HB 3001

<TARGET><BILL>HB3001</BILL><SUBJECT>HB3001</SUBJECT><COMM
>HRES27</COMM></TARGET>

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Governor Sean Parnell
STATE OF ALASKA

April 18, 2012

The Honorable Mike Chenault
Speaker of the House
Alaska State Legislature
State Capitol, Room 208
Juneau, AK 99801-1182

Dear Speaker Chenault,

Alaska's oil belongs to Alaskans, and oil production drives Alaskan opportunity. Alaskan engineers, contractors, and maintenance personnel earn their livelihoods from oil production; but so – indirectly – do restaurateurs, retailers, working men and women of all trades, and business owners. Oil production also supports the public sector, providing revenue that creates opportunities for schools, public safety, roads, libraries, energy infrastructure, and many other services for Alaskans.

Alaskans are well aware that oil production from the legacy fields is declining. The costs of maintaining a declining field go up, and higher cost barrels of oil get left in the ground if they are not economic to produce. That is the risk – that without meaningful tax change for legacy fields as well as new fields, a larger percentage of Alaskans' resource will remain locked in the ground. We can avoid this risk and ensure a more prosperous future for Alaskans if we are willing to continue working to increase oil production in all of Alaska's fields.

We must take decisive action to ensure that Alaska's petroleum resources are developed sensibly, starting with a tax structure that is designed not to maximize short-term revenues, but rather to ensure Alaska's long-term competitiveness. The Legislature has completed much study, the public is better informed, and the House and Senate now have positions on the table.

I am submitting a piece of legislation that blends the positions of the House and Senate into a comprehensive approach that will bring economic opportunity to Alaskans for generations to come. Under the authority of Article III, Section 18 of the Alaska Constitution, I am transmitting a bill proposing amendments to Alaska's oil and gas production tax. The bill would provide tax incentives for the oil and gas industry to increase exploration for new sources and greater development of existing fields.

The bill incentivizes new oil and gas production on the North Slope by providing a 30 percent exclusion, based on gross value at the point of production, from the production tax value used to calculate the base rate and the progressivity tax for the first ten years of sustained production from fields that were not, as of January 1, 2008, within a unit or in commercial production. For currently producing North Slope fields, the bill establishes an exclusion of 40 percent of gross value at the

point of production from the monthly production tax value used to calculate the progressivity tax. The bill caps progressivity by establishing a 60 percent maximum rate. Finally, the bill would extend tax incentives for well lease expenditures available elsewhere in the state through AS 43.55.023(l) to North Slope activities and would allow producers to apply tax credits in one year. These changes are designed both to encourage development of new, currently undeveloped leases or properties, and from known fields in the state.

These changes to Alaska's oil tax regime would foster new production sources and encourage further development of current sources to stem the decline in North Slope production.

I urge your prompt and favorable action on this measure.

Sincerely,

Sean Parnell
Governor

Enclosure

HOUSE BILL NO. 3001

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SEVENTH LEGISLATURE - THIRD SPECIAL SESSION

BY THE HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced: 4/18/12
Referred:

A BILL

FOR AN ACT ENTITLED

"An Act relating to adjustments to oil and gas production tax values based on a percentage of gross value at the point of production for oil and gas produced from leases or properties north of 68 degrees North latitude; relating to monthly installment payments of the oil and gas production tax; relating to the determinations of oil and gas production tax values; relating to oil and gas production tax credits including qualified capital credits for exploration, development, or production; making conforming amendments; and providing for an effective date."

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

*** Section 1.** AS 43.55.011(e) is amended to read:

(e) There is levied on the producer of oil or gas a tax for all oil and gas produced each calendar year from each lease or property in the state, less any oil and gas the ownership or right to which is exempt from taxation or constitutes a landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of

this section, the tax is equal to the sum of

(1) the annual production tax value of the taxable oil and gas as calculated under AS 43.55.160(a)(1)**, as adjusted by AS 43.55.162 if applicable,** multiplied by 25 percent; and

(2) the sum, over all months of the calendar year, of the tax amounts determined under (g) of this section.

*** Sec. 2.** AS 43.55.011(g) is amended to read:

(g) For each month of the calendar year for which the producer's average monthly production tax value under AS 43.55.160(a)(2) per BTU equivalent barrel of the taxable oil and gas is more than $30, the amount of tax for purposes of (e)(2) of this section is determined by multiplying the monthly production tax value**, as adjusted by AS 43.55.162 if applicable,** of the taxable oil and gas produced during the month by the tax rate calculated as follows:

(1) if the producer's average monthly production tax value per BTU equivalent barrel of the taxable oil and gas for the month is not more than $92.50, the tax rate is 0.4 percent multiplied by the number that represents the difference between that average monthly production tax value per BTU equivalent barrel and $30; or

(2) if the producer's average monthly production tax value per BTU equivalent barrel of the taxable oil and gas for the month is more than $92.50, the tax rate is the sum of 25 percent and the product of 0.1 percent multiplied by the number that represents the difference between the average monthly production tax value per BTU equivalent barrel and $92.50, except that the sum determined under this paragraph may not exceed **35** [50] percent.

*** Sec. 3.** AS 43.55.020(a) is amended to read:

(a) For a calendar year, a producer subject to tax under **AS 43.55.011** [AS 43.55.011(e) - (i)] shall pay the tax as follows:

(1) an installment payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each month of the calendar year on the last day of the following month; except as otherwise provided under (2) of this subsection, the amount of the installment payment is the sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be

applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount of the installment payment may not be less than zero:

(A) for oil and gas **not subject to AS 43.55.011(o)** produced from leases or properties in the state outside the Cook Inlet sedimentary basin [BUT NOT SUBJECT TO AS 43.55.011(o)], other than leases or properties subject to AS 43.55.011(f), the greater of

(i) zero; or

(ii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the leases or properties under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

(B) for oil and gas produced from leases or properties subject to AS 43.55.011(f), the greatest of

(i) zero;

(ii) zero percent, one percent, two percent, three percent, or four percent, as applicable, of the gross value at the point of production of the oil and gas produced from all leases or properties during the month for which the installment payment is calculated; or

(iii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for those leases or properties under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from those leases or properties during the month for which the installment payment is calculated; **for oil and gas for which an adjustment to the monthly production tax value is made by AS 43.55.162(a) or (b),**

the same adjustment is made to the remainder under this sub-subparagraph;

(C) for oil and gas **subject to AS 43.55.011(j), (k), or (o)** produced from each lease or property [SUBJECT TO AS 43.55.011(j), (k), OR (o)], the greater of

(i) zero; or

(ii) the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible under AS 43.55.160 for oil or gas, respectively, produced from the lease or property from the gross value at the point of production of the oil or gas, respectively, produced from the lease or property during the month for which the installment payment is calculated;

(2) an amount calculated under (1)(C) of this subsection for oil or gas produced from a lease or property subject to AS 43.55.011(j), (k), or (o) may not exceed the product obtained by carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable gas produced during the month for the amount of taxable gas produced during the calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount of taxable oil produced during the month for the amount of taxable oil produced during the calendar year;

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

(A) the applicable tax rate for oil provided under AS 43.55.011(i), multiplied by the gross value at the point of production of the

oil taxable under AS 43.55.011(i) and produced from the lease or property during the month; and

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

(4) any amount of tax levied by AS 43.55.011(e) or (i), net of any credits applied as allowed by law, that exceeds the total of the amounts due as installment payments of estimated tax is due on March 31 of the year following the calendar year of production.

*** Sec. 4.** AS 43.55.023(a) is amended to read:

(a) A producer or explorer may take a tax credit for a qualified capital expenditure as follows:

(1) notwithstanding that a qualified capital expenditure may be a deductible lease expenditure for purposes of calculating the production tax value of oil and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a qualified capital expenditure may also elect to apply a tax credit against a tax levied by AS 43.55.011(e) in the amount of 20 percent of that expenditure; [HOWEVER, NOT MORE THAN HALF OF THE TAX CREDIT MAY BE APPLIED FOR A SINGLE CALENDAR YEAR;]

(2) a producer or explorer may take a credit for a qualified capital expenditure incurred in connection with geological or geophysical exploration or in connection with an exploration well only if the producer or explorer

(A) agrees, in writing, to the applicable provisions of AS 43.55.025(f)(2); and

(B) submits to the Department of Natural Resources all data that would be required to be submitted under AS 43.55.025(f)(2).

*** Sec. 5.** AS 43.55.023(d) is amended to read:

(d) Except as limited by (i) of this section, a person that is entitled to take a tax credit under this section that wishes to transfer the unused credit to another person or

obtain a cash payment under AS 43.55.028 may apply to the department for **a** transferable tax credit **certificate** [CERTIFICATES]. An application under this subsection must be in a form prescribed by the department and must include supporting information and documentation that the department reasonably requires. The department shall grant or deny an application, or grant an application as to a lesser amount than that claimed and deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the year following the calendar year in which the qualified capital expenditure**, well lease expenditure,** or carried-forward annual loss for which the credit is claimed was incurred; (2) the date the statement required under AS 43.55.030(a) or (e) was filed for the calendar year in which the qualified capital expenditure**, well lease expenditure,** or carried-forward annual loss for which the credit is claimed was incurred; or (3) the date the application was received by the department. If, based on the information then available to it, the department is reasonably satisfied that the applicant is entitled to a credit, the department shall issue the applicant **a** [TWO] transferable tax credit **certificate for** [CERTIFICATES, EACH FOR HALF OF] the amount of the credit. [THE CREDIT SHOWN ON ONE OF THE TWO CERTIFICATES IS AVAILABLE FOR IMMEDIATE USE. THE CREDIT SHOWN ON THE SECOND OF THE TWO CERTIFICATES MAY NOT BE APPLIED AGAINST A TAX FOR A CALENDAR YEAR EARLIER THAN THE CALENDAR YEAR FOLLOWING THE CALENDAR YEAR IN WHICH THE CERTIFICATE IS ISSUED, AND THE CERTIFICATE MUST CONTAIN A CONSPICUOUS STATEMENT TO THAT EFFECT.] A certificate issued under this subsection does not expire.

*** Sec. 6.** AS 43.55.023(g) is amended to read:

(g) The issuance of a transferable tax credit certificate under (d) **of this section** or **former** (m) of this section or the purchase of a certificate under AS 43.55.028 does not limit the department's ability to later audit a tax credit claim to which the certificate relates or to adjust the claim if the department determines, as a result of the audit, that the applicant was not entitled to the amount of the credit for which the certificate was issued. The tax liability of the applicant under AS 43.55.011(e) and 43.55.017 - 43.55.180 is increased by the amount of the credit

that exceeds that to which the applicant was entitled, or the applicant's available valid outstanding credits applicable against the tax levied by AS 43.55.011(e) are reduced by that amount. If the applicant's tax liability is increased under this subsection, the increase bears interest under AS 43.05.225 from the date the transferable tax credit certificate was issued. For purposes of this subsection, an applicant that is an explorer is considered a producer subject to the tax levied by AS 43.55.011(e).

*** Sec. 7.** AS 43.55.023(*l*) is amended to read:

(*l*) A producer or explorer may apply for a tax credit for a well lease expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE] after **December 31, 2012** [JUNE 30, 2010], as follows:

(1) notwithstanding that a well lease expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE] may be a deductible lease expenditure for purposes of calculating the production tax value of oil and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under (a) of this section, AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a well lease expenditure in the state [SOUTH OF 68 DEGREES NORTH LATITUDE] may elect to apply a tax credit against a tax levied by AS 43.55.011(e) in the amount of 40 percent of that expenditure; [A TAX CREDIT UNDER THIS PARAGRAPH MAY BE APPLIED FOR A SINGLE CALENDAR YEAR;]

(2) a producer or explorer may take a credit for a well lease expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE] in connection with geological or geophysical exploration or in connection with an exploration well only if the producer or explorer

(A) agrees, in writing, to the applicable provisions of AS 43.55.025(f)(2); and

(B) submits to the Department of Natural Resources all data that would be required to be submitted under AS 43.55.025(f)(2).

*** Sec. 8.** AS 43.55.023(n) is amended to read:

(n) For the purposes of (*l*) [AND (m)] of this section, a well lease expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE] is a lease

expenditure that is

(1) directly related to an exploration well, a stratigraphic test well, a producing well, or an injection well other than a disposal well, located in the state [SOUTH OF 68 DEGREES NORTH LATITUDE], if the expenditure is a qualified capital expenditure and an intangible drilling and development cost authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made under 26 U.S.C. 263(c); in this paragraph, an expenditure directly related to a well includes an expenditure for well sidetracking, well deepening, well completion or recompletion, or well workover, regardless of whether the well is or has been a producing well; or

(2) an expense for seismic work conducted within the boundaries of a production or exploration unit.

*** Sec. 9.** AS 43.55.028(e) is amended to read:

(e) The department, on the written application of a person to whom a transferable tax credit certificate has been issued under AS 43.55.023(d) or **former AS 43.55.023(m)** [(m)] or to whom a production tax credit certificate has been issued under AS 43.55.025(f), may use available money in the oil and gas tax credit fund to purchase, in whole or in part, the certificate if the department finds that

(1) the calendar year of the purchase is not earlier than the first calendar year for which the credit shown on the certificate would otherwise be allowed to be applied against a tax;

(2) [REPEALED

(3) REPEALED

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

(3) [(5)] the applicant's total tax liability under AS 43.55.011(e), after application of all available tax credits, for the calendar year in which the application is made is zero;

(4) [(6)] the applicant's average daily production of oil and gas taxable under AS 43.55.011(e) during the calendar year preceding the calendar year in which the application is made was not more than 50,000 BTU equivalent barrels; and

(5) [(7)] the purchase is consistent with this section and regulations adopted under this section.

*** Sec. 10.** AS 43.55.028(g) is amended to read:

(g) The department may adopt regulations to carry out the purposes of this section, including standards and procedures to allocate available money among applications for purchases under this chapter and claims for refunds under AS 43.20.046 when the total amount of the applications for purchase and claims for refund exceed the amount of available money in the fund. The regulations adopted by the department may not, when allocating available money in the fund under this section, distinguish an application for the purchase of a credit certificate issued under **former** AS 43.55.023(m) or a claim for refund under AS 43.20.046.

*** Sec. 11.** AS 43.55.160(a) is repealed and reenacted to read:

(a) Except as provided in (b) of this section and AS 43.55.162, for the purposes of

(1) AS 43.55.011(e), the annual production tax value of taxable oil, gas, or oil and gas subject to this paragraph produced by a producer during a calendar year is equal to the gross value at the point of production of that oil, gas, or oil and gas, respectively, taxable under AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the calendar year that are applicable to the oil, gas, or oil and gas, as applicable, in that category produced by the producer, as adjusted under AS 43.55.170; this paragraph applies to

(A) oil and gas produced during the first 10 consecutive years after the start of sustained production or during the first 10 consecutive years of sustained production after the effective date of this section, whichever is later, from leases or properties north of 68 degrees North latitude that were not, as of January 1, 2008, either within a unit or in commercial production, other than gas produced before 2022 and used in the state;

(B) oil and gas not subject to (A) of this paragraph produced from leases or properties north of 68 degrees North latitude other than gas produced before 2022 and used in the state;

(C) oil and gas produced from leases or properties in the state

outside the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North latitude; this subparagraph does not apply to gas produced before 2022 and used in the state;

(D) oil produced before 2022 from a lease or property in the Cook Inlet sedimentary basin;

(E) gas produced before 2022 from a lease or property in the Cook Inlet sedimentary basin;

(F) gas produced before 2022 from a lease or property in the state outside the Cook Inlet sedimentary basin and used in the state;

(G) oil and gas produced from a lease or property, no part of which is north of 68 degrees North latitude, other than oil or gas described in (C), (D), (E), or (F) of this paragraph;

(2) AS 43.55.011(g), the monthly production tax value of taxable oil, gas, or oil and gas produced by a producer during a calendar month, for which a separate production tax value is required to be calculated under this paragraph, is equal to the gross value at the point of production of that oil, gas, or oil and gas, respectively, taxable under AS 43.55.011(e), less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year that are applicable to the oil, gas, or oil and gas, respectively, in that category produced by the producer during the calendar month, as adjusted under AS 43.55.170; a separate monthly production tax value must be calculated for each category of oil, gas, or oil and gas for which a separate annual production tax value is required to be calculated under (1) of this subsection.

*** Sec. 12.** AS 43.55.160(e) is amended to read:

(e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that would otherwise be deductible by a producer in a calendar year but whose deduction would cause an annual production tax value calculated under (a)(1) of this section of taxable oil or gas produced during the calendar year to be less than zero may be used to establish a carried-forward annual loss under AS 43.55.023(b). However, the department shall provide by regulation a method to ensure that, for a period for which a producer's tax liability is limited by AS 43.55.011(j), (k), or (o), any adjusted lease

expenditures under AS 43.55.165 and 43.55.170 that would otherwise be deductible by a producer for that period but whose deduction would cause a production tax value calculated under **(a)(1)(D), (E), or (F)** [(a)(1)(C), (D), OR (E)] of this section to be less than zero are accounted for as though the adjusted lease expenditures had first been used as deductions in calculating the production tax values of oil or gas subject to any of the limitations under AS 43.55.011(j), (k), or (o) that have positive production tax values so as to reduce the tax liability calculated without regard to the limitation to the maximum amount provided for under the applicable provision of AS 43.55.011(j), (k), or (o). Only the amount of those adjusted lease expenditures remaining after the accounting provided for under this subsection may be used to establish a carried-forward annual loss under AS 43.55.023(b). In this subsection, "producer" includes "explorer."

*** Sec. 13.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.162. Reduction of production tax value for certain oil and gas. (a) For purposes of AS 43.55.011(e)(1) and (2), the annual production tax value for a calendar year under AS 43.55.160(a)(1) and the monthly production tax value for a month under AS 43.55.160(a)(2) of oil and gas produced during the first 10 consecutive years after the start of sustained production or during the first 10 consecutive years after the effective date of this section, whichever is later, from leases or properties north of 68 degrees North latitude that were not, as of January 1, 2008, either within a unit or in commercial production, are reduced by 30 percent of the gross value at the point of production of that oil and gas produced from those leases or properties during the calendar year or during the month respectively.

(b) For purposes of AS 43.55.011(e)(2), the monthly production tax value for a month of oil and gas produced from leases or properties north of 68 degrees North latitude, other than oil and gas subject to (a) of this section, is reduced by 40 percent of the gross value at the point of production of that oil and gas produced during the month from those leases or properties.

(c) The annual and monthly production tax value may not be reduced under this section below zero.

(d) The tax rate under AS 43.55.011(g) shall be determined before the

application of the reduction provided by this section.

(e) This section does not apply to gas produced before 2022 and used in the state.

(f) If the annual or monthly gross value at the point of production is zero or below, an adjustment is not made under this section.

* **Sec. 14.** AS 43.55.023(m) is repealed.

* **Sec. 15.** The uncodified law of the State of Alaska is amended by adding a new section to read:

APPLICABILITY. (a) Sections 7 and 8 of this Act apply to expenditures incurred after December 31, 2012.

(b) Sections 1 - 3 and 11 - 13 of this Act apply to oil, gas, or oil and gas produced after December 31, 2012.

(c) Sections 4 - 6 of this Act apply to expenditures incurred after December 31, 2011.

* **Sec. 16.** The uncodified law of the State of Alaska is amended by adding a new section to read:

RETROACTIVITY. Sections 4 - 6, 9, 10, and 14 of this Act are retroactive to January 1, 2012.

* **Sec. 17.** The uncodified law of the State of Alaska is amended by adding a new section to read:

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

* **Sec. 18.** The uncodified law of the State of Alaska is amended by adding a new section to read:

REVISOR'S INSTRUCTION. If HCS CSSB 23(RLS) am H passed by the Twenty-Seventh Alaska State Legislature becomes law, the revisor of statutes shall give preference to this Act if a conflict arises among provisions when consolidating these Acts into the Alaska Statutes.

* **Sec. 19.** Sections 1 - 3, 7, 8, and 11 - 13 of this Act take effect January 1, 2013.

* **Sec. 20.** Except as provided in sec. 19 of this Act, this Act takes effect immediately under

AS 01.10.070(c).

FISCAL NOTE

STATE OF ALASKA cost ≠ codes
2012 LEGISLATIVE SESSION

Bill Version: **HB 3001**
Fiscal Note Number: **1**
Publish Date: **4/18/12 (H)**

Identifier (file name): 0358-DOR-TAX-04-18-12
Title: Oil and Gas Production Tax
Sponsor: Request of the Governor
Requester: Governor

Dept. Affected: Revenue
Appropriation: Treasury and Taxation
Allocation: Tax Division
OMB Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY13**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	**0.0**		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF	0.0		0.0	0.0	0.0	0.0	0.0
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

POSITIONS							
Full-time							
Part-time							
Temporary							

CHANGE IN REVENUES	***		***	***	***	***	***

Estimated SUPPLEMENTAL (FY12) operating costs _____ *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs _____ *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

This is the initial version of the bill.

Prepared by: Dan Stickel and Cherie Nienhuis, Economists — Phone: 907-465-3279
Division: Tax — Date/Time: 04/18/12 10:30am
Approved by: Bryan D. Butcher, Commissisoner — Date: 4/18/2012
Department of Revenue

(Revised 8/17/2011 OMB)

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. HB 3001

Analysis

The revenue impact of this bill is indeterminate.

This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with its potential revenue impact, is discussed below.

1. **A gross revenue exclusion is created for calculating the base tax and the progressive tax for North Slope production in areas that were not unitized or in commercial production as of January 1, 2008.** For production from qualifying areas, the production tax value is adjusted by 30 percent of the gross value at point of production for purposes of calculating the base tax and progressive tax due. The tax rates are calculated before application of this adjustment, and the production tax value may not be reduced below zero. The qualifying new fields provisions are effective for the first 10 years of production, after which the field would be taxed at the same rate as non-qualifying production. The effective date of this provision is 1/1/2013. Estimated revenue impacts based on our Fall 2011 revenue forecast assumptions, and illustrations of higher production levels, are shown in following tables.

2. **A gross revenue exclusion is created for calculating the progressive tax for North Slope production in areas that were unitized or in commercial production as of January 1, 2008.** For production from qualifying areas, the production tax value is adjusted by 40 percent of the gross value at point of production for purposes of calculating the progressive tax due (no change in calculation of the base tax). The tax rates are calculated before application of this adjustment, and the production tax value may not be reduced below zero. The effective date of this provision is 1/1/2013. Estimated revenue impacts based on our Fall 2011 revenue forecast assumptions, and illustrations of higher production levels, are shown in following tables.

3. **The maximum production tax rate is reduced from 75% to 60%.** Currently, the maximum production tax rate is 75% (25% base rate and 50% progressive rate) which would apply at a production tax value of $342.50 per barrel. This bill reduces the maximum rate to 60% (25% base rate and 35% progressive rate) which would apply at a production tax value of $192.50. The effective date of this provision is 1/1/2013. While this provision would provide a benefit and maintain the efficacy of the tax system at extremely high prices, we do not forecast a revenue impact because prices are expected to be lower than what would be needed to invoke the 60% maximum rate.

4. **The provision requiring that credits be taken over two years is eliminated.** This provision would result in companies using credits earlier than they would without this change, and except for time value of money impact, it is revenue neutral. This provision applies to expenditures after 12/31/2011. Using the Fall 2011 forecast assumptions, this provision is expected to increase credits taken in CY 2012 by around $400 million (presented in FY 13 for this fiscal note). Since the credit redemption is brought forward, not increased, a corresponding decrease in credit redemption would be expected in CY 2013 (presented in FY 2014). The impact would be seen in both tax liabilities and credits for refund, which are paid through appropriation.

5. **The 40% credit for well lease expenditures is expanded to include qualified expenditures incurred north of 68 degrees North Latitude.** This provision applies to expenditures incurred after 12/31/2012. Over the time horizon of this fiscal note, we estimate this provision will have an annual fiscal impact of between $200 million and $400 million annually. The fiscal impact would be seen in both tax liabilities and credits for refund, which are paid through appropriation. These estimates do not include any additional production or investment that might result from this bill.

FISCAL NOTE #1

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. HB 3001

Analysis

Estimated Change In Production Tax and Royalty Revenue (in $millions) and illustrations with additional production - impact of gross revenue exclusion only *					
Year	Estimated Change	Forecast + 5%	Forecast + 10%	Forecast + 15%	Forecast + 20%
FY 2013	-$575	-$525	-$400	-$300	-$150
FY 2014	-$1,075	-$800	-$550	-$300	-$50
FY 2015	-$900	-$650	-$450	-$200	$25
FY 2016	-$900	-$700	-$475	-$225	$0
FY 2017	-$850	-$650	-$425	-$225	$0
FY 2018	-$1,025	-$800	-$600	-$375	-$125

* In addition to our estimate of the fiscal impact of this provision, this table illustrates the production tax and royalty (including PF and SF contributions) fiscal impact of this bill with additional production, versus status quo with forecasted production. For purposes of this illustration, we simply increase all forecast production and costs by a flat percentage beginning 1/1/2013.

Estimated Change In Production Tax Revenue (in $millions) and illustrations with additional production - impact of gross revenue exclusion only *					
Year	Estimated Change	Forecast + 5%	Forecast + 10%	Forecast + 15%	Forecast + 20%
FY 2013	-$575	-$575	-$500	-$500	-$400
FY 2014	-$1,075	-$900	-$775	-$650	-$525
FY 2015	-$900	-$775	-$675	-$550	-$425
FY 2016	-$900	-$800	-$675	-$550	-$450
FY 2017	-$850	-$750	-$625	-$525	-$400
FY 2018	-$1,025	-$900	-$800	-$675	-$525

* In addition to our estimate of the fiscal impact of this provision, this table illustrates the production tax only fiscal impact of this bill with additional production, versus status quo with forecasted production. For purposes of this illustration, we simply increase all forecast production and costs by a flat percentage beginning 1/1/2013.

Analysis

Provisions in Bill and their Estimated Fiscal Impact as compared to Fall 2011 Forecast ($millions)						
Brief Description of Provisions	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**
1, 2. Gross revenue exclusion for new and existing fields.	-$575	-$1075	-$900	-$900	-$850	-$1025
3. Maximum tax rate changed from 75% to 60%.	$0	$0	$0	$0	$0	$0
4. Eliminate the provision that credits must be taken over two years.(1)	-$400	$400	$0	$0	$0	$0
5. Expand the well lease expenditure credit to include expenditures in areas north of 68 degrees North Latitude.(1)	-$200 to -$400	-$200 to -$400	-$200 to -$400	-$200 to -$400	-$200 to -$400	-$200 to -$400
TOTAL FISCAL IMPACT	**-$1175 to -$1375**	**-$875 to -$1075**	**-$1100 to -$1300**	**-$1100 to -$1300**	**-$1050 to -$1250**	**-$1225 to -$1425**

(1) The fiscal impact for these provisions would be seen both in changes to tax liability (ie, change in revenues) and in changes to credits available for refund, which are funded through the appropriation process (ie, change in expenditures).

Department of Revenue

Gross revenue exclusion for North Slope production and production tax credits

SECTIONAL ANALYSIS HB 3001

Tax calculations and monthly payments

Section 1: Amends AS 43.55.011(e), which levies the oil and gas production tax, to account for adjustments as set out in new AS 43.55.162 to the annual production tax value used to determine the levy of tax for certain new production from leases or properties north of 68 degrees North latitude. This change is effective January 1, 2013, and applies to oil and gas produced after December 31, 2012.

Section 2: Amends AS 43.55.011(g), the progressivity tax, to provide for adjustments under new AS 43.55.162 to the progressivity tax calculated for production from new and currently producing North Slope fields. For oil and gas production statewide, the percentage of the progressivity tax that can be added to the 25% base tax is reduced from 50% to 35% percent, for a total maximum tax of 60%. This change is effective January 1, 2013, and applies to oil and gas produced after December 31, 2012.

Section 3: This is a conforming amendment to AS 43.55.020(a), monthly installment payments, to include the tax adjustment under AS 43.55.162 if applicable, for monthly payment of estimated taxes for oil and gas produced from leases or properties on the North Slope.

Well lease expenditure credit and tax credit certificates

Section 4: AS 43.55.023(a) is amended to remove the requirement that tax credits for qualified capital expenditures be applied against taxes over two years. Tax credits could be used in a single calendar year, instead of split over two years. This change would be effective January 1, 2012.

Section 5: AS 43.55.023(d) is amended to provide that transferable tax credit certificates will be issued as one certificate and to remove the requirements that capital expenditures, well lease expenditures, and carried-forward annual loss certificates be applied against taxes over two years. This change would be effective January 1, 2012.

Section 6: A conforming amendment is made to AS 43.55.023(g), issuance of tax credit certificates, to account for the change that the tax credit certificate may be applied in a single calendar year.

Section 7: Amends AS 43.55.023(*l*) to expand the 40% well lease expenditure credit to qualified expenditures made for exploration or development wells north of 68 degrees North latitude. This change is effective for expenditures made after December 31, 2012.

Section 8: Amends AS 43.55.023(n) defining well lease expenditures, to include the expansion of the 40% credit to expenditures made for exploration or development wells north of 68 degrees North latitude.

Sections 9-10: These conforming amendments to AS 43.55.028(e) and (g) account for the repeal of AS 43.55.023(m) related to issuance of tax credit certificates and applications to the oil and gas tax credit fund for purchase of the tax credit certificate.

Section 11: AS 43.55.160(a), determination of annual and monthly production tax values, is repealed and reenacted to reorganize and clarify the calculation of annual and monthly production tax values that must be determined for each category of production to which a special tax calculation applies. This section is amended to recognize two new categories of production on land north of 68 degrees North latitude to reflect the new categories set out by AS 43.55.162. This section also simplifies the directions related to monthly production tax value calculations in subsection (2) that must be calculated for each category of oil, gas, or oil and gas for which an annual production tax value must be calculated.

Section 12: A conforming amendment is made to AS 43.55.160(e), determination of excess lease expenditures available for calculation of the carried-forward annual loss credit for categories of production subject to tax limitations.

Gross Revenue Exclusion

Section 13: Amends AS 43.55 to add a new section, AS 43.55.162. Subsection (a) establishes a new reduction (exclusion) to production tax value that is applied to the 25% base rate and progressivity. The reduction (exclusion) to production tax value is 30% of gross value at the point of production for the first 10 years of sustained production from a lease or property that was not in a unit or in commercial production as of January 1, 2008.

Subsection (b) establishes a reduction in the production tax value for purposes of applying progressivity for oil and gas produced from leases or property north of 68 degrees North latitude and not subject to subsection (a). The reduction to production tax value is 40% of gross value at the point of production.

Subsection (c) provides that the annual and monthly production tax value may not be less than zero and that if the applicable gross value of the oil and gas used to calculate the adjustment under AS 43.55.162 is zero or below, no adjustment is made.

Subsection (d) provides that the progressivity tax rate shall be determined before the application of the AS 43.55.162 adjustment. This section is effective January 1, 2013 for oil and gas produced after December 31, 2012.

Technical and Effective Dates

Section 14: Repeals AS 43.55.023(m) so that the department will issue one tax certificate regardless of the location of the exploration, development, or production expenditures.

Section 15: Application section setting out that production after December 31, 2012 qualifies for the tax rates and expenditures after December 31, 2011 qualify for the expanded well lease expenditure credit.

Section 16-20: Provisions for retroactivity, revisor's instructions, and effective dates.

Presentation to the
House Resources Committee
April 20, 2012

HB 3001
Goals

- To incentivize production on the North Slope, both within and outside existing units
- To generate additional jobs and activity for the Alaska economy
- To build on work already undertaken in legislative committees during the regular session
- To maintain existing structure of ACES, with slight modifications
- To maintain alignment of working interest owners by not tying incentives to individual companies

HB 3001
Key Provisions

- 30% gross revenue exclusion for calculating base tax and progressive tax for qualifying new North Slope fields
- 40% gross revenue exclusion for calculating progressive tax for other North Slope fields
- Maximum tax rate changed from 75% to 60%
- Extends 40% well lease expenditure credit to North Slope
- Allows capital credits to be redeemed in the year earned (currently must be spread over 2 years)

HB 3001
Hybrid of Other Tax Proposals

- Gross revenue exclusion introduced in Senate Finance Committee during regular session as a way to incentivize production
- Production tax cap of 60% introduced in Senate Resources Committee during regular session as a way to limit state take at high oil prices
- Well lease expenditure credit introduced and enacted in 2010 through Cook Inlet Recovery Act (HB 280)

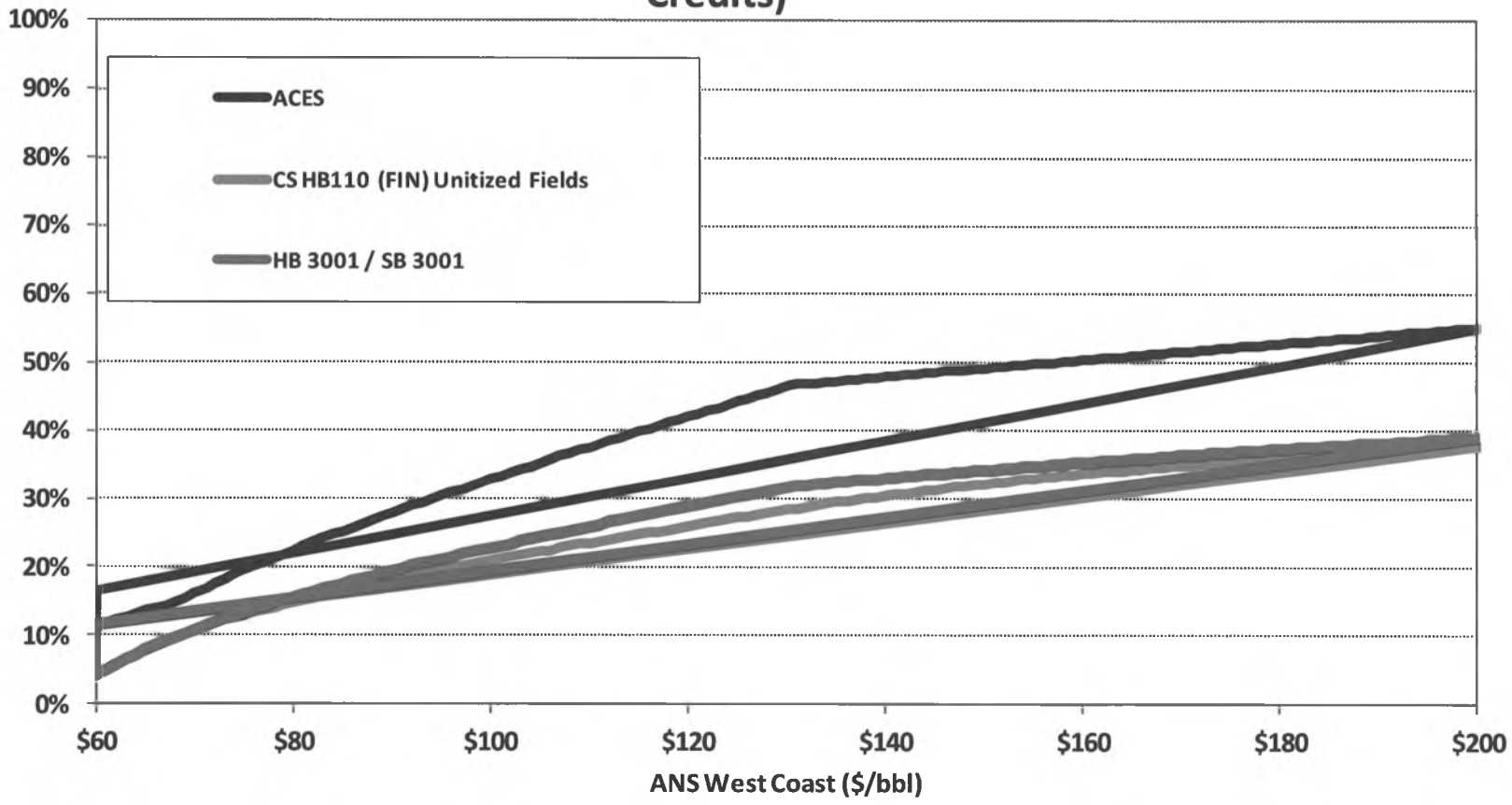
How the Gross Revenue Exclusion Works

FY 2013 Production Tax Estimates - for ILLUSTRATION ONLY - Assumes HB/SB 3001 in place for all of FY13

	Column A	B	C	D	E
		Price	Barrels	ACES ($M)	HB/SB 3001 Existing ($M)
1	**Avg ANS Oil Price ($/bbl) & Daily Production (bbls)**	$109.47	555,227	$60.8	$60.8
2	Sales value total barrels		202,657,895	$22,185.1	$22,185.1
3					
4	**Downstream (Transportation) Costs ($/bbl)**				
5	ANS Marine Transportation	-$2.70			
6	TAPS Tariff	-$4.96			
7	Other	-$0.91			
8	Total Transportation Costs	-$8.56	202,657,895	($1,735.3)	($1,735.3)
9					
10	Wellhead value total barrels	$100.91		$20,449.9	$20,449.9
11	Royalty, Federal and other barrels		-30,158,081	($3,043.2)	($3,043.2)
12	Gross value at Point of Production (GVPP)		172,499,814	$17,406.7	$17,406.7
13					
14	**Deductible Lease Expenditures**				
15	Deductible Operating Expenditures	-$13.75		($2,372.5)	($2,372.5)
16	Deductible Capital Expenditures	-$15.36		($2,648.9)	($2,648.9)
17	Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)	($5,021.5)
18					
19	**Production Tax**				
20	Production Tax Value (PTV)			$12,385.2	$12,385.2
21	Base Tax (25%*PTV)			$3,096.3	$3,096.3
22	Production Tax Value per barrel	$71.80			
23	Progressive Tax Rate	16.7%			
24	Gross Revenue Exclusion (40% * GVPP)			N/A	($6,962.7)
25	Production Tax Value or Adjusted Production Tax Value			$12,385.2	$5,422.6
26	Progressive Tax (Progressive Tax Rate * PTV or APTV)			$2,070.7	$906.6
27	Total Tax before credits			$5,167.0	$4,002.9
28	DELTA - Total Tax before credits				($1,164.1)
29					
30	**Credits (estimated)**			($450.0)	($750.0)
31	**Estimated Total Tax after credits**			**$4,717.0**	**$3,252.9**
32	DELTA - Total Tax after credits				($1,464.1)

See Page 104 of Fall 2011 Revenue Sources Book regarding the limitations of this presentation format.

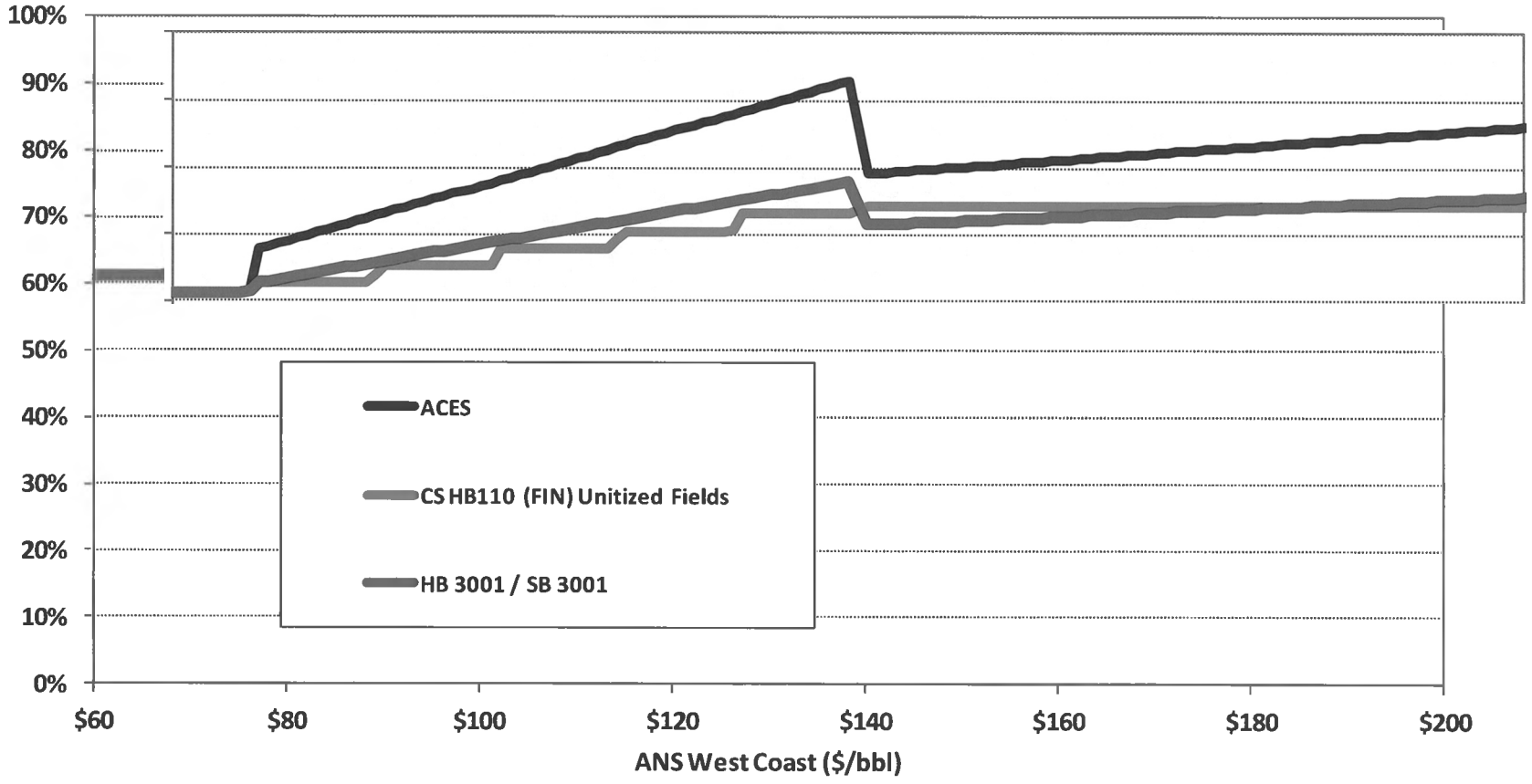
Effective production tax rates



Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Marginal Government Take

Marginal Government Take for existing production



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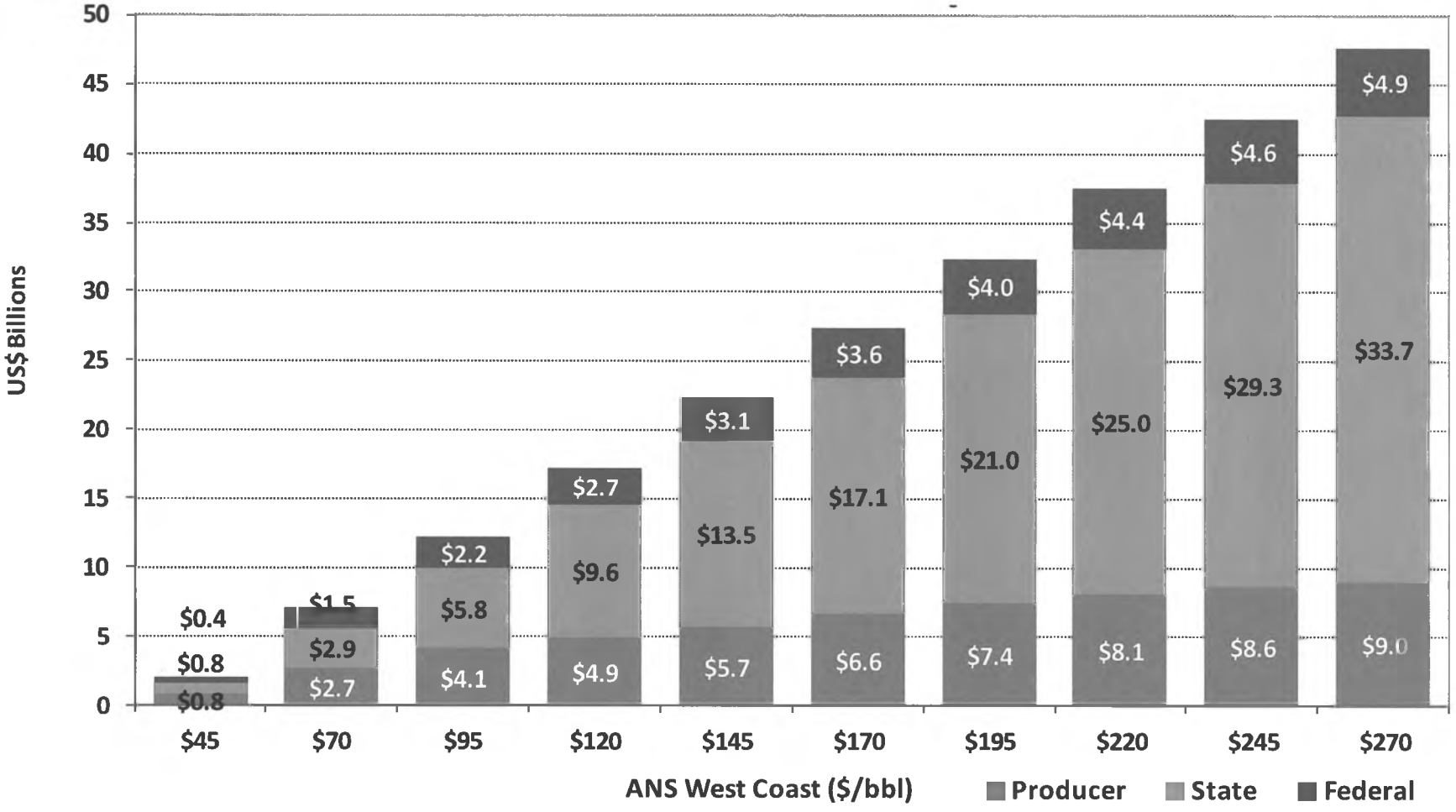
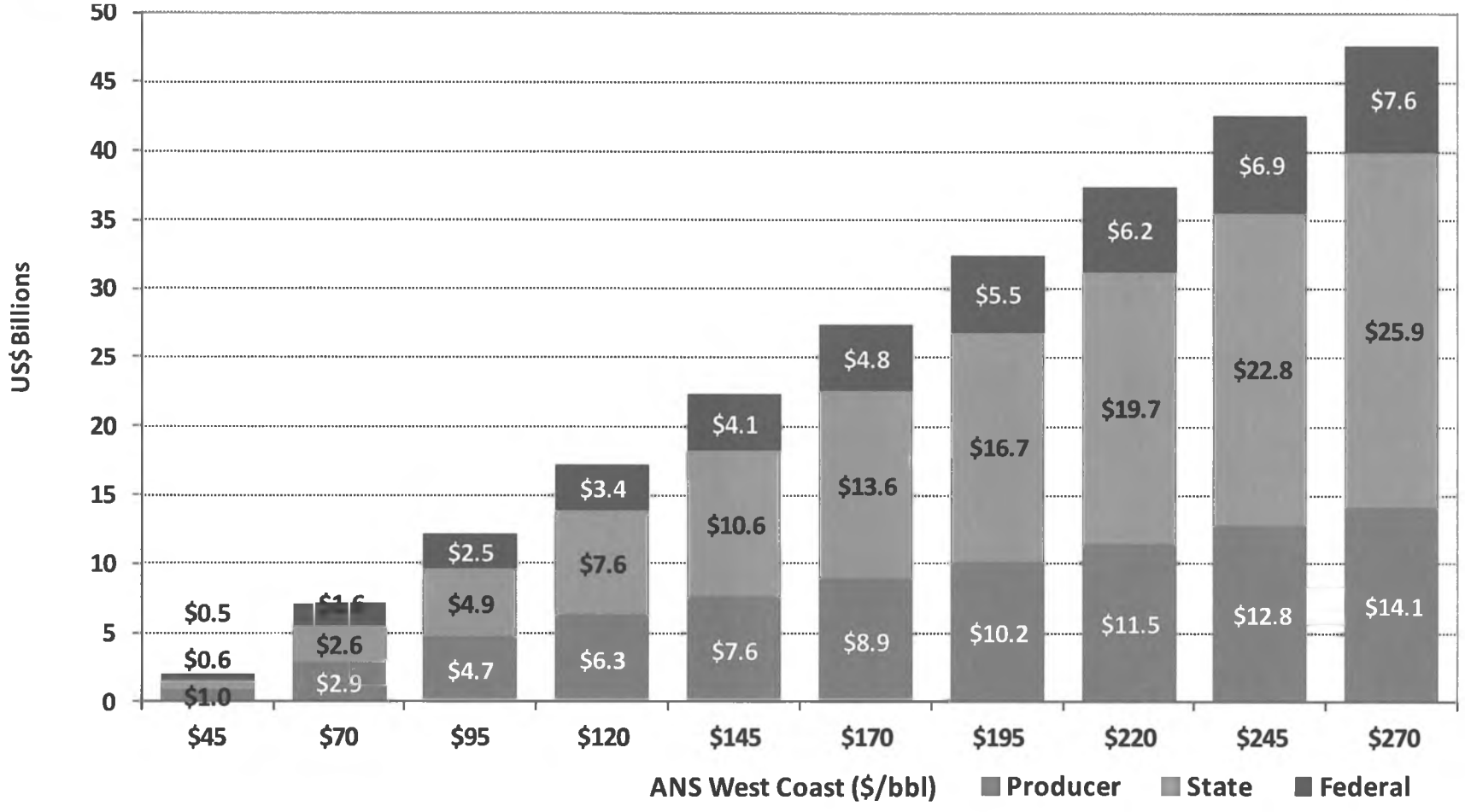
Absolute Profit – ACES



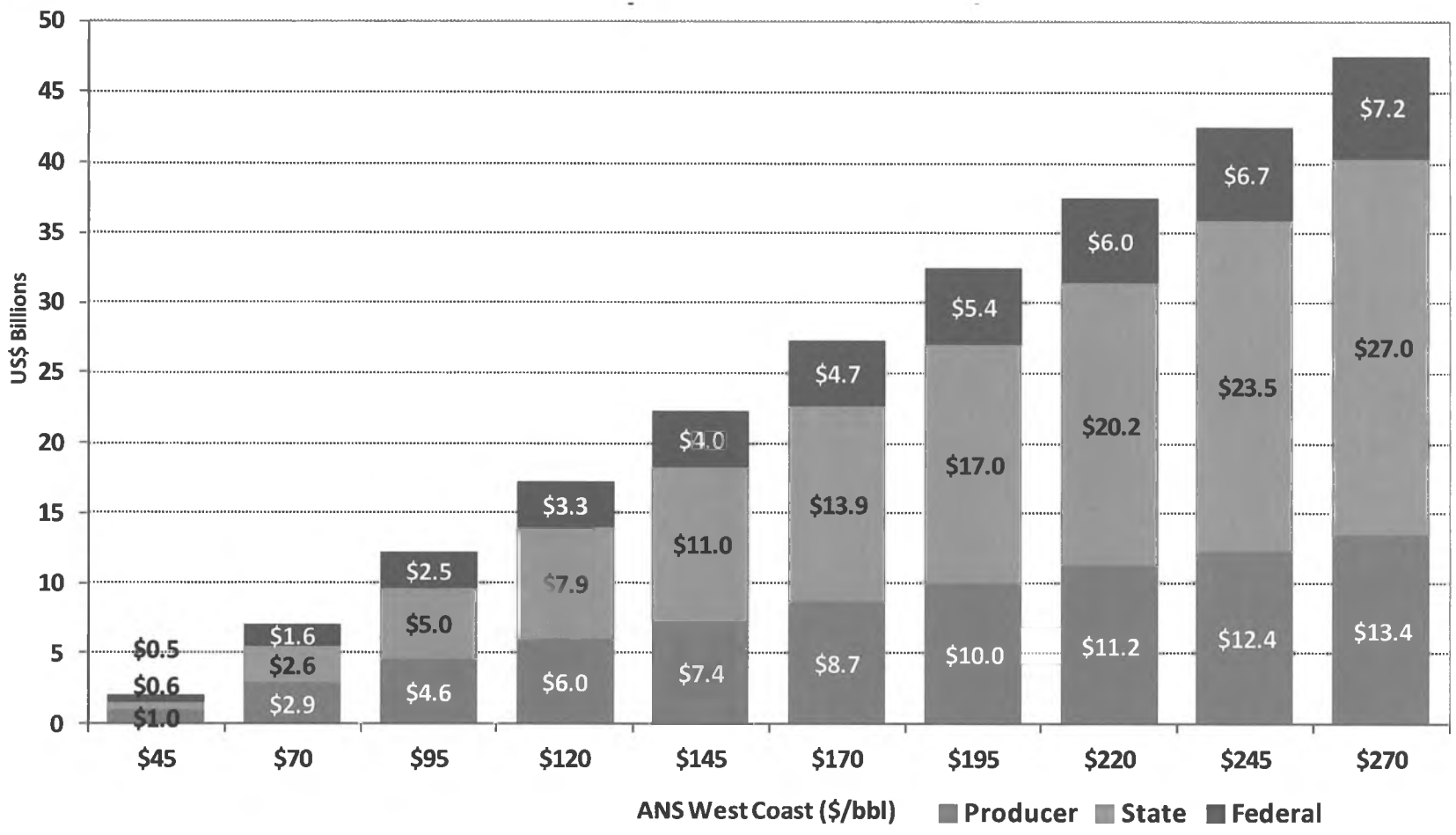
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Absolute Profit – CSHB 110 (FIN)



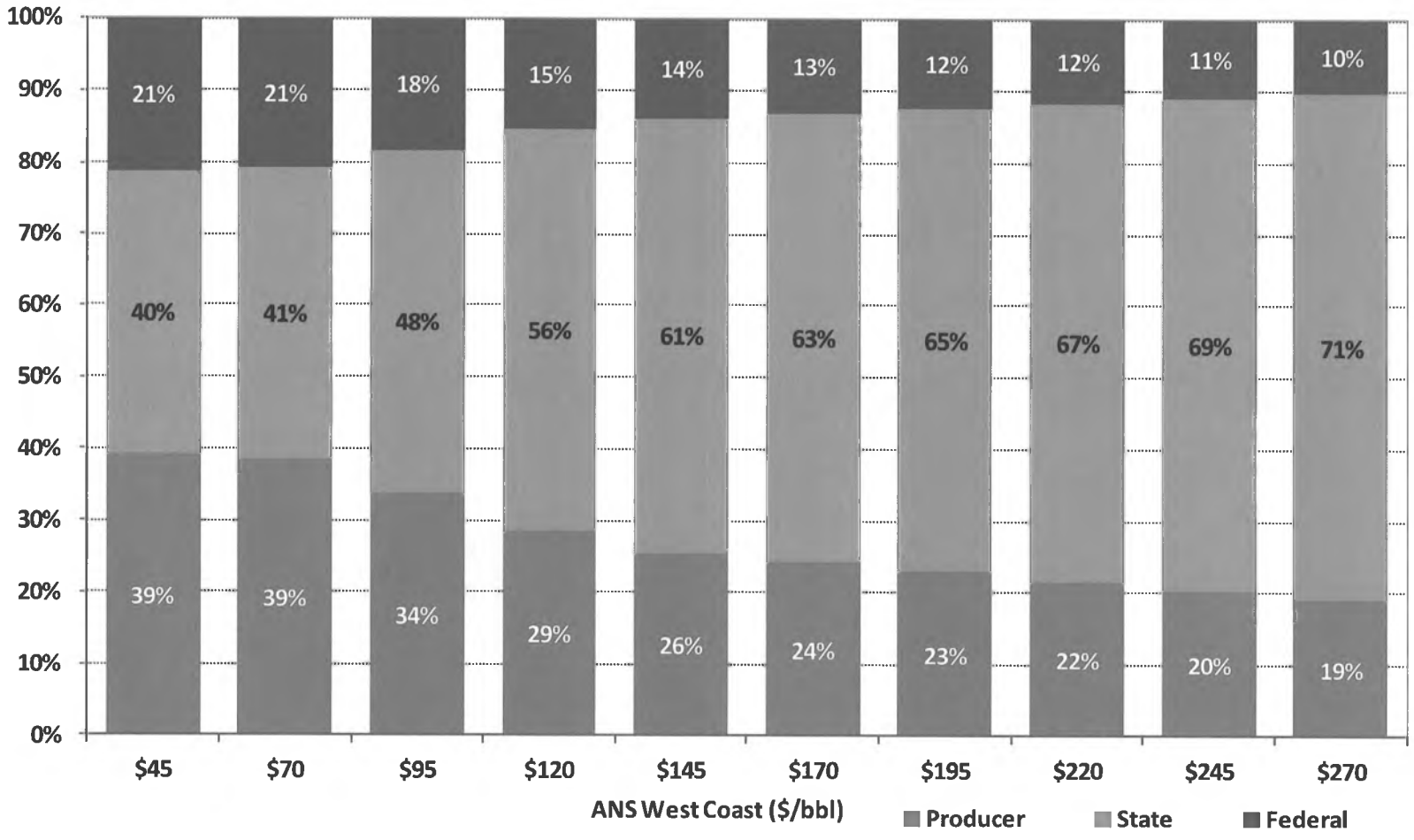
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Absolute Profit – HB 3001



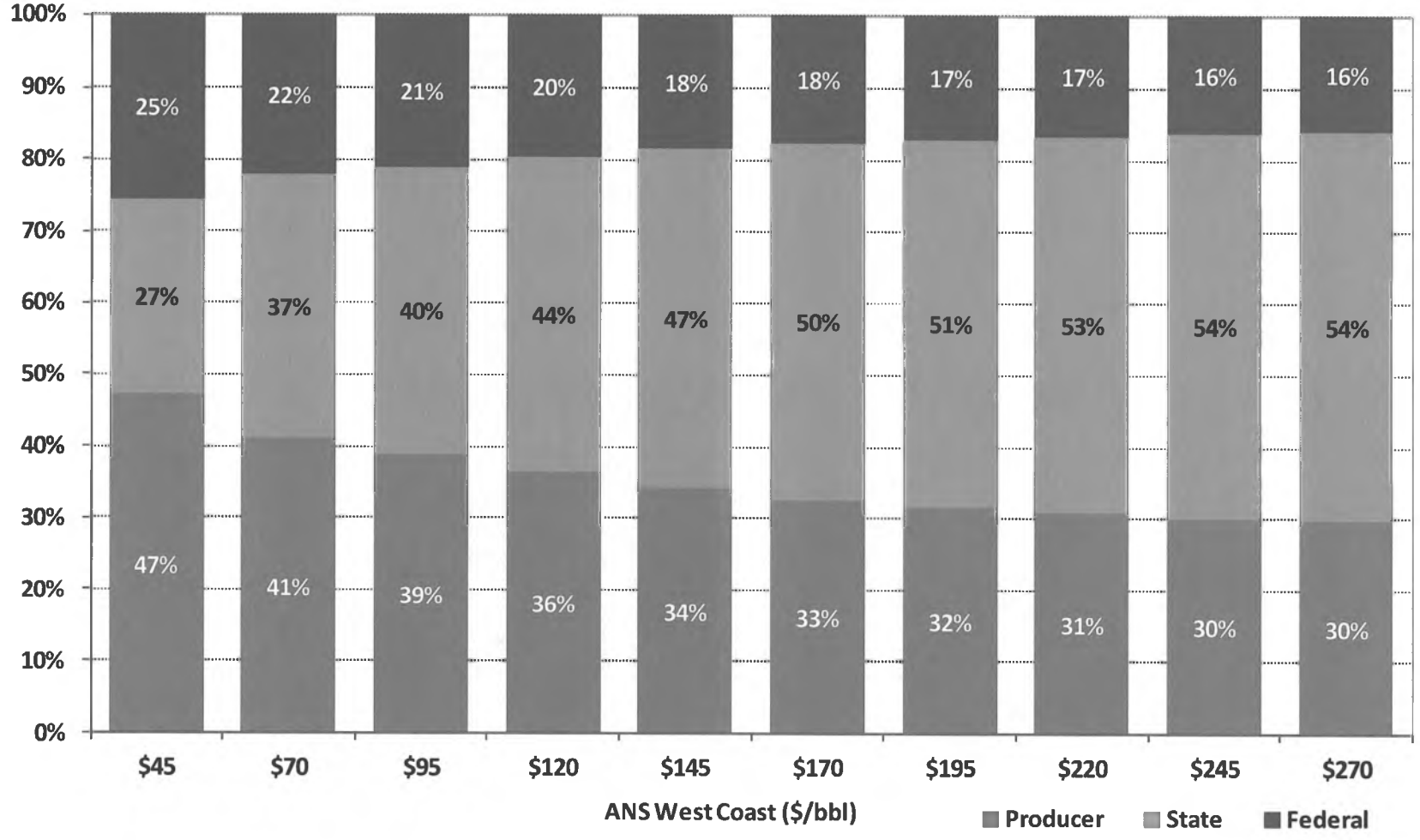
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Share of Profit – ACES



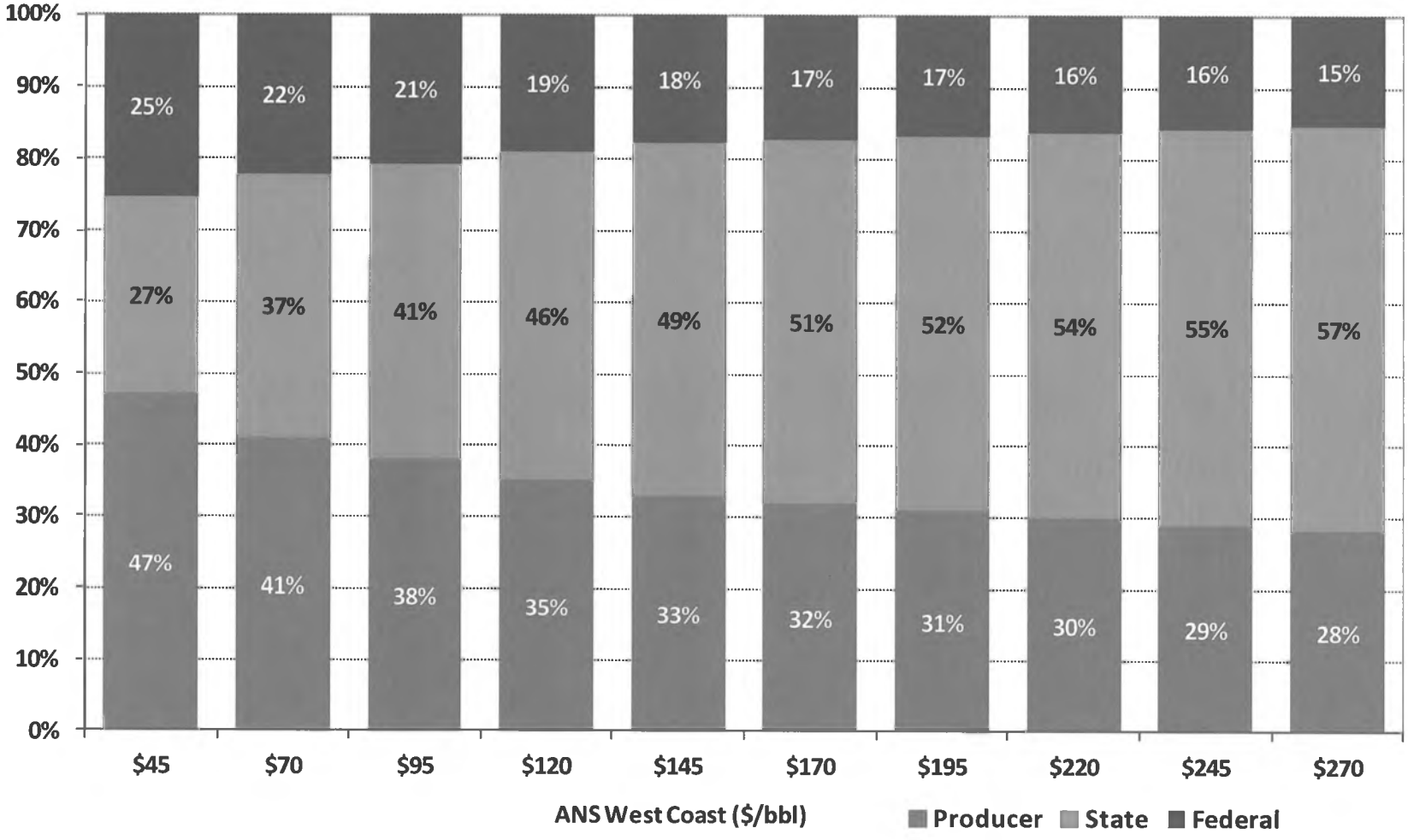
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Share of Profit – CSHB 110 (FIN)



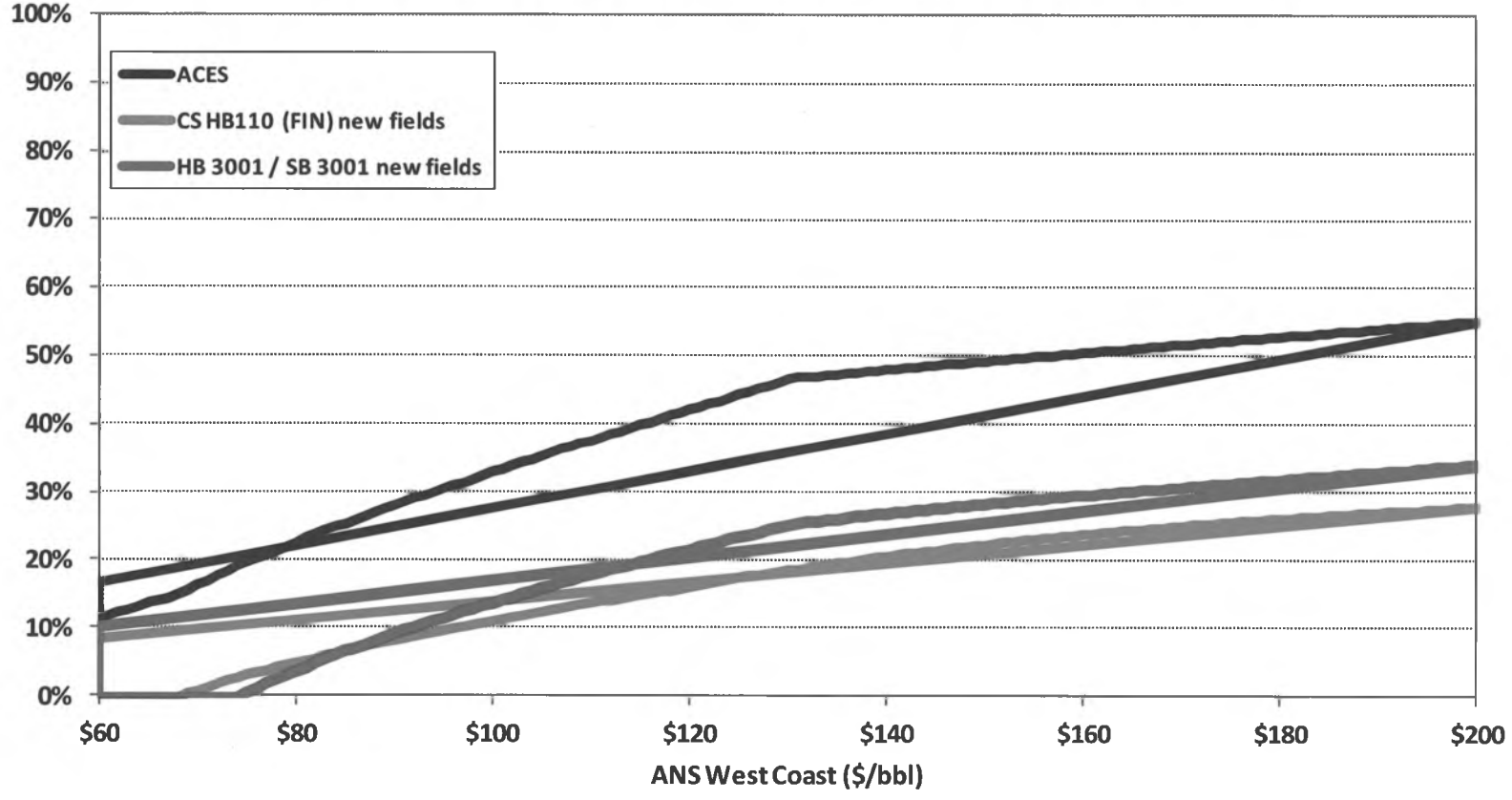
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Share of Profit – HB 3001



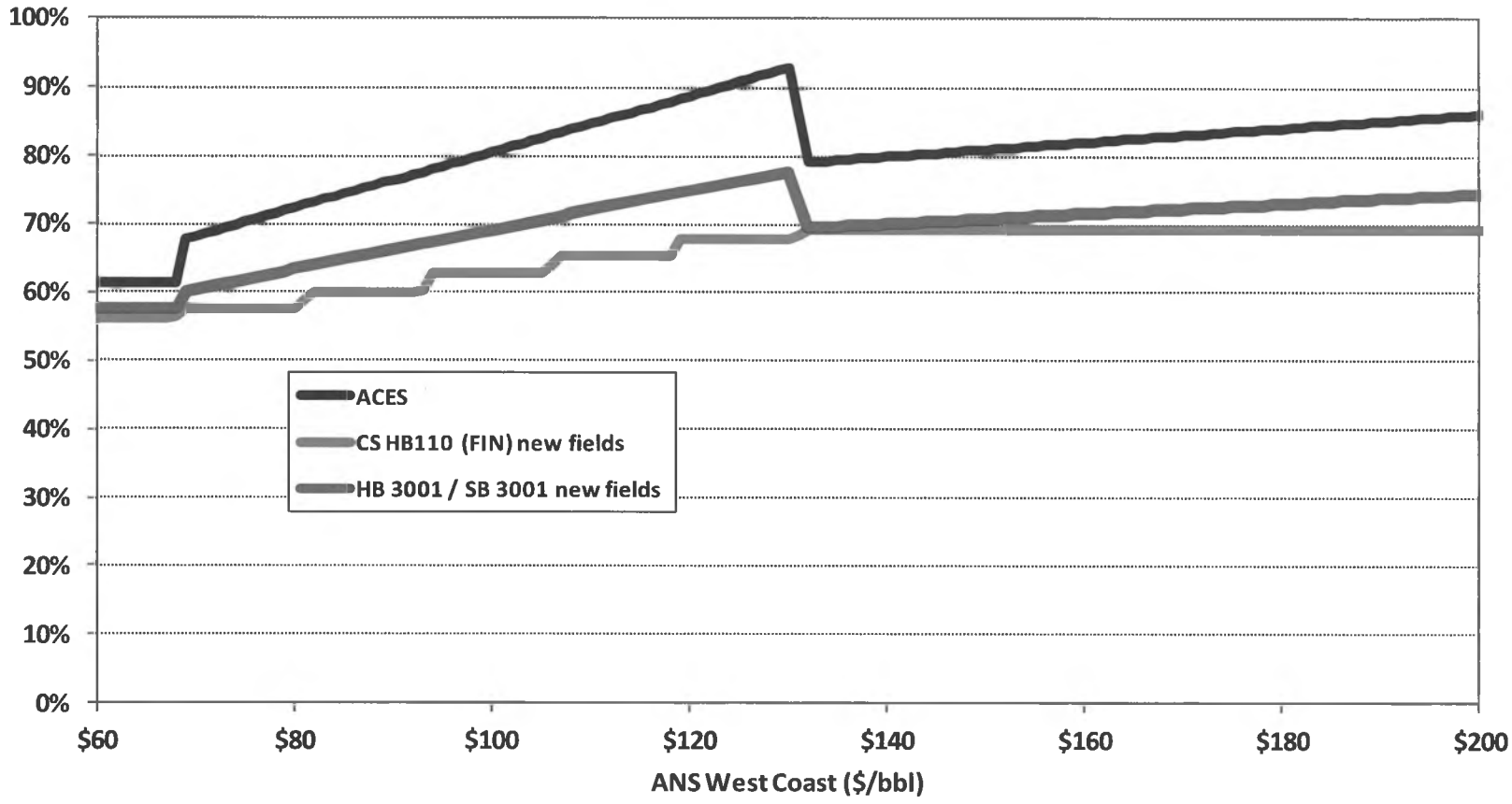
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Effective production tax rates – new fields



