# 2/24/10 OIL & GAS PRODUCTION TAX (FILE 2)

<target><bill></bill><subject>2-24-10 OIL and GAS PRODUCTION TAX (FILE 2)</subject><comm>SFIN26</comm></target>

(2) net profit share payments under 15 AAC 55.260(a)(2).

(b) An allowance for overhead expenses is not a qualified capital expenditure.

(c) This section applies to expenditures incurred on or after {*the first day of the first month that begins on or after the effective date of these regulation changes*}. (Eff. 2/27/2010, Register 193)

**Authority:** AS 43.05.080 AS 43.55.110 AS 43.55.165

15 AAC 55.800(a) is amended to read:

(a) The following provisions apply retroactively to April 1, 2006, to oil and gas produced after March 31, 2006:

(1) 15 AAC 55.192;

(2) 15 AAC 55.205;

(3) 15 AAC 55.215;

(4) 15 AAC 55.223;

(5) **15 AAC 55.245;**

**(6) 15 AAC 55.270, except 15 AAC 55.270(a)(2)(C) and (e), which apply retroactively to July 1, 2007;**

15 AAC 55.275 **(7) ~~15 AAC 275~~ - 15 AAC 55.315;**

**(8)** [15 AAC 55.245 - 15 AAC 55.315;

(6)] 15 AAC 55.330 – 15 AAC 55.340;

**(9)** [(7)] 15 AAC 55.345 – 15 AAC 55.355;

**(10)** [(8)] 15 AAC 55.370 - 15 AAC 55.380;


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(11) [(9)] 15 AAC 55.410;

(12) [(10)] 15 AAC 55.420;

(13) [(11)] 15 AAC 55.430;

(14) [(12)] 15 AAC 55.440;

(15) [(13)] 15 AAC 55.510;

(16) [(14)] 15 AAC 55.810;

(17) [(15)] 15 AAC 55.850;

**(18) 15 AAC 55.900(a)(21) - (26) and (b)(21) - (25)** [(16) 15 AAC 55.900(a)(21) - (22) AND (b)(21) - (24)].

15 AAC 55.800 is amended by adding a new subsection to read:

(i) The provisions of 15 AAC 55.250 and 15 AAC 55.260 apply retroactively to April 1, 2006, with respect to costs incurred before July 1, 2007, and otherwise apply retroactively to July 1, 2007. (Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192; am 2/27/2010, Register 193)

**Authority:** AS 43.05.080 Sec. 37, ch. 2, TSSLA 2006 Sec. 72, ch. 1, SSSLA 2007
AS 43.55.110

15 AAC 55.900(a) is amended by adding new paragraphs to read:

(23) "oil or gas development operations" means the physical operations conducted in the field to

(A) drill and complete wells to produce oil or gas or to support oil or gas

production, including installation of a drill pad or structure; or

(B) install oil or gas production equipment or facilities;

(24) "oil or gas exploration operations" means the physical operations conducted in the field to

(A) drill and obtain subsurface information from an exploration well, including installation of a drill pad or structure; or

(B) explore for oil or gas using geological or geophysical exploration techniques;

(25) "oil or gas production facility or equipment"

(A) means a facility or equipment other than a well that is used in oil or gas production operations and that handles produced fluids upstream of the point of production or fluids injected in a reservoir for reservoir pressure maintenance, repressuring, or enhanced recovery purposes;

(B) does not include a refinery, crude oil topping plant, or other manufacturing facility; for purposes of this subparagraph, "manufacturing facility" does not include a gas processing plant;

(26) "oil or gas production operations"

(A) means the physical operations conducted in the field to

(i) lift oil or gas to the surface;

(ii) gather, separate, treat, and store on the surface well fluids upstream of the point of production; in this sub-subparagraph, "treat" does not include performing gas treatment as defined in AS 43.55.900;

(iii) perform gas processing upstream of the point of production;

(iv) meter oil or gas upstream of the point of production; and

(v) inject fluids in the reservoir from which the oil or gas is being produced, for reservoir pressure maintenance, repressuring, or enhanced recovery purposes;

(B) does not include compression of gas for the purpose of gas treatment as defined in AS 43.55.900 or of transporting gas to a market.

15 AAC 55.900(b) is amended by adding a new paragraph to read:

(25) "other land" means, with respect to costs of exploration, land the right to explore for oil or gas deposits within which, or the right to drill a stratigraphic test well on which, has been granted by license or permit by the property owner to the producer or explorer that incurs, or on behalf of whom is incurred, the costs of that exploration.

(Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 1/1/2004, Register 168; am 5/3/2007, Register 182; am 10/21/2009, Register 192; am 2/27/2010, Register 193)

**Authority:** AS 43.05.080 AS 43.55.024 AS 43.55.160
AS 43.55.011 AS 43.55.025 AS 43.55.165
AS 43.55.020 AS 43.55.110 AS 43.55.170
AS 43.55.023 AS 43.55.150 AS 43.55.900

15 AAC 55 is amended by adding a new section to read:

**15 AAC 55.250. Standards for lease expenditures other than overhead.** (a) Unless the department has approved or required use of an operating agreement under AS 43.55.165(c) or (d), as those provisions read on June 30, 2007, costs incurred before July 1, 2007, other than an allowance for overhead expenses under 15 AAC 55.270, are ordinary and necessary costs upstream of the point of production of oil and gas and direct costs of exploring for, developing, or producing oil or gas deposits, under AS 43.55.165(a), as that provision read on June 30, 2007, only if they are

(1) direct charges under 15 AAC 55.260 incurred for an activity or purpose described in (c) of this section; and

(2) not excluded under AS 43.55.165(e), as that provision read on June 30, 2007, or under AS 43.55.165(e)(6) and (19), as amended and enacted by sec. 60, ch. 1, SSSLA 2007, to the extent made retroactive to April 1, 2006, by sec. 74(b), ch. 1, SSSLA 2007.

(b) Costs incurred after June 30, 2007, satisfy the requirements established in AS 43.55.165(a)(1)(B), as enacted by sec. 58, ch. 1, SSSLA 2007, only if they are

(1) direct charges under 15 AAC 55.260 incurred for an activity or purpose described in (c) of this section; and

(2) not excluded under AS 43.55.165(e), as amended by sec. 60, ch. 1, SSSLA 2007.

(c) The activities or purposes referred to in (a) and (b) of this section are

(1) conducting a geological or geophysical survey to explore for oil or gas;

(2) performing a geological, geophysical, geotechnical, or geochemical

examination or investigation specific to a reservoir to support development of that reservoir;

(3) processing or interpreting data acquired from an activity described in (1) or (2) of this subsection to support oil or gas exploration, development, or production operations;

(4) designing, surveying, preparing, constructing, operating, or maintaining a drill site for an exploration well or a well to produce oil or gas or to support oil or gas production;

(5) transporting, mobilizing, or demobilizing a rig, coil tubing unit, or similar equipment, or associated supplies, to and on a drill site to drill or perform downhole operations described in (6) - (8) of this subsection on a well described in (4) of this subsection; demobilization does not include transportation out of the state;

(6) designing, drilling, testing, logging, completing, operating, maintaining, repairing, or suspending a well described in (4) of this subsection;

(7) plugging and abandoning an exploration well, but excluding restoration of the drill site;

(8) plugging a well described in (4) of this subsection, or a portion of the well, for the purpose of redrilling;

(9) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining an oil or gas production facility or equipment;

(10) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a communications system for communications between the site of oil or gas exploration, development, or production operations, and the operator's headquarters in the state, and that are necessary for the operations;

(11) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a field automation system solely dedicated to and specific to a unit or a lease or property and necessary for oil or gas production operations of the unit or the lease or property;

(12) preparing and submitting an application, data, or report necessary to obtain or maintain a governmental permit or similar governmental approval for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection;

(13) performing an archaeological, geophysical, or environmental survey or preparing an environmental impact statement required by law or otherwise required by a government agency, or required by an oil and gas lease, for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection, or otherwise complying with environmental requirements imposed by law or oil and gas lease for those operations, or for that facility, equipment, or infrastructure;

(14) performing one or more of the following activities with respect to an oil or hazardous substance cleanup contingency plan, fire response plan, or disaster recovery plan required for safe operation or by law or oil and gas lease, for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection:

(A) preparing and maintaining the plan;

(B) training personnel or performing practice drills, monitoring, or inspection under the plan;

(C) obtaining and maintaining equipment and supplies required under the plan to be routinely kept on hand;

(15) monitoring and maintaining the safety of personnel located at the site, or in the vicinity, of oil or gas exploration, development, or production operations;

(16) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a facility, equipment, or infrastructure that is located in the vicinity of and is used to support oil or gas exploration, development, or production operations; that facility, equipment, or infrastructure

(A) includes

(i) camps;

(ii) operations centers;

(iii) laboratories;

(iv) staging pads, roads, bridges, docks, helipads, landing areas, and similar transportation structures;

(v) medical facilities;

(vi) emergency response facilities;

(vii) storage facilities;

(viii) security facilities;

(ix) repair and maintenance shops; and

(x) vehicles;

(B) does not include refineries, topping plants, or other manufacturing facilities.

(d) A cost incurred jointly for both an activity or purpose described in (c) of this section and an activity or purpose not described in (c) of this section must be allocated between the activity or purpose described in (c) of this section and the other activity or purpose using a reasonable allocation methodology.

(e) Costs incurred before July 1, 2007, that satisfy the requirements of (a)(1) and (2) of this section are not a producer's or explorer's lease expenditures under AS 43.55.165(a), as that provision read on June 30, 2007, unless the costs are costs, incurred by the producer after March 31, 2006, 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 or explorer does not own a working interest, are costs, incurred by the producer or explorer after March 31, 2006, of exploring for oil or gas deposits located within other land in the state.

(f) Costs incurred after June 30, 2007, that satisfy the requirements of (b)(1) and (2) of this section are not a producer's or explorer's lease expenditures under AS 43.55.165(a), as repealed and reenacted by sec. 58, ch. 1, SSSLA 2007, unless the costs also satisfy the requirements of AS 43.55.165(a)(1)(A), as enacted by sec. 58, ch. 1, SSSLA 2007.

(g) For purposes of this section, "designing" is limited to activities specific to an identifiable well, facility, item of equipment, or system, and does not include activities of more general applicability or that would ordinarily be considered research and development. (Eff. 2/27/2010 Register 193)

**Authority:** AS 43.05.080 AS 43.55.160 AS 43.55.170
AS 43.55.110 AS 43.55.165

15 AAC 55 is amended by adding a new section to read:

**15 AAC 55.250. Standards for lease expenditures other than overhead.** (a) Unless the department has approved or required use of an operating agreement under AS 43.55.165(c) or (d), as those provisions read on June 30, 2007, costs incurred before July 1, 2007, other than an allowance for overhead expenses under 15 AAC 55.270, are ordinary and necessary costs upstream of the point of production of oil and gas and direct costs of exploring for, developing, or producing oil or gas deposits, under AS 43.55.165(a), as that provision read on June 30, 2007, only if they are

(1) direct charges under 15 AAC 55.260 incurred for an activity or purpose described in (c) of this section; and

(2) not excluded under AS 43.55.165(e), as that provision read on June 30, 2007, or under AS 43.55.165(e)(6) and (19), as amended and enacted by sec. 60, ch. 1, SSSLA 2007, to the extent made retroactive to April 1, 2006, by sec. 74(b), ch. 1, SSSLA 2007.

(b) Costs incurred after June 30, 2007, satisfy the requirements established in AS 43.55.165(a)(1)(B), as enacted by sec. 58, ch. 1, SSSLA 2007, only if they are

(1) direct charges under 15 AAC 55.260 incurred for an activity or purpose described in (c) of this section; and

(2) not excluded under AS 43.55.165(e), as amended by sec. 60, ch. 1, SSSLA 2007.

(c) The activities or purposes referred to in (a) and (b) of this section are

(1) conducting a geological or geophysical survey to explore for oil or gas;

(2) performing a geological, geophysical, geotechnical, or geochemical

examination or investigation specific to a reservoir to support development of that reservoir;

(3) processing or interpreting data acquired from an activity described in (1) or (2) of this subsection to support oil or gas exploration, development, or production operations;

(4) designing, surveying, preparing, constructing, operating, or maintaining a drill site for an exploration well or a well to produce oil or gas or to support oil or gas production;

(5) transporting, mobilizing, or demobilizing a rig, coil tubing unit, or similar equipment, or associated supplies, to and on a drill site to drill or perform downhole operations described in (6) - (8) of this subsection on a well described in (4) of this subsection; demobilization does not include transportation out of the state;

(6) designing, drilling, testing, logging, completing; operating, maintaining, repairing, or suspending a well described in (4) of this subsection;

(7) plugging and abandoning an exploration well, but excluding restoration of the drill site;

(8) plugging a well described in (4) of this subsection, or a portion of the well, for the purpose of redrilling;

(9) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining an oil or gas production facility or equipment;

(10) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a communications system for communications between the site of oil or gas exploration, development, or production operations, and the operator's headquarters in the state, and that are necessary for the operations;

(11) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a field automation system solely dedicated to and specific to a unit or a lease or property and necessary for oil or gas production operations of the unit or the lease or property;

(12) preparing and submitting an application, data, or report necessary to obtain or maintain a governmental permit or similar governmental approval for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection;

(13) performing an archaeological, geophysical, or environmental survey or preparing an environmental impact statement required by law or otherwise required by a government agency, or required by an oil and gas lease, for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection, or otherwise complying with environmental requirements imposed by law or oil and gas lease for those operations, or for that facility, equipment, or infrastructure;

(14) performing one or more of the following activities with respect to an oil or hazardous substance cleanup contingency plan, fire response plan, or disaster recovery plan required for safe operation or by law or oil and gas lease, for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection:

(A) preparing and maintaining the plan;

(B) training personnel or performing practice drills, monitoring, or inspection under the plan;

15 AAC 55 is amended by adding a new section to read:

**15 AAC 55.260. Direct charges.** (a) Except as limited by (d) and (e) of this section, direct charges for purposes of 15 AAC 55.250(a) and (b) are

(1) costs paid to real property owners to acquire surface rights in real property located in the vicinity of oil or gas exploration, development or production operations, and used in support of those operations;

(2) net profit shares required to be paid to the state under leases issued under AS 38.05.180(f)(3)(B), (D), or (E) and paid after June 30, 2007;

(3) labor costs, not including work on tax, legal, purchasing, or accounting matters, or matters involving a dispute before a government agency, in the form of salaries and wages of

(A) employees of the operator, when those employees are directly employed in or in support of oil or gas exploration, development, or production operations, and

(i) on the site or in the vicinity of those operations;

(ii) in transit to or from the site or vicinity of those operations;

(iii) on a site of a system described in 15 AAC 55.250(c)(10) or (11) if assigned to and working on that system; or

(iv) on the site of the construction, transportation, repair, or maintenance of a facility, a system, equipment, or infrastructure described in 15 AAC 55.250(c)(9) - (11) or (16) if assigned to and working on that construction, transportation, repair, or maintenance; or

(B) any of the following employees of the operator, while those employees are assigned to a specific lease or property or unit that is the subject of oil or gas exploration, development, or production, and only as to that portion of the salaries and wages attributable to the time actually devoted to that exploration, development, or production, as supported by an approved timesheet or other time writing document:

(i) technical employees having special and specific engineering, geological, or other technical skills, including engineers, geologists, geophysicists, environmental specialists, and other technical personnel whose primary function with respect to that exploration, development, or production is the handling of specific problems or operating conditions involving the oil or gas exploration, development, or production operations or the support of those operations;

(ii) employees engaged in developing field automation systems dedicated to and specific to a unit or a lease or property and necessary for oil or gas production operations of the unit or the lease or property;

(iii) employees engaged in developing computer applications specific to a unit or a lease or property and necessary for oil or gas development or production operations of the unit or the lease or property;

(4) costs of employee training that directly relates to the job duties for the employees described in (3) of this subsection; the costs of professional memberships, dues, or periodicals, or of education or training in pursuit of an academic degree or professional credential, are not direct charges;

(5) expenditures or contributions made under assessments imposed by governmental authority that are applicable to the operator's labor costs described in (3) of this subsection; as to workers' compensation, if the operator self-insures, it may treat as an expenditure or contribution under this paragraph the charge that is regularly recorded as an accrual in the operator's general ledger as representing the fair and reasonable cost of the self-insurance;

(6) reasonable expenses incurred or reimbursed by the employer of those employees described in (3) of this subsection for travel by those employees to or from the site or vicinity of oil or gas exploration, development, or production operations, and for associated living quarters and meals; a reasonable per diem allowance, if paid by the employer in place of reimbursement of actual expenses, may be substituted for actual expenses for living quarters and meals;

(7) the employer's share of contributions to established plans for employee group life, disability, or medical insurance, pension, retirement, stock purchase, thrift, bonus, or other similar benefit plans, applicable to the operator's labor costs described in (3) of this subsection, if

(A) the plans are available on a regular basis to all employees of the operator who are directly working in oil or gas exploration, development, or production operations, other than employees excluded from a plan's coverage because of participation under a collective bargaining agreement; and

(B) the amount of the employer's share of contributions does not exceed the following percentage, as applicable, of the costs under (3) of this subsection incurred for employees covered by the plans:

(i) 32 percent for calendar year 2006;

(ii) 33 percent for calendar year 2007;

(iii) 36 percent for calendar year 2008;

(iv) 35 percent for calendar year 2009;

(v) 30 percent for a calendar year after 2009;

(8) the employer's share of contributions to established plans for employee group life, disability, or medical insurance, pension, retirement, stock purchase, thrift, bonus, or other similar benefit plans, applicable to the operator's labor costs described in (3) of this subsection, and available to employees under a collective bargaining agreement;

(9) costs to purchase or transport a facility, equipment, materials, or supplies used in oil or gas exploration, development, or production operations;

(10) costs to purchase or transport a facility, a system, equipment, or infrastructure described in 15 AAC 55.250(c)(10), (11), or (16), or to purchase or transport equipment, materials, or supplies used in a facility, a system, equipment, or infrastructure described in 15 AAC 55.250(c)(10), (11), or (16);

(11) costs paid to a third party for contract services, utilities, or use of a facility equipment, or infrastructure provided by the third party and used in oil or gas exploration, development, or production operations, or used in support of those operations, or for use of a system described in 15 AAC 55.250(c)(10) or (11) provided by the third party; for purposes of this paragraph,

(A) contract services

(i) do not include work in tax, legal, or accounting matters, or

matters involving a dispute before a government agency;

(ii) are limited to services the labor costs of which, under (3) of this subsection, would be allowable as direct charges if the operator's employees performed the services;

(B) support facilities, equipment, and infrastructure are limited to the categories described in 15 AAC 55.250(c)(16);

(12) costs charged to a unit or other joint operation for use in its oil or gas exploration, development, or production operations of a facility or equipment that

(A) is wholly or partly owned by a producer or explorer with an interest in the unit or other joint operation; and

(B) is not, and has not previously been, wholly or partly owned or acquired by or on behalf of the unit or other joint operation;

(13) a premium paid to a third-party insurer for insurance covering oil or gas exploration, development, or production operations;

(14) standby costs paid to a third party drilling rig contractor, and incurred

(A) while rig operations are deferred, suspended, or curtailed by reason of force majeure or another cause beyond the reasonable control of the operator; or

(B) to secure a rig for drilling if the rig is actually used for the operation for which it was secured;

(15) payments of property taxes, sales or use taxes, motor fuel taxes, or excise taxes if incurred with respect to the sale, acquisition, ownership, or use of a good, service, or property, the cost of which is a lease expenditure under AS 43.55.165, or would be a lease

expenditure if incurred during the period for which the payment is made;

(16) payments in lieu of property taxes, sales or use taxes, motor fuel taxes, or excise taxes that would otherwise be incurred with respect to the sale, acquisition, ownership, or use of goods, services, or property, the cost of which is a lease expenditure under AS 43.55.165, or would be a lease expenditure if incurred during the period for which the payment is made;

(17) a regulatory cost charge under AS 31.05.093;

(18) a fee charged by a government agency for a regulatory license, permit, or similar regulatory approval required for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in 15 AAC 55.250(c)(16);

(19) costs to transport to the injection site, oil, gas, or other fluid recovered from a well and injected for reservoir pressure maintenance, repressuring, or enhanced recovery purposes, and costs paid to a third party producer to purchase that oil, gas, or other fluid from the producer;

(20) 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 amount calculated by subtracting from the fair market value of the product used the prevailing value of the oil that is processed; for purposes of this paragraph,

(A) the amount of the oil that is processed equals the number of barrels of the product into which the oil is processed;

(B) the prevailing value of the oil that is processed in a field topping plant

in the Alaska North Slope area is the gross value at the point of production of that oil as determined under 15 AAC 55.163(b);

(21) costs paid to a third party to acquire geological or geophysical data used in oil or gas exploration, development, or production operations.

(b) For purposes of this section, an employee's salary or wages for a given period of time includes the cost in salary or wages for the employee's earned or compensatory time off attributable to the employee's work during that time period.

(c) In the absence of evidence to the contrary, and for purposes of AS 43.55.165(e)(12), the department will accept a charge under (a)(12) of this section as being not more than fair market value if the charge does not exceed the cost calculated on the basis of the net book value of the equipment or facility multiplied by the number of hours, days, miles, or throughput volumes for which the equipment or facility is used in the oil or gas exploration, development, or production operations, divided by the number of hours, days, miles, or throughput volumes, as applicable, of estimated remaining useful life of the equipment or facility, or calculated using another method approved by the department. For purposes of this subsection, "net book value" means the dollar amount the owner of an asset records in its financial statements, consistent with generally accepted accounting principles, as the historical cost of the asset, excluding capitalized interest and net of accumulated depreciation or amortization, if the historical cost does not exceed the fair market value of the asset at the time it was acquired by the owner.

(d) Except for a cost described in (a)(2), (13), or (19) of this section, a cost that relates to the exploration, development, or production of oil or gas deposits that are subject to a unit operating agreement or other agreement that provides for an operator to conduct the oil or gas

exploration, development, or production on behalf of itself and other producers or explorers is not a direct charge under this section if the cost is not (1) incurred in the first instance by the operator on behalf of the producers or explorers under the agreement; (2) actually billed to the producers or explorers under the agreement; and (3) paid, as to the producer's or explorer's share, by the producer or explorer to whom that share is billed. For purposes of this subsection, an agreement includes an instrument or arrangement among the parties to the agreement that modifies a party's rights or obligations under the agreement.

(e) A fee or other consideration paid to, or for the benefit of, a producer in connection with the use of a facility in which that producer has an ownership interest is not a direct charge under this section to the extent that the fee or other consideration

(1) compensates that producer for the deferral or loss of that producer's oil or gas production resulting from the payer's use of the facility; or

(2) reimburses that producer for its additional tax liability resulting from the receipt of fees or other consideration in connection with the payer's use of the facility.

(f) Direct charges under this section are net of any credits, refunds, reimbursements, purchase discounts, and cost recoveries, unless the credit, refund, reimbursement, or cost recovery is accounted for as an adjustment to lease expenditures under AS 43.55.170. For purposes of this subsection, "credits" do not include tax credits.

(g) For purposes of this section, "operator" means, in the case of

(1) a producer or explorer carrying out oil or gas exploration, development, or production on behalf of itself, that producer or explorer;

(2) a unit operating agreement or other agreement that provides for an operator to

carry out oil or gas exploration, development, or production on behalf of itself and other producers or explorers, the producer or explorer acting as operator under that agreement. (Eff. 2/27/2010 Register 193)

**Authority:** AS 43.05.080 AS 43.55.160 AS 43.55.170
AS 43.55.110 AS 43.55.165

15 AAC 55.270(a) is amended to read:

**15 AAC 55.270. Overhead before {*the first day of the first month that begins on or after the effective date of these regulation changes*}.** (a) This subsection applies only to determining allowable overhead expenses under AS 43.55.165(a) and (b), **as those provisions read on June 30, 2007, and under AS 43.55.165(a), as repealed and reenacted by sec. 58, ch. 1, SSSLA 2007**. For purposes of AS 43.55.165(b)(1)(C), **as that provision read on June 30, 2007, and AS 43.55.165(a)(2), as repealed and reenacted by sec. 58, ch. 1, SSSLA 2007**, a reasonable allowance for a producer's or explorer's overhead expenses directly related to exploring for, developing, **or** [AND] producing oil or gas deposits located within a lease or property or other land in the state is the sum of

(1) three percent of the producer's or explorer's non-overhead lease expenditures that are qualified capital expenditures; and

(2) nine percent of the producer's or explorer's non-overhead lease expenditures that are not

(A) qualified capital expenditures; [OR]

(B) payments of or in lieu of taxes**; or**

**(C) net profit share payments under 15 AAC 55.260(a)(2).**

15 AAC 55.270 is amended by adding new subsections to read:

(e) The provisions of (a)(2)(C) of this section apply to expenditures incurred after June 30, 2007.

(f) This section applies to expenditures incurred before *{the first day of the first month that begins on or after the effective date of these regulation changes}*. (Eff. 5/3/2007, Register 182; am 2/27/2010 Register 193)

**Authority:** AS 43.05.080 AS 43.55.110 AS 43.55.165

15 AAC 55 is amended by adding a new section to read:

**15 AAC 55.271. Overhead on or after *{the first day of the first month that begins on or after the effective date of these regulation changes}*.** (a) For purposes of AS 43.55.165(a)(2), as repealed and reenacted by sec. 58, ch. 1, SSSLA 2007, a reasonable allowance for the calendar year for a producer's or explorer's overhead expenses directly related to exploring for, developing, or producing oil or gas deposits located within a lease or property or other land in the state is 4.5 percent of the producer's or explorer's lease expenditures, net of adjustments under AS 43.55.170, that are incurred during the calendar year and that are allowed as direct charges under 15 AAC 55.260, excluding

(1) payments of or in lieu of taxes other than

(A) payroll taxes under 15 AAC 55.260(a)(3);

(B) sales taxes, use taxes, or excise taxes on goods or services;

(2) net profit share payments under 15 AAC 55.260(a)(2).

(b) An allowance for overhead expenses is not a qualified capital expenditure.

(c) This section applies to expenditures incurred on or after {*the first day of the first month that begins on or after the effective date of these regulation changes*}. (Eff. 2/27/2010, Register 193)

**Authority:** AS 43.05.080 AS 43.55.110 AS 43.55.165

15 AAC 55.800(a) is amended to read:

(a) The following provisions apply retroactively to April 1, 2006, to oil and gas produced after March 31, 2006:

(1) 15 AAC 55.192;

(2) 15 AAC 55.205;

(3) 15 AAC 55.215;

(4) 15 AAC 55.223;

(5) **15 AAC 55.245;**

**(6) 15 AAC 55.270, except 15 AAC 55.270(a)(2)(C) and (e), which apply retroactively to July 1, 2007;**

15 AAC 55.275 (7) ~~15 AAC 275~~ - 15 AAC 55.315;

**(8)** [15 AAC 55.245 - 15 AAC 55.315;

(6)] 15 AAC 55.330 – 15 AAC 55.340;

**(9)** [(7)] 15 AAC 55.345 – 15 AAC 55.355;

**(10)** [(8)] 15 AAC 55.370 - 15 AAC 55.380;

(11) [(9)] 15 AAC 55.410;

(12) [(10)] 15 AAC 55.420;

(13) [(11)] 15 AAC 55.430;

(14) [(12)] 15 AAC 55.440;

(15) [(13)] 15 AAC 55.510;

(16) [(14)] 15 AAC 55.810;

(17) [(15)] 15 AAC 55.850;

**(18) 15 AAC 55.900(a)(21) - (26) and (b)(21) - (25)** [(16) 15 AAC 55.900(a)(21) - (22) AND (b)(21) - (24)].

15 AAC 55.800 is amended by adding a new subsection to read:

(i) The provisions of 15 AAC 55.250 and 15 AAC 55.260 apply retroactively to April 1, 2006, with respect to costs incurred before July 1, 2007, and otherwise apply retroactively to July 1, 2007. (Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192; am 2/27/2010, Register 193)

**Authority:** AS 43.05.080 Sec. 37, ch. 2, TSSLA 2006 Sec. 72, ch. 1, SSSLA 2007
AS 43.55.110

15 AAC 55.900(a) is amended by adding new paragraphs to read:

(23) "oil or gas development operations" means the physical operations conducted in the field to

(A) drill and complete wells to produce oil or gas or to support oil or gas

production, including installation of a drill pad or structure; or

(B) install oil or gas production equipment or facilities;

(24) "oil or gas exploration operations" means the physical operations conducted in the field to

(A) drill and obtain subsurface information from an exploration well, including installation of a drill pad or structure; or

(B) explore for oil or gas using geological or geophysical exploration techniques;

(25) "oil or gas production facility or equipment"

(A) means a facility or equipment other than a well that is used in oil or gas production operations and that handles produced fluids upstream of the point of production or fluids injected in a reservoir for reservoir pressure maintenance, repressuring, or enhanced recovery purposes;

(B) does not include a refinery, crude oil topping plant, or other manufacturing facility; for purposes of this subparagraph, "manufacturing facility" does not include a gas processing plant;

(26) "oil or gas production operations"

(A) means the physical operations conducted in the field to

(i) lift oil or gas to the surface;

(ii) gather, separate, treat, and store on the surface well fluids upstream of the point of production; in this sub-subparagraph, "treat" does not include performing gas treatment as defined in AS 43.55.900;

(iii) perform gas processing upstream of the point of production;

(iv) meter oil or gas upstream of the point of production; and

(v) inject fluids in the reservoir from which the oil or gas is being produced, for reservoir pressure maintenance, repressuring, or enhanced recovery purposes;

(B) does not include compression of gas for the purpose of gas treatment as defined in AS 43.55.900 or of transporting gas to a market.

15 AAC 55.900(b) is amended by adding a new paragraph to read:

(25) "other land" means, with respect to costs of exploration, land the right to explore for oil or gas deposits within which, or the right to drill a stratigraphic test well on which, has been granted by license or permit by the property owner to the producer or explorer that incurs, or on behalf of whom is incurred, the costs of that exploration.

(Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 1/1/2004, Register 168; am 5/3/2007, Register 182; am 10/21/2009, Register 192; am 2/27/2010, Register 193)

**Authority:** AS 43.05.080 AS 43.55.024 AS 43.55.160
AS 43.55.011 AS 43.55.025 AS 43.55.165
AS 43.55.020 AS 43.55.110 AS 43.55.170
AS 43.55.023 AS 43.55.150 AS 43.55.900

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RAR/bgh/C1699.00/gcah.57.10 February 16, 2010

**Oil Company Upstream Capital Spending**

This Memorandum is an update to a previous note dated October 3, 2007 on this same matter. Additional data on Capital Expenditures and Acquisitions has been incorporated below and supplemented with further analysis.

## BACKGROUND

Like any corporation, oil companies are by definition in business to make a profit. Taxes and other forms of government take govern the amount of profits that a government deems it appropriate for an oil company to make. With all things being equal (which they rarely are), oil companies would preferentially invest in areas with the lowest overall government take (whether achieved through taxation or otherwise); however, this is not the real world calculus.

When prospectivity (the likelihood of making a discovery) and materiality (the expected size of such a discovery) are added to the investment decision criteria, oil companies quite often end up investing in countries with relatively high or above average levels of government take. They do so because they believe (and often realize) that notwithstanding the high government take investments in those countries will generate absolute levels of profit unachievable in countries with lower levels of take. Thus, countries that offer extraordinary potential (like Angola, Russia, Kazakhstan, Libya and Iraq) are able to command a greater share of the total pie while, at the other extreme, areas which have extremely favorable tax regimes (like Ireland and Morocco) still do not attract significant industry interest.

The number of locales in the world that offer the larger oil companies the needed level of materiality to invest are increasingly limited in number. ExxonMobil, BP, Chevron and ConocoPhillips for example, together produce over 12 million barrels of oil equivalent per day – to simply replace their production they need to add to their reserves a Kuparuk size accumulation every 8 to 9 months!

Thus, the investment decisions of oil companies are governed by a number of factors. These include both the unit level of profitability available (a reflection of the overall level of government take), and the size of the investment opportunity.

## CAPITAL SPENDING COMPARISON

The oil companies have compared Alaska's fiscal regime mainly to other lower 48 US fiscal regimes; however, such a comparison would only be valid for a small portion of their overall capital spending over the past few decades. Indeed, typically over 70% of the E&P capital spending of companies such as ExxonMobil, BP, Chevron and ConocoPhillips are outside the US.

As the oil companies continue to assert, the fiscal regime in the Gulf of Mexico (GOM) is more favorable than ACES. But given that, why do the companies predominately invest outside

the US in countries with fiscal regimes far less contractor friendly than Alaska? Indeed, why not spend all of their capital in the Gulf of Mexico? Reasons include:

- Scale: there are not enough opportunities in the GOM for companies of this scale to increase production, "book barrels" and maintain high reserves replacement ratios; and
- Diversification: best practice portfolio management strategies typically promote investments in various locations, i.e. avoid "putting all the eggs in the same basket".

As a result, a number of the countries that have been the recipients of significant capital spending have fiscal regimes that are seen as less favorable (and in some cases much less favorable) than in the lower 48 US. In fact, countries such as Indonesia, Norway, Angola and Iraq typically have average and marginal tax rates/government takes above those in place in Alaska, regardless of price.

It is thus misleading simply to compare Alaska's terms with those available in the Gulf of Mexico or other US jurisdictions. Given the amount of investment capital being spent by the large oil companies each year, Alaska is presently not competing with the GOM for funds; it is competing with these other, mostly high cost (from a government take perspective) international opportunities.

