAPSNER

TO: CSHB 488(RES)

Page 9, line 24:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 16, lines 2 - 3:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 18, line 15:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 18, lines 26 - 27:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 18, line 28:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 18, line 29:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 19, line 1:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 19, line 2:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 19, line 8:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 21, line 23:
Delete "March 31, 2016"
Insert "December 31, 2015"

Page 25, line 1:
Delete "April 1, 2006"
Insert "January 1, 2006"

Page 25, lines 6 - 24:
Delete all material and insert:

"TRANSITIONAL PROVISIONS. (a) For oil and gas produced before January 1, 2006, the provisions of AS 43.55, and regulations adopted under AS 43.55, that were in effect before January 1, 2006, and that were applicable to the oil and gas continue to apply to that oil and gas.

(b) Notwithstanding any provision in this Act to the contrary,

(1) a report and payment of production tax on oil and gas due under AS 43.55, as enacted by this Act, for any period before the effective date of this Act is due on the last day of the month following the month in which the effective date of this Act occurs; and

(2) penalty provisions of AS 43.55.020(h), added by sec. 13 of this Act, and of AS 43.55.030(d), amended by sec. 17 of this Act, apply to taxes that are due and unpaid and reports that are not filed by the date described in (1) of this subsection."

Page 26, lines 13 - 20:

Delete all material and insert:

"* **Sec. 42.** The uncodified law of the State of Alaska is amended by adding a new section to read:

RETROACTIVITY. Sections 5, 6, 8 - 11, 13, 14, 16 - 18, and 22 - 37 are retroactive to January 1, 2006, and apply to oil and gas produced on and after that date.

* **Sec. 43.** This Act takes effect immediately under AS 01.10.070(c)."

passed # 8

3-16-06

CONCEPTUAL AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE KAPSNER

TO: CSHB 488 (RES), Version Y

Delete sections relating to transitional investment expenditures.

held for 3-17-06 # 9

3-16-06

AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE KAPSNER

TO: CSHB 488 (RES), Version Y

Delete Sec. 27, page 16, line 23 through page 17, line 17.

3-17-06

	Y	N
FAILED	2	6

failed

10

3-16-06

AMENDMENT

OFFERED IN THE HOUSE
TO: CSHB 488 (RES)

BY REPRESENTATIVE
KAPSNER

Page 31, line 1

Add the following :

"Sec. 49. AS 43.55 is amended to read:

Sec.43.55.400. High energy cost offset fund.

(a) The high energy cost offset fund is established as a separate fund in the general fund. The fund consists of all money appropriated to it.

(b) The high energy cost offset fund shall be invested by the Department of Revenue so as to yield competitive market rates, as provided in AS 37.10.071. Money in the fund may be appropriated to provide cost offsets for high energy costs of consumers.

(c) Nothing in this section creates a dedication of funds

held for 3-17-06 to be restructured

#11 / 11-A

BY REP CRAWFORD

3-16-06

WITHDRAWN

CONCEPTUAL AMENDMENT

OFFERED IN THE HOUSE

TO: CSHB 488 (RES) Draft Version Y

This amendment would prevent a deduction from taxable income for the clean-up of oil spills, as in existing law Sec. 43.55.150 (c)(1) on the severance tax.

The existing language reads "the amount of loss of or damage to, or of expense incurred due to the loss of or damage to, a vessel used to transport oil if the loss, damage, or expense is incurred in connection with a catastrophic oil discharge from the vessel into the marine or inland waters of the state".

In addition, unless prohibited elsewhere in this bill, a provision should be added preventing a taxpayer from deducting the cost of any oil-spill related damage or penalty payments to a governmental or private party.

THE
FOLLOWING
DOCUMENT(S)
ARE
POOR
ORIGINAL
COPIES

Sec. 43.55.110. Administration. (a) The department may adopt regulations for the purpose of making and filing reports required by this chapter and otherwise necessary to the enforcement of this chapter.

(b) The department may require a sufficient bond from every person charged with the making and filing of reports and the payment of the tax. The bond shall run to the state and shall be conditioned upon the making and filing of reports as required by law, upon compliance with the regulations of the department, and for the prompt payment, by the principal on the bond, of all taxes due the state by virtue of this chapter.

(c) If reports required have not been filed, or are insufficient to furnish the information required by the department, the department shall institute, in the name of the state upon direction of the department, the necessary action or proceedings to enjoin the person from continuing operations until the reports are filed.

(d) Upon showing that the state is in danger of losing its claims or the property is being mismanaged, dissipated or concealed, a receiver shall be appointed at the suit of the state. (§ 13 ch 7 ESLA 1955)

Secs. 43.55.120 — 43.55.130. Noncompliance and false reports. [Repealed, § 46 ch 113 SLA 1980. For criminal penalties, see AS 43.05.290.]

Sec. 43.55.135. Measurement. For the purposes of AS 43.55.011 — 43.55.150, oil shall be measured in terms of a "barrel of oil" and gas shall be measured in terms of a "cubic foot of gas." (§ 16 ch 101 SLA 1972)

Revisor's notes. — A reference to "AS 43.55.011 — 43.55.150" was substituted for "this chapter" in this section in 1989 to reflect the enactment of AS 43.55.200 — 43.55.240.

Sec. 43.55.140. [Renumbered as AS 43.55.900.]

Sec. 43.55.150. Determination of gross value. (a) For the purposes of AS 43.55.011 — 43.55.150, the gross value shall be calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation shall be the actual costs, except

(1) when the parties to the transportation of oil or gas are affiliated;

(2) when the contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation;

(3) when the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

(b) If the department finds that the conditions in (a)(1), (2), and (3) of this section are present, the department shall determine the reasonable costs of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods. Transportation costs fixed by tariff rates properly on file with the Regulatory Commission of Alaska or other regulatory agency shall be considered prima facie reasonable.

(c) In determining the gross value of oil under (a) of this section, the department may not allow as reasonable costs of transportation

(1) the amount of loss of or damage to, or of expense incurred due to the loss of or damage to, a vessel used to transport oil if the loss, damage, or expense is incurred in connection with a catastrophic oil discharge from the vessel into the marine or inland waters of the state;

(2) the incremental costs of transportation of the oil that are attributable to temporary use of or chartered or substituted service provided by another vessel due to the loss of or damage to a vessel regularly used to transport oil and that are incurred in connection with a catastrophic oil discharge into the marine or inland waters of the state; and

Prevent Deduction For Cleanup

failed

#12

24-GH2052\Y.8
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE SEATON

TO: CSHB 488(RES), Draft Version "Y"

Page 4, line 16:

Delete "50"

Insert "45"

Page 4, line 18:

Delete "$50"

Insert "$45"

Page 4, line 19:

Delete "$150"

Insert "$145"

held for 3-17-06

AF 13

KAPSNER

Conceptual Amendment

OFFERED IN THE HOUSE

TO: CSHB 488 (RES), Draft Version "Y"

This amendment would substitute the progressive 20% income tax with a 25% income tax which increases at the same rate and at the same price points as provided in the current version of HB 488.

3-17-06

WITHDRAWN

H·RES 3-16-06 #13

Consultant Statements On An Appropriate PPT Tax Rate

p.2

Daniel Johnston, Legislative Consultant:
(Joint House Resources / House Finance Committee – March 6, 2006)
(Quoted in the Anchorage Daily News – March 7, 2006):

> "I am just not happy with 20/20. 25/20 is a starting point, and then it's got to be progressive from there."

Barry Pulliam, EconOne Consultant
(House Resources Committee – March 13, 2006):

> "Our view, we sat down with the administration folks who came up with the PPT, Dr. Van Meurs, and considered those very questions when he was first submitting his recommendations. And in our view certainly the 20/20 was very safe. Very safe. The 25/20 we even thought was safe."

> "But you don't want to lose a lot of interest and as, as economists who have worked with forecasting, and looking at decision-making, I think our view would also be you don't want to be in a position where you're... you've calculated that you've taken every last penny of what's available. You want to leave something... ***you want to make it attractive. You want to leave enough to make it attractive. Keep people real interested. We don't think the 25/20 goes beyond that at all, and then with some increment above that, we think it still stays real attractive.*** Now, in thinking about the sliding scale. What would you do? I think our view in general would be if you're thinking about starting it lower, have a lower increment. If you're thinking about starting it higher, have a higher increment. I think that's probably... just as a general thing. Otherwise, if you start real low and have a real high increment, you go pretty steep. So, that would be our...
>
> **Rep. Samuels**: Representative Gatto.
>
> ....
>
> **Rep. Seaton:** Thank you. And, so just to be clear, within these scenarios, are there any of them that you've projected here that you think are, from your standpoint, in your analysis, that would be detrimental to investment in the industry here in Alaska?
>
> ***Barry Pulliam:*** No. Looking at these, ***I don't see any that would be, that would fall into the detrimental area.*** I put, as I look at this, I try to put these into a historical context – look at what the rates have been at given price levels. And as you look at those, even as you look at the highest one of these that you'd have, which would be the 35 threshold with a .35% increment, you see as you... you know, when you're at 40 dollar prices there your tax rate is only 11.4%. That's at a higher price level, that's a lower percentage than your historical average. You start to ratchet up beyond there, but you have some pretty high prices that those are associated with. So, there might be a little bit of stuff around the margin that would look at that and say that's not of interest. I don't think for the majority of what you have that would be the case. But, I can see reasons why you wouldn't do that either. You might have a more cautious approach."

Dr. Tony Finizza, EconOne Consultant
(House Resources Committee March 13, 2006):

"And, to illustrate this question that was raised earlier about is ***25/20, could it look better for a producer, and in a funny kind of way it does***. I'm saying... lets... no one's going to drill a one well program, but just say you did, and it was 20 million dollars - and that's the number I'm actually going to use for a well, 20 million – it's pretty expensive, but this is an expensive state and they're low product wells, etc. and eventually we have the high cost assumptions to make. If you did this well exploration – 20 million dollars – with a pattern I put in here under a status quo your negative cash flow would be roughly 20 million dollars. There's inflation in there that makes it higher, and then there's some tax sheltering that goes on. In the other cases, the PPT, you get to deduct capital as a credit, etc. and sell it and all that stuff. So naturally in actuality the producer or the explorer has less cash flow. Negative cash flow. And by this calculation, ***marginally better off with 25/20 than 20/20***."

Rep. Gara: Just a follow up so I'm clearer in your answer to Representative Berkowitz. He asked you, you said at 25/20, you might be, that might be the point where you start maximizing revenues before you start hitting diminishing returns. Is that, did I understand that fairly?

Dr. Finizza: I said that I had a gut reaction that that was a point of diminishing returns, and that's... for an exploration, yup. I wouldn't think that you would have to go further than that to encourage or, you wouldn't, and then take a greater risk yourself.

Rep. Gara: Am I wrong in assuming... If I'm looking for the point where's you've started to maximize your long term state revenue but before you start losing money because you're taxing too much – that's your gut reaction on 25/20 or am I missing...?

Dr. Finizza: That's my gut reaction, yeah.

Dr. Pedro Van Meurs, Consultant
(House Resources Committee – February 23, 2006):

"The 25/20 and the 20/20 both are very competitive systems, that you could see from the investment. If I say competitive, it means that both systems would be considered quite attractive by investors."

"Whether you start the tax on January 1 or July 1 really has no impact on the competitiveness of the system. Because new investors would look at new investments and would not even have to pay tax for now, for awhile. So consequently whether you have a July or January start day, that would not have impact on new investors. So would be equally, say, attractive either way. The only difference between the January 1 and the July 1 start date is that of course it has enormous impact on existing production. So as far as existing production, you would have 6 months more of revenues if you moved the date back to January 1st of this year."

adopted

14

24-GH2052\Y.12
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE SEATON

TO: CSHB 488(RES), Draft Version "Y"

Page 18, line 31, through page 19, line 1:

Delete "April 1, 2006"

Insert "January 1, 2006"

Page 28, line 10, following "TRANSITIONAL PROVISIONS.":

Insert "(a) Notwithstanding any contrary provision of AS 43.55.024(a), enacted by sec. 14 of this Act, a producer or explorer may apply for a credit under AS 43.55.024 based on a qualified capital expenditure incurred on or after January 1, 2006."

Reletter the following subsections accordingly.

Page 29, line 21:

Delete "(f)(1)"

Insert "(g)(1)"

Page 29, line 23:

Delete "(f)(2)"

Insert "(g)(2)"

Page 29, line 25:

Delete "(f)(1)"

Insert "(g)(1)"

Page 29, line 26:

Delete "(g)(1)"

Insert "(h)(1)"

Page 30, following line 16:

Insert a new bill section to read:

"* **Sec. 46.** The uncodified law of the State of Alaska is amended by adding a new section to read:

RETROACTIVITY OF CERTAIN EXPENDITURES USED TO SUPPORT PRODUCTION TAX CREDIT CLAIM AND DETERMINATION OF PRODUCTION TAX VALUE OF OIL AND GAS. AS 43.55.160(c)(1), enacted by sec. 28 of this Act, applies to allow a producer to claim as lease expenditures certain expenditures incurred on or after January 1, 2006, and before the effective date of AS 43.55.160, added by sec. 28 of this Act, and sec. 43(a) of this Act applies to authorize a producer or explorer to apply for a credit under AS 43.55.024, enacted by sec. 14 of this Act, based on a qualified capital expenditure incurred on or after January 1, 2006, and before the effective date of AS 43.55.024, enacted by sec. 14 of this Act. To the extent these provisions give legal effect to prior conduct, they are retroactive to January 1, 2006."

Renumber the following bill sections accordingly.

Page 30, line 19:

Delete "sec. 48"

Insert "sec. 49"

Page 30, line 22:

Delete "46"

Insert "47"

Page 30, line 24:

Delete "sec. 47"

1 Insert "sec. 48"

15

adopted

24-GH2052\Y.13
Chenoweth
3/17/06

conceptual **AMENDMENT**

OFFERED IN THE HOUSE BY REPRESENTATIVE SEATON

TO: CSHB 488(RES), Draft Version "Y"

Page 4, line 8:

Delete "(g) of"

Page 4, lines 13 - 19:

Delete all material.

Insert "index as determined under this subsection. The oil price index for a month is the number equal to the average United States Gulf Coast price determined under (h) of this section for that month of West Texas Intermediate crude oil in dollars per barrel, less 50. If the average price determined under (h) of this section is not more than $50 per barrel, the oil price index is zero.

(g) Notwithstanding calculation of the rate of tax under (f) of this section, if the average price determined under (h) of this section is at least $110 per barrel, the rate of tax under (f) of this section is 37.5 percent."

failed

16

24-GH2052\Y.14
Chenoweth
3/17/06

AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE CRAWFORD

TO: CSHB 488(RES), Draft Version "Y"

Page 4, following line 31:

Insert a new subsection to read:

"(i) Notwithstanding any other provision of this chapter, except as to oil or gas described in (e) of this section, tax credits that are authorized against the tax due under this section by this title, AS 38.05.180, and AS 41.09 may not be applied to reduce the producer's total tax due under this section on oil and gas produced during a calendar year to less than six percent of the production tax value of the taxable oil and gas produced by the producer from all leases or properties in the state, based on the gross value of the oil and gas at the point of production and determined without reference to adjustments authorized by AS 43.55.160. In making the determination required by this subsection, the department shall exclude oil and gas produced, the ownership or right to which is exempt from taxation."

wants minimum floor - 6%

Y

N

failed

17

CONCEPTUAL AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE CRAWFORD

TO: CSHB 488 (RES), Version Y

Delete inclusion of gas in the new production tax; retain current tax on gas.

4 / 11

2 / 11

adopted

#18 (relates to 11-A)

24-GH2052\Y.10
Chenoweth
3/16/06

AMENDMENT

OFFERED IN THE HOUSE BY REPRESENTATIVE CRAWFORD

TO: CSHB 488(RES), Draft Version "Y"

Page 19, line 7, following "AS 38.05.132":

Insert ", and do not include, in connection with a catastrophic oil discharge into the marine or inland water of the state, the containment and clean up expenses incurred by the producer, the incremental expenses of transportation of oil due to loss or damage incurred by the producer, and any damages or penalties imposed on the producer"

adopted # 19

24G-2
3/17/2006
(12:05 P.M.)

AMENDMENT

OFFERED IN THE HOUSE RESOURCES COMMITTEE BY RAMRAS

TO: CSHB 488(RES) (24-GH2052\Y) (3/15/06 Work Draft: Chenoweth)

Page 4, following line 31:

Insert the following material:

"(i) In addition to the taxes levied under (a), (e), and (f) of this section, for each month for which the gas price index determined under (j) of this section is greater than zero, there is levied upon the producer of gas a tax for all gas produced during that month from each lease or property in the state, less any gas the ownership or right to which is exempt from taxation. The tax is equal to two percent of the gross value at the point of production of the gas multiplied by the gas price index as determined under (j) of this section.

(j) The gas price index for a month is the number equal to the average Henry Hub gas price determined under (k) of this section for that month in dollars per million British thermal units, less eight, except that if the average price determined under (k) of this section is

(1) not more than $8 per million British thermal units, the gas price index is zero; and

(2) more than $23 per million British thermal units, the gas price index is 15.

(k) For purposes of (i) and (j) of this section, the department may calculate the average price or may, by regulation, specify the method by which the average price shall be calculated with reference to one or more published sources of price information. If, in the department's judgment, reliable published sources of Henry Hub gas price

information ceases, or appear likely to soon cease, to be available, or if, in the department's judgment, the Henry Hub gas price ceases, or appears likely to soon cease, to be a reliable indicator of the general price level of gas, the department shall, by regulation, specify a substitute formula for computing the gas price index. The substitute formula specified by the department under this subsection must bear, as nearly as is reasonably possible, the same relationship to the general price level of gas as did the Henry Hub gas price."

Page 6, line 26:

Delete "and (f)"

Insert ", (f), and (i)"

Page 6, line 31:

Delete "and (f)"

Insert "(f), and (i)"

Page 17, line 24, following "AS 43.55.011(f)":

Insert "and (i)"

Page 29, line 12:

Delete "and (f)"

Insert ", (f), and (i)"

H. RES
3-17-06

accompanies # 19

Gas progressive formula

Same concept as oil

(Henry Hub − 8) × 2%

MIN = 0%

MAX = 30% at HH of

Petrojam Heats - $23/MMBTu

H.RGS
3-17-06

#21

by Seaton

Conceptual
Amendment # 21
(To Amend #19) Adopted 3/17/06

Page 1 line 16
delete 23
Insert 18

adopted

Page 1 line 17
delete 15
Insert 18.75

adopted

20

24G-2
3/17/2006
(11:58 A.M.)

AMENDMENT

OFFERED IN THE HOUSE RESOURCES COMMITTEE

BY RAMRAS

TO: CSHB 488(RES) (24-GH2052\Y) (3/15/06 Work Draft: Chenoweth)

Page 24, line 9:
Delete "$10,000,000"
Insert "$12,000,000"

Page 24, line 10:
Delete "$2,500,000"
Insert "$3,000,000"

Page 28, line 28:
Delete ""$10,000,000""
Insert ""$12,000,000""

Page 28, line 29:
Delete ""$7,500,000"
Insert ""$9,000,000""

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

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State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM March 24, 2006

SUBJECT: CSHB 488(RES) -- sectional analysis
(Work Order No. 24-GH2052\L)

TO: Representative Jay Ramras
Representative Ralph Samuels
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

The House Resources Committee Substitute proposes to repeal the state's current oil and gas properties production tax and replace it with a production tax on oil and gas. The replacement tax is to be based on a percentage of the production tax value of oil and gas, the determination of which is prescribed by the bill. The measure makes a number of related and conforming additions and changes.

The measure is an administration-sponsored bill, so in the preparation of this memo, for provisions not substantively altered by the Resources Committee, I have drawn on the explanatory language of the administration's February 21 sectional analysis of the bill as introduced.

PROVISIONS IMPOSING A PRODUCTION TAX ON THE NET VALUE OF OIL AND GAS:

Provisions imposing the tax and setting the basic tax rate(s) --

Bill section 5: The bill section enacts (as a repeal and reenactment of AS 43.55.011(a) levying a tax on a percentage of the gross value at the point of production) the tax levy as a production tax on both oil and gas, with exceptions and limitations noted in the provision's text, and sets the rate of levy at 20 percent of the production tax value of the taxable oil and gas.

Bill section 6: As part of this bill section, a new subsection, AS 43.55.011(e), is added to authorize a levy and set a rate of levy on oil and gas produced that constitutes a lessor's royalty interest under an oil and gas lease. The rate specifies a rate of five percent of the gross value at the point of production. It also sets out an alternative rate of 20 percent of the gross value that applies under circumstances in which there is evidence the producer's receipt of consideration from the lessor offsets the producer's royalty obligation.

Provisions authorizing a progressively higher tax rate for oil when the price exceeds $50 per barrel --

As part of **bill section 6**, proposed AS 43.55.011(f) sets out an oil price index by which the tax levy on oil is adjusted by an addition .3 percent of gross value per dollar in excess of $50, based on Gulf Coast prices for West Texas Intermediate crude. Subsection (g) caps the index increase when the average price reaches $110 per barrel. Subsection (h) sets out the manner in which the index may be calculated and authorizes use of a substitute formula under circumstances specified in the subsection.

Provisions authorizing a progressively higher tax rate for gas when the price of gas exceeds $8 per million BTUs --

Again, as part of **bill section 6**, proposed AS 43.55.011(i) sets out a natural gas price index by which the tax levy on gas is adjusted by 2 percent of gross value when the average Henry Hub price exceeds $8 per million BTUs. Subsection (j) caps the index increase at 18.75 and subsection (k) spells out the manner in which the index may be calculated and authorizes use of a substitute formula under circumstances specified in the subsection.

Provisions relating to the determination of the production tax value of oil and gas --

The oil and gas production tax levy is imposed as a percentage of the production tax value of the taxable oil and gas. Calculation of the production tax value is set out in AS 43.55.160, added by **bill section 28**:

-- Under AS 43.55.160(a), the calculation begins with the determination of the gross value at the point of production of all of a producer's taxable oil and gas statewide. The producer may deduct taxes paid that are attributable to application of the indexed production tax rate increases as well as the deductible costs of oil and gas exploration, development, and production (adjusted deductible lease expenses). Subsection (a) contains language that precludes net value calculation from falling below zero.

-- Subsection (b) sets out rules for the producer's claim and use of unused deductions.

-- Subsection (c) spells out the exploration, development, and production costs that qualify as deductible lease expenses ("total costs upstream of the point of production . . . incurred on or after January 1, 2006, . . . and that are direct, ordinary, and necessary costs for exploring for, developing, or producing oil or gas deposit"), and provides guidance to the department as to evidence of those costs, especially in situations involving activities occurring under operating agreements.

-- Subsection (d) spells out allowable direct costs and costs that may not be deductible because they are not direct costs.

-- The mechanics of making adjustments to a producer's lease expenditures are addressed in subsection (e). Adjustments are required to account for reimbursements, assets sales, and other producer receipts.

-- Subsection (f) authorizes substitution of determination of adjusted lease expenditures on a monthly basis, at the election of the producer.

--The provisions of subsections (g) - (i) spell out additional authority of the department with respect to tax administration, while subsection (j) supplies definitions of terms used.

Tax credit provisions --

The measure contains two separate sections authorizing tax credits.

Bill section 14 adds a new section, AS 43.55.024, that sets out tax credits for certain expenditures and losses. In the section,

-- Subsection (a) authorizes a tax credit of 20 percent of "qualified capital expenditures"--the term is defined in subsection (j)--against the production tax on the net value of taxable oil, bars claim of the tax if the same expenditures are used to claim a credit under AS 43.55.025 (existing tax credit for oil and gas exploration or gas only exploration), and authorizes claim and application of the credit on a monthly basis if, under AS 43.55.160(f), the producer has elected to substitute determination of adjusted lease expenditures on a monthly basis.

-- Subsection (b) authorizes election of a 20 percent tax credit on the basis of carried forward annual losses, defined in the subsection as "the producer's . . . adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b)."

-- Subsection (c) precludes a tax credit from reducing the producer's tax liability below zero but authorizes application of the unused portion of the credit in a later month.

-- Subsections (d) and (e) establish a system by which tax credits for expenditures and losses as authorized by the section may be transferred through transferable tax credit certificates. Subsection (f) authorizes the department to repurchase credit certificates and, subject to appropriation, make cash refunds, but repurchase and refunds must comply with the requirements spelled out in paragraphs (1) - (5).

-- Subsections (g) and (h) spell out the authority of the department with respect to the administration of transferable tax credit certificates.

-- Subsection (i) bars a producer from making a claim of a tax credit for expenditures to acquire and use certain assets or for costs associated with abandonment.

AS 43.55.170, enacted as part of **bill section 28**, sets out a second or additional tax credit. The section allows the producer to claim a credit for qualified capital expenditures (as that term is defined in AS 43.55.024). The credit may not be applied to reduce the producer's tax liability to less than zero. Unused portions of the credit may be carried forward from month-to-month within a calendar year, may not exceed a total of $12,000,000 for a calendar year, and may not be carried forward into a following calendar year. These credits are not transferable and not refundable. The authorization for these additional credits expires March 31, 2016.

Provisions relating to tax payment and the administration of the tax --

Bill section 8: The bill section enacts (as a repeal and reenactment of AS 43.55.020(a)) a requirement of monthly payment of the net value production tax on oil, with payment due at the end of the calendar month for production during the preceding month. The provision spells out conditions when a tax due is delinquent, the handling of overpayments, and limitations on interest that may be payable on tax overpayments.

Bill section 10, amending AS 43.55.020(d), deals with a producer's right to charge a private royalty owner for the share of production taxes attributable to royalty oil and gas. The amending language adds a method of determining the royalty share of taxes in the absence of an agreement between the producer and royalty owner to use a different method.

Bill section 11 expands the current production tax exemption for gas that is used in lease operations by including oil that is used in those lease operations. The section also clarifies the manner of tax treatment of flared gas, based on authorization to do so from the Alaska Oil and Gas Conservation Commission.

Bill sections 1 and 12: The latter provision amends AS 43.55.020(f) allowing the Department of Revenue to require production tax to be paid on the basis of prevailing value. It clarifies that the provision applies not only when the sale price differs from the prevailing value but also when the oil or gas on which tax is due is not sold at all. The former sets out a statement of intent for the amendment made to the permanent law provision.