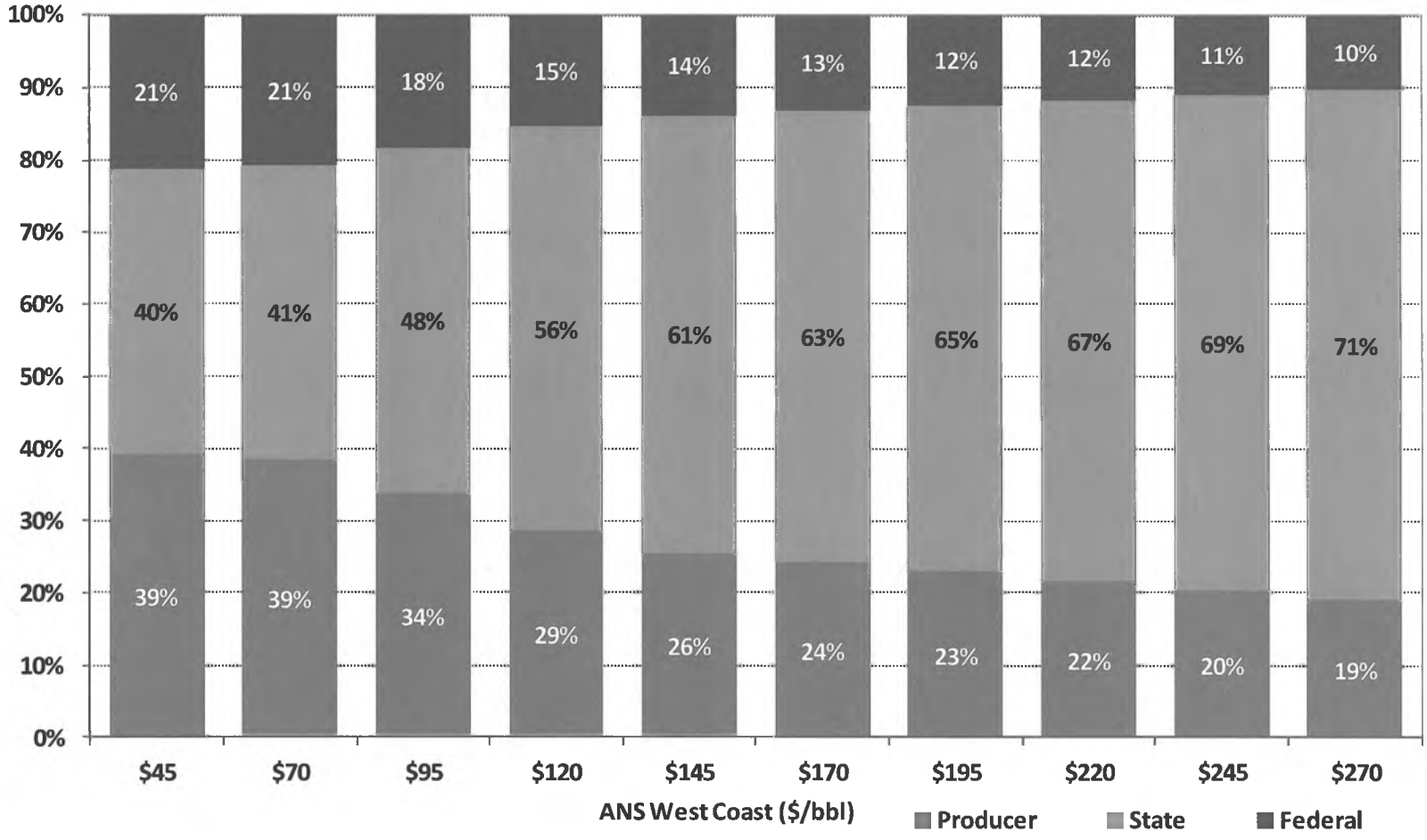
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Marginal Government Take – new fields



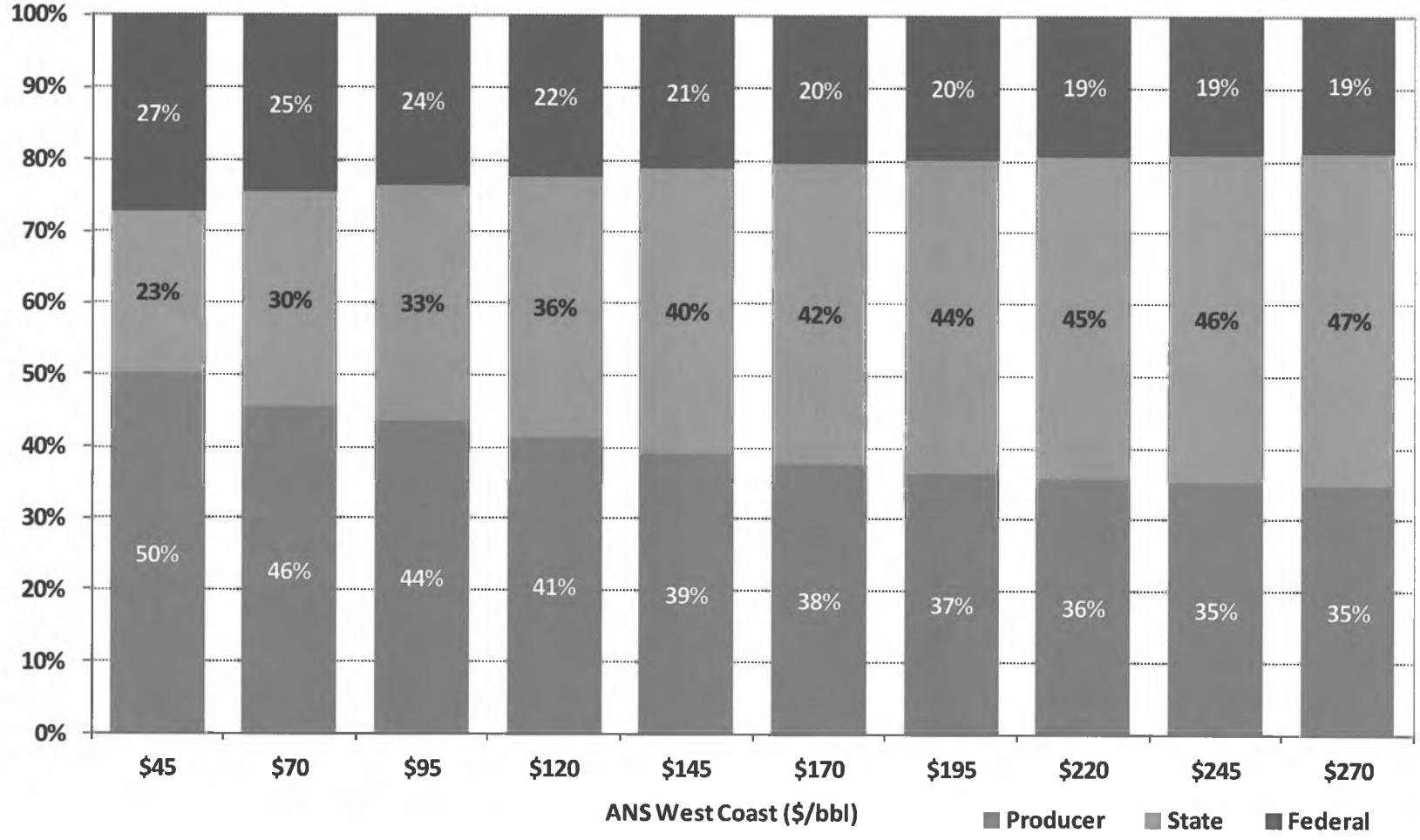
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Share of Profit – ACES new fields



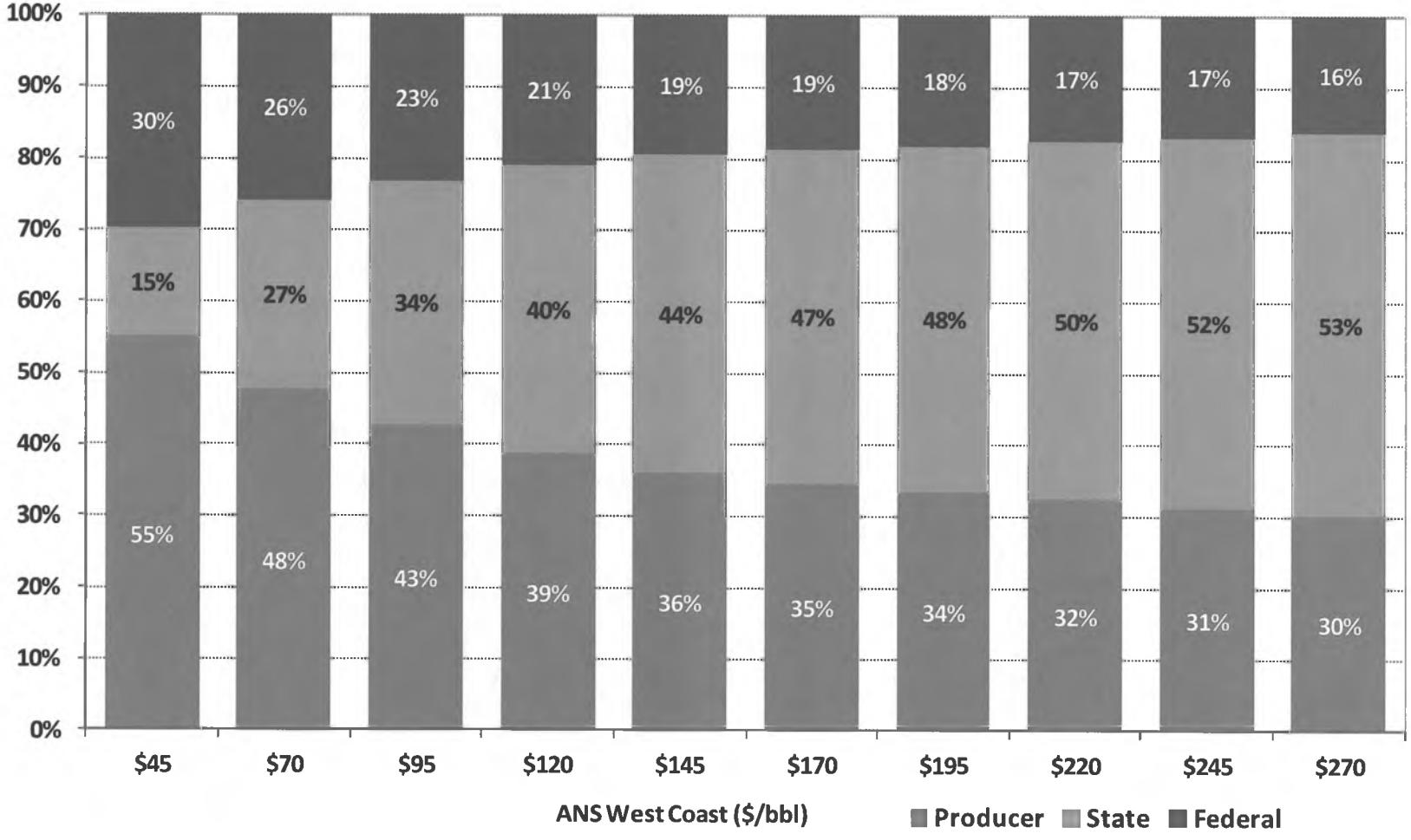
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Share of Profit – CSHB 110(FIN) new fields



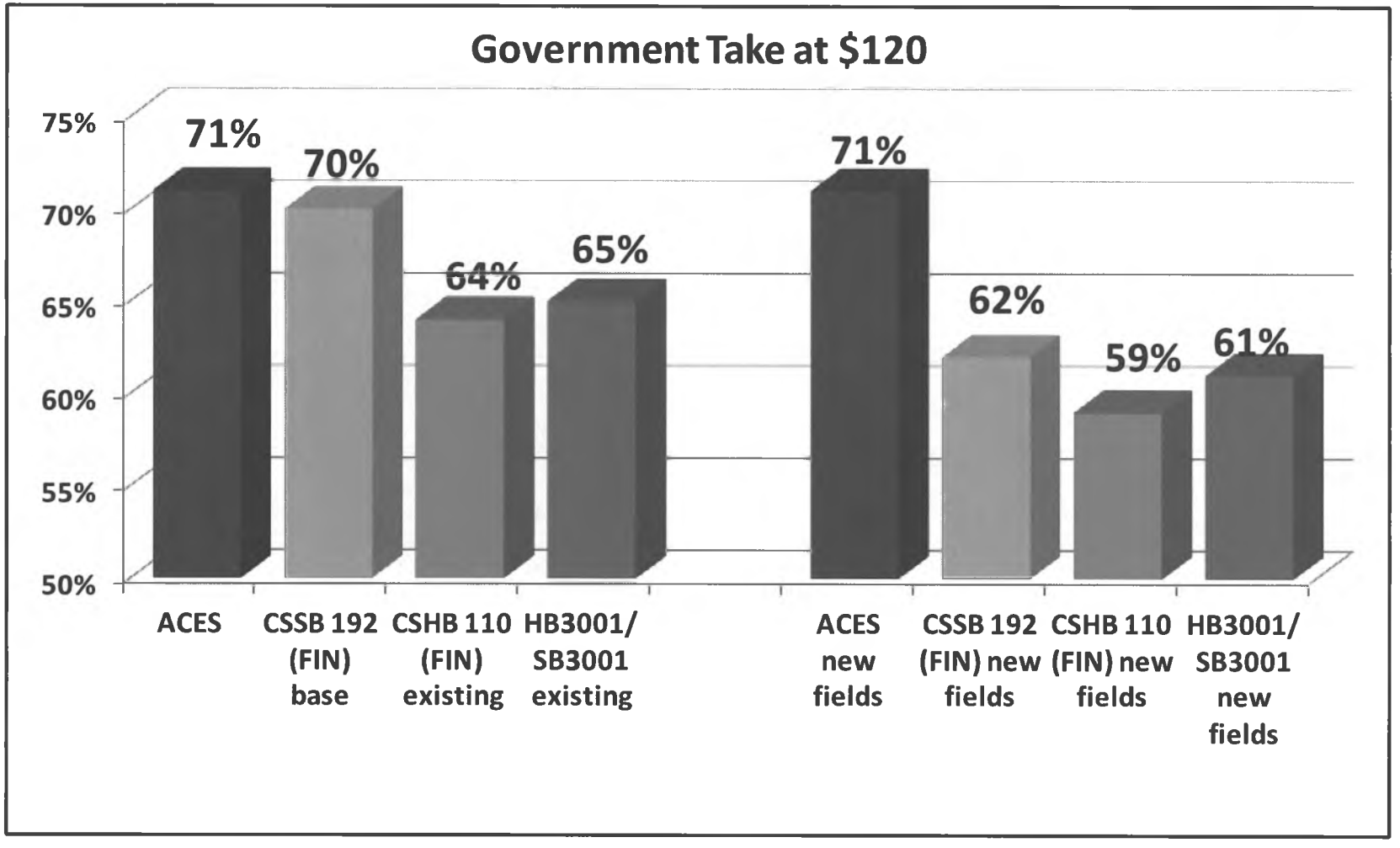
Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Share of Profit – HB 3001 new fields



Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

Government Take - comparison



Assumes FY 2013 Transport costs of $8.56/ bbl, Opex of $13.75 per taxable barrel, and Capex of $15.36 per taxable bbl.

HB 3001 Summary

- Provisions in HB 3001 / SB 3001 represent "meaningful change"
- Meaningful change is needed to incentivize development of Alaska's oil resources
- Meaningful change is needed to stimulate jobs and economic activity for Alaska's economy
- Producers have committed to additional investment contingent on meaningful change

Questions?

Presentation to the
House Resources Committee
April 21, 2012
Alaska Department of Revenue

Facts to Begin the Conversation

- Oil prices have been at all time highs for several years
- Other oil producing regions have been enjoying production and employment booms
- Competition is high - many other areas to invest around the world

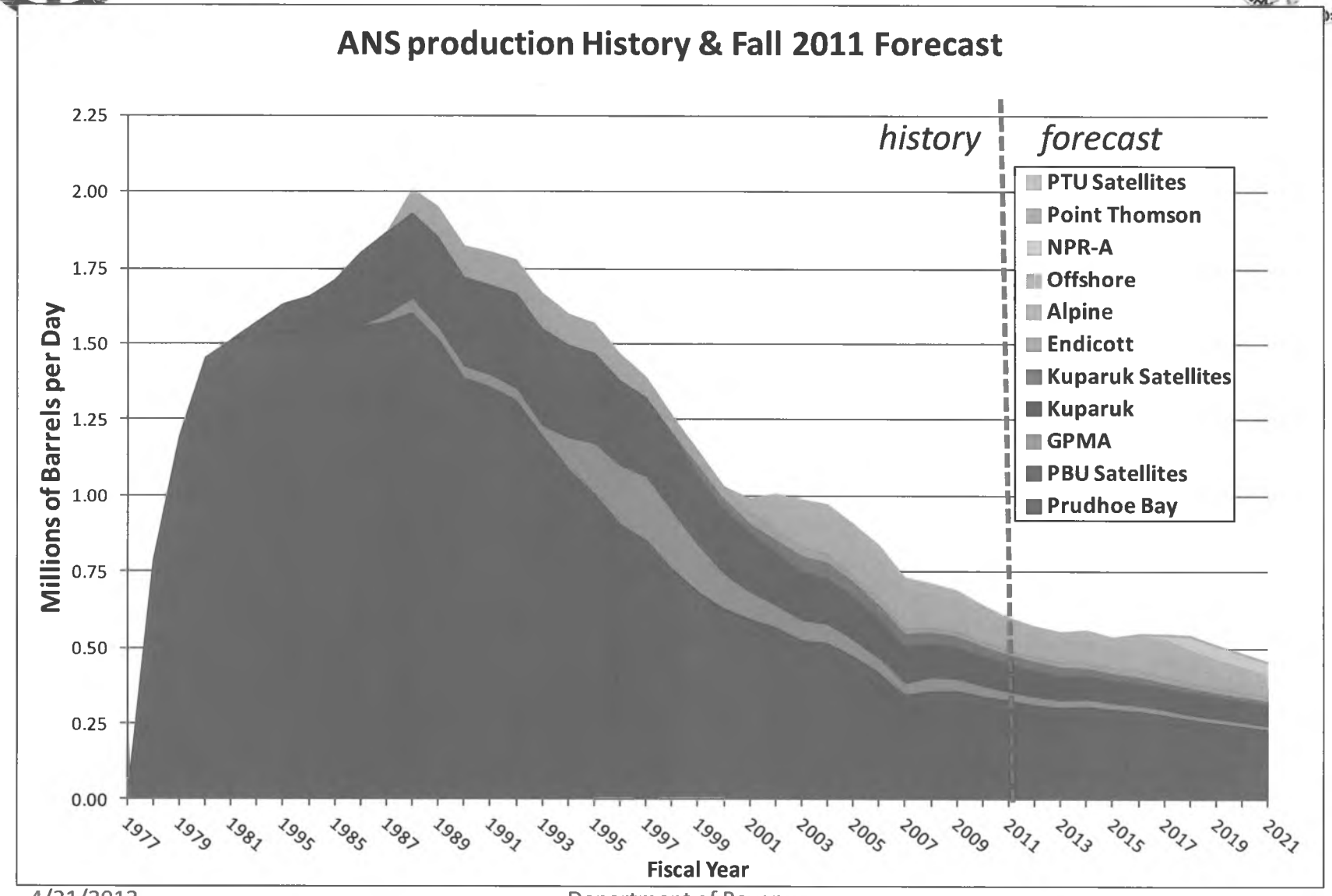
According to the USGS, It's Certainly Not A Resource Issue.....

- There's no debating.....Alaska is a world-class energy basin
- Cumulative production through 2010 over 16B barrels
- Oil: Estimated to have 40B barrels of conventional oil
- Gas: Estimated to have 236 TCF of conventional natural gas
- Plus tens of billions of heavy & viscous oil as well as shale oil & gas

More Important Points

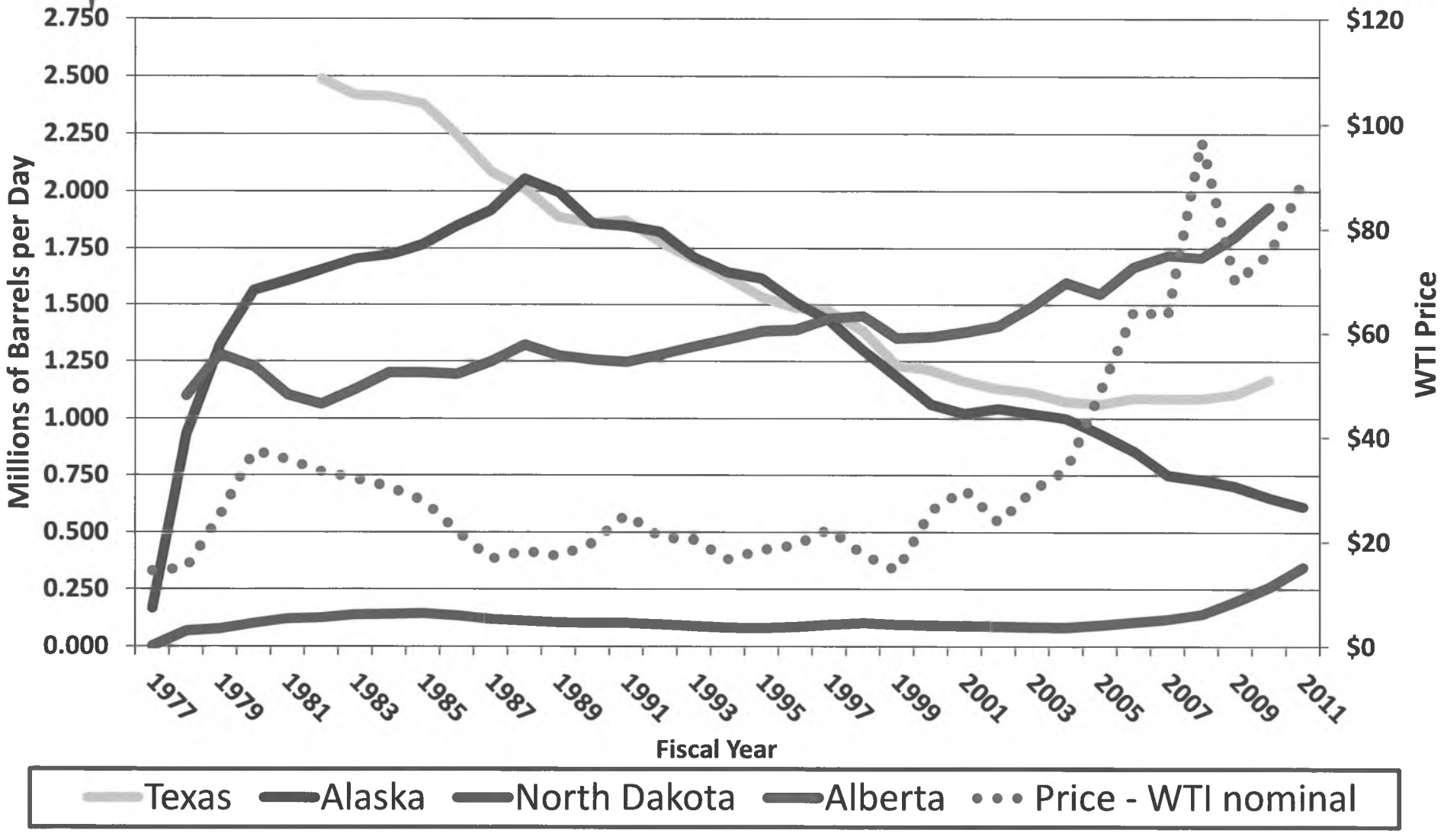
1. As a State, we are in a position we've never been in before
2. PPT/ACES Debate: "Actual" information utilized? Unfortunately No……was not available
3. Decision makers, through no fault of their own, had to rely on modeling, forecasts, projections, theoretical assumptions
4. We now have the luxury to look back and see what actually happened over the past 5 years
5. What do we see? Record high oil prices lead to oil & employment booms in competing oil producing regions
6. And Alaska continues to decline……..

Historical Oil Production



Historical Oil Production:

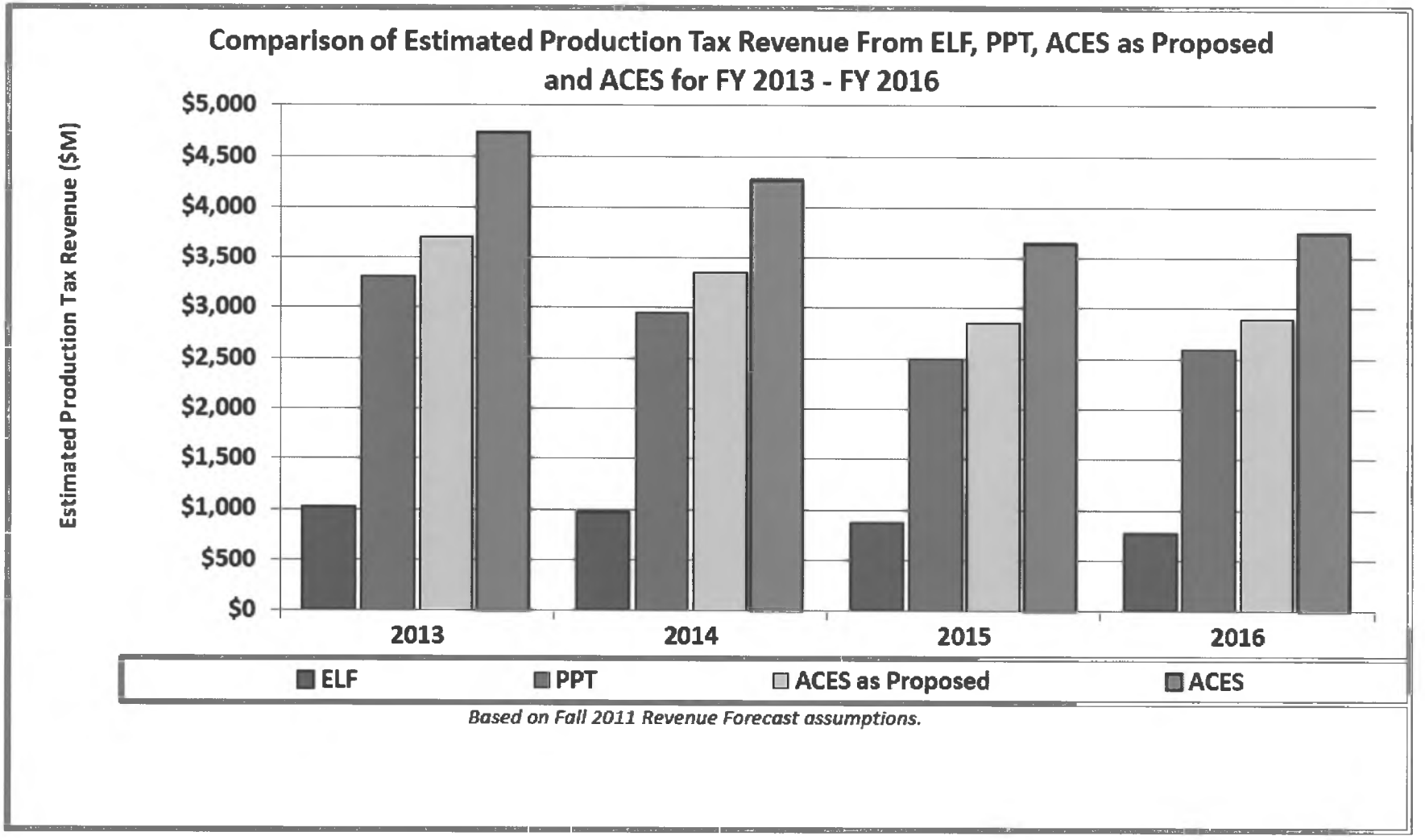
How Did Our Competition Fare When Prices Spiked?



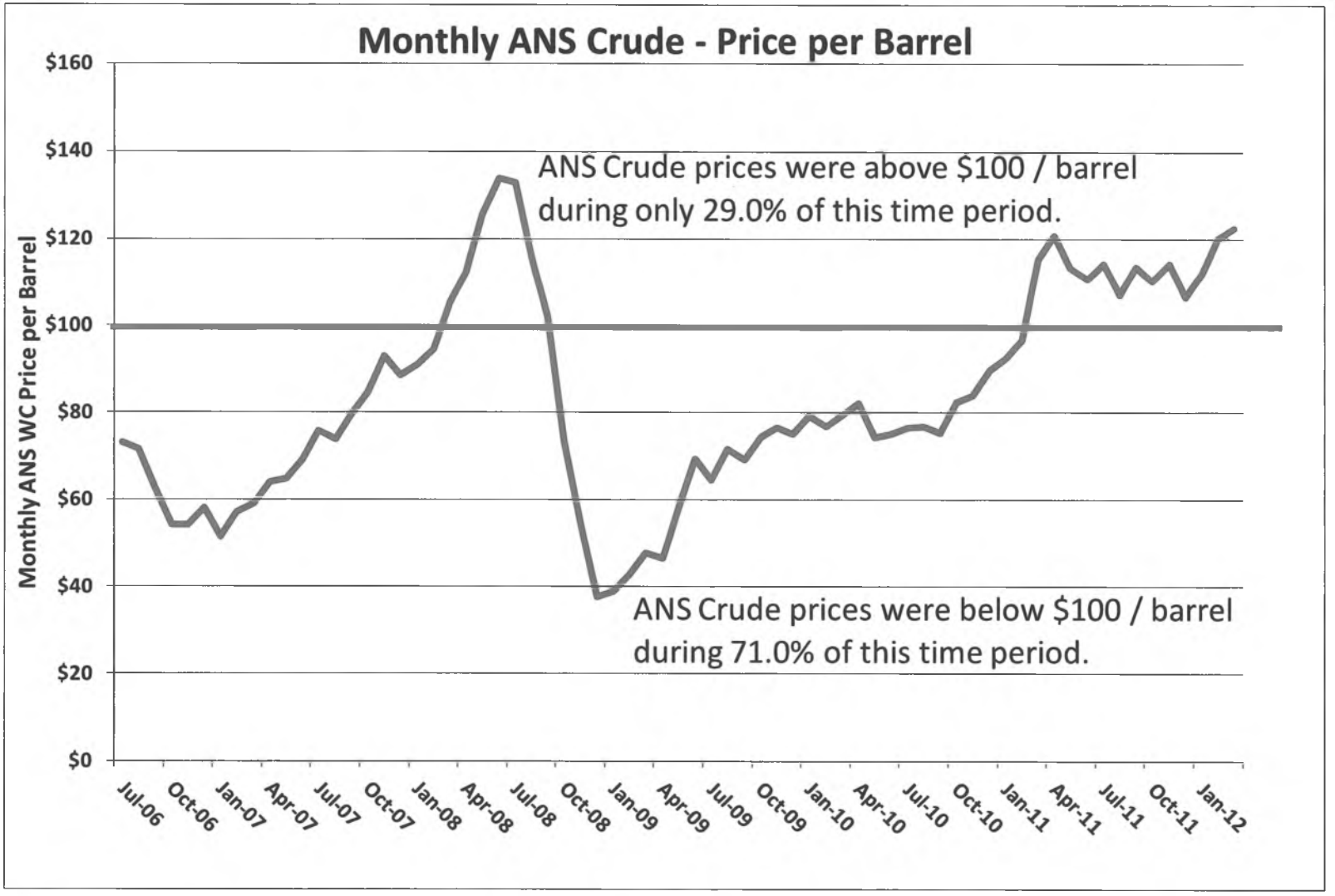
Two Distinct Elements of ACES: Can't discuss one without the other

1. Tax Credits:
   - ❑ Very generous tax credits made available over past several years help spur the anticipated exploration
   - ❑ Enthusiasm of explorers encouraging but they will eventually need to become or partner with producer
2. Production Tax:
   - ❑ Very progressive at high oil prices which makes AK not as attractive when compared to other world-wide options
   - ❑ This "windfall tax", while filling AK state coffers during the short term, is contributing to competitiveness issue long term

ELF, PPT & ACES: Did The Pendulum Swing Too Far?



Monthly ANS Crude Prices Under Net Tax System



Questions?

TESTIMONY OF JOHN K. NORMAN

HOUSE RESOURCES COMMITTEE

HB 3001: OIL AND GAS PRODUCTION TAX

APRIL 21, 2012

GOOD MORNING. FOR THE RECORD MY NAME IS JOHN NORMAN. I AM THE PUBLIC COMMISSIONER FOR THE ALASKA OIL AND GAS CONSERVATION COMMISSION.

COMMISSIONER FOERSTER IS TRAVELING AND SENDS HER REGRETS THAT SHE CANNOT BE HERE.

I AM HERE TO PROVIDE A CHARACTERIZATION OF POTENTIAL SOURCES OF INCREASED OIL AND GAS PRODUCTION FOR THE STATE OF ALASKA.

I'LL BREIFLY DISCUSS THE FOLLOWING POTENTIAL RESOURCES:

- LEGACY FIELDS
- NEW DISCOVERIES
- HEAVY OIL
- SHALE OIL
- CONDENSATE FROM PT THOMSON
- OCS OIL
- ANWR OIL

- BEAUFORT SEA OIL; AND FINALLY
- NORTH SLOPE GAS (AND GTL)

FOR EACH OF THESE RESOURCES, I WILL DESCRIBE ITS POTENTIAL FOR INCREASING PRODUCTION AND SOME OF THE CHALLENGES ASSOCIATED WITH THAT INCREASE.

LEGACY FIELDS:

THE LEGACY FIELDS ARE ALASKA'S BIRD IN THE HAND. WE COUNT ON THESE FIELDS DAY IN AND DAY OUT; SO WE CERTAINLY DON'T WANT TO IGNORE THEIR IMPORTANCE OR TAKE THEM FOR GRANTED. DURING THE REGULAR SESSION COMMISSIONER FOERSTER TESTIFIED THAT THE HEALTH OF ALL THE FIELDS ON THE NORTH SLOPE DEPENDS TO SOME DEGREE ON THE HEALTH OF PRUDHOE BAY AND THAT THIS WILL BE TRUE FOR THE FORESEEABLE FUTURE (LIKE HAVING AN ANCHOR TENANT IN A SHOPPING MALL). YOU MAY REMEMBER THAT THE ORIGINAL ESTIMATE FOR PRUDHOE BAY RECOVERY WAS ABOUT 9 BILLION BARRELS. WE'VE ALREADY PRODUCED OVER 11 BILLION BARRELS AND, WITH CURRENT TECHNOLOGY, THERE ARE STILL ABOUT TWO BILLION BARRELS OF OIL LEFT TO BE PRODUCED FROM THE PRUDHOE OIL POOL. THAT'S JUST WHAT'S LEFT, AND (WITH POSSIBLE EXCEPTION OF THE BAKKEN IN NORTH DAKOTA) IT'S BIGGER THAN ANY NEW DISCOVERY IN NORTH AMERICA IN THIS MILLENNIUM. THESE 2 BILLION BARRELS CANNOT BE

TAKEN FOR GRANTED; THE PRUDHOE BAY OWNERS ARE EXSPENDING LOTS OF TECHNICAL EFFORT AND MONEY TO FINESSE THIS ADDITIONAL OIL OUT OF THE GROUND. NEGATIVE IMPACTS ON PROFITABILITY (SUCH AS DROP IN OIL PRICE, INCREASE IN TAXATION, OR INCREASED REGULATORY BURDEN) WILL PUT SOME OF THESE 2 BILLION BARRELS AT RISK. CONVERSELY, THERE IS POTENTIAL FOR INCREASED ULTIMATE RECOVERY FROM PRUDHOE BAY, GIVEN ADVANCES IN TECHNOLOGY AND/OR POSITIVE IMPACTS ON PROFITABILITY. WE DON'T HAVE CONTROL OVER TECHNOLOGY ADVANCES OR OIL PRICE BUT WE CAN CERTAINLY USE CAUTION IN INCREASING THE BURDEN ON THE OPERATOR, EITHER THROUGH TAXATION OR REGULATION. I'VE TALKED ABOUT PRUDHOE BAY, BUT THIS CHARACTERIZATION IS VALID FOR THE OTHER LEGACY FIELDS AS WELL.

NEW DISCOVERIES:

NEW DISCOVERIES ARE ALREADY POSITIVELY IMPACTING THE PRODUCTION PROFILE IN ALASKA AND WE SHOULD CONTINUE TO ENCOURAGE OPERATORS TO TAKE THE RISKS TO EXPLORE FOR THESE RESERVOIRS. UNFORTUNATELY IT IS NOT LIKELY THAT WE WILL FIND ANOTHER PRUDHOE BAY IN THE AREAS WHERE WE CURRENTLY ALLOW EXPLORATION. THE EASY-TO-FIND FIELDS HAVE BEEN FOUND IN COOK INLET AND THE CENTRAL NORTH SLOPE. THAT SAID, THERE'S NOTHING WRONG WITH FINDING AN ALPINE, A NORTH STAR, AN OOOGURUK, OR A

NIKAITCHUK. SEVERAL "SMALL" FIELDS ADD UP TO A BIG ONE. I CALL THESE "SMALL" FIELDS, BUT I MUST REMIND YOU THAT SIMILAR FIELDS IN THE LOWER 48 WOULD BE CONSIDERED HUGE – IT'S THE COSTS ASSOCIATED WITH OUR REMOTE AND HOSTILE ENVIRONMENT THAT MAKE US VIEW A QUARTER BILLION BARREL DISCOVERY AS "SMALL." BUT, REMEMBER, WHAT MAKES THESE FIELDS VIABLE IS THEIR PROXIMITY TO THE INFRASTRUCTURE FOR THE LEGACY FIELDS. AS WE GET FURTHER AND FURTHER FROM THAT INFRASTRUCTURE, THE CHALLENGES OF COMMERCIALIZING A NEW DISCOVERY ONLY INCREASE.

HEAVY OIL:

FOR HEAVY AND VISCOUS OIL, THE RESOURCE ESTIMATE VARIES DEPENDING ON WHOSE NUMBERS YOU USE, BUT JUST ABOUT EVERYONE AGREES THAT THERE ARE OVER 20 BILLION BARRELS OF POTENTIAL ON THE NORTH SLOPE. BUT THIS IS NOT AN EASY RESOURCE TO COMMERCIALIZE. PRODUCING OIL FROM THIS KIND OF RESERVOIR IS LIKE FILLING A SANDBOX WITH MOLASSES AND THEN TRYING TO EXTRACT THE MOLASSES WITH A DRINKING STRAW. THE KEY TO DEVELOPING THIS RESOURCE WILL BE ADVANCES IN TECHNOLOGY AND THE NORTH SLOPE OPERATORS ARE WORKING ON THIS TECHNOLOGY AS WE SPEAK.

SHALE OIL:

SHALE OIL DEVELOPMENT HAS CREATED A BOOM IN THE LOWER 48, FROM PENNSYLVANIA TO NORTH DAKOTA. SHALE IS USUALLY THE SOURCE FOR THE OIL THAT WE FIND IN CONVENTIONAL RESERVOIRS. NOT ALL OF THE OIL IS ABLE TO MIGRATE FROM THE SHALE INTO THE CONVENTIONAL RESERVOIR AND THIS RESIDUAL OIL IS THE TARGET IN SHALE OIL DEVELOPMENTS. IN SOME WAYS, THE GEOLOGICAL RISK IS LOW BECAUSE WE KNOW THE SOURCE ROCK IS THERE AND THAT IT CONTAINS OIL. THE BIG RISKS LIE IN WHETHER THERE IS ENOUGH OIL AND WHETHER IT IS MOVEABLE. THE ONLY WAY TO FIND OUT IS TO DRILL IT, EVALUATE IT, AND ATTEMPT TO PRODUCE IT. WE HAVE EXPLORATION INCENTIVES IN PLACE AND THESE HAVE ALREADY PIQUED THE INTEREST OF AT LEAST ONE SHALE OIL EXPLORER, GREAT BEAR.

GAS LIQUIDS:

LET'S MOVE TO GAS LIQUIDS. DIFFERENT AGENCIES AND COMPANIES HAVE DIFFERENT ESTIMATES ON THE AMOUNT OF CONDENSATE ASSOCIATED WITH THE GAS IN THE POINT THOMSON FIELD, BUT IT'S AT LEAST 200 TO 400 MILLION BARRELS, NO MATTER WHO YOU ASK. THANKS IN PART TO THE RECENT SETTLEMENT OF THE PT THOMSON LITIGATION, THE PT THOMSON OPERATOR IS WORKING TOWARD A CYCLING PILOT PROJECT TO RECOVER THESE LIQUIDS AND SEND THEM TO TAPS. THIS IS ANOTHER EXAMPLE OF A KNOWN RESOURCE WITH AN UNCERTAIN

OUTCOME. WE KNOW THE CONDENSATE IS THERE; WE JUST DON'T KNOW IF CYCLING TO RECOVER IT WILL BE COMMERCIALLY VIABLE. AND THAT'S WHAT THE OPERATOR'S PILOT PROJECT WILL DETERMINE.

OCS:

EARLIER I SAID THAT THE LEGACY FIELDS ARE ALASKA'S BIRD IN THE HAND. OCS OIL IS OUR BIRD IN THE BUSH. THERE IS SIGNIFICANT POTENTIAL TO MAKE A LARGE OIL DISCOVERY; OTHERWISE SHELL WOULDN'T BE SO PATIENT IN ATTEMPTING TO EXPLORE THERE. EVEN THOUGH SUCH A DISCOVERY WOULD BE IN FEDERAL WATERS, THE BENEFITS TO ALASKANS WOULD BE ENORMOUS – EVERYTHING FROM JOBS TO EXTENDING THE LIFE OF TAPS. OTHER THAN GEOLOGIC RISK, THE GREATEST OBSTACLE TO OCS OIL IS THE OBSTRUCTIONIST POLICIES OF OUR OWN FEDERAL GOVERNMENT. ALASKANS SHOULD CONTINUE TO EXERT INFLUENCE IN EVERY WAY POSSIBLE TO TEMPER THESE POLICIES.

ANWR:

SPEAKING OF OBSTRUCTIONIST POLICIES, NO DISCUSSION OF ALASKA PRODUCTION OPPORTUNITIES WOULD BE COMPLETE WITHOUT AT LEAST MENTIONING ANWR. NO ONE KNOWS WHAT THE TRUE POTENTIAL IS THERE, AND THE ONLY WAY TO FIND OUT IS TO DRILL. AGAIN, WE NEED TO CONTINUE TO EXERT INFLUENCE EVERY WAY POSSIBLE TO TEMPER

THE OBSTRUCTIONIST POLICIES THAT DENY US THE OPPORTUNITY EVEN TO ASSESS AND QUANTIFY THIS POTENTIAL.

BEAUFORT SEA:

BEAUFORT SEA OIL IS ALREADY BEING PRODUCED. NORTH STAR, ENDICOTT, AND PART OF OOOGURUK ARE ALL IN THE BEAUFORT SEA. THERE ARE LIKELY OTHER OIL DEPOSITS YET TO BE DISCOVERED HERE AND AT LEAST ONE SUCH EXPLORATION EFFORT IS IN THE PLANNING – LIBERTY. LIBERTY WILL BE IN FEDERAL WATERS, BUT A SUCCESS THERE WILL STILL REAP BENEFITS FOR ALASKANS. LIBERTY IS NOT WITHOUT ITS RISKS. LIBERTY IS PLANNED TO BE DEVELOPED USING ULTRA-EXTENDED-REACH DRILLING STARTING FROM THE ENDICOTT ISLAND AND TRAVELING OUT AND UNDERGROUND FOR SEVERAL MILES. THE SORT OF DRILLING REQUIRED FOR LIBERTY DEVELOPMENT PUSHES THE LIMITS OF CURRENT DRILLING TECHNOLOGY. FOR THIS AND OTHER REASONS THE OPERATOR IS WORKING UNDER A DECELERATED SCHEDULE – USING CAUTION TO ENSURE THAT THE TECHNICAL RISKS AND CHALLENGES ARE ALL ADDRESSED BEFORE WORK BEGINS.

NORTH SLOPE GAS:

THE LAST RESOURCE I WILL ADDRESS IS NORTH SLOPE GAS. I DON'T HAVE A LETTERMAN TOP TEN, BUT HERE ARE THE TOP TWO REASONS NOT TO ACCELERATE PRODUCTION AND SALE OF NORTH SLOPE GAS.

1. RIGHT NOW EVERY BIT OF KNOWN NORTH SLOPE GAS IS ASSOCIATED WITH AN OIL RESERVOIR AND EITHER IS OR WILL BE BENEFICIALLY USED TO GET MORE OIL OUT OF THE GROUND.
2. THE RULE OF THUMB USED TO BE THAT ONE BARREL OF OIL WAS WORTH SIX THOUSAND CUBIC FEET OF GAS. WITH OIL CURRENTLY SELLING FOR ABOUT $120 PER BARREL AND GAS SELLING FOR ABOUT $3 PER THOUSAND CUBIC FEET, ONE BARREL OF OIL IS WORTH ABOUT 40 THOUSAND CUBIC FEET OF GAS. USING THIS MATH, THE ENTIRE 34 TCF OF KNOWN NORTH SLOPE GAS IS WORTH LESS THAN HALF OF THE OIL LEFT IN THE PRUDHOE BAY OIL POOL.

THEREFORE, WHY SELL GAS FOR THIS DECREASED VALUE, ESPECIALLY IF SELLING IT ALSO MEANS YOU'RE GOING TO GET LESS OF YOUR OIL OUT OF THE GROUND?

I WAS ALSO ASKED TO ADDRESS GTL. GTL IS JUST A WAY OF PACKAGING GAS. AND AT THIS TIME AT LEAST, IT'S THE MOST WASTEFUL WAY POSSIBLE. TO CONVERT THE GAS TO A LIQUID USING CURRENT TECHNOLOGY USES UP ABOUT 40 PER CENT OF THE RESOURCE. ENOUGH SAID.

THIS CONCLUDES MY PREPARED REMARKS. I'LL BE HAPPY TO TAKE QUESTIONS.

Potential for increasing production

Joint House Resources and Energy Committee

21 April 2012

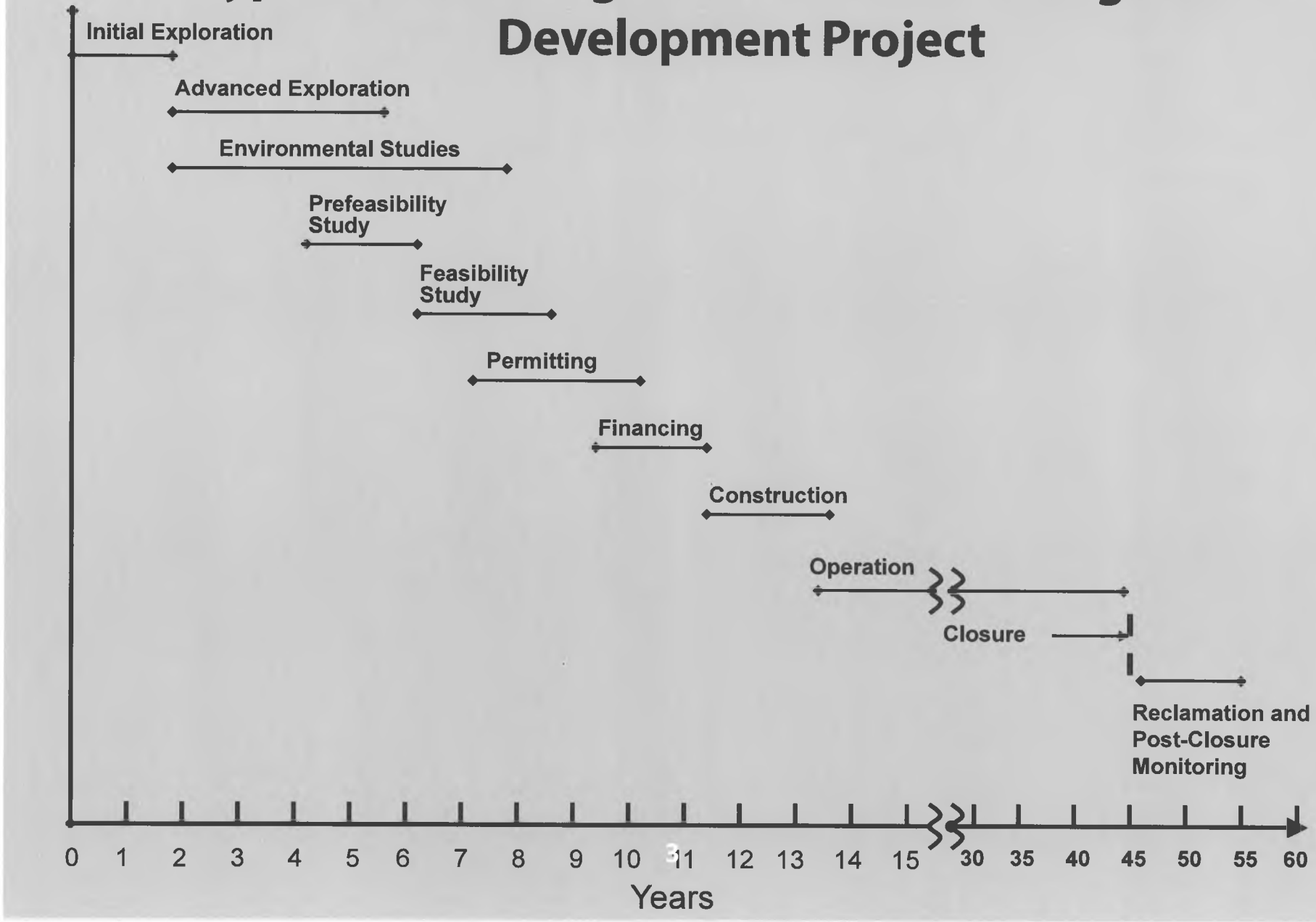
William C. Barron

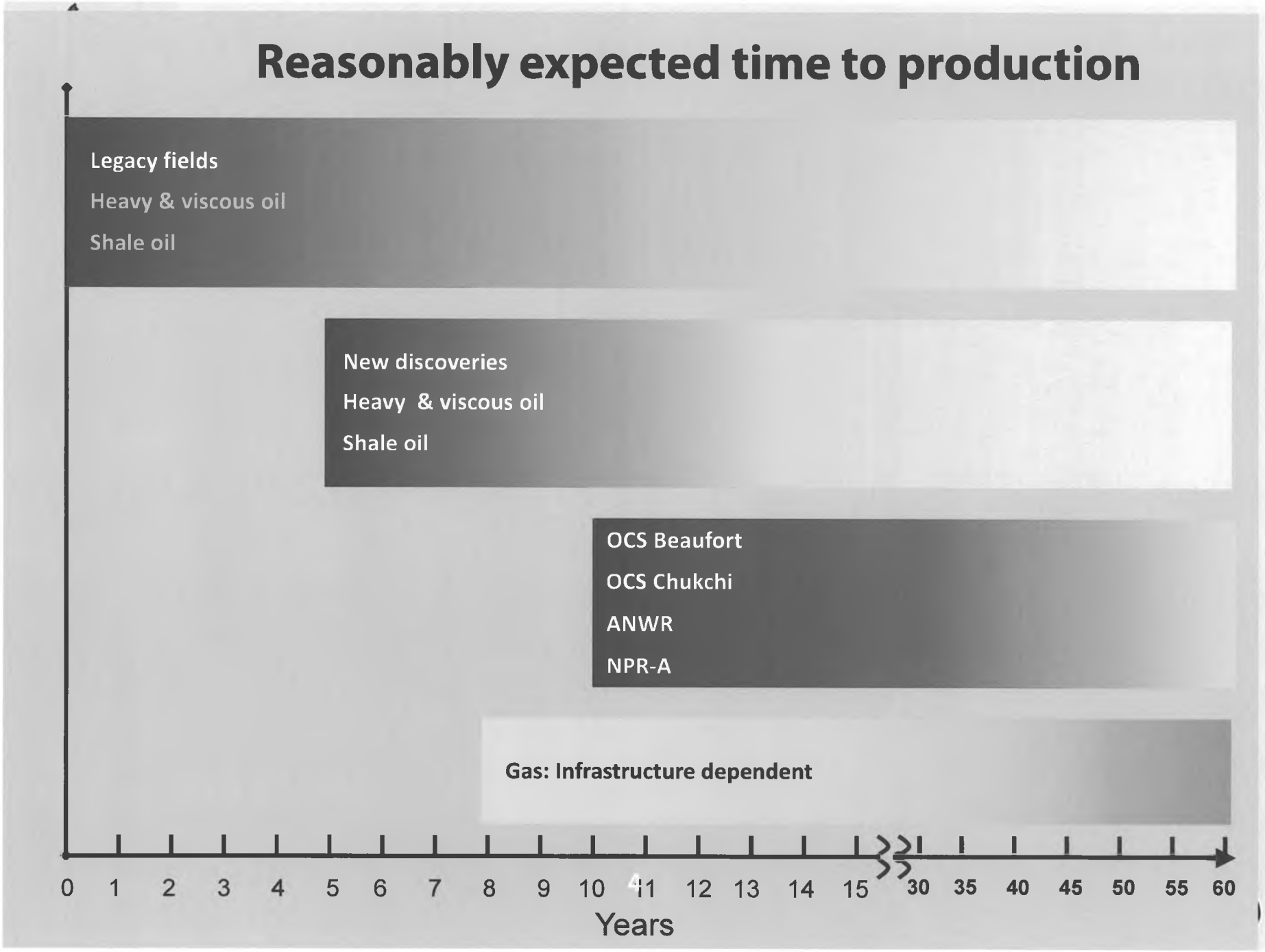
Division of Oil and Gas

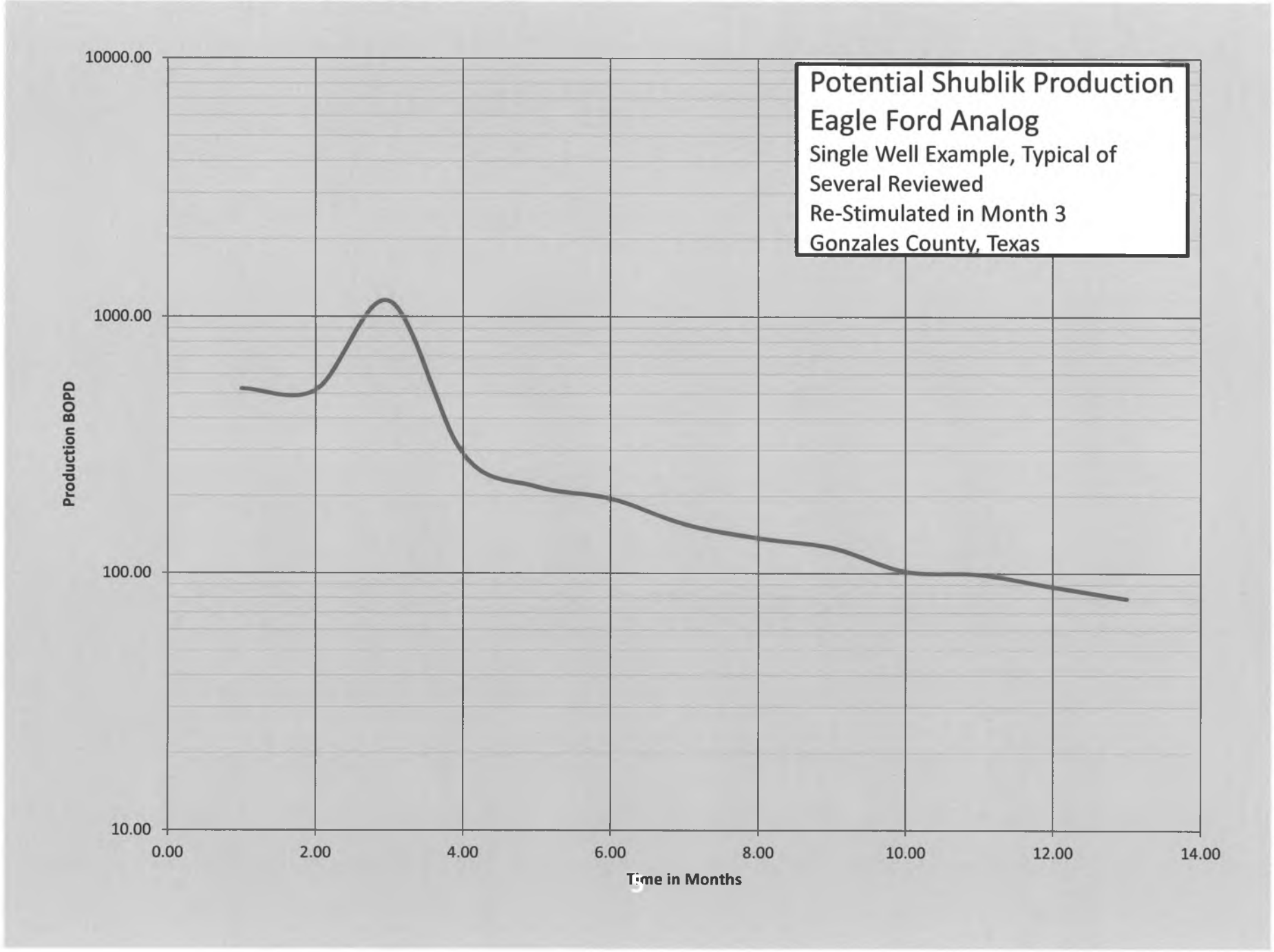
Barriers to new production

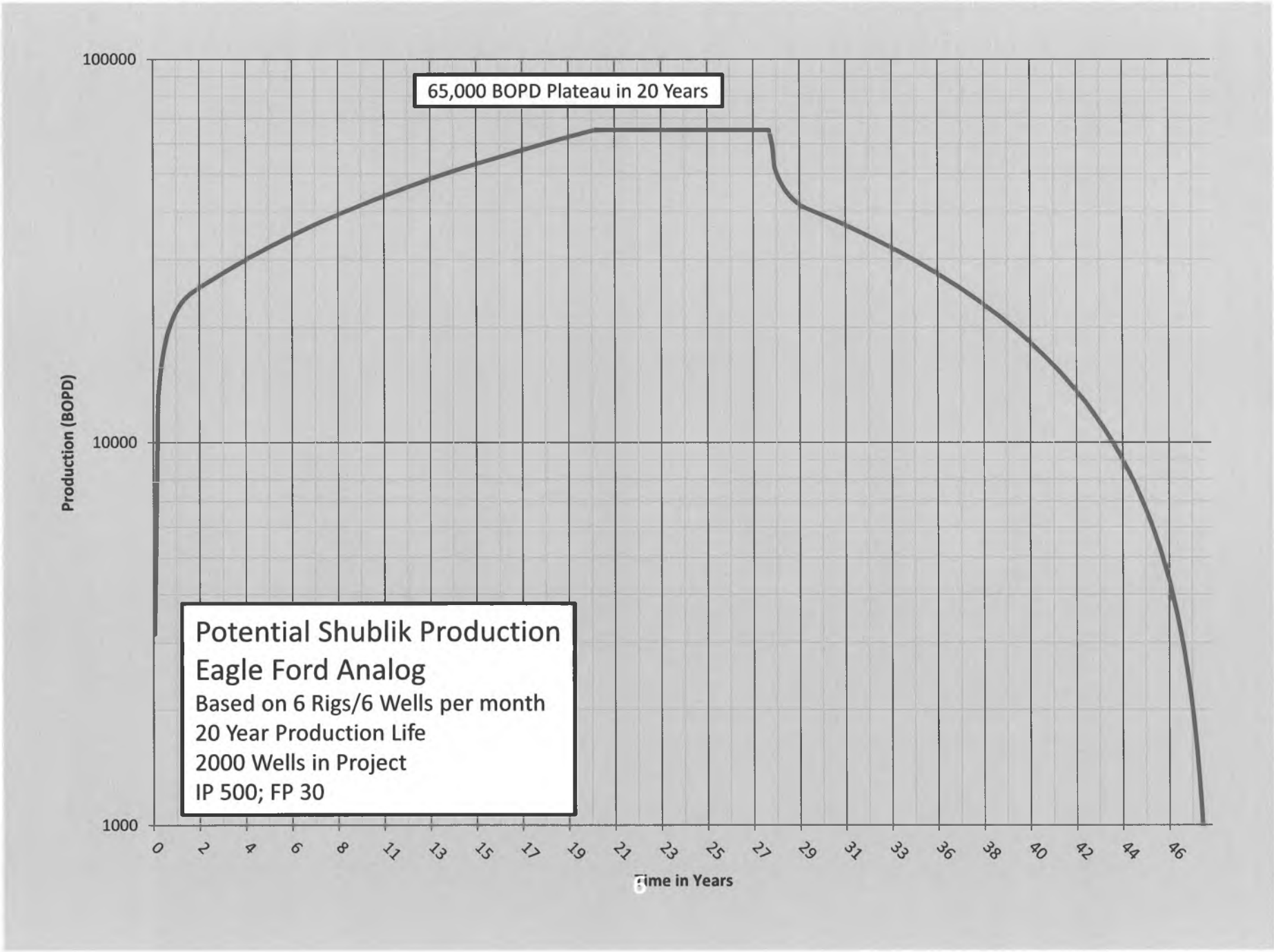
- Winter exploration season only
- Cost of development
- Lack of physical infrastructure
  - Roads
  - Power distribution systems
- Facility capacity & limitations, age
- Environmental/subsistence issues & permitting
- Fear of litigation-related delays
- Fiscal certainty

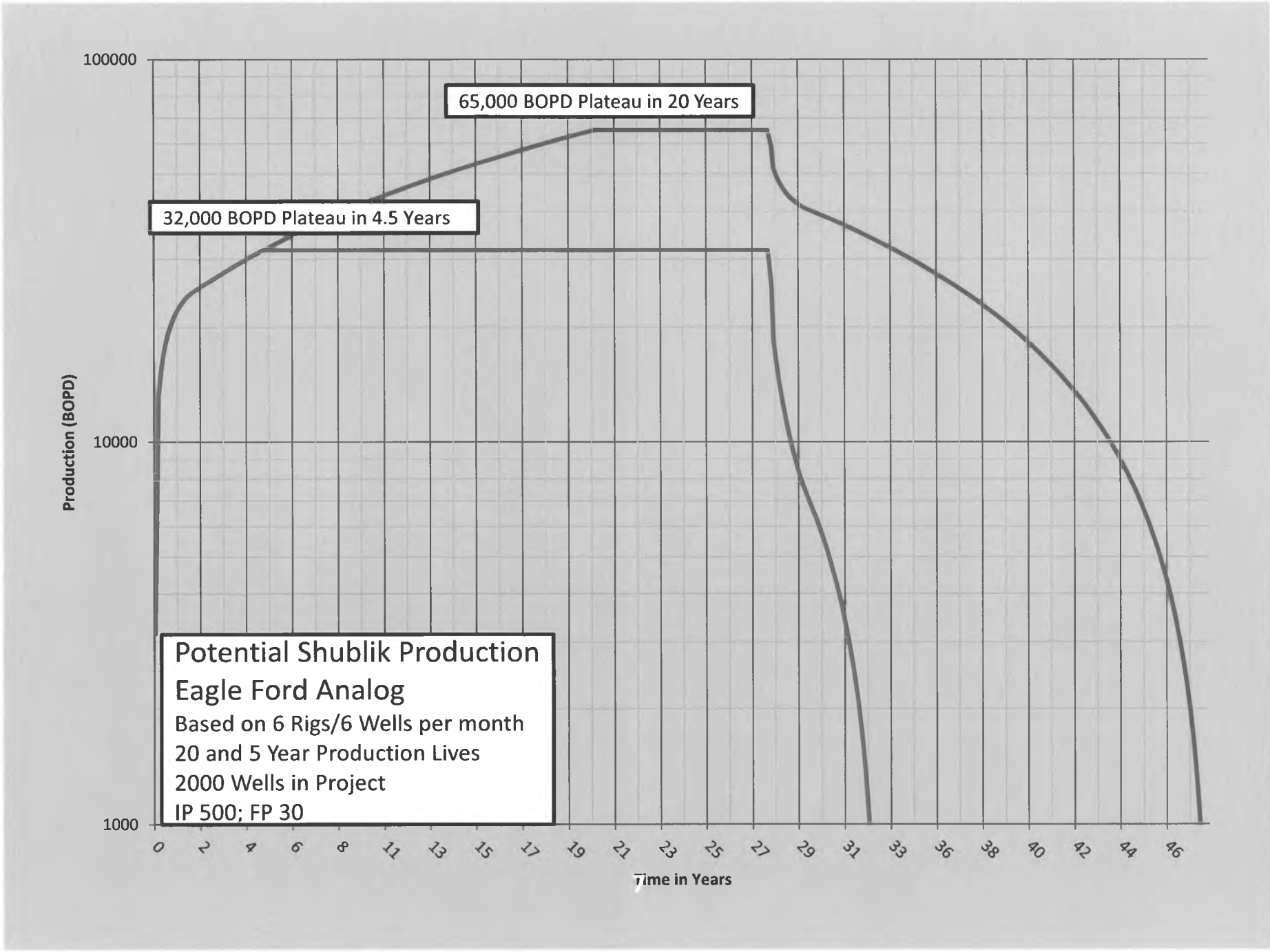
Typical Permitting Time Frame for a Large Scale Development Project




Reasonably expected time to production
Legacy fields
Heavy & viscous oil
Shale oil
New discoveries
Heavy & viscous oil
Shale oil
OCS Beaufort
OCS Chukchi
ANWR
NPR-A
Gas: Infrastructure dependent
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 30 35 40 45 50 55 60
Years


Potential Shublik Production
Eagle Ford Analog
Single Well Example, Typical of Several Reviewed
Re-Stimulated in Month 3
Gonzales County, Texas
10000.00
1000.00
100.00
10.00
Production BOPD
0.00
2.00
4.00
6.00
8.00
10.00
12.00
14.00
Time in Months


65,000 BOPD Plateau in 20 Years
Potential Shublik Production
Eagle Ford Analog
Based on 6 Rigs/6 Wells per month
20 Year Production Life
2000 Wells in Project
IP 500; FP 30
Production (BOPD)
100000
10000
1000
0 2 4 6 8 11 13 15 17 19 21 23 25 27 29 31 33 36 38 40 42 44 46
Time in Years


65,000 BOPD Plateau in 20 Years
32,000 BOPD Plateau in 4.5 Years
Potential Shublik Production
Eagle Ford Analog
Based on 6 Rigs/6 Wells per month
20 and 5 Year Production Lives
2000 Wells in Project
IP 500; FP 30
Production (BOPD)
100000
10000
1000
0 2 4 6 8 11 13 15 17 19 21 23 25 27 29 31 33 36 38 40 42 44 46
Time in Years

What will it take to reach the goal?

- Collaborative and competitive environment
- Minimize all barriers
- Access all fields and all types of oil

Regional Activity & PFC Energy Assessment

Country	Activity	PFC Energy Assessment
USA Alaska (Core)	• ConocoPhillips' assets in Alaska are legacy assets acquired from Arco Alaska in 2000 and include the Greater Prudhoe Area, Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. The company's largest producing area in Alaska is the Greater Prudhoe Area, a collection of mature, long-life fields. Production from the Alaska portfolio has been in slow decline since the late-1980s following a decade of growth made possible by commissioning of the ~2.1 mmbo/d capacity Trans Alaska Pipeline System (TAPS) in 1977. In 2010, net production from Alaska averaged 230 mb/d of oil and 82 mmcf/d of gas, accounting for ~36% of US production. • ConocoPhillips and BP have been joint proponents of the **Alaska Gas Pipeline** (or **Denali Pipeline**), intended to accelerate commercialization of Prudhoe Bay gas through Western Canada and into US markets. In 2010, the partners officially withdrew their support for the proposed project, in response to continued US gas price weakness and absence of buyer commitments. This places substantial uncertainty around further commercialization of ConocoPhillips' Alaska gas resources. • Activity in the ConocoPhillips-operated Greater Kuparuk Area (GKA), has recently focused on development of viscous oil resources. The GKA, located 40 miles west of Prudhoe Bay on the North Slope, includes the Kuparuk field and its satellites: West Sak, Tarn, Tabasco, Meltwater, and Palm. Heavy oil resources **West Sak** and **Ugnu** (52.2% w.i., operated) are potential projects currently in the appraisal phase. Expected gross peak production is ~23 mboe/d.	**Material harvest position.** As Alaska's largest oil and gas producer, ConocoPhillips holds a leading position in the region. Although the company continues to target smaller projects within the GKA (West Sak and Ugnu) and NPR-A (Alpine West, Greater Moose's Tooth unit and Fiord West), ConocoPhillips will ultimately need expanded access to US and/or Asia gas markets in order to reverse the downward production trend in Alaska.