The following table illustrates the upstream capital spending of ExxonMobil, BP, Chevron, and ConocoPhillips from 2002 through 2009.

| | US$ Millions | 2009* | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|---|---|---|---|
| Exxon-Mobil | US | 3,585 | 3,334 | 2,212 | 2,486 | 2,142 | 1,922 | 2,125 | 2,357 |
| | International | 17,119 | 16,400 | 13,512 | 13,745 | 12,328 | 9,793 | 9,863 | 8,037 |
| | US Share (%) | 17% | 17% | 14% | 15% | 15% | 16% | 18% | 23% |
| | TOTAL | 20,704 | 19,734 | 15,724 | 16,231 | 14,470 | 11,715 | 11,988 | 10,394 |
| BP | US | 6,169 | 10,359 | 5,096 | 4,605 | 3,870 | 4,096 | 4,097 | 4,303 |
| | International | 8,727 | 11,868 | 9,111 | 8,513 | 6,367 | 7,097 | 11,273 | 5,396 |
| | US Share (%) | 41% | 47% | 36% | 35% | 38% | 37% | 27% | 44% |
| | TOTAL | 14,896 | 22,227 | 14,207 | 13,118 | 10,237 | 11,193 | 15,370 | 9,699 |
| Chevron | US | 3,261 | 5,516 | 4,558 | 4,123 | 2,450 | 1,820 | 1,641 | 1,888 |
| | International | 13,848 | 11,944 | 10,980 | 8,696 | 5,939 | 4,501 | 4,034 | 4,395 |
| | US Share (%) | 19% | 32% | 29% | 32% | 29% | 29% | 29% | 30% |
| | TOTAL | 17,109 | 17,460 | 15,538 | 12,819 | 8,389 | 6,321 | 5,675 | 6,283 |
| Conoco-Phillips | Alaska | 832 | 1,414 | 666 | 820 | 746 | 645 | 570 | 706 |
| | US (Continental) | 2,668 | 3,836 | 3,122 | 2,008 | 891 | 669 | 848 | 499 |
| | International | 5,959 | 11,206 | 6,147 | 6,685 | 5,047 | 3,935 | 3,090 | 2,071 |
| | Alaska Share (%) | 9% | 9% | 7% | 9% | 11% | 12% | 13% | 22% |
| | US Share (%) | 37% | 32% | 38% | 30% | 24% | 25% | 31% | 37% |
| | TOTAL | 9,459 | 16,456 | 9,935 | 9,513 | 6,684 | 5,249 | 4,508 | 3,276 |
| TOTAL | US | 16,515 | 24,459 | 15,654 | 14,042 | 10,099 | 9,152 | 9,281 | 9,753 |
| | International | 45,653 | 51,418 | 39,750 | 37,639 | 29,681 | 25,326 | 28,260 | 19,899 |
| | US Share (%) | 27% | 32% | 28% | 27% | 25% | 27% | 25% | 33% |
| | TOTAL | 62,168 | 75,877 | 55,404 | 51,681 | 39,780 | 34,478 | 37,541 | 29,652 |

*Source: Company annual reports and press releases. - *2009 figures for ConocoPhillips are budget, not actual. Note: the scope of the activities included under Upstream Capital Spending varies from company to company, with ExxonMobil reporting Capital and Exploration Expenditures, BP reporting Capital Expenditure and Acquisitions, Chevron reporting Capital and Exploratory Expenditures and ConocoPhillips reporting Capital Expenditures and Investment.*

It is very clear from the above data that these companies invest more of their E&P budget outside the US than in the US, with overall only 27% percent of their upstream investment directed to US projects in 2009. Over the period from 2002 to 2009, the share of the US in these companies' total investment has dropped from 33% to 27%. Annual fluctuations in capital spending are often influenced by major acquisitions, such as Chevron's merger with Unocal in 2005 and ConocoPhillips' merger with Burlington Resources in 2006. In 2009, the total upstream capital spending outside the US represented over US$45 billion, while the US share represented over US$16 billion dollars.

Out of these four companies, ExxonMobil is the company which allocates the most significant portion of its budget to international investment, with over 80% of capital spending outside the US in 2009.

BP on the other hand has the highest percentage of its upstream capital spending in the US, representing over 40% in 2008 and 2009. This split is in part the result of BP's investments in US shale gas, such as the acquisition of Chesapeake's interests in the Arkoma Basin Woodford and Fayetteville Shale plays in 2008 for over US$3.6 billion.

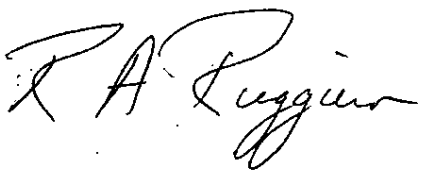
Chevron's US upstream investments have dropped from 32% to 19% from 2008 to 2009. Chevron's international focus is expected to remain strong in 2010 as reflected by its international upstream budget of US$13.2 billion out of a total upstream budget of US$17.3 billion, with major projects in Western Australia, GOM, Brazil, Nigeria, Angola, Thailand, China, and Canada.

ConocoPhillips' share of US spending significantly fluctuated since 2002, with a recent increase to 37% of its total upstream budget. The share of Alaska, out of total upstream budget, has dropped from 22% in 2002 to 9% in 2006 and remained below 10% since then.

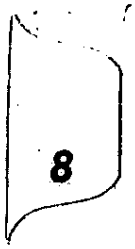
At the macro level there is no discernable change in investment patterns as Alaska moved from ELF to PPT to ACES. The continued investment by the large companies in high government take countries reflects the fact that, in deciding where to invest, government take is one of the factors considered but is demonstrably not, in and of itself, the controlling or deciding factor. In addition, it would be misleading to only compare the fiscal regime in Alaska with regimes in the lower 48 US, or other low government take regimes, as given strategic, investment community and growth drivers the large companies have and will continue to invest in high government take regimes which offer similar resource development opportunities.

Very truly yours,

**GAFFNEY, CLINE & ASSOCIATES, INC.**



Rich Ruggiero


8

# OPERATING AND CAPITAL LEASE EXPENDITURES

Senate Finance Committee

February 17, 2010

Alaska State Department of Revenue

# Lease Expenditure Agenda

- Lease Expenditure Sources
- Total North Slope Lease Expenditures
- Standard Deduction Provision
- $0.30/barrel Capital Expenditure Exemption
- Trends in North Slope Spending

# Lease Expenditure Information Sources

- Capital expenditure Information
- Monthly expenditure estimates
- Annual expenditure information, 2006 – 2009
- Future expenditure projections from North Slope operators
- Manual processing of all expenditure information

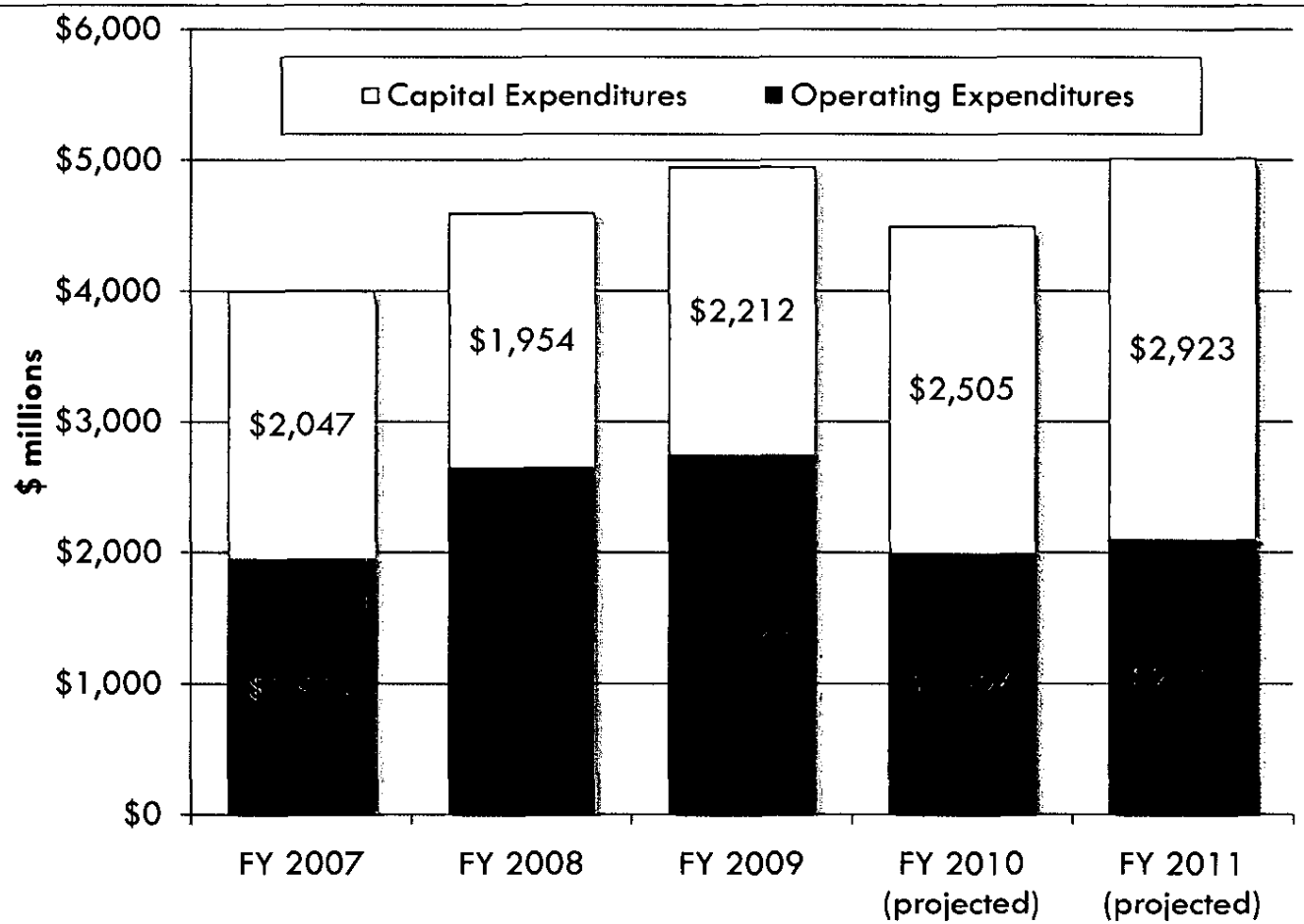
# Lease Expenditure Information Sources

- Capital expenditure Information
  - Dating back to April 2001
  - Received from applications for Transition Investment Expenditure (TIE) credits
- Monthly expenditure estimates
  - Beginning May 2008
  - Not audited - Expenditures represent estimates only

# Lease Expenditure Information Sources (Continued)

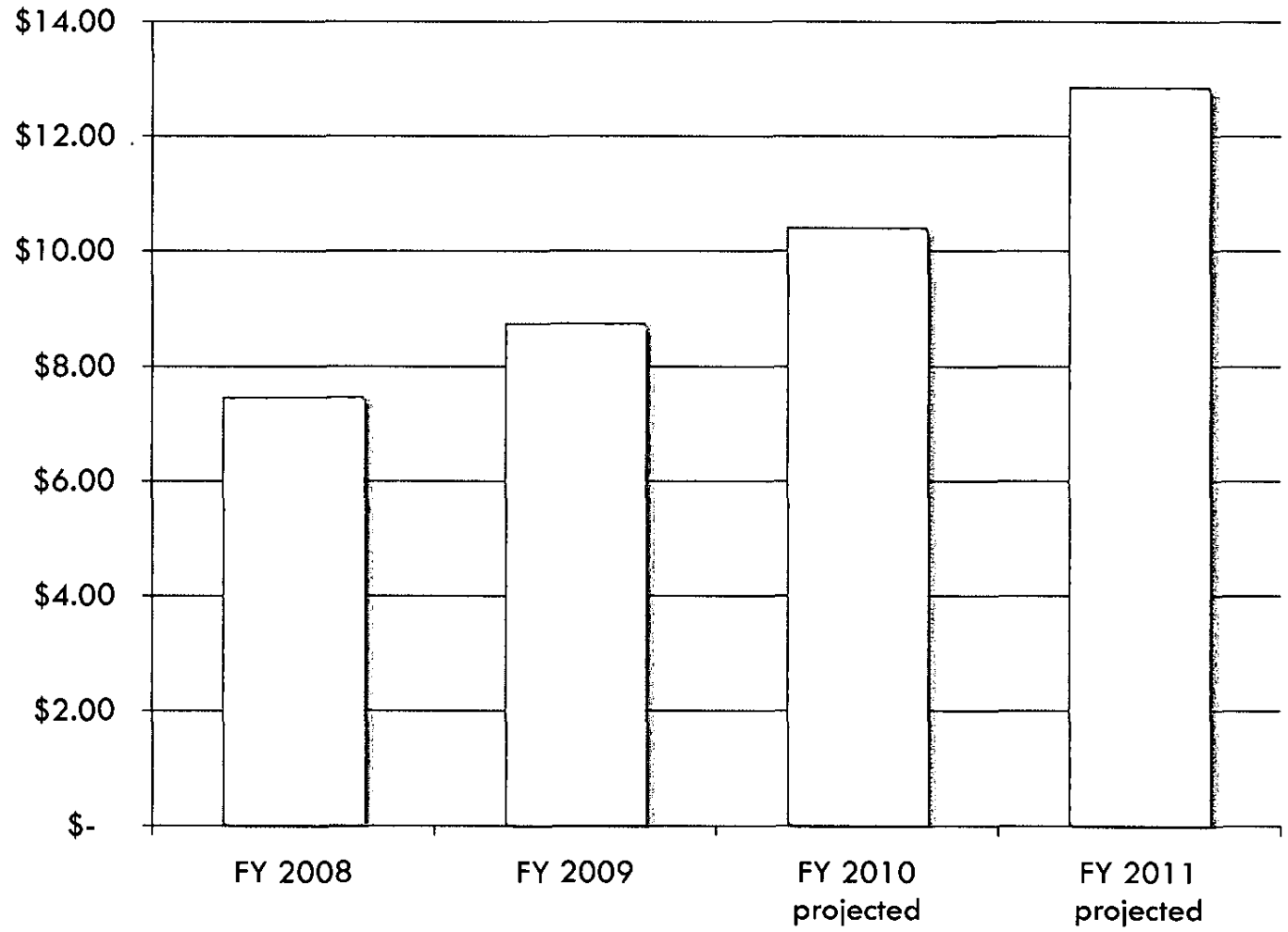
- Annual expenditure information, 2006 – 2009
  - Auditable production tax returns, due March 31 of each year
  - First filing March 31, 2007 (first under PPT)
  - Second filing March 31, 2008 (first under ACES)
  - Third filing March 31, 2009 (second under ACES)
  - Calendar year 2009 filings due March 31, 2010 – in process of developing a standardized tax return
- Future expenditure projections from North Slope operators
  - Requested of operators in spring and fall of each year
  - Request 5 years projections
  - Limited to communications with Working Interest Owners
  - Some categorization of expenditures, depending on operator and property
- Manual processing of all expenditure information

# North Slope Operating and Capital Expenditures, Reported and Projected

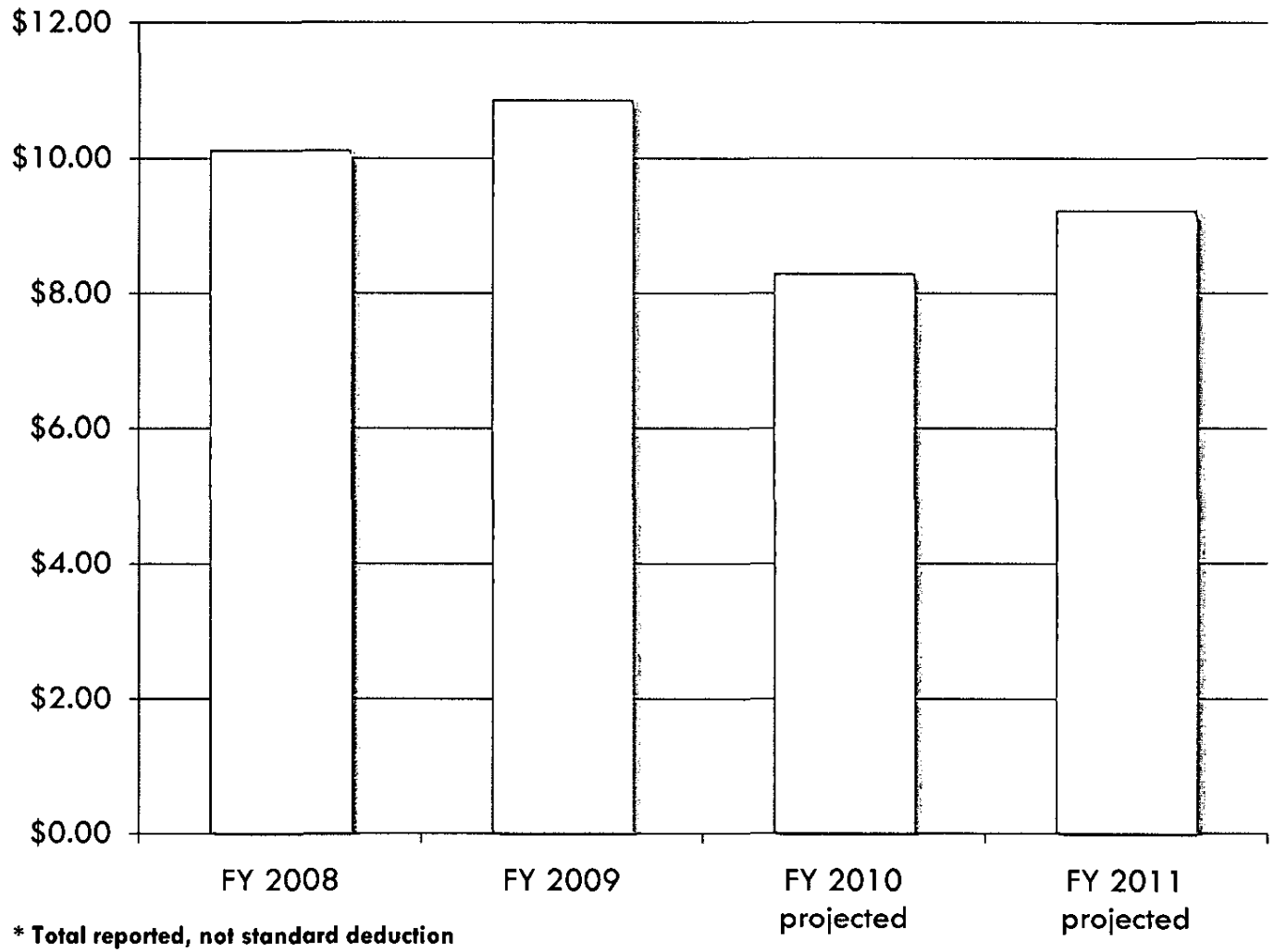



**NOTE: Operating expenditures includes total reported costs, not standard deduction; FY 2007 estimated based on incomplete reporting**

# Capital Expenditures per Barrel, Total North Slope

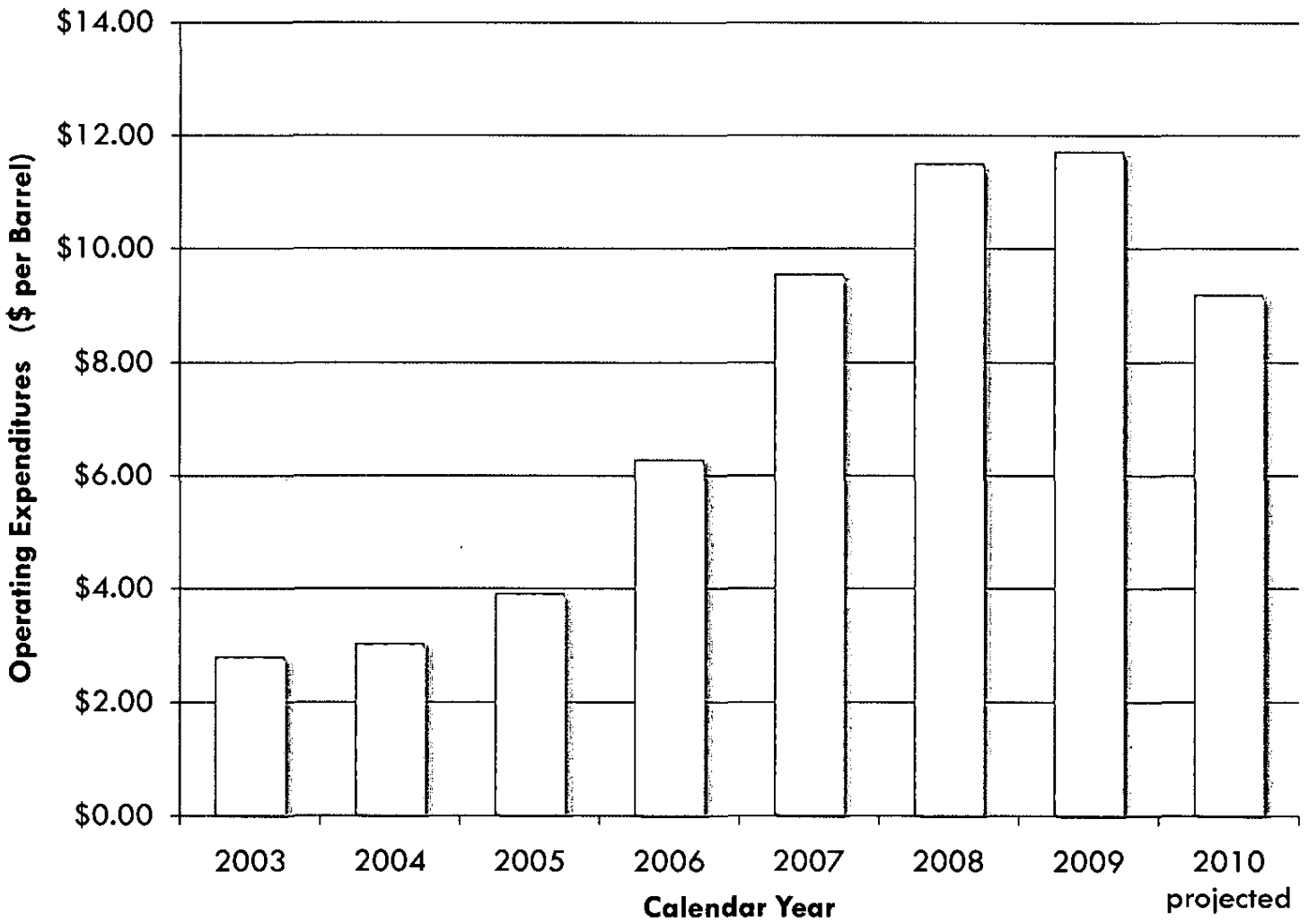


# Operating Expenditures per Barrel, Total North Slope *




*** Total reported, not standard deduction**

# Prudhoe Bay Operating Expenditures per Barrel, as Reported and Forecast

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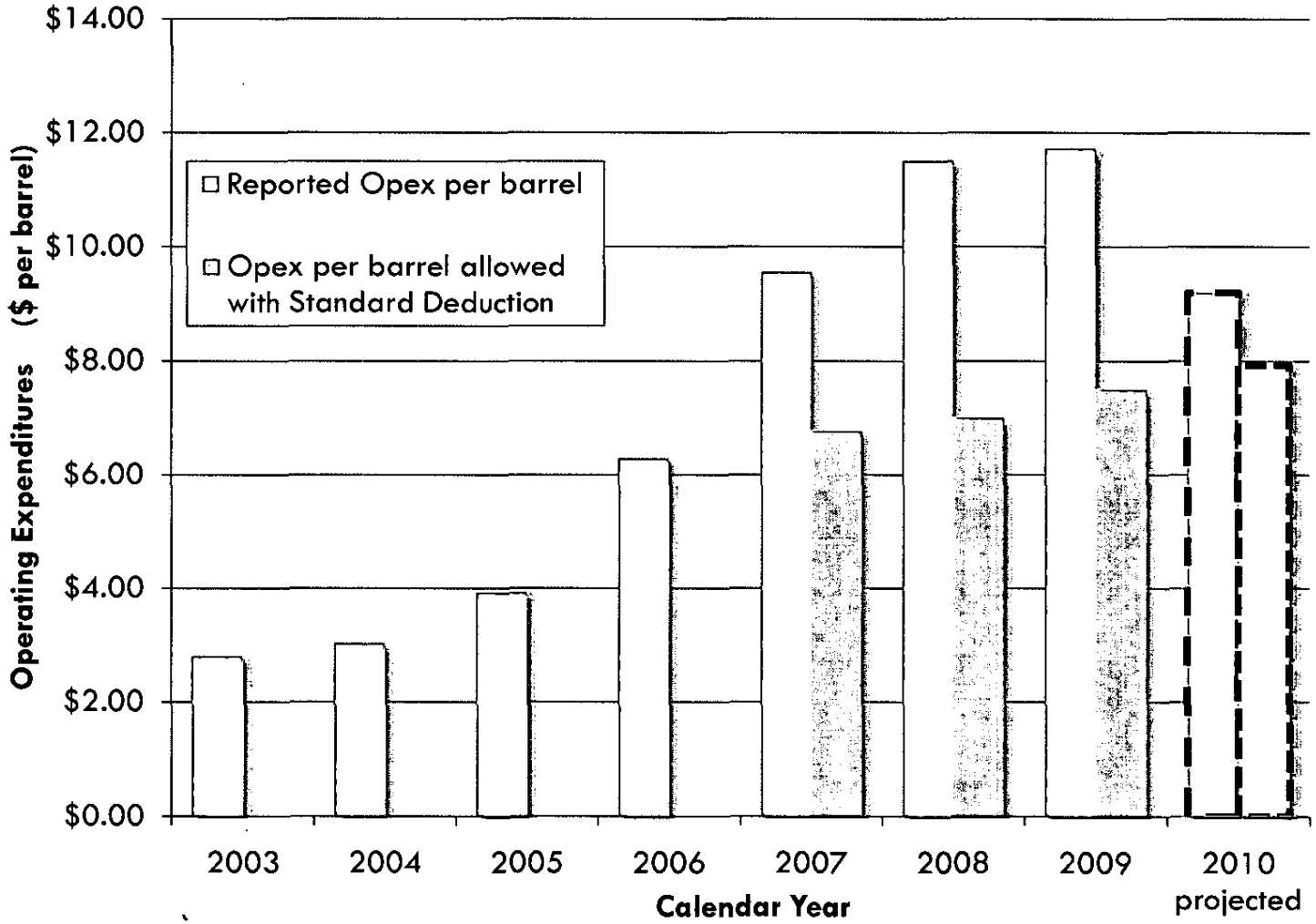
2/17/2010

# "Standard Deduction" Provision at AS 43.55.165(j)

- "Standard Deduction" refers to limitation on Operating Expenditures for Prudhoe and Kuparuk units
- Set at CY 2006 expenditure levels, with 3% inflation each year
- Sunset end of CY 2009

# Prudhoe Bay Opex per Barrel, as Reported and with Standard Deduction



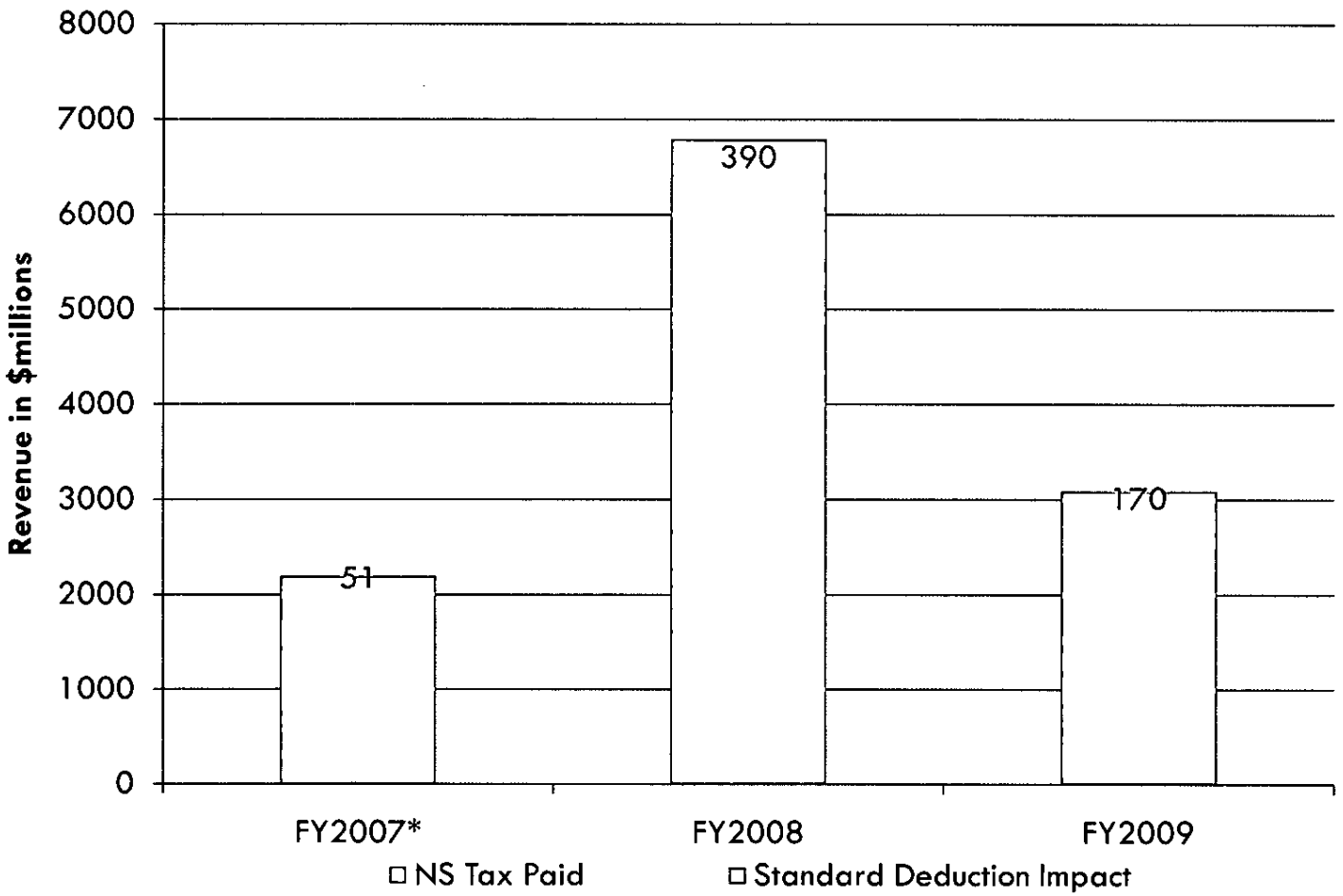

Alaska Department of Revenue

2/17/2010

# Impact of Standard Deduction

- Held operating expenditures fairly level for 3 years
- Expenditures more predictable for forecasting
- Difference between standard deduction and total reported costs greater at Prudhoe Bay unit than Kuparuk unit
- Impact on state revenues more significant as oil prices increase

# Increase to State Revenue from Standard Deduction Provision

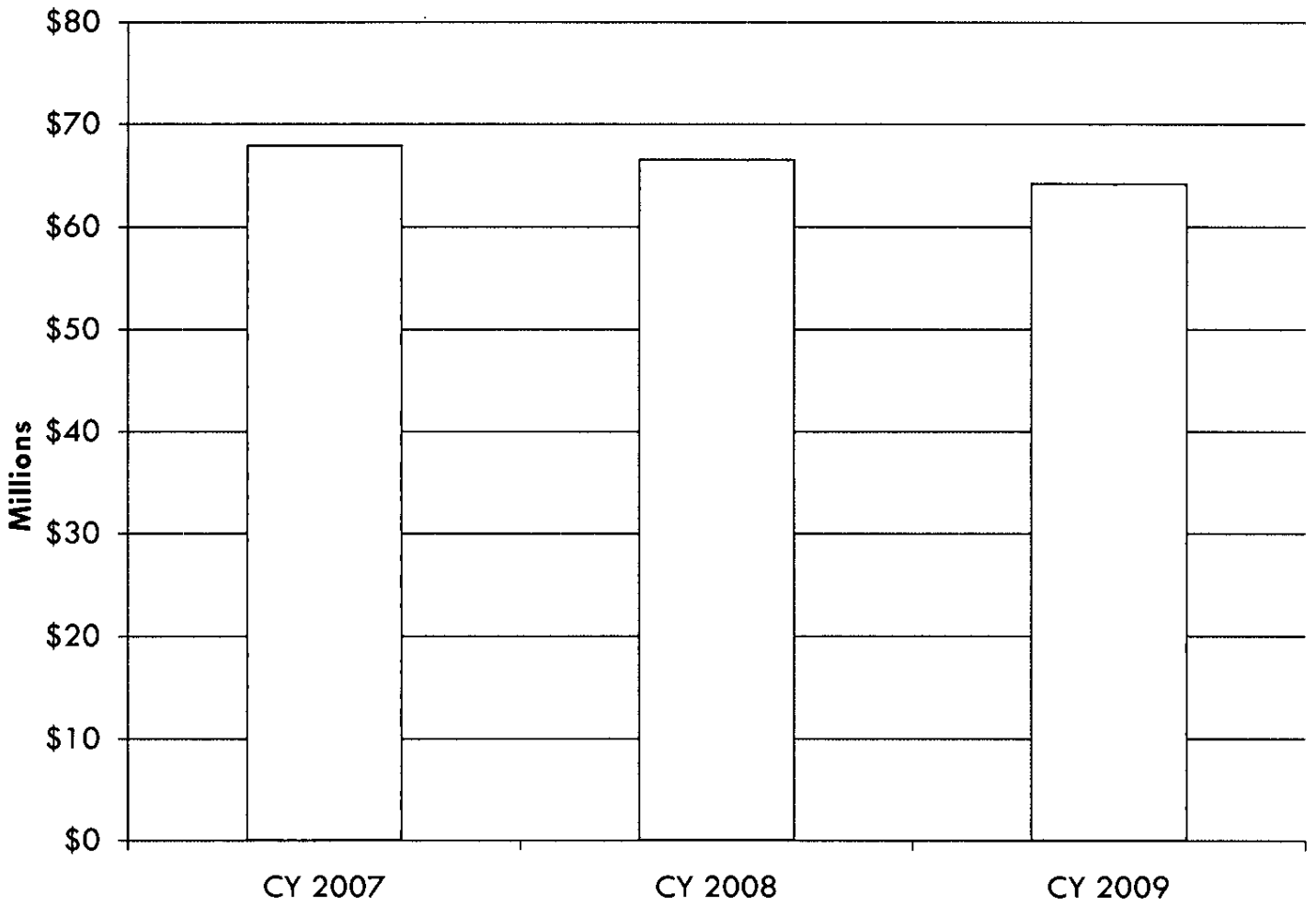



*Standard Deduction in place for half of FY 2007.

