LIST OF FILES

SENATE SPECIAL COMMITTEE ON TRANS ALASKA PIPELINE THROUGHPUT, 2013-2014 (SCOMM 177)

MEMBERS:

SENATOR DUNLEAVY, CO-CHAIR
SENATOR MICCICHE, CO-CHAIR
SENATOR FAIRCLOUGH
SENATOR MCGUIRE
SENATOR GARDNER

Established by SR 2, 2013

LIST OF FILES (PAGE 1)

01/17/13	Organizational Meeting - Discussion of Committee's Objectives
01/22/13	SB 21 - Oil and Gas Production Tax
01/24/13	SB 21 - Analysis of Alaska's Tax System by Barry Pulliam, Econ One Research
01/29/13	SB 21 - Department of Revenue Overview
01/31/14	SB 21 - Presentation: Alaska Hydrocarbons Fiscal Systems by Janak Mayer, and Public Testimony
02/05/13	SB 21 - Oil Industry Presentations
02/07/13	SB 21 - Proposed Amendments and Letter of Intent
02/26 & 03/05/13	SB 59 - Oil and Gas Exploration and Development Areas
04/08/14	Presentation: Alaska Oil and Gas Conservation Commission Overview and Issues

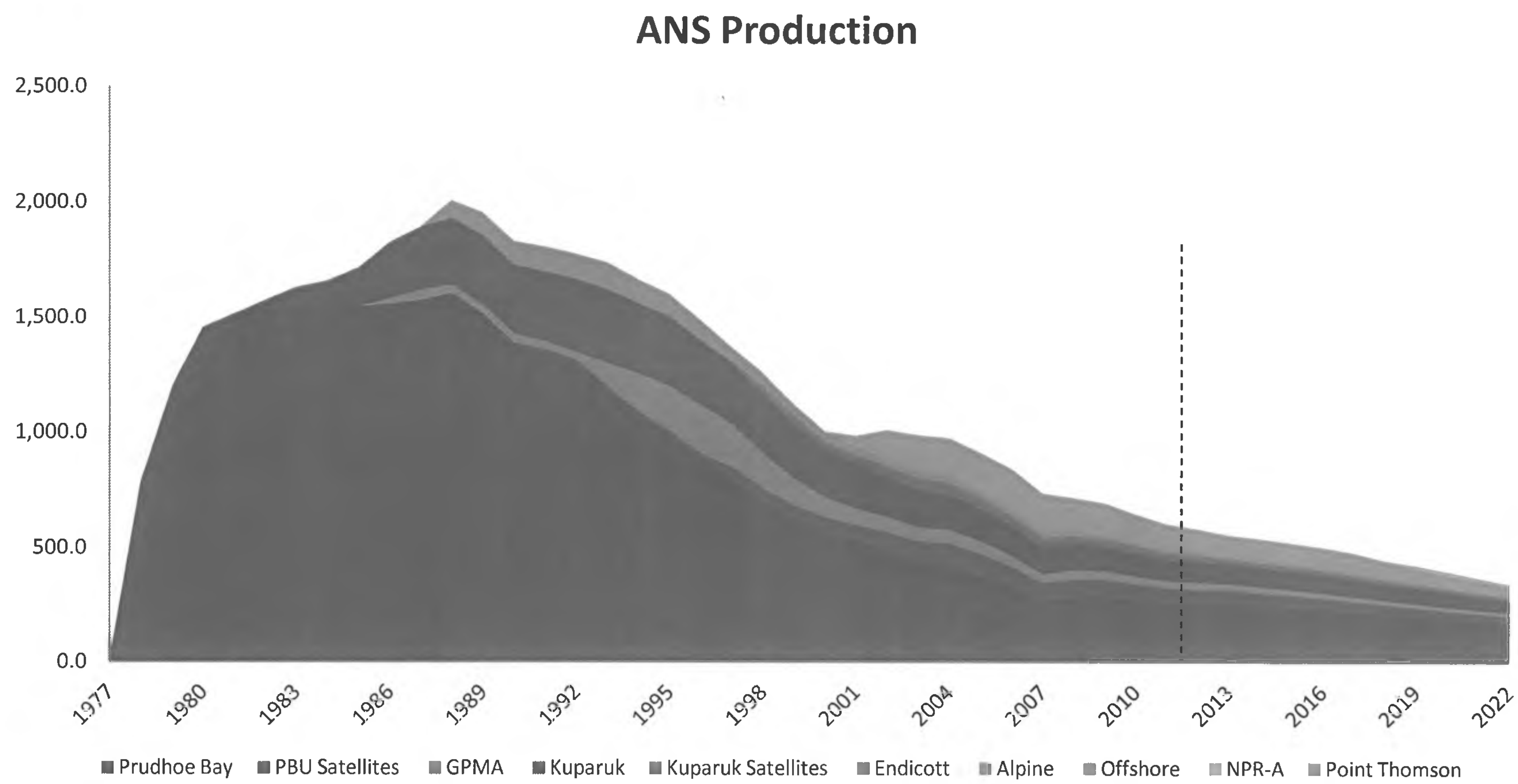
01/17/13 Organizational Meeting – Discussion of Committee's Objectives

<TARGET><BILL></BILL><SUBJECT>01-17-13 Organizational Meeting – Discussion of Committee's Objectives</SUBJECT><COMM>STTP28</COMM></TARGET>

North Slope Oil Production History and Forecast

Presentation to the Senate Special Committee on TAPS Throughput

Production History and Forecast



Source: Alaska Department of Revenue Fall 2012 Revenue Sources Book: http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2682f

Forecast Alaska ANS Price, Production, State General Fund Unrestricted Revenues FY 2012 -2017

	FY 2012 Actual	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
Forecast ANS WC Oil Price ($ / bbl)	$112.65	$108.67	$109.61	$111.67	$114.88	$116.22
Total ANS Production (State + Federal) (ths bbls/day)	579.1	552.8	538.4	518.6	499.7	476.1
General Fund Unrestricted Revenues (Millions of $)	$9,485	$7,512	$7,002	$6,659	$6,999	$7,105

Source: Department of Revenue, Revenue Sources Book Fall 2012

Forecast Alaska ANS Price, Production, State General Fund Unrestricted Revenues FY 2018 –FY 2022

	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Forecast ANS WC Oil Price ($ / bbl)	$117.16	$118.29	$119.74	$121.42	$123.34
Total ANS Production (State + Federal) (ths bbls/day)	442.9	421.6	394.8	365.9	338.5
General Fund Unrestricted Revenues (Millions of $)	$6,970	$6,719	$6,487	$6,209	5,969

Source: Department of Revenue, Revenue Sources Book Fall 2012

01/22/13 SB 21 - Oil and Gas Production Tax

<TARGET><BILL>SB 21</BILL><SUBJECT>01-22-13 SB 21 - Oil and Gas Production Tax</SUBJECT><COMM>STTP28</COMM></TARGET>

THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

COMMISSIONER'S OFFICE
Bryan Butcher, Commissioner

333 Willoughby Avenue, 11th Floor
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January 17, 2013

The Honorable Peter Micciche, Co-Chair
Senate Special Committee on TAPS Throughput
State Capitol Room 125
Juneau, Alaska 99801

The Honorable Mike Dunleavy, Co-Chair
Senate Special Committee on TAPS Throughput
State Capitol Room 510
Juneau, Alaska 99801

Dear Co-Chairs Micciche and Dunleavy:

Senate Bill 21 was read across the floor on January 16, 2013 and referred to the Senate Special Committee on TAPS Throughput for consideration. I respectfully request a hearing to be scheduled at your earliest convenience for the proposed changes to Alaska's oil and gas production tax to be discussed.

Governor Parnell is committed to getting more oil into the pipeline and increasing job opportunities for Alaskans. The current oil and gas production tax system is one of the obstacles the Governor has identified to stemming the decline in TAPS throughput and increasing oil production in Alaska.

Senate Bill 21:

- Eliminates the progressive function in the current production tax and maintains the current 25% tax rate.
- Eliminates qualified capital expenditure credits for expenditures made after December 31, 2014 for expenditures made, north of 68 degrees north latitude (the North Slope) to explore for, and develop oil and gas.
- Establishes a 20% gross revenue exclusion for production from units formed after January 1, 2003 and new participating areas in units that were in existence prior to January 1, 2003.
- Reforms the current net loss carry forward to require that it be carried forward to offset a tax liability and limits the instances in which the credit may be transferred.
- Extends the current small producer tax credit.
- Changes the fund source for the Community Revenue Sharing Fund from the progressive function in the current production tax system to the Alaska Net Income tax.

These changes are aimed at ensuring that the state continues to receive fair compensation for the sale of its resources while establishing a more competitive investment climate for job creation.

If the Committee requires any additional information, please contact me.

Sincerely,

Bryan Butcher

Bryan Butcher
Commissioner

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Governor Sean Parnell
STATE OF ALASKA

January 15, 2013

The Honorable Charlie Huggins
President of the Senate
Alaska State Legislature
State Capitol, Room 111
Juneau, AK 99801-1182

Dear President Huggins,

To create more economic opportunity for Alaskans, we must proactively choose a future of more oil production. Therefore, under the authority of Article III, Section 18 of the Alaska Constitution, I am transmitting a bill relating to oil production taxation.

Alaska's oil belongs to Alaskans, and increased oil production will mean increased private sector opportunity for Alaskans. Alaska engineers, contractors, and maintenance personnel earn their livelihoods from oil production; indirectly so do business owners, retailers, and working men and women of all trades. Oil production also provides revenue and drives public sector opportunities for schools, public safety, roads and ferries, energy infrastructure, and many other services for Alaskans.

Need for Legislation

Alaskans are well aware that oil production from legacy fields is declining. Not because we are running out of oil, but because we are running behind the competition. Alaska's North Slope has billions of proven barrels of oil, but we do not have a tax system designed to attract new investment for more production. At high oil prices, the current progressive tax rate structure creates highly variable tax rates and takes far more profit from investors than other competing jurisdictions. Investors take their money where they get a greater return, and they are investing new capital elsewhere. Legislation is necessary to drive new investment to create new Alaska production and new opportunities for Alaskans.

Under current law, the generous tax credits for capital expenditures support company spending now, but on spending not necessarily targeted for new production. Consequently, the State experiences the short-term risk of writing large checks from the treasury for those credits with no corresponding increase in production. Legislation is necessary to mitigate this risk, and focus company investment on long-term, new Alaska production.

Guiding Principles

Tax policy must be fair to Alaskans. Any changes to oil taxes should, when taken together, be geared to foster new production. Changes should result in a more simple tax system and restore balance to our fiscal system. And, tax policy must make Alaska competitive for the long-term. If these guiding principles are met, I believe we will more fully maximize the benefit of Alaskans' oil resources for Alaskans.

Legislation Summary

The bill maintains a 25 percent base tax rate with a 20 percent gross revenue exclusion for new oil. It eliminates the progressivity calculation, and eliminates the qualified capital expenditure credits for North Slope expenditures. The bill reforms the remaining credits so that they are taken when there is production.

Fair to Alaskans and Fosters New Production

The legislation provides more downside price protection for Alaskans in exchange for more upside price revenue to the companies. Under the current tax system, State revenues depend primarily on the price of oil, but the current qualified capital expenditure credits depend on the level of company spending. If prices fall, State revenues are reduced but the State retains the obligation to pay credits. Further, if additional development occurs, under the current system, the credit obligation could grow substantially. Given the State's other obligations like public safety and schools, this imbalance exposes the State to substantial financial risks. By reforming the credit system, this bill rebalances the current tax structure to ensure revenues to the State in low price environments.

The legislation targets new Alaska production rather than just company spending, thus unlocking more of Alaskans' oil for more Alaskan private sector and public sector opportunities. This goal is accomplished by eliminating the current 20 percent tax credit under AS 43.55.023(a) for qualified capital expenditures incurred after December 31, 2013, to explore for, develop, or produce oil and gas deposits located on the North Slope. The bill would amend the 25 percent tax credit issued under AS 43.55.023(b) for a carried-forward annual loss based on expenditures incurred after December 31, 2013, to explore for, develop, or produce oil and gas deposits located on the North Slope by limiting the transferability and monetization of the tax credit. The amendment to AS 43.55.023(b) will encourage investment aimed at production by requiring a producer or explorer to carry the credit forward to offset future tax liabilities. Additionally, the bill extends the small producer tax credit available under AS 43.55.024(c). The small producer tax credit is nontransferable.

The bill creates additional incentives for new production on the North Slope by providing for a 20 percent revenue exclusion based on the gross value at the point of production of oil and gas produced from a lease or property that was not, as of January 1, 2003, within a unit. It also proposes the same 20 percent revenue exclusion for oil and gas production from new participating areas in units that were formed before January 1, 2003. Similar to the new North Slope carried-forward annual loss tax credit and the extended tax credit for small producers, these incentives only would apply to a company when it has production.

More Simple, Restores Balance

The bill simplifies the oil and gas production tax by repealing the progressive tax rate structure in Alaska's current tax system by levying a flat rate tax of 25 percent on oil and gas production statewide, subject to current tax ceilings on certain oil and gas, for production beginning January 1, 2014. The repeal of the progressive tax rate structure in this bill encourages the type of long-term planning and investment needed to promote new investment in new production in Alaska.

Long-Term Competitiveness

By shifting the incentives away from spending and towards new production we assure these tax changes are for the long run. Producers get the benefit of tax changes later – after they produce new oil when they can offset earlier liabilities against new production. Additionally, by giving back more of the high side at high oil prices (while better protecting Alaskans against the downside of lower oil prices), we assure companies will make their investments for the long haul because they are more likely to take short-term risk with capital if they are assured greater return over time at higher prices.

In summary, this bill provides a path to more Alaskan opportunity through more Alaskan oil production. I urge your prompt and favorable action on this measure.

Sincerely,

Sean Parnell
Governor

Enclosure

Senate Bill 21
Oil and Gas Production Tax
SECTION ANALYSIS

Section 1: AS 29.60.850, relating to certain appropriations to the general fund is amended to allow the legislature to make appropriations based on taxes paid during the previous calendar year under the Alaska Net Income Tax Act, AS 43.20, to conform to the repeal of AS 43.55.011(g) in section 26 of the bill.

Section 2: AS 43.55.011(e), relating to the levy of the oil and gas production tax, is amended to eliminate the reference to AS 43.55.011(g), the monthly progressivity tax, which is repealed in section 26 of the bill. Beginning January 1, 2014, AS 43.55.011(e) would levy on producers of oil and gas produced each calendar year a flat rate tax of 25 percent of the production tax value of taxable oil and gas produced from each lease or property in the state. No change is made to current tax ceilings that apply to Cook Inlet oil and gas, gas produced outside the Cook Inlet basin and used in the state, and oil and gas produced from new fields outside the Cook Inlet basin and south of the North Slope.

Section 3: Amends AS 43.55.011(o), relating to gas used in the state, to clarify that the tax ceiling applicable to gas used in the state does not apply to gas subject to AS 43.55.011(p)(the seven year tax limitation of four percent of gross value at the point of production for oil and gas first produced commercially outside of the Cook Inlet basin and south of 68 degrees North latitude after December 31, 2012, and before January 1, 2022).

Section 4: Amends AS 43.55.020(a), monthly installment payments of estimated tax, to clarify payment provisions relating to the determination of tax due for oil and gas subject to AS 43.55.011(p) and makes other minor clarifying amendments.

Section 5: Amends AS 43.55.020(a), monthly installment payments of estimated tax, for oil and gas produced after January 1, 2014, to conform to the repeal of AS 43.55.011(g), and to amend the calculation of monthly payments based on North Slope oil and gas to conform with the gross revenue exclusion in new subsection (f), AS 43.55.160, in section 24 of the bill.

Section 6: AS 43.55.020(d), related to payment by a producer to a private royalty owner, is amended to refer to the tax levied by AS 43.55.011(e) instead of AS 43.55.011(e)–(g). This amendment does not change the substance or effect of AS 43.55.020(d) although to avoid confusion, the amendment is made effective the same date as the repeal of AS 43.55.011(g).

Section 7: Amends AS 43.55.023(a) to eliminate the current restrictions on use of a tax credit for qualified capital expenditures and allow the full amount of a tax credit to be applied in a single calendar year beginning January 1, 2013 for expenditures after December 31, 2012.

Section 8: Amends AS 43.55.023(a), effective immediately, to limit the 20 percent tax credit for qualified capital expenditures incurred north of 68 degrees North latitude (North Slope) to expenditures incurred before January 1, 2014. Tax credits under AS 43.55.023(a) based on expenditures to explore for, develop, or produce oil and gas deposits south of the North Slope are not affected.

Section 9: Amends AS 43.55.023(b) to provide that the 25 percent tax credit for a carried-forward annual loss based on expenditures incurred after December 31, 2013, to explore for, develop, or produce oil and gas deposits located on the North Slope are no longer redeemable for cash, nor are they transferable except as provided in new AS 43.55.023(t) in section 15 of the bill. Carried-forward annual loss tax credits based on expenditures incurred after December 31, 2013, to explore for, develop, or produce oil or gas deposits located south of the North Slope are not affected.

Section 10: Amends AS 43.55.023(c) to conform with new amendments to AS 43.55.023 in section 15 of the bill, related to the new rules that will apply to the tax credit for carried-forward losses incurred for expenditures related to North Slope activities.

Section 11: Amends AS 43.55.023(d), issuance of transferable and redeemable tax credit certificates for qualified capital expenditures, to conform to the amendments to AS 43.55.023(a) in section 7 of the bill authorizing the Department of Revenue to issue one tax credit certificate for the full amount of a transferable tax credit.

Section 12: Amends AS 43.55.023(d), issuance of transferable and redeemable tax credit certificates for qualified capital expenditures, so that tax credits certificates based on lease expenditures incurred after December 31, 2013 to explore for, develop, or produce oil and gas deposits on the North Slope are no longer redeemable for cash; nor are the tax credits transferable except in limited circumstances. The reference to AS 43.55.023(i), the transitional expenditure credit, is deleted to conform to the repeal of AS 43.55.023(i) in section 26 of the bill. Tax credits based on lease expenditures to explore for, develop, or produce oil and gas deposits south of the North Slope are still transferable and redeemable for cash from the oil and gas tax credit fund.

Section 13: Amends AS 43.55.023(g), issuance of tax credit certificates, to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 14: Amends AS 43.55.023(n), issuance of tax credit certificates, to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 15: Amends AS 43.55.023 by adding new subsections (p)–(u), effective January 1, 2014 relating to tax credits for carried-forward annual losses based on adjusted lease expenditures incurred to explore for, develop, or produce oil or gas deposits located on the North Slope.

Subsection (p) limits application of a North Slope carried-forward loss credit to tax liability two or more calendar years after the expenditures on which the credit is based were incurred, but the credit may not be applied later than 10 years after the expenditures were incurred.

Subsection (q) establishes a "first earned, first used" rule by requiring that available North Slope carried-forward loss tax credits must be applied in order of the year the expenditures were incurred, with the earliest year first, against tax liability under AS 43.55.011(e).

Subsection (r) provides an annual 15 percent increase in the amount of a North Slope carried-forward loss tax credit subject to compliance with subsections (p), (q) and (s). An amount of a tax credit subject to this subsection begins to increase on January 1 of the second calendar year immediately following the year the expenditures on which the credit is based were incurred, unless that second calendar year is the year for which the credit is applied. The credit stops increasing on December 31 of the year preceding the year against which the credit is applied against the person's tax liability. The increase under this subsection has no value except as applied against a person's tax liability, and the credit expires if not used within the 10 year period in AS 43.55.023(p) of this section.

Subsection (s) provides that a tax credit will not increase under section (r) if the credit could have been applied to a producer's tax liability and provides the order in which credits must be applied and calculations for the determination of when a tax credit could be applied against a person's tax liability.

Subsection (t) provides that a North Slope carried-forward loss tax credit is not transferable except to another person that acquires an interest in the lease or property owned by the transferee at the time the lease expenditures on which the credit is based were incurred. A transferee's use of the credit is subject to the provisions of (u) of this section, and includes filing information on the transfer with the Department of Revenue. The transferee's use of the credit against its tax liability is subject to audit by the Department of Revenue to the same extent as a tax credit that has not been transferred.

Subsection (u) sets out limitations for use of a North Slope carried-forward loss tax credit where a tax credit is used by a producer to whom a tax credit has been transferred through acquisition of leases or properties, or by a producer that has acquired the person that holds the tax credit. The transferee or successor may use the amount of the tax credit specified in this subsection, but the amount of the credit that may be applied against the transferee's or successor's tax liability under AS 43.55.011(e) for a calendar year may not exceed 20 percent of the sum obtained by an equation based on the taxable gross value at the point of production from the lease or property in a calendar year multiplied by the percentage interest in the lease or property owned by the person that incurred the expenditures on which the tax credit is based.

Section 16: Amends AS 43.55.024(d) to extend for 6 years the time that a producer may take a tax credit under AS 43.55.024(c), the small producer credit. Qualifying producers would have until 2022 (instead of 2016) to take the nontransferable small producer tax credit. The extension also applies to producers that did not have commercial production in the state before April 1, 2006, but that first have commercial production before May 1, 2022. Those producers may take the tax credit for nine calendar years (the same period as in current law) after the start of commercial production.

Section 17: Amends AS 43.55.028(e) to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 18: Amends AS 43.55.028(g) to conform to the repeal of AS 43.55.023(m) in section 25 of the bill.

Section 19: Amends AS 43.55.030(e) (1), annual statements of qualified capital expenditures, to clarify current practice that both explorers and producers must file statements reporting qualified capital expenditures and other information required under AS 43.55.030(e).

Section 20: Amends AS 43.55.030 by adding new subsection (g) which requires an explorer or producer claiming a tax credit subject to AS 43.55.023(p)–(u) (section 15 of the bill) to file an annual statement with the Department of Revenue reporting the nature and amount of the expenditures on which the North Slope carried- forward loss credit is based, the amount the person intends to carry forward, any increase in the amount of the credit, and other information required by the Department of Revenue.

Section 21: Amends AS 43.55.160(a), calculation of annual production tax values, to clarify and conform to the provisions of AS 43.55.011(p).

Section 22: AS 43.55.160(a), calculation of annual production tax values, is repealed and reenacted to conform to the repeal of the monthly progressivity tax in section 26 of the bill. For oil and gas produced after January 1, 2014, a producer of oil and gas will no longer need to calculate monthly production tax values for oil and for purposes of AS 43.55.011(g), the progressivity tax. Other clarifying amendments are made setting out the categories for which a separate annual production tax value must be calculated, but the method of calculating annual production tax value is not affected.

Section 23: Amends AS 43.55.160(e) to conform to the amendments in section 22 of the bill.

Section 24: Amends AS 43.55.160 by adding new subsection (f) which provides that in calculating the annual production tax value for oil and gas produced north of 68 degrees North latitude the gross value at the point of production of the oil or gas meeting either or both of the following criteria is reduced by 20 percent if (1) produced from a lease or property that does not contain land that was within a unit on January 1, 2003; (2) produced from a participating area established after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before January 1, 2012. The gross value at the point of production is not reduced if it is zero or less before any reduction.

Section 25: Repeals AS 43.55.023(m) relating to tax credit certificates.

Section 26: Repeals AS 43.55.011(g), 43.55.023(i) and 43.55.160(c).

Section 27: Applicability sections.

Section 28: Retroactivity provisions for sections 3, 7, 11, 13, 14, 17, 21 and 25.

Section 29: Transition provision providing the Department of Revenue authority to adopt regulations, to be effective not before the date of the effective date of the provisions of this bill.

Section 30: Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22-24, and 26 take effect January 1, 2014.

Section 31: Except as provided in section 30, the remaining sections of the bill will take effect immediately under AS 01.10.070(c).

FISCAL NOTE

STATE OF ALASKA
2013 LEGISLATIVE SESSION

Bill Version	**SB 21**
Fiscal Note Number	1
(S) Publish Date	1/16/13

Identifier (file name)	0647-DOR-TAX-01-15-13	Dept. Affected	Revenue
Title	Production Tax on Oil and Gas	Appropriation	Treasury and Taxation
		Allocation	Tax Division
Sponsor	Rules by Request of the Governor		
Requester	Governor	OMB Component Number	2476

Expenditures/Revenues (Thousands of Dollars)

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

	FY14 Appropriation Requested	Included in Governor's FY14 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY14**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	**0.0**	**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							
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 (FY13) operating costs ______ *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY14) costs ______ *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? yes
If yes, by what date are the regulations to be adopted, amended, or repealed? 1/1/2014 Discuss details in analysis section.

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

Initial version.

Prepared by	Cherie Nienhuis, Ed King and Michael Pawlowski	Phone	907-269-1019
Division	Tax Division	Date/Time	1/15/2013, 11:39 pm
Approved by	Bryan Butcher, Commissioner Department of Revenue	Date	1/15/2013

(Revised 11/5/12 OMB)

FISCAL NOTE ANALYSIS #1

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. SB 21

Analysis

This bill limits the provision that the State of Alaska purchase transferable tax credit certificates for credits earned from leases or properties that contain land that is north of 68 degrees North latitude to credits based on expenditures incurred before January 1, 2014. The operating portion of the long-term fiscal plan anticipates an average of $400 million in refundable credits through 2023. It is anticipated that the limitation of this provision would reduce those future appropriations, beginning in FY 2015.

Regulations: The bill does not direct DOR to adopt new regulations to implement its provisions, but existing regulations may need to be amended to conform to changes in eligibility for redeemable tax credits, and to account for repeal of some sections. There may be additional regulations required, but not before January 1, 2014.

*****The revenue impact of this bill is an estimate based on Fall 2012 Forecast.**
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 separately below. The effective date of each of the bill's provisions listed below is January 1, 2014, with the exception of provision 6 (bill section 7), which is effective for expenditures beginning January 1, 2013.

1. The progressive portion of the production tax at AS 43.55.011(g) is repealed, and the production tax at AS 43.55.011(e) is retained at a tax rate of 25% of production tax value. Based on our Fall 2012 forecast, this change decreases production tax revenue over the forecast period analyzed. Please see detailed summary table on page 3 of this fiscal note.

2. Production tax credits under AS 43.55.023(a) for qualified capital expenditures are limited to expenditures incurred before January 1, 2014 on leases or properties that contain land north of 68 degrees North latitude. Based on our Fall 2012 forecast, this change increases production tax revenue annually over the forecast period analyzed. Please see detailed summary table on page 3 of this fiscal note.

3. Companies that incur net losses from leases or properties that contain land north of 68 degrees North latitude will earn a credit of 25% of those losses to be carried forward for a maximum period of ten years. These net loss carry-forwards will increase at an annual rate of 15 percent beginning on January 1 of the second calendar year following the year of the loss. The revenue impact of this provision is confidential under our forecast, however, the impact is expected to be minimal.

4. A gross revenue exclusion (GRE) is applicable to production from leases or properties containing land that is north of 68 degrees North latitude and meets one or both of two criteria: (1) is produced from a lease or property that does not contain land that was within a unit on January 1, 2003; or (2) is produced from a participating area established after December 31, 2011 for lease or properties in a unit formed before January 1, 2003. This provision is intended to incentivize future production and the revenue impact of this provision based on the current production forecast is minimal.

5. The small producer credit at AS 43.55.024 is extended to the later of 2022 or the ninth calendar year after the calendar year that the producer first has commercial production. This provision extends the small producer credit six years from the original sunset date of 2016. The revenue impact based on the current revenue forecast is minimal.

6. 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 the time value of money impact, it is revenue neutral. This provision applies to expenditures after December 31, 2012

7. The community revenue sharing fund is amended to allow the legislature to make appropriations from the tax revenue collected under AS 43.20, as opposed to revenue collected under AS 43.55.011(g). The impact of this provision is indeterminate.

Analysis Continued

Provisions in the Bill and their Estimated Fiscal Impact as compared to Fall 2012 Forecast ($millions)

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$800	-$1,500	-$1,700	-$1,800	-$1,750	-$1,650
2. Limitation of credits for qualified capital expenditures for North Slope	$300	$700	$650	$550	$475	$400
3. Net operating losses carried forward and increased at 15% per year	Less than -$50 million per year under Fall 2012 forecast					
4. Gross revenue exclusion for certain areas						
5. Small producer credit extended to 2022	$0	$0	$0	-$25	-$25	-$50
6. Provision requiring credits be taken over 2 year eliminated*	-$250					
7. Amendment to the community revenue sharing fund	Indeterminate					
Total Revenue Impact	-$750	-$800	-$1,050	-$1,275	-$1,300	-$1,300
Impact on Operating Budget	-$150	$250	$250	$250	$250	$250
Total Fiscal Impact	**-$900**	**-$550**	**-$800**	**-$1,025**	**-$1,050**	**-$1,050**

*Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $400 million, with $250 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

The impacts listed above are based on production and prices as forecasted in our Fall 2012 revenue forecast. The forecasted oil prices are between $109.61 and $118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

FISCAL NOTE ANALYSIS #1

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. SB 21

Analysis Continued

Differences in General Fund Unrestricted Revenue under Proposed Bill from Current Tax System in $Millions*

*Note: These hypothetical examples of additional production assess the impacts from the **change in tax rates and credits only** and do not attempt to quantify impacts of other parts of the bill, such as the removal of the credit split or the impact on the long-range budget.

At Forecasted Production

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$25	$275	$225	$75	$50	$0
$100	-$200	-$100	-$175	-$300	-$350	-$300
$120	-$900	-$1,350	-$1,425	-$1,525	-$1,475	-$1,350

All additional production scenarios below compare additional production under the proposed bill to ACES without the additional production.

Additional Production Scenario A

Forecasted production plus 50 million barrel field developed by a New Entrant

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$50	$375	$300	$175	$75	$75
$100	-$200	-$75	-$150	-$275	-$350	-$300
$120	-$900	-$1,375	-$1,400	-$1,500	-$1,475	-$1,375

Assumes field outside of a current unit and subject to gross revenue exclusion, first oil in 2017 and peak production of 10,000 barrels per day in 2019. Total development cost of $500 million.

Additional Production Scenario B

With addition of 4 oil rigs to legacy fields drilling from 2014-2019

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$100	$550	$575	$525	$550	$475
$100	-$125	$125	$175	$150	$225	$150
$120	-$825	-$1,100	-$1,000	-$975	-$800	-$800

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

With new well pad and 4 additional rigs in legacy fields, plus new 10,000 bopd field starting in 2017

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	$50	$525	$675	$800	$1,275	$1,200
$100	-$175	$150	$325	$500	$1,025	$975
$120	-$825	-$1,000	-$725	-$475	$225	$225

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

FISCAL NOTE

STATE OF ALASKA
2013 LEGISLATIVE SESSION

Bill Version	**SB 21**
Fiscal Note Number	2
(S) Publish Date	1/16/13

Identifier (file name)	LL0647-DNR-DOG-1-14-13
Title	Production Tax on Oil and Gas
Sponsor	Rules by Request of the Governor
Requester	Governor

Dept. Affected	Natural Resources
Appropriation	Oil & Gas
Allocation	Oil & Gas
OMB Component Number	439

Expenditures/Revenues (Thousands of Dollars)

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

	FY14 Appropriation Requested	Included in Governor's FY14 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY14**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	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							
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 (FY13) operating costs *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY14) costs *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No

If yes, by what date are the regulations to be adopted, amended, or repealed? N/A Discuss details in analysis section.

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

Initial Version.

Prepared by	Bill Barron, Director	Phone	269-8800
Division	Division of Oil and Gas	Date/Time	1/14/13 5:00 PM
Approved by	Daniel S. Sullivan, Commissioner	Date	1/14/2013
	Department of Natural Resources		

(Revised 11/5/12 OMB)

FISCAL NOTE ANALYSIS #2

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. SB 21

Analysis

LL0647 reforms the oil and gas production tax system in Alaska. This bill will not result in any procedural changes in how the Division of Oil and Gas operates and therefore the Department of Natural Resources (DNR) does not anticipate any fiscal impact to the Department's operating budget.

This bill proposes to improve Alaska's competitiveness and encourage producers to invest more by simplifying the oil and gas production tax system. First, this bill repeals the progressive tax structure, which will help encourage the type of long-term planning and investment needed to promote new investment in new production in Alaska. Further, this bill shifts incentives away from spending and provides new incentives to reward new production. At forecasted price ranges, overall government take and marginal tax rates are reduced materially. To the extent that investments are made as a consequence of these changes to the tax regime, royalty revenue may rise.

The fiscal impact on royalty revenue is an indeterminate positive.

FISCAL NOTE ANALYSIS #2

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. SB 21

Analysis Continued

Differences in Royalty Revenues from New Production Scenarios in $Millions*

*Note: These scenarios are based on Department of Revenue modeling.

At Forecasted Production

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$ 120	$0	$0	$0	$0	$0	$0
$ 100	$0	$0	$0	$0	$0	$0
$ 90	$0	$0	$0	$0	$0	$0

Additional Production Scenario A

Forecasted production plus 50 million barrel field developed by a New Entrant

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$0	$0	$0	$12	$24	$35
$100	$0	$0	$0	$10	$20	$29
$90	$0	$0	$0	$9	$17	$26

Assumes field outside of a current unit and subject to gross revenue exclusion, first oil in 2017 and peak production of 10,000 barrels per day in 2019. Total development cost of $500 million.

Additional Production Scenario B

With addition of 4 oil rigs to legacy fields drilling from 2014-2019

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$57	$106	$147	$181	$212	$179
$100	$47	$87	$120	$148	$173	$146
$90	$42	$77	$107	$132	$154	$130

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day and declining at a rate of 15% per year. Development costs for each well assumed to be $20 million.

Additional Production Scenario C

With new well pad and 4 additional rigs in legacy fields, plus new 10,000 bopd field starting in 2017

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$120	$111	$213	$307	$433	$557	$533
$100	$91	$174	$251	$354	$455	$435
$90	$81	$155	$223	$314	$404	$386

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2015 at total development costs of $5 billion. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new 50-million barrel field.

Overview of SB 21
Oil & Gas
Production Tax

January 22, 2013
Alaska Department of Revenue

The Proposal (Highlights)

1. Eliminate Progressivity and Credits Based on Capital Expenditures.
2. Reform remaining credits to be carried forward to when there is production.
3. Establish a “Gross Revenue Exclusion” for newer units and new participating areas in existing units (NEW OIL).
4. Hold Cook Inlet and Middle Earth Harmless.

Eliminate Progressivity & Credits Based on Capital Expenditures

Progressivity

Main Sections: 1,2,26

Conforming Sections: 5,6,22,23

North Slope QCE Credits

Main Sections: 8

Conforming Sections: 7, 11, 12

Reform remaining credits to be carried forward to when there is production.

North Slope Net Operating Loss Credits

Main Sections: 9, 15

Conforming Sections: 10, 19, 20

Small Producer Tax Credits

Main Sections: 16

Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units.

Gross Revenue Exclusion (The GRE)

Main Sections: 24

Conforming Sections: 5

Hold Cook Inlet and Middle Earth Harmless

Hold Cook Inlet & Middle Earth Harmless

Main Sections: 3

Conforming Sections: 4, 13, 14, 17, 18, 21, 25

ARRESTING TAPS THROUGHPUT DECLINE & OIL TAX REFORM

TAPS Throughput Committee

Tuesday, January 22, 2013

Juneau, Alaska

Dan Sullivan, Commissioner

Alaska Department of Natural Resources

Bryan Butcher, Commissioner

Alaska Department of Revenue

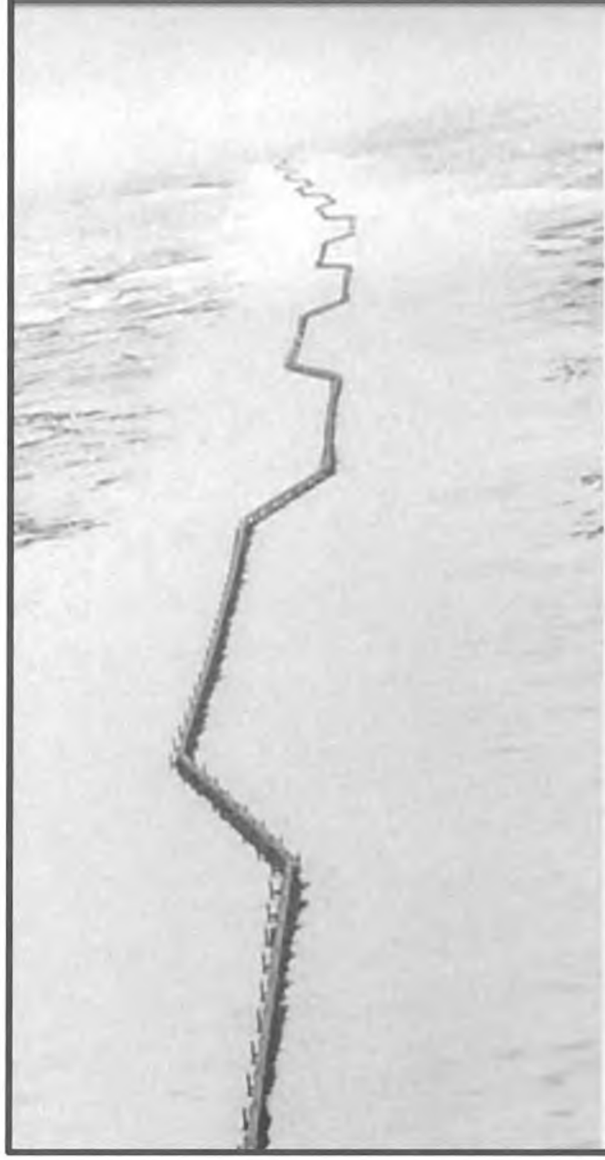
TAPS

- A Critical State & National Energy Asset -

- The Trans Alaska Pipeline, 11 pump stations, several hundred miles of feeder pipelines, and the Valdez Marine Terminal constitute the Trans-Alaska Pipeline System (TAPS).
- At 800 miles long, the Trans Alaska Pipeline is one of the longest pipelines in the world; it crosses more than 500 rivers and streams and three mountain ranges as it carries Alaska's oil from Prudhoe Bay to Valdez.
- The U.S. Congress was instrumental in the approval and rapid development of TAPS. Congress approved construction of the pipeline with the Trans Alaska Pipeline Authorization Act of 1973.
- The principle focus of this Act is as relevant today as it was in 1973: *"the early development and delivery of oil and gas from Alaska's North Slope to domestic markets is in the national interest because of growing domestic shortages and increasing dependence upon insecure foreign sources."*

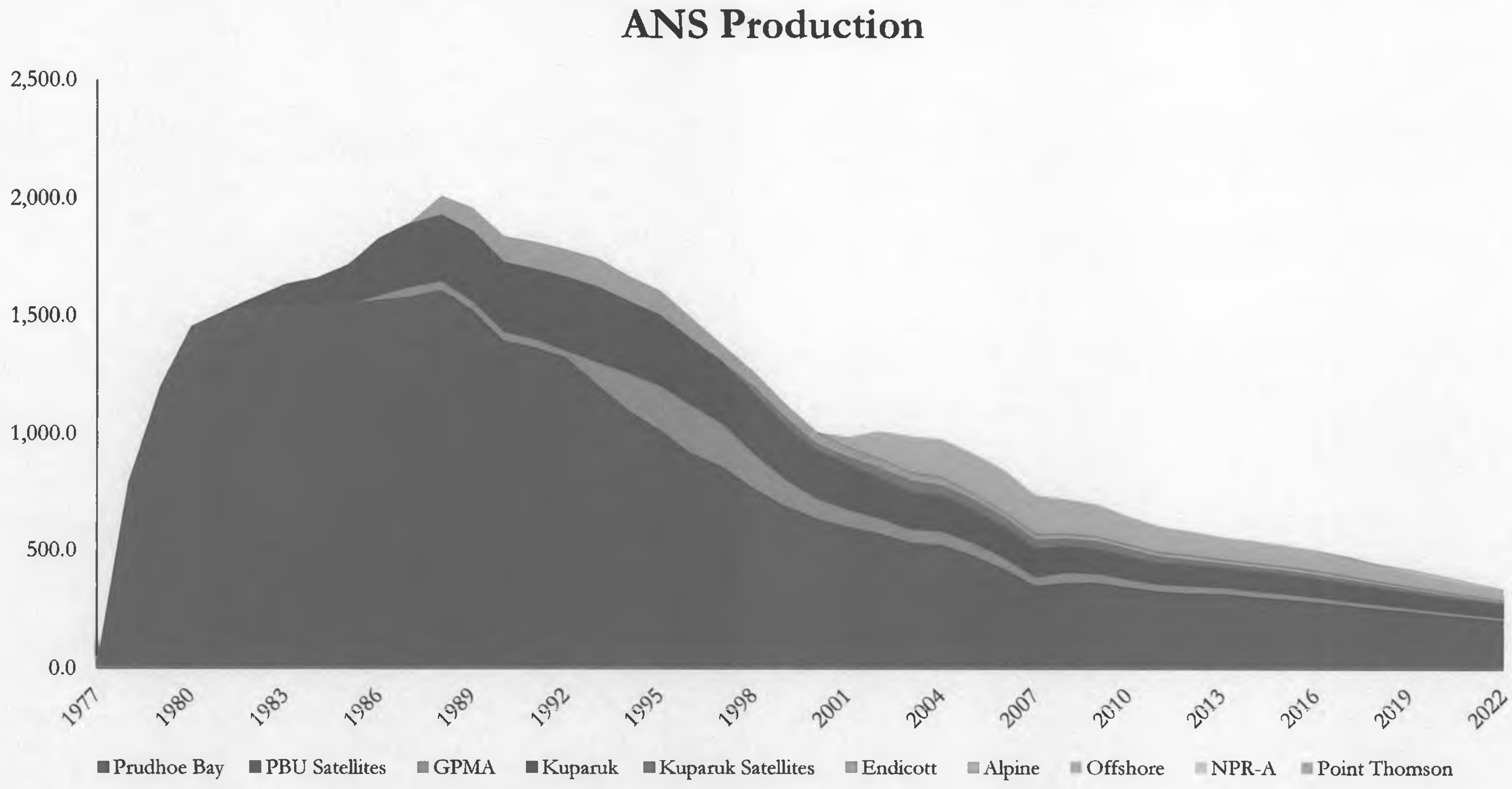
TAPS

- A Critical State & National Energy Asset -



- TAPS has transported over 16.3 billion barrels of oil and natural gas liquids since June of 1977. Production peaked at 2.2 million barrels per day in the late 1980s, representing 25% of U.S. domestic production
- Since its peak, however, throughput has steadily declined; today, TAPS is 2/3 empty and declining at an average of 6% per year
- TAPS throughput decline threatens economic disruption and the very existence of our pipeline
- We must encourage industry to invest in exploration and development of conventional and unconventional resources on state and federal land, onshore and offshore
- TAPS has plenty of capacity for increased throughput
- Most near-term critical economic issue facing the state
- Less oil in the pipeline year after year takes away revenue from future generations—the ultimate giveaway
- Reconfiguration, 1.2 million barrels/day

OIL TAX REFORM
- PRODUCTION HISTORY -



Source: Alaska Department of Revenue Fall 2012 Revenue Sources Book: http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2682f

TAPS

- Throughput Decline is an Urgent Problem -

- TAPS throughput decline is the MOST URGENT issue facing the State's economic future
- January 2011 TAPS shutdown

Petroleum News, February 27, 2011:
"Jan. shutdown puts TAPS close to brink:

Alyeska executives describe efforts to prevent freezing in pipeline after pump station oil leak in era of low oil throughput"

WSJ, May 11, 2011:

"Shrinking Oil Supplies Put Alaskan Pipeline at Risk"

"Now, dwindling oil production along Alaska's northern edge means the pipeline carries less than one-third the volume it once did—and the crude takes five times as long to get to its destination.

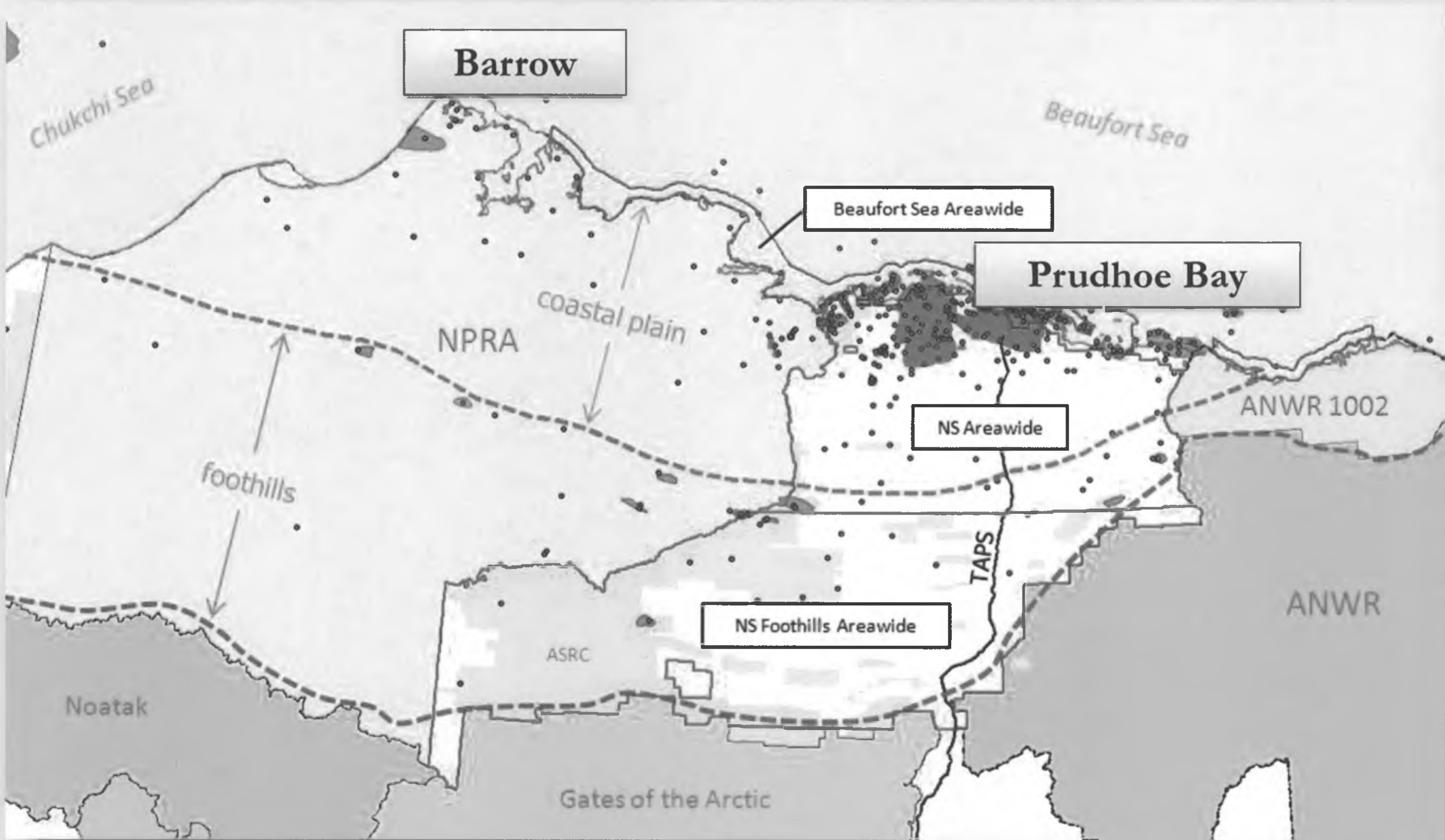
That leisurely flow means the oil is above ground longer and more exposed to Alaska's frigid weather; the crude sometimes arrives chilled to 40 degrees. As the flow and temperature continue to drop, experts say the risks of a clog or corrosion increase, as do the odds of ruptures and spills."

ALASKA'S NORTH SLOPE OIL & GAS POTENTIAL

- USGS estimates that Alaska's North Slope has more oil than any other Arctic nation
  - **OIL:** Est. 40 billion barrels of conventional oil *(USGS & BOEMRE)*
  - **GAS:** Est. over 200 trillion cubic feet of conventional natural gas *(USGS)*
- Alaska has world-class unconventional resources, including tens of billions of barrels of heavy oil, shale oil, and viscous oil, and hundreds of trillions of cubic feet of shale gas, tight gas, and gas hydrates
  - Positive methane hydrate test production

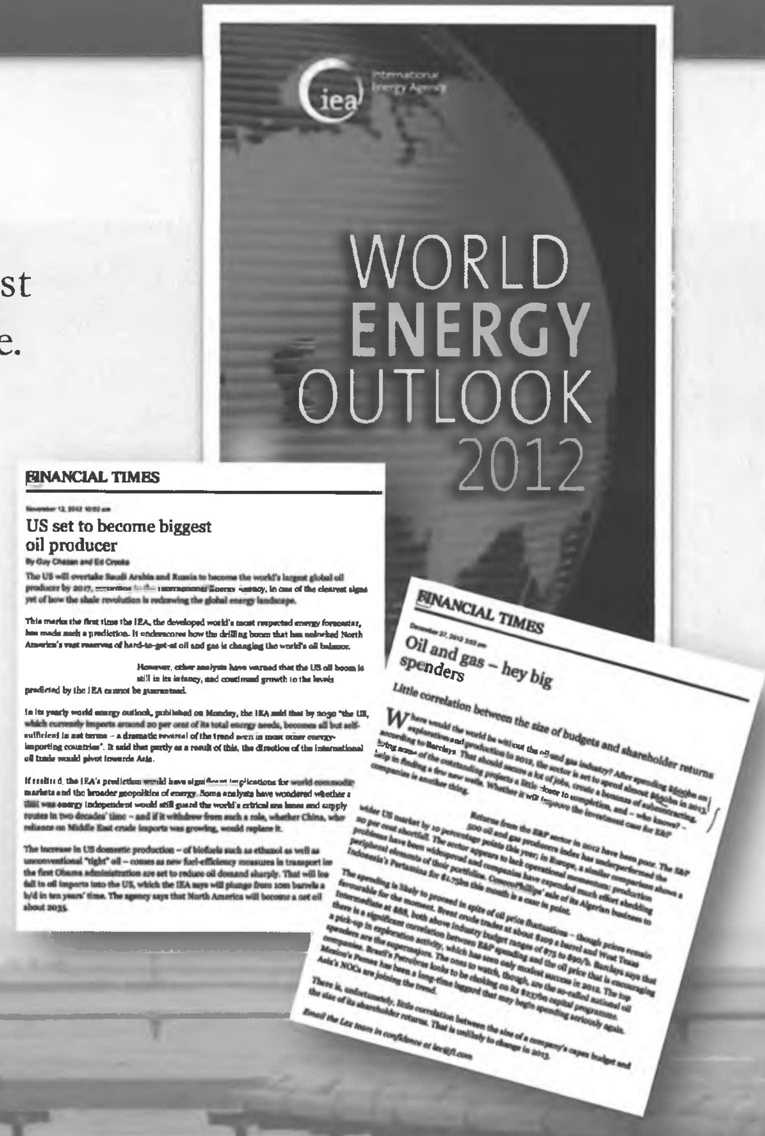
Compared to most hydrocarbon basins, Alaska is relatively underexplored, with 500 exploration wells on the North Slope, compared to Wyoming's 19,000.

Alaska's North Slope Oil & Gas Potential



U.S. Energy Renaissance

- Global and U.S. hydrocarbon boom
- IEA World Energy Outlook 2012 – U.S. to overtake Saudi Arabia and Russia to become the world's largest global oil producer by the second half of this decade.
- **Financial Times, November 12, 2012 –**
  "U.S. set to become biggest oil producer"
- **Financial Times, December 27, 2012 –**
  "Oil and gas – hey big spenders"
  - 2012 - $600 billion on exploration and production in oil and gas industry
  - 2013 projected - $650 billion on exploration and production in oil and gas industry



Other Basins have Turned Decline Around

THE INDEPENDENT

North Sea set to create 50,000 new jobs as investment soars

Tom Bawden

Monday, 14 January 2013

North Sea employment is set to boom this year. Up to 50,000 new jobs are expected in
Britain's oil and gas in

The jobs bonanza wil
support-services staff
North Sea to nearly ha

"There's been a lot of
at the moment," said
behind the research.
their life. At the same
have made it economi
he added.

Further down the line,
35,000 jobs in the ne
Institute of Directors.