Capital Allocation and Global Portfolio Review:

Discussion Slides for the Alaska House Resources Committee

April 21, 2012

Tony Reinsch
Senior Director, Upstream & Gas
PFC Energy

PFC Energy

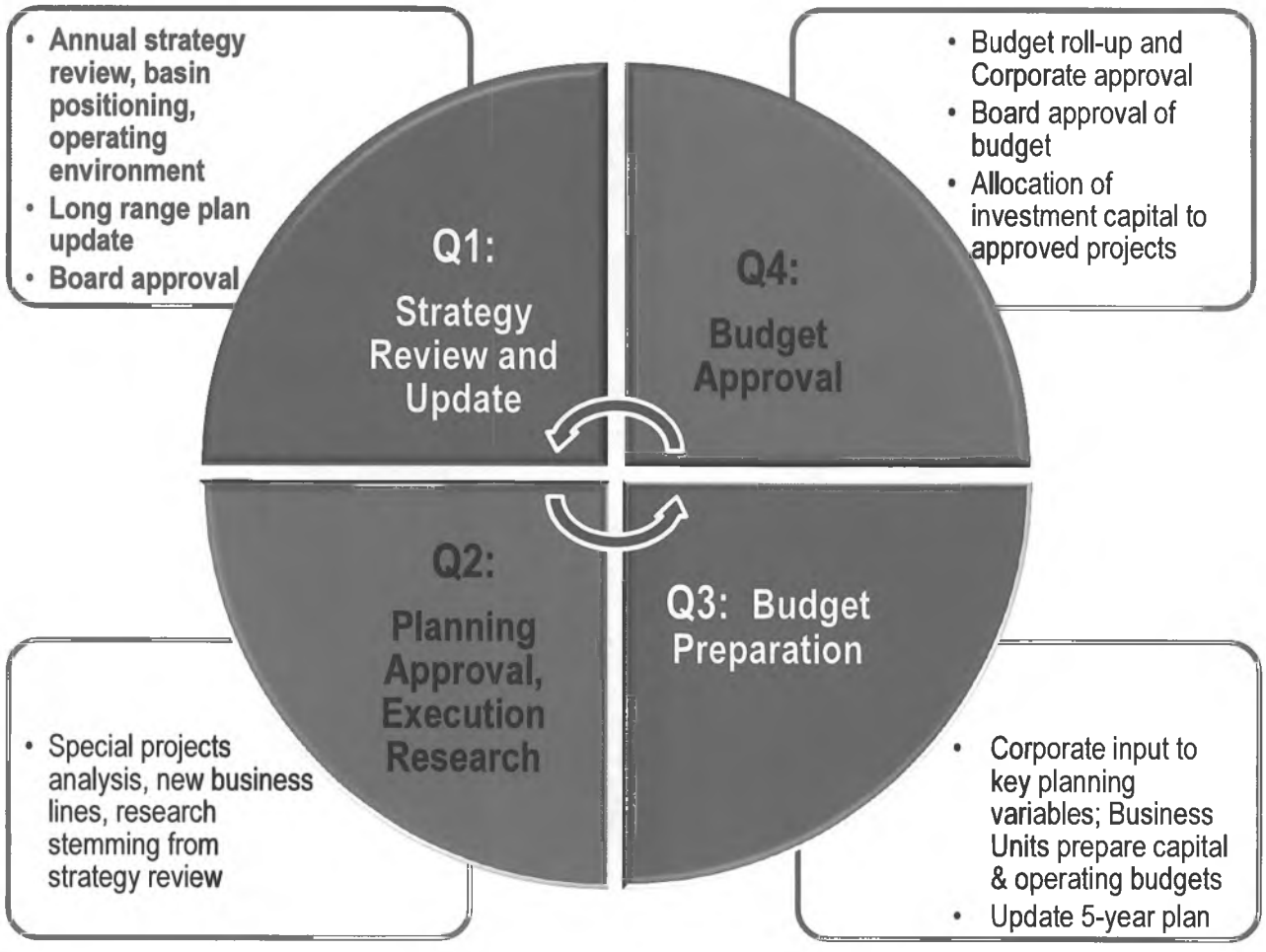
Oil & Gas Company Decision Making: Capital Allocation, Budget and Long-Range Planning

Points to Address: Discussion of Company Behaviors and Decision Making

- Key considerations for companies in making investment decisions, including decisions on whether to develop particular resources in the near term or postpone development
- Key metrics including ROCE, NPV, IRR, consideration of asset metrics versus portfolio metrics, and differences between integrated vs non-integrated companies

Annual Planning Cycle

Oil and gas companies follow a standardized process linking the annual Budget cycle to the Long Range Plan and corporate Strategy



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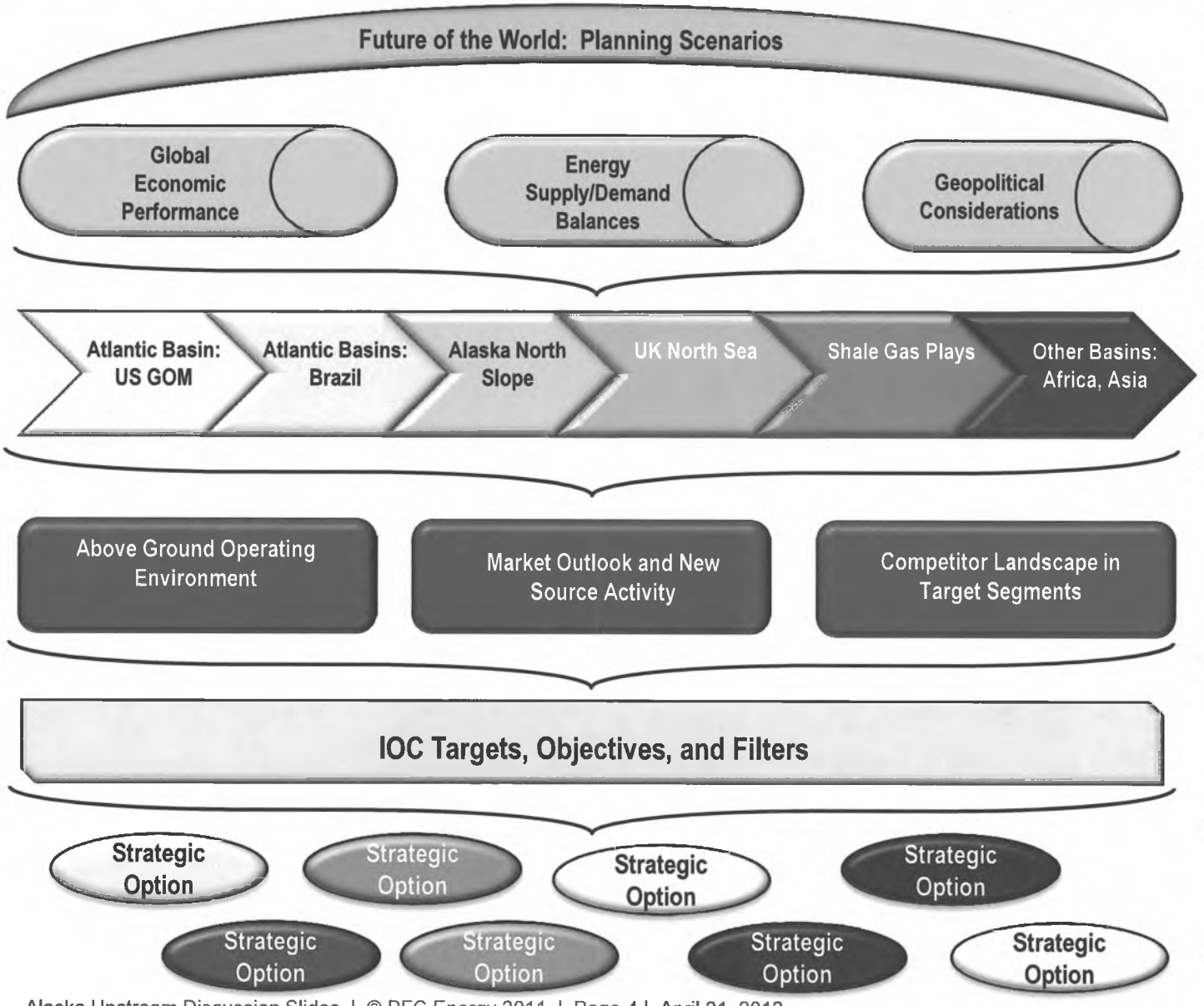
Strategy, Planning and Positioning



External Planning Environment: Identifying key uncertainties and forcing factors that will impact company Strategy and Long Run Planning

Preferred Operating Regions and Basins

Above ground risk, Potential "No Go" Geography

Blockers, Enablers, Gaps, Logjams; Determine materiality "Size of the Prize"

Identify Filters for Option Selection

Strategic Options: Robust across scenarios, Consistent with Objectives and Filters

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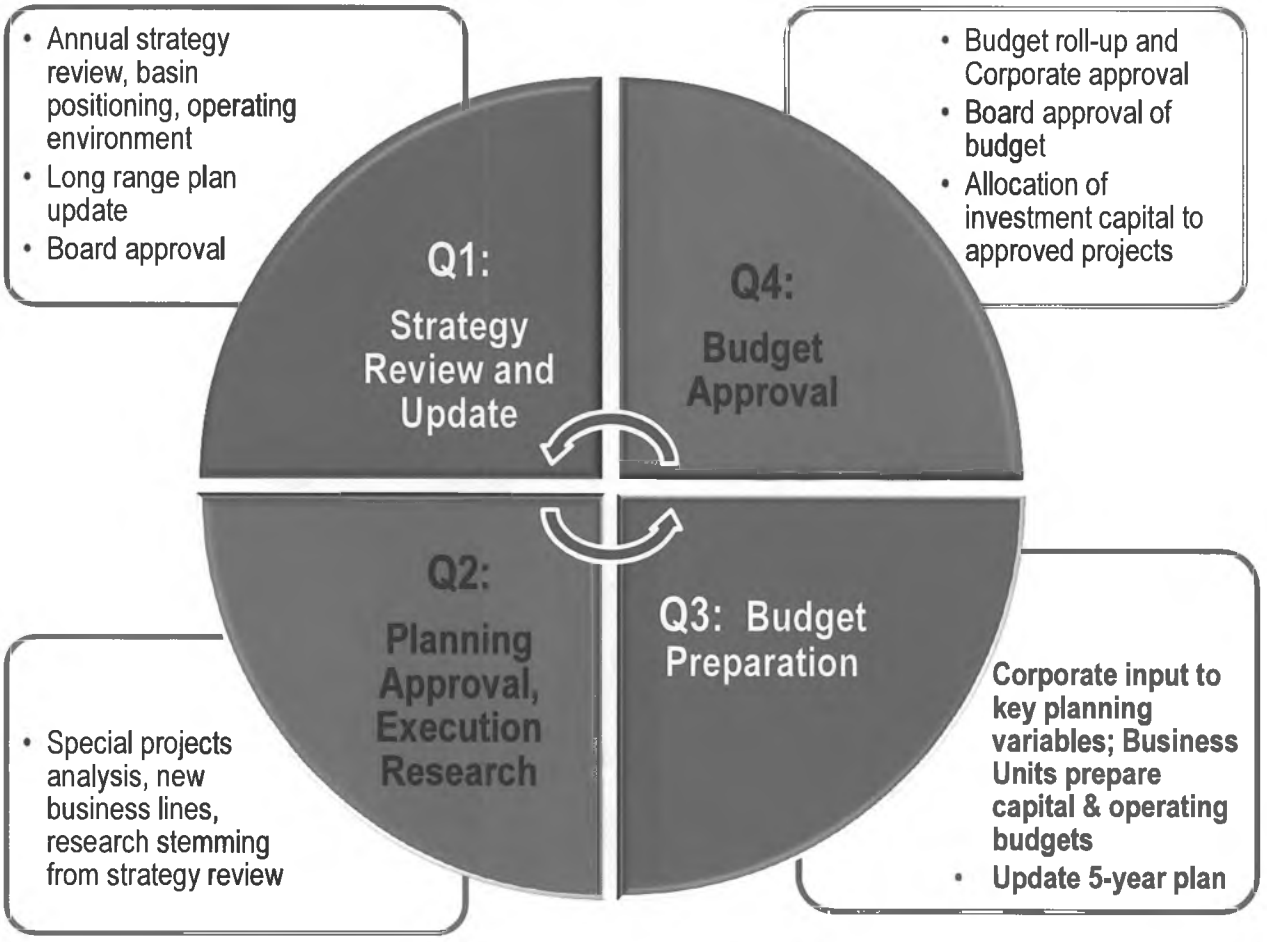
Annual Planning Cycle



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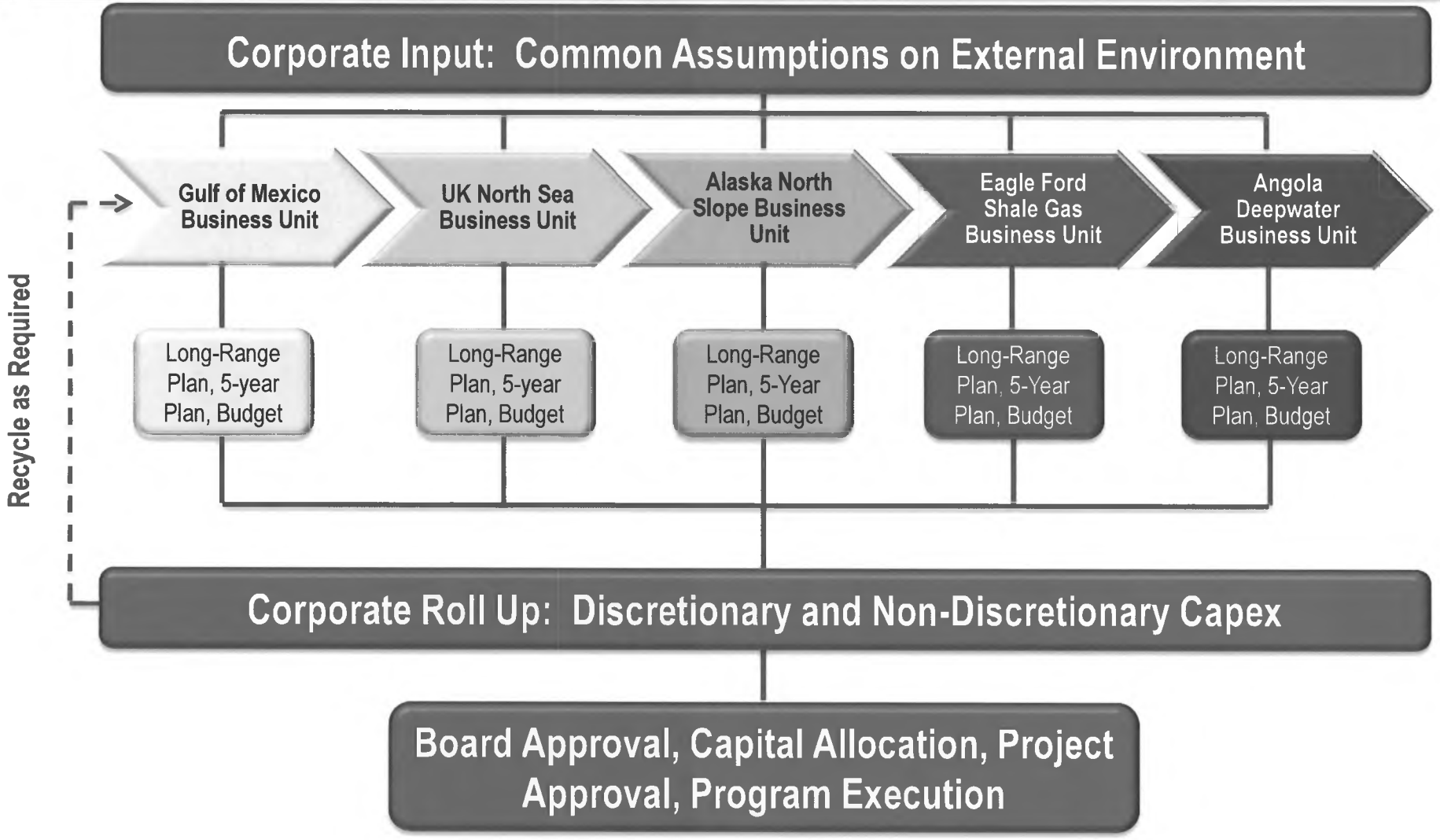
Planning Cycle and Capital Allocation



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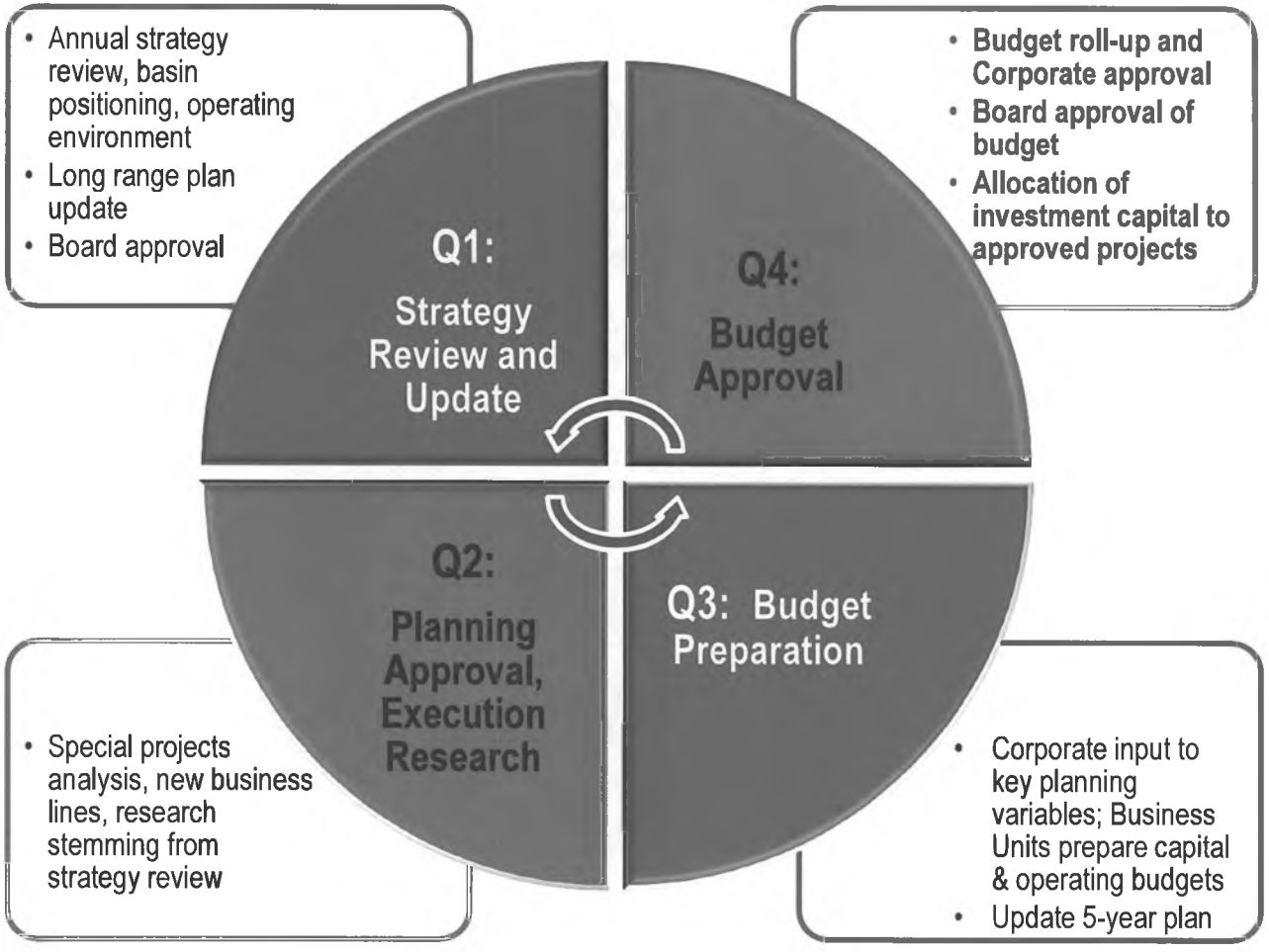
Annual Planning Cycle



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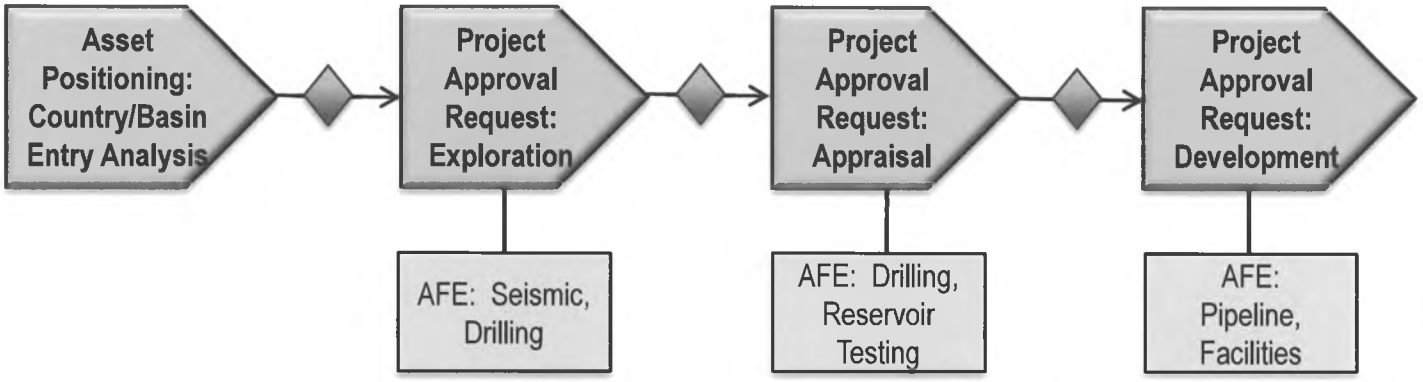
Attracting Capital: The Project Approval Process

- Materiality, total capex exposure, full-cycle economics/metrics, are all considerations in determining whether an IOC will position, or continue to invest, in a particular asset, basin, country.
- Each project is disaggregated into "discrete investment decisions", in the form of Project Approval Requests (PARs), creating a natural *stage-gate* for capital approval and allocation.
  - A PAR can extend beyond a single fiscal year budget, depending on scope of the work program. Represents ***non-discretionary*** capex at the start of the budget year
  - Each PAR has one or a series of associated Approval for Expenditure (AFE) documents for a specific activity or capex element
  - Sum of AFEs for a calendar year = ***capital Budget***
- Each stage-gate creates an opportunity for the Company to continue, amend, suspend, or exit/divest

Asset Modelling and Decision Process: Materiality and Total Capex Exposure



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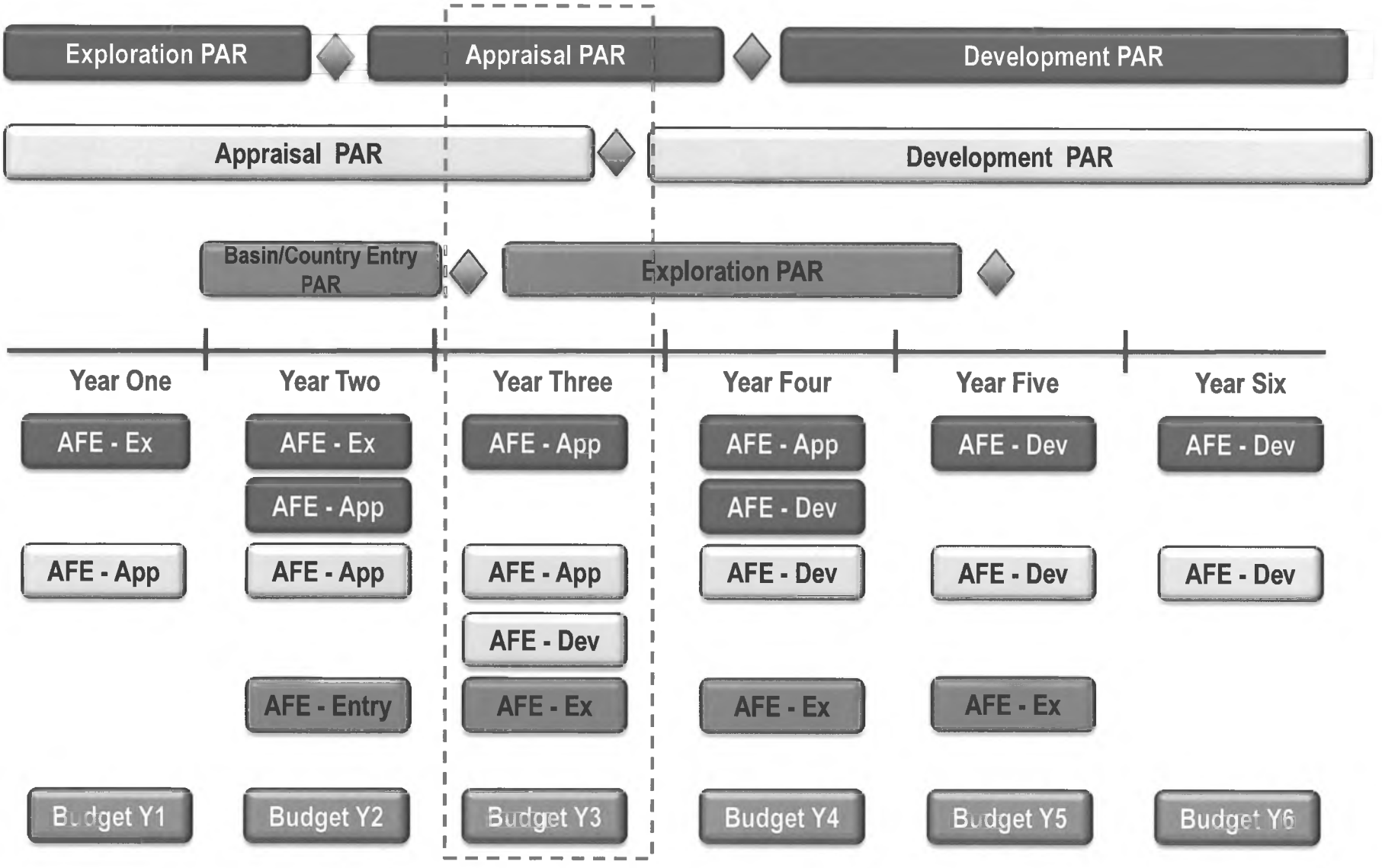
Business Control Architecture:
PAR => AFE => Budget



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Upstream Financial Metrics: Measuring Performance

- **Growth** .. Ability to manage the "top line."
  - CAGR in Production and Reserves relative to target
  - Quality of growth .. Where, how, consistent or not
  - Plowback Rate. .. To show relative growth intentions between different regions

- **Profitability** .. Ability to manage the "bottom line."
  - Upstream Cash flows
  - Upstream Net Income
  - Upstream Production Costs

  } Absolute and "per boe" basis

- **Efficiency** .. Ability to manage capital.
  - Upstream ROCE
  - Finding costs, F&D costs, Replacement Costs

- **Cash Flow** .. Ability to manage investment/re-investment in the portfolio.
  - Financial Strategy (debt targets, debt/capital ratio, dividend requirements)
  - Self-financing nature of portfolio (free cash flow versus capex: regional and global)

- **Risk** .. Ability to manage a diversified portfolio.
  - Financial Risk: Debt-to-Capital ratio, financial flexibility
  - New Source Risk: Thinner margin barrels dominating new source volumes

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Project Selection and Decision Metrics

Energy companies employ a variety of Benchmarks or Metrics to rank investment opportunities and to allocate financial capital. Some of the more common include:

- Pay-out period; length of time required to recoup financial capital being placed at risk. Simplest selection metric, important to firms with scarce capital resources. No reference to project value after pay-out
- Internal Rate of Return; discount rate at which PV of costs = PV of revenues
- Net Present Value; PV of costs less PV of revenue flows (using discount rate reflecting cost of capital, cost of borrowing, or other);
  - NPV/boe; incorporates concept of investment efficiency
  - NPV/Investment; incorporates assessment of return to the investment dollar. Also referred to as **PVPI**
- Recycle Ratio: Netback or profit per boe divided by F&D cost per boe. A measure of project or corporate profitability (target >1)
- Discounted and Undiscounted Net Cash Flow Profiles; measure of availability of free cash flow for follow on or alternative investments
- Maximum Negative Cash Flow Exposure; useful in situations where access to financial capital is an issue. What is the maximum exposure being undertaken by the firm
- Net Booked Reserves; contribution of the projects to corporate value (based on bookable reserves, amongst other measures)
- Capex/boe; cost per barrel of production capacity. Burdens the projects by the cost of infrastructure, facilities, etc. Tends to favor less complex, more mature capex alternatives

Project Metrics: Net Present Value

- **Net Present Value (NPV)**: The estimated value of a project when all future net cash flows are discounted to the present at an appropriate rate (the "discount factor"). If NPV > 0, then the project is expected to deliver a return greater than the cost of development, including a return on capital invested (accounted for in the discount rate).
- Advantages:
  - **Time value at corporate rate included**
  - **Can be calculated exactly**
  - **Can accommodate risk**
    - **NOTE: Above ground risk incorporated through discounting of costs and/or revenue flows, *NOT* through use of alternative discount rates**
  - **Useful for valuing projects**
  - **Discount rate reflects corporate preference for opportunity cost of investment capital (e.g., market interest rate, cost of equity capital, weighted average cost of capital (debt and equity))**
- Disadvantages:
  - **Difficult to rank projects. Significantly different capital and expenditure profiles can deliver the same NPV, due to the effect of discounting.**
    - **E.g., very large cash flows in a future time period can have the same "present value" as small cash flows in forward years. This may not, however, have the same impact and value for the company treasury**

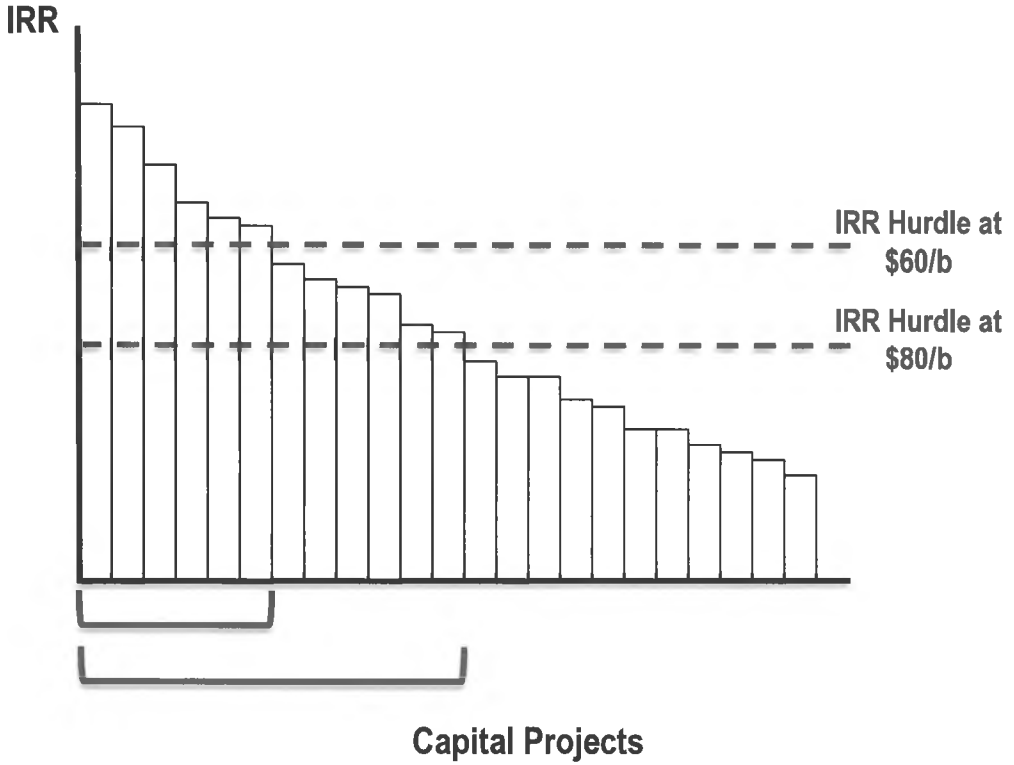
Project Decision Variables: Internal Rate of Return

- **Internal Rate of Return (IRR)**: The discount rate that equates all future cash inflows to outflows at a point in time (usually the present)
- Advantages:
  - **Easy to understand.**
  - **Incorporates time value**
  - **Can be compared to a required minimum (or hurdle rate)**
  - **Independent of magnitude of cash flows.**
- Disadvantages:
  - **Multiple rates of return are possible in cases of material cash flow volatility (e.g., large positive and negative swings over project life); uncomfortable for decision makers looking for unique decision criteria**
  - **Doesn't measure absolute worth of the project**
  - **Not useful for single project analysis**
  - **Implicit assumption that interim cash flow is invested at calculated IRR (issue for high return projects) => overstates the true project value**

Capital Allocation: IRR Hurdle Rate

- Eligible projects ranked by IRR:
  - **Eligibility based on series of discrete project metrics within each PAR**
  - **Metrics change at each stage of the project cycle, as risks are addressed and estimates become more certain**
  - **Examples:**
    - **NPV10 > 0**
    - **PVPI > 1.3**
    - **Payback < 3 years**
- Corporate establishes a "hurdle" IRR number. Projects with IRR's in excess of the hurdle rate attract budget capital, while those below the hurdle rate are not funded

Capital Allocation using IRR Hurdle Rate



- Issues with IRR Hurdle Rate:
  - **Increase in free cash flow (due to, say, rise in energy prices) => increased capital budget => lower Hurdle rate in order to undertake additional projects => reduce overall portfolio quality and lower efficiency of capital employed. Evidenced in *cycles of value destruction* within the industry**
  - ***Gaming the system*: Project managers have an incentive to overstate the "size of the prize" or understate costs, in order to attract investment capital to proposed projects**
  - **IRR ranking does not speak to *materiality* => equivalent IRR's can have substantially different capex and revenue profiles**

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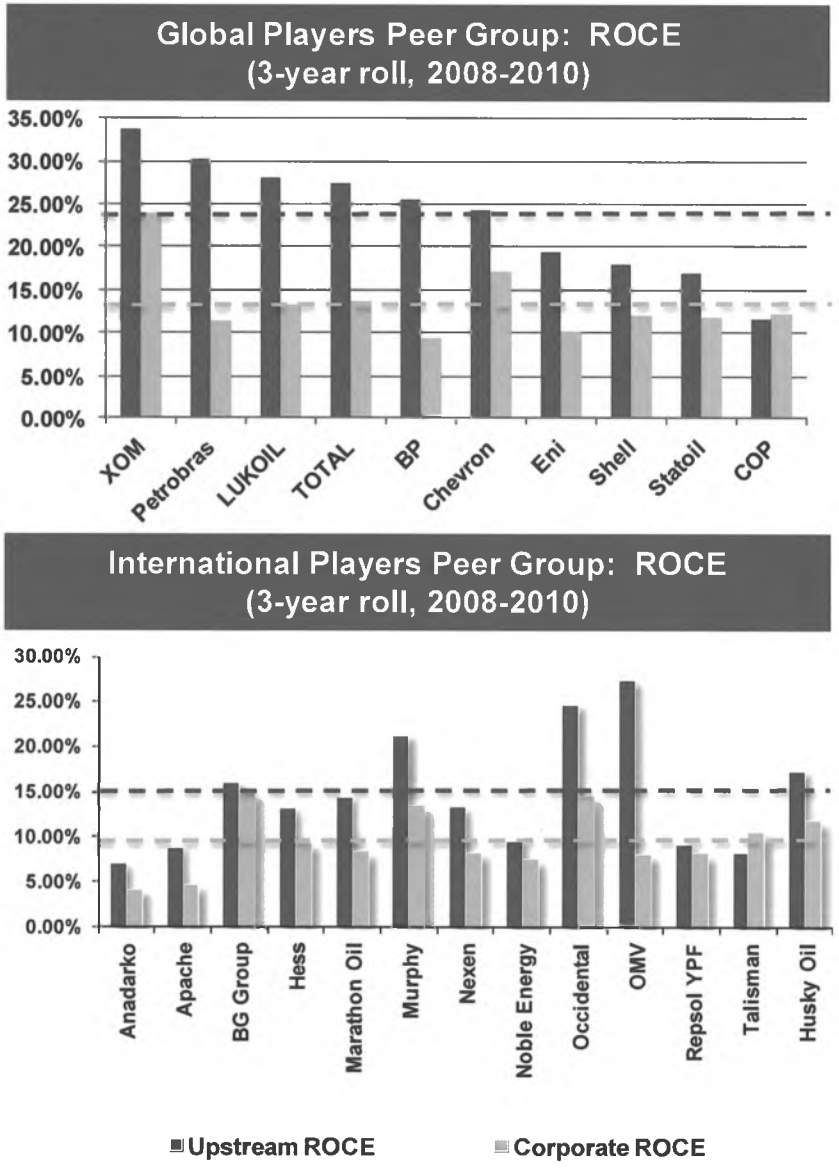
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **Return on Capital Employed**:
  - ROCE = [(Net profit before interest and taxes) / (Gross Capital employed)] x 100
  - Where:
    - Gross capital employed = Fixed assets + Investments + Current assets OR
    - Gross capital employed = Share Capital + General & Capital Reserves + Long term loans
    - (+) Correlation with production, commodity prices
    - (-) Correlation with upstream spending
  - Indicates how well management has used the investment made by owners and creditors into the business.
  - The higher the return on capital employed, the more efficient the firm is in using its funds. Over time, ROCE reveals whether the profitability of the company is improving or eroding



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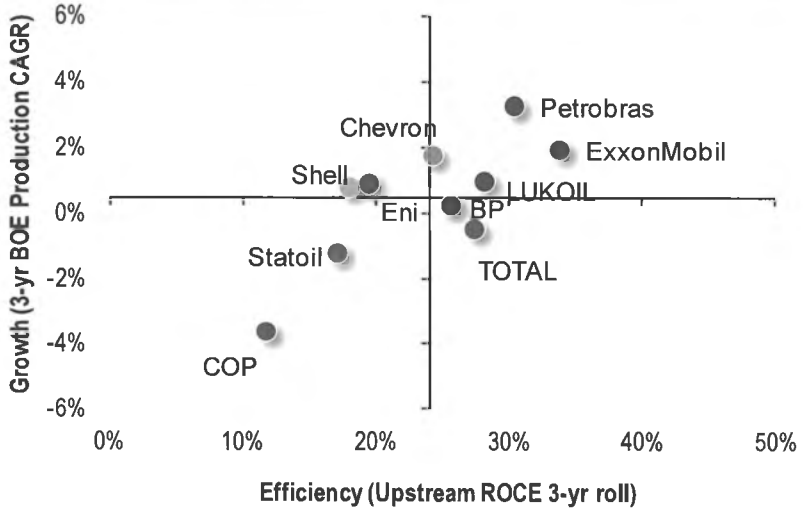
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **Issues with ROCE**:
  - Major capital project investments increase the denominator in advance of revenue (profit) impacts in the numerator => *penalizes the IOC for major capital investment undertakings*
    - Explains in part why it is unusual to find companies with high ROCE and high growth metrics
  - Once in place, the scale of major capital project investments tend to deliver superior ROCE performance => *bias toward large asset portfolios*
    - Exception is deepwater developments, where high, short plateaus and steep production declines can result in highly volatile ROCE outcomes
  - Depreciation creates *bias in favor of mature portfolio*: More mature the asset base, the lower the denominator (capital exposed) and the higher the ROCE (all else being equal)

Global Players Peer Group: Growth v Efficiency



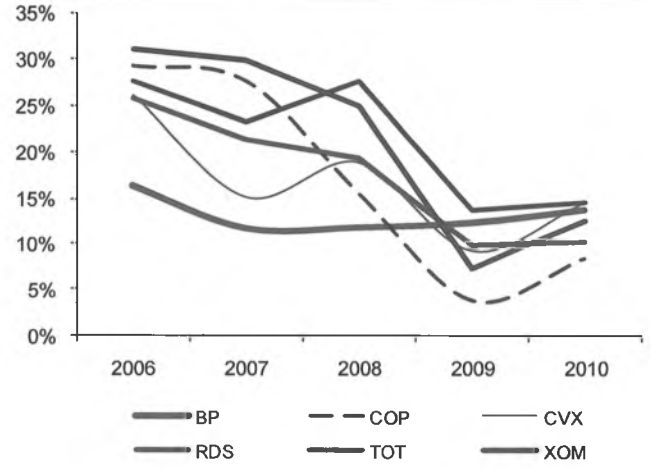
PFC Energy

Special Issue: Integration vs. De-Integration

Arguments For Integration

- Superior market/financial management over commodity cycle
  - Counter: Collapse in Downstream profitability has seen a rise in successful "pure play" refining companies
- Integration is important for molecule management; ensures sophisticated refining capacity is in place for particular crudes
  - Counter: Independent energy producers are not hitting roadblocks in this regard; independent refiners are responsive to requirements.

Downstream ROCE – Selected Integrated IOCs (3-year roll)



- Integration is relevant for specific oil developments (e.g., Canadian oil sands, Venezuela heavy, high wax or acid content)
- Integration is a technical differentiator amongst energy companies => enhance ability to secure projects
  - Counter: The ability to build a refinery—which few integrated energy players have actually done recently—has little in common with the ability to execute on complicated upstream projects
- Integration allows participation in the Downstream Non-OECD growth story
  - Counter: The rapid petroleum product demand growth regions (China, Middle East, India) are dominated by National Oil Companies (NOCs) or quasi-NOCs, that choose partners based on what they bring to the table

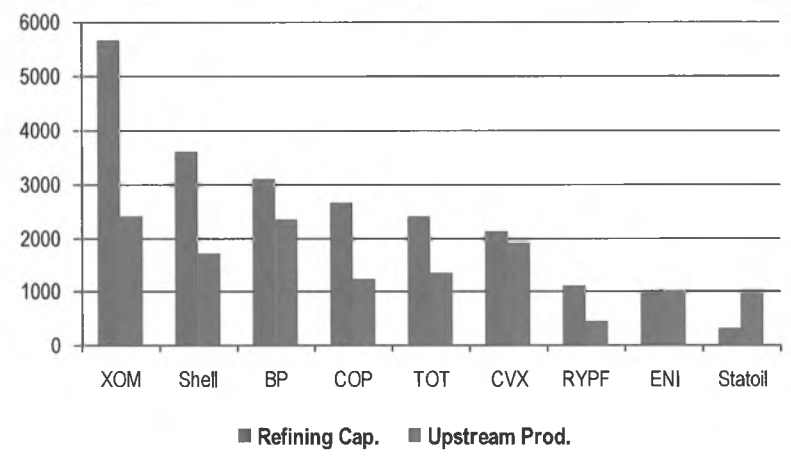
PFC Energy

Special Issue: Integration vs. De-Integration

Arguments Against Integration

- Capital markets value integrated IOCs below the sum of their parts
  - Counter: Expensive to split a company => if there is any identifiable value, should remain integrated (e.g., refining-petchems)
- Strategic focus: In many integrated companies, the Downstream sector is neglected strategically at the expense of Upstream positioning and growth—particularly in the current climate of narrow refining margins and sustained, high oil prices.
  - Counter: Unless the integrated IOC is certain that refining margins and economics will never recover, there is merit to retaining this mechanism for optimal capital allocation between sectors
- Materiality: There are few materially, physically integrated IOCs remaining
  - ExxonMobil and TOTAL have pursued integration between refining and petrochemicals, and there are strong arguments to continue this form of integration
  - Statoil, Eni, and Repsol are integrated on the basis of past roles as quasi-NOCs, and would likely face considerable government opposition to de-integration
- The world has evolved: more flexible and liquid trading markets and improved market & industry regulation have eroded whatever market management or cross subsidization benefits integrated IOCs derived from Downstream presence/dominance over the first 70+ years of their existence.

Refining Capacity versus Upstream Oil Production
Selected Integrated IOCs, 2010 (mboe/d)

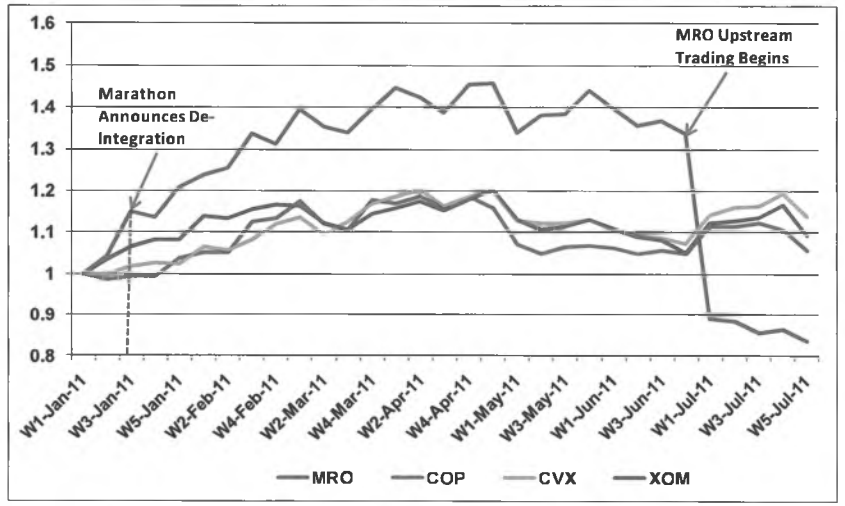


PFC Energy

Special Issue: Integration vs. De-Integration

- *Share appreciation* appears the Number One driver for de-integration. Marathon and ConocoPhillips have both concluded that integration hides value that can otherwise be secured through greater management focus, transparency, and more appropriate strategy and execution within the de-integrated entities
- *Market development arguments* for a Downstream presence have largely ended
  - BP, TOTAL, Shell all divesting from Africa in favor of "pure play" refiners and marketers
  - No remaining examples where downstream presence is key to upstream success.

Weekly Share Price Performance, Selected IOCs (Week 1, January 2011 = 1.0)



- Improvements in internal decision processes and external regulation have eroded any value that could be secured through *cross-subsidization or barriers to competitor entry*
  - Rate of return regulation in midstream operations, open-access provisions, increased sophistication in both project and portfolio analysis => few opportunities remaining for active market manipulation
- There are *technical drivers* for integration, related to specific crude types and processing challenges (e.g., Canadian oil sands, Brazil waxy heavy crude, Venezuela ultra-heavy, Chad acidic crudes). However, these benefits can be secured through contracts and JV or partnering agreements with third party refiners

Conclusion: Pressure for further de-integration moves will come from "share appreciation" arguments, most likely directed to Chevron and Shell (and BP once its portfolio has re-stabilized)

PFC Energy

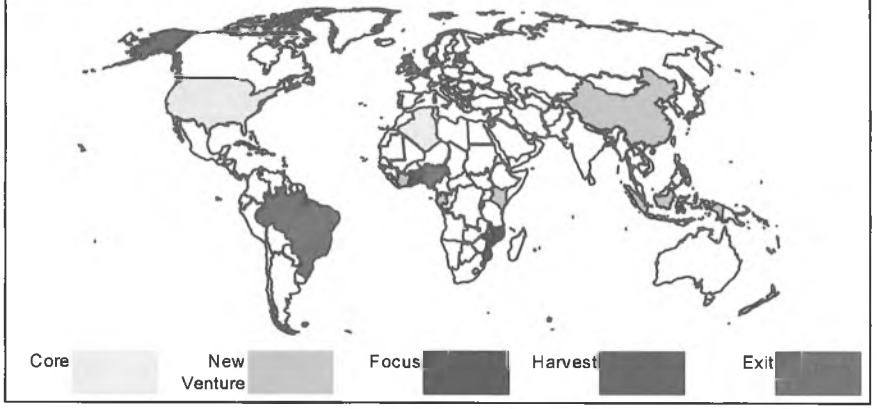
Special Issue: Basin Designation and Allocation of Free Cash Flow

- **"Core Area": Stable stream of net cash flows, and is material to the company. Can contribute to investment activity in other regions, but requires more than replacement level investment in order to maintain core area status. Tends to corresponds to a company's legacy assets.**
- **"Focus Area": Significant contributor to projected new source production and reserves growth in the medium- to long-term. Typically a net consumer of free cash flow until significant production levels are achieved.**
- **"New Venture": Areas new to the company—may be unexplored to fairly mature. Company has few, if any, assets and investment inflows can be modest (positions are usually characterized by exploration activity).**
- **"Harvest Area": Produces positive net cash flow, with Investment activity typically at/below replacement level. Limits to growth from lack of geological potential, competitor landscape, limited "room to run", etc.**

Global Areas of Upstream Operations

		US	Algeria	China	Cote d'Ivoire	Gabon	Indonesia	Kenya	Liberia	New Zealand	Sierra Leone
Liquids	(mboe/d)	30	23	0	0	0	0	0	0	0	0
Gas	(mboe/d)	38	0	0	0	0	0	0	0	0	0

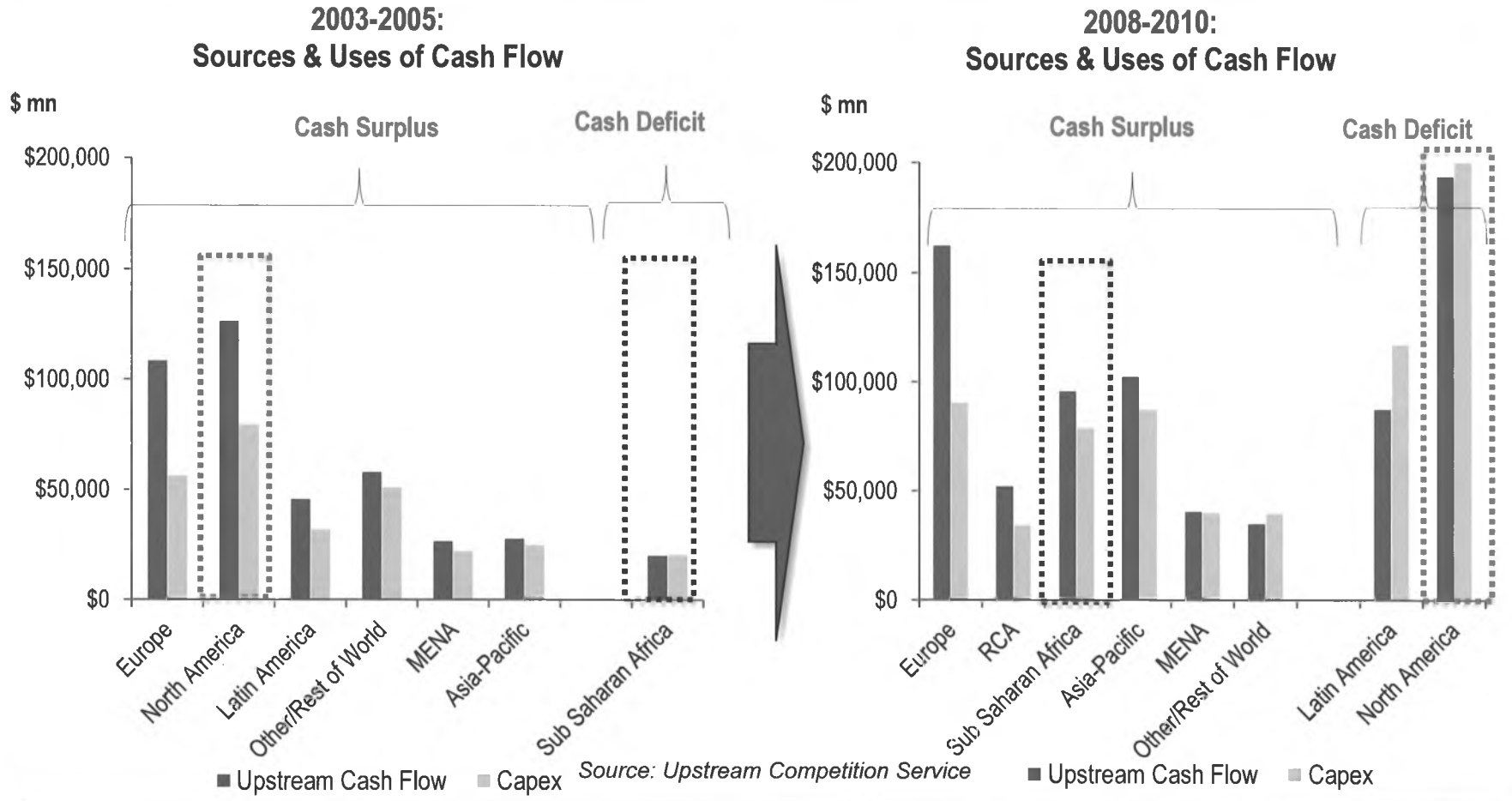
		Ghana	Mozambique	Benin	Brazil	Faroe Islands	Malta	Nigeria	Qatar	T&T	United Kingdom
Liquids	(mboe/d)	0	0	0	0	0	0	0	0	0	0
Gas	(mboe/d)	0	0	0	0	0	0	0	0	0	0



- **"Sit & Hold": Substantial resource base but investment delayed due to unattractive fiscal terms or significant above ground risks. Company may hold large projects in this area but is holding back the pace of investment (more common for National Oil Companies).**
- **"Exit/Potential Exit": For reasons including lack of materiality, limits to future growth, change in strategy, the company has/is expected to make a decision to exit (asset sales, asset swaps, relinquishment of acreage).**

PFC Energy

Special Issue: Basin Designation and Allocation of Free Cash Flow



Source: Upstream Competition Service

Along with Europe, Sub-Saharan Africa is now a key cash generating region for the large Upstream companies—with surplus cash flow now supporting growth in North America

** Includes data from the following companies: Anadarko, Apache, BG, BHP, BP, CNRL, Chevron, ConocoPhillips, Devon, EnCana, Eni, ExxonMobil, Hess, Husky Oil, Marathon, Murphy, Nexen, Noble Energy, Oxy, Petrobras, Repsol YPF, Santos, Shell, Statoil, Suncor, Talisman, TOTAL, Woodside*

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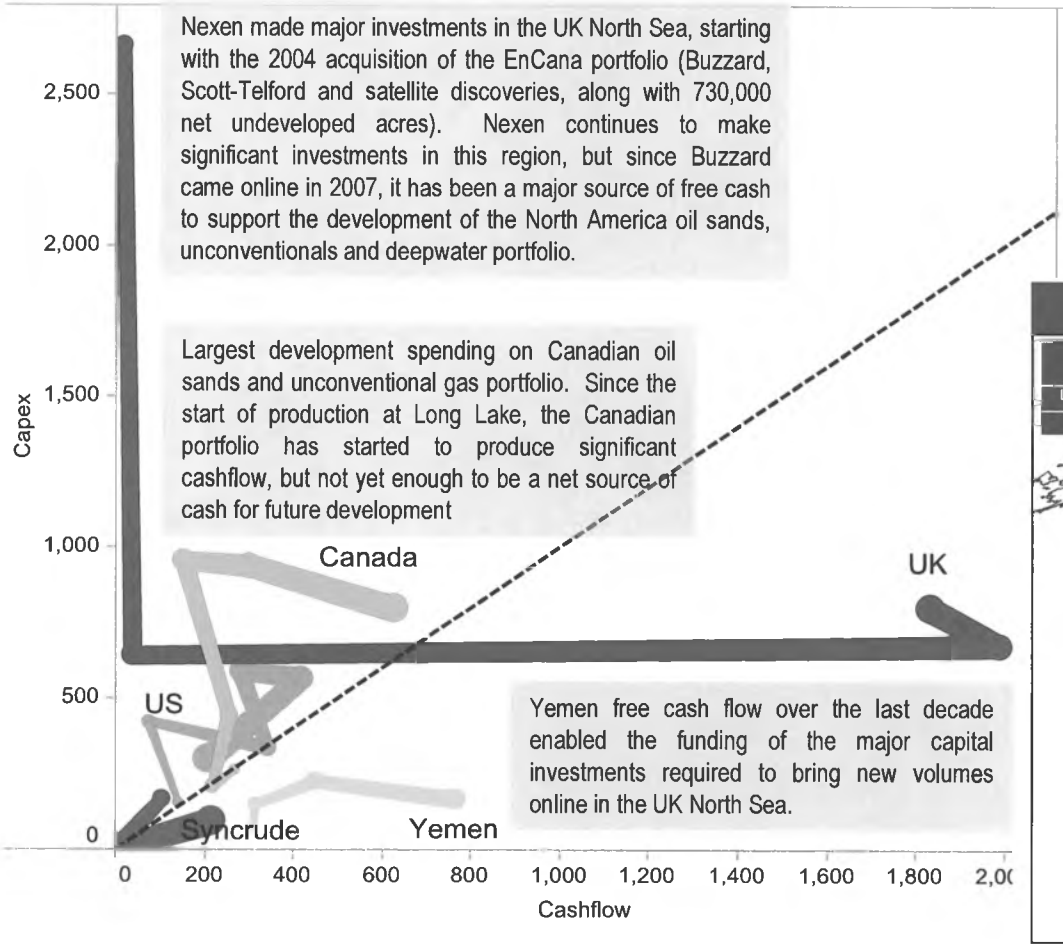
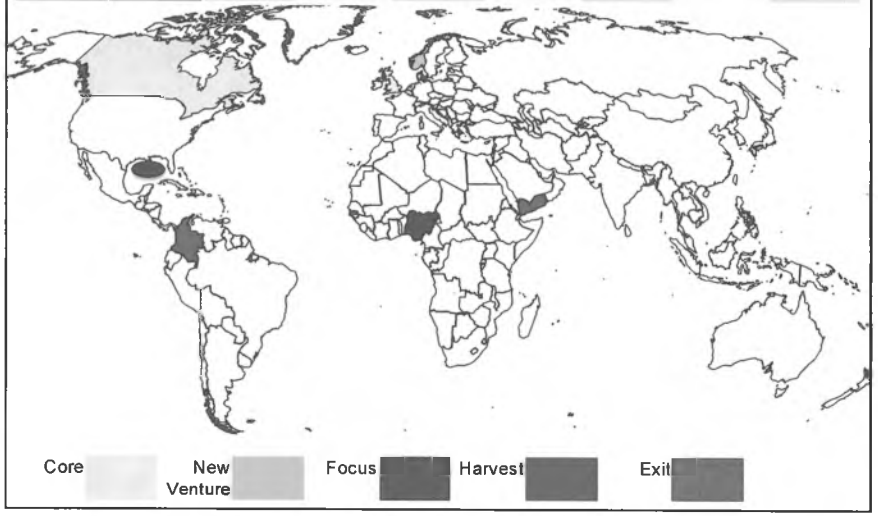
Example: Nexen Inc.

- Free cash flow from Yemen/Masila block directed to North Sea (Buzzard) assets; then from North Sea to Canadian oil sands and shale gas assets.
- Currently in Exit process in Yemen and shifting to Harvest in the UK



Global Areas of Upstream Operations

		Canada	United Kingdom	USA	Nigeria	Yemen	Colombia	Norway
Liquids	(mboe/d)	41	104	8	0	23	2	0
Gas	(mboe/d)	19	6	16	0	0	0	0



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Questions & Discussion

Global Strategy & Portfolio Overview of Major Alaska Producers

- BP
- ConocoPhillips
- ExxonMobil

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BP: Company Overview

Strategic Signature

- BP is a global integrated company, with production in 16 countries and upstream operations in an additional 10 countries.
- In 2011, total global production averaged ~3,400 mboe/d, making it the second largest company in the peer group (superseded by ExxonMobil (~4,513 mboe/d). The Russia & Central Asia (RCA) and North America regions accounted for ~55% of 2011 production.
- Much of the post-Macondo portfolio rationalization program (targeting $30 bn in asset sales including mid/downstream assets) has been completed. The result is a pared down and more focused geographic portfolio.
- BP expects growth of 1%-2% per annum through 2015 from a 3-pronged growth strategy:
  - **Deepwater Basins**: US GOM, Angola, Egypt, Brazil
  - **Global Gas**: US, Trinidad & Tobago, North Sea
  - **Giant Oil Fields**: Russia, Alaska, Iraq, others.
- Committed ~$20 bn net investment to 16 projects sanctioned over 2010-2011. Will curb ROCE performance for the coming 2-3 years.
- With the burden of the Macondo oil spill and reparations continuing through the mid-term, BP will be hard pressed to outperform its peers on any key metrics, leaving the company open to calls for more radical restructuring.

Company Overview

- **HQ:** London
- **Employees:** 79,700
- **2011 Reserves:** 17,330 mmboe
- **2011 Production:** 3,400 mboe/d
- **3 Yr Production Growth:** -3.53% CAGR (2008-2011)
- **April 2012 Market Cap:** $133 bn
- **April 2012 P/E Ratio:** 6.15
- **2011 Corp Revenue:** $375 bn
- **2011 Upstream Capex (Est.):** $17 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	LNG
✓	✓	✓	✓	✓	✓

Partnership History

Date	Partner	Region (or Country)	Type
2007	Husky	Canada	Sunrise Oil Sands
2008	Chesapeake	US	Unconventional
2009	CNPC	Iraq	Rumaila TSA
2011	Reliance	India	Offshore Gas

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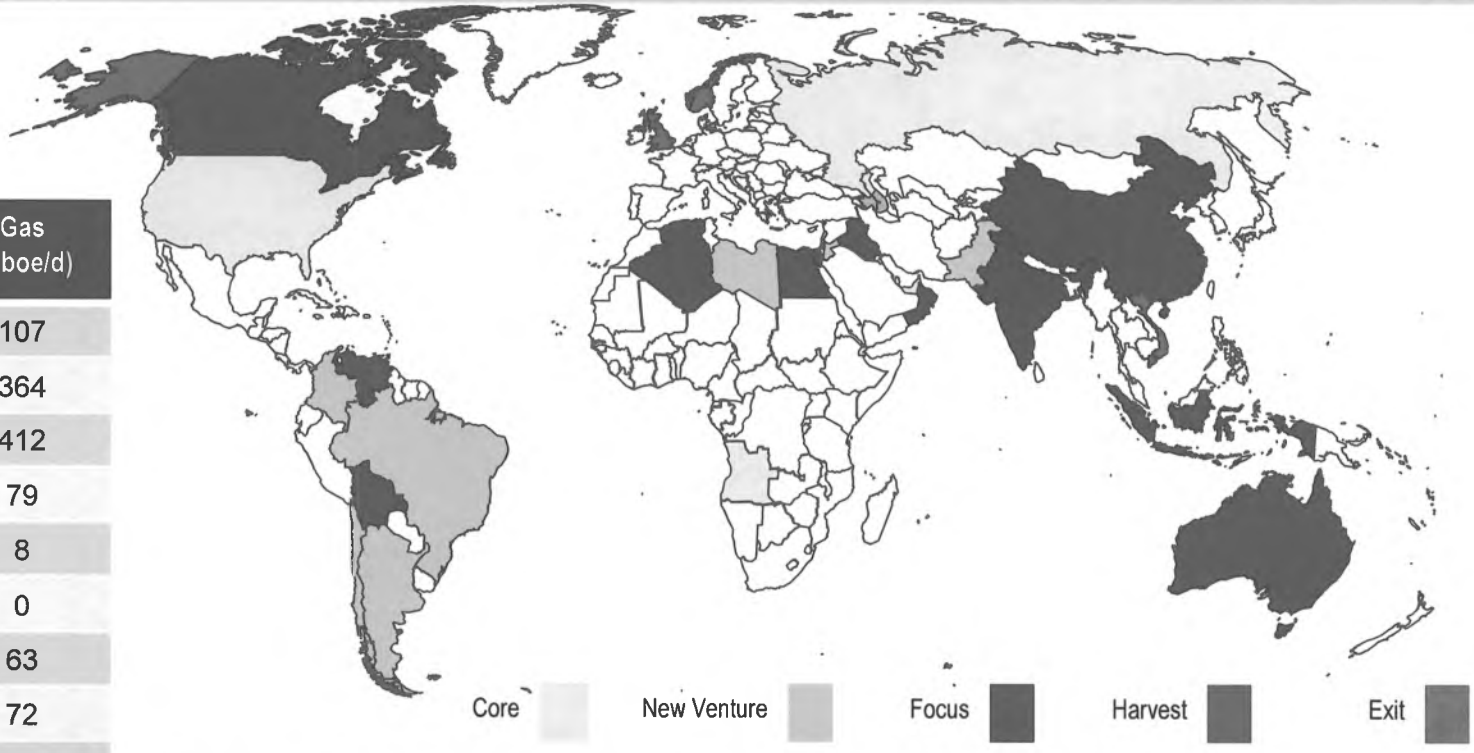
BP: Global Areas of Upstream Operations



	Liquids (mboe/d)	Gas (mboe/d)
Russia	856	107
US	594	364
T&T	36	412
UK	137	79
UAE	190	8
Angola	170	0
Argentina	75	63
Egypt	59	72
Azerbaijan	103	22
Australia	30	77
Indonesia	2	71
Norway	40	3
Canada	7	34
Algeria	17	21
Pakistan	10	25
Venezuela	23	2

	Liquids (mboe/d)	Gas (mboe/d)
China	0	16
Vietnam	0	13
Bolivia	0	2
Brazil	0	0
Chile	0	0

	Liquids (mboe/d)	Gas (mboe/d)
Iraq	0	0
Oman	0	0
Jordan	0	0
Libya	0	0
India	0	0

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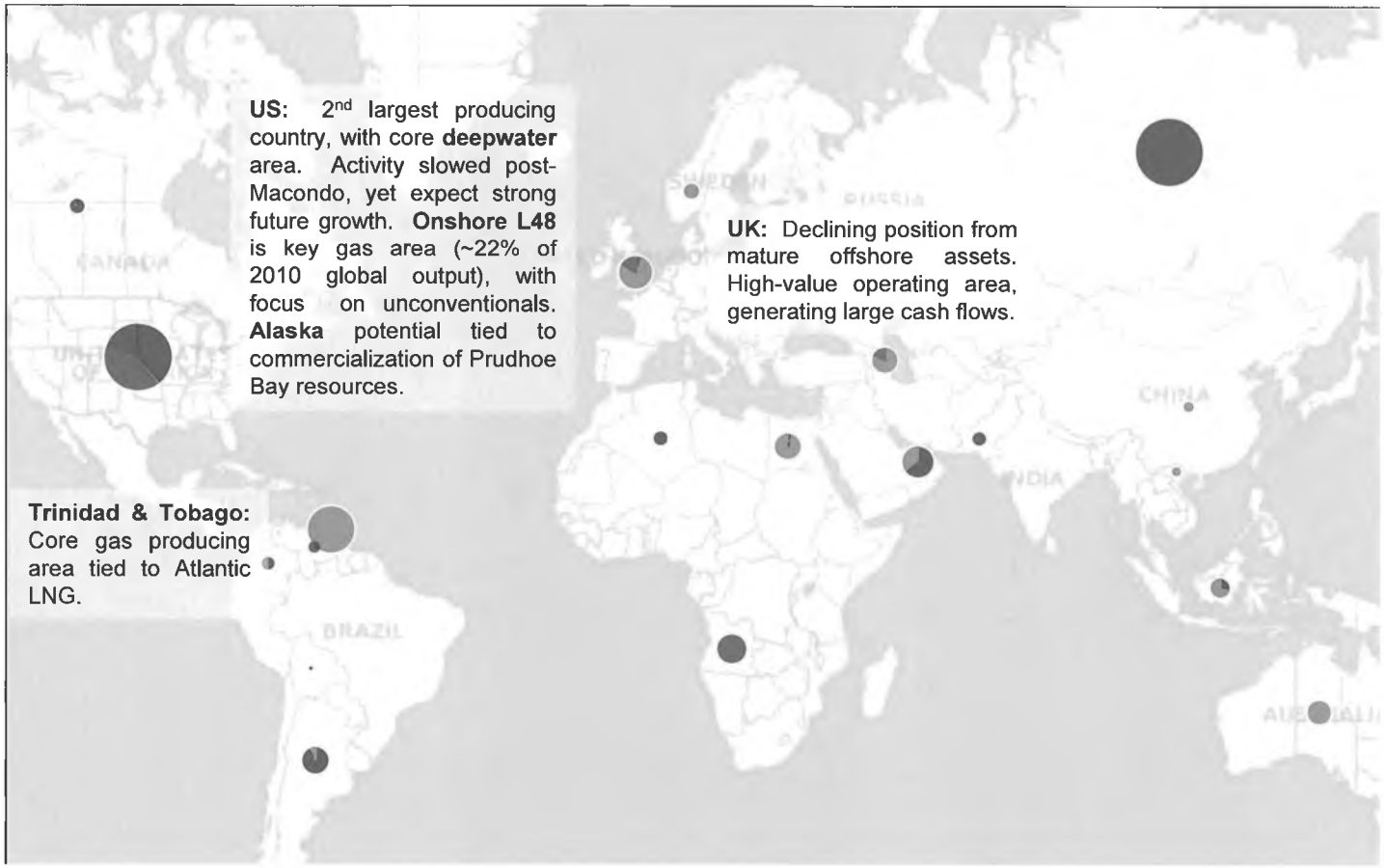
BP Global Production Portfolio - 2010

Canada: modest conventional production, with future potential tied to oil sands

Russia: BP's largest producing country (963 mboe/d), representing ~26% of 2010 output. Substantial long term growth potential. Continued interest in Russia (and Arctic) expansion, despite limitations arising from the TNK-BP joint venture.



US: 2nd largest producing country, with core **deepwater** area. Activity slowed post-Macondo, yet expect strong future growth. **Onshore L48** is key gas area (~22% of 2010 global output), with focus on unconventionals. **Alaska** potential tied to commercialization of Prudhoe Bay resources.

UK: Declining position from mature offshore assets. High-value operating area, generating large cash flows.

Trinidad & Tobago: Core gas producing area tied to Atlantic LNG.

mboe/d

0
500
1,000
1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Azerbaijan: Participation in 2 large-scale projects: Azeri-Chirag-Guneshli & Shah Deniz.

UAE: Core position through equity affiliates, though concession are being re-negotiated

India: 2011 Partnership with Reliance for exploration in shallow and deepwater.

Australia and **Indonesia** are key gas producing areas tied to investments in LNG.

Argentina: onshore & shallow water assets (held by PAE) were to be sold to Bridas, but transaction failed in 4Q:11.