Bill section 13: As is done earlier in the bill with respect to oil, proposed AS 43.55.020(g) enacts a requirement of monthly payment of the net value production tax on amounts due under the lessor's royalty share provisions, on the indexed production tax rate increases as applied to oil and the indexed production tax rate increases as applied to gas. Payment is due at the end of the calendar month for production during the preceding month and, if not paid, the tax due is delinquent. Proposed AS 43.55.020(h)

authorizes imposition and collection of a five percent civil penalty on the difference between the amount not paid and a 90 percent threshold if payment, when due, falls below that threshold.

Bill section 20: This section, proposing amendments to AS 43.55.030(a), clarifies what the Department of Revenue may obtain as information relevant to determining taxes due under AS 43.55.

Bill section 21 amends AS 43.55.030(d) to delete a per day penalty for failure to file a tax return under AS 43.55. Other provisions in this measure and in AS 43 are applicable to late filing of tax return documents.

Bill section 22, adding AS 43.55.030(e), sets out a requirement of an annual "true-up" of the prior year monthly returns and directs submission of adjustments or corrections of the previously-filed statements.

Bill section 23, amending AS 43.55.040, clarifies the department's power to obtain information relevant to determining taxes imposed under AS 43.55 by adding the authority to require filing of regular statements or reports. In addition, the bill section modifies the statutory confidentiality restrictions related to use of information in returns and reports when necessary to determine a taxpayer's liability, particularly as those provisions may be applicable to persons -- state officers and employees and privately-retained contractors -- who may have access to the information.

Bill section 27: AS 43.55.150 deals with determining the gross value at the point of production of oil and gas. The addition of new subsection (d) authorizes the Department of Revenue to allow producers to calculate that gross value with a formula that uses a producer's royalty agreement with the state, a royalty value or valuation method accepted by the Department of Natural Resources or the United States Department of the Interior, or another formula using factors such as published price indices.

OTHER SUBSTANTIVE PROVISIONS AFFECTING OIL PRODUCTION AND GAS PRODUCTION TAXES:

Bill section 16: The amendment to AS 43.55.025(b) extends the current production tax credit for exploration expenditures, authorized by AS 43.55.025, from the current deadline of July 2007 (July 2010 for the North Slope and Cook Inlet activities) to July 1, 2016, on a statewide basis.

Bill section 29: The amendments to AS 43.55.201 modify the component of the so-called nickel-per-barrel surcharge that directs a portion of the money to the response account in the oil and hazardous substance release prevention and response fund, reducing by one cent the amount directed to that account, and making necessary conforming changes to cross-references.

Bill section 30: The addition of AS 43.55.201(d) relieves from payment of this component of the tax surcharge oil that is exempt from the production tax because it is used in lease operations.

Bill section 31: The amendments to AS 43.55.300 modify the component of the so-called nickel-per-barrel surcharge that directs a portion of the money to the release prevention account in the oil and hazardous substance release prevention and response fund, increasing by one cent the amount directed to that account, and making necessary conforming changes to cross-references.

Bill section 32: The addition of AS 43.55.300(d) relieves from payment of this component of the tax surcharge oil that is exempt from the production tax because it is used in lease operations.

Bill sections 33 - 35 amend definitions of terms used in the chapter: "gas", "gross value at the point of production," and "oil."[1]

Bill section 36 adds definitions for "explorer" (for use in the chapter), "gas processing", and "gas treatment".[2]

PROVISIONS PROPOSING REPEAL OF THE CURRENT OIL AND GAS PROPERTIES PRODUCTION TAX:

In addition to repeals and reenactments made in bill sections 1 and 8, **bill section 37** collects and sets out repeals of provisions relating to the current oil and gas properties production tax that are obsolete or unnecessary due to other changes proposed in the measure:

-- repeal of AS 43.55.011(b) and (c) delete the provisions spelling out the percentage-of-value and cents-per-barrel tax methodologies applicable to taxation of oil;

-- repeal of AS 43.55.012(b) repeals the special cents-per-barrel provisions for heavy oil;

---

[1] By cross-reference, the change in the definition of "gas" has the effect of changing the definition of "gas" as used in AS 43.82, the Alaska Stranded Gas Development Act. See AS 43.82.900.

[2] As to the definitions, the administration's initial sectional analysis noted that

> Under these definitions, gas processing is considered an operation upstream of the point of production for gas, and generally the line between what is oil and what is gas corresponds to what substances are in liquid form and what substances are in gaseous form, respectively, at the point of production.

-- repeal of AS 43.55.013 eliminates the economic limit factor, or ELF;

-- repeal of AS 43.55.016 deletes the current gas production tax;

-- repeal of AS 43.55.025(k)(3) eliminates the definition of "explorer" as applicable to the current tax credit for oil and gas exploration; the term is defined for the chapter by an addition made in bill section 36;

-- repeal of paragraphs (1), (8), (11), (12) and (16) of AS 43.55.900 eliminate definitions appearing in other repealed sections --"API gravity", "intangible drilling expense", "oil production operation", "old crude oil", and "well days".

CONFORMING ADDITIONS AND AMENDMENTS:

Bill section 2 amends criminal provisions for unauthorized disclosure of confidential records. The section imposes criminal penalties on current or former officers and employees for unauthorized disclosure; the amendment extends the penalties to others, private persons such as legal counsel and consultants, who make an unauthorized disclosure of otherwise confidential information to which they have had access.

Bill sections 3 and 4 authorize a producer who is a taxpayer under the Alaska Net Income Tax Act, AS 43.20, to deduct the production tax payments and disallows the adding back of the production taxes levied and paid in the determination of the producer's corporate income tax.

Bill section 7 conforms certain statutory language to that used in the Internal Revenue Code and incorporates by reference a definition for a term used elsewhere in the chapter.

Bill section 9 makes a corrective amendment to AS 43.55.020(b).

Bill sections 15, 17, 18, and 19: The provisions are in the nature of conforming amendments made to various subsections of AS 43.55.025, authorizing the current tax credit for oil and gas exploration or gas only exploration. The amendments insert or substitute reference to the specific subsection levying the production tax on oil and gas. The changes are necessary because, as proposed in the original bill and the committee substitute, the chapter (AS 43.55) would have multiple tax credits rather than the one existing tax credit for oil and gas, or gas only, exploration.

Bill section 24 proposes amendments to AS 43.55.080, directing that production taxes be deposited into the general fund, to incorporate exceptions imposed under the constitutional budget reserve fund amendment, and making a conforming amendment due to addition of new sections to article 1 of AS 43.55.

Bill section 25, amending AS 43.55.135, sets out a conforming amendment due to addition of new sections to article 1 of AS 43.55.

Bill section 26, amending AS 43.55.150(a), makes conforming amendments relating to the determination of gross value to be calculated and in the reference due to addition of new sections to article 1.

APPLICABILITY, TRANSITIONAL, AND RELATED PROVISIONS:

Bill section 38 specifies that provisions relating to the new tax on the production tax value of oil and gas apply to oil and gas produced on or after April 1, 2006, and that the provision under which the Department of Revenue collects the tax on the basis of prevailing value and that clarifies how that value is to be measured, confirming long-standing agency policy, applies to all production without reference to date.

Bill section 39 sets out a series of transitional provisions that clarify how certain calendar year rules added by the new tax will apply during the first nine-month period that the tax is in effect, that authorize the claim of tax credit for expenditures and losses based on expenditures made on or after January 1, 2006, that set out a transitional schedule for tax payments, and that former regulations in effect under the previous severance tax statute continue to govern oil and gas produced before the April 1, 2006, effective date of the new production tax.

Bill section 40 authorizes adoption of new regulations and provides that the new regulations adopted may apply retroactively as of the April 1, 2006, effective date of the new production tax.

Bill section 41 prescribes editorial instructions for the revisor of statutes.

Bill section 42 adds a provision authorizing retroactive application of expenditures incurred on or after January 1, 2006, for expenditures that support the tax credit claims under the new production tax.

In the event the bill becomes law after April 1, 2006, **bill section 43** makes the provisions of the measure that are identified as taking effect on that date retrospectively effective to that date.

Bill sections 44 and 45 are the measure's effective dates. The production tax provisions have an April 1 effective date; the remainder of the bill is given immediate effect.

JBC:lmb
06-118.lmb

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

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FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM March 17, 2006

SUBJECT: Resources Committee amendment 8 to CSHB 488(RES), draft version "Y" (Work Order No. 24-GH2052\Y)

TO: Representative Jay Ramras
Representative Ralph Samuels
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

Tim Benintendi has provided copies of amendments adopted by the committee during yesterday's mark-up of the above-captioned bill.

To meet the direction set out in committee amendment 8 ("delete sections relating to transitional investment expenditures"), captioned as a conceptual amendment, unless someone gives me different guidance, to meet the committee's direction, I propose to delete

(1) AS 43.55.160(a)(3) [bill, page 17, lines 26 to the end of the sentence on line 28];

(2) all of AS 43.55.160(b)(2) [bill, page 18, lines 14 - 22], and

(3) all of AS 43.55.160(g) and (h) [bill, page 21, line 25, through page 23, line 6].

The deletions will necessitate some internal renumbering or relettering.

If there are other provisions covered under the general direction that deserve attention or that were intended to be encompassed within the scope of committee amendment 8, please advise.

JBC:ljw
06-135.ljw

cc: Representative Mary Kapsner, amendment sponsor

Estimated Revenue Impact of Status Quo and PPT Tax Proposals, FY 2007 - 2012							
Fiscal Year	Spring 2006 DOR Forecast	Status Quo Tax System	Difference SQ & HB 488/ SB 305	HB 488/ SB 305 Tax Proposal	Difference HB 488/SB 305 & House CS	House CS Tax Proposal	Difference SQ & House CS
	$/bbl	$Millions	$Millions	$Millions	$Millions	$Millions	$Millions
2007	53.60	939	525	1,514	311	1,825	836
2008	46.90	759	377	1,136	182	1,318	559
2009	25.50	355	(53)	302	21	323	(32)
2010	25.50	315	(32)	283	21	304	(11)
2011	25.50	281	10	291	21	312	31
2012	25.50	271	20	291	21	312	41
5-Year Average (2007-2011)		**540**	**165**	**705**	**111**	**816**	**277**

Title: Comparison of Status Quo and PPT Tax Proposals

Preparer: Cherie Nienhuis

Purpose: For Representative Ralph Samuels

Data Source: PPT Models, and PPT Fiscal Note Adjustments.xls

Key Assumptions: All assumptions included in PPT model

History: None

Disclaimer:

The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

The information contained in this workbook may be privileged, confidential or otherwise protected from disclosure. If you are not the intended recipient, any use, dissemination, disclosure, distribution or copying is strictly prohibited.

Tim Benintendi

From: Cherie Nienhuis [cherie_nienhuis@revenue.state.ak.us]
Sent: Friday, March 24, 2006 2:41 PM
To: Tim Benintendi
Cc: Roger Marks; Jerry Burnett; Robynn J Wilson
Subject: PPT Proposals: Revenue Impacts
Attachments: House CS Comparison.xls

Tim,

Attached is a file with the information you requested on the revenue impact of the status quo tax system and the HB 488/SB 305 and House CS tax proposals. The revenue figures are based on our Spring 2006 production and price forecast.

I hope you find this information to be useful. Please do not hesitate to contact me if you need further information.

Cherie

Cherie Nienhuis
Petroleum Economist
Alaska Department of Revenue
907.465.3682

.2.4 NORWAY

Background

The petroleum industry is over thirty years old and plays a vital part in the economy; petroleum accounts for approximately 32% of export value and about 12% of GDP. Norway has significant oil and gas reserves. Proven oil reserves are 1.3 bt, which will last 8.3 years at current production rates and proven gas reserves are 1.48 tcm, which will last 32 years at current production levels.
Norway is the biggest oil producer in Western Europe and accounts for 4.3 % of world oil production or the eight largest oil production in the world. Production in 1997 was 156.9 mt. Norway is the second biggest exporter of oil in the world and oil consumption was 10.2 mt in 1997, a small increase on 1996. Approximately two thirds of the country's oil reserves are located in or close to the Statfjord, Oseberg, Gullfaks and Ekofisk fields in the North Sea. At the beginning of 1998, there were 42 oil and gas fields in production, 11 fields had been approved for development and 3 fields had stopped producing. In addition, there are 129 oil and gas discoveries, which have not been approved for development. Approximately 25% of oil reserves and 10% of gas reserves have been produced. Oil production is expected to peak at 194 mt in 2001-2002.
Oil reserves are now maturing and no major new discoveries have been made in the past decade. Exploration activity is focusing further north. The Norwegian Government has introduced the NORSOK plan in 1993, which aims to reduce development costs and to extend the recovery life of a field through the use of new technology.
Norway produced 46.7 bcm of gas in 1997, an increase of 13.9% on 1996. The country is a primary gas exporter and exported 42.3 bcm by pipeline in 1997, all of it to Europe and the majority to France and Germany. Gas exports are expected to increase significantly in the future. Contracted gas sales will increase from 46 bcm in 1997 to 76 bcm in 2005. Gas consumption began in 1995 and remains low (0.4 bcm in 1997). Gas consumption is low in Norway, due to the availability of hydro-electric sources and also due to the fact that the country is not densely populated. Gas consumption is, however, expected to rise in the future. Norway's exports of oil and gas represented 37% of all Norsk exports in 1997 and investments in the oil and gas sector amounted to 22% of all investments in Norway in 1997.

Control

The key concepts of Norwegian oil and gas policy have been state ownership and management of natural resources and state participation. The petroleum industry is characterised by co-operation between the State and private Norwegian and foreign companies. The largest oil and gas producer is Statoil, the state-owned oil and gas company. Other major Norwegian companies are Norsk Hydro and Saga Petroleum. Until 1996, Statoil was awarded shares in all petroleum licences in Norway, but now competes on competitive terms with private Norwegian and foreign companies. Norsk Hydro is owned 51% by the State, although it is run as if it were completely private. Saga is now owned 15% by Statoil after Hydro disposed of its interest in Saga at the beginning of 1998. In order to reduce the level of investment in the offshore sector, the government announced plans to delay all new fields by one year (with only a few exceptions).

Operating Framework

A concession system is in operation and all exploration/development activity is performed through joint ventures. Norway holds regular licensing rounds and the first round was announced in 1965. The licensing framework for the Barents Sea changed in 1994 and may be applied to the rest of Norway. The new system allows companies to make a group application and thus waives licence fees and reduces pre-evaluation costs. It enables companies to carry out most of the work after the licence has been awarded.

Privatisation

There are three major oil companies in Norway. Statoil, the most dominant in terms of production and biggest operator, is state-owned. Currently, there are no plans to privatise Statoil. However, Statoil's shipping company Navion has announced its intention to seek a market quotation and its marketing activities will be put into a joint venture with a Norwegian supermarket chain. Norsk Hydro is owned 51% by the State and Saga Petroleum is a private company.

Pricing and Sales

Norway has no pricing or sales restrictions.

Trade Restrictions

No restrictions on the import or export of oil and gas are in place.

Fiscal Framework

A Special Petroleum Tax (SPT) exists. There are some special concessions and allowances available.

RESEARCHANDMARKETS

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Transformation of Norway's Oil and Gas Industry (Special Report)

Description: This is a story of how Norway grew from a relatively modest position as an industrialised country, although with an important strategic position in post war political tensions, to a world power in the politics of energy. It is also a story of how a nation, suddenly finding itself very rich in a natural resource of strategic importance to the world, had to protect its interests and at the same time find its position in the process of globalisation. It is therefore a story about the processes that fuelled the transformation of a nation, its oil and gas resources.

Traditionally there has been a high degree of agreement across political dividing lines about Norway's national policy towards its upstream oil and gas industries. The fundamental basis on which the policy builds, is the principle of public ownership to the country's natural resources. The law has placed the onus on the government to grant concessions to private or public companies to exploit the resources to the maximum benefit of the people of Norway.

When policy is based on such strong declarations of public ownership, this is bound to influence the management of a country's resource base. In some political quarters the principle of public ownership has been interpreted to mean maximum state participation in the actual exploitation of the resources. This has been the issue over which there has been some degree of political controversy in Norway. In a process that has lasted for some 30 years, consensus has now been reached over the issue, and Norway has entered a process of re-organising the state's direct participation in the oil and gas sector. In concrete terms this means partial privatisation of Statoil and the sell-off of some of the state's direct financial interests (Sdfi) in exploration/production licences.

Contents:

1. Foreword (by the Minister of Oil & Energy)

2. The Transformation of Norway's Oil and Gas Industry
In political terms the process of transformation occurring in Norway's oil and gas sector is deep and fundamental.This process represents a break with a political tradition built over 30 years on the strong principal foundation of public ownership of a nation's natural resources.In practical terms,the process could mean the beginning of a process that could lead to a real transformation of the framework and therefore conditions under which the oil and gas industry will operate in Norway.

3. Country of opportunities
There is no doubtNorway has been brought back to the top of the target lists of many international oil companies as they continue to nominate candidate areas for their global exploration efforts.

4. Norway's historic opportunity
As Europe's gas markets expand and EU legislation adds to the dynamics of the markets, Norway faces the challenge of exploiting its position as a supplier.

5. Gas drives Norway's offshore E&P expenditures
Total expenditures in offshore exploration,field development and field operations in Norway are set to increase from US$6.4bn this year to almost US$10bn in 2004.The most important contributors to this growth are new field development projects and soaring operations costs.The other major factor affecting expenditure is the takeover of oil by gas as the prime driver of the offshore E&P market.

6. Something as rare as a successful State Oil Company
As Statoil appears on the international arena as a partially privatised national oil company,it becomes exposed to the scrutiny of the financial world and the psychology of the stock markets, a relatively far cry from the safe heaven of state ownership and the
appurtenant privileges.

7. Norsk Hydro -Building on solid traditions
Norsk Hydro in the 1960s was about the only Norwegian based industrial group working internationally. Based on processes owned by the group and relatively un-restricted availability of hydro power, Norsk Hydro had built a substantial activity in chemicals, fertilisers and magnesium, and was a world wide exporter of the products.

8. The Norwegian implementation of the EU Gas Directive
Ingvald Falch provides an outline of the contents of the EU Gas Directive and discusses some key issues of interpretation that are of particular relevance to Norway

9. The role of an independent in a changing industry
There have been many changes in the Norwegian oil and gas industry recently which companies have had to adapt to and Enterprise Oil has faced these challenges head on

10. A symbiotic relationship between Norway and the outside world
Dieter Schaubert and Haakon Haaland discuss the role of international energy companies in creating value for Norway

11. Norwegian gas sales post-GFU:Opportunities and challenges
Eirik Høiby looks at the way ahead for sales of gas in Norway,following the abolition of the GFU

12. The new structure of Norway 's interests on the Norwegian Continental ShelfNorsk Hydro
The new structure of the Norwegian State 's oil and gas ownership interests on the Norwegian Continental Shelf

Company Profiles

- The New Statoil
- Advokatfirmaet Schjødt

- Enterprise Oil Norge Ltd
- Norske Conoco
- Simonsen Foyen
- Thommessen Krefting Greve Lund

Summary:

Foreword by the Minister of Oil & Energy - Einar Steensnæs

The coalition partners which hav formed the new Norwegian government hav been active supporters and part initiators of the policy moves that hav started the process towards the transformation of Norway's oil and gas industry.The new government intends to continue this process,with the intention of creating a framework of conditions under which the continued development of Norway's oil and gas resources can take place in a safe and efficient manner,with full consideration made to the protection of the environment.

After more than 30 years of exploration and production activities, Norway's oil and gas resource base is far from being exhausted. The country has large un-explored continental shelf areas and huge potential reserves of oil and gas. In exploiting this potential, a number of unrivalled opportunities lie ahead for Norway and its people, but also some significant challenges.

Indications are that most of Norway's future hydrocarbon potential is in natural gas and that the most immediate new opportunities for development of the natural gas resources are in the Norwegian Sea. These opportunities appear to coincide with a rapidly expanding market for gas imports in the European Union, predominantly in the United Kingdom. Norway could obviously be a natural source of supply to meet Europe's growing gas needs. The liberalisation of the gas market in Europe could result in increasing risk exposure for Norwegian gas producers. Development of new gas reserves will therefore be more demanding in the future.

Norway's northern waters offer a number of special environmental challenges. These challenges will have to be tackled as a precondition of the development of the oil and gas resources in the region. Our government will be uncompromising in its demands for environmentally safe exploitation of these resources.

At the same time, however, Norway fully recognises its responsibilities as a supplier of oil and gas in support of the social and economic development of nations and people in need of the energy. One such responsibility is the creation of a business environment that will safeguard the investments and skills needed to develop Norway's natural resources.

Reorganising and diminishing the state's direct financial participation in the industry are means by which a business environment can be improved in order to attract further private investments in Norway's oil and gas sector.

Norway offers excellent opportunities for investors who are ready to employ their best human, financial and technical skills in the safe and efficient development of the country's hydrocarbon resources, on behalf of the people of Norway.

Einar Steensnæs

ISSUE:

Third Quarter 2005 Earnings Compared to Other Industries

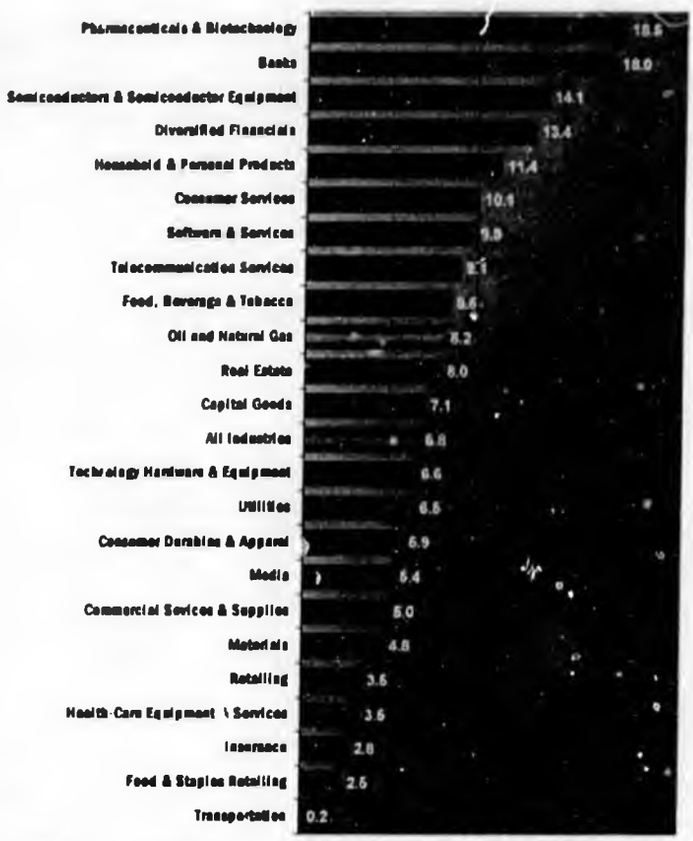
The oil and natural gas industry is among one of the world's largest industries. Its revenues are large, but so are its costs of providing consumers with the energy they need. Among those are the cost of finding and producing oil and natural gas and the costs of refining, distributing and marketing it. The energy Americans consume today is brought to us by investments made years or even decades ago. Today's oil and natural gas industry earnings are invested in new technology, new production, and environmental and product quality improvements to meet tomorrow's energy needs.

The industry's earnings are very much in line with other industries and often they are lower. This fact is not well understood, in part, because reports typically focus on only half the story-the profits earned. Profits reflect the size of an industry, but they're not necessarily a good reflection of financial performance. Profit margins or earnings per dollar of sales (measured as net income divided by sales) provide a more relevant and accurate measure of a company or an industry's health, and also provide a useful way of comparing financial performance between industries large and small.

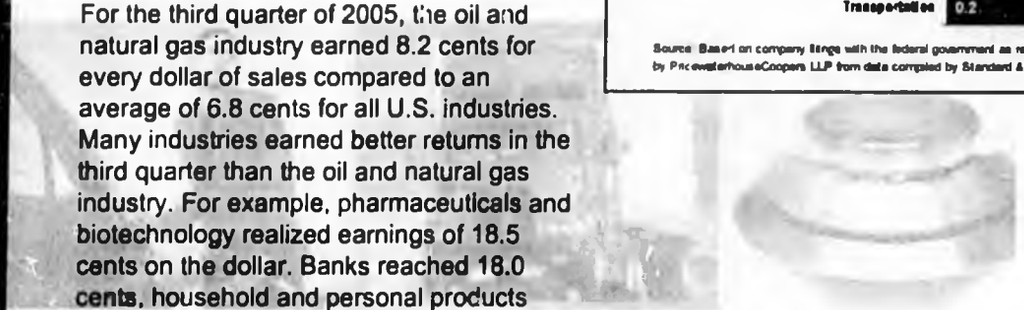
For the third quarter of 2005, the oil and natural gas industry earned 8.2 cents for every dollar of sales compared to an average of 6.8 cents for all U.S. industries. Many industries earned better returns in the third quarter than the oil and natural gas industry. For example, pharmaceuticals and biotechnology realized earnings of 18.5 cents on the dollar. Banks reached 18.0 cents, household and personal products averaged 11.4 cents, customer services earned 10.1 cents and software and services saw 9.9 cents for every dollar of sales.

Earnings of Major Industries

(cents per dollar of sales)



Source: Based on company filings with the federal government as reported by the Oil Daily for the oil and natural gas and by PricewaterhouseCoopers LLP from data compiled by Standard & Poor's Compustat for all other industries.



API.
American Petroleum Institute
www.api.org

Constituent/**Non-Constituent** Saved/ **Not Saved**

Charley Walton of Fairbanks (07) wrote the following message On 2/28/2006 at 09:17 In opposition of *SB 305 OIL AND GAS PRODUCTION TAX*

Message:

Concerning Oil Production Tax: The governor starts with secret negotiations, all parties have come to a compromise pipeline agreement, two days later oil official testifies will discourage oil industry from working Alaska. If they don't like this tax bill then raise the taxes. Trouble paying my bills on their profits.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Charley Walton
1062 Steele Creek Rd
Fairbanks 99712

Constituent/**Non-Constituent** Saved/ **Not Saved**

Richard Melms of Anchorage (31) wrote the following message On 2/27/2006 at 16:38 about *Oil & Gas*

Message:

Congratulations on tackling the issue of oil taxation. This is long overdue and difficult. Pls make the best decision for Alaska. The resources are ours and the oil companies have had a "sweetheart" deal for to long. We are counting on all of you to protect our interests first. Thank y

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Richard Melms
4201 Leyden Rd
Anchorage 99516
Email:rdzmelms@alaska.net
day:907 3456184
eve:907 3456184

Constituent/**Non-Constituent** Saved/ **Not Saved**

Matthew Erickson of Fairbanks (09) wrote the following message On 2/28/2006 at 03:32 about *Oil & Gas*

Message:

PLEASE!! Should we support an oil tax scheme, that causes government to desire continued high oil prices? Flat percent tax on each barrel of oil, and penalty tax for under production, is the only fair and equitable way!