# Capital Exemption of $0.30 per barrel at AS 43.55.165(e)(18)

- AS 43.55.165(e)(18) exempts $0.30 per barrel
  - Initially intended to address costs of maintaining and upgrading pipelines and facilities
  - Applies to all barrels produced, regardless of property
- Impact of Capital Exemption
  - Reduced reported capital expenditures by close to $70 million per year
  - Expenditure forecasts indicate maintenance and upgrade of several hundred million
  - Maintenance and upgrade expenditures could be amortized over 10-20 years
- AS 43.55.165(e)(19) addresses **unplanned** maintenance
  Some reporting of unplanned maintenance expenditures by companies

# $0.30/bbl Capital Expense Exemption



# Lease Expenditure Information "Mixed Bag"

- Is lease expenditure categorization required ?
  - Monthly information forms - NOT REQUIRED
  - Annual production tax returns - NOT REQUIRED
  - Future expenditure projection from North Slope operators - NOT REQUIRED

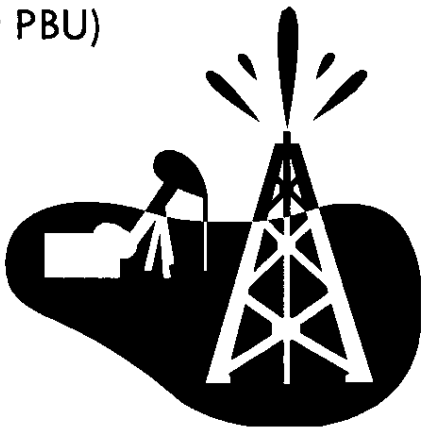
*However...*

# Lease Expenditure "Mixed Bag" (Cont.)

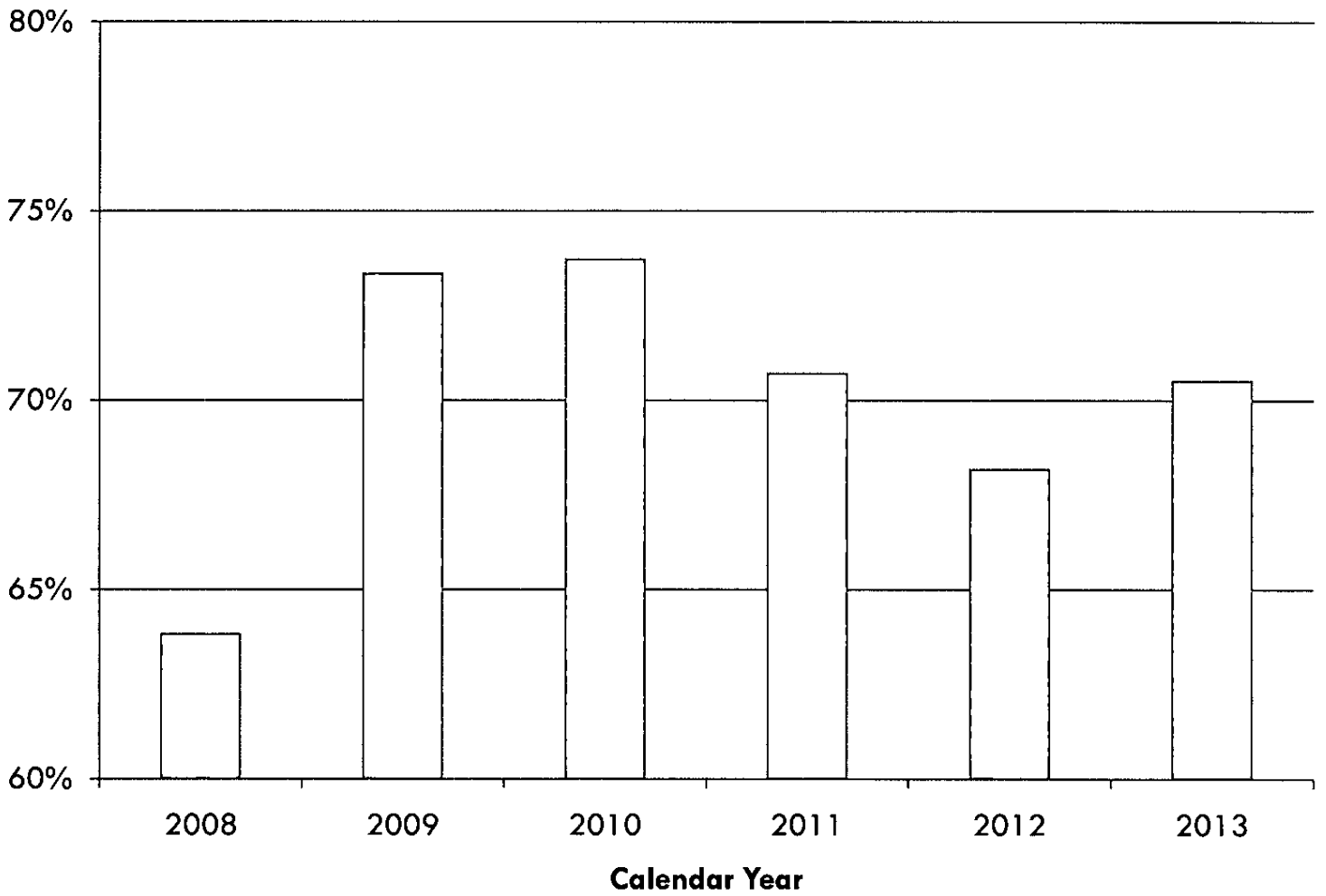
- SOME operators provide categorization in very broad categories on SOME properties
- Examples of Categories
  - Expense workovers
  - Major Repairs
  - Seismic Acquisition and Testing
  - Major Accident Review
  - Facility Integrity
  - Wellwork

# Composition of North Slope Capital Expenditures

- Based on review of company confidential cost information, capital expenditures are placed into two categories:
  - "Resource or Development-related"
    - Drilling & Wellwork
    - Enhanced Oil Recovery Projects
    - Seismic
    - Facilities at New Fields (e.g. PT Thomson, WRD at PBU)
  - Other Capital Expenditures
    - Major Repairs and Work on Existing Facilities
    - Corrosion-Related Expenditures
    - Safety Upgrades



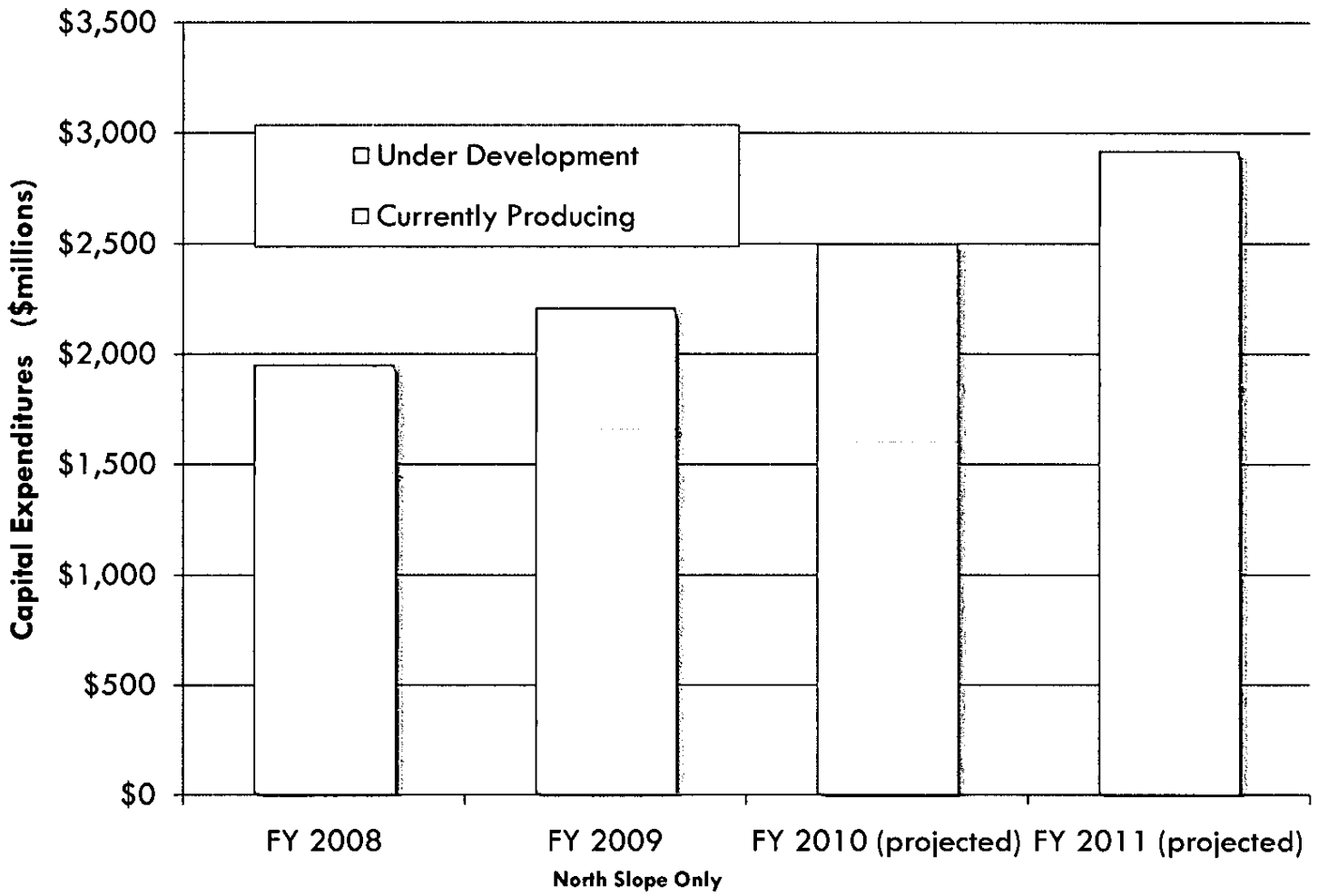
# Share of Planned North Slope capital Expenditures for "Resource and Development" Related Costs



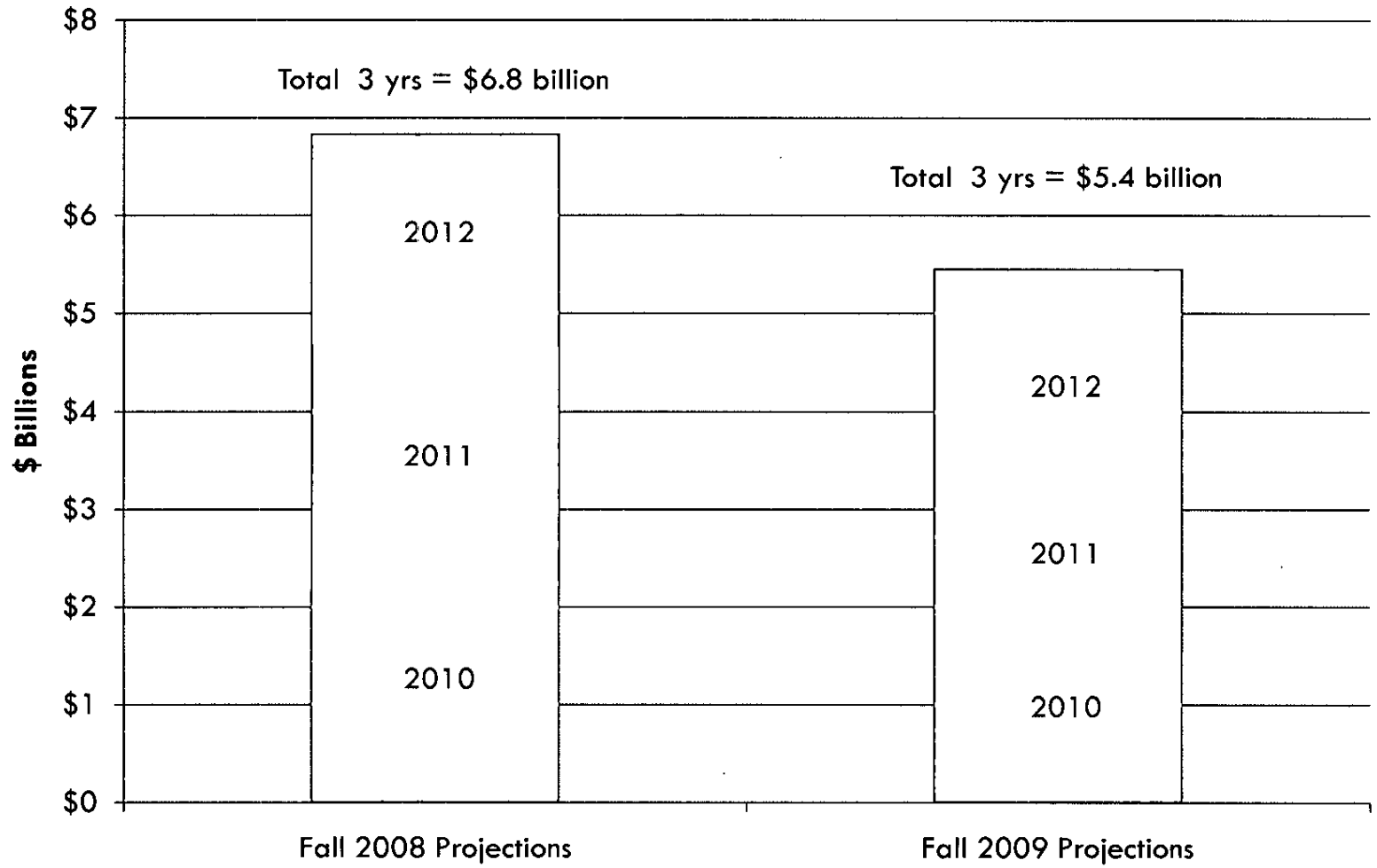
# Spending Trends

- Company projections of expenditures changing
- Fall 2008 projected increased expenditures in most units
- Fall 2009 projected divergence in plans
  - Currently producing units – projected lower expenditures
  - Developing units – projected higher expenditures

# Capital Expenditures by Type of Property

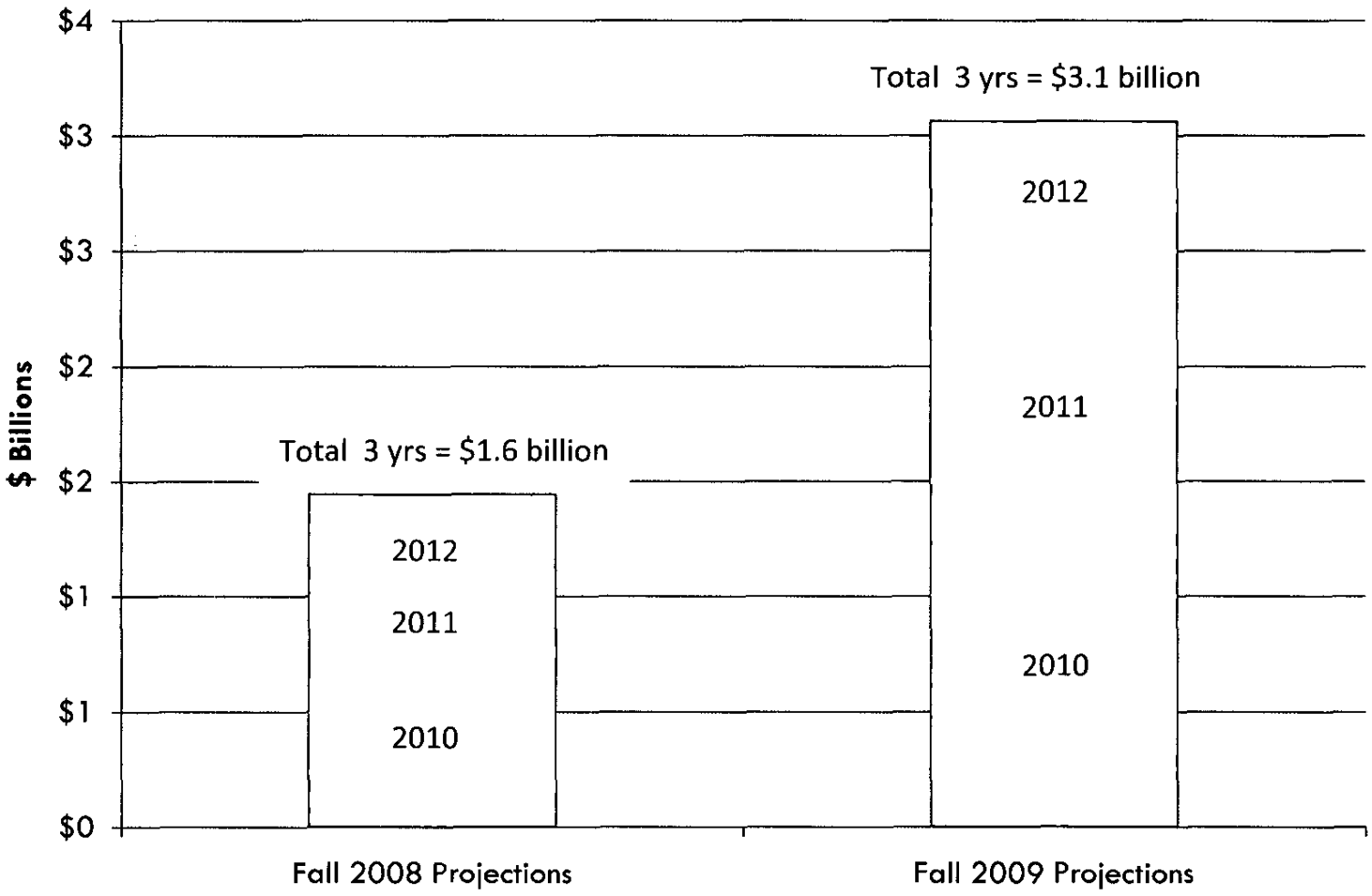


# Capital Expenditure on Currently Producing Properties




Note: Excludes Coville River, Oooguruk, Nikiatchuq and PT Thomson

# Capital Expenditures of Developing Properties



# Recent Trends in North Slope Costs

- DOR has limited data to work with in analyzing historic cost trends.
- Limited comparison of expenditures for 3 years before and after PPT
- Capital Expenditures at Prudhoe Bay
  - Maintenance and corrosion repair expenses are **not** the key driver behind the growth in capital expenditures.
  - Majority of the increase in capital expenditures is due to drilling, seismic and projects (such as development of the Western Region of Prudhoe Bay).
- Operating Expenditures at Prudhoe Bay
  - Major Repairs were a small part of total operating expenditures pre-PPT&ACES and is still a relatively small part of total lifting costs.
  - Wellwork expenditures are the primary driver behind the rise in Operating Expenditures.

# The End

# PRODUCTION TAX CREDITS

Senate Finance Committee

2/18/2010

Alaska State Department of Revenue

# Overview



- **Types of Tax Credits**
- Credits Applied Against Tax Liability
- Transferable Tax Credit Certificates
- Cash Refunds History
- Tax Credit Analysis

# Types of Credits



Credits which may be taken against oil and gas production taxes include:

- Capital Expenditure Credits
- Exploration Credits
- Net Operating Loss ("NOL") Carry Forward Credits
- Transitional Investment Expenditure ("TIE") Credit
- Small Producer Credits

# Types of Credits



**Capital Expenditure Credits** (AS 43.55.023(a)(1))

- 20% of qualified capital expenditures (QCE)
- QCE include drilling, construction of facilities, new equipment, etc.
- Same expenditures may also qualify for NOL Carry Forward Credit
- Same expenditures do ***not*** qualify for additional EIC credit
- Must be spread over 2 years
- Credits may be cashed or transferred

# Types of Credits



## Exploration Credits

- Two Main Types
  - 43.55.023(a)(2) Capital Credit for Exploration Activity (20%)
  - 43.55.025 Exploration Incentive Credits ("EIC") (30%-40%)

# Types of Credits



## 43.55.023(a)(2)**Capital Credit for Exploration Activity**

- **20%** of qualifying expenditures
- Qualifying expenditures related to geologic and geophysical exploration, or in connection with an exploration well
- Must be spread across 2 years
- Same expenditures may also qualify for NOL Carry Forward Credits
- Credits may be cashed or transferred

# Types of Credits



## Exploration Credits

- Two Main Types
  - 43.55.023(a)(2) Capital Credit for Exploration Activity (20%)
  - 43.55.025 Exploration Incentive Credits ("EIC") (30%-40%)

# Types of Credits



## 43.55.025 **Exploration Incentive Credits**

- **30% - 40%** of qualified expenditures depending on well location and proximity to existing wells and unit boundaries
- Qualified expenditures include certain expenses associated with seismic and geophysical exploration work, and exploration well drilling
- Same expenditures may also qualify for NOL Carry Forward Credit
- Same expenditures do ***not*** qualify for Capital Expenditure Credit
- To receive credit, taxpayer must provide certain well data to DNR
- Expires 2016
- Credits may be cashed or transferred

# Types of Credits



## **NOL Carry Forward Credit** - 43.55.023(b)

- **25%** of net operating loss
  - Applied against tax liability in following year
- Credit based on adjusted lease expenditures which include both operating and capital expenses
- Same capital expenditures may also qualify for exploration credit under 43.55.023(a)(2)
- Credits may be cashed or transferred

# Types of Credits



## Transitional Investment Expenditure (TIE) Credits - 43.55.023(i)

- Credit equals 20% of qualifying capital expenditures:
  - incurred between March 31, 2001 and April 1, 2006, and
  - not exceeding 10% of the capital expenditures incurred between March 31, 2006 and January 1, 2008.
- Revised under Aces to cover only producer or explorer not having production prior to January 1, 2008
- Credits are ***not*** transferable and may ***not*** be carried forward beyond 2013
- Same capital expenditures may ***not*** qualify for exploration credit under 43.55.025

# Types of Credits



**Small Producer Credit -** 43.55.024(a)

- Available for companies producing less than 50,000 bbl/day of oil BTU-equivalent
- Credit is up to $6 million against tax liability
- Production must be from wells outside of Cook Inlet and North Slope
- Expires 2016 or 9 years after first commercial oil or gas production if before May 1, 2016
- Credits may ***not*** be cashed or transferred or carried forward

# Types of Credits



**Small Producer Credit -** 43.55.024(c)

- Available for companies producing not more than 100,000 bbl/day of oil BTU-equivalent
- Credit ranges between $12 million and $0 depending upon level of production.
- Credit can only be applied against tax liability
- Production not restricted by region
- Expires 2016 or 9 years after first commercial oil or gas production if before May 1, 2016
- Credits may ***not*** be cashed or transferred or carried forward

# Overview



- Types of Tax Credits
- **Credits Applied Against Tax Liability**
- Transferable Tax Credit Certificates
- Cash Refunds History
- Tax Credit Analysis

# Credits Applied Against Tax Liability



## Credits may be claimed in up to two ways:

### (1) All Credits may be applied against tax liability

- .023(a) credits split over two years
- NOL , TIE, Small Producer and .025 credits all in current year

### (2) Some Credits may be converted into a transferable Tax Credit Certificate

- .023(a), NOL, and .025 Credits are convertible
- .023(a) and NOL Tax Credit Certificates must be applied over two years
- .025 Tax Credit Certificates can be used in single year

# Credits Applied Against Tax Liability



## Tax Credits Earned by Producers, by Tax Year*

| Credit Type | 2006 | 2007 | 2008 | Total |
|---|---|---|---|---|
| Capital Expenditure Credit | 204 | 282 | 342 | 828 |
| TIE Credit | 98 | 145 | 0 | 243 |
| Small Producer Credit | 27 | 38 | 21 | 86 |
| Exploration Incentive Credits | 2 | 105 | 12 | 119 |
| **TOTAL** | **331** | **569** | **376** | **1,276** |

* Does not include explorers without current production

# Credits Applied Against Tax Liability



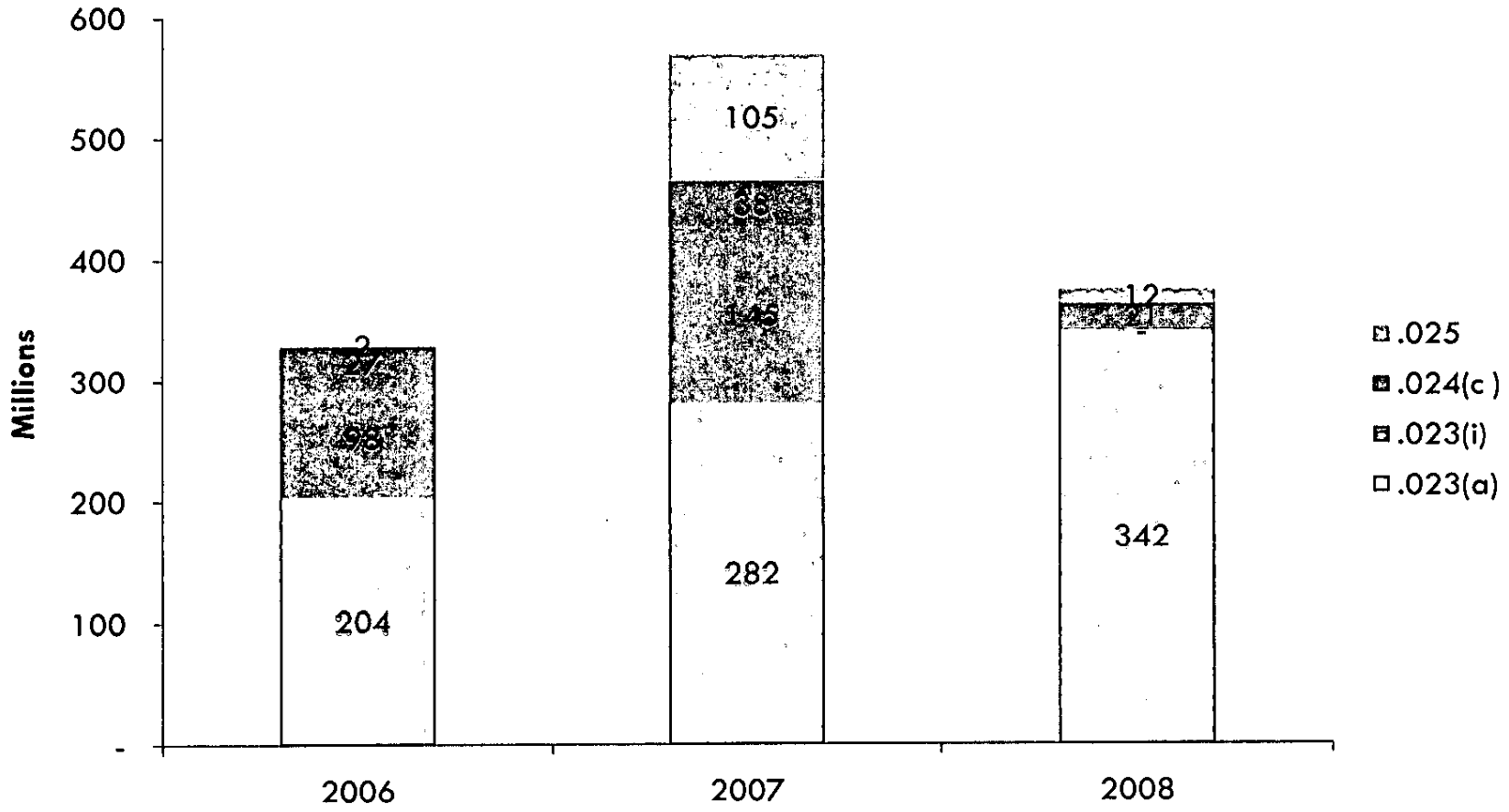
## Tax Credits Applied by Producers Against Tax Liability, by Tax Year

| Credit Type | 2006 | 2007 | 2008 | Total |
|---|---|---|---|---|
| Capital Expenditure Credit | 195 | 194 | 243 | 632 |
| TIE Credits | 98 | 145 | 0 | 243 |
| Small Producer Credits | 27 | 38 | 21 | 86 |
| Exploration Incentive Credits | 2 | 92 | 17 | 112 |
| **TOTAL** | **322** | **469** | **282** | **1,073** |

# Credits Applied Against Tax Liability

## Credit Claimed On Tax Filings 2006 - 2008

17

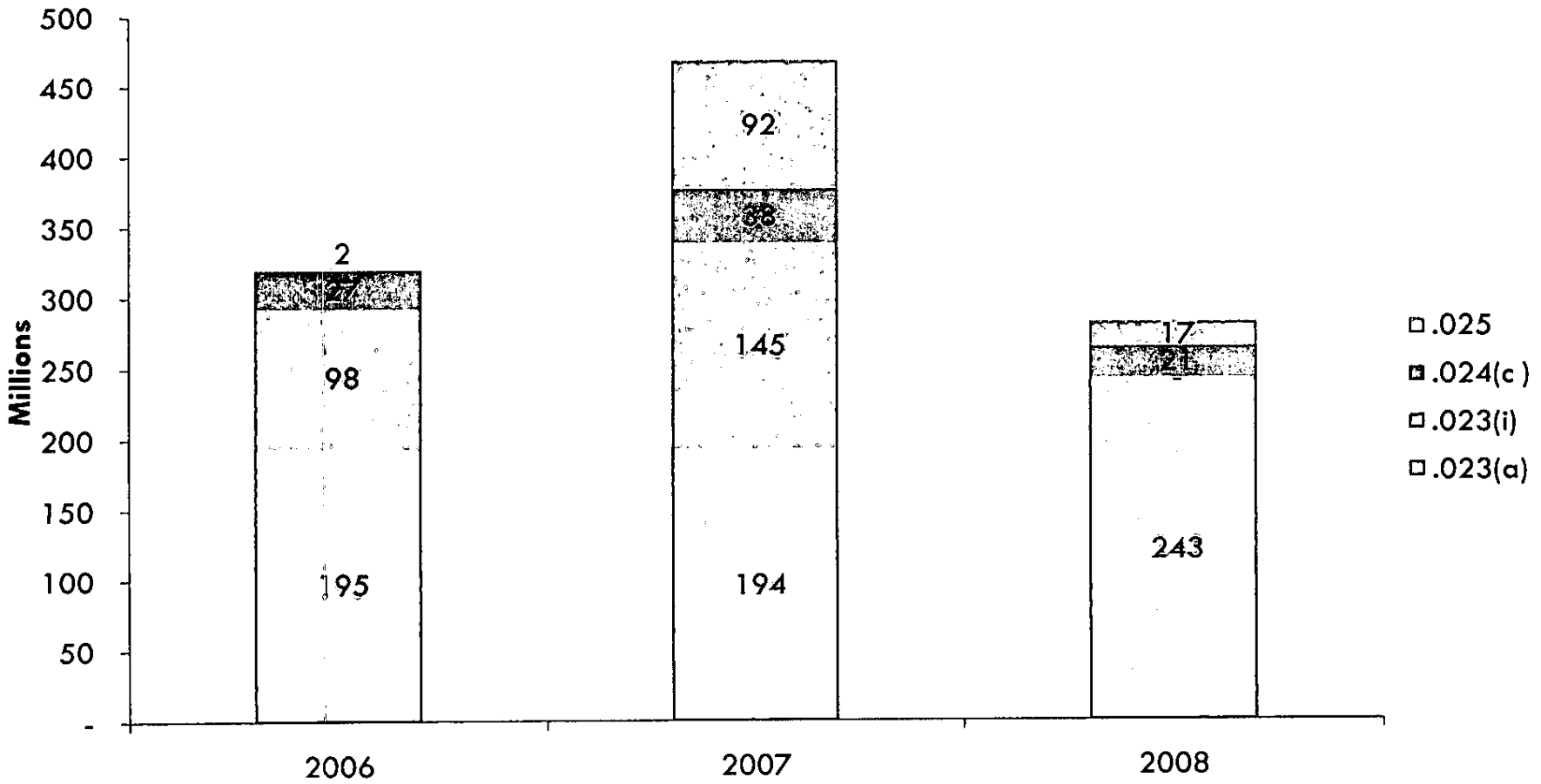



Department of Revenue 2/18/2010

# Credits Applied Against Tax Liability

## Credits Applied Against Taxes 2006 - 2008

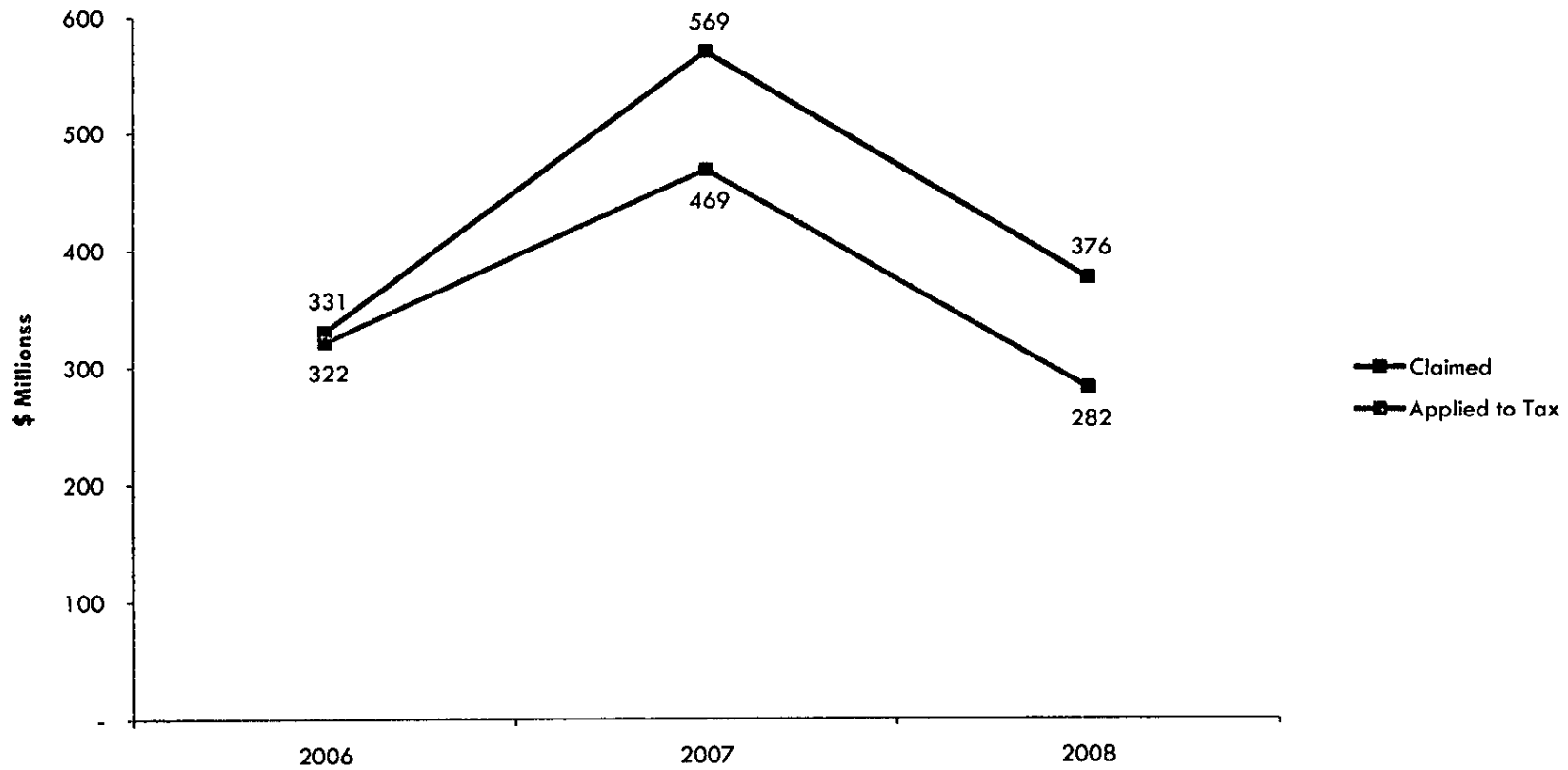
18



# Credits Applied Against Tax Liability

## Tax Credits Earned and Applied to Tax





# Overview



- Types of Tax Credits
- Credits Applied Against Tax Liability
- **Transferable Tax Credit Certificates**
- Cash Refunds History
- Tax Credit Analysis

# Transferable Tax Credit Certificates



## Capital Credit Tax Certificates

- Number issued since 2006- 211 transferable credit certificates
- Capital Credits issued by type:
  - .023 (a)(1) Qualified Capital Exp- $228.9 M
  - .023 (a)(2) Exploration/G&G- $64.9M
  - .023 (b) NOL- $340.1M