Angola: Sole presence in SSA is Angola deepwater. High growth from 2002-2009, now challenged with start-up of several unsanctioned projects

Iraq: Development of Rumailia oil field

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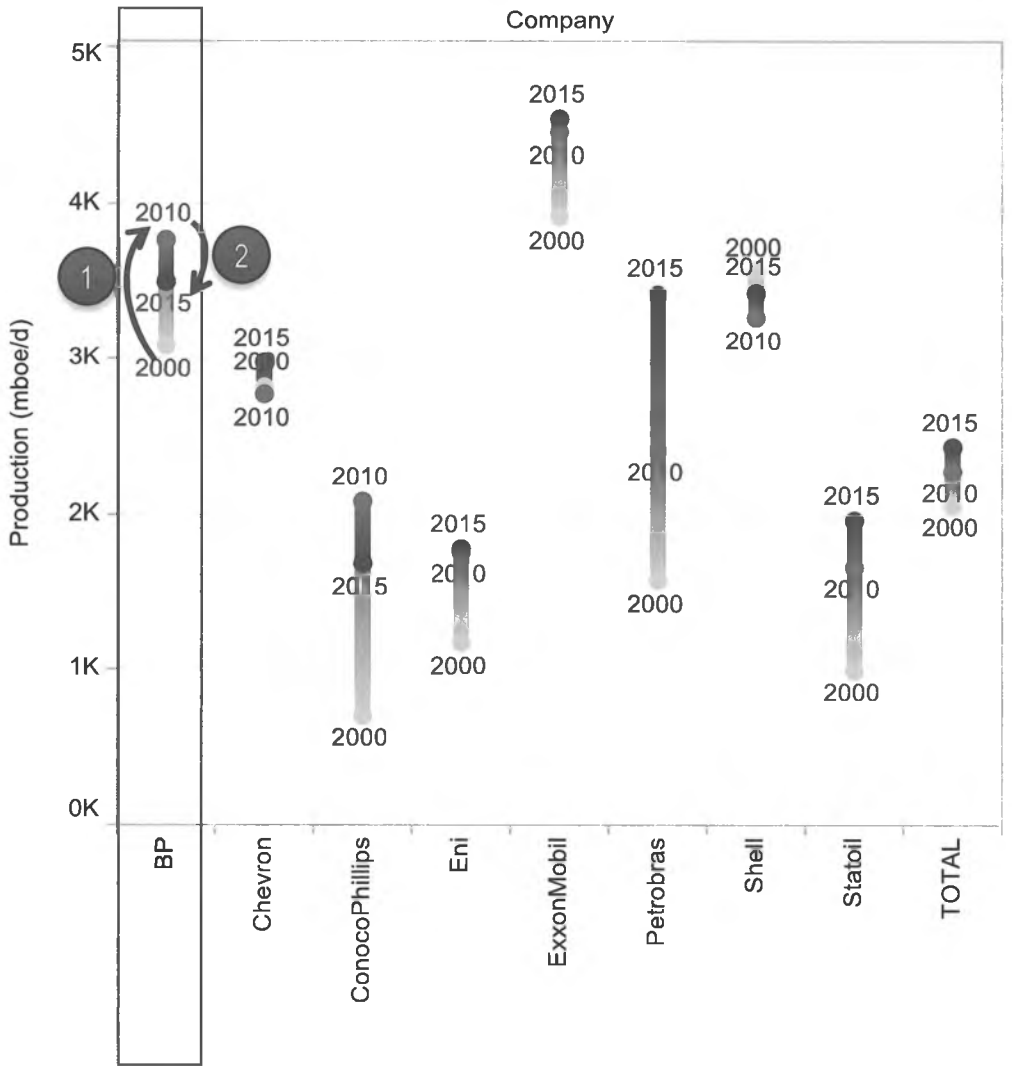
Total Portfolio Evolution: BP vis-à-vis the Competition

Production (mboe/d) in 2000, 2010 and 2015 (PFC Forecast): BP and Peers



In 2010, BP was the second largest producer of the peer group. BP and COP are the only two companies forecast to deliver production declines over the 2010-2015 period.

1. **2000-2010:** Production increases from ~3,080 mboe/d to ~3,780 mboe/d due to addition of Russia (~960 mboe/d), Trinidad & Tobago (~250 mboe/d) and Angola (~170 mboe/d). This expansion offsets declines from Europe (-660 mboe/d and North America -350 mboe/d) .

2. **2011-2015:** BP's production is expected to decline from 2000-2015, due mostly to the post-Macondo asset divestiture program, combined with curbed activity in the GOM deepwater.

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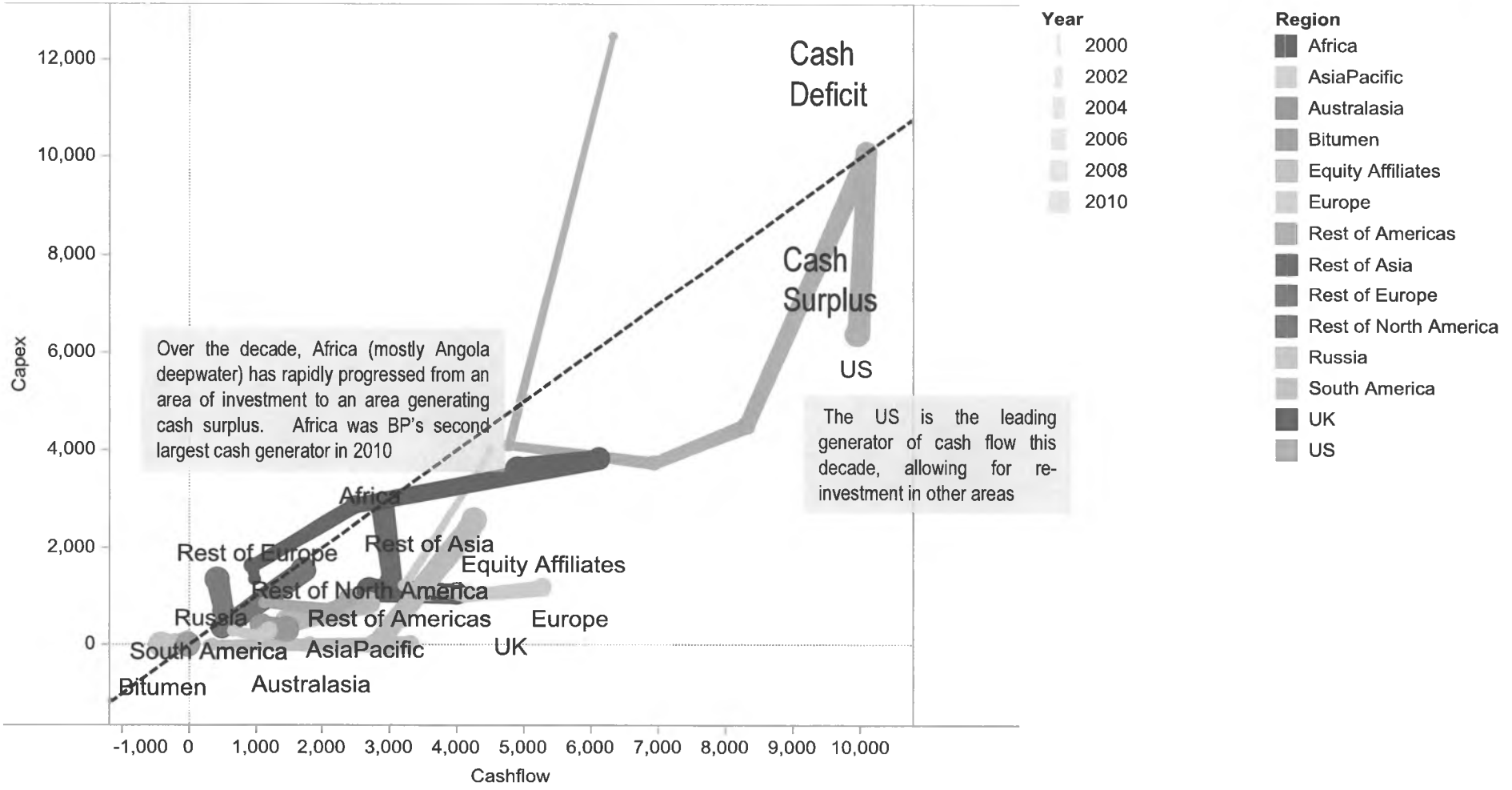
How the Portfolio is Financed: Sources and Uses of Cash



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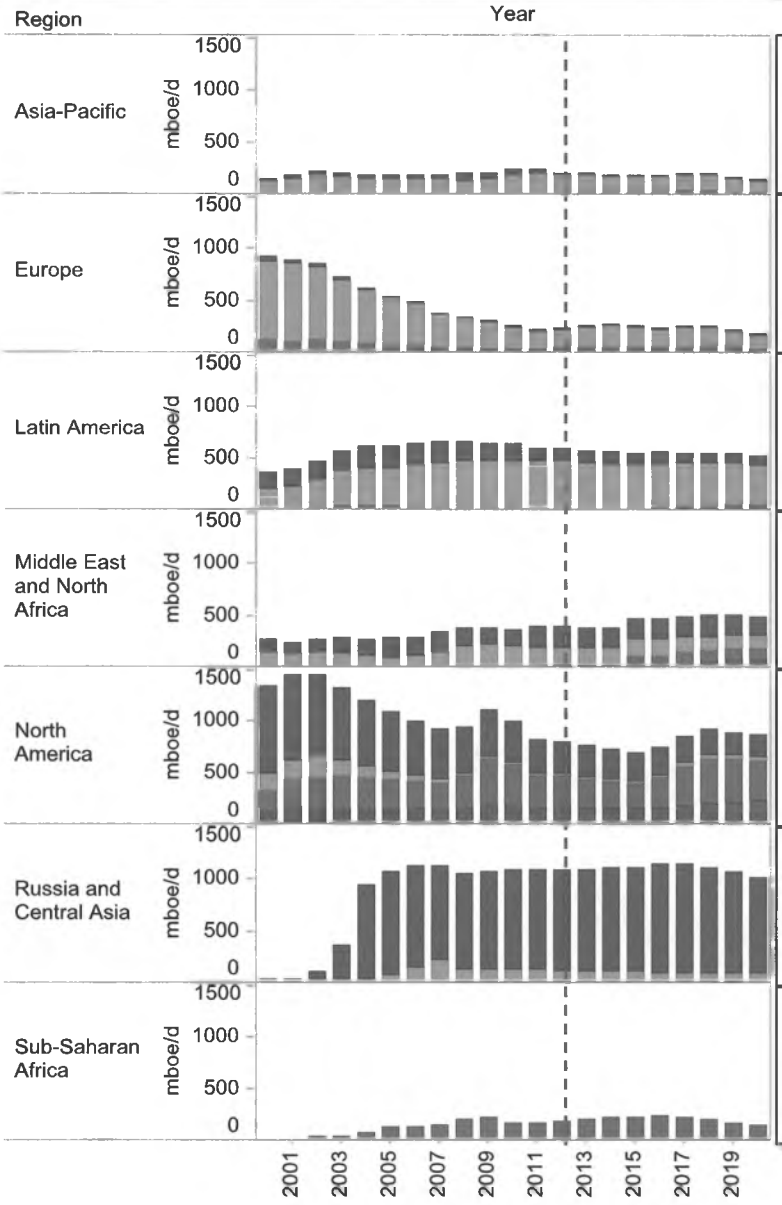
Global Production: Evolution of the Portfolio



Asia Pacific: Relatively small producing area (~6% of 2010 output). Production largely from offshore Australia and Indonesia with lesser volumes from China. Partnership with Reliance (India) creates exploration opportunities. Focus on deepwater and CBM. Divested assets in Pakistan and farmed down in Vietnam.

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Exploration and development projects are ongoing, often leveraging BP's existing infrastructure and assets in the region.

Latin America: Growth driven by shallow water gas developments in Trinidad & Tobago. Focus on onshore gas commercialization in Bolivia. Failed to sell Argentine assets (held through PAE) to Bridas in 2011. Brazil deepwater offers mid- to long-term potential from newly acquired deepwater acreage.

Middle East & North Africa: Position built from collaboration with NOCs (Adma-Opco, GUPCO, Sonatrach, LNOC, etc.). Substantial new source growth expected from Iraq, Egypt deepwater, offshore Oman. Exploration opportunities in Jordan.

North America: Second largest production region & largest cash flow generator. Deepwater GOM holds significant growth potential after years of investment. US L48 portfolio is material, yet declining, source of gas, with a growing emphasis on shale gas. Additional future growth from Canadian oil sands.

Russia & Central Asia: Principally comprised of TNK-BP venture created in 2003, now BP's largest source of production, characterized as long-life, slow decline output. In Azerbaijan, production is from large-scale ACG and Shah-Deniz. The Region is the largest source of new source volumes through 2015.

Sub-Saharan Africa: Operates only in the Angola deepwater play, which quickly emerged as a key oil-producing country. BP has collaborated with operators TOTAL (Block 17) and Chevron (Block 15). In the future, development of BP-operated blocks 31 and 18 is expected to reverse the recent decline in production.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

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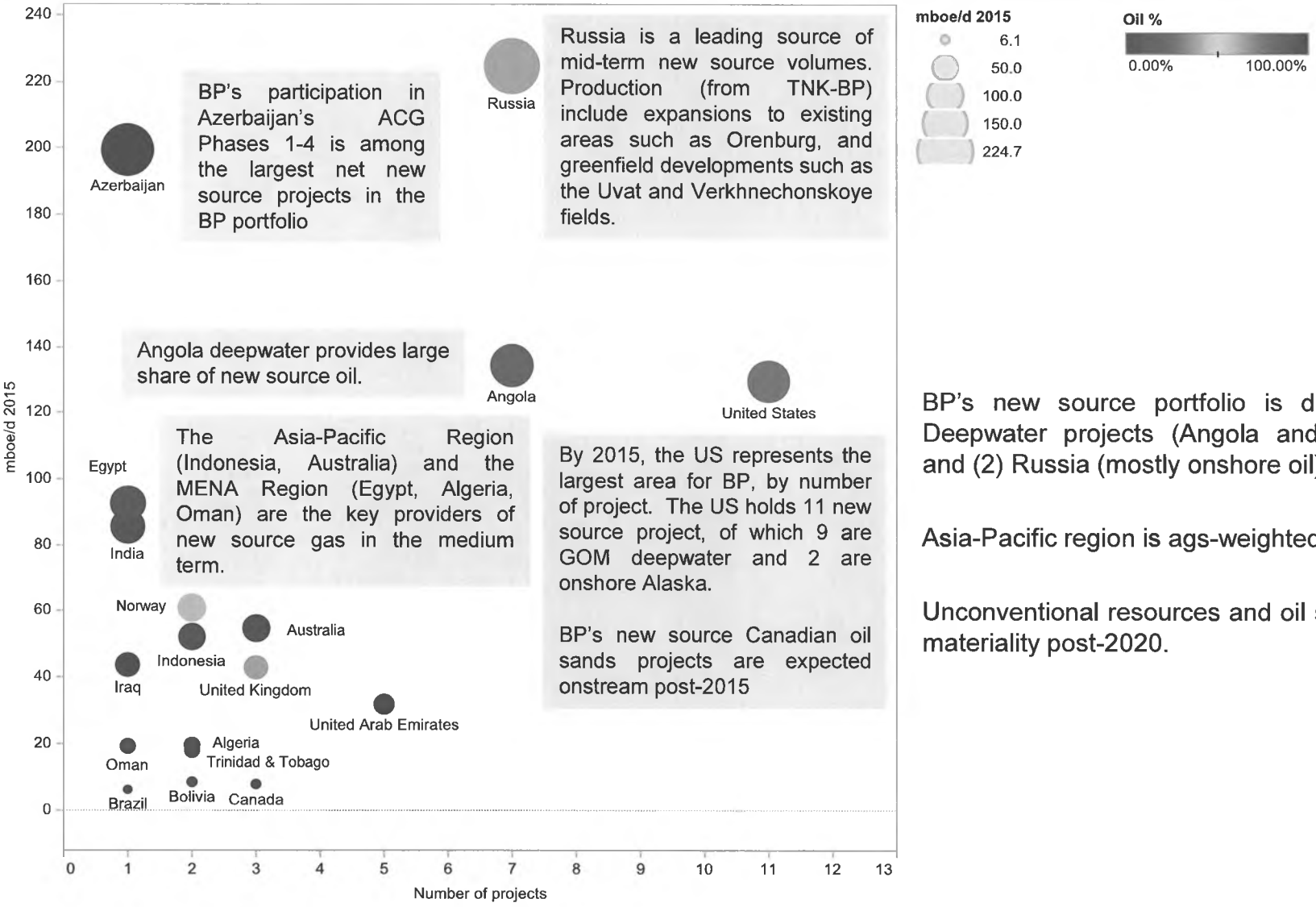
Global Production:
Country Growth Project Analysis

BP: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split



BP's new source portfolio is driven by (1) Deepwater projects (Angola and US GOM); and (2) Russia (mostly onshore oil).

Asia-Pacific region is ags-weighted.

Unconventional resources and oil sands deliver materiality post-2020.

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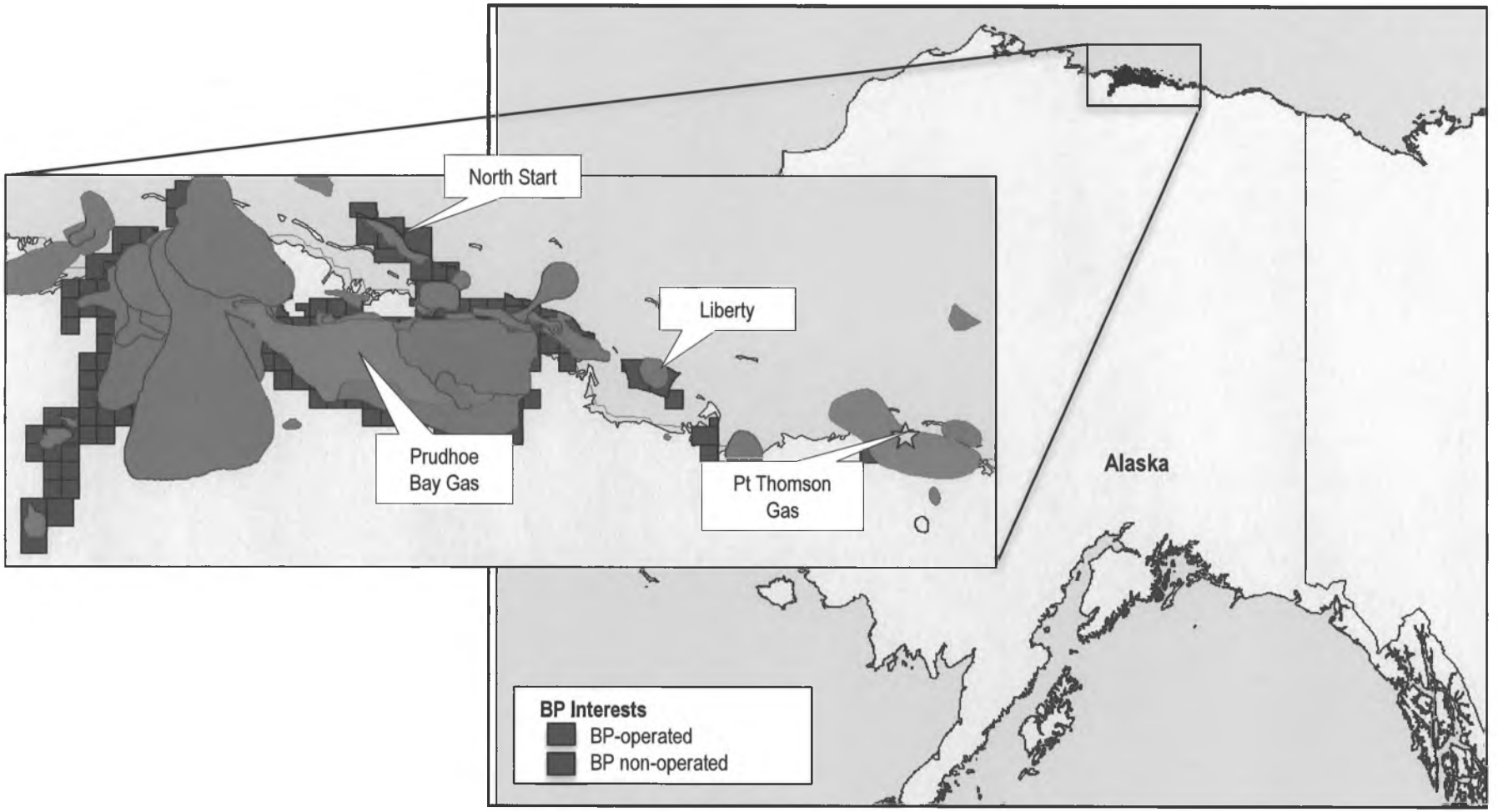
BP in Alaska



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BP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• Most of BP's assets are located on the **North Slope**, where production volumes have generally declined because of the maturity of the asset base and/or gas infrastructure constraints. Liquid production has declined from ~224 mboe/d in 2006 to ~166 mboe/d in 2010, while gas production has fallen from ~67 mmcf/d to ~46 mmcf/d over the same period. • BP's largest source of production is the **Greater Prudhoe Area** (26% w.i., operated), covering ~150,000 acres with more than 1,000 active wells. Gas resources are currently stranded because of the lack of pipeline capacity to southern markets. BP and ConocoPhillips had teamed up to propose a new natural gas pipeline (**Denali**) to run from Prudhoe Bay through western Canada to US markets. However, in May 2011, the partners announced that plans for the pipeline had been terminated, citing the lack of long-term purchase contracts. The proposed pipeline would have accommodated 4 bcf/d of natural gas. • BP and partners are moving forward with the development of gas liquids on the ~8 tcf **Point Thomson** field (32% w.i., non-operator). The gas cycling project is expected to produce ~10 mb/d of liquids; first production is targeted for 2014. Full field development awaits gas transport infrastructure. • In the **Beaufort Sea**, BP has suspended work on the extended-reach drilling program on the **Liberty** oil field (100% w.i.), pending revision of project design and schedule. • BP is also seeking to develop viscous (**Kuparuk**) and heavy (**Milne**) oil resources on the North Slope.	**Current production volumes are modest and declining, yet significant potential lies in the long-term commercialization of Prudhoe Bay and Point Thomson gas resources. Cancellation of the Denali gas pipeline proposal leaves BP as a potential supplier to an alternative pipeline/LNG export option, should one be approved and developed.**

PFC-Identified Challenges

- **Re-establish its operator profile in the global deepwater:** While its competitors extend their commitments to global LNG, unconventional shale gas exploitation, and oil sands development in order to drive future portfolio growth, BP has deepened its commitment to the global deepwater play, despite the ongoing fallout from the Macondo oil spill. Expansion of its US GOM lease holdings (through the Devon portfolio acquisition), entry into the Brazil deepwater, and a material commitment to the K-G Basin deepwater play in India, together with phased field development offshore Angola and West Nile Delta in Egypt, positions BP as arguably the premier deepwater player in the Global Player peer group. BP will be under the spotlight regarding its future conduct and performance throughout the global deepwater basins.
- **Resolve shareholder relationship issues within the TNK-BP JV:** Accounting for ~29% of total worldwide production in 2011 (and ~40% of total worldwide oil production), the TNK-BP position is absolutely core to the BP portfolio from a volumetric perspective. However, the unsuccessful attempt to partner with Rosneft in the Russia Arctic raises concern over how much value TNK-BP can continue to create for BP. With TNK-BP now focused on international expansion, must BP settle for lower returns from what has until now been a highly lucrative position?
- **Complete the portfolio rationalization process:** The strength of the global asset transactions market prompted BP to expand its divestiture program from an initial $20 bn to $30 bn, divesting large swaths of its portfolio deemed non-Core and/or non-aligned with the company's growth focus. While the company did not plan on the depth of portfolio rationalization undertaken to date, this is a rare opportunity to high-grade asset holdings with the blessing of shareholders and analysts alike. BP is expecting to complete the divestiture process by end-2012.
- **Determine a path forward in the Brazil deepwater:** Having secured Brazil government approval to acquire the Devon asset portfolio, BP has established a foothold in the Brazil deepwater, with potentially the largest operated pre-salt portfolio outside Petrobras. The next step is to determine the appropriate approach to growth in the pre-salt play. With legislation now in place granting NOC Petrobras a minimum 30% w.i. and operatorship in all unlicensed pre-salt acreage, this may be another case of executing a strategic alliance (similar to that secured with Reliance in India and proposed with Rosneft in the Russia Arctic).
- **Accelerate development of US Onshore unconventional gas resource:** BP received a very competitive price for the Permian Basin and Western Canada conventional gas assets sold to Apache (totaling ~75 mboe/d of production and ~340 mmboe of reserves, equivalent to ~$24.60/boe of reserves in the ground or ~$109,000/flowing boe of production). This is particularly so given what is shaping up to be an extended period of gas price weakness in the North America market. To make up for lost volumes, BP may look to accelerate production from its ~10 tcf of reserves in the Woodford, Fayetteville, Haynesville, and Eagle Ford shale gas plays.
- **Accelerate development of BP's oil sands leases:** BP has built up a material oil sands lease portfolio in Western Canada, including 50% w.i. in the Sunrise in situ development project (sanctioned in November 2010), a 75% w.i. in the Terre de Grace in situ project (secured in March 2010 from Value Creation for ~$900 mn), and 50% w.i. in the Kirby in situ oil sands leases (with the other 50% divested to Devon in March 2010). Full development of these projects could represent 500-600 mbo/d of stable, long-life oil production, complementing the "Giant Oil Fields" growth platform and providing a portfolio buffer against the steep decline production profiles associated with deepwater developments.

ConocoPhillips: Company Overview

Strategic Signature

- March 2010, ConocoPhillips announces a new strategic pathway: Direct proceeds from a ~$15 bn asset and joint venture divestment program to:
  - reduce its debt-to-capital position;
  - increase near-term shareholder returns;
  - shift further out of the downstream, and
  - position the company for future growth from a smaller but higher-value portfolio position.
- Since the 2010-2012 Restructuring Plan, ConocoPhillips has:
  - executed on ~$7 bn in asset sales
  - divested its entire 20% equity interest in LUKOIL, and
  - directed proceeds from these sales to debt reduction and share repurchase.
- July 2011, ConocoPhillips announces a restructuring, to create ***two separate corporate entities***, Downstream (Phillips 66) and a pure play, E&P company (ConocoPhillips).
- Production expected to decline to ~1.5 mmboe/d in 2012, recovering to 1.64-1.69 mmboe/d by 2015. The company will rely on a large, diversified upstream portfolio positioned heavily in OECD countries (US, Canada, Australia, UK, and Norway, which accounted for ~72% of worldwide production in 2010).
- Growth of 0.5% per annum from 2012 through 2015 is forecast to come from Global Gas/LNG, SAGD Oil Sands, and Unconventional developments. However, as ConocoPhillips now stands to compete with the Independent, non-integrated oil & gas companies, the company's future strategy remains uncertain.

Company Overview

- **HQ:** Houston, TX
- **Employees:** 29,600
- **2011 Reserves:** 8,387 mmboe
- **2010 Production:** 1,610 mboe/d
- **3 Yr Production Growth:** -30.68% CAGR (2008-2011)
- **Apr 2012 Market Cap:** $3.3 bn
- **Apr 2012 P/E Ratio:** 8.12
- **2011 Corp Revenue:** $235 bn
- **2011 Upstream Capex:** $13.5 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✓	✓		✓	✓	

Partnership History

Date	Partner	Region (or Country)	Type
2003	LUKOIL	Russia	Various
2006	Cenovus	Canada	Oil Sands
2008	Origin Energy	Australia	LNG

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ConocoPhillips: Global Areas of Upstream Operations

Country	Liquids (mboe/d)	Gas (mboe/d)
USA L48	142	279
USA Alaska	230	14
USA GOM	18	3
Russia	336	42
Canada	109	164
United Kingdom	74	101
Norway	137	35
Indonesia	17	232
Australia/ Timor Sea	31	58
China	68	0
Libya	46	1
Nigeria	20	24
Vietnam	24	2
Algeria	13	0
Qatar	3	9

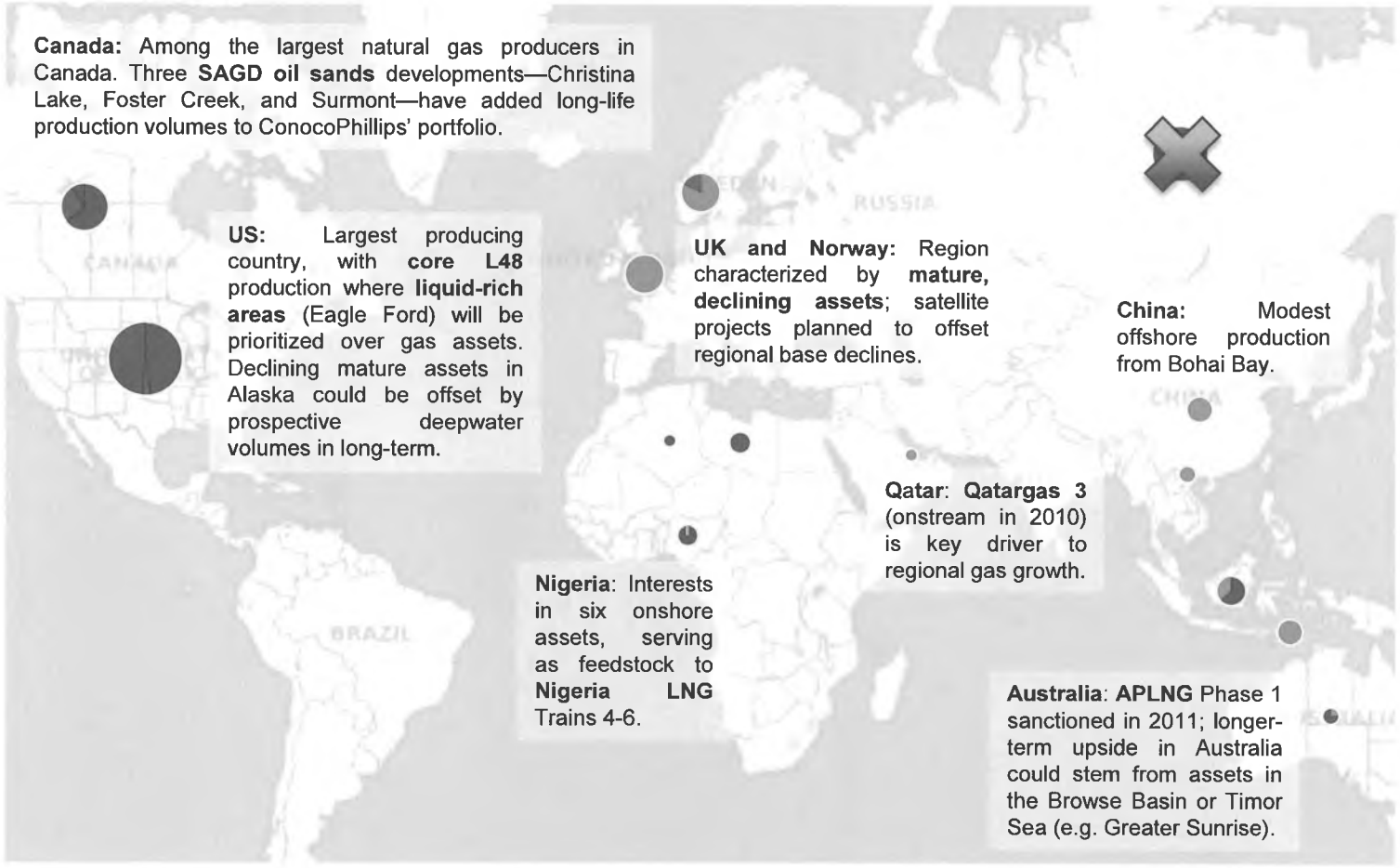
Country	Liquids (mboe/d)	Gas (mboe/d)
Angola	0	0
Bangladesh	0	0
Brunei	0	0
Greenland	0	0
Kazakhstan	0	0
Malaysia	0	0
Poland	0	0
Peru	0	0

Core
New Venture
Focus
Harvest
Exit

PFC Energy

ConocoPhillips Global Production Portfolio - 2010

Russia: LUKOIL sale leaves ConocoPhillips with modest production from its two joint ventures in Russia (Polar Lights Company and Naryanmarneftegaz). Regional production declines from **21% of worldwide production in 2009 to 3% in 2011**.



Canada: Among the largest natural gas producers in Canada. Three **SAGD oil sands** developments—Christina Lake, Foster Creek, and Surmont—have added long-life production volumes to ConocoPhillips' portfolio.

US: Largest producing country, with **core L48** production where **liquid-rich areas** (Eagle Ford) will be prioritized over gas assets. Declining mature assets in Alaska could be offset by prospective deepwater volumes in long-term.

UK and Norway: Region characterized by **mature, declining assets**; satellite projects planned to offset regional base declines.

China: Modest offshore production from Bohai Bay.

Qatar: **Qatargas 3** (onstream in 2010) is key driver to regional gas growth.

Nigeria: Interests in six onshore assets, serving as feedstock to **Nigeria LNG** Trains 4-6.

Australia: **APLNG** Phase 1 sanctioned in 2011; longer-term upside in Australia could stem from assets in the Browse Basin or Timor Sea (e.g. Greater Sunrise).

Algeria: Onshore oil field production; additional volumes from El Merk (EMK) expected for 2012 start-up.

Libya: Legacy onshore Waha concession; above ground conflict will delay new source oil projects.

mboe/d

0
500
1,000
1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Vietnam: Continued development of mature Cuu Long Basin; **potential divestment target**.

Malaysia: Development of **deepwater** fields (Gumusut-Kakap and Kebabangan) will bring Malaysia into ConocoPhillips' producing country portfolio.

Indonesia: Largest contributor to Asia-Pacific production; ongoing development of **Corridor PSC** and **South Natuna Block B**.

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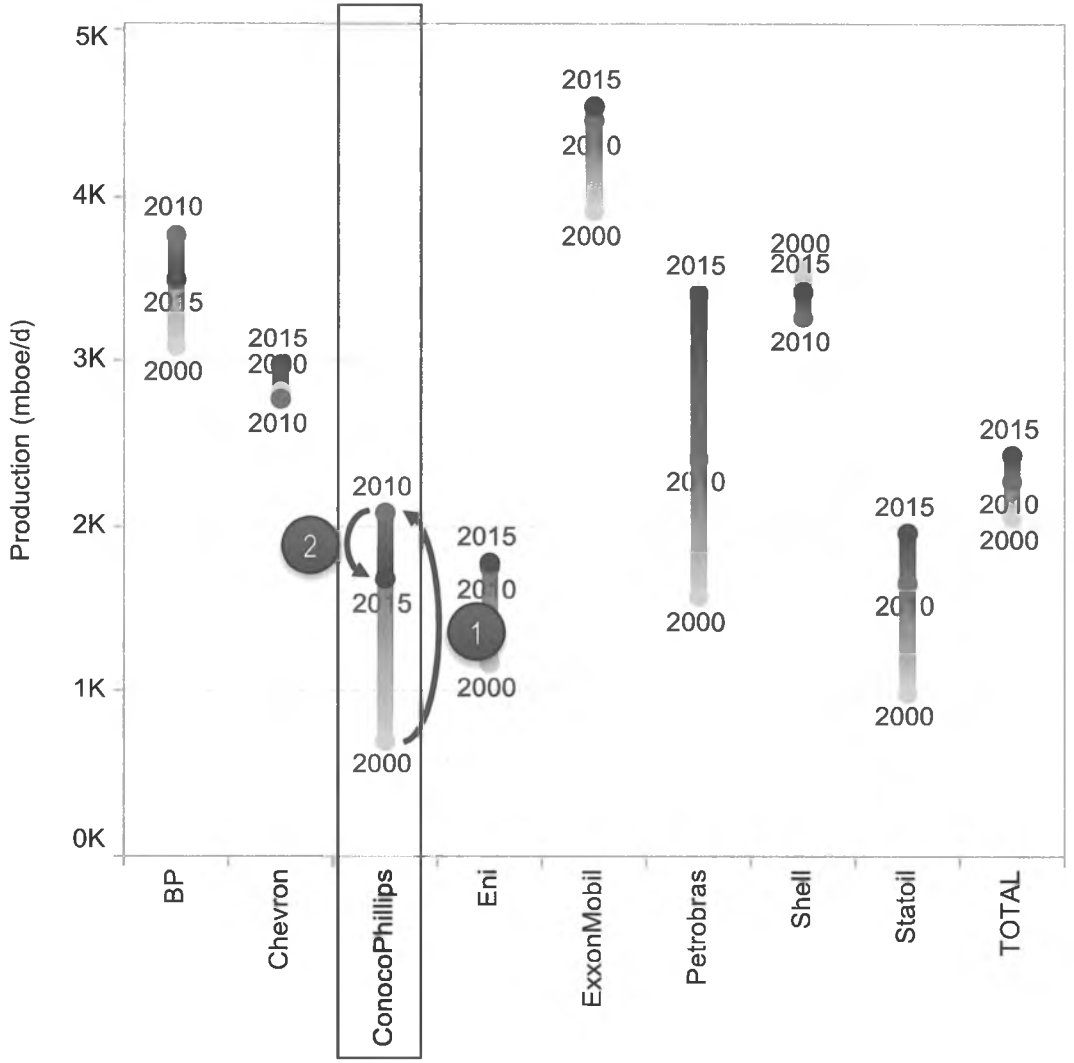
Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition

Production (mboe/d) in 2000, 2010 and 2015 (PFC Forecast): ConocoPhillips and Peers



ConocoPhillips' 2010-2012 Restructuring Plan will see the company become the largest of the Independent, non-integrated international oil & gas companies, compared to its former position as the third-smallest of PFC Energy's expanded Global Player peer group.

1. **2000-2010:** Production increases largely driven by the merger of Conoco and Phillips in the beginning of the decade (growing volumes from 698 mboe/d in 2000 to 1,082 mboe/d in 2002) and the Burlington Resources purchase in 2006 (growing volumes from 1,824 mboe/d in 2005 to 2,358 mboe/d in 2006). The gradual acquisition of a 20% stake in LUKOIL was a key driver to mid-decade growth.

2. **2011-2015:** ConocoPhillips's production is expected to decline from 2010-2015, due to the company's intensive asset divestiture program (the initial ~$15 bn asset and joint venture divestment program was expanded in 2011 when ConocoPhillips announced it would shed an additional $5-$10 bn in non-Core assets by end-2012). Volumes are forecast to decline from ~2,078 mboe/d in 2010 to ~1,674 mboe/d in 2015.

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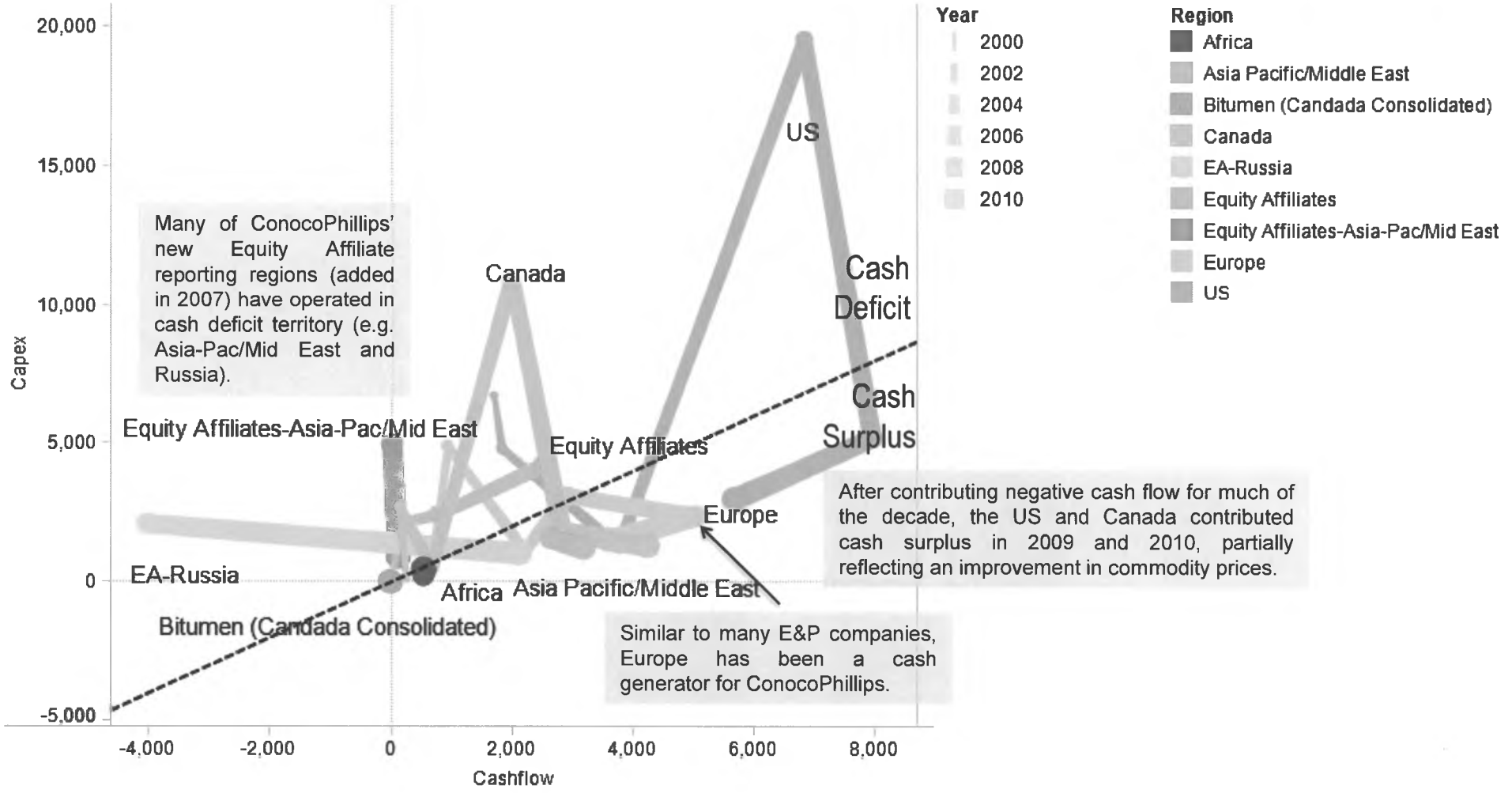
How the Portfolio is Financed: Sources and Uses of Cash



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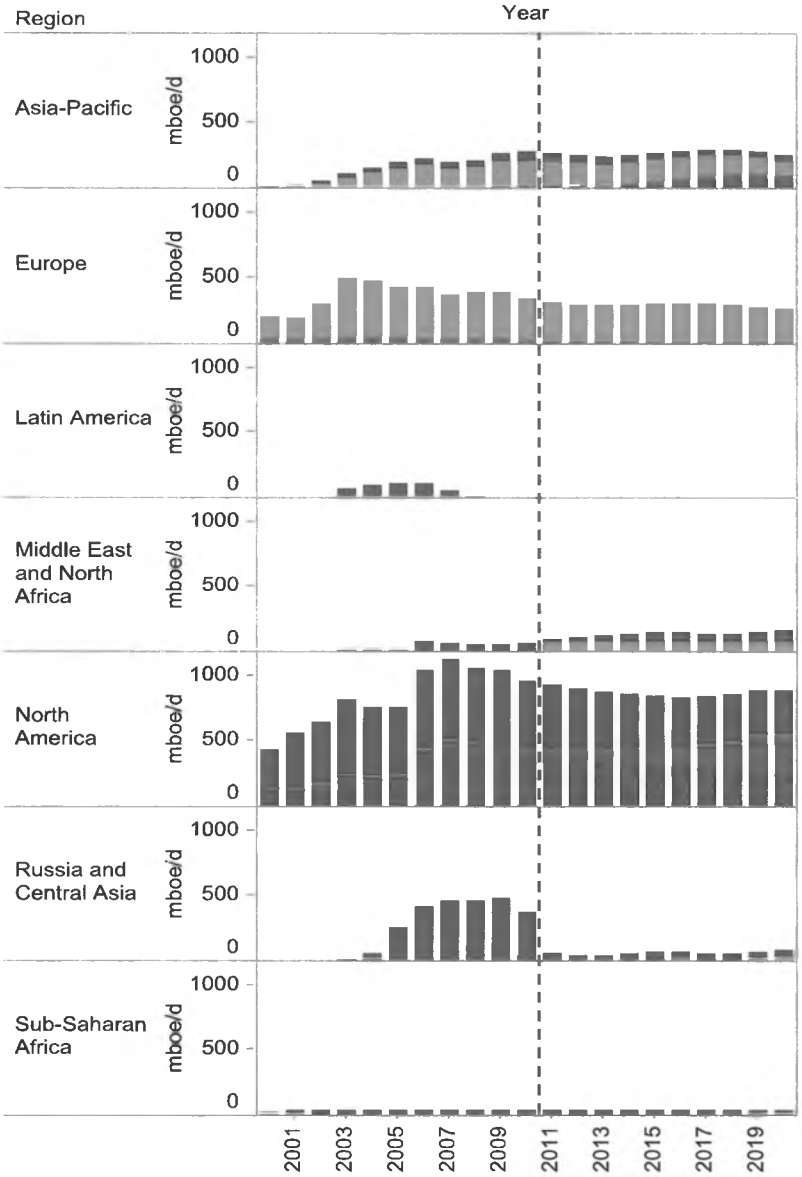
Global Production: Evolution of the Portfolio



Asia Pacific: Project queue 14 projects deep makes Asia-Pacific the largest development pipeline in all of ConocoPhillips' portfolio. Region estimated to occupy 20% of 2011 upstream capex. New projects in both legacy countries (Indonesia, Vietnam) are being complimented by start ups in Malaysia (Gumusut-Kekap, Kebabangan) and Australia (APLNG).

Europe: Mature and generally declining production position in the UK and Norway, mostly in shallow waters. Satellite projects poised to somewhat offset base declines.

Latin America: After reaching historic peak production in 2005, volumes fell to zero in 2009. The Latin America portfolio, largely acquired through the Burlington transaction, has never been a material part of ConocoPhillips' global operations. With no new volumes anticipated in the portfolio, a complete exit from the region could be likely.

Middle East & North Africa: Future growth is largely tied to the Qatargas 3 LNG project and El Merk (EMK) in Algeria. Longer-term growth is poised to stem from Libya (as yet unsanctioned joint NC 98 and North Gialo developments) assuming a timely re-commencement of upstream activities.

North America: Largest production region & cash flow generator. New growth initiatives focus on exploitation of Eagle Ford shale liquids and Canadian oil sands (Christina Lake, Foster Creek, and Surmont), which are projected to reverse the decline in Canadian production by 2014 and deliver medium- and long-term volume growth.

Russia & Central Asia: LUKOIL sale leaves ConocoPhillips with only modest production from its two joint ventures in Russia and few growth opportunities within the remaining portfolio. The sole growth asset is an 8.4% stake in the Kashagan field, which continues to face major challenges.

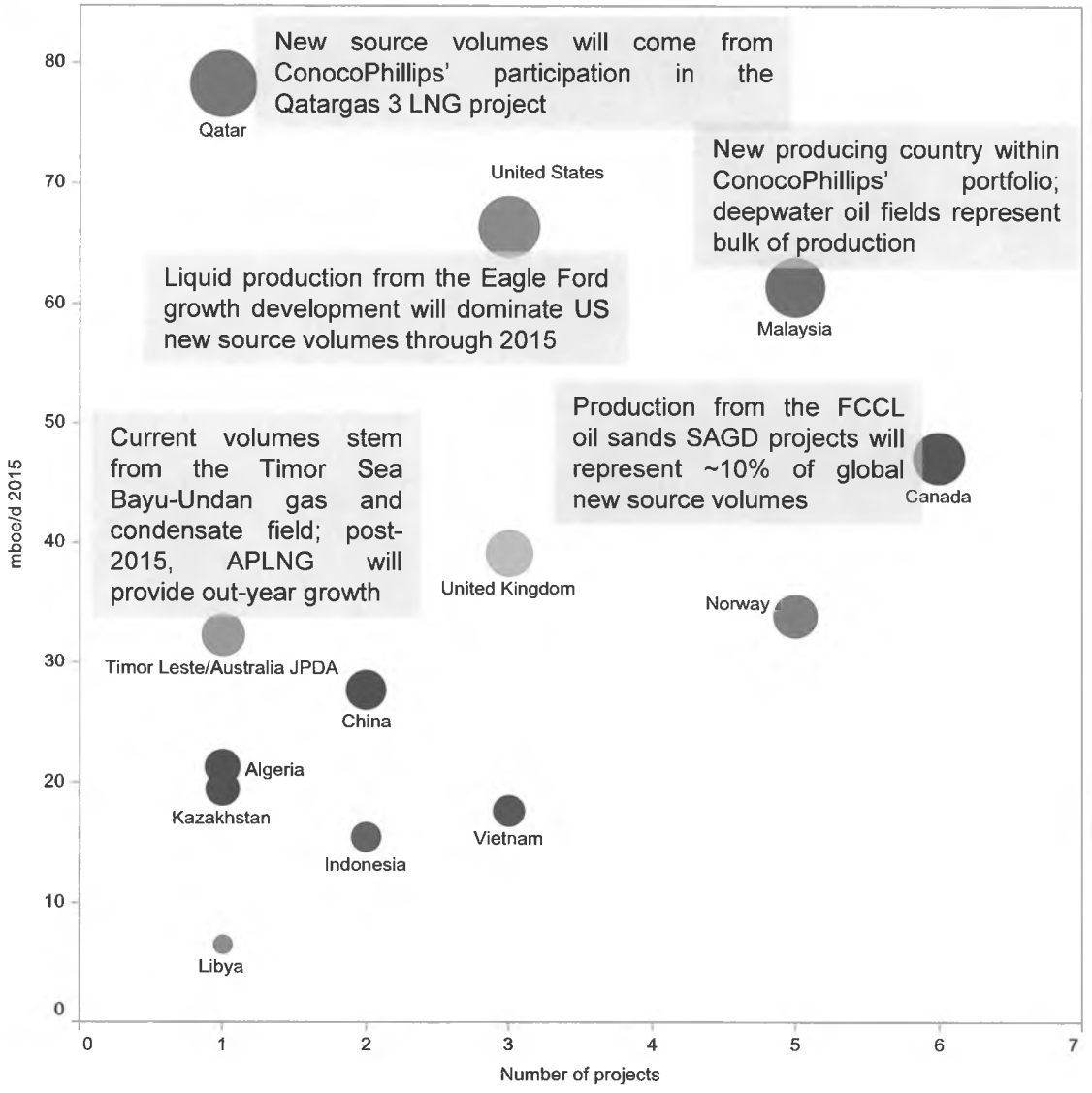
Sub-Saharan Africa: Onshore assets serve as feedstock to Nigeria LNG Trains 4-6. Longer-term upside tied to feedstock for the yet-to-be-sanctioned Brass LNG plant, while 2011 re-positioning in Angola could provide exploration opportunities critical to securing new source ventures for long-term growth.

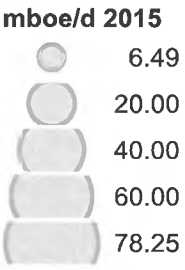
Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

PFC Energy

Global Production:
Country Growth Project Analysis

ConocoPhillips: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split



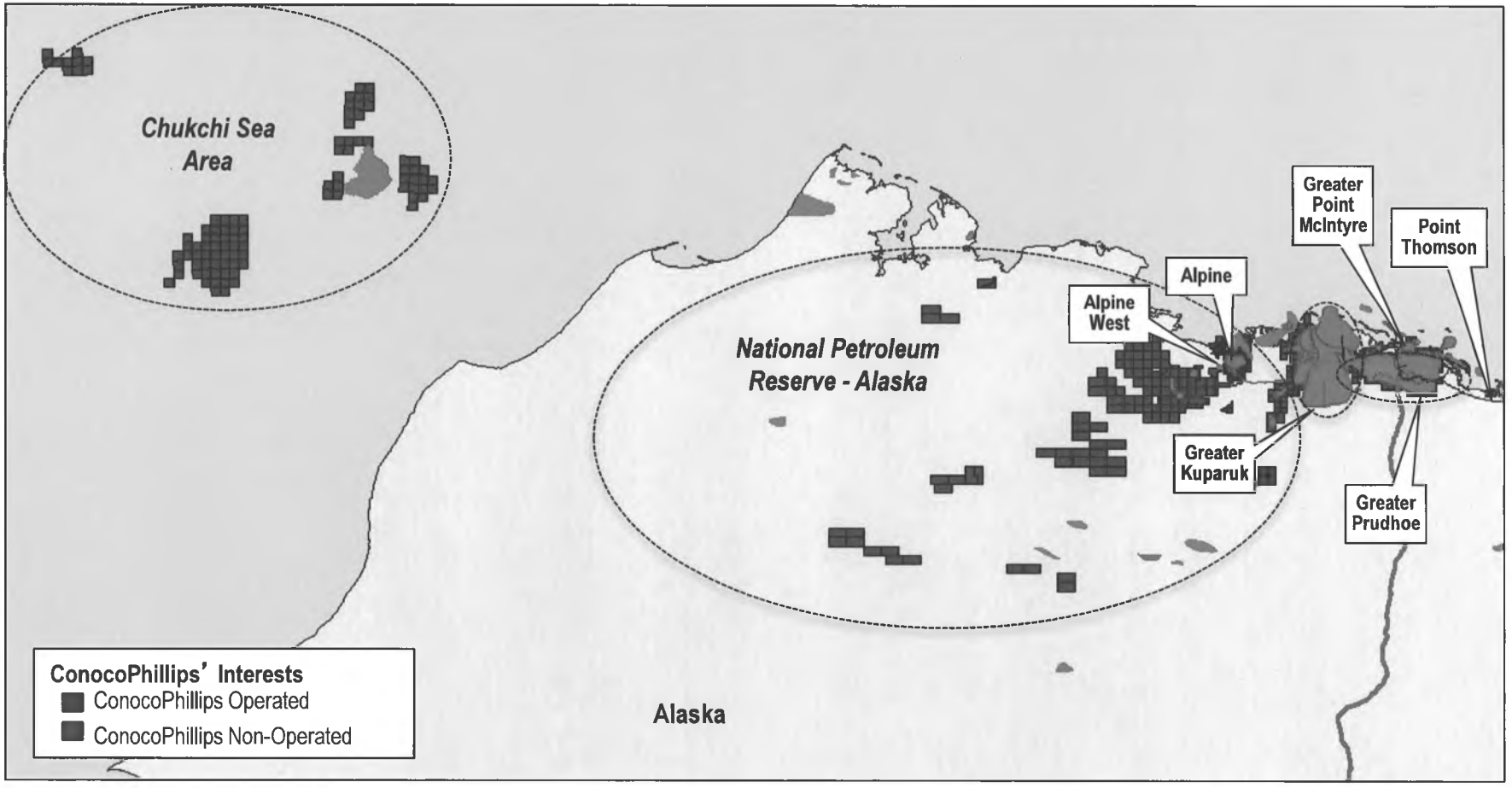


ConocoPhillips's new source portfolio is driven by (1) Shallow water gas production (Qatar); (2) Canadian SAGD Oil Sands Developments; and (3) US Unconventional production (Eagle Ford).

Deepwater projects, sourced mainly from the Asia-Pacific region (Malaysia) and the US GOM deepwater (mostly non-operated positions), will ramp up steadily over the decade; by 2020 deepwater is poised to represent 7% of global volumes (compared to ~2% in 2010).

PFC Energy

ConocoPhillips in Alaska – North Slope



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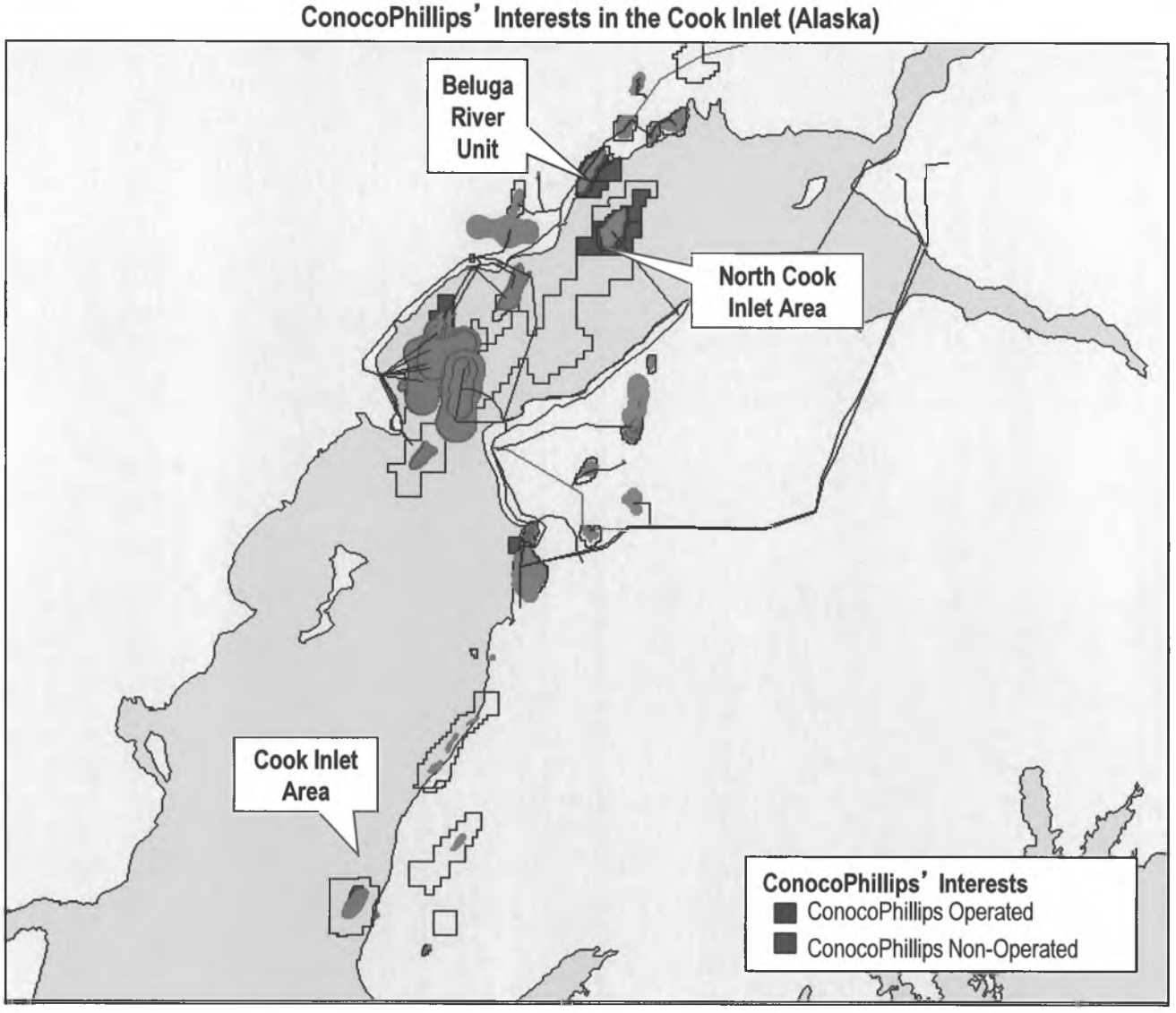
PFC Energy

ConocoPhillips in Alaska – Cook Inlet



PFC Energy

ConocoPhillips **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• ConocoPhillips' assets in Alaska are legacy assets acquired from Arco Alaska in 2000 and include the Greater Prudhoe Area, Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. The company's largest producing area in Alaska is the Greater Prudhoe Area, a collection of mature, long-life fields. Production from the mature Alaska portfolio has been in slow decline since 2004. In 2010, net production from Alaska averaged 230 mb/d of oil and 82 mmcf/d of gas, accounting for ~21% of US production. • ConocoPhillips and BP have been joint proponents of the **Alaska Gas Pipeline** (or **Denali Pipeline**), intended to accelerate commercialization of Prudhoe Bay gas through Western Canada and into US markets. In 2010, the partners officially withdrew their support for the proposed project, in response to continued US gas price weakness and absence of buyer commitments. This places substantial uncertainty around further commercialization of ConocoPhillips' Alaska gas resources. • Activity in the ConocoPhillips-operated Greater Kuparuk Area (GKA), has recently focused on development of viscous oil resources. The GKA, located 40 miles west of Prudhoe Bay on the North Slope, includes the Kuparuk field and its satellites: West Sak, Tarn, Tabasco, Meltwater, and Palm. Heavy oil resources **West Sak** and **Ugnu** (52.2% w.i., operated) are potential projects currently in the appraisal phase. Expected gross peak production is ~23 mboe/d.	As Alaska's largest oil and gas producer, ConocoPhillips holds a leading position in the region. Although the company continues to target smaller projects within the GKA (West Sak and Ugnu) and NPR-A (Alpine West, Greater Moose's Tooth unit and Fiord West), ConocoPhillips will ultimately need expanded access to Asia gas markets in order to reverse the downward production trend in Alaska.

COP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• In the Western North Slope, ConocoPhillips faces regulatory challenges surrounding project development in the NPR-A region. In order to offset declines at the **Alpine** field (78% w.i., operated) and its three satellites, Nanuq, Fiord, and Qannik, ConocoPhillips is exploring development of additional satellite fields in the adjacent NPR-A, an area that requires distinct permit approval. **Alpine West** (or **CD-5**), a proposed Alpine satellite project, has been significantly delayed due to local opposition and regulatory barriers. Most recently, in early 2010, the U.S. Army Corps of Engineers denied a permit for a bridge that would provide access to the CD-5 site, a move that will further delay the project (originally planned for 2012) and several additional developments that would depend on the infrastructure. Other possible projects on the NPR-A include the **Greater Moose's Tooth** unit and **Fiord West**, which are both in appraisal phases. • While ConocoPhillips has three primary gas fields in the Alaska region–the North Cook Inlet, Beluga River, and Point Thomson–**Point Thomson** (5% w.i., non-operated) remains the only potential new source development. In 2010, development activities continued with the drilling of two appraisal wells. First production of gas liquids is anticipated in 2014. Longer-term growth potential lies in commercialization of the gas reserves, which is in turn dependent on construction of a long-distance gas trunk line. • In 2010, ConocoPhillips and Statoil engaged in an asset swap wherein ConocoPhillips sold a 25% w.i. in 50 of its **Chukchi Sea** leases to Statoil in exchange for financial payment and a 50% w.i. interest in 16 Statoil-operated Gulf of Mexico leases, as well as Statoil's 25% w.i. in five additional GOM leases already operated by ConocoPhillips. All of the involved GOM blocks are in the emerging Lower Tertiary play. ConocoPhillips plans to begin exploratory drilling on its Chukchi acreage in 2013.	

PFC Energy

PFC-Identified Challenges

- **Competing as a "Pure Play" E&P Company**: The separation of ConocoPhillips into two, stand-alone Upstream and Downstream entities is scheduled to be finalized in 1H:2012. The ~85% of total portfolio value residing in E&P assets will thereby become the largest "pure play" E&P Independent, a competitor landscape position the company held uncomfortably prior to the Burlington Resources acquisition in 2006. Can ConocoPhillips Upstream compete successfully in the Independent's space by delivering either leading shareholder returns or leading production growth? Or has it simply re-established its original dilemma—too large to compete with the faster moving International Independents, and too small to compete with the Global Players? And if so, does it survive?
- **Re-Establishing a Value Proposition**: ConocoPhillips' new strategic focus on Sustained Value Generation is intended to re-establish the company's competitive advantage in the E&P space. In the near-term, the 2010-2013 Restructuring Plan will deliver a smaller company with limited medium-term production growth and improved, but unlikely to be leading, ROCE and financial performance. Clearly, the cannibalization of the company's assets and recycling of proceeds to shareholders in order to shore up share valuation and total shareholder returns is a stop-gap strategy at best. Given continuing financial and operational challenges (ROCE, production cost, upstream net income, etc.), ConocoPhillips may struggle to deliver a value proposition that will compete successfully in either the Global Player or International Independents peer group.
- **Improving Operational Performance**: While showing improvement in finding and development costs, ConocoPhillips ranks at or near the bottom of the expanded Global Players peer group in net income/boe, production costs/boe, and Upstream ROCE. The current portfolio high-grading has already delivered Upstream ROCE improvement (from 7% in 2009 to 10% in 2010) and should deliver improvement in operational metrics; both Syncrude and the LUKOIL holdings were arguably underperforming positions. With long lead time, large scale, capital intensive developments like Qatargas 3, Jasmine, Kashagan Phase 1, and Surmont poised to deliver material production and cash flow, ConocoPhillips should see the flow-through benefits in terms of more competitive ROCE and operational metrics.
- **Delivering Production Growth**: The share repurchase program accompanying portfolio rationalization under the Restructuring Plan is projected to deliver ~3% growth in per share production in 2010 and 2011. However, physical volumes will decline in absolute terms over the 2010-2011 period—by ~208 mboe/d in 2010 from 2009 levels, and a further ~360 mboe/d in 2011 from 2010. The only region poised to deliver higher production volumes in 2020 versus 2010 is the relatively minor MENA region, projected to reach ~177 mboe/d in 2020 versus 72 mboe/d in 2010. New source volumes in Canada and the North Sea will struggle to offset mature asset declines, delivering flat production in the core North America and Europe regions, while the LUKOIL sell-down will dampen what was once considered a core driver of future growth for the company. While boasting a 10 bn boe resource base, it is not clear how ConocoPhillips will deliver the promised surge in organic growth over the 2015-2020 period from its captured portfolio—although the enhanced capex spend in the Eagle Ford play is a good starting point. Barring a material acquisition (certainly not out of the question), the company will be looking to its exploration portfolio to deliver a medium term "engine of growth".

ExxonMobil: Company Overview

Strategic Signature

- ExxonMobil: largest global integrated oil and gas company
  - ~4,513 mboe/d in 2011; production in 21 countries, with upstream operations in an additional 20 countries.
- Growth strategy based on scale, basin dominance, and execution excellence => continuously seek access to investment opportunities of adequate size and materiality.
- Faced with (i) commissioning of the final elements of the company's Qatar project portfolio, (ii) declining production from its Europe and Asia-Pacific portfolios, (iii) roadblocks to materiality in Brazil deepwater, Venezuela extra-heavy, and Equatorial Margin, and (iv) already holding a considerable stake in the Canadian oil sands, ExxonMobil took an aggressive move into unconventional shale gas exploitation.
- The 2009 acquisition of XTO Energy brings materiality to ExxonMobil's technical expertise in tight gas, CBM, and shale oil and gas exploitation, with ~2.3 bcf/d and 87 mboe/d of production, proved reserves of ~2.3 bn boe, and a resource base of 7.5 bn boe.
- Will seek to leverage XTO into a global unconventional portfolio.
- Acquisition drove a 13% increase in production in 2010, returning ExxonMobil to first place amongst its peers

Company Overview

- **HQ:** Irving, Texas
- **Employees:** 83,600
- **2011 Reserves:** 24,922 mmboe
- **2011 Production:** 4,513 mboe/d
- **3 Yr Production Growth:** 4.53% CAGR (2008-2011)
- **Apr 2012 Market Cap:** $402 bn
- **Apr 2012 P/E Ratio:** 10.1
- **2011 Corp Revenue:** $3433bn
- **2011 Upstream Capex:** ~$28 bn

Technological Competence

EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✓	✓		✓	✓	✓

Partnership History

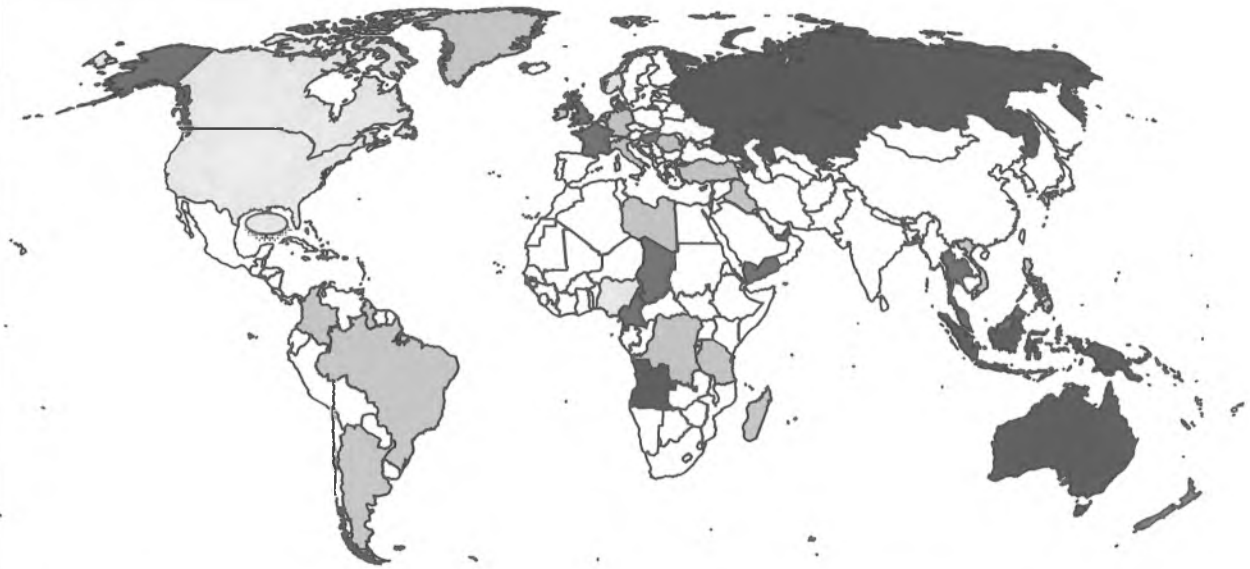
Date	Partner	Region (or Country)	Type
2011	Sinopec	China	Unconventional
2011	Rosneft	Russia	Offshore Oil & Gas

ExxonMobil has a limited history of partnership, preferring instead to purchase and operate material positions independently

PFC Energy

ExxonMobil: Global Areas of Upstream Operations

Country	Liquids (mboe/d)	Gas (mboe/d)
Qatar	232	644
USA	408	433
Nigeria	391	2
Norway	246	117
Netherlands	0	340
Canada	242	86
UAE	246	0
United Kingdom	80	92
Kazakhstan	127	24
Angola	141	0
Malaysia	48	86
Australia	51	55
Germany	0	91
Equatorial Guinea	53	0
Russia	43	8
Indonesia	13	36
Chad	43	0
Azerbaijan	21	0
Argentina	0	9
Papua New Guinea	7	0
Thailand	0	4



Country	Liquids (mboe/d)	Gas (mboe/d)
Brazil	0	0
Cameroon	0	0
Colombia	0	0
Congo	0	0
Greenland	0	0
Guyana	0	0
Hungary	0	0
Iraq	0	0
Ireland	0	0
Italy	0	0
Libya	0	0

Country	Liquids (mboe/d)	Gas (mboe/d)
Madagascar	0	0
New Zealand	0	0
Philippines	0	0
Poland	0	0
Romania	0	0
Tanzania	0	0
Turkey	0	0
Vietnam	0	0
Yemen	0	0

Core
New Venture
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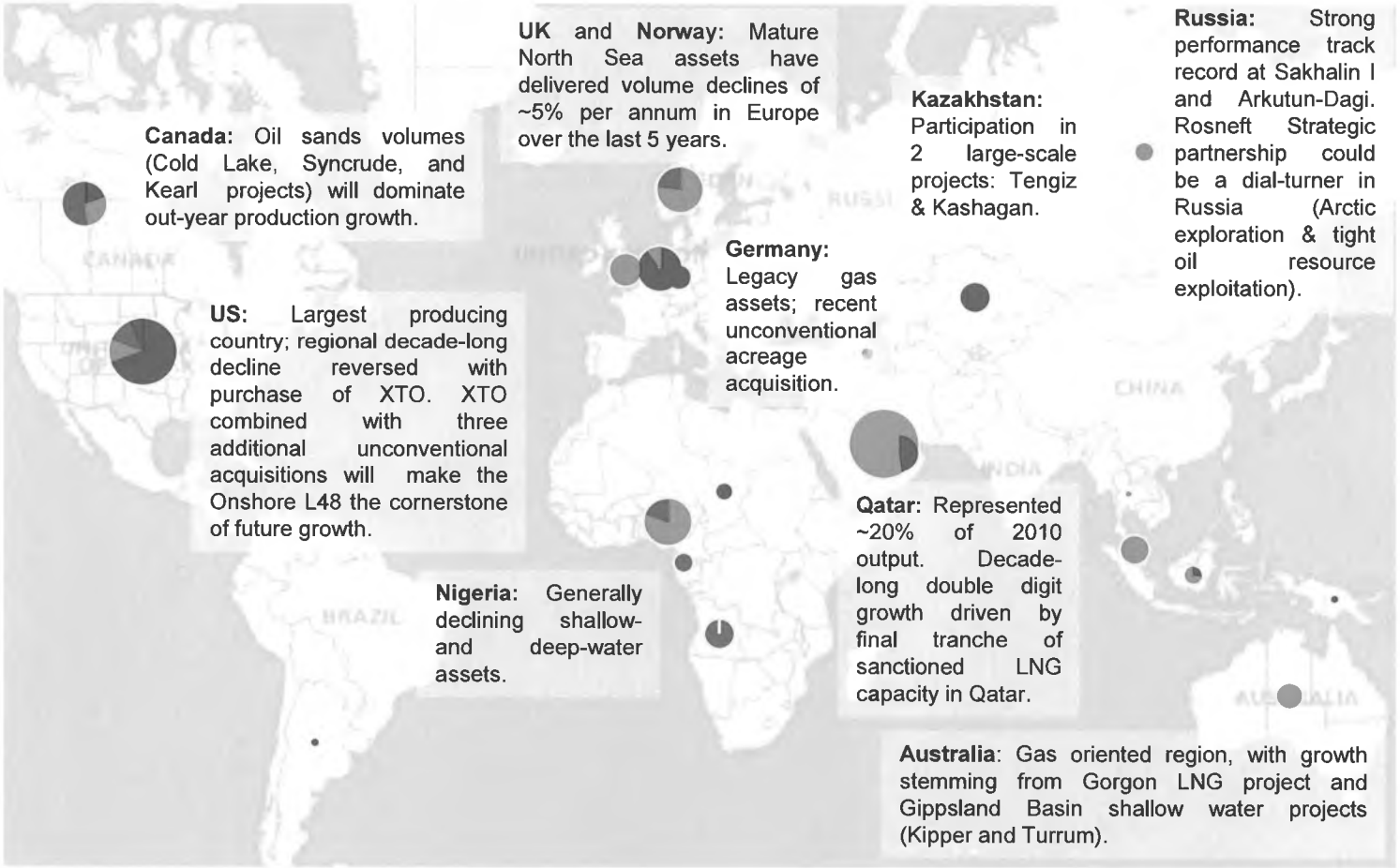
PFC Energy

ExxonMobil Global Production Portfolio - 2010



Canada: Oil sands volumes (Cold Lake, Syncrude, and Kearl projects) will dominate out-year production growth.

