ALASKA STATE LEGISLATURE

Official Business

HOUSE SPECIAL COMMITTEE ON OIL AND GAS
Representative Kurt Olson, Chair
State Capitol, Room 408
Juneau, AK 99801-1182
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Saturday, October 27, 2007
House Finance Committee Room 519
2 pm

AGENDA

HB 2001 - Oil and Gas Production Tax Amendments

- **Committee Action on HB 2001**

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HOUSE OIL & GAS TESTIMONY
on HB 2001
October 24, 2007

Thank you, Chairman Olson and members of the House Oil & Gas Committee. My name is Eric Dompeling. I'm a technical representative at Baker Oil Tools and president of the Alaska Support Industry Alliance, a trade organization representing companies and individuals that provide goods and services to Alaska's oil, gas and mining industries. I'm testifying on behalf of the Alliance.

Our 400 member companies and their 35,000-plus Alaska employees don't make the multibillion-dollar investments in oil and gas development that fuel Alaska's economy ... they make the investments work.

As companies and workers whose livelihoods depend on oil and gas investment, we're deeply concerned about constant changes in fiscal policy that put some of those investments at risk.

It's difficult for us to understand why you're back in Juneau so soon to fix a system that hasn't even had time to work, let alone for compelling evidence that it's broken. Regulations for the PPT adopted just 14 months ago haven't even been finalized, and the first returns haven't been audited.

So far, proponents of this tax increase have presented you with a plethora of projections and a paucity of proof.

We don't know if a 22.5% tax rate with the current escalator and credits strikes the right balance between ensuring the state its fair share of oil revenues and encouraging long-term investment and production. We don't know if 25% is the right rate ... or 20 ... or 15.

None of us does ... not the Alliance, not the legislature, not the administration and not even the producers.

We do know that every dollar in additional taxes is a dollar that won't be invested in sustaining production, in creating business opportunities for Alaska companies like Alliance members, in generating good-paying private sector jobs for Alaskans.

We do know that while the extent to which yet another tax increase will discourage investment is debatable, the fact that it will do absolutely nothing to encourage new oil production and construction of a gas project is not.

Isn't that what this discussion should be about: how we can work together to promote investments ... how we can ensure our "fair share" of long-term jobs and business opportunities for Alaskans, rather than how much more money we can extract from the private sector without further risking our long-term future ... just so state government can have more money to spend in the short term?

When you adopted the new PPT in 2006 after months of deliberations, debate and countless votes, you included provisions requiring a complete review of the system five years later - in 2011. You understood then that it would take several years to reasonably determine how and if it's working. That hasn't changed.

Do what you need to do in the short term to make the PPT work - hire more auditors, pay them more, take steps to ensure the timely flow of accurate data from the producers to the state, authorize the state to buy back credits.

But we urge you to reject premature, fundamental changes to the PPT that will increase taxes, increase costs, jeopardize the economics of critical long-term investments and put production, Alaska jobs and business opportunities at risk.

The testimony of Jerry McCutcheon

The taxes as proposed are FAR TOO LOW.

Increasing AK take will decrease the Fed's take,a good thing. The percent attributed to the Fed's take is much more than the oil companies actually pay.

Van Meurs pointed out that the State's take should be more and made that argument to Governor Murkowski in memo withheld from the legislature. Van Meurs also pointed out that PPT and Governor Palin's ACES' take, the percentage of the State of Alaska's take, actually declines with the increasing price of oil and they, Johnston also, thought that was stupid; the state percentage should increase with the increasing price of oil. Van Meurs quoted takes from 75% to 85% as usual and customary and takes of 90% to 95 % as not unusual and some takes were up to 98.5% and still the oil companies came. Johnston concurred.

Gross take on Alaska oil should approach 90%. See Shell oil's contract on North Star; it was over 90%, not the 80% that Johnston guessed for an example and that was when oil was $18/barrel.

Also see the other lease about the same time, those were willing bids; nobody held a gun to their heads. Maybe AK should go back that system.

AS both van Meurs and Johnston pointed that having the oil companies threaten to leave Alaska or actually leaving Alaska is not a bad thing and it maybe in Alaska's best interest for the long term if some of the oil companies did leave. Alaska should not be magnet for every body.

However, considering the fact that the FBI and the grand jury have not completed their investigation and the fact the grand jury may bring a RICO Act indictment against not only the oil companies but also some legislators, not yet investigated, when the FBI begins to address the mechanics of passing legislation and what happed in the process. Remember the standards of proof are much lower under RICO and far broader in scope.

It would appear the legislature should adopt a clean tax on the gross pending the completion of the FBI and grand jury investigations. Then modify I, aft, to include any tax credits thought necessary.

Jerry McCutcheon susitnahydronow@yahoo.com

25-GH0014\K
Bullock
10/27/07

CS FOR HOUSE BILL NO. 2001(O&G)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FIFTH LEGISLATURE - SECOND SPECIAL SESSION

BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Offered:
Referred:

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

A BILL

FOR AN ACT ENTITLED

"An Act relating to the production tax on oil and gas and to conservation surcharges on oil; providing a limit on the amount of tax that may be levied on the production of certain gas that is produced outside of the Cook Inlet sedimentary basin and south of 68 degrees North latitude; relating to the sharing between agencies of certain information relating to the production tax and to oil and gas or gas only leases; expanding the period in which the Department of Revenue may assess the amount of oil and gas production tax and conservation surcharges; amending the State Personnel Act to place in the exempt service certain state oil and gas auditors and their immediate supervisors; providing for retroactive application of certain statutory and regulatory provisions relating to the production tax on oil and gas and conservation surcharges on oil; making conforming amendments; and providing for an effective date."

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

*** Section 1.** AS 38.05.035(a) is amended to read:

(a) The director shall

(1) have general charge and supervision of the division and may exercise the powers specifically delegated to the director; **the director** may employ and fix the compensation of assistants and employees necessary for the operations of the division; **the director** [AND] is the certifying officer of the division, with the consent of the commissioner, and may approve vouchers for disbursements of money appropriated to the division;

(2) manage, inspect, and control state land and improvements on it belonging to the state and under the jurisdiction of the division;

(3) execute laws, rules, regulations, and orders adopted by the commissioner;

(4) prescribe application procedures and practices for the sale, lease, or other disposition of available land, resources, property, or interest in them;

(5) prescribe fees or service charges, with the consent of the commissioner, for any public service rendered;

(6) under the conditions and limitations imposed by law and the commissioner, issue deeds, leases**,** or other conveyances disposing of available land, resources, property**,** or any interests in them;

(7) have jurisdiction over state land, except that land acquired by the Alaska World War II Veterans Board and the Agricultural Loan Board or the departments or agencies succeeding to their respective functions through foreclosure or default; to this end**,** the director possesses the powers and, with the approval of the commissioner, shall perform the duties necessary to protect the state's rights and interest in state land, including the taking of all necessary action to protect and enforce the state's contractual or other property rights;

(8) [REPEALED

(9)] maintain **the** [SUCH] records [AS] the commissioner considers necessary, administer oaths, and do all things incidental to the authority imposed; the following records and files shall be kept confidential upon request of the person supplying the information:

(A) the name of the person nominating or applying for the sale, lease, or other disposal of land by competitive bidding;

(B) before the announced time of opening, the names of the bidders and the amounts of the bids;

(C) all geological, geophysical, and engineering data supplied, whether or not concerned with the extraction or development of natural resources;

(D) except as provided in AS 38.05.036, cost data and financial information submitted in support of applications, bonds, leases, and similar items;

(E) applications for rights-of-way or easements;

(F) requests for information or applications by public agencies for land **that** [WHICH] is being considered for use for a public purpose;

(9) [(10)] account for the fees, licenses, taxes, or other money received in the administration of this chapter including the sale or leasing of land, identify their source, and promptly transmit them to the proper fiscal department after crediting them to the proper fund; receipts from land application filing fees and charges for copies of maps and records shall be deposited immediately in the general fund of the state by the director;

(10) [(11)] select and employ or obtain at reasonable compensation cadastral, appraisal, or other professional personnel the director considers necessary for the proper operation of the division;

(11) [(12)] be the certifying agent of the state to select, accept, and secure by whatever action is necessary in the name of the state, by deed, sale, gift, devise, judgment, operation of law, or other means any land, of whatever nature or interest, available to the state; and be the certifying agent of the state, to select, accept, or secure by whatever action is necessary in the name of the state any land, or title or interest to land available, granted, or subject to being transferred to the state for any purpose;

(12) on request, furnish records, files, and other information related to the administration of AS 38.05.180 to the Department of Revenue for

use in forecasting state revenue under or administering AS 43.55, whether or not those records, files, and other information are required to be kept confidential under (8) of this subsection; in the case of records, files, or other information required to be kept confidential under (8) of this subsection, the Department of Revenue shall maintain the confidentiality that the Department of Natural Resources is required to extend to records, files, and other information under (8) of this subsection

[(13) REPEALED

(14) REPEALED].

*** Sec. 2.** AS 38.05.036(b) is amended to read:

(b) The Department of Revenue may obtain from the department information relating to royalty and net profits payments and to exploration incentive credits under this chapter or under AS 41.09, whether or not that information is confidential. The Department of Revenue may use the information in carrying out its functions and responsibilities under AS 43, and shall hold that information confidential to the extent required by an agreement with the department or by **AS 38.05.035(a)(8)** [AS 38.05.035(a)(9)], AS 41.09.010(d), or AS 43.05.230.

*** Sec. 3.** AS 38.05.036(f) is amended to read:

(f) Except as otherwise provided in this section or in connection with official investigations or proceedings of the department, it is unlawful for a current or former officer, employee, or agent of the state to divulge information obtained by the department as a result of an audit under this section that is required by an agreement with the department or by **AS 38.05.035(a)(8)** [AS 38.05.035(a)(9)] or AS 41.09.010(d) to be kept confidential.

*** Sec. 4.** AS 38.05.036(g) is amended to read:

(g) Nothing in this section prohibits the publication of statistics in a manner that maintains the confidentiality of information to the extent required by an agreement with the department or by **AS 38.05.035(a)(8)** [AS 38.05.035(a)(9)] or AS 41.09.010(d).

*** Sec. 5.** AS 38.05.123(f) is amended to read:

(f) As part of the timber sale negotiations authorized by this section, the commissioner may require a prospective purchaser negotiating a timber sale contract to submit financial and technical data that demonstrates that the requirements of this section have been or will be met. Upon the prospective purchaser's request, the commissioner shall keep data provided by the purchaser confidential in accordance with the requirements of **<u>AS 38.05.035(a)(8)</u>** [AS 38.05.035(a)(9)].

*** Sec. 6.** AS 38.05.133(e) is amended to read:

(e) The commissioner may make a written request to a prospective licensee for additional information on the prospective licensee's proposal. The commissioner shall keep confidential information described in **<u>AS 38.05.035(a)(8)</u>** [AS 38.05.035(a)(9)] that is voluntarily provided if the prospective licensee has made a written request that the information remain confidential.

*** Sec. 7.** AS 38.05.180(j) is amended to read:

(j) The commissioner

(1) may provide for modification of royalty on individual leases, leases unitized as described in (p) of this section, leases subject to an agreement described in (s) or (t) of this section, or interests unitized under AS 31.05

(A) to allow for production from an oil or gas field or pool if

(i) the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;

(ii) the field or pool has not previously produced oil or gas for sale; and

(iii) oil or gas production from the field or pool would not otherwise be economically feasible;

(B) to prolong the economic life of an oil or gas field or pool as per barrel or barrel equivalent costs increase or as the price of oil or gas decreases, and the increase or decrease is sufficient to make future production no longer economically feasible; or

(C) to reestablish production of shut-in oil or gas that would not otherwise be economically feasible;

(2) may not grant a royalty modification unless the lessee or lessees requesting the change make a clear and convincing showing that a modification of

royalty meets the requirements of this subsection and is in the best interests of the state;

(3) shall provide for an increase or decrease or other modification of the state's royalty share by a sliding scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs;

(4) may not grant a royalty reduction for a field or pool

(A) under (1)(A) of this subsection if the royalty modification for the field or pool would establish a royalty rate of less than five percent in amount or value of the production removed or sold from a lease or leases covering the field or pool;

(B) under (1)(B) or (1)(C) of this subsection if the royalty modification for the field or pool would establish a royalty rate of less than three percent in amount or value of the production removed or sold from a lease or leases covering the field or pool;

(5) may not grant a royalty reduction under this subsection without including an explicit condition that the royalty reduction is not assignable without the prior written approval, which may not be unreasonably withheld, by the commissioner; the commissioner shall, in the preliminary and final findings and determinations, set out the conditions under which the royalty reduction may be assigned;

(6) shall require the lessee or lessees to submit, with the application for the royalty reduction, financial and technical data that demonstrate that the requirements of this subsection are met; the commissioner

(A) may require disclosure of only the financial and technical data related to development, production, and transportation of oil and gas or gas only from the field or pool that are reasonably available to the applicant; and