# Transferable Tax Credit Certificates

## Exploration Tax Credits .025

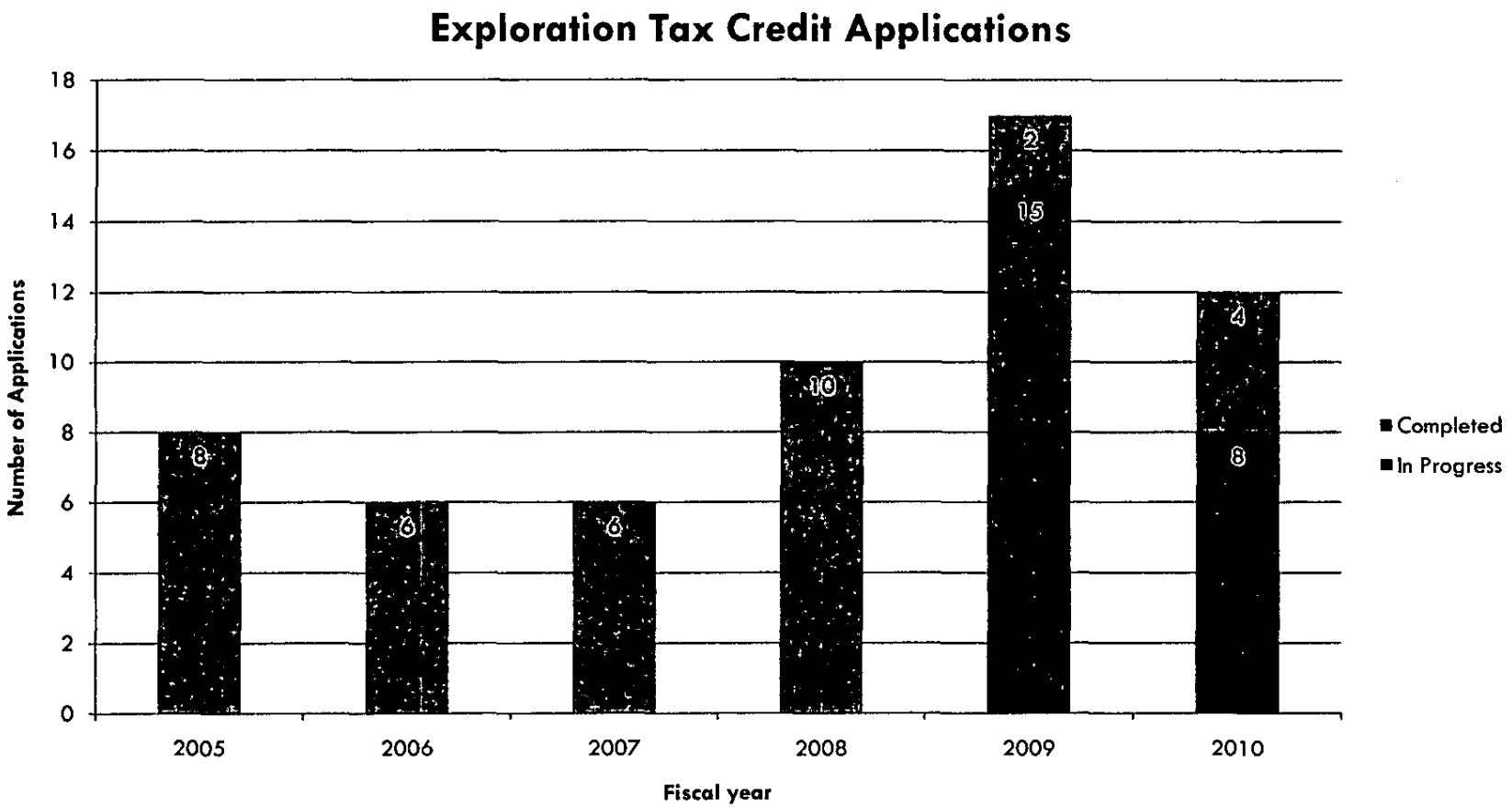


Exploration Tax Credit Certificates

- Number of Applications- 59
- Gross Expenditures claimed- $945.2 M
- Number Issued- 36 for $185.2 M
- Applications in progress- 23 representing Gross Expenditures of$439.9 M requesting $148.3 M in credits

# Transferable Tax Credit Certificates
# Exploration Tax Credits AS 43.55.025





# Overview



- Types of Tax Credits
- **Credits Applied Against Tax Liability**
- Transferable Tax Credit Certificates (TTCC)
- Cash Refunds History
- Tax Credit Analysis

# Cash Refunds History



## Cash Refunds Governed by AS 43.55.028:

- To cash must be usable against tax liability
- Must show subsequent (24 months) QCEs or lease bids equal to cash sought
- Have a zero tax owed in current and past years
- Have no more than 50,000 BOE/d

# Cash Refunds History



## Tax Credits Purchased

By fiscal year ($M)

| | |
|---|---|
| □ 2007 | 54.6 |
| □ 2008 | 54.1 |
| □ 2009 | 193.1 |
| □ 2010 (thru 2/12) | 98.4 |
| TOTAL | 400.2 |

# Cash Refunds History



## Oil & Gas Tax Credit Fund

| | |
|---|---|
| Appropriations - | $ 469 M |
| Tax Credit Purchases (TC Fund) | (321) M |
| Tax Credit Purchases (GF) | (79) M |
| Interest Earned | 21 M |
| Balance | $ 90 |

# Overview

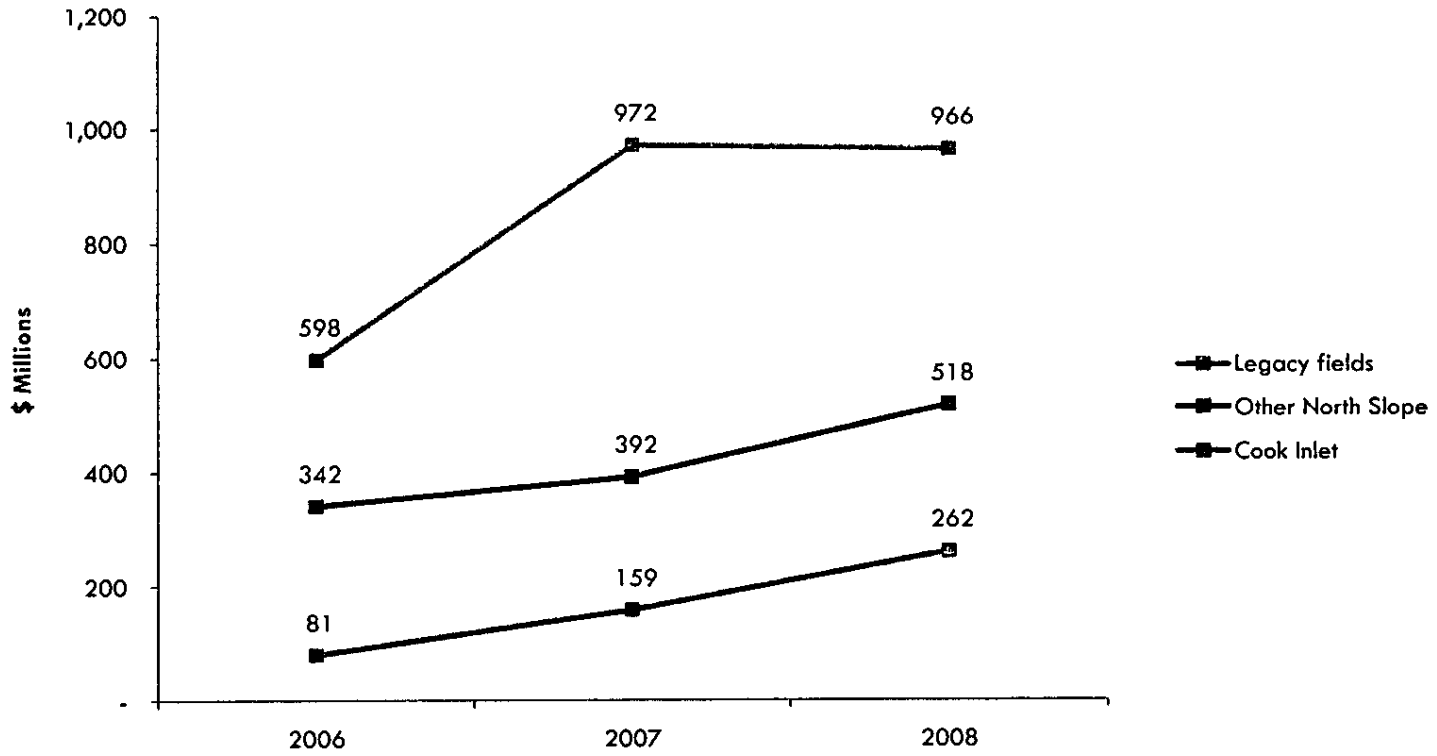


- Types of Tax Credits
- Credits Applied Against Tax Liability
- Transferable Tax Credit Certificates
- Cash Refunds History
- **Tax Credit Analysis**

# Tax Credit Analysis

## Qualified Capital Expenditure Deductions

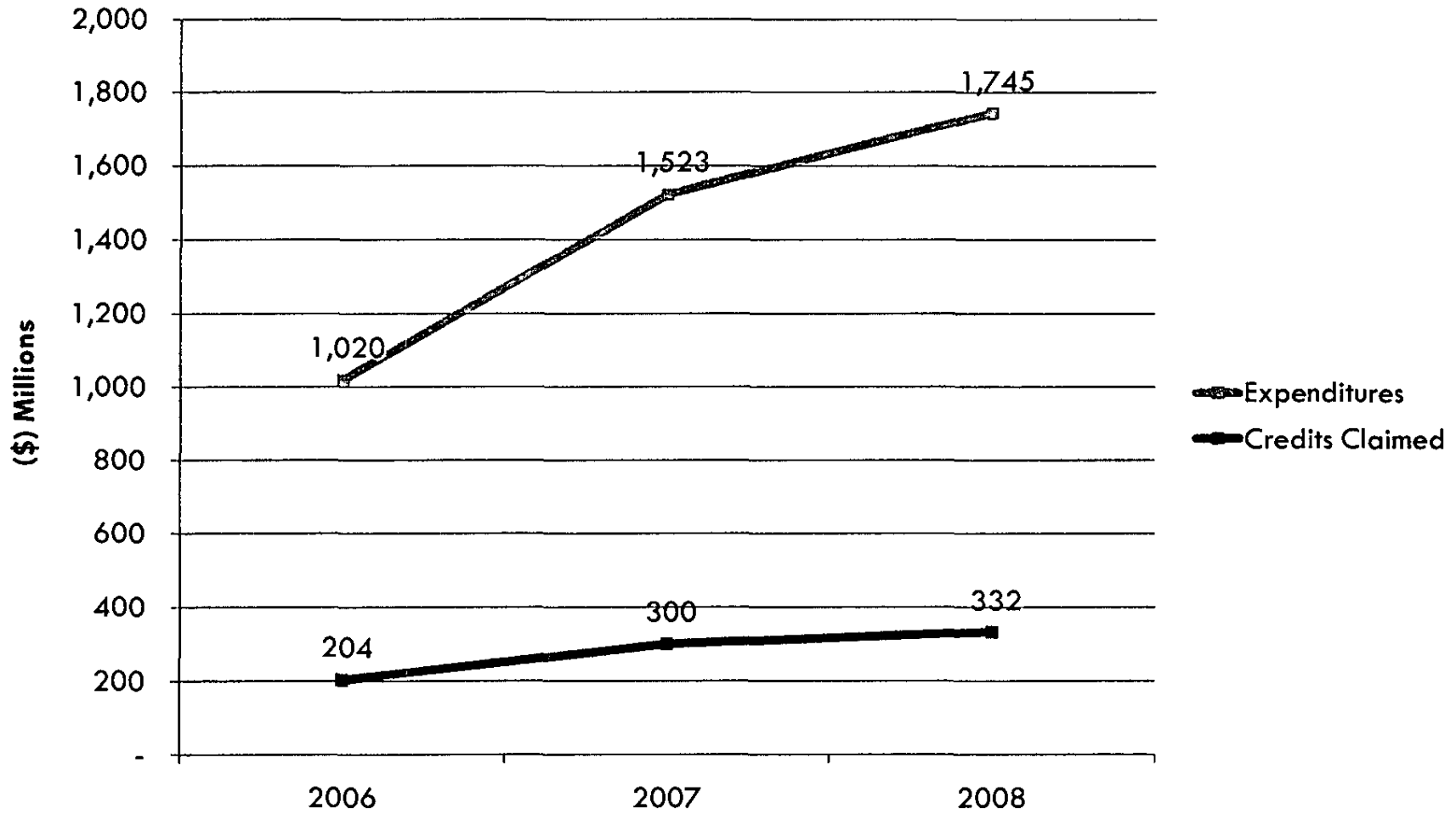




# Tax Credit Analysis

## Credits Claimed under .023 Against Tax Liability

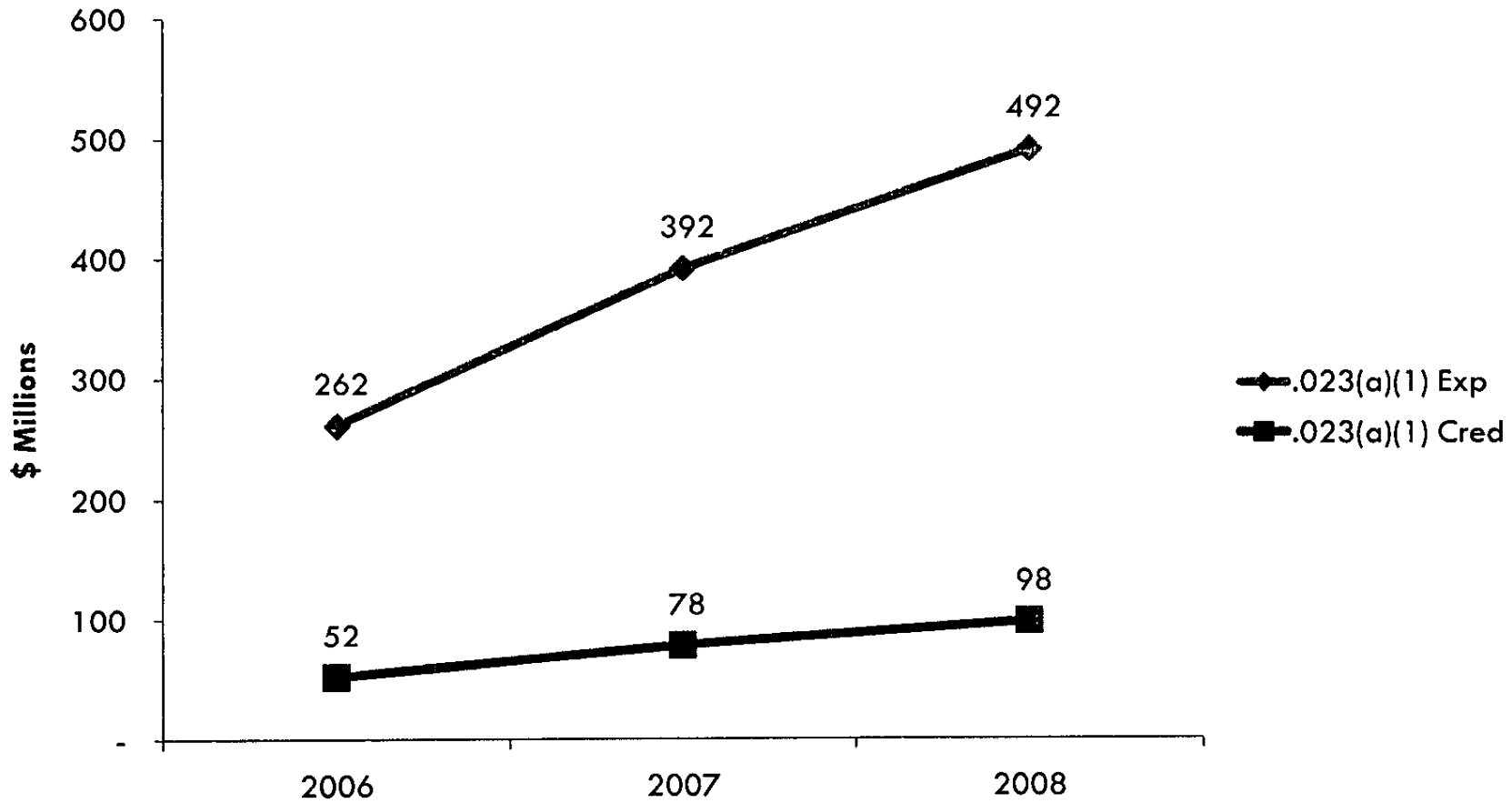




# Tax Credit Analysis

## Capital Credit Certificates under .023(a)(1)

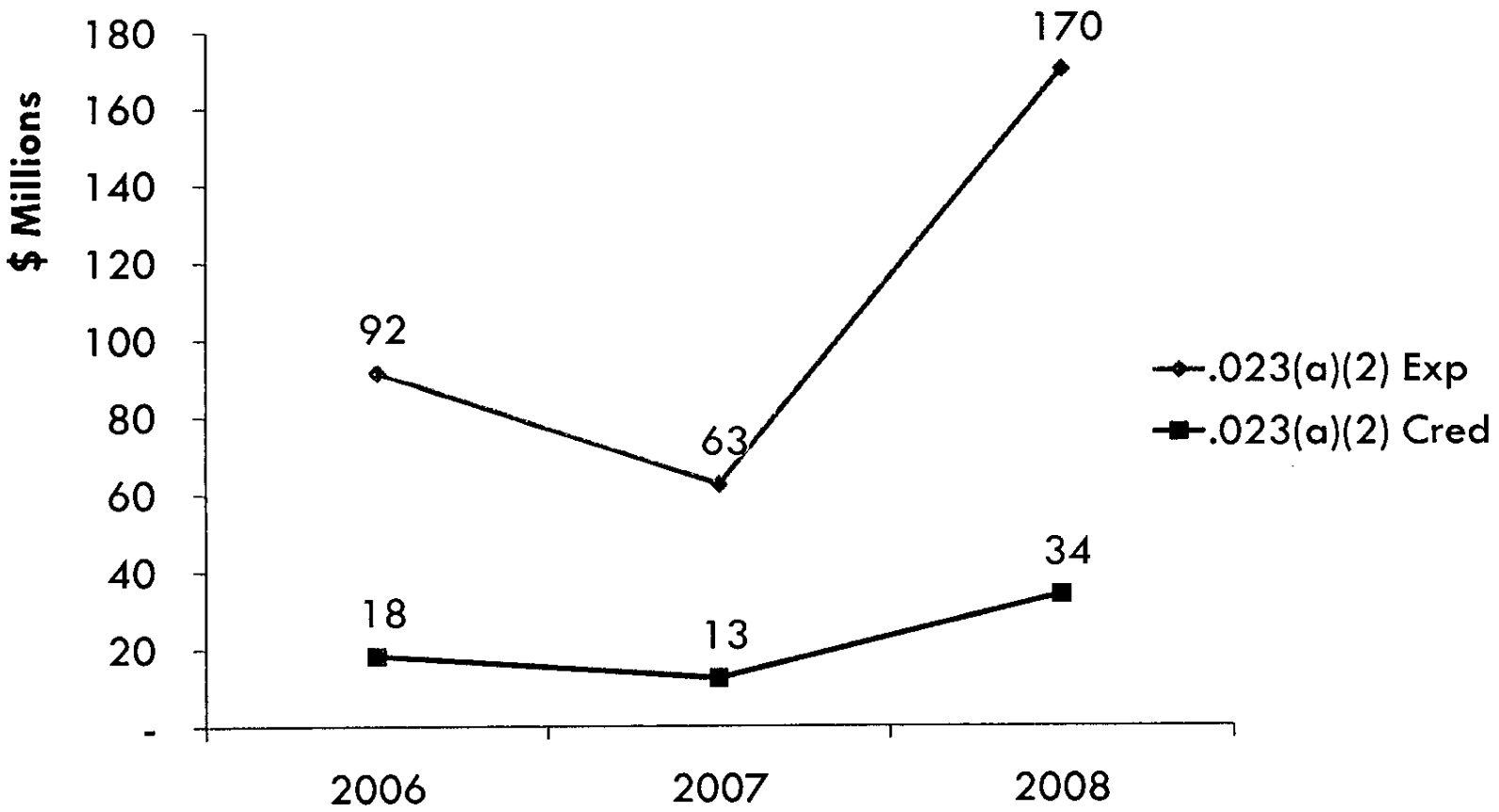




# Tax Credit Analysis

## Capital Credit Certificates Under .023(a)(2)

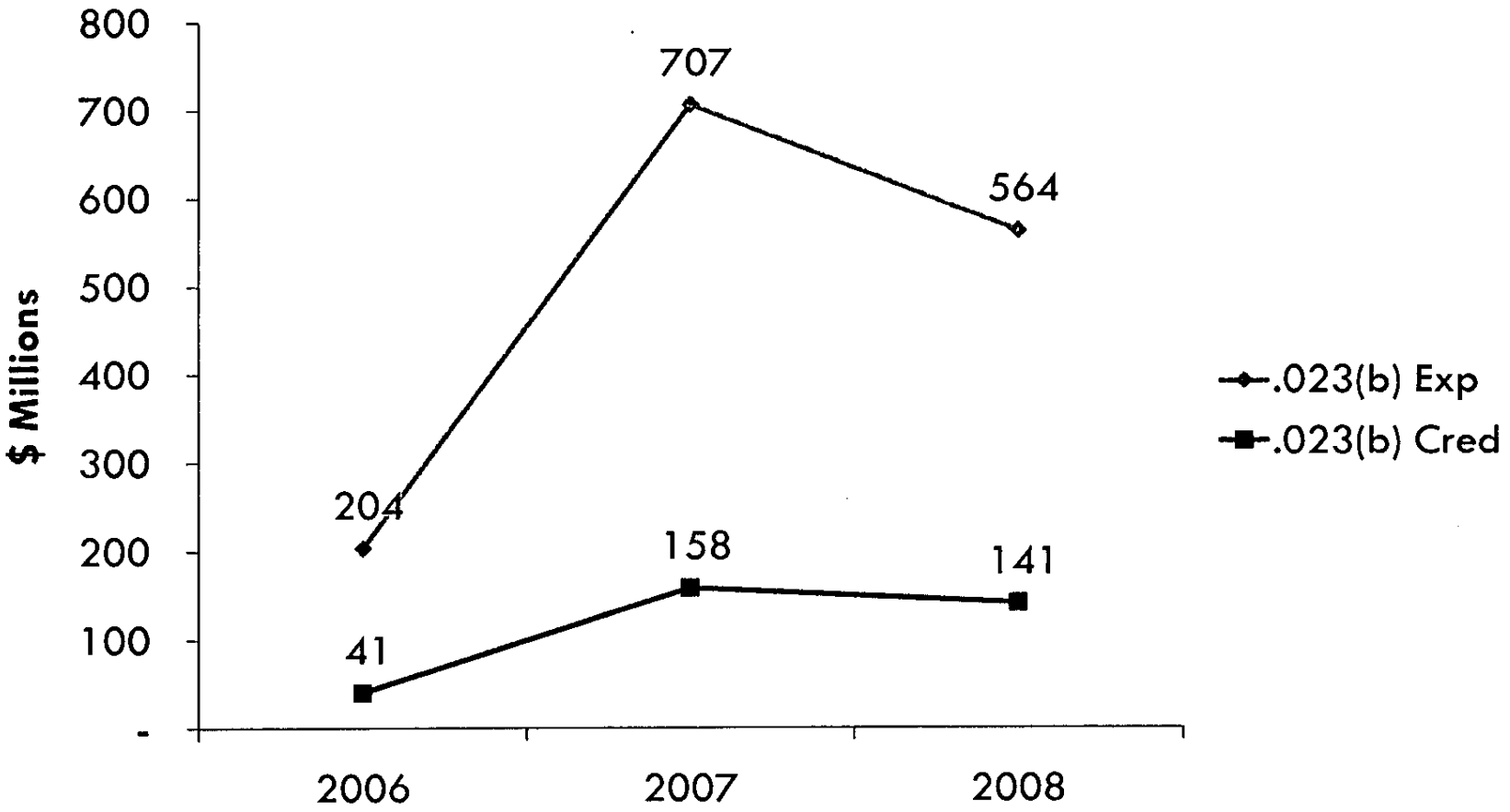
32



# Tax Credit Analysis

## Expenditures vs. NOL Credit Certificates

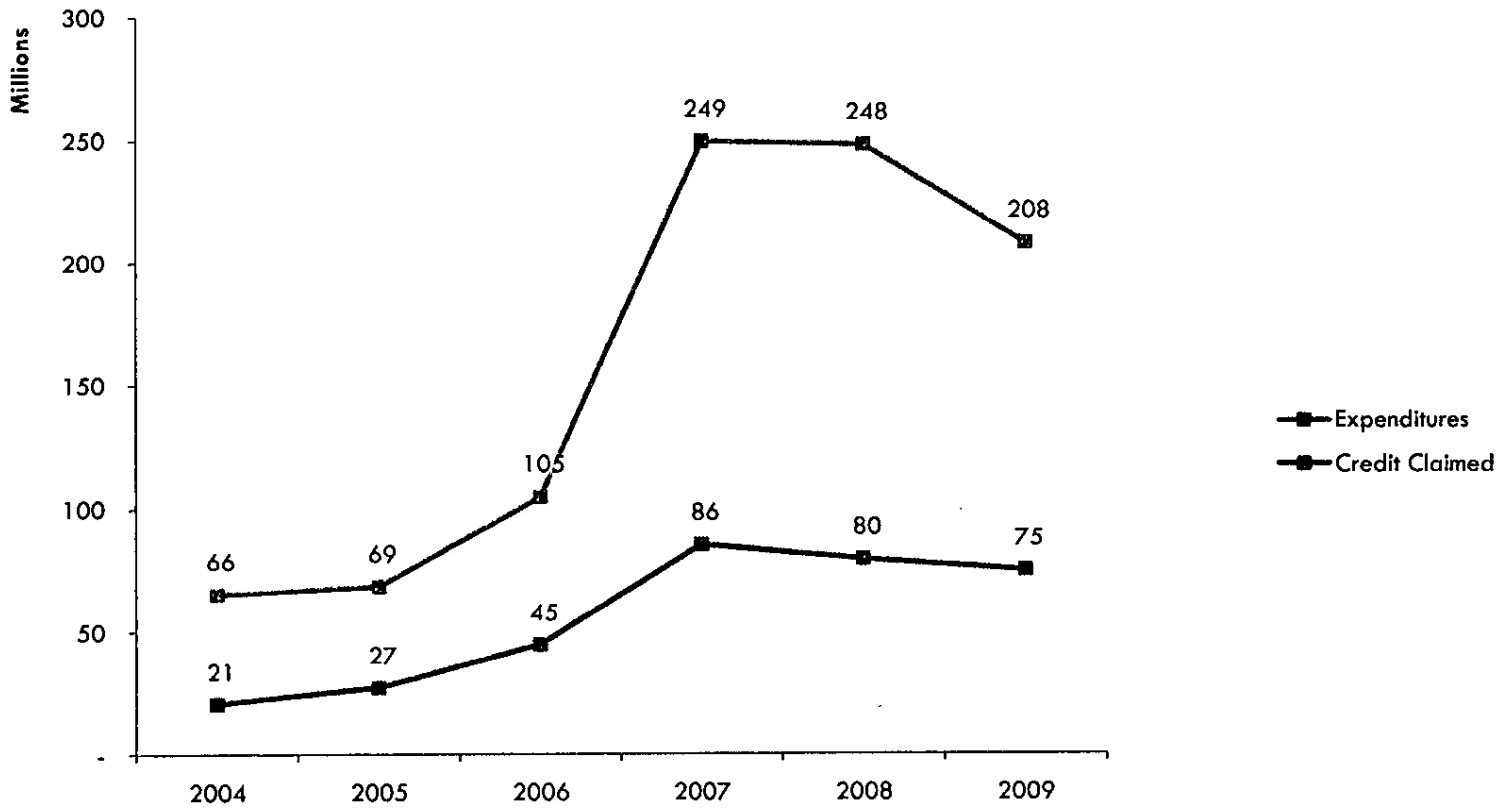




# Tax Credit Analysis

## Expenditures vs. .025 Exploration Credit Applications

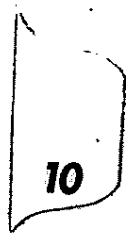




# Conclusions



- Legacy NS Fields- Increase in Producers' Capital expenditures from 2006-2008 but plateau in Capital deductions from 2007-2008
- Non-Legacy NS fields and Cook Inlet- Steady Increase in Capital expenditures
- Since 2007- Exploration Credit Applications have more than doubled
- Increased .023(a)(2) and NOL credits in 2007 and 2008 also suggest increased Exploration activity


10

# SUMMARY OF THE PRODUCTION TAX REVIEW (SO FAR...)

Senate Finance Committee

February 19, 2010

Alaska State Department of Revenue

# Production Tax Calculation – FY2009

| | Per Barrel | Barrels | Value |
|---|---|---|---|
| Avg ANS Oil Price ($/bbl) & Daily Production (bbls) | $68.34 | 692,127 | $47,299,959 |
| **Annual Production (bbl)** | | | |
| **Total Annual Production/Value** | **$68.34** | **252,626,355** | **$17,264,485,101** |
| Royalty and Federal barrels | | (34,187,360) | ($2,336,364,182) |
| **Taxable barrels** | | **218,438,995** | **$14,928,120,918** |
| **Downstream (Transportation) Costs ($/bbl)** | | | |
| ANS Marine Transportation | ($2.05) | | |
| TAPS Tariff | ($4.59) | | |
| Other | $0.16 | | |
| **Total Transportation Costs** | **($6.48)** | **218,438,995** | **($1,415,484,688)** |
| **Lease Expenditures** | | | |
| Deductible Operating Expenditures | ($9.39) | | ($2,050,000,000) |
| Deductible Capital Expenditures | ($8.01) | | ($1,750,000,000) |
| **Total Lease Expenditures** | **($17.40)** | **218,438,995** | **($3,800,000,000)** |
| **Production Tax Value (PTV)** | **$44.46** | **218,438,995** | **$9,712,636,231** |
| **Production Tax** | | | |
| Base Tax (25%*PTV) | | | $2,428,159,058 |
| Progressive Tax Rate = ($44.46-$30) * 0.4% = 5.8% | | | |
| Progressive Tax = (5.8% * PTV) | | | $561,928,014 |
| **Total Tax Due before credits** | | | **$2,990,087,072** |
| **Credits Applied Against Taxes** | | | ($350,000,000) |
| **Total Tax after credits** | | | **$2,640,087,072** |

Source: Department of Revenue from production tax monthly information forms, annual returns, and company forecasts

# Oil Price and Production Outlook

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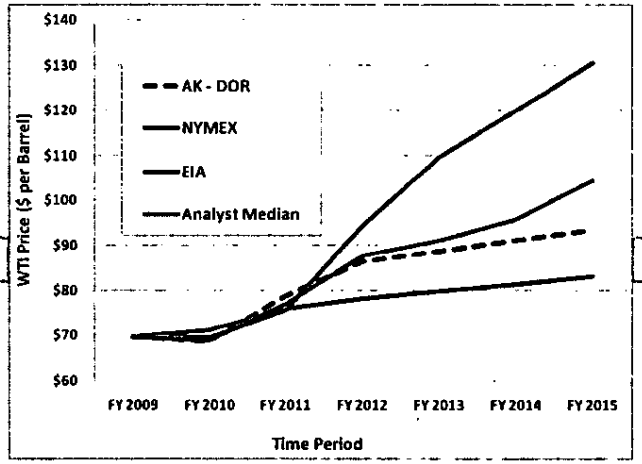


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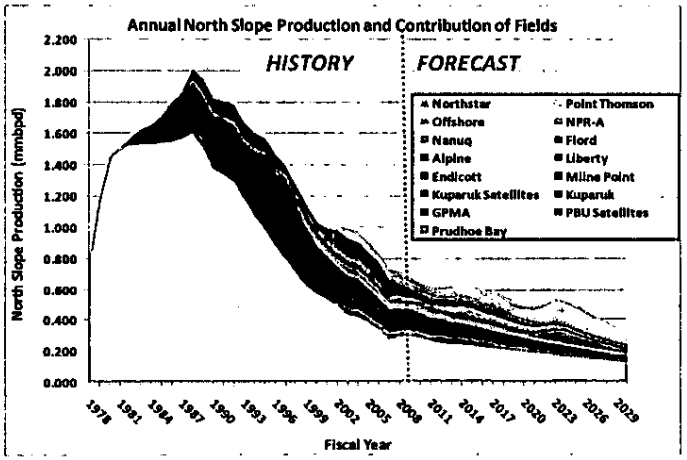


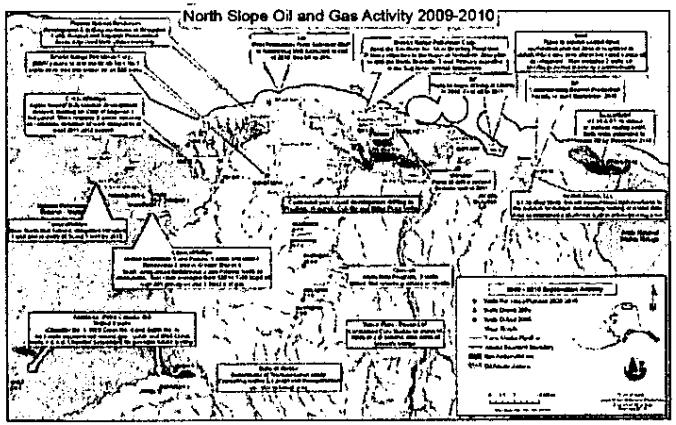


Alaska Department of Revenue

# Transportation Costs

| | Per Barrel | Barrels | Value |
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# Transportation Costs