The expansion has bee
set to be ploughed int
be the biggest creator
the North Sea for a de
Shetland Isles, that wi

The surge in investme
Sea development, pro
Energy and Climate Ch

Although North Sea p
output was 4.5m barr
2m barrels. On the do
to compete for emplo
more than twice the n

"The expansion has been spurred by record-breaking levels of investment, with about £40bn set to be ploughed into North Sea production in the next three years…"

"The surge in investment comes after the government relaxed the tax regime around North Sea development, prompting a record-breaking licensing round when the Department of Energy and Climate Change awarded 167 new licenses on 330 blocks last October."

"Budget 2012: North Sea oil tax reforms 'to lead to £50bn investment': An extra £50bn could be pumped into the North Sea oil and gas industry thanks to a new package of tax reforms."

Budget 2012: North Sea oil tax reforms 'to lead to £50bn investment'

An extra £50bn could be pumped into the North Sea oil and gas industry thanks to a new package of tax reforms.

The Budget was a 'turning point' for industry relations with the Treasury. Photo: Rex Features

By Emily Gosden

10:11PM GMT 21 Mar 2012

Industry body Oil & Gas UK said the Chancellor's promise of certainty on decommissioning tax relief and new tax breaks on small and deepwater fields would stimulate tens of billions of pounds of additional investment.

The Budget was a "turning point" for industry relations with the Treasury after outrage at the surprise tax rise in last year's Budget, Oil & Gas UK said. The measure means more than 2bn barrels of the UK's oil and gas reserves that would otherwise have been left in the ground will now eventually be recovered at no net cost to the Exchequer.

The Treasury estimates that the reforms could actually boost its coffers by £1bn over the next five years, due to tax on projects that would not otherwise have gone ahead.

The Chancellor confirmed that he would draw up a contract with the industry to permanently guarantee levels of tax relief on the £30bn bill for decommissioning old infrastructure, a move that Oil & Gas UK said could stimulate up to £40bn investment during the lifetime of the North Sea basin. Anxiety over whether rates might be cut has blocked some deals.

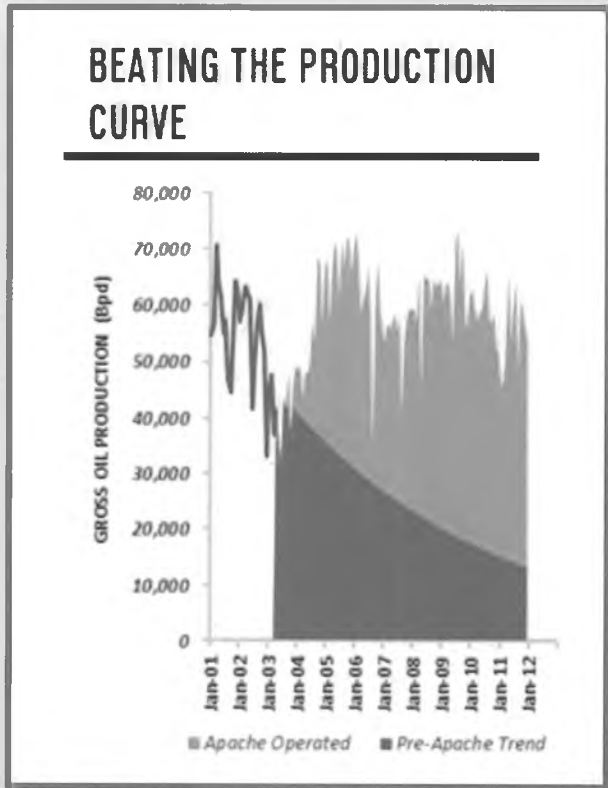
The Chancellor unveiled new 'field allowances', doubling tax breaks for developing smaller fields and introducing a £3bn allowance for some deepwater fields with significant reserves in the new exploration frontier West of Shetland. The allowances should see £10bn extra investment, the industry body said.

Malcolm Webb, Oil & Gas UK's chief executive, said the Budget was a "turning point for the UK's oil and gas industry" toward "a more stable future fostered by constructive collaboration between government and industry".

Other Basins have Turned Decline Around

Apache Corporation: Forties Field Acquisition

- Field discovered in early 1970s by BP; purchased by Apache in 2003
- Contains estimated 4.2 to 5.0 billion barrels of oil in place
- Production peaked at over 500,000 Bpd, but by 2003, had declined to 40,000-45,000 Bpd
- Apache has "beaten the curve" by adding reserves, production, and value
- Have returned over 400% of their original 2003 investment



Data from www.apachecorp.com

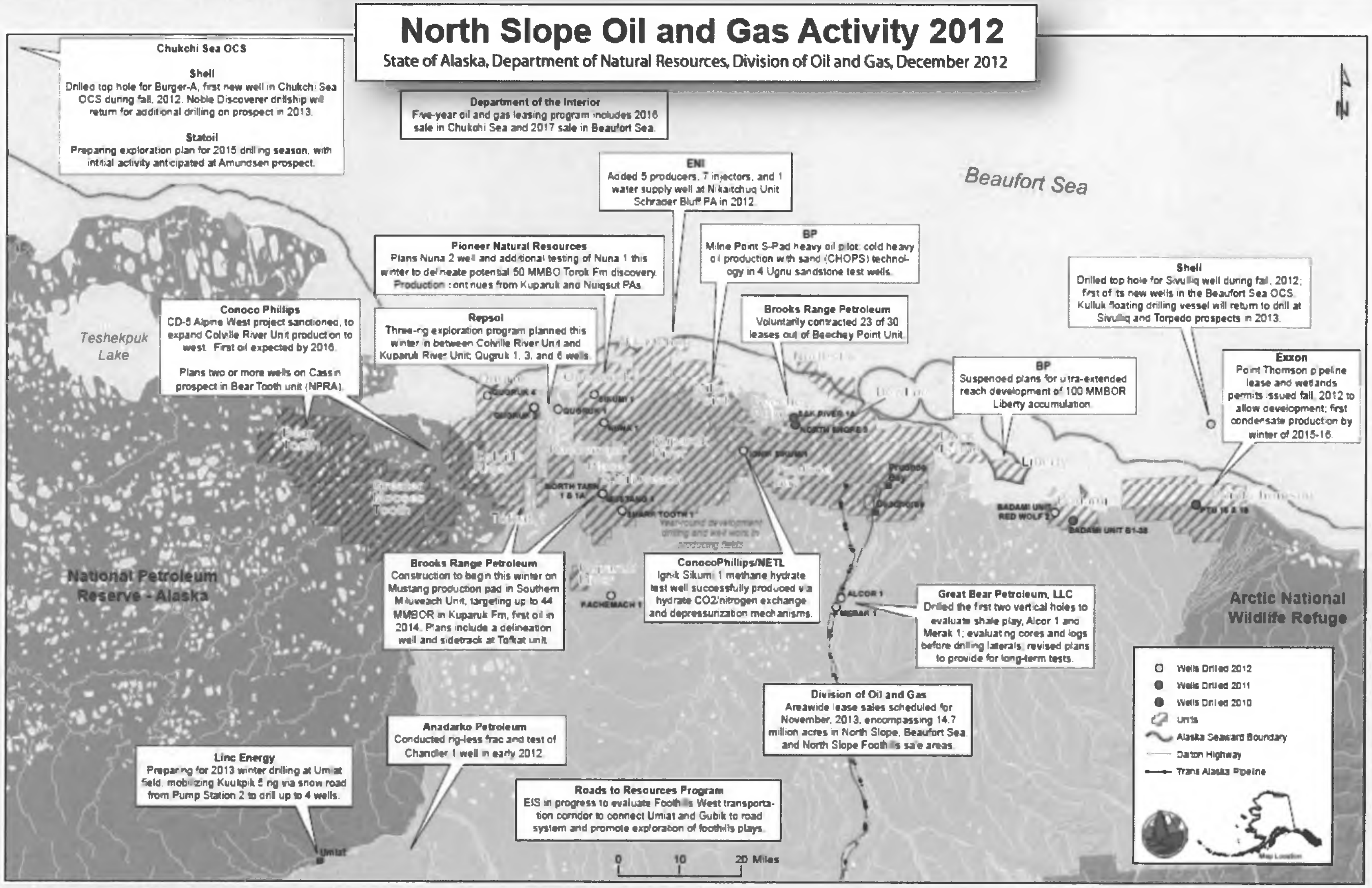
SECURE ALASKA'S FUTURE—*OIL*

- ***Secure Alaska's Future—Oil*** is the State's comprehensive strategy to increase TAPS throughput to one million barrels a day
    I. Enhance Alaska's global competitiveness and investment climate
    II. Ensure the permitting process is structured and efficient
    III. Facilitate and incentivize the next phases of North Slope development
    IV. Promote Alaska's resources and positive investment climate to world markets

- **Governor Parnell's 2013 State of the State: *"Our problem is not below the ground. Our problem is above the ground."***
    - The missing piece is meaningful tax reform
    - "Our state's prosperity has always rested on natural resources. Tonight, that foundation is at risk, not because we are running out of oil, but because we are running behind the competition."

SECURE ALASKA'S FUTURE: *OIL*

- NORTH SLOPE RECENT & PROPOSED ACTIVITY FOR OIL & GAS -



OIL TAX REFORM
- PRINCIPLES -

- Governor reiterated his principles:
  - Tax reform must be fair to Alaskans
  - Encourage new production
  - Simple so that it restores balance to the system
  - Durable for the long-term
- Integrated team – DOR and DNR
- Consultants - EconOne

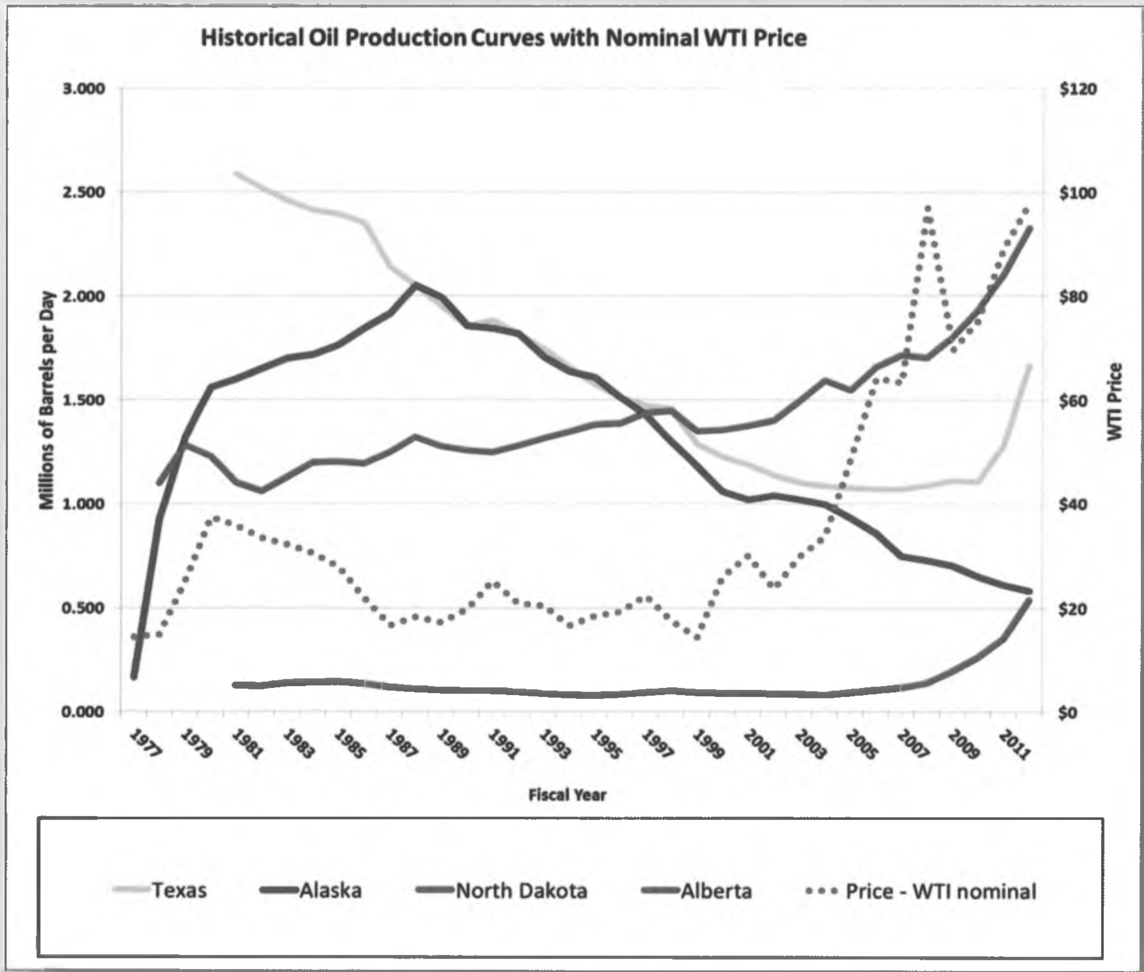
OIL TAX REFORM
- THE PROCESS -

- The team reviewed previous work by both the Legislature and the Administration
- Identified problems with the current tax system
  - Declining Production
  - Competitive Environment
  - Progressivity
  - Tax Credits
- Coordinated effort to understand impacts of production decline on TAPS/Revenues

OTHER BASINS HAVE TURNED DECLINE AROUND

- HISTORICAL OIL PRODUCTION -

How Did Our Competition Fare When Prices Spiked?



Comparing Alaska

- Consultants have compared Alaska to other opportunities using detailed models and analyzing a variety of financial metrics.
- The following example is for a 50 million barrel development in Alaska and comparable developments in the Lower-48, Canada and United Kingdom North Sea.
  - Developed by a new entrant to the State.
  - Compares net present value (NPV) per barrel of oil equivalent discounted 12%

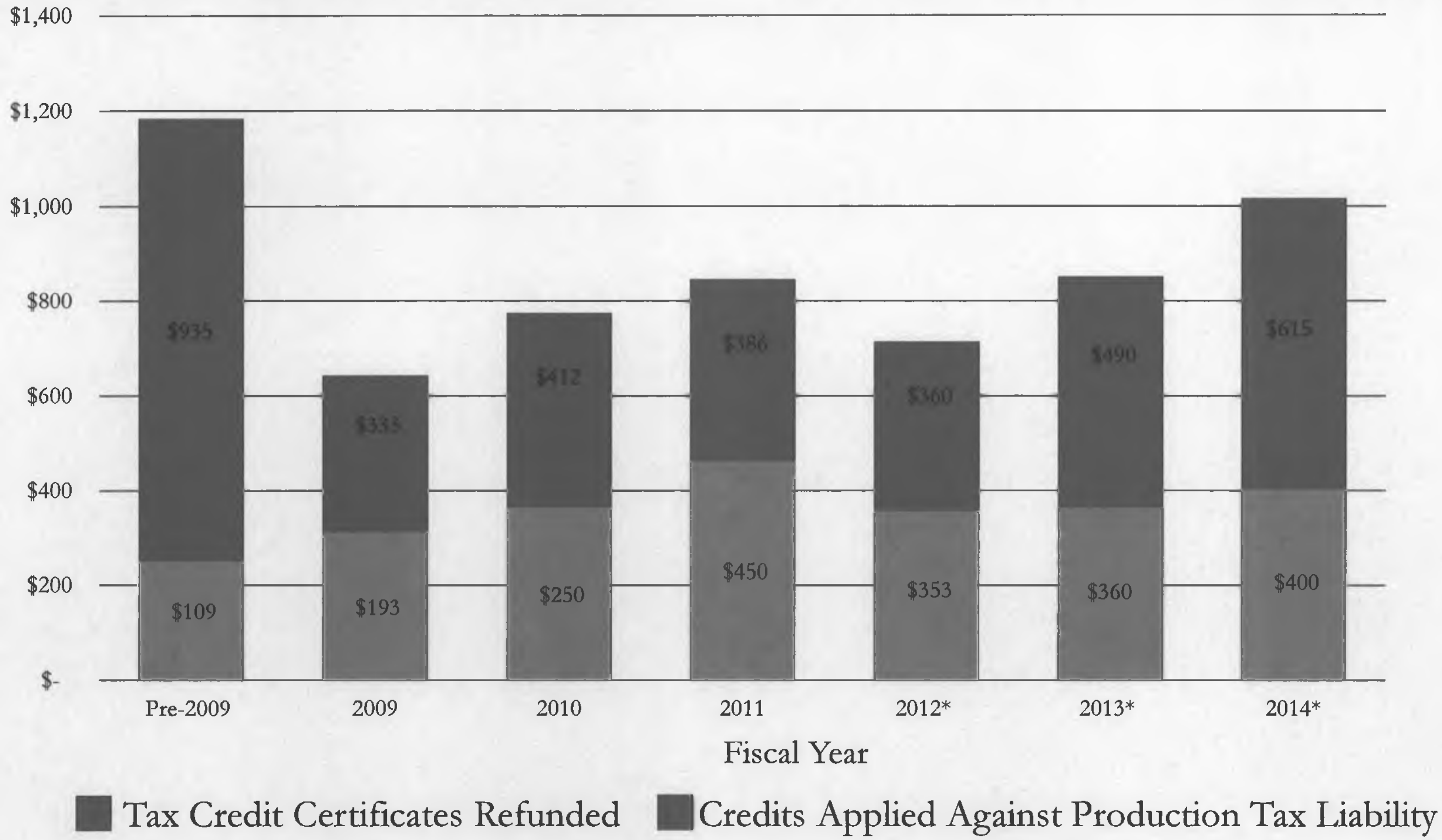
West Coast ANS Prices	NPV-12% ACES (Current)	NPV-12% Average L48 Unconventional	NPV-12% Norway	NPV-12% UK Post-1993 with Brownfield
$70	$1.78	$.11	-$.81	$2.74
$90	$3.47	$3.66	$1.29	$6.43
$100	$4.07	$5.53	$2.34	$8.25
$110	$4.86	$7.84	$3.39	$10.06

Example: ***at $100 a barrel, a company would earn $4.07 in Alaska but $5.53 in the Lower 48 and $8.25 in the U.K. North Sea.***

OIL TAX REFORM
- PROGRESSIVITY-

- Progressivity is complicated and unpredictable, both for the state and investors
  - Tax rate increases by .4% for every $1 per barrel that the production tax value (price minus transportation costs minus lease expenditures) exceeds $30/barrel up to $92.50 per barrel, then .1% until the total tax rate equals 75%
  - Calculated Monthly
- High marginal tax rates

OIL TAX REFORM
- PRODUCTION TAX CREDITS -



*Estimated pending final true-ups
** Fall 2012 Revenue Sources Forecast

Source: Alaska Department of Revenue

OIL TAX REFORM
- TAPS TARIFFS—WORK TO DATE-

- Identified growing concern in DOR and DNR that TAPS tariffs in our revenue modeling did not dynamically link throughput with tariff rates or capture any added capex or opex spending for low-throughput mitigation measures
- Current work **NOT** designed to find the optimal low-flow mitigation option or forecast specific operational outcomes and exact tariffs

- Preliminary Observations:
  - Low flow mitigation capital and operating expenditures could increase tariffs by as much as $1 (18%) per barrel by 2019 and as much as $2.50 (33%)per barrel in 2022
  - Assuming price, production and tariff provided in the Fall 2012 Revenue Sources Book, a $1 increase in the TAPS tariff will decrease state oil and gas revenue by an average of $110 million

OIL TAX REFORM
- THE PROPOSAL: HIGHLIGHTS -

1. Eliminate Progressivity and Credits Based on Capital Expenditures
2. Reform remaining credits to be carried forward to when there is production
3. Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units (NEW OIL)
4. Hold Cook Inlet and Middle Earth Harmless

01/24/13 SB 21 - Analysis of Alaska’s Tax System by Barry Pulliam, Econ One Research

<TARGET><BILL>SB 21</BILL><SUBJECT>01-24-13 SB 21 - Analysis of Alaska’s Tax System by Barry Pulliam, Econ One Research</SUBJECT><COMM>STTP28</COMM></TARGET>

Analysis of Alaska's Tax System, North Slope Investment and The Administration's Proposal

Econon One Research, Inc.

January 24, 2013

Presentation Structure

I. Introduction

II. The Petroleum Industry in Alaska

III. History of North Slope Production, Development and Tax Systems

IV. North Slope Activity Over The Past Decade

V. Benchmarking North Slope Activity Against Other Areas

VI. Attractiveness of Investments Under ACES

VII. The Administration's Proposed Changes

I. Introduction

Econ One: Who We Are

- Economic Research and Consulting Firm
  - Offices in Los Angeles, Houston, Sacramento and Washington D.C.
  - Provide Economic Analysis In Energy and Other Industries
- The Econ One Team Is Led By Barry Pulliam
  - Includes Washington Lem, Lisa McGuff, Tasha Reese and Dr. Anthony Finizza
- Advised the State of Alaska on Petroleum Related Matters For Over Two Decades
- Worked With the Cowper, Hickel, Knowles, Murkowski, Palin, and Parnell Administrations
- Assisted the Legislature Between 2005 and 2008 on Tax and Gas Development Issues
- Energy-Related Work Outside Alaska
  - State Governments: Texas, Louisiana, New Mexico, Oklahoma, California
  - Federal Government Agencies: Department of Interior, Federal Trade Commission
  - Producers, Refiners, Pipelines and Chemical Companies

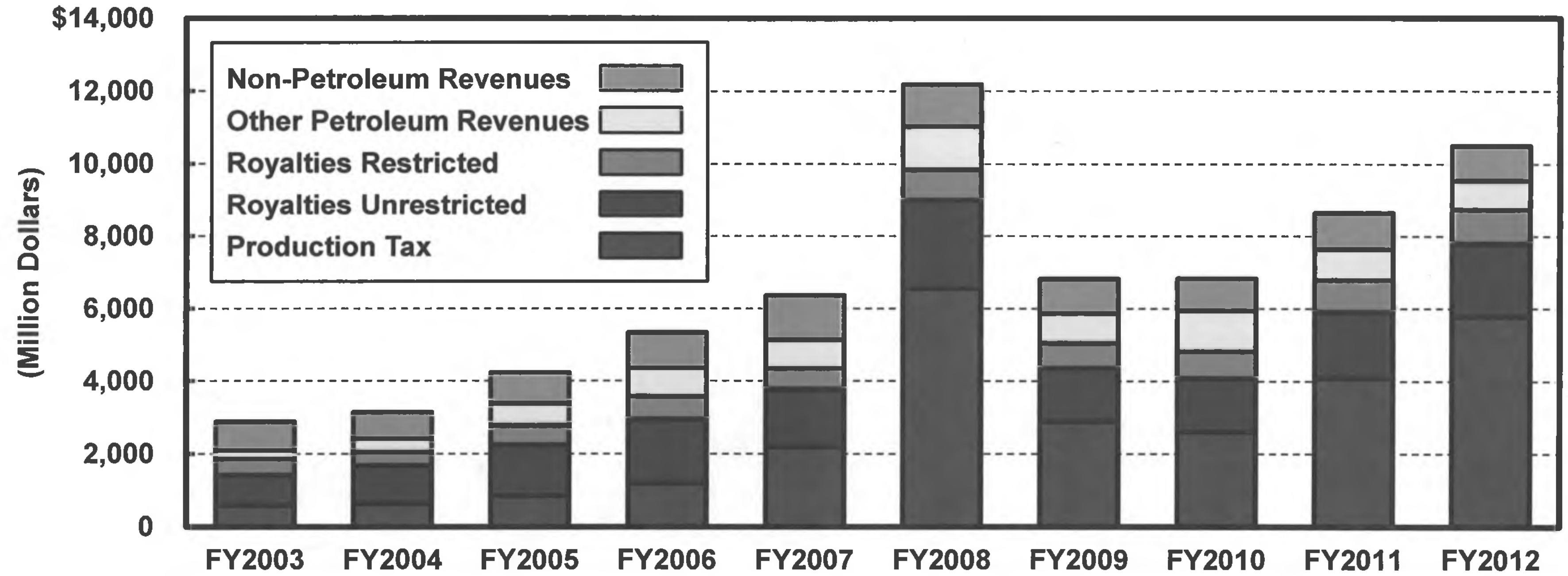
Overview of Analysis

- North Slope Development, Production, and Resources
- Evolution of Alaska's Fiscal and Tax System
  - Gross Tax (ELF), Net Tax (PPT, ACES)
- Examination of North Slope Activity Over The Past Decade
  - Production, Employment, Spending, Drilling
- Benchmarking the North Slope Against Other Areas
  - Key Producing Areas in OECD Countries
  - Lower-48, Canada, North Sea, Australia
- Examination of North Slope Investment Opportunities
  - Across Alaska's Gross and Net Tax Systems
  - Relative to Benchmark Areas
- Examination of Proposed Changes to Tax System
  - Rationale and Implications
  - Impact on Investment Opportunities

II. The Petroleum Industry in Alaska

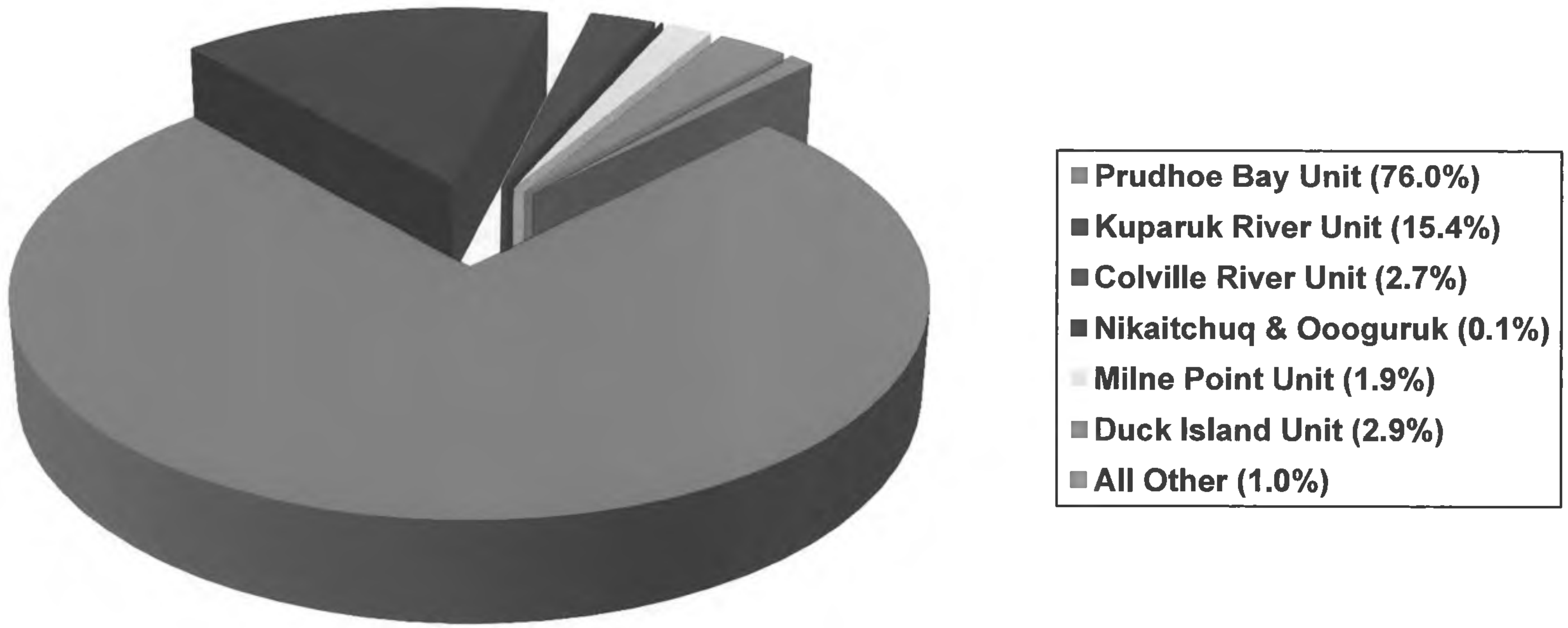
Impact of Petroleum on State Revenues
Total State Revenues Excluding Federal and Investment
FY2003 - FY2012

- Petroleum Industry is Largest Contributor to State Economy
- Industry Accounted For 92% of Unrestricted Revenues and 86% of Restricted and Unrestricted Revenues Over the Past Decade
- Production Taxes Accounted for 61% of Petroleum Revenues In FY2012, Up From 27% Prior to FY2007



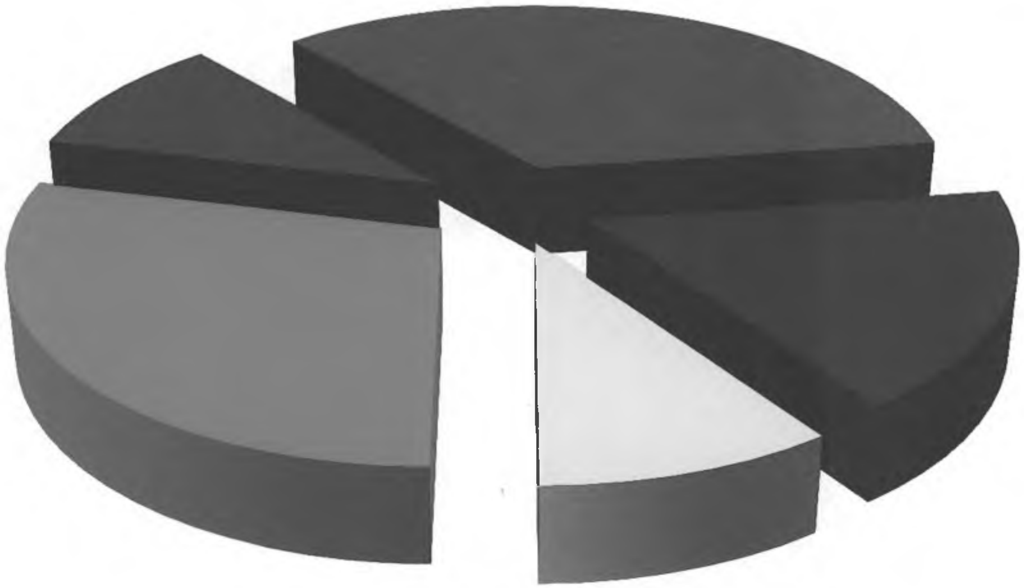
Alaska North Slope: An Overview

- The North Slope Has Produced Approximately 16 Billion Barrels of Crude Oil Since 1977
- The Vast Majority of North Slope Production Has Come From Two Giant "Legacy" Fields, Prudhoe Bay and Kuparuk, Discovered in the 1960s. Production From These Two Fields is Naturally Declining Over Time, Though the Decline Has Been Partially Offset by the Addition of Smaller Discoveries.



Alaska North Slope: An Overview (cont'd)

- Many North Slope Fields are Now at Mature Stages. However, Less Than Half of its Potential Economic Oil Resources Have Been Produced to Date
- In Total, the North Slope Contains Approximately 40 Billion Barrels of Additional Estimated Economic Recoverable Resources at Today's Prices



- Historical Production (16.2 BBO)
- Conventional Resources - Discovered (5.6 BBO est.)
- Conventional Resources - Undiscovered (19.2 BBO est.)
- ANWR (9.9 BBO est.)
- Unconventional Resources (5.5 BBO est.)

Alaska North Slope: An Overview (cont'd)

- While the Potential is Great, These Remaining Resources are Not "Low-Hanging" Fruit
  - The Exploration and Development Costs on the North Slope are High Relative to Much of the Rest of the World
  - The North Slope is a Physically Challenging Environment, With Much of the Remaining Resources Located Offshore
  - And Much of the Remaining Resources are Located on Federal Properties, Where Development Has Been and May Continue to be Delayed Due to Legal Challenges and Changing Federal Policies and Requirements

- In Addition, the North Slope has Significant Natural Gas Resources That Have Yet to be Commercialized

Estimated Undiscovered Conventional Oil Resources on Alaska North Slope

	Technically Recoverable Resources			Economically Recoverable	Expected Typical
	P95	Mean	P5	@ $90/bbl	Field Size
	(Million Barrels)				
	(1)	(2)	(3)	(4)	(5)
Central North Slope	2,800	3,400	3,900	3,000	32 - 64
Beaufort Sea	400	8,200	23,200	5,800	-
Chukchi Sea	2,300	15,400	40,100	9,900	-
NPRA	400	900	1,700	500	32 - 64
ANWR	5,900	10,400	15,200	9,900	64 - 128
Total		**38,300**		**29,100**	

Source:
USGS Reports 2011–1103 and 2009-1112;
BOEM, Assessment of undiscovered technically recoverable oil and gas resources of the nation's outer continental shelf.

Estimated Undeveloped Unconventional Oil Resources on Alaska North Slope

Shale ~ 1 Billion Bbls

(Mean Estimated Technically Recoverable Barrels)

(USGS, 2012)

Viscous and Heavy Oil

(Includes All Schrader/West Sak and Ugnu Reservoirs in the Kuparuk River, Prudhoe Bay, Milne Point and Nikaitchuq Units, Not Just PAs or Areas Under Development)

Total In-Place Resource 24 - 27 Billion Bbls

(Hartz, et al., 2007; AOGCC)

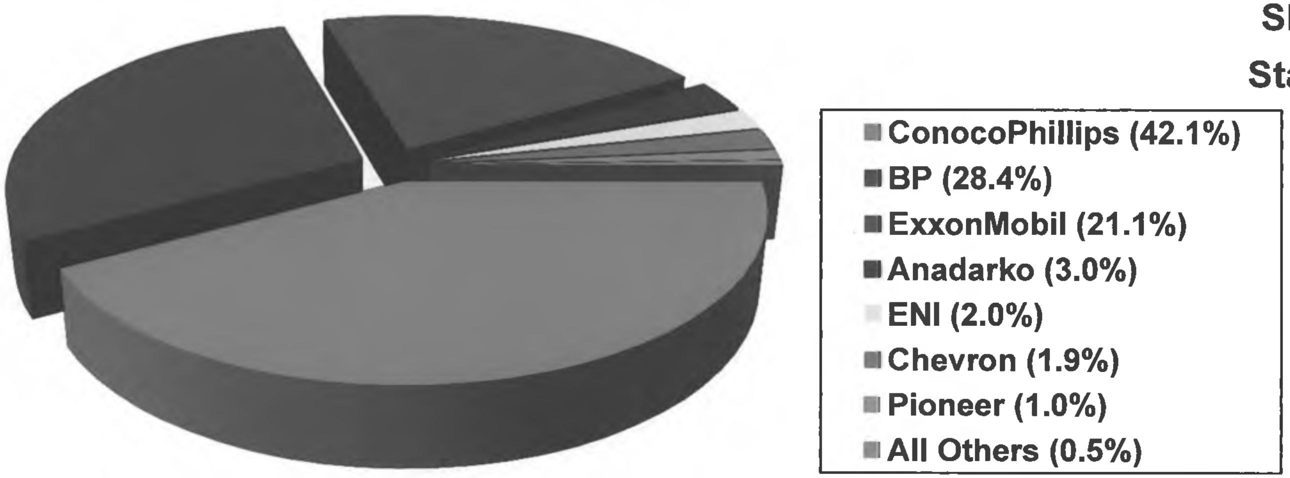
Economically Recoverable 3.6 - 5.6 Billion Bbls

(Assuming 15% Average Recovery)

Current and Potential ANS Producers

- **Three Large Producers Account for Most of the State's Current Production. However, in Recent Years, Alaska Has Attracted a Number of New Participants, With Several Developing and Operating Fields on Their Own**

The Majors	Other Producers	Explorers
BP	Anadarko	Armstrong
ConocoPhillips	Pioneer	Brooks Range
Exxon Mobil	ENI	Great Bear Petroleum
Chevron	Savant	Linc Energy
		Repsol
		Shell
		Statoil



Current and Potential ANS Producers
The Majors

- Account for Approximately 9.5 Million BOED of Production Worldwide
- Account for More Than 90% of North Slope Production, About 0.4 Million BOED Net in Alaska
- Activity in Alaska
  - BP: Developing Resources From Existing Fields; Facility Renewal; Liberty Suspended
  - ConocoPhillips: Developing Kuparuk, Colville River and Expansion
  - ExxonMobil: Developing Point Thomson
  - Not Actively Exploring Outside These Areas
- Outside of Alaska
  - BP: High Margin Areas: Angola, Azerbaijan, Gulf of Mexico, North Sea
  - ConocoPhillips: High Margin Areas: Unconventional Lower-48, North Sea, Canada, Asia Pacific
  - ExxonMobil: Russia; Recent Offshore Discoveries in Gulf of Mexico (Hadrian) and Newfoundland (Hebron)

Current and Potential ANS Producers
Other Producers / Explorers

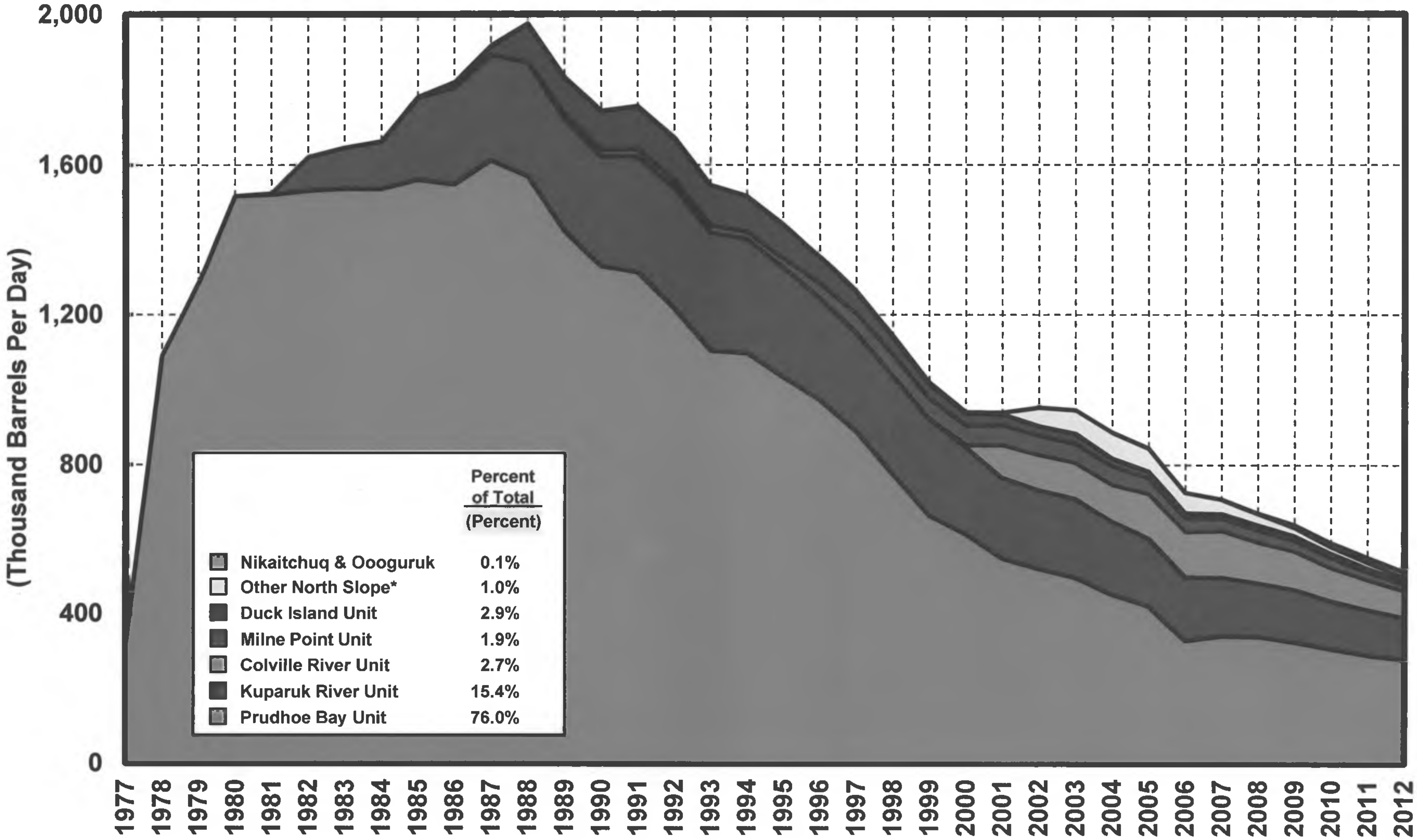
- Pioneer and ENI Operating and Continuing to Develop Oooguruk and Nikaitchuq, Respectively
  - First Operators on North Slope Other Than Majors
  - Combined Resource Potential Greater Than 250 Million BOE
- Anadarko is Fourth Largest Interest Owner on North Slope; Acquired Additional Foothill Leases This Year
- Repsol Partnering With Affiliate of Armstrong Oil and Gas
  - Announced $768 Million Multi-Year Budget; Drilled 3 Exploration Wells in 2012
- Brooks Range Developing Mustang: Estimated P2 Reserves Between 40 and 50 Million BOE
  - Working With AIEDA on Initial Financing
- Great Bear Exploring Shale Potential
- Linc Energy Exploring Umiat in NPRA
- Savant Operating and Developing Badami; Took Over From BP in 2011

Current and Potential ANS Producers
Offshore Explorers

- ➢ Shell Spent $2.1 Billion to Acquire Chukchi and Beaufort Sea Leases in 2008
  - Estimated Spending of $4.5 Billion to Date
  - First Drilling in 2012
- ➢ ConocoPhillips Spent $500 Million on Chukchi Leases
  - Plans Drilling Activity in 2014
- ➢ Statoil Spent $23 Million on Offshore Leases
  - Watching Shell for Now

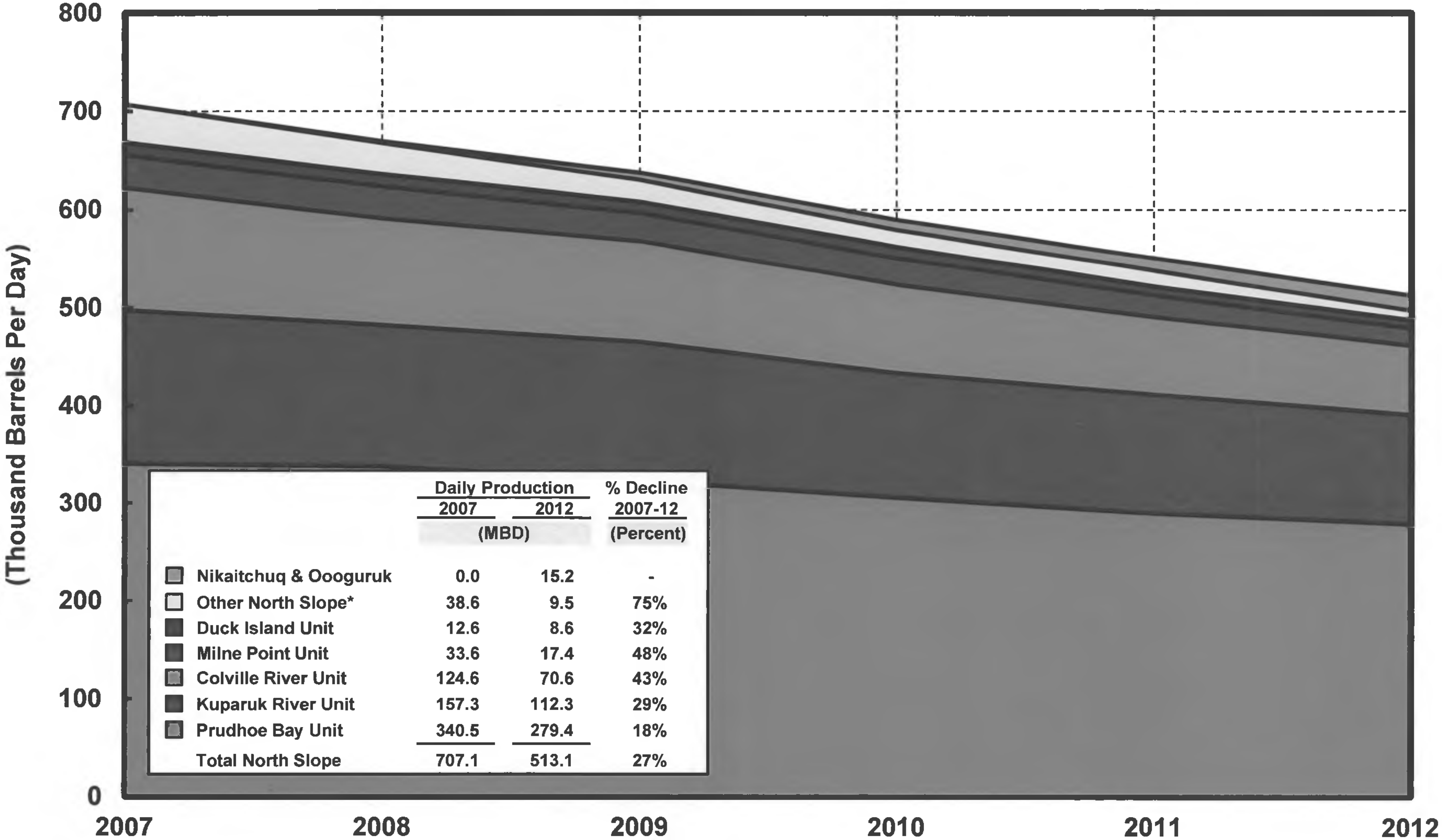
III. History of North Slope Production, Development and Tax Systems

Historical Volumes by Year and Field
1977 - 2012



* Badami and Northstar.
Source: AOGCC.

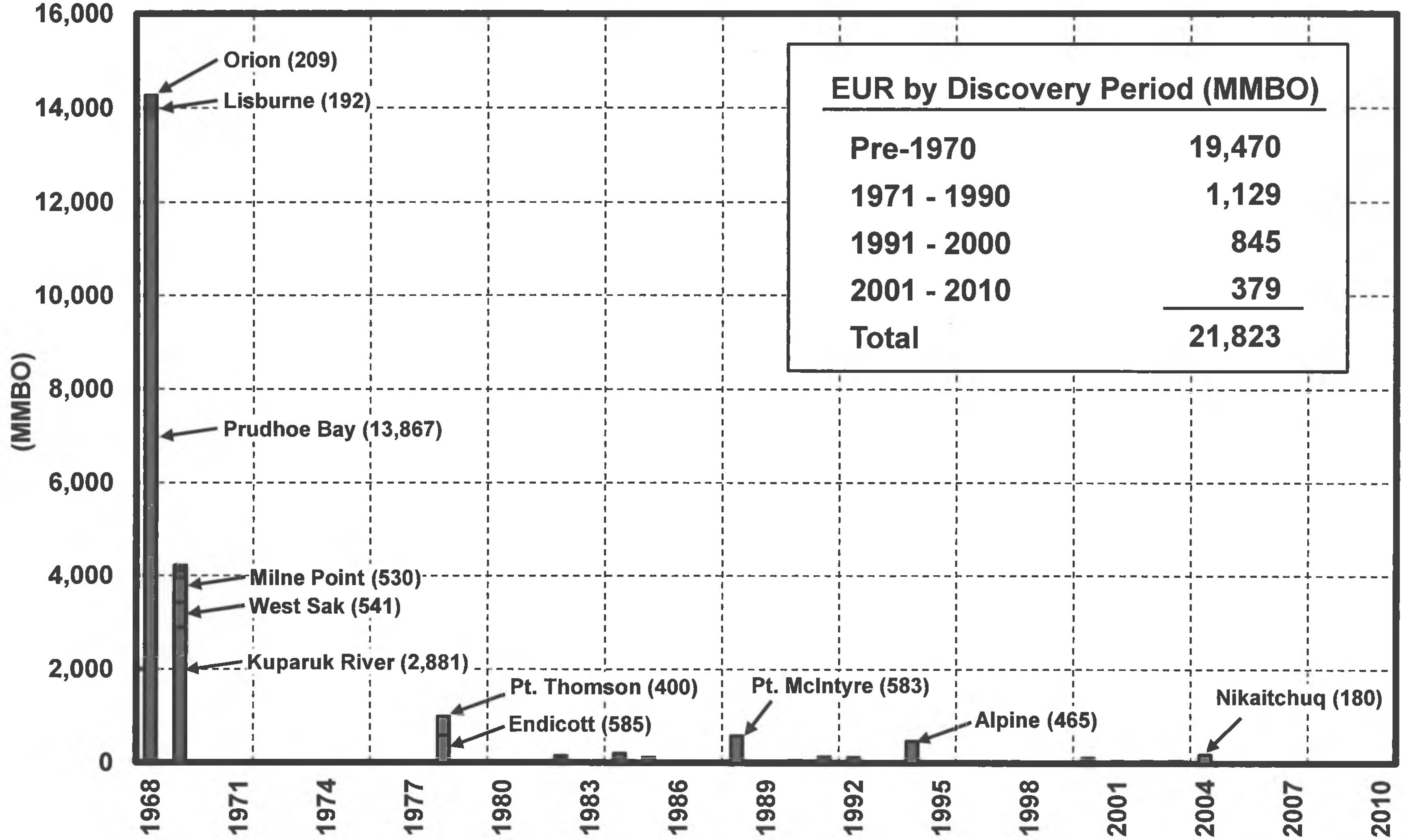
Historical Volumes by Year and Field
2007 - 2012



	Daily Production 2007	Daily Production 2012	% Decline 2007-12
	(MBD)		(Percent)
Nikaitchuq & Oooguruk	0.0	15.2	-
Other North Slope*	38.6	9.5	75%
Duck Island Unit	12.6	8.6	32%
Milne Point Unit	33.6	17.4	48%
Colville River Unit	124.6	70.6	43%
Kuparuk River Unit	157.3	112.3	29%
Prudhoe Bay Unit	340.5	279.4	18%
Total North Slope	707.1	513.1	27%

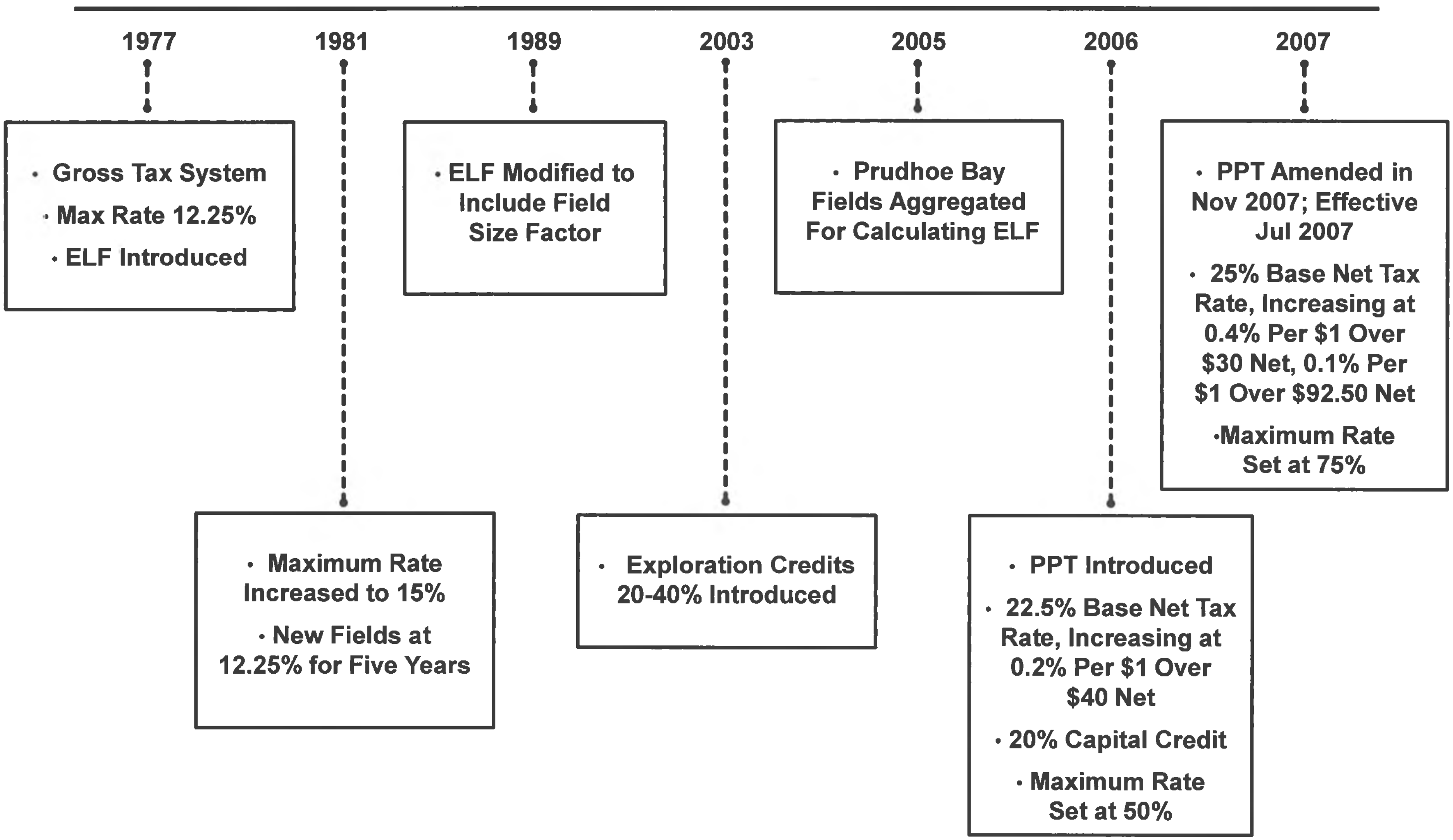
* Badami and Northstar.
Source: AOGCC.