(B) shall keep the data confidential under **AS 38.05.035(a)(8)** [AS 38.05.035(a)(9)] at the request of the lessee or lessees making application for the royalty reduction; the confidential data may be disclosed by the commissioner to legislators and to the legislative auditor and as directed by the chair or vice-chair of the Legislative Budget and Audit Committee to the director of the division of legislative finance, the permanent employees of their respective divisions who are responsible for evaluating a royalty reduction, and to agents or contractors of the legislative auditor or the legislative finance director who are engaged under contract to evaluate the royalty reduction, if they sign an appropriate confidentiality agreement;

(7) may

(A) require the lessee or lessees making application for the royalty reduction under (1)(A) of this subsection to pay for the services of an independent contractor, selected by the lessee or lessees from a list of qualified consultants compiled by the commissioner, to evaluate hydrocarbon development, production, transportation, and economics and to assist the commissioner in evaluating the application and financial and technical data; if, under this subparagraph, the commissioner requires payment for the services of an independent contractor, the total cost of the services to be paid for by the lessee or lessees may not exceed $150,000 for each application, and the commissioner shall determine the relevant scope of the work to be performed by the contractor; selection of an independent contractor under this subparagraph is not subject to AS 36.30;

(B) with the mutual consent of the lessee or lessees making application for the royalty reduction under (1)(B) or (1)(C) of this subsection, request payment for the services of an independent contractor, selected from a list of qualified consultants to evaluate hydrocarbon development, production, transportation, and economics by the commissioner to assist the commissioner in evaluating the application and financial and technical data; if, under this subparagraph, the commissioner requires payment for the services of an independent contractor, the total cost of the services that may be paid for by the lessee or lessees may not exceed $150,000 for each application, and the commissioner shall determine the relevant scope of the work to be performed by the contractor; selection of an independent contractor under this subparagraph is not subject to AS 36.30;

(8) shall make and publish a preliminary findings and determination on the royalty reduction application, give reasonable public notice of the preliminary findings and determination, and invite public comment on the preliminary findings and determination during a 30-day period for receipt of public comment;

(9) shall offer to appear before the Legislative Budget and Audit Committee, on a day that is not earlier than 10 days and not later than 20 days after giving public notice under (8) of this subsection, to provide the committee a review of the commissioner's preliminary findings and determination on the royalty reduction application and administrative process; if the Legislative Budget and Audit Committee accepts the commissioner's offer, the committee shall give notice of the committee's meeting to all members of the legislature;

(10) shall make copies of the preliminary findings and determination available to

(A) the presiding officer of each house of the legislature;

(B) the chairs of the legislature's standing committees on resources; and

(C) the chairs of the legislature's special committees on oil and gas, if any;

(11) shall, within 30 days after the close of the public comment period under (8) of this subsection,

(A) prepare a summary of the public response to the commissioner's preliminary findings and determination;

(B) make a final findings and determination; the commissioner's final findings and determination prepared under this subparagraph regarding a royalty reduction is final and not appealable to the court;

(C) transmit a copy of the final findings and determination to the lessee;

(D) with the applicant's consent, amend the applicant's lease or unitization agreement consistent with the commissioner's final decision; and

(E) make copies of the final findings and determination available to each person who submitted comment under (8) of this subsection and who has filed a request for the copies;

(12) is not limited by the provisions of AS 38.05.134(3) or (f) of this section in the commissioner's determination under this subsection.

* **Sec. 8.** AS 38.05.275(c) is amended to read:

(c) Subsection (b) of this section may not be construed to limit the director in the exercise of authority granted by **AS 38.05.035(a)(11)** [AS 38.05.035(a)(12)].

* **Sec. 9.** AS 39.25.110 is amended by adding a new paragraph to read:

(42) oil and gas auditors performing

(A) production tax audits, and their immediate supervisors, in the Department of Revenue;

(B) royalty audits, including net profit share audits, and their immediate supervisors, in the Department of Natural Resources.

* **Sec. 10.** AS 41.09.010(d) is amended to read:

(d) Data derived from drilling a stratigraphic test well or exploratory well that is provided to the commissioner under (c)(3) of this section shall be kept confidential for 24 months after receipt by the commissioner unless the owner of the well gives written permission to the state to release the well data at an earlier date, and, notwithstanding AS 31.05.035(c), confidentiality may not be extended beyond 24 months. The provisions of **AS 38.05.035(a)(8)(C)** [AS 38.05.035(a)(9)(C)] apply to other data provided to the commissioner under (c)(3) of this section, except that the commissioner, under appropriate confidentiality provisions and without preference or discrimination, may display to all interested third parties, but may not distribute or transfer in hard copy or electronic form, those data with respect to all land if the commissioner determines that the limited disclosure is necessary to further the interest of the state in evaluating or developing its land.

* **Sec. 11.** AS 43.05.230(a) is amended to read:

(a) It is unlawful for a current or former officer, employee, or agent of the state to divulge the amount of income or the particulars set out or disclosed in a report or return made under this title, except

(1) in connection with official investigations or proceedings of the department, whether judicial or administrative, involving taxes due under this title;

(2) in connection with official investigations or proceedings of the child support enforcement agency, whether judicial or administrative, involving child support obligations imposed or imposable under AS 25 or AS 47;

(3) as provided in AS 38.05.036 pertaining to audit functions of the Department of Natural Resources;

(4) as provided in AS 43.05.405 - 43.05.499; and

(5) as otherwise provided in this section **or AS 43.55.890**.

* **Sec. 12.** AS 43.05.230(h) is amended to read:

(h) The commissioner shall, upon request, furnish to the Department of Natural Resources copies of tax returns, reports, **and other** documents filed under **AS 43.55 or** AS 43.65, and the Department of Revenue's determinations and workpapers **under those chapters**. The Department of Natural Resources shall maintain the confidentiality that the Department of Revenue is required to extend to the returns, reports, documents, determinations, and workpapers furnished to the Department of Natural Resources under this subsection.

* **Sec. 13.** AS 43.05.260(a) is amended to read:

(a) Except as provided in (c) of this section**,** [AND] AS 43.20.200(b), **and AS 43.55.075,** the amount of a tax imposed by this title must be assessed within three years after the return was filed, whether or not a return was filed on or after the date prescribed by law. If the tax is not assessed before the expiration of the **applicable** [THREE-YEAR] period, proceedings may not be instituted in court for the collection of the tax.

* **Sec. 14.** AS 43.55.011(j) is amended to read:

(j) For a calendar year before 2022, the total tax levied by (e) and **(o)** [(g)] of this section on gas produced from a lease or property in the Cook Inlet sedimentary basin may not exceed

(1) for a lease or property that first commenced commercial production of gas before April 1, 2006, the product obtained by multiplying (A) the

amount of taxable gas produced during the calendar year from the lease or property, times (B) the average rate of tax that was imposed under this chapter on taxable gas produced from the lease or property for the 12-month period ending on March 31, 2006, times (C) the quotient obtained by dividing the total gross value at the point of production of the taxable gas produced from the lease or property during the 12-month period ending on March 31, 2006, by the total amount of that gas;

(2) for a lease or property that first commences commercial production of gas after March 31, 2006, the product obtained by multiplying (A) the amount of taxable gas produced during the calendar year from the lease or property, times (B) the average rate of tax that was imposed under this chapter on taxable gas produced from all leases or properties in the Cook Inlet sedimentary basin for the 12-month period ending on March 31, 2006, times (C) the average prevailing value for gas delivered in the Cook Inlet area for the 12-month period ending March 31, 2006, as determined by the department under AS 43.55.020(f).

*** Sec. 15.** AS 43.55.011(k) is amended to read:

(k) For a calendar year before 2022, the total tax levied by (e) and **(o)** [(g)] of this section on oil produced from a lease or property in the Cook Inlet sedimentary basin may not exceed

(1) for a lease or property that first commenced commercial production of oil before April 1, 2006, the product obtained by multiplying (A) the amount of taxable oil produced during the calendar year from the lease or property, times (B) the average rate of tax that was imposed under this chapter on taxable oil produced from the lease or property for the 12-month period ending on March 31, 2006, times (C) the quotient obtained by dividing the total gross value at the point of production of the taxable oil produced from the lease or property during the 12-month period ending on March 31, 2006, by the total amount of that oil;

(2) for a lease or property that first commences commercial production of oil after March 31, 2006, the product obtained by multiplying (A) the amount of taxable oil produced during the calendar year from the lease or property, times (B) the average rate of tax that was imposed under this chapter on taxable oil produced from all leases or properties in the Cook Inlet sedimentary basin for the 12-

month period ending on March 31, 2006, times (C) the average prevailing value for oil produced and delivered in the Cook Inlet area for the 12-month period ending on March 31, 2006, as determined by the department under AS 43.55.020(f).

* **Sec. 16.** AS 43.55.011(m) is amended to read:

(m) Notwithstanding any contrary provision of AS 38.05.180(i), AS 41.09.010, AS 43.20.043, AS 43.55.024, or 43.55.025, tax credits under AS 38.05.180(i), AS 41.09.010, AS 43.20.043, AS 43.55.024, and 43.55.025 that are allocated to gas produced from leases or properties in the Cook Inlet sedimentary basin and that are available to be applied against a tax levied by (e) of this section **<u>for</u>** [ON] gas produced from leases or properties in the Cook Inlet sedimentary basin during a calendar year may be applied only against the tax levied by (e) of this section **<u>for</u>** [ON] that gas. The amount by which the amount of tax credits that are allocated to gas produced from leases or properties in the Cook Inlet sedimentary basin and that the producer would otherwise be allowed to use for a later calendar year or transfer to another person exceeds the amount of tax credits whose application would reduce the tax levied by (e) of this section **<u>for</u>** [ON] that gas to zero, if any, is considered the amount of excess tax credits, and the excess tax credits are subject to the following:

(1) for each lease or property for which a limitation under (j) or (k) of this section on the tax levied by (e) and **<u>(o)</u>** [(g)] of this section has the effect of reducing the producer's tax below the amount of tax that would be levied in the absence of that limitation, the producer shall calculate the amount of that reduction;

(2) the producer shall calculate the total of the reductions calculated under (1) of this subsection for all affected leases or properties;

(3) the producer shall reduce the amount of excess tax credits by the total calculated under (2) of this subsection, but not to less than zero;

(4) any amount of excess tax credits remaining after reduction under (3) of this subsection may be used for a later calendar year, transferred to another person, or applied against a tax levied **<u>for</u>** [ON] oil or gas produced from a lease or property located anywhere in the state to the extent otherwise allowed under applicable law governing the tax credits.

* **Sec. 17.** AS 43.55.011 is amended by adding new subsections to read:

(o) In addition to the tax levied under (e) of this section, for each month for which the gross value at the point of production exceeds $50 a barrel, there is levied on the producer of oil or gas a tax for all oil and gas produced 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 or constitutes a landowner's royalty interest. Except as otherwise provided under (j) and (k) of this section, the tax levied under this subsection is equal to .225 percent of the difference between the gross value at the point of production for the month and the product of the total amount of production for that month in BTU equivalent barrels multiplied by $50.

(p) For a calendar year before 2022, the tax levied by (e) and (o) of this section for gas produced from a lease or property that is outside of the Cook Inlet sedimentary basin and no part of which is north of 68 degrees North latitude may not exceed the product of the amount of taxable gas produced during the calendar year from the lease or property, multiplied by the average rate of tax imposed under this chapter for taxable gas produced from all leases or properties in the Cook Inlet sedimentary basin, multiplied by the average prevailing value for gas delivered in the Cook Inlet area for the 12-month period ending March 31, 2006, as determined by the department under AS 43.55.020(f). This subsection applies only to gas produced from a lease or property for which the start of regular deliveries of marketable gas is after December 31, 2007.

*** Sec. 18.** AS 43.55.020(a) is amended to read:

(a) For a calendar year, a producer subject to tax under AS 43.55.011(e), (f), [(g), OR] (i), **<u>or (o),</u>** and notwithstanding that a producer may be liable for the tax under AS 43.55.011(f) rather than the tax under AS 43.55.011(e), shall pay the tax as follows:

(1) an installment payment of the estimated tax levied by AS 43.55.011(e) or (f), net of any tax credits applied as allowed by law, is due for each month of the calendar year on the last day of the following month; the amount of the installment payment is the sum of the amounts calculated under (2) and (3) of this subsection, but not less than zero;

(2) the first of the two amounts used to calculate the installment

payment for a month under (1) of this subsection is equal to the remainder obtained by subtracting

(A) 1/12 of the tax credits that are allowed by law to be applied against the tax levied by AS 43.55.011(e) for the calendar year; from

(B) the total of the monthly production values calculated **under** [IN THE MANNER PROVIDED IN] AS 43.55.160(a)(2) of all oil and gas taxable under AS 43.55.011(e) and produced by the producer from leases or properties in the state during the month, multiplied by 22.5 percent;

(3) the second of the two amounts used to calculate the installment payment for a month under (1) of this subsection is the amount calculated for the month under **AS 43.55.011(o)** [AS 43.55.011(g)];

(4) an installment payment of the estimated tax levied by AS 43.55.011(i) for each lease or property is due for each month of the calendar year on the last day of the following month; the amount of the installment payment is the sum of

(A) the applicable percentage rate for oil provided under AS 43.55.011(i), multiplied by the gross value at the point of production of the oil taxable under AS 43.55.011(i) and produced from the lease or property during the month; plus

(B) the applicable percentage rate for gas provided under AS 43.55.011(i), multiplied times the gross value at the point of production of the gas taxable under AS 43.55.011(i) and produced from the lease or property during the month;

(5) any amount of tax levied by **AS 43.55.011(e), (f), (i), and (o)** [AS 43.55.011(e) - (g) AND (i)], net of any credits applied as allowed by law, that exceeds the total of the amounts due as installment payments of estimated tax is due on March 31 of the year following the calendar year of production.