6

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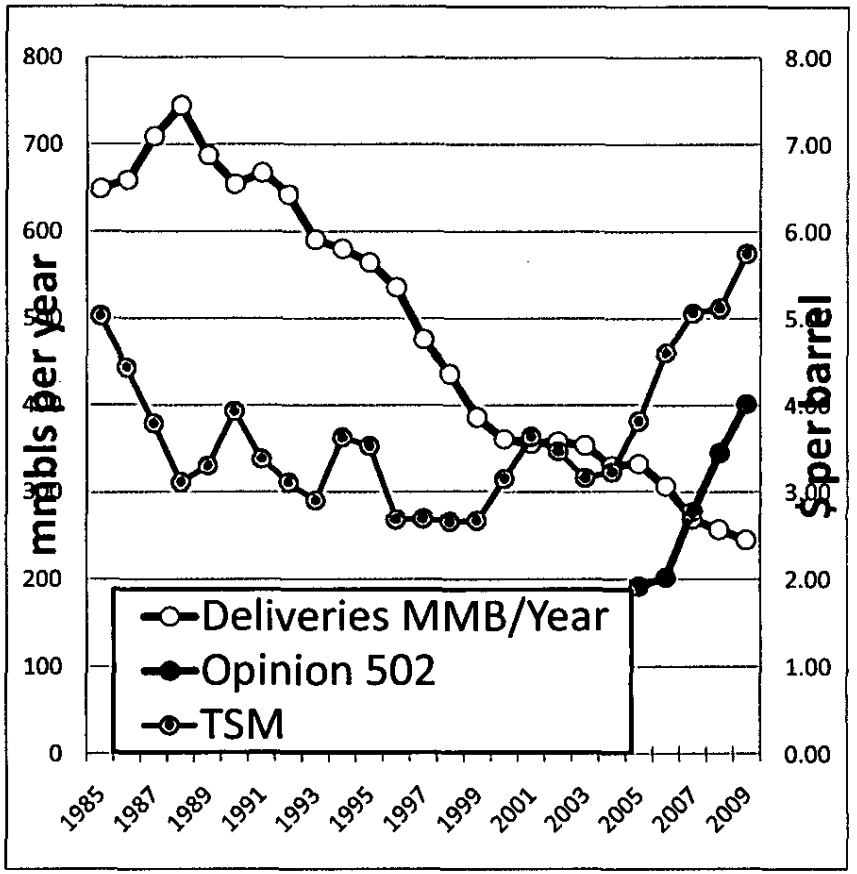


TAPS Throughput and Tariff

Alaska Department of Revenue

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8

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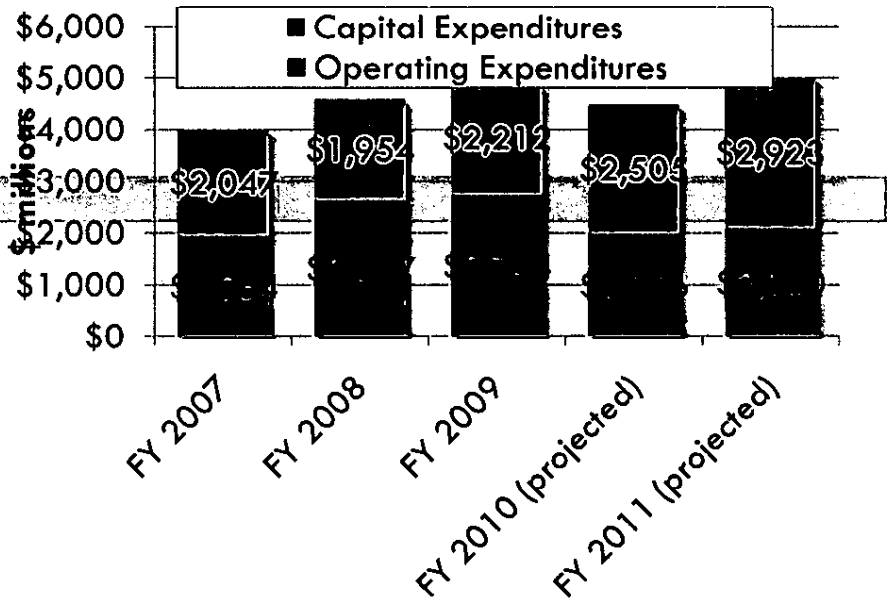
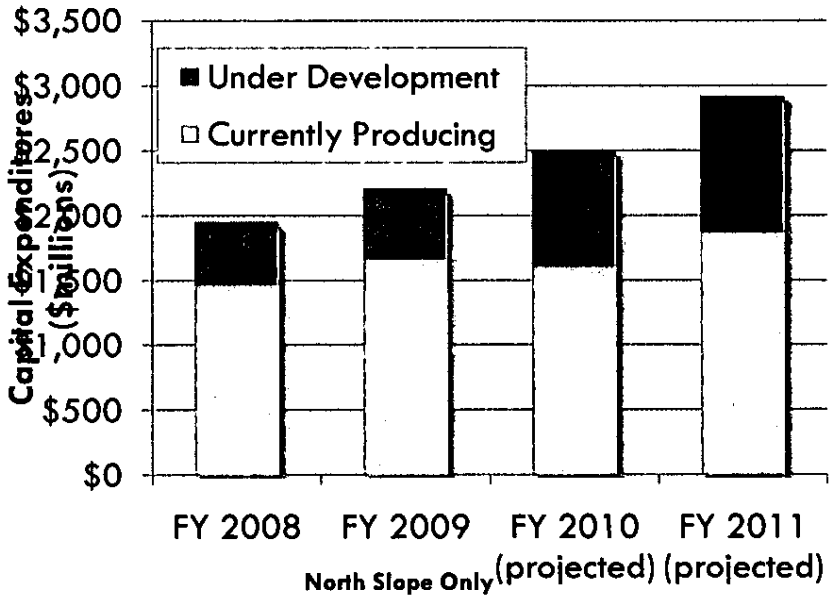



**NOTE: Operating expenditures includes total**




Alaska Department of Revenue

# Base Tax & Progressivity

| | Per Barrel | Barrels | Value |
|---|---|---|---|
| Avg ANS Oil Price ($/bbl) & Daily Production (bbls) | $68.34 | 692,127 | $47,299,959 |
| **Annual Production (bbl)** | | | |
| **Total Annual Production/Value** | **$68.34** | **252,626,355** | **$17,264,485,101** |
| Royalty and Federal barrels | | (34,187,360) | ($2,336,364,182) |
| **Taxable barrels** | | **218,438,995** | **$14,928,120,918** |
| **Downstream (Transportation) Costs ($/bbl)** | | | |
| ANS Marine Transportation | ($2.05) | | |
| TAPS Tariff | ($4.59) | | |
| Other | $0.16 | | |
| **Total Transportation Costs** | **($6.48)** | **218,438,995** | **($1,415,484,688)** |
| **Lease Expenditures** | | | |
| Deductible Operating Expenditures | ($9.39) | | ($2,050,000,000) |
| Deductible Capital Expenditures | ($8.01) | | ($1,750,000,000) |
| **Total Lease Expenditures** | **($17.40)** | **218,438,995** | **($3,800,000,000)** |
| **Production Tax Value (PTV)** | **$44.46** | **218,438,995** | **$9,712,636,231** |
| **Production Tax** | | | |
| Base Tax (25%*PTV) | | | $2,428,159,058 |
| Progressive Tax Rate = ($44.46-$30) * 0.4% = 5.8% | | | |
| Progressive Tax = (5.8% * PTV) | | | $561,928,014 |
| **Total Tax Due before credits** | | | **$2,990,087,072** |
| **Credits Applied Against Taxes** | | | ($350,000,000) |
| **Total Tax after credits** | | | **$2,640,087,072** |

Source: Department of Revenue from production tax monthly information forms, annual returns, and company forecasts

# Tax Credits

| | Per Barrel | Barrels | Value |
|---|---|---|---|
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# Tax Credits

11

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|---|---|---|---|
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Source: Department of Revenue from production tax monthly information forms, annual returns, and company forecasts

- Capital Expenditure Credits
- Exploration Credits
- Net Operating Loss ("NOL") Carry Forward Credits
- Transitional Investment Expenditure ("TIE") Credit
- Small Producer Credits

# Updated Credits Applied Against Tax Liability



**Tax Credits Applied by Producers Against Tax Liability, by Tax Year**
**($million)**

| Credit Type | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | Total |
|---|---|---|---|---|---|---|---|
| Capital Expenditure Credit | 195 | 194 | 243 | 247 | 339 | 384 | 1,603 |
| TIE Credits | 98 | 145 | 0 | | | | 243 |
| Small Producer Credits | 27 | 38 | 21 | | | | 86 |
| Exploration Incentive Credits | 2 | 92 | 17 | | | | 112 |
| **Total** | 322 | 469 | 282 | 247 | 339 | 384 | 2,043 |

# How Credits Are Used

13

- Two Examples
  - New Entrant
    - $200 million exploration project
    - No Current Production
  - Incumbent Producer
    - $200 million new development project

# Credit Example 1: New Entrant



- A new entrant with no current production pursues an exploration project requiring $200 million in investment
- Company receives a 20% - 40% investment credit (depending on location), worth $40 - $80 million
- Company also receives an additional 25% credit for its "tax loss" or "net operating loss (NOL)", worth up to $50 million

# Credit Example 1: New Entrant (*cont.*)

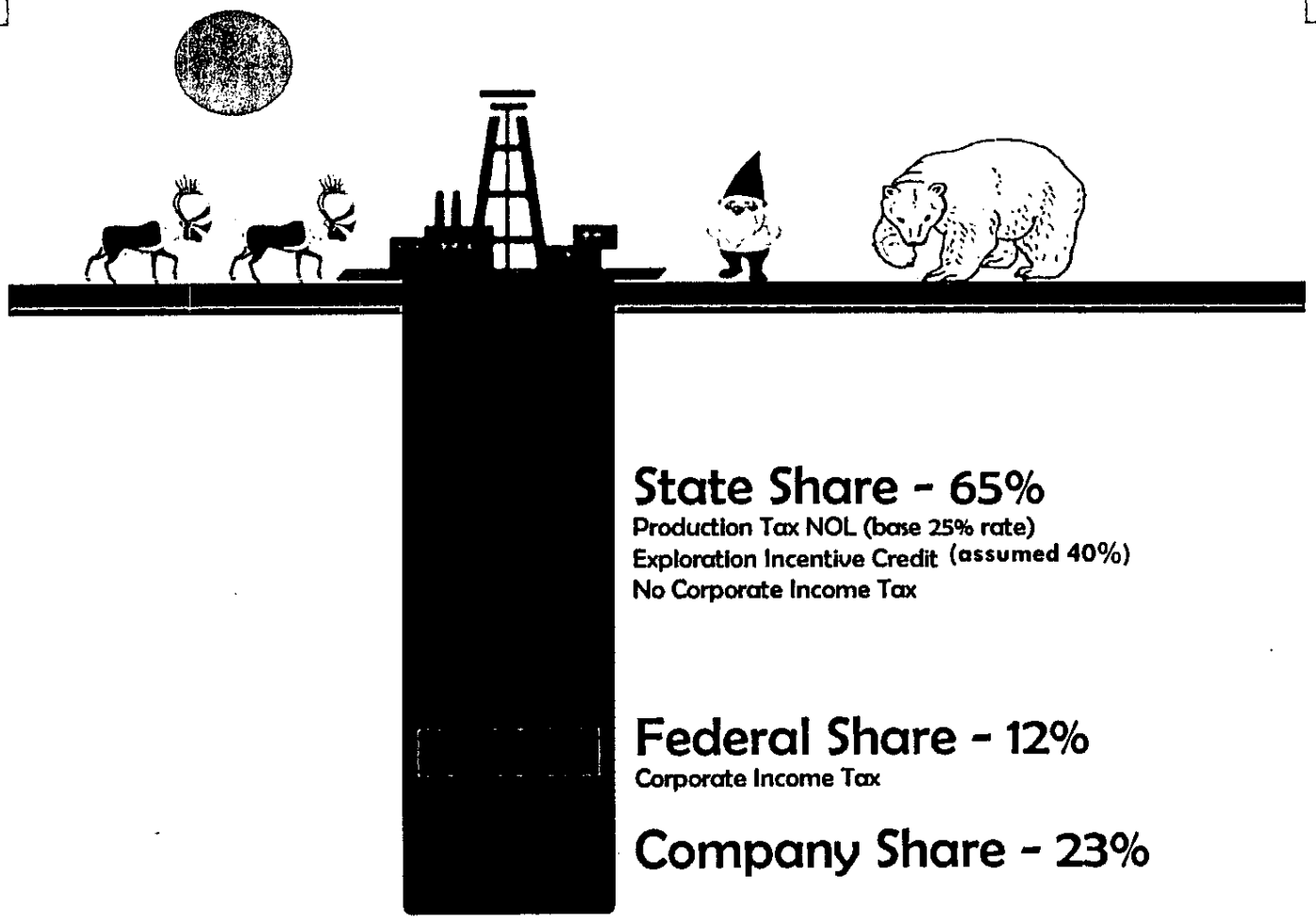


- The total credits of $90 - $130 million, can be:
  - Directly recouped (cash) from the state
  - Transferred to a person that does pays tax, so that the Transferee pays $90 - $130 million less in tax
- Either way, State pays $90 - $130 million for the exploration; company pays $70 - $110 million.
- If the exploration effort fails, the state never recoups this money.

  ***The state bears the risk for failure as does the new entrant***

# Exploration Dry Hole – New Entrant

16



## State Share - 65%

Production Tax NOL (base 25% rate)
Exploration Incentive Credit (assumed 40%)
No Corporate Income Tax

## Federal Share - 12%

Corporate Income Tax

## Company Share - 23%

*This graphic assumes a producer has federal corporate income tax liability to offset but no state corporate income tax; and does not have other production tax liability to offset.

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# Credit Example 2: Incumbent Producer



- Incumbent with current production pursues a development requiring $200 million investment
- Company receives a 20% capital investment credit, worth $40 million
- By reducing their Production Tax Value (PTV), the company reduces their taxes due by the total capital expense multiplied by the tax rate:
  - $200 million * 25%, worth $50 million; plus
  - $200 million * progressivity surcharge rate (which is reduced due to the drop in PTV)

# Credit Example 2: Incumbent Producer (*cont.*)

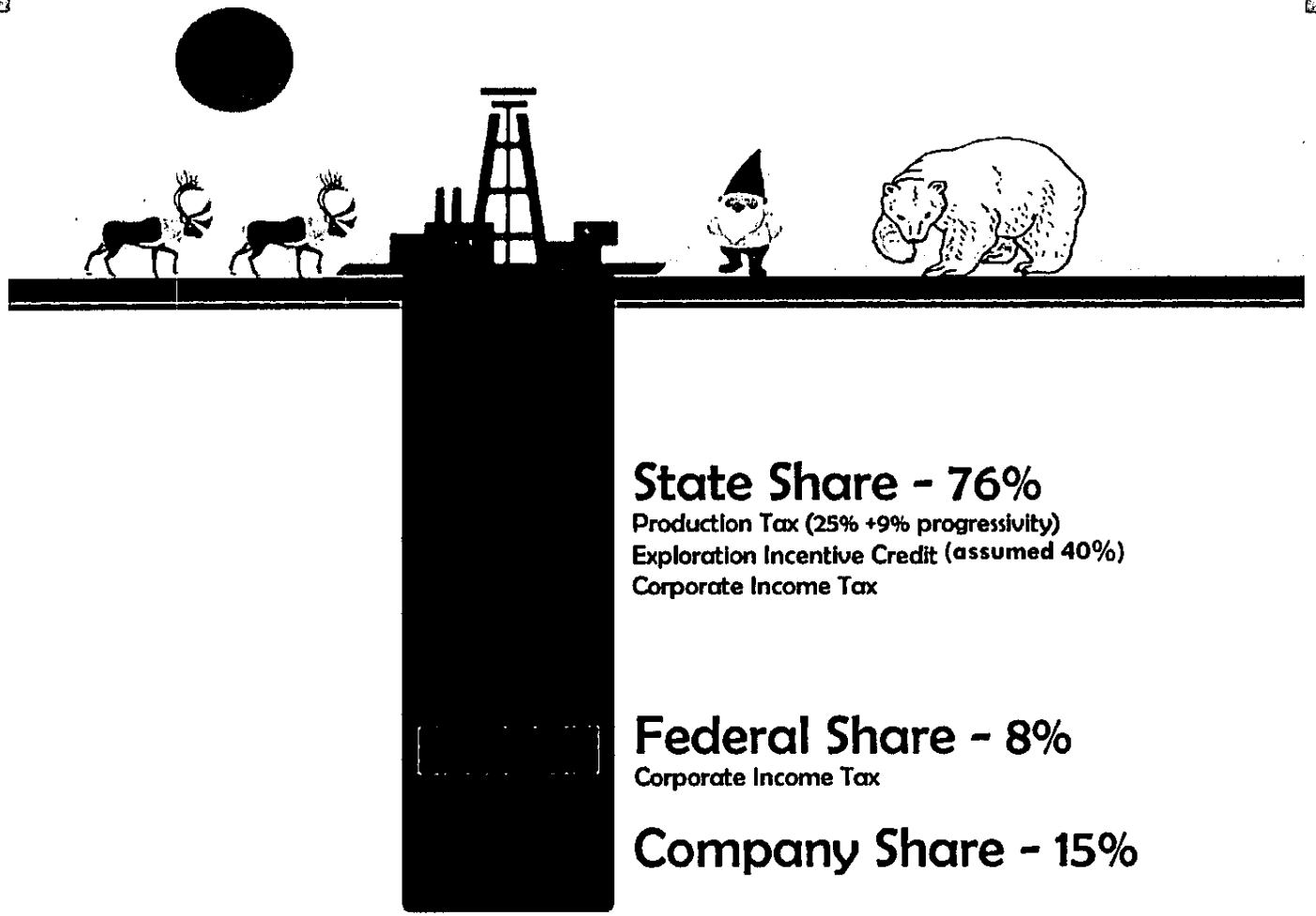


- Deductions and credits total more than 45% of the $200 million, greater than $90 million
- State pays more than $90 million of the new development's capital cost; true investment cost for the incumbent is less than $110 million
- If the development fails, the state never recoups this money

***The state bears the risk for failure as does the incumbent investor***

# Unsuccessful Development Project – Existing Producer





**State Share - 76%**
Production Tax (25% +9% progressivity)
Exploration Incentive Credit (assumed 40%)
Corporate Income Tax

**Federal Share - 8%**
Corporate Income Tax

**Company Share - 15%**

*This graphic assumes a producer has state and federal corporate income tax liability to offset; and has production tax liability to offset with $70 wellhead value and $18 / barrel costs.

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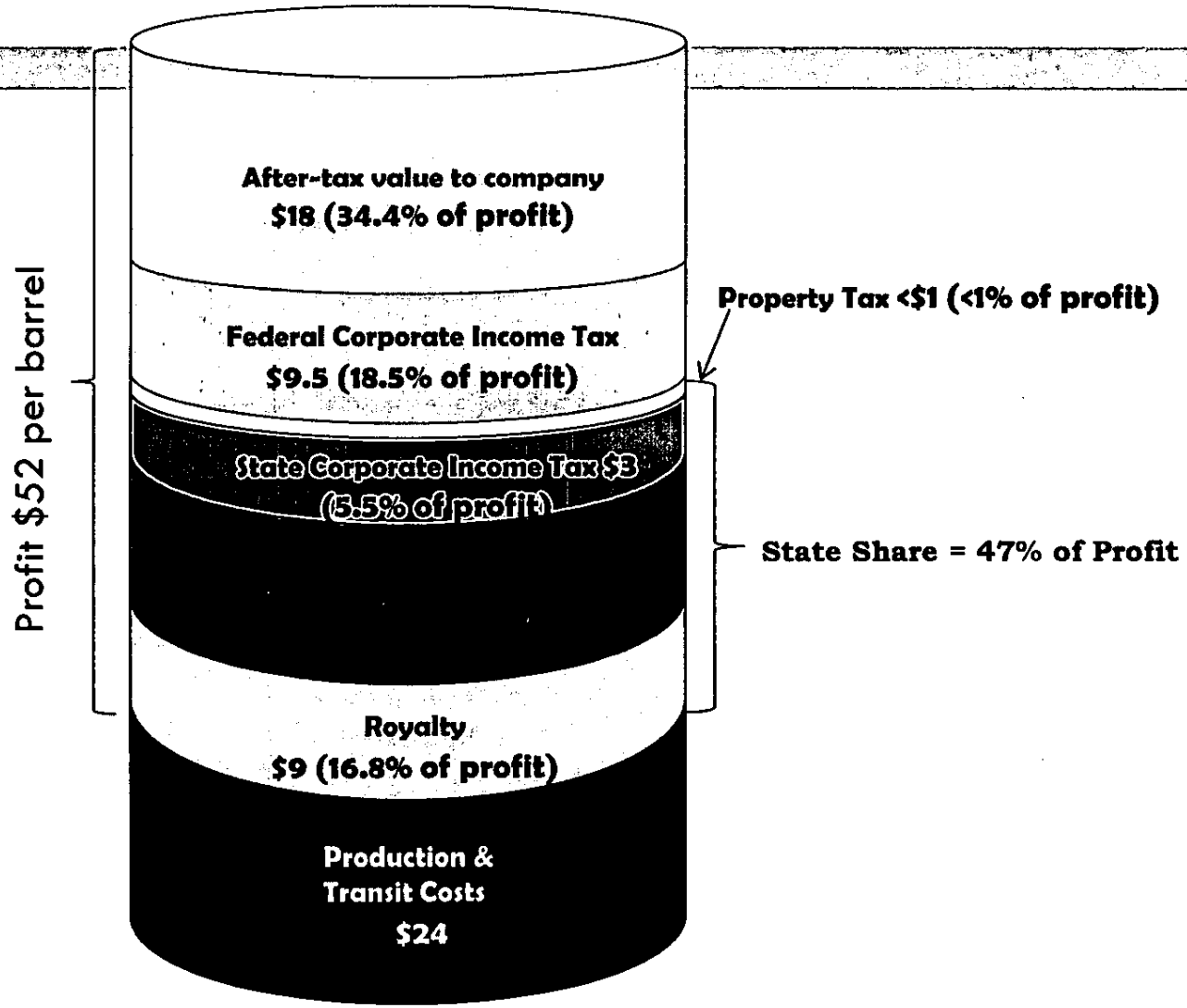
# Overall Sharing of Oil Revenue and Profit

# Allocation of Revenue and Profit on $76 Barrel of Alaska North Slope Oil*






*This graphic assumes average transportation and production costs and royalty and tax rates, and is not intended to represent the allocation of every barrel produced on the North Slope.

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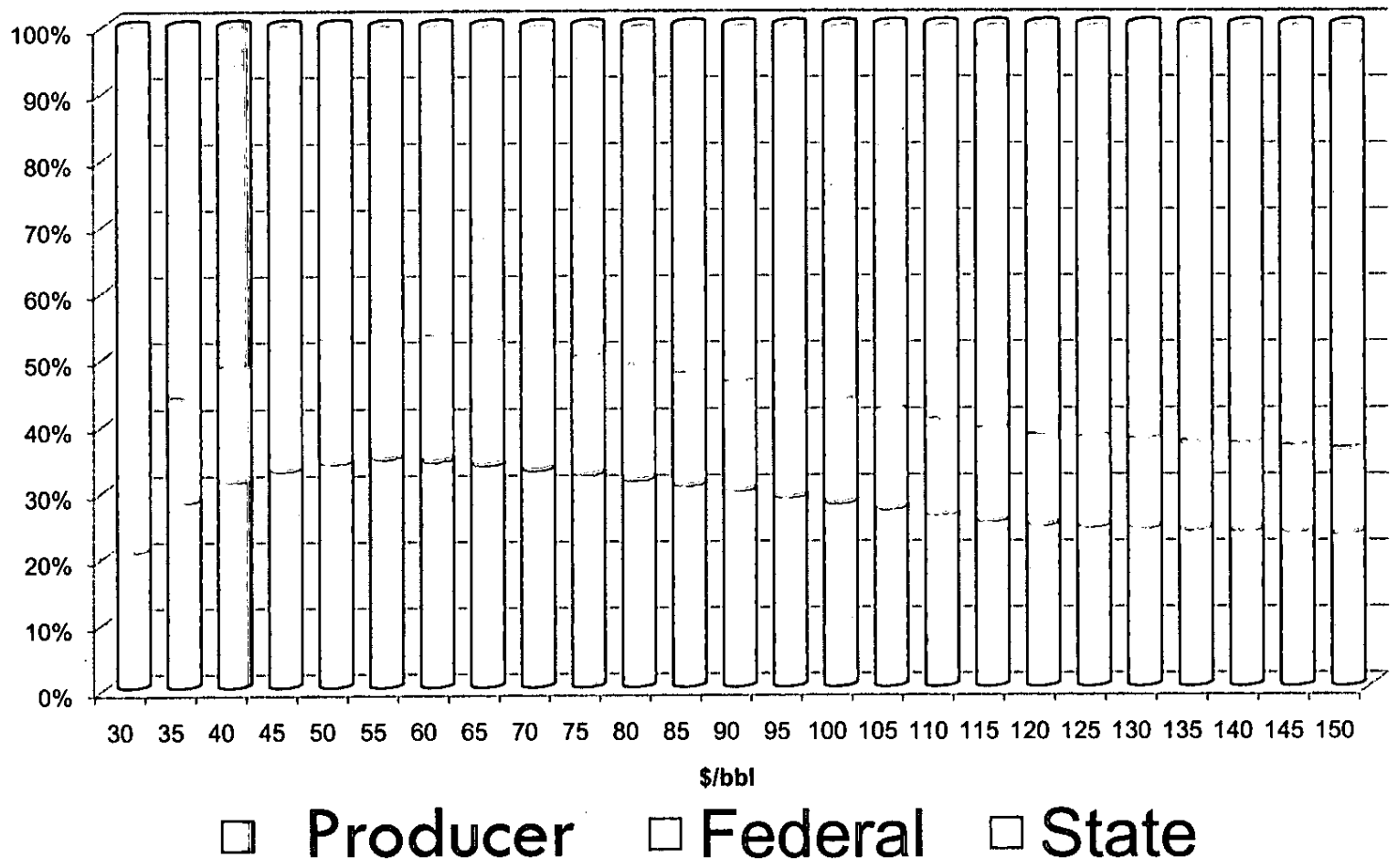
# Shares of North Slope Oil Profit at Different Prices

22

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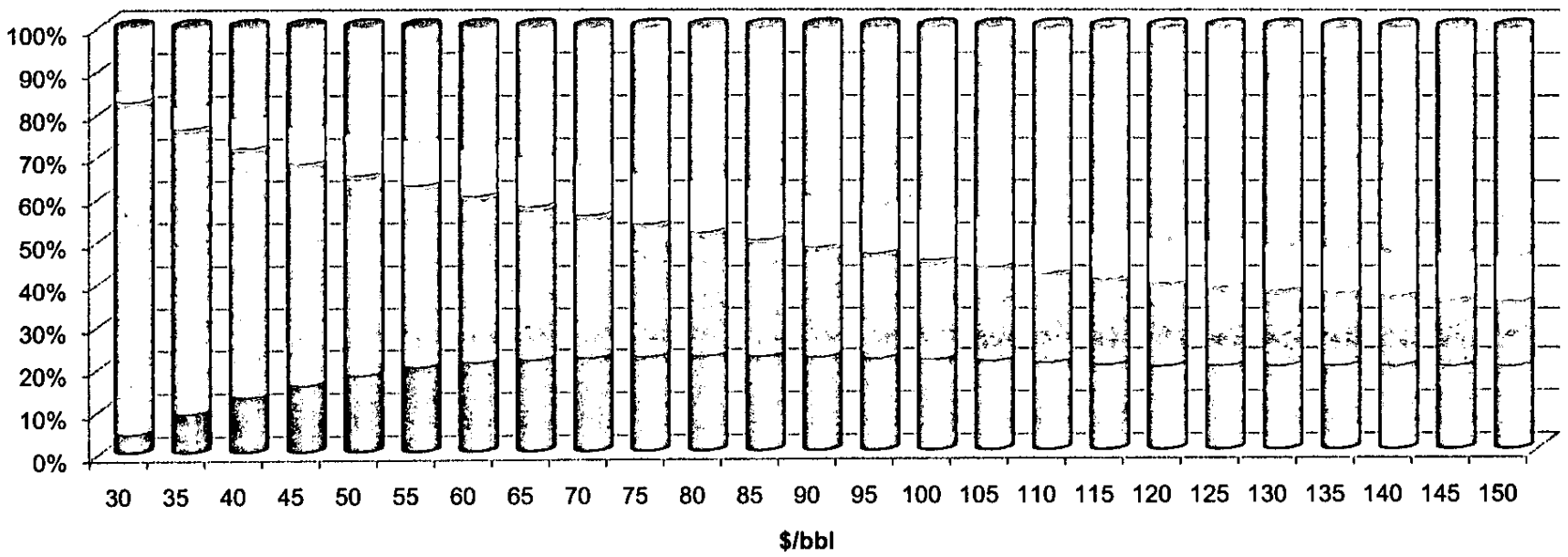
# Split of Total Oil Revenue



- Reviewing only "Take" does not reveal the fact that the Producer recovers all costs before taxes are assessed.
- Whereas State share of profit is high at low prices, the Producer retains the majority of the revenue.

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# How Does Production Tax Calculation Differ For Different Fields?

# Estimated FY 2010 Tax- Prudhoe Bay and Kuparuk

25

## FY 2010 Production Tax *Rounded Estimates* for Combined Prudhoe Bay Unit and Kuparuk River Unit

| | Price | Barrels | Value |
|---|---|---|---|
| **Avg ANS Oil Price ($/bbl) & Daily Production (bbls)** | $66.93 | 488,000 | $32,661,840 |
| **Annual Production (bbl)** | | | |
| Total | | 178,120,000 | $11,921,571,600 |
| Royalty and Federal barrels | | -22,265,000 | ($1,490,196,450) |
| Taxable barrels | | 155,855,000 | $10,431,375,150 |
| | | | |
| **Downstream (Transportation) Costs ($/bbl)** | | | |
| ANS Marine Transportation | -$2.00 | | |
| TAPS Tariff | -$4.00 | | |
| Other | $0.40 | | |
| Total Transportation Costs | -$5.60 | 155,855,000 | ($872,800,000) |

# Estimated FY 2010 Tax- Prudhoe Bay and Kuparuk

26

| | | | |
|---|---|---|---|
| **Lease Expenditures** | | | |
| Deductible Operating Expenditures | -$9.62 | | ($1,500,000,000) |
| Deductible Capital Expenditures | -$6.10 | | ($950,000,000) |
| Total Lease Expenditures | -$15.72 | 155,855,000 | ($2,450,000,000) |
| **Production Tax** | | | |
| Production Tax Value (PTV) | | | $7,110,000,000 |
| Base Tax (25%*PTV) | | | $1,780,000,000 |
| Production Tax Value per barrel | $45.61 | | |
| Progressive Tax = (6.2% * PTV) | | | $444,000,000 |
| Total Tax before credits | | | $2,224,000,000 |
| **Credits (20% of Deductible Capital Exp.)** | | | ($190,000,000) |
| **Estimated Total Tax after credits** | | | **$2,034,000,000** |

# Estimated FY 2010 Tax for Producing North Slope Units excluding Prudhoe Bay and Kuparuk

27

**FY 2010 Production Tax *Rounded Estimates* for Producing Units excluding Prudhoe Bay and Kuparuk**

| | Price | Barrels | Value |
|---|---|---|---|
| **Avg ANS Oil Price ($/bbl) & Daily Production (bbls)** | $66.93 | 165,000 | $11,043,450 |
| **Annual Production (bbl)** | | | |
| Total | | 60,225,000 | $4,030,859,250 |
| Royalty and Federal barrels | | -7,528,125 | ($503,857,406) |
| Taxable barrels | | 52,696,875 | $3,527,001,844 |
| **Downstream (Transportation) Costs ($/bbl)** | | | |
| ANS Marine Transportation | -$2.00 | | |
| TAPS Tariff | -$4.00 | | |
| Other | $0.40 | | |
| Total Transportation Costs | -$5.60 | 52,696,875 | ($295,102,500) |

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# Estimated FY 2010 Tax for Producing North Slope Units excluding Prudhoe Bay and Kuparuk



| | | | |
|---|---|---|---|
| **Lease Expenditures** | | | |
| Deductible Operating Expenditures | -$9.49 | | ($500,000,000) |
| Deductible Capital Expenditures | -$10.63 | | ($560,000,000) |
| Total Lease Expenditures | -$20.12 | 52,696,875 | ($1,060,000,000) |
| **Production Tax** | | | |
| Production Tax Value (PTV) | | | $2,170,000,000 |
| Base Tax (25%*PTV) | | | $543,000,000 |
| Production Tax Value per barrel | $41.21 | | |
| Progressive Tax = (4.4% * PTV) | | | $97,500,000 |
| Total Tax before credits | | | $640,500,000 |
| **Credits (20% of Deductible Capital Exp.)** | | | ($112,000,000) |
| **Estimated Total Tax after credits** | | | **$528,500,000** |

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# Estimated FY 2010 Tax for Developing Units*

29

**FY 2010 Production Tax *Rounded Estimates* for Developing Units***

| | Price | Barrels | Value |
|---|---|---|---|
| **Avg ANS Oil Price ($/bbl) & Daily Production (bbls/day)** | $66.93 | 0 | $0 |
| **Annual Production (bbl)** | | | |
| Total | | 0 | $0 |
| Royalty and Federal barrels | | 0 | $0 |
| Taxable barrels | | 0 | $0 |
| **Downstream (Transportation) Costs ($/bbl)** | | | |
| ANS Marine Transportation | | | |
| TAPS Tariff | | | |
| Other | | | |
| Total Transportation Costs | | 0 | $0 |

* Developing units include Pt. Thomson, Nikaitchuq and NPR-A

Alaska Department of Revenue

# Estimated FY 2010 Tax for Developing Units*



| | | | |
|---|---|---|---|
| **Lease Expenditures** | | | |
| Deductible Operating Expenditures | | | ($25,000,000) |
| Deductible Capital Expenditures | | | ($950,000,000) |
| Total Lease Expenditures | | 0 | ($975,000,000) |
| | | | |
| **Production Tax** | | | |
| Production Tax Value (PTV) | | | ($975,000,000) |
| Base Tax (25%*PTV) | | | ($243,750,000) |
| Production Tax Value per barrel | | | $0 |
| Progressive Tax = (0% * PTV) | | | $0 |
| Total Tax before credits | | | ($243,750,000) |
| | | | |
| **Credits (20% of Deductible Capital Exp.)** | | | ($190,000,000) |
| **Estimated Total Potential Credits** | | | **($433,750,000)** |

* Developing units include Pt. Thomson, Nikaitchuq and NPR-A

# Summary of Tax Calculation for Different Fields



| ($ in millions) | Prudhoe Bay and Kuparuk | Other NS Producing Units | Developing NS Units* |
|---|---|---|---|
| **Production (bbl/day)** | 488,000 | 165,000 | 0 |
| **Capital Expenditures** | $950<br>$6.10/bbl | $560<br>$10.63/bbl | $950 |
| **Operating Expenditures** | $1,500<br>$9.62/bbl | $500<br>$9.49/bbl | $25 |
| **Credits (20% of Capex)** | $190 | $112 | $190 |
| **Credits for Losses(NOL)** | $0 | $0 | $244 |
| **Estimated Tax** | $2,034 | $528 | ($434) |

* Developing units include Pt. Thomson, Nikaitchuq and NPRA

# At the Close of the Week



- Covered Information on Production Tax Components, their Function, and Relationship
- Provided a Broad Understanding of How Oil Production Tax is Calculated
- Upcoming Topics
  - How Alaska's Fiscal System stacks up to Global Comparables
  - How the Production Tax performs in an **Oil <u>and Gas</u>** production basin

# The End


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# TAX PAYMENT PENALTIES

Senate Finance Committee

February 19, 2010

Alaska State Department of Revenue

# Presentation Overview



- Tax penalty provisions with general application
- Compromise and settlement
- Provisions that apply to production tax

# Overview-Tax Penalties and Interest



Alaska Statutes 43.05

- General application to Title 43 except as provided in specific tax chapters
- Covers returns, agreements on liability, compromise of tax or penalty, assessment, interest on underpayments and refunds
- Production tax has some specific provisions on interest and penalties, discussed below
- Disputes over tax assessments, including penalties, are first heard through informal conference at DOR
- Appeal is to Office of Administrative Hearings – confidential until final administrative decision AS 43.05.470 (may be subject to protective order)

# Penalties



## AS 43.05.220: civil penalties

- Failure to file or pay: 5% for each 30 days up to 25%

  -Penalties won't be imposed if taxpayer shows that failure to file or pay is due to reasonable cause and not wilful neglect.