Alaska North Slope Estimated Ultimate Oil Recovery (EUR) by Discovery Year (1969 – 2010)

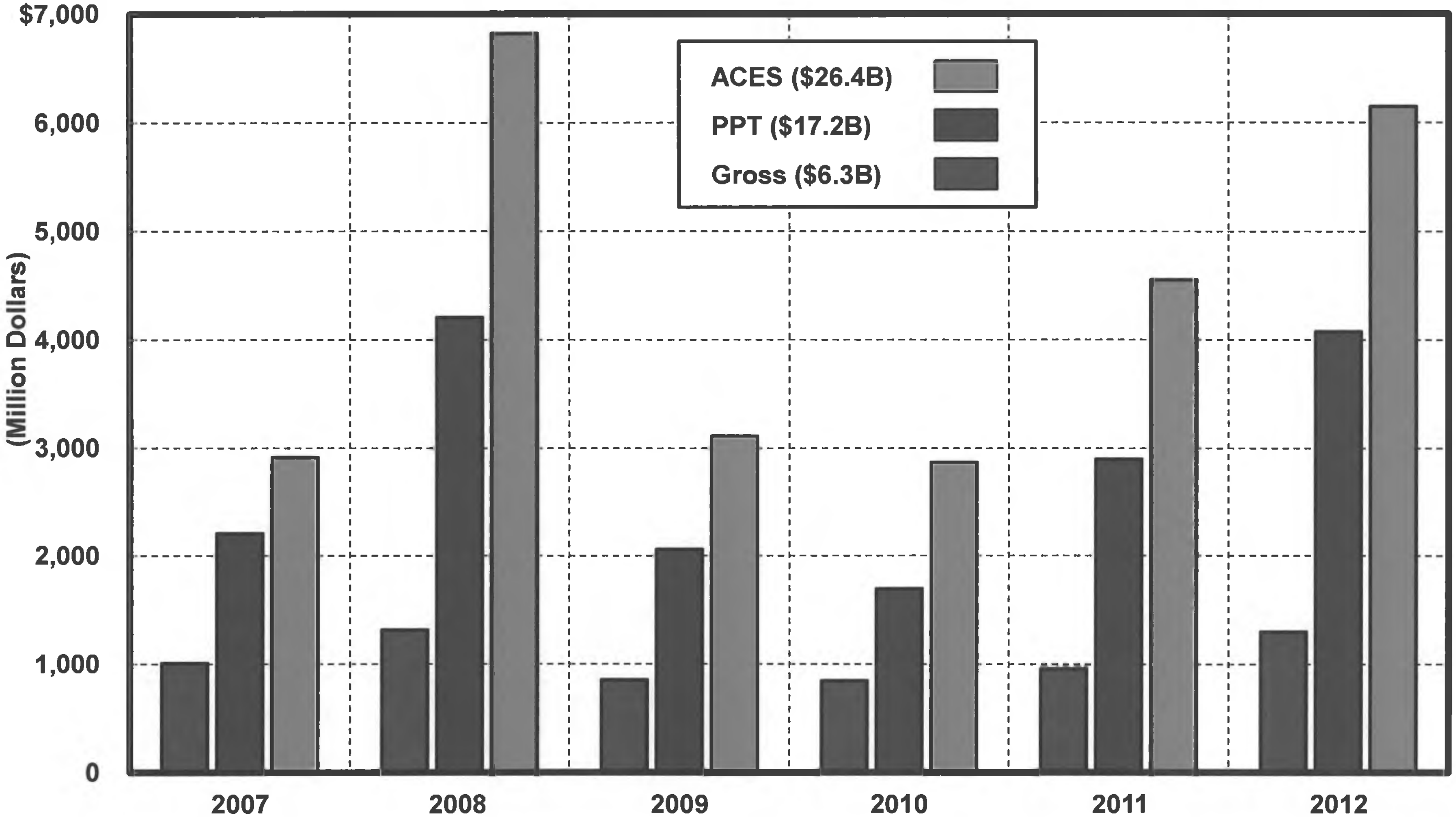


Source: DNR: The Historical Resource and Recovery Growth in Developed Fields, Arctic Slope of Alaska, 2004; DOE/NETL-2009/1385; AOGCC.

A History of Alaska's Production Tax System: North Slope



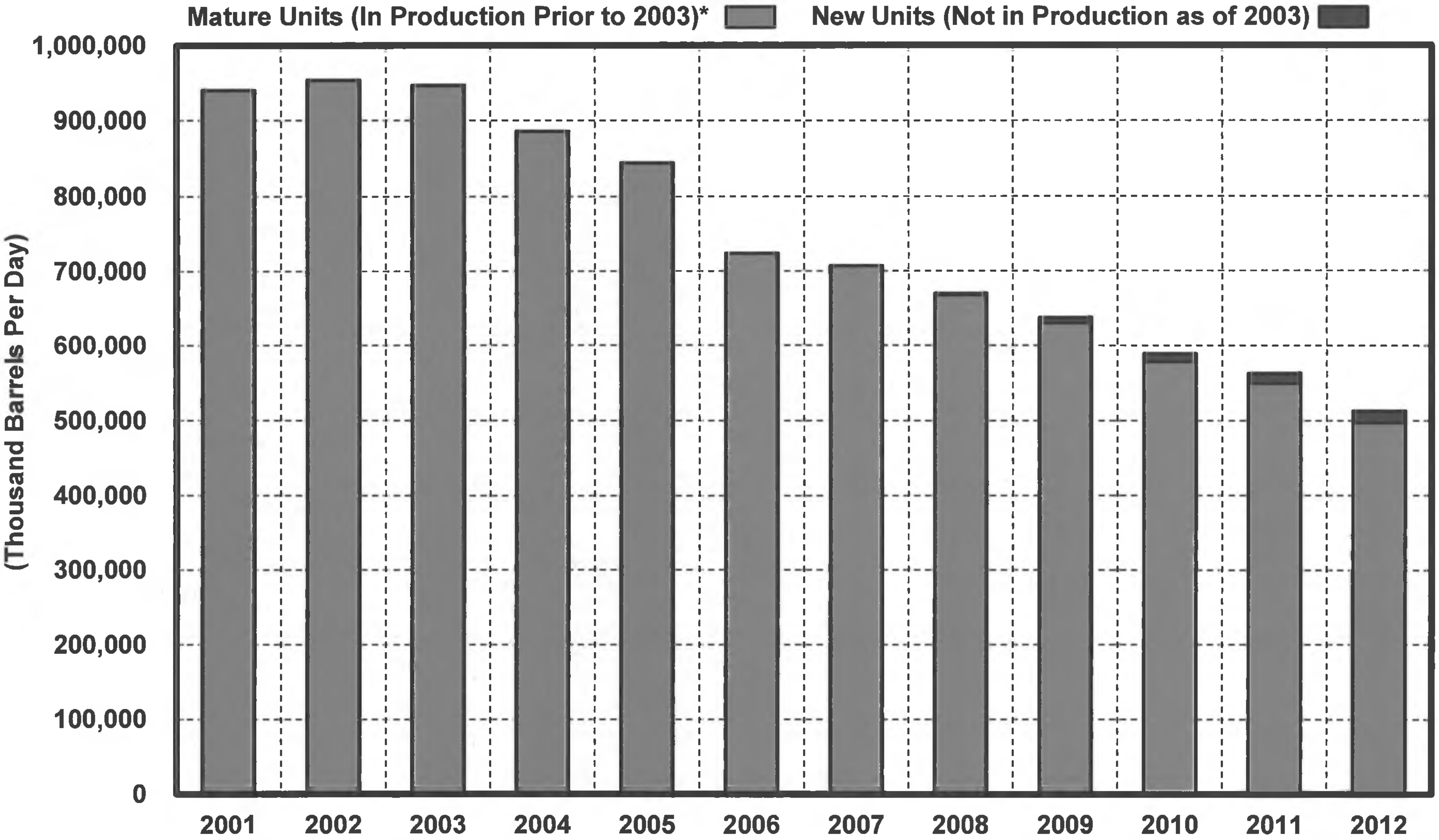
Estimated Production Tax Revenue (Assuming No Production Changes Across Systems) FY2007 - FY2012



Note: ACES figures are actual amount collected; figures for PPT and Gross are estimated based on application of terms under these tax systems to actual production and prices.
Source: DOR.

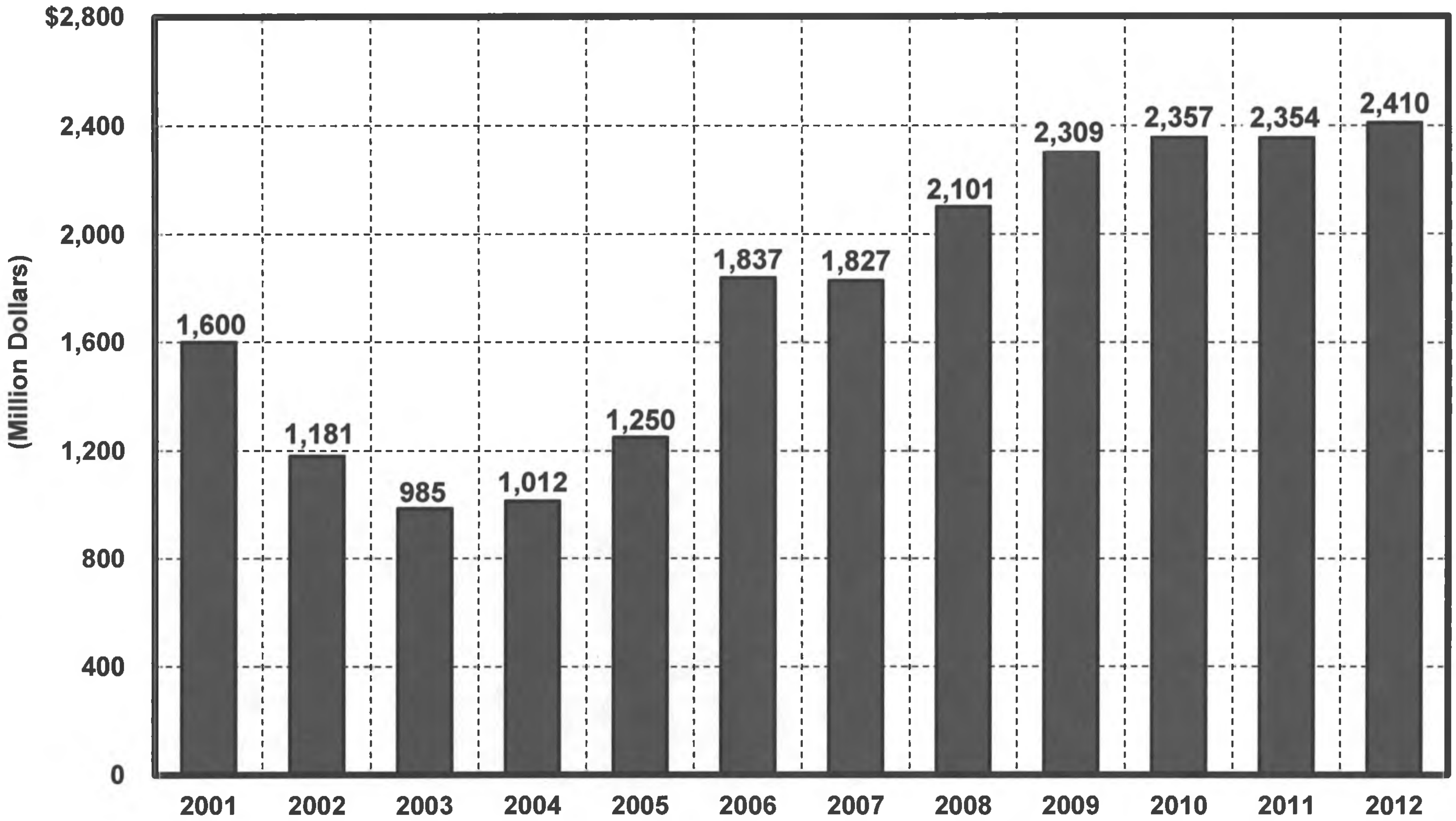
IV. North Slope Activity Over the Past Decade

Alaska North Slope Production by Unit
2001 - 2012



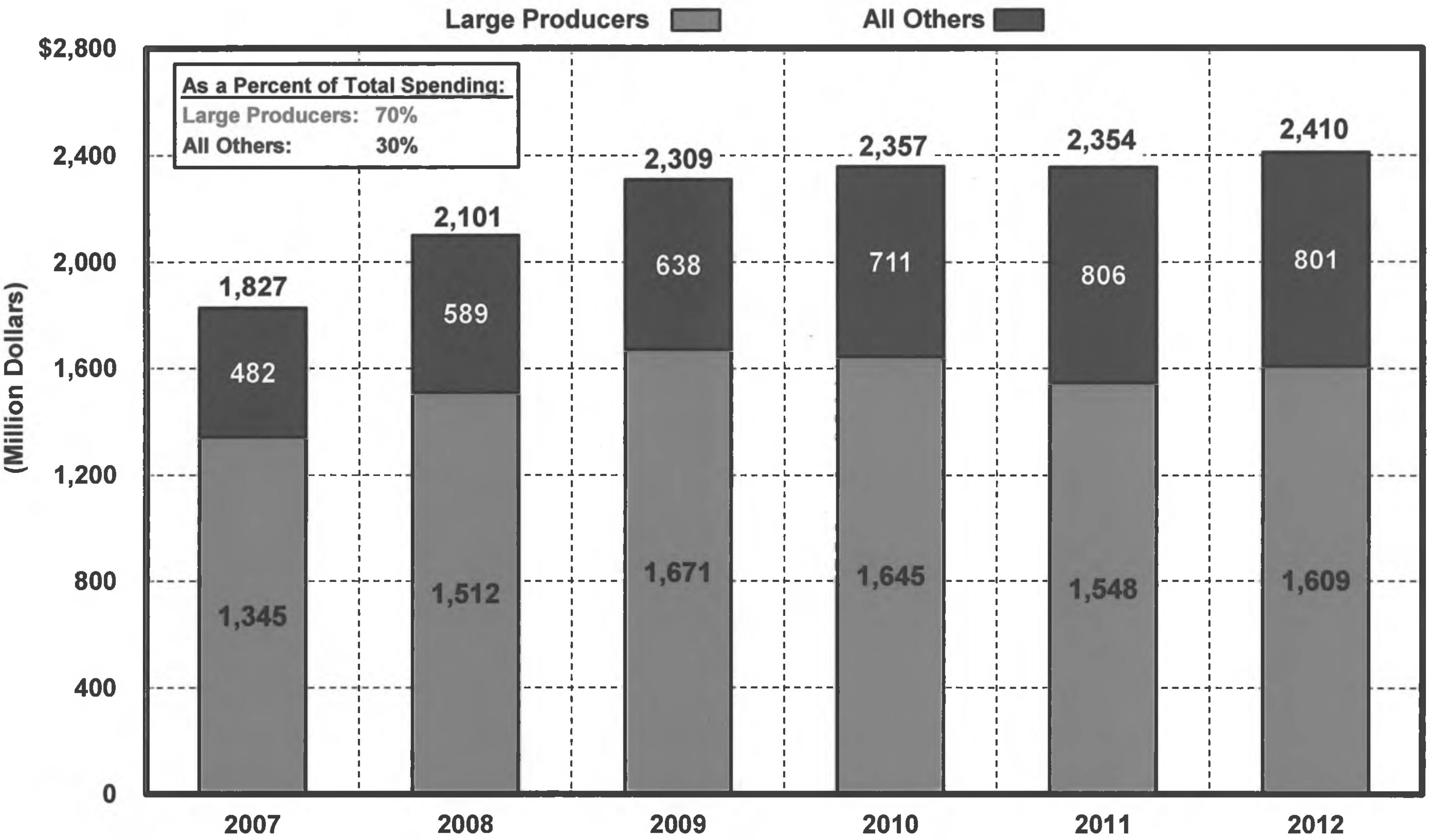
* Comprised of Prudhoe Bay, Kuparuk, Colville River, Badami, Northstar, Duck Island, Milne Point
Source: AOGCC.

Reported Capital Spending for Alaska North Slope CY2001 - CY2012*



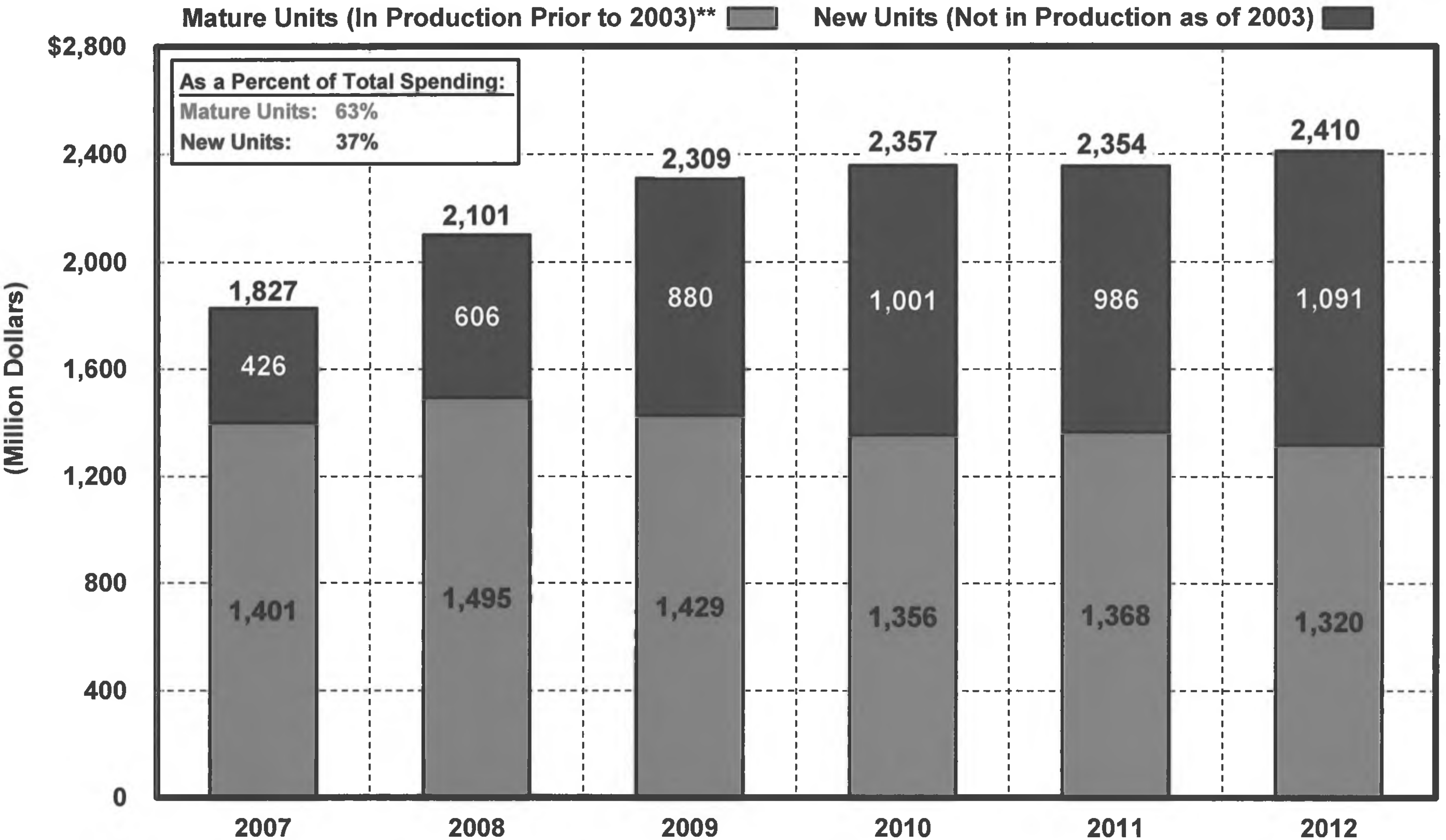
* Does not include expenditures associated with offshore federal properties.; 2012 estimated from preliminary data.
Source: DOR.

Reported Capital Spending by Alaska North Slope Producers CY2007 - CY2012*



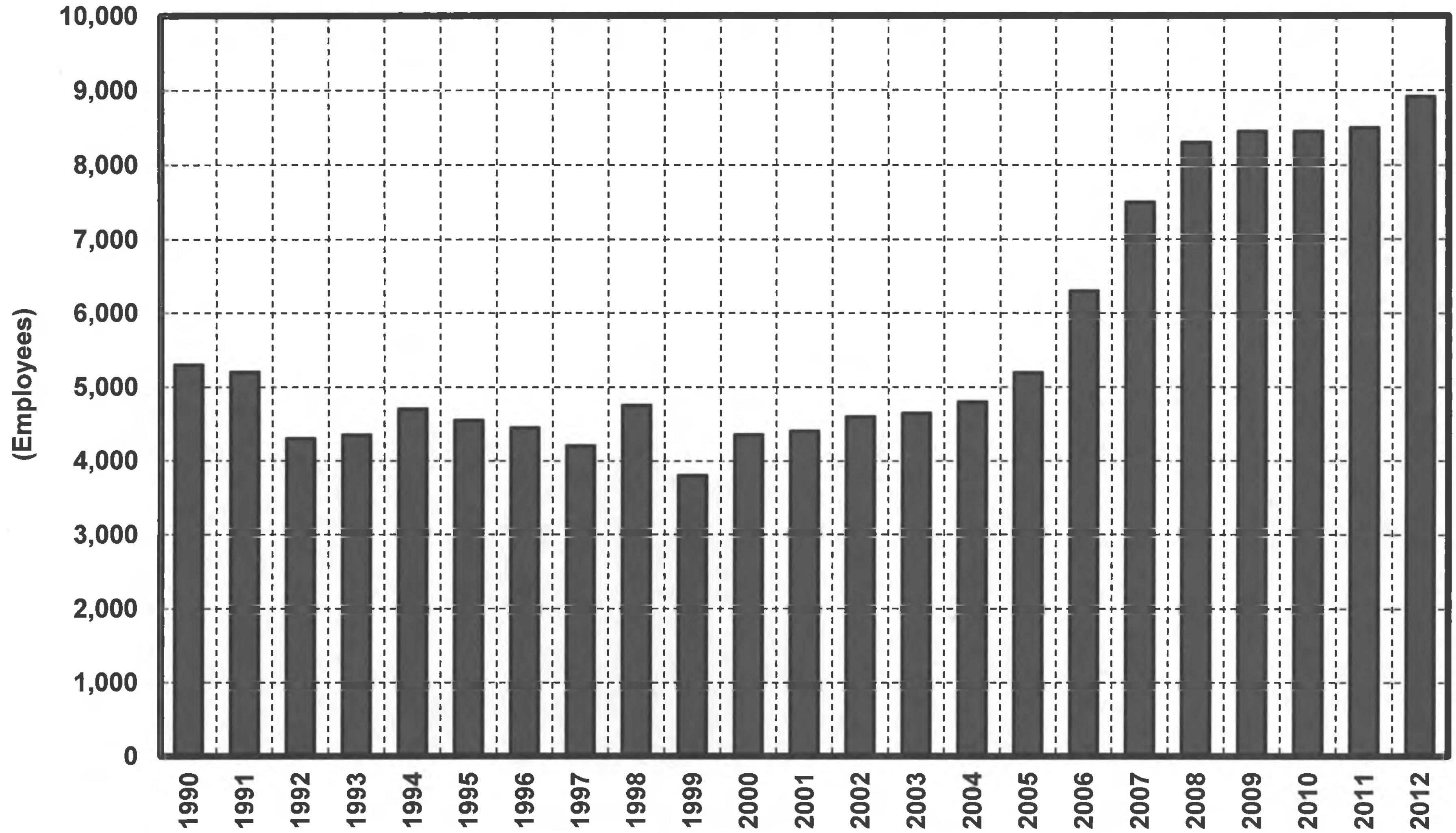
* Does not include expenditures associated with offshore federal properties.; 2012 estimated from preliminary data.
Source: DOR.

Reported Capital Spending by Alaska North Slope Producers by Unit CY2007 - CY2012*



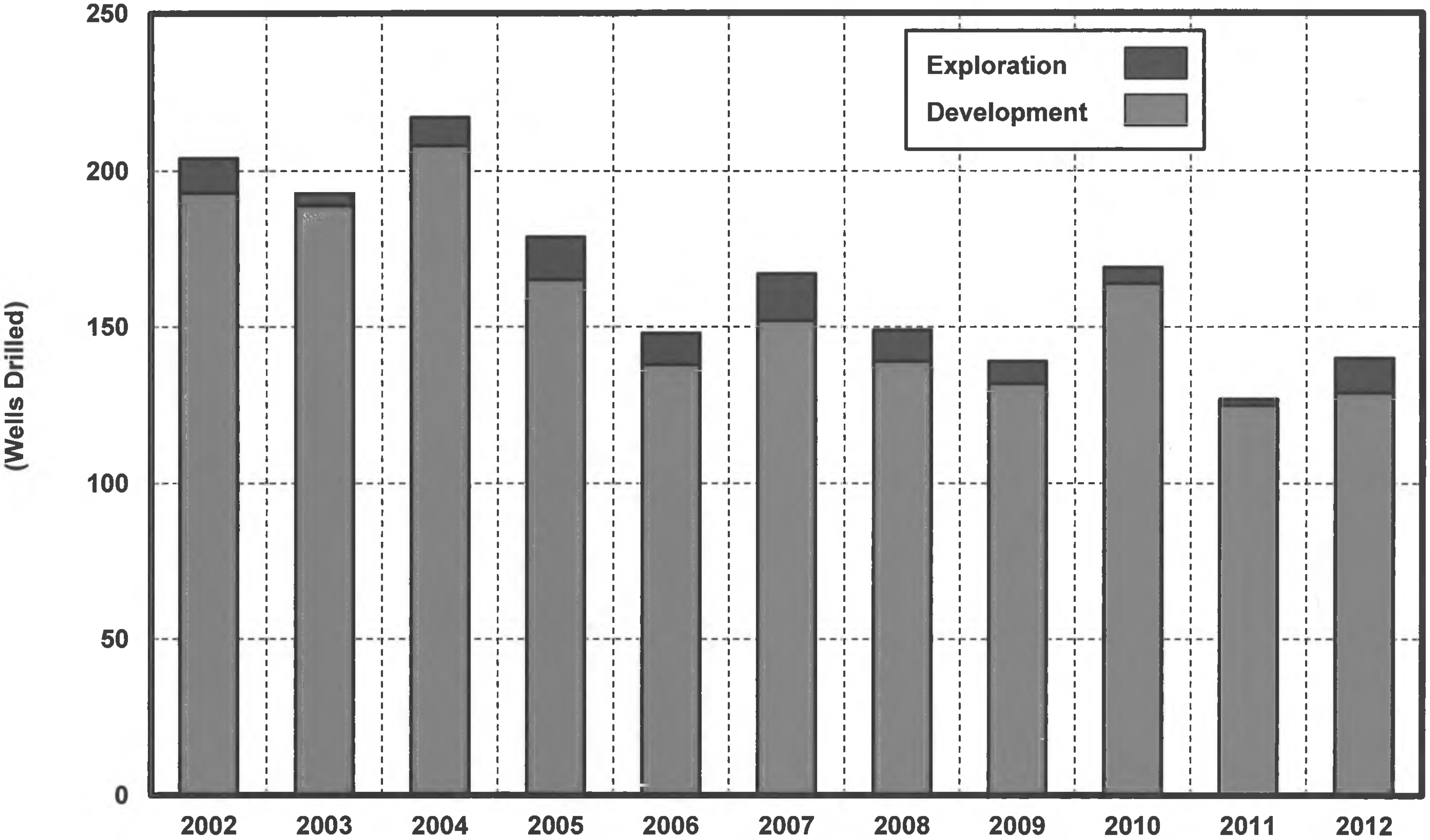
* Does not include expenditures associated with offshore federal properties.; 2012 estimated from preliminary data.
** Comprised of Prudhoe Bay, Kuparuk, Colville River, Badami, Northstar, Duck Island, Milne Point
Source: DOR.

Alaska North Slope Oil and Gas Industry Employment
1990 - 2012



Source: Alaska Department of Labor.

Alaska North Slope Wells Drilled
2002 - 2012



Source: 2002-2010: DNR; 2011-2012: AOGCC.

Drilling Activity in Alaska North Slope: By Well Completed Date
January 2005 - December 2012

	2005	2006	2007	2008	2009	2010	2011	2012	Total
Development*									
BPXA	98	72	80	85	82	83	48	49	669
ConocoPhillips	67	65	72	49	40	65	61	56	522
ENI (inc. Kerr-McGee)	-	-	-	-	2	7	9	15	33
Pioneer	-	-	-	4	9	8	5	6	32
Brooks	-	-	-	-	-	-	-	-	-
Anadarko	-	-	-	-	-	-	-	-	-
Repsol	-	-	-	-	-	-	-	-	-
ExxonMobil	-	-	-	-	-	-	-	-	-
Others	-	-	-	-	-	1	2	3	6
Total	**165**	**137**	**152**	**138**	**133**	**164**	**125**	**129**	**1,262**
Exploratory									
BPXA	-	-	5	1	-	-	-	-	6
ConocoPhillips	5	5	2	2	2	-	1	1	18
ENI (inc. Kerr-McGee)	6	1	4	-	-	-	-	-	11
Pioneer	-	2	-	-	1	-	-	2	5
Brooks	-	-	1	4	-	2	1	3	11
Anadarko	-	-	1	2	3	-	-	-	6
Repsol	-	-	-	-	-	-	-	3	3
ExxonMobil	-	-	-	-	-	2	-	-	2
Others	3	3	7	9	5	3	-	2	32
Total	**14**	**11**	**20**	**18**	**11**	**7**	**2**	**11**	**94**
Total									
BPXA	98	72	85	86	82	83	48	49	675
ConocoPhillips	72	70	74	51	42	65	62	57	540
ENI (inc. Kerr-McGee)	6	1	4	-	2	7	9	15	44
Pioneer	-	2	-	4	10	8	5	8	37
Brooks	-	-	1	4	-	2	1	3	11
Anadarko	-	-	1	2	3	-	-	-	6
Repsol	-	-	-	-	-	-	-	3	3
ExxonMobil	-	-	-	-	-	2	-	-	2
Others	3	3	7	9	5	4	2	5	38
Total	**179**	**148**	**172**	**156**	**144**	**171**	**127**	**140**	**1,356**

*** Development includes service wells.**
Source: AOGCC.

Timeline of Significant Events on Alaska North Slope Since 2005

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2005
- ELF aggregation decision for Prudhoe Bay
- Conoco applies for CD-5 permit

2006
- PPT introduced (April 1)
- BP discovers Prudhoe Bay transit line corrosion. Begins multi-year facility renewal
- Est. Production Loss of ~35 MMBO
- Alpine satellites begin production

2007
- ACES introduced (↑ tax rate)

2008
- FERC overturns TSM reduces TAPS rates
- Ooogaruk begins producing

2009
- Conoco re-submits CD-5 permit, after local agreement over bridge location

2010
- Gulf Horizon delays offshore Alaska activity; Federal offshore drilling moratorium
- BP suspends Liberty; cites rig problems
- USACE denies CD-5 permit (early 2010)

2011
- Ugnu PA test well @ Milne Point initial flow
- Pt. Thomson development begins
- Nikiatchuq production begins
- Conoco fed. permits @ W. Alpine in NPRA

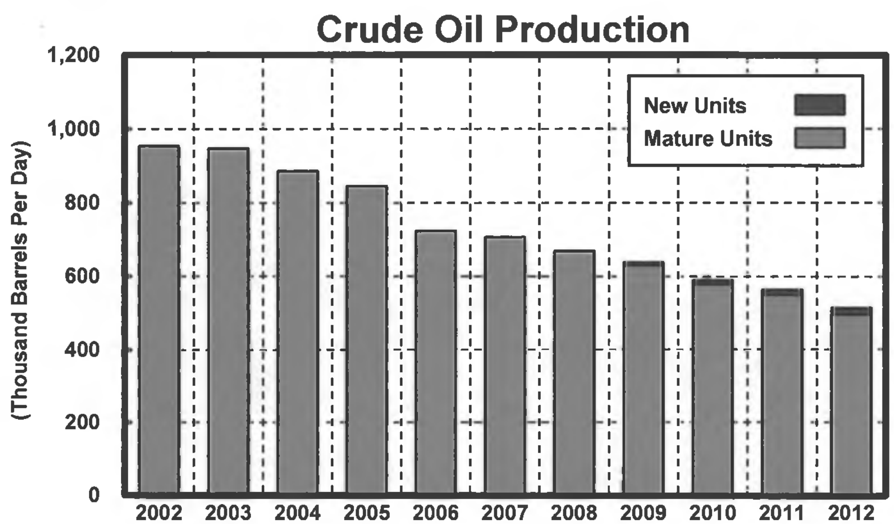
2012
- Chukchi and Beaufort drilling begins (Shell)
- Great Bear drills shale test well
- 11 Wells drilled
- Statoil delays Chukchi drilling to 2015 (+1 yr); Cites Shell delays

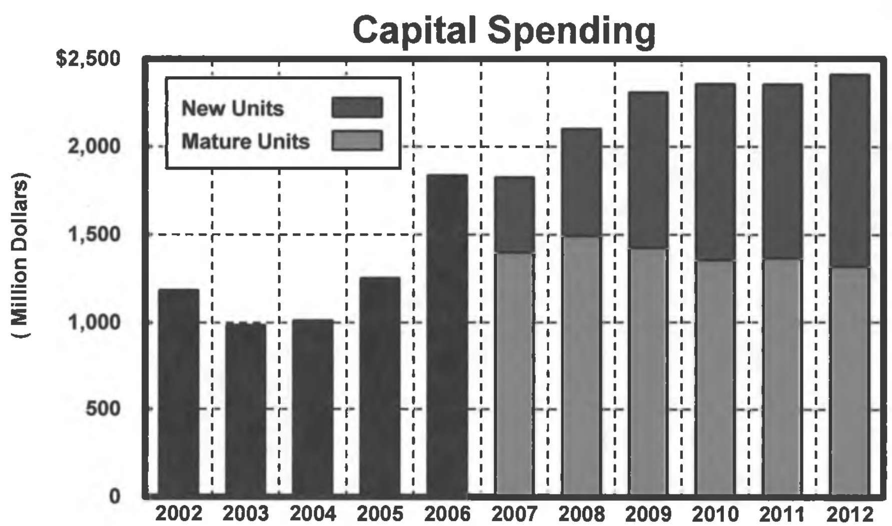
V. Benchmarking North Slope Activity Against Other Areas

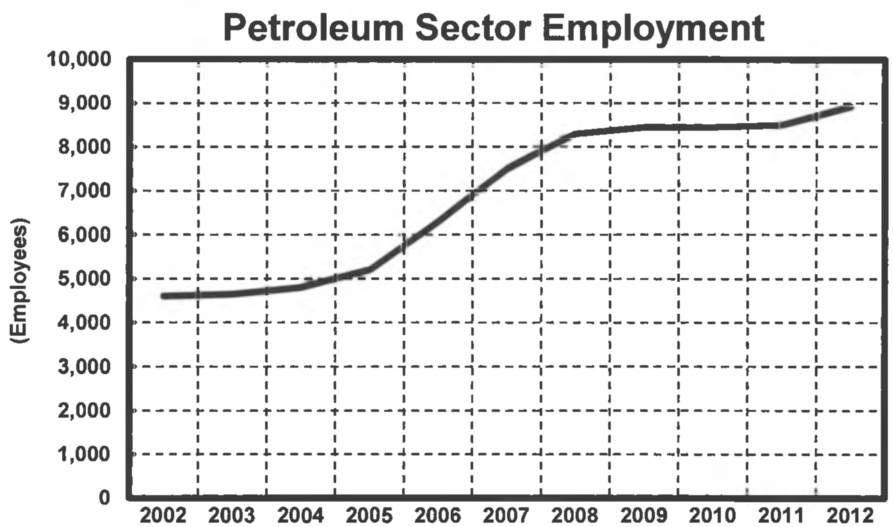
Benchmarking

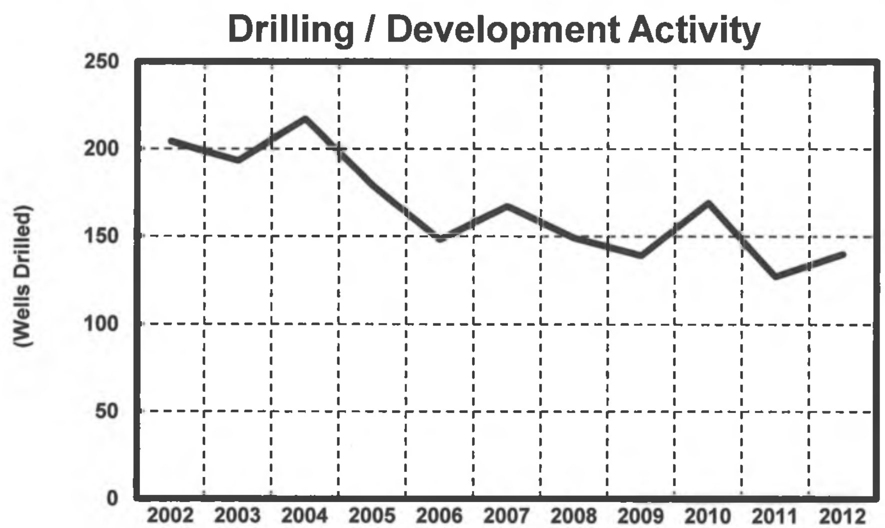
- Benchmarking Allows Us to Evaluate Activity in Alaska by Controlling for Significant Variables That are Common to All Oil Producing Properties, Such as Price and General Economic Conditions
- No Two Producing Areas are Exactly Alike. Mindful of This, We Attempt to Choose Locations That Share a Number of Similar Characteristics, Allowing for the Most Meaningful Comparisons
- We Benchmark the North Slope Against Several Areas Located in OECD Countries
  - The North Sea
  - The U.S. and Several Key Producing States / Areas
  - Canada and Producing Provinces
  - Australia
- All of These OECD Areas Share Many of the Same, Characteristics With the North Slope
  - Similar Political and Legal Structure / Risk
  - Significant Prospectivity
  - But, Much of the "Low-Hanging" Fruit Has Been Produced
  - Development of Remaining Resources are Largely High-Cost, Either Conventional or Unconventional
  - Resources are Developed in Large Part by the Private Sector

Country/Area Profile
Alaska North Slope

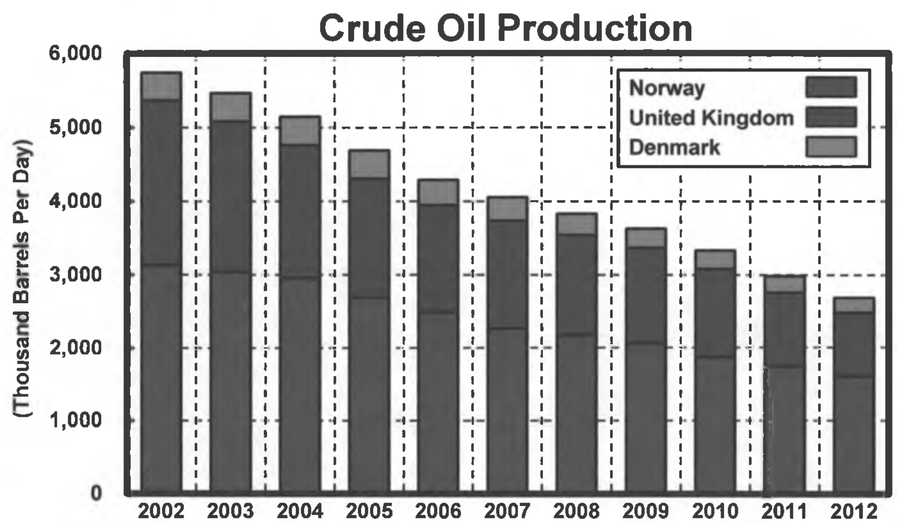


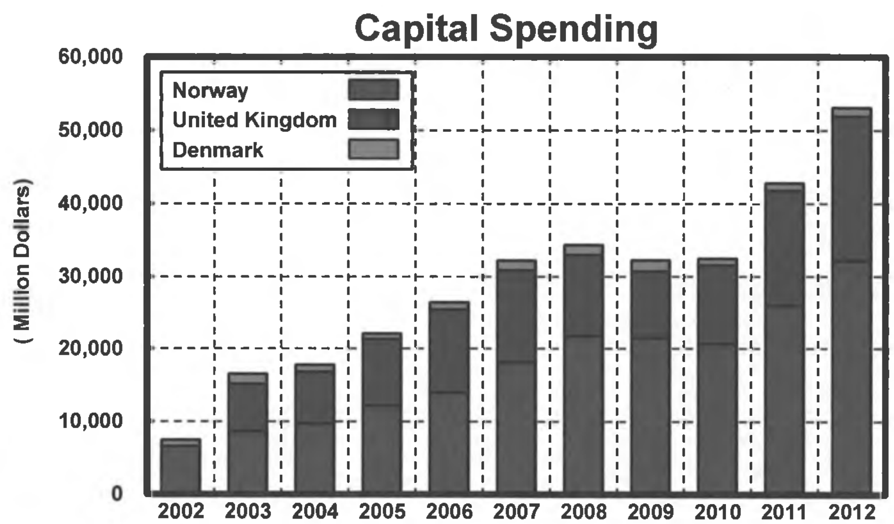


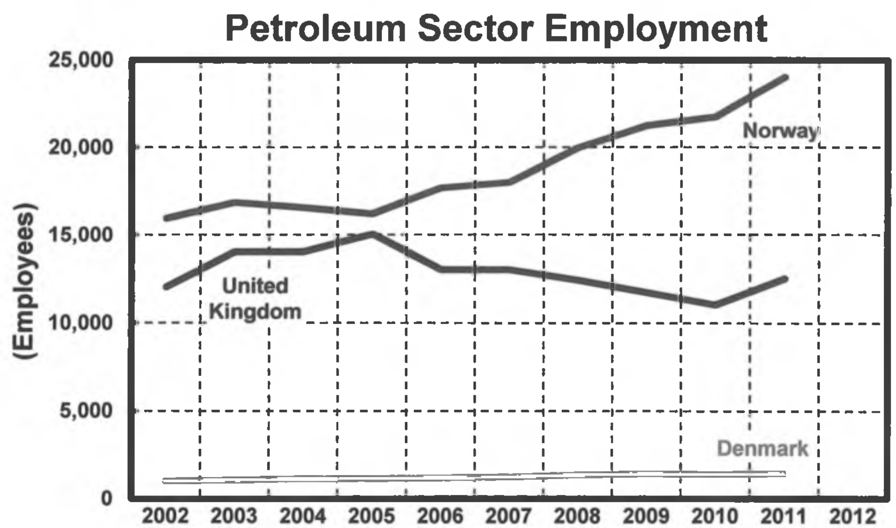


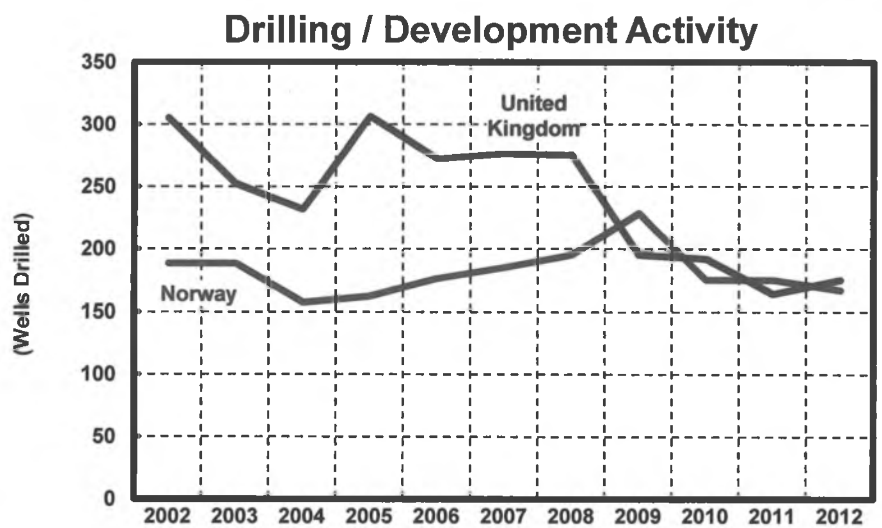


Country/Area Profile
Northwest Europe (North Sea)





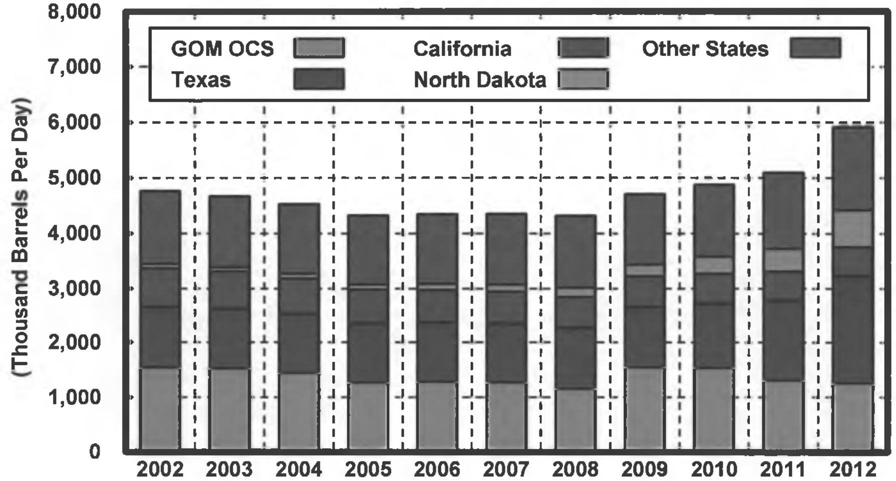




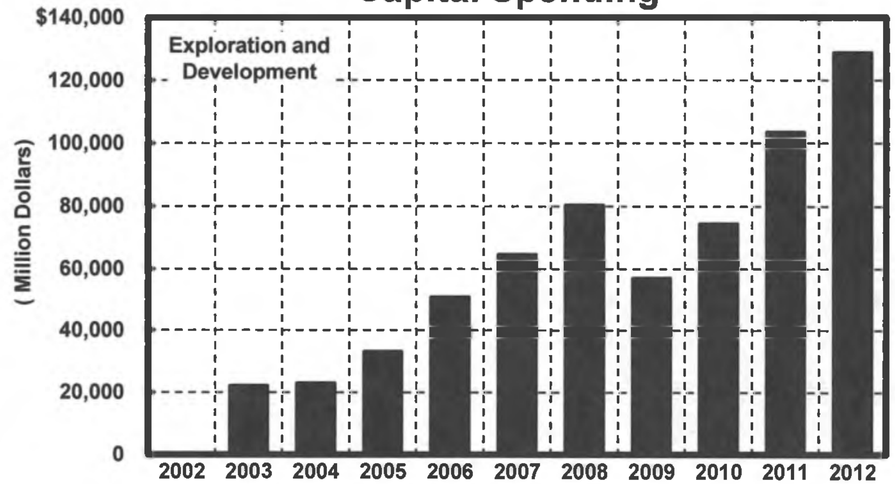
Note: 2012 figures are preliminary.

Country/Area Profile
United States Excluding Alaska North Slope

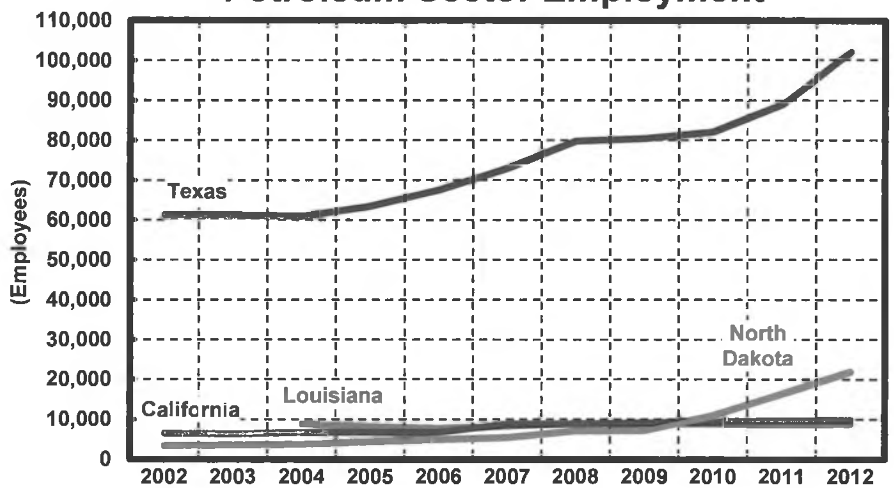
Crude Oil Production



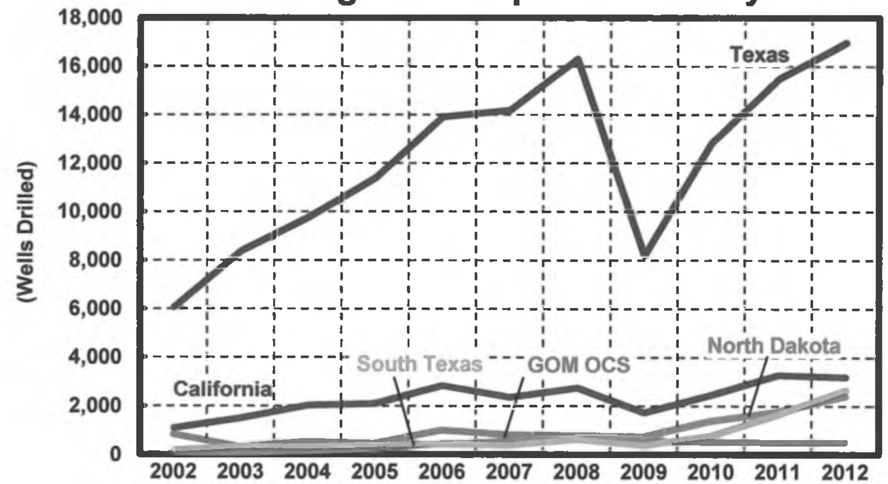
Capital Spending



Petroleum Sector Employment



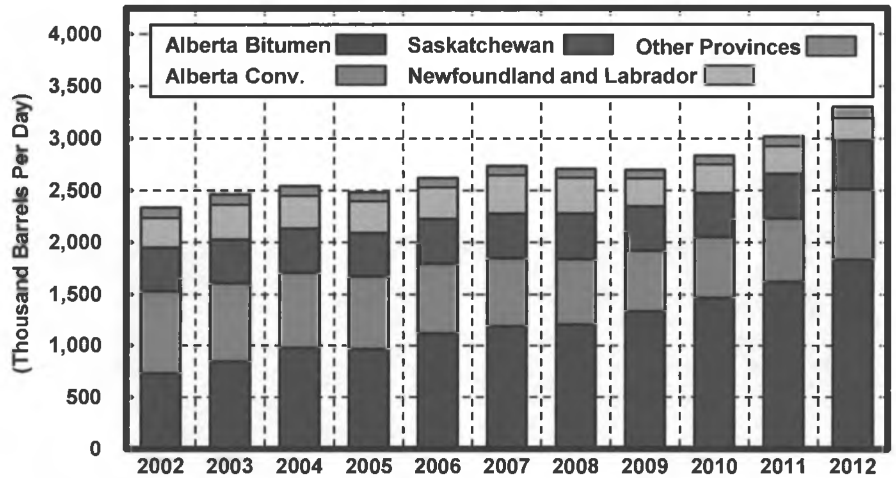
Drilling / Development Activity



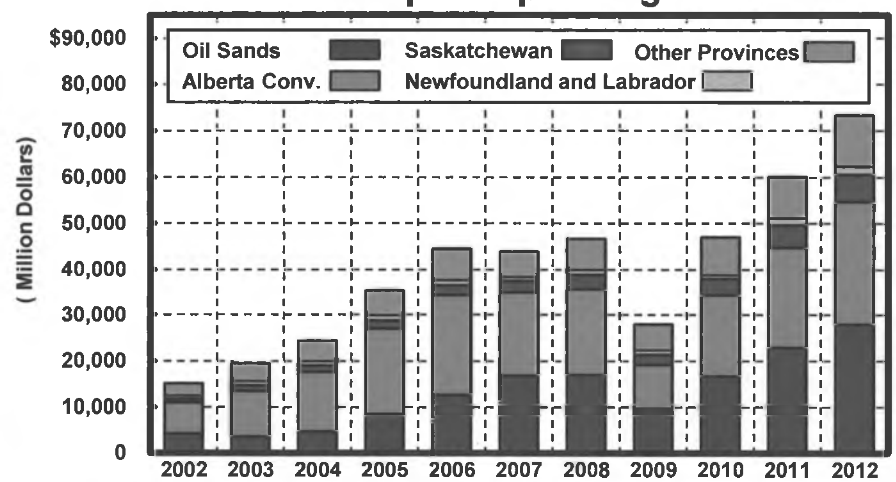
Note: 2012 figures are preliminary.