*** Sec. 19.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner for oil and gas that is taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable royalty oil and 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. If the total deductions of installment payments of estimated tax for a calendar year exceed the actual tax for that calendar year, the producer shall, before April 1 of the following year, refund the excess to the royalty owner. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under **AS 43.55.011(e), (f), and (o)** [AS 43.55.011(e) - (g)] on taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or right to which constitutes a landowner's royalty interest, is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the calendar year 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(e), (f), and (o)** [AS 43.55.011(e) - (g)] for the calendar year 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), (f), and (o)** [AS 43.55.011(e) - (g)] produced by the producer from all leases and properties in the state during the calendar year.

* **Sec. 20.** AS 43.55.020(g) is amended to read:

(g) Notwithstanding any contrary provision of AS 43.05.225, an unpaid amount of an installment payment required under (a)(1) - (4) of this section that is not paid when due bears interest (1) at the rate provided for an underpayment under 26 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from the date the installment payment is due until [THE] March 31 **following the calendar year of production** [DESCRIBED IN AS 43.55.030(a)], and (2) as provided for a delinquent tax under AS 43.05.225 after that March 31. Interest accrued under (1) of this subsection that remains unpaid after that March 31 is treated as an addition to tax that bears interest under (2) of this subsection. An unpaid amount of tax due under (a)(5) of this section that is not paid when due bears interest as provided for a delinquent tax under AS 43.05.225.

* **Sec. 21.** AS 43.55.020(h) is amended to read:

(h) Notwithstanding any contrary provision of AS 43.05.280,

(1) an overpayment of an installment payment required under (a)(1) - (4) of this section bears interest at the rate provided for an overpayment under 26 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from the later of the date the installment payment is due or the date the overpayment is made, until the earlier of

(A) the date it is refunded or is applied to an underpayment<u>;</u> [,] or

(B) [THE] March 31 **<u>following the calendar year of production</u>** [DESCRIBED IN AS 43.55.030(a)];

(2) except as provided under (1) of this subsection, interest with respect to an overpayment is allowed only on any net overpayment of the payments required under (a) of this section that remains after the later of [THE] March 31 **<u>following the calendar year of production</u>** [DESCRIBED IN AS 43.55.030(a)] or the date that the statement required under AS 43.55.030(a) is filed;

(3) interest is allowed under (2) of this subsection only from a date that is 90 days after the later of [THE] March 31 **<u>following the calendar year of production</u>** [DESCRIBED IN AS 43.55.030(a)] or the date that the statement required under AS 43.55.030(a) is filed; interest is not allowed if the overpayment was refunded within the 90-day period;

(4) interest under (2) and (3) of this subsection is paid at the rate and in the manner provided in AS 43.05.225(1).

* **Sec. 22.** AS 43.55.023(d) is amended to read:

(d) Except as limited by (i) of this section, 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 in 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) 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 is claimed was incurred, the date the statement **required under AS 43.55.030(a) or (e)** 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.

*** Sec. 23.** AS 43.55.023(i) is amended to read:

(i) For the purposes of this section,

(1) a producer's or explorer's transitional investment expenditures are the sum of the expenditures the producer or explorer incurred after March 31, **2003** [2001], and before April 1, 2006, that would be qualified capital expenditures if they were incurred after March 31, 2006, less the sum of the payments or credits the producer or explorer 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 or explorer as a result of expenditures the producer or explorer incurred before April 1, 2006, that would be qualified capital expenditures, if they were incurred after March 31, 2006;

(2) a producer or explorer may elect to take a tax credit against a tax due under AS 43.55.011(e) in the amount of 20 percent of the producer's or explorer's transitional investment expenditures, but only to the extent that the amount does not exceed 1/10 of the producer's or explorer's qualified capital expenditures that are incurred during the calendar year for which the credit is taken;

(3) a producer or explorer may not take a tax credit for a transitional investment expenditure

(A) for any calendar year after the later of

(i) 2013; or

(ii) the sixth calendar year after the calendar year for which the producer first applies a credit under this subsection against a tax due under AS 43.55.011(e), if the producer did not have commercial production of oil or gas from a lease or property in the state before April 1, 2006;

(B) more than once; or

(C) if a credit for that expenditure was taken under AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025;

(4) notwithstanding (d), (e), and (g) of this section, a producer or explorer may not transfer a tax credit or obtain a transferable tax credit certificate for a transitional investment expenditure.

* **Sec. 24.** AS 43.55.030(a) is amended to read:

(a) **<u>A producer that produces oil or gas from a lease or property in the state during a calendar year, whether or not any tax payment is due under AS 43.55.020(a) for that oil or gas,</u>** [THE PERSON PAYING THE TAX] shall file with the department on March 31 of the **<u>following</u>** year [FOLLOWING THE CALENDAR YEAR FOR WHICH THE TAX WAS LEVIED] a statement, under oath, in a form prescribed by the department, giving, with other information required, the following:

(1) a description of each lease or property from which [THE] oil **<u>or</u>** [AND] gas **<u>was</u>** [WERE] produced, by name, legal description, lease number, or accounting codes assigned by the department;

(2) the names of the producer and**<u>, if different,</u>** the person paying the tax**<u>, if any</u>**;

(3) the gross amount of oil and the gross amount of gas produced from each lease or property, and the percentage of the gross amount of oil and gas owned by **<u>the</u>** [EACH] producer [FOR WHOM THE TAX IS PAID];

(4) the gross value at the point of production of the oil and of the gas produced from each lease or property owned by **<u>the</u>** [EACH] producer **<u>and the costs of transportation of the oil and gas</u>** [FOR WHOM THE TAX IS PAID];

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

(6) the producer's **qualified capital expenditures, as defined in AS 43.55.023, other** lease expenditures [AND ADJUSTMENTS AS CALCULATED] under **AS 43.55.165, and adjustments or other payments or credits under AS 43.55.170;**

(7) the production tax values of the oil and gas under AS 43.55.160;

(8) any claims for tax credits to be applied; and

(9) calculations showing the amounts, if any, that were or are due under AS 43.55.020(a) and interest on any underpayment or overpayment [AS 43.55.160 - 43.55.170].

*** Sec. 25.** AS 43.55.030 is amended by adding new subsections to read:

(e) An explorer or producer that incurs a lease expenditure under AS 43 55.165 or receives a payment or credit under AS 43.55.170 during a calendar year but does not produce oil or gas from a lease or property in the state during the calendar year shall file with the department on March 31 of the following year a statement, under oath, in a form prescribed by the department, giving, with other information required, the following:

(1) the producer's qualified capital expenditures, as defined in AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other payments or credits under AS 43.55.170; and

(2) if the explorer or producer receives a payment or credit under AS 43.55.170, calculations showing whether the explorer or producer is liable for a tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount.

(f) The department may require a producer, an explorer, or an operator of a lease or property to file monthly reports, as applicable, of

(1) the amounts and gross value at the point of production of oil and gas produced;

(2) transportation costs of the oil and gas;

(3) any unscheduled interruption of, or reduction in the rate of, oil or gas production;

(4) lease expenditures and adjustments under AS 43.55.165 and

43.55.170;

(5) joint interest billings;

(6) contracts for the sale or transportation of oil or gas;

(7) information and calculations used in determining monthly installment payments of estimated tax under AS 43.55.020(a); and

(8) other records and information the department considers necessary for the administration of this chapter.

* **Sec. 26.** 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 <u>**the**</u> [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**; and**

(5) require a producer, an explorer, or an operator of a lease or property to file reports and copies of records that the department considers necessary to forecast state revenue under this chapter; in the case of reports and copies of records relating to proposed, expected, or approved unit expenditures for a unit for which one or more working interest owners other than the operator have authority to approve unit expenditures, the required reports and copies of records are limited to those reports or copies of records that constitute or disclose communications between the operator and the working interest owners relating to unit budget matters.

* **Sec. 27.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.075. Limitation on assessment and amended returns. (a) Except as provided in AS 43.05.260(c), the amount of a tax imposed by this chapter must be assessed within six years after the latest return was filed.

(b) A decision of a regulatory agency, court, or other body with authority to resolve disputes that results in a retroactive change to a lease expenditure, to an adjustment to a lease expenditure, to costs of transportation, to sale price, to prevailing value, or to consideration of quality differentials relating to the commingling of oils has a corresponding effect, either an increase or decrease, as applicable, on the production tax value of oil or gas or the amount or availability of a tax credit as determined under this chapter. For purposes of this section, a change to a lease expenditure includes a change in the categorization of a lease expenditure as a qualified capital expenditure or as not a qualified capital expenditure. The producer shall

(1) within 60 days after the change, notify the department in writing; and

(2) within 120 days after the change, file amended returns covering all

periods affected by the change, unless the department agrees otherwise or a stay is in place that affects the filing or payment, regardless of the pendency of appeals of the decision.

(c) If an alteration in or modification of a producer's federal income tax return or a recomputation of the producer's federal income tax or determination of deficiency occurs that affects the amount of a tax imposed on the producer under this chapter, the producer shall

(1) within 60 days after the final determination of the alteration, modification, recomputation, or deficiency, notify the department in writing; and

(2) within 120 days after the final determination of the alteration, modification, recomputation, or deficiency, file amended returns covering all affected periods.

(d) In this section,

(1) "qualified capital expenditure" has the meaning given in AS 43.55.023;

(2) "return" includes a report, a statement, and an amended return, report, or statement.

*** Sec. 28.** AS 43.55.110 is amended by adding new subsections to read:

(e) The department may require that returns, statements, reports, notifications, and applications filed under this chapter be filed electronically in a form and manner approved or prescribed by the department.

(f) The department may require that payments required under this chapter be made electronically in a form and manner approved or prescribed by the department.

(g) Notwithstanding AS 44.62, the department may issue, for the information and guidance of producers, explorers, and other interested persons, advisory bulletins stating the department's interpretation of provisions of this chapter and of regulations adopted under this chapter. Unless otherwise provided by the department by regulation, interpretations stated in the advisory bulletins are not binding on the department or others.

*** Sec. 29.** AS 43.55.160(a) is amended to read:

(a) Except as provided in (b) of this section, for the purposes of

(1) AS 43.55.011(e), the annual production tax value of the taxable

(A) oil and gas produced during a calendar year from leases or properties in the state that include land north of 68 degrees North latitude is the gross value at the point of production of the oil and gas taxable under AS 43.55.011(e) and produced by the producer from those leases or properties, less the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil and gas produced by the producer from those leases or properties, as adjusted under AS 43.55.170;

(B) oil and gas produced during a calendar year from leases or properties in the state outside the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North latitude, is the gross value at the point of production of the oil and gas taxable under AS 43.55.011(e) and produced by the producer from those leases or properties, less the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil and gas produced by the producer from those leases or properties, as adjusted under AS 43.55.170;

(C) oil produced during a calendar year from a lease or property in the Cook Inlet sedimentary basin is the gross value at the point of production of the oil taxable under AS 43.55.011(e) and produced by the producer from that lease or property, less the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil produced by the producer from that lease or property, as adjusted under AS 43.55.170;

(D) gas produced during a calendar year from a lease or property in the Cook Inlet sedimentary basin is the gross value at the point of production of the gas taxable under AS 43.55.011(e) and produced by the producer from that lease or property, less the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the gas produced by the producer from that lease or property, as adjusted under AS 43.55.170;

(2) **AS 43.55.020(a)(2)(B)** [AS 43.55.011(g)], the monthly production tax value of the taxable

(A) oil and gas produced during a month from leases or properties in the state that include land north of 68 degrees North latitude is the gross value at the point of production of the oil and gas taxable under **<u>AS 43.55.011(e)</u>** [AS 43.55.011(g)] and produced by the producer from those leases or properties, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil and gas produced by the producer from those leases or properties, as adjusted under AS 43.55.170;

(B) oil and gas produced during a month from leases or properties in the state outside the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North latitude, is the gross value at the point of production of the oil and gas taxable under **<u>AS 43.55.011(e)</u>** [AS 43.55.011(g)] and produced by the producer from those leases or properties, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil and gas produced by the producer from those leases or properties, as adjusted under AS 43.55.170;

(C) oil produced during a month from a lease or property in the Cook Inlet sedimentary basin is the gross value at the point of production of the oil taxable under **<u>AS 43.55.011(e)</u>** [AS 43.55.011(g)] and produced by the producer from that lease or property, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil produced by the producer from that lease or property, as adjusted under AS 43.55.170;

(D) gas produced during a month from a lease or property in the Cook Inlet sedimentary basin is the gross value at the point of production of the gas taxable under **<u>AS 43.55.011(e)</u>** [AS 43.55.011(g)] and produced by the producer from that lease or property, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the gas produced by the producer from that lease or property, as adjusted under AS 43.55.170.