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Matthew Erickson
Po Box 70335
Fairbanks 99707-0335
Email:look412_2001@hotmail.com

Constituent/**Non-Constituent** Saved/ **Not Saved**

Thomas Patmor of Clam Gulch (34) wrote the following message On 2/28/2006 at 12:14 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

Expecting oil companies to voluntarily pay their taxes doesn't always work, traditionally. We've just been paying millions for lawyers' fees trying to collect. If we charge them for the oil as soon as it's out of the ground, we'd have the money and they could apply to be reimbursed accordingly.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Thomas Patmor
Po Box 124
Clam Gulch 99568-0124

Constituent/**Non-Constituent** Saved/ **Not Saved**

Thomas Patmor of Clam Gulch (34) wrote the following message On 2/27/2006 at 15:15 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

If a big company makes 10 billion dollars and are charged 2 billion taxes which they reinvest and so are thus charged nothing for the oil that year,decides to sell out to smaller satellite companies making less that 73 million, they still get the oil for nothing every year.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Thomas Patmor
Po Box 124
Clam Gulch 99568-0124

Alaska State Legislature

Please enter into the record my testimony to the House Resource
committee name

committee on HB 488 . dated 3-14-06 .
bill/subject

Subject: Elimination of ELF

Sirs,
As you well know, the Cook Inlet oil fields are very mature and extremely challenging to operate in a manor that is profitable enough to out weigh the risks involved. My families as well as thousands of people in the Cook Inlet region rely heavily on the long term economic viability of this field. Elimination of the ELF without a doubt will significantly shorten the life of this field and cause more harm than good to the State of Alaska.

Chevron

Paul Delago
Production Foreman
Unocal Alaska Business Unit
Trading Bay Production Facility
907-776-6855
Monopod Platform
907-776-6672
Cell 398-9943

Signed: _____
Testifier

_____
Representing (Optional)

_____
Address

_____
Phone No.

District 16
Bill Stoltze

Maxine Blake

From: Ray, Malcolm (PROFESSIONAL BUSINESS SERVICES (PBS)) [MALCOLM.Ray@bp.com]
Sent: Wednesday, March 08, 2006 2:42 PM
To: Senator Johnny; Senator_Tom_Waggoner@legis.state.ak.us; Rep. Vic Kohring; Rep. Ralph Samuels; Rep. Mark Neuman; Representative_Michael_Kelly@legis.state.ak.us; Rep. David Guttenberg; Sen. Gretchen Guess
Cc: radianresources@alaska.com; Ray, Malcolm (PROFESSIONAL BUSINESS SERVICES (PBS))
Subject: Proposed Oil Taxation Increase

Dear Alaska State Senator/Representative:

There are dozens of issues about this state government policies that are of great concern to me. But on this occasion I want to address this singular matter of the proposed increased tax on oil and gas E & P; my 40 years experience is directly connected to the exploration and production of hydrocarbon energy. Please keep in mind that I could address numerous specific points regarding this taxation, but will try to effectively make important points relating to a particular aspect.

I take this proposal by the state administration to increase taxes on petroleum mining and upstream operations as a direct attack on my life, personally, and as a potentially devastating recipe for utter disaster for Alaska's future. There are impressive reasons for this statement that I will not go into at this time, but perhaps if we have time to talk one on one. Note that other mining industries pay around 3% tax and is permitted depletion allowables for taxation purposes that range as high as 50%. Therefore it is not that difficult to see the unfairness directed at oil & gas.

Oil and gas is already carrying the bulk of expenses in this state; the state school system is failing to educate the youth of Alaska, and waste is rampant throughout almost every state office that I have visited. The ignorance of the industry that is evident even from public statements by past directors of the State's AOGCC is quite unbelievable at times.

With these remarks as a backdrop, I offer the following more specific comments concerning the impropriety of only a single aspect of increased taxation.

March 7, 2006

Oil Profits Tax; Excessive Taxation Without Price Subsidies?

No oil company has the capacity to control the price of petroleum. There is no historical precedent for any oil company ever having set oil price (*petroleum is and has been for decades now, a global commodity with global pricing implications*). This proposed tax, with implications very similar to the unconstitutional proposal for royalty taxation of in-place reserves by Alaska in c. 1980, is extremely unfair; the tax, if enacted, imposes further burden on a high-risk industry that is already paying 83% of Alaska's ticket for big government and this additionally excessive taxation will be the deciding factor that will substantially halt further investment by already-overtaxed oil and gas companies in Alaska. All of us will suffer when the state makes O&G exploration unprofitable by imposing even more taxes. As a petroleum engineer of 40 years experience, I consider this proposed tax as an unnecessary attack on my livelihood, as should all oil and gas industry people; Alaska government should first make some effort to control its runaway expenditures, which it has not done.

If there is over-production in the future giving us much lower crude oil prices, is the State of Alaska going to provide subsidies to the oil companies? Upon making this tax proposal, the administration is remiss in it's responsibilities and has not written subsidy provisions into this tax proposal. Fair consideration on the downside can only be achieved by addressing this issue, as Alaska continues its 29-year trend of exploitation of the oil and gas industry. The profit-producing current crude oil product prices have been in effect now for only a 19-month period, as set by TEMPORARY world oil demand. Note that other businesses are reaping as much as $15 billion each year with a skeleton staff of employees and very low risk; for example check out PayPal Inc, the online instant money transfer company. *Yet these businesses are not objects of governmental taxation attacks.* The industry has waited numerous decades for this event. The industry needs more price stabilization then a brief year-and-a-half interval in order to march into uncharted, high risk exploration ventures in this state. The State has no reason to punish business unless the same state is prepared to prop up the bottom line when prices fall. The provision for these subsidies should have been written into the proposal, but were not for lack of an educated and professional treatment of this matter by the present administration of the State of Alaska and its rather inept consultants.

Malcolm G. Ray
Petroleum Engineer
Professional Business Services Consultant
DAY: 907 / 564-4087
Night: 907 / 688-8977

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3175 College Road #1, Fairbanks Alaska 99709 office 907-452-7274 fax 907-456-6997 800-354-7274

March 8, 2006

Representative Samuels and Representative Ramras, Co Chairs
Natural Resource Committee

Dear Sirs:

Thank you for you diligence in the process of evaluating future financial structure of the partnership between Alaska and the Oil and Gas Industry. It is complicated and difficult and only could be made easier with a crystal ball!

I have been in business a long time in Alaska and I have seen the strengths and weaknesses of our taxing structure. Please be careful when deciding at what level to tax the industry that you do not make future exploration and development such a high risk that the return on their investments would be better even in a less stable environment.

In the restaurant business, we have enjoyed busy and profitable seasons and those that were more challenging. Being profitable in some years keeps us in business to weather the less positive years. Do not expect less for the Oil industry and allow them the same level of flexibility that we in the private sector enjoy. Tax credits are available in many businesses and do provide incentives for investments. I would not like to see our State with an inability to develop our natural resources due to high taxes, high labor, high materials costs, etc. and less stability than we could provide by being fair and reasonable. A predictable tax regime and an attitude of we are open for business is what we all deserve as residents of this wonderful State.

The negotiated 20/20 may not be perfect, but it should be close if that is what has been negotiated in good faith. Good luck with your tasks and I appreciate your service.

Sincerely

Rick Winther

TECHNICAL CONSULTANTS, INC.
3425 International Way
Fairbanks, Alaska 99701
Phone: 907-452-1792 • Fax: 907-452-8207 • tci@mosquitonet.com • www.tci-alaska.com

March 8, 2006

Representative Samuels, co-Chair Natural Resources Committee
Representative Jay Ramras, Co Chair Natural Resources Committee

RE. HB488

Honorable Representatives:

You are obviously working very diligently on determining a future gas and oil industry tax structure. I applaud your intentions and believe that after all of the debate you will realize that we need these valuable investors in our state.

Maybe we have been spoiled with the Permanent Fund Checks and somewhat take these companies for granted. While I understand that we are "negotiating" please do not tax them higher than the governor's recommended agreement unless they are compensated for with tax investment credits of some type. In my opinion, 20/20 as we hear is reasonable and although I will never be convinced they will leave the State of Alaska entirely, I am sure that they will not invest here unless they make some money!

Good luck and God bless your endeavors because you are making a big decision for the future of our State.

Sincerely and with respect,

David Gerdes, Engineer

TECHNICAL CONSULTANTS, INC.
3425 International Way
Fairbanks, Alaska 99701
Phone: 907-452-1792 • Fax: 907-452-8207 • tci@mosquitonet.com • www.tci-alaska.com

March 9, 2006

Representative Samuels and Representative Ramras, Co-Chairs
Natural Resource Committee

Subject: HB488

Dear Sirs:

I have heard Gavel to Gavel coverage and read the news papers of the hearings before your Resources committee and the testimony of experts that you pay to give you good advice.

Well, my advice is free! It is easy for these experts to tell you that you should demand more from the oil and gas producers, but my view as a lifelong Alaskan is-don't kill the golden goose! Please make your decisions in a fair and balanced mind set that will encourage future development and a possible gas line project.

After all, your consultants will move on to another $3000 per day contract and we Alaskans have to live with the consequences of their advice.

Please do not sacrifice a reasonably stable future with a continued partnership with the oil and gas community for a quick sound bite about "sticking it to the oil industry"!

We want another 30 years of business and financial fairness.

Sincerely,

Mike McGlinchy



3425 International Way • Fairbanks, Alaska 99701 • 907-456-5155

March 9, 2006

Representative Samuels and Representative Ramras, Co- Chairs
Natural Resource Committee

Subject: HB488

In the Interior of our state we saw the problems that came from being unprepared for the oil boom of the TransAlaska Pipeline. We have all learned a great deal since then and we have watched as our children and grandchildren have reaped the rewards of an excellent and visionary financial structure that produces Permanent Fund Checks.

As you are negotiating now for the next generations taxing structure with the oil and gas industry I want to ask you to remember that basic business principals should apply to any natural resource development. Investment tax credits from today forward are good. That creates incentive for new development. The negotiated agreement existing now is reasonable and is a "win- win" for the industry and the residents of the state. The ELF concept worked for a long time and now we have to be aware of the higher risks of developing marginal fields. If the largest oil companies in the world can look at the return on their investment in Alaska and compare it to other parts of the country, please do not make our tax structure so complicated and instable that the politically unstable countries appear more attractive due to other factors. We need to remain open for business and we need predictability to insure a natural gas line being developed.

Thank you for your public service and your endless hours of research and awareness.

Sincerely,

Vernon H. Boyles

Vernon H Boyles

Constituent/**Non-Constituent** **Saved**/ Not Saved
Matthew Erickson of Fairbanks (09) wrote the following message On 3/9/2006 at 16:47 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
It seems as though Murkowski hinges retirement on whether or not his oil tax scheme is approved. I have to ask, "Is he desperate, or is it obsession?" How can anyone support a proposal where so many factors are being kept secret? Please don't be rushed by Murkowski's agenda.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Matthew Erickson
Po Box 70335
Fairbanks AK, 99707-0335
Email:look412_2001@hotmail.com

Constituent/**Non-Constituent** **Saved**/ Not Saved

Britton Cook of Kenai (33) wrote the following message On 3/10/2006 at 08:09 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

New statewide tax structure is not warranted. Producers need stability in order to invest. New tax structure may make Chevron's sizable investment strategy in Cook Inlet financially unfeasible. The Cook Inlet does not have the same economics as the North Slope. Cook Inlet should be left alone under ELF.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Britton Cook
4092 Lupine Dr
Kenai 99611
Email: Britt@gci.net

Constituent/**Non-Constituent** **Saved**/ Not Saved
Kevin Morin of Kenai (33) wrote the following message On 3/10/2006 at 09:14 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
I believe that a tax structure change is unwise and will result in a loss of investment in Cook Inlet. The C.I. fields are mature and declining so investment by Chevron is critical to continued output. Stability of regulatory and tax outlook is vital to corporate planning.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
Kevin Morin
114 Paula St
Kenai 99611-6814
organization:iisco@acsalaska.net

Constituent/**Non-Constituent** **Saved**/ Not Saved
Christine Cook of Kenai (33) wrote the following message On 3/10/2006 at 10:12 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
i make my living as a contractor within the Cook Inlet oil and gas industry. I would like to continue to do so! I strongly urge you to oppose HB 488 and SB 305. "Encouraging investment", replacing ELF "with a more progressive...tax system"?? Puhleeese! Just say NO!

Message was delivered by Pom
The number of original recipients of this message is 6

View Case Delete case

Contact Info:
Christine Cook
4092 Lupine Dr
Kenai 99611
Email:chrisc@gci.net
day:907-283-8350
eve:same
organization: Citizen

3-10-06
PUBLIC TESTIMONY

My name is Mike Koy.

I've worked with BP for over eleven years in various capacities including numerous business development roles, which includes strategy and economic evaluations of gas sales from the north slope of Alaska, mergers and acquisitions and finance.

I am currently on a leave of absence and therefore free to speak with all the knowledge and perspective of someone from within the industry but without any of the associated limitations or constraints.

Let me start by saying that most oil companies use fixed prices when making investment decisions and those prices have tended to be in the $20-$30/bbl range. Within this price range is where the tax regime needs to look attractive relative to other places in the world in order to attract investment. What happens outside of this range is important, but largely immaterial when making investment decisions. This, coupled with the State's objectives, is what is important in determining a tax structure.

Having said that, and inferring what the State wants to achieve, the basis of HB488 and SB305 is reasonable. An oil tax that is less regressive, provides incentive for investment and is based on profits instead of revenues is a good thing.

However, while the premise is ok, the proposed bill misses the mark on several points which the committee should consider in its deliberations. These are:

- **Risks:** The tax as proposed dramatically increases the risks to the State. This occurs for several reasons, but the most important is that it reduces the regressive nature of the current tax without sufficiently allowing the State to participate in the upside when oil prices are high. To mitigate this, the legislature should increase slightly the regressive nature of the tax while implementing a graduated profit tax structure which increases the State's proportional share of profits as price goes up. Again, as long as the graduated profit tax kicks in at prices high enough not to impact investment decisions, the State can and should consider a maximum profit tax rate that exceeds the proposed 20% rate.

- **Incentives:** The 20% tax incentive is reasonable. As mentioned though most oil companies use fixed prices to make investment decisions and providing a tax incentive outside of this investment range is a concession by the State without any offsetting benefit. High oil price is the incentive and the State should consider tapering off the tax incentive as prices increase. In addition, rather than apply the credit to exploration costs, which again increases the State's risk and in reality makes them a participant in exploration, the State should consider allowing a higher tax incentive on viscous oil development, which is a large discovered resource close to existing infrastructure which means it can be brought on line faster.

- **Tax Phase-ins:** The tax phase-in period should be removed.

The final thing I would like to say is around the relationship of oil fiscal terms and a gas pipeline project. Oil fiscal terms have no bearing whatsoever on the economics of a gas pipeline project. They are not related at all accept through negotiation. The legislature should and must separate the two and insure that no oil tax fiscal terms are included in the gas fiscal contract in order to preserve their rights to set fiscal terms.

In summary, while I think there are better starting points for amending the State's oil fiscal terms than this bill, if it is to be the basis for a new system amendments should be made to make it slightly more regressive on the low price side, implement a graduated progressive tax on the high side, consider a tax incentive for viscous oil and most importantly consider oil tax legislation separate from a gas pipeline project and ensure oil fiscal terms are not included in a gas contract.

Thank you.

Tim Benintendi

From: Kirby Koy [kirbykoy@gmail.com]
Sent: Friday, March 10, 2006 2:23 PM
Attachments: Testimony.doc

Attached is my testimony from today's public hearing for HB488. I very much appreciate the opportunity to speak today.

What I didn't mention is the point of production issue is extremely important. It is most relevant for the gas treatment plant which would be constructed at the cost of $2.5-$4.0bn if there is a gas pipeline. The propoposed tax structure would allow these costs to qualify for the 20% investment credit which is worth $0.4- 0.8bn. Just as important, it allows the owners in the Prudhoe Bay Unit to make a stronger arguement for ringfencing the gas treatment plant within the Unit. This means that it would not be subject to RCA or FERC regulation and gives the Prudhoe Bay producers a lot of control over who utilizes the gas treatment plant and at what price. Since the gas treatment plant is the first part of a gas pipeline it means that the Prudhoe Bay owners will be able to control to some extent who uses the pipeline and who doesn't. This control is as important if not more so than the tax credits.

Best Regards,
Mike Koy

MAR 0 9 2006

Oil and Gas Call Ins

Bill Warren, Kenai, 776-8551. Has lived in AK for 55 years and has been a part of the "industry" for years.

Watched RS on the news yesterday and was disappointed in comments re: not taxing stranded gas. Would like you:

- to get a gas contract date
- would like gas to be run through Southcentral AK first
- the pipeline should be an all AK pipeline/no Canada
- feels the Governor needs to give you the contract so that you have all the information to make decisions
- does not like it that you are being nice to oil producers

Would like a call back to talk about it further.

Frank Shelton, Fairbanks

Came to AK in '51, so knows the history of the last deal. The oil companies took us for a bunch of country pumpkins. It looks like they plan to do the same deal.

Are we caving in? We shouldn't give any write-offs, look at all the money they make.

The State took away the money from the elderly here and we should set it up that we have enough to take care of them and the schools.

Senator Samuels, don't weaken. Murkowski is a rat, a schill fo the oil companies. The oil companies told him what to say. Stand up now and be a statesman.

Even if we have to walk away to get a good profit, we should do it.

The people here don't want to give in. Put a ramrod up your back and stand strong.

March 9, 2006

Dear Senator or Representative:

I am a member of a partnership that owns a commercial building in Anchorage. A major tenant in our building is a popular restaurant, the owner of which owns and operates restaurants in several states. Our rent from the restaurant is based on a percentage of gross receipts. We, as the landlord, negotiated the gross receipts percentage rent to avoid the arguments and creative accounting that can arise in determining net profits.

I believe that a smaller percentage tax on the gross value, or receipts, of oil and gas production AS DEFINED under 43.55.160 and 43.55.900(7) as set forth in SB305 is a better way to go than a tax on net value or net profit, especially where the major producers are multi-national corporations who are able to, and will, allocate and shift costs internally so as to distort and diminish net profits or value in Alaska.

I am a 58-year resident of Alaska and am tired of seeing Alaska duped by the "Big Guys."

Kenneth R. Atkinson
1336 W. 15th Avenue
Anchorage, Alaska 99501
Phone: 272-1836
Fax: 272-1837

83617/9999.1

SENT TO:

BEN STEVENS FAX 465-3872
THOMAS WAGONER " 465-4779
JAY RAMRAS " 465-2070
RALPH SAMUELS " 465-3810
JOHN HARRIS " 465-3799

Jane Pierson

From: Craig O'Donoghue [dentist@gci.net]
Sent: Thursday, March 09, 2006 5:58 PM
To: Rep. Jay Ramras

Dear Representative Ramras:

I have some concerns about all the details of the Net Profits Tax and Gas Pipeline. I trust that you are researching the details of the former in depth. It also does not make sense that the Net Profits Tax Bill needs to be passed before the details of the Gas Pipeline deal are revealed. Well, it might make sense if there is something to hide.

As a small businessman in Fairbanks, I want to see economic growth as much as the next guy, but somehow, my gut reaction to these developments is that something isn't right. When someone says that in order for you to see the details of one deal, you need to make this other bill law, one has to ask the question "what are they hiding?" Why will the governor not put everything on the table if he thinks it is such a great deal for the state?

Also, thank you for taking the time away from your business to serve in Juneau. I know that not many business owners can afford the time to do what you are doing.

Sincerely,

Craig O'Donoghue, DDS
General Dentist
Fairbanks, Alaska
www.alaskasmiles.com
(907) 374-6688

FLOWLINE ALASKA, INC.

March 10, 2006

State of Alaska, Legislature
House of Representatives
House Resources Committee
Juneau, Alaska

RE: HB 488 and SB 305

Thank you for this opportunity to comment on House Bill 488 and SB 305. My name is Richard Schok, I operate Flowline Alaska a Fairbanks based family owned business. Our firm provides value added products and services to the oil industry.

By 9 am this morning I walked through our insulation and fabrication shop, twice, drove around our storage yard, checked on progress of a few different projects, spoke with a few hands, and returned to my office where I proceeded to sign 94 paychecks for our weekly payroll. Every Friday morning I complete this same ritual. I share this experience because it relates to my next points.

Investment in the oil industry in Alaska only happens when Alaska is competitive on a global scale. The investment tax credit and standard deduction as outlined in HB488 are strong tools for encouraging investment. From independents to the majors this tool will encourage investment, new discoveries and opportunities for Alaskans and Alaskan businesses. Investments in Alaska by the oil industry allowed 94 individuals at my facility to earn a paycheck last week.

At current crude price levels the State of Alaska stands to generate an additional $1 billion in tax revenues from the oil industry if HB 488 and SB [illegible] pass. One billion dollars that is a lot of money. As a business owner I cringe when I hear about raising taxes. Taxes affect the value of investments over the long term. This bill, which is acceptable to the producers, will provide the long term fiscal certainty they need in order to invest in a $25 billion gas project. Long term stability is another major puzzle piece to investment in Alaska. Over the past few months I have 94 weekly recurring paychecks to prove it.

I caution this legislative body to tread lightly when the urge strikes to tinker with the details of this legislation. This piece of legislation will have effects on more than just the "Big 3" producers; there are at least 94 more reasons which I know of to take into consideration.

Thank you for taking time to review to my comments.

Sincerely

Richard Schok
Vice President
Flowline Alaska, Inc.

1881 Livengood • Fairbanks, Alaska 99701
Phone: (907) 456-4911 • Fax: (907) 456-1194
http://www.flowlinealaska.com

Jane Pierson

From: Kirby Koy [kirbykoy@gmail.com]
Sent: Friday, March 10, 2006 2:23 PM
Attachments: Testimony.doc

Attached is my testimony from today's public hearing for HB488. I very much appreciate the opportunity to speak today.

What I didn't mention is the point of production issue is extremely important. It is most relevant for the gas treatment plant which would be constructed at the cost of $2.5-$4.0bn if there is a gas pipeline. The propoposed tax structure would allow these costs to qualify for the 20% investment credit which is worth $0.4- 0.8bn. Just as important, it allows the owners in the Prudhoe Bay Unit to make a stronger arguement for ringfencing the gas treatment plant within the Unit. This means that it would not be subject to RCA or FERC regulation and gives the Prudhoe Bay producers a lot of control over who utilizes the gas treatment plant and at what price. Since the gas treatment plant is the first part of a gas pipeline it means that the Prudhoe Bay owners will be able to control to some extent who uses the pipeline and who doesn't. This control is as important if not more so than the tax credits.

Best Regards,
Mike Koy

My name is Mike Koy.

I've worked with BP for over eleven years in various capacities including numerous business development roles, which includes strategy and economic evaluations of gas sales from the north slope of Alaska, mergers and acquisitions and finance.

I am currently on a leave of absence and therefore free to speak with all the knowledge and perspective of someone from within the industry but without any of the associated limitations or constraints.

Let me start by saying that most oil companies use fixed prices when making investment decisions and those prices have tended to be in the $20-$30/bbl range. Within this price range is where the tax regime needs to look attractive relative to other places in the world in order to attract investment. What happens outside of this range is important, but largely immaterial when making investment decisions. This, coupled with the State's objectives, is what is important in determining a tax structure.

Having said that, and inferring what the State wants to achieve, the basis of HB488 and SB305 is reasonable. An oil tax that is less regressive, provides incentive for investment and is based on profits instead of revenues is a good thing.

However, while the premise is ok, the proposed bill misses the mark on several points which the committee should consider in its deliberations. These are:

- **Risks:** The tax as proposed dramatically increases the risks to the State. This occurs for several reasons, but the most important is that it reduces the regressive nature of the current tax without sufficiently allowing the State to participate in the upside when oil prices are high. To mitigate this, the legislature should increase slightly the regressive nature of the tax while implementing a graduated profit tax structure which increases the State's proportional share of profits as price goes up. Again, as long as the graduated profit tax kicks in at prices high enough not to impact investment decisions, the State can and should consider a maximum profit tax rate that exceeds the proposed 20% rate.

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In summary, while I think there are better starting points for amending the State's oil fiscal terms than this bill, if it is to be the basis for a new system amendments should be made to make it slightly more regressive on the low price side, implement a graduated progressive tax on the high side, consider a tax incentive for viscous oil and most importantly consider oil tax legislation separate from a gas pipeline project and ensure oil fiscal terms are not included in a gas contract.

Thank you.

Jane Pierson

From: Hugh Fate [hbfate@gci.net]
Sent: Friday, March 10, 2006 11:45 AM
To: Rep. Jay Ramras; Rep. Ralph Samuels
Cc: Hugh B. Fate
Subject: HB488

I have been watching with great interest all the committee hearings and presentations on HB488. I have also taped most of them. It seems to me you are quite close with the 20/20 provision. Several in the Legislature want a higher tax of 25% or more. The Producers are saying 25% is too high and **could** drive off new exploration efforts. Even though the Producers signed on with HB488, they are not necessarily happy with the tax provision. It therefore follows that when both parties to a negotiated agreement are not happy, a titration point has been reached; In this case, around the Governor's 20% figure in the Bill.

Good luck and God speed,

Hugh "Bud" Fate (Rep.,retired)

Home tel. (907) 457 6860
Cell 378 2222
Fax 457 6861

Jane Pierson

From: LIO Fairbanks
Sent: Friday, March 10, 2006 1.16 PM
To: Jane Pierson
Subject: FW: Statement FOR Increasing Oil Taxes

From: Ken Larson [mailto:larson_ken@hotmail.com]
Sent: Fri 3/10/2006 12:41 PM
To: LIO Fairbanks
Subject: Statement FOR Increasing Oil Taxes

Ken & Marla Larson
1074 Eliz Street
North Pole, AK 99705
(907) 488-2960
Email: larson_ken@hotmail.com

REF: Overhaul of the State's Oil Taxation System

Gentlefolk of the House Resources Committee:

Thank you for this oppurtunity to express my concern about Governor Murkowski's proposed Oil Tax Bill. His actions prior to formally introducing his Oil Tax Bill surely indicates his close ties to the Big Oil companies! It's obvious the oil companies are calling his shots even more so than they were for VP Dick Cheney, and you see what happened to him! This is doing a disservice to the State of Alaska! Let's face it, **Alaska is a SUPER GOOD DEAL for the oil companies** and they know it!