UK and **Norway:** Mature North Sea assets have delivered volume declines of ~5% per annum in Europe over the last 5 years.

Germany: Legacy gas assets; recent unconventional acreage acquisition.

Kazakhstan: Participation in 2 large-scale projects: Tengiz & Kashagan.

Russia: Strong performance track record at Sakhalin I and Arkutun-Dagi. Rosneft Strategic partnership could be a dial-turner in Russia (Arctic exploration & tight oil resource exploitation).

US: Largest producing country; regional decade-long decline reversed with purchase of XTO. XTO combined with three additional unconventional acquisitions will make the Onshore L48 the cornerstone of future growth.

Nigeria: Generally declining shallow- and deep-water assets.

Qatar: Represented ~20% of 2010 output. Decade-long double digit growth driven by final tranche of sanctioned LNG capacity in Qatar.

Australia: Gas oriented region, with growth stemming from Gorgon LNG project and Gippsland Basin shallow water projects (Kipper and Turrum).

mboe/d

0
500
1,000
1,345

Asset Type

- Conventional Onshore
- Conventional Shallow
- Deepwater
- Oil Sands
- Other
- Unconventional

Indonesia: Near-term gas volumes will hold production steady as ExxonMobil positions for new ventures in the unconventional space (coal bed methane).

Malaysia: Key gas producing area; focus on enhanced oil recovery (EOR) and field life extension schemes.

Argentina: legacy, declining gas assets; recent acreage positioning in prospective shale Neuquen Basin.

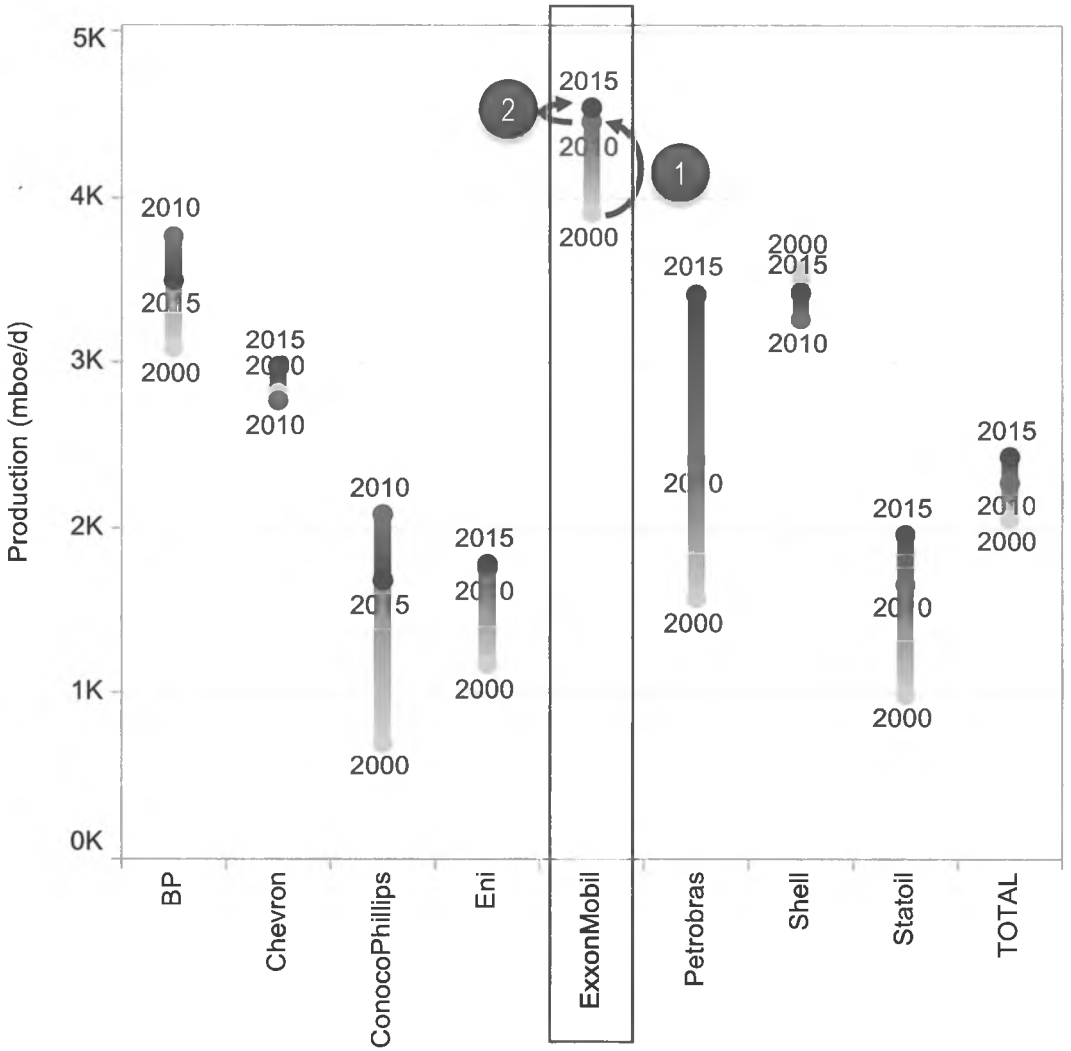
Angola: Multi-field new source developments (Kizomba Satellites Phase 1, Pazflor, and CLOV) drive regional growth.

Papua New Guinea: Formerly small contributor to the ExxonMobil portfolio, PNG will rise in prominence within the portfolio through the monetization of gas reserves at PLNG.

PFC Energy

Total Portfolio Evolution: ExxonMobil vis-à-vis the Competition

Production (mboe/d) in 2000, 2010 and 2015 (PFC Forecast): ExxonMobil and Peers



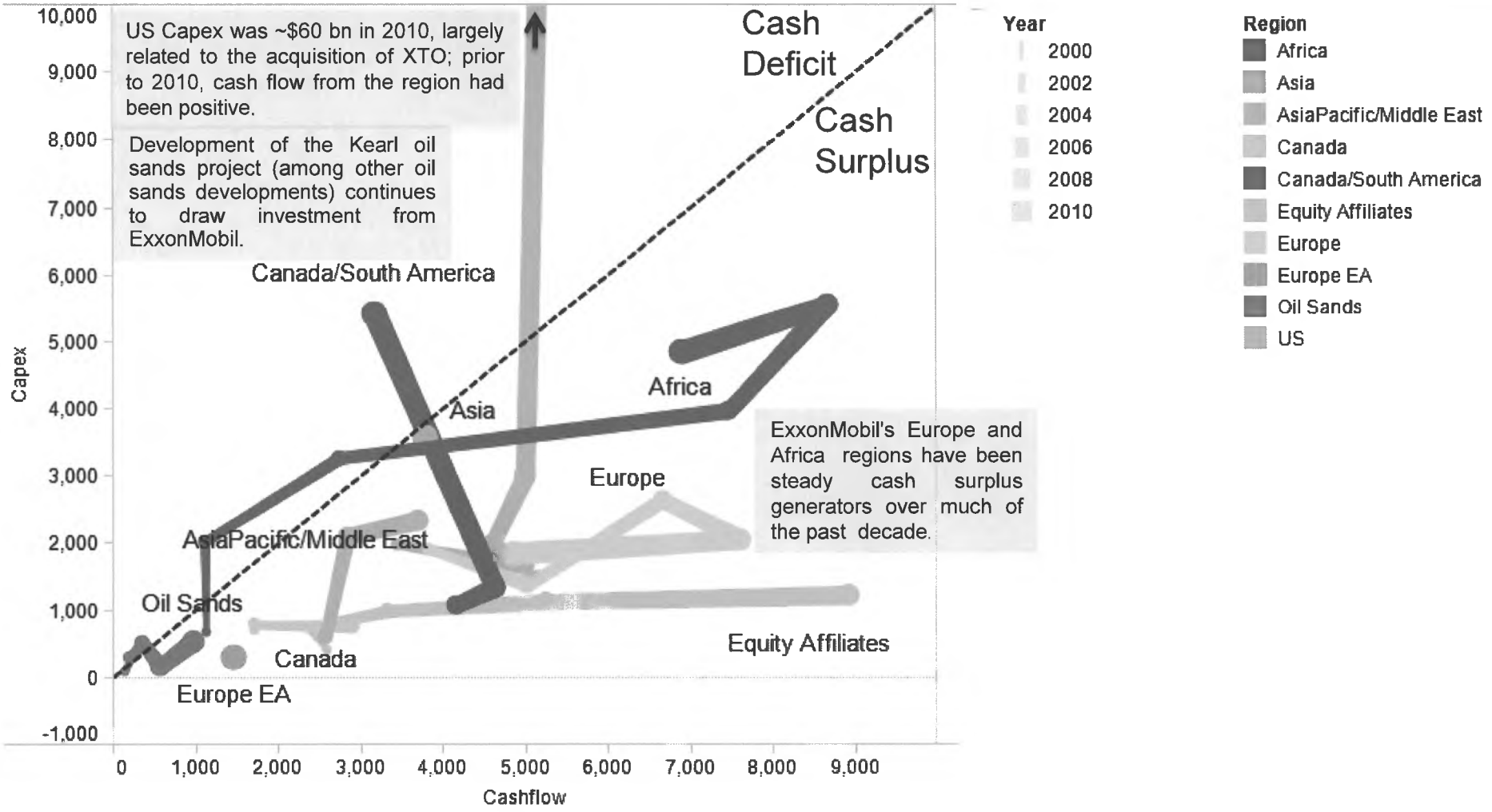
Averaging ~4.45 mmboe/d in 2010, ExxonMobil continues to lead its peer group in terms of production.

1 **2000-2010:** Production oscillated through the decade, landing in 2009 at roughly the same level as 2000 (roughly ~3.9 mmboe/d), before rising 13% in 2010 (~6% excluding the XTO acquisition), reaching ~4.45 mmboe/d. For a company that has prided itself on organic reserves and production growth, the XTO acquisition marks a considerable departure in growth strategy for ExxonMobil.

2 **2011-2015:** Modest volume growth, reaching ~4.54 mmboe/d in 2015. While PFC Energy estimates are lower than ExxonMobil targets, the absence of guidance regarding growth projects associated with the XTO portfolio makes the pace of future growth uncertain.

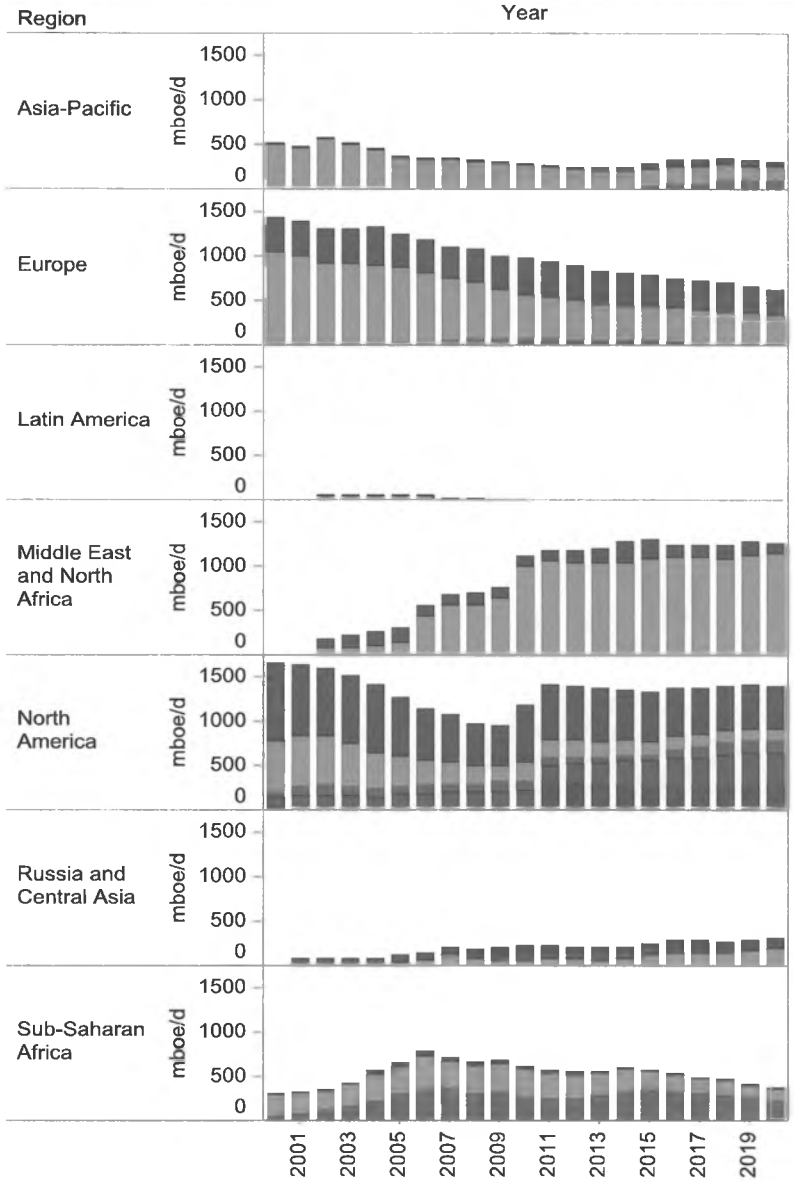
PFC Energy

How the Portfolio is Financed: Sources and Uses of Cash



PFC Energy

Global Production: Evolution of the Portfolio



Asia Pacific: Declines in ExxonMobil's relatively mature Asia-Pacific portfolio have been consistent for most of the past decade. A revival in regional production (though medium to long term in nature) is based primarily on two large gas export projects: Papua New Guinea LNG and Gorgon LNG (Australia).

Europe: Mature and generally declining production position. Positive net cash flow enables, in part, financing of frontier exploration in both unconventionals and the deepwater: ExxonMobil will seek to leverage the capabilities of XTO in Germany and Poland, while also assessing the prospectivity of the Turkish Black Sea.

Latin America: At 9 mboe/d, the region has no material impact on the ExxonMobil portfolio. Production is sourced solely from mature, declining gas assets in Argentina. The recent acquisition of 130,000 net acres of prospective shale gas resource in the Neuquen basin is part of a global strategy to leverage XTO capabilities in unconventional resource plays.

Middle East & North Africa: The rapid growth in MENA production that ExxonMobil experienced between 2002 and 2010 is on the cusp of reaching plateau, as the final Qatargas, RasGas, and Al-Khaleej phases have come onstream. While ExxonMobil will record growth from the West Qurna I project, upside in Iraq remains unclear.

North America: The acquisition of XTO Energy will drive a resurgence in regional production. A focus on Fayetteville, Haynesville/Bossier, Barnet, and Woodford shale gas plays, and transitioning portfolio to a more balanced oil:gas ratio in the out-years. A suite of Canadian oil sands developments and potential offshore projects will also contribute growth.

Russia & Central Asia: Major growth 2005-2010 was driven by a handful of mega-projects (Tengiz and Kashagan, Sakhalin I, and Azeri-Chirag-Guneshli); future performance relies heavily on subsequent development phases of these projects, most of which face challenges. The Rosneft partnership could provide additional long-term opportunity.

Sub-Saharan Africa: Growth in SSA has leveled off as new developments struggle to keep pace with steep deepwater decline rates. The primary bright spot in portfolio is Angola, where three new projects (Pazflor, Kizomba Satellites, and PSVM) are scheduled to come onstream over the next two years.

Asset Type
- Conventional Onshore
- Conventional Shallow
- Deepwater
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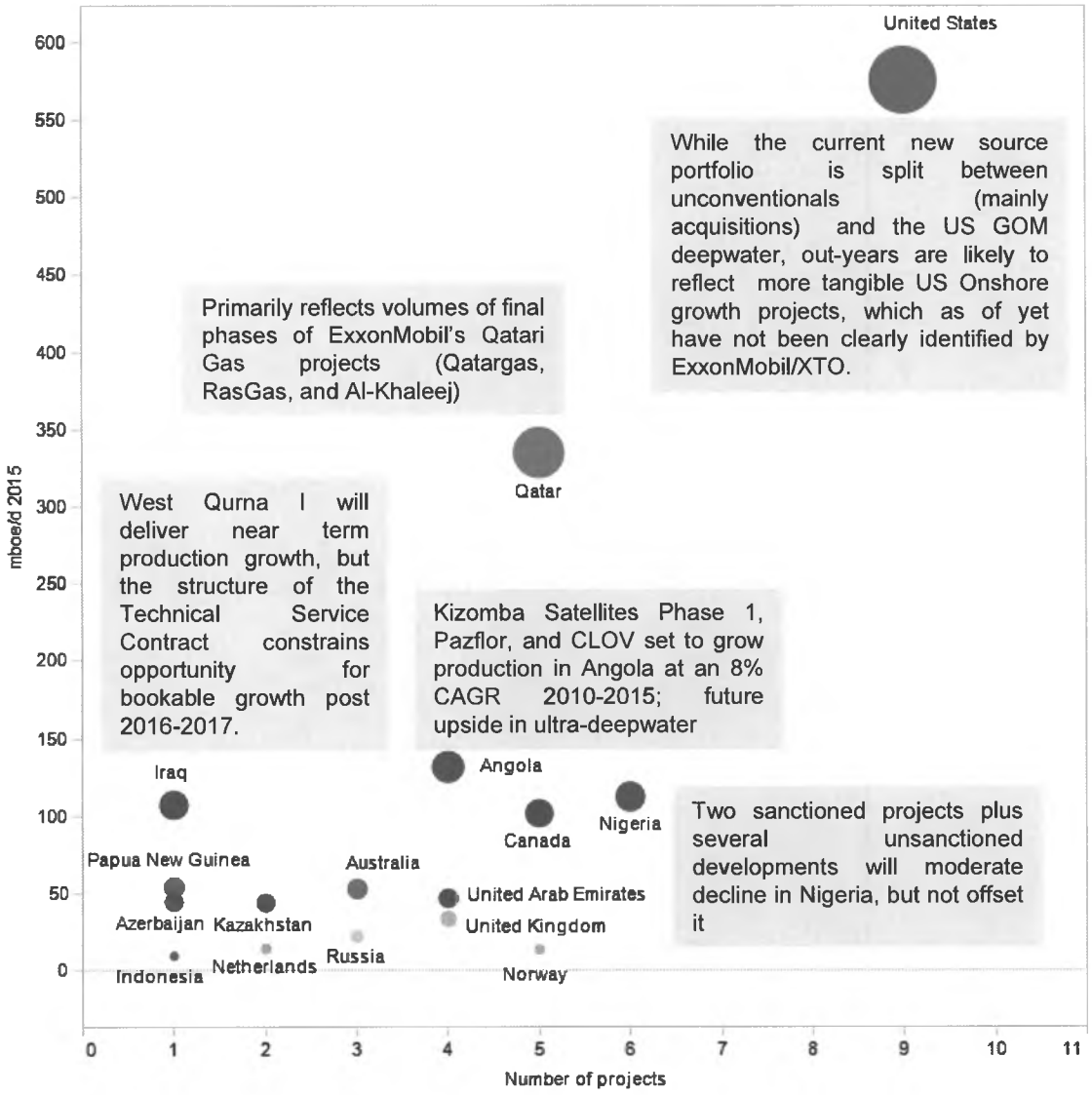
PFC Energy

Global Production:
Country Growth Project Analysis

ExxonMobil: New Source Production – Number of Projects by 2015 Production and Oil/Gas Split



ExxonMobil's US new source portfolio will dwarf new source production from all other countries. Through 2015, the US will contribute nearly 40% of global new source incremental volumes, 99% of which will stem from the company's unconventional activities (acquisitions plus the Piceance tight gas development).

International unconventional developments to remain largely immaterial until 2020 or thereafter.

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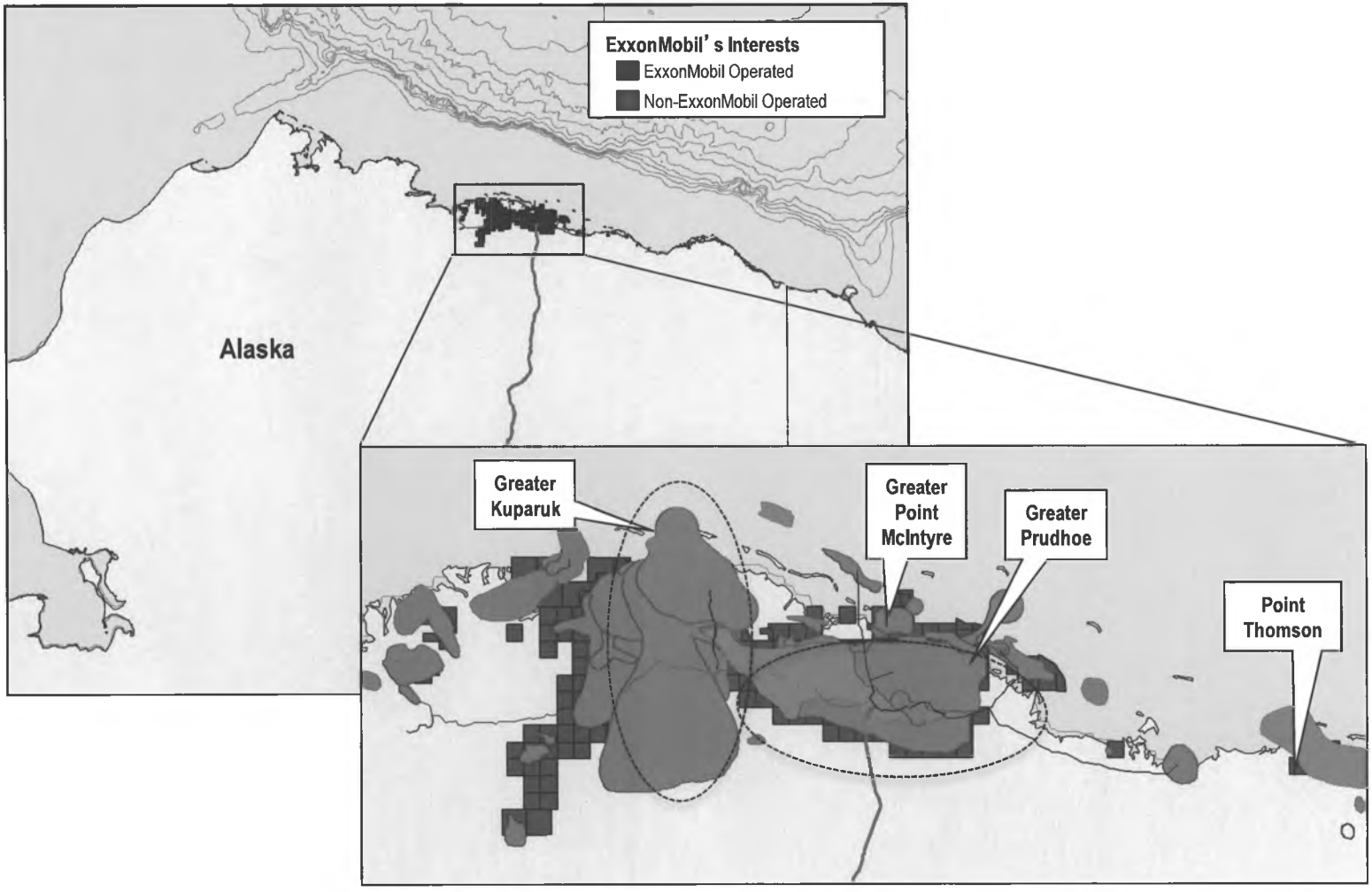
ExxonMobil in Alaska – North Slope



PFC Energy

ExxonMobil **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• In Alaska, ExxonMobil holds interests in the **Greater Prudhoe**, **Greater Point McIntyre**, and **Greater Kuparuk** areas. The company is one of the largest North Slope producers, although production from the region is declining; 2010 net production averaged 117 mb/d of liquids. • Development activities continued at **Point Thomson** in 2010 (35% w.i., operated), and first production of gas liquids is anticipated in 2014. The longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline.	**Material harvest position.** As the largest holder of discovered gas resources on the North Slope and a co-operator of the Prudhoe Bay Western Region development, ExxonMobil holds a leading position in Alaska.

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PFC-Identified Challenges

- **Deliver on unconventional resource positioning**: The XTO Energy acquisition and subsequent shale gas acreage transactions have made ExxonMobil a force in the North America unconventional resource play. That said, the company has provided limited guidance on pace of forward development despite continued acreage accumulation. Furthermore, given the weak US gas price environment, it is unclear how rapidly ExxonMobil's management will grow sales volumes. ExxonMobil is counting on additional long-term value arising from the XTO transaction through development of its expanding portfolio of International unconventional resource holdings.
- **Execute on Asia-Pacific LNG Projects**: ExxonMobil has a queue of LNG developments in Asia-Pacific, including Gorgon LNG (operated by Chevron), PNG LNG, and the potential Scarborough gas field development, all of which are poised to generate longer-term volume growth. Each of these projects comes with significant technical challenges—CO_2 capture and disposal at Gorgon LNG, remote gas field development and long distance pipeline transport in the case of PNG LNG, and the remote offshore location of the Scarborough field in the Carnarvon Basin (which may result in the field being dedicated as feedstock supply to the Pluto or Wheatstone LNG projects, rather than a greenfield LNG development). Performance will be critical to ensuring long-term regional portfolio growth.
- **Maintain leadership in share buy-back and dividend performance**: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing ~$19.7 bn through dividends and share buy-backs in 2010 and spending ~$114 bn on share repurchase over the 2006-2010 period. With the increased emphasis being placed on unconventional gas resources to deliver future volume growth, shareholders will be looking for ExxonMobil to continue its leading dividend and share buy-back performance, as the core differentiator from its faster growing (in volumetric terms) peer group companies.
- **Replace volume growth from Qatar North Field commercialization**: With full ramp-up of the final four liquefaction trains at the RasGas and Qatargas LNG complexes, and continued imposition of a development moratorium for the North Field resource by the Qatar government, ExxonMobil will be challenged to deliver material global growth.
  - It is not clear how aggressively ExxonMobil will look to develop its US Onshore unconventional gas resources, given current and projected gas pricing in the North America market;
  - Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta) continues to face delays in the form of regulatory hurdles (recently removed for the Mackenzie Valley gas pipeline project) and gas market supply-demand balances => renewed interest in Alaska LNG expansion;
  - Development of captured oil reserves in the Caspian region have experienced significant delays and cost over-runs, and are coming under increased political risk through accelerating resource nationalism;
  - ExxonMobil was successful in securing a growth position in Iraq through the West Qurna-1 redevelopment project, but positioning in Kurdistan exploration appears to have cost them a spot in Iraq's 4th Licensing Round. It is not clear that Iraq can become a Core growth area for the company.

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Questions & Discussion

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PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

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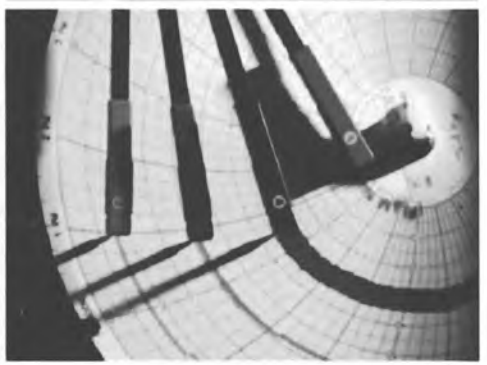

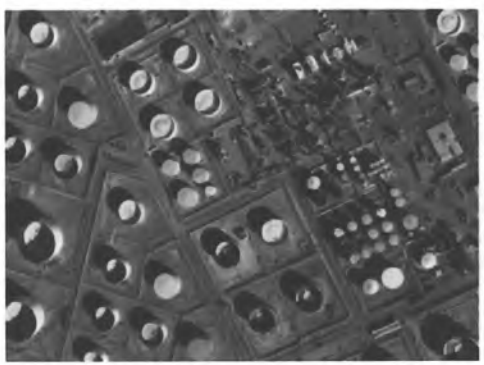

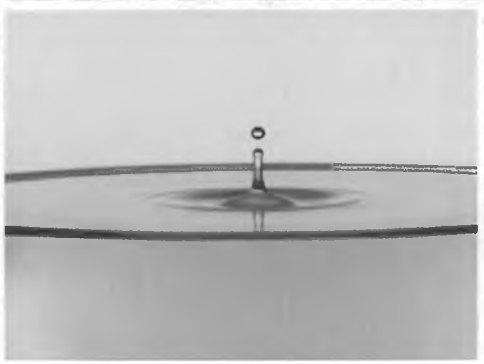

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Discussion Slides: Alaska House Resources Committee

April 23, 2012

Janak Mayer
Manager, Upstream & Gas
PFC Energy

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Alaska's Oil & Gas Competitive Context

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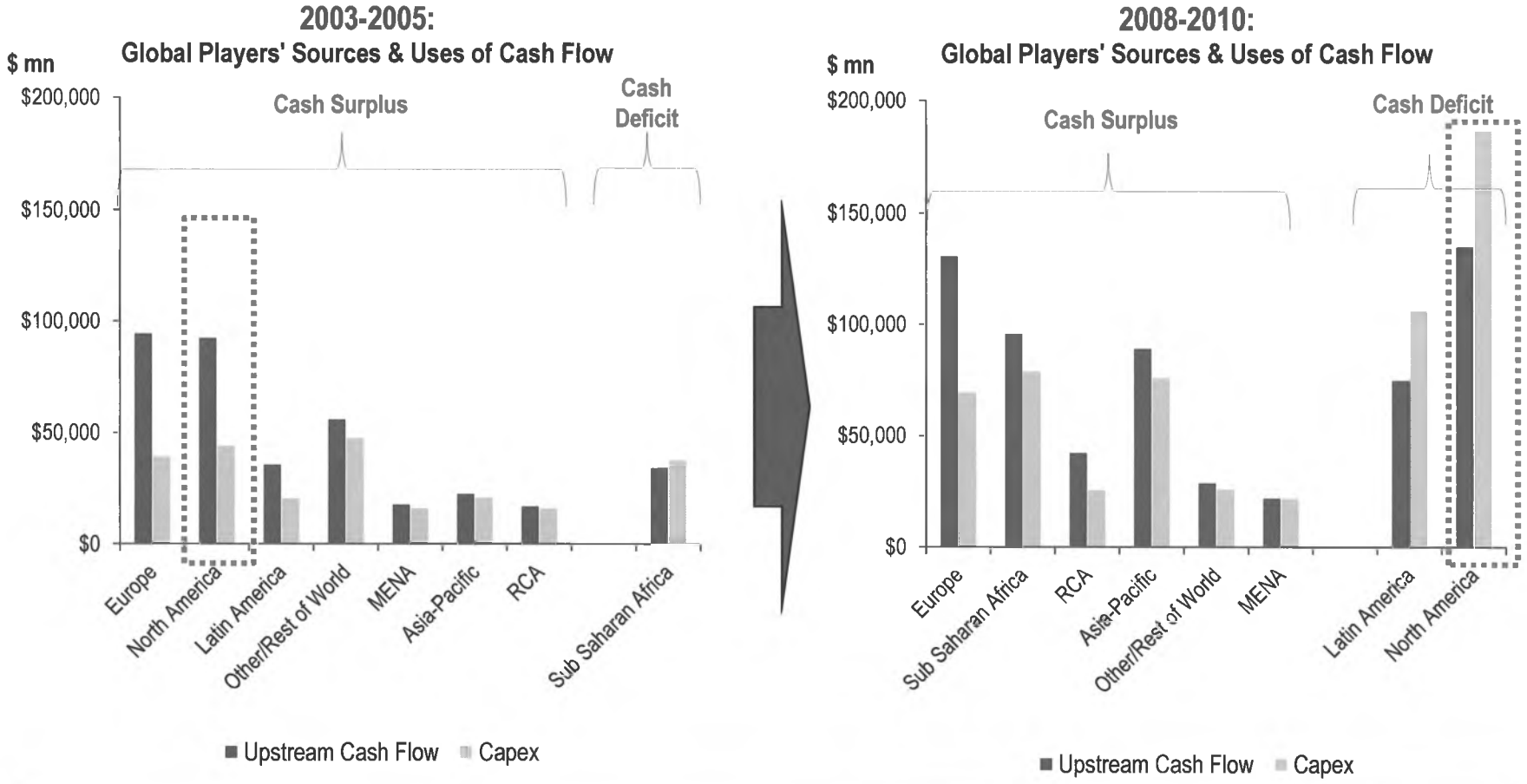
Fixed-Royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars



It is now an exception not to be targeting unconventionals in North America as a major growth platform.

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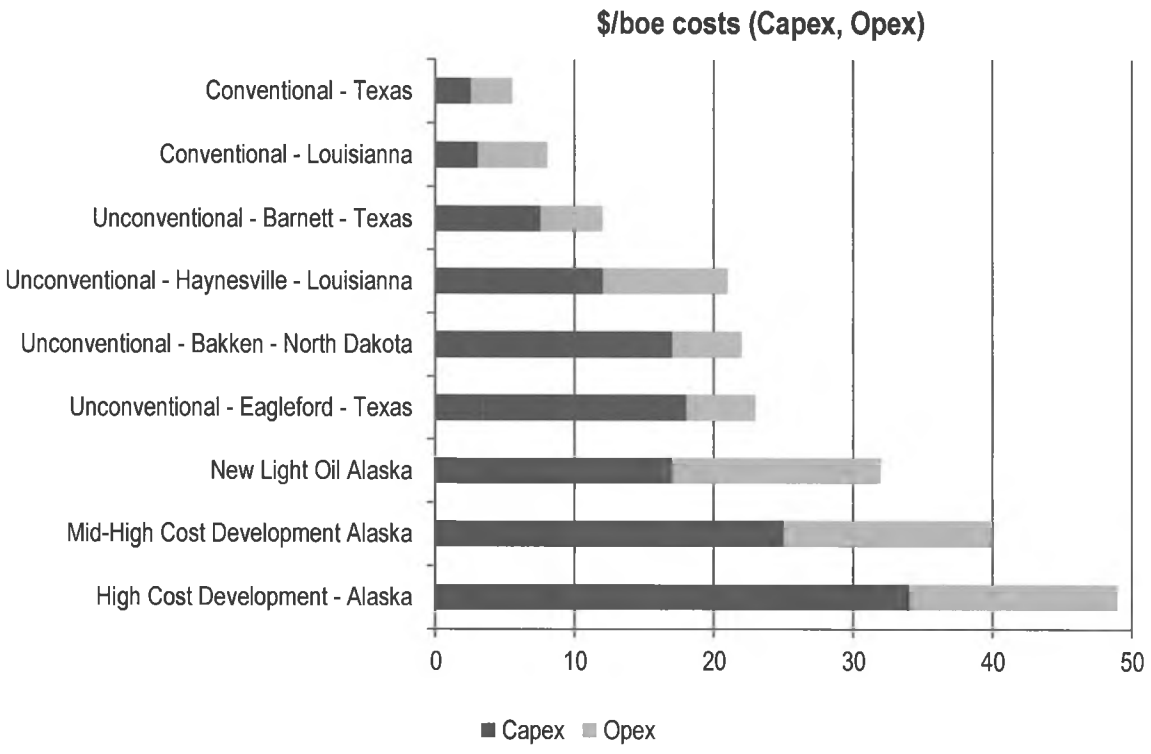
Alaska's Days of "Easy Oil" Are Gone: High Costs and High Government Take Present Challenges

$/boe Costs (Capex, Opex)



Costs are significantly higher in Alaska than the Lower 48 – even compared to unconventionals. Meanwhile, Alaska's Government Take has risen significantly over recent years, meaning new project economics can be very challenging

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Relative Government Take (Definition)

$$\textbf{Relative Government Take} = \frac{\text{Government Take}}{\text{Divisible Income}}$$

Divisible Income equals Gross Revenues less costs, including capex and transportation costs.

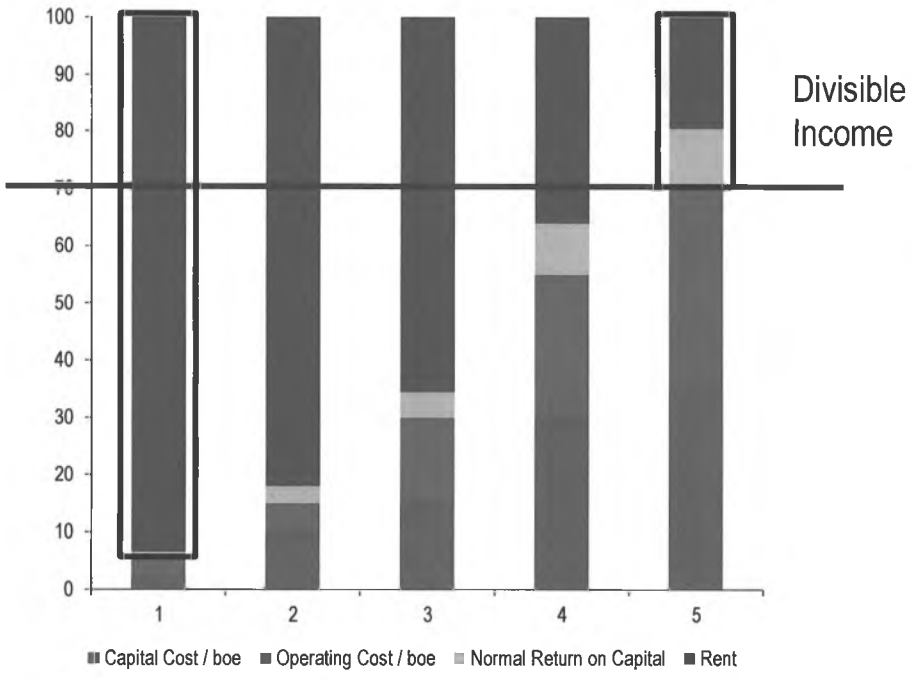
Government Take includes all payments the government mandates in its function as a sovereign:

- Royalties
- Land rental fees, property taxes
- Production taxes
- Income taxes

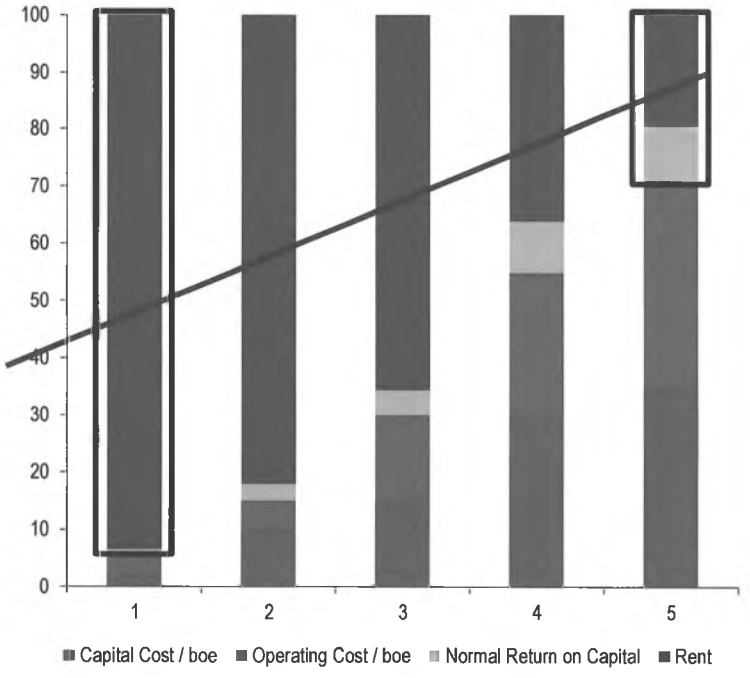
Government Take does not include amounts the government earns via a direct equity stake

Fixed Royalty v Profit Based Fiscal Systems

Incidence of a 30% Fixed Royalty on 5 Different Projects



Incidence of a 50% Profit-Based Tax on 5 Different Projects



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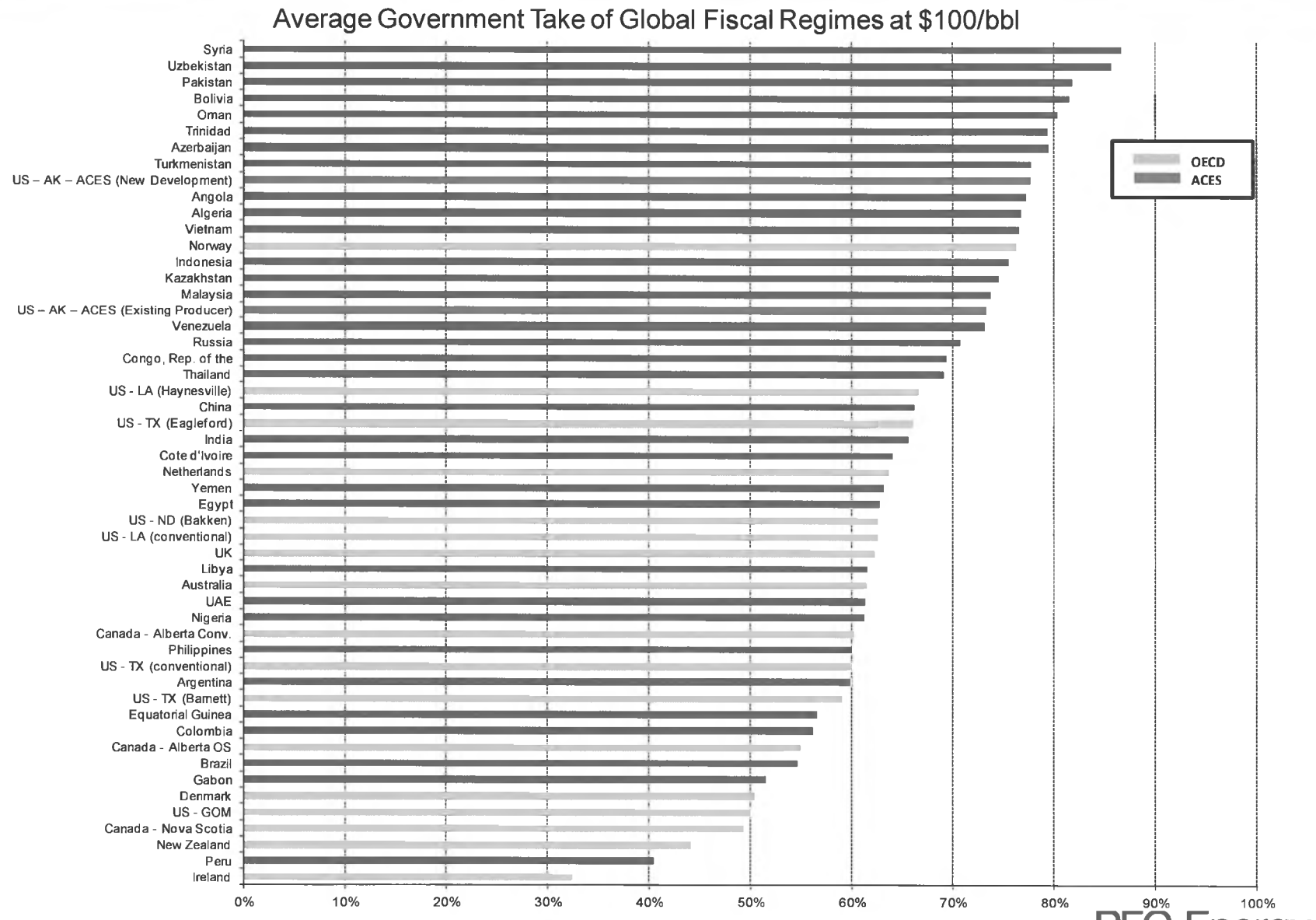
Regime Competitiveness: Average Government Take



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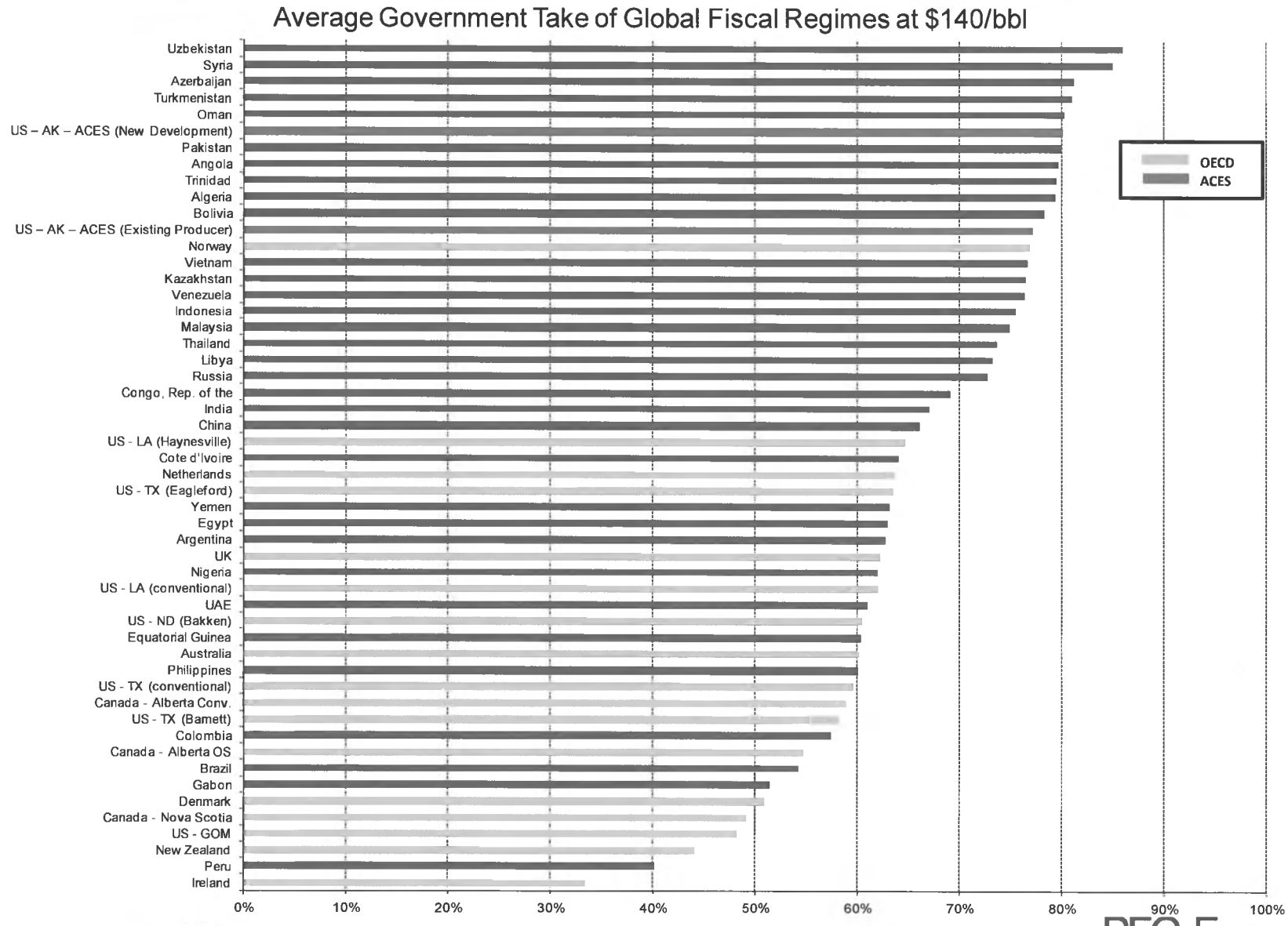
Regime Competitiveness: Average Government Take



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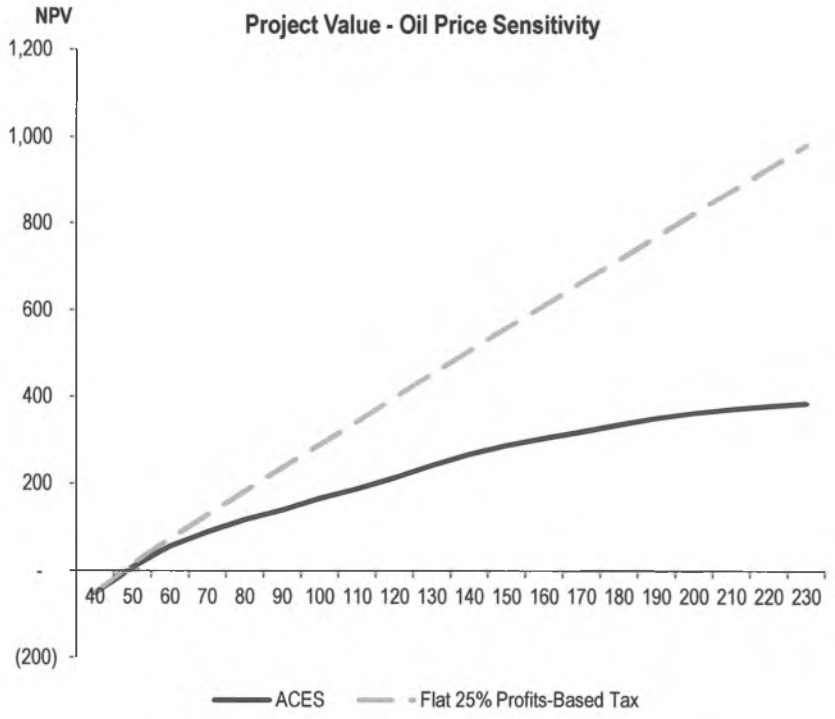
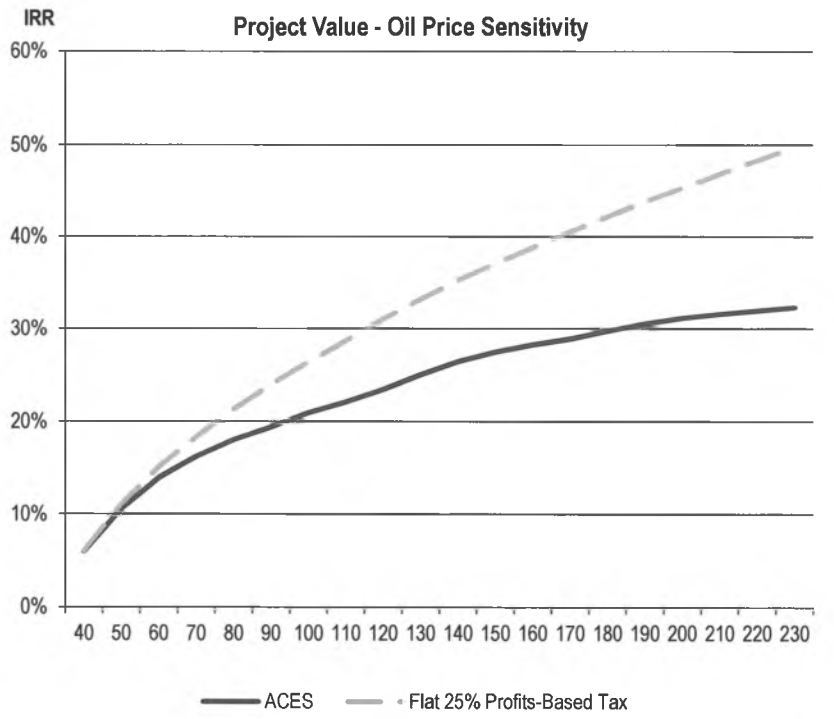
Effect of Progressivity on Price Upside





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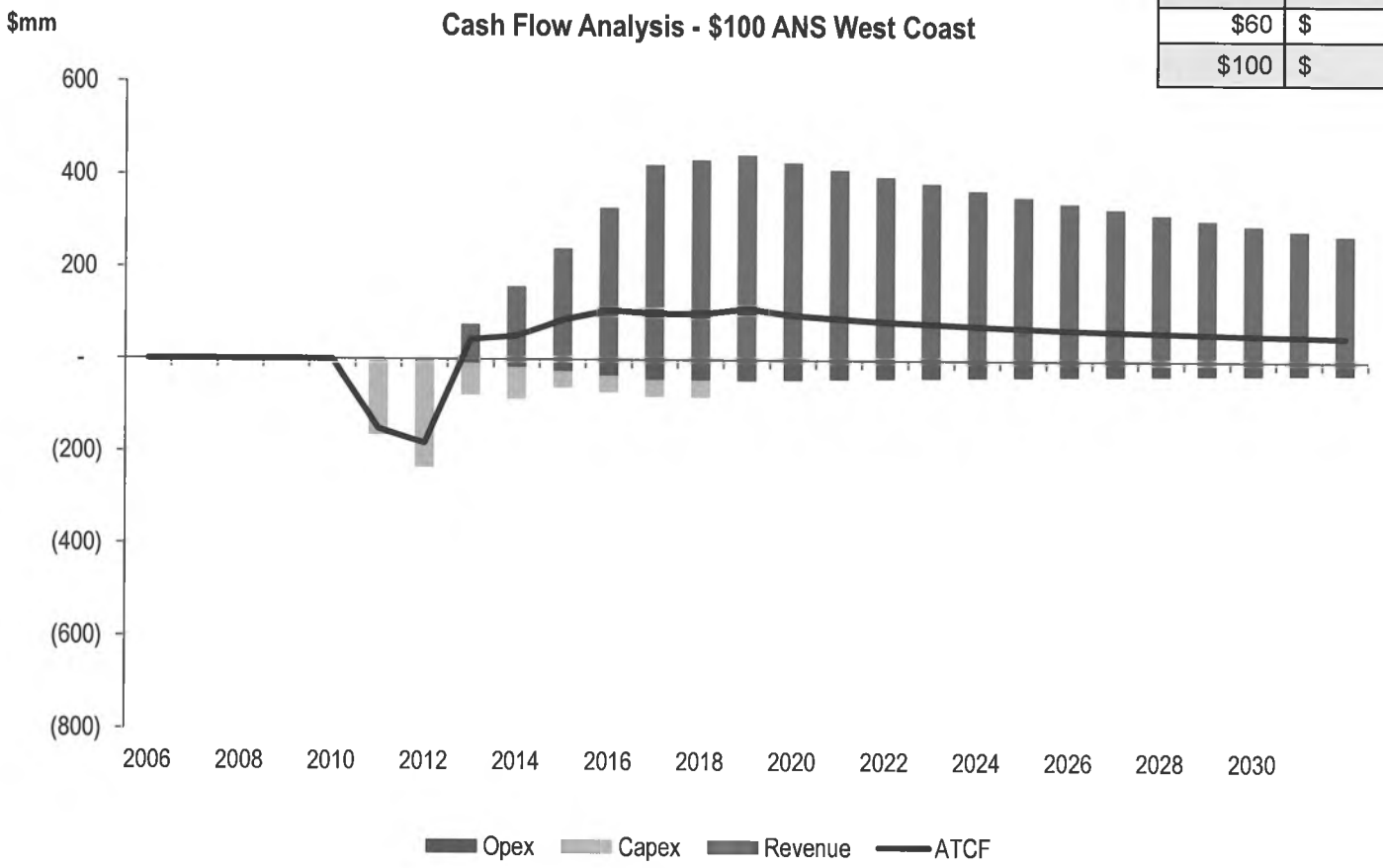
Low Cost Light Oil: Hypothetical 10 mb/d Project Cashflows ($13/bbl Capex, $10/bbl Opex)

Price	NPV	IRR
$40	$ (52)	6%
$60	$ 55	14%
$100	$ 166	21%



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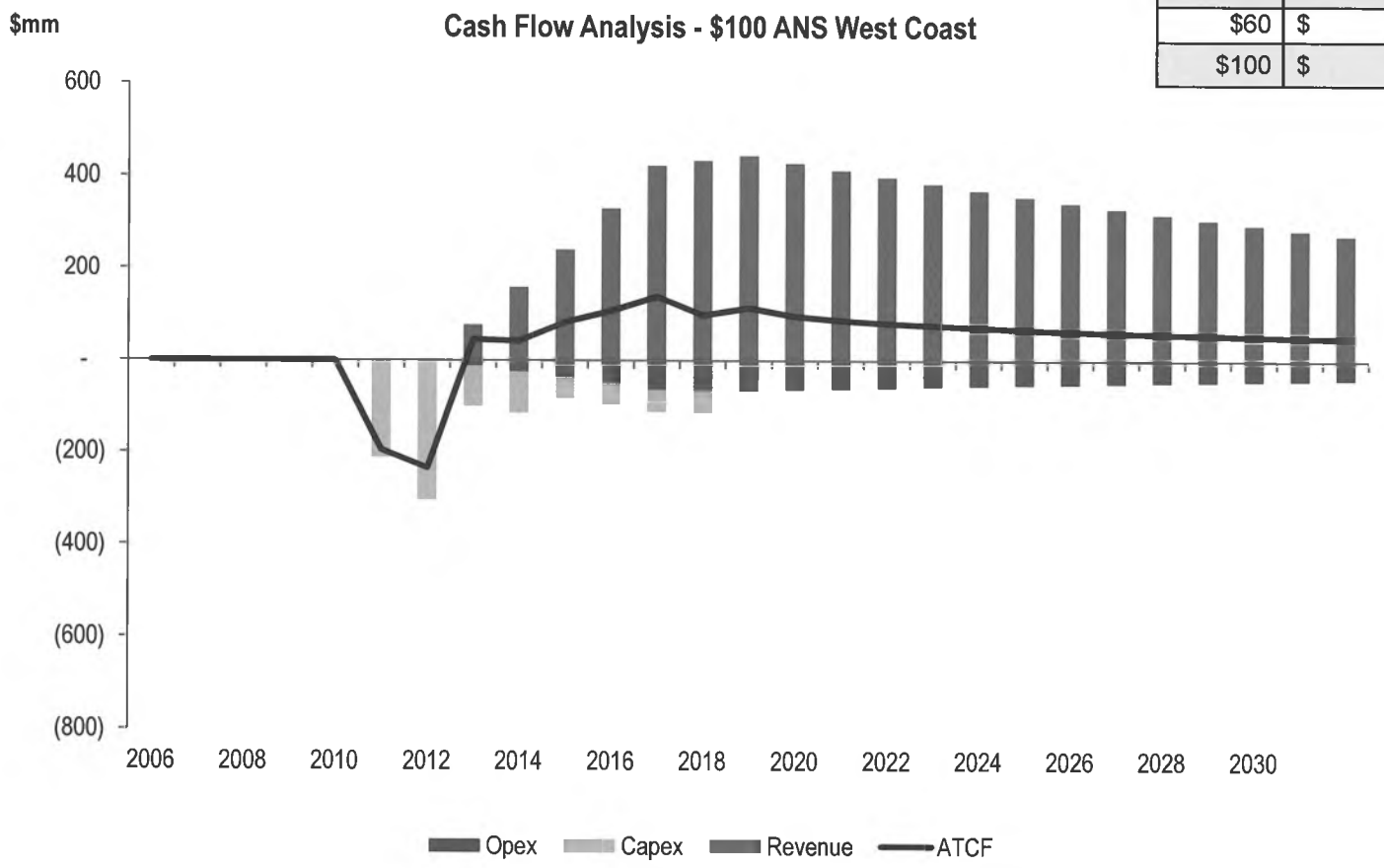
New Light Oil: Hypothetical 10 mb/d Project Cashflows ($17/bbl Capex, $15/bbl Opex)

Price	NPV	IRR
$40	$ (167)	-11%
$60	$ (24)	9%
$100	$ 113	16%



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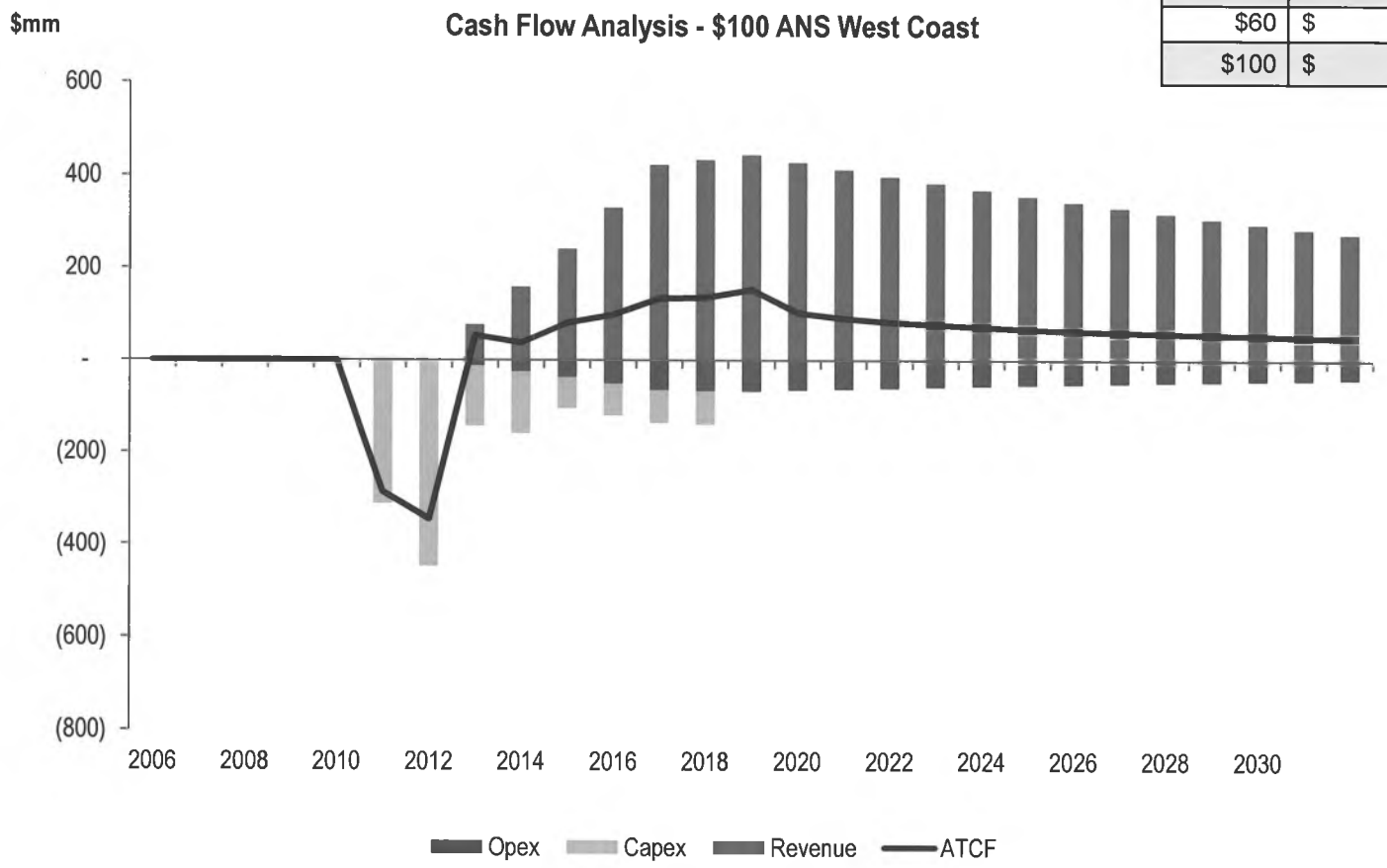
Mid-High Cost Project: Hypothetical 10 mb/d Project Cashflows ($25/bbl Capex, $15/bbl Opex)

Price	NPV	IRR
$40	$ (304)	
$60	$ (140)	4%
$100	$ 24	11%



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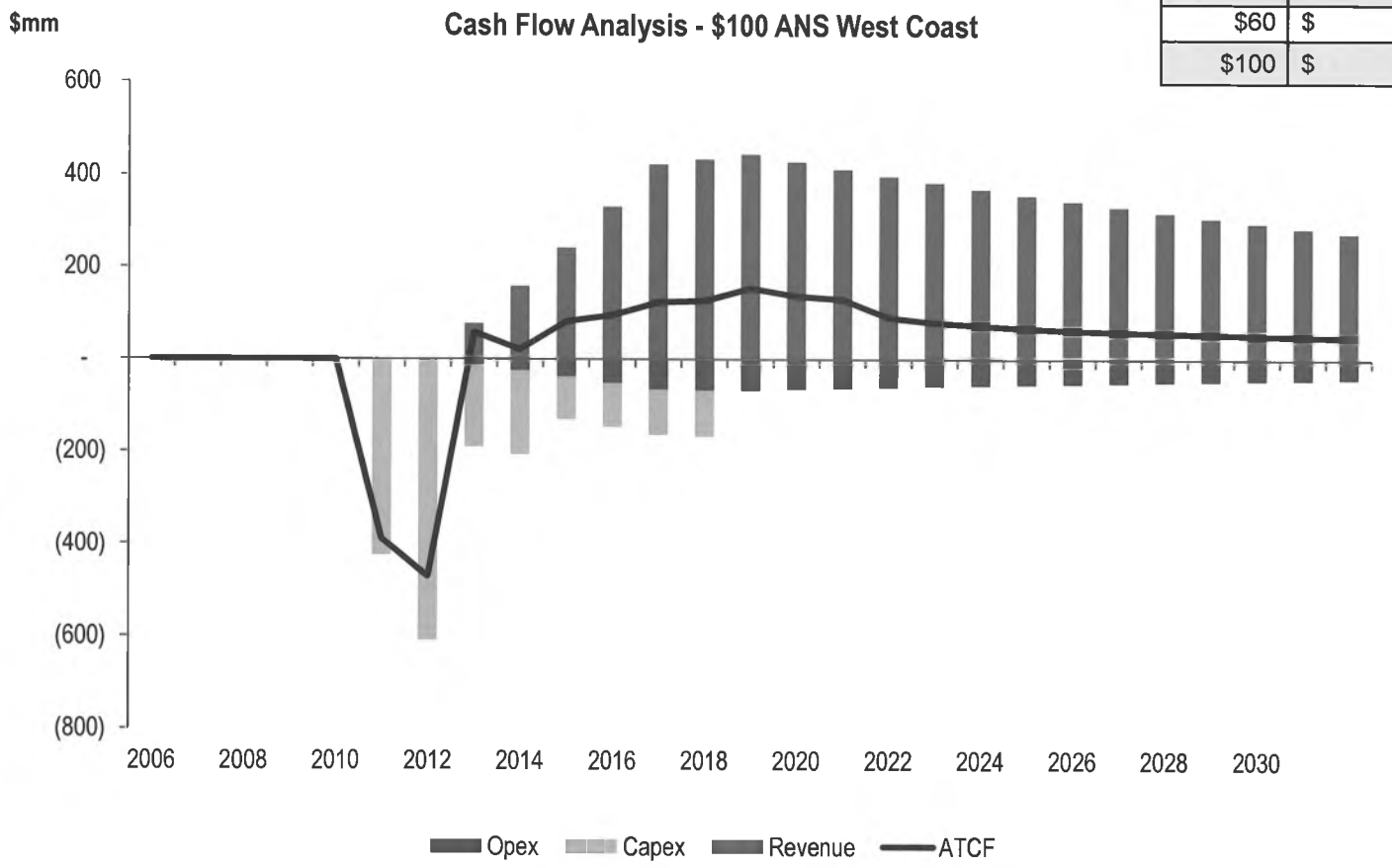
High Cost Project: Hypothetical 10 mb/d Project Cashflows ($34/bbl Capex, $15/bbl Opex)