* **Sec. 30.** AS 43.55.165(a) is amended to read:

(a) Except as provided under **<u>(e)</u>** [(c) - (e)] of this section, for the purposes of AS 43.55.160, a producer's lease expenditures for a calendar year are the ordinary and necessary costs upstream of the point of production of oil and gas that are incurred during the calendar year by the producer after March 31, 2006, and that are direct 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, that are direct costs of exploring for oil or gas deposits located within other land in the state. In determining whether costs are lease expenditures, the department shall consider, among other factors,

(1) the typical industry practices and standards in the state that determine the costs, other than items listed in (e) of this section, 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 before December 2, 2005, and were subject to negotiation with at least one working interest owner with substantial bargaining power, other than the operator; and

(2) the standards adopted by the Department of Natural Resources that determine the costs, other than items listed in (e) of this section, 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).

* **Sec. 31.** AS 43.55.165(e) is amended to read:

(e) For purposes of this section, lease expenditures do not include

(1) depreciation, depletion, or amortization;

(2) oil or gas royalty payments, production payments, lease profit shares, or other payments or distributions of a share of oil or gas production, profit, or revenue;

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

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

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

(6) costs arising from fraud, wilful misconduct, [OR] gross negligence**, violation of law, or failure to comply with an obligation under a lease, permit, or license issued by the state or federal government**;

(7) fines or penalties imposed by law;

(8) 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;

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

(10) 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;

(11) surcharges levied under AS 43.55.201 or 43.55.300;

(12) for a transaction that is an internal transfer or is otherwise not an arm's length transaction, expenditures incurred that are in excess of fair market value;

(13) an expenditure incurred to purchase an interest in any corporation, partnership, limited liability company, business trust, or any other business entity, whether or not the transaction is treated as an asset sale for federal income tax purposes;

(14) a tax levied under AS 43.55.011;

(15) [THE PORTION OF] costs incurred for dismantlement, removal, surrender, or abandonment of a facility, pipeline, well pad, platform, or other structure, or for the restoration of a lease, field, unit, area, **tract of land,** body of water, or right-of-way in conjunction with dismantlement, removal, surrender, or abandonment [, THAT IS ATTRIBUTABLE TO PRODUCTION OF OIL OR GAS OCCURRING BEFORE APRIL 1, 2006; THE PORTION IS CALCULATED AS A RATIO OF THE AMOUNT OF OIL AND GAS PRODUCTION, IN BARRELS OF OIL EQUIVALENT, ASSOCIATED WITH THE FACILITY, PIPELINE, WELL PAD, PLATFORM, OTHER STRUCTURE, LEASE, FIELD, UNIT, AREA, BODY OF WATER, OR RIGHT-OF-WAY OCCURRING BEFORE APRIL 1, 2006, TO THE TOTAL AMOUNT OF OIL AND GAS PRODUCTION, IN BARRELS OF OIL EQUIVALENT, ASSOCIATED WITH THAT FACILITY, PIPELINE, WELL PAD, PLATFORM, OTHER STRUCTURE, LEASE, FIELD, UNIT, AREA, BODY OF WATER, OR RIGHT-OF-WAY THROUGH THE END OF THE CALENDAR MONTH BEFORE COMMENCEMENT OF THE DISMANTLEMENT,

REMOVAL, SURRENDER, OR ABANDONMENT]; a cost is not excluded under this paragraph if the dismantlement, removal, surrender, or abandonment for which the cost is incurred is undertaken for the purpose of replacing, renovating, or improving the facility, pipeline, well pad, platform, or other structure; [FOR THE PURPOSES OF THIS PARAGRAPH, "BARREL OF OIL EQUIVALENT" MEANS

(A) IN THE CASE OF OIL, ONE BARREL;

(B) IN THE CASE OF GAS, 6,000 CUBIC FEET;]

(16) costs incurred for containment, control, cleanup, or removal in connection with any unpermitted release of oil or a hazardous substance and any liability for damages imposed on the producer or explorer for that unpermitted release; this paragraph does not apply to the cost of developing and maintaining an oil discharge prevention and contingency plan under AS 46.04.030;

(17) costs incurred to satisfy a work commitment under an exploration license under AS 38.05.132;

(18) that portion of expenditures, that would otherwise be qualified capital expenditures**<u>,</u>** as defined in **<u>AS 43.55.023</u>** [AS 43.55.023(k)], incurred during a calendar year that are less than the product of $0.30 multiplied by the total taxable production from each lease or property, in BTU equivalent barrels, during that calendar year, except that, when a portion of a calendar year is subject to this provision, the expenditures and volumes shall be prorated within that calendar year**<u>;</u>**

<u>(19) costs incurred for repair, replacement, or deferred maintenance of a facility, a pipeline, a structure, or equipment, other than a well, that results in or is undertaken in response to a failure, problem, or event that results in an unscheduled interruption of, or reduction in the rate of, oil or gas production; or costs incurred for repair, replacement, or deferred maintenance of a facility, a pipeline, a structure, or equipment, other than a well, that is undertaken in response to, or is otherwise associated with, an unpermitted release of a hazardous substance or of gas; however, costs under this paragraph that would otherwise constitute lease expenditures under (a) of this section may be treated as lease expenditures if the department determines that the repair or replacement is solely necessitated by an act of war, by an unanticipated grave</u>

natural disaster or other natural phenomenon of an exceptional, inevitable, and irresistible character, the effects of which could not have been prevented or avoided by the exercise of due care or foresight, or by an intentional or negligent act or omission of a third party, other than a party or its agents in privity of contract with, or employed by, the producer or an operator acting for the producer, but only if the producer or operator, as applicable, exercised due care in operating and maintaining the facility, pipeline, structure, or equipment, and took reasonable precautions against the act or omission of the third party and against the consequences of the act or omission; in this paragraph,

(A) "costs incurred for repair, replacement, or deferred maintenance of a facility, a pipeline, a structure, or equipment" includes costs to dismantle and remove the facility, pipeline, structure, or equipment that is being replaced;

(B) "hazardous substance" has the meaning given in AS 46.03.826;

(C) "replacement" includes renovation or improvement;

(20) costs incurred to construct, acquire, or operate a refinery or crude oil topping plant, regardless of whether the products of the refinery or topping plant are used in oil or gas exploration, development, or production operations; however, if a producer owns a refinery or crude oil topping plant that is located on or near the premises of the producer's lease or property in the state and that processes the producer's oil produced from that lease or property into a product that the producer uses in the operation of the lease or property in drilling for or producing oil or gas, the producer's lease expenditures include the amount calculated by subtracting from the fair market value of the product used the prevailing value, as determined under AS 43.55.020(f), of the oil that is processed.

* **Sec. 32.** AS 43.55.170(a) is amended to read:

(a) **A** [UNLESS THE PAYMENT OR CREDIT HAS ALREADY BEEN SUBTRACTED IN CALCULATING BILLABLE OR BILLED COSTS UNDER AS 43.55.165(c) OR (d), A] producer's lease expenditures under AS 43.55.165 must be adjusted by subtracting payments or credits, other than tax credits, received by the producer or by an operator acting for the producer for

(1) the use by another person of a production facility in which the producer has an ownership interest or the management by the producer of a production facility under a management agreement providing for the producer to receive a management fee;

(2) a reimbursement or similar payment that offsets the producer's lease expenditures, including an insurance recovery from a third-party insurer and 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 after March 31, 2006; for purposes of this subparagraph,

(i) if a producer removes from the state, for use outside the state, an asset described in this subparagraph, the value of the asset at the time it is removed is considered a payment received by the producer for sale or transfer of the asset;

(ii) for a transaction that is an internal transfer or is otherwise not an arm's length transaction, if the sale or transfer of the asset is made for less than fair market value, the amount subtracted must be the fair market value; 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.

*** Sec. 33.** AS 43.55 is amended by adding a new section to article 4 to read:

Sec. 43.55.890. Disclosure of tax information. Notwithstanding any contrary provision of AS 40.25.100, and regardless of whether the information is considered under AS 43.05.230(e) to constitute statistics classified to prevent the identification of particular returns or reports, the department may publish the following information under this chapter, if aggregated among three or more producers or explorers, showing by month or calendar year and by lease or property, unit, or area of the state:

(1) the amount of oil or gas production;

(2) the amount of taxes levied under this chapter or paid under this chapter;

(3) the effective tax rates under this chapter;

(4) the gross value of oil or gas at the point of production;

(5) the transportation costs for oil or gas;

(6) qualified capital expenditures under AS 43.55.023(k);

(7) exploration expenditures under AS 43.55.025;

(8) production tax values of oil or gas under AS 43.55.160;

(9) lease expenditures under AS 43.55.165;

(10) adjustments to lease expenditures under AS 43.55.170;

(11) tax credits applicable or potentially applicable against taxes levied by this chapter.

* **Sec. 34.** AS 43.55.900 is amended by adding new paragraphs to read:

(22) "producer" means an owner of an operating right, operating interest, or working interest in a mineral interest in oil or gas;

(23) "unit" means a group of tracts of land that is

(A) subject to a cooperative or a unit plan of development or operation that has been certified by the commissioner of natural resources under AS 38.05.180(p);

(B) subject to a cooperative or a unit plan of development or operation that has been certified by the United States Secretary of the Interior under 30 U.S.C. 226(m);

(C) subject to an agreement of the owners of interests in the tracts of land to validly integrate their interests to provide for the unitized management, development, and operation of the tracts of land as a unit, within the meaning of AS 31.05.110(a); or

(D) within the unit area of a unit created by order of the Alaska Oil and Gas Conservation Commission under AS 31.05.110(b).

*** Sec. 35.** AS 43.55.165(c) and 43.55.165(d) are repealed.

*** Sec. 36.** AS 43.55.011(g), 43.55.011(h), 43.55.011(*l*), and 43.55.160(c) are repealed.

*** Sec. 37.** The uncodified law of the State of Alaska is amended by adding a new section to read:

APPLICABILITY. (a) Sections 23, 30, 31, 32, and 35 of this Act apply to oil and gas produced after March 31, 2006.

(b) Sections 14 - 19, 29, and 36 of this Act apply to oil and gas produced after December 31, 2007.

(c) Sections 24 and 25 of this Act apply to statements and reports under AS 43.55.030(a), as amended by sec. 24 of this Act, and AS 43.55.030(e) and (f), as added by sec. 25 of this Act, required to be filed after December 31, 2007.

(d) AS 43.55.075(a), enacted by sec. 27 of this Act, applies to any tax liability under AS 43.55 with respect to which the period of limitations on assessment under AS 43.05.260 had not expired before the effective date of secs. 13 and 27 of this Act.

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

TRANSITION: ASSIGNMENT OF OIL AND GAS AUDITORS IN THE DEPARTMENT OF REVENUE AND DEPARTMENT OF NATURAL RESOURCES. Notwithstanding any contrary provision of law, employees employed as oil and gas auditors performing production tax audits or as their immediate supervisors in the Department of Revenue and employees employed as oil and gas auditors performing royalty audits, including net profit share audits, or as their immediate supervisors in the Department of Natural Resources are assigned to the exempt service in accordance with AS 39.25.110(42), added by sec. 9 of this Act, and may not be included in the general government or supervisory collective bargaining units of state employees except as provided in this section. All oil and gas auditors performing production tax audits or royalty audits and their immediate supervisors hired before the effective date of sec. 9 of this Act have the option of

(1) continuing in the general government or supervisory collective bargaining units and being subject to their respective collective bargaining agreements; or (2) being removed from those bargaining units. Those employees have 90 days from the effective date of sec. 9 of this Act to exercise the option to continue in the collective bargaining units. The option taken under this section by the employee is irrevocable. The employees choosing to be removed from those bargaining units are removed after any notice period required by a collective bargaining agreement.

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

TRANSITION: RETROACTIVITY OF REGULATIONS. Notwithstanding any contrary provision of AS 44.62.240,

(1) if the Department of Revenue expressly designates in the regulation that the regulation applies retroactively to that date, a regulation adopted by the Department of Revenue to implement, interpret, make specific, or otherwise carry out

(A) secs. 23, 30, 31, 32, and 35 of this Act may apply retroactively to April 1, 2006;

(B) secs. 14 - 19, 24, 25, 29, and 36 of this Act may apply retroactively to January 1, 2008;

(2) a regulation adopted by the Department of Natural Resources to implement, interpret, make specific, or otherwise carry out statutory provisions for the administration of oil and gas leases issued under AS 38.05.180(f)(3)(B), (D), or (E), to the extent the regulation deals with the treatment of oil and gas production taxes in determining net profits under those leases, may apply retroactively to April 1, 2006, if the Department of Natural Resources expressly designates in the regulation that the regulation applies retroactively to that date.

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

TRANSITION: REGULATIONS. The Department of Natural Resources and the Department of Revenue may proceed to adopt regulations to implement 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:

RETROACTIVITY OF CERTAIN PROVISIONS OF THIS ACT. Sections 23, 30, 31, 32, and 35 of this Act are retroactive to April 1, 2006.

* **Sec. 42.** Sections 14 - 19, 24, 25, 29, and 36 of this Act take effect January 1, 2008.

* **Sec. 43.** Except as provided in sec. 42 of this Act, this Act takes effect immediately under AS 01.10.070(c).

State of Alaska

Department of Revenue
Commissioner's Office

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To: All members of the Legislature
From: Marcia Davis, Deputy Commissioner, DOR

October 26, 2007

Dear Members:

The attached report details Alberta Premier, Ed Stelmach's policy to reform the territory's oil and gas royalty structure. I have also included a summary by the Department of Revenue spelling out the report's major provisions. I hope you will find this information helpful in your current deliberations.