I have been following UAF's Prof. Doug Reynolds' oil tax analysis books and articles fairly closely and have to say I agree with most of what he says. As he said in his 5 Mar 06 News-Miner Article, **the oil companies' "...earnings based on price rises are not due to skill or hard work but due to world events and marketplace forces. There is no reason to reward oil companies for OPEC-induced price changes."** The Guv's proposed 20% tax rate on net profits and 20% deduction on capital expenses is supposed to yield an effective profits tax of about 60% according to the various experts. This compares rather poorly to the rest of the world where many countries have an effective profits tax of 80%. As a result I strongly support Doug Reynolds' idea of a Progressive Tax Rate when high prices generate progressive revenues.

Go ahead and establish a 25% profit tax rate/20% deduction or something close to that now while Oil is around $60/barrel, and include a GDP-indexed inflation rate. But when, not if, the price of oil starts climbing and hits a pre-determined threshold, like $75/barrel, then start the super-progressive tax. So, once the gas and oil prices rise above the threshold, then the progressive tax rate increases kick in. For example, add a 1% increase for every 10% the price increases up to some pre-determined maximum, like 100%. So at $75 the law becomes 26/20, at $82.50, 27/20, and so on. There has also got to be some monitoring measures put in place to keep the Oil Companies from just continuing to pass on these taxes to the consumers as they have in the past.

The oil companies have been manipulating us folks for years and we all know it, and have accepted it because of our demand-created reliance on oil products. They have not been very active in creating new energy efficient products or new fuel types since there is so much money

to be made in oil. Their competition is all but non-existant (if not collusive) and they retain oil and gas in the ground to help manipulate prices to their best profit advantage. That's why the other Bill being considered for action to Tax the undeveloped Natural Gas in the ground just makes a whole lot of sense to me. **I feel great outrage at how the world oil companies manipulate us and we just keep accepting their self serving pronouncements and control of our elected officials through Lobbying and Campaign Contributions!**

I guess I would feel a little more sympathetic toward the oil companies if their profits were not so OBSCENE and obviously following the same price run-up scenario that occurred in the early 1970's prior to the Alaska Oil Pipeline being built. What part of history repeating itself don't we understand? It would also help if Exxon would just pay their Exxon Valdez fine, which they've held in escrow for years, and quit paying the lawyers to obfuscate the process! The oil companies' threats to leave the State if they can't continue receiving these obscene profits by using Alaskan's resources need to be ignored. **Alaska needs to collect part of the windfall profits the oil companies keep reaping through no extraordinary efforts of their own**! If the present oil companies don't want to play fair then Alaska needs to sell their leases to someone else who will develop the products.

Thank you,

Ken & Marla Larson

Jane Pierson

From: LIO Fairbanks
Sent: Friday, March 10, 2006 10:28 AM
To: Jane Pierson
Subject: FW: HB 488

From: Robert Perry [mailto:robert_perry@dot.state.ak.us]
Sent: Fri 3/10/2006 8:49 AM
To: LIO Fairbanks
Subject: HB 488

The proposed legislation does not address the approprate reembursement for what the oil companies extract from the ground. A flat rate per barrel taken at the well head and take the accountants out of the mix makes accountability fair and just for both parties involved. Operating expenses can be monipulated, but flat rate per barrel as it is taken out of Alaskan soil makes for a friendly business relationship with large and small producers. Simplicity should be our goal so that everyone knows what is expected.

Robert Perry

Jane Pierson

From: LIO Fairbanks
Sent: Friday, March 10, 2006 11:12 AM
To: Jane Pierson
Subject: FW: House Bill 488

number 5

From: Wendee Colette [mailto:wendee.colette@chugach-ak.com]
Sent: Fri 3/10/2006 11:05 AM
To: Fairbanks_LIO@legis.state.ak.us.
Subject: House Bill 488

I think the tax bill should NOT be linked to the gas line. I feel that Gov. Murkowski can not be trusted to do what is right for Alaskans and the mere fact he is trying to push this through merits a closer look. Slow down, give us all a chance to get up to speed on what is truly going on before we are forced to vote on it.

Wendee Colette
907-452-4811
fax 907-456-2875

Jane Pierson

From: LIO Fairbanks
Sent: Friday, March 10, 2006 10:29 AM
To: Jane Pierson
Subject: FW: Oil and gas legislation

From: Mike Hersey [mailto:kicksaver@acsalaska.net]
Sent: Thu 3/9/2006 11:22 PM
To: LIO Fairbanks
Cc: Tom Brice Jr.
Subject: Oil and gas legislation

Since Gov. Murkowski is rated at the bottom of the list of governors in the United States and has already acted like a bull in the china cabinet why don't we let his term expire before we make any long term deal with the BIG THREE. We have waited many years for this deal and the gas is becoming harder to find. We will not lose an opportunity, and if we do it may be better than making a deal without knowing what you are signing off on. If you were my lawyers, you would not be signing any agreement that you didn't read and fully understand. Murkowski has nerve even suggesting that we should take his word for anything. mike hersey

3982 lancelot dr.
North Pole Ak. 99705

Jane Pierson

From: LIO Fairbanks
Sent: Friday, March 10, 2006 10:30 AM
To: Jane Pierson
Subject: FW: Overhaul of Oil Tax

From: Mary and Tim [mailto:yetna@acsalaska.net]
Sent: Fri 3/10/2006 9:44 AM
To: LIO Fairbanks
Subject: Overhaul of Oil Tax

To whom it may concern,

It is impossible to make a decision without making all the information available to those making the decision. This seems to be the position the governor is putting the legislators in by keeping the details of the gas pipeline deal secret and asking the legislators to pass a change in the way the state receives its revenue from the oil industry.

Any decisions made by the legislators and the governor today will affect the residents of this state and the economic well being of the state for years to come. Why would a governor who should have those concerns as the elemental driving force of his administration (after all he is a public SERVANT) place the electorate and the legislators in a position of limited knowledge? It seems something is amiss here and the legislators should stand strong and demand disclosure.

Thank you for considering my comments,
Mary A. Calmes

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Rep Ralph Samuels's office

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Messages

Constituent/**Non-Constituent** **Saved**/ Not Saved

Timothy Tilsworth of Fairbanks (07) wrote the following message On 3/10/2006 at 02:36 about *Oil & Gas*

Message:

Get tough with the Oil Industry They've had 30 years great years of oil and now it's the State's turn for a better return. I and my friends support a tax initative on the gas reserves. We have the ace of trump - not them.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:

Timothy Tilsworth
1900 Raven Dr
Fairbanks 99709-6661
Email:fftt@uaf.edu
day:907-479-0643
eve:907-479-0643
organization:self

Go to Main Menu | Go to Search Page

Jane Pierson

From: LIO Fairbanks
Sent: Friday, March 10, 2006 10:32 AM
To: Jane Pierson
Subject: FW: oil taxation system

From: Len Osimowicz [mailto:LenO@fcmhc.org]
Sent: Fri 3/10/2006 10:18 AM
To: LIO Fairbanks
Subject: oil taxation system

Please consider a progressive tax. Listen to the oil consultants you hired and not the "big oil companies"
Thanks
Len Osimowicz

Confidentiality Notice: The information disclosed within this email is intended only for the use of the individual(s) named above. If you are not the intended recipient, please return this message to sender. The information disclosed may be considered Confidential and may be protected under state law or federal regulations. These laws and regulations prohibit any further disclosure of this information without the specific written consent of the person to whom the information pertains, or as otherwise permitted by laws and regulations. Re-disclosure of this information is a violation of HIPAA laws and may subject the offender to civil and/or criminal penalties.

Tim Benintendi

From: Kirby Koy [kirbykoy@gmail.com]
Sent: Saturday, March 11, 2006 7:49 AM
Subject: HB488: Increased Risk to the State – A Simple Example

Increased Risk to the State – An Example

A simple example showing how the State takes on more risk with the proposed tax legislation

Relative to the current oil tax system, the proposed system earns the State less money at low oil prices and more money at high oil prices. By my calculations, which are in the same ballpark as those mentioned by the State's consultants, with the proposed tax system the State earns $250 million less when oil prices are $20/bbl and earns $800 million more when oil prices are $60/bbl.

The average long term oil price is between $18-$22/bbl which is significantly less than today's oil price of $60/bbl. However, unless there has been a paradigm shift we can expect oil prices to be in the $18-$22/bbl range a lot more often than in the $60/bbl range. That also means we can expect, with the proposed tax system, to be paying the oil companies $250 million more often than we'll receive $800 million.

For example, for every year that oil prices are $60/bbl there needs to be seven years of $15/bbl prices in order to equal the average long term oil price of between $18-$22/bbl. That means for the one time the State earns $800 million, when oil prices are at $60/bbl, the State will be paying $250 million seven times when oil prices are at $15/bbl. Netting that out the State is down -$950 million relative to the current system. If you are in to probabilities the expected outcome is -$115 million. The State's experts can perform a more sophisticated analysis, but the result will be the same.

Why does this happen? It occurs because relative to the current tax structure the State has given away a bit too much on the low side and not gained enough on the high side. To reduce the State's risk, or to at least make them more neutral, the State should make the proposed tax system slightly more regressive than it is on the low price side. On the high price side, the State should implement a graduated progressive tax which allows it to share in greater proportions of the upside as price goes up than the current tax proposal allows.

As far as other risks, namely investment credits for exploration, we'll save that for another day.

Best Regards,
Mike Koy
907 250 7169

Emily Stancliff

From: Larry & Rhonda Fisk [fisk@acsalaska.net]

Sent: Tuesday, February 28, 2006 6:40 AM

To: Rep. Jay Ramras

Subject: Oil Tax's

Mr. Ramas,
I am outraged that you and your colleagues are pursuing to put a heavy tax on oil companies because they made a large profit. Oil has brought so much to our state and now I am sure their interest will wane with this action. Tell me why anyone would want to do business here if they had their tax increased heavily because they were making a profit! That is what a business is supposed to do! Do you raise tax's on other citizens because they make a big profit for their families? NO! But oil companies are an easy target seen as the golden cow for you and your state problems. They take all the risk in finding and producing the product while you stand there with your hands out when they actually make a nice profit. Where were you and your cohorts when oil prices were low and many citizens were losing their jobs? I never heard a word of sympathy from you bunch of wolves. I realize this e-mail will make no difference in your decision to enact this tax. I fear that government will always allow their greed and hunger for more money to cloud any good judgment. I know the talk with friends is how sad it is at a time that ConocoPhillips, BP, and other producers are investing so much in our state we reward them with a hefty tax and then laugh about it. You and your friends on the Natural Resources committee are a sorry bunch that I consider pitiful state representatives. Yes, and I AM a republican!

Larry Fisk
P.O. Box 2604
Soldotna, AK 99669

Constituent/**Non-Constituent** Saved/ **Not Saved**

William Phillips of Soldotna (33) wrote the following message On 3/6/2006 at 10:11 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

Under the one third to each oil monies idea, Alaska's share at current oil prices and production would be about 6.5 billions per year. Are we getting it?

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

William Phillips
35555 Spur Hwy # 294
Soldotna AK, 99669-7625
Email:wj_phillips@hotmail.com

Constituent/**Non-Constituent** Saved/ **Not Saved**

Charley Walton of Fairbanks (07) wrote the following message On 3/6/2006 at 12:05 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

Don't give up the farm on the oil production tax. There are still many questions unanswered that I have as well as the one's your asking. This lifeline is important to Alaskans and before we let any gas out of our state we should have a petrochemical plant with Railroad.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Charley Walton
1062 Steele Creek Rd
Fairbanks 99712

Constituent/**Non-Constituent** **Saved/ Not Saved**
Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/7/2006 at 14:45 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
When the drunk shot a hole in the oil line, the oil companies took their time getting around to repair it. Because they were making money at it. The more it leaked, the more they made. The state rewarded negligence. Murkowski's tax plan will extend it to the gathering lines.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:
Jerry Mccutcheon
Po Box 101838
Anchorage AK, 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Clifford Boner of Copper Center (06) wrote the following message On 3/9/2005 at 14:43 about *Oil & Gas*

Message:

Revamp what oil companies pay per barrel of oil and solve some of the States problems. A floating scale with the price of oil would be far to all.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Clifford Boner
Hc 60 Box 2465
Copper Center 99573-9801
day:822-3806

Constituent/**Non-Constituent** Saved/ **Not Saved**

Clifford Boner of Copper Center (06) wrote the following message On 1/18/2006 at 09:48 about *Oil & Gas*

Message:

We need to change the state's oil production tax! Any Legislator against this re-do should resign from office; it looks like you are in the pockets of the oil companies. Get Alaskans what they are due!

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Clifford Boner
Hc 60 Box 2465
Copper Center 99573-9801
day:822-3806

Constituent/**Non-Constituent** Saved/ **Not Saved**
Ron Kovalik of Fairbanks (08) wrote the following message On 1/24/2006 at 14:30 about *Oil & Gas*

Message:
How much longer are you going to keep giving away our crude oil for a fraction of what it is worth?
Does "bought-off" mean anything to you?

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:
Ron Kovalik
Po Box 72563
Fairbanks 99707-2563

Constituent/**Non-Constituent** Saved/ **Not Saved**

William Phillips of Soldotna (33) wrote the following message On 1/30/2006 at 13:37 about *Oil & Gas*

Message:

Note the latest news reports that big oil claims one price to stockholders then a lower price to the feds,cutting 700 million in payments. Conoco Phillips new buy, Burlington Resources is a repeat offender. Don't assume they'll be any more honest with Alaska.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

William Phillips
35555 Spur Hwy # 294
Soldotna AK, 99669-7625
Email:wj_phillips@hotmail.com

Constituent/**Non-Constituent** Saved/ **Not Saved**
Richard Olson of Homer (35) wrote the following message On 1/30/2006 at 16:32 about *Oil & Gas*

Message:
Repeal the ELF now! Make Exxon pay the 6 billion it lost in the oil spill case or start arresting CEOs. DIvide that 6 billion amount all Alaskans. Increase the PFD yearly payout to individual Alaskans. Increase taxes on big oil.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:
Richard Olson
64615 Star Ct
Homer 99603

Constituent/**Non-Constituent** Saved/ **Not Saved**

William Phillips of Soldotna (33) wrote the following message On 2/7/2006 at 15:54 about *Oil & Gas*

Message:

If the oil companies want tax changes as part of any gasline deal, it can only mean Alaska will get stiffed. There is no goodness in their hearts.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

William Phillips
35555 Spur Hwy # 294
Soldotna AK, 99669-7625
Email:wj_phillips@hotmail.com

Constituent/**Non-Constituent** Saved/ **Not Saved**

Clifford Boner of Copper Center (06) wrote the following message On 2/9/2006 at 14:03 about *Oil & Gas*

Message:

Pass the oil tax legislation and put a tax on natural gas. We need the funds to get public safety officers or VPSOs back into the villages. Let's get it done!

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Clifford Boner
Hc 60 Box 2465
Copper Center 99573-9801
day:822-3806

Constituent/**Non-Constituent** Saved/ **Not Saved**

Gail Boerwinkle of Anchorage (25) wrote the following message On 2/22/2006 at 10:44 about *Oil & Gas*

Message:

If you do not stop Murkowski's tax plan for the oil you shgould all be fired. That oil belongs to us, the people of the State of Alaska. It needs to be at 33% not 20%

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Gail Boerwinkle
1210 W 47th Ave Apt 2
Anchorage 99503-6980
day:563-1440

Constituent/**Non-Constituent** Saved/ **Not Saved**

Matthew Erickson of Fairbanks (09) wrote the following message On 2/24/2006 at 03:42 about *Oil & Gas*

Message:

Don't try to tax "net profits" that can be grossly reduced in overspending. A tax of 7% on the barrel, would eliminate many problems. I would also have that increased to 12% if production falls below a certain margin. Keep it simple.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Matthew Erickson
Po Box 70335
Fairbanks 99707-0335
Email:look412_2001@hotmail.com

Constituent/**Non-Constituent** Saved/ **Not Saved**

Kenneth Ambrosius of Palmer (16) wrote the following message On 2/26/2006 at 10:02 about *Oil & Gas*

Message:

RE the Governor's oil & gas tax bill - PLEASE look to Alaska's intrests, the tax rate should be 25%, and there should be no credits for investments already made. Don't give the state's resources away for less than they are worth.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Kenneth Ambrosius
1005 N Witherspoon Rd.
Palmer 99645-9510
Email:kcbrosus@mtaonline.net
day:564-5139
eve:745-3860
organization:myself

Constituent/**Non-Constituent** Saved/ **Not Saved**

Gordon Pospisil of Anchorage (26) wrote the following message On 2/27/2006 at 07:58 about *Oil & Gas*

Message:

The Gas Pipeline and Oil Tax legislation proposed by the governor gives Alaskans the opportunity to participate in sustained production from Alaska's oil and gas resources at the highest rate in the US. You should support these bills for the benefit of all Alaskans.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Gordon Pospisil
3001 Mccollie Ave
Anchorage 99517
Email:blythewm@msn.com

Constituent/**Non-Constituent** Saved/ **Not Saved**

Richard Melms of Anchorage (31) wrote the following message On 2/27/2006 at 16:38 about *Oil & Gas*

Message:

Congratulations on tackling the issue of oil taxation. This is long overdue and difficult. Pls make the best decision for Alaska. The resources are ours and the oil companies have had a "sweetheart" deal for to long. We are counting on all of you to protect our interests first. Thank y

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Richard Melms
4201 Leyden Rd
Anchorage 99516
Email:rdzmelms@alaska.net
day:907 3456184
eve:907 3456184

Constituent/**Non-Constituent** Saved/ **Not Saved**

Matthew Erickson of Fairbanks (09) wrote the following message On 2/28/2006 at 03:32 about *Oil & Gas*

Message:

PLEASE!! Should we support an oil tax scheme, that causes government to desire continued high oil prices? Flat percent tax on each barrel of oil, and penalty tax for under production, is the only fair and equitable way!

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Matthew Erickson
Po Box 70335
Fairbanks 99707-0335
Email:look412_2001@hotmail.com

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:39 about *Oil & Gas*

Message:

Taxes before gasline contract, weird! Most of you know that Pedro vanMeurs said for Governor Murkowski in Anchorage that just because the oil companies sign a gasline contract the contract is not going to obligate the oil companies to construct a gasline.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:43 about *Oil & Gas*

Message:

Why are you buying a pig in a poke when you are not allowed to even see the poke let alone the pig? What harm could it do to at least see the gasline contract?

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:46 about *Oil & Gas*

Message:

The gasline contract contains provisions that allow the oil companies to just quit in 3 or 4 years after signing the gasline contract. After that they have to offer a reason like they do not think the gasline is in their best interest.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** Saved/ **Not Saved**

Jerry Mccutcheon of Anchorage (23) wrote the following message On 3/1/2006 at 15:48 about *Oil & Gas*

Message:

Do you often buy pigs in pokes for your own business when you are not even allowed to see the poke? Then why are you conducting the States business in a manner that you would not tolerate in your own business.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Jerry Mccutcheon
Po Box 101838
Anchorage 99510-1838

Constituent/**Non-Constituent** **Saved**/ Not Saved
Stephen Conn of Seward (35) wrote the following message On 2/27/2006 at 14:58 about *Oil & Gas*

Message:
During your deliberations on the new tax structure, please discover what will motivate Exxon-Mobil to enter into settlement deliberations on Exxon Valdez? ASK EVERY COMPANY REPRESENTATIVE.

Message was delivered by Pom

View Case Delete case

Contact Info:
Stephen Conn
Po Box 1690
Seward AK, 99664-1690
Work:2246061
Home:2246061
Email:steveconn@hotmail.com

Alaska State Public Opinion Message System:

Rep Ralph Samuels's office

Filter applied is: All

Messages About HB 488

There are 7 messages about HB 488

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Sort messages by: District or Date or Last_Name or <Subject>

Messages

Constituent/**Non-Constituent** Saved/ **Not Saved**

Connie Ballow of Valdez (12) wrote the following message On 2/25/2006 at 11:06 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

I want the legislature to slow down and implement the public process for hearing HB488 and SB305. I'm outraged this bill was created behind closed doors. The public needs time to assess this bill point by point and then give you our opinion.

Message was delivered by Pom
The number of original recipients of this message is 27

Save case Delete case

Contact Info:

Connie Ballow
Po Box 2911
Valdez 99686-2911

Go to Main Menu | Go to Search Page

Constituent/**Non-Constituent** Saved/ **Not Saved**

Richard Ballow of Copper Center (12) wrote the following message On 2/25/2006 at 11:15 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

I want the legislature to slow down and implement the public process for hearing HB488 and SB305. I'm outraged this bill was created behind closed doors. The public needs time to assess this bill point by point and then give you our opinion.

Message was delivered by Pom
The number of original recipients of this message is 27

Save case Delete case

Contact Info:

Richard Ballow
PO Box 160
Copper Center 99573

Constituent/**Non-Constituent** Saved/ **Not Saved**

Thomas Patmor of Clam Gulch (34) wrote the following message On 2/27/2006 at 15:15 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

If a big company makes 10 billion dollars and are charged 2 billion taxes which they reinvest and so are thus charged nothing for the oil that year,decides to sell out to smaller satellite companies making less that 73 million, they still get the oil for nothing every year.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Thomas Patmor
Po Box 124
Clam Gulch 99568-0124

Constituent/**Non-Constituent** Saved/ **Not Saved**

Thomas Patmor of Clam Gulch (34) wrote the following message On 2/28/2006 at 12:14 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

Expecting oil companies to voluntarily pay their taxes doesn't always work, traditionally. We've just been paying millions for lawyers' fees trying to collect. If we charge them for the oil as soon as it's out of the ground, we'd have the money and they could apply to be reimbursed accordingly.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Thomas Patmor
Po Box 124
Clam Gulch 99568-0124

Constituent/**Non-Constituent** Saved/ **Not Saved**

William Phillips of Soldotna (33) wrote the following message On 3/6/2006 at 10:11 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

Under the one third to each oil monies idea, Alaska's share at current oil prices and production would be about 6.5 billions per year. Are we getting it?

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

William Phillips
35555 Spur Hwy # 294
Soldotna AK, 99669-7625
Email:wj_phillips@hotmail.com

Constituent/**Non-Constituent** **Saved/ Not Saved**

Charley Walton of Fairbanks (07) wrote the following message On 3/6/2006 at 12:05 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

Don't give up the farm on the oil production tax. There are still many questions unanswered that I have as well as the one's your asking. This lifeline is important to Alaskans and before we let any gas out of our state we should have a petrochemical plant with Railroad.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Charley Walton
1062 Steele Creek Rd
Fairbanks AK, 99712

Constituent/**Non-Constituent** **Saved**/ Not Saved

William Phillips of Soldotna (33) wrote the following message On 2/23/2006 at 10:53 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

The fact that big oil executives are pleased with the oil tax proposal has me paraphrasing a country song, big oil gets the gold mine and alaska gets the shaft. No deal is better than a bad deal.

Message was delivered by Pom

View Case Delete case

Contact Info:

William Phillips
35555 Spur Hwy # 294
Soldotna AK, 99669-7625
Email:wj_phillips@hotmail.com

Alaska State Public Opinion Message System:

Rep Ralph Samuels's office

Filter applied is: All

Messages About SB 305

There are 13 messages about SB 305

Save all messages about SB 305
Delete all messages about SB 305
Sort messages by: District or Date or Last_Name or <Subject>

Messages

Constituent/**Non-Constituent** **Saved**/ Not Saved
Russell Holmes of Anchorage (21) wrote the following message On 2/22/2006 at 15:58 In opposition of *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
Please oppose HB488 and SB305. It is a loss of tax revenues of hundreds of millions. Please oppose any bill related to taxes or anything to do with oil/gas contracts until there is a guarantee of a 100% all Alaskan pipe line and a supply to South Central.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Russell Holmes
5842 Jennifer Cir #2a
Anchorage 99504-4344
Email:rahrahrah@gci.net
day:339-0352

Go to Main Menu | Go to Search Page

Constituent/**Non-Constituent** **Saved**/ Not Saved
Kenneth Ambrosius of Palmer (16) wrote the following message On 2/26/2006 at 16:13 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
RE: Governor's oil tax - make tax rate 25%, no standard deduction, no credit for investments already made. If producers claim gas pipeline is 'uneconomic' as result start negotiations with pipeline company that is already in pipeline business or with ANGDA. Don't let the Governor give too much away.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Kenneth Ambrosius
1005 N Witherspoon Rd.
Palmer AK, 99645-9510
Work:564-5139
Home:745-3860
Email:kcbrosus@mtaonline.net

Constituent/**Non-Constituent** **Saved**/ Not Saved
Charley Walton of Fairbanks (07) wrote the following message On 2/28/2006 at 09:17 In opposition of
SB 305 OIL AND GAS PRODUCTION TAX

Message:
Concerning Oil Production Tax: The governor starts with secret negotiations, all parties have come to a compromise pipeline agreement, two days later oil official testifies will discourage oil industry from working Alaska. If they don't like this tax bill then raise the taxes. Trouble paying my bills on their profits.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Charley Walton
1062 Steele Creek Rd
Fairbanks AK, 99712

Constituent/Non-Constituent **Saved**/ Not Saved

Albert Rothfuss of Copper Center (06) wrote the following message On 3/10/2006 at 12:56 about *Oil & Gas*

Message:

If we didn't allow Alyeska to lay off so many people, someone could be there to check the line instead of reading a guage. You can't replace a set of eyes for technology.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:

Albert Rothfuss
Po Box 4
Copper Center AK, 99573-0004
Work:822-5367

Constituent/**Non-Constituent** **Saved**/ Not Saved
Burle Beard of Fairbanks (07) wrote the following message On 3/14/2006 at 10:30 about *Oil & Gas*

Message:
Remember our ferry in Vancouver? Do not vote for the gas pipeline through Canada. Putting a national resource in the hands of another is stupidity at its greatest.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Burle Beard
1721 Moose Trl
Fairbanks AK, 99709-6617
Work:479-3640

Constituent/**Non-Constituent** **Saved**/ Not Saved
Lorne Smagge of Kenai (33) wrote the following message On 3/13/2006 at 10:32 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
and SB 305. We need to reconsider HB 488 & SB 305. In my opinion they are counter productive for the Cook Inlet Region. These two pieces of Legislation will effectively kill the life of Cook Inlet. ELF should be left alone under these conditions.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
Lorne Smagge
Po Box 2326
510 Hemlock Ave
Kenai 99611
day:252-6972

Constituent/**Non-Constituent** **Saved**/ Not Saved

Loren Smagge of Kenai (33) wrote the following message On 3/13/2006 at 08:20 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

We need to reconsider HB488 and SB305. In my opinion they are counter productive for the Cook Inlet region. These two pieces of legislation will effectively kill the life of Cook Inlet. ELF should be left alone under these current conditions.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Loren Smagge
PO Box 2326
Kenai 99611
Email:lsmagge@alaska.net

Constituent/**Non-Constituent** **Saved**/ Not Saved

Paul Delago Sr of Kenai (34) wrote the following message On 3/10/2006 at 14:33 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

The long term economic viability of the Cook Inlet oil fields is an important part of the state and local economy. Elimination of the ELF will significantly shorten the life of aging fields and jeopardize the future of many families living here. Thank you for your time.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Paul Delago Sr
46125 Spruce Pl
Kenai 99611
Email:delagpa@chevron.com

Constituent/**Non-Constituent** **Saved**/ Not Saved

Gregory Thorsell of Anchorage (32) wrote the following message On 3/13/2006 at 13:52 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

and SB 305. Please consider amending the PPT bill to exclude Cook Inlet. The Cook Inlet area fields are very mature and are necessary to support the majority of the State's population. This area needs incentives for development much more than dis-incentives like additional taxes.