Country/Area Profile
Canada

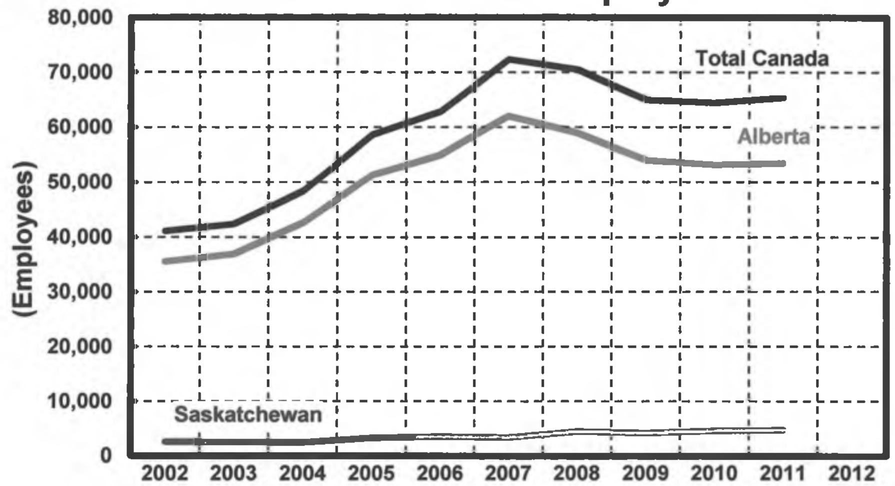
Crude Oil Production



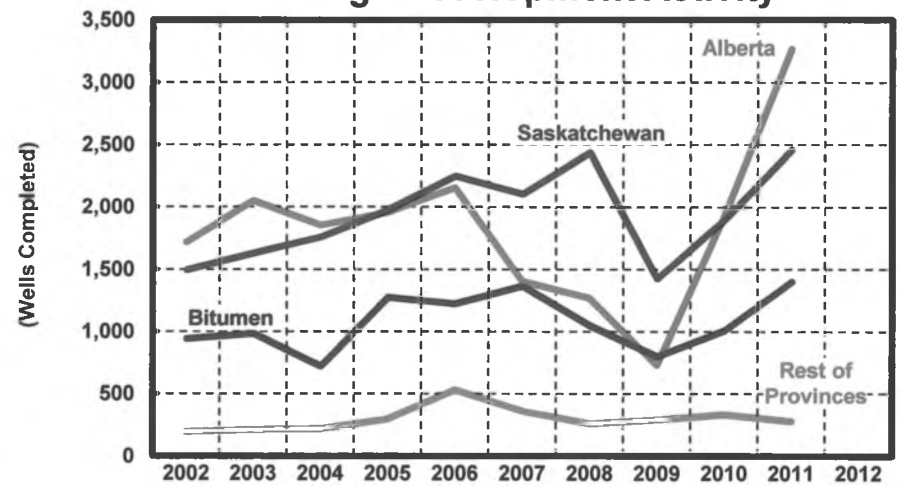
Capital Spending



Petroleum Sector Employment

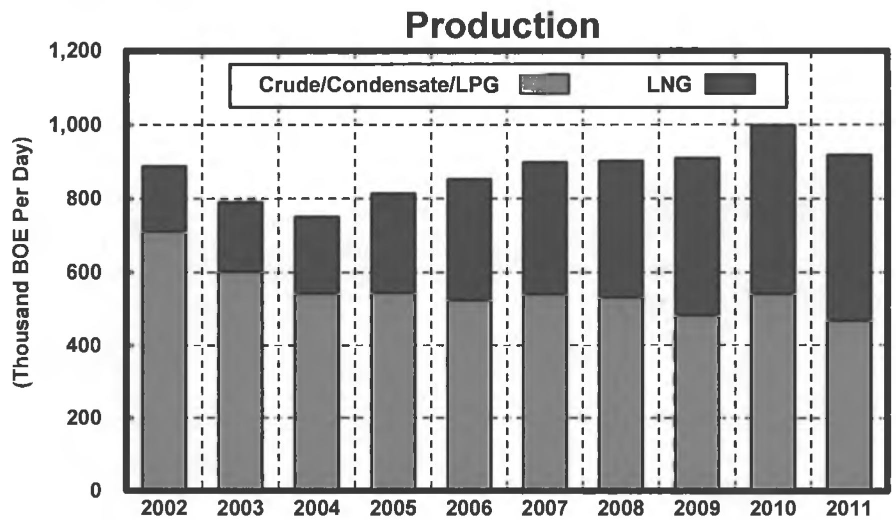


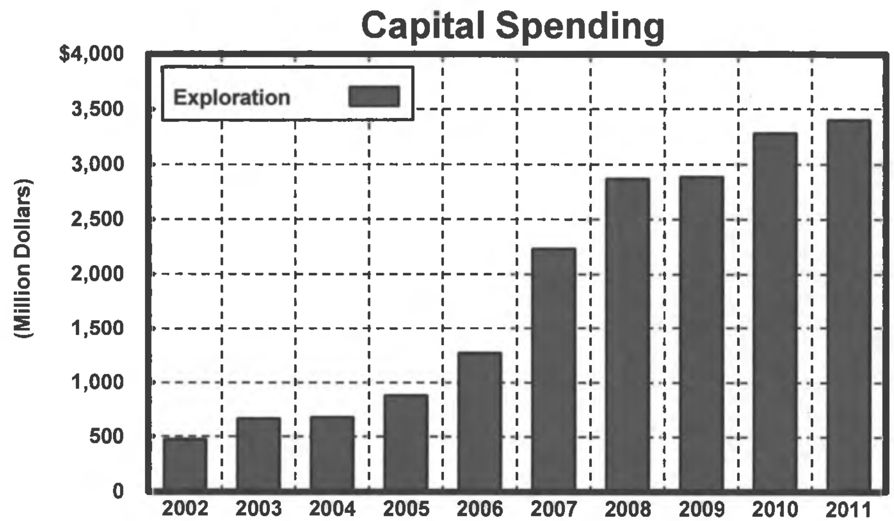
Drilling / Development Activity

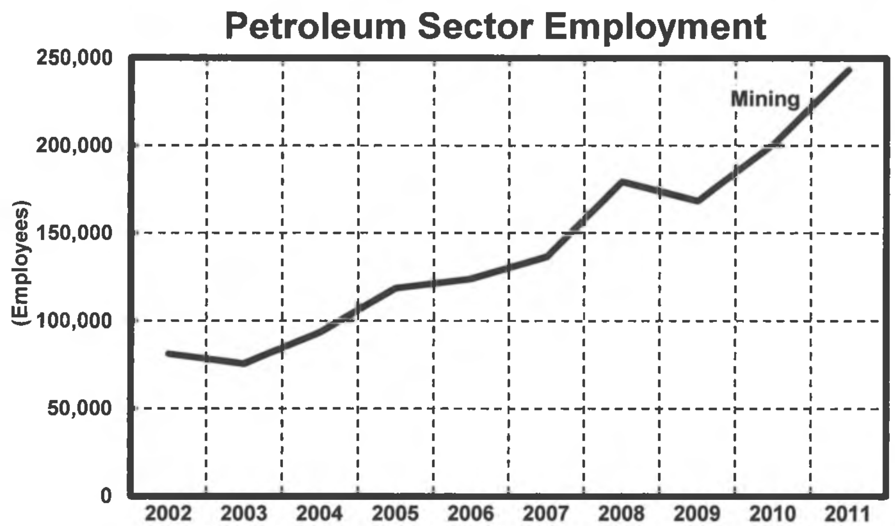


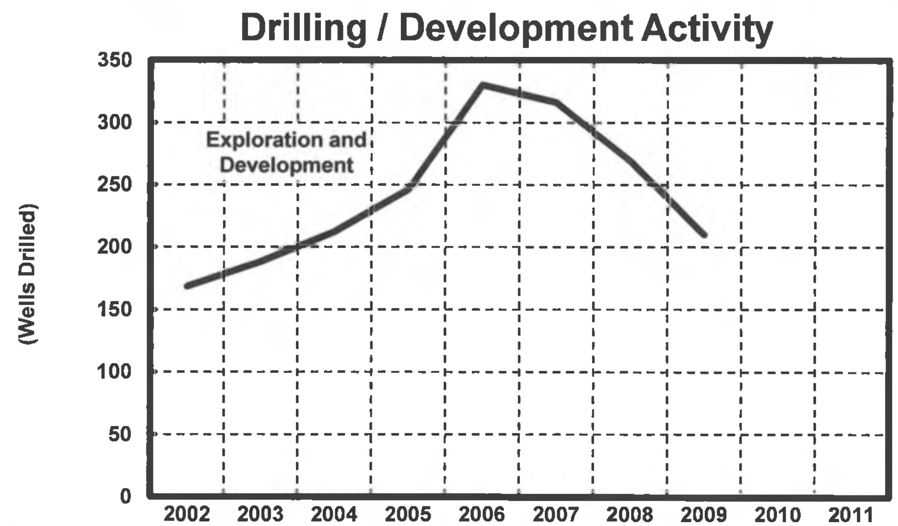
Note: 2012 figures are preliminary.

Country/Area Profile
Australia









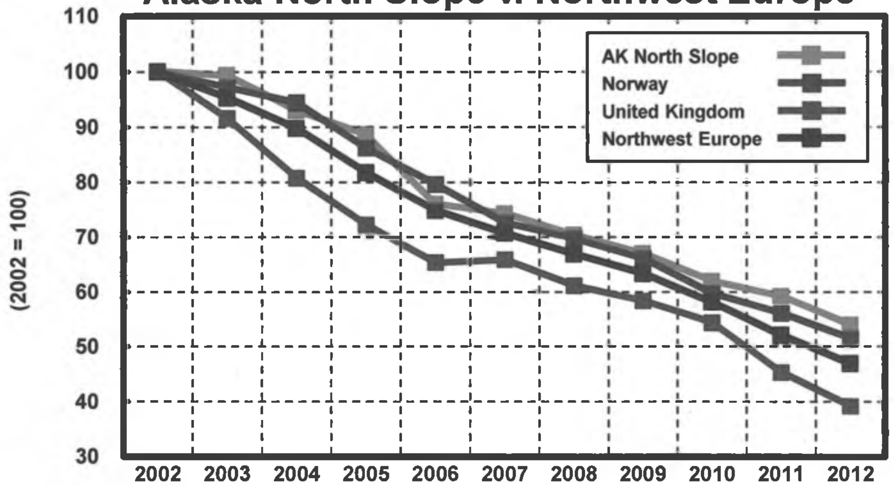
Comparisons Across Locations: Indexing

econ ONE

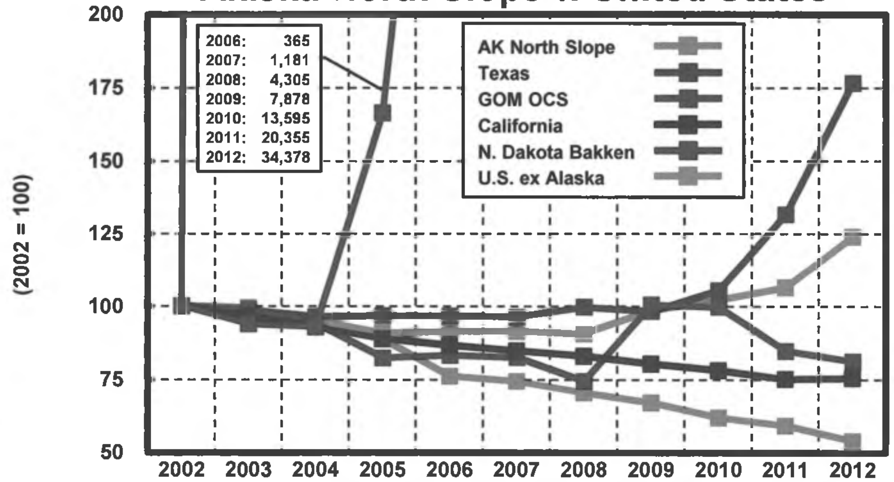
Year	Daily Production: Alaska North Slope	Daily Production: California	Daily Production: Texas	Index Value: Alaska North Slope	Index Value: California	Index Value: Texas
	(Thousand Barrels Per Day)			(2002 = 100)		
2002	954	707	1,112	100 *= (954/954)*100*	100 *= (707/707)*100*	100 *= (1,112/1,112)*100*
2006	724	612	1,075	76 *= (724/954)*100*	87 *= (612/707)*100*	97 *= (1,075/1,112)*100*
2010	513	552	1,171	62 *= (513/954)*100*	78 *= (552/707)*100*	105 *= (1,171/1,112)*100*

Crude Oil Production Comparisons to Alaska

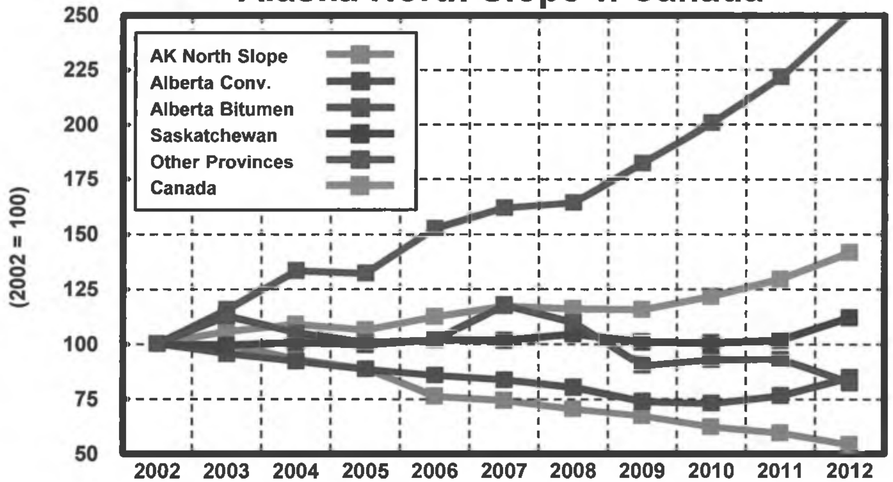
Alaska North Slope v. Northwest Europe



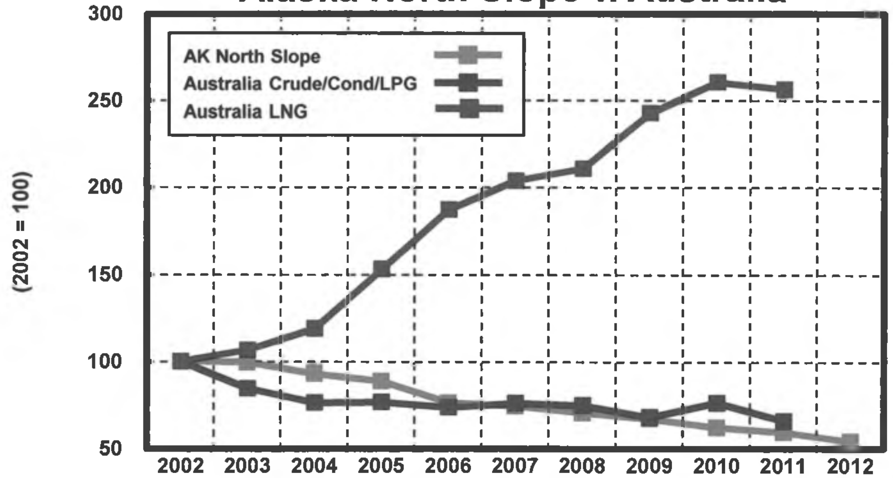
Alaska North Slope v. United States



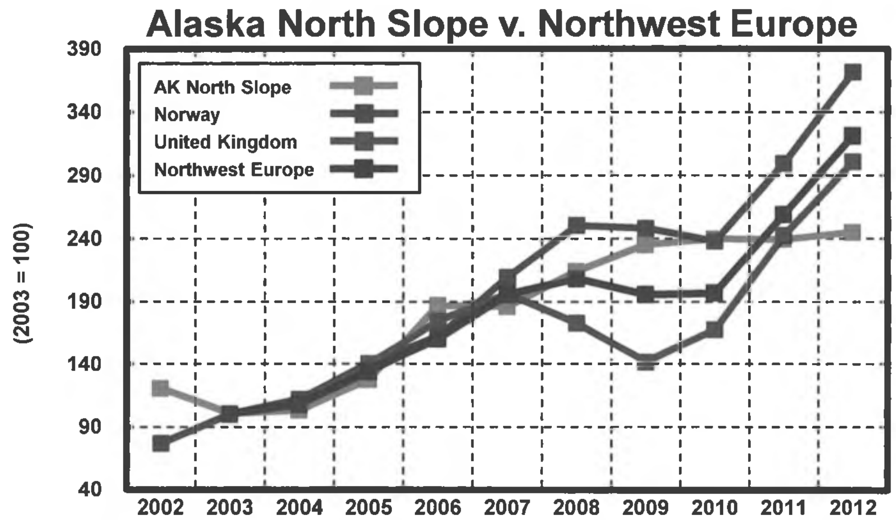
Alaska North Slope v. Canada

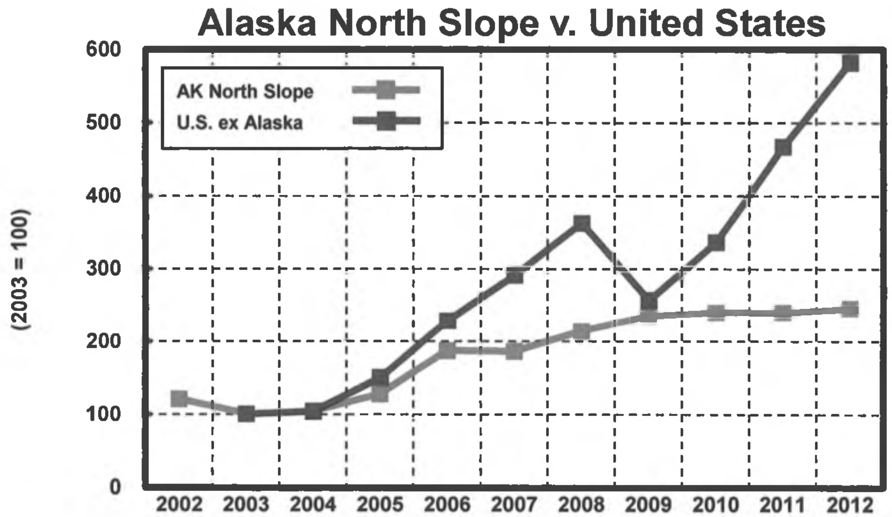


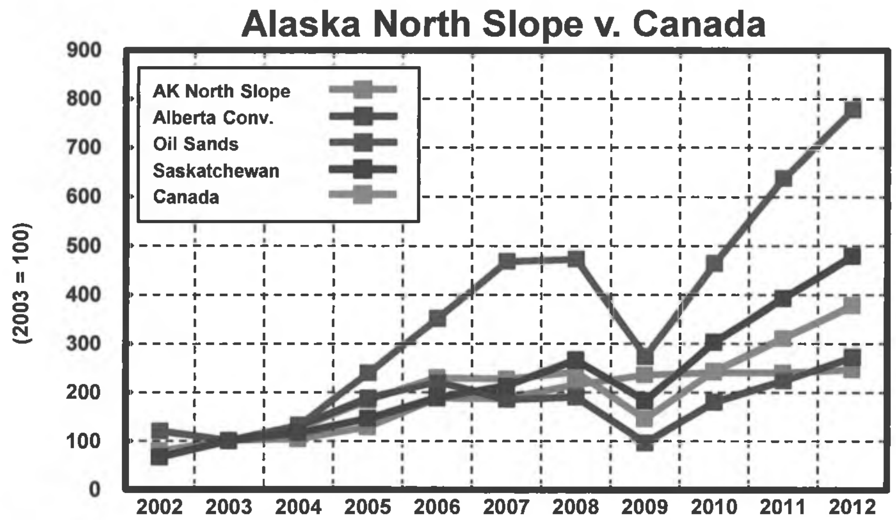
Alaska North Slope v. Australia

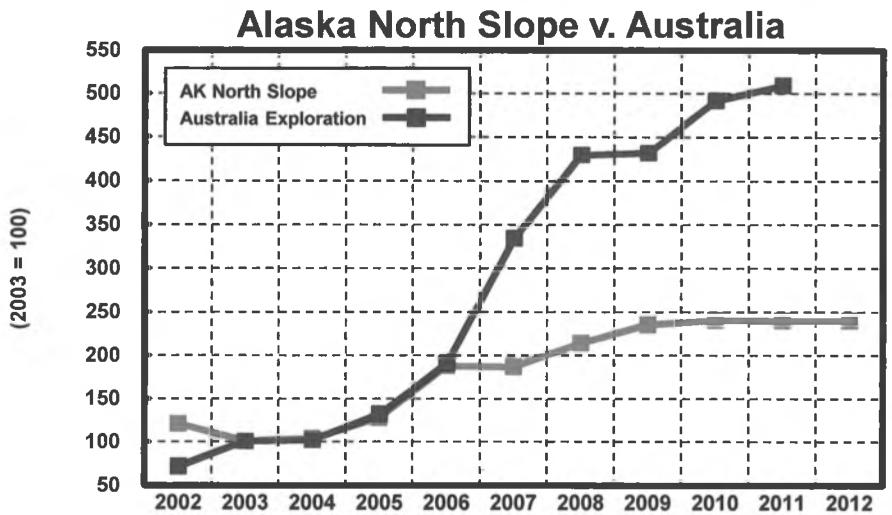


Capital Spending Comparisons to Alaska

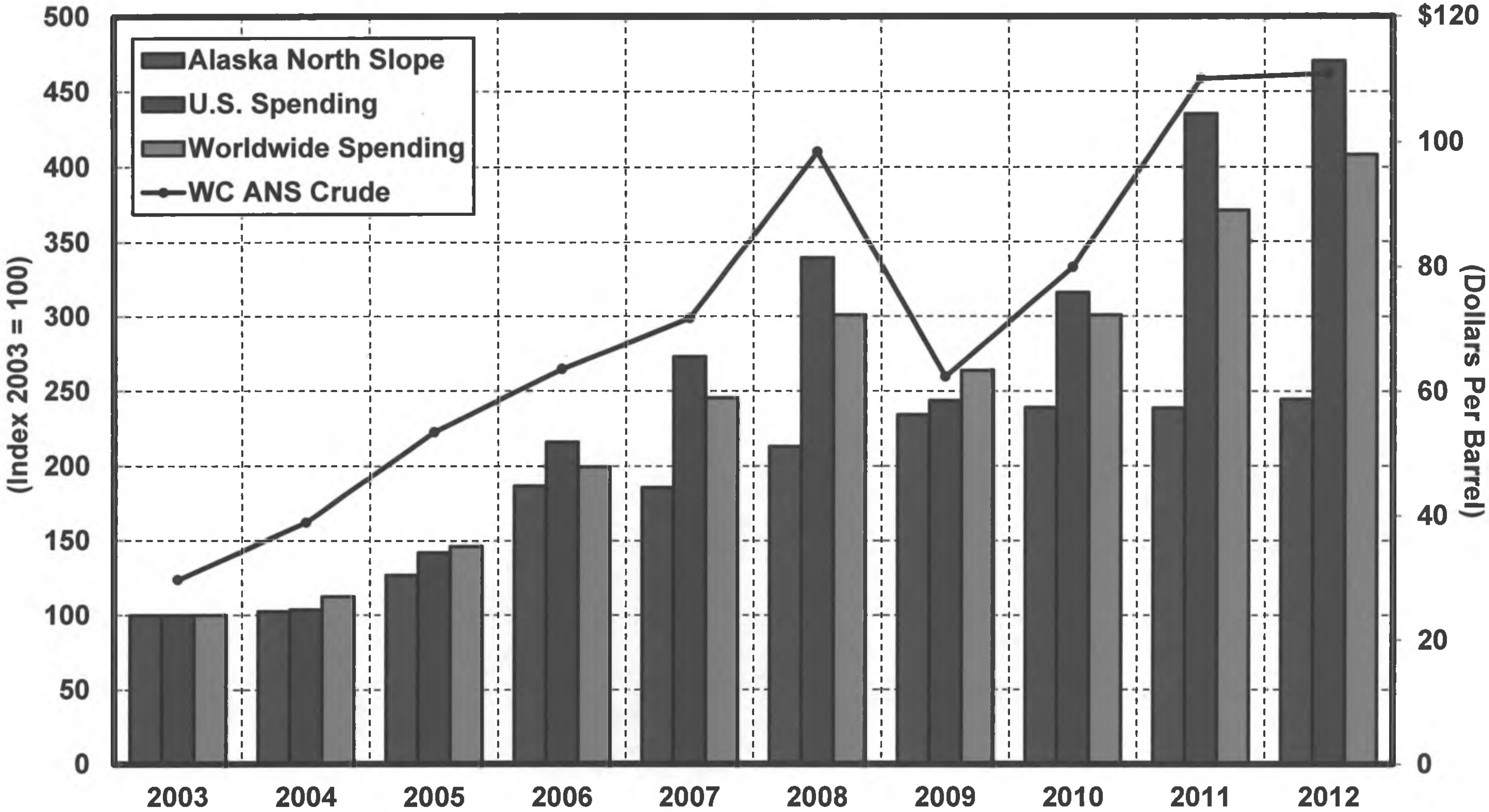








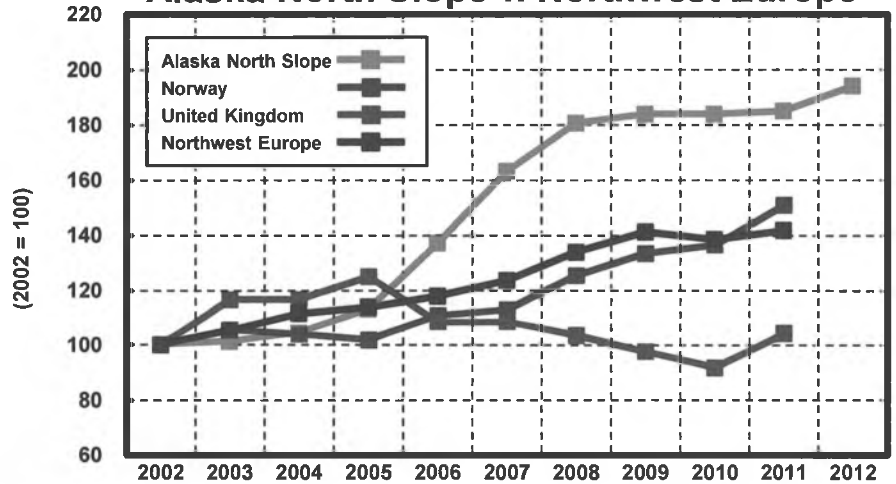
Estimated Capital Spending for Exploration and Development Alaska North Slope vs. U.S. and Worldwide Spending* 2003 - 2012



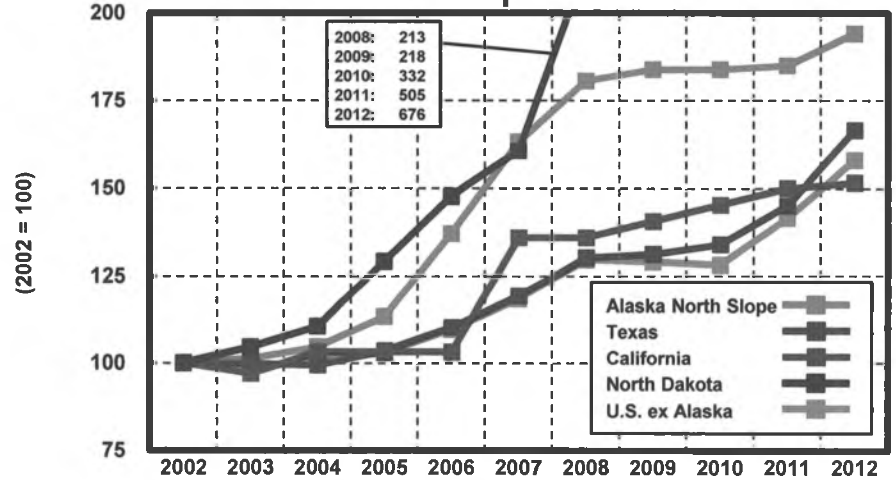
* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

Employment Comparisons to Alaska

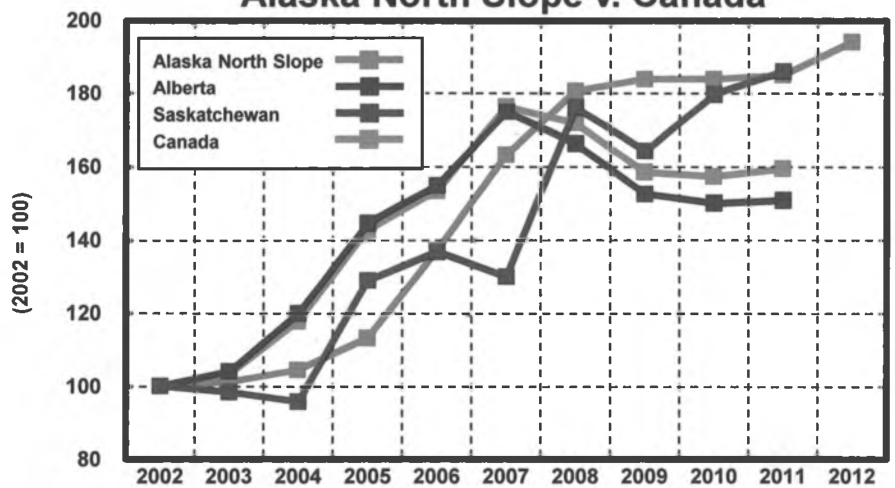
Alaska North Slope v. Northwest Europe



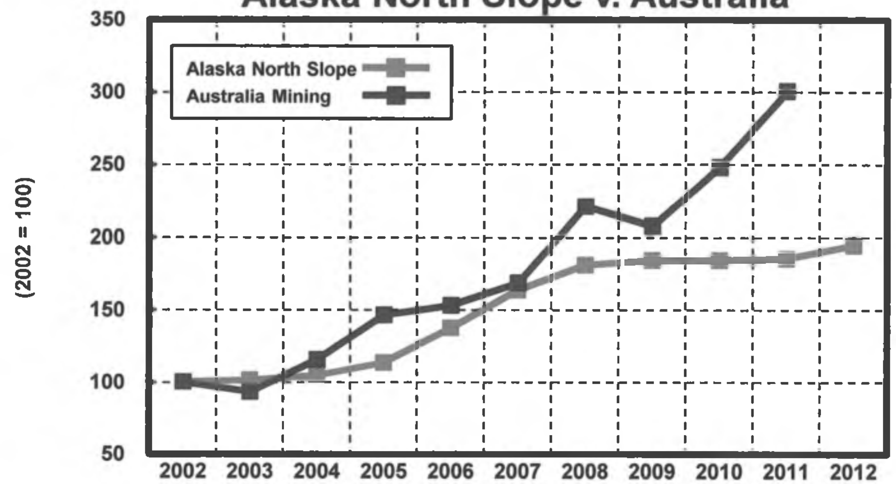
Alaska North Slope v. United States



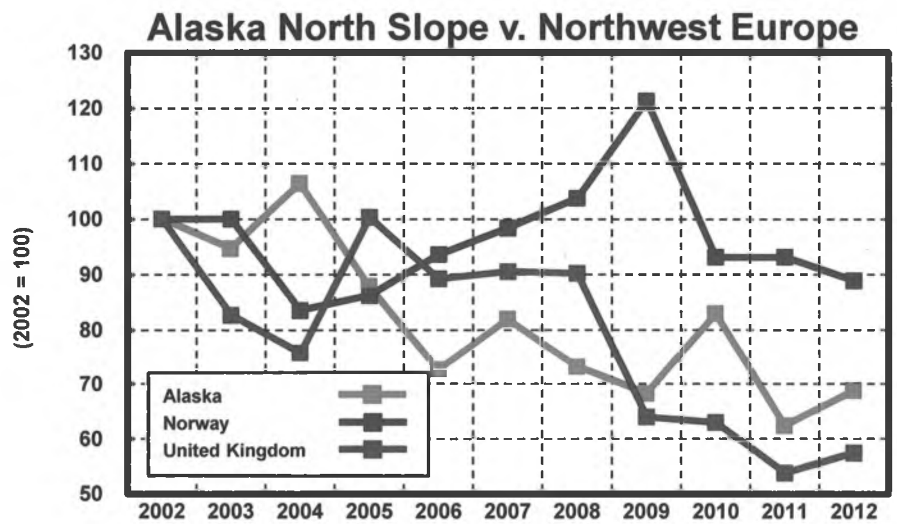
Alaska North Slope v. Canada

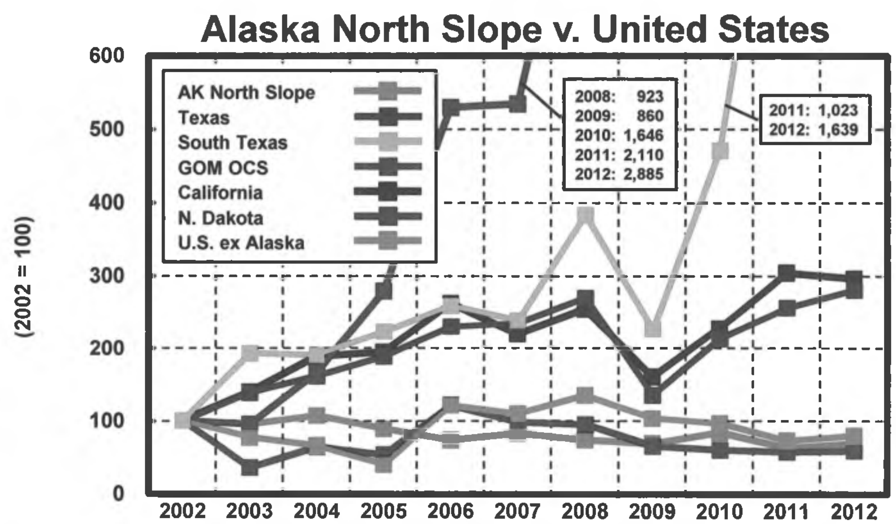


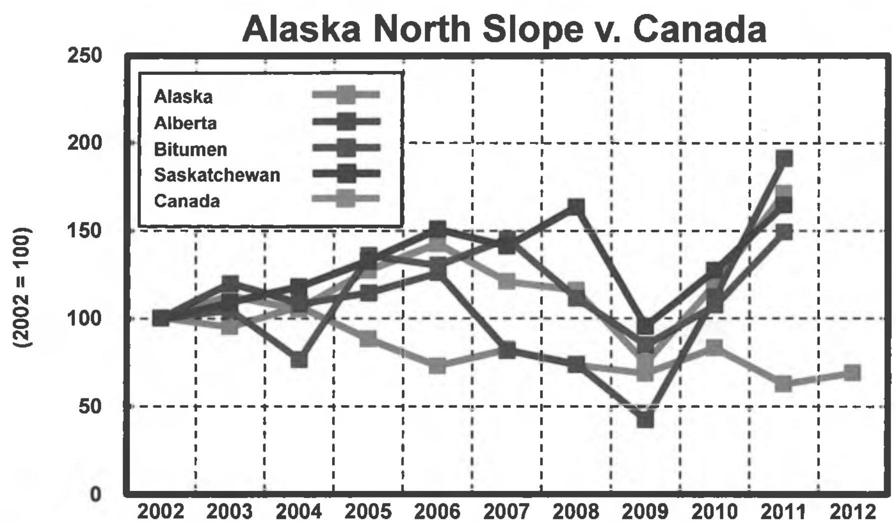
Alaska North Slope v. Australia

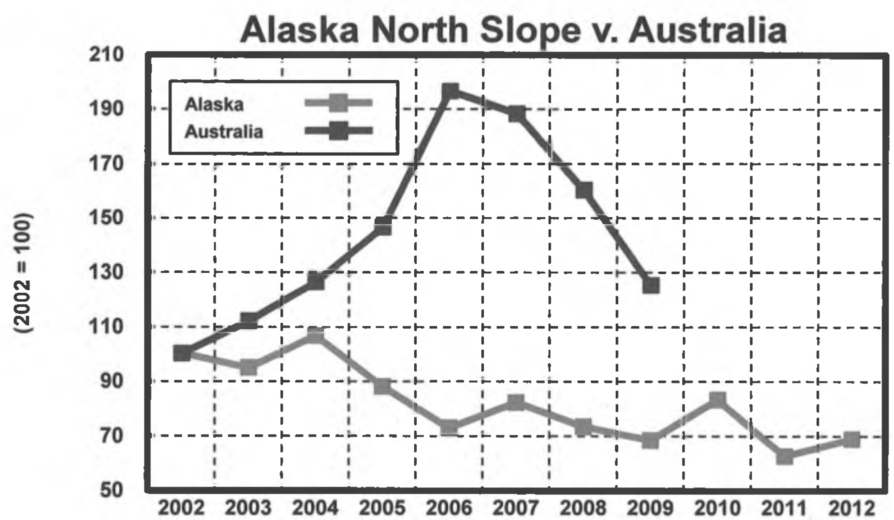


Drilling / Development Activity Comparisons to Alaska





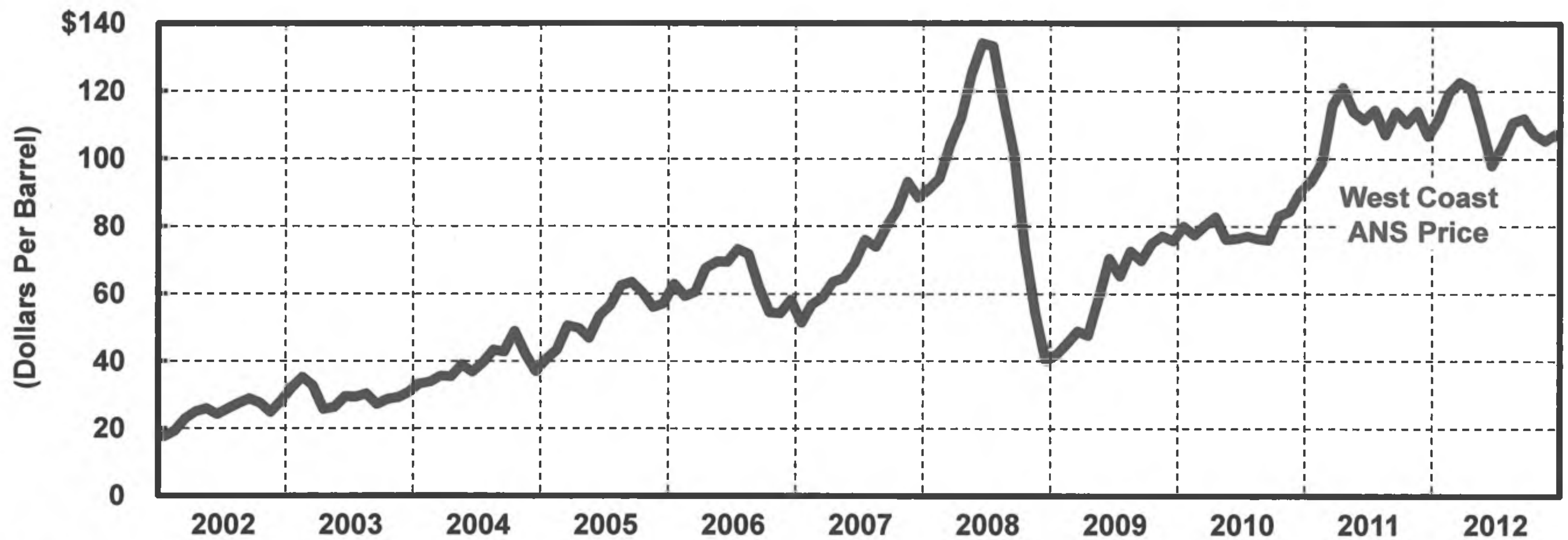




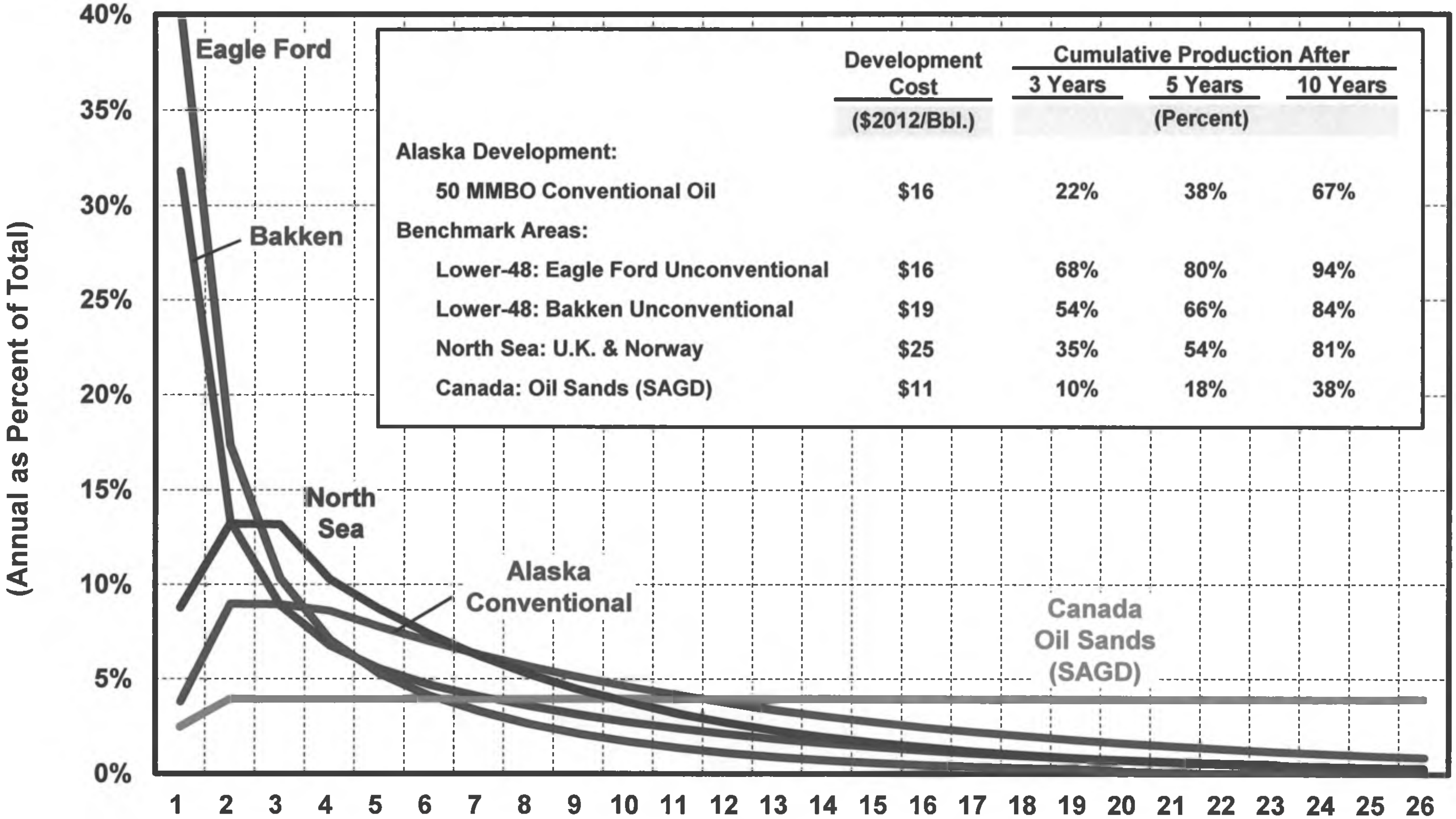
VI. Attractiveness of Investments Under ACES

Crude Oil Prices Used for Analysis

- Likely Long Term Sustainable Range Between $80/Bbl and $130/Bbl Real
- Prices May Move Out of This Range for Periods of Time
- Sustained Prices Below Range Makes Many Projects Uneconomic; Supplies Reduced
- Sustained Prices Above Range Starts to Attract More Oil Supply, Reduces Demand for Petroleum Products (e.g., Gasoline Prices Above $5/Gal.) and Encourages Substitutes
- Producers Will "Stress Test" Projects Near Lower End of Range



Summary of Production Profiles Examined For Alaska and Benchmark Developments



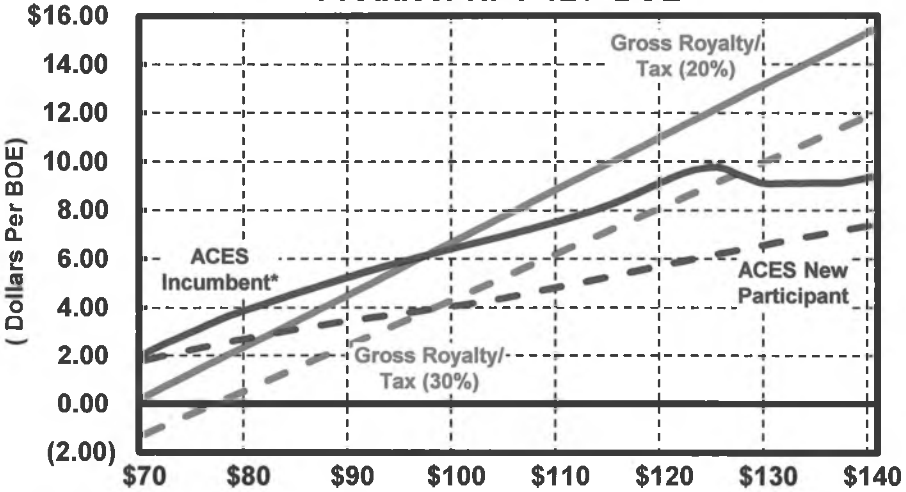
	Development Cost ($2012/Bbl.)	Cumulative Production After 3 Years	5 Years	10 Years
		(Percent)		
Alaska Development:				
50 MMBO Conventional Oil	$16	22%	38%	67%
Benchmark Areas:				
Lower-48: Eagle Ford Unconventional	$16	68%	80%	94%
Lower-48: Bakken Unconventional	$19	54%	66%	84%
North Sea: U.K. & Norway	$25	35%	54%	81%
Canada: Oil Sands (SAGD)	$11	10%	18%	38%

Investment Measures Analyzed

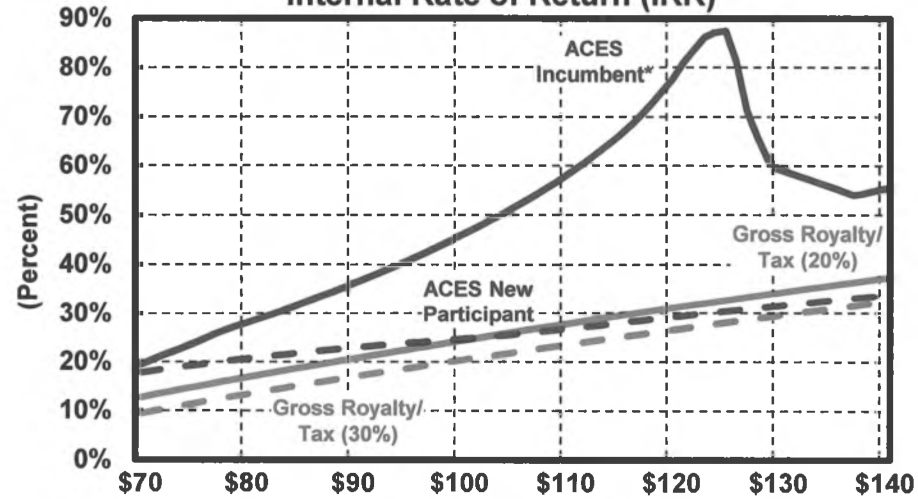
- Producer NPV-12 Per BOE
- Internal Rate of Return (IRR)
- 5-Year Cash Margins
- Profitability Index-12
- Government Take
- State NPV-12 Per BOE

Investment Measures
Development of Conventional Oil Reserves

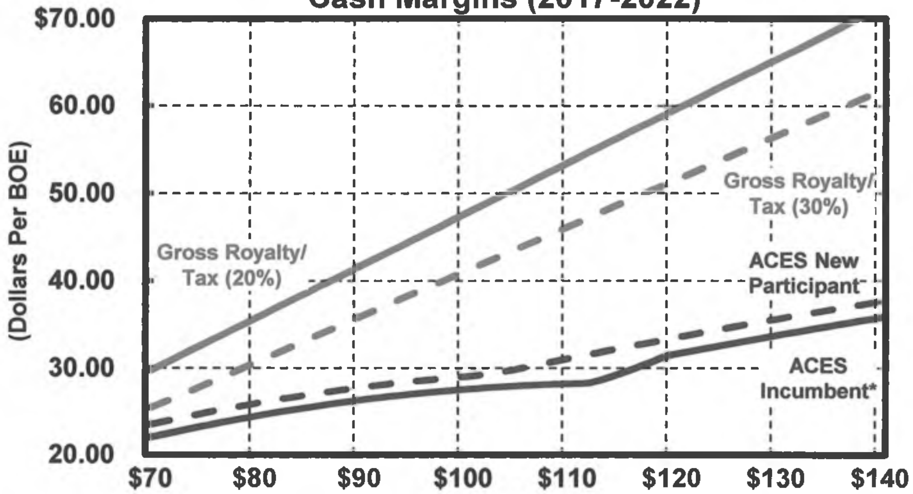
Producer NPV-12 / BOE



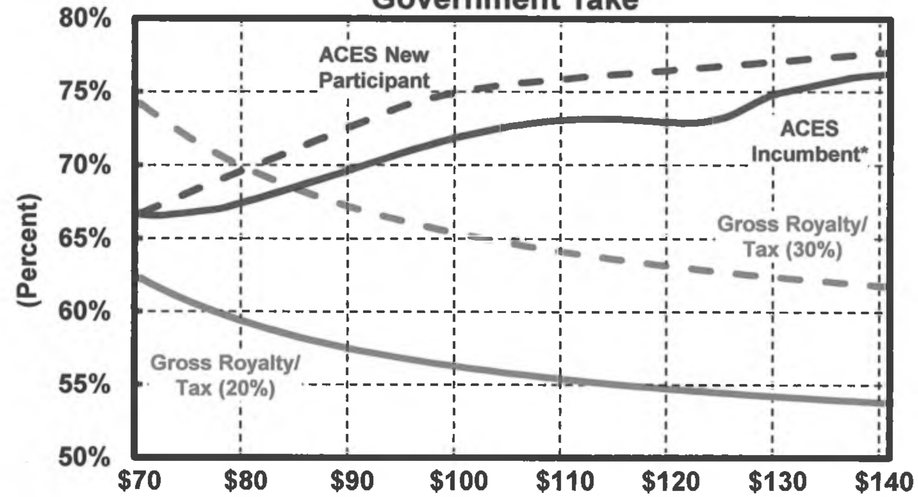
Internal Rate of Return (IRR)



Cash Margins (2017-2022)