Sincerely,

Marcia Davis

Marcia Davis, *Deputy Commissioner*
Department of Revenue

Alberta's Plan to Change its Fiscal System for Oil & Gas

Alberta will change its royalty system for conventional oil, natural gas and oil sands; the changes will be effective January 1, 2009 and are expected to bring in an additional Canadian $1.4 billion in 2010. Information for this summary is from the Minister's report[1]. The three principles that guided the final selection of choices are the following:

1. The new system would support sustainable economic development
2. The new system would provide a fair, predictable and transparent royalty regime.
3. The new system would align Alberta's royalty regime with overall government objectives.

Overall, the new royalty regime will **simplify** the current system, allow for greater **progressivity** by increasing the "caps" on oil and gas prices, and **increase** the **government share**.

Conventional Oil

The government will simplify royalties for conventional oil, eliminating specialty royalty programs and "old and "new" tiers. Royalties will be set by a single sliding rate formula containing separate elements that account for oil price and well production. The formula will be applied monthly to match current royalty reporting. Overall, royalty rates will increase from the current maximums of 30% and 35% for old and new tiers. The new rates will range up to 50%, and rate caps will be raised to Canadian $120 per barrel [from $30].

Natural Gas

Natural gas royalties will be set by a single sliding rate formula sensitive to price and production volume. Royalty rates, currently 5% to 35%, will range from 5% to 50%, with rate caps at Canadian $16.59 per gigajoule [from $3.70]. The Alberta government will retain and revamp the Deep Gas Drilling Program and will apply lower royalty rates over a wider price range for wells with less productivity. The government will eliminate "old" and "new" tiers, but will retain the Otherwise Flared Solution Gas Royalty Waiver Program, which improves air quality through solution gas conservation.

Oil Sands

Under the new system, the base rate will start at 1%, and increase for every dollar oil is priced above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. The net royalty, applied post-payout is currently 25%. In the future, the royalty rate will start at 25% and increase for every dollar oil is priced above $55 per barrel to 40% when oil is priced at $120 or higher. The government will adopt a permanent generic "bitumen valuation methodology" by June 30, 2008.

Credits

A credit of 5% will be given for the development of "upgraders" to refine the oil sands crude oil. This is instituted to provide an incentive for a "value added" industry in Alberta.

Accountability

The government will assess and make improvements in the systems, structures and resources supporting the collection, verification and reporting of provincial revenues arising from conventional oil, natural gas and oil sands. Former Auditor General Peter Valentine will lead this project and will be completed by March 31, 2008.

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[1]Premier Ed Stelmach, "The New Royalty Framework", October 25, 2007.

BUILDING TOMORROW

A PLAN to secure Alberta's future

THE

New Royalty Framework

OCTOBER 25, 2007

A message from Premier Ed Stelmach

"I made a commitment and I delivered."

I am proud to deliver *The New Royalty Framework* to Albertans. I know it is the right plan to secure Alberta's future. I made a commitment and I delivered.

The New Royalty Framework gives future generations of Albertans a fair share from the development of their resources. It gives stability and predictability to the oil and gas industry. And it assures investors that Alberta will remain an internationally competitive and stable place to do business.

The New Royalty Framework furthers my plan for Alberta's future — a plan to build communities, green our growth and create opportunity.

Together, we're building tomorrow.

PREMIER ED STELMACH

CONTENTS

Executive Summary

The New Royalty Framework is the culmination of detailed study and analysis, extensive consultation, thoughtful deliberation, and political commitment.

It fulfills the promise Premier Ed Stelmach made to Albertans to review Alberta's royalty structure for oil and gas and ensure Albertans are getting a fair return on their resources. The Premier initiated this review in February. It is a key element of his plan to build a stronger Alberta.

The New Royalty Framework is the right plan – it increases royalty rates while allowing industry to remain competitive. It recognizes that a vibrant energy sector provides jobs and tax revenue as well as royalties. The *Framework* will ensure Albertans continue to receive all of these benefits.

The *Framework* represents fundamental and necessary change to current royalty structures. It creates a system that is more sensitive to market value, and also one that better reflects the growing importance of unconventional oil and gas resources to the future prosperity and economic development of the province.

Through vigorous and sometimes tough debate, the Stelmach government used three principles to guide decision-making on Alberta's royalties:

- support sustainable economic development that contributes to a high quality of life for all Albertans now and into the future
- support a fair, predictable and transparent royalty regime
- align Alberta's royalty regime with overall government objectives.

The Stelmach government has taken action and kept the promise. Government analysts project royalties will increase approximately $1.4 billion in 2010, an increase of 20% over revenues forecast for that year under the current regime.

All changes take effect January 2009 unless otherwise noted.

Here are the major changes to Alberta's royalty regime:

Conventional Oil

The government will simplify royalties for conventional oil, eliminating specialty royalty programs and "old and "new" tiers. Royalties will be set by a single sliding rate formula containing separate elements that account for oil price and well production. The formula will be applied monthly to match current royalty reporting.

Overall, royalty rates will increase from the current maximums of 30% and 35% for old and new tiers. The new rates will range up to 50%, and rate caps will be raised to Cdn $120 per barrel.

Natural Gas

As with conventional oil, natural gas royalties will be set by a single sliding rate formula sensitive to price and production volume. Royalty rates, currently 5% to 35%, will range from 5% to 50%, with rate caps at Cdn $16.59/GJ (gigajoule).

Some members of the Alberta Royalty Review Panel have conceded their report erred by not mentioning Alberta should keep a benefit for deep wells with high drilling costs. The Alberta government will retain and revamp the Deep Gas Drilling Program and will apply lower royalty rates over a wider price range for wells with less productivity. Although government royalties from these sources will be lower, overall benefits to the economy will be higher, as production from marginal wells creates more jobs and benefits Alberta's businesses and communities.

The government will eliminate "old" and "new" tiers, but will retain the Otherwise Flared Solution Gas Royalty Waiver Program (OFSG), which improves air quality through solution gas conservation.

Oil Sands

The government supports increasing Albertans' share of revenues from the oil sands. It will do so by increasing royalty rates rather than by imposing an industry-wide tax on oil sands production.

Currently, the base or startup royalty rate for oil sands is 1%. While the Alberta Royalty Review Panel supported keeping this rate, Alberta's new royalty regime will ensure Albertans get a greater share of oil sands revenues right from the start. Under the new system, the base rate will start at 1%, and increase for every dollar oil is priced above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher.

The net royalty, applied post-payout is currently 25%. In the future, it will start at 25% and increase for every dollar oil is priced above $55 per barrel to 40% when oil is priced at $120 or higher.

The government will not grandfather existing oil sands projects. The government is in discussions with Syncrude and Suncor, whose Crown agreements expire in 2016, to participate in the new oil sands royalty regime. The transition details will be worked out over the next 90 days. In the event the agreement cannot be reached, the government will take other measures to ensure a level playing field for all industry stakeholders.

The government will adopt a permanent generic "bitumen valuation methodology" by June 30, 2008, after consulting with stakeholders and independent advisors. It will apply to projects with insufficient third party sales of bitumen.

Value Added

The Alberta government recognizes that to build a stable and prosperous future, the province must get the best economic return on the development of its energy resources. Alberta needs to add value to its exports and expand its economy by upgrading resources here in Alberta. By doing so, we will secure jobs and prosperity for future generations of Albertans.

The Alberta Royalty Review Panel recommended an upgrader credit of 5% as an incentive for industry to upgrade and refine in Alberta. Government analysis indicates the 5% credit would be ineffective. The government will consider other options, such as taking bitumen in kind rather than cash. Bitumen could then be used strategically to supply potential upgraders and refineries in Alberta.

Accountability

The government will assess and make improvements in the systems, structures and resources supporting the collection, verification and reporting of provincial revenues arising from conventional oil, natural gas and oil sands.

Former Auditor General Peter Valentine will lead this project and will report to Premier Stelmach. The project will begin in November 2007 and will be completed by March 31, 2008.

Background

The current royalty regime for oil and natural gas was developed in the early 1970s, and substantial changes were made in 1994.

Over the years, both the typical geology of pools being discovered and the way prices move in the world market have changed. A system that worked extremely well for oil prices up to $30 per barrel and natural gas up to $4/GJ (gigajoule) will not work as well for prices that can vary from $5/GJ to $14/GJ, and oil prices up to $90/barrel. Costs have also changed over time as smaller and smaller pools tend to be found.

In 1997 the oil sands generic regime was created to encourage investment in the oil sands. This policy, along with higher prices and improvements in technology, has attracted close to $60 billion of investment, and billions more in economic activity and tax revenue have benefited all Albertans.

But times change. A policy of lower royalties to maintain a minimum level of investment is no longer needed to attract investment to Alberta.

In February of this year, Premier Stelmach appointed the Alberta Royalty Review Panel. Premier Stelmach wanted to ensure Albertans are receiving a fair share from energy development and asked the Panel to provide advice. Premier Stelmach made the report public as soon as he received it, so it could receive the widest possible public debate.

Almost 9000 Albertans posted, faxed, phoned and e-mailed their views to the Government of Alberta. The Alberta Royalty Review Panel has had more than 640,000 hits to its website. Premier Stelmach appointed Ron Stevens, Deputy Premier and Minister of Justice, to meet with energy industry officials to ensure a shared understanding of the government's review process and give them an opportunity to provide their analysis of the impacts of the Panel's recommendations. Energy Minister Mel Knight led a technical analysis of the Panel's report to help decision-makers better understand the implications of their decisions.

All these pieces — the Alberta Royalty Review Panel Report, the Auditor General's Report, further public and industry feedback, as well as the technical analysis – were considered by government in this report.

Guiding Principles

The government used three principles to guide its decision-making:

1. **Support sustainable economic development that contributes to a high quality of life for all Albertans now and into the future.**

Alberta's new royalty regime is a key element of Premier Stelmach's plan to build a stronger Alberta. The revenues generated from increased royalty rates will benefit current and future Albertans – one-third will go to provincial savings, with the remainder allocated to infrastructure and maintenance. The Framework encourages prosperity for Albertans in the long term and ensures that those who come after us receive a fair share of a well-managed and vigorous energy sector.

2. **Support a fair, predictable and transparent royalty regime.**

The new royalty framework will help Alberta plan for a secure future by providing stability and predictability to business, and time to adjust to royalty changes.

Companies are investing billions of dollars in Alberta; they need to have a reasonable set of rules to play by if they are to compete internationally and contribute to the Alberta economy. Such rules require clear accountability and sound stewardship by government. This principle also supports fairness in sharing costs and benefits between owners and producers.

3. **Align Alberta's royalty regime with overall government objectives.**

Premier Stelmach outlined the government's priorities in his television address *Alberta: A Plan for the Future: building communities, greening our growth, and creating opportunities for long-term prosperity.*

Alberta's jobs and prosperity will increasingly depend on the development of new sources of energy such as the oil sands and coal-bed methane. This Framework also supports the government's objective of maximizing recovery of existing known oil and gas resources.

Government Decision Summary

The following is a summary of the government's new royalty regime. A complete listing of the Alberta Royalty Review Panel's recommendations, government response and rationale is attached in Appendix One.

Conventional Oil

Price-sensitive and volume-sensitive conventional oil royalty rates will become separate elements within a single sliding rate formula. New royalty rates will range from 0% to 50%, up from the current maximums of 30% and 35% for new and old vintages.

Royalties will be calculated on a monthly production rate as is done currently and as collected, reported and used by industry.

To simplify the royalty system, several special royalty programs will be eliminated:

- Third Tier Exploratory Well Royalty Exemption
- Re-activated Well Royalty Reduction
- Low Productivity Well Royalty Reduction
- Horizontal Re-entry Well Royalty Program
- Experimental Project Petroleum Royalty

The new royalty formula will effectively deal with the economic issues these programs previously addressed. Oil project royalty programs like Enhanced Oil Recovery and the Innovative Energy Technology Program will be retained to encourage research and additional oil recovery.

The tiers in conventional oil that distinguish vintages based on the discovery date will be eliminated to simplify the system. Under current economic conditions the difference between tiers is no longer significant.

Rate caps on price will be raised for conventional oil to $120 per barrel to ensure that the royalty system is sensitive over a broader range of prices. Currently maximums are reached at around $30 per barrel for conventional oil. The new cap balances the royalty reductions at the low end of the production and price curve, thus contributing to a stable fiscal system.

Natural Gas

Price-sensitive and volume-sensitive gas royalty rates now become separate elements with a single sliding rate formula. New royalty rates range from 5% to 50%, up from ranges of 5% to 30% for new and 5% to 35% for old vintages. Changes to the price point at which lower royalty rates apply provide better protection to low productivity wells, also contributing to a more stable fiscal system.

For gas processing facilities, the government will move from using corporate effective royalty rates (CERR) to calculate costs of the Crown's share of capital to establishing facility effective royalty rates (FERR). This will improve the link of capital costs for natural gas to a particular facility. The Alberta Royalty Review Panel had recommended going to deemed or set fees, an approach tried before in Alberta, but it does not recognize significant actual cost differences in processing plants. While the FERR may initially be more administratively onerous on industry, it has the advantages of:

- not creating a disconnect with actual costs that are typical in a deemed fee system
- requiring less modification to the existing system
- moving cost calculations to the facility level.