  -Regulations apply administrative and judicial interpretations of IRC 6651 15 AAC 05.200 (reasonable cause for delay)

- Negligence or intentional disregard: 5% of deficiency

  -Includes substantial deviation from statutes in reporting income or claiming deductions, exaggerated deductions, failure to keep adequate records, or failure to justify understatement of income. 15 AAC 05.220

- Fraud: greater of 50% of deficiency or $500

  -Requires clear and convincing evidence that tax liability was understated as attempt to evade tax. 15 AAC 05.230

- Penalties are cumulative

# Penalties - Criminal



- AS 43.05.290: criminal penalties
- Wilful attempted tax evasion, failure to collect, or truthfully account for and pay tax: class C felony
- Wilful failure to pay, make return, keep records: class A misdemeanor
- Wilfully making and subscribing, or assisting in making, a false return (perjury): felonies, up to $25k and 3 years imprisonment
- Wilfully delivery or disclosure of a false return: class A misdemeanor
- Wilful failure to obtain a required license: misdemeanor, up to $2000 fine, 6 months imprisonment

# Compromise and Settlement



- AS 43.05.070 – If in opinion of DOR there is doubt over liability or collectibility of tax or penalty, DOR, with approval of Attorney General, may compromise tax or penalty

- Agreements are final absent fraud, malfeasance or misrepresentation of material fact

- Confidential under AS 43.05.230

# Production tax penalties: failure to provide information



- AS 43.55.030-Filing of statements
  - Annual report due March 31 whether or not tax payment due
  - Statement: description of lease or property, producer name, gross amount of oil or gas production, gross value at point of production, purchaser and price information, qualified capital expenditures, lease expenditures and payments or credits from facility sharing
  - Department adopted standards in regulation for delinquent reports
  - Penalty maximum $1,000 a day
  - Regulation 15 AAC 55.840 covers notice and penalty amount
- In addition to other penalties

# 15 AAC 55.840 (b)-Penalties AS 43.55.030

- (b) If, 30 days after a report required to be filed under AS 43.55.030 is due, the department has not notified the person required to file the report ... the department will not assess ... a penalty .... that begins earlier than a date specified in a written notice to the person, except in case of the person's fraud or willful concealment. ...[T]he department will specify a date that is at least 10 days after the date of the department's delivery of the notice .... Nothing in this subsection affects the person's obligation to file a complete and accurate report.

# Production tax penalties: failure to provide information



## AS 43.55.040:

- DOR may require person engaged in production, purchaser or royalty owner to provide information necessary to compute the tax
- If person fails to provide information, DOR may assess a penalty, under standards determined by DOR of not more than $1,000 a day for each day the person fails to file *after notice by the department.* 15 AAC 55.840
- In addition to any penalties under AS 43.05.220 or 43.05.290

# 15 AAC 55.840(c) –Penalties 43.55.040

- (c) If a person fails to file a report, statement, or other document required to be filed under AS 43.55.040, the department will provide written notice of the failure to the person and will specify in the notice a date beginning on which the person will be liable for a penalty under AS 43.55.040(7) if the person does not remedy the failure before that date.... If, 30 days after the date specified, the department has not assessed a penalty or otherwise notified the person in writing that the person has failed to remedy the failure before the date specified, the department will not assess a penalty under AS 43.55.040 (7) for the failure, except in case of the person's fraud or willful concealment.
- Nothing in this subsection limits the department's right to require the additional or more complete and accurate filing of a report, statement, or other document.

# Penalties 43.55.030 and .040

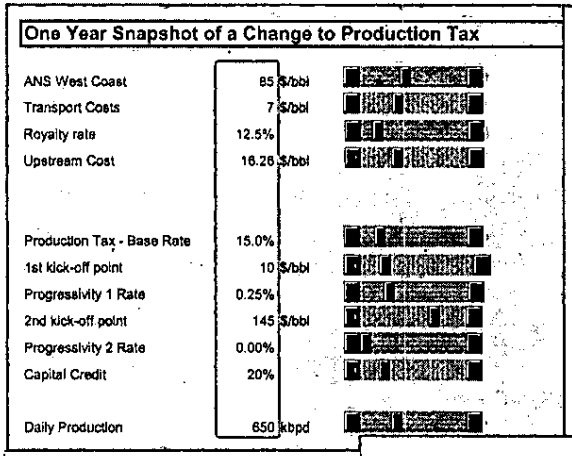
## To determine amount of penalty, DOR will consider:

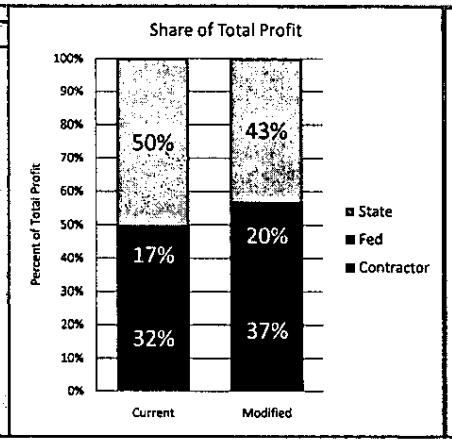
- Willful or knowing nature of act or omission
- Importance of required information and effect on ability of DOR to proceed in absence of information
- Benefits to person in failure to file
- History of noncompliance by person
- Need to deter future noncompliance by that person and others
- Effort made by person to correct noncompliance
- 15 AAC 55.840(d)

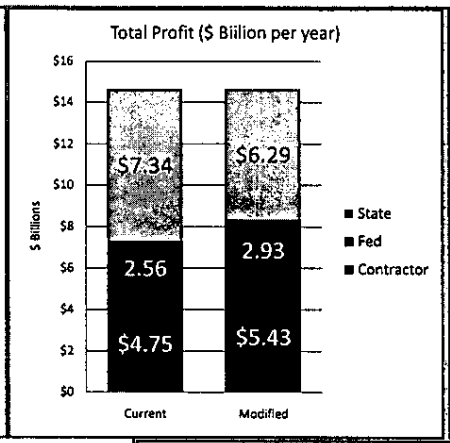
# Summary

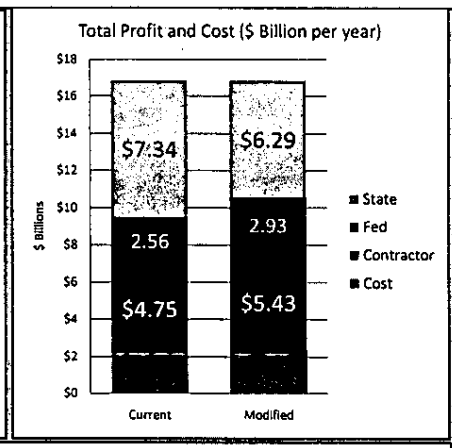
- Penalties are imposed for failure to comply with reporting provisions of production tax
- In addition to penalties under 43.05.220 and .290
- DOR has implemented clear and balanced regulations for taxpayers

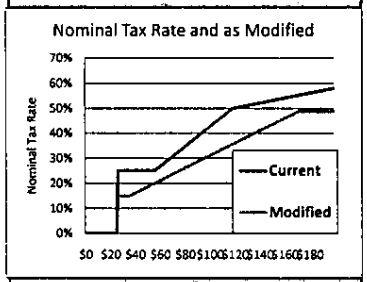

12

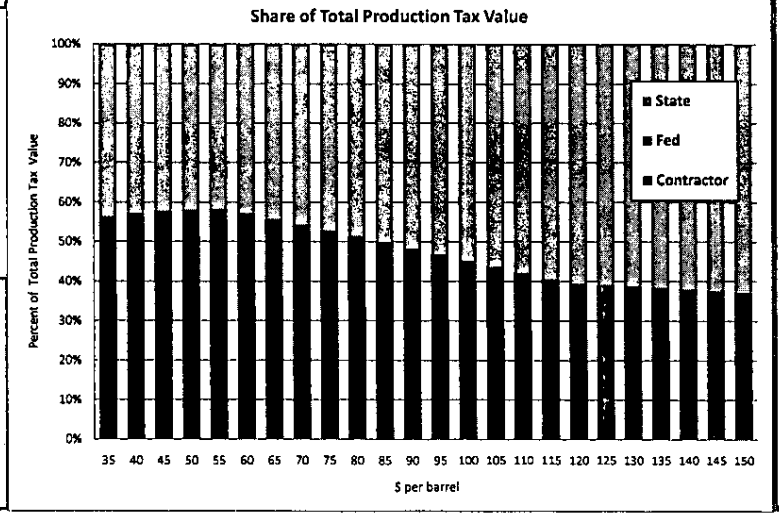

One Year Snapshot of a Change to Production Tax
ANS West Coast 85 $/bbl
Transport Costs 7 $/bbl
Royalty rate 12.5%
Upstream Cost 16.26 $/bbl
Production Tax - Base Rate 15.0%
1st kick-off point 10 $/bbl
Progressivity 1 Rate 0.25%
2nd kick-off point 145 $/bbl
Progressivity 2 Rate 0.00%
Capital Credit 20%
Daily Production 650 kbpd

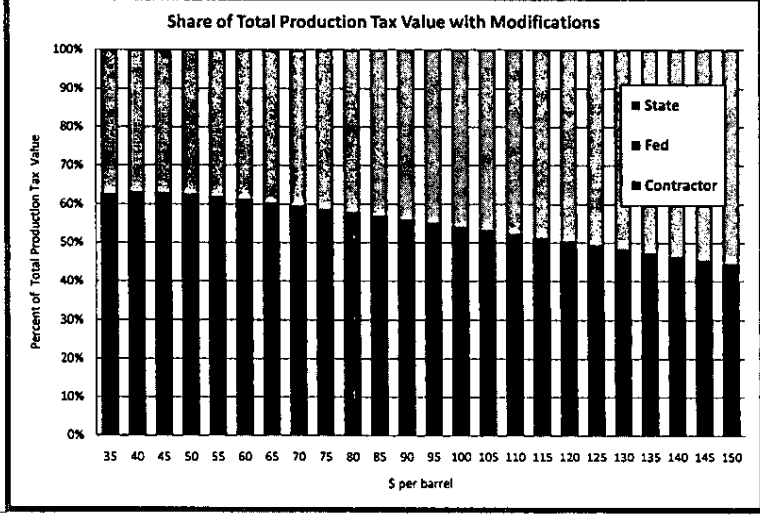

Share of Total Profit
Percent of Total Profit
50%
17%
32%
43%
20%
37%
State
Fed
Contractor
Current
Modified


Total Profit ($ Billion per year)
$ Billions
$7.34
2.56
$4.75
$6.29
2.93
$5.43
State
Fed
Contractor
Current
Modified


Total Profit and Cost ($ Billion per year)
$ Billions
$7.34
2.56
$4.75
$6.29
2.93
$5.43
State
Fed
Contractor
Cost
Current
Modified


Nominal Tax Rate and as Modified
Nominal Tax Rate
Current
Modified
$0 $20 $40 $60 $80 $100 $120 $140 $160 $180


Share of Total Production Tax Value
Percent of Total Production Tax Value
State
Fed
Contractor
$ per barrel


Share of Total Production Tax Value with Modifications
Percent of Total Production Tax Value
State
Fed
Contractor
$ per barrel

## Oil and Gas Tax Credits Overview and Forecast

Oil and Gas Production Tax Statutes contained in Title 43, Chapter 55 authorize several types of credits to be applied against the state's production tax. Among these are credits for capital expenditures (AS 43.55.023(a)), carried-forward annual losses (AS 43.55.023(b)), and exploration expenditures (AS 43.55.025). These are the primary credit programs applicable under the state oil and gas production tax, and are the focus of this report.

Credits may be redeemed in two ways: (1) they may be converted into transferable tax credit certificates and transferred or sold, either to another production taxpayer, or to the state treasury or (2) they may be claimed and applied against a production tax liability on a taxpayer's annual tax filing. For purposes of this report, we assume that companies with tax liabilities will apply their credits against their tax liabilities whenever possible and that companies with no tax liabilities will seek to sell their credits to the state, rather than hold them for future use or sale to third parties.

Exploration tax credits were first available in 2003, and have been expanded in the years since. Prior to revisions to the production tax law in 2007, exploration tax credits could only be redeemed by using them against a tax liability or by selling them to another tax payer. Credits under this program have always been audited by the DOR prior to the issuance of a certificate.

The production tax revisions passed in 2006 created the authority for credits for capital expenditures and net loss carry forwards to be claimed beginning in April 2006, and these credit provisions were further amended by the legislation effective July 1, 2007. The DOR Tax division issues transferable certificates for these two classes of credits after completion of a due diligence review.

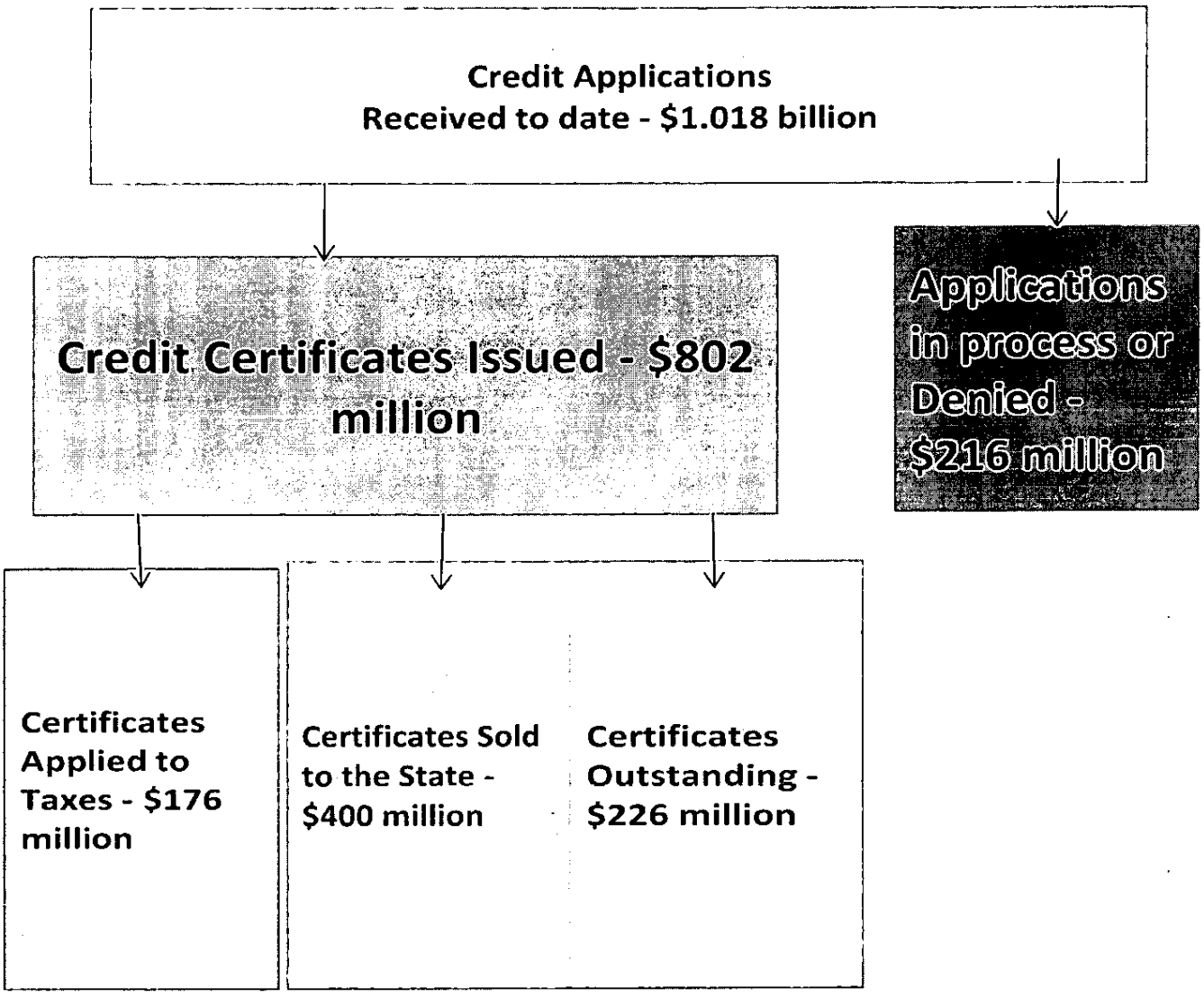
### *History of Tax Credit Certificates Authorization and Use*

Figure 1 on the following page shows the dollar amount of all applications for transferable tax credit certificates received from the credit program's inception to date, as well as dollar value of certificates issued, redeemed and outstanding. In total, companies sought $1.018 billion in credit certificates since the program began in 2003. The applications are split, with $334 million in exploration credits and $684 million capital/net loss carry forward credits. Taxpayers are increasing their use of these credit programs as shown in the credit history table below: For FY 2010, we expect to receive additional requests for credit certificates related to capital expenditures and carried-forward annual losses when annual returns for calendar year 2009 are filed on March 31, 2010.

**Amount of Transferable Tax Credit Certificates Sought under AS 43.55.023 and .025**

FY 2005 - $21 million
FY 2006 - $27 million
FY 2007 - $151 million
FY 2008 - $326 million
FY 2009 - $320 million
FY 2010 - $172 million (as of February 2010)

**Figure 1: Oil and Gas Tax Credits and Certificates to Date**




Department of Revenue, Tax Division
February 22, 2010

As can also be seen in Figure 1, $802 million in credit certificates have been issued since the credit program began in 2003; of these, $176 million have been applied to tax liabilities, either directly or through transfers to other companies, $400 million have been sold to the state, and $226 million are still outstanding. In addition to this, there are $216 million in credit applications either in process or denied; it is estimated that about $148 million of these will ultimately be redeemed. From this information, we can determine that the total amount of outstanding certificates and yet-to-be processed applications is just over $374 million.

Figure 2 below shows the payment history for production tax credits certificates that have been sold to the state, along with the appropriations that authorized those payments, either through the Oil and Gas Tax Credit Fund, authorized at AS 43.55.028 or through appropriations prior to the creation of the fund.

**Figure 2: Appropriations and Payments Made for Oil and Gas Tax Credits Certificates**

| | | |
|---|---|---|
| Appropriation | CH 6, SLA 2007 | 54,646,593 |
| Payment | FY 2007 Refunds | (54,646,593) |
| | | |
| Appropriation | CH 28 SLA 2007 | 25,000,000 |
| Appropriation | CH 11, SLA 2008 | 125,000,000 |
| Earnings | | 39,116 |
| Payment | FY 2008 Refunds | (54,143,421) |
| | | |
| Appropriation | CH29, SLA 2008 | 325,000,000 |
| Appropriation | CH 27, SLA 2008 | 175,000,000 |
| Earnings | | 18,168,845 |
| Payment | FY 2009 Refunds | (193,099,396) |
| | | |
| Appropriation | CH12, SLA 2009 | (415,000,000) |
| Appropriation | CH12, SLA 2009 | 180,000,000 |
| Earnings | | 2,715,382 |
| Payment | | (98,444,018) |
| | | |
| **Oil and Gas Tax Credit Fund Balance** | | 90,236,508 |

### *History of Credits Applied Against Tax Liabilities*

In addition to the exploration tax credits under AS 43.55.025 and the capital expenditure credits under AS 43.55.023 (a)(1) & (2), the production tax statutes under the 2006 and 2007 amendments, allowed producers to take against the production tax liability, the transitional investment expenditures (TIE) credits authorized under AS43.55.023(i) and the small producer credits under AS 43.55.024.

*Transitional Investment Expenditures (TIE) Credits*

The 2006 tax amendments authorized taxpayers to take a 20% credit on allowable qualifying capital expenditures incurred between March 31, 2001 and April 1 2006 with the credit not exceeding 10% of qualified capital expenditures incurred between March 31, 2006 and January 1, 2008. The 2007 amendments revised the credit to cover only producers or explorers not having production prior to January 1, 2008. The TIE credits are not transferable and may not be carried forward beyond 2013.

*Small Producer Credits*

There are 2 types of small producer credits allowable under the production tax statutes in AS 43.55.024. Under section (a) of the statute, companies producing less than 50,000 barrel per day of oil BTU equivalent may take a credit of up to $6 million against a production tax liability. The credit is allowed for production from wells outside of Cook Inlet and North Slope and can be taken annually; however, the credit may not be converted to transferable cash certificates for cash or transfer, and may not be carried forward. This credit expires in 2016.

The small producer credit under section (d) of AS 43.55.024, is available for companies producing not more than 100,000 barrel per day of oil BTU equivalent and ranges from $12 million to $0 depending on the level of production. Production is not restricted by region. The credit is not cashable or transferable and can only be applied against a production tax liability. This credit expires in 2016.

*Credits Applied Against Production Tax Filings*

Companies filing production tax annual returns claimed earned production tax credits of $331 million in FY07, $569 million in FY08 and $376 million in FY09, a total of $1.276 billion over the 3 year period. Of these amounts, the producers used these credits to offset their production tax liabilities by $322 million in FY07, $469 million in FY08 and $282 million in FY09 a total of $1.073 billion. Under the 2006 amendments, companies could apply tax credits earned for qualifying capital expenditures in the year that the expenditures were incurred. The 2007 amendments changed the statute to allow only 50% of the credit to be applied against the production tax liability in the year earned, thus the amount of credit earned increasingly exceeded the credits applied against tax liabilities in FY08 and FY09. At the end of FY09, there remains a balance of $203 million of unused credits to be applied against tax liabilities in future years. This is illustrated on Figure 3 below. Figure 4 shows the type of credits applied against production tax liabilities. The amounts reported on the tax filings are subject to audit and may change upon adjustment.

***Figure 3: Credits earned versus Credits applied against tax liabilities***

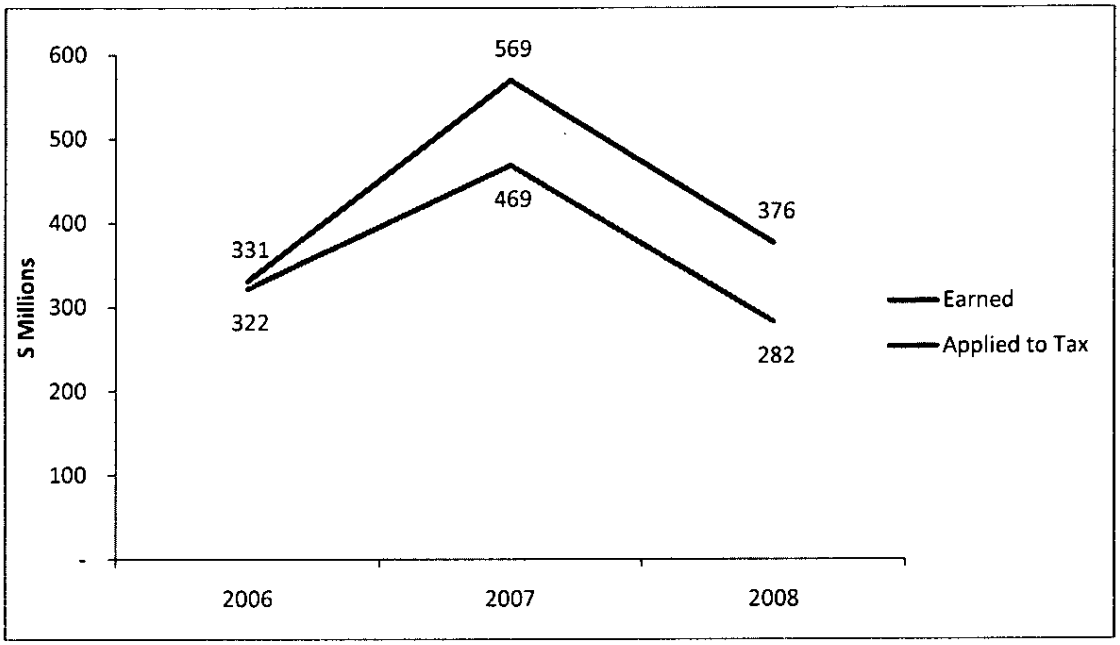
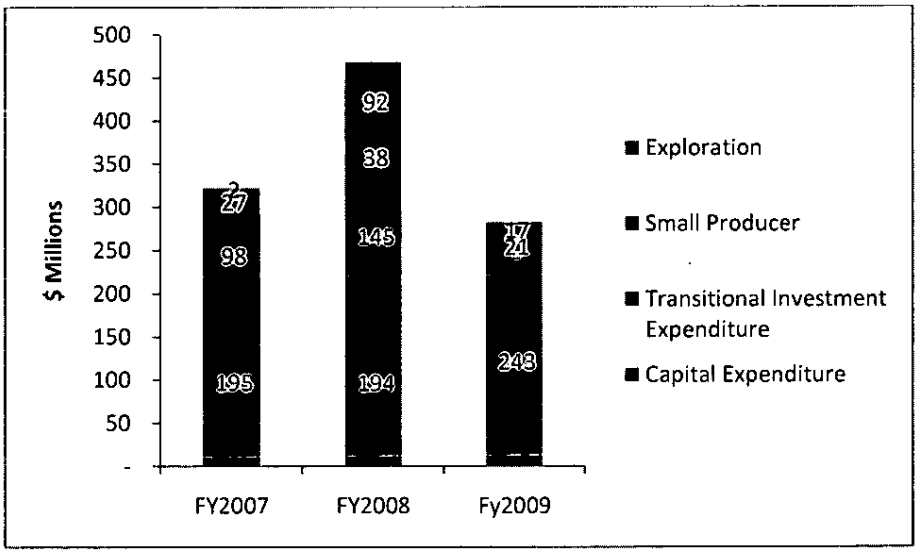



**Figure 4: Credits by type applied on tax returns**

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February 22, 2010


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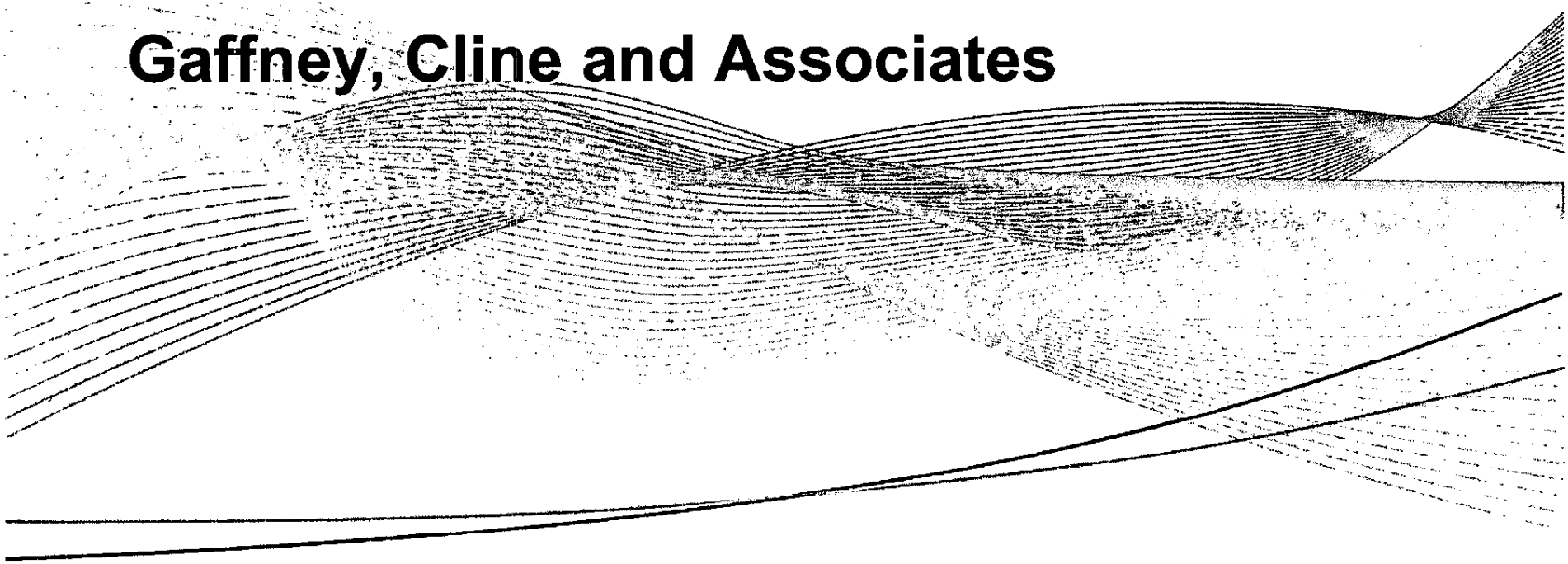
# Fiscal System Benchmarking

## Gaffney, Cline and Associates



# Glossary

- AK – Alaska
- bpd – barrels per day
- bbl – barrel
- BRIC – Brazil, Russia, India, China
- Capex – Capital Expenditures
- GOM – Gulf of Mexico
- IOC – International Oil Company
- INOC – International National Oil Company
- NS – North Slope
- NOC – National Oil Company
- FSU – Former Soviet Union
- IRR – Internal Rate of Return
- NPV – Net Present Value
- NOL – Net Operation Loss
- OECD – Organization for Economic Co-operation and Development
- Opex – Operating Expenditures
- PRT – Petroleum Revenue Tax
- PSC – Production Sharing Contract
- T&R – Tax and Royalty
- UK – United Kingdom

# Objective

- Provide brief background on the evolution of hydrocarbon fiscal regimes

- Compare government take under Alaska Tax to other sample international regimes and to the US

- Percentage Government take:

$$\frac{\textit{Royalty + Gov. Share of Production + Taxes}}{\textit{Field Revenue – Capex – Opex}}$$

# Agenda

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1. Historical Perspective

2. Impact of Key Components

3. International benchmark

# Reviewing Fiscal Comparisons

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- **It is critical to understand the basis upon which any fiscal comparison is being made.**

- **Some "results" can be misused if not placed in context for which they were intended.**

- **Need to know what they do and do not represent:**
  - Full cycle including Exploration?
  - From point of development investment decision?
  - Remaining life?
  - High price or low price scenario? .....etc.