Message was delivered by Pom
The number of original recipients of this message is 39

View Case Delete case

Contact Info:

Gregory Thorsell
14730 Park Hills Cir
Anchorage 99516
day:263-7642

Constituent/**Non-Constituent** **Saved**/ Not Saved

Paul Bartolowits of Clam Gulch (34) wrote the following message On 3/13/2006 at 14:40 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

This bill shouldn't include Cook Inlet. Chevron made a decision to invest 100,000,000 in Cook Inlet under current tax rules. This bill would change investment strategy. They pulled out when they were pushed over the Kenai refinery. It could happen again. An ugly event for Kenai Borough & State.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Paul Bartolowits
Po Box 528
Clam Gulch 99568-0528
day:262-4945

Constituent/**Non-Constituent** **Saved**/ Not Saved

Paul Bartolowits of Clam Gulch (34) wrote the following message On 3/13/2006 at 14:42 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

This bill shouldn't include Coook Inlet. Chevron made a decision to invest $100,000,000 in Cook Inlet under current tax rules.Investment strategies would change. They pulled out when pushed over the Kenai Refinery. It could happen again. An ugly event for the Kenai Borough and the State.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Paul Bartolowits
Po Box 528
Clam Gulch 99568-0528
day:262-4945

Constituent/**Non-Constituent** **Saved**/ Not Saved

James Isham of Soldotna (34) wrote the following message On 3/14/2006 at 10:30 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

I strongly advise all House, Senate and Committee members to amend the PPT bill to exclude Cook Inlet from new taxes as this will impact my livelyhood.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

James Isham
Po Box 51
Soldotna 99669-0051
Email:sawadee@alaska.net

Constituent/**Non-Constituent** **Saved**/ Not Saved
James Isham of Soldotna (34) wrote the following message On 3/14/2006 at 10:31 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
I strongly advise all House and Senate and Committee members to amend the PPT bill to exclude Cook Inlet from new taxes as this will impact my livelihood.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
James Isham
Po Box 51
Soldotna 99669-0051
Email:sawadee@alaska.net

Constituent/**Non-Constituent** **Saved**/ Not Saved

Charley Walton of Fairbanks (07) wrote the following message On 3/14/2006 at 07:48 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

Samuels tax proposal should start about $30 per barrel. You forget that the Legislature's wages go up and the poor humble people out here in the real world don't get any raises. The idea is to keep the price of oil down unless you are going to increase our PFD.

Message was delivered by Pcm
The number of original recipients of this message is 60

View Case Delete case

Contact Info:

Charley Walton
1062 Steele Creek Rd
Fairbanks AK, 99712

Constituent/**Non-Constituent** **Saved**/ Not Saved
Charley Walton of Fairbanks (07) wrote the following message On 3/14/2006 at 08:13 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
You should be taxing on gross profits - not net profits. After 25 billion dollar line there won't be any net profits. It's just the price of doing business - gross profits.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Charley Walton
1062 Steele Creek Rd
Fairbanks AK, 99712

Constituent/**Non-Constituent** **Saved**/ Not Saved
David Birchfield of Soldotna (33) wrote the following message On 3/14/2006 at 08:34 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
SB305 Cook Inlet contains mature oil/gas properties that cannot withstand additional tax. Any increase in Cook Inlet will negatively impact pending investments. My wife and I are life long Alaskan residents. We have raised three children here. I've worked for thirty years in Cook Inlet. Help protect our future. Thanks

Message was delivered by Pom
The number of original recipients of this message is 33

View Case Delete case

Contact Info:
David Birchfield
Po Box 442
Soldotna 99669-0442
Email:birchdr@ptialaska.net
day:262-1468

Constituent/**Non-Constituent** **Saved**/ Not Saved

David Cole of Anchorage (31) wrote the following message On 3/14/2006 at 09:04 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

and SB 305. This new petroleum profits tax bill should be amended to exclude the Cook Inlet Fields from new taxes. The Cook Inlet contains mature fields, both oil & gas, that cannot withstand additional taxes. Any increase in tax in Cook Inlet will negatively impact the investment climate.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

David Cole
2941 Capstan Dr
Anchorage 99516-3508
Email:dcole@chevron.com
day:263-7805

Constituent/**Non-Constituent** **Saved**/ Not Saved
James Isham of Soldotna (34) wrote the following message On 3/14/2006 at 12:04 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
I strongly advise all House and Senate and Committee Members to exclude Cook Inlet from new taxes as this will impact my livelyhood.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
James Isham
Po Box 51
Soldotna 99669-0051
Email:sawadee@alaska.net

Constituent/Non-Constituent **Saved/** Not Saved
David Buthman of Eagle River (17) wrote the following message On 3/14/2006 at 11:08 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
and SB 305. Changing tax laws for the long lead time oil & gas activities is bad business. Just when Alaska is starting to boom, with fiscal terms similar to the lower 48 but with larger resources, the legislature wants to pull the rug and I get transferred out!

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
David Buthman
19503 Highland Ridge Dr
Eagle River 99577-8595
Email:davebuthman@gci.net
day:263-7699

Constituent/**Non-Constituent** **Saved**/ Not Saved
William Phillips of Soldotna (33) wrote the foilowing message On 3/14/2006 at 09:15 about *HB 488 OIL AND GAS PRODUCTION TAX*

Message:
Ignore Conoco-Phillips tax whine ads. Big oil is being shut out of other countries as those countries take over control of their own oil. If Conoco-Phillips wants to leave, there will be plenty of others to take their place.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
William Phillips
35555 Spur Hwy # 294
Soldotna AK, 99669-7625
Email:wj_phillips@hotmail.com

Constituent/**Non-Constituent** **Saved**/ Not Saved

James Isham of Soldotna (34) wrote the following message On 3/14/2006 at 10:33 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:

I strongly adivse all House, Senate and Committee members to amend the PPT bill to exclude Cook Inlet from new taxes as this will impact my livelyhood.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

James Isham
Po Box 51
Soldotna 99669-0051
Email:sawadee@alaska.net

Constituent/**Non-Constituent** **Saved**/ Not Saved

Paul Bartolowits of Clam Gulch (34) wrote the following message On 3/13/2006 at 14:47 about: *SB 305 OIL AND GAS PRODUCTION TAX*

Message:

This bill shouldn't include Cook Inlet. Chevron made a decisic.. to invest 100,000,000 in Cook Inlet under current tax rules. This bill would change investment strategy. They pulled out when they were pushed over the Kenai refinery. It could happen again. An ugly event for Kenai Borough & State.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Paul Bartolowits
Po Box 528
Clam Gulch 99568-0528
day:262-4945

Constituent/**Non-Constituent** **Saved**/ Not Saved
Janet Nelson-dormady of Kenai (33) wrote the following message On 3/13/2006 at 15:04 In opposition of *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
and HB 488.These bills provide no incentives for energy companies to invest in Cook Inlet and will have an adverse affect on the Kenai Peninsula economy and the State. Do not change the tax base on the oil and gas properties in the State. NO NEW Taxation On The Industry.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
Janet Nelson-dormady
1507 Fathom Dr
Kenai 99611-7914
Email:dormady2@acsalaska.net

Constituent/**Non-Constituent** **Saved**/ Not Saved

Paul Bartolowits of Clam Gulch (34) wrote the following message On 3/13/2006 at 15:26 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:

and HB488 shouldn't include Cook Inlet. Chevron made a decision to invest 100,000,000 in Cook Inlet under current tax rules. This bill would change investment strategy. They pulled out when they were pushed over the Kenai refinery. It could happen again. An ugly event for Kenai Borough and State.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Paul Bartolowits
Po Box 528
Clam Gulch 99568-0528
day:?62-4945

Constituent/**Non-Constituent** **Saved**/ Not Saved

Ralph Affinito of Anchorage (32) wrote the following message On 3/13/2006 at 16:55 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:

The PPT bill should be amended to exclude the Cook Inlet from new taxes but still have incentives to initiate new exploration and development.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:

Ralph Affinito
5436 Woodshire Cir
Anchorage 99516

Constituent/**Non-Constituent** **Saved**/ Not Saved
Lee Tanner of Kenai (33) wrote the following message On 3/13/2006 at 14:12 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
and HB 488. The PPT bill should be amended to EXCLUDE the Cook Inlet from new taxes while still providing incentives to spur additional investments in the Cook Inlet area.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
Lee Tanner
PO BOX 1678
Kenai 99611
Email:tannerl@cheveron.com
day:776-6825

Constituent/**Non-Constituent** **Saved**/ Not Saved
Philip Bindon of Wasilla (15) wrote the following message On 3/13/2006 at 14:19 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
and HB 488. The PPT bill should be amended to exclude the Cook Inlet from new taxes while still providing incentives to spur additional investment in the Cook Inlet area.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
Philip Bindon
2390 Cranberry
Wasilla 99654
day:350-1822

Constituent/**Non-Constituent** **Saved**/ Not Saved
Martha Henderson of Anchorage (27) wrote the following message On 3/13/2006 at 14:22 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
and HB 488. The PPT bill should be amended to exclude the Cook Inlet from new taxes while still providing incentives to spur additional investment in the Cook Inlet area.

Message was delivered by Pom
The number of original recipients of this message is 18

View Case Delete case

Contact Info:
Martha Henderson
7501 Setter Dr
263-7665
Anchorage 99502

Constituent/**Non-Constituent** **Saved**/ Not Saved
Jeffrey Smetanka of Anchorage (32) wrote the following message On 3/14/2006 at 11:32 about *SB 305 OIL AND GAS PRODUCTION TAX*

Message:
and HB 488. The PPT bill should be amended to exclude the Cook Inlet from new taxes while still providing incentives to encourage additional investment in the area.

Message was delivered by Pom
The number of original recipients of this message is 17

View Case Delete case

Contact Info:
Jeffrey Smetanka
5124 Cape Seville Dr
Anchorage 99516
Email:jeff.smetanka@acsalaska.net
day:263-7622

Jane Pierson

From: LIO Fairbanks
Sent: Monday, March 13, 2006 7:32 AM
To: Jane Pierson
Subject: FW: House Resource Committee Bill 488
Attachments: 64669.jpg; ATT1193645.txt

One more ---

From: Alice Reeves [mailto:ar3753@mosquitonet.com]
Sent: Fri 3/10/2006 4:13 PM
To: undisclosed-recipients
Subject: House Resource Committee Bill 488

I would like to able to trust my governor to get the best deal for the people, but Governor Jay Hammond broke me from handing out blank checks.
Our governor is good at playing politics with the" Big Boys" in Washington, but I am afraid when it comes to dealing with the Big Oil Companies that he is out of his league.
The oil companies have the best lawyers that money can buy and they are not above lying to get what they want.
I would like to see how the gas pipeline is being tied into this, before supporting the bill.
Legislator Ralph Seekins has copies of lies taken right out of Atlantic Richfield's folders (ARCO), where they promised they would never block the public except in section 4 on the 510 acres that they purchased from DNR. I am sure he would share them with you.
If you don't have a copy of "Alaska Agonistes" by Joe E. LaRocca I suggest you get it and read it. he exposes the crooked deals of the oil companies and our past governors.
I have clipping from the Fairbanks News Miner sent from Juneau News paper on march the 22nd 1969 that I would like to share with you. Then I found the Joe LaRocca had used it on the inside cover of his book and he says it best.

One of Alaska's most revered political figures uncannily foretold this sad state of affairs more than 30 years ago. At a meeting of the Senate Resources Committee on March 22, 1969 considering a bill which would retain a long-standing policy of non-competitive oil and gas leasing in Alaska in the face of efforts to repeal it, State Senator John Butrovich, in support of the bill, which he sponsored, prophetically declaimed: "The majors are going to own the whole damned state. You'll rue the day. The majors will own you. They have no soul...robber barons don't change." His warning was ignored, and "Butro," who died in 1997, lived long enough to see his prophecy fulfilled.

Constituent/**Non-Constituent** **Saved**/ Not Saved
Wilfred Blais Sr of Delta Junction (06) wrote the following message On 3/9/2006 at 09:33 about *Miscellaneous*

Message:
Add increased oil taxes to govenors bill if oil companies do not proceed with gas line in a timely manner. make increase retroactive. They afterall are trying to hold us hostage to the oil tax bill with the gas line.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Wilfred Blais Sr
Po Box 473
Delta Junction 99737-0473
Email:luckylynn@wildak.net

Constituent/**Non-Constituent** Saved/ **Not Saved**
William Phillips of Soldotna (33) wrote the following message On 3/9/2006 at 10:06 In opposition of
HB 488 OIL AND GAS PRODUCTION TAX

Message:

CONCO Phillips purchased Canadian and lower 48 gas producer Burlington Resources. They don't need AK natural gas now. Frank has been dazzled by big oil BS into an oil tax scheme big oil can manipulate to their benefit. Not Alaska's.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

William Phillips
35555 Spur Hwy # 294
Soldotna AK, 99669-7625
Email:wj_phillips@hotmail.com

Constituent/**Non-Constituent** **Saved**/ Not Saved
James Wright of Cantwell (08) wrote the following message On 3/9/2006 at 07:29 about *Taxation*

Message:
It is said that figures never lie, but that liars figure. Such a deal, taxing net profit. I wish my Federal Income Tax was based on my net profit. I visualize oil companies dancing with glee. Tax oil-gas production, not managed net profits. Play safe, don't gamble with Alaskas future.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
James Wright
Po Box 9
Mile 131.5 Denali Highway
Cantwell AK, 99729-0009
Work:(907) 768-2434
Email:akflier@hotmail.com

Constituent/**Non-Constituent** Saved/ **Not Saved**

Charley Walton of Fairbanks (07) wrote the following message On 3/9/2006 at 11:00 In opposition of *HB 488 OIL AND GAS PRODUCTION TAX*

Message:

I have been keeping up on the Oil Production Tax on Gavel to Gavel. Murkowski is trying to give away too much. The consultants even agree. No to big oil running Alaska. Thank you.

Message was delivered by Pom
The number of original recipients of this message is 60

Save case Delete case

Contact Info:

Charley Walton
1062 Steele Creek Rd
Fairbanks AK, 99712

Constituent/Non-Constituent **Saved**/ Not Saved

Lapriel Stephan of Anchorage (29) wrote the following message On 3/15/2006 at 15:09 about *Oil & Gas*

Message:

Can't you ever leave well enough alone. Keep the 20% agreement as Governor Murkowski negotiated it. Stop being so greedy. We need a gas pipeline. Thank-you

Message was delivered by Pom

View Case Delete case

Contact Info:

Lapriel Stephan
Po Box 112114
Anchorage AK, 99511-2114

Constituent/**Non-Constituent** **Saved**/ Not Saved
Patricia Stark of Fairbanks (07) wrote the following message On 3/15/2006 at 08:55 about *Oil & Gas*

Message:
Please alter the governor's oil tax plan. I think a higher percentage would be good. And the provision where if oil goes above say $70 a barrel, the State can raise the tax. This way we would not be stuck with a low tax when oil prices are high.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Patricia Stark
Po Box 82525
Fairbanks 99708-2525
Email:pstark@mosquitonet.com

Constituent/**Non-Constituent** **Saved**/ Not Saved
Roger Davis of Homer (35) wrote the following message On 3/14/2006 at 16:27 about *Taxation*

Message:

A "maximum benefit" on resource extraction for the people of this state is a constitutional requirement. To let the Oil "Overlords" dictate what they are willing to pay is to take the power of taxation from the people and hand it to the extractors...a constitutional violation.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:

Roger Davis
3817 Bartlett St
Homer 99603
Email:rogerdavis@gci.net
day:235 5650
eve:235 5650
organization:god&country

Constituent/**Non-Constituent** **Saved**/ Not Saved
Roger Davis of Homer (35) wrote the following message On 3/14/2006 at 16:58 about *Taxation*

Message:
To "low ball" the tax on nonrenewable resources to satisfy the Oil "Overlords" and their investors, while being threaten by them of going else where...is black mail. The generations of Alaskan children to come are the investors of consequence, the ones the legislature should be protecting.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Roger Davis
3817 Bartlett St
Homer 99603
Email:rogerdavis@gci.net
day:235 5650
eve:235 5550
organization:god&country

Constituent/**Non-Constituent** **Saved**/ Not Saved
Roger Davis of Homer (35) wrote the following message On 3/14/2006 at 17:04 about *Taxation*

Message:
Don't let the "Greed" of the present steal from the future, leave something for the children of tomorrow. The Alaskan Constitution says that the source of government is founded upon the will of the people only...it says nothing about the will of the Oil "Overlords".

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Roger Davis
3817 Bartlett St
Homer 99603
Email:rogerdavis@gci.net
day:235 5650
eve:235 5650
organization:god&country

Constituent/**Non-Cons ..uent** **Saved**/ Not Saved
Roger Davis of Homer (35) wrote the following message On 3/14/2006 at 21:41 about *Taxation*

Message:
The Oil "Overlord's" latest ad has one of their hired hands stating, "raising their tax shows that the state does not appreciate their investment"...this from a industry that has made billions in profit from Alaskans while paying the least amount of taxes compared to anywhere else in the world.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Roger Davis
3817 Bartlett St
Homer 99603
mail:rogerdavis@gci.net
ay:235 5650
eve:235 5650
organization:god&country

Constituent/**Non-Constituent** **Saved**/ Not Saved
Roger Davis of Homer (35) wrote the following message On 3/14/2006 at 22:00 about *Taxation*

Message:
The Oil "Overlords" are well able to take care of themselves, the Alaska legislature constitutional obligation is to the people of this state. One gets the impression that the "Overlords" idea of appreciation is the kissing of their backside while their "shills" are working out how to continue the "screwing".

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Roger Davis
3817 Bartlett St
Homer 99603
Email:rogerdavis@gci.net
day:235 5650
eve:235 5650
organization:god&country

Constituent/**Non-Constituent** **Saved**/ Not Saved
Michael States of Fairbanks (09) wrote the following message On 3/15/2006 at 13:44 In opposition of
HB 488 OIL AND GAS PRODUCTION TAX

Message:
Republicans will be replaced if they do the Murkowski deal, or any variation of it. Gas Line and Oil Taxes are separate issues. Raise the taxes. Tax the gas in the ground.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Michael States
Po Box 81485
Fairbanks 99708-1485

Constituent/**Non-Constituent** **Saved**/ Not Saved
Michael States of Fairbanks (09) wrote the following message On 3/15/2006 at 13:40 In opposition of
HB 488 OIL AND GAS PRODUCTION TAX

Message:
I am a 40-year-Alaskan and conservative Republican who always votes. Do NOT go anywhere near Murkowski's tax or gasline deal. Throw it out the window. Start over again. The Oil Companies are laughing at you. Well they should.

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Michael States
Po Box 81485
Fairbanks 99708-1485

Constituent/**Non-Constituent** **Saved**/ Not Saved
Michael States of Fairbanks (09) wrote the following message On 3/15/2006 at 13:47 In opposition of
SB 305 OIL AND GAS PRODUCTION TAX

Message:
Do not spend a penny on Murky's P.R. campaign!!! We are watching you! Put excess money into the Perm Fund for rainy days. Don't spend it all! Mike States

Message was delivered by Pom
The number of original recipients of this message is 60

View Case Delete case

Contact Info:
Michael States
Po Box 81485
Fairbanks 99708-1485

Maxine Blake

From: Margo Waring [margowaring@ak.net]
Sent: Thursday, March 16, 2006 10:13 AM
To: Rep. Ralph Samuels; Rep. Jay Ramras; Rep. Paul Seaton; Rep. Kurt Olson; Representaive_James_Elkins@legis.state.ak.us; Rep. Mary Kapsner; Rep. Carl Gatto; Rep. Gabrielle LeDoux; Rep. Harry Crawford
Cc: Rep. Beth Kerttula
Subject: oil taxation

live in Juneau

To House Resources Committee:

I am writing regarding oil tax proposals. I know that the oil companies are saying that Governor Murkowski's proposal is in line with what the companies have historically paid in Alaska production taxes. I haven't looked at the numbers to know if this is true or not. But I do know that the numbers you should be looking at are what they would have been paying if Governor Hammond had not changed the ELF. He had been taken in by the industry's claims, but Gov. Hammond publicly acknowledged that this was the biggest mistake of his career, depriving Alaska of revenues it deserved.
Please don't make the same mistake.

I support the 30%, no investment credits (made at a time of exceptionally large industry profits) and the proposed sliding scale, but with no cap.
Oil and gas resources belong to the people of Alaska and you are sworn to not give these away to private interests.

The industry always poor mouths and claims fair taxes will limit their ability to do business in Alaska. But the truth of the situation is that they make profits at anything above $10 per barrel (independent analyst, Richard Fineberg). We are in the new era of "peak oil", that is, worldwide production is in decline. Each remaining barrel brings an increasingly higher price, because demand is increasing worldwide.

Sincerely,
Margo Waring

Alaska State Legislature

Sent 3-14-06 5 pgs

MAR 16 2006

Please enter into the record my testimony to the HOUSE RESOURCE committee name

committee on HB 488 bill/subject . dated 3-14-06 .

Subject: Elimination of ELF

Sirs,
As you well know, the Cook Inlet oil fields are very mature and extremely challenging to operate in a manor that is profitable enough to out weigh the risks involved. My families as well as thousands of people in the Cook Inlet region rely heavily on the long term economic viability of this field. Elimination of the ELF without a doubt will significantly shorten the life of this field and cause more harm than good to the State of Alaska.

Chevron

Paul Delago
Production Foreman
Unocal Alaska Business Unit
Trading Bay Production Facility
907-776-6855
Monopod Platform
907-776-6672
Cell 398-9943

Signed: _____
Testifier

_____
Representing (Optional)

_____
Address

_____
Phone No.

LIO Fairbanks

From: Len Osimowicz [LenO@fcmhc.org] **Sent:** Fri 3/10/2006 10:18 AM
To: LIO Fairbanks
Cc:
Subject: oil taxation system
Attachments:

Please consider a progressive tax. Listen to the oil consultants you hired and not the "big oil companies"

Thanks

Len Osimowicz

Confidentiality Notice: The information disclosed within this email is intended only for the use of the individual(s) named above. If you are not the intended recipient, please return this message to sender. The information disclosed may be considered Confidential and may be protected under state law or federal regulations. These laws and regulations prohibit any further disclosure of this information without the specific written consent of the person to whom the information pertains, or as otherwise permitted by laws and regulations. Re-disclosure of this information is a violation of HIPAA laws and may subject the offender to civil and/or criminal penalties.

LIO Fairbanks

From: Mary and Tim [yetna@acsalaska.net] **Sent:** Fri 3/10/2006 9:44 AM
To: LIO Fairbanks
Cc:
Subject: Overhaul of Oil Tax
Attachments:

To whom it may concern,

It is impossible to make a decision without making all the information available to those making the decision. This seems to be the position the governor is putting the legislators in by keeping the details of the gas pipeline deal secret and asking the legislators to pass a change in the way the state receives its revenue from the oil industry.

Any decisions made by the legislators and the governor today will affect the residents of this state and the economic well being of the state for years to come. Why would a governor who should have those concerns as the elemental driving force of his administration (after all he is a pub_ SERVANT) place the electorate and the legislators in a position of limited knowledge? It seems something is amiss here and the legislators should stand strong and demand disclosure.

Thank you for considering my comments,
Mary A. Calmes

LIO Fairbanks

From: Mike Hersey [kicksaver@acsalaska.net] **Sent:** Thu 3/9/2006 11:22 PM
To: LIO Fairbanks
Cc: Tom Brice Jr.
Subject: Oil and gas legislation
Attachments:

Since Gov. Murkowski is rated at the bottom of the list of governors in the United States and has already acted like a bull in the china cabinet why don't we let his term expire before we make any long term deal with the BIG THREE. We have waited many years for this deal and the gas is becoming harder to find. We will not lose an opportunity, and if we do it may be better than making a deal without knowing what you are signing off on. If you were my lawyers, you would not be signing any agreement that you didn't read and fully understand. Murkowski has nerve even suggesting that we should take his word for anything. mike hersey

3982 lancelot dr.
North Pole Ak. 99705

LIO Fairbanks

From: Robert Perry [robert_perry@dot.state.ak.us] **Sent:** Fri 3/10/2006 8:49 AM
To: LIO Fairbanks
Cc:
Subject: HB 488
Attachments:

The proposed legislation does not address the approprate reembursement for what the oil companies extract from the ground. A flat rate per barrel taken at the well head and take the accountants out of the mix makes accountability fair and just for both parties involved. Operating expenses can be monipulated, but flat rate per barrel as it is taken out of Alaskan soil makes for a friendly business relationship with large and small producers. Simplicity should be our goal so that everyone knows what is expected.

Robert Perry

LIO Fairbanks

From: Wendee Colette [wendee.colette@chugach-ak.com] **Sent:** Fri 3/10/2006 11:05 AM
To: Fairbanks_LIO@legis.state.ak.us.
Cc:
Subject: House Bill 488
Attachments:

I think the tax bill should NOT be linked to the gas line. I feel that Gov. Murkowski can not be trusted to do what is right for Alaskans and the mere fact he is trying to push this through merits a closer look. Slow down, give us all a chance to get up to speed on what is truly going on before we are forced to vote on it.

Wendee Colette
907-452-4811
fax 907-456-2875

You forwarded this message on 3/10/2006 1:15 PM.