For gathering and compression in Alberta, however, the government will continue to use set fees which do recognize actual costs.

The government will eliminate the tiers in conventional natural gas that distinguish vintages based on the discovery date to simplify the system. Under current economic conditions the difference between tiers is minimal.

The government will retain the Otherwise Flared Solution Gas Royalty (OFSG) Waiver Program and extend it to bitumen wells. This program was developed in consultation with industry and environmental stakeholders. It encourages solution gas conservation, rather than venting the gas, resulting in improved air quality. The OFSG program is part of an overall program that has contributed to about a 70% reduction in flaring across Alberta. Extending the OFSG program to bitumen wells makes the program more equitable and is consistent with the environmental intent of the program.

As well, the government will revamp the Deep Gas Drilling Program. Some members of the Alberta Royalty Review Panel have conceded their report erred by not mentioning Alberta should keep a benefit for deep wells with high drilling costs. Support for deep gas drilling is instrumental to the viability of gas development in Alberta. These deeper reserves are ten times the volume of natural gas reserves and remain to be developed.

The government will raise rate caps on the price of natural gas to Cdn $16.59/GJ. The cap will ensure the royalty system is sensitive over a broad range of prices. Currently maximums are reached at around $3.70/GJ for natural gas.

Royalties for natural gas liquids will now be set at 40% for pentanes, a change from 22-50% for old tiers and 22-35% for new. The new royalties for butanes and propane will be 30%, up from 15-30%.

The government will eliminate the option to use the Corporate Average Price (CAP) to determine natural gas royalties. CAP is a labour-intensive manual process used only by a small number of royalty payers. Natural gas can be reflected by a single reference price since it is processed to become relatively homogeneous. Use of the single reference price will provide an administrative saving to both industry and government.

Enhanced Oil and Gas Production

In 2005-06 the province's revenue from natural gas was 58% of total energy revenues.

Currently, new reserves of natural gas that can be easily developed form only 20% of Alberta's potential future production. The rest require enhanced means of development, such as deep or horizontally drilled wells. They are found in special formations, such as coal beds and shale. These reserves tend to have low productivity, but represent the future of the natural gas industry in Alberta. In the coming decades, jobs and prosperity will increasingly depend on unconventional oil and gas sources.

To encourage exploration and production, the Alberta government will apply somewhat lower royalty rates over a wider price range to low productivity reserves. As well, as noted previously, the government will revamp the Deep Gas Well Drilling Program.

The government will implement "shallow rights reversion" to maximize extraction of the resource. Under this policy, mineral rights to shallow gas geological formations that are not being developed would revert back to the government and be made available for resale.

Oil development has the potential for similar opportunities. Currently we leave 70% of oil in the ground. Government will continue to support investment in new technologies, such as using carbon dioxide to recover oil. This would not only benefit the economy, but carbon dioxide capture and sequestration would enhance the environment.

In the short term, there is a cost to supporting enhanced oil and gas production, but in the long term it will bring jobs and business opportunities to Alberta, securing our future and giving Albertans a bigger piece of an even bigger pie.

Oil Sands

Rather than impose a new tax, government will increase base and net royalty rates to achieve similar results.

Currently, the base or startup royalty rate for oil sands is 1%. While the Alberta Royalty Review Panel supported keeping this rate, Alberta's new royalty regime will ensure Albertans get a greater share of oil sands revenues right from the start. Under the new system, the base rate will start at 1%, and increase for every dollar oil is priced above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher.

The net royalty, applied post-payout is currently 25%. In the future, it will start at 25% and increase for every dollar oil is priced above $55 per barrel to 40% when oil is priced at $120 or higher.

The government will not grandfather existing oil sands projects. The government is in discussions with Syncrude and Suncor, whose Crown agreements expire in 2016, to participate in the new oil sands royalty regime. The transition details will be worked out over the next 90 days. In the event that agreement cannot be reached, the government will take other measures to ensure a level playing field for all industry stakeholders.

The government will eliminate the provincial portion of the Accelerated Capital Cost Allowance (ACCA) for oil sands projects, consistent with the federal government's recent elimination of the allowance.

The government will adopt a permanent, generic bitumen valuation methodology (BVM) after consulting with stakeholders and independent advisors. This methodology will be determined by June 30, 2008, and will be used wherever there are non-arm's length transactions. Where there are arm's-length sales at market price that price will be used. The development of the valuation method will include consideration of methods to deal with commodities that trade in markets that are not well functioning.

The government already has comprehensive rules and enforcement procedures for oil sands projects and eligible expenditures. However, the government will review and, if required, improve procedures. This policy aligns with others already being pursued by the government for enhanced cost and operating reporting requirements.

Value Added

The Alberta government recognizes that to build a stable and prosperous future, the province must get the best economic return on the development of its energy resources. Alberta needs to add value to its exports and expand its economy by upgrading resources here in Alberta. By doing so, we will secure jobs and prosperity for future generations of Albertans.

The Alberta Royalty Review Panel recommended an upgrader credit of 5% as an incentive for industry to upgrade and refine in Alberta. Government analysis indicates the 5% credit would be ineffective. The government will consider other options, such as:

- taking bitumen in kind rather than cash. Bitumen could be used strategically to supply potential upgraders and refineries in Alberta. The Crown would share in potential gains (and risks) in the upgrading, refining and petrochemical markets, and optimize its royalty share.

- advocating for adjusting pipeline toll differentials that currently may have an effect of subsidizing bitumen exports.

- expediting conditional regulatory approvals for projects with value-added content, while maintaining our strong environmental controls.

- investing in specific infrastructure projects, including investments in infrastructure for regional industrial development, and potentially carbon dioxide removal and storage.

Freehold Mineral Rights Tax

The government will review the federal mineral rights tax to ensure it is fulfilling its intended objectives. Freehold mineral rights for these reserves are held by individuals not the province. Current taxes cover the province's cost of administering the regulatory system.

Accountability

The government is determined that royalties will be collected within an equitable, flexible and competent administrative framework. It will initiate a project to assess and make improvements in the systems, structures and resources supporting the collection, verification and reporting of provincial revenues arising from conventional oil, natural gas and oil sands.

This initiative will:

- provide clarity on the goals of the province's non-renewable resource revenue regime.

- ensure the government has the systems and processes in place to assess the performance of royalty policy and collection for non-renewable resources.

- ensure complete and timely reporting to Albertans on royalties collected.

Former Auditor General Peter Valentine will lead this project and will report to Premier Stelmach. The project will start in November 2007 and will be completed by March 31, 2008.

This initiative will fully respond to the recommendations made by Alberta's Auditor General in his recent report.

Expenditures on Environmental Protection

Any discussion of programs and policies in the energy sector cannot be made without considering the environment. The Alberta government is committed to greening our growth:

- Alberta already is the first jurisdiction in North America to place real and measurable limits on large industrial plants that produce about 70% of greenhouse gas emissions.
- Recently, the government announced that instead of looking at the environmental impacts of industrial development on a project by project basis, for the first time, it will assess the overall impacts to land, air and water and set regional limits.
- Alberta has a comprehensive strategy for protecting our water, and we will soon be introducing a framework to better manage the competing demands on Alberta's landscape.
- And earlier this year, Premier Stelmach asked the Minister of Energy to develop a comprehensive energy strategy, one which will ensure the sustainable development of the province's resources in an environmentally responsible manner, making full use of innovations such as near zero-emission coal.

To encourage responsible resource management, the government will continue to assess and recognize any new environmental fees or levies as an eligible cost of doing business, and therefore deductible in determining royalties on oil sands projects.

Implications

The estimated increase in royalties will be $1.4 billion dollars, a 20% increase over royalty revenues projections under the current system. These projections are based on the same assumptions the Alberta Royalty Review Panel used to reach its 2010 projections.

Yearly royalty revenues can be volatile, and are solely dependent on price and production levels for each of the commodities. Revenues could be higher or lower than the levels projected for 2010.

The recommendations will decrease royalties on 88% of conventional gas wells at a price of $6.00/mcf (compared to 82% based on the Panel recommendations). The 57% of conventional oil wells paying less remains unchanged from the Panel recommendation.

In 2010, additional revenues from the government's new royalty program are forecasted to be:

Gas	$470 million
Conventional oil	$460 million
Oil sands	$470 million
TOTAL	$1,400 million

Government forecasts are less than those projected by the Alberta Royalty Review Panel for natural gas because of changes to encourage production from low producing gas wells and revamping of the Deep Gas Royalty Program. In the short term, there is a cost to such support, but in the long term it will bring jobs and business opportunities to Albertans, securing our future and giving Albertans a bigger piece of an even bigger pie.

Former Auditor General Peter Valentine will establish government benchmarks as part of his review of Alberta's accountability systems.

Corporate and personal tax implications were not estimated by the Alberta Royalty Review Panel and have not been estimated by the government at this time. However, we anticipate there will be reduced tax revenues from corporate income in the short term.

Currently low natural gas prices are causing a modest slowdown in economic growth and some job loss. The government does not expect any significant immediate economic impacts from its royalty changes. Industry has over a year to adjust its operations and address implementation issues.

Next Steps

As the title of this report indicates, this is a framework for Alberta's new royalty regime. As the government further develops the new royalty regime, adjustments may be made to ensure there are no unintended consequences to its decisions. Both the public and stakeholders will be consulted should significant adjustment be necessary. This is in keeping with Premier Stelmach's commitment to open, transparent government.

The new royalty regime takes effect in January 2009. A lead time of one year is required to ensure the appropriate legal framework and administrative systems are in place, and new accountability measures are identified. Changes to numerous pieces of legislation are required including the Mines and Minerals Act, the Petroleum Royalty Regulation, the Oil Sands Royalty Regulation, and the Natural Gas Royalty Regulation, to name a few. Government information systems, administrative procedures and audit functions will need substantial changes to accommodate the new royalty regime.

The accountability review will begin in November 2007 and be completed by March 31, 2008. Implementation of the new accountability initiatives is set to begin in May 2008.

ISBN 978-0-7785-7194-0

Glossary

Bitumen Valuation Methodology (BVM)
a formula used to calculate the value of bitumen for the purposes of calculating royalties.

Bitumen
the heaviest, thickest form of petroleum as found in Alberta's oil sands.

Coal-bed Methane
natural gas found in coal seams. It is still in the early stages of development in Alberta and may help meet the growing demand for natural gas.

Conventional crude oil
petroleum found in liquid form, which can pumped without processing or dilution.

Deep gas
refers to natural gas from wells drilled to depths greater than 2,500 metres.

Freehold Mineral Tax
is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands

Natural Gas Liquids (NGLs)
liquids obtained during production of natural gas comprising ethane, propane and butane.

Ring fence
refers to the definition of an oil sands project and the eligible expenditures deemed necessary for operation.

Royalties
the price that the owner of a natural resource charges for the right to develop the resource.

Royalty-in-Kind
refers to the Crown receiving resources, such as bitumen, in lieu of cash royalties.

Synthetic Crude
a product similar to crude oil, created by upgrading bitumen from oil sands.

Payout
in reference to oil sands projects, the point when the developer has recovered capital costs plus 6% return on the investment.

Primary wells
refers to wells producing heavy oil in areas designated as oil sands.

Value added
the upgrading or refining of resources into products of a higher value (e.g. synthetic crude, petrochemicals, plastics)

Vintage
refers to the date of discovery which is used to determine how conventional oil and natural gas royalties are calculated under the province's current system. Also refered to as "tiers."

APPENDIX ONE

A Summary of Decisions in comparison with the Alberta Royalty Review Panel's Recommendations

PANEL RECOMMENDATION	GOVERNMENT DECISION	RATIONALE
Implementation		
1. Implement Recommendations in July 2008	**Reject** Implement in January 2009	A lead time of one year is required to ensure the appropriate legal framework, administrative and accountability systems are in place.
Conventional Oil		
2. Royalty rates are determined by a single sliding rate formula with separate elements sensitive to price and production volumes. **New royalty rates range from 0% to 50%**	**Accept with modification** This is a change from current royalty rates.	Albertans will receive a greater royalty share at higher oil prices.
Royalties are calculated on a **daily** production rate.	**Reject** Royalty will be calculated on a monthly production rate instead of the daily rate suggested by the Panel.	Moving to a per day calculation would add administrative complexity and cost with no apparent benefit. Information is currently collected on a monthly basis.
3. Several special **royalty programs be eliminated.**	**Accept** Eliminate the following well-based oil royalty programs: • Third Tier Exploratory Well Royalty Exemption • Re-activated Well Royalty Reduction • Low Productivity Well Royalty Reduction • Horizontal Re-entry Well Royalty Program • Experimental Project Petroleum Royalty.	Simplifies the current royalty system. The government's new royalty formula will effectively deal with the economic issues addressed by these programs. Oil project royalty programs like, Enhanced Oil Recovery and the Innovative Energy Technology Program will be retained to encourage research and additional oil recovery.
4. **Eliminate** the **tiers** in conventional oil that distinguish "vintages" based on discovery date.	**Accept**	Simplifies the current royalty system. Allows officials to focus on more value-added activities. Under current economic conditions the difference in royalties between tiers is no longer significant.
5. **Rate caps** on price be **raised** for conventional oil to Cdn $120/barrel.	**Accept** Ensures the royalty system is sensitive over a broad range of prices. Current maximums are reached at around $30 per barrel.	Improves Albertans' share at higher prices.