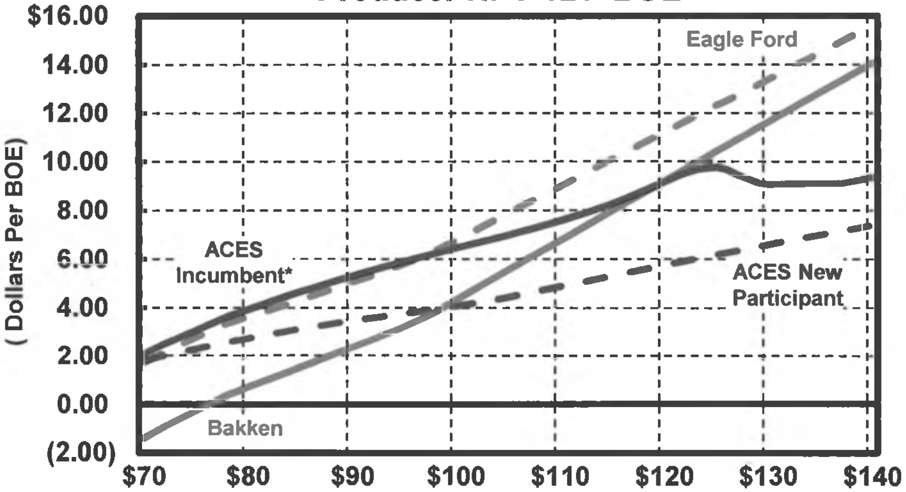
Government Take



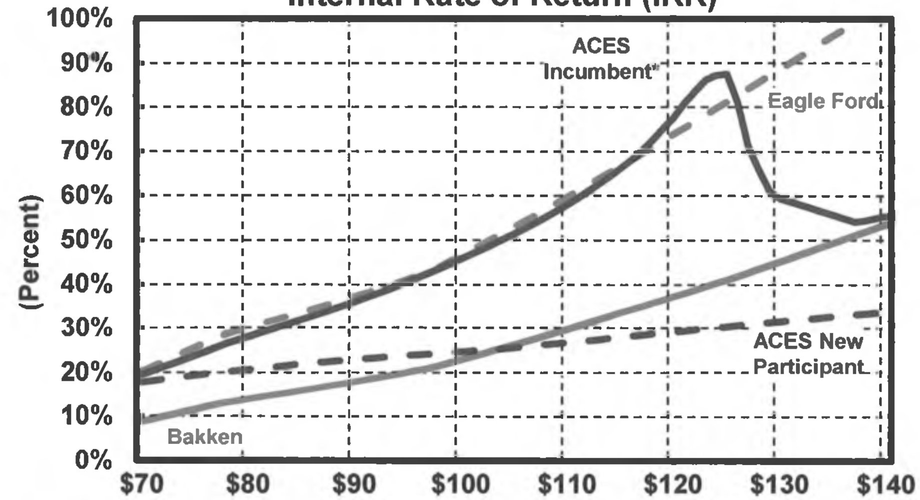
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Measures
Conventional Oil Alaska Development
v. Unconventional Lower-48

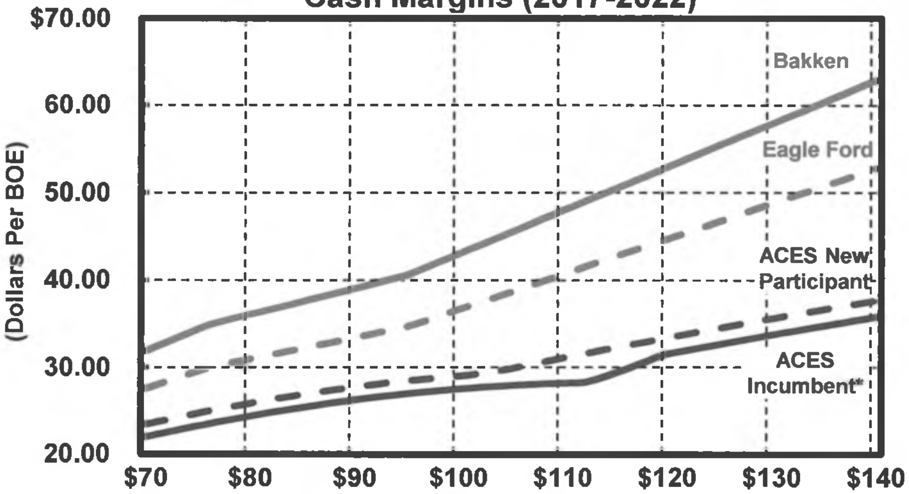
Producer NPV-12 / BOE



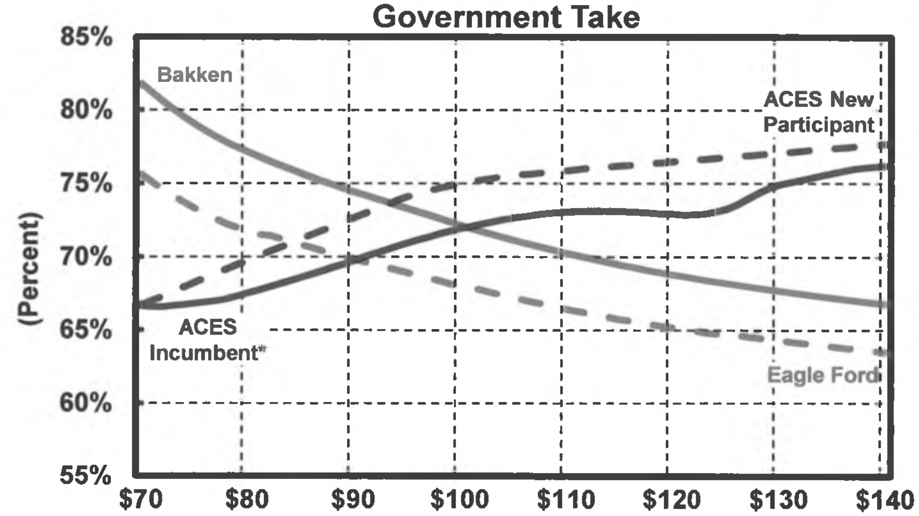
Internal Rate of Return (IRR)



Cash Margins (2017-2022)

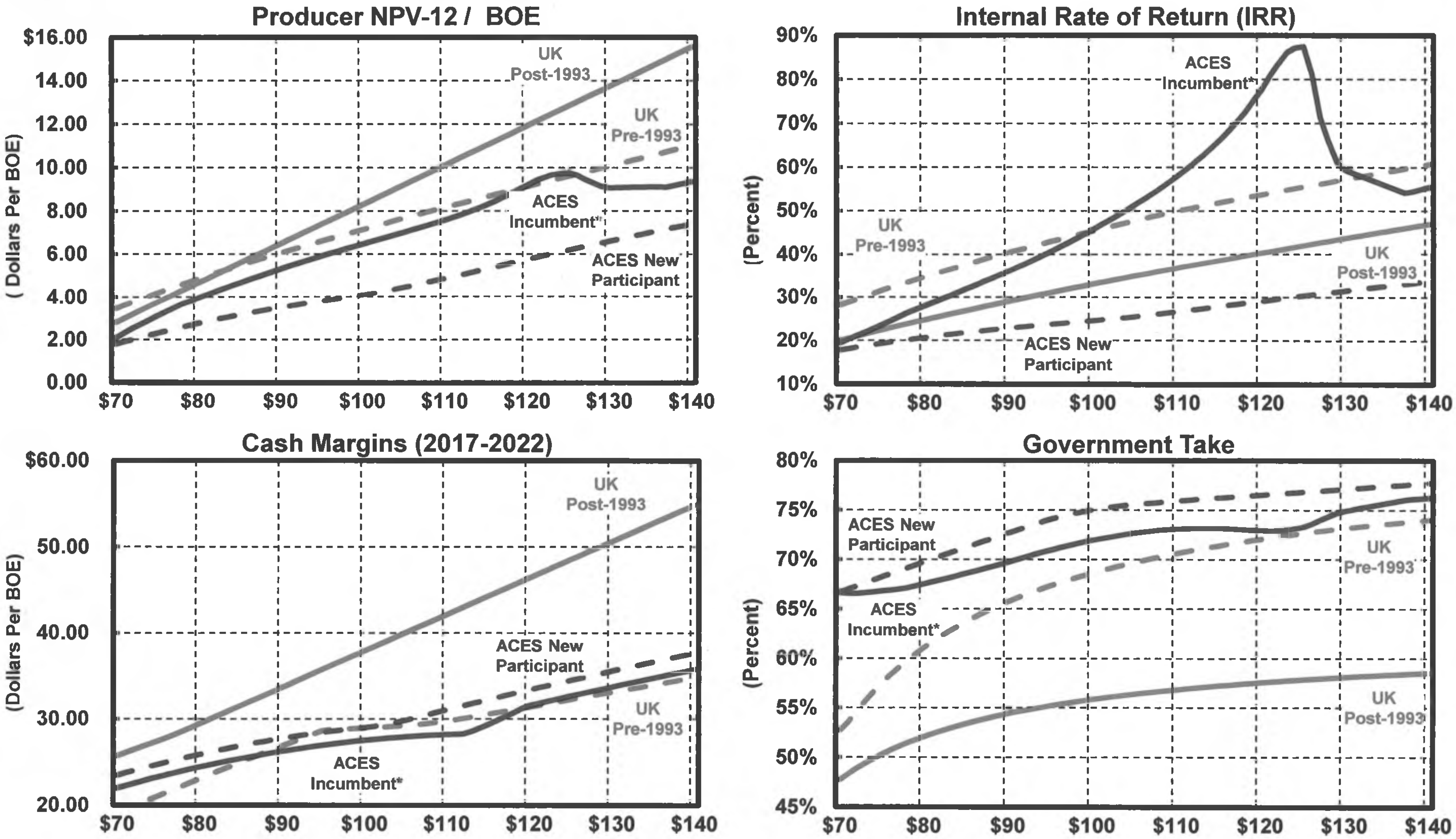


Government Take



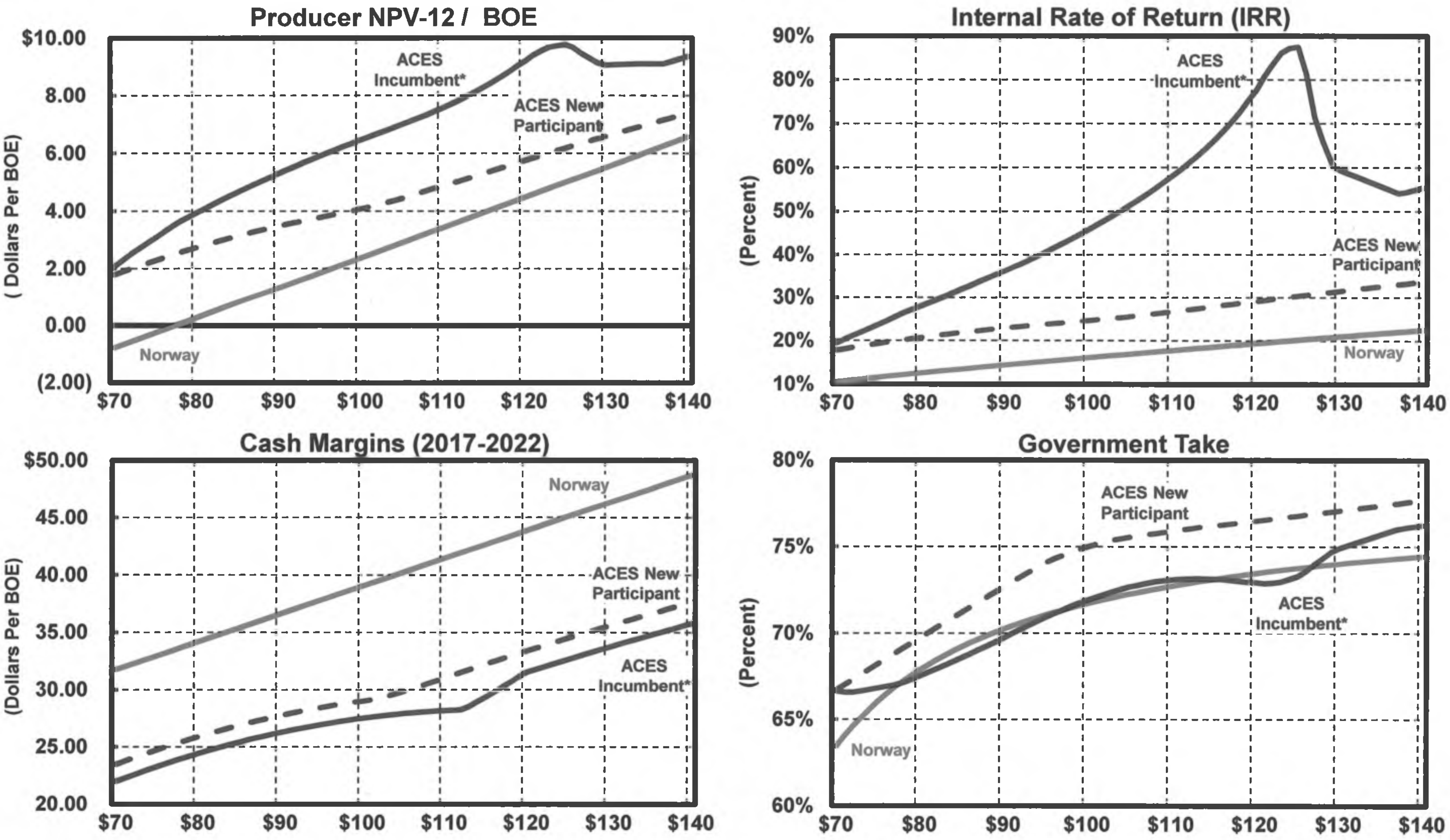
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Conventional Oil Alaska Development
v. North Sea (United Kingdom with Brownfield Allowance)



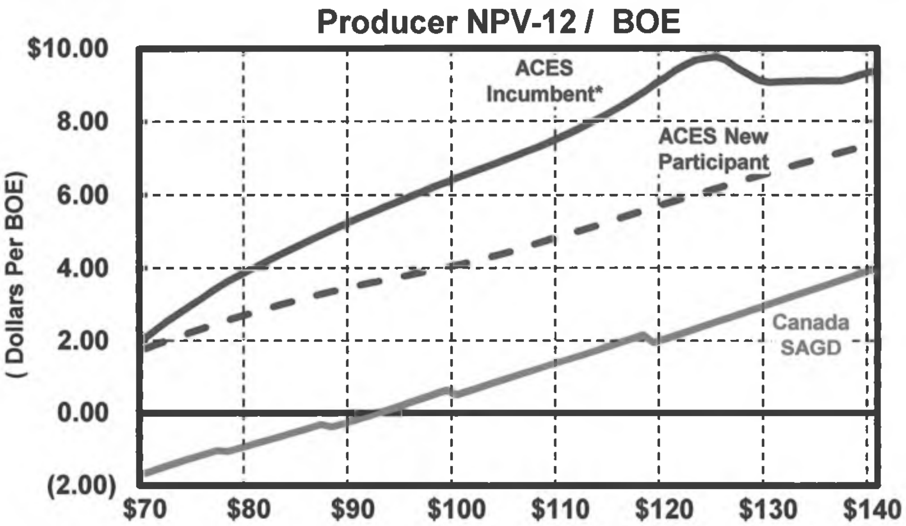
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

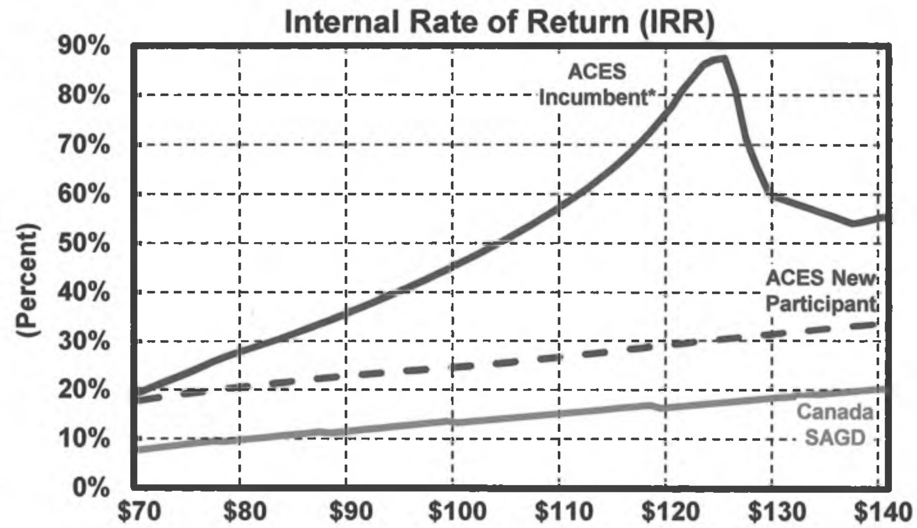
Investment Metrics
Conventional Oil Alaska Development v. North Sea (Norway)

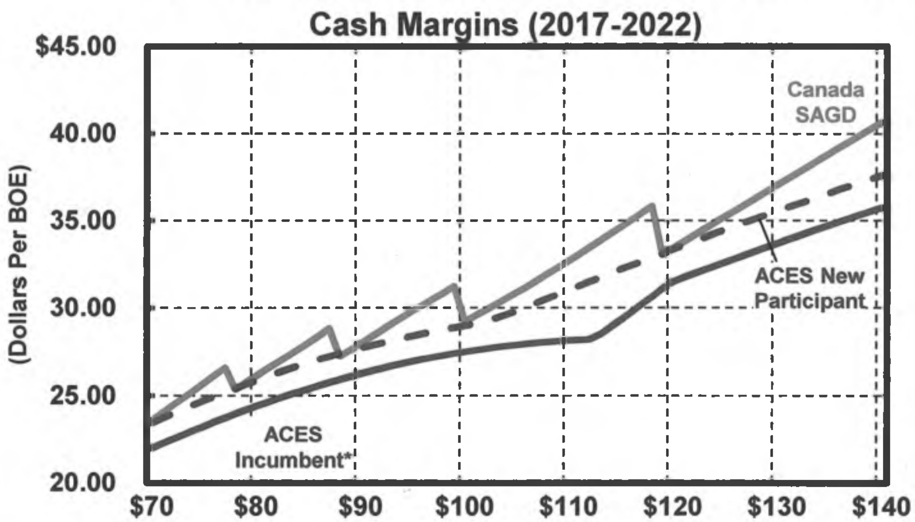


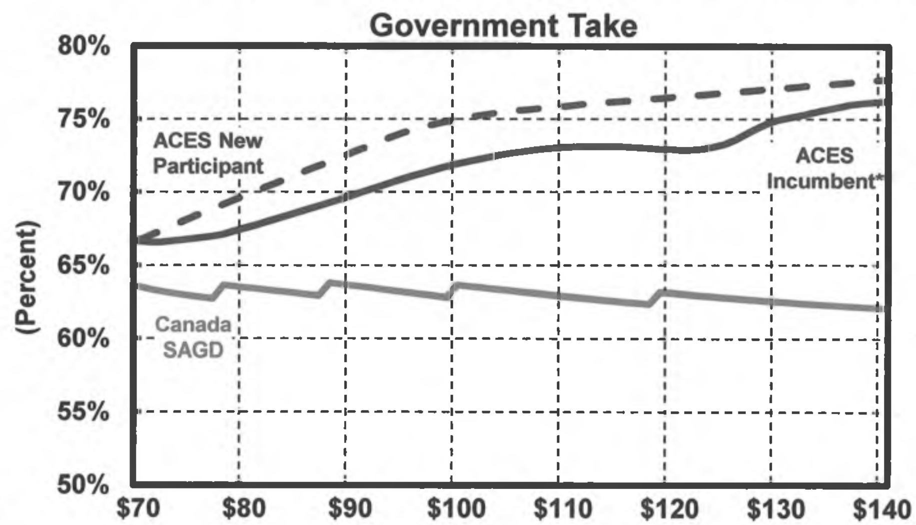
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Conventional Oil Alaska Development v. Canada Oil Sands (SAGD)









* Analysis of incumbent production includes “buy-down” impact for reduced taxes on existing production.

Summary of Investment Measures

West Coast ANS Price	Alaska 50 MMBO Conventional Oil: New Participant	Alaska 50 MMBO Conventional Oil: Incumbent Participant	Uncoventional Lower-48	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System: Pre-1993	U.K.: Pre-1993 w/ Brownfield Allowance*	U.K.: Post-1993	U.K.: Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Producer NPV-12 / BOE (Dollars Per BOE)									
$80	$2.73	$3.93	$2.14	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	$4.07	$6.45	$5.52	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	$5.74	$9.17	$10.17	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
Profitability Index-12									
$80	1.21	1.30	1.15	0.88	1.01	1.06	1.22	1.11	1.21
$100	1.31	1.49	1.37	1.06	1.14	1.14	1.33	1.28	1.38
$120	1.43	1.69	1.69	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)									
$80	20.6%	27.9%	21.8%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	24.6%	45.7%	34.5%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	29.1%	77.6%	55.3%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)									
$80	$25.85	$24.38	$33.41	$26.07	$34.11	$12.45	$22.94	$24.91	$29.35
$100	$28.95	$27.48	$39.69	$29.14	$38.96	$16.69	$28.85	$33.38	$37.82
$120	$33.35	$31.50	$48.71	$33.37	$43.81	$20.93	$31.29	$41.86	$46.30
Government Take (Percent)									
$80	69.7%	67.5%	74.4%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	75.0%	71.9%	70.0%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	76.5%	72.9%	66.9%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State NPV-12/BOE (Dollars Per BOE)									
$80	$5.95	$4.10	-	-	-	-	-	-	-
$100	$12.54	$8.88	-	-	-	-	-	-	-
$120	$18.61	$13.34	-	-	-	-	-	-	-

*** Brownfield Allowance applied to 100 MMBOE development.**

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

VII. The Administration's Proposed Changes

Key Aspects of Administration's Proposal

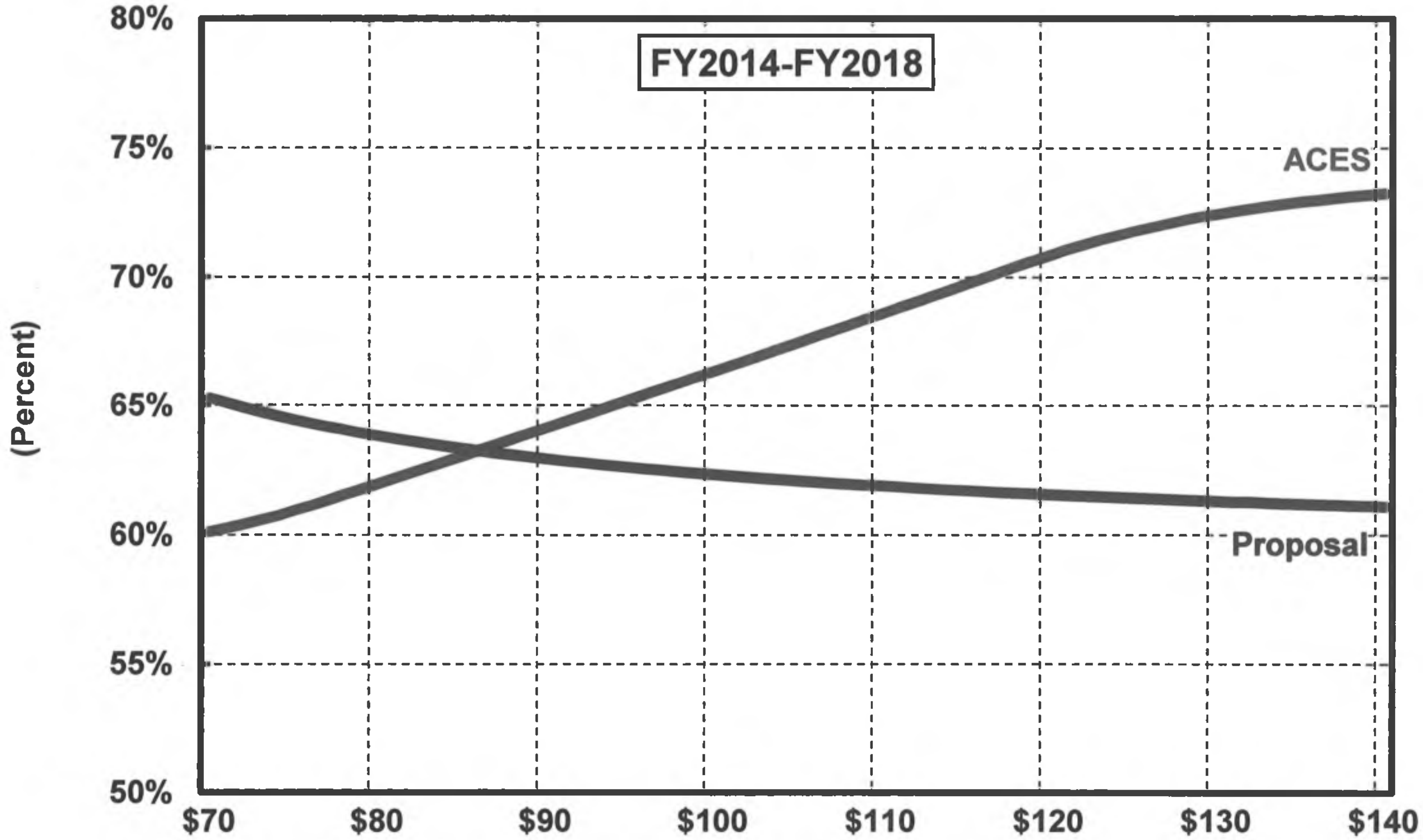
- Establishes 25% Flat Net Tax Rate; No Progressivity
- Eliminates Capital Credit and State Purchase of Losses
- Establishes 20% Gross Revenue Exclusion (GRE) to Incent Production of New Oil
- Losses May be Carried Forward and Applied Against Tax Obligation When Production Occurs
- Extends New Entrant Credits Through 2022
- No Change Outside of North Slope

Key Aspects of Administration's Proposal (cont'd)

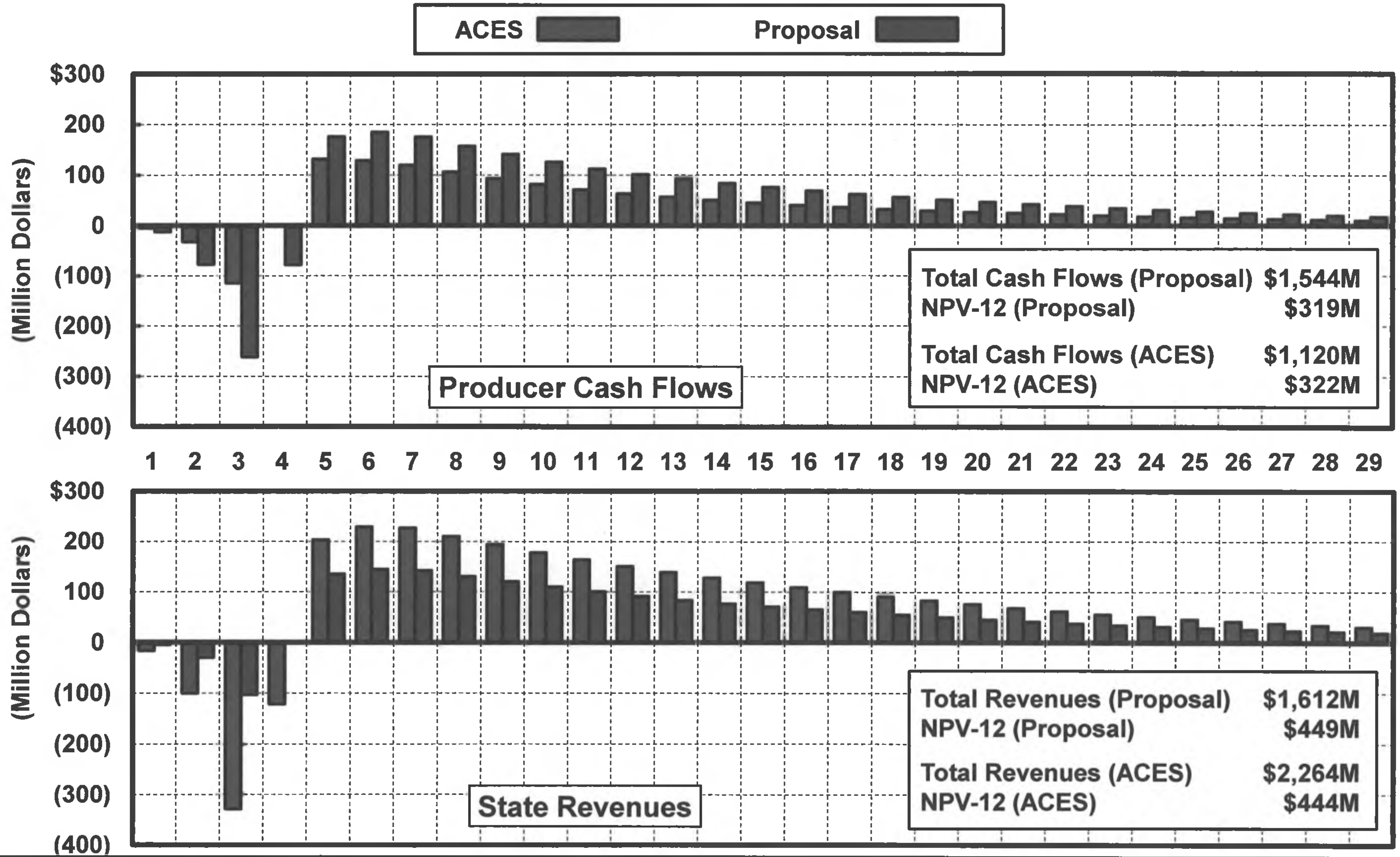
- Provides Balance Between State and Producers
  - Reduction of Tax Rates at High Prices, Balanced with Elimination of Credits
  - State Continues to Receive Largest Percentage of Oil Production Revenues at Any Price
  - Provides Tax Relief and Higher Margins in Sustainable Price Ranges
- Simplifies Tax System and Provides Clarity for Planning
  - Eliminates Question of Marginal Tax Rate / Take for Investment Planning
  - Eliminates Incentives for "Gold Plating" Caused by High Marginal Rates
- Maintains Alignment Between State and Producer Incentives
  - Net Tax Allows for Deduction of Costs Against Tax
- Provides Incentive for Development of New Resources Without Taxing State Treasury
  - GRE Provides Lower Effective Tax Rate for New Development
  - New Developers can Recover Costs of Development Once Production Begins
  - Does Not Require State to Fund Development Costs Through Potentially Expensive Credit Purchases
- Extremely Positive Message to Potential Investors
  - Will Encourage Broader Participation in Development of Alaska's North Slope
  - Economics of New Participants Closer to Incumbents'

Key Aspects of Administration's Proposal (cont'd)

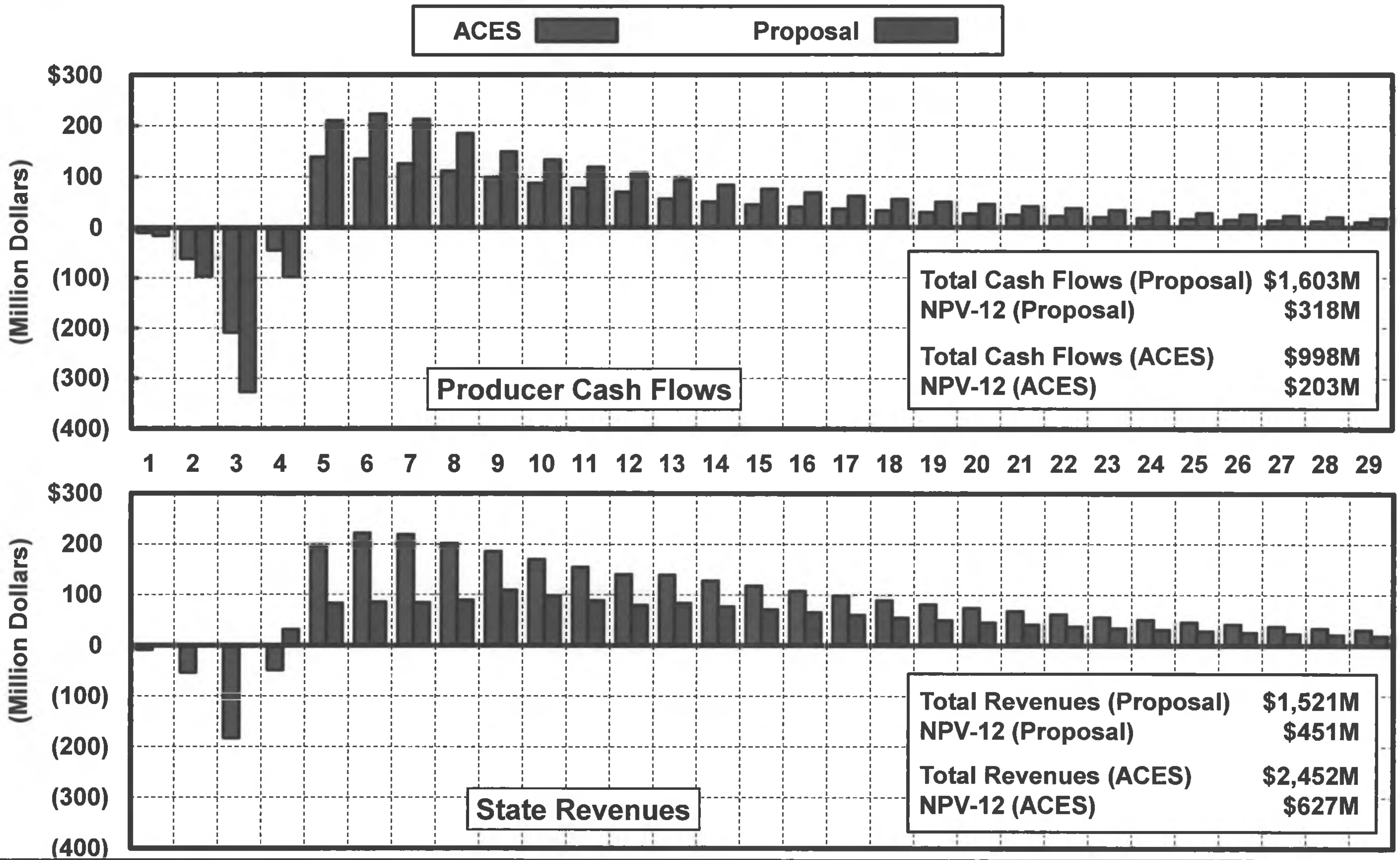
➢ **Average Government Take Moves From Progressive to Relatively Neutral Under Proposal**



Annual State Revenues and Producer Cash Flows at $100 West Coast ANS
50 MMBO Conventional Oil Alaska Development
Incumbent Participant in Alaska



Annual State Revenues and Producer Cash Flows at $100 West Coast ANS
50 MMBO Conventional Oil Alaska Development
New Participant in Alaska

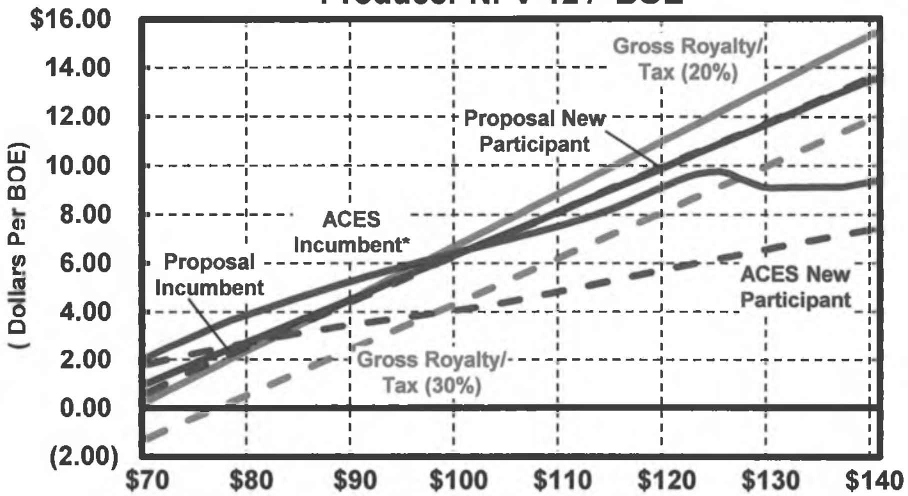


Summary of State Revenues and Producer Cash Flows
Totals and NPV-12
50 MMBO Conventional Oil Alaska Development

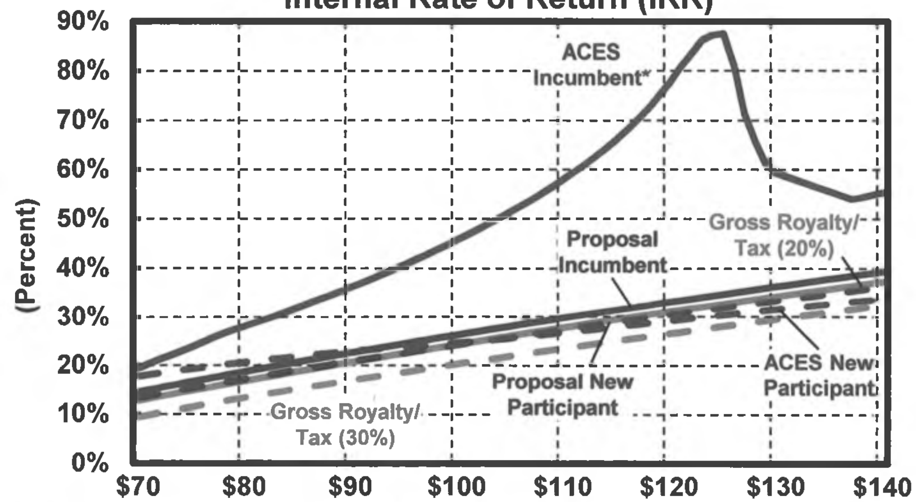
West Coast ANS Price	New Participant ACES (1)	New Participant Proposal (2)	Incumbent Participant ACES (3)	Incumbent Participant Proposal (4)
Producer Cash Flows (Million Dollars)				
$80	$806	$1,053	$865	$993
$100	$998	$1,603	$1,120	$1,544
$120	$1,250	$2,153	$1,440	$2,094
Producer NPV-12 (Million Dollars)				
$80	$136	$130	$196	$140
$100	$203	$318	$322	$319
$120	$287	$500	$458	$498
State Revenues (Million Dollars)				
$80	$1,422	$1,042	$1,331	$1,133
$100	$2,452	$1,521	$2,264	$1,612
$120	$3,390	$2,001	$3,098	$2,091
State NPV-12 (Million Dollars)				
$80	$298	$307	$205	$292
$100	$627	$451	$444	$449
$120	$931	$602	$667	$606

Investment Measures
Development of Conventional Oil Reserves

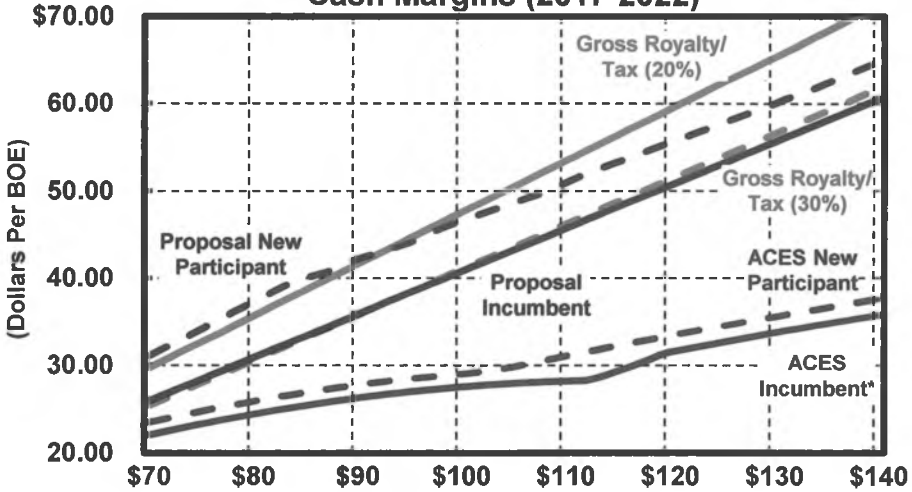
Producer NPV-12 / BOE



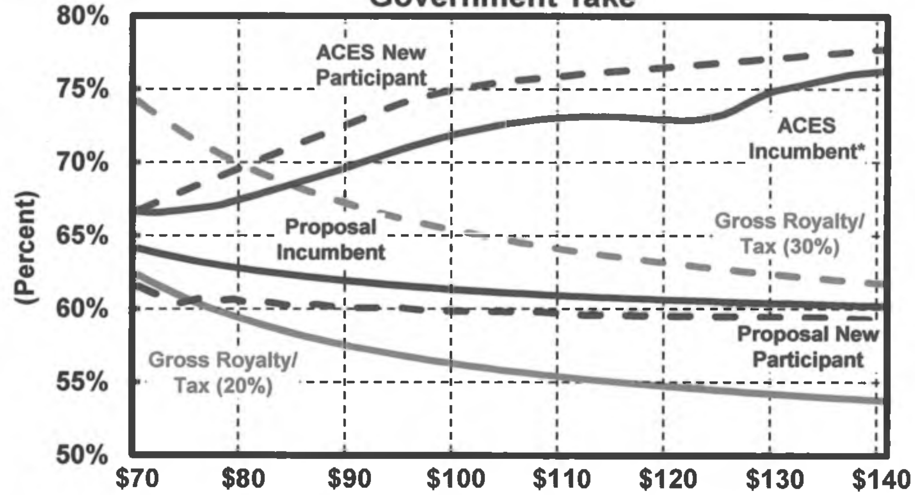
Internal Rate of Return (IRR)



Cash Margins (2017-2022)

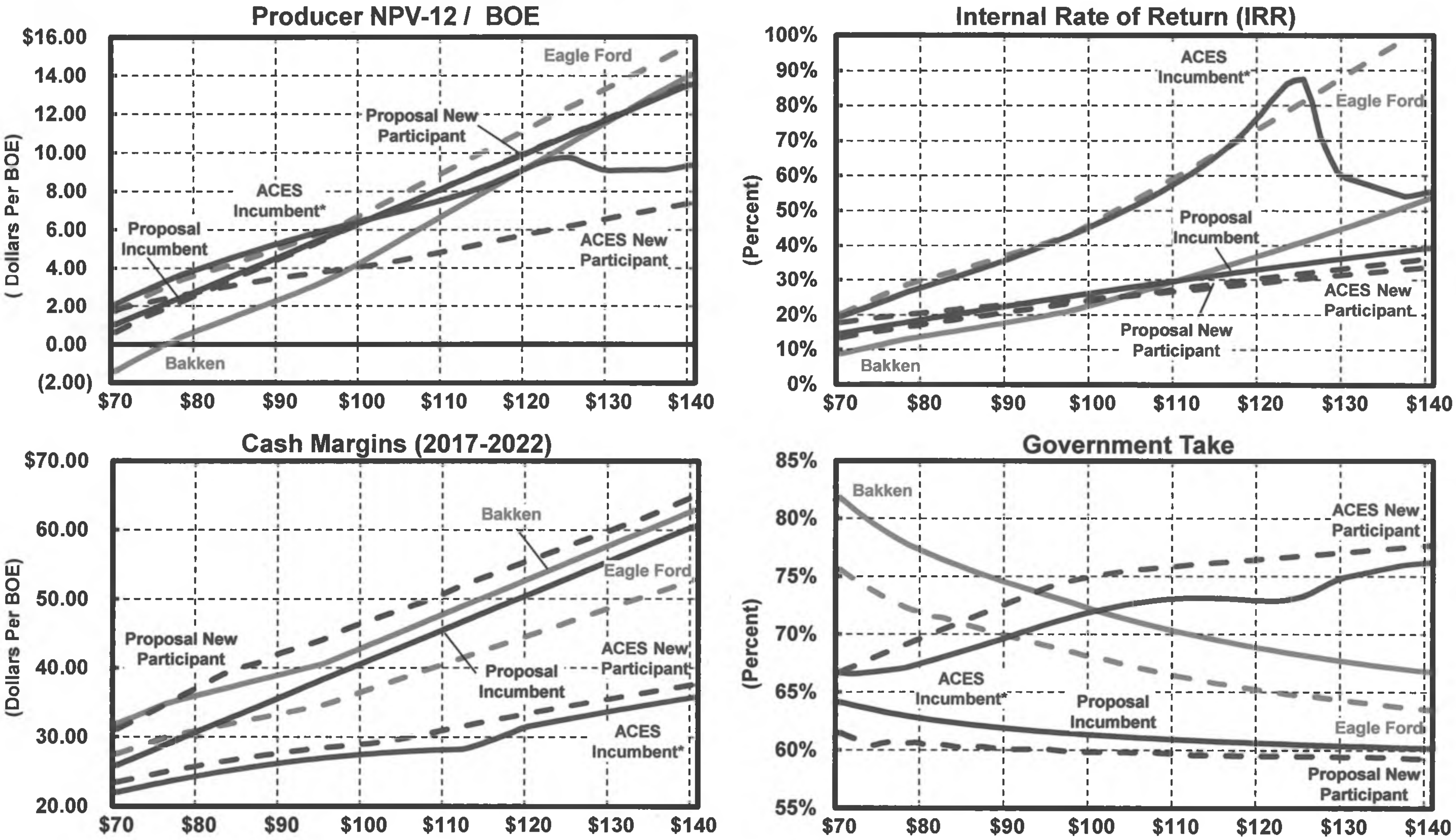


Government Take



* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Measures
Conventional Oil Alaska Development v. Unconventional Lower-48



* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Conventional Oil Alaska Development
v. North Sea (United Kingdom with Brownfield Allowance)

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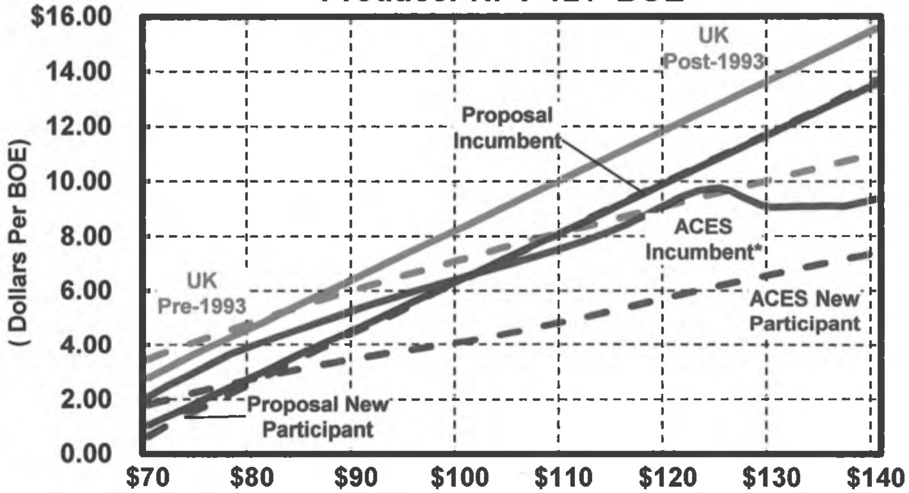
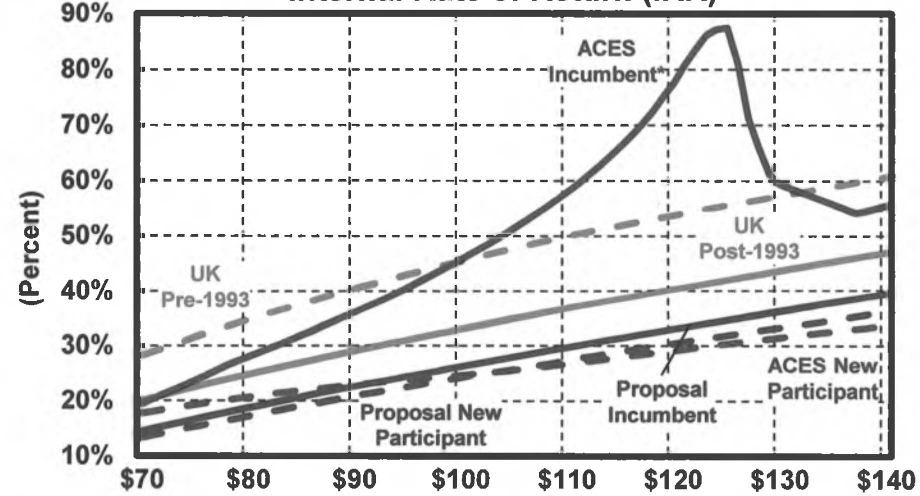
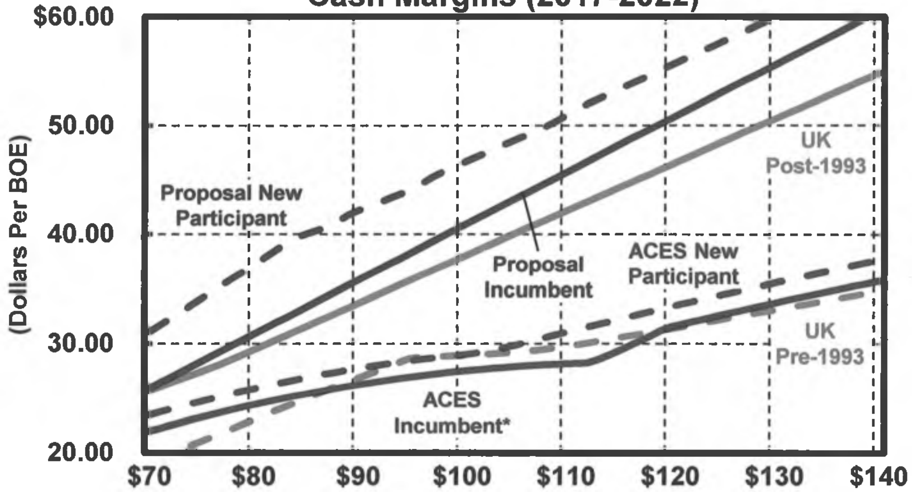
Producer NPV-12 / BOE



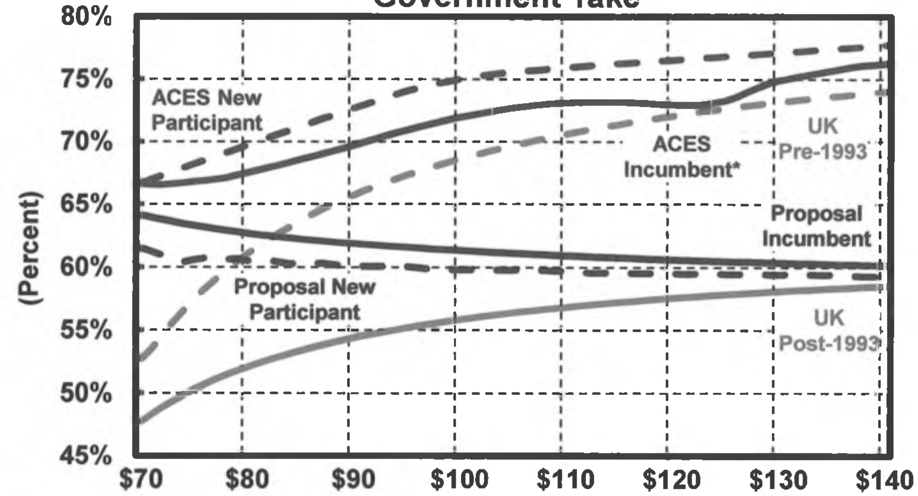
Internal Rate of Return (IRR)



Cash Margins (2017-2022)