LIO Fairbanks

From: Ken Larson [larson_ken@hotmail.com] **Sent:** Fri 3/10/2006 12:41 PM
To: LIO Fairbanks
Cc:
Subject: Statement FOR Increasing Oil Taxes
Attachments:

Ken & Marla Larson
1074 Eliz Street
North Pole, AK 99705
(907) 488-2960
Email: larson_ken@hotmail.com

REF: Overhaul of the State's Oil Taxation System

Gentlefolk of the House Resources Committee:

Thank you for this oppurtunity to express my concern about Governor Murkowski's proposed Oil Tax Bill. His actions prior to formally introducing his Oil Tax Bill surely indicates his close ties to the Big Oil companies! It's obvious the oil companies are calling his shots even more so than they were for VP Dick Cheney, and you see what happened to him! This is doing a disservice to the State of Alaska! Let's face it, **Alaska is a SUPER GOOD DEAL for the oil companies** and they know it!

I have been following UAF's Prof. Doug Reynolds' oil tax analysis books and articles fairly closely and have to say I agree with most of what he says. As he said in his 5 Mar 06 News-Miner Article, **the oil companies' "...earnings based on price rises are not due to skill or hard work but due to world events and marketplace forces. There is no reason to reward oil companies for OPEC-induced price changes."** The Guv's proposed 20% tax rate on net profits and 20% deduction on capital expenses is supposed to yield an effective profits tax of about 60% according to the various experts. This compares rather poorly to the rest of the world where many countries have an effective profits tax of 80%. As a result I strongly support Doug Reynolds' idea of a Progressive Tax Rate when high prices generate progressive revenues.

Go ahead and establish a 25% profit tax rate/20% deduction or something close to that now while Oil is around $60/barrel, and include a GDP-indexed inflation rate. But when, not if, the price of oil starts climbing and hits a pre-determined threshold, like $75/barrel, then start the super-progressive tax. So, once the gas and oil prices rise above the threshold, then the progressive tax rate increases kick in. For example, add a 1% increase for every 10% the price increases up to some pre-determined maximum, like 100%. So at $75 the law becomes 26/20, at $82.50, 27/20, and so on. There has also got to be some monitoring measures put in place to keep the Oil Companies from just continuing to pass on these taxes to the consumers as they have in the past.

The oil companies have been manipulating us folks for years and we all know it, and have accepted it because of our demand-created reliance on oil products. They have not been very active in creating new energy efficient products or new fuel types since there is so much money to be made in oil. Their competition is all but non-existant (if not collusive) and they retain oil and gas in the ground to help manipulate prices to their best profit advantage. That's why the other Bill being considered for action to Tax the undeveloped Natural Gas in the ground just makes a whole lot of sense to me. **I feel great outrage at how the world oil companies manipulate us and we just keep accepting their self serving pronouncements and control of our elected officials through Lobbying and Campaign Contributions!**

I guess I would feel a little more sympathetic toward the oil companies if their profits were not so OBSCENE and obviously following the same price run-up scenario that occurred in the early 1970's prior to the Alaska Oil Pipeline being built. What part of history repeating itself don't we understand? It would also help if Exxon would just pay their Exxon Valdez fine, which they've held in escrow for years, and quit paying the lawyers to obfuscate the process! The oil companies' threats to leave the State if they can't continue receiving these obscene profits by using Alaskan's resources need to be ignored. **Alaska needs to collect part of the windfall profits the oil companies keep reaping through no extraordinary efforts of their own**! If the present oil companies don't want to play fair then Alaska needs to sell their leases to someone else who will develop the products.

Thank you,

Ken & Marla Larson

BILL ID: HB 488/SB 305

"An Act repealing the oil production tax and gas production tax and providing for production tax on the ~~net~~taxable value of oil and gas; relating to the relationship of the production tax to other taxes; relating to the dates tax payments and surcharges are due under AS 43.55; relating to interest on overpayments under AS 43.55; relating to the treatment of oil and gas production tax in a producer's settlement with the royalty owner; relating to flared gas, and to oil and gas used in the operation of a lease or property, under AS 43.55; relating to the prevailing value of oil or gas under AS 43.55; providing for tax credits against the tax due under AS 43.55 for certain expenditures, losses, and surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, under AS 43.55; relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, under AS 43.55; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the oil and gas production tax; relating to the deposit of money collected by the Department of Revenue under AS 43.55; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the ~~net~~taxable value of taxable oil and gas for purposes of a production tax on the ~~net~~taxable value of oil and gas; relating to the definitions of 'gas,' 'oil,' and certain other terms for purposes of AS 43.55; making conforming amendments; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** The uncodified law of the State of Alaska is amended by adding a new section to read:

INTENT OF SEC. 11 OF THIS ACT. It is the intent of the legislature through sec. 11 of this Act to confirm by clarification the long-standing interpretation of AS 43.55.020(f) by the Department of Revenue.

*** Sec. 2.** AS 43.20.031(c) is amended to read:
(c) In computing the tax under this chapter, the taxpayer is not entitled deduct any taxes based on or measured by net income. **The taxpayer may deduct the tax levied and paid under AS 43.55.**

*** Sec. 3.** AS 43.20.072(b) is amended to read:
(b) A taxpayer's business income to be apportioned under this section to the state shall be the federal taxable income of the taxpayer's consolidated business for the tax period, except that

(1) taxes based on or measured by net income that are deducted in the determination of the federal taxable income shall be added back; **the tax levied and paid under AS 43.55 may not be added back;**

(2) intangible drilling and development costs that are deducted as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) in the determination of the federal taxable income shall be capitalized and depreciated as if the option to treat them as expenses under 26 U.S.C. 263(c) (Internal Revenue Code) had not been exercised;
(3) depletion deducted on the percentage depletion basis under 26 U.S.C. 613 (Internal Revenue Code) in the determination of the federal taxable income shall be recomputed and deducted on the cost depletion basis under 26 U.S.C. 612 Internal Revenue Code); and
(4) depreciation shall be computed on the basis of 26 U.S.C. 167(Internal Revenue Code) as that section read on June 30, 1981.

* **Sec. 4.** AS 43.05.230(f) is amended to read:
(f) A willful violation of the provisions of this section **or of a condition imposed under AS 43.55.040(1)(B)** is punishable by a fine of not more than $5,000, or by imprisonment for not more than two years, or by both.

* **Sec. 5.** AS 43.55.011(a) is repealed and reenacted to read:
(a) There is levied upon the producer of oil or gas a tax for all oil and gas produced each month from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation. The tax is equal to 20 percent of the ~~net~~ taxable value of the taxable oil and gas as calculated under AS 43.55.160. [AOGA anticipates proposed language by ASRC will be adopted regarding AS 43.55.014]

* **Sec. 6.** AS 43.55.017(a) is amended to read:
(a) Except as provided in this chapter, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax upon
(1) producing oil or gas leases;
(2) oil or gas produced or extracted in the state;
(3) the value of intangible drilling and **development costs, as defined in 26 U.S.C. 263(c) (Internal Revenue Code), as amended through January 1, 1974** [EXPLORATION EXPENSES].

* **Sec. 7.** AS 43.55.020(a) is repealed and reenacted to read:
(a) The production tax on oil and gas shall be paid as set out in this subsection. Ninety percent of the tax levied under AS 43.55.011, net of any credits applied under this chapter, is due on the last day of each calendar month on oil and gas produced from each lease or property during the preceding month. The remaining portion of the tax levied under AS 43.55.011, net of any credits applied under this chapter, is due on March 31 of the year following the calendar year during which the oil and gas were produced. An unpaid amount of tax that is not paid when due in accordance with this subsection becomes delinquent. An overpayment of tax with respect to a month may be applied against the tax due for any later month. Notwithstanding any contrary provision of

AS 43.05.280, interest on an overpayment is allowed only from a date that is 90 days after the later of (1) the March 31 described in this subsection; or (2) the date that the statement required under AS 43.55.030(a) and 43.55.030(e) to be filed on or before that March 31 is filed. However, interest is not allowed if the overpayment was refunded within the 90-day period.

*** Sec. 8.** AS 43.55.020(b) is amended to read:
(b) The production tax on oil **and** [OR] gas shall be paid by or on behalf of the producer.

*** Sec. 9.** AS 43.55.020(d) is amended to read:
(d) In making settlement with the royalty owner **with respect to oil or gas that is taxable under AS 43.55.011,** the producer may deduct the amount of the tax paid on **taxable** royalty oil **and** [OR] gas, or may deduct **taxable** royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. **Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under AS 43.55.011(a) on taxable royalty oil and gas for a month is deemed to be the product of**

(1) the ~~quantity~~ taxable value under AS 43.55.160 of that taxable royalty oil and gas produced during the month; times

(2) the quotient of

(A) the producer's total tax liability for the month of production under AS 43.55.011, divided by

(B) the taxable value under AS 43.55.160 of the producer's total quantity of taxable oil and gas, including taxable ~~other than~~ royalty oil and gas taxed under AS 43.55.011(a) [AOGA anticipates proposed language by ASRC will be adopted regarding AS 43.55.011], **produced from all leases and properties in the state during the month. ~~For purposes of the product calculated under this subsection, 6,000 cubic feet of gas are considered to be equivalent in amount to one barrel of oil.~~**

*** Sec. 10.** AS 43.55.020(e) is repealed and reenacted to read:
(e) Gas flared, released, or allowed to escape in excess of the amount authorized by the Alaska Oil and Gas Conservation Commission is considered, for the purpose of AS 43.55.011 - 43.55.160, as gas produced from a lease or property. Oil or gas used in the operation of a lease or property in the state in drilling for or producing oil or gas, or for repressuring, except to the extent determined by the Alaska Oil and Gas Conservation Commission to be waste, is not considered, for the purpose of AS 43.55.011 - 43.55.160, as oil or gas produced from a lease or property.

*** Sec. 11.** AS 43.55.020(f) is amended to read:
(f) If oil or gas is **not sold, or if oil or gas is** sold under circumstances where the sale price does not represent the prevailing value for oil or gas of like kind, character, or quality in the field

or area from which the product is produced, the department may require the tax to be paid upon the basis of the value of oil or gas of the same kind, quality, and character prevailing during the calendar month of production for that field or area.

Sec. 12. AS 43.55 is amended by adding a new section to read:
Sec. 43.55.024. Tax credits for certain losses and expenditures. (a) Notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the ~~net~~taxable value of oil and gas under AS 43.55.160(a), a producer or explorer that incurs a qualified capital expenditure may also elect to take a tax credit in the amount of 20 percent of that expenditure, unless a credit for that expenditure is taken under AS 43.55.025. A credit under this subsection may be applied ~~only~~ against any state tax due under AS 43.55.011 - 43.55.160 or AS 43.20, provided the total amount of credit applied does not exceed the amount of the credit under this subsection. ~~Only f~~For a calendar year for which the producer makes an election under AS 43.55.160(f), a producer that incurs a qualified capital expenditure during that year and that wishes to apply a credit based on that expenditure against a tax due under AS 43.55.011 - 43.55.160 shall calculate and apply every month an annualized tax credit in an amount equal to one and two-thirds percent of the total qualified capital expenditures incurred during that year and for which the tax credit is taken for that year, instead of taking a tax credit of 20 percent of each separate qualified capital expenditure after it has been incurred.

(b) A producer may elect to take a tax credit in the amount of 20 percent of a carried-forward annual loss. A credit under this subsection may be applied only against a tax due under AS 43.55.011 - 43.55.160. For purposes of this subsection, a carried-forward annual loss is the amount of a producer's adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b).

(c) A credit under this section may not be used to reduce a person's tax liability under AS 43.55.011- 43.55.160 for any month below zero; any portion of a credit not used for that reason may be applied in a later month.

(d) A person entitled to take a tax credit under this section that wishes to transfer the unused credit to another person may apply to the department for a transferable tax credit certificate. An application under this subsection must be on a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall either grant or deny an application, or grant it as to a lesser amount than that claimed and deny it as to the excess, no later than 60 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure or carried-forward annual loss for which the credit is claimed was incurred; (2) if the applicant required under AS 43.55.030(a) and 43.55.030(e) to file a statement on or before the March 31 described in (1) of this subsection, the date the statement was filed; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a

tax credit, the department shall issue the applicant a transferable tax credit certificate for the amount of the credit. A certificate issued under this subsection does not expire.

(e) A person to which a transferable tax credit certificate is issued under (d) of this section may transfer the certificate to another person, and a transferee may further transfer the certificate. Subject to the limitations set out in (a) - (c) of this section, and notwithstanding any action the department may take with respect to the applicant under (f) of this section, the owner of a certificate may apply the credit or a portion of the credit shown on the certificate only against a tax due under AS 43.55.011 -43.55.160 or AS 43.20. ~~However, credits shown on transferable tax credit certificates may not be applied so as to reduce a producer's total tax due under AS 43.55.011 – 43.55.160 on oil and gas produced during a calendar year to less than 80 percent of the tax that would otherwise be due without applying those credits.~~ Any portion of a credit not used ~~for that reason~~ may be applied in a later period.

(f) The issuance of a transferable tax credit certificate under (d) of this section does not limit the department's ability to later investigate or audit a tax credit claim to which the certificate relates or to adjust or deny the claim if the department determines that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011 -.55.160 is increased by the amount of the credit that is in excess of that to which the applicant was entitled. That amount bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, and applicant that is an explorer is considered a producer subject to the tax levied under AS 43.55.011.

(g) The department may adopt regulations to carry out the purposes of this section, including prescribing reporting, record-keeping, and certification procedures and requirements for purposes of verifying the accuracy of credits claimed and insuring that a credit is not used more than once, and otherwise implementing this section.

(h) For purposes of this section,

(1) "explorer" has the meaning given in AS 43.55.025(k);

(2) "qualified capital expenditure"

(A) means, except as otherwise provided under (B) of this paragraph, an expenditure that is a lease expenditure under AS 43.55.160 and is

(i) incurred for geological or geophysical exploration, including associated staff and support costs for analysis and interpretation of the data; or

ii) treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, and

either is treated as a capitalized expenditure by the person incurring the expenditure or is eligible to be deducted as an expense under 26 U.S.C. 263(c) (Internal Revenue Code), as amended;

(B) does not include an expenditure to acquire an asset (i) the cost of previously acquiring which was a lease expenditure under AS 43.55.160(c) or would have been a lease expenditure under AS 43.55.160(c) if it had been incurred on or after July 1, 2006; or (ii) that previously has been placed in service in the state; an expenditure to acquire an asset is not excluded under this subparagraph if no more than ~~an immaterial portion,~~ fifteen percent, of the asset meets a description under (i) or (ii) of this subparagraph; for purposes of this subparagraph (h)(2)(B), "asset" includes geological, geophysical, and well data, and interpretations of these data, but does not include such data and interpretations when they are being purchased from a person who is not a producer or explorer under AS 43.55.

* **Sec. 13.** AS 43.55.030(a) is amended to read:

(a) The tax shall be paid to the department and the person paying the tax shall file with the department at the time the tax **or a portion of the tax** is required to be paid a statement, under oath, on forms prescribed by or acceptable to the department, giving with other information required, the following:

(1) a description of **each** [THE] lease or property from which the oil **and** [OR] gas **were** [WAS] produced, by name, legal description, lease number, or [BY] accounting **codes** [CODE NUMBERS] assigned by the department;

(2) the names of the producer and the person paying the tax;

(3) the gross amount of oil **and the gross amount of** [OR] gas produced from **each** [THE] lease or property, and the percentage of the gross amount **of oil and of gas** owned by each producer for whom the tax is paid;

(4) the **gross** [TOTAL] value **at the point of production** of the oil **and of the** [OR] gas produced from **each** [THE] lease or property owned by each producer for whom the tax is paid; [AND]

(5) the name of the first purchaser and the price received for the oil **and for the** [OR] gas, **unless relieved from this requirement in whole or in part by the department; and**

(6) the producer's lease expenditures and adjustments as calculated under AS 43.55.160 [IF SOLD IN THE STATE].

* **Sec. 14.** AS 43.55.030(d) is amended to read:

(d) Reports by or on behalf of the producer are delinquent the first day following the day the tax is due. [EACH PRODUCER IS SUBJECT TO A PENALTY OF $25 A DAY FOR EACH LEASE OR PROPERTY UPON WHICH THE REPORT IS NOT FILED. THE PENALTY FOR FAILURE TO FILE A REPORT IS IN ADDITION TO THE PENALTY FOR DELINQUENT TAXES, AND IS A LIEN AGAINST THE ASSETS OF THE PRODUCER.]

* **Sec. 15.** AS 43.55.030 is amended by adding a new subsection to read:
(e) In addition to other required information, the statement required to be filed on or before March 31 of a year must show any adjustments or corrections to the statements that were required under (a) of this section to be filed for the months of the preceding calendar year during which the oil or gas was produced.

* **Sec. 16.** AS 43.55.040 is amended to read:
Sec. 43.55.040. Powers of Department of Revenue. Except as provided in AS 43.05.405 - 43.05.499, the department may

(1) require a person engaged in production and the agent or employee of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil or gas to furnish, **whether by the filing of regular statements or reports or otherwise,** additional information that is considered by the department as necessary to compute the amount of the tax; **notwithstanding any contrary provision of law, the disclosure of additional information under this paragraph to the producer obligated to pay the tax does not violate AS 40.25.100(a) or AS 43.05.230(a) before disclosing information under this paragraph that is otherwise required to be held confidential under AS 40.25.100(a) or AS 43.05.230(a), the department shall**

(A) provide the person that furnished the information a reasonable opportunity to be heard regarding the proposed disclosure and the conditions to be imposed under (B) of this paragraph; and

(B) impose appropriate conditions limiting
(i) access to the information to those legal counsel, consultants, employees, officers, and agents of the producer who have a need to know that information for the purpose of determining or contesting the producer's tax obligation; and
(ii) the use of the information to use for that purpose;

(2) examine the books, records, and files of [SUCH] a person **described in (1) of this section;**

(3) conduct hearings and compel the attendance of witnesses and the production of books, records, and papers of any person; and

(4) make an investigation or hold an inquiry that is considered necessary to a disclosure of the facts as to (A) the amount of production from any oil or gas location, or of a company or other producer of oil or gas; and (B) the rendition of the oil and gas for taxing purposes.

* **Sec. 17.** AS 43.55.080 is amended to read:
Sec. 43.55.080. Collection and deposit of revenue. Except as otherwise provided under art. IX, sec. 17, Constitution of the State of Alaska, the [THE] department shall deposit in the general fund the money collected by it under **AS 43.55.011 - 43.55.160** [AS 43.55.011 - 43.55.150].

* **Sec. 18.** AS 43.55.135 is amended to read:
Sec. 43.55.135. Measurement. For the purposes of **AS 43.55.011 - 43.55.160** [AS 43.55.011 - 43.55.150], oil **is** [SHALL BE] measured in

terms of a "barrel of oil" and gas **is** [SHALL BE] measured in terms of a "cubic foot of gas."

* **Sec. 19.** AS 43.55.150(a) is amended to read:

(a) For the purposes of **AS 43.55.011 - 43.55.160** [AS 43.55.011 - 43.55.150], the gross value **at the point of production is** [SHALL BE] calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation **are** [SHALL BE] the actual costs, except **when the**

(1) [WHEN THE] parties to the transportation of oil or gas are affiliated;

(2) [WHEN THE] contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation;

(3) [WHEN THE] method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

* **Sec. 20.** AS 43.55.150 is amended by adding a new subsection to read:

(d) Under regulations adopted by the department~~, the department may allow a producer, subject to limitations prescribed by the department~~ as to the frequency of making elections, ~~to~~ a producer ~~elect prospectively to calculate the gross value at the point of production of oil or gas based in whole or part upon~~

(1) shall calculate the gross value at the point of production of oil or gas based upon the ~~a~~ royalty value determined under a royalty settlement agreement between the producer and the state applicable to one or more leases of state land in the same region or geologic province in the state, or in the case of a lease or property ~~where~~ in which there is no state land, the owner of the land or mineral interest, with adjustments for differences in location between the point where the royalty is valued under the terms of that settlement agreement and the point where the gross value at the point of production under AS 43.55.011 - 43.55.160 is determined, if and to the extent appropriate;

(2) may, in all cases not covered by (1) of this subsection, elect prospectively to calculate the gross value at the point of production of oil and gas based upon

(A) a formula prescribed by the department that uses, with adjustments if appropriate, a royalty value or valuation methodology accepted by the

(~~i~~A) Department of Natural Resources under AS 38.05, in the case of oil and gas produced from a lease issued by the Department of Natural Resources or produced from a lease or property that is part of a unit approved by the Department of Natural Resources; or

(~~ii~~B) United States Department of the Interior under applicable federal oil and gas leasing statutes, in the case of oil and gas produced from lease issued by the United States Department of the Interior that is not part of a unit approved by the Department of Natural Resources, or produced from a lease or property that is part of a unit approved by

the United States Department of the Interior but not approved by the Department of Natural Resources; or

(B3) another formula prescribed by the Ddepartment ~~of Revenue~~ that reasonably ~~estimates~~ determines the market ~~a~~ value for the oil or gas at a specific geographical location such as the point of tender or delivery into a common carrier pipeline, and then adjusts that value to the corresponding value at the point where the gross value at the point of production is for that oil or gas; the formula may use such factors as published price indices for oil or gas in or outside the state, quality differentials for oil or gas, transportation costs between markets, and inflation adjustments.

* **Sec. 21.** AS 43.55 is amended by adding a new section to article 1 to read:

Sec. 43.55.160. Determination of ~~net~~taxable value of oil and gas. (a) Except as provided in (f) and (i) of this section, for purposes of AS 43.55.011, the ~~net~~taxable value of the taxable oil and gas produced during a month is the total of the gross value at the point of production of the oil and gas taxable under AS 43.55.011 and produced by the producer from all leases or properties in the state, less (1) first, the gross value at the point of production of taxable royalty oil and gas taxed under AS 43.55.011(a) [AOGA anticipates proposed language by ASRC will be adopted regarding AS 43.55.014], and (2) second, the producer's lease expenditures for the month as adjusted under (e) of this section, and (~~2~~3) ~~second~~third, to the extent allowed under (g) of this section and until the total amount of the producer's transitional investment expenditures has been deducted, an amount equal to 1/72 of the producer's transitional investment expenditures. However, the ~~net~~taxable value calculated under this subsection may not be less than zero.

(b) Any adjusted lease expenditures that would otherwise be deductible in a month but whose deduction would cause the ~~net~~taxable value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero may be added to the producer's adjusted lease expenditures for one or more other months in the same calendar year. The total of any adjusted lease expenditures that are not deductible in any month during a calendar year because their deduction would cause the ~~net~~taxable value calculated under (a) of this section of the taxable oil and gas produced during one or more months to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.024(b). An amount of transitional investment expenditures that would otherwise be deductible in a month but whose deduction would cause the ~~net~~taxable value calculated under (a) of this section of the taxable oil and gas produced during the month to be less than zero (1) may be deducted in a later month during any calendar year to the extent allowed under (g) of this section, but no more than 1/72 of a producer's transitional investment expenditures may be deducted in any month; (2) may not be used to establish a carried-forward annual loss under AS 43.55.024(b).

(c) For purposes of this section, a producer's lease expenditures for a period are the total costs in support of activities upstream of the point of production of oil and gas that are incurred on or after July 1, 2006, by the producer during the period and that are ~~direct,~~

ordinary~~,~~ and necessary costs of exploring for, developing, or producing oil or gas deposits located within the producer's leases or properties in the state or, in the case of land in which the producer owns no working interest, ~~direct,~~ ordinary~~,~~ and necessary costs of exploring for oil or gas deposits located within other land in the state. However, lease expenditures do not include the costs incurred to satisfy a work commitment under an exploration license under AS 38.05.132. In determining whether costs are ~~direct,~~ ordinary~~,~~ and necessary costs of exploring for, developing, or producing an oil or gas deposit located within a lease or property or other land in the state, the department shall apply ~~give substantial weight to~~ (1) the typical industry practices and standards in the state and in the United States in determining the amount ~~as to costs~~ that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, ~~not~~ other than the operator, with substantial bargaining power; and (2) in the absence of unit operating agreements or similar operating agreements that were in effect on or before December 1, 2005, and were subject to negotiation with working interest owners, other than the operator, with substantial bargaining power, the standards adopted by the Department of Natural Resources as to the costs, other than interest, that a lessee is allowed to deduct from revenue in calculating net profits under a lease issued under AS 38.05.180(f)(3)(B), (D), or (E). The Department of Revenue may authorize a producer, including the operator as a working interest owner, to treat as its lease expenditures under this section the costs paid by the producer that are billed to the producer by an operator in accordance with the terms of a unit operating agreement or similar operating agreement, if the Department of Revenue finds that the pertinent provisions of the operating agreement are substantially consistent with the Department of Revenue's determinations and standards otherwise applicable under this subsection and that at least one working interest owner party to the agreement, other than the operator, has substantial incentive and ability to effectively audit billings under the agreement.

(d) For purposes of (c) of this section, lease expenditures ~~direct costs~~

(1) include

(A) outlays for capital assets;

(B) payments for or in lieu of property taxes, sales and use taxes, motor fuel taxes, and excise taxes;

(C) a reasonable allowance, as determined under regulations adopted by the department, for overhead expenses directly related to exploring for, developing, and producing oil or gas deposits located within leases or properties or other land in the state~~;~~

(2) do not include

(A) depreciation or amortization of capital assets;

(B) royalty payments for oil and gas;

(C) taxes based on or measured by net income;

(D) interest or other financing charges or costs of raising equity or debt capital;

(E) acquisition costs for a lease or property or exploration license;

(F) costs arising from fraud, willful misconduct, or negligence;
(G) fines or penalties imposed by law;
(H) costs of arbitration, litigation, or other dispute resolution activities that involve the state or concern the rights or obligations among owners of interests in, or rights to production from, one or more leases or properties or a unit;
(I) donations;
(J) costs incurred in organizing a ~~partnership, joint venture, or other~~ business entity or arrangement, except for those costs incurred in organizing a partnership or joint venture for future operation of a lease, property or unit;
(K) amounts paid for purposes of indemnification from the state.