# Fiscal Take Also Depends.....

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- **....On where you were and when!**
  - In the early 1980's, prices were escalating, but the places to invest were limited.
    - The UK had a 90+% government take and investment activity level was high.
  - By the late 1990's prices had remained low for most of the decade and upwards of 70 countries were holding license rounds in search of 'revenues'.
    - The UK had eliminated all taxes but Corporate Income Tax in an attempt to attract investors.
- **Simple tables and charts of comparison are limited in their ability to explain why regimes change or the need for fiscal regime changes.**

# The 1980s – Companies in Search of Countries

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- ■ Open to Foreign Investment in the Energy Sector
- □ Some Foreign Investment in the Energy Sector
- □ Limited Access to Foreign Investment in the Energy Sector

# The early 2000's – Countries in Search of Companies

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- Open to Foreign Investment in the Energy Sector
- Some Foreign Investment in the Energy Sector
- Limited Access to Foreign Investment in the Energy Sector

# The 2010's - Returning Nationalism, Transparency...

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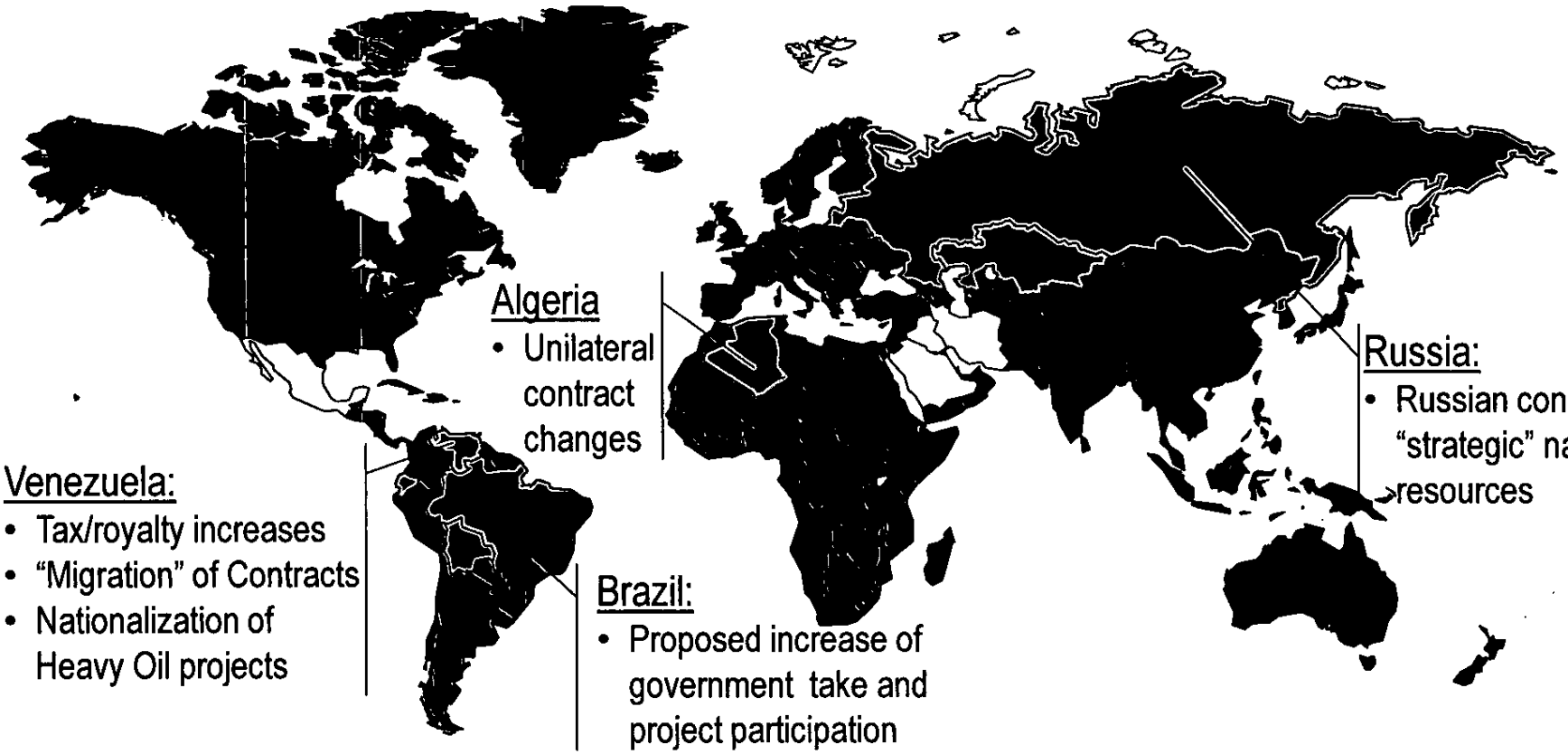

**Algeria**
- Unilateral contract changes

**Russia:**
- Russian control of "strategic" national resources

**Venezuela:**
- Tax/royalty increases
- "Migration" of Contracts
- Nationalization of Heavy Oil projects

**Brazil:**
- Proposed increase of government take and project participation

■ **Open to Foreign Investment in the Energy Sector**

□ **Some Foreign Investment in the Energy Sector**

▣ **Reduced Access for Foreign Investment in the Energy Sector**

# ...and Competition from International National Oil Companies (INOCs)

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## *Contract Awards in Recent Iraq Bidding Rounds*

| Contract Area | Consortium (*Operators – INOCs underlined) | Plateau Prod. Target (b/d) | Final Rem. Fee (US$/bbl) |
|---|---|---|---|
| Rumaila | BP*, CNPC | 2,850,000 | 2.00 |
| West Qurna 1 | ExxonMobil*, Shell | 2,325,000 | 1.90 |
| Majnoon | Shell*, PETRONAS | 1,800,000 | 1.39 |
| West Qurna 2 | Lukoil*, Statoil | 1,800,000 | 1.15 |
| Zubair | Eni*, Occidental, Kogas | 1,200,000 | 2.00 |
| Halfaya | CNPC*, PETRONAS, Total | 535,000 | 1.40 |
| Garraf | PETRONAS*, Japex | 230,000 | 1.49 |
| Badra | Gazprom*, TPAO, Kogas, PETRONAS | 170,000 | 5.50 |
| Qaiyarah | Sonangol | 120,000 | 5.00 |
| Najmah | Sonangol | 110,000 | 6.00 |

# Creating "Best" Fiscal Systems

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- **Countries continually assess their internal needs and their world-wide competitive position to set hydrocarbon fiscal terms.**
  - Attract Investment
  - Generate revenue for the treasury
  - Create jobs, increase local skill base

- **There are roughly as many systems in place as there are countries with petroleum legislation.**
  - Many areas of similarity
  - Many areas of difference
  - Different 'vintages' can be active at the same time

# Countries Adapting to Higher Prices

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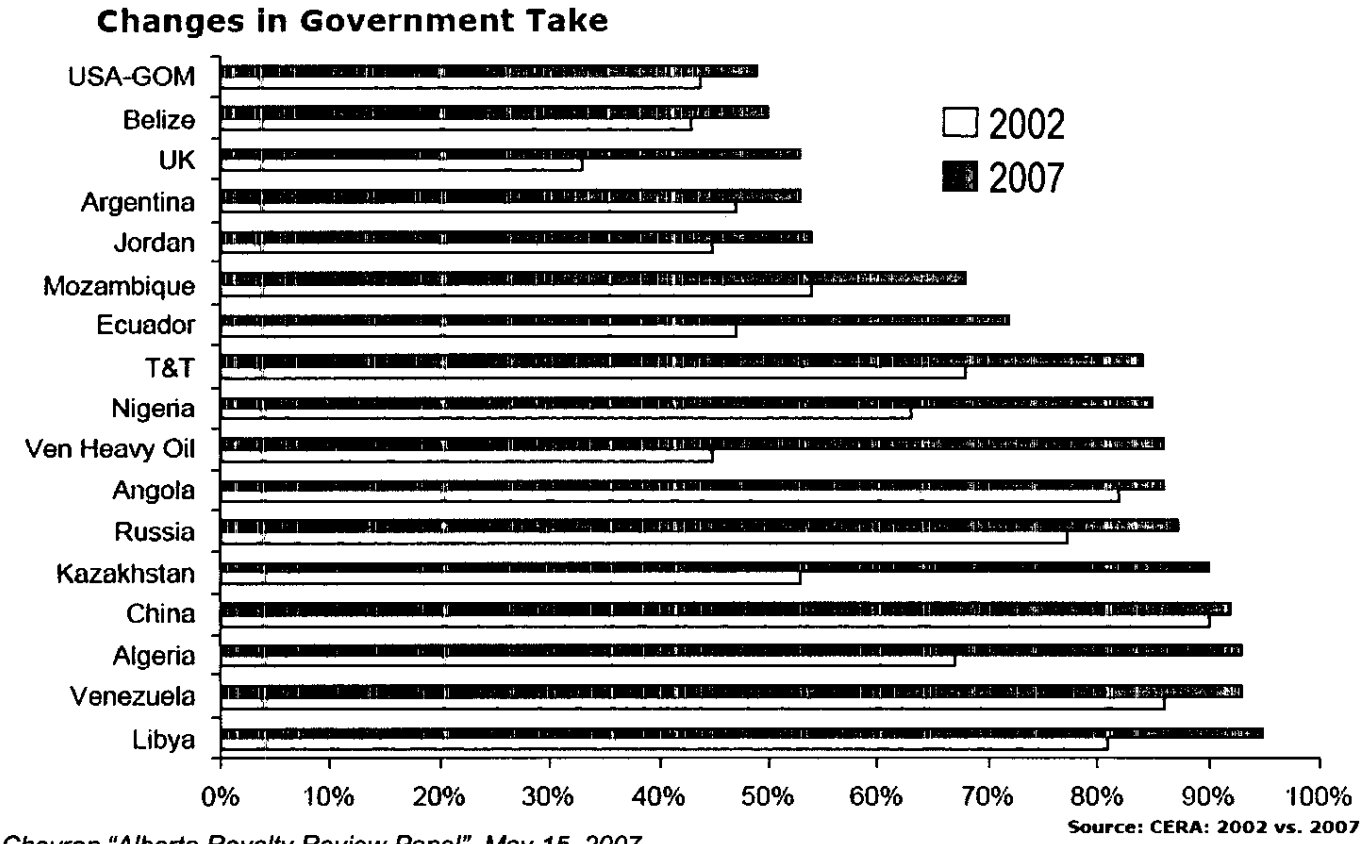
## Assessment of Oil and Gas Jurisdictions is Complex and Continuous




*Source: Chevron "Alberta Royalty Review Panel" May 15, 2007*

# Industry "Take" Assessments

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- **The many studies that attempt to "rank" regimes are typically based on:**
  - Marginal Government Take
  - Average Government Take
  - Total Government Take
  - Risk
  - Stability

- **While informative in the right context, the aspects of fiscal regimes that these studies do not cover or rank can at times be more important.**

# What these studies tend to Ignore

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- Signature bonuses
- Time Value
- Investment Credits
- Ringfencing
- Tax credits
- Booking Reserves
- Lifting Rights
- Domestic Obligations
- Different oil/gas rates
- Lease rentals
- Limits on cost recovery
- Exclusions
- Cross crediting
- Timing of Take
- Allowable costs
- Uplifts

Many of the above can have a significant financial impact and if included might generate a different ranking outcome.

# New Players Today – the International National Oil Companies

- **National Oil Companies (NOCs) are investing internationally**
  - The focus of their expansion includes Middle East, Former Soviet Union, Africa and Latin America
  - For example, China-Africa trade: $4 billion in 1995, $40 billion in 2005, expected to be over $100 billion in 2010
- **INOCs are changing the competitive landscape**
  - Different (lower?) investment criteria
  - Different drivers
  - Government to government deals
    - China and India to cooperate on energy acquisitions
    - Emergence of the BRIC *(Brazil, Russia, India, China)* alliance

# Then there are the Hidden Drivers

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- **"Punished by Reward"**
  - Compensation packages drive decision making
  - Good deals are sometimes passed up to do deals that score more bonus points
  - These are usually not obvious nor acknowledged

- **Examples of executives' performance targets:**
  - Maintaining reserve replacement/growth
  - Reducing cost per barrel
  - Increasing market share

# Agenda

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1. Historical Perspective

2. Impact of Key Components

3. International benchmark

# What these studies tend to Ignore

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- Signature bonuses
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- Investment Credits
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- Domestic Obligations
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- Lease rentals
- Limits on cost recovery
- Exclusions
- Cross crediting
- Shared royalty
- Allowable costs
- Uplifts

Many of the above can have a significant financial impact and if included might generate a different ranking outcome.

# Time Value of Money

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- Most fiscal regime comparisons do not adequately compare the time value of benefits in one regime versus another.

- Alaska is very generous to investors in that it allows all eligible costs to be deducted immediately from revenue (and even receive cash back) plus provides capital and exploration credits for the same expenses.

# Simplified Field Model

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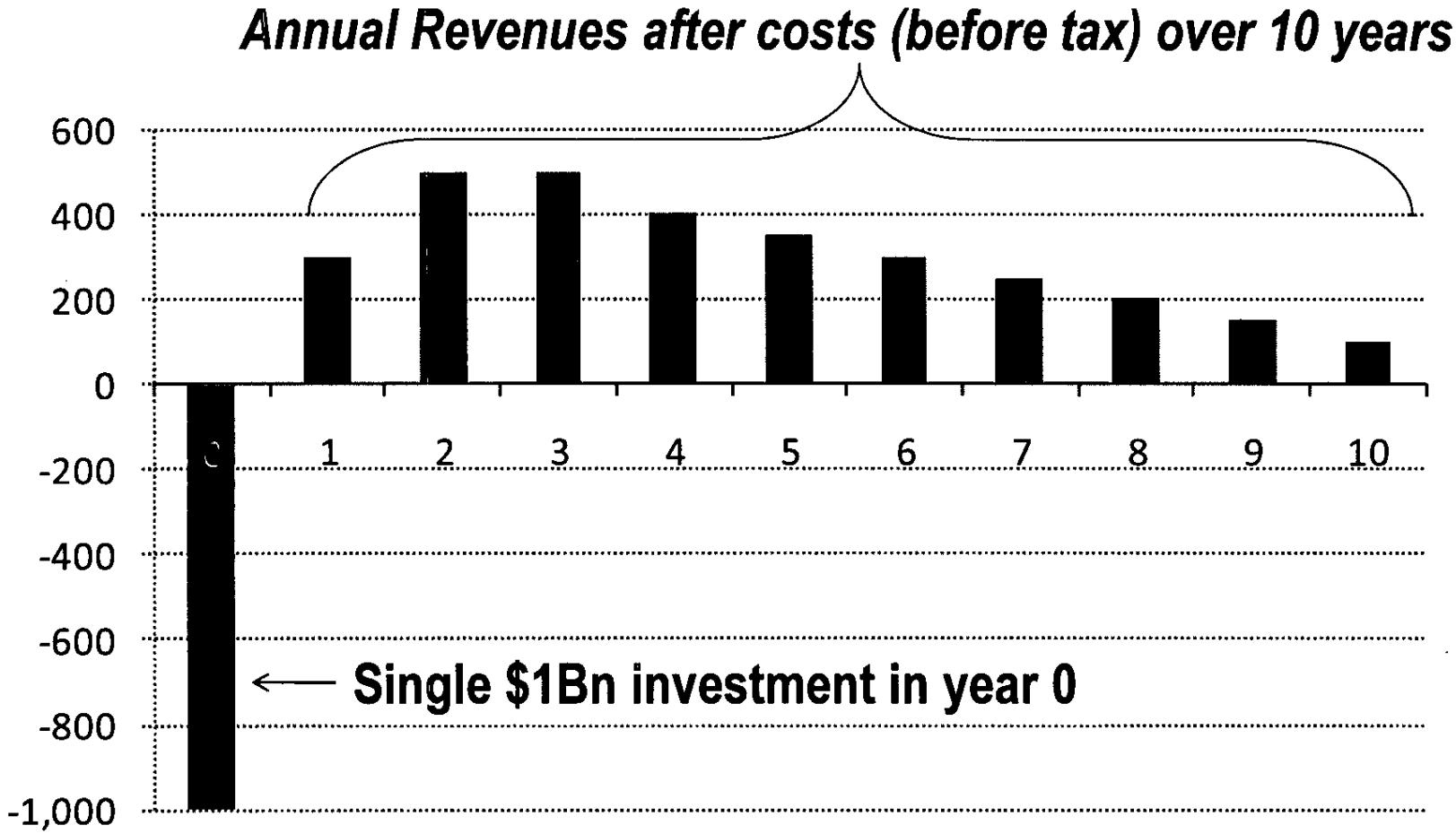


*Note: This is not intended to represent any Alaska asset*

# Scenarios

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- **Range of depreciation from other regimes**
  - Straight line 3 year, 5 year and 10 year
  - Compared to immediate write off, such as Alaska allows
- **Single tax rates**
  - To illustrate the time value effect
  - Not looking to highlight other nuances in one regime versus another
- **Investment credits, such as Alaska allows**

# Impact of Depreciation on Investors' Internal Rate of Return (IRR) and Net Present Value (NPV)

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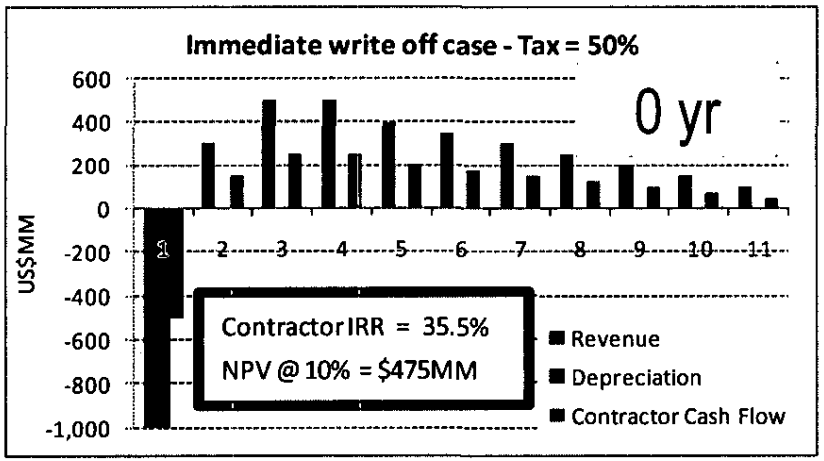


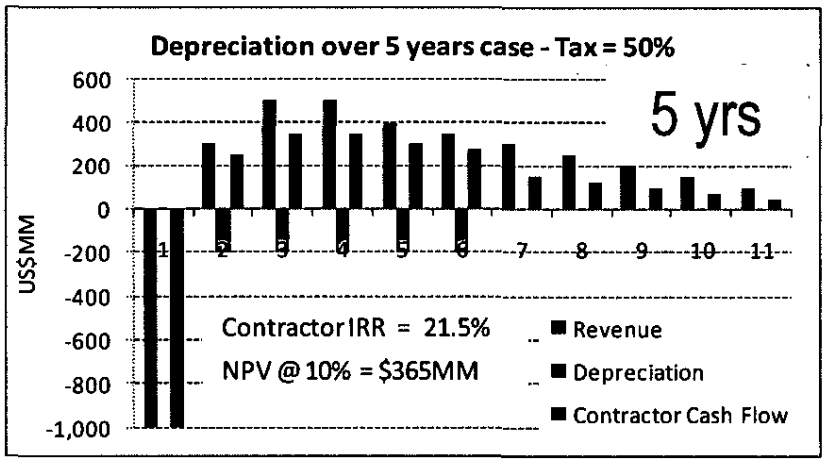


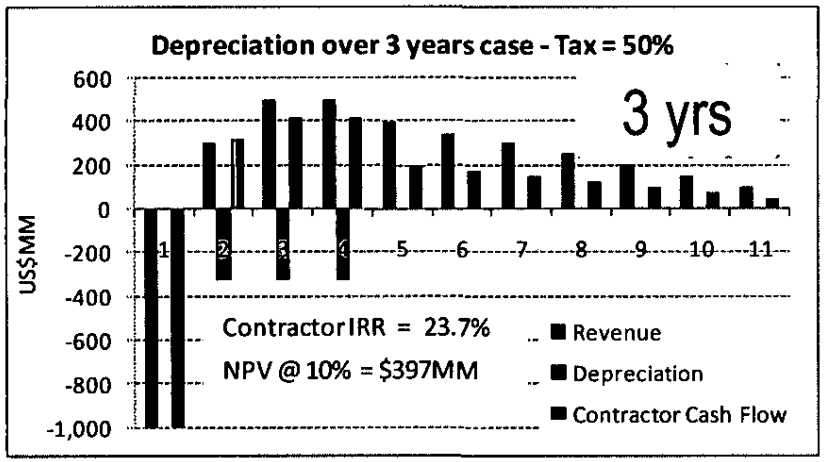


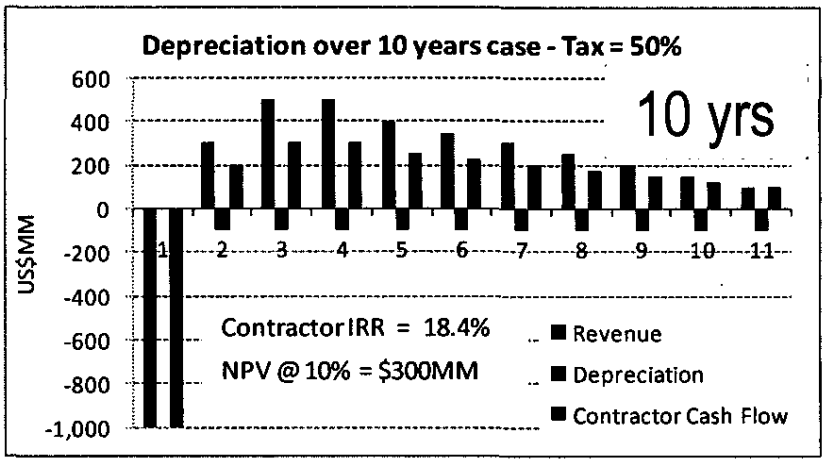


*Note: Cashed Out Net Operating Losses (NOLs)*

# Tax Impact of Depreciation

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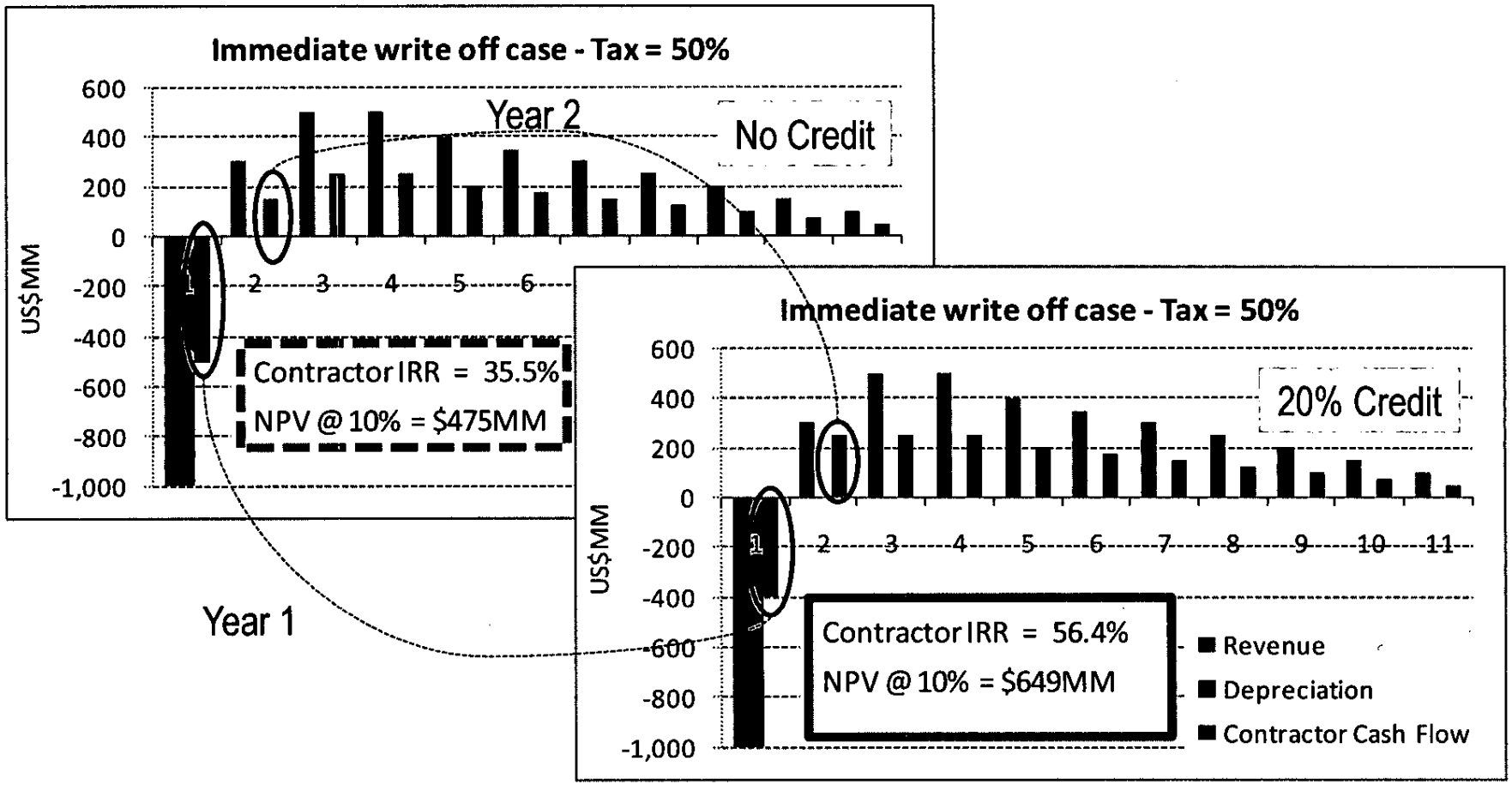
| Depreciation | Tax Rate | Producer IRR | $NPV_{10}$ (US$MM) |
|---|---|---|---|
| **Immediate write off** | **50%** | **35.5%** | **475** |
| 3 years | 50% | 23.7% | 397 |
| 5 years | 50% | 21.5% | 365 |
| 10 years | 50% | 18.4% | 300 |
| **Immediate = 3 yrs** | **58%** | **35.5%** | **~397** |
| **Immediate = 5 yrs** | **62%** | **35.5%** | **~365** |
| **Immediate = 10 yrs** | **69%** | **35.5%** | **~300** |

- **The economic impact of immediate write off is significant**

- **For a same tax rate of 50%, the longer the depreciation, the lower the producer IRR and the lower the producer NPV**

*Note: The IRR of the immediate write off case is not impacted by the tax rate as any increase is balanced by a proportional cashed out NOL*

# Impact of 20% investment credits over 2 years



# Investment Credits Impact

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| Depreciation | Tax Rate | Investment Credits | $NPV_{10}$ Match (US$MM) |
|---|---|---|---|
| **Immediate write off** | **50%** | **0%** | **475** |
| **Immediate write off** | **50%** | **20%** | **649** |
| **Immediate write off** | **76%** | **20%** | **~397** |
| 3 years | 50% | 0% | 397 |
| **Immediate write off** | **80%** | **20%** | **~365** |
| 5 years | 50% | 0% | 365 |
| **Immediate write off** | **87%** | **20%** | **~300** |
| 10 years | 50% | 0% | 300 |

- **A fiscal regime with a combination of immediate write off and investment credits can compete favorably on select financial metrics with regimes with lower Government Takes**

# What these studies tend to Ignore

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- Signature bonuses
- Time Value
- Investment Credits
- **Ringfencing**
- Tax credits
- Booking Reserves
- Lifting Rights
- Domestic Obligations
- Different oil/gas rates
- Lease rentals
- Limits on cost recovery
- Exclusions
- Cross crediting
- Timing of Take
- Allowable costs
- Uplifts

Many of the above can have a significant financial impact and if included might generate a different ranking outcome.

# Ringfencing

- **Fiscal regime comparative studies tend to use single type fields or stand alone existing fields.**
- **Most contracts or licenses in the world are 'ringfenced'.**
  - Implication: The same producer, in the same country, can have a highly profitable project but be unable to offset or deduct losses from another project.
  - One of the biggest surges of activity in the UK offshore occurred when the ringfence around PRT (their special petroleum tax) was removed.

# Why Ringfencing Matters

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- **Some might evaluate the economics of Alaska's heavy oil opportunities as a stand alone projects**
  - Market price lower than NS crude based on quality
  - Higher development and operating costs
  - Ignores fact that project is connected (fiscally) to existing operations

# Simple Ringfence Example

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- **Assume existing NS oil project**
  - Production 650,000 bpd
  - Market oil price $70/bbl
  - Transportation costs of $7/bbl
  - Upstream costs $18/bbl (50% opex, 50% capex)

- **Potential NS heavy oil project**
  - Production 250,000 bpd
  - Market oil price 90% of NS oil price (quality)
  - Transportation costs of $7/bbl
  - Upstream costs twice as high as oil project $36/bbl

# Heavy Oil and Alaska Tax

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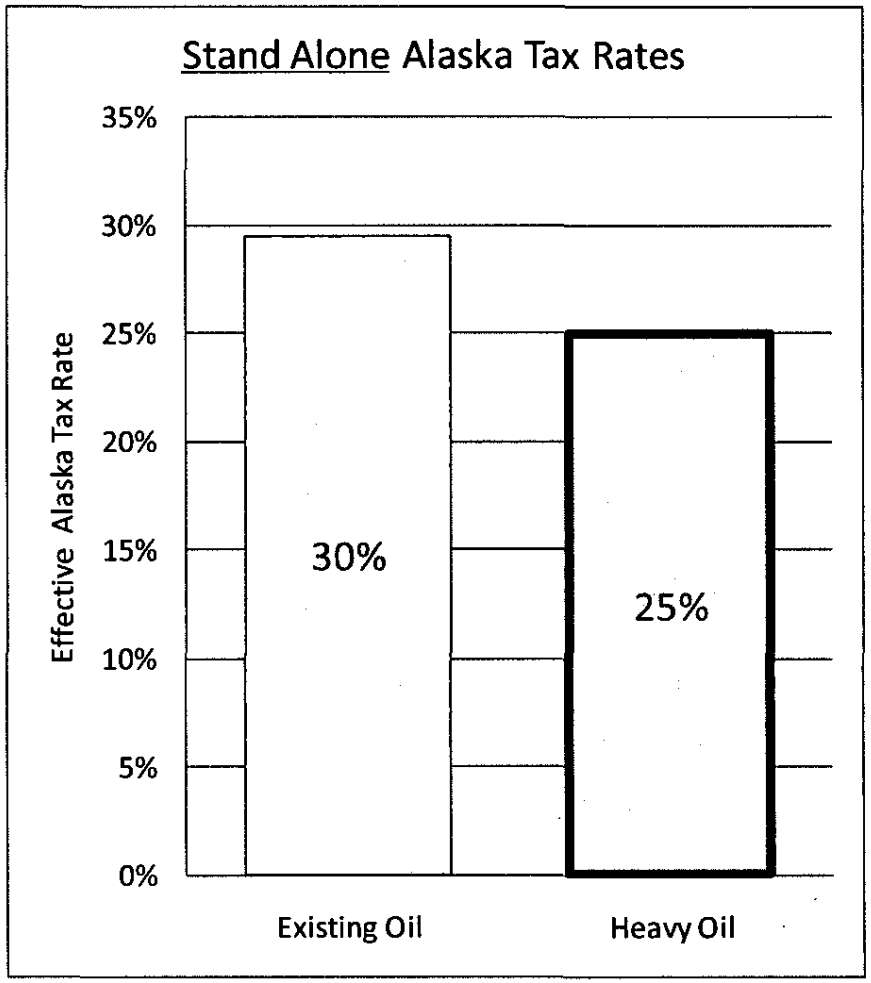
- **The following charts present one year 'snapshot' views of the Alaska tax in two cases:**
  - Project ringfence
  - North Slope-wide ringfence as allowed under Production Tax Law

- **This illustrates the State available assistance for Heavy Oil developments**

# Stand Alone - Project Ringfence

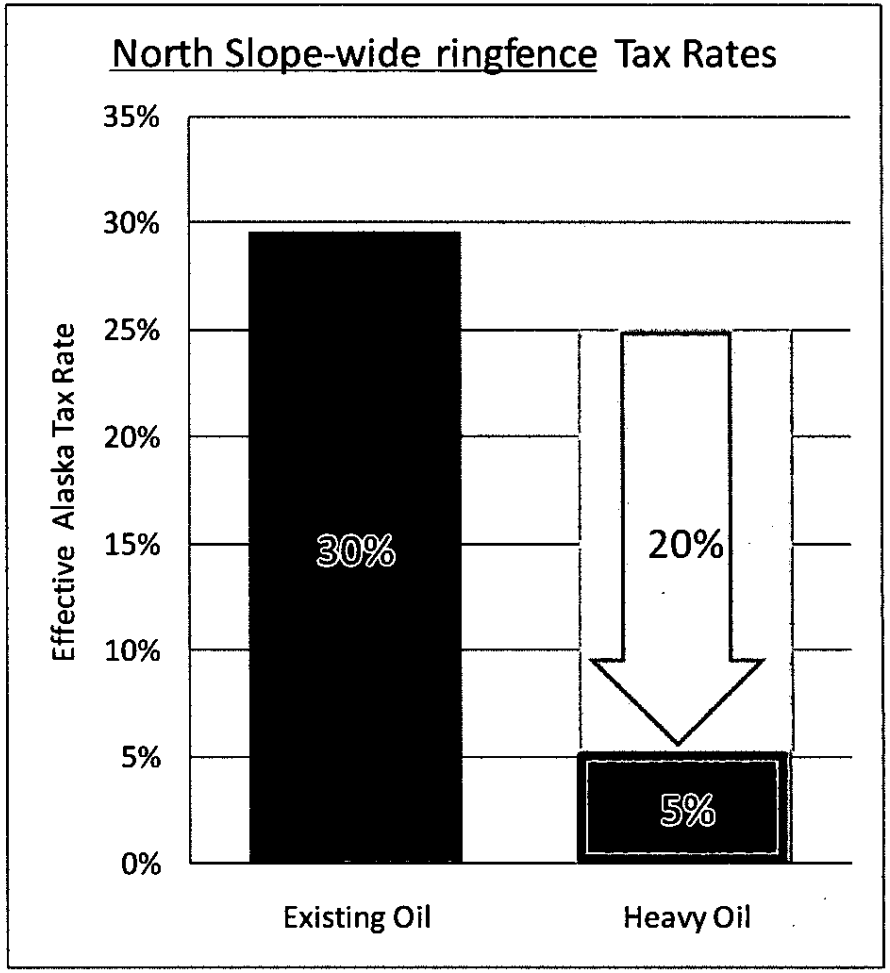
- If ringfenced as separate projects, as in many fiscal regimes, existing oil tax rate would be 30% and heavy oil would be 25%
- However, reality is this needs to be viewed as a blended portfolio



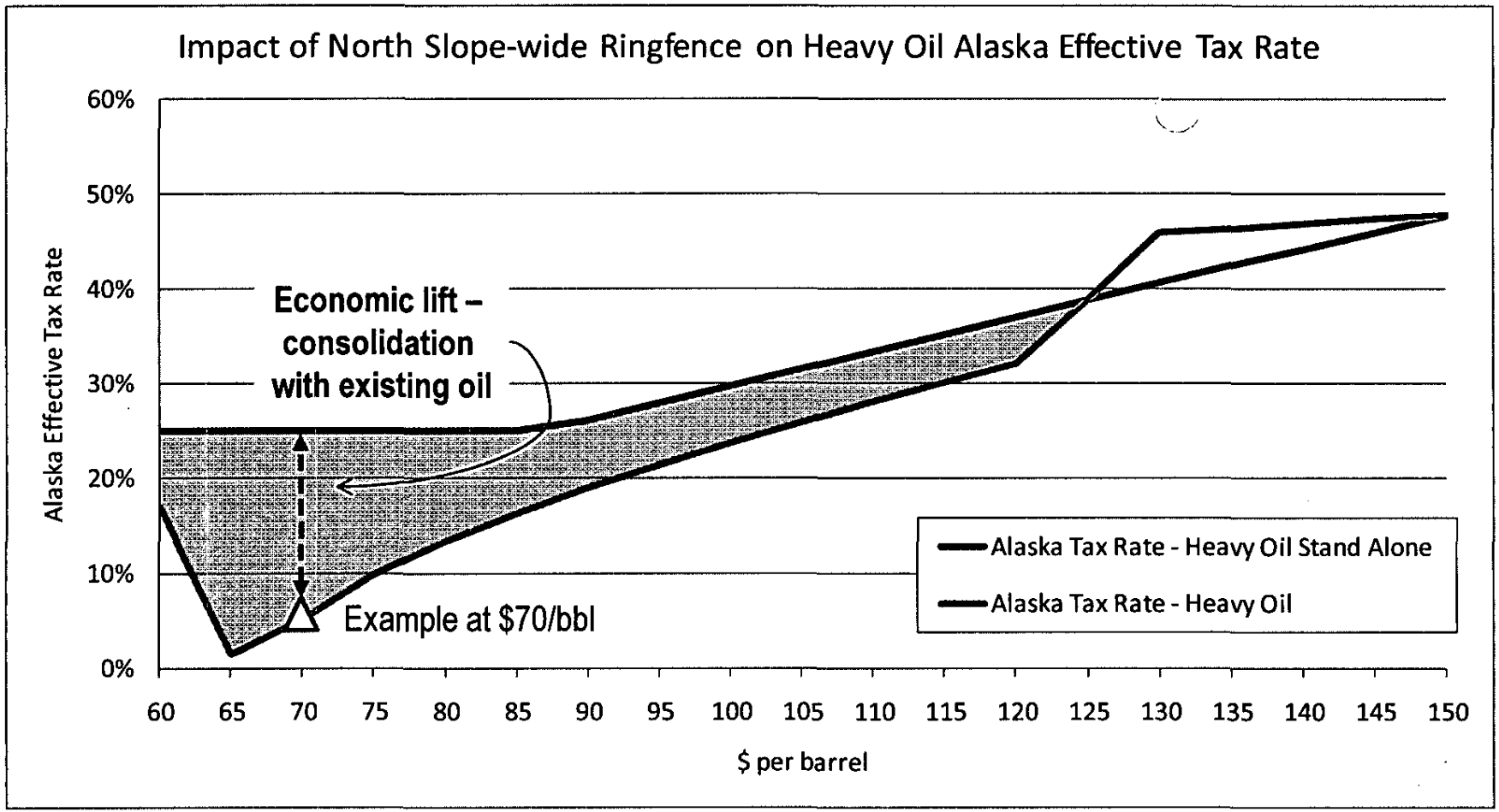

*Oil Price - ANS West Coast : $70/bbl*

# North Slope-wide Ringfence

- If the Producer adds the heavy oil project to its portfolio, the heavy oil project will effectively be taxed at 5% instead of 25%
- The effective tax on heavy oil varies across a range of oil prices