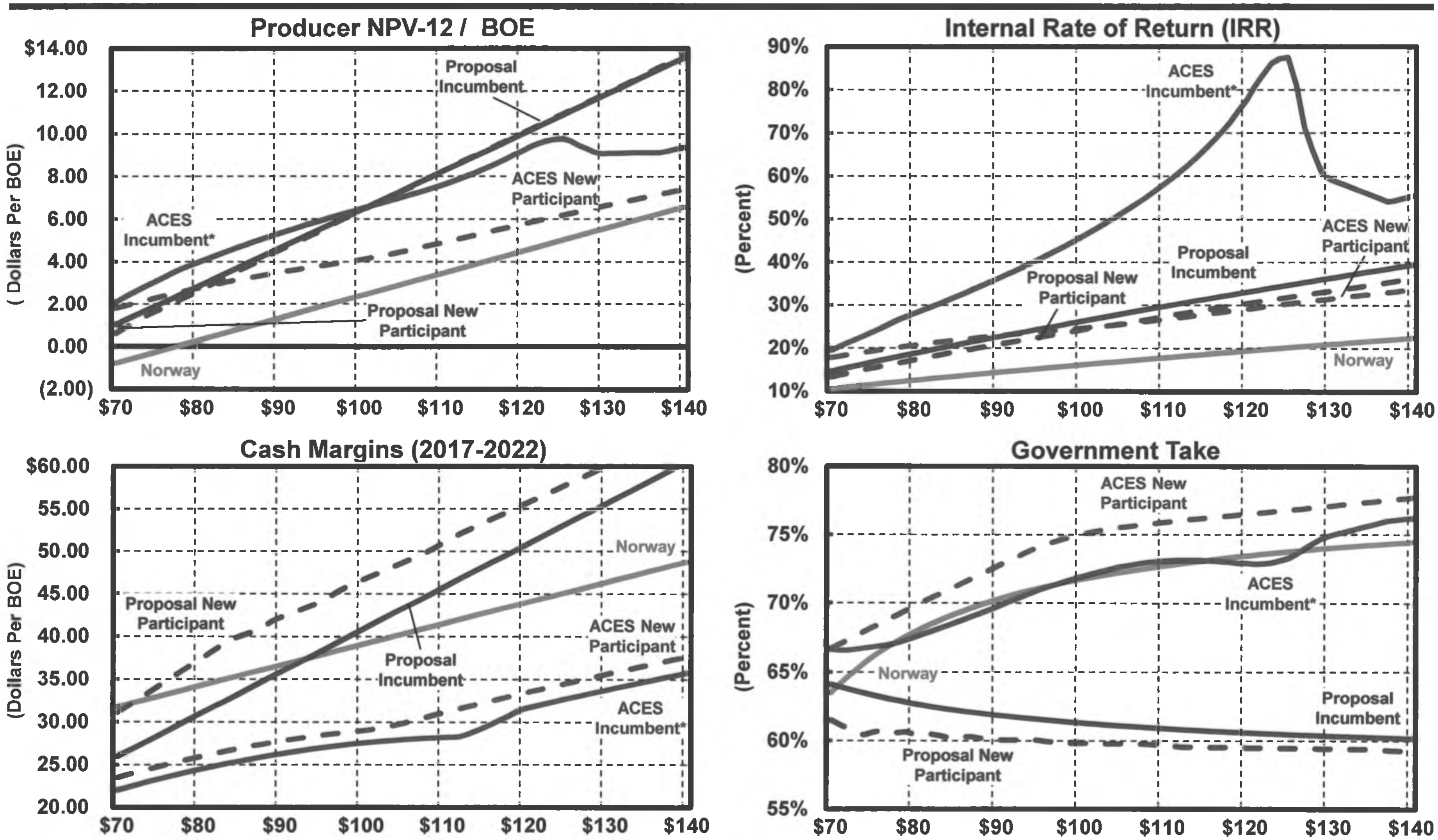


Government Take



* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

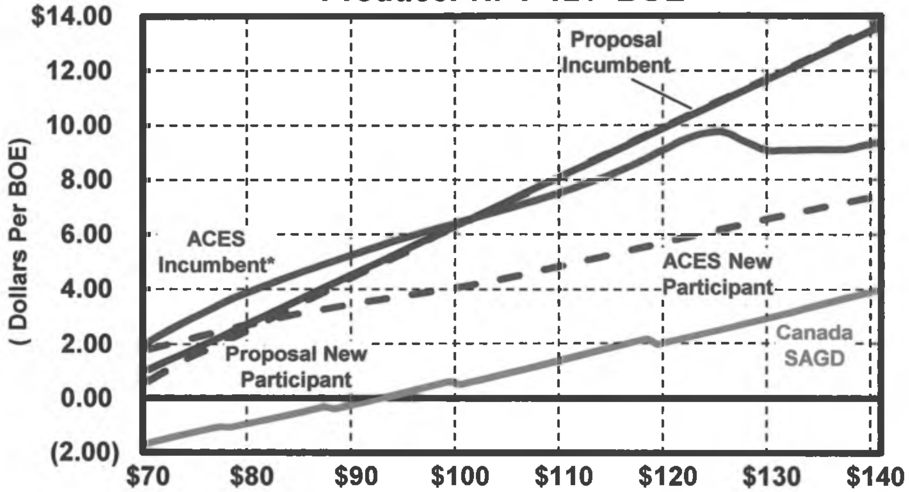
Investment Metrics
Conventional Oil Alaska Development v. North Sea (Norway)



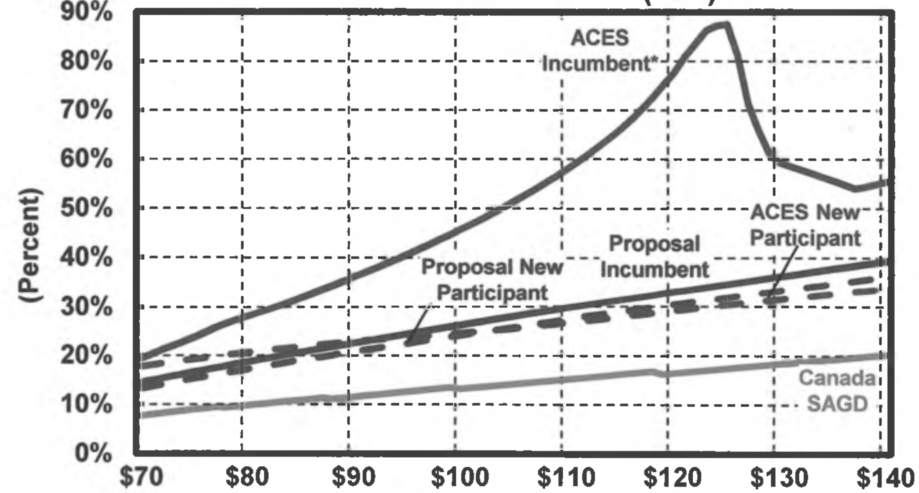
* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Investment Metrics
Conventional Oil Alaska Development v. Canada Oil Sands (SAGD)

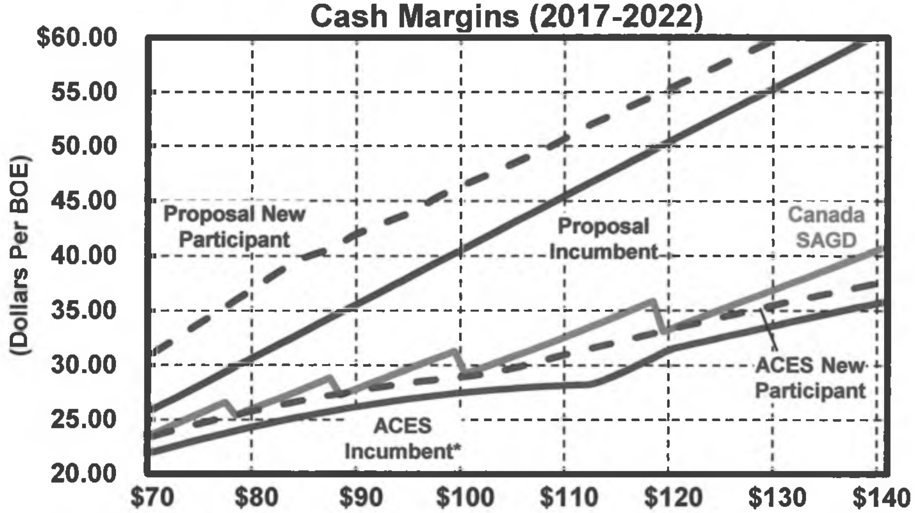
Producer NPV-12 / BOE



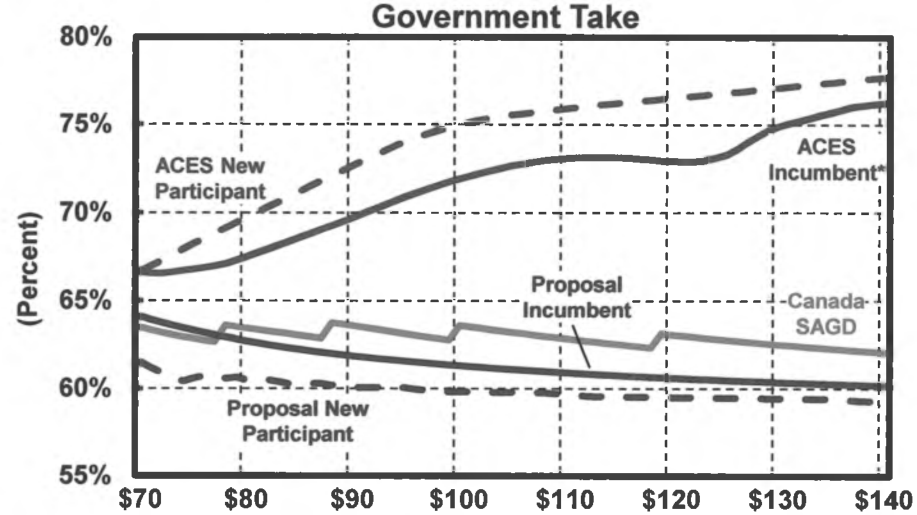
Internal Rate of Return (IRR)



Cash Margins (2017-2022)



Government Take



* Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

Summary of Investment Measures for New Participant Conventional Oil Alaska Development ACES and Proposal v. Benchmark Areas

West Coast ANS Price	ACES	Proposal: With GRE	Proposal: Without GRE	Uncoventional Lower-48	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System: Pre-1993	U.K.: Pre-1993 w/ Brownfield Allowance*	U.K.: Post-1993	U.K.: Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Producer NPV-12 / BOE (Dollars Per BOE)										
$80	$2.73	$2.60	$1.98	$2.14	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	$4.07	$6.35	$5.49	$5.52	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	$5.74	$10.01	$8.95	$10.17	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
Profitability Index-12										
$80	1.21	1.20	1.15	1.15	0.88	1.01	1.06	1.22	1.11	1.21
$100	1.31	1.48	1.41	1.37	1.06	1.14	1.14	1.33	1.28	1.38
$120	1.43	1.75	1.67	1.69	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)										
$80	20.6%	17.2%	16.2%	21.8%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	24.6%	24.2%	22.8%	34.5%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	29.1%	30.3%	28.9%	55.3%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)										
$80	$25.85	$37.22	$34.68	$33.41	$26.07	$34.11	$12.45	$22.94	$24.91	$29.35
$100	$28.95	$46.51	$43.11	$39.69	$29.14	$38.96	$16.69	$28.85	$33.38	$37.82
$120	$33.35	$55.53	$51.62	$48.71	$33.37	$43.81	$20.93	$31.29	$41.86	$46.30
Government Take (Percent)										
$80	69.7%	60.4%	64.8%	74.4%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	75.0%	59.8%	63.5%	70.0%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	76.5%	59.5%	62.8%	66.9%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State NPV-12/BOE (Dollars Per BOE)										
$80	$5.95	$6.15	$7.10	-	-	-	-	-	-	-
$100	$12.54	$9.02	$10.35	-	-	-	-	-	-	-
$120	$18.61	$12.04	$13.67	-	-	-	-	-	-	-

*** Brownfield Allowance applied to 100 MMBOE development.**

Summary of Investment Measures for Incumbent Conventional Oil Alaska Development ACES and Proposal v. Benchmark Areas

West Coast ANS Price	ACES	Proposal: With GRE	Proposal: Without GRE	Uncoventional Lower-48	Canada Oil Sands SAGD	Norway	U.K. Development & Fiscal System: Pre-1993	U.K. Development & Fiscal System: Pre-1993 w/ Brownfield Allowance*	U.K. Development & Fiscal System: Post-1993	U.K. Development & Fiscal System: Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Producer NPV-12 / BOE (Dollars Per BOE)										
$80	$3.93	$2.80	$2.09	$2.14	($0.93)	$0.24	$1.20	$4.81	$2.41	$4.62
$100	$6.45	$6.38	$5.46	$5.52	$0.46	$2.34	$3.02	$7.09	$6.04	$8.25
$120	$9.17	$9.96	$8.83	$10.17	$2.01	$4.44	$4.83	$9.09	$9.67	$11.88
Profitability Index-12										
$80	1.30	1.21	1.16	1.15	0.88	1.01	1.06	1.22	1.11	1.21
$100	1.49	1.48	1.41	1.37	1.06	1.14	1.14	1.33	1.28	1.38
$120	1.69	1.75	1.67	1.69	1.26	1.27	1.22	1.42	1.45	1.55
IRR (Percent)										
$80	27.9%	18.7%	17.1%	21.8%	9.7%	12.4%	18.4%	34.5%	18.4%	24.7%
$100	45.7%	26.2%	24.4%	34.5%	13.1%	16.0%	27.0%	45.2%	27.0%	32.9%
$120	77.6%	33.0%	31.0%	55.3%	16.3%	19.3%	34.6%	53.5%	34.6%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)										
$80	$24.38	$30.83	$28.72	$33.41	$26.07	$34.11	$12.45	$22.94	$24.91	$29.35
$100	$27.48	$40.73	$38.00	$39.69	$29.14	$38.96	$16.69	$28.85	$33.38	$37.82
$120	$31.50	$50.63	$47.28	$48.71	$33.37	$43.81	$20.93	$31.29	$41.86	$46.30
Government Take (Percent)										
$80	67.5%	62.7%	66.9%	74.4%	63.4%	67.8%	81.0%	61.0%	62.0%	52.0%
$100	71.9%	61.3%	65.0%	70.0%	63.5%	71.7%	81.0%	68.6%	62.0%	55.8%
$120	72.9%	60.6%	64.0%	66.9%	63.0%	73.4%	81.0%	72.0%	62.0%	57.5%
State NPV-12/BOE (Dollars Per BOE)										
$80	$4.10	$5.84	$6.94	-	-	-	-	-	-	-
$100	$8.88	$8.98	$10.40	-	-	-	-	-	-	-
$120	$13.34	$12.11	$13.85	-	-	-	-	-	-	-

*** Brownfield Allowance applied to 100 MMBOE development.**

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

01/29/13 SB 21 - Department of Revenue Overview

<TARGET><BILL>SB 21</BILL><SUBJECT>01-29-13 SB 21 - Department of Revenue Overview</SUBJECT><COMM>STTP28</COMM></TARGET>

Overview of SB 21
Oil & Gas
Production Tax

January 29, 2013
Alaska Department of Revenue

Principles

- Governor' Principles:
  - –Tax reform must be fair to Alaskans.
  - –Encourage new production.
  - –Simple so that it restores balance to the system.
  - –Durable for the long-term.

The Proposal (Highlights)

1. Eliminate Progressivity and Credits Based on Capital Expenditures.
2. Reform remaining credits to be carried forward to when there is production.
3. Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units (NEW OIL).
4. Hold Cook Inlet and Middle Earth Harmless.

Eliminate Progressivity & Credits Based on Capital Expenditures

Progressivity

Main Sections: 1,2,26

Conforming Sections: 5,6,22,23

North Slope QCE Credits

Main Sections: 8

Conforming Sections: 7, 11, 12

Reform remaining credits to be carried forward to when there is production.

North Slope Net Operating Loss Credits

Main Sections: 9, 15

Conforming Sections: 10, 19, 20

Small Producer Tax Credits

Main Sections: 16

Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units.

Gross Revenue Exclusion (The GRE)

Main Sections: 24

Conforming Sections: 5

Cook Inlet and Middle Earth

No Changes to Cook Inlet & Middle Earth

Main Sections: 3

Conforming Sections: 4, 13, 14, 17, 18, 21, 25

01/31/14
SB 21 - Presentation: Alaska Hydrocarbons Fiscal Systems by Janak Mayer, and Public Testimony

<TARGET><BILL>SB 21</BILL><SUBJECT>01-31-14 SB 21 - Presentation Alaska Hydrocarbons Fiscal Systems by Janak Mayer, and Public Testimony</SUBJECT><COMM>STTP28</COMM></TARGET>

Senate TAPS Throughput Committee

Alaska Hydrocarbons Fiscal Systems

January 31 2013

Janak Mayer
Manager, Upstream
PFC Energy

Tony Reinsch
Senior Director, Upstream
PFC Energy

Part 1:

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

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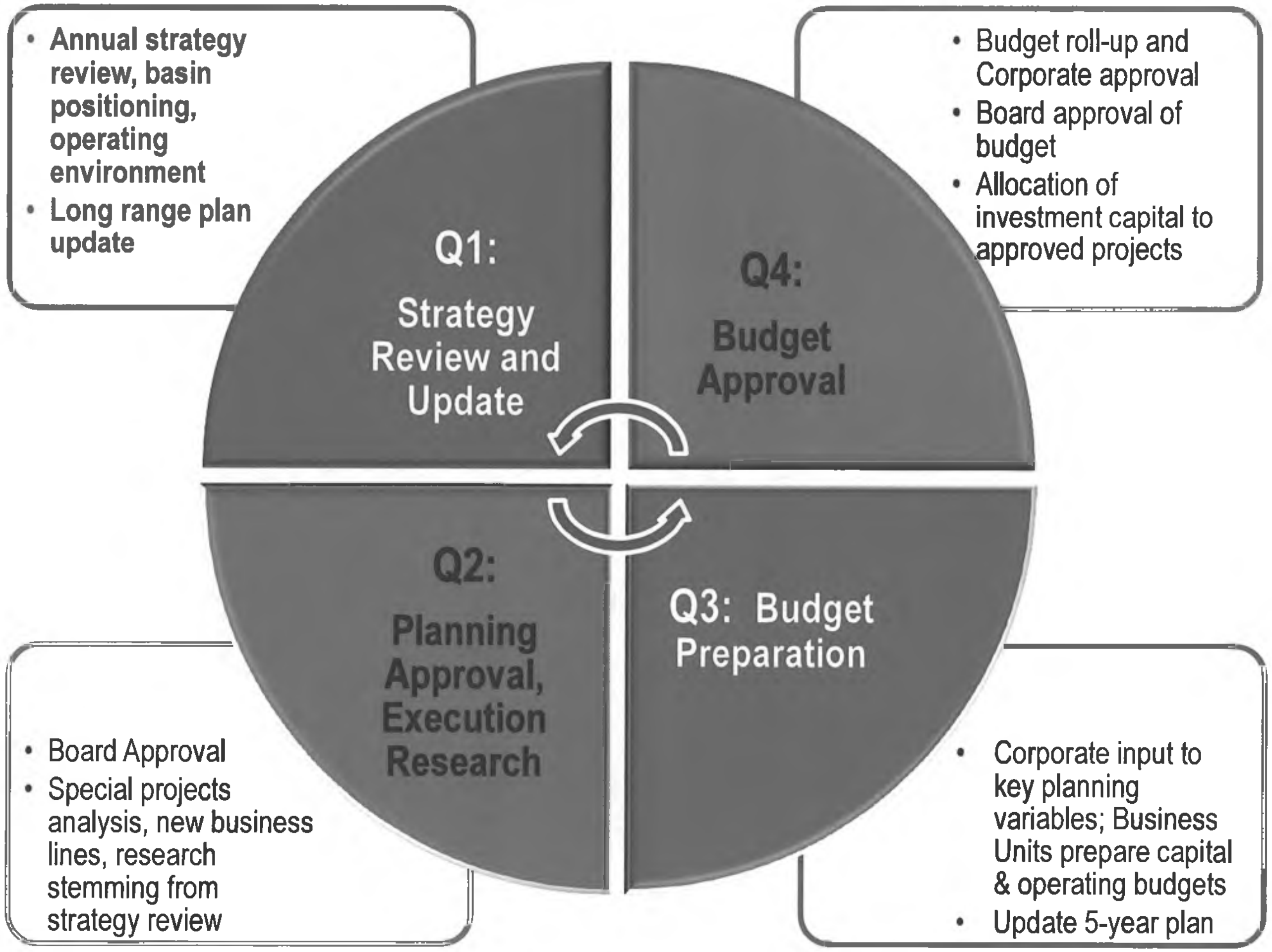
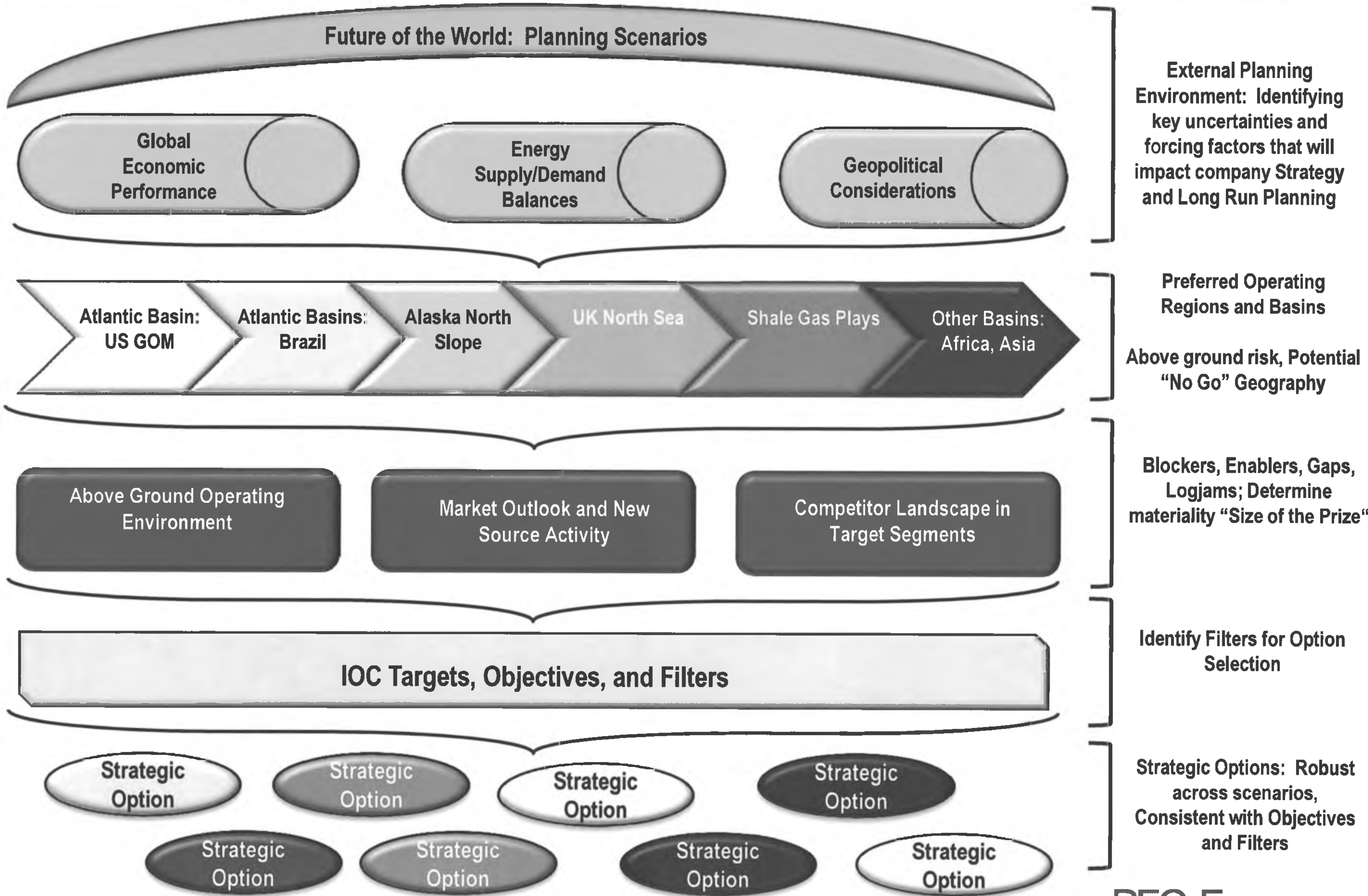
Annual Planning Cycle

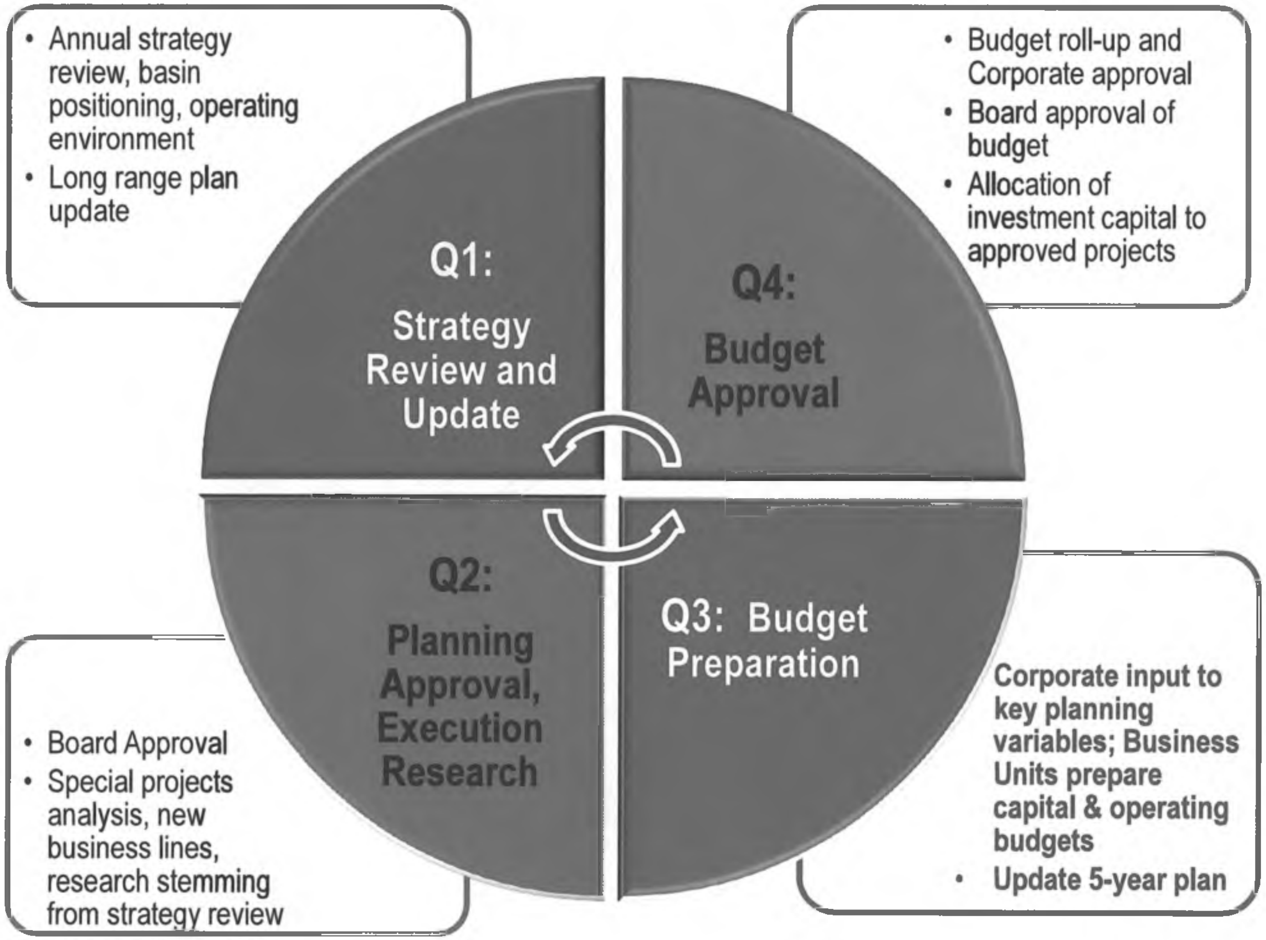
Oil and gas companies follow a standardized process linking the annual Budget cycle to the Long Range Plan and corporate Strategy



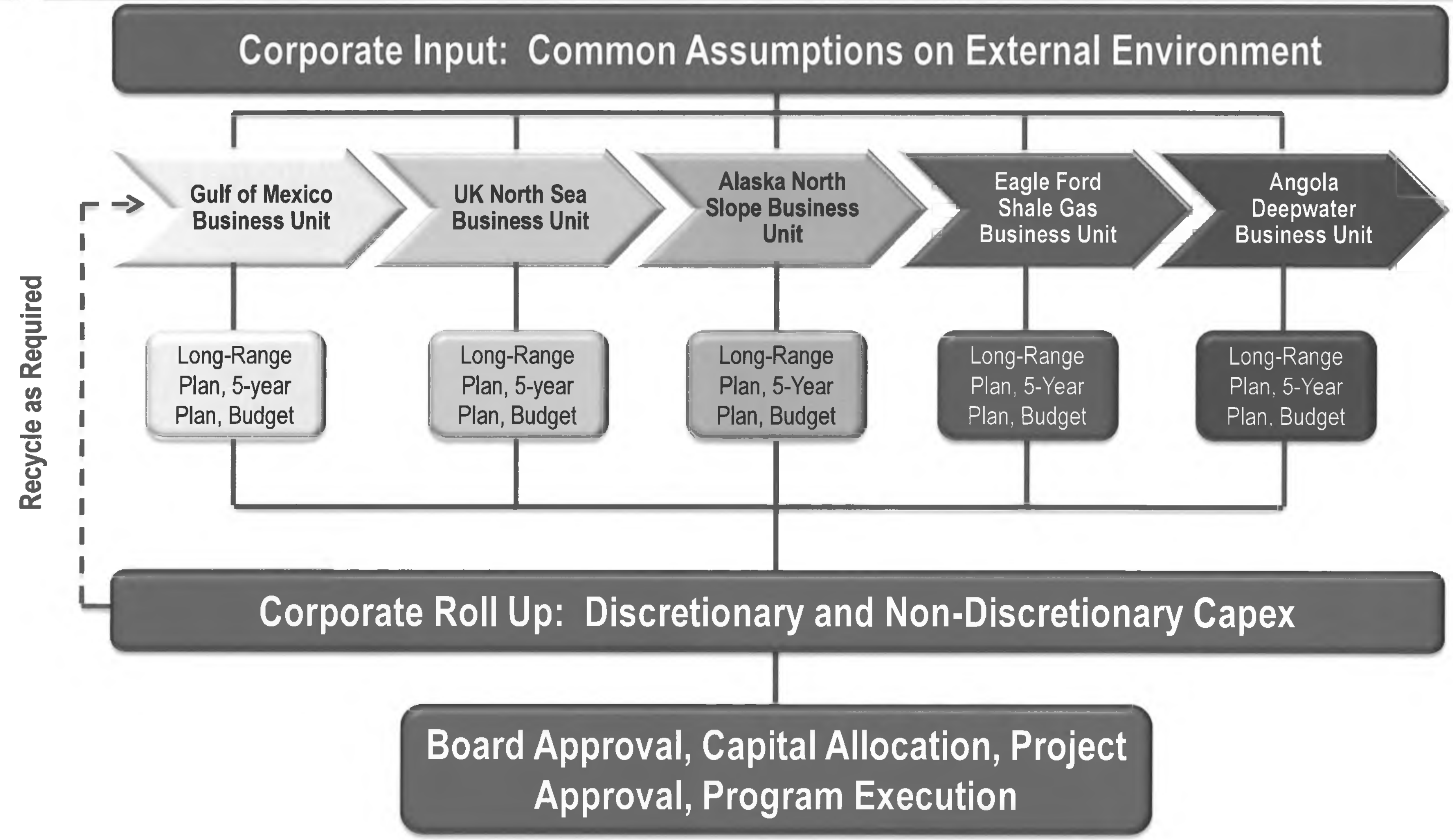
Strategy, Planning and Positioning



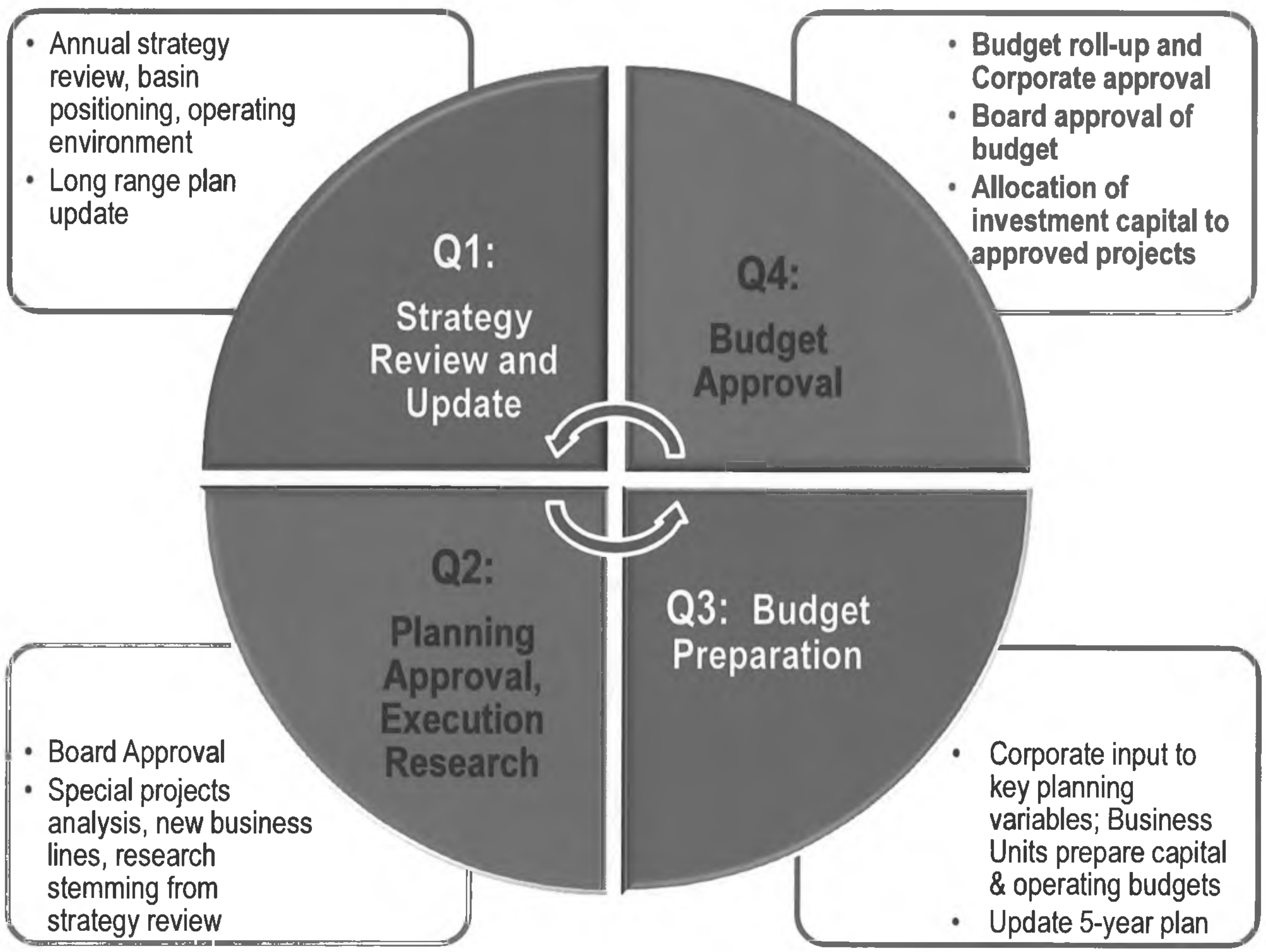
Annual Planning Cycle



Planning Cycle and Capital Allocation



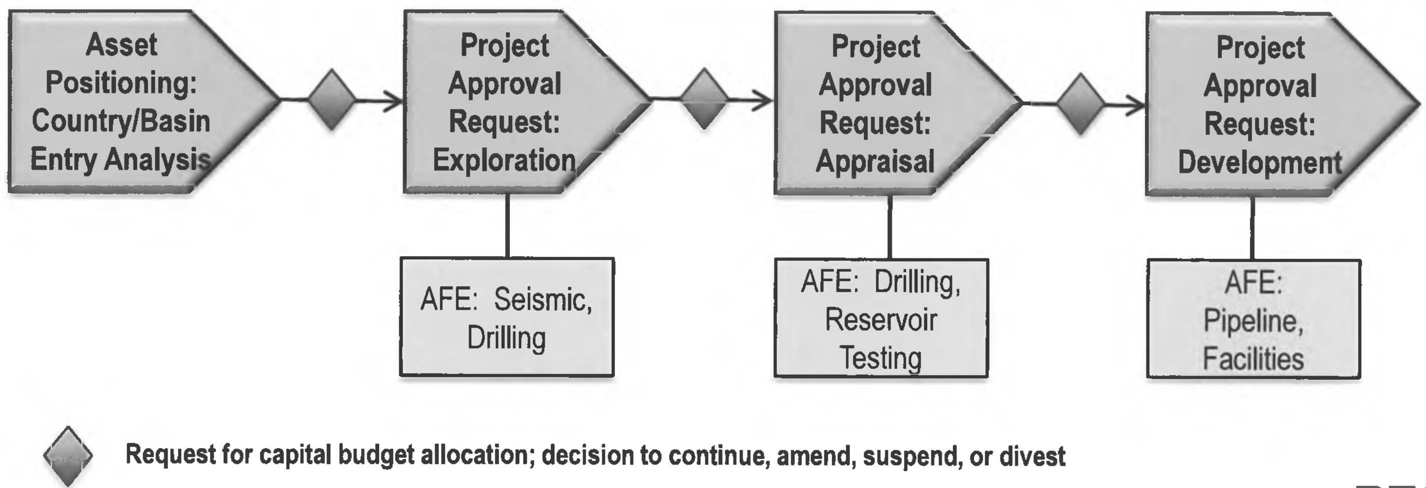
Annual Planning Cycle



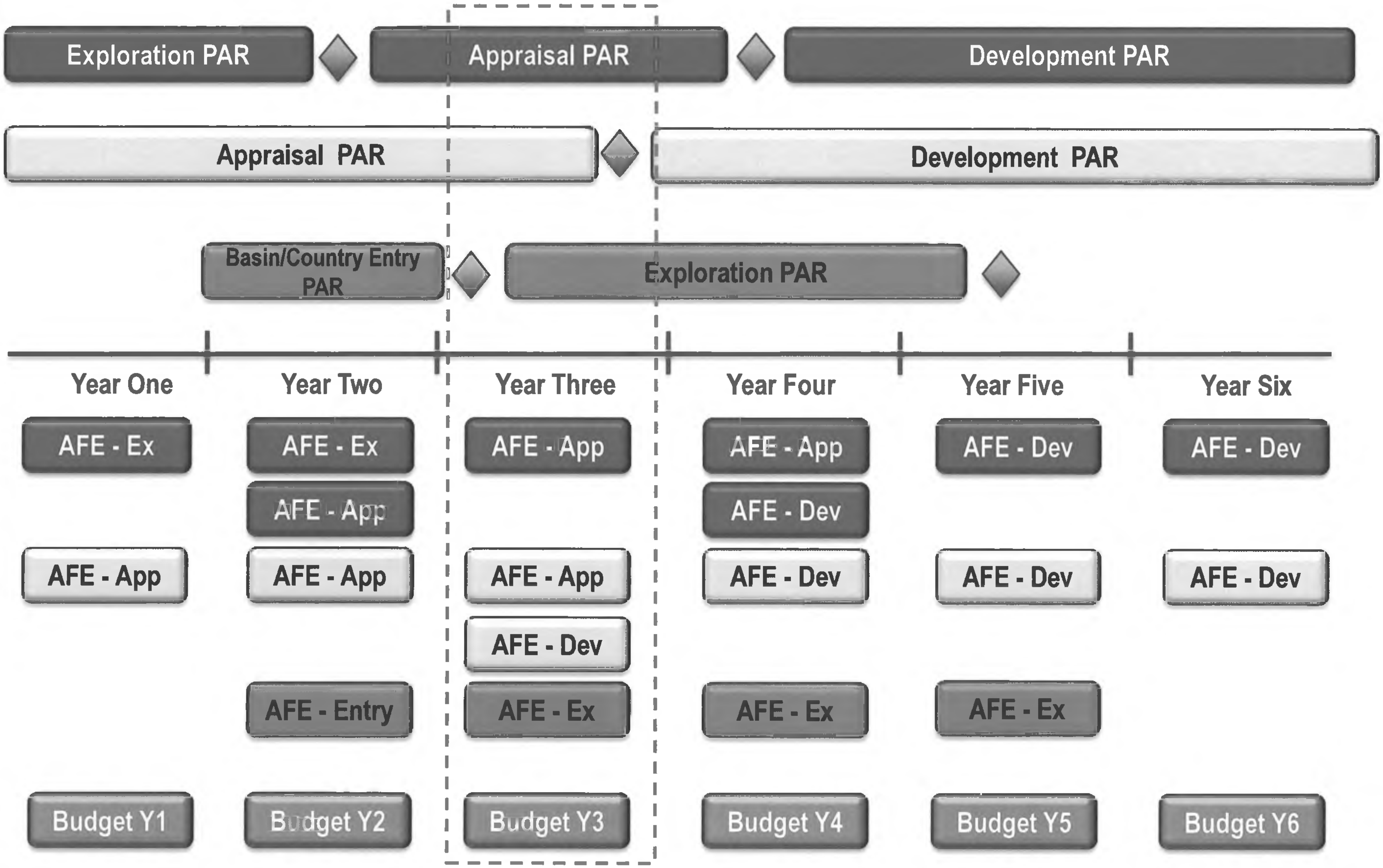
Attracting Capital: The Project Approval Process

- 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 or basin.
- 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 Management/Board to determine whether to *continue, amend, suspend, or exit/divest*

Asset Modelling and Decision Process: Materiality and Total Capex Exposure



Business Control Architecture:
PAR => AFE => Budget



Question: On what basis does an E&P company allocate investment capital to opportunities?

- There are a core set of metrics that allow comparison of projects and investments *within* a given basin/area, and *across* the portfolio of available investment opportunities
- For example, an enhanced recovery project in Alaska will compete for capital against:
  - Capex investments in Alaska;
  - Enhanced recovery projects elsewhere in the portfolio;
  - Capex investments elsewhere in the portfolio
- Capital programs must also compete against debt repayment, share buyback, and dividend policies

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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 (room to run)
  - Plowback Rate. .. Showing 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

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; measure of investment efficiency
  - NPV/Investment (or PVPI); assessment of return to the investment dollar.
- Recycle Ratio: 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. Measures the maximum exposure being committed to 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

- <u>**Net Present Value (NPV)**</u>: The estimated value of a project when all future net cash flows are discounted to the present at an appropriate rate (the "discount factor").
- NPV > 0 => project is expected to deliver a return greater than the cost of development, <u>including</u> a return on capital invested (accounted for in the discount factor).
- Advantages:
  - **Time value at corporate rate included**
  - **Can be calculated exactly**
  - **Can accommodate risk through discounting of costs and/or revenue flows**
  - **Useful for valuing projects**
  - **Discount factor 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 <u>not</u>, however, have the same impact and value for the company treasury**

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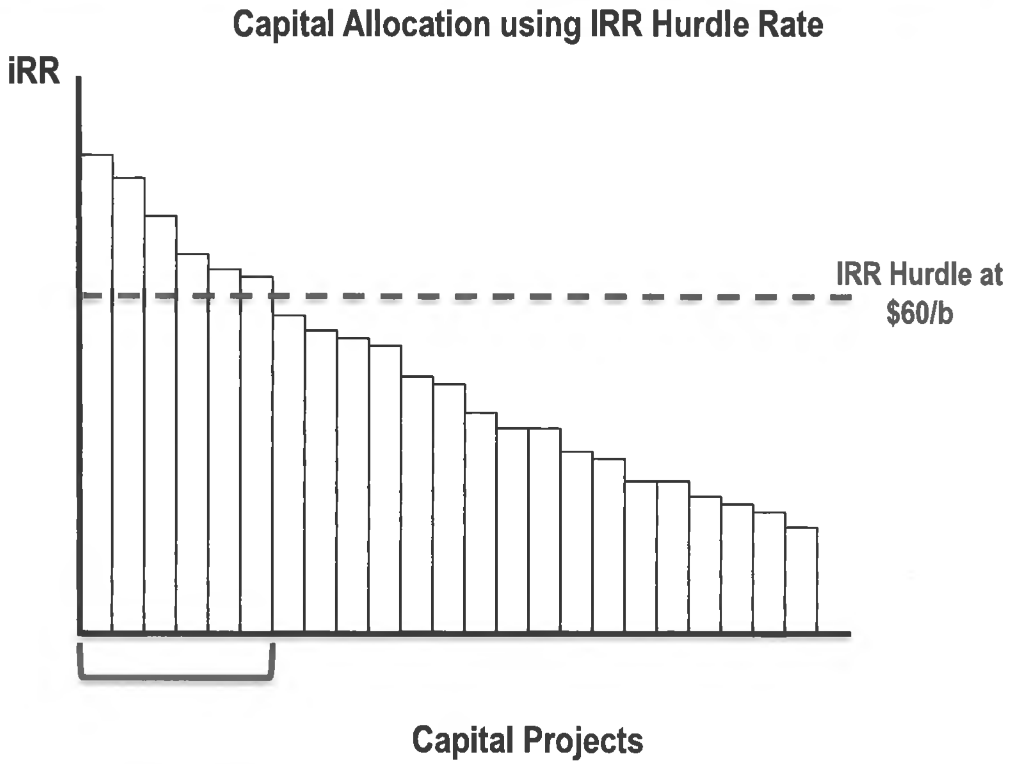
Project Decision Variables: Internal Rate of Return

- 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**

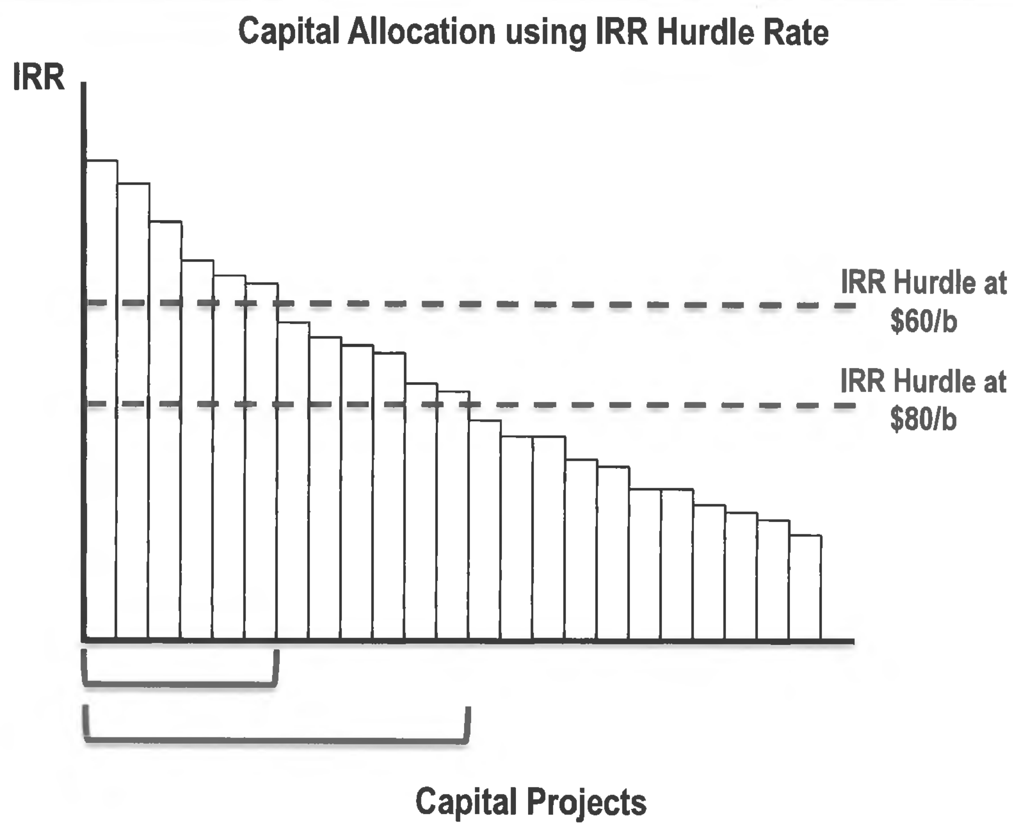
Capital Allocation: IRR Hurdle Rate

- Eligible projects ranked by IRR:
  - **"Eligibility" normally a function of a number of discrete project metrics within each PAR**
  - **Examples:**
    - **NPV10 > 0**
    - **PVPI > 1.3**
    - **Payback < 3 years**
  - **NOTE: These metrics will change over the project cycle, as risks are addressed and estimates become more certain (e.g., 60:40 to 80:20)**
- 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: 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
    - E&P companies will create capital scarcity by increasing share buyback programs, paying down debt, and/or increasing dividends
  - *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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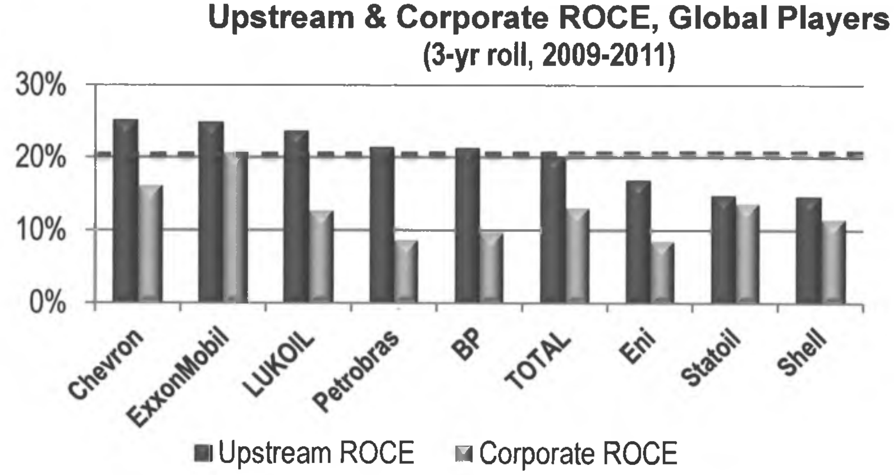
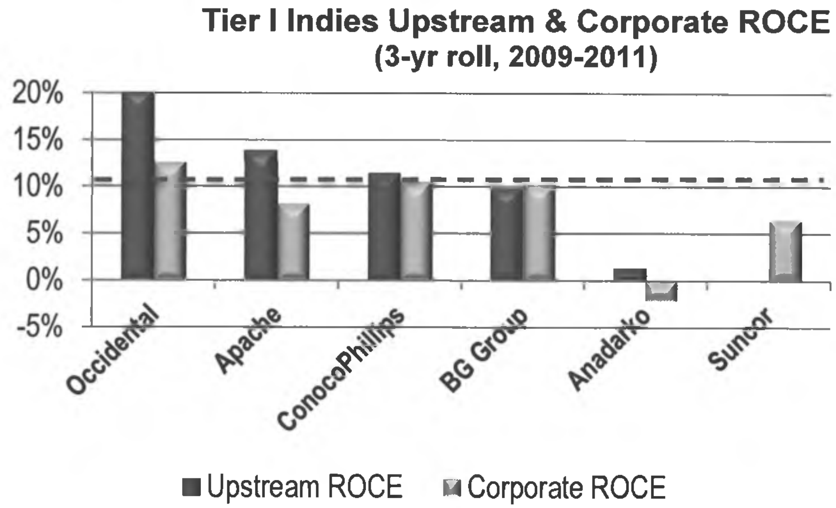
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **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





Global Players Average Upstream ROCE: 20.4%
Tier I Independents Average Upstream ROCE: 11.4%

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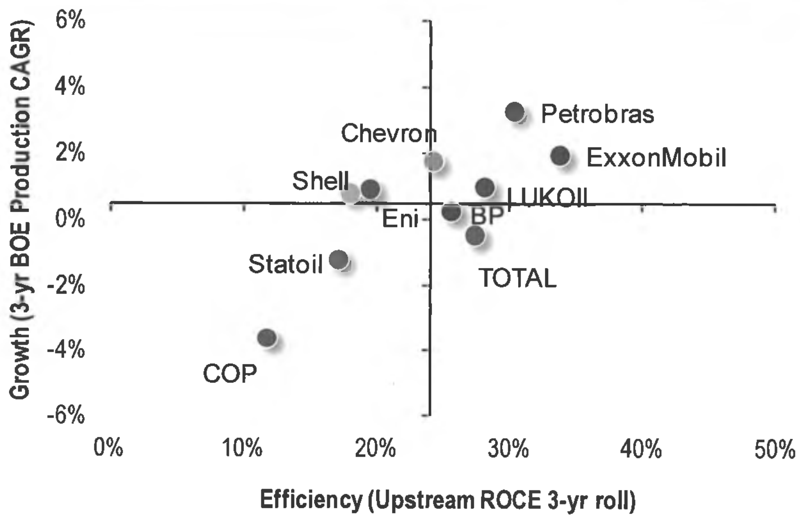
Portfolio Efficiency: Return on Capital Employed (ROCE)

- **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 <u>and</u> high growth metrics
  - Once commissioned, 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



Questions & Discussion

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Part 2:

Global Strategy & Portfolio Overview of Major Alaska Producers

- BP
- ConocoPhillips
- ExxonMobil

Points to Address: Discussion of Portfolio Composition and Growth/Capex Focus

- Where are these companies looking to grow. Which plays and basins are attracting investment capex
- What is the position and role of Alaska within these portfolios

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BP: Company Overview

Strategic Signature

- Global integrated company; production in 23 countries, upstream operations in an additional 6 countries.
- 2011 worldwide production of ~3,400 mboe/d, making it the second largest company in the peer group (after ExxonMobil with ~4,513 mboe/d).
  - The Russia & Central Asia (RCA) and North America regions = ~55% of 2011 production.
- Post-Macondo portfolio rationalization program (~$28 bn in asset sales and ~$17 bn in GOM production allocation to Macondo fund) completed in 2013. The result is a pared down and more focused geographic portfolio.
- Executing on a 3-pronged growth strategy:
  - **Deepwater Basins**: US GOM, Angola, Egypt, Brazil
  - **Global Gas**: US, Trinidad & Tobago, North Sea
  - **Giant Oil Fields**: 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.
- Sale of TNK-BP (~$22 bn proceeds) => ~1 mmboe/d production decline in 2013 from 2012. BP will be hard pressed to outperform its peers on any key metrics.