(e) A producer's lease expenditures must be adjusted by subtracting any monetary payment or credit the producer receives (1) for the use by another person of a production facility in which the producer has an ownership interest; (2) for a reimbursement or similar payment that offsets the producer's lease expenditures, including any payment from the state or federal government for reimbursement of the producer's upstream costs, including any costs for gathering, separating, cleaning, dehydration, compressing, or other field handling costs associated with the production of oil or gas upstream of the point of production; (3) for the sale or other transfer of (A) an asset, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of a lease expenditure or an expenditure that would be a lease expenditure if it were incurred on or after July 1, 2006; and
(B) oil or gas (i) that is not considered produced from a lease or property under AS 43.55.020(e); and (ii) the cost of acquiring which is a lease expenditure incurred by the person that acquires the oil or gas.

(f) In place of the adjusted lease expenditures for a month under (a) of section, a producer may at any time elect to substitute for every month of a calendar year one-twelfth of the producer's adjusted lease expenditures for the calendar year.
(g) For the purposes of this section, a producer's transitional investment expenditures are (1) the sum of the expenditures the producer incurred on or after July 1, 2001, and before July 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024(h), if they were incurred on or after July 1, 2006, less (2) the sum of the payments or credits the producer received before July 1, 2006, for the sale or other transfer of assets, including geological, geophysical, or well data or interpretations, acquired by the producer as a result of expenditures the producer incurred on or after July 1, 2001, and before July 1, 2006, that would be qualified capital expenditures, as defined in AS 43.55.024(h), if they were incurred on or after July 1, 2006. An amount of transitional investment expenditures may not be deducted under (a) of this section for a month for which the average price of Alaska Slope oil delivered on the United States West Coast, as determined under (h) of this section, is equal

to or less than $40 per barrel, as adjusted for inflation under (h) of this section.

(h) The average price described in (g) of this section shall be an average, as calculated using a formula prescribed by the department by regulation, of published daily spot price assessments during the month for Alaska North Slope oil delivered on the United States West Coast. However, if the department determines that such daily assessments cease or appear likely to soon cease to be published throughout the calendar year or that they cease or appear likely to soon cease to be reliable evidence of market conditions, the department shall by regulation provide that the average price described in (g) of this section is the prevailing value of Alaska North Slope oil delivered on the United States West Coast as determined under regulations of the department implementing AS 43.55.020(f). For each year after 2006, the reference price of $40 per barrel set out in (g) of this section shall be adjusted for inflation using an appropriate consumer price index published by the United States Bureau of Labor Statistics, as prescribed by the department by regulation.

(i) For a month for which the ~~net~~taxable value of the taxable oil and gas produced during the month calculated under (a) of this section exceeds zero, a producer that is qualified under (j) of this section may reduce the ~~net~~taxable value by deducting an allowance in an amount calculated such that (1) the ~~net~~taxable value for the month is not reduced below zero; and (2) the total of the allowances deducted for all months during the calendar year does not exceed $73,000,000. An unused allowance or portion of an allowance under this subsection may not be carried forward to a later calendar year or used to establish a carried-forward annual loss under AS 43.55.024(b).

(j) Upon written application by a producer, including any information the department may require, the department shall determine whether the producer qualifies under this subsection for a calendar year. To qualify under this subsection, a producer must demonstrate that its operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer entity would not result in the division among multiple producer entities of any ~~net~~taxable value of taxable oil and gas, as defined under (a) of this section, that would be reasonably expected to be attributed to a single producer entity if the allowance provision of (i) of this section did not exist.

(k) If a cost that would otherwise constitute a lease expenditure under (c) of this section is incurred to explore for, develop, or produce (1) both an oil or gas deposit located within land outside the state and an oil or gas deposit located within a lease or property, or other land, in the state, or (2) an oil or gas deposit located partly within land outside the state and partly within a lease or property, or other land, in the state, the department shall specify or approve a reasonable allocation method for determining the portion of the cost that is appropriately treated as a lease expenditure under (c) of this section.

(l) The department may adopt regulations that establish additional standards necessary to carrying out the purposes of this section.

(m) For purposes of AS 43.55.024(a) and (b) and only as to expenditures incurred to explore for an oil or gas deposit located within land in which an explorer, as defined in AS 43.55.025(k), owns no working interest, the term "producer" in (c) and (e) of this section includes "explorer."

(n) For purposes of this section,

(1) "explore" includes to conduct geological or geophysical exploration;

(2) the drilling of a stratigraphic test well is considered ~~geological~~ exploration for geologic strata capable of forming a commercial quality oil and/or gas reservoir ~~an oil or gas deposit~~ located within land in the state onl, if the well's target zones are located in the state or in a contiguous part of the same geologic basin; for purposes of this paragraph, a stratigraphic test well is a well drilled for the sole purpose of obtaining geological information to aid in exploring for an oil or gas deposit.

* **Sec. 22.** AS 43.55.201(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011, except notwithstanding anything to the contrary in AS 43.55.020(a), the full amount of the surcharge is due on the last day of each calendar month on oil produced from each lease or property during the preceding month. The surcharge** [AS 43.55.011 - 43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.300 - 43.55.310.

* **Sec. 23.** AS 43.55.201(c) is amended to read:

(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.160** [AS 43.55.011 -43.55.150].

* **Sec. 24.** AS 43.55.201 is amended by adding a new subsection to read:

d) Oil not considered under AS 43.55.020(e) to be produced from a property is not considered to be produced from a lease or property for purposes of this section.

* **Sec. 25.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.205. Tax credit for surcharge payment. The amount of a surcharge paid by a producer under AS 43.55.201 may be applied as a credit the producer's taxes due under AS 43.55.011 - 43.55.160. A credit under this section may not be used to reduce a person's tax liability under AS 43.55.011 - 43.55.160 for any month below zero; any portion of a credit not used for that reason may be applied in a later month.

* **Sec. 26.** AS 43.55.300(b) is amended to read:

(b) The surcharge imposed by (a) of this section is in addition to and shall be paid in the same manner as the tax imposed by **AS 43.55.011, except that notwithstanding anything to the contrary in AS 43.55.020(a), the full amount of the surcharge is due on the last day of each calendar month on oil produced from each lease or property during the preceding month. The surcharge** [AS 43.55.011- 43.55.150; AND] is in addition to the surcharge imposed by AS 43.55.201 - 43.55.231.]

* **Sec. 27.** AS 43.55.300(c) is amended to read:
(c) A producer of oil shall make reports of production in the same manner and under the same penalties as required under **AS 43.55.011 - 43.55.160** [AS 43.55.011 - 43.55.150].

* **Sec. 28.** AS 43.55.300 is amended by adding a new subsection to read:
(d) Oil not considered under AS 43.55.020(e) to be produced from a lease property is not considered to be produced from a lease or property for purposes of section.

* **Sec. 29.** AS 43.55 is amended by adding a new section to read:
Sec. 43.55.305. Tax credit for surcharge payment. The amount of a surcharge paid by a producer under AS 43.55.300 may be applied as a credit against the producer's taxes due under AS 43.55.011 - 43.55.160. A credit under this section may not be used to reduce a person's tax liability under AS 43.55.011 - 43.55.160 for any month below zero; any portion of a credit not used for that reason may be applied in a later month.

- **Sec. 30.** AS 43.55.
- 900(6) is repealed and reenacted to read:
(6) "gas" means (A) all natural, associated, or casinghead gas;
(B) all hydrocarbons that (i) are recovered by mechanical separation of well fluids or by gas processing; and (ii) exist in a gaseous phase at the completion of mechanical separation and any gas processing; and
(C) all other hydrocarbons produced from a well not defined as oil;

* **Sec. 31.** AS 43.55.900(7) is repealed and reenacted to read:
(7) "gross value at the point of production" means
(A) for oil, the value of the oil at the automatic custody transfer meter or device through which the oil enters into the facilities of a carrier pipeline or other transportation carrier in a condition of pipeline quality; in the absence of an automatic custody transfer meter or device, "gross value at the point of production" means the value of the oil at the mechanism or device to measure the quantity of oil that has been approved by the department for that purpose, through which the oil is tendered and accepted in a condition of pipeline quality into the facilities of a carrier pipeline or other transportation carrier or into a field topping plant;
(B) for gas, other than gas described in (C) of this paragraph, that is (i) not subjected to or recovered by mechanical separation or gas processing, the value of the gas at the first point where the gas is accurately metered; (ii) subjected to or recovered by mechanical separation but not gas processing, the value of the gas at the first point where the gas is accurately metered after completion of mechanical separation; (iii) subjected to or recovered by gas processing, the value of the gas at the first point where the gas is accurately metered after completion of gas processing;
(C) for gas run through an integrated gas processing and gas treatment facility that does not accurately meter the gas after the gas

processing and before the gas treatment, the value of the gas at the first point where gas processing is completed or where gas treatment begins, whichever is further upstream;

* **Sec. 32.** AS 43.55.900(10) is repealed and reenacted to read:
(10) "oil" means
(A) crude petroleum oil; and
(B) all liquid hydrocarbons that are recovered by mechanical separation of well fluids or by gas processing;

* **Sec. 33.** AS 43.55.900 is amended by adding new paragraphs to read:
(17) "gas processing"
(A) means processing a gaseous mixture of hydrocarbons
(i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation;
(ii) for the purpose of extracting and recovering liquid hydrocarbons; and
(iii) upstream of any gas treatment and upstream of the inlet of any gas pipeline system transporting gas to a market;
(B) does not include gas treatment;

(18) "gas treatment"
(A) means conditioning gas and removing from gas non- hydrocarbon substances, for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system; and (B) may include incidentally removing liquid hydrocarbons from the gas.

(19) "Ordinary and Necessary" as defined in Internal Revenue Code for deductible costs in IRC 162 and for capital costs in IRC 263 and 263A including federal regulations thereunder.

(20) "mechanical separation" means

(A) the natural separation of well fluids into gaseous and liquid substances due to gravity and the different densities of the gases and liquids;

(B) the release of gaseous substances dissolved in well fluids that occurs as the ambient pressure of the well fluids when recovered at the surface is reduced under controlled conditions;

(C) the evaporation or other release of gaseous substances from well fluids that occurs while any emulsion of oil and water in the well fluids is broken down chemically or electrostatically or while water and any sediments and impurities dissolved or suspended in it are separated from the oil either due to the buoyancy of oil relative to water or by other mechanical means.

* **Sec. 34.** AS 43.55.011(b), 43.55.011(c), 43.55.012(b), 43.55.013(b), 43.55.013(c), 24 43.55.013(d), 43.55.013(g), 43.55.013(h), 43.55.013(i), 43.55.013(j), 43.55.013(k),43.55.016, 43.55.900(1), 43.55.900(8), 43.55.900(11), 43.55.900(12),and 43.55.900(16) are repealed.

* **Sec. 35.** The uncodified law of the State of Alaska is amended by adding a new section to read:
APPLICABILITY. (a) Sections 5, 7 - 10, 12, 13, 15, and 19 - 34 of this Act apply to oil and gas produced on or after July 1, 2006.
(b) Section 11 of this Act applies to oil and gas produced before, on, or after the effective date of sec. 11 of this Act.

* **Sec. 36.** The uncodified law of the State of Alaska is amended by adding a new section to read:
TRANSITION PROVISIONS. (a) Notwithstanding any contrary provisi n of AS 43.55.024(a), enacted by sec. 12 of this Act, for oil and gas produced on or after July 1, 2006, and before January 1, 2007, the phrase "every month an annualized tax credit in an amount equal to one and two-thirds percent" in AS 43.55.024(a), enacted by sec. 12 of this 08 Act, shall be replaced by the phrase "every month during the period July 1, 2006, through December 31, 2006, an annualized tax credit in an amount equal to three and one-third percent."
(b) Notwithstanding any contrary provision of AS 43.55.024(e), enacted by sec. 12 of this Act, for oil and gas produced on or after July 1, 2006, and before January 1, 2007, the phrase "a calendar year" in AS 43.55.024(e), enacted by sec. 12 of this Act, shall be replaced by the phrase "the last six months of the calendar year."
(c) Notwithstanding any contrary provision of AS 43.55.160(f), enacted by sec. 21 of this Act, for oil and gas produced on or after July 1, 2006, and before January 1, 2007, the phrase "for every month of a calendar year one-twelfth of the producer's adjusted lease expenditures for the calendar year" in AS 43.55.160(f), enacted by sec. 21 of this Act, shall be replaced by the phrase "for each of the last six months of 2006, one-sixth of the producer's adjusted lease expenditures for that six-month period."
(d) Notwithstanding any contrary provision of AS 43.55.160(i), enacted by sec. 21 of this Act, for oil and gas produced on or after July 1, 2006, and before January 1, 2007, the number "$73,000,000" in AS 43.55.160(i), enacted by sec. 21 of this Act, shall be replaced by the number "$36,500,000."
(e) For oil and gas produced before July 1, 2006, the provisions of AS 43.55, and 26 regulations adopted under AS 43.55, that were in effect before July 1, 2006, and that were applicable to the oil and gas continue to apply to that oil and gas.

* **Sec. 37.** The uncodified law of the State of Alaska is amended by adding a new section to read:
TRANSITION: REGULATIONS. The Department of Revenue may proceed to adopt regulations to implement the changes made by this Act. The regulations take effect under AS 44.62 (Administrative Procedure Act), but not before the effective date of the law implemented by the regulation.

* **Sec. 38.** The uncodified law of the State of Alaska is amended by adding a new section to read:
REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the heading of AS 43.55 from "Oil and Gas Production Taxes and Oil Surcharge" to "Oil and Gas Production Tax and Oil Surcharge"; article 1 of AS 43.55 from "Oil and Gas Properties Production Taxes" to "Oil and Gas Production Tax"; AS 43.55.011 from "Oil production tax" to

"Oil and gas production tax"; AS 43.55.025 from "Tax credit for oil and gas exploration or gas only exploration" to "Alternative tax credit for oil and gas exploration or gas only exploration"; (5) AS 43.55.150 from "Determination of gross value" to "Determination of gross value at the point of production."

* **Sec. 39.** Sections 1 - 4, 6, 11, 14, 16, and 37 of this Act take effect immediately under AS 01.10.070(c).

* **Sec. 40.** Except as provided in sec. 39 of this Act, this Act takes effect July 1, 2006.

HOUSE COMMITTEE REPO T

(9)

Date Referred to Committee: February 21, 2006 **FURTHER REFERRALS: Finance**

Date of Committee Action: MARCH 17, 2006

The RESOURCES Committee considered: **HB 488**

HOUSE BILL NO. 488 **OIL AND GAS PRODUCTION TAX**

"An Act repealing the oil production tax and gas production tax and providing for a production tax on the net value of oil and gas; relating to the relationship of the production tax to other taxes; relating to the dates tax payments and surcharges are due under AS 43.55; relating to interest on overpayments under AS 43.55; relating to the treatment of oil and gas production tax in a producer's settlement with the royalty owner; relating to flared gas, and to oil and gas used in the operation of a lease or property, under AS 43.55; relating to the prevailing value of oil or gas under AS 43.55; providing for tax credits against the tax due under AS 43.55 for certain expenditures, losses, and surcharges; relating to statements or other information required to be filed with or furnished to the Department of Revenue, and relating to the penalty for failure to file certain reports, under AS 43.5 relating to the powers of the Department of Revenue, and to the disclosure of certain information required to be furnished to the Department of Revenue, under AS 43.55; relating to criminal penalties for violating conditions governing access to and use of confidential information relating to the oil and gas production tax; relating to the deposit of money collected by the Department of Revenue under AS 43.55; relating to the calculation of the gross value at the point of production of oil or gas; relating to the determination of the net value of taxable oil and gas for purposes of a production tax on the net value of oil and gas; relating to the definitions of "gas," "oil," and certain other terms for purposes of AS 43.55; making conforming amendments; and providing for an effective date."

Recommends it be replaced with: [ ] HCS *or* [X] CS *for* HB 488 (RES)

For Senate Bills with new title: [ ] *Technical Title* [ ] *New Title: HCR*_____ [ ] Same Title [X] New Title

[ ] attach amendments
[ ] add new referral to _____Committee
[ ] Letter of Intent_____Committee

List of Abbrev for Depts.:
ADM
CED
COR
CRT
EED
DEC
DFG
GOV
HSS
LEG
LAW
LWF
MVA
DNR
DPS
REV
DOT
UA

NEW FISCAL NOTES *Assigned by Chief Clerk's Office

List by Dept(s):	*FN#	Fiscal	Indet.	Zero

PREVIOUS FISCAL NOTES

List by Dept(s):	FN#	Fiscal	Indet.	Zero
DNR	1			✓
REV	2	✓		

Signing with recommendations	Printed Last Name	DP	DNP	NR	AM
Harry D Crawford Jr	CRAWFORD		X		
Mary Kapsner	KAPSNER				✓
	Gatto	X			
Paul F Seaton	SEATON	X			
	ELKINS	✓			
	OLSON	✓			
Chair:	RAMRAS	X			
Chair:	SAMUELS	X			

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SPONSOR STATEMENT CSHB 488 (RES)

Wednesday, March 22, 2006 / Tim Benintendi, Staff, 465-3715

(version 24-GH2052/L)

COMMITTEE REPORT: 6 "Do Pass" / 1 "Do Not Pass" / 1 "Amend"

CSHB 488 (RES) would convert Alaska's oil severance tax structure from the Economic Limit Factor (ELF) method, to a petroleum profits tax (PPT) method. The governor's version would increase revenue by about $705 million per year, on average, over the next five years. The House Resources Committee (HRC) version would increase revenue by about $816 million per year, on average, over the same five years.

The severance tax is one of four levies paid by the oil industry in Alaska, the others being royalties, property taxes, and income taxes. Tax deductions and tax credits continue to be used to motivate industry for exploration, production, and development activities. The objectives of the bill remain as follows: Increase the state's share or "government take," under conditions of high oil market prices; provide industry with new or expanded incentives to explore and produce from marginal and frontier fields; and to ensure motivation for continued activity in the Cook Inlet fields.

The HRC proposed several changes to the governor's bill, most notably, installing a two-pronged progressivity feature on the PPT tax rate. In the governor's version, the PPT rate is a flat 20% regardless of the market price of oil. The HRC version also uses the 20% rate, but only at market prices up to $50 per barrel (WTI benchmark). At market prices between $50 and $110 per barrel, the progressivity feature adds 3/10% of the wellhead value for every dollar the market price is over $50. A single year of additional revenue in times of high market prices can offset many years of lower revenues when prices are close to their historical average.

If there is a dramatic price shock or the value of oil continues to rise at market prices over $110 per barrel, the tax generates an additional 37.5% of wellhead value for the state. We would get a greater share at very high market prices. As prices climb, the combined effect of the 20% PPT base rate and the 37.5% progressivity factor (which is deductible in calculating the amount payable under the PPT rate) approaches 50% of the oil's value in Alaska. The committee felt this two-pronged progressivity feature would keep investment opportunity in Alaska strong, while allowing the state to share in windfalls at high spikes of market prices.

Another policy change from the governor's bill to the HRC version was the elimination of transition costs as deductions from income tax. The governor provided a deduction for investment costs incurred in the past five-years, feeling that investments made in that period and directly tied to the production of oil which would be taxed at the new rate, should be allowed. After hearing considerable testimony on this component, the HRC deleted it completely.

Exploration tax credits of 40% under SB 185 (Ch. 59, SLA 03) will be extended ten years under the HRC version, and the governor's credit rate of 20% remains intact. This is intended to motivate explorers and independent firms. As is currently done, a company will be able to choose from the two options as they assess which is most beneficial to them.

The House Resources Committee allowed no credit for abandonment costs, but such expenses remain tax-deductible. And, in terms of a private royalty severance tax rate, the HRC version set it at 5%.

As introduced, the governor's version of HB 488 proposes to make the current oil spill contingency surcharge (which is currently 5-cents per barrel) creditable against the PPT. The HRC left the current statute in place, but modified the program. The current 2-cents per barrel which goes into the Response Mitigation Account (RMA), is reduced to 1-cent. This surcharge will continue in suspension as long as the RMA balance holds at $50 million. The remaining 3-cent per barrel surcharge, which is deposited into the Prevention Mitigation Account (PMA), increases to 4-cents per barrel under the HRC substitute bill.

The governor provided a $73 million annual allowance for all producers, against which a 20% credit would be applied, resulting in a $14.6 million tax credit per company annually. The merits of this allowance and credit incentive eluded committee members, so this provision was changed to a direct tax credit, dollar for dollar, on the first $12 million worth of capital investment for exploration, production, or development work. This annual credit is non-transferable, non-salable, not eligible for carry-forward, and can only be applied to a current year's severance tax. Should a company spend less than $12 million, the credit would be applied to whatever amount they did spend.

As protection for explorers and new entrants to Alaska, the HRC devised a tax credit repurchasing program for those credits a company earns on expenditures of up to $10 million per year for investments in exploration and/or lease purchases in Alaska.

The effective date for HB 488 as introduced by the governor, was July 1, 2006. The HRC version changed that to April 1st, also the beginning of a fiscal quarter, but a change which would bring the state another $200 million this year.

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MEMORANDUM March 24, 2006

SUBJECT: CSHB 488(RES) -- sectional analysis
(Work Order No. 24-GH2052\L)

TO: Representative Jay Ramras
Representative Ralph Samuels
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

The House Resources Committee Substitute proposes to repeal the state's current oil and gas properties production tax and replace it with a production tax on oil and gas. The replacement tax is to be based on a percentage of the production tax value of oil and gas, the determination of which is prescribed by the bill. The measure makes a number of related and conforming additions and changes.

The measure is an administration-sponsored bill, so in the preparation of this memo, for provisions not substantively altered by the Resources Committee, I have drawn on the explanatory language of the administration's February 21 sectional analysis of the bill as introduced.

PROVISIONS IMPOSING A PRODUCTION TAX ON THE NET VALUE OF OIL AND GAS:

Provisions imposing the tax and setting the basic tax rate(s) --

Bill section 5: The bill section enacts (as a repeal and reenactment of AS 43.55.011(a) levying a tax on a percentage of the gross value at the point of production) the tax levy as a production tax on both oil and gas, with exceptions and limitations noted in the provision's text, and sets the rate of levy at 20 percent of the production tax value of the taxable oil and gas.

Bill section 6: As part of this bill section, a new subsection, AS 43.55.011(e), is added to authorize a levy and set a rate of levy on oil and gas produced that constitutes a lessor's royalty interest under an oil and gas lease. The rate specifies a rate of five percent of the gross value at the point of production. It also sets out an alternative rate of 20 percent of the dross value that applies under circumstances in which there is evidence the producer's receipt of consideration from the lessor offsets the producer's royalty obligation.

Provisions authorizing a progressively higher tax rate for oil when the price exceeds $50 per barrel --

As part of **bill section 6**, proposed AS 43.55.011(f) sets out an oil price index by which the tax levy on oil is adjusted by an addition .3 percent of gross value per dollar in excess of $50, based on Gulf Coast prices for West Texas Intermediate crude. Subsection (g) caps the index increase when the average price reaches $110 per barrel. Subsection (h) sets out the manner in which the index may be calculated and authorizes use of a substitute formula under circumstances specified in the subsection.

Provisions authorizing a progressively higher tax rate for gas when the price of gas exceeds $8 per million BTUs --

Again, as part of **bill section 6**, proposed AS 43.55.011(i) sets out a natural gas price index by which the tax levy on gas is adjusted by 2 percent of gross value when the average Henry Hub price exceeds $8 per million BTUs. Subsection (j) caps the index increase at 18.75 and subsection (k) spells out the manner in which the index may be calculated and authorizes use of a substitute formula under circumstances specified in the subsection.

Provisions relating to the determination of the production tax value of oil and gas --

The oil and gas production tax levy is imposed as a percentage of the production tax value of the taxable oil and gas. Calculation of the production tax value is set out in AS 43.55.160, added by **bill section 28**:

-- Under AS 43.55.160(a), the calculation begins with the determination of the gross value at the point of production of all of a producer's taxable oil and gas statewide. The producer may deduct taxes paid that are attributable to application of the indexed production tax rate increases as well as the deductible costs of oil and gas exploration, development, and production (adjusted deductible lease expenses). Subsection (a) contains language that precludes net value calculation from falling below zero.

-- Subsection (b) sets out rules for the producer's claim and use of unused deductions.

-- Subsection (c) spells out the exploration, development, and production costs that qualify as deductible lease expenses ("total costs upstream of the point of production . . . incurred on or after January 1, 2006, . . . and that are direct, ordinary, and necessary costs for exploring for, developing, or producing oil or gas deposit"), and provides guidance to the department as to evidence of those costs, especially in situations involving activities occurring under operating agreements.

-- Subsection (d) spells out allowable direct costs and costs that may not be deductible because they are not direct costs.

-- The mechanics of making adjustments to a producer's lease expenditures are addressed in subsection (e). Adjustments are required to account for reimbursements, assets sales, and other producer receipts.

-- Subsection (f) authorizes substitution of determination of adjusted lease expenditures on a monthly basis, at the election of the producer.

--The provisions of subsections (g) - (i) spell out additional authority of the department with respect to tax administration, while subsection (j) supplies definitions of terms used.

Tax credit provisions --

The measure contains two separate sections authorizing tax credits.

Bill section 14 adds a new section, AS 43.55.024, that sets out tax credits for certain expenditures and losses. In the section,

-- Subsection (a) authorizes a tax credit of 20 percent of "qualified capital expenditures"--the term is defined in subsection (j)--against the production tax on the net value of taxable oil, bars claim of the tax if the same expenditures are used to claim a credit under AS 43.55.025 (existing tax credit for oil and gas exploration or gas only exploration), and authorizes claim and application of the credit on a monthly basis if, under AS 43.55.160(f), the producer has elected to substitute determination of adjusted lease expenditures on a monthly basis.

-- Subsection (b) authorizes election of a 20 percent tax credit on the basis of carried forward annual losses, defined in the subsection as "the producer's . . . adjusted lease expenditures under AS 43.55.160 for a previous calendar year that was not deductible in any month under AS 43.55.160(a) and (b)."

-- Subsection (c) precludes a tax credit from reducing the producer's tax liability below zero but authorizes application of the unused portion of the credit in a later month.

-- Subsections (d) and (e) establish a system by which tax credits for expenditures and losses as authorized by the section may be transferred through transferable tax credit certificates. Subsection (f) authorizes the department to repurchase credit certificates and, subject to appropriation, make cash refunds, but repurchase and refunds must comply with the requirements spelled out in paragraphs (1) - (5).

-- Subsections (g) and (h) spell out the authority of the department with respect to the administration of transferable tax credit certificates.

-- Subsection (i) bars a producer from making a claim of a tax credit for expenditures to acquire and use certain assets or for costs associated with abandonment.