Price	NPV	IRR
$40	$ (456)	
$60	$ (285)	1%
$100	$ (92)	7%



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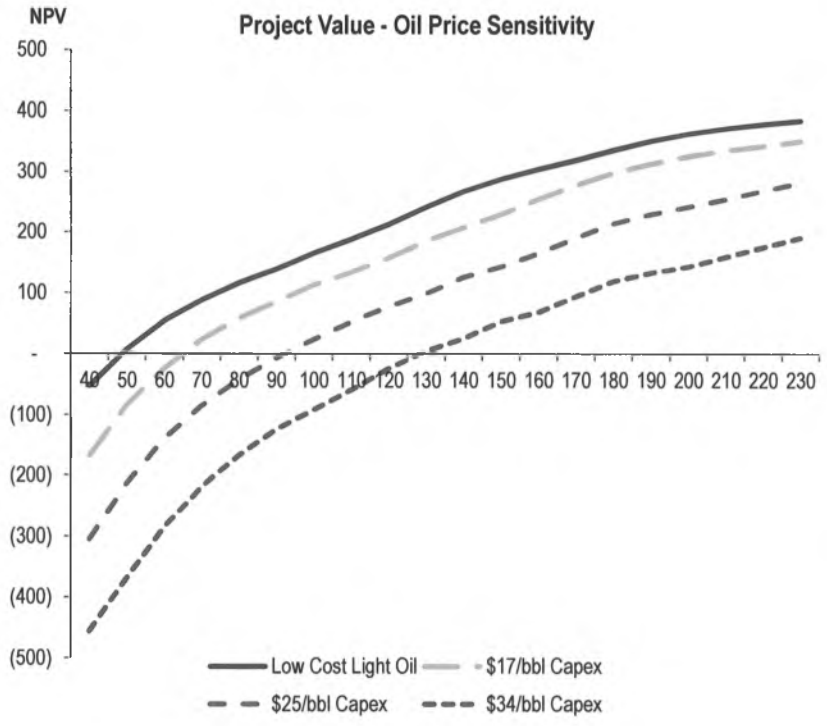
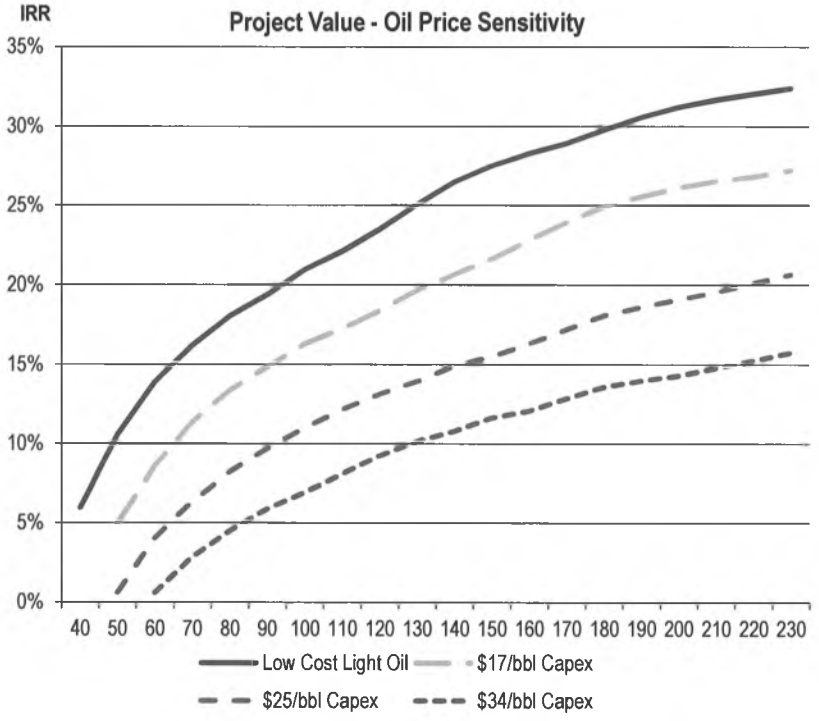
Project Value Under ACES: Cost and Price Sensitivity





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ACES – Effective as a Harvest Area Fiscal Regime

- ACES appears to work well as a "harvest" regime
  - Existing **mature fields remain profitable**, including capital work required to achieve ~6% decline (renewal capex)
  - **Maximum 'rent'** extracted from a declining production base is captured for the state
- ACES inhibits the development of new projects and resources that might help stem or even reverse the decline
  - ACES is **not progressive with regard to costs**, so high government take applies even to very high cost projects
  - Existing system of capital credits etc appears to do more to encourage 'renewal capex' than it does new production spending
  - Progressivity can have a major **detrimental impact on breakeven prices** for high-cost projects at current oil prices

Options to Spur New Developments

Approach	Implementation Options	Advantages	Disadvantages
Uniform lowering of Government Take	•Bracketing •Reduced Base Rate •Increased Progressivity Thresholds •Reduced Progressivity Rates •Progressivity Caps	•Does not require increased complexity •May present opportunities for simplification	•Incentivizing new high cost resources through this method alone requires giving substantial 'rent' back to producers on the mature producing assets
Differentiation between old and new production	•Allowance for New Oil •Switching in part away from Net Profits taxation to Gross Revenue Taxation, to enable different tax rates for different production streams without separate cost accounting and tax returns •Use of some combination of definitions for incremental production, ie base decline rate, regulator-agreed new programs, new areas	•Allows significant reductions in Govt Take on new and costlier developments (including heavy oil etc) without requiring significant reductions on the mature producing assets	•Administrative difficulties around definitions of 'new production'
Enhancements to cost progressivity of ACES	•Changes to allowable cost deduction or credits mechanism etc to provide greater 'uplift' for high capital and operating costs, while restricting negative Production Tax in marginal cases •Enhancements to royalty relief	•Does not require structural change away from ACES	•Increases already high complexity and opacity •May exacerbate problem of poor cost control incentives •Increases likelihood of unintended consequences •Likely less significant impact than new production differentiation

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Analysis of HB 3001

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Options to Spur New Developments

Approach	Implementation Options	Advantages	Disadvantages
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HB 3001 – Main Aspects

- For production from new North Slope fields, 30% gross revenue exclusion
  - Applies to calculation of both base and progressive tax amounts
  - Does not apply to progressivity rate calculation
  - Applies for 10 years
- For all other North Slope production, 40% gross revenue exclusion
  - Applies to calculation of progressive tax amount only
  - Does not apply to base tax amount or to progressivity rate calculation
  - Applies indefinitely
- Maximum progressive tax rate capped at 60% (reduced from 75%)
- 40% Well Lease Expenditure Credit applied to North Slope
- Capital credits redeemed in single year (rather than spread over two)

Understanding the Gross Revenue Exclusions

	Price /Barrel	Barrels	ACES ($mm)	HB 3001 Existing	HB 3001 New Fields
ANS Oil Price	$ 109.47	555,227.00			
Total Annual Production		202,657,895	$ 22,185	$ 22,185	$ 22,185
Royalty Barrels		(30,158,081)	$ (3,301)	$ (3,301)	$ (3,301)
Taxable Barels		172,499,814	$ 18,884	$ 18,884	$ 18,884
Total Transportation Costs	$ (8.56)		$ (1,477)	$ (1,477)	$ (1,477)
Gross Value at Point of Production (GVPP)		172,499,814	$ 17,407	$ 17,407	$ 17,407
Total Lease Expenditures	$ (29.11)		$ (5,021)	$ (5,021)	$ (5,021)
Production Tax Value (PTV)	**$ 71.80**		**$ 12,385**	**$ 12,385**	**$ 12,385**
30% GVPP Allowance					$ 5,222
40% GVPP Allowance				$ 6,963	
Adjusted PTV for Base Tax			$ 12,385	$ 12,385	$ 7,163
Adjusted PTV for Progressive Tax			$ 12,385	$ 5,423	$ 7,163
Base Production Tax - 25%			$ 3,096	$ 3,096	$ 1,791
Progressive Production Tax - 16.72%			$ 2,071	$ 907	$ 1,198
Production Tax before Credits			$ 5,167	$ 4,003	$ 2,989
Credits			$ 450	$ 750	$ 750
Estimated Total Tax After Credits			$ 4,717	$ 3,253	$ 2,239

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Purpose of Gross Revenue Exclusion Concept

- ACES Production Tax is a profit-based tax – ie it taxes wellhead revenue net of costs
- Under the ACES structure, varying either the base or the progressive rates for some forms of production and not others introduces significant complexity – requires 'ring-fencing' to allocate costs between different streams of production
- Gross Revenue Exclusion is a concept that makes it possible to reduce government take on some streams of production but not others, without requiring ring-fencing
- In HB 3001, however, it is also used to reduce government take across all North Slope fields
  - This could also be accomplished through simply lowering progressivity
  - Approximately equivalent to reducing progressivity from .4% to .15%

FY 2013 Revenue Comparison

ANS West Coast Oil Price	Production Tax				Total State Take				Total Government Take				Cash to Companies				FY 2013 % Government Take			
	ACES	HB 3001 (ex 40% Well Credit)	HB 3001 (With 40% Well Credit)	HB110	ACES	HB 3001 (ex 40% Well Credit)	HB 3001 (With 40% Well Credit)	HB110	ACES	HB 3001 (ex 40% Well Credit)	HB 3001 (With 40% Well Credit)	HB110	ACES	HB 3001 (ex 40% Well Credit)	HB 3001 (With 40% Well Credit)	HB110	ACES	HB 3001 (ex 40% Well Credit)	HB 3001 (With 40% Well Credit)	HB110
40	(233)	(233)	(528)	(323)	1,413	1,413	1,142	1,330	1,616	1,616	1,441	1,563	378	378	554	432	81%	81%	72%	78%
50	82	82	(213)	(8)	2,148	2,148	1,877	2,065	2,803	2,803	2,628	2,750	1,218	1,218	1,393	1,271	70%	70%	65%	68%
60	513	513	218	423	2,989	2,989	2,719	2,907	4,060	4,060	3,884	4,006	1,988	1,988	2,164	2,042	67%	67%	64%	66%
70	996	957	662	864	3,878	3,842	3,572	3,757	5,347	5,323	5,148	5,268	2,727	2,751	2,927	2,806	66%	66%	64%	65%
80	1,736	1,493	1,198	1,339	5,002	4,779	4,509	4,638	6,787	6,642	6,466	6,550	3,314	3,459	3,635	3,551	67%	66%	64%	65%
90	2,613	2,111	1,816	1,898	6,252	5,792	5,522	5,597	8,308	8,010	7,834	7,883	3,819	4,118	4,293	4,245	69%	66%	65%	65%
100	3,628	2,813	2,518	2,522	7,629	6,881	6,611	6,615	9,913	9,427	9,251	9,254	4,241	4,727	4,903	4,900	70%	67%	65%	65%
110	4,782	3,597	3,302	3,210	9,132	8,046	7,776	7,692	11,599	10,893	10,718	10,663	4,582	5,287	5,463	5,517	72%	67%	66%	66%
120	6,073	4,464	4,169	3,963	10,761	9,287	9,017	8,829	13,367	12,409	12,233	12,111	4,840	5,798	5,974	6,096	73%	68%	67%	67%
130	7,503	5,414	5,119	4,783	12,517	10,603	10,333	10,026	15,218	13,974	13,798	13,598	5,016	6,260	6,435	6,635	75%	69%	68%	67%
140	8,550	6,193	5,898	5,645	13,922	11,764	11,494	11,261	16,841	15,438	15,262	15,111	5,420	6,823	6,998	7,149	76%	69%	69%	68%
150	9,623	6,989	6,694	6,507	15,352	12,940	12,670	12,498	18,479	16,911	16,736	16,624	5,808	7,376	7,551	7,663	76%	70%	69%	68%
160	10,730	7,806	7,511	7,370	16,813	14,135	13,864	13,735	20,138	18,397	18,222	18,137	6,175	7,916	8,092	8,176	77%	70%	69%	69%
170	11,873	8,644	8,349	8,232	18,306	15,349	15,078	14,971	21,818	19,896	19,720	19,650	6,522	8,444	8,620	8,690	77%	70%	70%	69%
180	13,049	9,503	9,208	9,095	19,830	16,581	16,311	16,208	23,518	21,406	21,231	21,163	6,849	8,960	9,136	9,203	77%	70%	70%	70%
190	14,261	10,382	10,087	9,957	21,386	17,833	17,563	17,444	25,239	22,929	22,753	22,676	7,155	9,464	9,640	9,717	78%	71%	70%	70%
200	15,506	11,282	10,987	10,820	22,974	19,104	18,834	18,681	26,980	24,464	24,289	24,189	7,440	9,955	10,131	10,230	78%	71%	71%	70%

Note: Consistent with DOR methodology, these revenue numbers do not include payments for tax credits which are not claimed against current production, as these are accounted for separately in the budget. In 2013, DOR forecasts a potential liability of $400mm for these credits.

Well Credit impact has been estimated assuming 40% of Capex dollars are Well Expenditures, qualifying for the 40% Well Credit. Actual impact will vary depending on proportion of Capex qualifying for the Well Credit.

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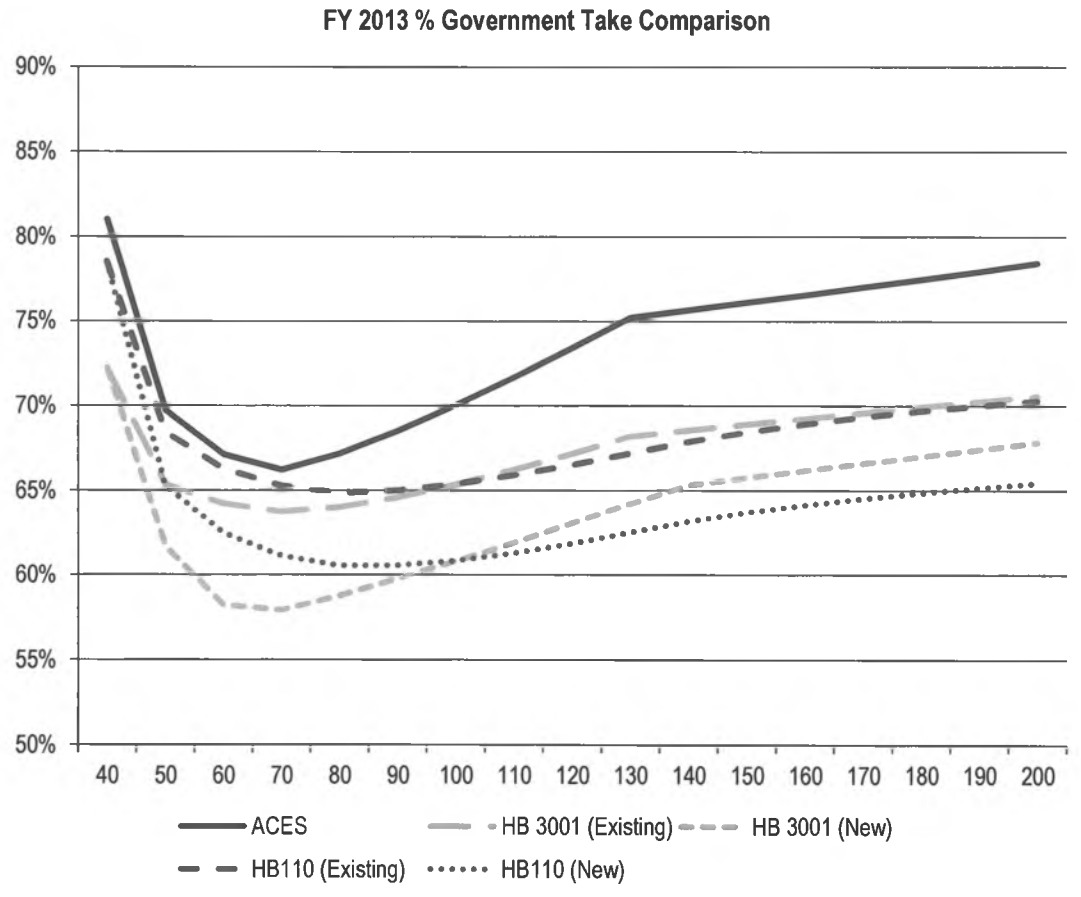
FY 2013 Government Take Comparison

Price	FY 2013 % Government Take				
	ACES	HB 3001 (Existing)	HB 3001 (New)	HB110 (Existing)	HB110 (New)
40	81%	72%	72%	79%	79%
50	70%	65%	62%	68%	65%
60	67%	64%	58%	66%	62%
70	66%	64%	58%	65%	61%
80	67%	64%	59%	65%	61%
90	69%	65%	60%	65%	61%
100	70%	65%	61%	65%	61%
110	72%	66%	62%	66%	61%
120	73%	67%	63%	67%	62%
130	75%	68%	64%	67%	63%
140	76%	69%	65%	68%	63%
150	76%	69%	66%	68%	64%
160	77%	69%	66%	69%	64%
170	77%	70%	67%	69%	65%
180	77%	70%	67%	70%	65%
190	78%	70%	67%	70%	65%
200	78%	71%	68%	70%	65%



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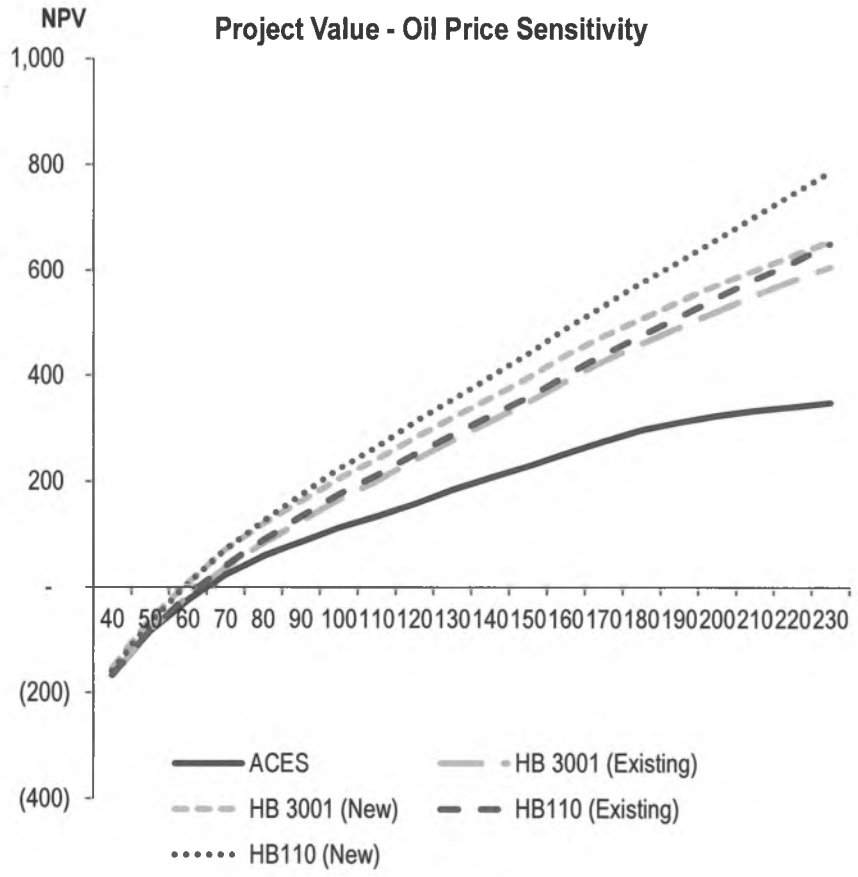
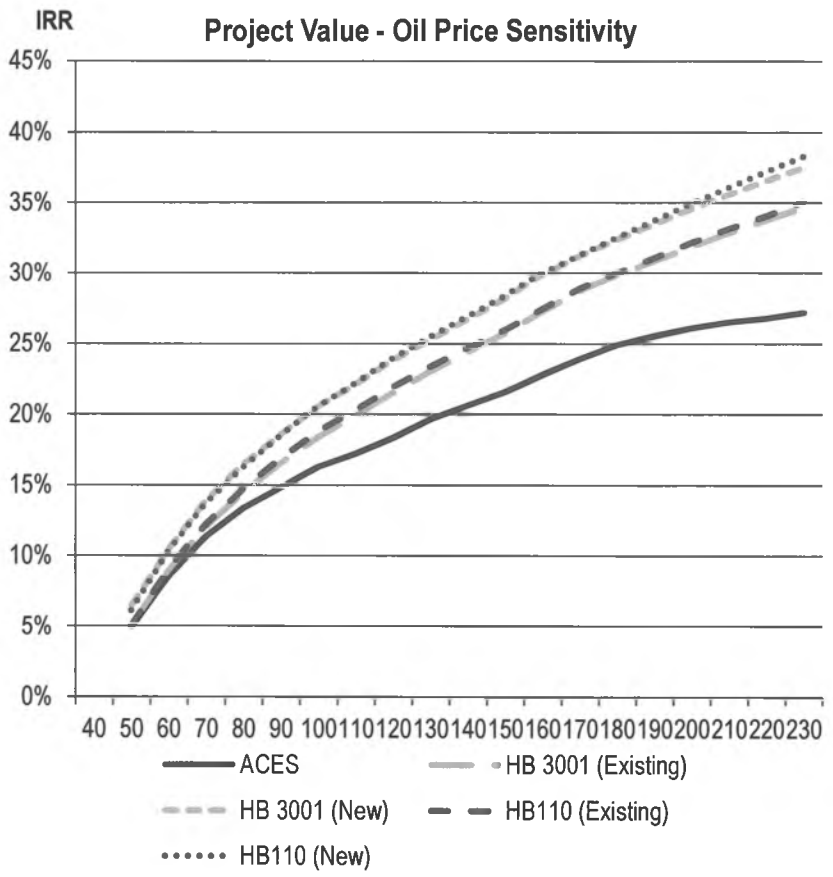
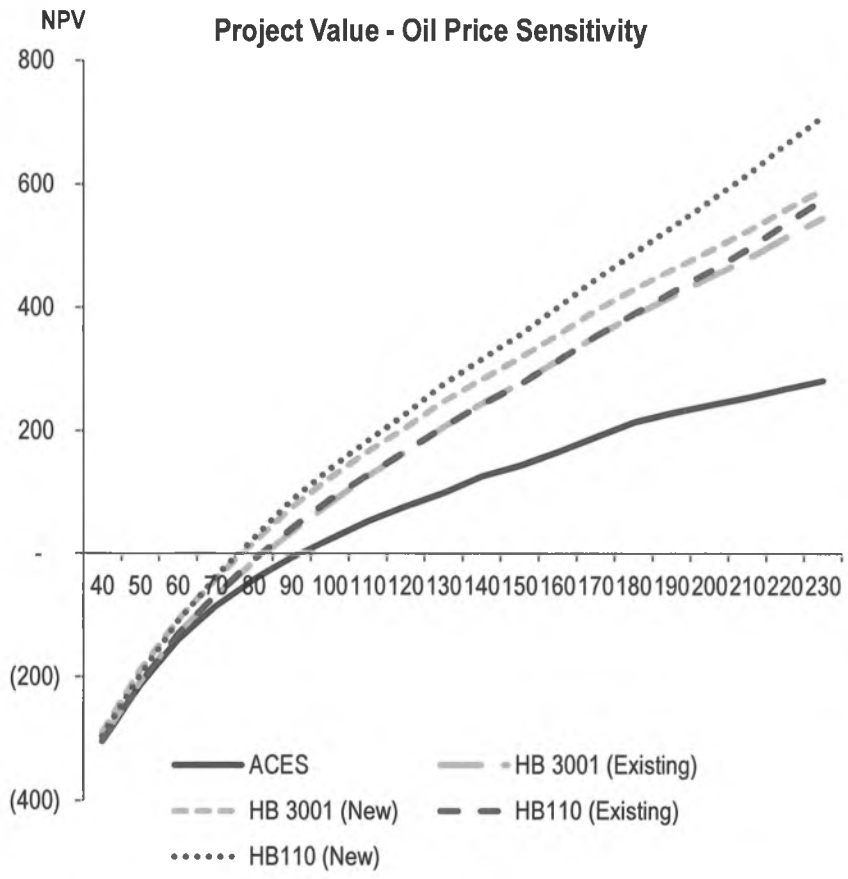
$17/bbl Field: Project Value Under Different Fiscal Options

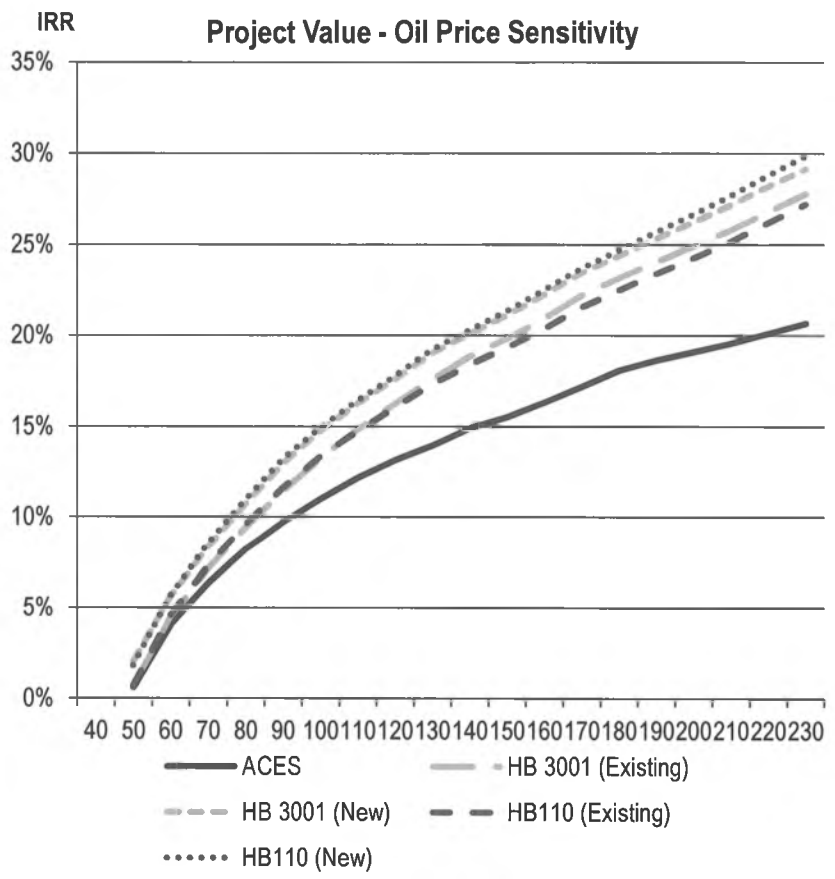




PFC Energy

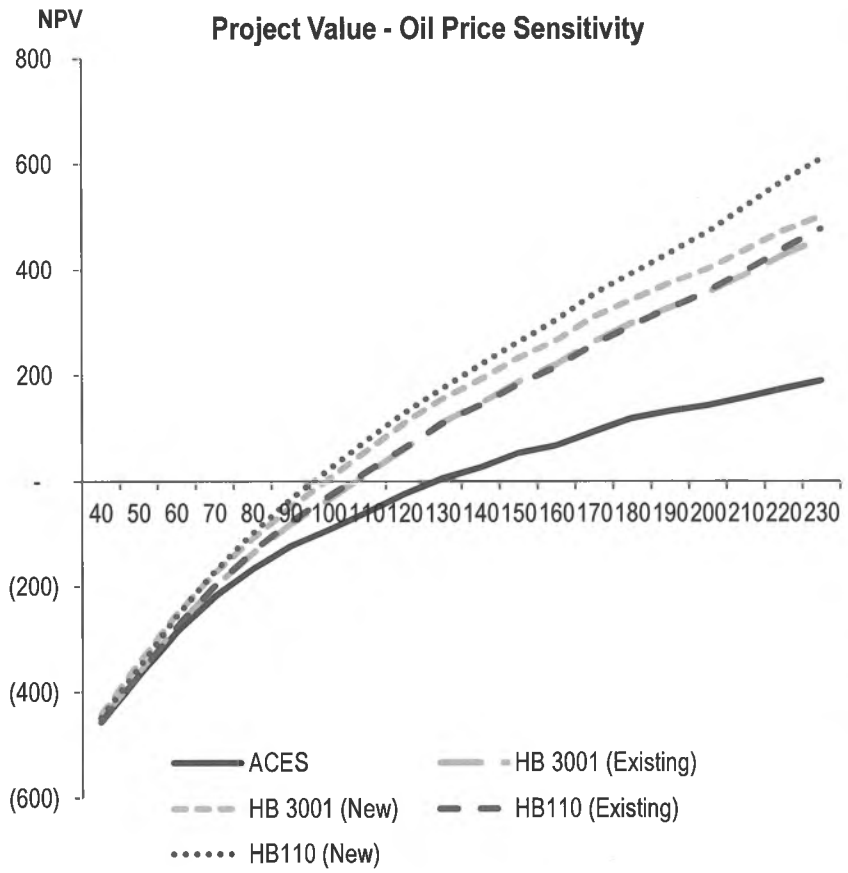
$25/bbl Field: Project Value Under Different Fiscal Options

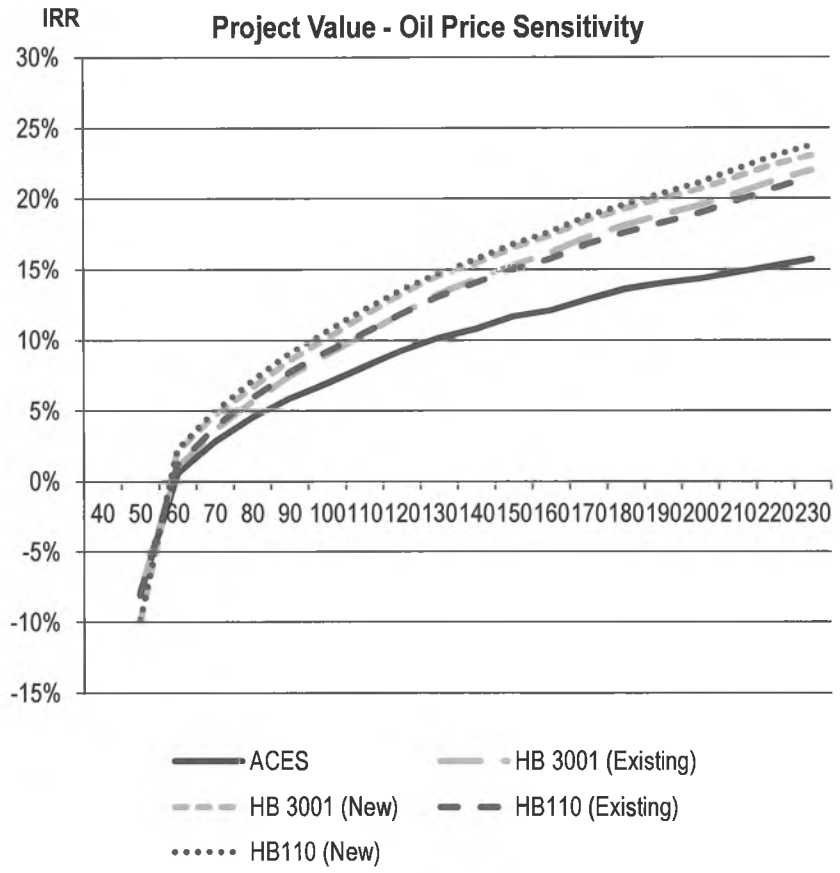




PFC Energy

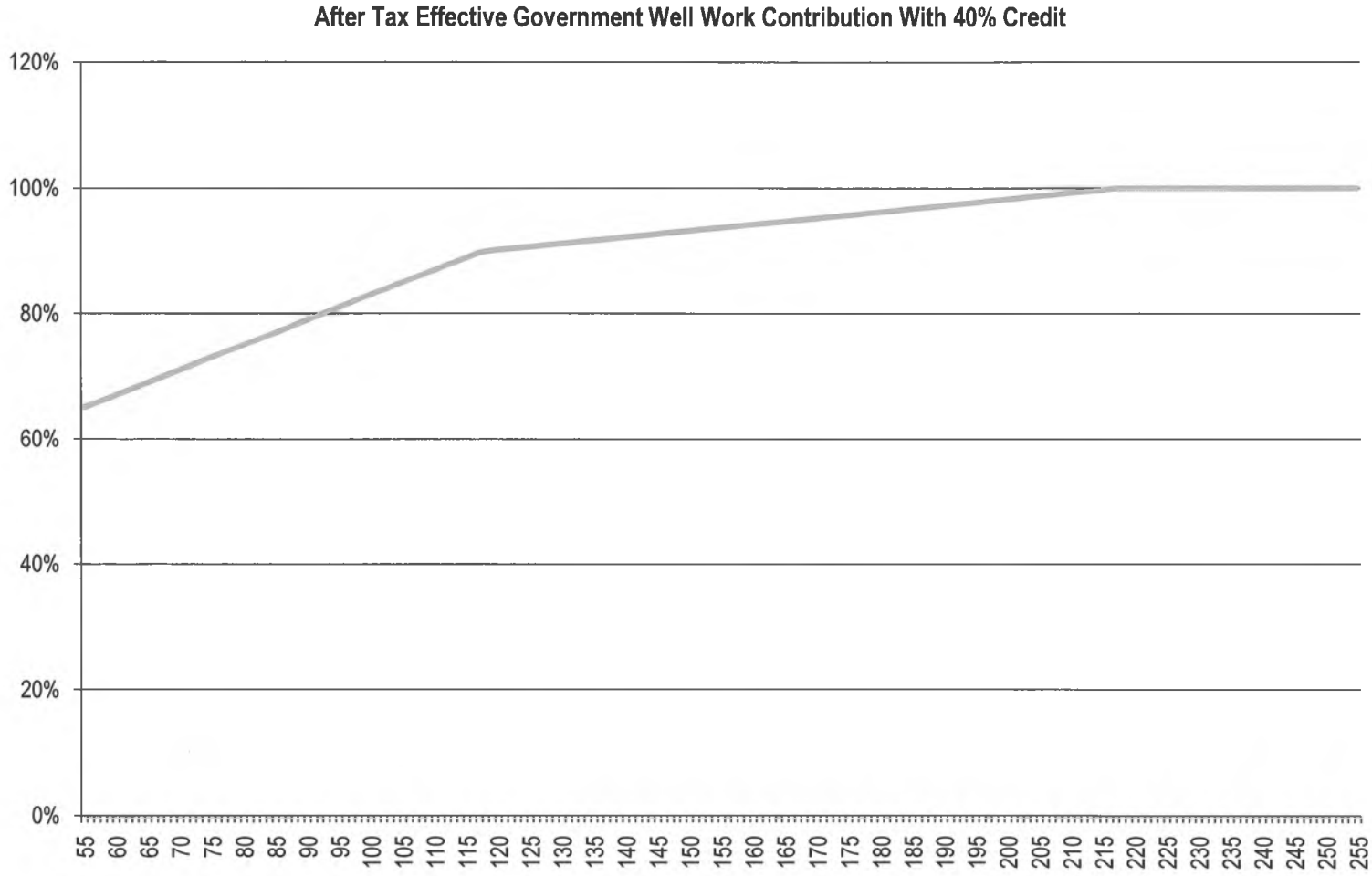
$34/bbl Field: Project Value Under Different Fiscal Options





PFC Energy

40% Well Credits Create High Levels of Government Support



PFC Energy

Key Issues

- Across-the-board reduction in government take is simplest approach, but requires forgoing significant revenue on activities that are currently economic
- If, hypothetically, decline on legacy fields could be reduced to 2% from 6%, revenue from 2020 onward could be higher than under current scenario; revenue until that point would be significantly reduced
- Alternative approach is to endeavor to differentiate between existing v incremental production from legacy fields
  - Significant complexities to doing this effectively
- HB3001 does not address other key issues with ACES including
  - Oil / Gas decoupling
  - High levels of spending support through high credits & progressivity

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PFC Energy

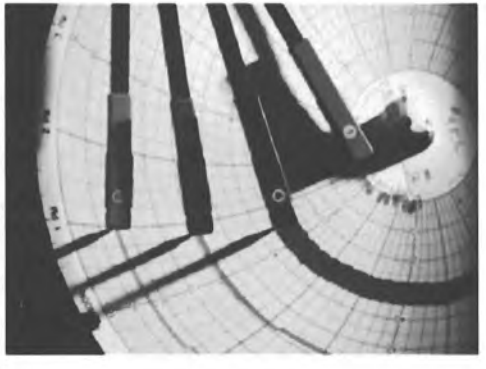
Notice

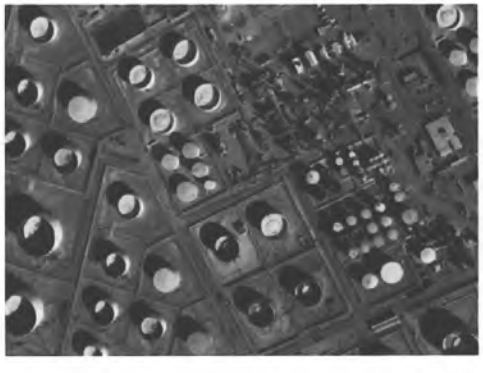
PFC Energy has prepared the materials utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice, based on information available at the time such materials were created. To the extent these materials contain forecasts or forward looking statements, such statements are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen, including the actions of governments, individuals, third parties and market competitors. **ACCORDINGLY, THESE MATERIALS AND THE INFORMATION CONTAINED THEREIN ARE PROVIDED "AS IS" WITHOUT WARRANTY OF ANY KIND, EITHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO THE IMPLIED WARRANTIES OF MERCHANTABILITY, ACCURACY, OR FITNESS FOR A PARTICULAR PURPOSE.** Conclusions presented herein are intended for information purposes only and are not intended to represent recommendations on financial transactions such as the purchase or sale of shares in the companies profiled in this report.

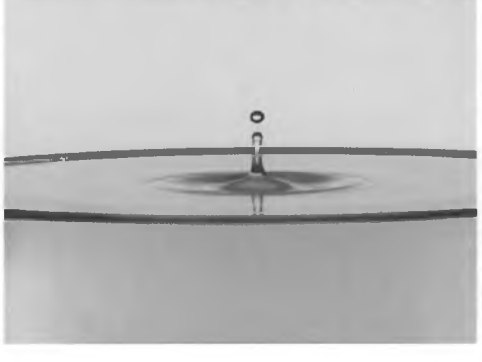
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

This report reflects information available to PFC Energy as of the date of publication. Clients are invited to check our web site periodically for new updates.

A trusted advisor to energy companies and governments for over twenty five years







PFC Energy

Decline Curves

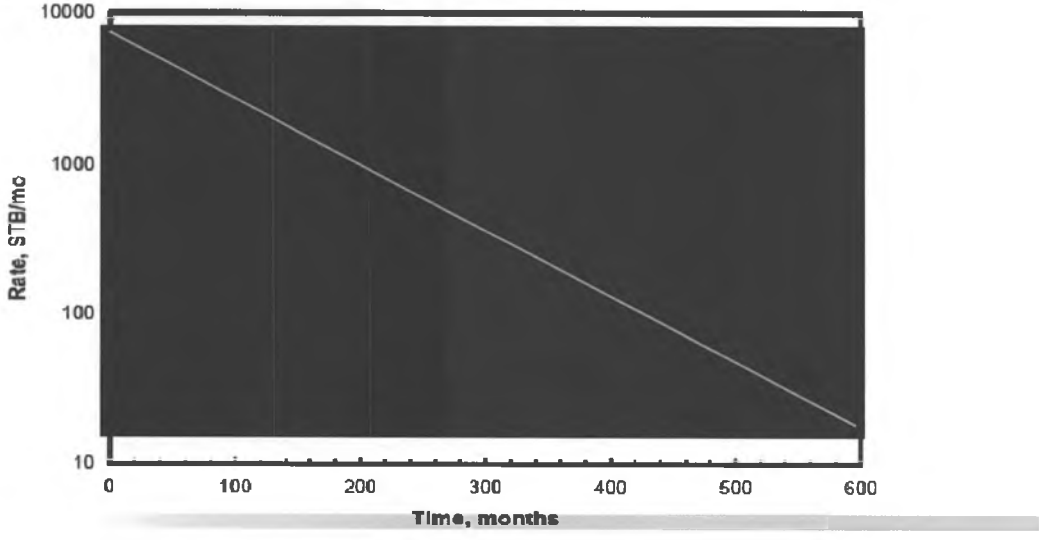
Joint House Resources and Energy Committees

23 April 2012

William C. Barron

Division of Oil and Gas

Decline Curve Shapes: Semilog Rate-Time



- Exponential b=0, $q_t=q_i exp^{(-Dt)}$
- Hyperbolic decline b>1 :$q_t=q_i /(1+bD_it)^{(-1/b)}$
- Harmonic Decline where b=1, $q_t=qi/(1+D_it)$

Where: t= time of interest, q_t= rate at time t, q_i=initial rate, D_i is decline rate at time 0 (1/time), b=Arps' decline constant describing curvature of simi-log rate vs. time

Items Affecting Production

Adding Production

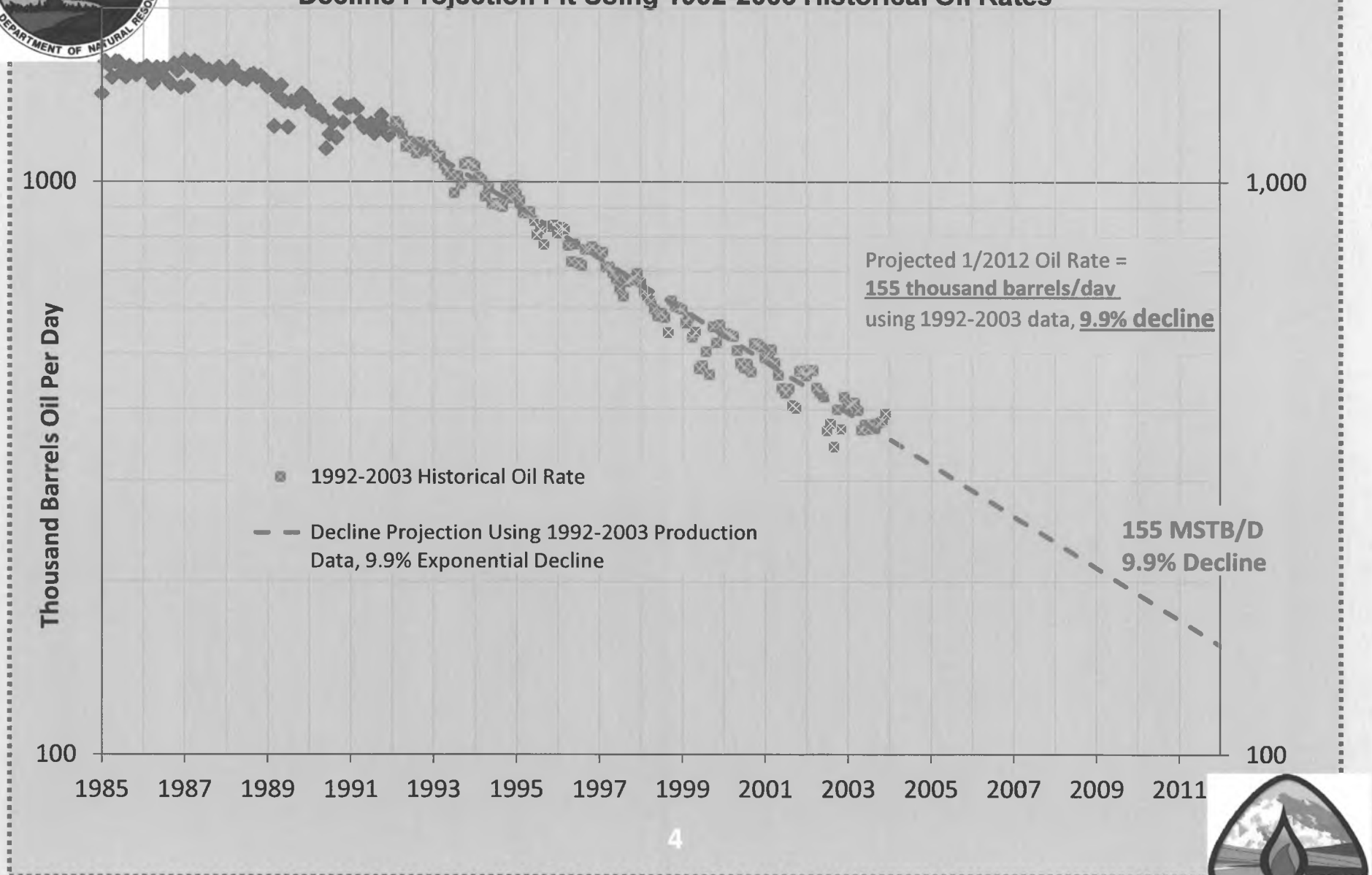
- Well Drilling
- Well Maintenance
- Enhanced Oil Recovery
- New Facilities, Infrastructure, Debottlenecking
- New Technology

Decreasing Production

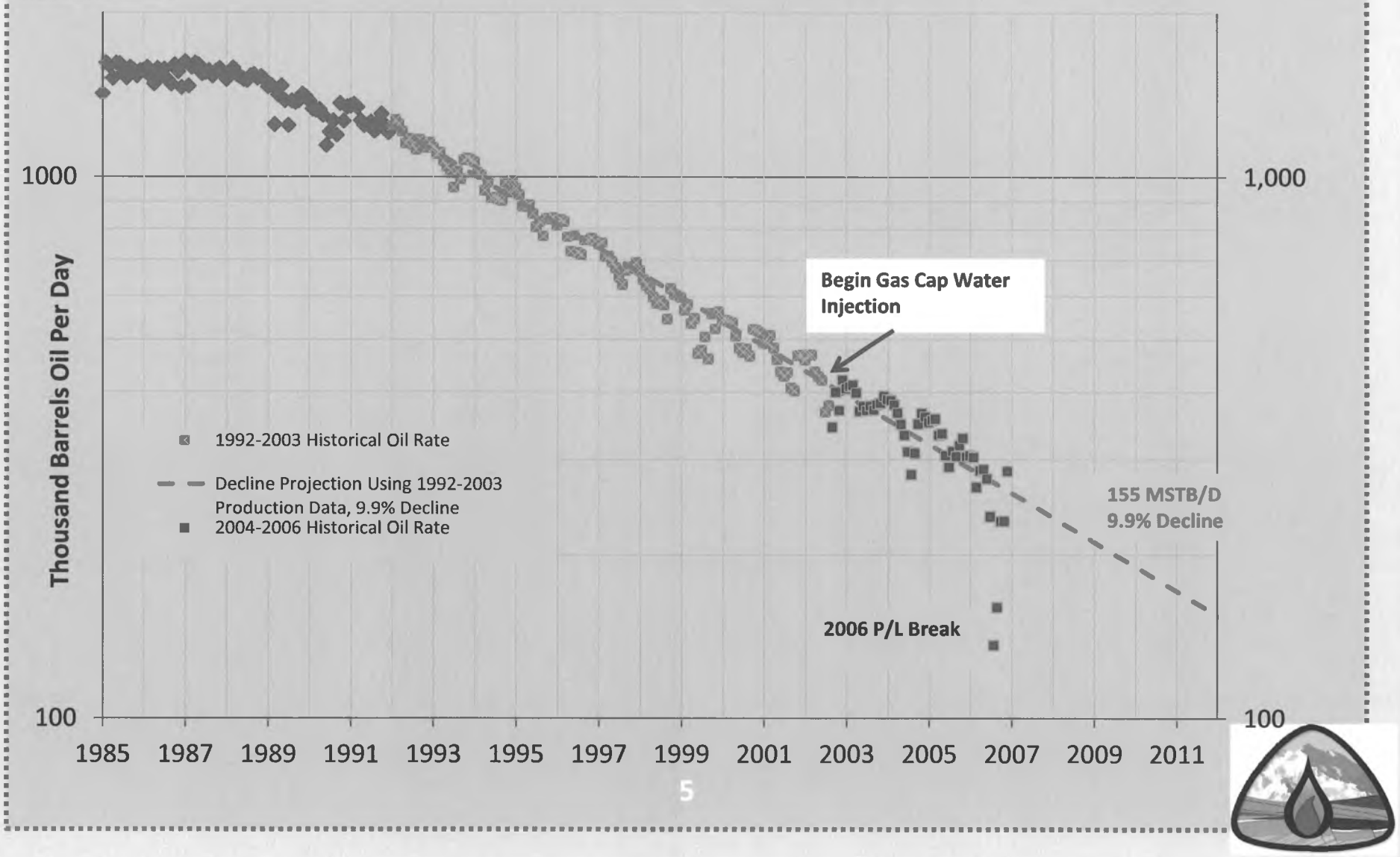
- Aging facilities and infrastructure
- Gas and Water Handling
- Well Failures
- Decreasing new well rate with time
- Costs

PBU Initial Participating Area

Decline Projection Fit Using 1992-2003 Historical Oil Rates

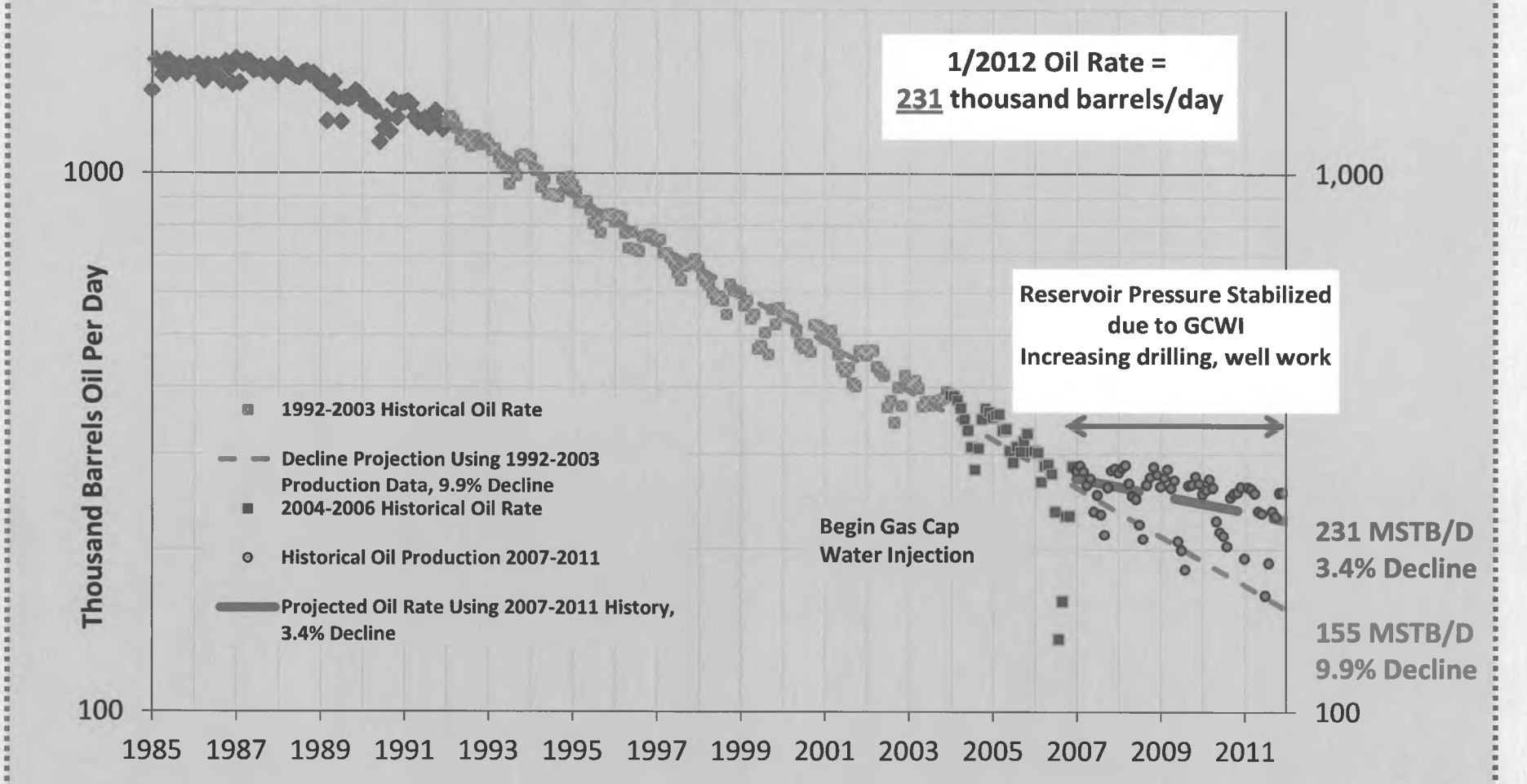


PBU Initial Participating Area



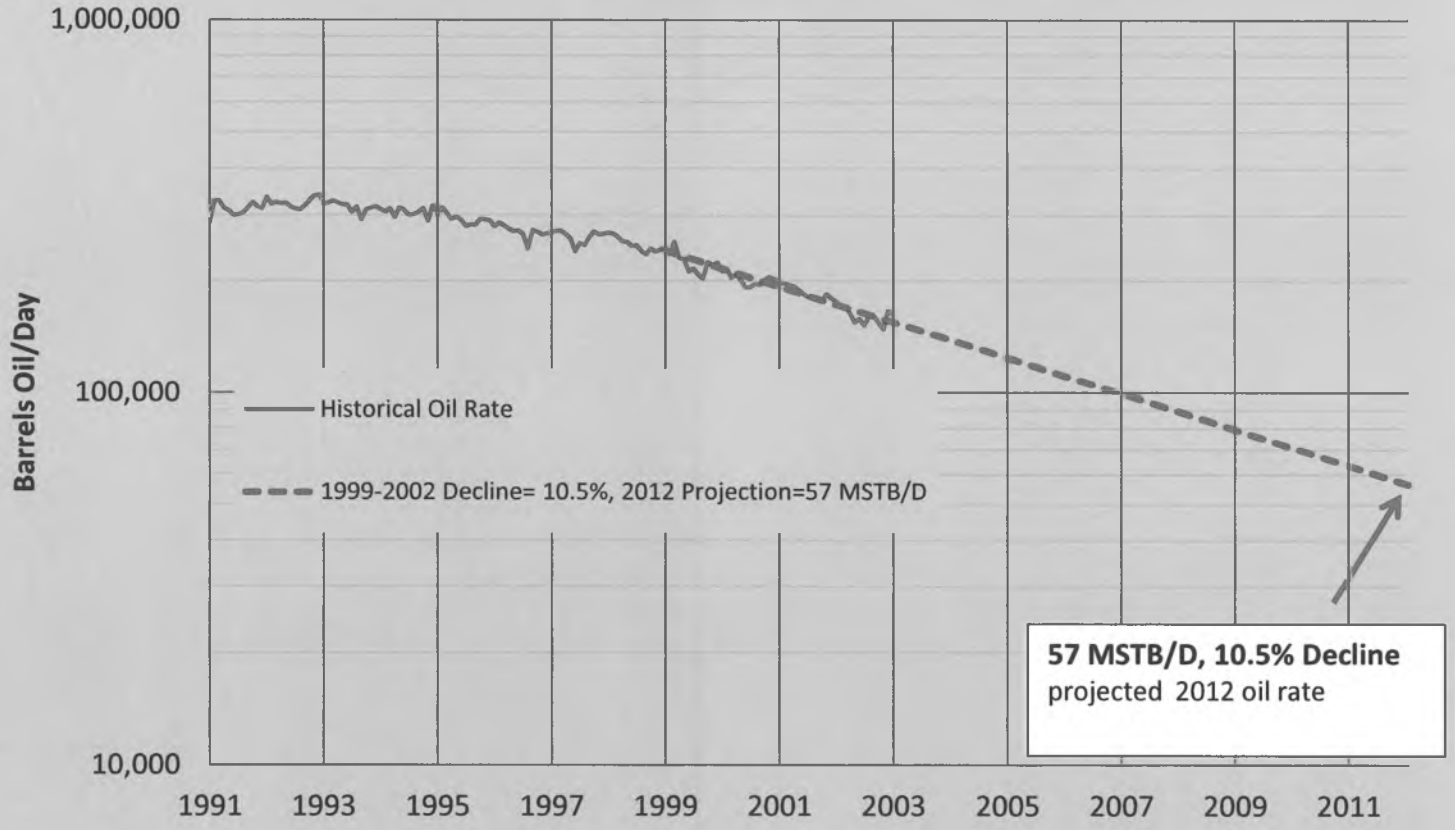
PBU Initial Participating Area

Decline Projection Using 2007-2011 Data
Effect of Gas Cap Water Injection, Drilling, Well Work
Oil Rate increase of +/- 75 thousand barrels/day

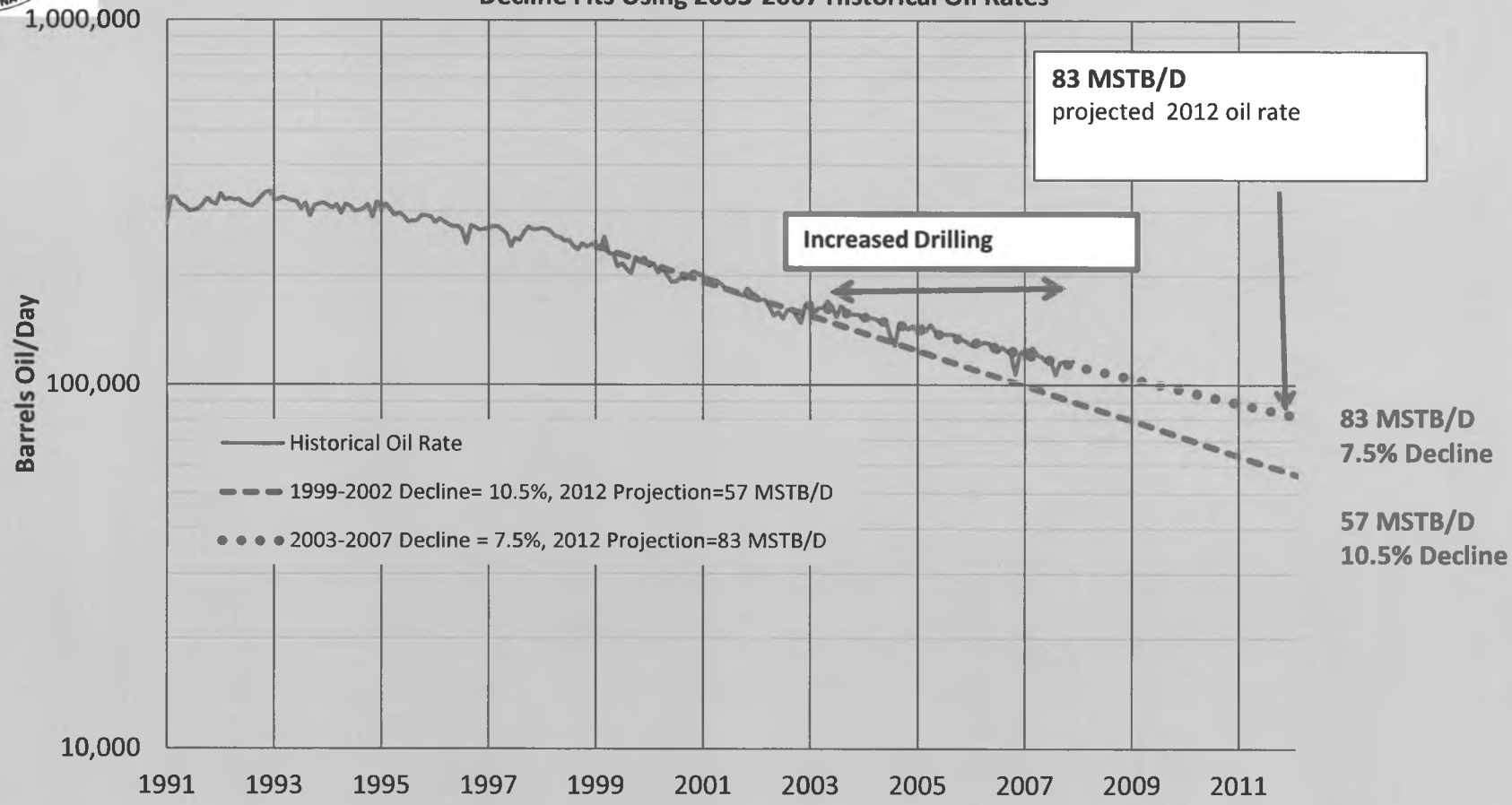


Kuparuk River Unit - Kuparuk Participating Area

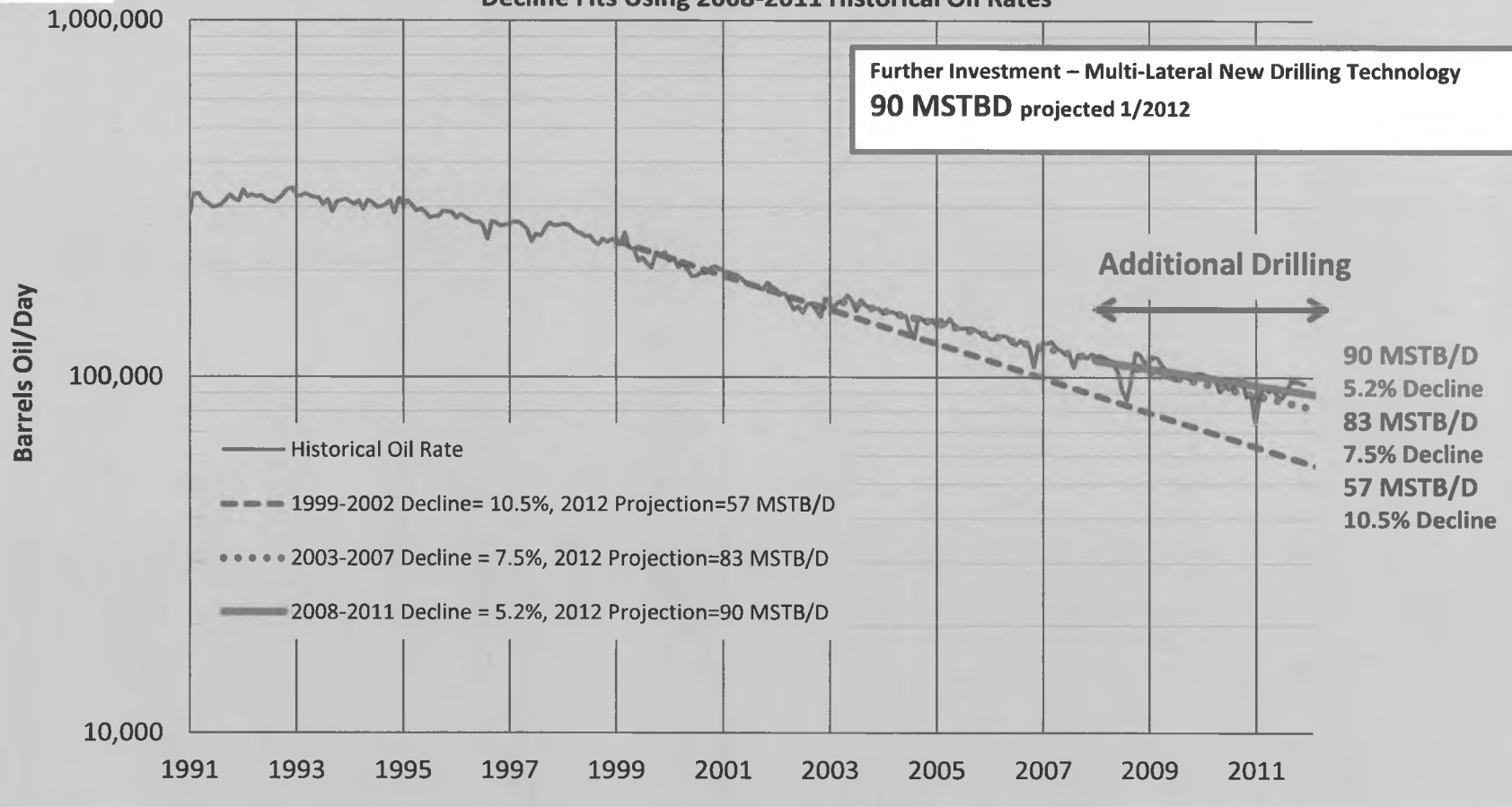
Decline Fits Using 1999-2002 Historical Oil Rates

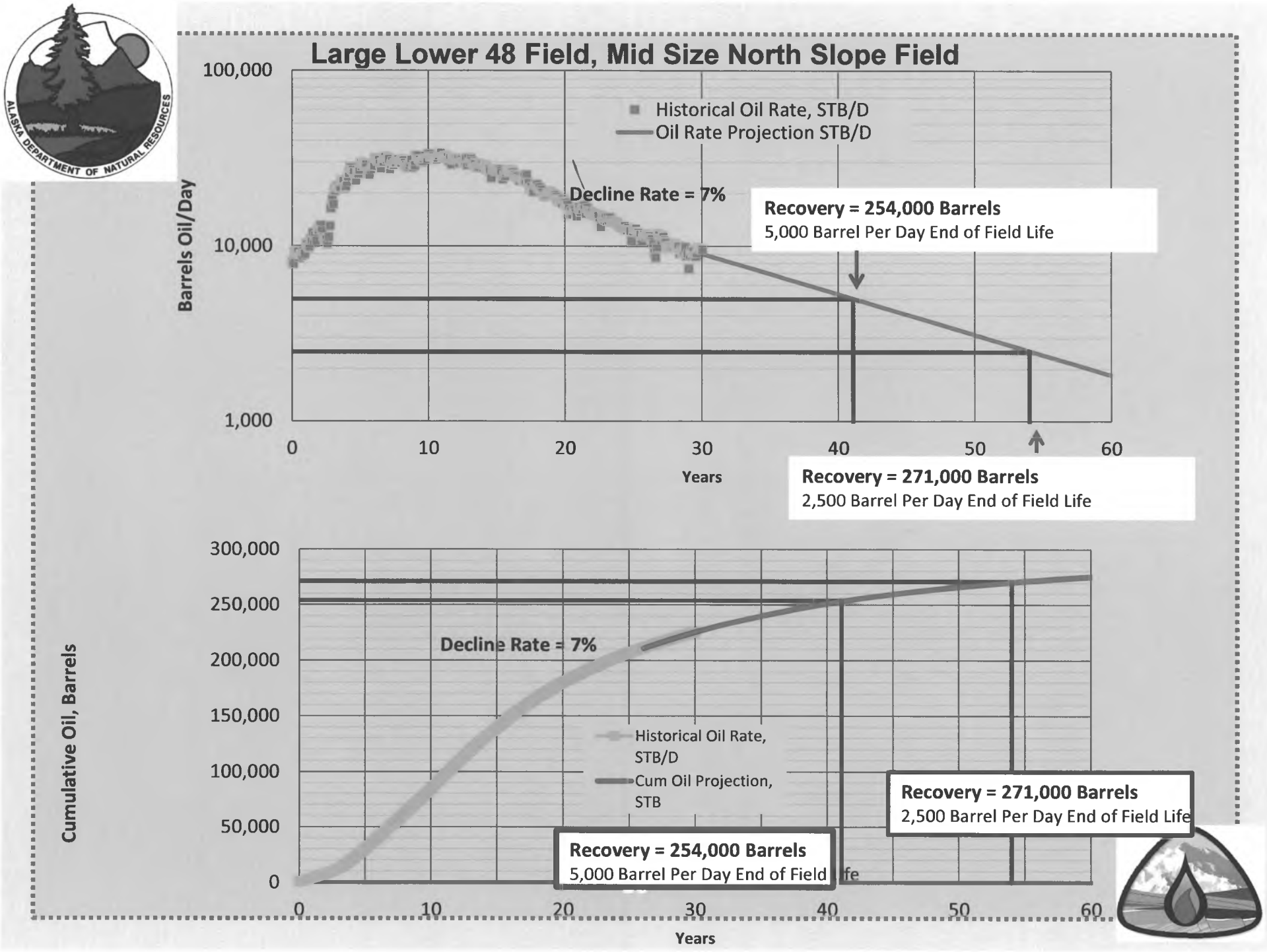


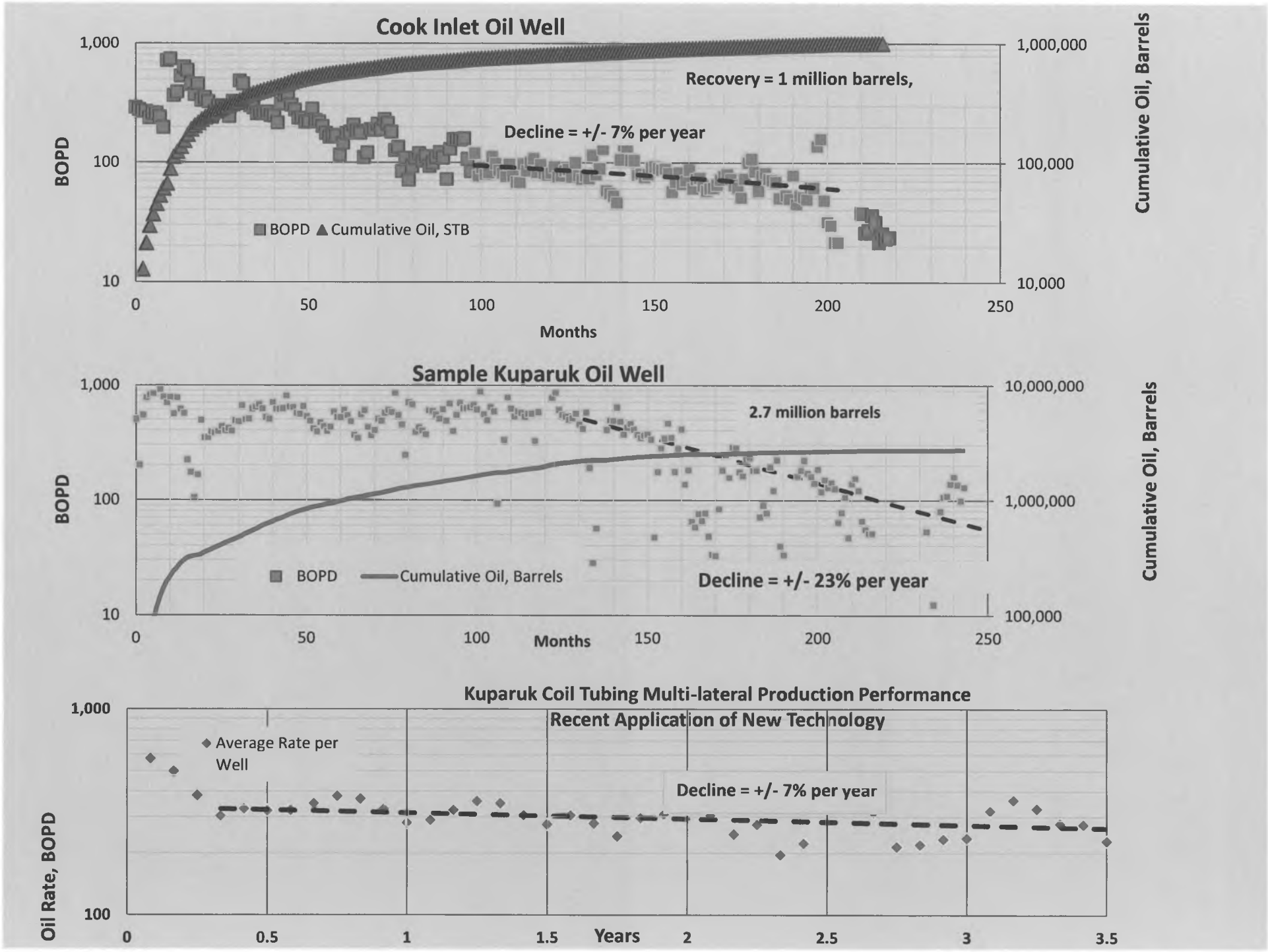
Kuparuk River Unit - Kuparuk Participating Area



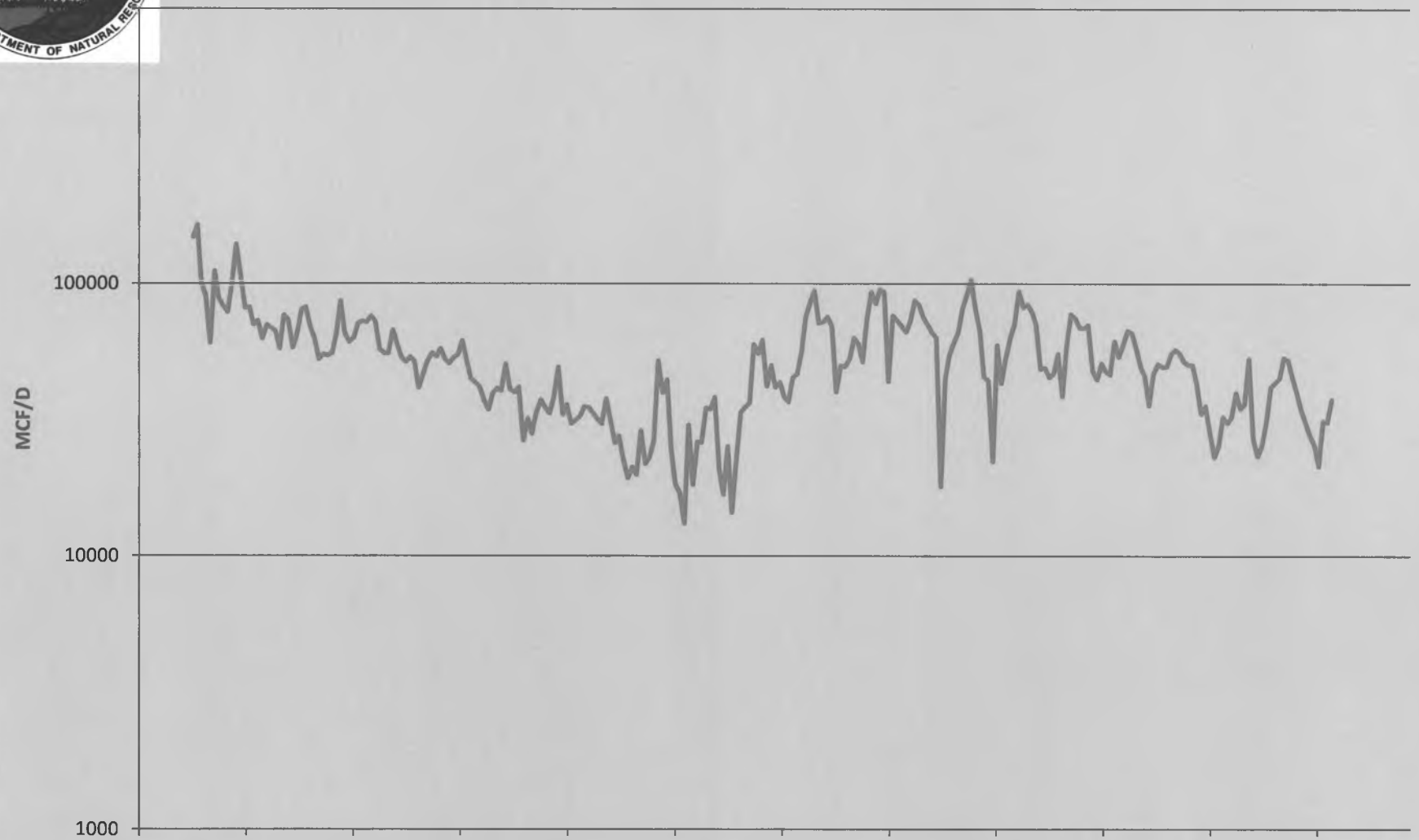
Kuparuk River Unit - Kuparuk Participating Area



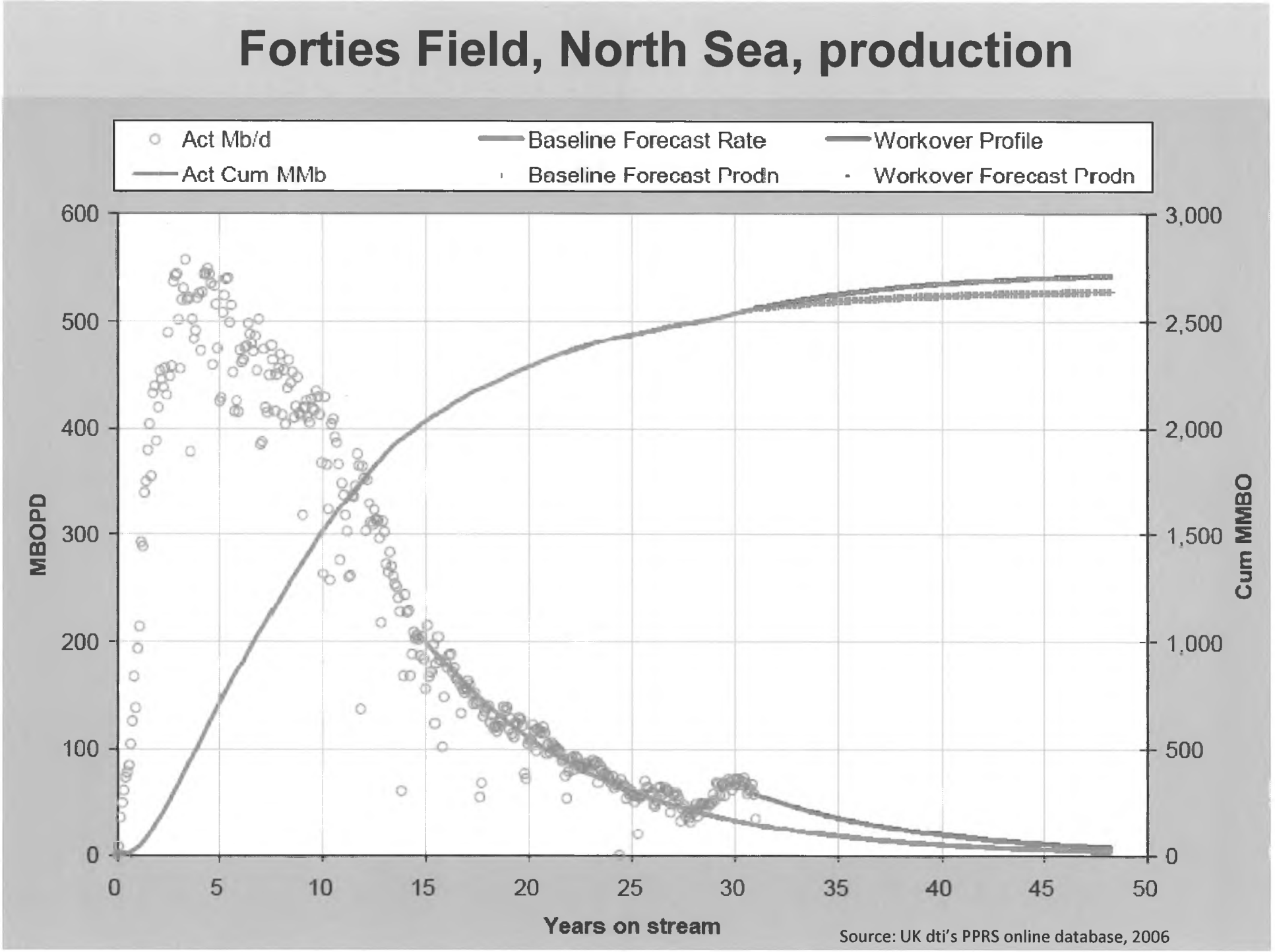

Large Lower 48 Field, Mid Size North Slope Field
100,000
10,000
1,000
Barrels Oil/Day
Historical Oil Rate, STB/D
Oil Rate Projection STB/D
Decline Rate = 7%
Recovery = 254,000 Barrels
5,000 Barrel Per Day End of Field Life
0
10
20
30
40
50
60
Years
Recovery = 271,000 Barrels
2,500 Barrel Per Day End of Field Life
300,000
250,000
200,000
150,000
100,000
50,000
0
Cumulative Oil, Barrels
Decline Rate = 7%
Historical Oil Rate, STB/D
Cum Oil Projection, STB
Recovery = 271,000 Barrels
2,500 Barrel Per Day End of Field Life
Recovery = 254,000 Barrels
5,000 Barrel Per Day End of Field Life
0
10
20
30
40
50
60
Years


Cook Inlet Oil Well
1,000
100
10
BOPD
1,000,000
100,000
10,000
Cumulative Oil, Barrels
Recovery = 1 million barrels,
Decline = +/- 7% per year
BOPD
Cumulative Oil, STB
0
50
100
150
200
250
Months
Sample Kuparuk Oil Well
1,000
100
10
BOPD
10,000,000
1,000,000
100,000
Cumulative Oil, Barrels
2.7 million barrels
BOPD
Cumulative Oil, Barrels
Decline = +/- 23% per year
0
50
100
Months
150
200
250
Kuparuk Coil Tubing Multi-lateral Production Performance
Recent Application of New Technology
1,000
100
Oil Rate, BOPD
Average Rate per Well
Decline = +/- 7% per year
0
0.5
1
1.5
Years
2
2.5
3
3.5

Kenai Gas Field Daily Gas Production in mcf/d



Forties Field, North Sea, production



Source: UK dti's PPRS online database, 2006

What will it take to reach the goal?