Company Overview

- **HQ:** London
- **Employees:** 83,400
- **2011 Reserves:** 17,750 mmboe
- **2011 Production:** 3,400 mboe/d
- **3 Yr Production Growth:** -3.53% CAGR (2009-2011)
- **Jan 2013 Market Cap:** $141 bn
- **Jan 2013 P/E Ratio:** 8
- **2011 Corp Revenue:** $375 bn
- **2011 Upstream Capex:** $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

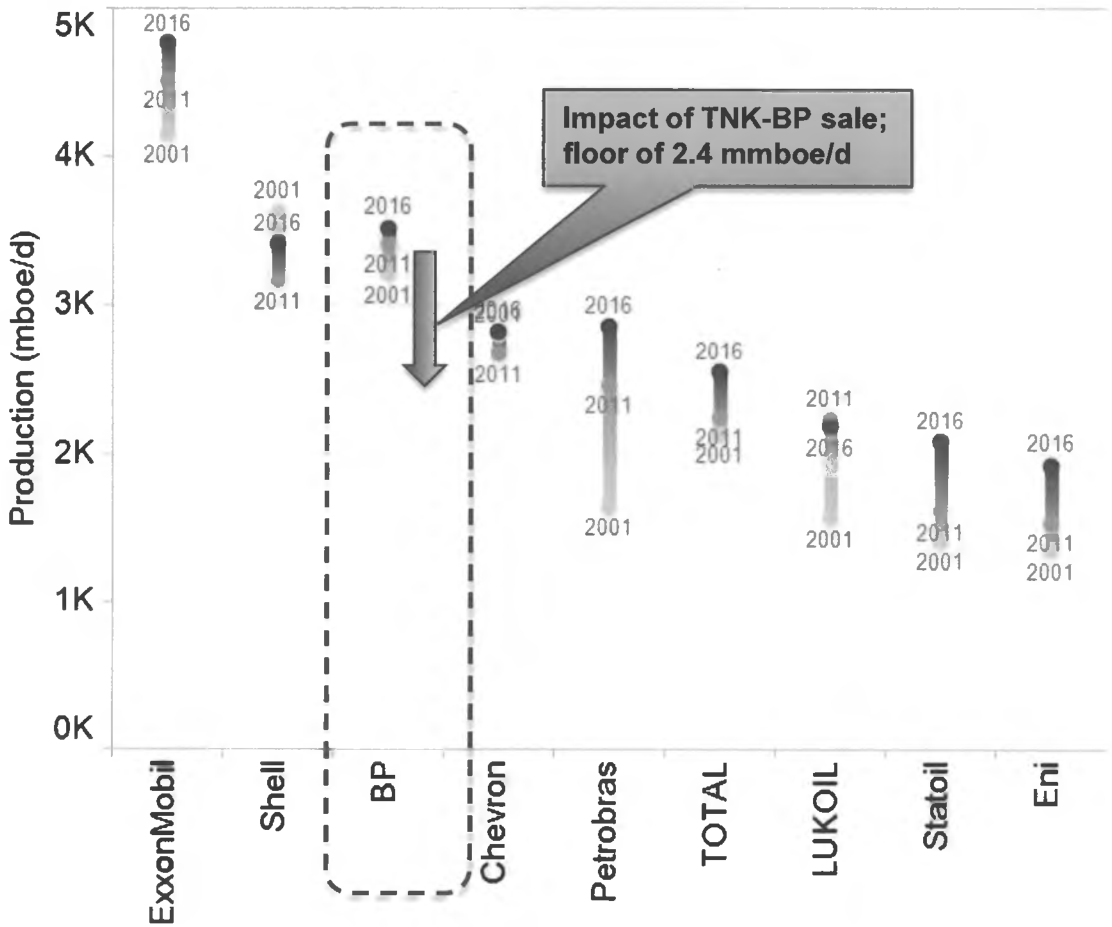
BP: Global Areas of Upstream Operations

Designation	Country	2011 Total (mboe/d)
Core	United States	760
	Trinidad & Tobago	397
	United Arab Emir..	216
	Angola	123
Exit/Potential Exit	Russia	982
	Argentina	136
	Venezuela	17
	Pakistan	17
	Vietnam	13
	Colombia	2
	Chile	
	Ukraine	
Focus	Egypt	119
	Azerbaijan	117
	Australia	99
	Indonesia	73
	Algeria	41
	Norway	34
	Iraq	31
	India	24
	China	12
	Brazil	7
	Canada	4
	Oman	3
	Bolivia	2
Harvest	United Kingdom	172
New Venture	Jordan	
	Libya	
	Namibia	
	Uruguay	

Core
Exit/Potential Exit
Focus
Harvest
New Venture

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

Production (mboe/d) in 2001, 2011 and 2016 (PFC Forecast): BP and Peers

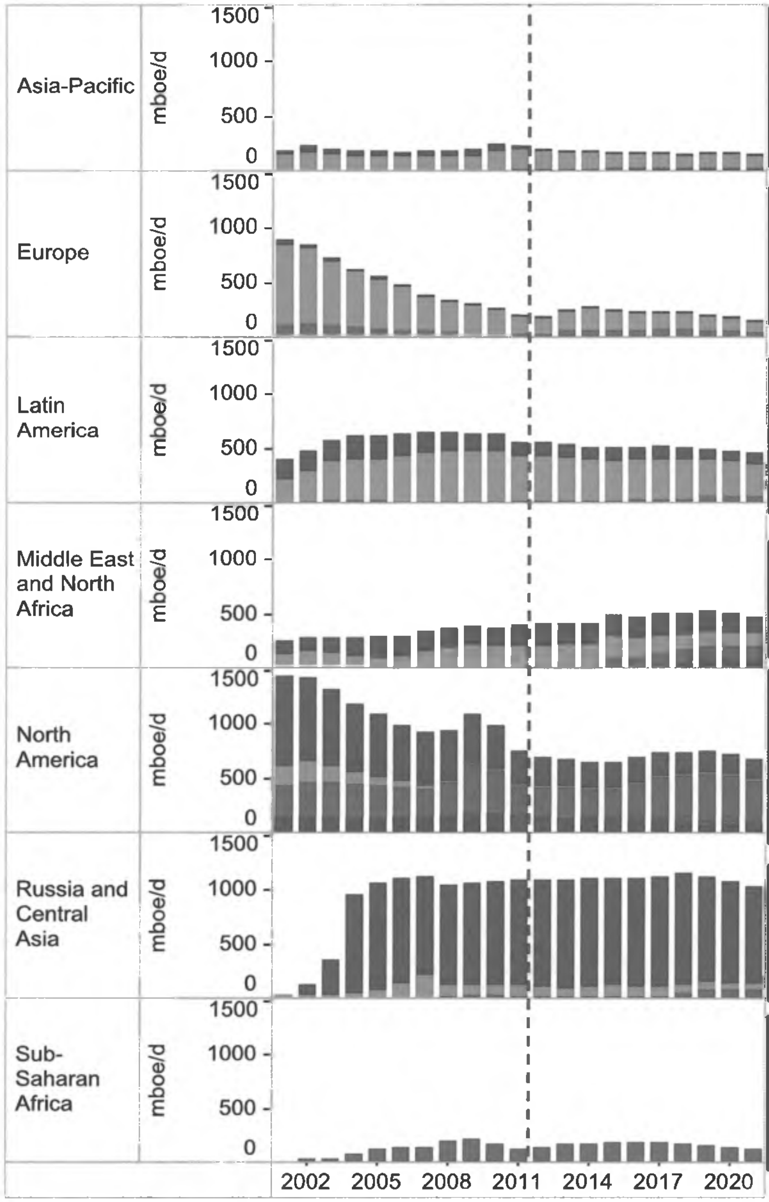


In 2011, BP was the second largest producer of the peer group. BP and COP are the only two companies forecast to deliver production declines over the 2010-2015 period.

2001-2011: Production increases from ~3,080 mboe/d to ~3,400 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), and portfolio divestitures .

2012-2016: BP was forecast to show modest production gains over the period. The sale of its stake in TNK-BP lowers this outlook by ~1 mmboe/d, a volume that would be offset (with improved upside) should the 19.74% equity positioning in Rosneft be concluded

BP: Regional Trajectories



Asia-Pacific: ~246 mboe/d in 2011, centered on LNG feedstock. Expanding deepwater exploration acreage and a growing exposure to CBM. Reliance partnership in India offshore coinciding with divestiture of Pakistan and Vietnam portfolios.

Europe: ~206 mboe/d in 2011; Mature offshore asset portfolio in UK and Norway. Steep fall from ~895 mboe/d in 2001. Harvest Area with near-term production gains through a series of field redevelopment projects.

Latin America: ~561 mboe/d in 2011 (~34% of global gas volumes). Sale of assets in Colombia, reduced exposure in Venezuela (sold to TNK-BP); shift in regional strategy to South Atlantic deepwater exploration and development (Brazil, Uruguay).

Middle East & North Africa: ~410 mboe/d in 2011, a decade high. Large development portfolio (Iraq, Oman, Egypt deepwater) challenged by above ground issues.

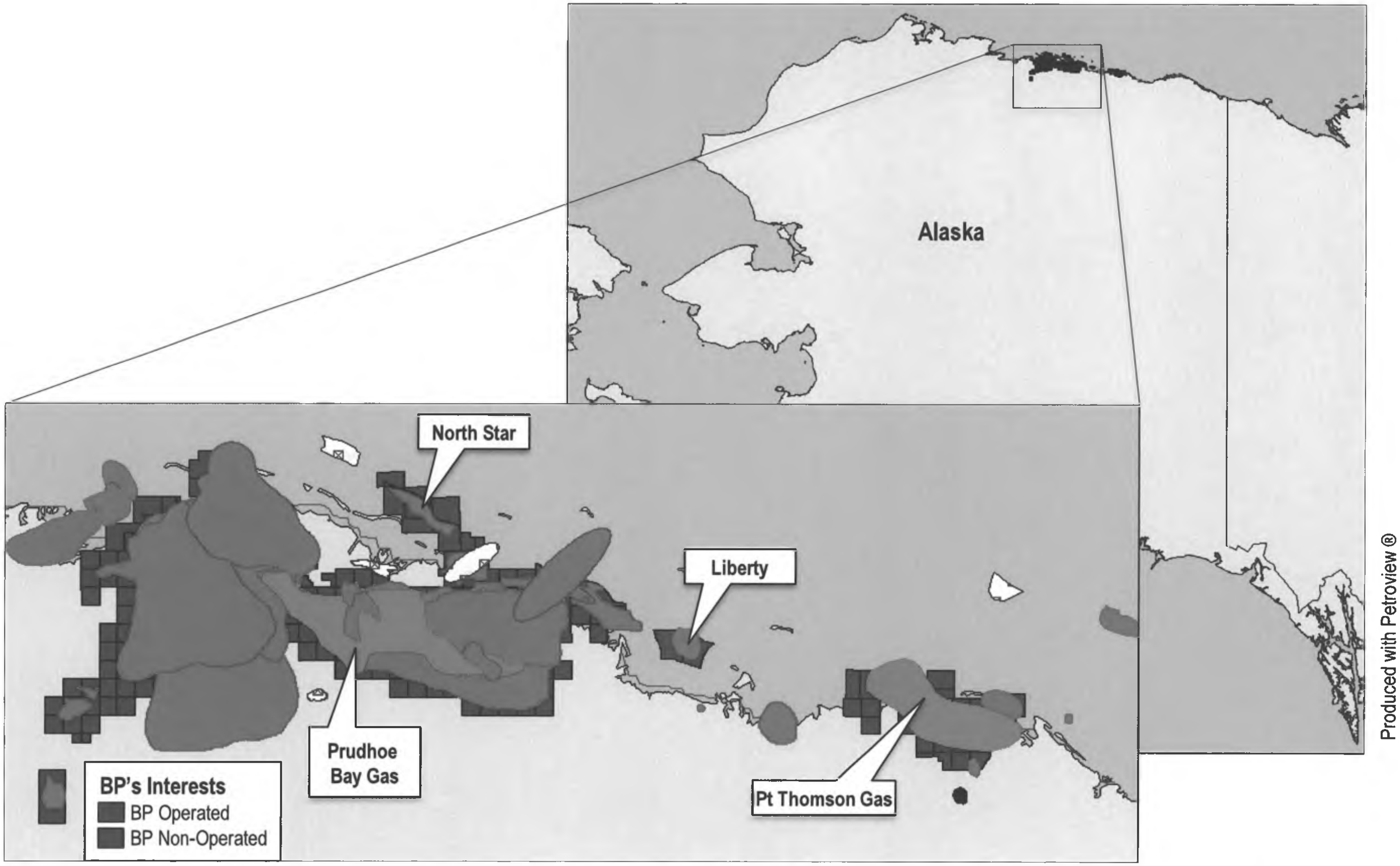
North America: ~764 mboe/d in 2011, 2nd largest production region, focused on Deepwater GOM. Sale of conventional oil and gas assets in Onshore L48, growing focus on shale gas and oil sands development(first oil from the in-situ (SAGD) Sunrise project expected in 2014).

Russia & Central Asia: ~1,099 mboe/d in 2011; dominated by TNK-BP in Russia (divested 2013). Leave Azerbaijan as the sole source of medium-term volume growth.

Sub-Saharan Africa: ~123 mboe/d in 2011, sourced from Angola deepwater. New source volumes from a suite of multi-field deepwater development projects. Positioned to test the pre-salt analog in the Kwanza basin in Angola and further south in Namibia.

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

BP in North America: Alaska



BP Alaska Activity & PFC Energy Assessment

Alaska Designation	Activity	PFC Energy Assessment
Harvest Area	• Asset concentration 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 ~153 mboe/d in 2011, while gas production has fallen from ~67 mmcf/d to ~22 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. BP and ConocoPhillips withdrew the 4 bcf/d **Denali** pipeline proposal (Prudhoe Bay => western Canada => US markets) in May 2011, citing the lack of long-term purchase contracts. • In March 2012 ExxonMobil, ConocoPhillips and BP settled litigation with the Alaskan government over the development of Point Thomson gas reserves, publicly announcing their interest in gas commercialization and export opportunities from Alaska • 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. 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

- **Bring a close to the portfolio rationalization process**: With ~$16 bn in upstream asset divestitures announced since June 2010 and another $17 bn in royalty over-rides redirected to the Deepwater Horizon Oil Spill Reparation Fund, BP indicated in 2Q:2012 a further ~$12 bn in total portfolio asset sales before end-2013 – excluding the net ~$22 bn from the TNK-BP sale. The portfolio repositioning represents an exchange of secure production and proved reserves for higher-risk, less certain, but potentially more material future growth opportunities (Krishna-Godavari basin offshore India, Kwanza pre-salt analog offshore Angola, Equatorial Margin analog offshore northern Brazil). Both analysts and shareholders are looking for a clearer read of where this repositioned portfolio will lead BP over the coming years.
- **Secure a new Core Area**: With positioning in both Russia and the UAE in question, BP faces the prospect of a diminished number of Core areas capable of delivering material, sustained production and free cash flow. This places significant pressure on the transitioning of Focus areas into larger, stable Core operations in order to remain above the targeted 2.3 mmboe/d production floor (ex-TNK-BP volumes). BP is betting heavily on the potential of nascent deepwater plays in the South Atlantic and Asia-Pacific – a strategy that will hinge on exploration success and performance of newly established and uncertain partnerships.
- **Execute the exit from TNK-BP JV and Repositioning in Russia**: Russia production tied to TNK-BP accounted for ~29% of BP's global production in 2011 (and ~25% of total production since 2004), and the second largest source of free cash flow after the US. BP will look to secure a position in Russia's emerging Arctic Resource play through equity positioning (19.74%) in Rosneft – a move with greater upside than TNK-BP, but markedly less control.
- **Develop deepwater partnership with Petrobras**: Having secured Brazil government approval for its acquisition of the Devon asset portfolio (potentially the largest operated pre-salt portfolio outside Petrobras), BP has moved to deepen its ties with the Brazil NOC, farming into Petrobras operated licenses in the pre-salt analog basin areas offshore Angola and Namibia. Subsequent partnering in the Brazil Equatorial Margin suggests a budding deepwater strategic alliance between the two premier deepwater developers, with the prospects of substantial, long term rewards.
- **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: new strategic pathway => ~$15 bn asset and joint venture divestment program, targeting:
  - Debt reduction;
  - Near-term shareholder returns;
  - Shift out of downstream; and
  - Growth from smaller, higher-value portfolio position.
- 2010-2012 Restructuring Plan:
  - ~$7 bn in asset sales
  - Divested i20% equity interest in LUKOIL
  - Poceeds to debt reduction and share repurchase.
- July 2011: Announces restructuring into ***two separate corporate entities***, Downstream (Phillips 66) and a pure play, E&P company (ConocoPhillips).
- Net impact:
  - Production decline to ~1.5 mmboe/d in 2012, recovering to 1.64-1.69 mmboe/d by 2015.
  - Portfolio focus in OECD countries (US, Canada, Australia, UK, and Norway, which accounted for ~75% of worldwide production in 2011).
- Grow 0.5% per annum from 2012 through 2015 from ***Global Gas/LNG, SAGD Oil Sands, and Unconventional Resource*** developments.

Company Overview

- **HQ:** Houston, TX
- **Employees:** ~16,000
- **2011 Reserves:** 8,387 mmboe
- **2011 Production:** 1,610 mboe/d
- **3 Yr Production Growth:** -30.68% CAGR (2008-2011)
- **Jan 2013 Market Cap:** $74 bn
- **Jan 2013 P/E Ratio:** 7.5
- **2011 Corp Revenue:** $235 bn
- **2011 Upstream Capex:** $13.5 bn

Technological Competence

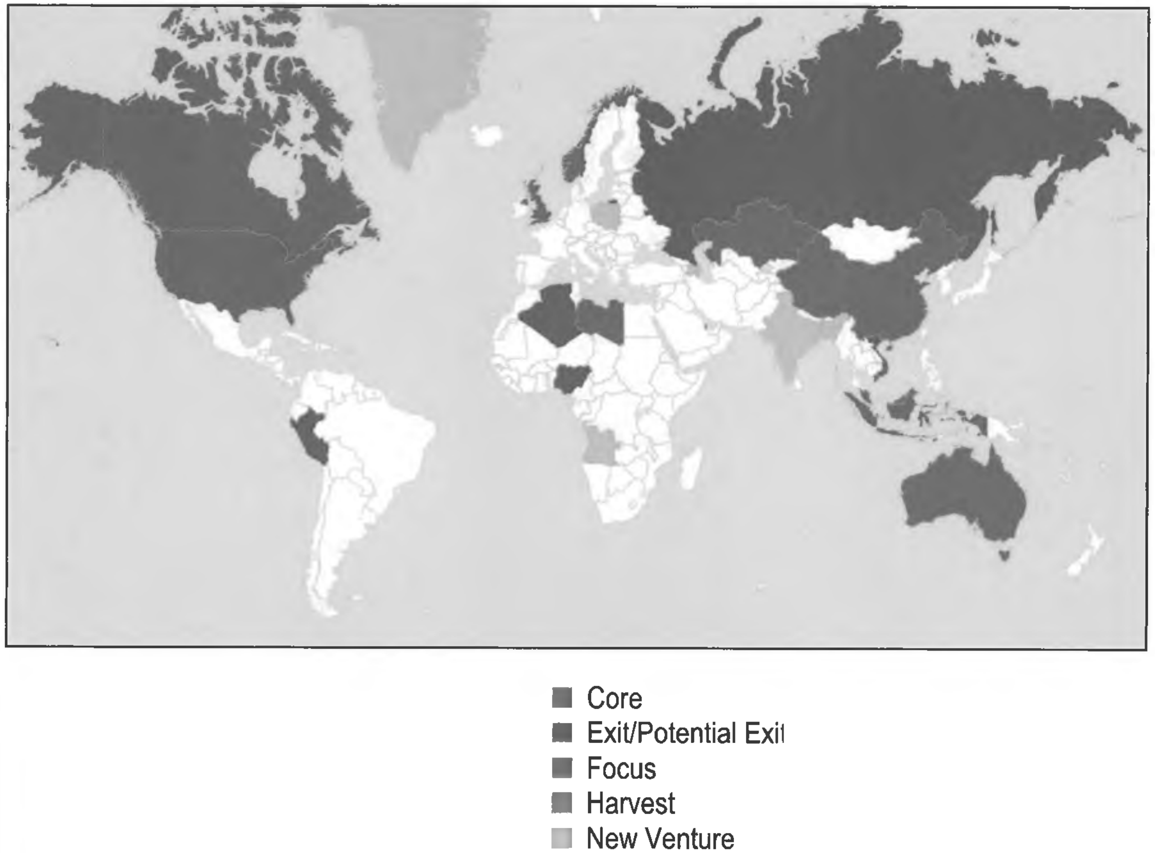
EOR & Recovery	Offshore	Heavy Oil	Unconven-tionals	Oil Sands	Other
✓	✓		✓	✓	

Partnership History

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

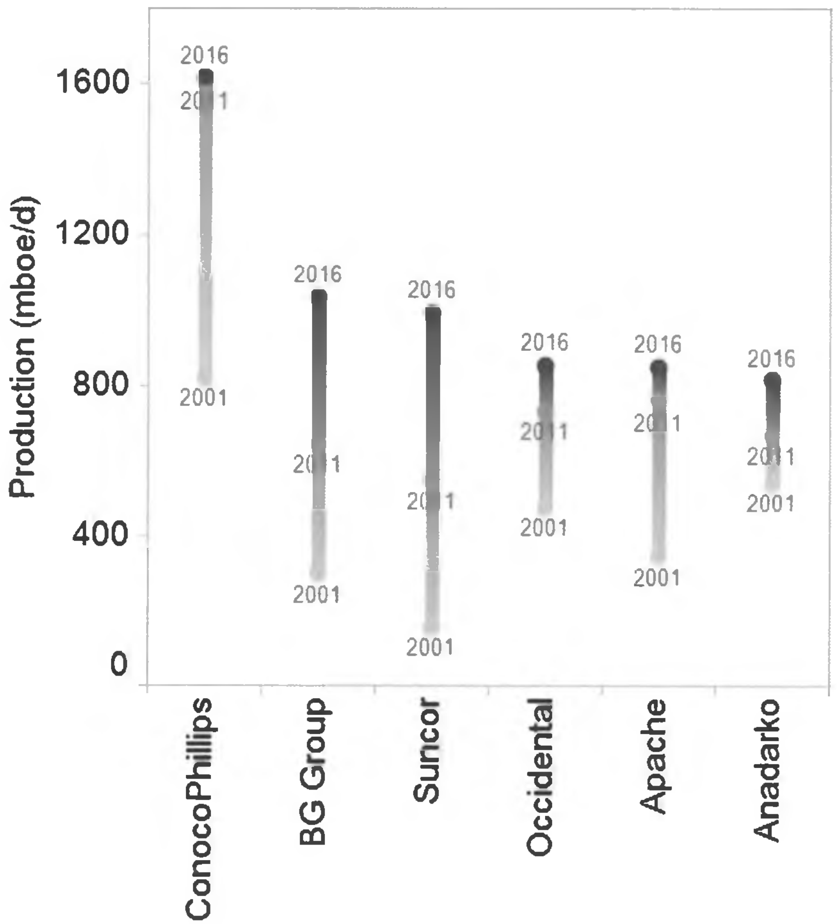
ConocoPhillips: Global Areas of Upstream Operations

Designation	Country	2011 Total (mboe/d)
Core	United States	653
	Canada	250
	Norway	147
	United Kingdom	132
	Indonesia	86
Focus	Qatar	85
	Timor Leste/Australia JPDA	63
	China	52
	Australia	26
	Libya	8
	Kazakhstan	
	Malaysia	
Exit/Potential Exit	Nigeria	45
	Russia	29
	Vietnam	20
	Algeria	13
	Peru	
New Venture	Angola	
	Bangladesh	
	Brunei	
	Greenland	
	India	
	Poland	
Grand Total		1,610



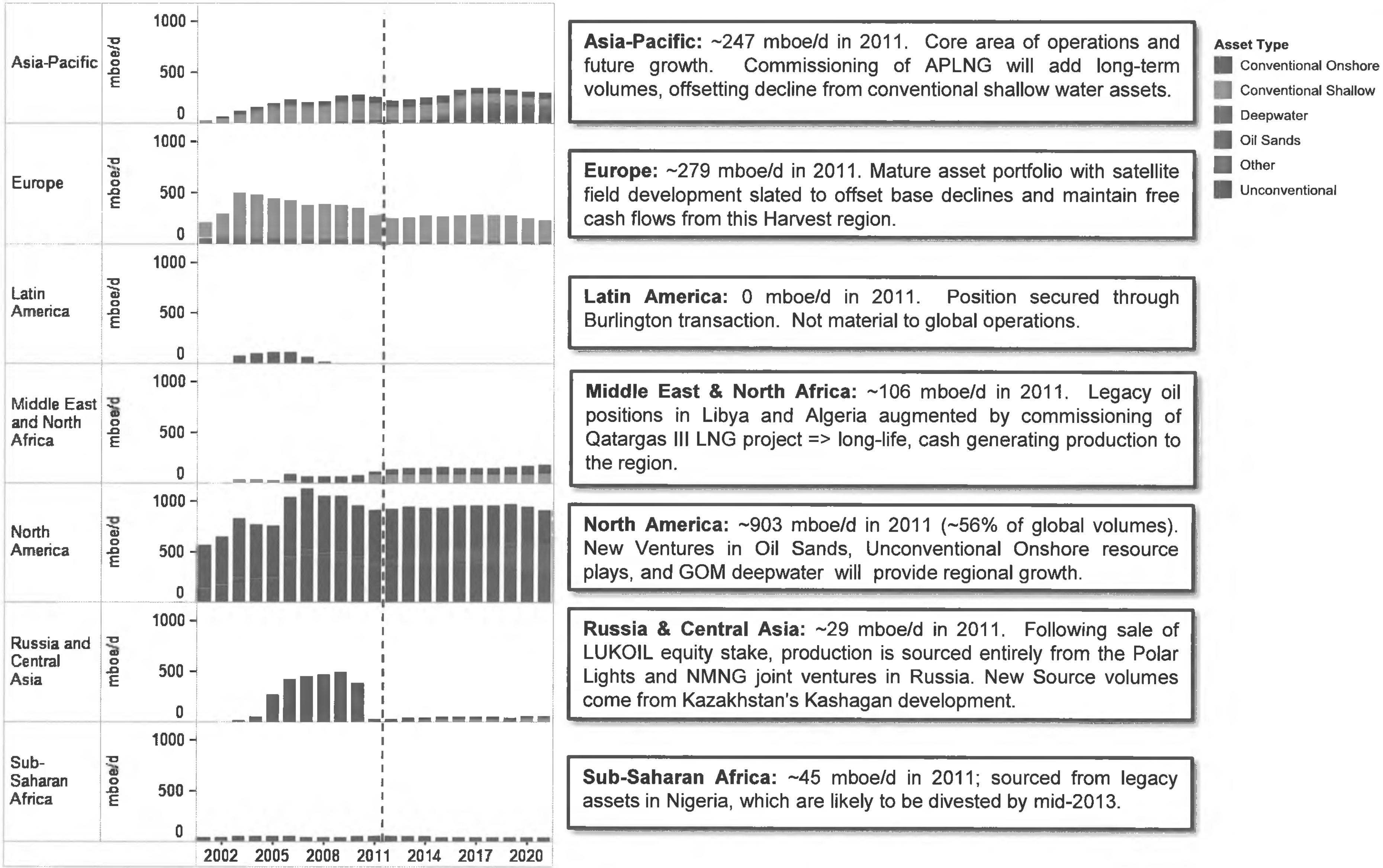
Total Portfolio Evolution: ConocoPhillips vis-à-vis the Competition

Tier I International Independents Production 2001, 2011 and 2016 (PFC Forecast)



- The Tier I peer group is comprised of Independents with portfolios capable of delivering ~1 mmboe/d of production over the next 5-7 years
- ConocoPhillips joined the Tier I peer group following its de-integration. Will see production continue to slide, before recovering to slightly above 2011 levels by 2016
- Production increases over 2001-2011 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); the Burlington Resources purchase in 2006 (growing volumes from 1,824 mboe/d in 2005 to 2,358 mboe/d in 2006); and the gradual acquisition of a 20% stake in LUKOIL later in the decade

ConocoPhillips: Regional Trajectories



Asia-Pacific: ~247 mboe/d in 2011. Core area of operations and future growth. Commissioning of APLNG will add long-term volumes, offsetting decline from conventional shallow water assets.

Europe: ~279 mboe/d in 2011. Mature asset portfolio with satellite field development slated to offset base declines and maintain free cash flows from this Harvest region.

Latin America: 0 mboe/d in 2011. Position secured through Burlington transaction. Not material to global operations.

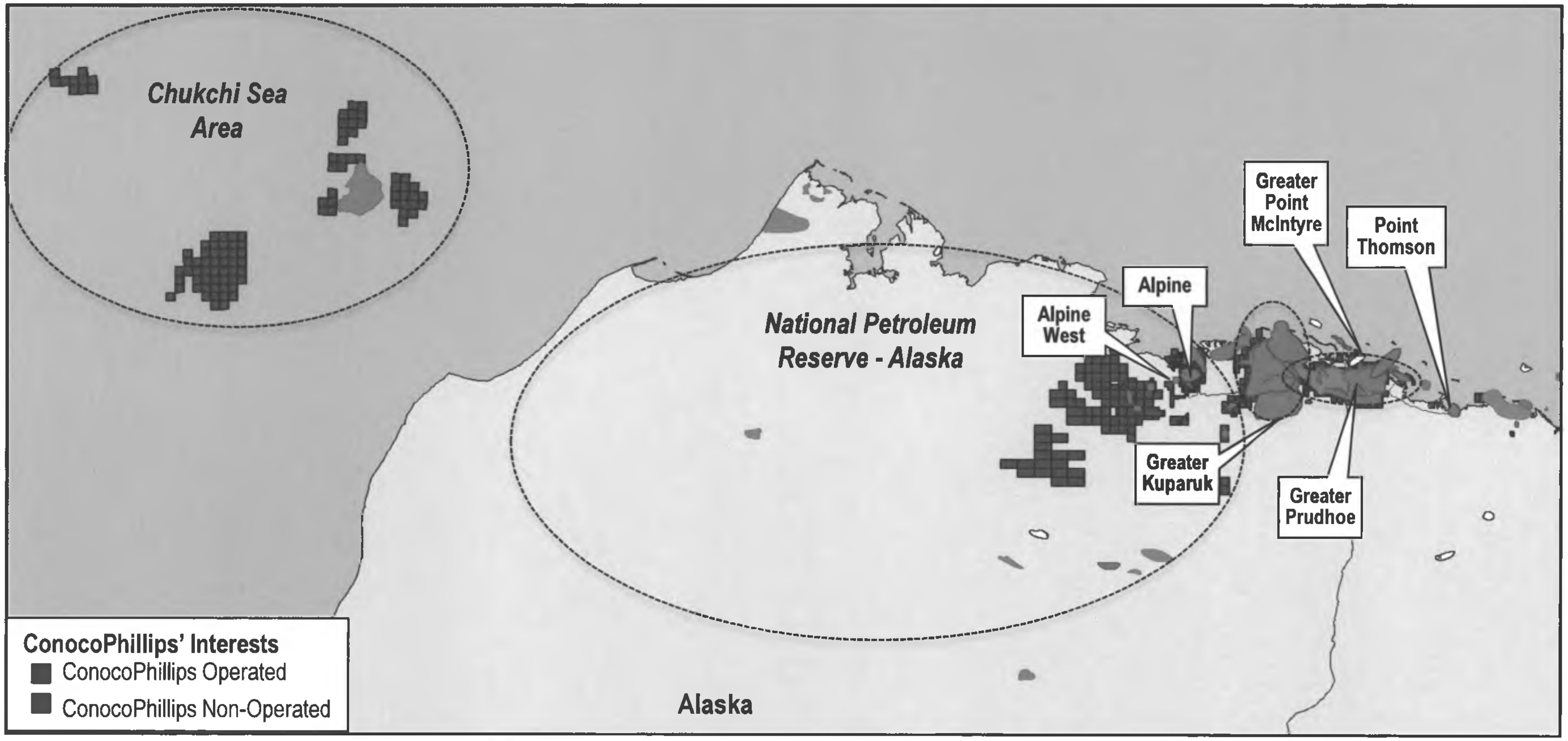
Middle East & North Africa: ~106 mboe/d in 2011. Legacy oil positions in Libya and Algeria augmented by commissioning of Qatargas III LNG project => long-life, cash generating production to the region.

North America: ~903 mboe/d in 2011 (~56% of global volumes). New Ventures in Oil Sands, Unconventional Onshore resource plays, and GOM deepwater will provide regional growth.

Russia & Central Asia: ~29 mboe/d in 2011. Following sale of LUKOIL equity stake, production is sourced entirely from the Polar Lights and NMNG joint ventures in Russia. New Source volumes come from Kazakhstan's Kashagan development.

Sub-Saharan Africa: ~45 mboe/d in 2011; sourced from legacy assets in Nigeria, which are likely to be divested by mid-2013.

ConocoPhillips in North America—Alaska



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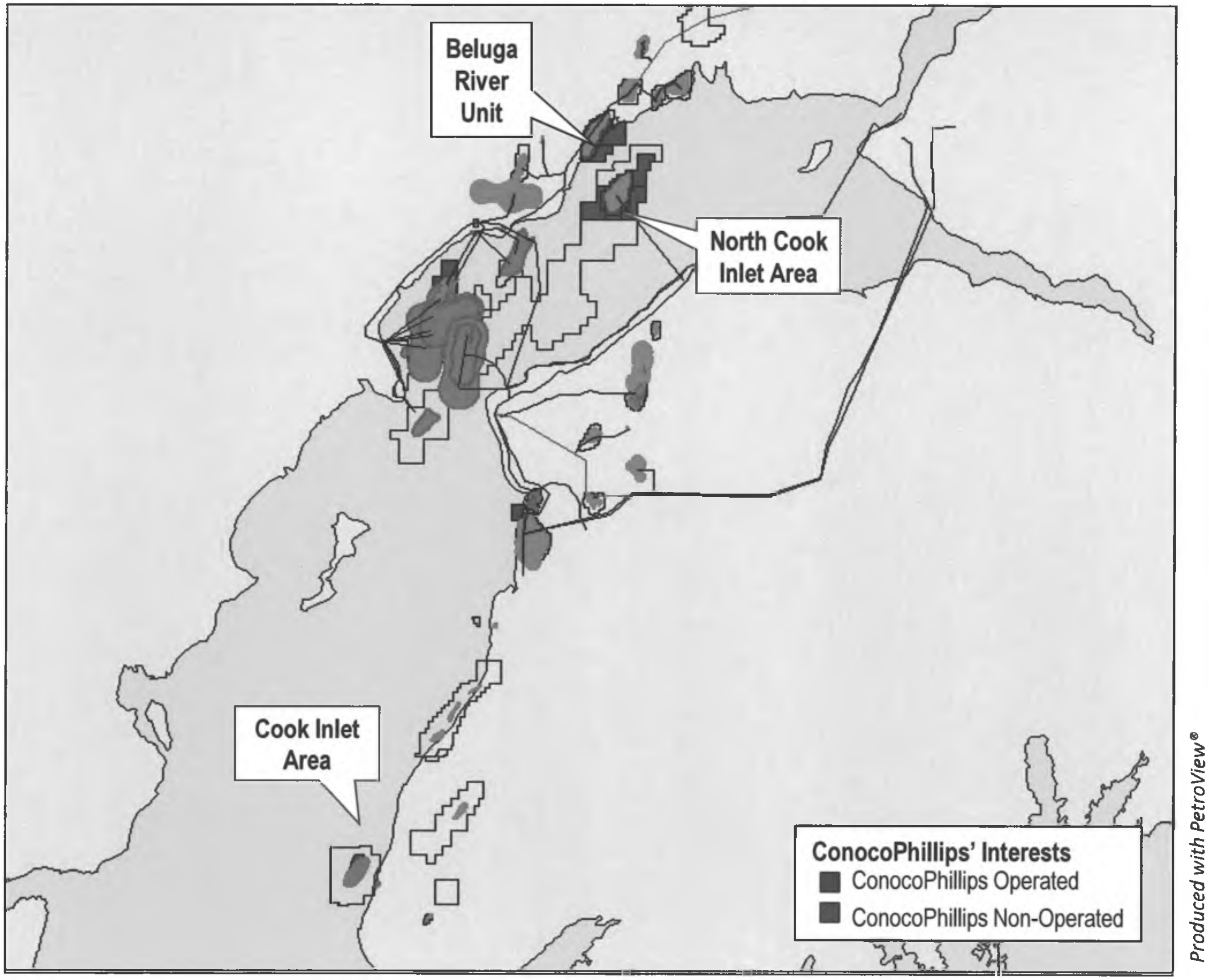
ConocoPhillips in North America—Alaska Cook Inlet

ConocoPhillips' Interests in the Cook Inlet (Alaska)



PFC Energy

ConocoPhillips **Alaska Activity & PFC Energy Assessment**

Alaska Designation	Activity	PFC Energy Assessment
Core Area	• Legacy portfolio acquired from Arco Alaska in 2000; includes the Greater Prudhoe Area (largest production), Greater Prudhoe Bay Area, Greater Kuparuk Area, Western North Slope, and Cook Inlet Area. • Production from the mature Alaska portfolio has been in slow decline since the late 1980s. In 2011, net production from Alaska averaged 215 mb/d of oil and 61 mmcf/d of gas, accounting for ~35% of US production. • 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. • 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 2015-2016. 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.	**Alaska's largest oil and gas producer. While continuing 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. • 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 2014.	

PFC-Identified Challenges

- **Competing as a "Pure Play" E&P Company**: Repositioned as the largest Independent E&P company by a considerable margin. In the near-term, COP is a smaller company with limited near-term production growth and improved, but unlikely to be leading, ROCE and financial performance.
  - Has the company simply re-introduced its prior dilemma—too large to compete with the smaller International Independents on volume growth, and too small to compete effectively with the Global Players on efficiency metrics? Or can the company successfully deliver both volume and value/efficiency performance form its high-graded, down-sized asset portfolio?
- **Effectively Positioning in High Value Assets**: Sale of low margin, non-core (and largely non-OECD) assets => loss of optionality and diversity within its portfolio that can act as a hedge against commodity cycles and changing market conditions over the long term. Targeting of low risk (OECD) and high margin assets (such as US unconventional oil plays) raises the risk of destroying value by overpaying for competitive assets.
- **Defining Operational Strengths**: Strong partnerships => majority of growth will come from non-operated and/or JV related activity with specialized developers – FCCL JV with Cenovus in the Canadian Oil Sands; Australia Pacific LNG JV with Origin Energy; non-operated assets in the US GOM; Shell in the Malaysia deepwater. Also building considerable expertise in unconventional resource exploitation (both shale gas and tight oil) in the US Onshore.
  - Successful leveraging to unconventional resource plays outside North America could deliver the differentiating competitive advantage and volume growth required for ConocoPhillips to compete effectively within the Independent E&P peer group over the long term.
- **Effectively Managing Base Production**: Minimizing the decline in production from the company's base portfolio—which has a high proportion of gas production exposed to continued weak North American gas prices—is essential for the company to deliver simultaneous production and margin growth.
- **Delivering Production Growth**: Production has fallen by 30% since 2009 (2,286 mboe/d to 1,610 mboe/d in 2011). New source developments basically keep pace with mature asset declines in the MENA, Europe, and RCA regions => material net growth must come from ***North America and Asia Pacific***. US Onshore unconventional liquids plays are currently projected to deliver ~22% of total worldwide new source volumes in 2021

ExxonMobil: Company Overview

Strategic Signature

- Largest of the Global Players
  - ~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.
- Move into unconventional resource plays was a default for ExxonMobil:
  i. Commissioning of the final elements of the company's Qatar project portfolio in 2011
  ii. Declining production from its Europe and Asia-Pacific portfolios
  iii. Roadblocks to materiality in Brazil deepwater, Venezuela extra-heavy, and Equatorial Margin
  iv. Already holding a considerable stake in the Canadian oil sands, ExxonMobil took an aggressive move into unconventional shale gas exploitation.
- 2009 acquisition of XTO Energy brings materiality to ExxonMobil's technical expertise in tight gas, CBM, and shale oil and gas exploitation (~2.3 bcf/d and 87 mboe/d of production, proved reserves of ~2.3 bn boe, resource base of 7.5 bn boe).
- Leveraging XTO into a global unconventional portfolio.

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)
- **Jan 2013 Market Cap:** $415 bn
- **Jan 2013 P/E Ratio:** 9.6
- **2011 Corp Revenue:** $486 bn
- **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

ExxonMobil: Global Areas of Upstream Operations

Designation	Country	2011 Total (mboe/d)
Core	United States	1,076
	Qatar	972
	Nigeria	325
	Norway	315
	Canada	313
	Netherlands	311
Harvest	United Arab Emirates	278
	United Kingdom	129
	Malaysia	108
	Germany	89
	Equatorial Guinea	45
	Chad	40
	Azerbaijan	21
	Thailand	3
Focus	Kazakhstan	151
	Australia	100
	Angola	99
	Russia	57
	Indonesia	39
	Papua New Guinea	6
New Venture	Iraq	27
	Argentina	8
	China	
	Colombia	
	Congo, Republic of the (Brazz..	
	Greenland	
	Guyana	
	Ireland	
	Madagascar	
	Poland	
	Romania	

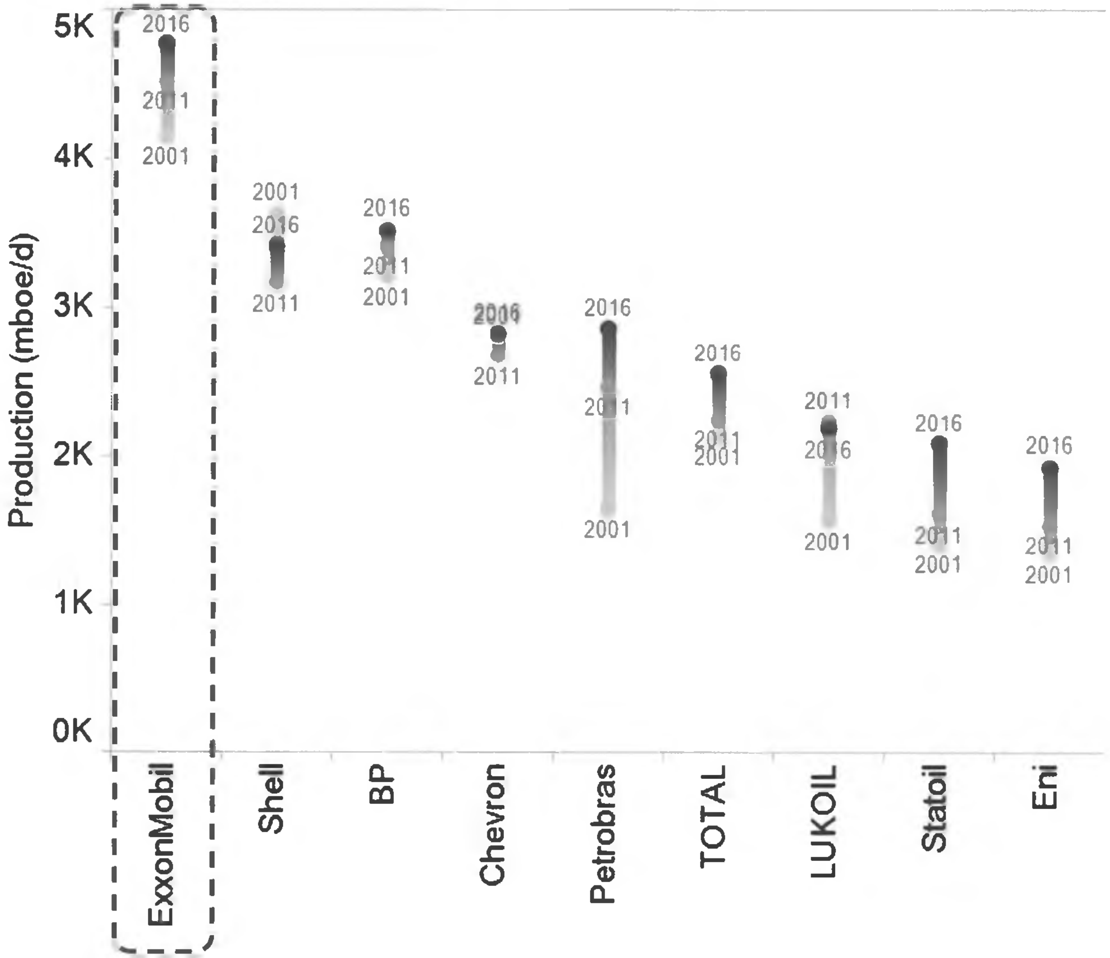
Designation	Country	2011 Total (mboe/d)
New Venture	Tanzania	
	Turkey	
	Vietnam	
Exit/Potential Exit	Brazil	
	Cameroon	
	Italy	
	Libya	
	Philippines	
	Yemen	
Grand Total		4,513

- Core
- Exit/Potential Exit
- Focus
- Harvest
- New Venture

PFC Energy

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

Production (mboe/d) in 2001, 2011 and 2016 (PFC Forecast): XOM and Peers

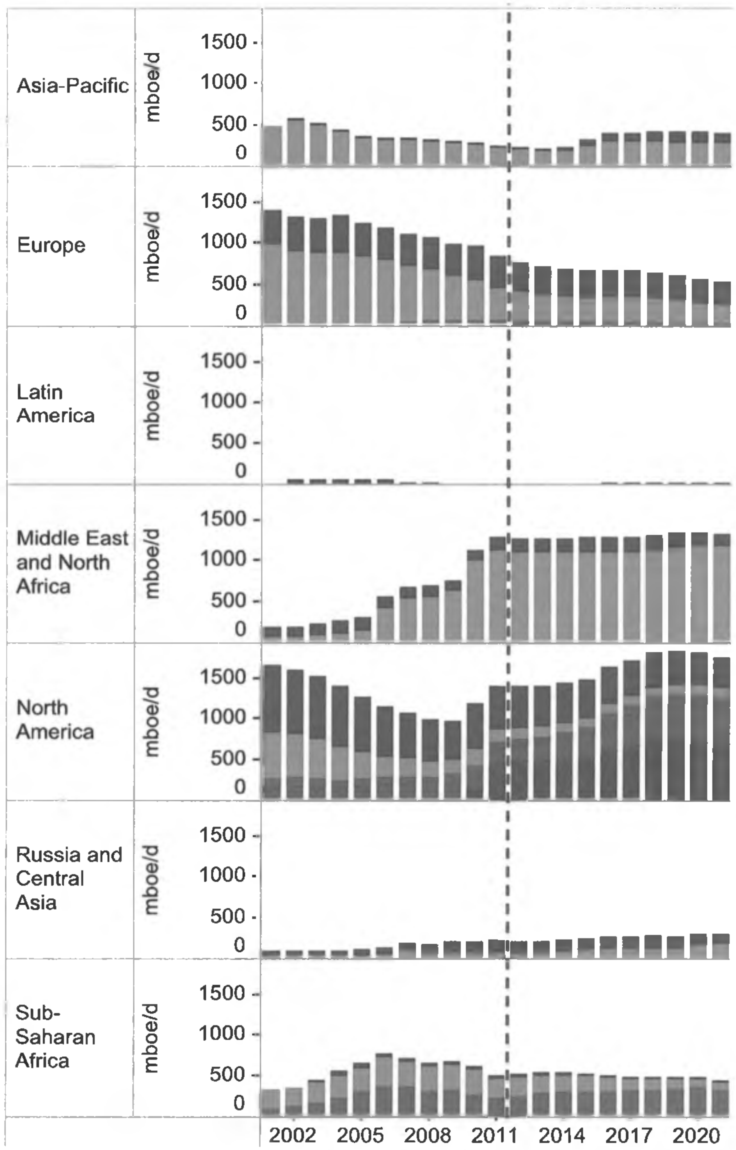


Averaging ~4.5 mmboe/d in 2011, ExxonMobil continues to lead its peer group in terms of production.

2001-2011: Production oscillated through the decade, landing in 2009 at roughly the same level as 2001 (~4.0 mmboe/d), before rising 13% in 2010 (~6% excluding the XTO acquisition) to ~4.45 mmboe/d. The XTO acquisition marked a considerable departure from ExxonMobil's longstanding organic growth strategy.

2011-2016: Modest volume growth, reaching ~4.69 mmboe/d in 2016. 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.

ExxonMobil: Regional Trajectories



Asia-Pacific: ~256 mboe/d in 2011. Focus on strengthening gas position in the region, to offset rapidly declining oil production base. Several MT/LT gas export projects including Gorgon and PNG LNG.

Europe: ~845 mboe/d in 2011. Mature asset decline and accelerating divestiture program have eroded region production from 1,393 mboe/d in 2001. New source volumes not expected to reverse this downward trend.