PANEL RECOMMENDATION	GOVERNMENT DECISION	RATIONALE

Natural Gas

PANEL RECOMMENDATION	GOVERNMENT DECISION	RATIONALE
6. Royalty rates are determined by a single sliding rate formula with separate elements sensitive to price and production volumes **New royalty rates range from 2% to 50%.**	**Accept with modification** New royalty rates will range from 5% to 50%.	Significantly increases the government take at higher gas prices. Coal bed methane, tight gas, and shale gas represent important future gas resources for Alberta, but they are not highly productive. These wells will be subject to lower royalties at a wider price range to ensure the continued development of these unconventional gas reserves.
7. Crown **deem a fee for processing** to apply to all gas processing facilities in the province, with adjustments for different types of plant production (e.g., wet, dry, sweet)	**Reject** Establish a facility effective royalty rate (FERR) rather than the recommended deemed fee. The current system uses a corporate effective royalty rate (CERR)	Moves cost calculations to the facility level, better connecting costs to facility. Requires less modifications to the existing system.
8. **Eliminate the tiers** in conventional natural gas that distinguish "vintages" based on discovery date.	**Accept**	This change simplifies the system. Under current economic conditions the difference in royalties between tiers is minimal.
9. No panel recommendation on **shallow gas.**	The government will implement "shallow rights reversion" to maximize extraction of the resource. Under this policy, mineral rights to undeveloped geological formations above zones that are being developed would revert back to the government and be made available for resale.	This change would allow for development of currently undeveloped resources consistent with government's objective of maximizing recovery of known gas resources. This would allow for capture of increased royalty revenues for Albertans.
10. Several special **royalty programs be eliminated.**	**Accept** A number of well-based oil royalty programs will be eliminated. The following gas royalty programs will be retained and revamped: • Otherwise Flared Solution Gas Royalty Waiver Program. It will be extended to bitumen wells. • Deep Gas Drilling Program. Some revisions will be required to the current program to reflect the change in the royalty formula.	The OFSG program was developed in consultation with industry and environmental stakeholders. It encourages solution gas conservation, rather than venting the gas, resulting in improved air quality. The OFSG program is part of an overall program that has contributed to a 70% reduction in flaring across Alberta. Extending the OFSG program to bitumen wells makes the program more equitable and is consistent with the environmental intent of the program. The deep gas drilling program is instrumental to the viability of gas development in Alberta. Although royalties from unconventional gas will be lower, overall benefits to the economy will be higher, as production from marginal wells creates more jobs and benefits Alberta's businesses and communities.
11. **Rate caps** on price be **raised** for natural gas to Cdn $16.59/GJ.	**Accept** Currently the maximum rate is reached just above $3.70/GJ.	Improves Albertans' share at higher prices.
12. Treating **natural gas liquids** (propane, butanes, pentanes plus) as oil. Treat ethane as natural gas.	**Reject** Maintain the status quo for ethane and apply fixed royalty rates for propane, butane and pentanes to maximize their economic contribution to Alberta.	Ethane is already treated as natural gas. The panel recommendation is not justified by current drilling economics. Implementation would result in a considerable revenue loss for Alberta. There is no logical tie between the production and markets for oil and natural gas liquids.
13. **Eliminate** option to use Corporate Average Price (CAP) to determine natural gas royalties.	**Accept**	This is a minor change from the existing system. It is a labour-intensive manual process. Its elimination will result in administration savings to both industry and government.

PANEL RECOMMENDATION	GOVERNMENT DECISION	RATIONALE

Oil Sands

PANEL RECOMMENDATION	GOVERNMENT DECISION	RATIONALE
14. **Base Royalty** rate to remain at 1%.	**Reject** Implement a sliding rate structure where the base rate increases from 1% when the West Texas Intermediate (WTI) price is at $55 per barrel to 9% when WTI reaches $120.	At high prices the province will receive higher revenues from oil sands development. Albertans will receive a greater share from oil sands development. Ensures all components of the royalty system are price sensitive.
15. **Increase net royalty** rate from 25% to 33%.	**Reject** Implement a sliding rate structure where the net royalty rate increases from 25% when WTI price is at $55 per barrel to 40% when WTI reaches $120.	Albertans will receive a greater share from oil sands development. Ensures all components of the royalty system are price sensitive.
16. **Implement a new Oil Sands Severance Tax:** • 0% for price less than $40/ bbl • 1% at $40/ bbl • Increase by 0.1% for each dollar per barrel increase • Maximum of 9%.	**Reject** Royalties are a right of ownership. Other jurisdictions use severance taxes to meet their revenue need because they do not own the resources. Alberta's fair share is not based on revenue needs, but ownership rights.	By introducing a price sensitive base royalty rate, Alberta can obtain more revenue upfront, especially at high prices.
17. Recognize any **environmental fees** or levies as **eligible cost** of doing business.	**Accept**	Government already allows this for costs directly related to oil sands projects.
18. Introduce a **tradable royalty credit** at a rate of 5% of eligible capital expenditures on additional upgrading capacity in Alberta: • Requires EUB approval. • Requires that a new Bitumen Valuation Methodology be in place. • Credit is transferable.	**Reject** Implement royalty in kind for bitumen (rather than cash). Continue work on the Value-Added Strategy to determine most effective tools to encourage value-added product development in Alberta. Upgrader credit may be one option to consider within this review.	Other tools may be more effective at encouraging value-added activity in Alberta. Upgrading may be less critical than expanding refining or other value added activities. Numerous upgrading projects are already likely to go ahead in Alberta without the need for the special incentive, particularly if independent bitumen supply is available.
19. Elimination of **Accelerated Capital Cost Allowance** (ACCA) for oil sands projects.	**Accept**	The government will eliminate the provincial portion of the ACCA for oil sands projects, consistent with the federal government decision.
20. Adopt permanent, generic **"bitumen valuation methodology"** (BVM) by June 30, 2008 to replace all other BVMs and alternative valuations. All bitumen to be subject to this valuation system. Consult independent advisor.	**Accept with Modification** Accept the use of a formula-based approach as an option for the permanent BVM. Reject the application of the permanent BVM to all bitumen produced in the province.	A formula based approach is only required for non-arm's length transactions. Where there are arm's length sales at market price, the market price will be used.

continued

PANEL RECOMMENDATION	GOVERNMENT DECISION	RATIONALE
Oil Sands *continued*		
21. **Cost Rule Clarification** Encourage the Government of Alberta to comprehensively and extensively review and tighten, if required, current rules and enforcement procedures to ensure that absolutely clear, transparent, auditable and appropriate definitions exist for projects and eligible expenditures.	**Accept**	Aligns with initiatives/policies already being pursued by government for enhanced cost and operating reporting requirements.
22. Recommendation against **grandfathering** on the grounds of fair treatment for all participants The panel did not make a specific recommendation on the treatment of the Crown Agreements, which it felt was "beyond the scope of the Panel's work."	**Accept**	This ensures a level playing field for all industry stakeholders. The government is in discussions with Syncrude and Suncor, whose Crown agreements expire in 2016, to participate in the new oil sands royalty regime by 2009. The transition details will be worked out over the next 90 days. In the event agreement cannot be reached, the government will take other measures to ensure a level playing field for all industry stakeholders.
23. Eliminate the option to elect **oil sands administrative status** for primary wells in certain areas.	**Reject**	For many heavy oil projects in the region, the economics and development conditions are similar to oil sands, and primary wells may become part of a project that is in-situ. Conventional rates are not appropriate for these situations and would not improve recovery efficiency. The generic royalty regime encourages enhanced recovery from primary wells.
24. The existing schedule of **escalating rentals** begin in the sixth year of any agreement (lease or license) and that no deductions be allowed in the calculation of escalating rentals.	**Reject**	Six years is a short time frame for evaluating, planning, obtaining regulatory approvals and developing complex projects. The shortened time frame could lead to acceleration of activity and further strain Alberta's infrastructure.
Freehold Mineral Rights Tax		
25. **Flat 6% tax** apply regardless of level of production. Retain the base exemption of $1,600	**Reject**	The Panel did not provide any significant rationale for moving to the flat tax system. Freehold mineral rights are owned by individual Albertans not the Crown. Royalties recover Albertans' share of Albertans' resources. Current taxes cover administrative costs of managing the process. Elimination of low productivity rate reductions could lead to well abandonment and oil and gas being left behind that could have been extracted. The government will review the freehold mineral rights tax to ensure it is fulfilling its intended objectives.
Accountability		
26. Royalties are collected within an equitable, flexible and competent **administrative framework.**	**Accept** Initiate a review to improve the systems and structures used to collect, verify and report non-renewable resource revenues received by the Province of Alberta.	Government is committed to a sound, accountable system for collecting royalties.

State of Alaska

Department of Revenue
Commissioner's Office

SARAH PALIN, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0405
Phone: (907) 465-2300
Fax: (907) 465-2394

The Honorable Jay Ramras
Alaska State Representative
State Capitol, Room 118
Juneau, AK 99801-1182

October 27, 2007

Dear Representative Ramras,

You have requested that we provide you with what you call a "risk delta" associated with passage of ACES through year 2020. We have interpreted your inquiry as a request for a quantification of "what would happen if ACES were passed and investment decreased." To evaluate your question, we compared state revenues through 2020 under the scenarios of PPT with a 3% decline and ACES with a 6% decline. Slide 1 of the attached PowerPoint presentation depicts total severance taxes and royalties. The assumptions we used in this calculation were:

- -Starting production of 750,000 bbls/day in 2008
- -Most current DOR price forecast
- -Capex of $7.00/bbl in the 3% decline case and $4.50/bbl in the 6% decline case
- -Opex of $8.00/bbl in the 3% decline case and $7.00/bbl in the 6% decline case
- -These cost estimates are based on our research

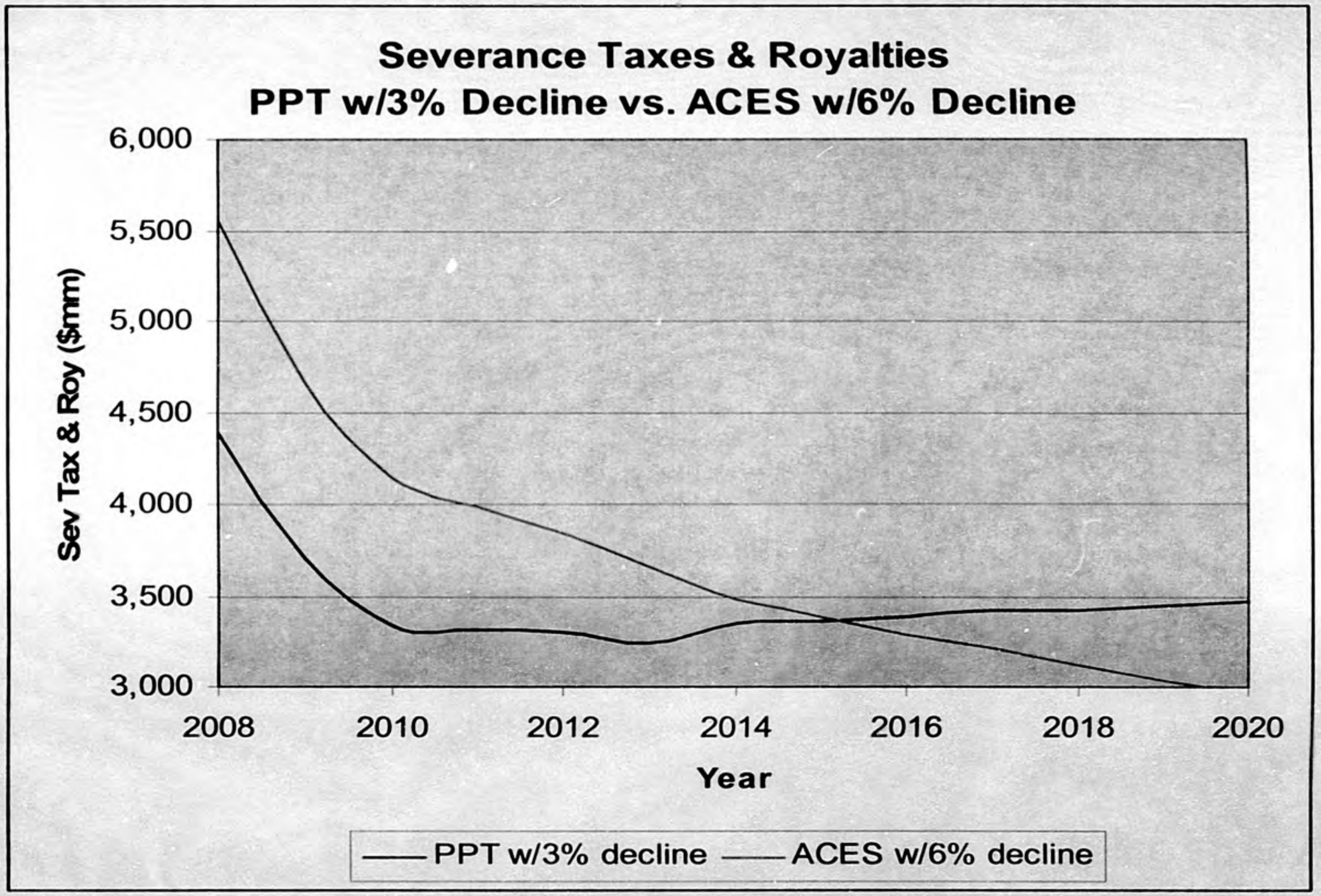
Slide 1 demonstrates that notwithstanding the lower total oil production should ACES result in reduced investment and thus, lower production through a higher decline rate, the total revenues under the ACES case with higher decline rate were slightly higher than PPT base case with lower decline rate: $48 billion under ACES vs. $45 billion under PPT.