- Collaborative and competitive environment
- Minimize all barriers
- Access all fields and all types of oil

Rep Seaton

bp

BP Exploration (Alaska) Inc
PO Box 196612
900 East Benson Boulevard
Anchorage, Alaska 99519-6612

April 27, 2012

Co-Chair Eric Feige
Co-Chair Paul Seaton
House Resource Committee
State Capitol MS3100
Juneau, AK 99801-1182

Dear Co-Chairs Feige and Seaton:

During the House Resource Committee's deliberations on April 25, 2012 regarding HB 3001, Representative Gardner asked whether BP included the $5 billion of incremental growth projects that would progress with meaningful tax change, in our September 2011 submission to support the Department of Revenue (DOR) preparation of the Fall 2011 Revenue Source Book. Please accept this letter as BP's response to the question.

Context
In the DOR's Fall 2011 Revenue Source Book, production data is represented in three categories (see DOR Fall 2011 Revenue Source Book, page 39):

1) Currently Producing: This includes producing fields with ongoing activity/investment with production declining averaging approximately 6%-11%
2) Under Development: This includes various projects at different levels of maturity, and represents a total (Currently Producing plus Under Development) of approximately 4%.
3) Under Evaluation: Includes projects with various challenges to progress; these options, when added to the Currently Producing and the Under Development, manage the total decline rate to approximately 3%.

It is important to note that the DOR creates its own production forecast and only uses producer data as a "sense check", not as direct input. Furthermore, the DOR uses the three categorizations above in support of its own forecasting methodology and producers do not submit data using the same structure however we do discuss the categories with the DOR when we answer their questions regarding our submission.

BP Data Submittal

In BP's September 2011 submission to the DOR, BP included data from two groups of data:

1) Group 1: Our base plan, which forecasts a 6%-8% production decline in the near and mid-term. This is the data set that we use for our own internal business planning purposes and is consistent with slide 9 of BP's testimony before your Committee on April 25, 2012 (see the sum of the blue and green bricks of the 2020 Production bar)
2) Group 2: Our incremental set of opportunities, which are currently economically challenged and require efficiency and technology improvements to progress to sanction, or a change in state production taxes to reduce the efficiency and technology challenges. This production is primarily reflective of the $5 billion of additional opportunities that BP has communicated externally as moving forward with meaningful tax change, as well as a few other options that are less mature and which we would expect to impact production in outer-years. We consider these projects to fall under the DOR's category of "Under Development" or "Under Evaluation". Once again, this is consistent with slide 9 of BP's testimony of April 25 (the mustard brick of the 2020 Production bar).

BP has been pleased to support the DOR's efforts to continuously improve its production forecasting methodology and we remain available to discuss this matter further in the future.

Please let me know if you have any remaining questions or concerns.

Sincerely,

Damian Bilbao
Head of Finance, Developments and Resources

cc: House Resource Committee Members
House Special Committee on Energy Members

Alaska's Budget Outlook

House Resources and Energy Committees

April 25, 2012

Office of Management and Budget

Budget Vision

Governor Parnell's vision

Economic Growth and Strengthening Families

Budget Principles

Guiding principles

- Fiscal Restraint
- Strategic Investments
- Cash Reserves
- Focus on Results

Budget Priorities

Focus on Administration's strategic investment priorities

- Resource Development
- Education
- Public Safety
- Transportation/Infrastructure
- Military Support

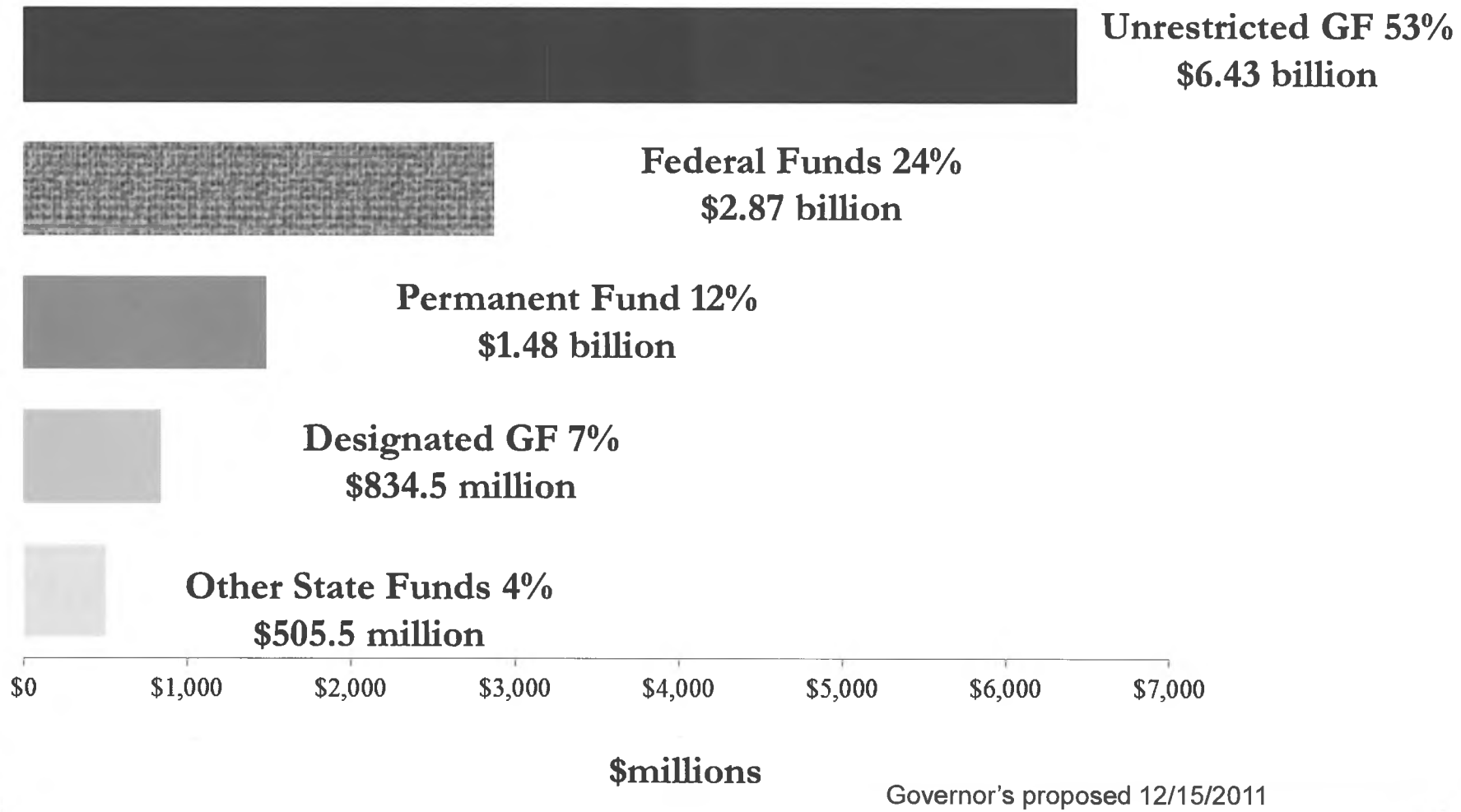
FY2012/2013 Revenue & Savings

Budget Restraint = Surplus

Unrestricted General Funds	FY2012	FY2013
Revenue (FY12 includes $53.6 reapprop./carry forward)	$9,869.9	$8,440.1
Spending	$7,352.1	$7,679.8
Available Balance	$2,516.8	$760.3
Savings (deposits to SBR)	$1,750.0	$250.0
Opportunity for add'l Savings	$766.8	$510.3
Total potential savings		$3,277.1

FY2013 Proposed Budget Sources of Funds

Total FY2013 Proposed Budget $12.1 Billion

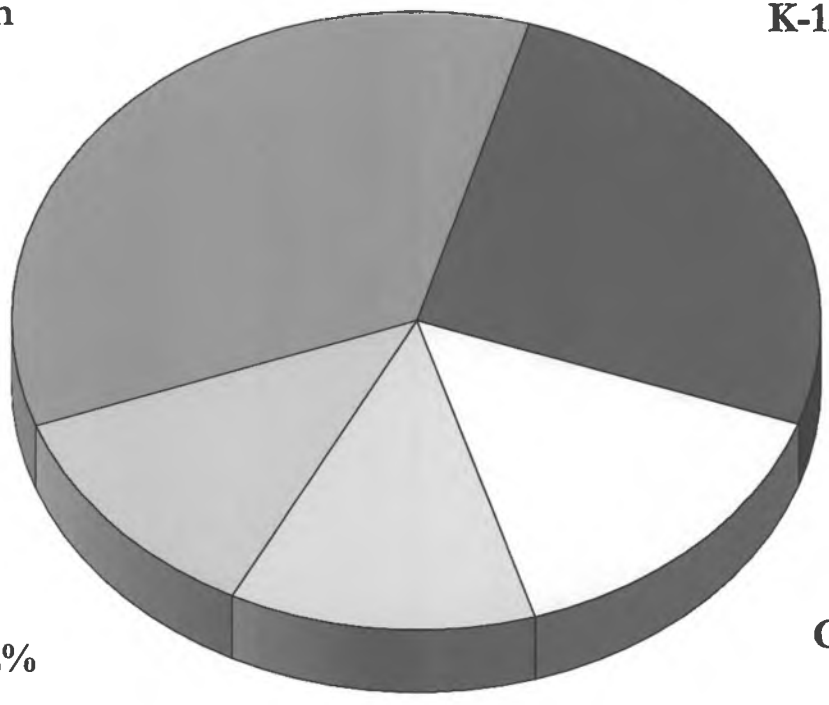


Governor's proposed 12/15/2011

FY2013 Proposed Expenditures by Category

Agency Nonformula 35%
$4.24 Billion

K-12 & Other Formula 26%
$3.13 Billion



Statewide
Appropriations 12%
$1.44 Billion

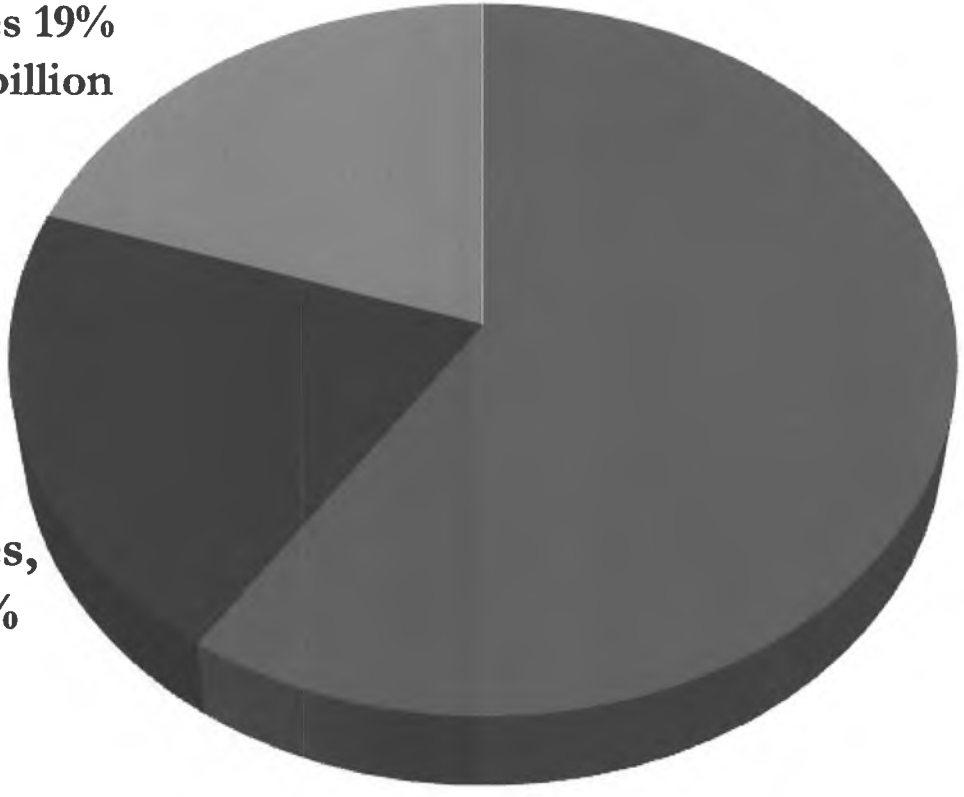
Capital Budget 15%
$1.80 Billion

Permanent Fund 12%
$1.48 Billion

Total Funds = $12,120.6 million

FY2013 Proposed Budget- Another Perspective

60% of Alaska's budget benefits communities, organizations and individuals through grants, direct payments and capital project funding



Includes duplicate funds, savings, investments and the Permanent Fund

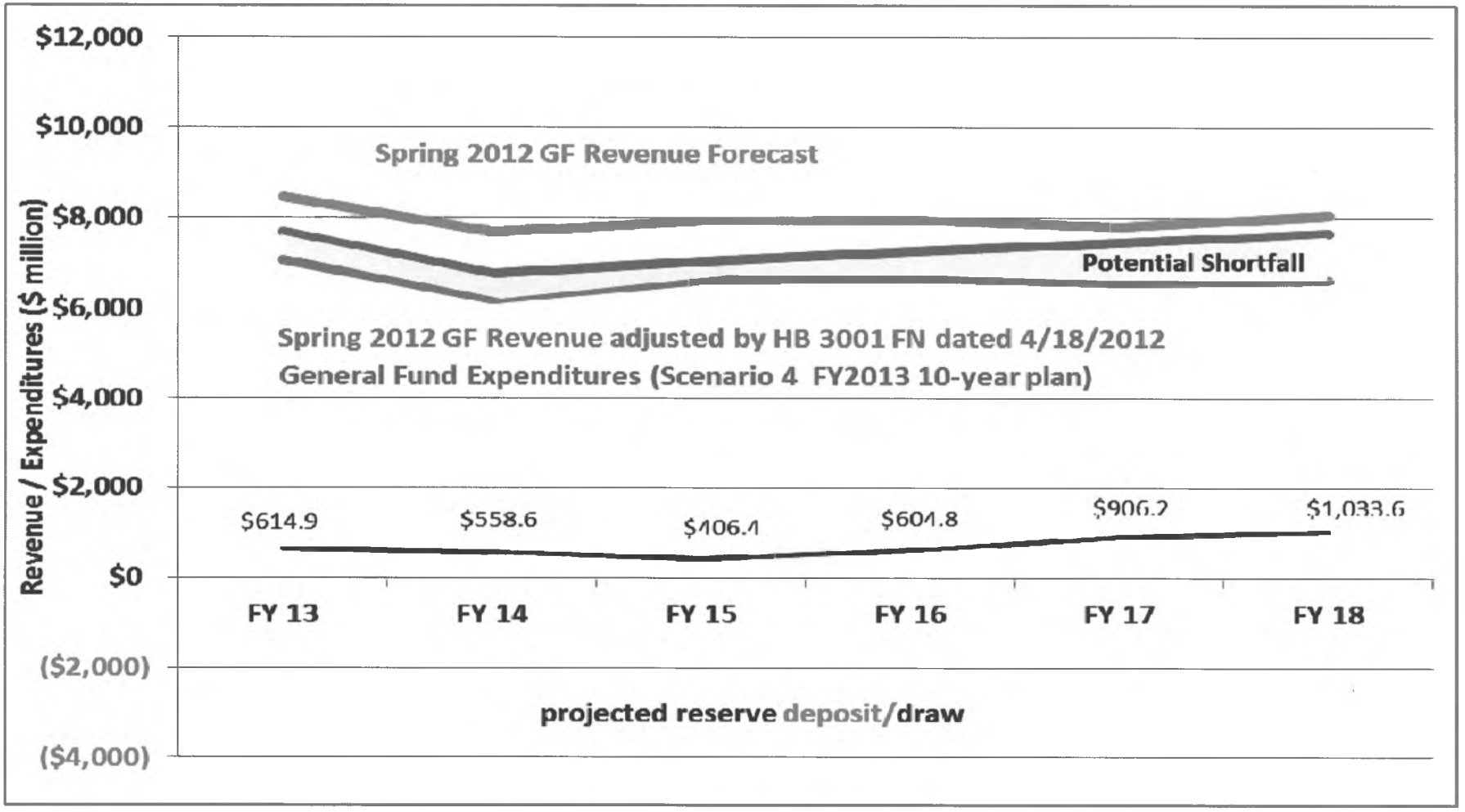
Governor's proposed 12/15/2011

Ten-Year Fiscal Plan

Guiding principles

- Develop Alaska's Natural Resources
- Restrain spending
- Save for future generations of Alaskans

Revenues v Expenditures adjusted for HB 3001



Source: Spring 2012 Revenue forecast. DOR fiscal note dated 4/18/2012. FY2013 10 -year plan Scenario 4 (Governor's FY2013 proposed budget with 4% annual GF expenditure growth, PERS/TRS State Assistance projections and capital capped at $1.0 B GF annually.

Appropriations projections in the plan do not represent a commitment by the Administration to propose spending or generate revenue at a particular level in FY2012, FY2013 or any future year.

Revenues v Expenditures adjusted for HB 3001

Fall 2012 Spring forecast, adjusted for HB 3001 with FY2013 10-year plan expenditures

	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
Forecast Oil Price ($ / bbl.) Spring 2012	**$110.44**	**$109.12**	**$114.53**	**$113.29**	**$111.31**	**$114.16**
(Amounts below in $ Millions)						
Spring 2012 Forecast General Fund Unrestricted	**$8,440**	**$7,680**	**$7,923**	**$7,967**	**$7,807**	**$8,055**
HB 3001 Fiscal Note Adjustments	$1,375	$1,475	$1,300	$1,300	$1,250	$1,425
General Fund Revenues Adjusted for HB 3001	***$7,065***	***$6,205***	***$6,623***	***$6,667***	***$6,557***	***$6,630***
General Fund Expenses	$7,680	$6,764	$7,029	$7,271	$7,463	$7,663
Budget Surplus/(Shortfall)	**$(615)**	**$(559)**	**$(406)**	**$(605)**	**$(906)**	**$(1,034)**
CBRF Total	$11,256	$11,869	$12,518	$13,205	$13,932	$14,702
Statutory Budget Reserve Balance	$4,416	$ 3,855	$3,445	$2,873	$1,928	$891
TOTAL RESERVES	**$15,672**	**$15,724**	**$15,963**	**$16,042**	**$15,860**	**$15,593**

Source: Department of Revenue Spring 2103 Forecast. Dept. of Revenue fiscal note for HB 3001 dated 4/18/2012.

FY2013 10-year plan Scenario 4 (governor's FY13 proposed budget with 4% annual GF expenditure growth , PERS/TRS State Assistance projections and capital capped at $1.0 B GF annually.

Appropriations projections in the plan do not represent a commitment by the Administration to propose spending or generate revenue at a particular level in FY2012, FY2013 or any future year.

For More Information on the Budget

http://www.omb.alaska.gov

Karen J. Rehfeld, Director

Office of Management and Budget

907.465.4660

Karen.Rehfeld@alaska.gov

AOGA

OIL & GAS: FUELING ALASKA'S ECONOMY

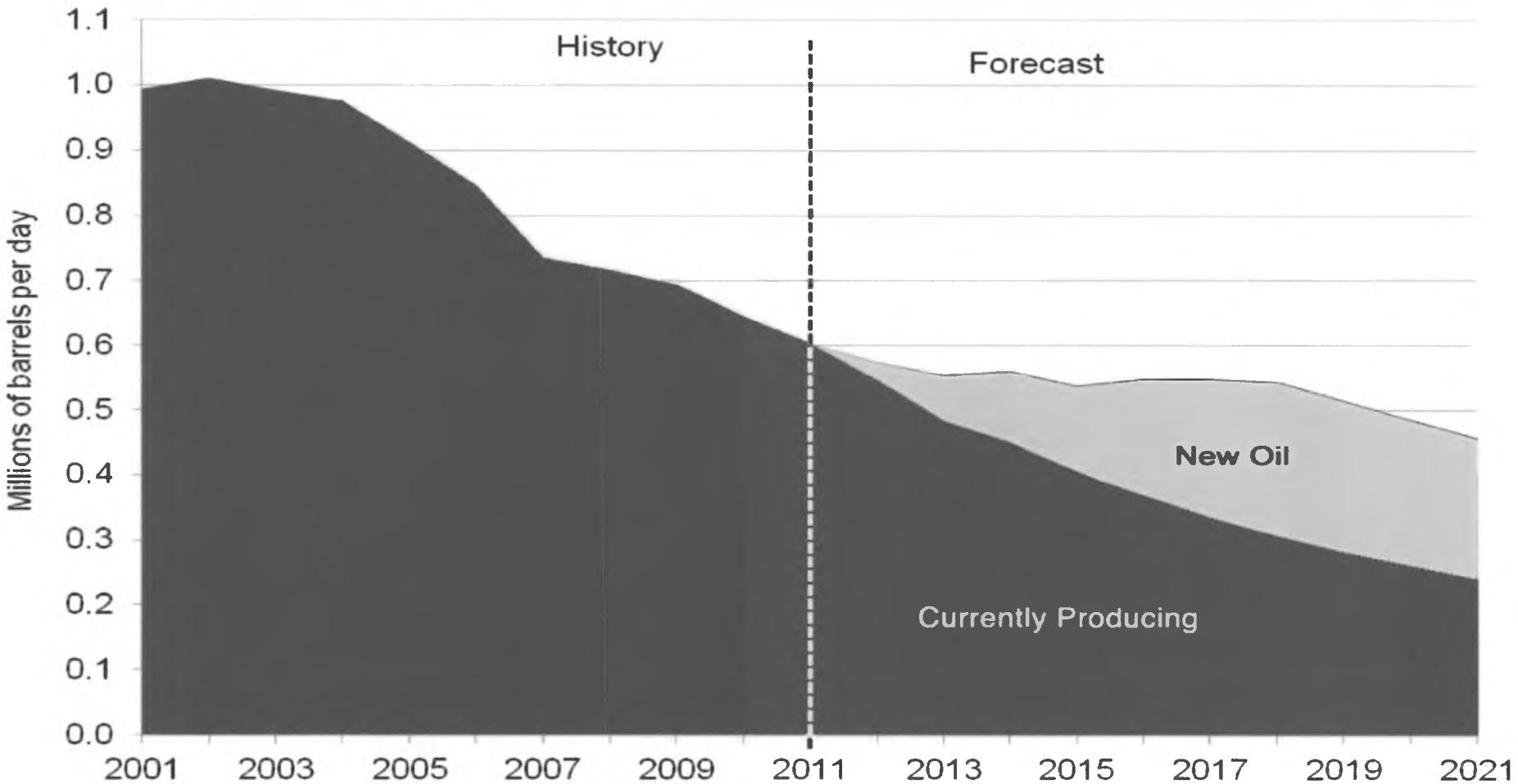
House Resources & Energy Committees

April 25, 2012

Kara Moriarty, Executive Director

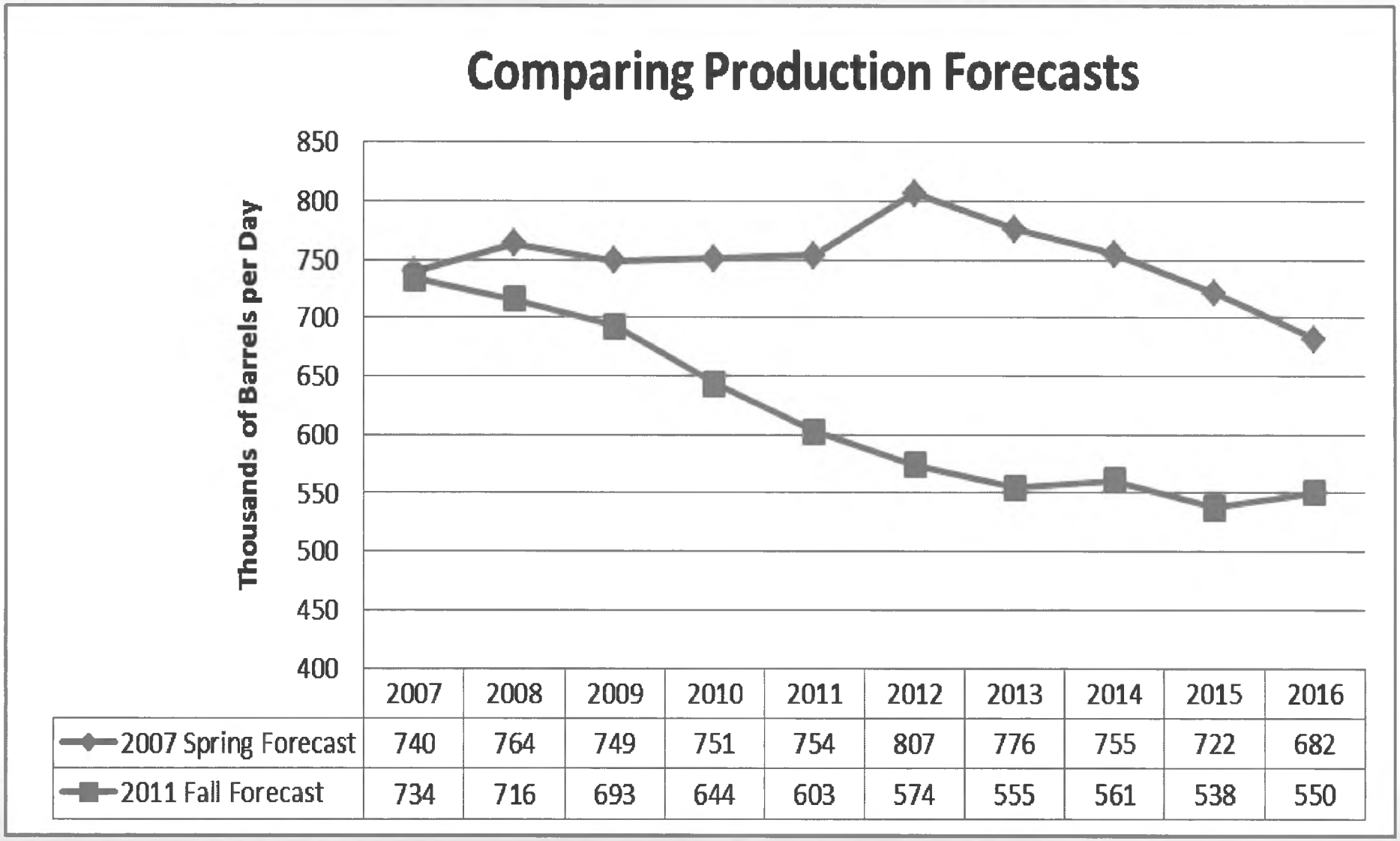
AOGA Member Companies

Production Decline Is Real



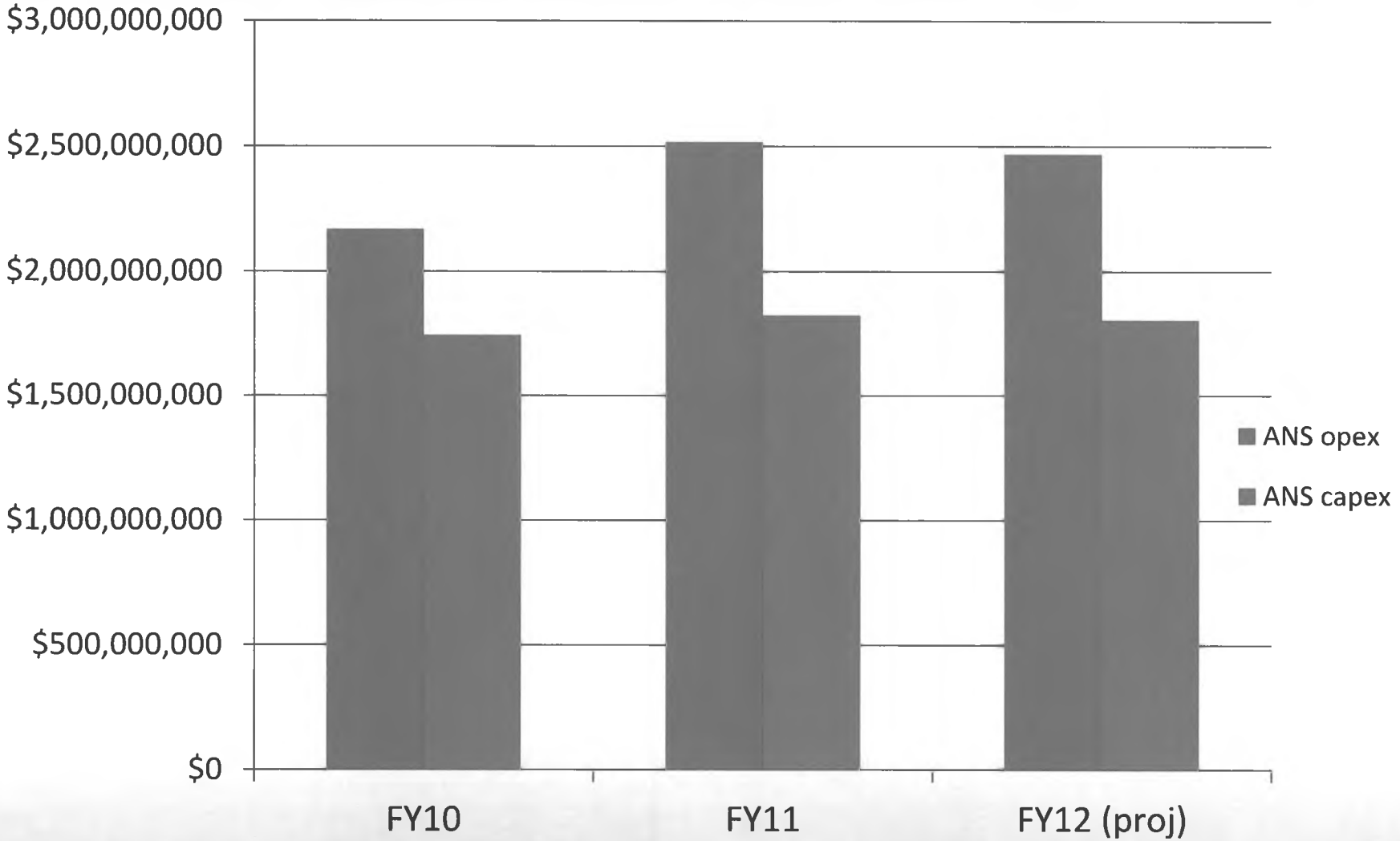
Source: State of Alaska

Forecast in 2007 vs. 2011 Actual Production



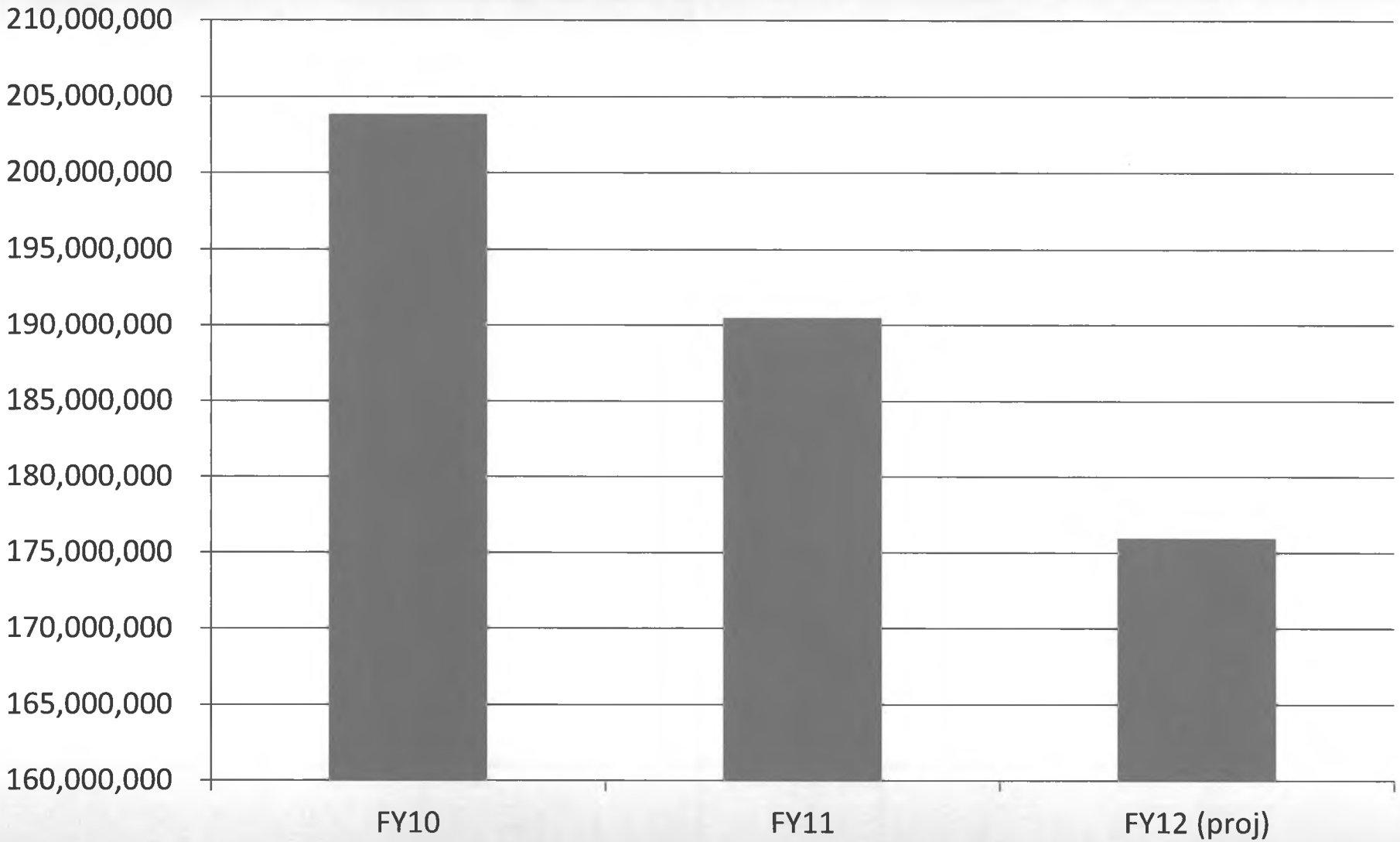
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
2007 Spring Forecast	740	764	749	751	754	807	776	755	722	682
2011 Fall Forecast	734	716	693	644	603	574	555	561	538	550

Current Industry Investment



Source: Department of Revenue

Current Industry Investment = Declining Production



Total Taxable ANS Production – Source: Department of Revenue

Rich In Resources

RESOURCE POTENTIAL	
STATE LAND	**FEDERAL LAND**
Cook Inlet 599 mbo and 19 tcf gas	**Offshore Arctic** 27 bbo and 132 tcf gas
Onshore North Slope Conventional: 5 bbo and 35 tcf gas Heavy/Viscous: 24-33 bbo Unconventional: 2 bbo and 80 tcf gas	**NPR-A** 896 mbo and 53 tcf gas **ANWR** 10 bbo and 3.5 tcf gas

mbo – million barrels of oil bbo – billion barrels of oil tcf – trillion cubic feet

Alaska's Future is Under Our Feet

ExxonMobil Production Company
P. O. Box 196601
Anchorage, Alaska 99519-6601
907 561 5331 Telephone
907 564 3677 Facsimile

Dale Pittman
Alaska Production Manager
Joint Interest U.S.

ExxonMobil
Production

April 25, 2012

The Honorable Representative Paul Seaton
The Honorable Representative Eric Feige
Co-Chairmen, House Resources Committee
State Capitol Building, Room 124
Juneau, Alaska 99801-1182

Dear Representatives Seaton and Feige:

Thank you for the invitation to testify before the House Resources Committee on HB 3001 and on the need for meaningful reform to Alaska's high production tax structure and please accept my apologies as work commitments do not allow me to appear in person to provide ExxonMobil's views on these important topics. I am grateful for the time we spent together yesterday discussing these issues.

ExxonMobil appreciates the careful examination by your committee and other committees within both bodies of the Legislature on these critical issues to ensure the appropriate balance between the level of government take and encouraging an active, healthy oil and gas industry in Alaska.

Simply put, Alaska's production tax is too high to attract the additional investment necessary to fully develop Alaska's oil and gas resources in the decades ahead. It is essential that Alaska develop a tax structure that will encourage long-term, material development of all of Alaska's resource potential to support State revenues, secure jobs and stem production decline. Meaningful tax reform like that proposed in HB 3001 is an important and necessary first step to achieving that goal.

HB 3001 is a substantial improvement to Alaska's current production tax as it provides significant reform across all levels of production, both new fields and resource development opportunities in existing fields. Alaska needs new production from all fields, not just new developments, but also from existing fields which represent the only known resources capable of stemming Alaska's production decline.

Alaska is currently producing approximately 600,000 barrels of oil per day from the North Slope. Industry currently invests more than $1 billion per year just to maintain current North Slope oil production decline at six to seven percent and without that continued investment, the annual production decline would be in the range of 12 to 15 percent annually. While economic investments in existing fields will continue, the number of economic opportunities decreases with each successive year.

Without meaningful tax reform that includes the legacy fields, Alaska should expect to continue at, or likely below, the Department of Revenue's production forecasts.

Production from the legacy fields not only provides the core of the State's revenues, it sustains the current North Slope infrastructure and the operation of TAPS. The legacy field production and these assets are essential to allow the producers of the existing non-legacy fields on the North Slope, and the developers of any new fields that may be discovered, to economically process and transport their oil from the North Slope to refinery destinations. Without healthy legacy fields, the prospects of any future new fields or developments become even more economically challenged and the probability of Alaska reaching its desired goal of long-term sustained production levels more difficult.

HB 3001, as proposed, will begin to address this critical issue. The proposed enhanced in-fill drilling tax credits and reduction to the progressivity tax would encourage additional drilling and well work activity in legacy fields such as the Prudhoe Bay Unit. This kind of developmental drilling in the core field on the North Slope is critical to Alaska's future, particularly over the next five to ten years. Production decline must be stemmed until new developments can be discovered, progressed and brought on production.

Considerable attention has been placed on making Alaska more competitive relative to other taxing regimes and while that focus is extremely important, it is only part of the overall examination that needs to be undertaken. Benchmarking government take against other areas is a useful tool for gauging basic competitiveness, but that analysis alone does not provide the full picture of investment health. Another key indicator is whether investment in new production activities is growing. That growth is not occurring in Alaska.

As your consultants and the Department of Revenue have testified, spending on the North Slope has remained relatively flat since the enactment of ACES. But what needs to be clarified is that the majority of that investment has not been for new exploration and development opportunities that would bring new production. It is also worth noting that costs for this investment activity have gone up, so while some may argue there has been additional investment, it does not necessarily translate into more activity.

At today's oil prices, fiscal policy that encourages investment should result in near record levels of activity, yet that is not happening in Alaska. Under ACES, the State is not attracting the necessary investment to increase production. Without meaningful reform, Alaska's fiscal regime will prevent the State from attracting the necessary investments to enable Alaska to reach its goal of significantly increasing oil production.

ExxonMobil continues to support Governor Parnell's and the Legislature's efforts toward substantive tax reform and we believe the Governor's HB 3001 provides meaningful change. While Alaska's fiscal regime will still remain one of the highest progressive tax structures in the world if HB 3001 is enacted in its current form, it is ExxonMobil's firm belief that investment activity in Alaska will significantly increase, leading to greater development, increased production and reliable, long term state revenues. Although ExxonMobil does not currently operate production in the state, we fully support both of our operators, ConocoPhillips at Kuparuk and BP at Prudhoe Bay in their continued commitment to invest in Alaska and to pursue all additional investments that become viable with meaningful tax reform such as that proposed in HB 3001.

The need for Alaska to develop a competitive fiscal regime to attract the levels of investments that the North Slope requires is one of the most important issues facing the State's economic future. ExxonMobil remains hopeful that the dialogue in your Committee and with the entire Legislature for needed, meaningful tax reform will continue and will ultimately lead to the development of a competitive fiscal regime to support the full development of the State's vast oil resources.

Thank you again for the opportunity to provide ExxonMobil's input on HB 3001 and the need for meaningful tax reform.

Sincerely,

DDP:jpc

xc: Governor Sean Parnell
Members of the House Resources Committee
Members of the House Energy Committee

Joint
House Resources Committee
House Energy Committee

Testimony re: HB 3001

April 25, 2012

NYSE: PXD

www.pxd.com

Pioneer Natural Resources, Alaska

Forward Looking Statements

PIONEER
NATURAL RESOURCES

Except for historical information contained herein, the statements, charts and graphs in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, international operations and associated international political and economic instability, litigation, the costs and results of drilling and operations, availability of equipment, services and personnel required to complete the Company's operating activities, access to and availability of transportation, processing and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, and acts of war or terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Pioneer undertakes no duty to publicly update these statements except as required by law.

Pioneer Alaska Profile

PIONEER
NATURAL RESOURCES

Overview:

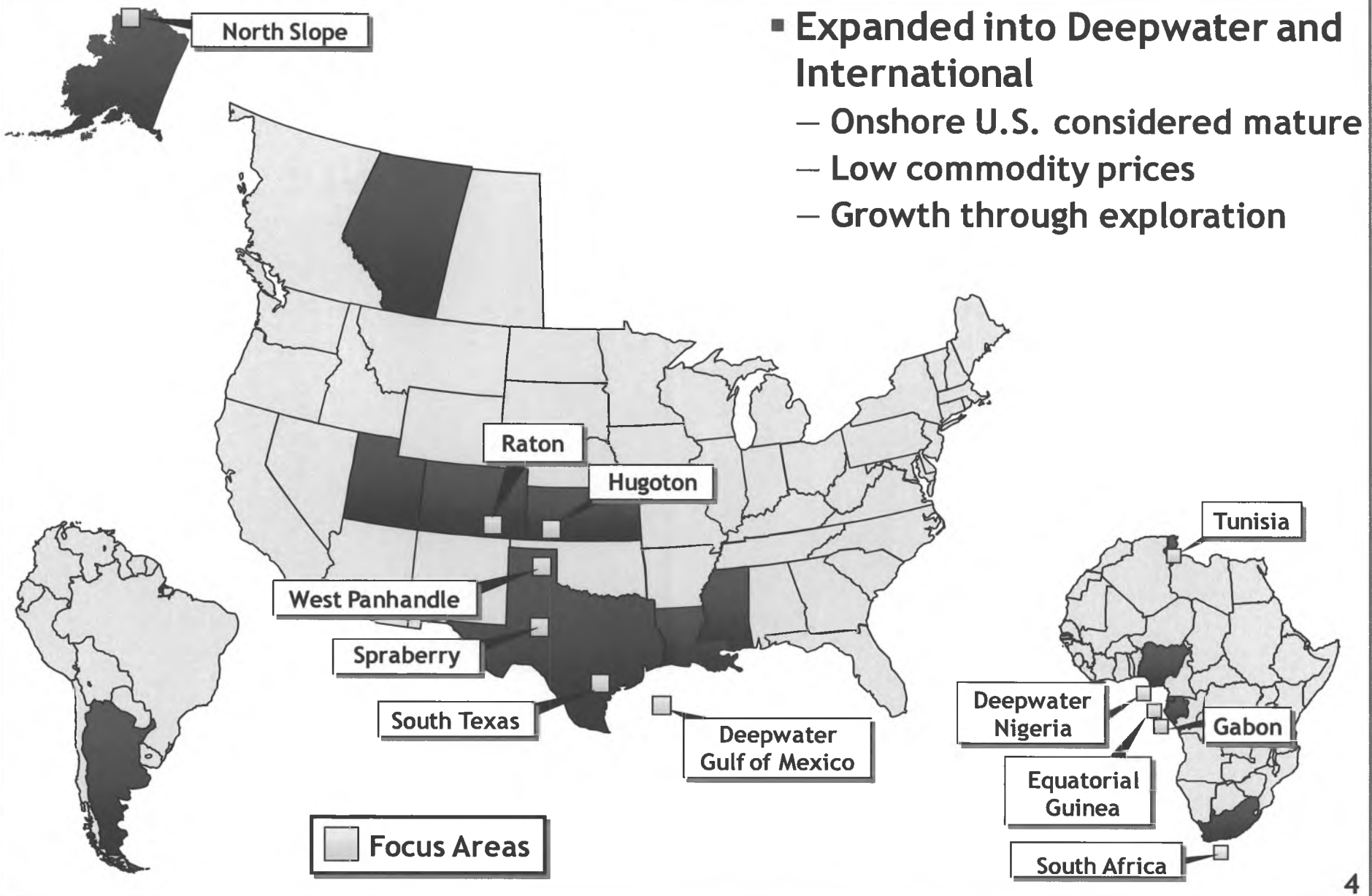
- Anchorage HQ
- 70 + full-time AK employees
- ~120 AK contract workers
- 1st independent operator on NS

Oooguruk Quick Facts:

- IOGCC Award winning project
- 70% Pioneer (operator) / 30% Eni
- 120-150MMBO resource potential (net)
- 2011 Production ~6,900BOPD (gross)
- ~$1B capital investment (project)

Pioneer: 1997 - 2005 Deepwater / International Focus

PIONEER NATURAL RESOURCES



- Expanded into Deepwater and International
  - Onshore U.S. considered mature
  - Low commodity prices
  - Growth through exploration

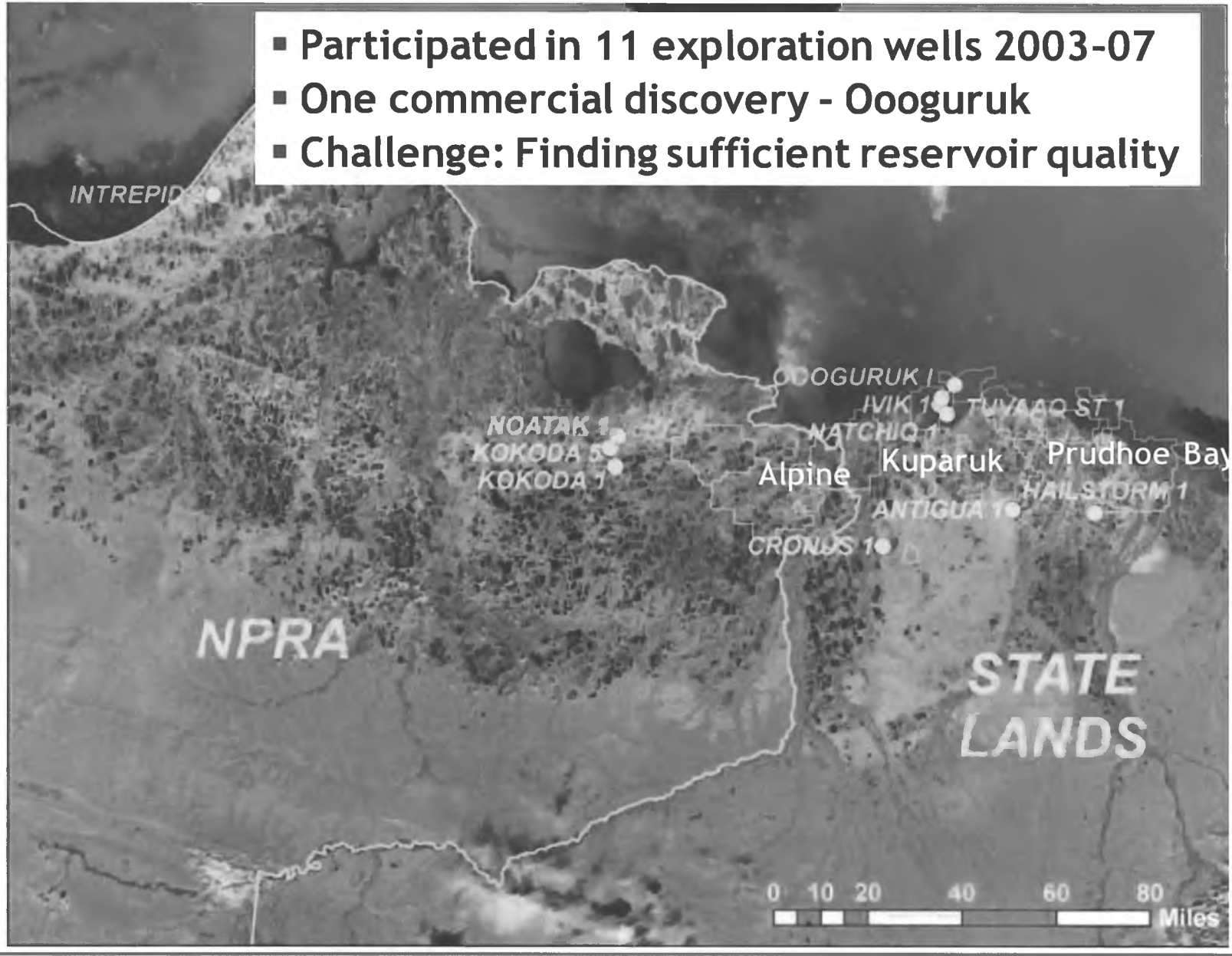
Why Alaska in 2002?

PIONEER
NATURAL RESOURCES

- **Worldwide exploration focus**
- **Alaska - large, oil resource potential in the U.S.**
- **Limited competition for resources**
- **State actively courting independents**
  - Exploration credits, low severance tax (ELF)
  - Available acreage at a low cost
- **Independent mindset**
  - Quick decision making
  - Lower cost structure

North Slope Exploration History

PIONEER NATURAL RESOURCES



Alaska's Severance Tax

PIONEER
NATURAL RESOURCES

- **Pre 2007: ELF (Oooguruk project sanction)**
  - Low rate fields - no severance tax
  - Exploration Credits introduced (2003)
- **2007: PPT (Oooguruk construction)**
  - Additional credits and deductions introduced
  - 22.5% net profits tax
  - Moderate progressivity
- **2008: ACES (Oooguruk first production)**
  - Credits and deductions rate adjustments
  - 25% base tax rate
  - Aggressive progressivity (not indexed)
  - Maximum tax rate of 75%

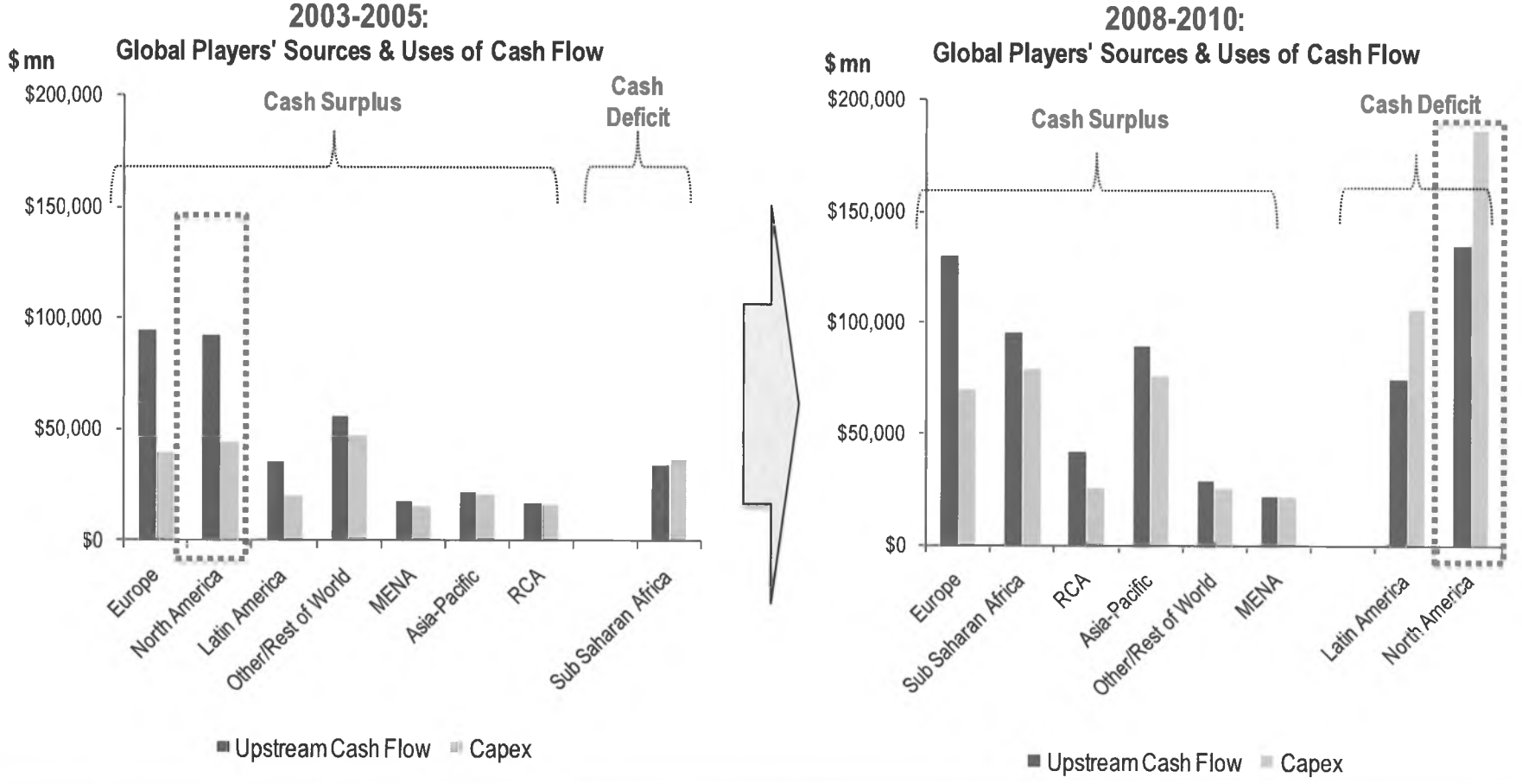
8 Years Later - What Else Has Changed?

PIONEER NATURAL RESOURCES

- **Oil and gas prices**
- **Technology**
  - Horizontal well improvements
  - Fracture stimulation technology
- **Result has been a boom in resource play development in North America**

Fixed-Royalty Jurisdictions in US Lower 48 Are A Key Competitor to Alaska for Investment Dollars

PIONEER NATURAL RESOURCES

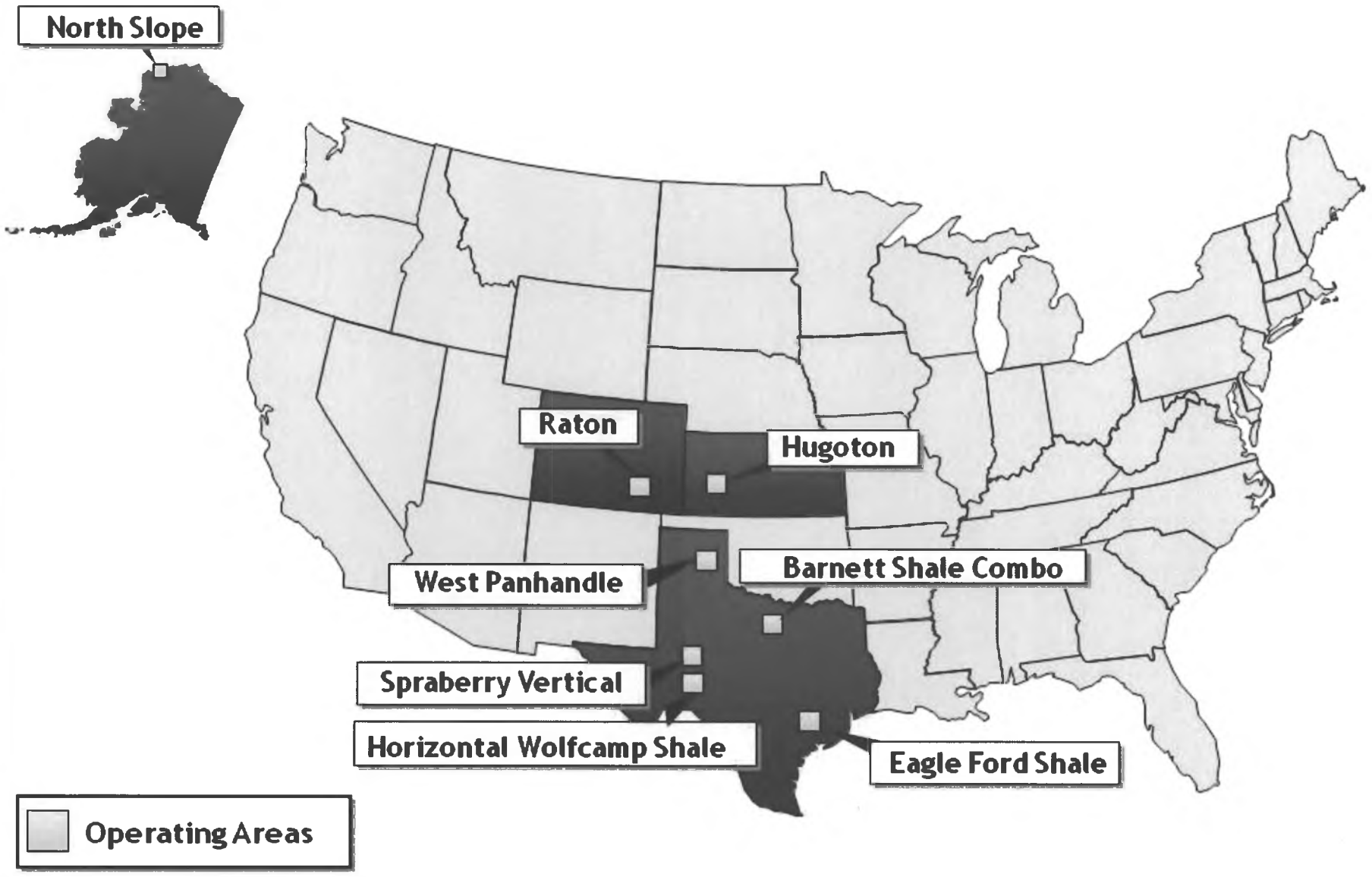


It is now an exception <u>not</u> to be targeting unconventionals in North America as a major growth platform.