AS 43.55.170, enacted as part of **bill section 28**, sets out a second or additional tax credit. The section allows the producer to claim a credit for qualified capital expenditures (as that term is defined in AS 43.55.024). The credit may not be applied to reduce the producer's tax liability to less than zero. Unused portions of the credit may be carried forward from month-to-month within a calendar year, may not exceed a total of $12,000,000 for a calendar year, and may not be carried forward into a following calendar year. These credits are not transferable and not refundable. The authorization for these additional credits expires March 31, 2016.

Provisions relating to tax payment and the administration of the tax --

Bill section 8: The bill section enacts (as a repeal and reenactment of AS 43.55.020(a)) a requirement of monthly payment of the net value production tax on oil, with payment due at the end of the calendar month for production during the preceding month. The provision spells out conditions when a tax due is delinquent, the handling of overpayments, and limitations on interest that may be payable on tax overpayments.

Bill section 10, amending AS 43.55.020(d), deals with a producer's right to charge a private royalty owner for the share of production taxes attributable to royalty oil and gas. The amending language adds a method of determining the royalty share of taxes in the absence of an agreement between the producer and royalty owner to use a different method.

Bill section 11 expands the current production tax exemption for gas that is used in lease operations by including oil that is used in those lease operations. The section also clarifies the manner of tax treatment of flared gas, based on authorization to do so from the Alaska Oil and Gas Conservation Commission.

Bill sections 1 and 12: The latter provision amends AS 43.55.020(f) allowing the Department of Revenue to require production tax to be paid on the basis of prevailing value. It clarifies that the provision applies not only when the sale price differs from the prevailing value but also when the oil or gas on which tax is due is not sold at all. The former sets out a statement of intent for the amendment made to the permanent law provision.

Bill section 13: As is done earlier in the bill with respect to oil, proposed AS 43.55.020(g) enacts a requirement of monthly payment of the net value production tax on amounts due under the lessor's royalty share provisions, on the indexed production tax rate increases as applied to oil and the indexed production tax rate increases as applied to gas. Payment is due at the end of the calendar month for production during the preceding month and, if not paid, the tax due is delinquent. Proposed AS 43.55.020(h)

authorizes imposition and collection of a five percent civil penalty on the difference between the amount not paid and a 90 percent threshold if payment, when due, falls below that threshold.

Bill section 20: This section, proposing amendments to AS 43.55.030(a), clarifies what the Department of Revenue may obtain as information relevant to determining taxes due under AS 43.55.

Bill section 21 amends AS 43.55.030(d) to delete a per day penalty for failure to file a tax return under AS 43.55. Other provisions in this measure and in AS 43 are applicable to late filing of tax return documents.

Bill section 22, adding AS 43.55.030(e), sets out a requirement of an annual "true-up" of the prior year monthly returns and directs submission of adjustments or corrections of the previously-filed statements.

Bill section 23, amending AS 43.55.040, clarifies the department's power to obtain information relevant to determining taxes imposed under AS 43.55 by adding the authority to require filing of regular statements or reports. In addition, the bill section modifies the statutory confidentiality restrictions related to use of information in returns and reports when necessary to determine a taxpayer's liability, particularly as those provisions may be applicable to persons -- state officers and employees and privately-retained contractors -- who may have access to the information.

Bill section 27: AS 43.55.150 deals with determining the gross value at the point of production of oil and gas. The addition of new subsection (d) authorizes the Department of Revenue to allow producers to calculate that gross value with a formula that uses a producer's royalty agreement with the state, a royalty value or valuation method accepted by the Department of Natural Resources or the United States Department of the Interior, or another formula using factors such as published price indices.

OTHER SUBSTANTIVE PROVISIONS AFFECTING OIL PRODUCTION AND GAS PRODUCTION TAXES:

Bill section 16: The amendment to AS 43.55.025(b) extends the current production tax credit for exploration expenditures, authorized by AS 43.55.025, from the current deadline of July 2007 (July 2010 for the North Slope and Cook Inlet activities) to July 1, 2016, on a statewide basis.

Bill section 29: The amendments to AS 43.55.201 modify the component of the so-called nickel-per-barrel surcharge that directs a portion of the money to the respon account in the oil and hazardous substance release prevention and response fund, reducing by one cent the amount directed to that account, and making necessary conforming changes to cross-references.

Bill section 30: The addition of AS 43.55.201(d) relieves from payment of this component of the tax surcharge oil that is exempt from the production tax because it is used in lease operations.

Bill section 31: The amendments to AS 43.55.300 modify the component of the so-called nickel-per-barrel surcharge that directs a portion of the money to the release prevention account in the oil and hazardous substance release prevention and response fund, increasing by one cent the amount directed to that account, and making necessary conforming changes to cross-references.

Bill section 32: The addition of AS 43.55.300(d) relieves from payment of this component of the tax surcharge oil that is exempt from the production tax because it is used in lease operations.

Bill sections 33 - 35 amend definitions of terms used in the chapter: "gas", "gross value at the point of production," and "oil."[1]

Bill section 36 adds definitions for "explorer" (for use in the chapter), "gas processing", and "gas treatment".[2]

PROVISIONS PROPOSING REPEAL OF THE CURRENT OIL AND GAS PROPERTIES PRODUCTION TAX:

In addition to repeals and reenactments made in bill sections 1 and 8, **bill section 37** collects and sets out repeals of provisions relating to the current oil and gas properties production tax that are obsolete or unnecessary due to other changes proposed in the measure:

-- repeal of AS 43.55.011(b) and (c) delete the provisions spelling out the percentage-of-value and cents-per-barrel tax methodologies applicable to taxation of oil;

-- repeal of AS 43.55.012(b) repeals the special cents-per-barrel provisions for heavy oil;

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[1] By cross-reference, the change in the definition of "gas" has the effect of changing the definition of "gas" as used in AS 43.82, the Alaska Stranded Gas Development Act. See AS 43.82.900.

[2] As to the definitions, the administration's initial sectional analysis noted that

> Under these definitions, gas processing is considered an operation upstream of the point of production for gas, and generally the line between what is oil and what is gas corresponds to what substances are in liquid form and what substances are in gaseous form, respectively, at the point of production.

-- repeal of AS 43.55.013 eliminates the economic limit factor, or ELF;

-- repeal of AS 43.55.016 deletes the current gas production tax;

-- repeal of AS 43.55.025(k)(3) eliminates the definition of "explorer" as applicable to the current tax credit for oil and gas exploration; the term is defined for the chapter by an addition made in bill section 36;

-- repeal of paragraphs (1), (8), (11), (12) and (16) of AS 43.55.900 eliminate definitions appearing in other repealed sections --"API gravity", "intangible drilling expense", "oil production operation", "old crude oil", and "well days".

CONFORMING ADDITIONS AND AMENDMENTS:

Bill section 2 amends criminal provisions for unauthorized disclosure of confidential records. The section imposes criminal penalties on current or former officers and employees for unauthorized disclosure; the amendment extends the penalties to others, private persons such as legal counsel and consultants, who make an unauthorized disclosure of otherwise confidential information to which they have had access.

Bill sections 3 and 4 authorize a producer who is a taxpayer under the Alaska Net Income Tax Act, AS 43.20, to deduct the production tax payments and disallows the adding back of the production taxes levied and paid in the determination of the producer's corporate income tax.

Bill section 7 conforms certain statutory language to that used in the Internal Revenue Code and incorporates by reference a definition for a term used elsewhere in the chapter.

Bill section 9 makes a corrective amendment to AS 43.55.020(b).

Bill sections 15, 17, 18, and 19: The provisions are in the nature of conforming amendments made to various subsections of AS 43.55.025, authorizing the current tax credit for oil and gas exploration or gas only exploration. The amendments insert or substitute reference to the specific subsection levying the production tax on oil and gas. The changes are necessary because, as proposed in the original bill and the committee substitute, the chapter (AS 43.55) would have multiple tax credits rather than the one existing tax credit for oil and gas, or gas only, exploration.

Bill section 24 proposes amendments to AS 43.55.030, directing that production taxes be deposited into the general fund, to incorporate exceptions imposed under the constitutional budget reserve fund amendment, and making a conforming amendment due to addition of new sections to article 1 of AS 43.55.

Bill section 25, amending AS 43.55.135, sets out a conforming amendment due to addition of new sections to article 1 of AS 43.55.

Bill section 26, amending AS 43.55.150(a), makes conforming amendments relating to the determination of gross value to be calculated and in the reference due to addition of new sections to article 1.

APPLICABILITY, TRANSITIONAL, AND RELATED PROVISIONS:

Bill section 38 specifies that provisions relating to the new tax on the production tax value of oil and gas apply to oil and gas produced on or after April 1, 2006, and that the provision under which the Department of Revenue collects the tax on the basis of prevailing value and that clarifies how that value is to be measured, confirming long-standing agency policy, applies to all production without reference to date.

Bill section 39 sets out a series of transitional provisions that clarify how certain calendar year rules added by the new tax will apply during the first nine-month period that the tax is in effect, that authorize the claim of tax credit for expenditures and losses based on expenditures made on or after January 1, 2006, that set out a transitional schedule for tax payments, and that former regulations in effect under the previous severance tax statute continue to govern oil and gas produced before the April 1, 2006, effective date of the new production tax.

Bill section 40 authorizes adoption of new regulations and provides that the new regulations adopted may apply retroactively as of the April 1, 2006, effective date of the new production tax.

Bill section 41 prescribes editorial instructions for the revisor of statutes.

Bill section 42 adds a provision authorizing retroactive application of expenditures incurred on or after January 1, 2006, for expenditures that support the tax credit claims under the new production tax.

In the event the bill becomes law after April 1, 2006, **bill section 43** makes the provisions of the measure that are identified as taking effect on that date retrospectively effective to that date.

Bill sections 44 and 45 are the measure's effective dates. The production tax provisions have an April 1 effective date; the remainder of the bill is given immediate effect.

JBC:lmb
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House Resources March 16 and 17:

The House Resources Committee released a summary of its committee substitute on Wednesday, and dealt with amendments on the following Thursday and Friday. A total of 18 amendments were offered. Twelve were adopted. Three amendments were distributed but not offered.

Following the last amendment on Friday, Rep. Carl Gatto moved the bill with individual recommendations. All committee members excepting Rep. Harry Crawford voted to move the measure. Reps. Samuels, Ramras, Seaton, Olson, Elkins and Gatto gave the bill a do pass recommendation. Rep. Kapsner signed, "amend," and Rep. Crawford signed, "do not pass." Rep LeDoux attended the meeting by teleconference and could not vote to move the bill or sign the committee report.

Approved amendments

Amendment to remove gas from the surtax

On Thursday, Rep. Kurt Olson offered amendment #5, designed to make the surtax—what Olson and others called the "escalator"—in subsections AS 43.55.011 (f)-(g), only apply to oil. He said it made little sense to link the two.

Gatto agreed, saying it would be just a nonsensical to apply the escalator to coal.

Co-chair Jay Ramras said he favors increased progressivity for both oil and gas, but agreed that the same index probably isn't appropriate for both. He said he would research a better index and possibly offer it later as an amendment. (See amendment #18, below).

Rep. Paul Seaton said he favors the amendment, but agreed with Ramras that the solution is a separate index.

Amendment #5 was approved without objection.

Amendment reapplying the surtax to gas under a new van Meurs escalator

On Friday the committee returned to the issue of the surtax on gas, and passed amendment #19, undoing the effect of amendment #5 approved the day before. The gas surtax rate, however, was changed to escalate under the amendment at a rate tied to the price of gas at Louisiana's Henry Hub, the intersection of several interconnected natural gas pipelines and the trading point for natural gas futures contracts on the New York Mercantile Exchange.

"I have the top secret formula here in my hand," quipped Ramras, holding up a sheet of paper containing the holographic formula written by consultant Pedro van Meurs. Amendment #19, offered by Ramras, incorporated the van Meurs formula. The surtax will start to apply when the Henry Hub gas price is above $8 per million BTU, starting at zero and escalating by 2 percentage points per dollar per million BTU, until reaching a ceiling of 30 percent at $23 per million BTU.

No one mentioned that on a BTU equivalence basis the $23 ceiling price is roughly equal to $150 per barrel, not the $110 for oil in an amendment #15, adopted just a few minutes earlier, or that the top surtax rate for gas is 30 percent instead of the 37.5 percent also established in amendment #15 (see below). But a few minutes later Seaton figured that out, and offered amendment #21, described below.

Amendment amending the new van Meurs gas escalator

A few minutes after the committee approved amendment 19, described immediately above, Seaton offered a hastily handwritten amendment #21, which he described simply as "doing for gas what we did for oil." The amendment was adopted without discussion or objection. The import of the amendment was not immediately apparent because it adjusted index numbers in a formula, but the effect is to raise the top surtax rate from 30 percent to 37.5 percent, and lower the gas price at which that rate kicks in from $23 per million BTU to $18 per million. On a BTU equivalence basis the amendment made the gas surtax parallel the oil surtax.

Amendment increasing the "standard credit" by 20 percent

The draft committee substitute eliminates the $73 million annual standard per company deduction, substituting instead a $10 million annual credit. On Friday Ramras proposed amendment #20, increasing this credit to $12 million. Co-chair Ralph Samuels objected.

Ramras said he wanted to be sure that the bill offers sufficient incentives for the smaller companies that he considers so important to maintaining the flow of new ideas and investments. "It puts a smile on explorer's faces."

"A bigger smile," added Samuels, but he removed his objection and the amendment was approved without objection.

Amendment eliminating credits for past investments

Following the rejection of Rep. Mary Kapsner's Thursday amendment to make the tax retroactive to January 1, 2006 (see rejected amendments, below), Kapsner suggested that the committee should be consistent. "In keeping with our decision and philosophy on retroactivity I would like to move amendment #8." The conceptual amendment directs the legal drafters to delete the "sections relating to transitional investment expenditures," thus disallowing any deduction or credits for investments made before April 1, 2006.

Samuels objected, suggesting that viewing the deduction as equivalent to taxable income is an apples and oranges comparison. Ramras agreed, noting that the draft substitute greatly reduces the retroactive deductions in the original bill (which allowed 100 percent of investments in the previous five years) to a reduced percentage of the investments during the previous three years.

Crawford said the companies have for years benefited from the inappropriately low severance tax, which more than compensated them for those investments.

Seaton acknowledged that this is a "troubling area," but said he doesn't think it will affect future exploration

To the probable surprise of the oil lobbyists in the room—and certainly to the surprise of Kapsner—her amendment passed on a 5-4 vote. "I thought, gee, maybe I should go out in the hall and write some more amendments," she said later.

Voting to eliminate the transition deductions were Crawford, Rep. Jim Elkin, Rep. Gabrielle LeDoux, Kapsner and Seaton. Voting against the amendment were the two co-chairs, Samuels and Ramras, joined by Olson and Gatto.

Amendment allowing credits and deductions for investments made in the first quarter of 2006

Having removed the transition provisions entirely, the committee decide to give back a little bit of transition relief allowing deductions and credits for investments made after January 1, three months before the April 1 date when most of the tax provisions start collecting money for the state.

The amendment (#14) was approved on Friday with little discussion and no dissent.

Amendment increasing the surtax to 37.5 percent at WTI prices above $110 per barrel

Seaton described his amendment #15 as if it simply clarified the effect of the surtax in terms of the "50-50 split at $110 per barrel and above." The effect of the amendment, however is to establish a new surtax formula under which the tax rate increases from 17.7 percent at $109.99 per barrel to 37.5 percent at $110.00 per barrel and above. The draft substitute bill had the surtax ceiling at 30 percent, which would apply at any WTI price above $150 per barrel

The amendment was approved with no further discussion and without objection, although Ramras referred to it later in dissuading Kapsner from offering another amendment that she had drafted, to raise the base PPT rate from 20 to 25 percent.

Amendment limiting deductibility of expenses of a catastrophic oil spill

By Crawford, amendment #18, lifted from language applying to the state corporate income tax, disallows as a deductible expense any costs incurred as a result of a catastrophic oil spill.

The amendment was approved without objection.

Technical amendments

Four technical amendments to correct drafting errors and clear up confusions were approved without objection. Robert Mintz, the assistant attorney general who drafted the administration's original bill, explained all. Despite the explanations, most committee members, lobbyists and reporters had only the dimmest understanding of the specifics.

Amendment #1 clarifies the adjustments that must be made to avoid allowing windfall deductions of lease expenditures that are later reimbursed by a third party. "It corrects a timing problem," explained Mintz. Without the amendment an asset acquired in one year could create a net loss carry-forward in that year, and then be sold in another year.

Amendment #2 conforms the language to the change made elsewhere in AS 23.55.170 to substitute a the $10 million annual credit for the previous $73 million allowance, and requires that the expenditure must be a qualified capital expenditure as defined elsewhere in the bill. In response to a question from Paul Seaton, Co-chair Samuels said the provision does not allow lease acquisition expenses as a qualified capital expense.

Amendment #3 allows the Dept. of Revenue to adopt retroactive regulations to deal with a retroactive effective date. Generally the law prohibits regulations to have retroactive effect.

Amendment #4 fixes ambiguities and inconsistencies in the effective date clauses created by the overall change creating two effective dates.

Amendment #7 conforms language and references to be consistent with the three-fold scheme of taxation in the new bill--the original 20-percent tax on the leaseholder's net-profits from oil and gas, 5 percent on the gross value of private royalty oil, and the "surtax" on the gross value of all oil when prices are above the trigger price ($50 per barrel in the Resources CS).

Rejected amendments

The following amendments were offered and rejected:

Amendment to make tax retroactive to January 1, 2006

On Thursday Kapsner offered amendment #6, to make the tax retroactive to January 1 instead of April 1, 2006. She noted the change would add approximately $250 million to state revenue, and read from testimony by consulting economist Pedro van Meurs suggesting that the retroactive date would have little impact on the producers' long-run economics.

"I wouldn't want the IRS to do it to me," commented Samuels, opposing the amendment.

Kapsner responded that the April 1 date would almost certainly also be retroactive to the date that the bill finally becomes law.

Samuels agreed: "We may not get this done by April 1. We may be here to July."

The amendment failed on a 3 to 6 vote, with Crawford, Elkin and Kapsner in favor, Gatto, Olson, LeDoux, Samuels, Ramras and Seaton opposed.

Amendment to establish a "high energy cost offset fund"

Kapsner's amendment #10 establishes a "high energy cost offset fund" in the general fund, but the amendment did not say where the money would come from, or include any scheme for how it would be spent. Kapsner said her plan, though not yet reflected in the amendment, is to have money only flow into the fund when oil prices are especially high. The money in the fund would be used to subsidize energy costs when they are high. Kapsner said the details could be worked out later.

Seaton said the notion of creating an "energy fund" doesn't belong in this bill.

Samuels agreed, suggesting that doing a big tax bill is treacherous enough without loading it up with all sorts of extraneous provisions.

Crawford disagreed. "Now is the proper time to go on record."

Ramras expressed moral support for the concept. "People in Fairbanks are using credit cards to straddle the high heating cost months in the winter of '05-'06." He said he agrees that this bill is not the right place for it, but he supports the intent.

The amendment failed on a 3-6 vote, with Republican LeDoux joining Democrats Crawford and Kapsner in favor.

Amendment to lower the surtax trigger to $45 per barrel

Under the draft House Resources Committee substitute bill the trigger price above which the surtax would be levied was set at $50 per barrel. Seaton's amendment #12 would have lowered that to $45. The amendment stimulated lots of philosophical discussion about balancing the extra progressivity and the revenue the amendment would bring to the treasury with the risk that the oil industry would cut back it's Alaska investments.

"If somebody is on the bubble, and their investment falls off, it's a tremendous loss to my community Fairbanks," commented Ramras. He said the PPT bill is about three things: raising taxes to a fair level for the state, getting more oil down the pipe, and facilitating the shift of Alaska from an oil economy to a gas-based economy. From his perspective, the state treasury is the least important of the three: "It's the bronze medal. I'm more interested in the gold and silver."

Ramras said he was impressed with the charts submitted by BP that showed the sources of new oil coming predominately from developments in existing fields. "We need to get the last barrel, not just the next barrel."

Crawford said the current substitute puts all the state's eggs in the "high oil price basket." He did not explain how Seaton's proposed amendment would change that, and admitted that he is in a quandary about how to vote on it. "I would have preferred a graduated tax, with a floor." He said he is afraid the oil companies will outfox the state anytime the issue comes down to determining net profits. "If you look at our net profits leases, we don't do nearly as well on them as we do [with royalty leases]. ... This is putting perfume on a pig," said Crawford in summary, but a few moments later he voted for the amendment anyway. The tally was 3-6, with Seaton and Kapsner joining him in support.

Amendment to delete the optional use of royalty settlements on determining production value

On Friday Kapsner moved her amendment #9 to eliminate the discretion the commissioner of revenue would have to use royalty settlement agreements as a benchmark in establishing the gross value at the point of production. Administration consultant and former Tax Division Director Dan Dickinson testified that the provision is only an option, and that he presumes that the commissioner would be sure to prevent any field cost deductions that might be a part of the royalty valuation from entering the tax calculation.

The amendment failed on a vote of 2-7, with only Democrats Crawford and Kapsner voting in favor.

Amendment to establish a PPT revenue floor

Crawford moved amendment #16, to establish a floor on PPT revenue equal to 6 percent of the gross value at the point of production. "This will protect the state on the downside," said Crawford.

Ramras agreed it would protect the state on the downside, but said he fervently considers that kind of protection unfair. He recalling his lease for restaurant space in a Fairbanks mall, where the landlord took a percent of gross when times were good, and a fixed rent when gross revenue was below a threshold: "[With this bill] we're getting it on the high end. We need to take the risk on the low end."

Samuels said he agrees with Ramras, adding that "savings is the key," so the state will be able to weather the times when prices are low.

Amendment to remove gas from the bill

Crawford offered conceptual amendment 17, to remove natural gas from the tax changes in the bill. He argued that the state should not change its tax structure on gas until it sees the Stranded Gas Act contract that the producers and the state say they have agreed to.

Samuels pointed out the conceptual difficulties that applying the PPT to just oil or just gas would entail in terms of allocating costs, but Crawford countered that costs could be allocated based on production, presumably using BTU or some other measure of equivalence.

The amendment failed on a vote of 2-7, with the two Democrats, Crawford and Kapsner voting yes.

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MEMORANDUM March 16, 2006

SUBJECT: Amendments to CSHB 488(RES), draft version "Y"
(Work Order No. 24-GH2052\Y.4 - Y.7)

TO: Representative Jay Ramras
Representative Ralph Samuels
Co-Chairs of the House Resources Committee

FROM: Jack Chenoweth
Assistant Revisor

Dan Dickinson visited me this morning, bringing with him four "clean up" amendments to the draft committee substitute supplied yesterday. Since I could not assure him that we could produce a new draft committee substitute incorporating the changes by the time of your scheduled early afternoon hearing, this memo transmits that material set out as four amendments.

In the main, the material tracks the language offered by Mr. Dickinson. However, in amendment Y.6, reference in material supplied by Mr. Dickinson to "sec. 16" seemed incorrect, and I renumbered; please check the references.

I told Dan that, in any final version of the committee substitute, the content of bill sections 29 - 31, amending various subsections of AS 43.55.201, would be brought together in just one bill section, and the content of bill sections 33 - 35, amending various subsections of AS 43.55.300, would be similarly treated.

JBC:med
06-221.med

Enclosures

Alaska Oil and Gas Association

AOGA

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Judith Brady, Executive Director

TO: Senator Tom Wagoner
Senate Resources Chairman

Representative Ralph Samuels
House Resources Co-Chairman

Representative Jay Ramras
House Resources Co-Chairman

FROM: Judith Brady, AOGA Executive Director

DATE: February 24, 2006

RE: Written Testimony for Joint Resources Committee – February 25, 2006

Thank you for the opportunity to provide written testimony for the Joint Resources Committee, Saturday, February 25, 2006 regarding HB 488 and SB 305 – Governor Murkowski's proposal to create a new production tax on the net value of oil and gas.

The Governor's proposal is estimated to be a billion dollar annual tax increase on the Alaska oil and gas industry – doubling the severance tax collected from the current system. This is, by any standard, an unprecedented increase that is of significant concern to AOGA.

Any changes to the existing tax system should continue to maintain as well as improve Alaska's competitiveness in the world in order to attract new capital spending. Increased industry spending will result in greater oil and gas production, more revenue to the State and more jobs for Alaskans. Alaska should strive to be in the upper quartile of competitiveness to attract companies and grow the Alaska private sector economy.

As we all know, this bill is complex. Individual AOGA member companies will need time to fully evaluate the details contained in the 22-page proposal and determine how the provisions of the bill affects each of their operations.

We look forward to working with you.

Cc: Members of House & Senate Resources Committees

THE ALLIANCE

... for responsible development of Alaska's Oil, Gas & Mineral Resources

HOUSE-SENATE RESOURCES TESTIMONY.1
On House Bill 488 – Senate Bill 305
February 25, 2006

Mr. Chairman, thank you for this opportunity to comment on Senate Bill 305 and House Bill 488. My name is Paul Laird, and I'm the general manager of the Alaska Support Industry Alliance.

As a trade organization representing companies and individuals that provide goods and services for Alaska's oil, gas and minerals industries, we know first-hand the critical role that investments in oil and gas exploration and development play in sustaining our members' businesses. As Alaskans, we also know the critical role they play in the future of our state's economy.

We're encouraged by the tax credits and annual allowance contained in these bills, because we believe they will achieve their goal of stimulating new investments both in developing known oil and gas resources and in finding new ones.

To the extent that this legislation could represent a critical step toward providing the fiscal stability and predictability investors will need in order to build a multibillion-dollar gas project, we're encouraged by that, too.

But the Alliance is also deeply concerned about the prospect of a $1 billion annual tax increase on the industry that's already providing about 90% of Alaska's state revenues and the potential impacts on Alaska's competitiveness and its ability to attract the investments that are our state's lifeblood.

We're also concerned about extracting another $1 billion a year from the private sector in order to provide even greater funding to a state government that's already projecting a $1.2 billion budget surplus in the short term, that's growing at a disturbing rate and that still has no fiscal plan for managing excess funds during the good times or balancing the budget when times are lean.

This legislation is very complex, and it has historic implications not only for our industry, but for our state. We, like you, are still working to fully understand the implications to future investments, and thereby, to the economic future of Alaska.

As you consider how to ensure that Alaska gets its "fair share" of the profits from oil and gas production, which effectively means more money to grow the size of state government, the Alliance's 400 member organizations and the more than 30,000 employees who work for them in Alaska urge you to also consider what effect this legislation will have on growing Alaska's economy, and on Alaskans getting our fair share of the private sector jobs and business opportunities that will only come through new oil and gas investments.

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