# Heavy Oil Effective Tax Rates



# Agenda

GCA
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1. Historical Perspective

2. Impact of Key Components

3. International benchmark

# Selection of benchmarks

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- **Exploration and Production 'hotspots' where the Majors are investing**

- **Range of fiscal regimes**
  - Production Sharing Contract, Royalty, Technical Services Contract, Special Taxes

- **Range of locations**
  - US, South America, Europe, Africa, Middle East, Asia Pacific

# Benchmarks: Selected "hotspots"

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# GCA Analysis Assumptions

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- **DOR's North Slope Production and Revenue forecasts (no gas pipeline case)**
  - 4.4 Billion barrels of oil produced
  - $23/bbl Capex + Opex + Tariffs (non indexed)

- **Used GCA proprietary fiscal regime information**
  - Inclusive of all nuances that are part of a particular regime including many ignored by other regimes

- **Compared Government Take at $70 & $150/bbl**

# Remaining NS Oil Profile
# Total Government Take

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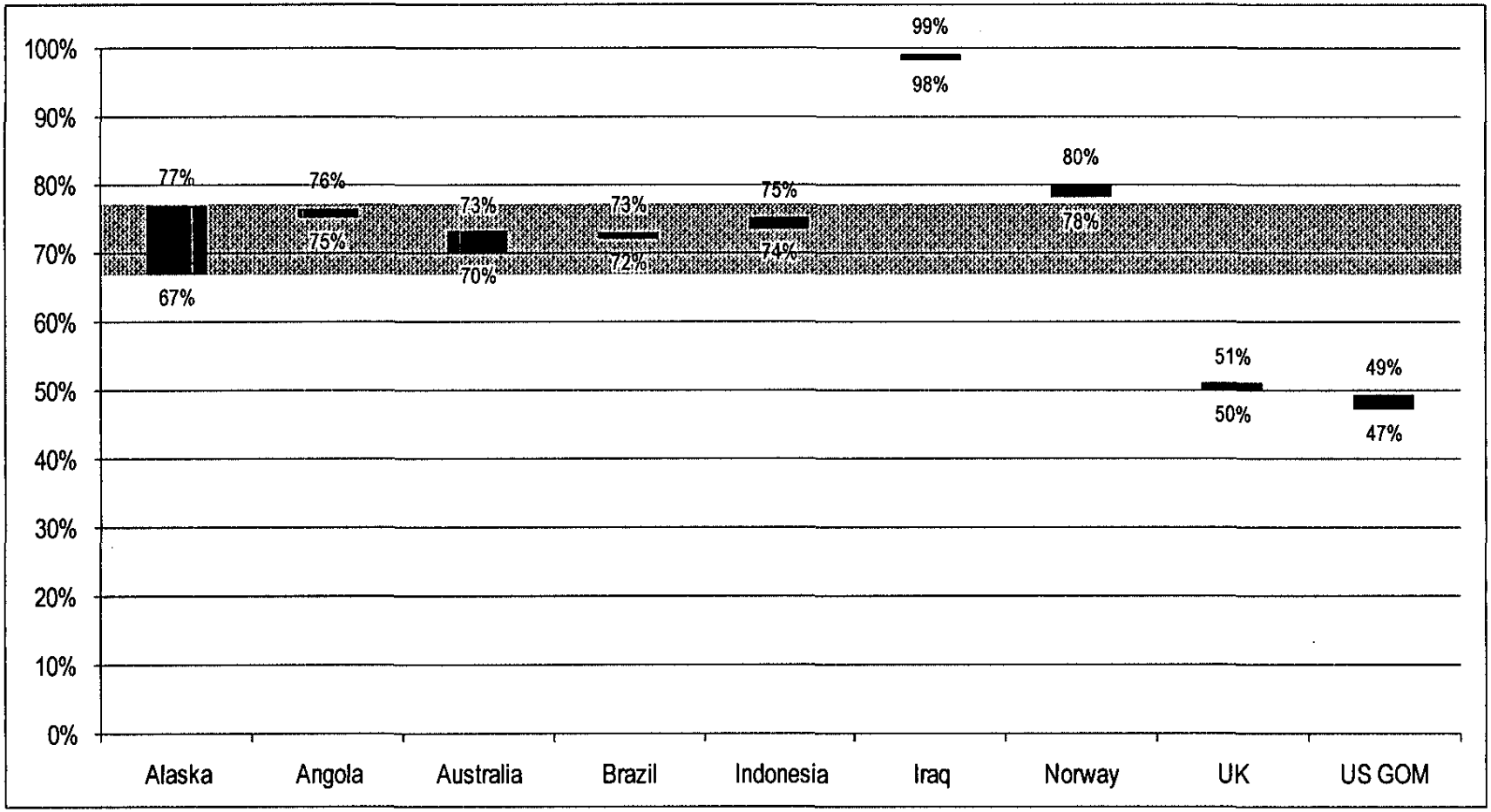


*Note: Oil price $70-$150/bbl*

*Total Government Take - Alaska*

# Industry Profit NPV 10 (US$B)

GCA
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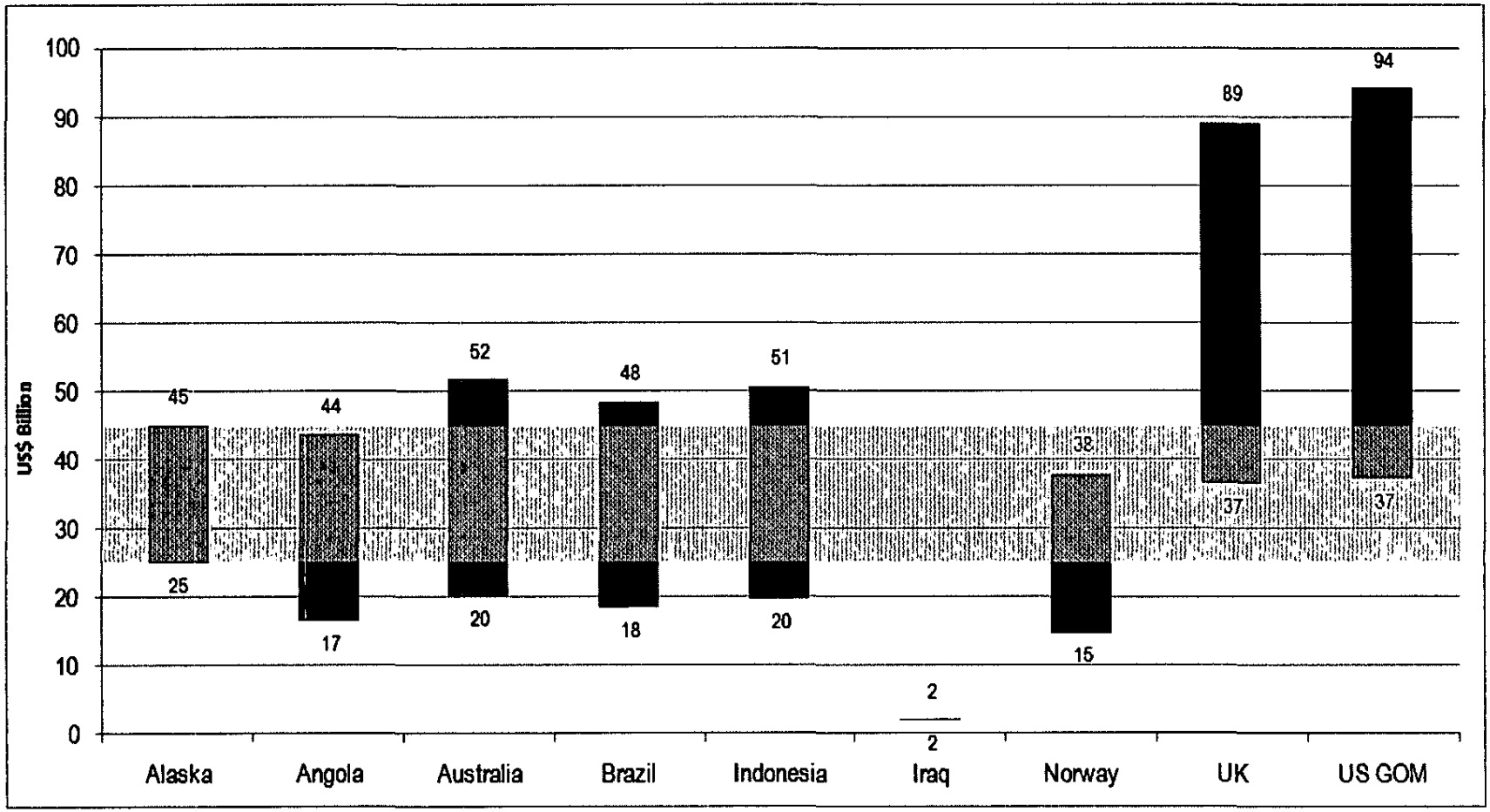


*Note: Oil price $70-$150/bbl*

*Industry Profit NPV 10 - Alaska*

# Observations

- **Bearing in mind the limitations of any benchmarking exercise, we observe the following:**
  - These results are in the same range as the ones provided by various industry players and consultants.
  - The total Government Take in Alaska appears to be competitive with most hydrocarbon prolific areas.
  - The Government Take in the recent Iraq contracts, which have attracted significant international competition (including from Industry players present in Alaska) is the highest.

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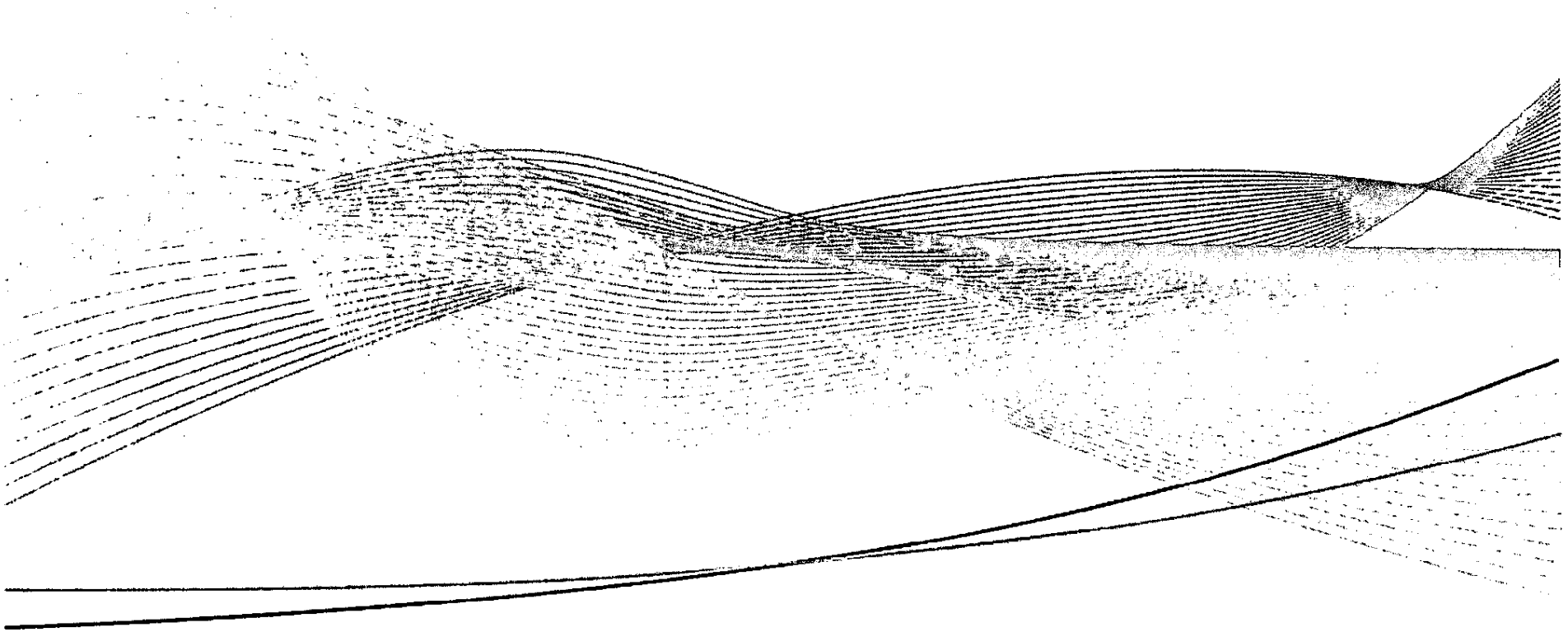
# Understanding the Message



TECHNICAL AND MANAGEMENT ADVISORS TO THE INTERNATIONAL PETROLEUM INDUSTRY

Fiscal System Benchmarking

January, 2010

# Government Take Studies

GCA
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- **To make a valid comparison of Alaska's fiscal system requires knowing the basis on which on comparisons are being made:**
  - IRR or rate of return?
  - NPV? Undiscounted? What discount rate?
  - Marginal take at the absolute worse 'spot' in the fiscal regime or averaged across a range of expected outcomes?
  - Single fields or portfolios?
  - High rate oil developments versus extended plateau gas developments?
- **What is it you are being shown?**

# Vintage

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- **Many countries have producers operating under a number of different vintage agreements.**
  - Most of the older agreements are specific to the field(s) being produced. A comparison to these would be misleading and unfair.
  - Even if older agreements provide opportunity for new exploration, the new projects may be ringfenced.
  - New investors can't receive the terms of the older agreements.
- **When the oil companies offer their comparison, what vintage agreement are they using?**

# Vintage – Trinidad & Tobago

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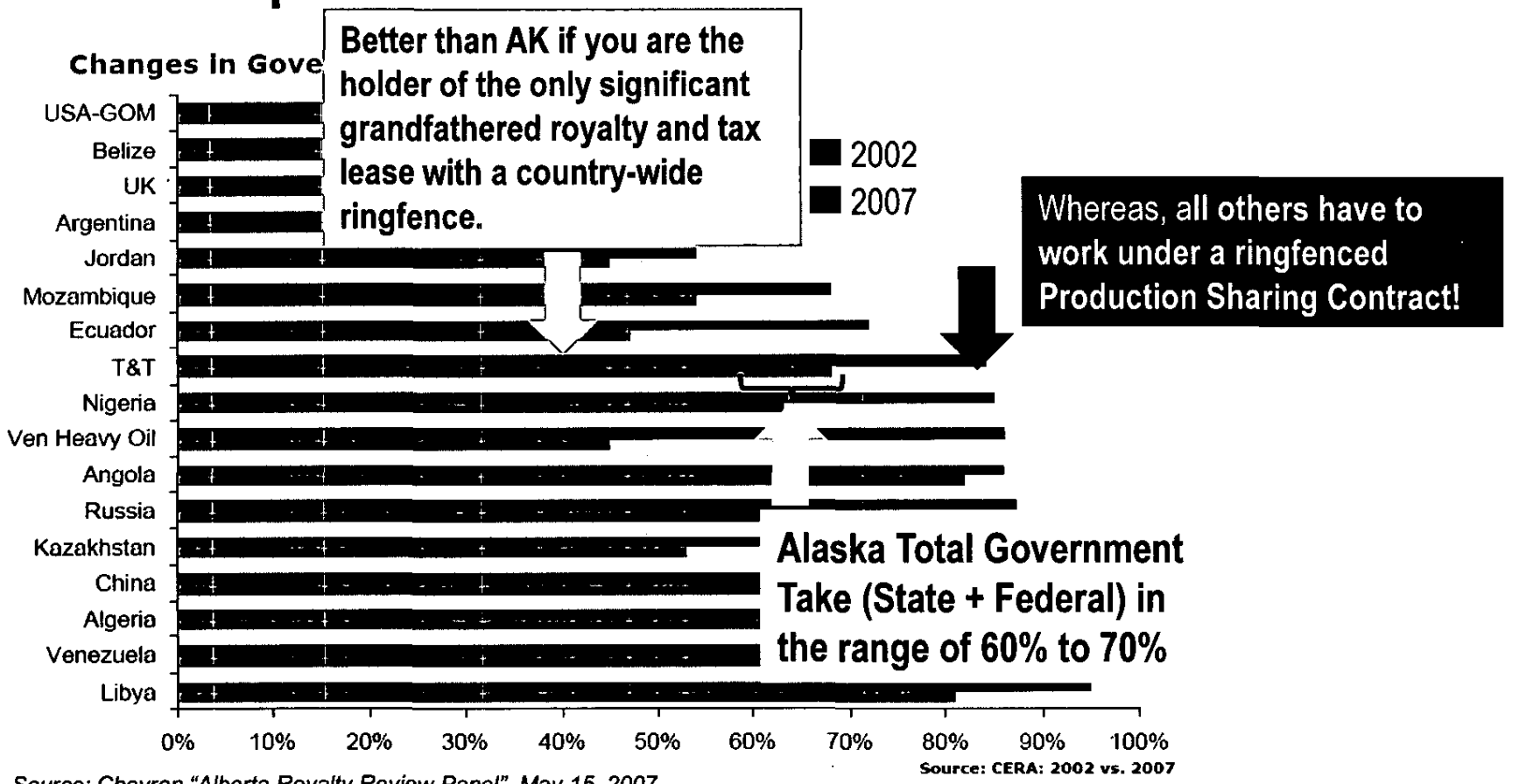
## Assessment of Oil and Gas Jurisdictions is Complex and Continuous




*Source: Chevron "Alberta Royalty Review Panel" May 15, 2007*

# OECD vs. Non-OECD

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- **One would think that a non-OECD environment would carry higher risk – and therefore need a greater reward**
  - Non-OECD countries control the vast majority of all hydrocarbons
  - Non-OECD countries also average very high total Government Take
  - Yet, major producers continue to include high take non-OECD countries as part of their portfolio
    - Recent Iraq deals

*OECD: Organization for Economic Co-operation and Development*

1958

# List of OECD Countries

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| | | | |
|---|---|---|---|
| Australia | Austria | Belgium | Canada |
| Czech Republic | Denmark | Finland | France |
| Germany | Greece | Hungary | Iceland |
| Ireland | Italy | Japan | Korea |
| Luxembourg | Mexico | Netherlands | New Zealand |
| Norway | Poland | Portugal | Slovak Republic |
| Spain | Sweden | Switzerland | Turkey |
| United Kingdom | United States | | |

# Which Gulf of Mexico (GOM)?

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- **Really three different GOMs with different economics and different government terms**
  - Shallow water, paid for platforms, producing fields from relatively low depths, low operating cost structure and relatively inexpensive transportation to market.
  - Recent deep water developments, new state-of-the-art platforms, producing from deep horizons, challenging technology, high cost to drill, high cost to operate, long distance to market.
  - Recent ultra deep drilling from the shallow water shelf, middle range costs, close to shore and market.
- **Old 12.5% federal royalty vs. new 18.75% federal royalty**

# At what oil price?

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- **Relatively low prices**
  - Progressive systems take the minimum
  - Regressive systems take a larger bite
  - Comparison studies of the progressive Alaska tax regime would cast Alaska in a better light
- **Very high prices**
  - Progressive systems take a big bite
  - Regressive systems look favorable
  - Comparison studies of Alaska would cast Alaska in a worse light
- **Best comparisons use a number of prices across a reasonable range so that the workings of the fiscal system can be adequately assessed.**

# Does it include all Government Take?

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- **Bonuses**
  - Even though these can vary from lease to lease, are they included?
  - Recent $1Bn bonuses paid in Angola
  - Sizeable bonuses paid in other regimes as well
- **Domestic Market Obligation**
  - Has the requirement to provide a portion of the oil and gas to the local market at a discount been taken into account?
- **Government Partner**
  - Has the government participation been included, even if it is as a full paying equity partner?

# Available Investment Capital

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- **Producer spending can be put in three categories:**
  - Mandatory – loss of license if they don't
  - Should – monetary penalties / loss of production if they don't
  - Discretionary
- **2008 was a big Industry spend year. Now oil prices have fallen and global economy is in a recession. How much of the lack of new discretionary spending in Alaska is because the 'tax is too high' versus significant spending being directed to the top two categories above?**

# Wrap Up

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- Understand what comparative studies are and are not before you draw conclusions.
- Many important factors such as timing, ringfencing, signature bonuses are often left out.
- Do not underestimate the value of immediate write off and capital credits in balancing differences between Alaska and other regimes that may lack these, but have lower government take.
- Alaska's government take is competitive with most hydrocarbon prolific areas.


14

**TESTIMONY OF THE**

**ALASKA OIL AND GAS ASSOCIATION**

**TO THE SENATE FINANCE COMMITTEE**

**ABOUT THE FAILINGS OF THE**

**"ACES" PRODUCTION TAX**

**February 23, 2010**

Mr. Chairman and Members of the Committee:

My name is Marilyn Crockett and I am the Executive Director of the Alaska Oil and Gas Association ("AOGA"). AOGA is the trade association for the oil and gas industry in Alaska. Our 14 members account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. The testimony I am about to present has been prepared and approved without dissent by the members of the AOGA Tax Committee.

First of all, we apologize to the Committee for the fact that our testimony today cannot be a detailed or comprehensive review of the many problems, issues and failings of ACES. Instead, it is only an overview, a snapshot from 50,000 feet if you will, of what's wrong or going wrong with this tax. And we can offer at this time only a handful of specific examples to illustrate these problems — not because the examples are few, but because we were simply unable before this hearing to compile the many more examples that we could otherwise have presented. Also, during your hearings last week you were given information that was either inaccurate, incomplete or misleading, and we would like to use part of our time with you today to set the record straight on a number of those points.

ACES was proposed and enacted with two primary goals: One, to raise the amount of production taxes from what the State would have received under either the old ELF-based tax or the "Petroleum Production Tax" – also known as the "PPT" – that replaced the ELF. And two, to attract new capital investment for oil and gas exploration, development and production on the massive scale that is needed to mitigate the decline in production rates as the resource is depleted. These goals seem fundamentally inconsistent with one another. How can the tax be raised for the industry and at the same time have the tax attract greater industry investment here?

ACES' answer was to take the tax deduction and tax credits for new capital investments that PPT first created, modify the credits to make them less attractive, and substantially increase the amount of production taxes on the oil and gas industry. There are numerous technical problems in ACES that need to be fixed, and many others that

tax rate would be worth 30¢, and the 20% tax credit would be 12¢, making a total tax benefit of only 42 cents. This difference between a 42¢ tax benefit and a 70¢ one may not sound like very much, but if the hypothetical project being evaluated costs $100 million, it means $28 million would be drained out of its economic performance as perceived by the investment decision-maker, simply because of this lack of clarity in the tax. Put in these terms, one can begin to appreciate how the go/no-go decision for such an investment could be affected by a lack of clarity in ACES.

And the key point here is: this adverse impact on the investment decision will occur even if the Department of Revenue, after audit, would have ultimately found 100¢ of that dollar to be completely justified and proper. In other words, the tax benefit actually allowed would turn out to be 70¢ for that dollar, but only 42¢ of that benefit was taken into account by the decision-maker at the time of the investment decision. This is a terrible dilution or waste of the incentive for investing that ACES is designed to give.

There are clarity issues with the ACES statutes themselves, but as I mentioned, the regulations that the Department of Revenue has adopted and is in the process of adopting are compounding and re-compounding the uncertainty and lack of clarity. Attached to the written copies of this testimony is an attachment illustrating the kinds of uncertainty being created unnecessarily by the Department. I will not take the Committee's time to read that attachment now, but I invite you to peruse it at your leisure.

Bad as it is, that example is only the tip of the iceberg in terms of what is going wrong with the ACES regulations. There are many, many more examples that we could offer. The written comments and testimony submitted to the Department by AOGA and by individual companies about the issues and problems with the draft and final regulations run to nearly 200 pages — just on the subject of deductible lease expenditures. That total does not include what we told the Department about its tax-credit regulations. And, as Deputy Commissioner Marcia Davis acknowledged to this Committee last week, we expect to have a lot of comments about the transportation-cost regulations that the Department is proposing to adopt, especially since the Department is dispensing with the public workshop process and going straight to the public hearing for actually adopting them.

One final problem with the ACES regulations that I would draw to your attention is the fact that the Department of Revenue has totally failed to address the question of how the non-operating working-interest owners in a unit or other oil and gas property are supposed to comply with all these requirements. Each month the non-operating owners are required by ACES to report and pay estimated taxes, and on March 31 of the following year they have to "true up" those estimates to the actual results for the year. All that they have available when these reports and payments come due are the billings that they receive from the operator for their respective shares of the unit's costs. Even though the non-operating interests can and do audit the operator's billings to them, their audits are done for several years of billings at a time, and the billing periods in question for those

We are not suggesting, however, that the Department should rely blindly on the non-operators to audit the operator's billings. As Ronald Reagan famously said about dealing with the Soviet Union during the Cold War, "Trust, but verify." In the case of ACES, "verify" for the Department would mean auditing the automated system of accounts that each operator has for recording its expenditures as operator and billing out those costs to the non-operating participants. Particular cost codes within such a system of accounts could be identified by this audit as disallowed kinds of cost, and by giving notice to the operator and all the non-operating interests that those cost codes are disallowed, the Department would ensure that all the participants in a unit or property would be on the same page with respect to cost codes that are allowed and billable under their operating agreement but disallowed for ACES purposes. The Department's audits of individual companies could then be simplified to verifying that nothing in the disallowed cost codes was deducted by any of them in their respective ACES tax returns, thereby conserving audit resources while ensuring consistency among taxpayers.

At the same time the Department could "verify" the ongoing integrity of each automated system of accounts by periodically confirming, first, that the software for that system has not been changed since the Department's last audit of that system, or if changed, has not been changed incorrectly for ACES purposes. And if there has been an incorrect change, the Department would identify the resulting new cost codes that are disallowed and put all taxpayers in that unit or field on notice of those changes to the list of disallowed cost codes.

The Department of Revenue could actually do all these things without having to change any of the substance of what it intends to allow or disallow as lease expenditures in its new regulations. But, to do so, the Department — instead of using the regulations to define what is or is not allowed — needs to adopt its concepts of allowed and disallowed costs as audit standards that it will then apply and enforce in its audits of automated systems of accounts and software, as well as in its audits of any claimed lease expenditures for costs that a company may incur in house that are not billable to others under the applicable operating agreement.

We have proposed this alternative approach to the Department in each round of public workshops and hearings on the lease-expenditures regulations. And in each new draft that came out after a workshop or hearing, including the regulation that has just been adopted, this superior alternative was rejected. We do not know why. But if the Department of Revenue will not adopt this superior approach voluntarily for administering ACES, then perhaps one alternative solution to fix ACES would be to rewrite the tax statutes so the Department has no choice but to use this clearer and more efficient approach.

This is very different from the picture that the Department of Revenue pointed for the Committee last week. In fact, they even showed a slide quoting from a letter I wrote. In the interest of time, I won't read the entire quote, but this the heart of it:

in those projects. This is completely and fundamentally wrong.

The only tax credits that the State is actually spending money for are the ones that the Oil and Gas Tax Credit Fund buys from explorers and small producers that do not have enough production to incur ACES tax liability that they could apply their credits against. This expenditure is incurred because the State has made the policy choice to do this in order to attract more independent explorers and small producers to Alaska. And, for the record, let me say AOGA supports this goal: Having more companies exploring and producing here is good for our industry, as well as Alaska.

But the overall tax deductions and credits under ACES do not inherently share this special attribute of the subset of tax credits that the Tax Credit Fund actually buys. Think about it for a second. Suppose it were true that each dollar of tax benefit from a deduction or tax credit is literally an expenditure or investment by the State. What would this imply? Well, in order to be true, it would mean the State is legally entitled that dollar instead of the producer — the State, in other words, literally owns that dollar and is making an expenditure or investment to the extent it lets the producer have any part of it.

Applying this principle in other contexts would mean the State owns the value of the next fish that a commercial fishing boat catches, that it owns the room charge that a guest pays to stay at the Baranof tonight, and that it owns the sales proceeds for the next car that a dealership sells. And consistent with this, the State would be "spending" billions and billions of dollars to the extent it lets the fishers keep any of the value of their catch, lets hotels keep any of their guests' room charges, and lets car dealers keep any of the proceeds from their car sales. This certainly would take the expression "owner state" to an extraordinary degree of literalness, but it is not what we have in this country as our legal and economic system.

Some might object to what I've just said, arguing that the State actually is the owner of the oil and gas since it is the owner of the land from which the resource is produced. Such an objection breaks down, however, at two levels. First, ACES applies to oil and gas produced from land that the State does not own, such as Native corporation land and federal lands within Alaska's legal boundaries. For these non-state lands, the very premise for the objection is lacking. Second, and more fundamentally, it ignores the fact, although the State owns the land, it has sold the exclusive right to explore for, develop and produce oil and gas from that land. The State sold this right in each of its oil and gas lease sales, and it has been paid more than $2.1 billion in bonus bids through 2007 for selling this right. Paragraph 37 in the Form DL-1 leases that represent virtually all of the main Prudhoe Bay and Kuparuk fields states, "the rights vested in Lessee by this lease shall constitute an interest in real property in said land." In other words, what the lessees have paid for is not a license, but actual ownership.

Thus, when a producer produces oil or gas from a state lease, it owns all of its share of that oil or gas as it comes out of the ground. In fact, when the State takes its royalty in value instead of in kind as physical oil or gas, the physical oil or gas attributable to

field drilling like this has a rate of return of over 100 percent. Without getting side-tracked about the assumptions needed to mathematically allow rates of return to be that high, our reply is that, if in-field drilling is highly profitable, why did the number of these in-field wells decrease from 166 wells in 2007 to 153 in 2008 and 147 last year? Putting rhetoric or political posturing aside, this is the fact of the matter. And since we have been critical of the Department of Revenue, we should acknowledge at this point that the Department has disclosed this decline in its public ACES materials, although its numbers mistakenly include exploration wells.

The decline in in-field drilling is confirmed by public statements of the two major operators on the North Slope, ConocoPhillips and BP. For instance, John Mingé of BP told the Meet Alaska Conference last month that his company's "total drilled footage" for in-field wells "will be more than 50% lower in 2010 vs. 2007" when the figure was nearly one million feet drilled. He added that BP had "[r]educed our rig count from 10 to 7 from January last year." And I would point out that each drilling rig represents about a quarter of a million man-hours of work a year, or about 119 full-time equivalent jobs at 2100 hours of work per year. At that same Meet Alaska Conference Larry Archibald, the senior vice president of exploration and business development for the corporate parent in ConocoPhillips' organization, noted that industry in the last five years added about 450 million barrel-of-oil-equivalents to reserves for existing Alaska fields, but "Only 35 million since ACES".

The news is also bad for exploration wells. ConocoPhillips has been the leading explorer in Alaska for the last decade and more, focusing especially on the National Petroleum Reserve – Alaska, or NPR-A for short. But Helene Harding, who is now interim president of ConocoPhillips Alaska Inc., warned the Resource Development Council on November 18 last year that the number of North Slope exploration wells had declined from 11 in 2007, to nine in 2008 and eight in 2009, with the figure for 2010 expected to be even lower. More recently, Mr. Archibald in his remarks last month at Meet Alaska said ConocoPhillips will not be drilling any exploration wells in NPR-A this year, nor was he aware of any other company planning to do so this year. He noted that "Significant potential remains in North Slope Giants" but "Giant fields have worst fiscal terms" under ACES. Perhaps more ominous is the fact that Mr. Archibald told the conference that ConocoPhillips in 2009 had relinquished some 880,000 acres of leases that it had in NPR-A.

Now, lest we be accused of being misleading in this testimony to you, let us be absolutely clear: We do not claim that every single one of these signs of deterioration in the situation here has been solely the result of ACES. But ACES has necessarily been an economic factor within the overall circumstances surrounding each one of them. For some it may only have been a contributing factor, while for others it may have been decisive. It is even possible that ACES might not have been a material factor at all, although we would expect these to be very few in number. Be that as it may in particular situations, the point we wish to make is that these facts, taken as a whole, do provide a clear

Third, there are clear, but ominous signs that ACES is not succeeding in attracting as much new investment as it is supposed to do. This impending failure is reflected in the decline in drilling, both for exploration wells as well as development wells within existing fields. It is reflected in the relinquishment of huge amounts of exploration acreage. It is reflected in the declining amounts being invested for new projects and development.

In its public presentations about ACES and the future, ConocoPhillips — using DNR's production forecasts and extrapolating from published data by the Department of Revenue about industry expenditures — has identified a need for more than $40 billion dollars of new investments for "core fields" to make it through the next decade and reach the promised land, where Alaska has a Gas Pipeline, where the technological challenges are overcome to produce the billions of barrels of heavy oil that are already discovered and known to exist, and where the dream for half a century or more of production from the North Slope is fulfilled. Alaska is blessed simply to have the possibility of such a future. But, to help this future become a reality, the State must correct the present-day problems and obstacles being created artificially by its fiscal regime.

Thank you, Mr. Chairman, for allowing us this opportunity to testify to your Committee today.

an approved timesheet or other time writing documents:

(i) technical employees having special and specific engineering, geological, or other technical skills, including engineers, geologists, geophysicists, environmental specialists, and other technical personnel whose primary function with respect to that exploration, development, or production is the handling of specific problems or operating conditions involving the oil or gas exploration, development, or production operations or the support of those operations;

(ii) employees engaged in developing field automation systems dedicated to an specific to a unit or a lease or property and necessary for oil or gas production operations of the unit or the lease or property;

(iii) employees engaged in developing computer applications specific to a unit or a lease or property and necessary for oil or gas development or production operations of the unit or the lease or property;

...

(11) costs paid to a third party for contract services, utilities, or use of a facility equipment, or infrastructure provided by the third party and used in oil or gas exploration, development, or production operations, or used in support of those operations, or for use of a system described in 15 AAC 55.-250(c)(10) or (11) provided by the third party; for purposes of this paragraph,

(A) contract services

(i) do not include work in tax, legal, or accounting matters, or matters involving a dispute before a government agency;

(ii) are limited to services the labor costs of which, under (3) of this subsection, would be allowable as direct charges if the operator's employees performed the services[.]

Simply reading this regulation should speak for itself about how hard it is just to make sense of what it's saying. But even after one does read it a few times and finally figures out what it means, there are three hidden ways in which it fails to be clear.

First, subparagraph (a)(3)(A) requires an operator's own non-technical employees to be "directly employed in or in support of oil or gas exploration, development, or production operations" in order for their labor costs to be allowed as lease expenditures. But there is no definition or other indication about what "directly" means in the context of being "directly employed in ... oil or gas ... operations[.]" Since the entire regulation is defining what the "direct costs" are of oil and gas operations, the lack of any definition of "directly" within this regulation makes its logic circular. In addition, there is no objective standard for determining whether an employee is even "employed" at all "in support of [such] operations" — be it "directly" or otherwise.

happens even if the regulation is correctly applied and an employer's contributions turns out to exceed the specified percentages.