* Source: PFC Energy

Current Pioneer Operations Footprint

PIONEER
NATURAL RESOURCES

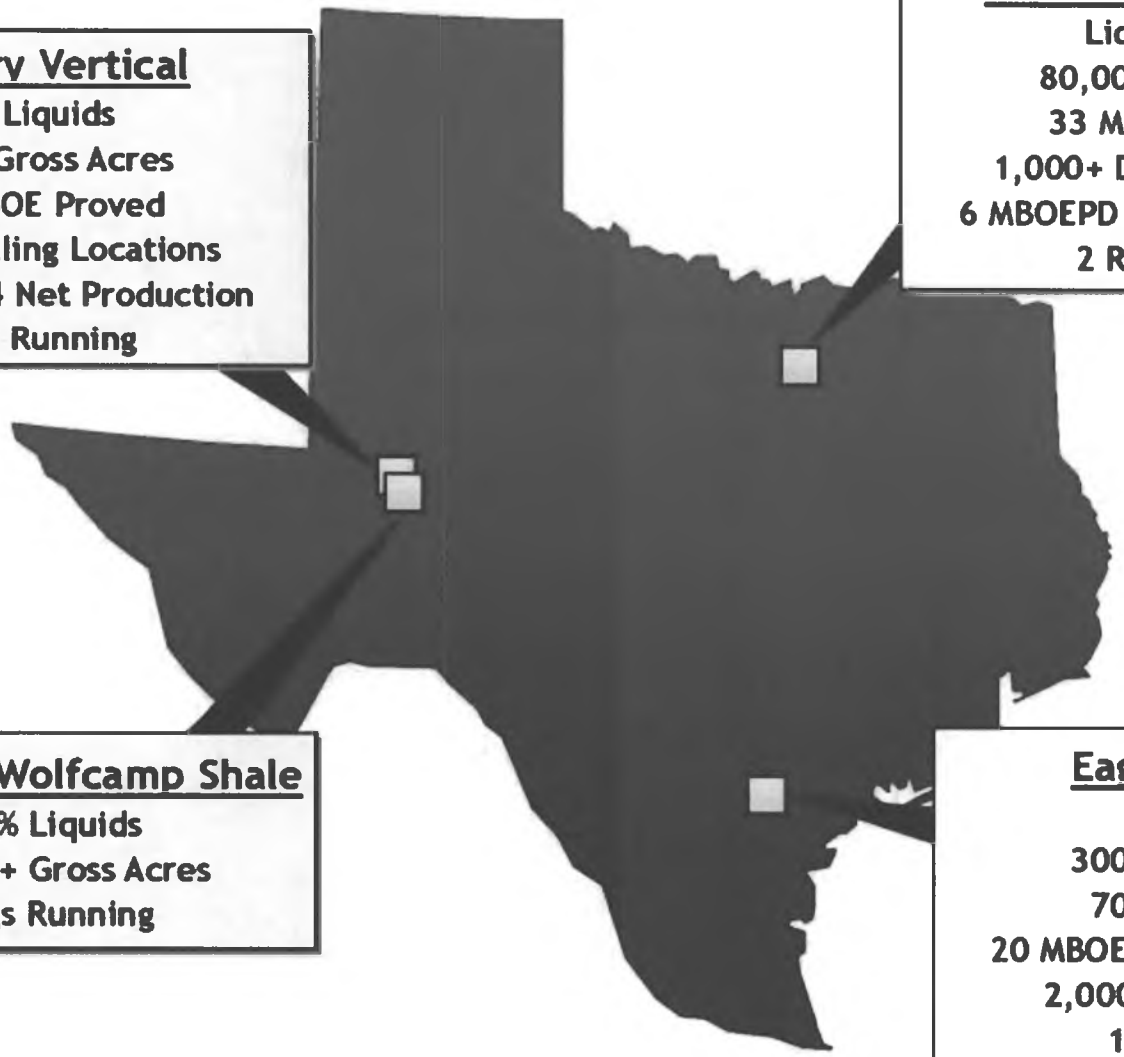


Major Focus Areas

PIONEER NATURAL RESOURCES

Spraberry Vertical
~90% Liquids
900,000 Gross Acres
609 MMBOE Proved
20,000+ Drilling Locations
53 MBOEPD Q4 Net Production
41 Rigs Running

Barnett Shale Combo
Liquids & Gas
80,000 Gross Acres
33 MMBOE Proved
1,000+ Drilling Locations
6 MBOEPD Q4 Net Production
2 Rigs Running

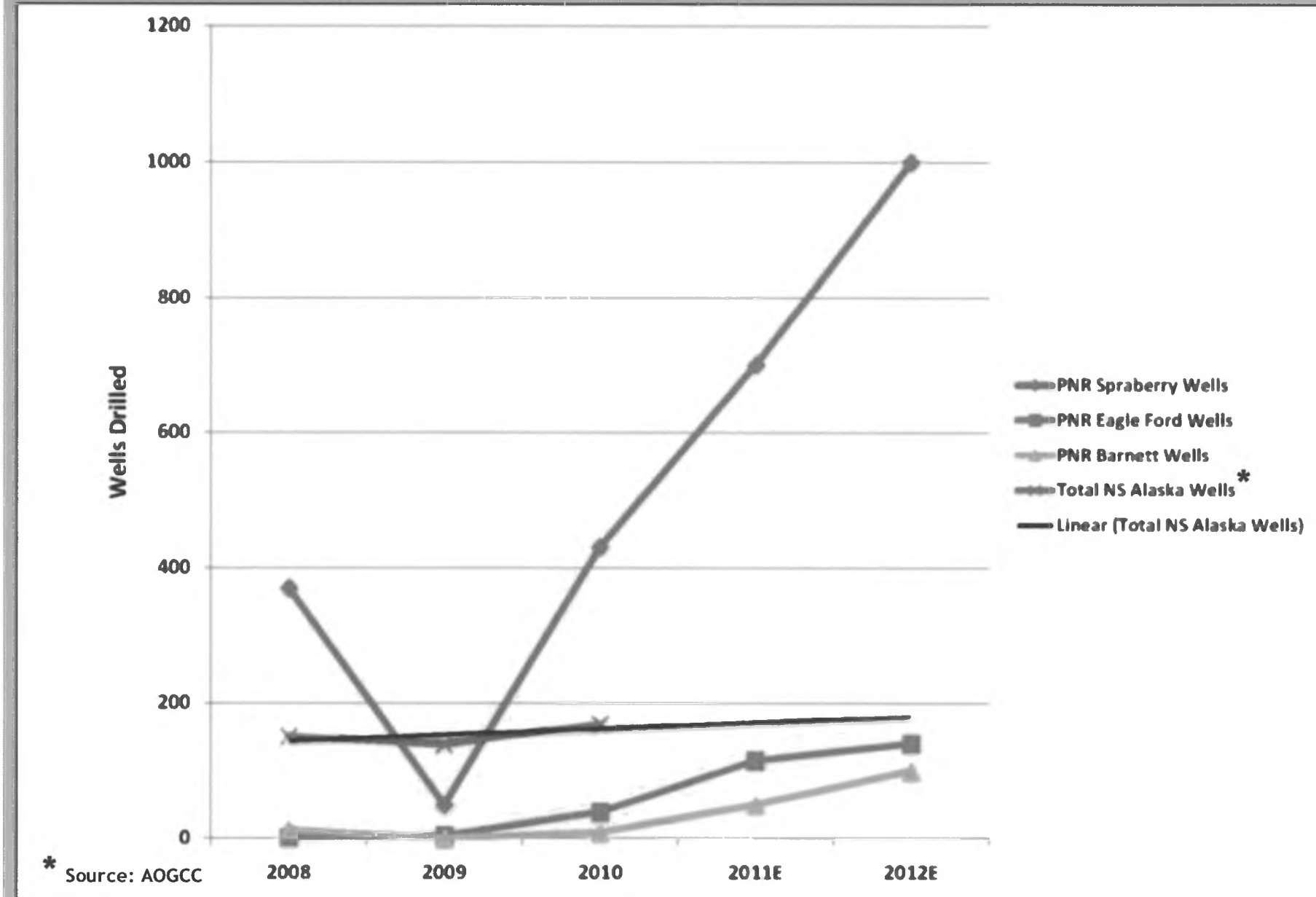


Horizontal Wolfcamp Shale
~90% Liquids
400,000+ Gross Acres
3 Rigs Running

Eagle Ford Shale
Liquids & Gas
300,000 Gross Acres
70 MMBOE Proved
20 MBOEPD Q4 Net Production
2,000 Drilling Locations
12 Rigs Running

Competition for Capital

PIONEER NATURAL RESOURCES



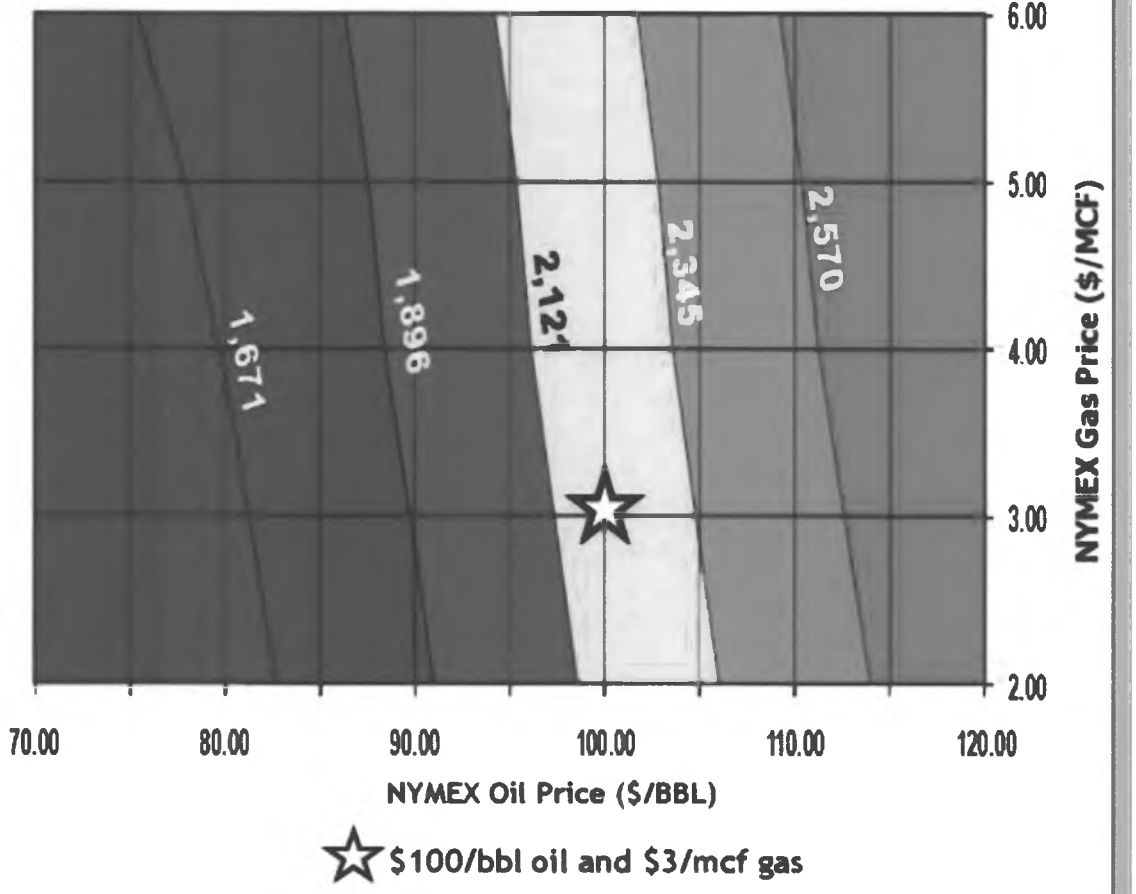
* Source: AOGCC

2012E Capital Spending and Cash Flow[1]

PIONEER NATURAL RESOURCES

- **Capital program includes:**
  - Drilling capital: $2.4 B
    - $1,525 MM Spraberry Vertical
      - Includes $100 MM for infrastructure
    - $275 MM Horizontal Wolfcamp Shale
      - Includes $25 MM for seismic and coring
    - $130 MM Eagle Ford Shale (net of carry)
    - $215 MM Barnett Shale Combo
    - $135 MM Alaska
    - $120 MM Other (includes land capital for existing assets)
  - Vertical integration and facilities: $0.4 B
    - $300 MM sand mine
    - $100 MM pressure pumping and well service equipment
- **Capital program funded from:**
  - Operating cash flow of $2.2 B
  - Equity offering proceeds of $0.5 B
  - Inventory reduction of $0.1 B

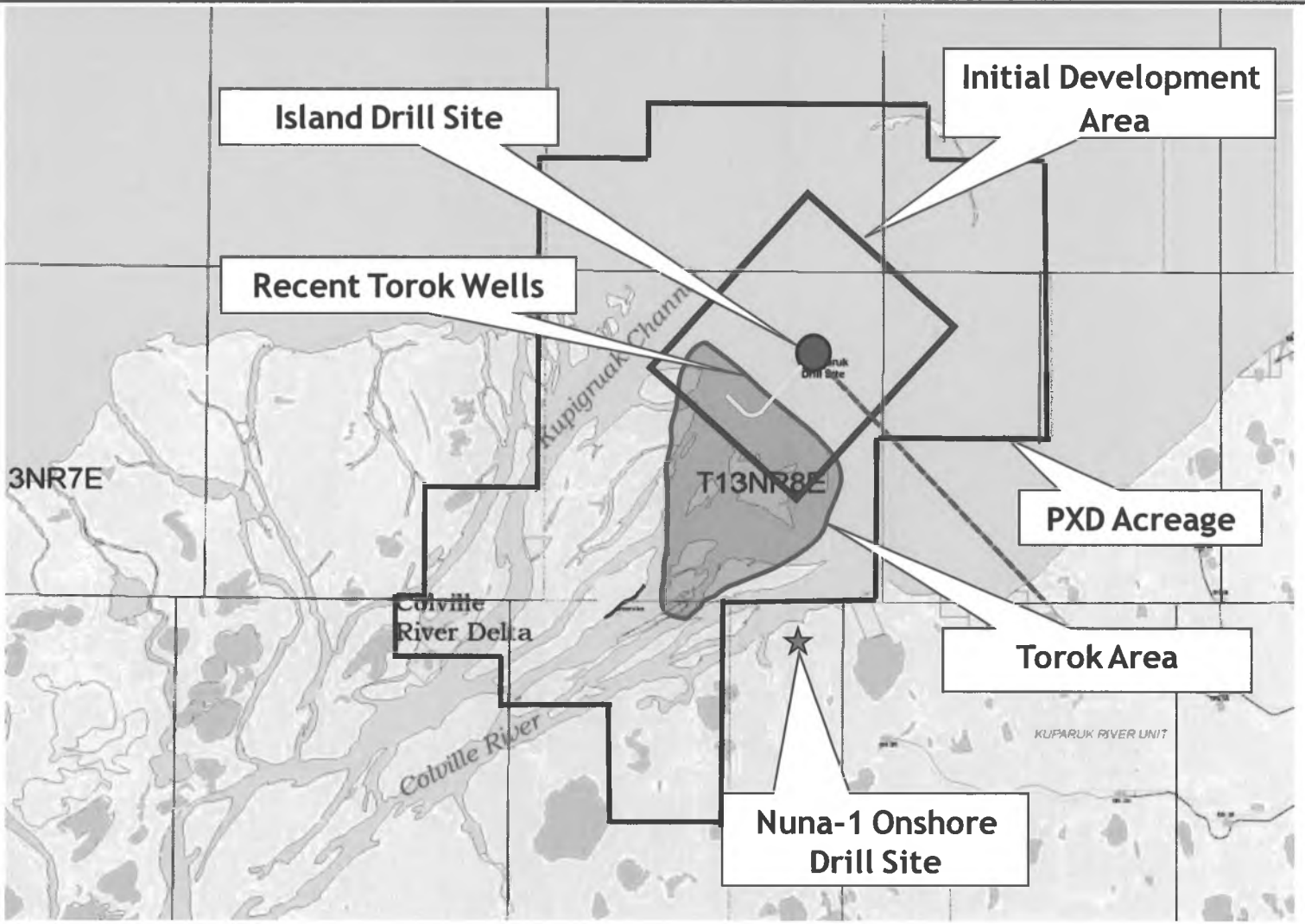
Sensitivity to Commodity Prices ($ MM)



1) Capital spending excludes acquisitions, asset retirement obligations, capitalized interest and G&G G&A

What's Next? Oooguruk potential

PIONEER
NATURAL RESOURCES

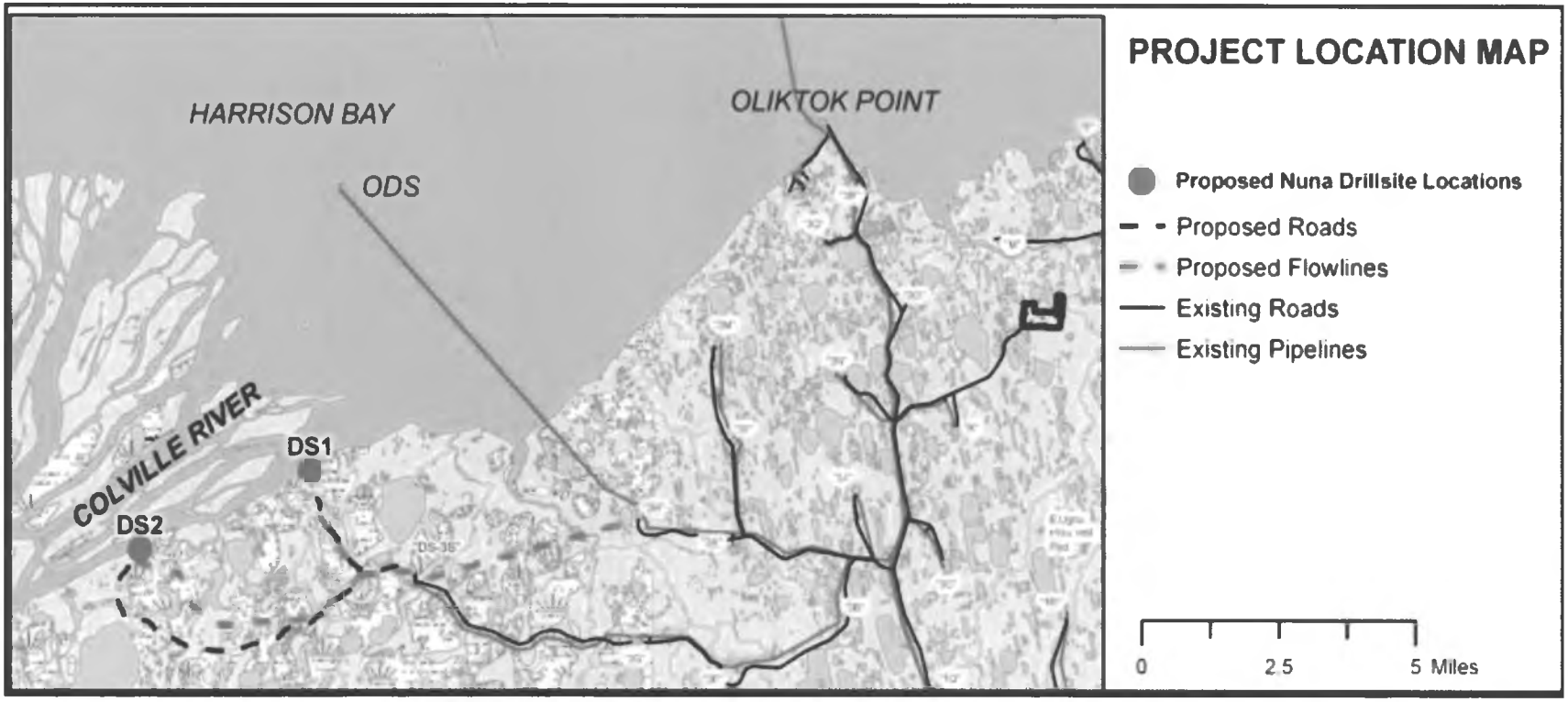


PIONEER

Expansion Project Scope

PIONEER NATURAL RESOURCES

- 1 or 2 onshore drillsites connected to Oooguruk tie-in pad
- Large, but challenged oil resource
- Project contingent upon pilot waterflood success
- Must compete with low risk, high margin projects in L48



Competition For Alaska - An *Independent's* View

PIONEER NATURAL RESOURCES

Alaska Relative to Lower 48 Resource Plays:

- **Resource**

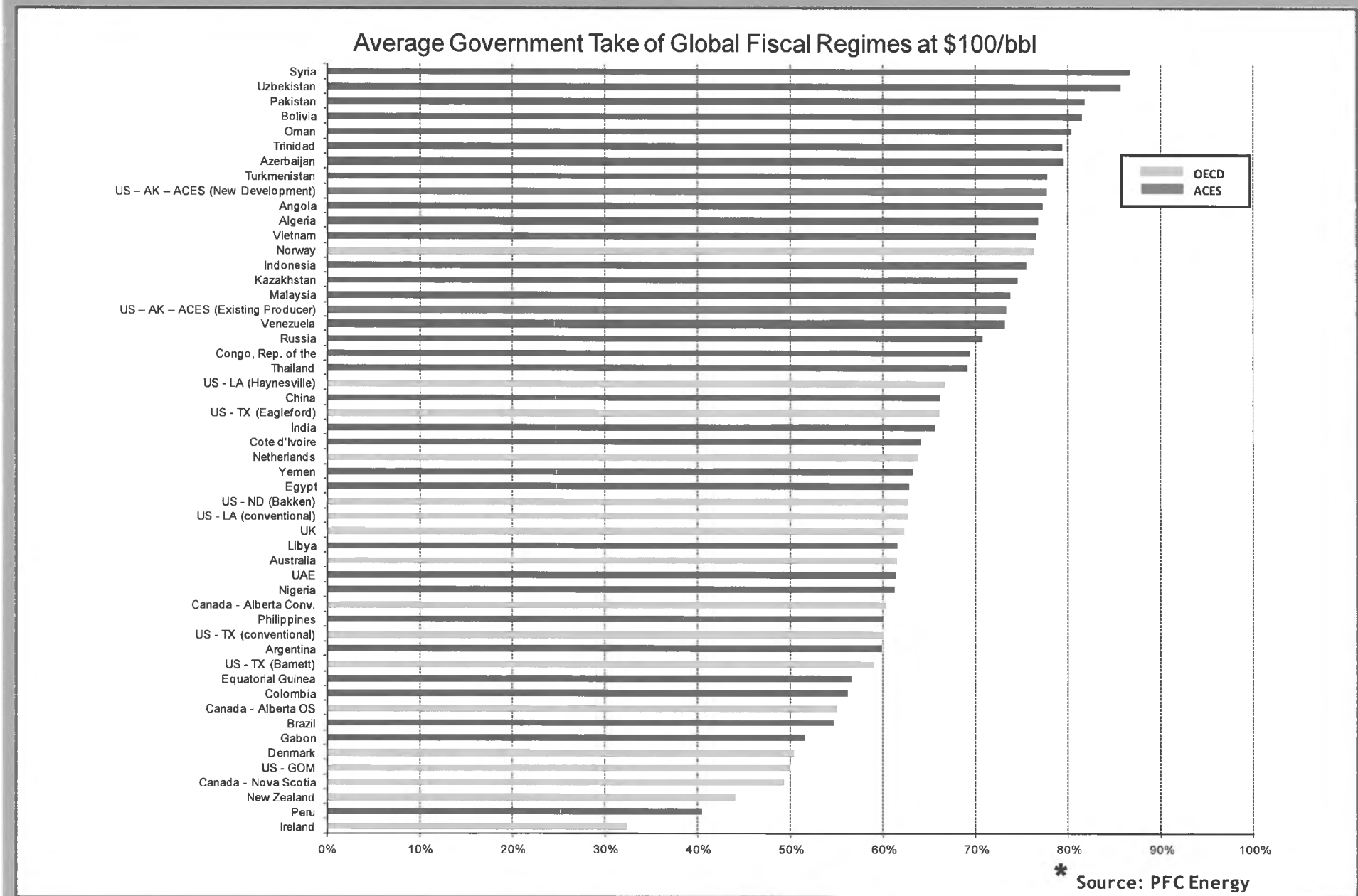
	Alaska	Lower 48
Resource Report Card		
Resource Potential	✓	✓
Resource Competition	✓	
Oil Bias	✓	
Regulatory Process Ease		✓
Land Acquisition	✓	

- **Profitability**

	Alaska	Lower 48
Profitability Report Card		
Cycle Times / Payback		✓
Execution Risk		✓
Operational Flexibility		✓
Low Operating Cost		✓

Average Government Take ($100/BBL)

PIONEER NATURAL RESOURCES



* Source: PFC Energy

HB 3001

PIONEER
NATURAL RESOURCES

- **Incents wide array of projects**
- **Reduces the negative impact of progressivity**
- **Makes Alaska projects significantly more competitive**
- **Missing?**
  - Small Producer Tax Credit extension

Closing Thoughts

PIONEER NATURAL RESOURCES

- **Our Alaska projects must compete with L48 resource plays with:**
  - Large resource potential in Pioneer's back yard
  - Short project cycle times and lower operating costs
  - Very favorable fiscal terms
  - Much lower capital cost
- **Oooguruk expansion**
  - New project - new barrels in TAPS
  - Create ~500 construction jobs
  - Create ~100 development jobs
- **HB 3001 will have a positive, material impact**
  - Increased investment credits for well related costs
  - 40% Gross reduction and progressivity cap lowering

BP Testimony to House Resources and House Energy

Damian Bilbao, Head of Finance, Developments and Resources

April 25, 2012

Agenda

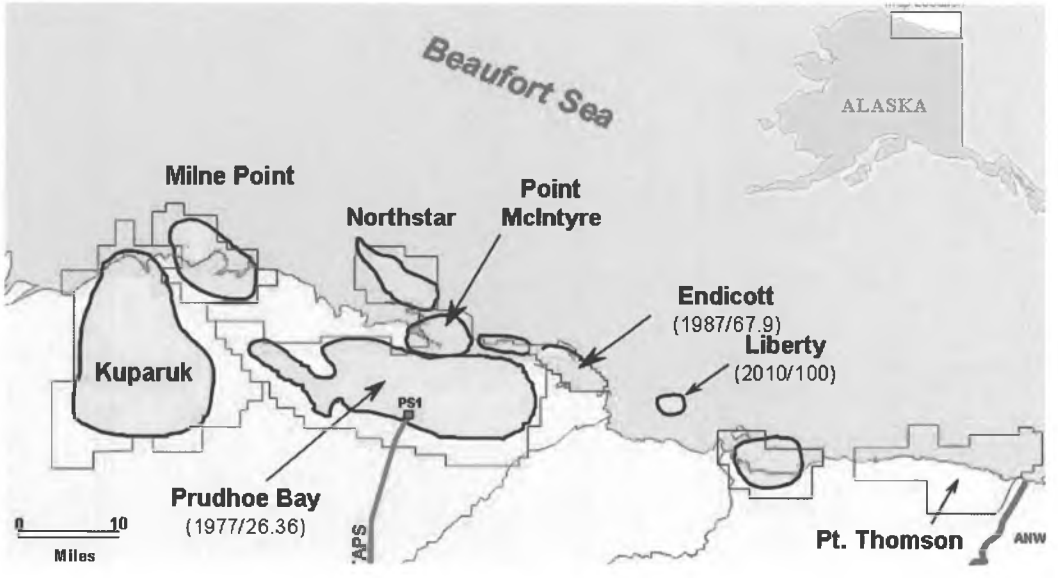
BP in Alaska

How BP makes investment decisions

What could growth in investment mean for Alaska's future

BP in Alaska since 1959

- 53 years in Alaska
  - Office opened in 1959
- $13.4 billion in upstream spend with Alaska Firms the last 10 years
- 2,100 Employees (82% Alaska residents)
  - 275 APICC students hired in last 10 years
  - 54 internships, 100+ fulltime jobs in last 5 years
- 6,000+ Contractors
- $70 million of direct community investment since 2001



Agenda

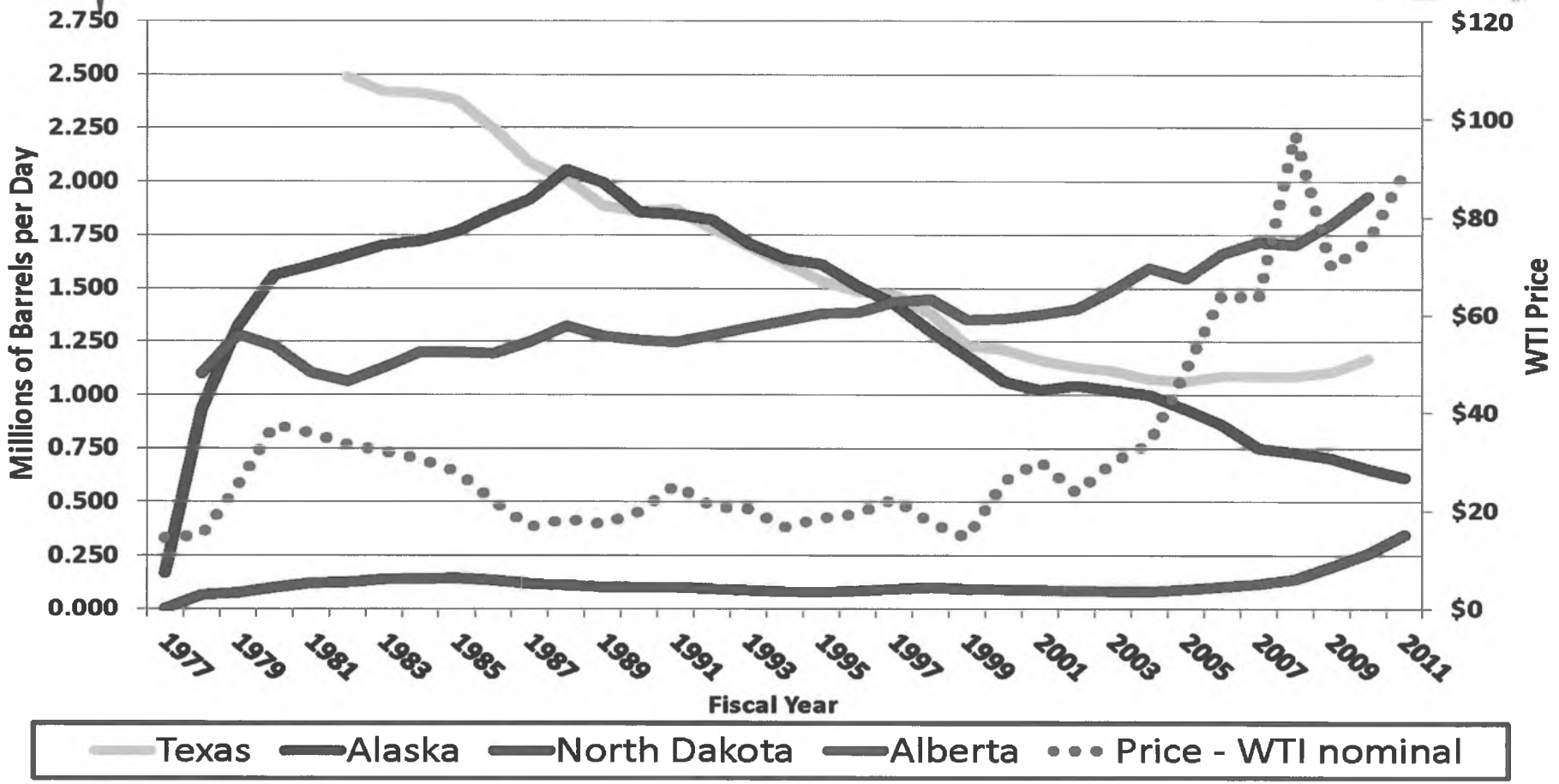
BP in Alaska

How BP makes investment decisions

What could growth in investment mean for Alaska's future

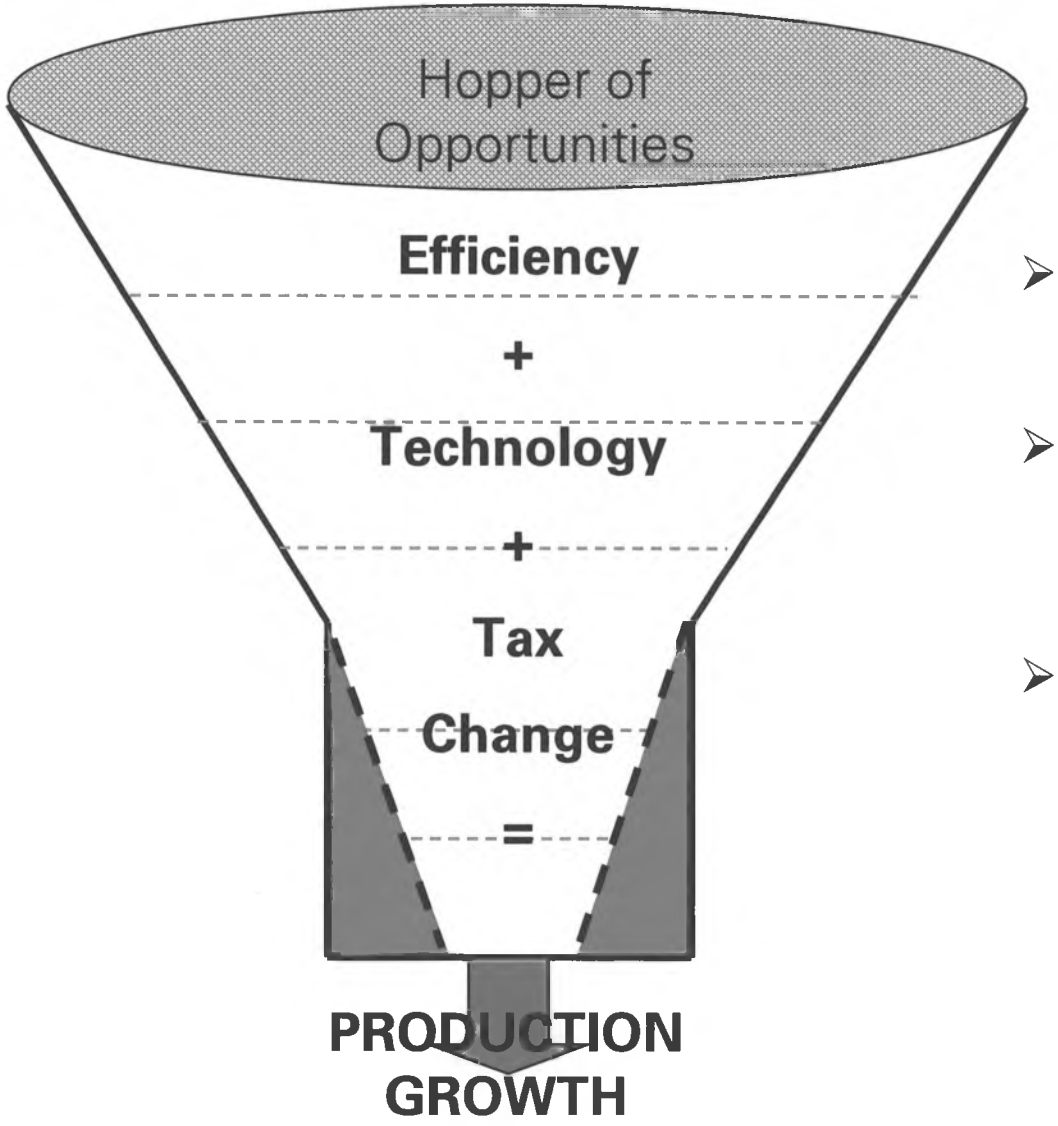
Global investment is limited and goes to the most attractive regions

Historical Oil Production:
How Did Our Competition Fare When Prices Spiked?



Source: DOR presentation to House Resources, April 21, 2012

The tax policy will greatly influence how many projects move forward



- Healthy base business
- Brightwater, Multi-lateral drilling, Lo Sal, etc.
- $5 billion in potential new investment
  - Prudhoe I Pad
  - Kuparuk Eastern NEWS
  - Prudhoe Sag @ scale
  - Add'l drilling in legacy fields

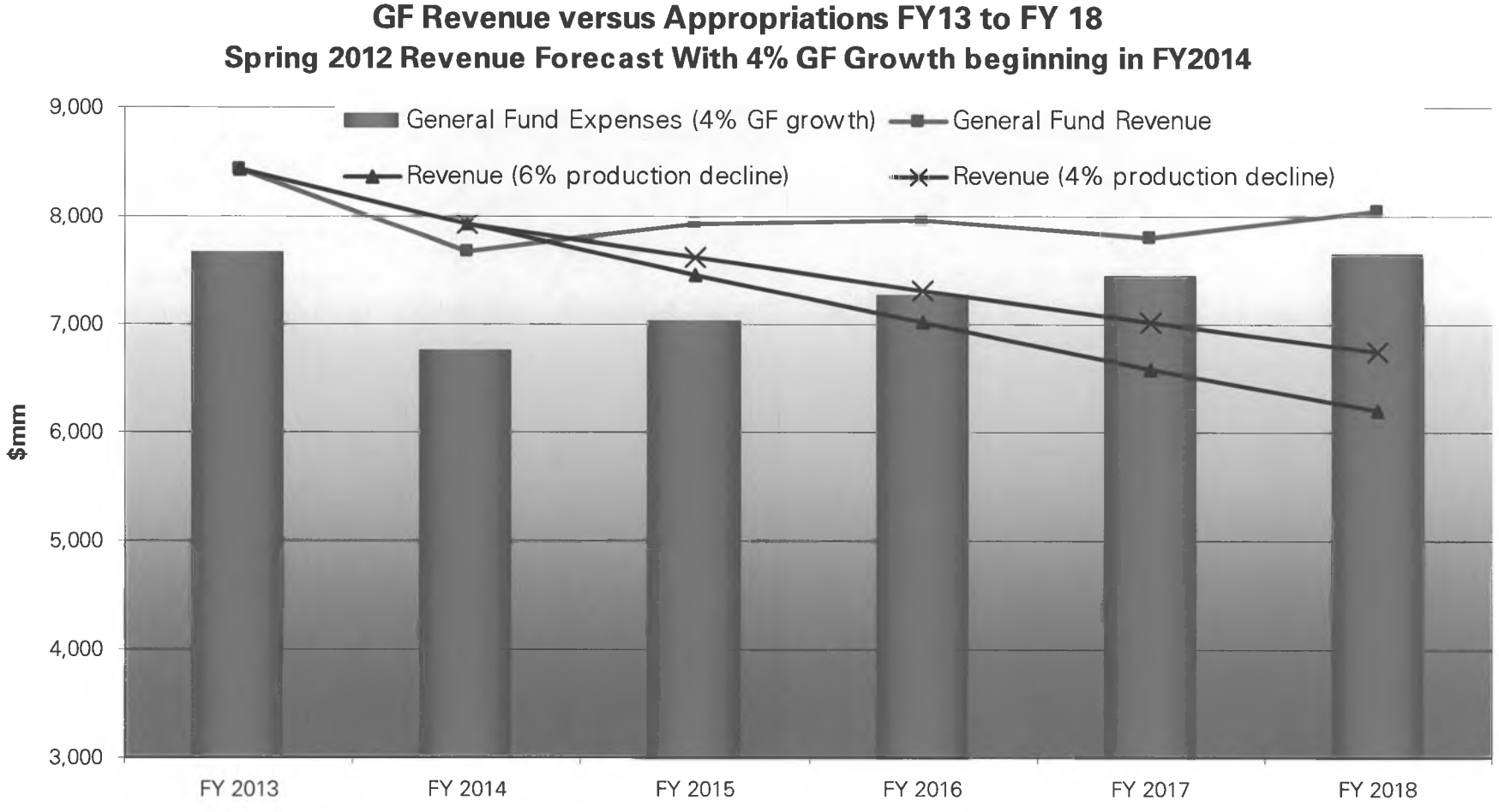
Agenda

BP in Alaska

How BP makes investment decisions

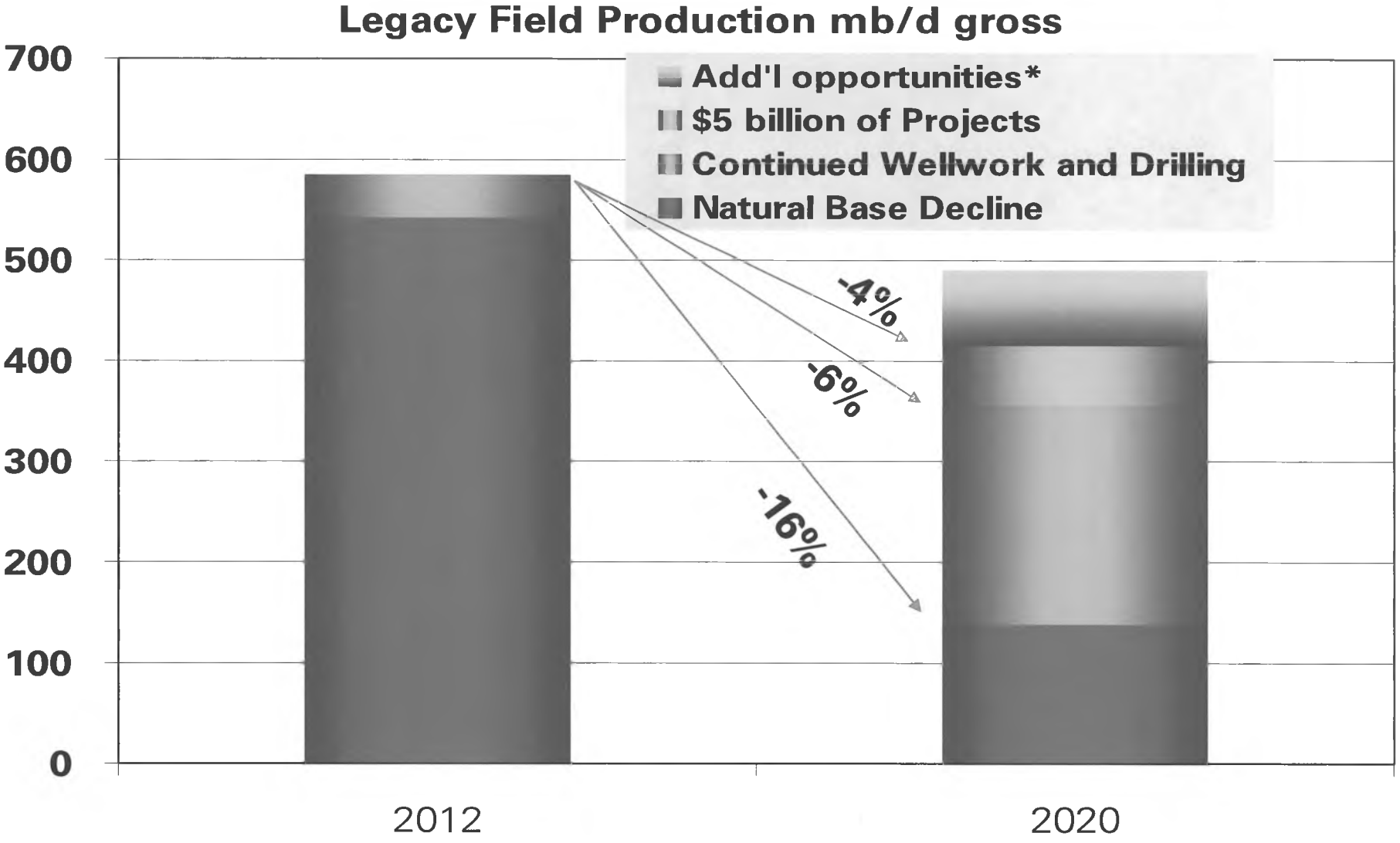
What could growth in investment mean for Alaska's future

Declining production is a crisis



Source: Office and Management and Budget presentation to House Resources, April 25, 2012

Two-thirds of production in 2020 derives from activity performed from 2012 to 2020



* Indicative

Key Messages

- ACES is a no growth policy that bets Alaska's future on high oil prices
- Legacy fields are the only near-term option for new production
- If taxes do not change, our business will have to
- Other regions, like Alberta, have lowered taxes and increased investment and production

ConocoPhillips
Alaska

House Resources Committee
Discussion of HB3001

Scott Jepsen, VP External Affairs
Dan Clark, Manager Strategy and Portfolio Management
ConocoPhillips Alaska

April 25, 2012

Outline

ConocoPhillips
Alaska

- ConocoPhillips Latest Financial Performance
- Alaska Potential
- Fiscal Framework Discussion
- ConocoPhillips Commitment

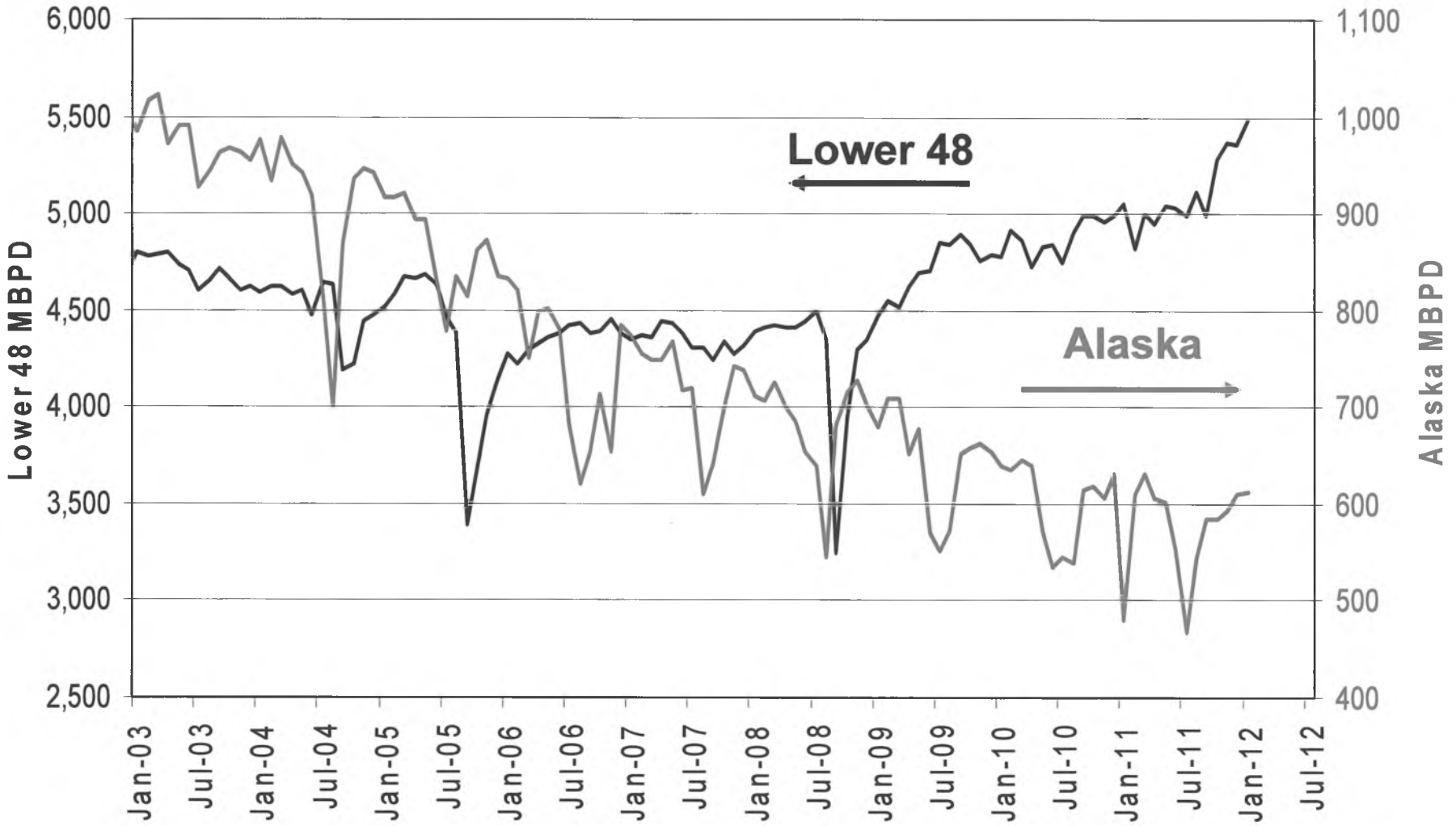
Latest Financial Performance

ConocoPhillips Alaska

- Alaska First Quarter 2012 Earnings
  - Paid $1.5 billion in taxes and est. royalties; earned $616 million
  - $13.1 million per day of taxes and est. royalties to State of Alaska
  - $16.5 million per day of total government take
  - $173 million higher than 4th quarter 2011 due to timing of sales and increased prices

Production is Declining in Alaska

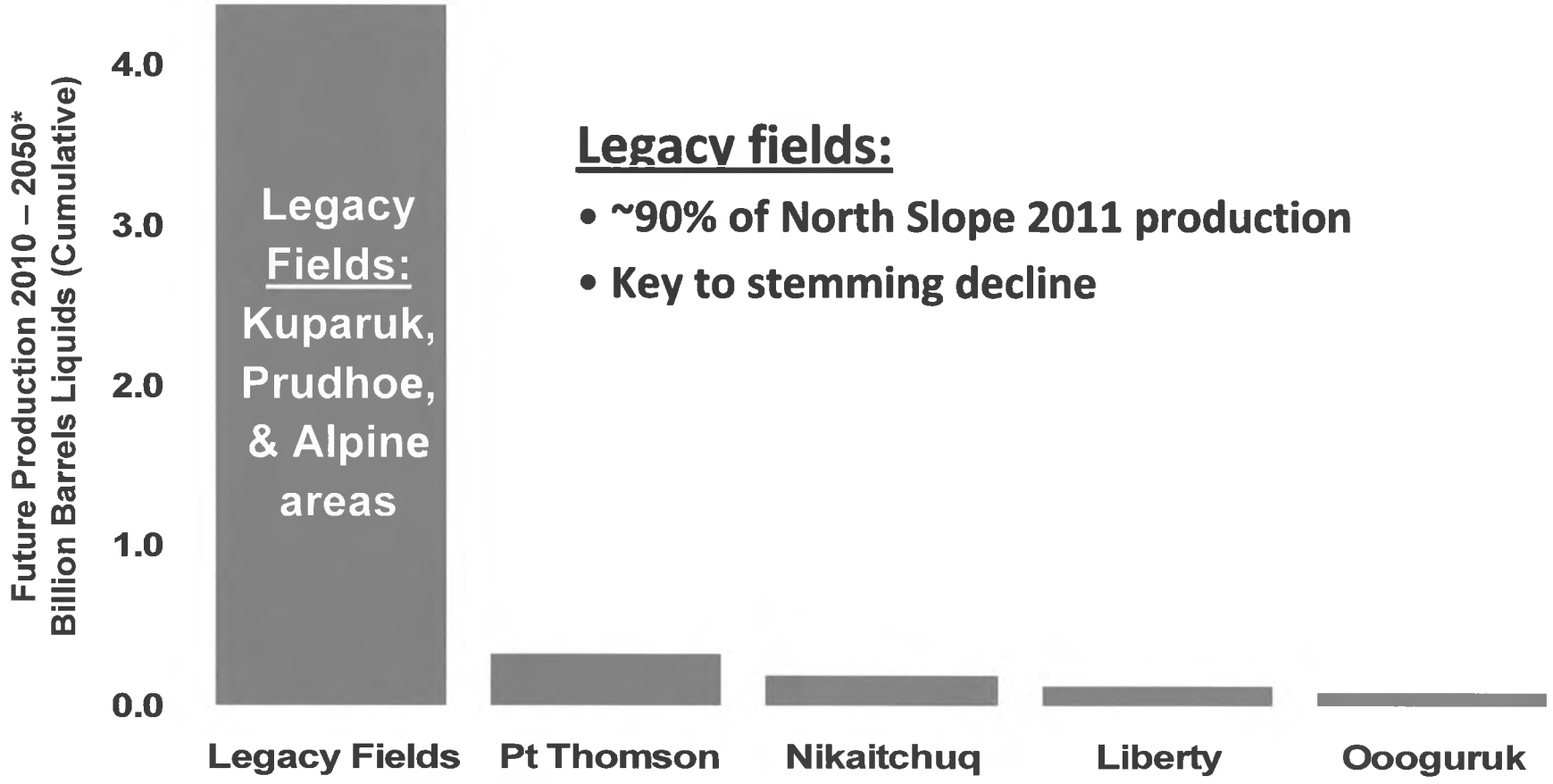
ConocoPhillips Alaska



Source: Energy Information Administration (EIA)

Legacy Fields are Key to Future Production

ConocoPhillips Alaska



Legacy fields:

- **~90% of North Slope 2011 production**
- **Key to stemming decline**

Realization of legacy field potential dependent upon attracting additional capital investment

Source: DOR 2009 production forecast 2010 – 2050 volumes

Opportunities within Legacy Fields

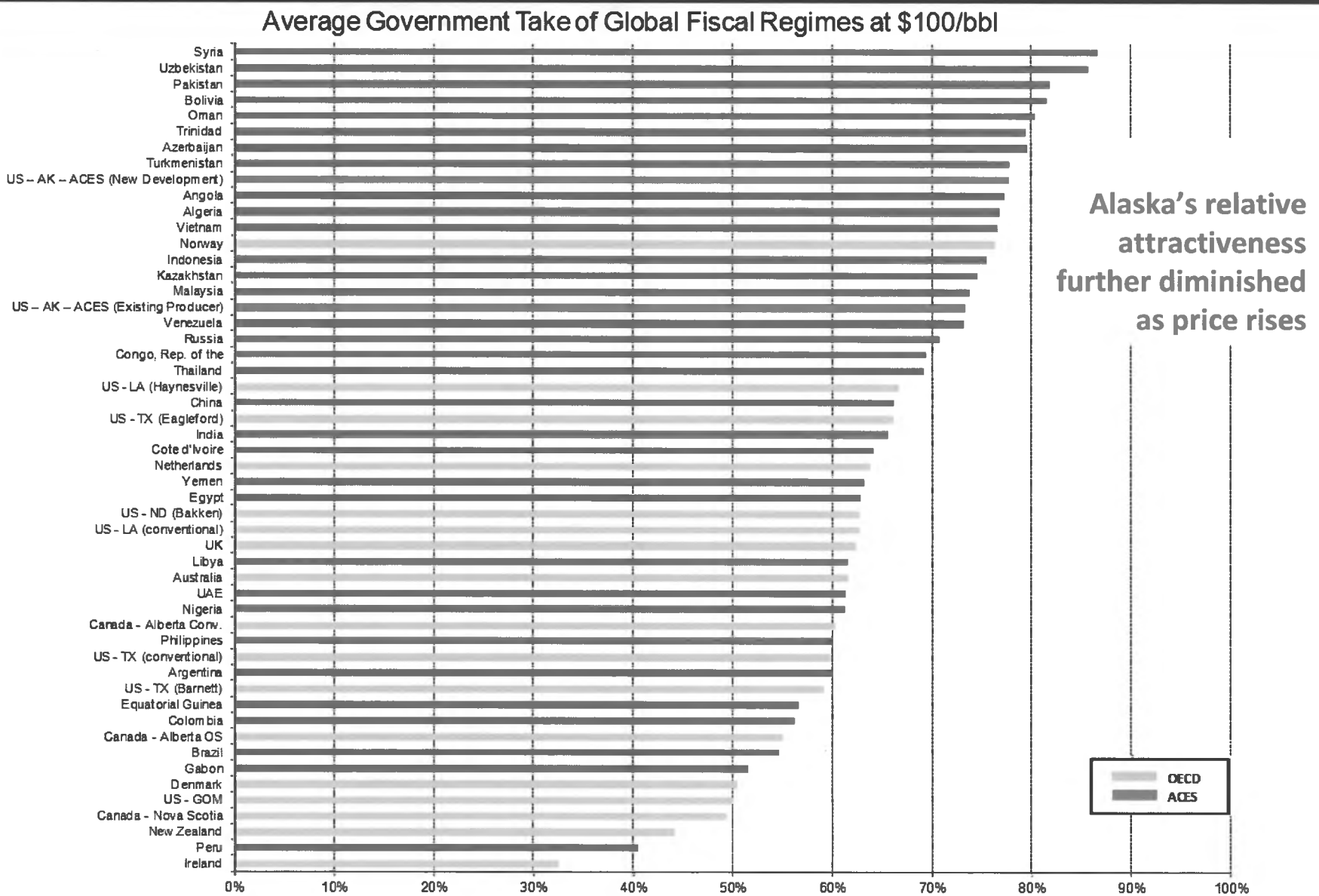
ConocoPhillips Alaska

- Drilling technology is opening new opportunities for light oil development
  - Designer wells
  - Thin sand targets
  - Opportunities can support more rigs in Western North Slope, Prudhoe
  - High costs, technical risks significant
- Viscous oil maturing
  - Have made technological advancements
  - Core area West Sak on line at 14,000 BOPD
  - Evaluating next significant investment (Eastern NEWS)
    - Challenged technically and commercially
    - More engineering needed
- Additional exploration, satellite opportunities
- Evaluating heavy oil technologies
  - Long standing efforts to develop heavy oil is continuing
  - No commercially viable technology identified to date

Cost, production/reserves, technical, regulatory and fiscal framework considerations will determine level of capital investment

ACES - High Average Government Take

ConocoPhillips Alaska

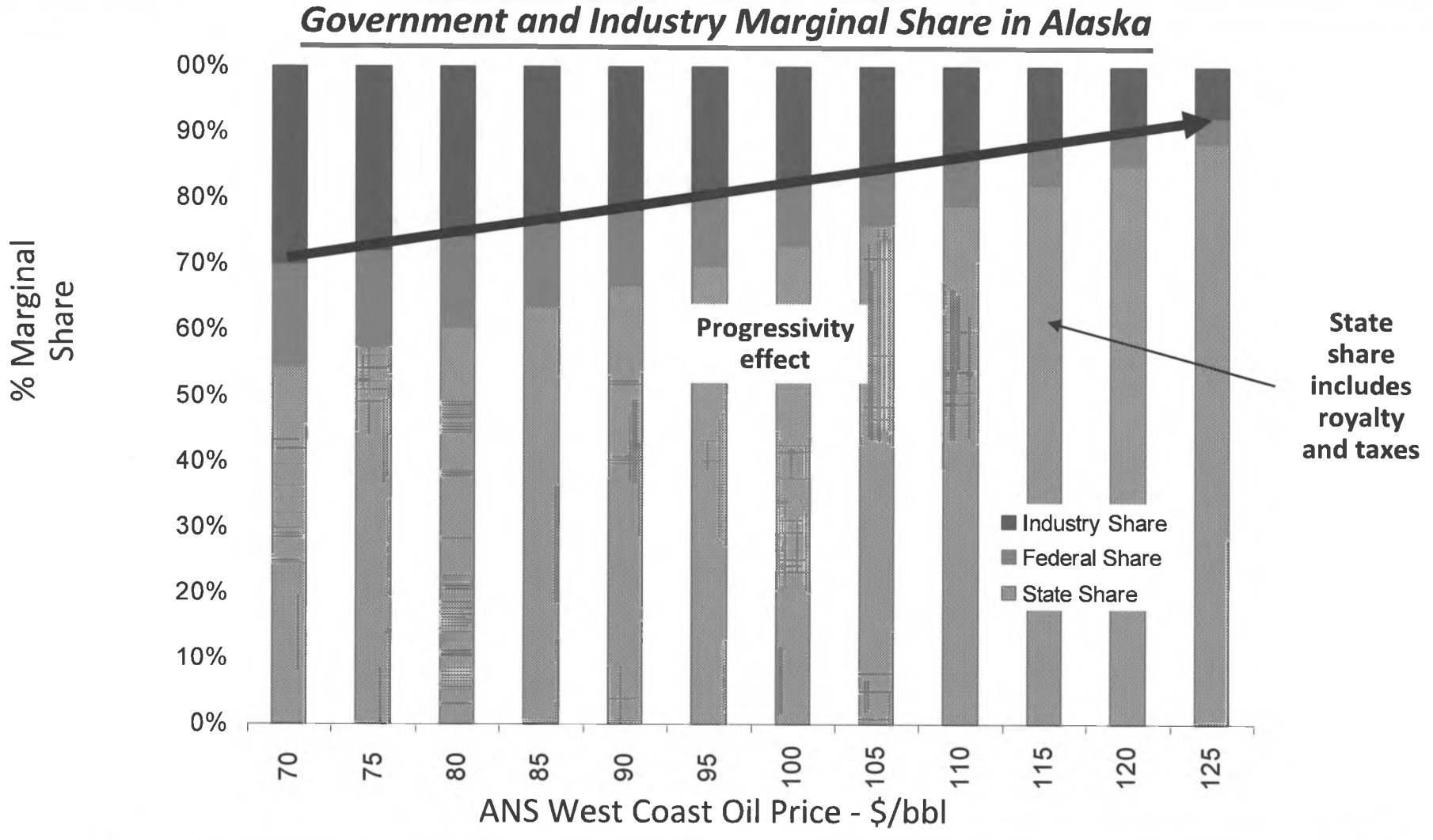


Alaska's relative attractiveness further diminished as price rises

Source: PFC Energy, Alaska House Resources Committee Discussion Slides, April 23, 2012

ACES Takes Away the Upside

ConocoPhillips Alaska



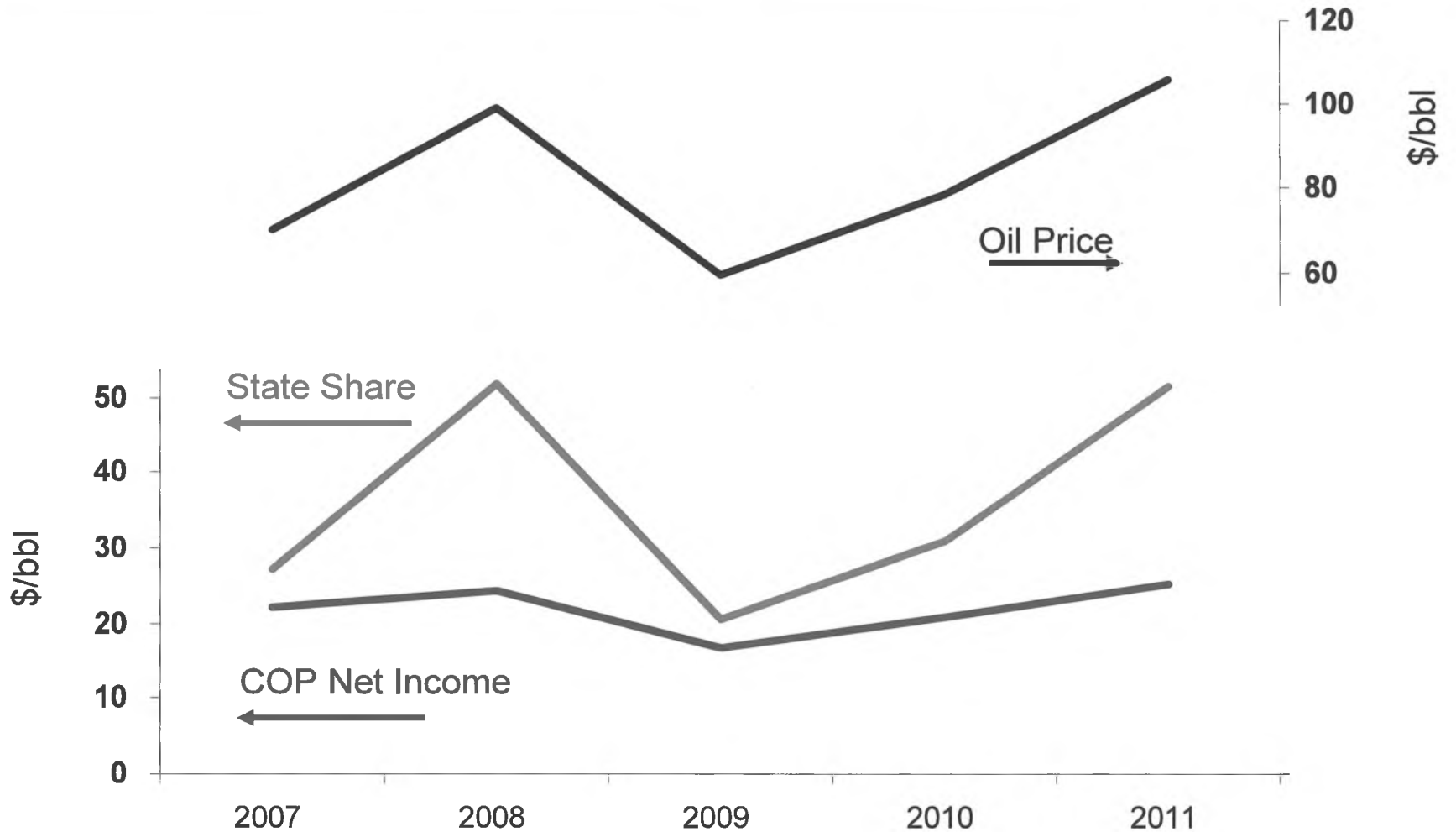
By comparison, industry marginal share in L48 40% to 50%

Based on Fall 2011 RSB for FY2013
Assume 35% federal tax rate, 9.4% SIT rate

Alaska Share includes royalty, severance tax, income tax, and property tax

ACES Takes Away the Upside

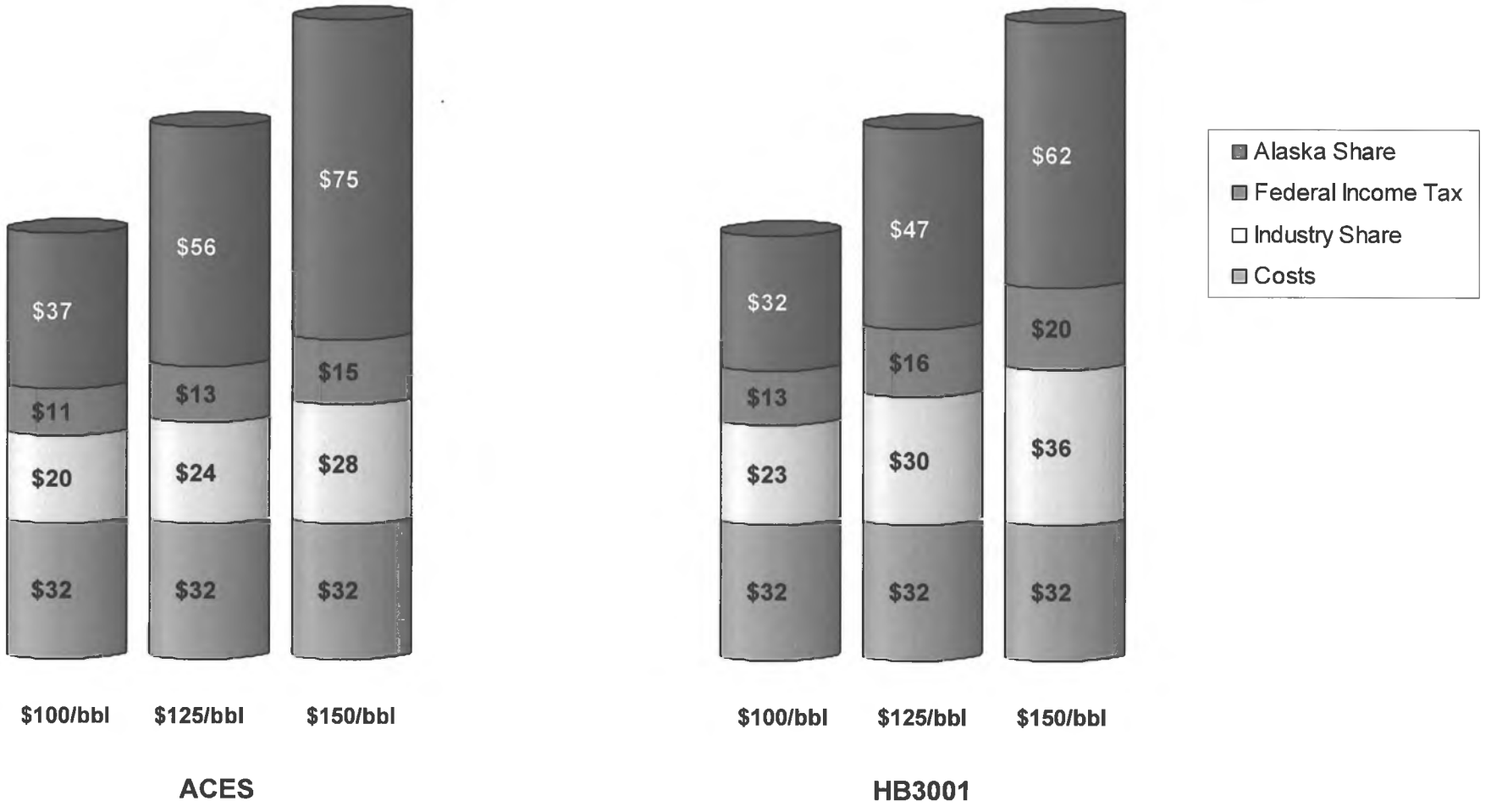
ConocoPhillips Alaska



Source: ConocoPhillips 10-K

HB3001 Provides More Equitable Split

ConocoPhillips Alaska

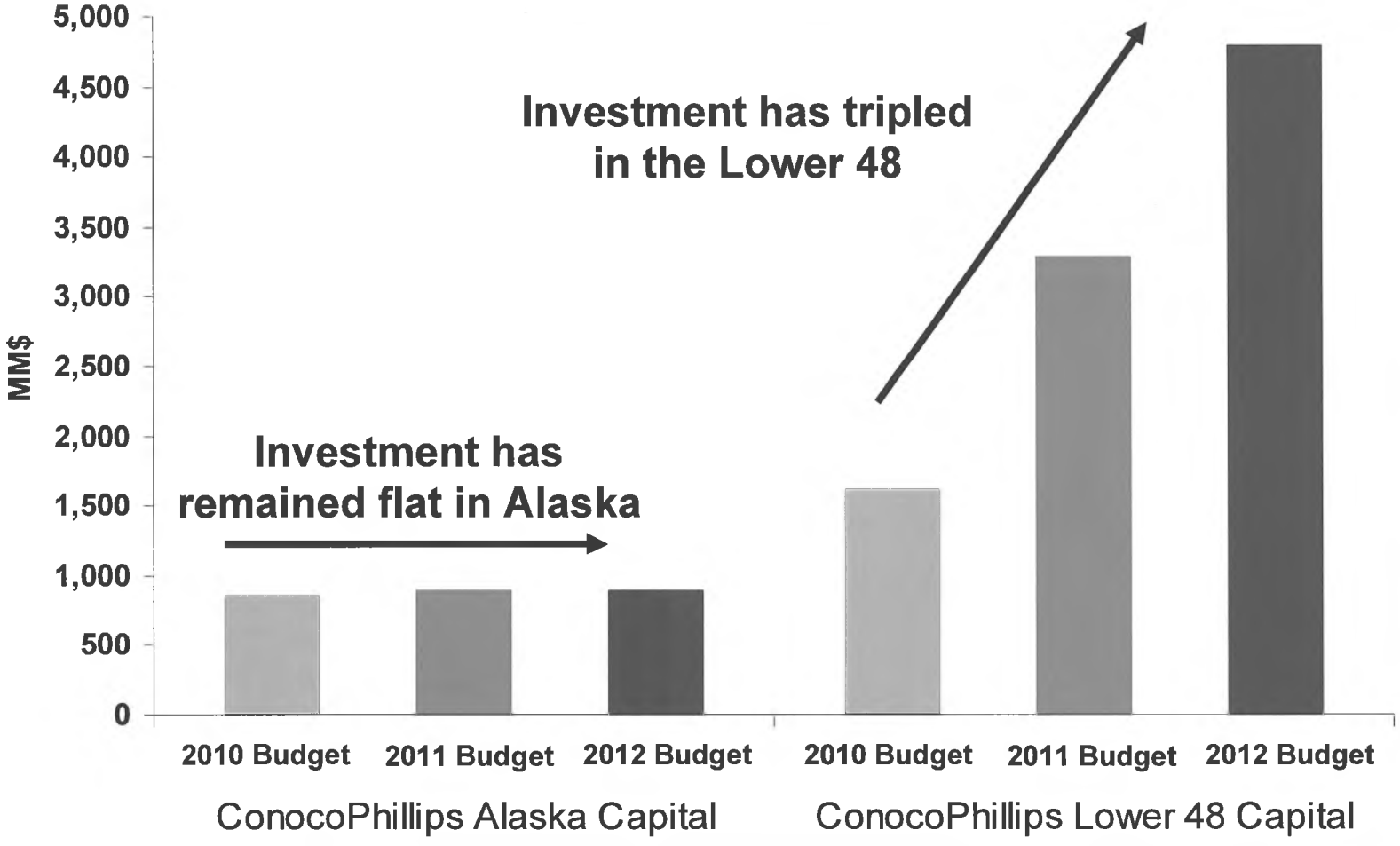


Based on Fall 2011 RSB for FY2013
Assume 35% federal tax rate, 9.4% SIT rate

Alaska Share includes royalty, severance tax, income tax, and property tax
Assume 35% of capex is eligible for 40% credits under HB3001

ConocoPhillips Capital Expenditures

ConocoPhillips Alaska



Investment flows where investor has upside

Source: ConocoPhillips 10K

ConocoPhillips Commitment

ConocoPhillips Alaska

Last spring, ConocoPhillips made the following commitments to Alaska if HB110 or similar legislation is passed:

- We will pursue increased drilling activity on the North Slope
- We will aggressively pursue more satellite developments at Alpine and Kuparuk
- We will work with partners to develop major projects at Prudhoe Bay
- We will proactively pursue other projects that can move the needle on oil production

An Open Letter to All Alaskans from ConocoPhillips

Our Commitment to Moving Alaska Forward

Dear Alaskans:

The oil industry in Alaska is at a crossroads. The amount of oil in the Trans Alaska Pipeline is declining at a faster rate than projected even a year ago. State and federal officials are, for the first time, talking openly about the challenges with TAPS low flow in light of the recent shut down of TAPS.

No other state's production has declined more than Alaska in the past eight years. But it doesn't have to be that way. The oil industry and the state of Alaska must work together now to put more oil in the pipeline and bridge the more than 10-year gap between now and when oil from offshore and other sources can hopefully refill TAPS.

Governor Parnell has introduced a bill, HB 110/SB 49, to reduce oil taxes in an effort to restart development and create new jobs. However, some have questioned the oil industry's commitment to Alaska.

In Alaska this week, ConocoPhillips reinforced that commitment to the state. If the business environment is changed, we at ConocoPhillips will do more to help bring Alaska's challenged oil to the market.

We will increase our drilling activity on the North Slope.

We will proactively pursue more North Slope projects that can move the needle on oil production while employing Alaskans and creating new opportunities for Alaska businesses.

We will work with BP and ExxonMobil to advance significant projects like Gas Partial Processing (GPP) and IPAD at Prudhoe Bay.

We will aggressively pursue more satellite developments at both Kuparuk and Alpine.

Our company believes Governor Parnell's goal of producing 1 million barrels of oil per day is a goal around which we can all unite.

At ConocoPhillips, we believe in the potential that Alaska has to offer. We have demonstrated our commitment to the environment by continuing to operate in the cleanest and safest way we can. We have shown a long history of investment, both human and financial, to bring the resources of this great state to the market. We have stood with many Alaska companies, including Alaska Native corporations, to build an oil and gas industry that has provided many jobs to Alaskans.

If the Legislature provides for an effective date of 2012, ConocoPhillips will do our part to accelerate new activity on the North Slope.

Alaska has tremendous resource potential, and we at ConocoPhillips have over 50 years in Alaska in solving technical and environmental challenges associated with oil development. We support improving the investment climate and believe changing oil taxes will lead to a better future with more production and jobs for Alaska families than the current path we are on.

Sincerely,

Trond-Erik Johansen
President
ConocoPhillips Alaska Inc.

Jim Mulva
Chairman and Chief Executive Officer
ConocoPhillips

ConocoPhillips
Alaska's Oil & Gas Company