Slide 2 supports the administration's statements that ACES would not cause a curtailment of investment, and associated increase in oil production decline until oil prices dropped below $30-40 a barrel. Above this oil price range, the higher taxes paid under ACES pales in comparison to the additional revenue investors would receive as a result of selling additional oil resulting from the additional investment. At prices above $35/bbl the net present value (NPV) to the producers of their additional investments to achieve a 3% decline under ACES is higher than the NPV of reducing investment and having 6% decline under ACES.

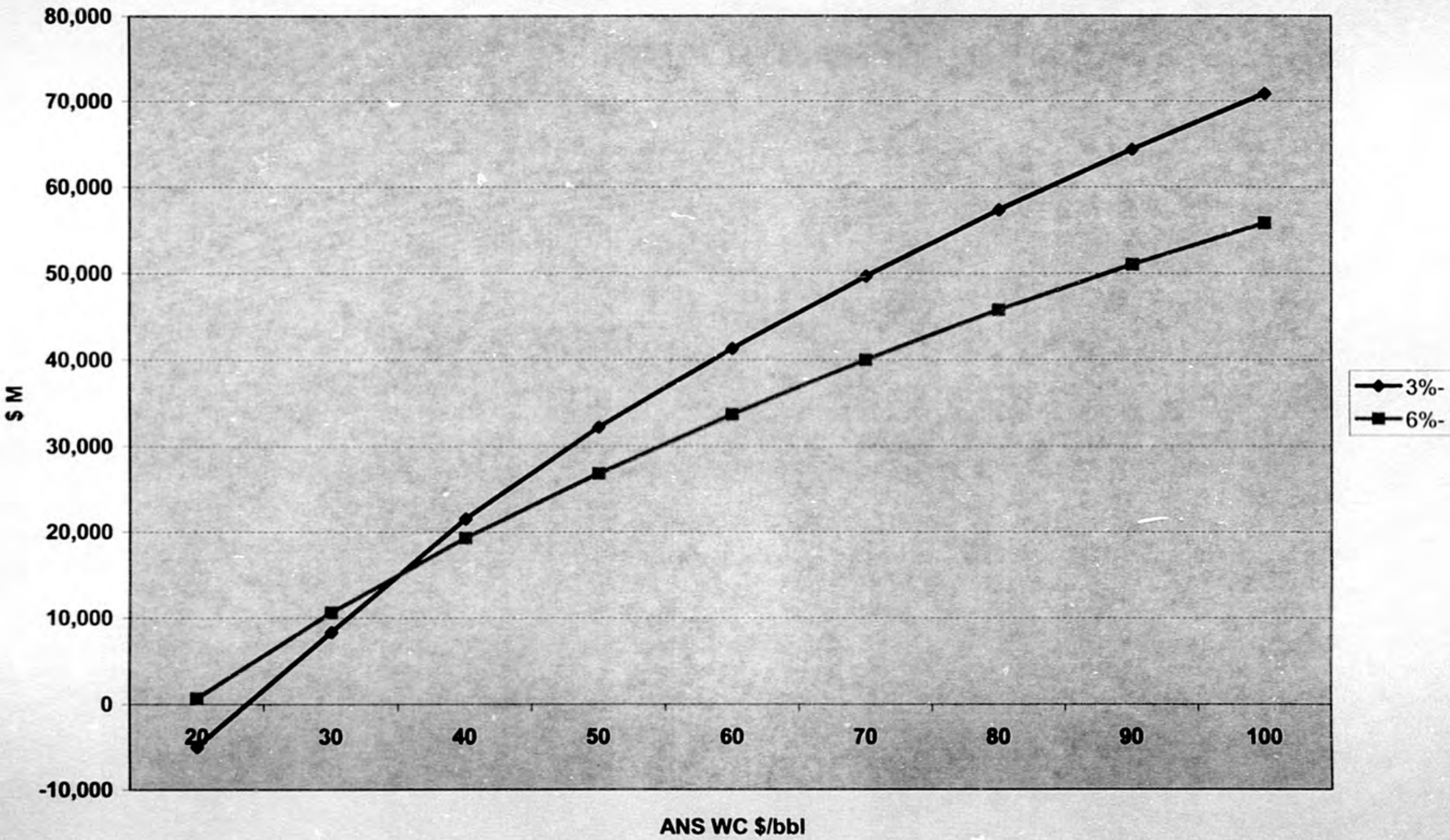
Sincerely,

Marcia Davis

Marcia Davis, Deputy Commissioner
Department of Revenue


Severance Taxes & Royalties
PPT w/3% Decline vs. ACES w/6% Decline
6,000
5,500
5,000
4,500
4,000
3,500
3,000
Sev Tax & Roy ($mm)
2008
2010
2012
2014
2016
2018
2020
Year
PPT w/3% decline
ACES w/6% decline

Producer Economics - NCF NPV10
ACES Under Two Decline Scenarios



Attached please find all Public Opinion messages received since last distribution (10/25/07)

Konrad Jackson

From: Shay Wilson
Sent: Saturday, October 27, 2007 2:42 PM
To: Konrad Jackson
Subject: New Pom:Oil & Gas

Gary Miller
20135 Cohen Dr

Juneau 99801-8211,gmiller
gmiller_juneauak@hotmail.com
907-789-3757
907-789-3757

Figures given by the oil companies for the PPT were wrong. Figures given now are meant to confuse. Create your own data. Pass a gross tax on oil and gas without deductions. After one year you will have your own data to base taxes on. $800,000,000 was a big mistake!

Konrad Jackson

From: Shay Wilson
Sent: Friday, October 26, 2007 11:40 PM
To: Konrad Jackson
Subject: New Pom:Oil & Gas

Ronald Bennett
1265 Airline Dr

North Pole 99705-5390,iflychamp

Considering the obscene profits and lack of concern for what oil prices are doing to the country the oil companies should be taxed as much as possible. What they're doing to the country is treasonous.

Konrad Jackson

From: Shay Wilson
Sent: Friday, October 26, 2007 7:32 PM
To: Konrad Jackson
Subject: New Pom:Resources

William Harvey Jr
13720 Davis St

Anchorage 99516-3614,blueraven
bluedog@ak.net

Why not build the Alaska Railroad to the slope..Take the oil and Natural Gas in tanker cars back here..Refine it and use it and sell the extra amount. When we build up enough extra $ then we build our own pipeline to southcentral and start to whoever..

From: Shay Wilson
Sent: Friday, October 26, 2007 7:29 PM
To: Konrad Jackson
Subject: New Pom:Resources

William Harvey Jr
13720 Davis St

Anchorage 99516-3614,blueraven
bluedog@ak.net

Why not build the Alaska Railroad to the slope..Take the oil and Natural Gas in tanker cars back here..Refine it and use it and sell the extra amount. When we build up enough extra $ then we build our own pipeline to southcentral and start selling the oil and gas to whoever..

Whats wrong with that idea.

Konrad Jackson

From: Shay Wilson
Sent: Friday, October 26, 2007 6:50 PM
To: Konrad Jackson
Subject: New Pom:Taxation

Terry Walters Sr
6821 Gold Kings Cir Unit D-8

Anchorage 99504-1172,terry4570
terrywalters4570@msn.com
338-6414

PPT must be redone. It was born out of corruption and really looks bad.
You need to restore confidence in the political process.

Konrad Jackson

From: Shay Wilson
Sent: Friday, October 26, 2007 4:47 PM
To: Konrad Jackson
Subject: New Pom:Taxation

Connie Sipe
102 Kelly St

Sitka 99835,cjsipe
cjsipe@cfc.org
907-747-6960
907-747-1432

32 yr Alaskan, former assistant Dept. Law, 10 yrs private sector providing direct health/social services, URGE you set higher tax rate: petroleum production. Strike balance between "incentive" to develop & MORE for Alaskans approach, but "err" on side of larger share for Alaska. World growth will keep oil prices up.

Konrad Jackson

From: Shay Wilson
Sent: Friday, October 26, 2007 4:11 PM
To: Konrad Jackson
Subject: New Pom:Resources

William Harvey Jr
13720 Davis St

Anchorage 99516-3614,blueraven
bluedog@ak.net

AP Today;

Four former BP employees were indicted by a federal grand jury in Chicago on 20 counts of mail and wire fraud connected to a scheme to manipulate energy markets.

The bulk of the fines aim to punish BP for conspiring to fix propane prices in 2003 and 2004.

Konrad Jackson

From: Shay Wilson
Sent: Friday, October 26, 2007 4:04 PM
To: Konrad Jackson
Subject: New Pom:Resources

William Harvey Jr
13720 Davis St

Anchorage 99516-3614,blueraven
bluedog@ak.net

I'm for developing our resources for the BEST value for our citizens as OUR Constitution says:

Before you decide, read this

http://www.pbs.org/now/transcript/transcriptNOW145_full.html

Conspiracy to control prices?

Konrad Jackson

From: Shay Wilson
Sent: Friday, October 26, 2007 2:32 PM
To: Konrad Jackson
Subject: New Pom:Oil & Gas

Dixie Hood
9350 View Dr

Juneau 99801,

I support a more transparent and measurable gross tax on oil revenues. I am sick of the fear mongering in the newspaper, TV ads and mailings and pitches to the Chambers of Commerce and legislators. Don't fall for it.

Konrad Jackson

From: Shay Wilson
Sent: Thursday, October 25, 2007 11:26 PM
To: Konrad Jackson
Subject: New Pom:Oil & Gas

Matthew Erickson
Po Box 70335

Fairbanks 99707-0335,look412
look412_2001@hotmail.com

government is banking on high oil prices & profits but seems to be forgetting who's footing the bill for the inflation related to high heating/gas costs. CONFLICT OF INTEREST. Does government service itself or the people? Will new tax proposals force more production & lower costs? or just allow for increased gov employee salaries? THINK!!!

Konrad Jackson

From: Shay Wilson
Sent: Thursday, October 25, 2007 2:18 PM
To: Konrad Jackson
Subject: New Pom:Revenue

Tomas Boutin
Po Box 35116

Juneau 99803-5116,
b0utin@alaska.net
789-7936

Gavel to Gavel today; appears leg consultants found no PPT receipts discrepancies but Revenue continues to find $200 million and $800 million shortages of some undetermined type(s). We all need to know what actually happened and to learn details of any discrepancies. Thanks for all your hard work.

Konrad Jackson

From: Shay Wilson
Sent: Thursday, October 25, 2007 1:01 PM
To: Konrad Jackson
Subject: New Pom:Oil & Gas

Lisa Peger
3873 Peger Rd

Fairbanks 99709-5464,Lisa Peger
lisapeger2@hotmail.com
907-452-8397
same

"Big Lie" tactic and the public can see it clearly even if you can't. Taxes up or down a few points is worth them half million in ads, for SPIN. These global companies ring out profit from least stable governments worldwide first and keep Alaska as ace in hole.

Konrad Jackson

From: Shay Wilson
Sent: Thursday, October 25, 2007 12:56 PM
To: Konrad Jackson
Subject: New Pom:Oil & Gas

Carole Pender
1725 S University Ave D2

Fairbanks 99709,

474-2150

I came to Fairbanks in 1955; before that I was a petroleum geologist in North Dakota where the state passed a lot of laws and taxes dealing with the oil companies. The oil companies are still there more than 50 years later. Oil companies don't up and leave when taxes are raised. They stay.

Konrad Jackson

From: Shay Wilson
Sent: Thursday, October 25, 2007 12:49 PM
To: Konrad Jackson
Subject: New Pom:Oil & Gas

Lisa Peger
3873 Peger Rd

Fairbanks 99709-5464,Lisa Peger
lisapeger2@hotmail.com
907-452-8397
same

Fourteen months of PPT did not attract "billions of dollars of investment." You are legislating! Big Three are representing their interest - not giving a balanced view. Pull focus from their selective presentation. Can't you figure out Alaska's taxes, are most unstable in US WHILE MOST profitable!

Konrad Jackson

From: Shay Wilson
Sent: Thursday, October 25, 2007 9:14 AM
To: Konrad Jackson
Subject: New Pom:Taxation

Margo Waring
11380 N Douglas Hwy

Juneau 99801,
margowaring@ak.net

The Special Session should undo PPT taxation mistakes. Bring back gross profits tax with a fairer return to petroleum owners--Alaskans. If it's PPT, omit deductions for maintenance/spill cleanup, have 30% and new minimum tax.Show the legislature hasn't been bought (or is willing to be bought) by Big Oil.