Latin America: ~8 mboe/d in 2011. Sole new source production is forecast from Argentina's Neuquen Basin, where ExxonMobil is a relatively early entrant to the unconventional shale gas play

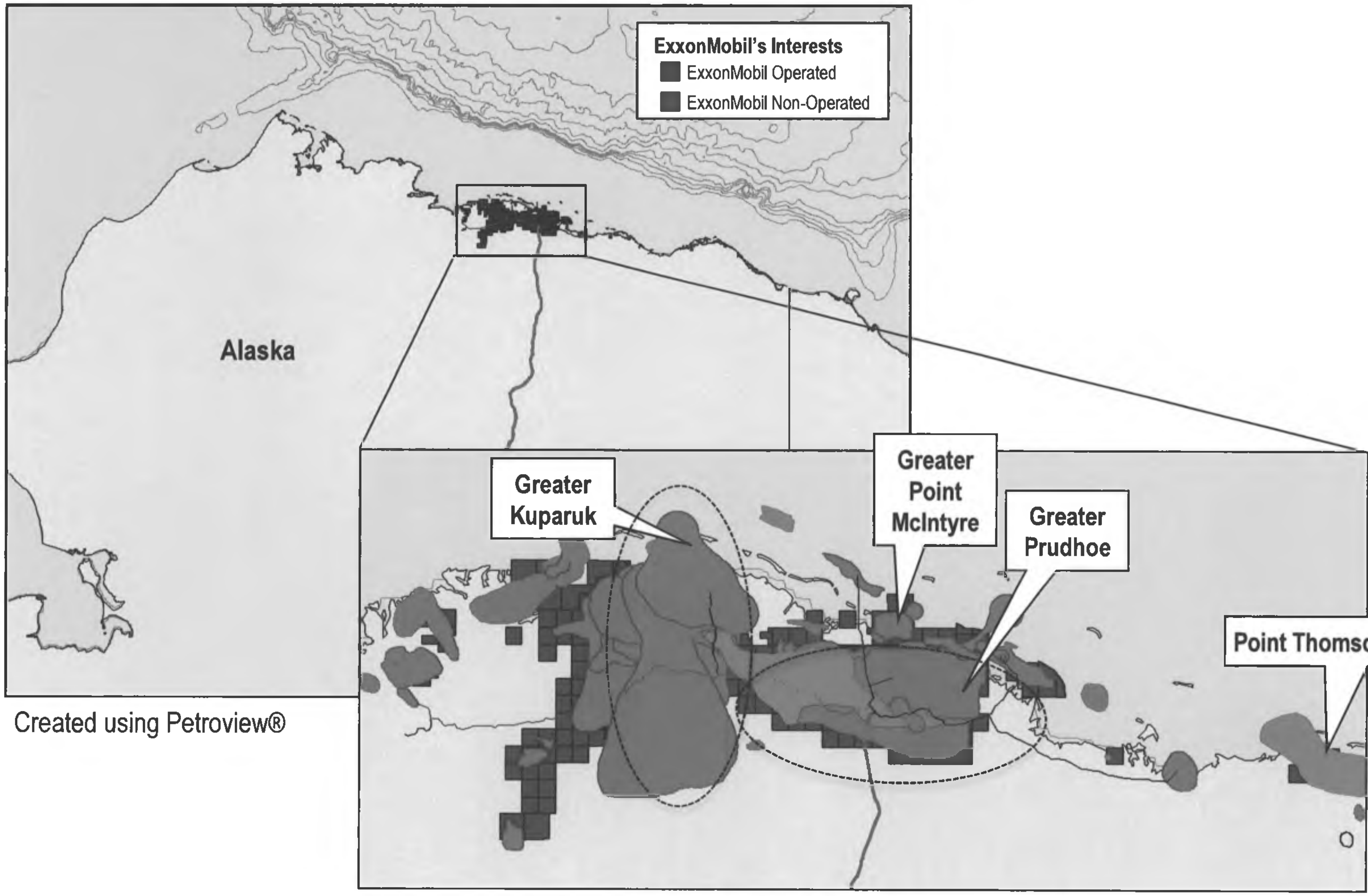
Middle East & North Africa: ~1,277 mboe/d in 2011. Growth over the last decade driven by LNG projects in Qatar (stalled by ongoing moratorium on North Field development). Large legacy position in the UAE, a challenged upstream position in southern Iraq, and new exploration in Kurdistan.

North America: ~1,389 mboe/d in 2011. Expanded positioning in the US Onshore shale gas plays, material deepwater US GOM portfolio, development projects in the Canadian Oil Sands combine to deliver material production growth over the long term.

Russia & Central Asia: ~229 mboe/d in 2011. Growth from a small portfolio of large-scale assets, most of which face above ground challenges. Project execution on unsanctioned development queue remains critical.

Sub-Saharan Africa: ~509 mboe/d in 2011. A "treadmill" operation, with robust new source volumes centered in deepwater Nigeria and Angola keeping pace with field declines.

ExxonMobil in North America: Alaska



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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 114 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 2015-2016. Longer-term potential lies in commercialization of the gas reserves, which is dependent on building a gas pipeline and accessing export markets.	**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. Maintaining and growing upstream investment increasingly hinges on a gas commercialization/export scheme.**

PFC-Identified Challenges

- **Adapting to the unconventional resource play business environment** : The XTO Energy acquisition and subsequent shale gas acreage transactions have made ExxonMobil a force in the North America unconventional resource play, shifting growth focus to a business model that is quite different from the large-scale, major capital projects that have driven core growth for the company over the last decade. With more than two-thirds of its unconventional resource acreage holdings (excluding the oil sands) positioned in gas plays, the company is clearly challenged by the ongoing weakness in natural gas realizations in North America. This is reflected in the company's growing interest in US LNG exports—both from Alaska and the US Onshore. However, this is a long-term fix for a near-term challenge, and one with considerable arbitrage risk in the form of firming Henry Hub gas prices over the latter half of the decade.
- **Delivering on a new growth strategy based on strategic partnerships and frontier exploration opportunities**. The development moratorium on the Qatar North Field has left ExxonMobil searching for new engines of growth. One response has been a shift in strategy towards strategic partnerships and frontier exploration – reflected in the Rosneft strategic agreement covering frontier exploration in the Russia Arctic.
- **Execution or rationalization of challenged reserves and/or developments positions**. These include:
  - Monetization of captured frontier gas resources in North America (Alaska North Slope, Mackenzie Delta);
  - Development of captured oil reserves in the Caspian region, plagued by delays, cost over-runs, and accelerating resource nationalism;
  - Delivering on the West Qurna I redevelopment project in Iraq, which remains challenged by export infrastructure constraints. The securing of six exploration licenses in the northern Kurdistan region is the latest signal of ExxonMobil's concern over the ability of Iraq to evolve into a Core area for the company.
- **Maintain leadership in share buy-back and dividend performance**: ExxonMobil has been a clear peer group leader in returns to shareholders, distributing ~$29 bn through dividends and share buy-backs in 2011 and spending ~$109 bn on share repurchase over the 2007-2011 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.

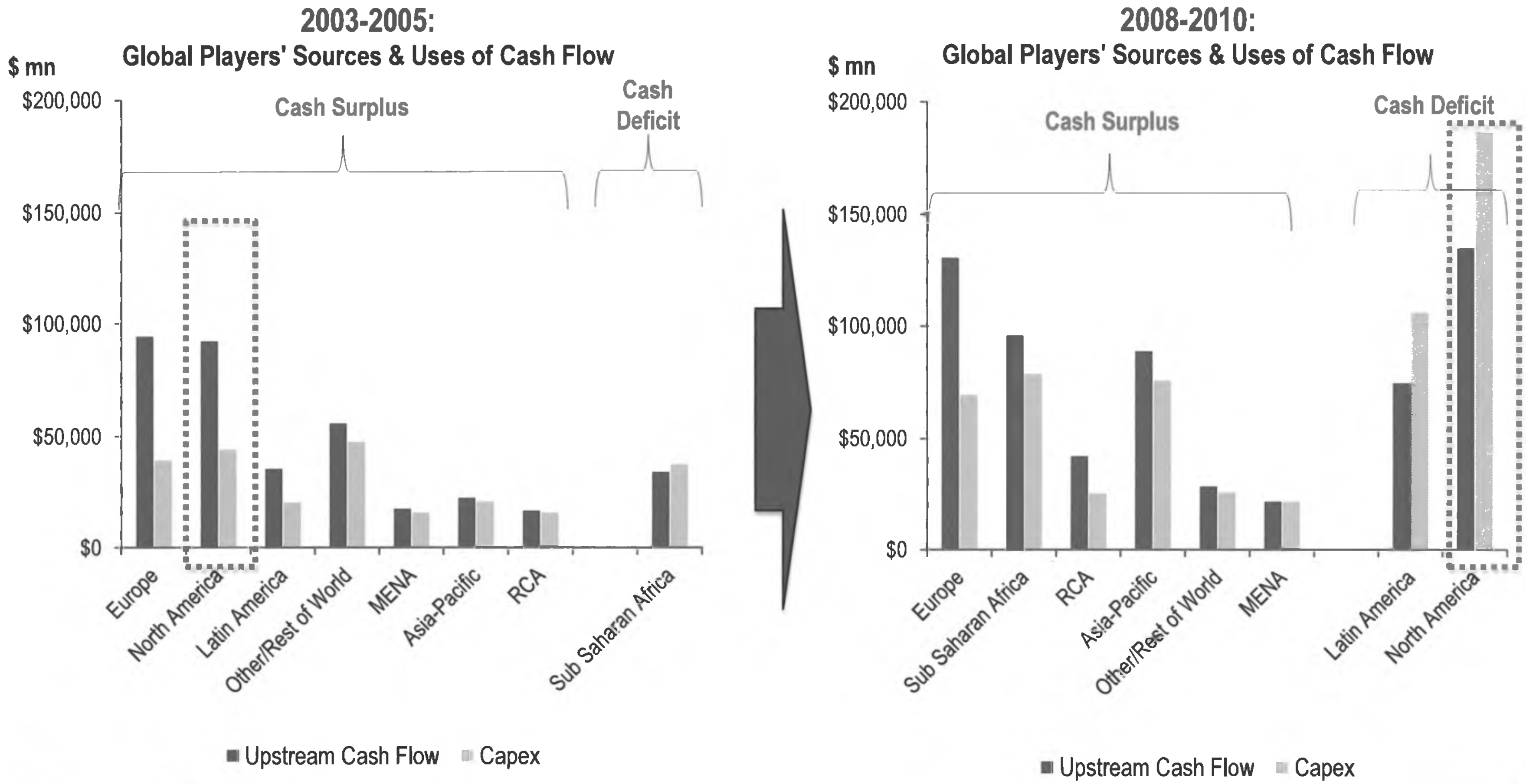
Questions & Discussion

2011	Alaska	% US	% Global	% Trend
BP	173 mboe/d	17	5	↓
COP	244 mboe/d	36	14	↑
XOM	117 mboe/d	14	3	↓

PFC Energy

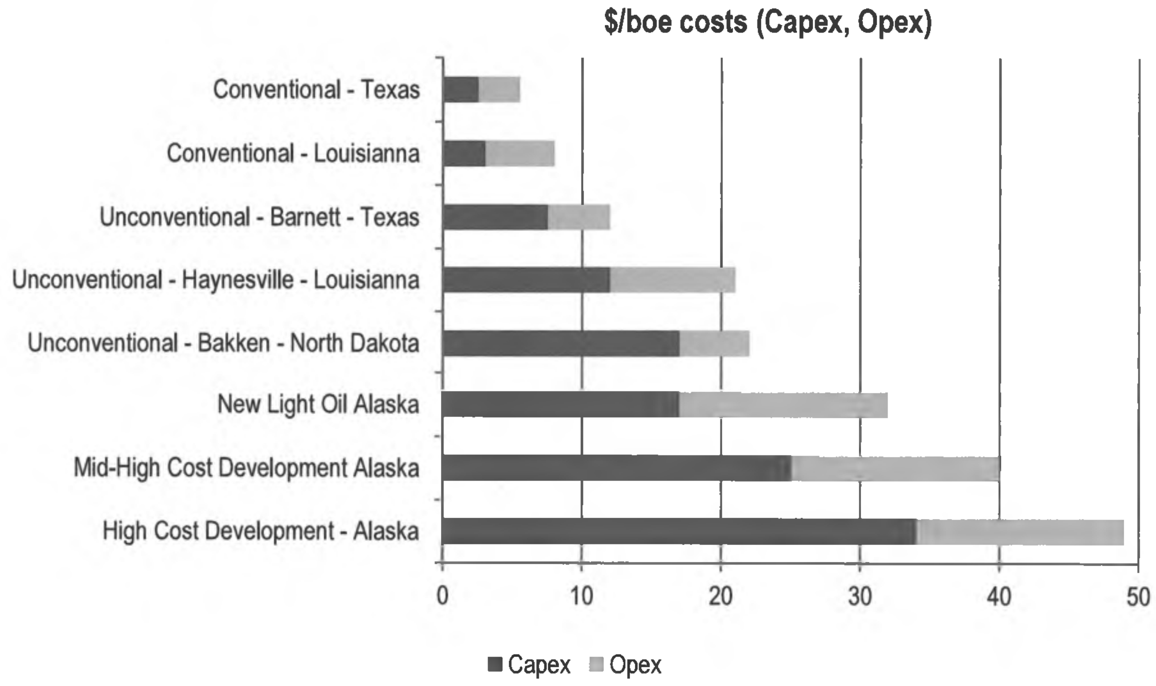
Alaska's Fiscal Regime in a Global Competitive Context

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.

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



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

Relative Government Take (Definition)

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

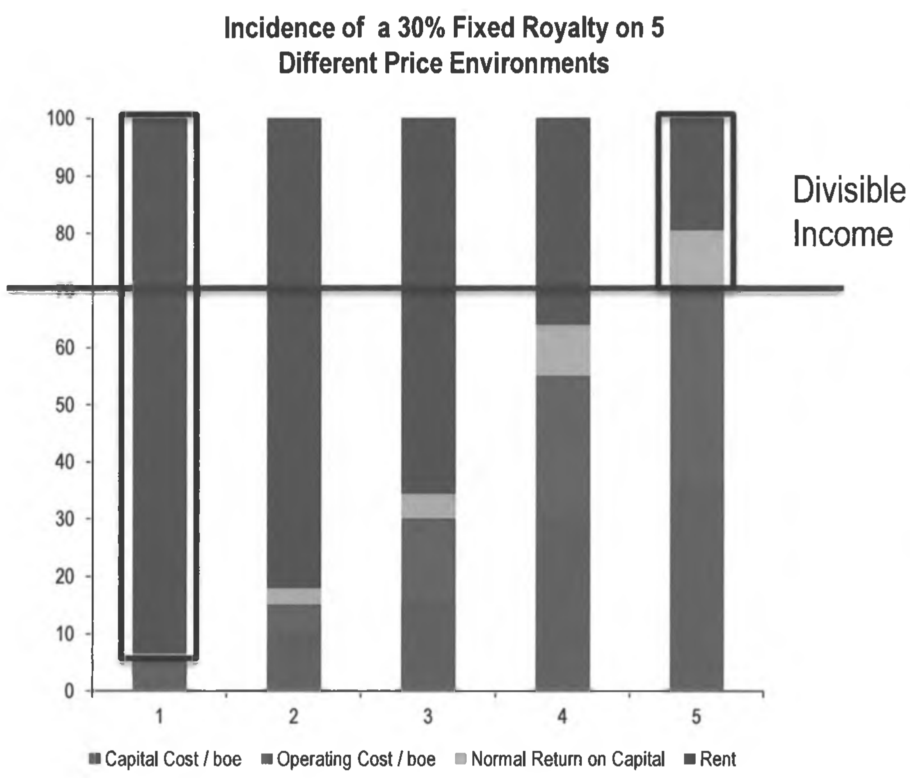
Divisible Income equals Gross Revenues less costs, including capex and transportation costs.

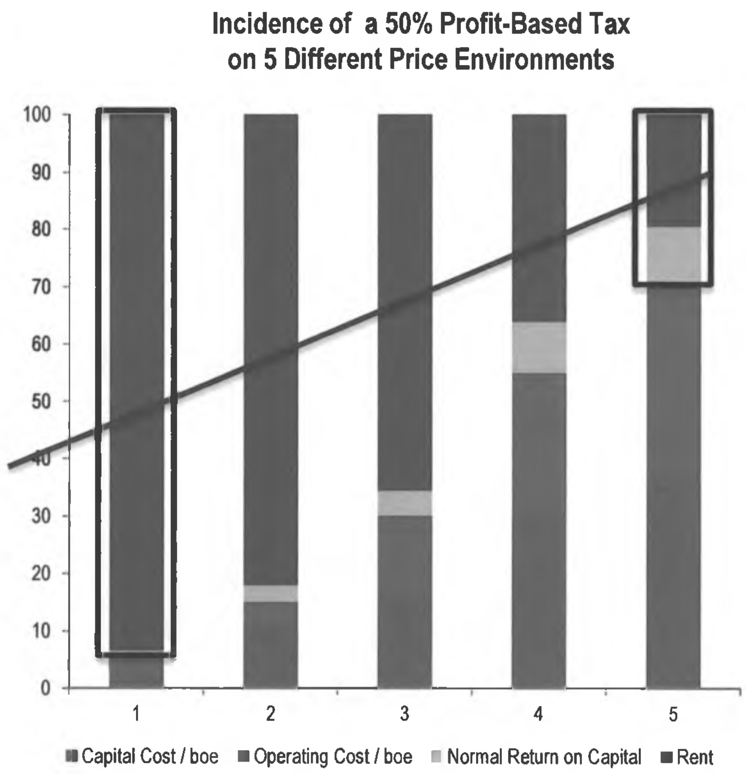
Government Take includes all payments the government mandates in its function as a sovereign:

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

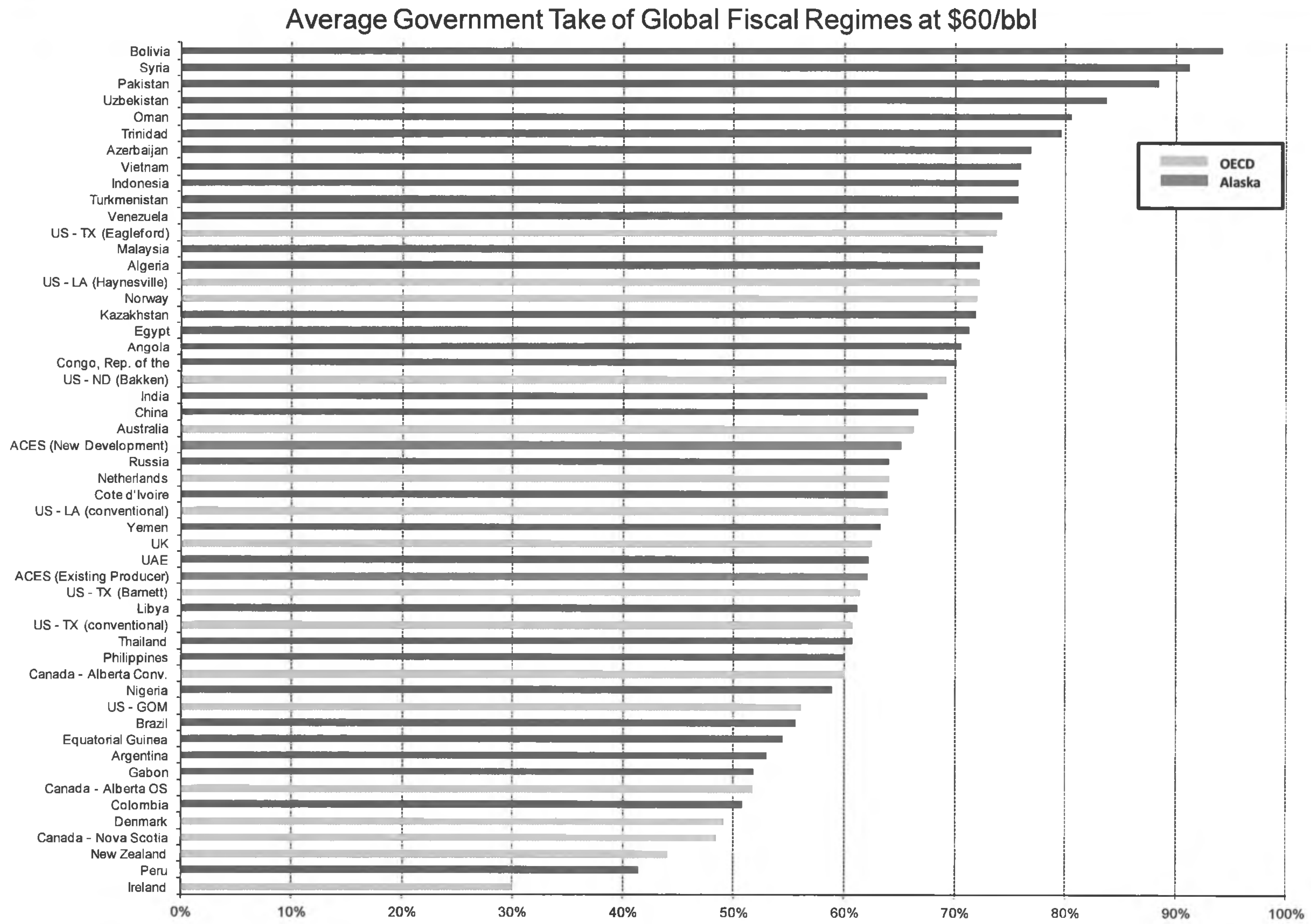
Government Take does not include amounts the government earns via a direct equity stake

Fixed Royalty v Profit Based Fiscal Systems

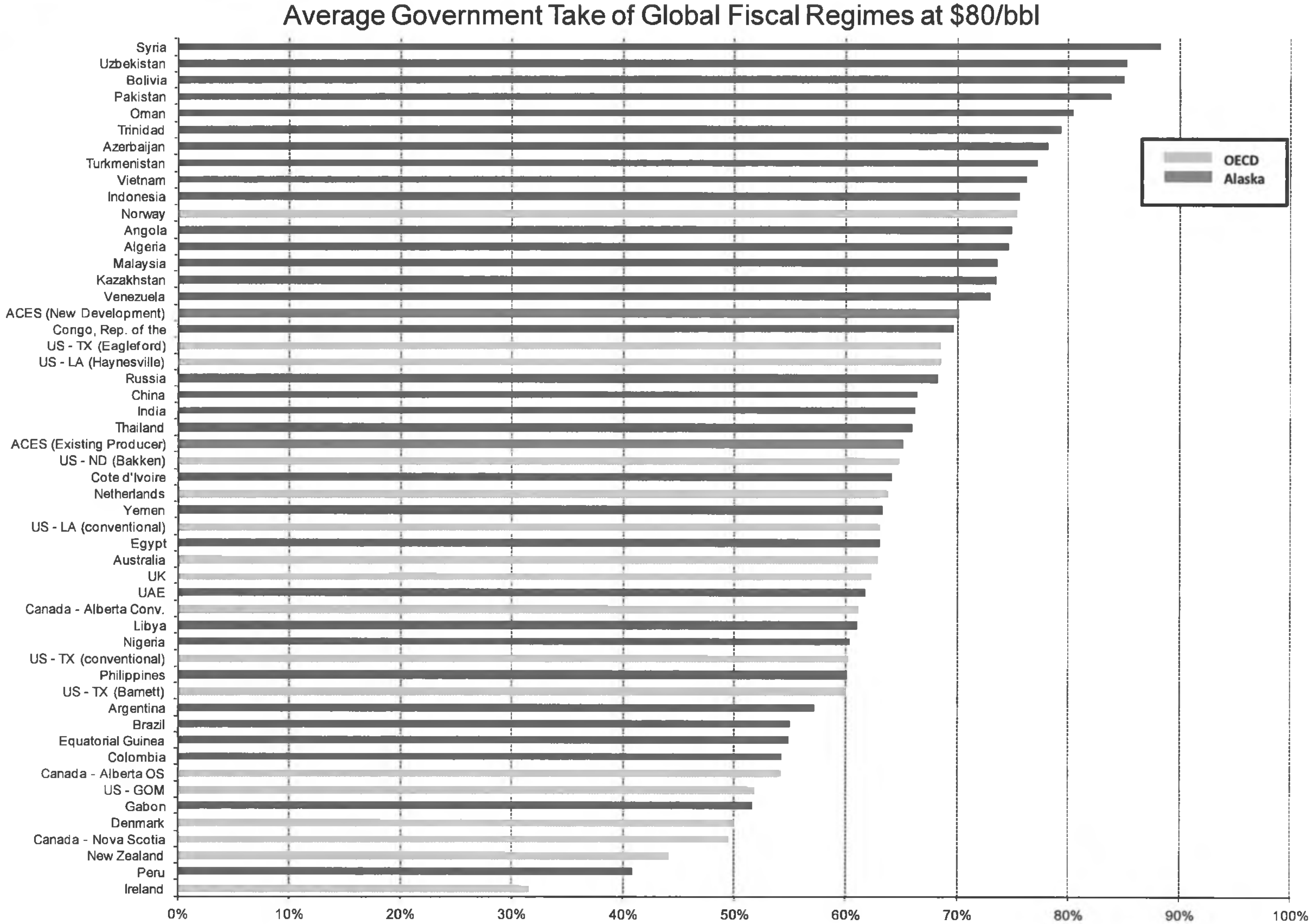




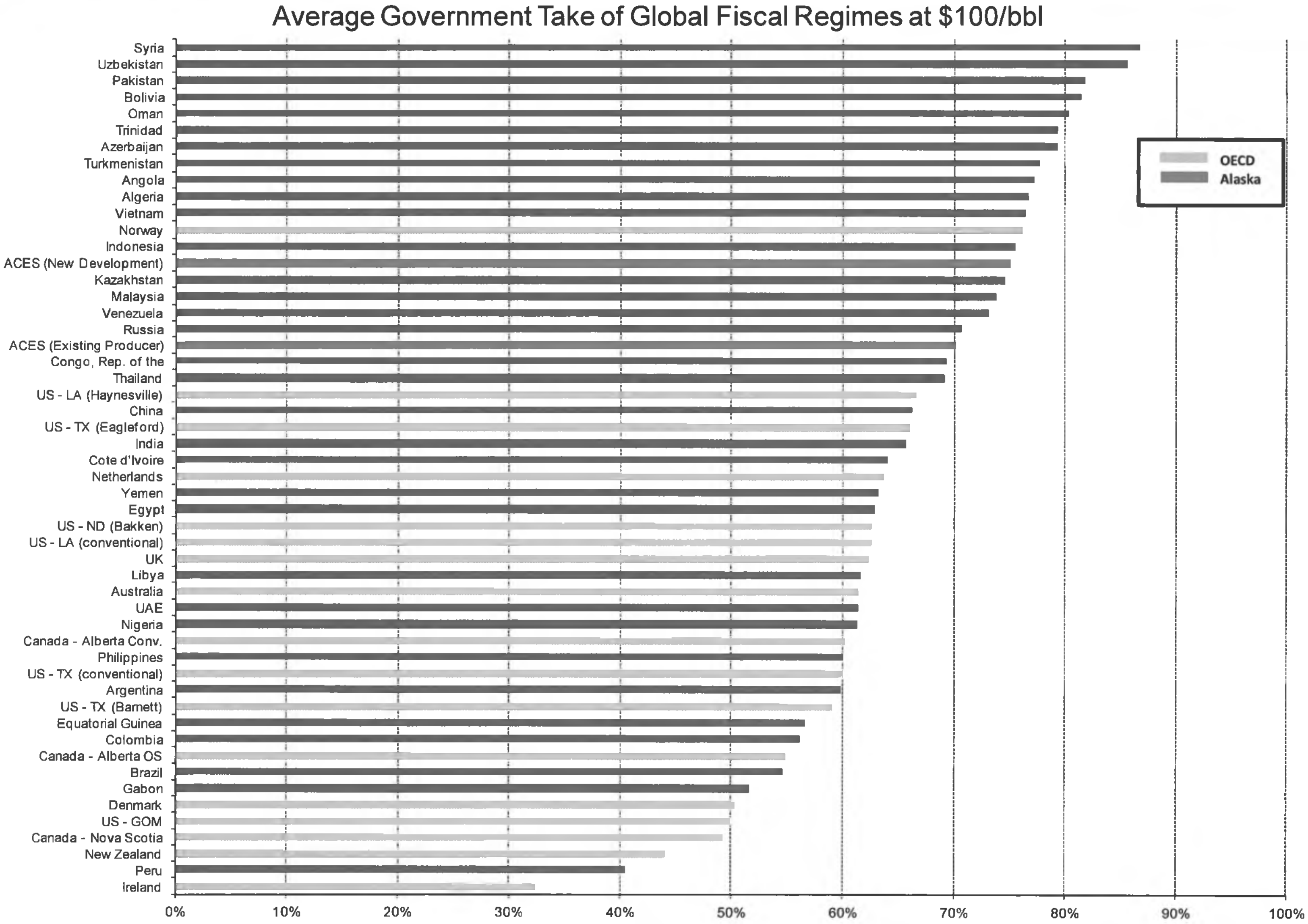
Regime Competitiveness: Average Government Take at $60/bbl



Regime Competitiveness: Average Government Take at $80/bbl

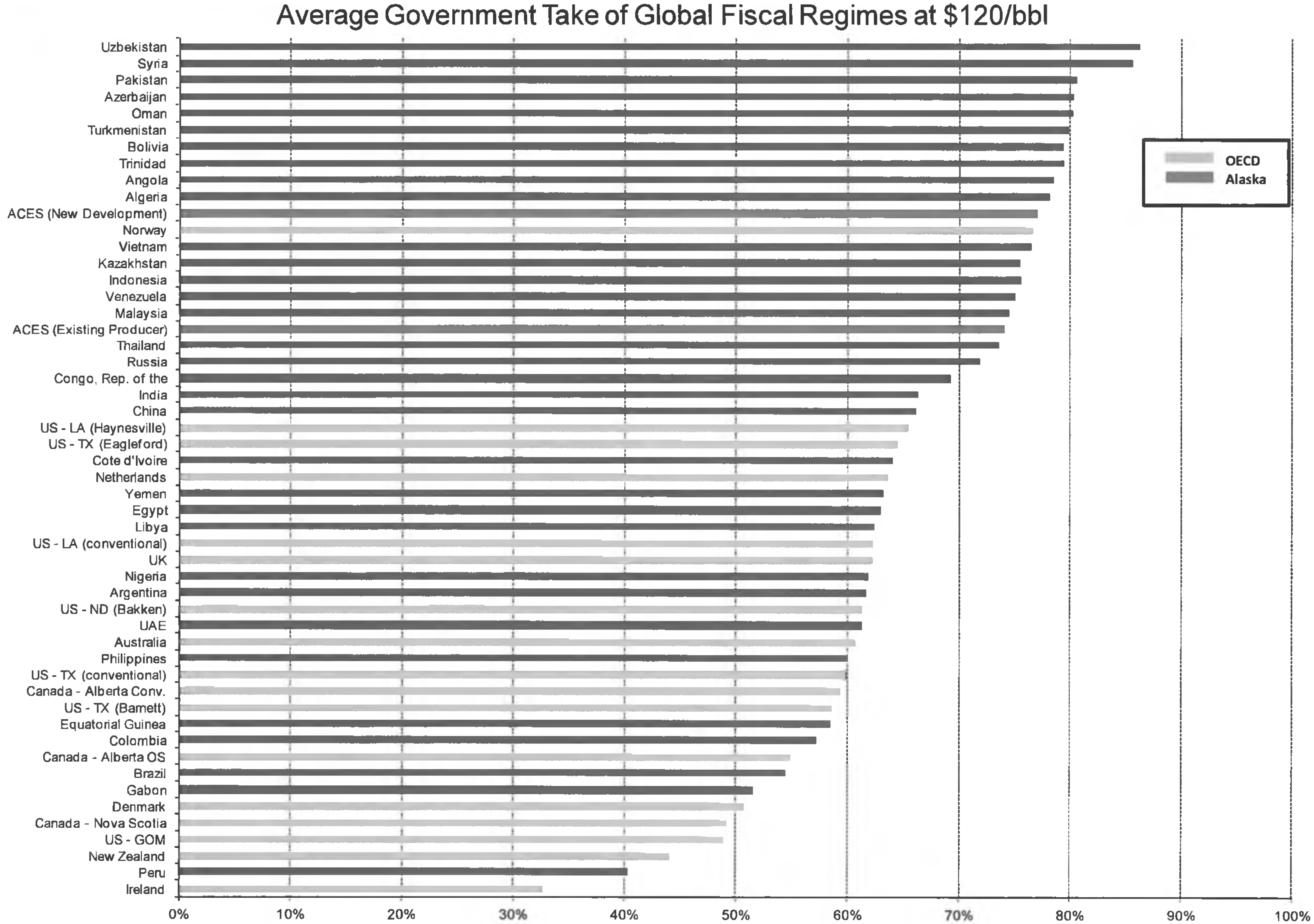


Regime Competitiveness: Average Government Take at $100/bbl

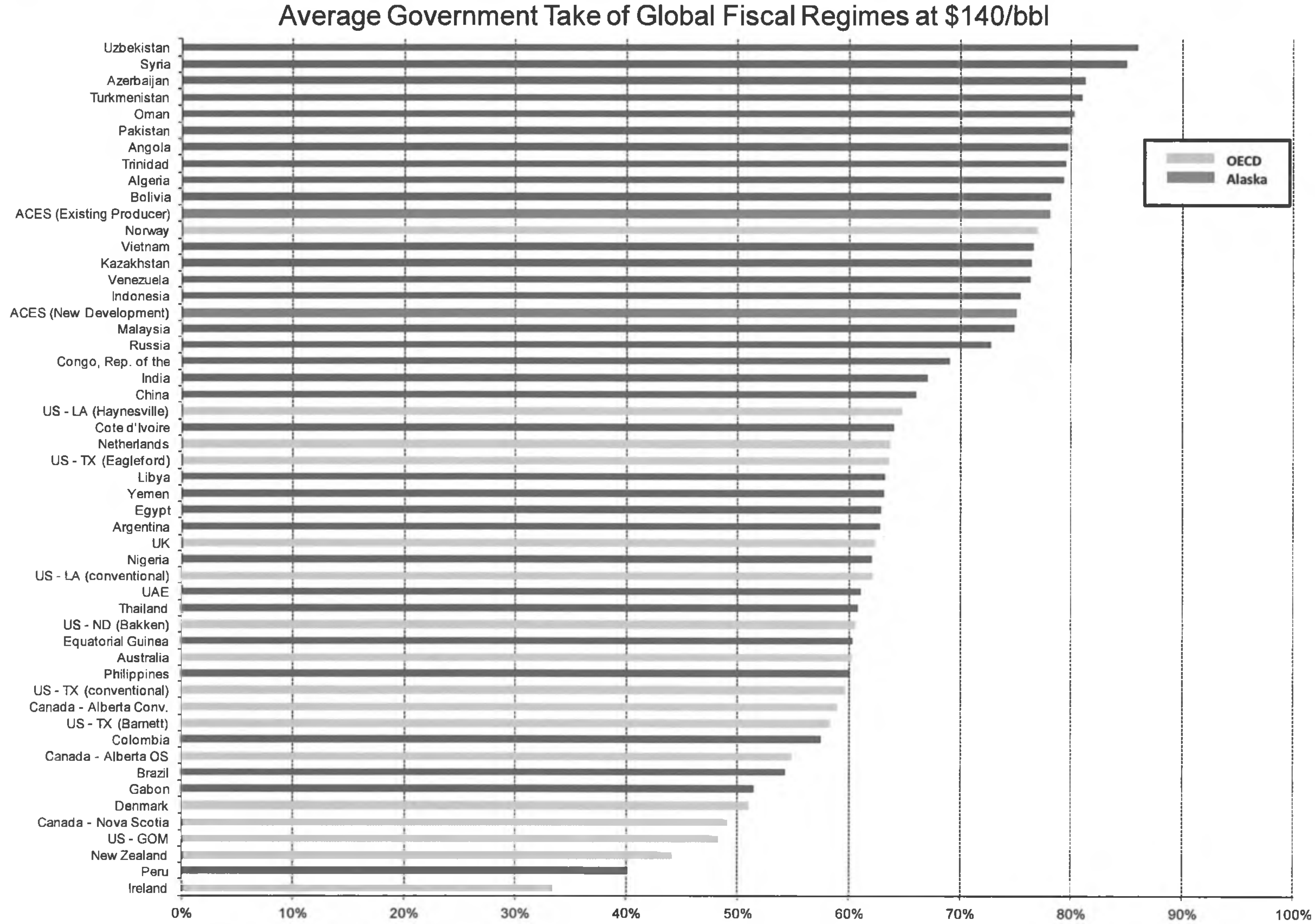


PFC Energy

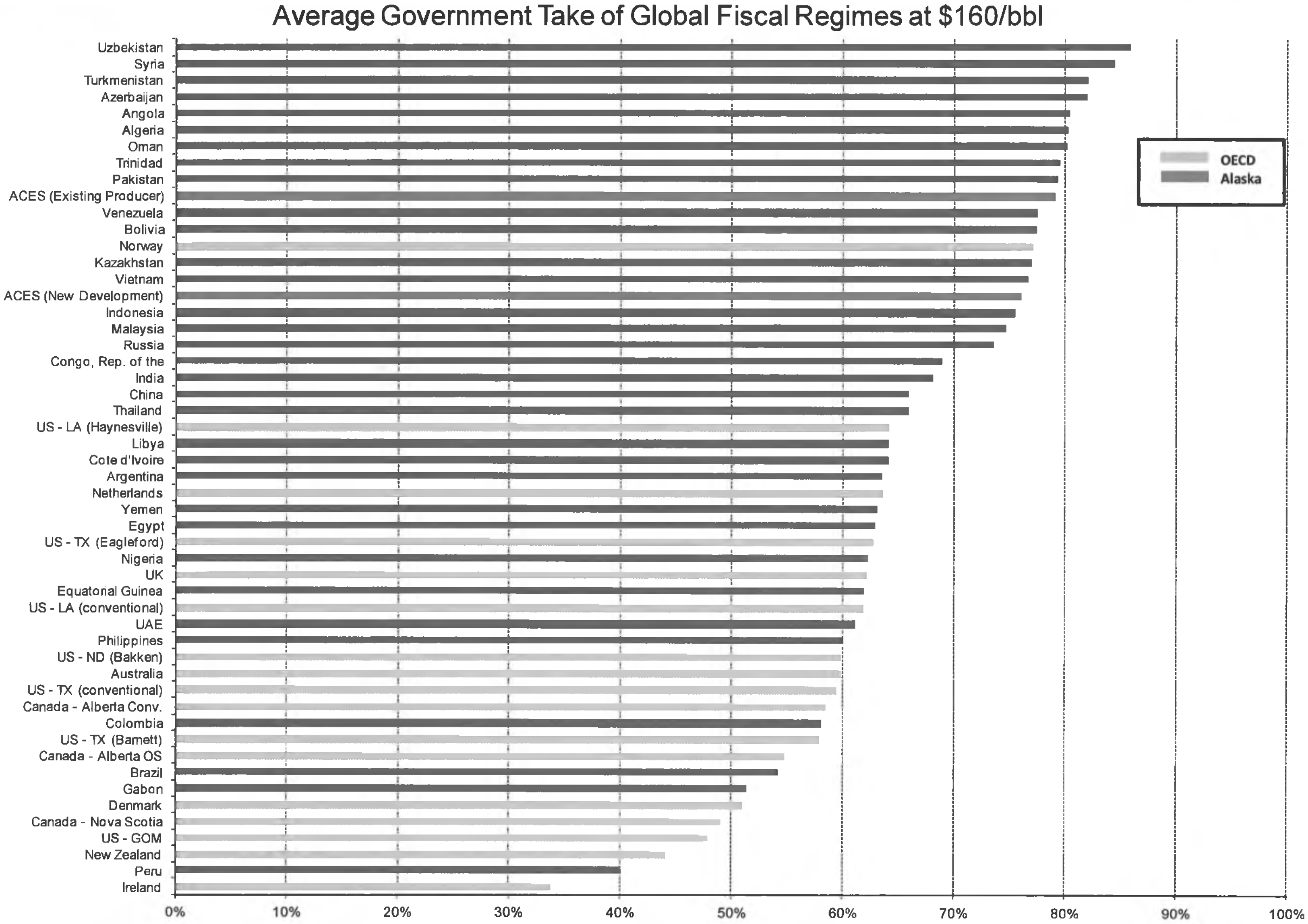
Regime Competitiveness: Average Government Take at $120/bbl



Regime Competitiveness: Average Government Take at $140/bbl



Regime Competitiveness: Average Government Take at $160/bbl



PFC Energy

ACES & SB 21

ACES – Existing Production – Government Take

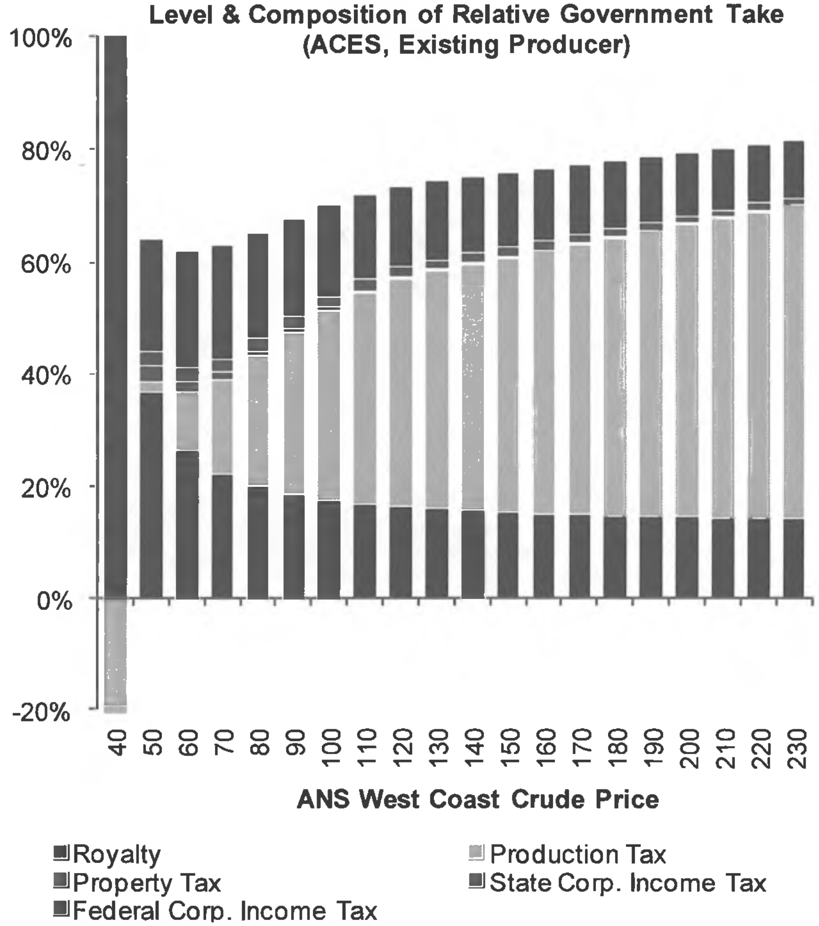


Table 1: Level & Composition of Relative Government Take (ACES, Existing Producer)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	104%	-24%	11%	2%	**93%**	14%	**107%**
50	37%	2%	3%	2%	**44%**	21%	**64%**
60	26%	10%	2%	3%	**41%**	21%	**62%**
70	22%	17%	1%	2%	**43%**	20%	**63%**
80	20%	23%	1%	2%	**46%**	19%	**65%**
90	19%	29%	1%	2%	**50%**	18%	**68%**
100	18%	34%	1%	2%	**54%**	16%	**70%**
110	17%	38%	1%	2%	**57%**	15%	**72%**
120	16%	40%	0%	2%	**59%**	14%	**74%**
130	16%	42%	0%	2%	**60%**	14%	**74%**
140	16%	44%	0%	2%	**61%**	14%	**75%**
150	15%	45%	0%	2%	**63%**	13%	**76%**
160	15%	47%	0%	2%	**64%**	13%	**76%**
170	15%	48%	0%	1%	**65%**	12%	**77%**
180	15%	49%	0%	1%	**66%**	12%	**78%**
190	15%	51%	0%	1%	**67%**	12%	**79%**
200	15%	52%	0%	1%	**68%**	11%	**79%**
210	14%	53%	0%	1%	**69%**	11%	**80%**
220	14%	55%	0%	1%	**70%**	10%	**81%**
230	14%	56%	0%	1%	**71%**	10%	**81%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

ACES – New Development – Government Take

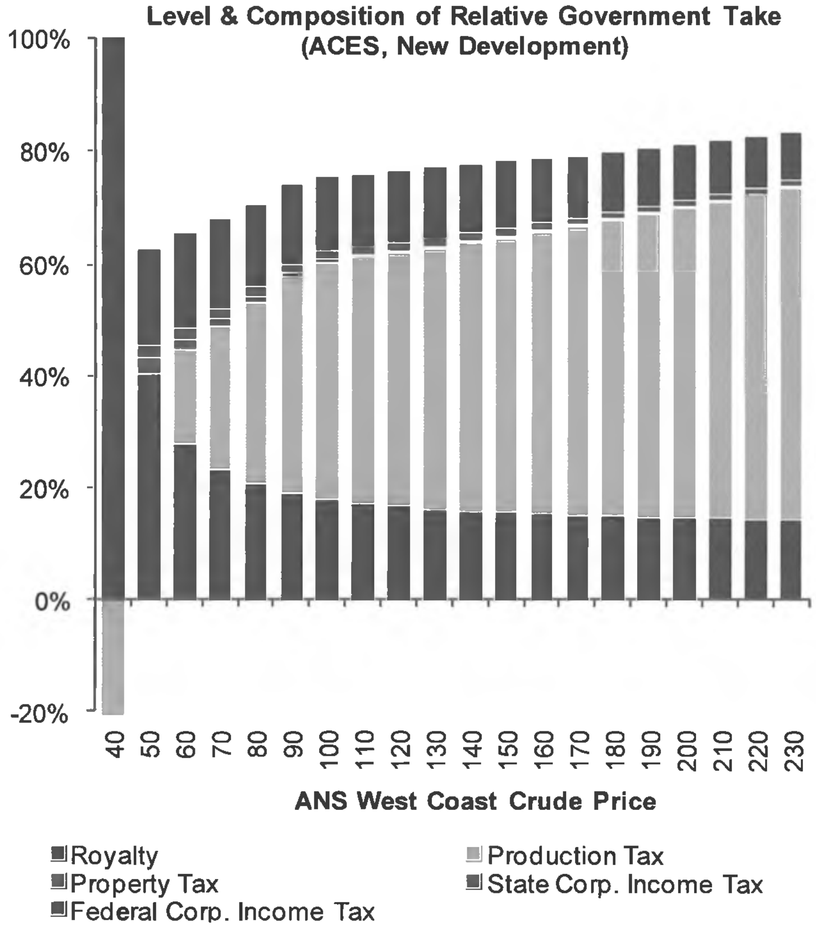
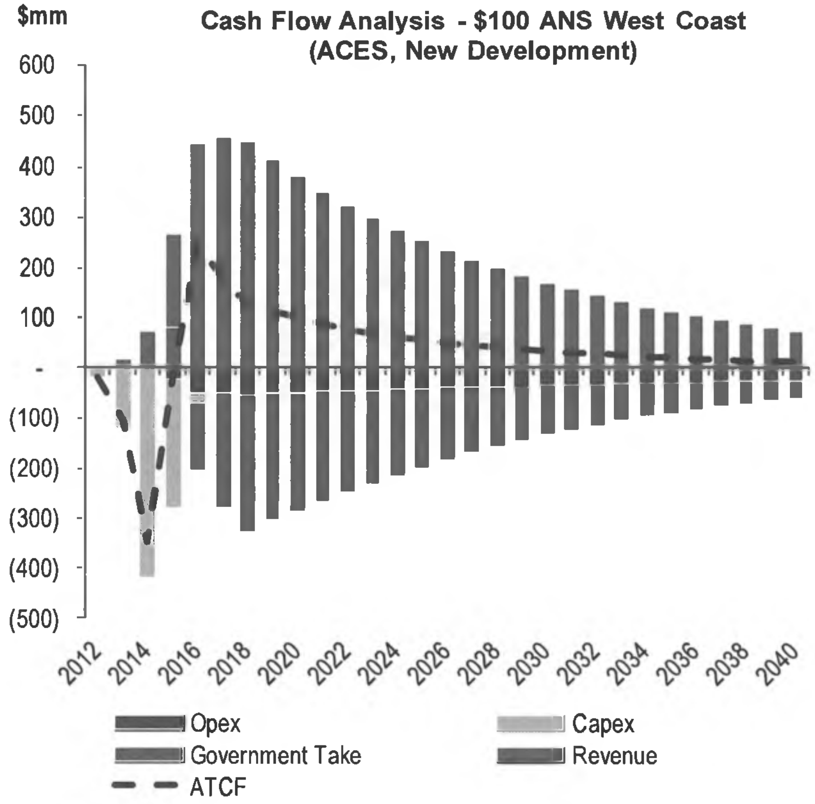


Table 1: Level & Composition of Relative Government Take (ACES, New Development)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	Total State Take	Federal Corp. Income Tax	Total Govt. Take
40	155%	-101%	16%	3%	**72%**	15%	**87%**
50	40%	0%	3%	2%	**45%**	18%	**63%**
60	28%	17%	2%	2%	**48%**	17%	**65%**
70	23%	26%	1%	2%	**52%**	16%	**68%**
80	21%	33%	1%	2%	**56%**	15%	**70%**
90	19%	39%	1%	2%	**60%**	14%	**74%**
100	18%	42%	1%	2%	**62%**	13%	**75%**
110	17%	44%	1%	1%	**63%**	13%	**76%**
120	17%	45%	0%	1%	**64%**	13%	**77%**
130	16%	47%	0%	1%	**65%**	13%	**77%**
140	16%	48%	0%	1%	**65%**	12%	**78%**
150	16%	49%	0%	1%	**66%**	12%	**78%**
160	15%	50%	0%	1%	**67%**	11%	**79%**
170	15%	52%	0%	1%	**68%**	11%	**79%**
180	15%	53%	0%	1%	**69%**	11%	**80%**
190	15%	54%	0%	1%	**70%**	10%	**80%**
200	15%	55%	0%	1%	**71%**	10%	**81%**
210	14%	57%	0%	1%	**72%**	9%	**82%**
220	14%	58%	0%	1%	**74%**	9%	**83%**
230	14%	59%	0%	1%	**75%**	9%	**83%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

ACES – New Development – Cash Flow Analysis



Price	NPV12	NPV/Bbl	IRR
40	(174)	(3.49)	1.3%
50	(78)	(1.56)	7.7%
60	(11)	(0.22)	11.4%
70	45	0.91	14.4%
80	95	1.91	17.1%
90	118	2.35	18.2%
100	151	3.03	19.9%
110	193	3.86	21.8%
120	228	4.56	23.4%
130	261	5.22	24.9%
140	302	6.03	26.9%

SB21 – Existing Production – Government Take

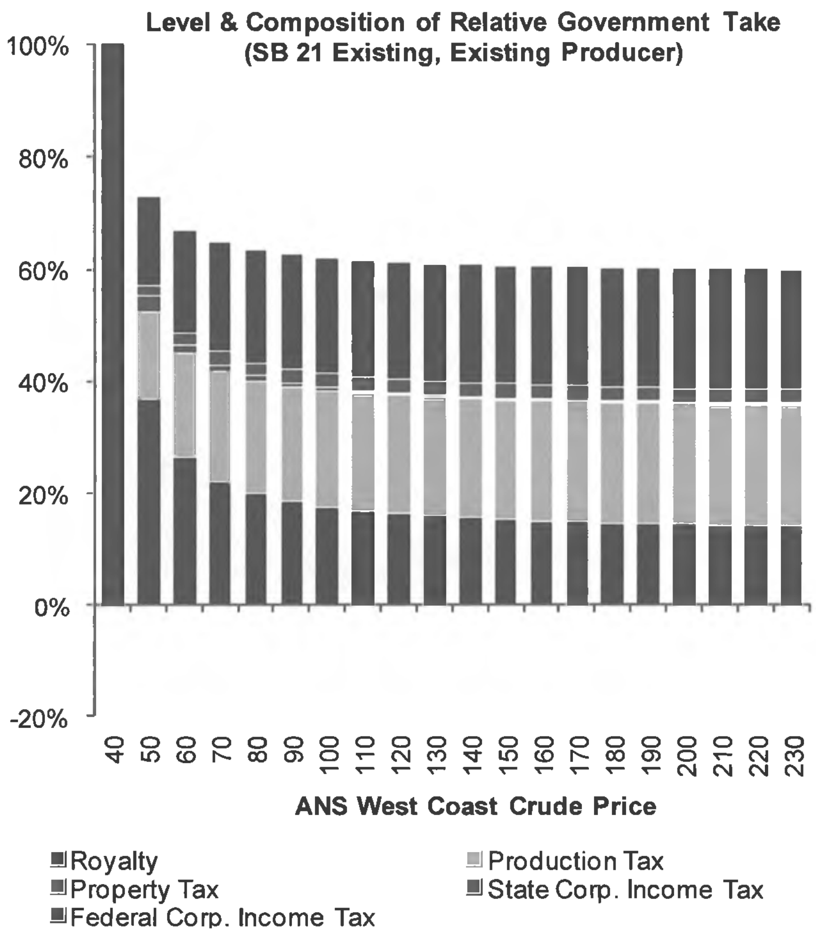


Table 1: Level & Composition of Relative Government Take (SB 21 Existing, Existing Producer)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	104%	21%	11%	1%	**137%**	7%	**144%**
50	37%	16%	3%	2%	**57%**	16%	**73%**
60	26%	18%	2%	2%	**49%**	18%	**67%**
70	22%	19%	1%	2%	**45%**	20%	**65%**
80	20%	20%	1%	2%	**43%**	20%	**63%**
90	19%	20%	1%	2%	**42%**	20%	**63%**
100	18%	21%	1%	2%	**41%**	21%	**62%**
110	17%	21%	1%	2%	**41%**	21%	**62%**
120	16%	21%	0%	3%	**40%**	21%	**61%**
130	16%	21%	0%	3%	**40%**	21%	**61%**
140	16%	21%	0%	3%	**40%**	21%	**61%**
150	15%	21%	0%	3%	**39%**	21%	**61%**
160	15%	21%	0%	3%	**39%**	21%	**61%**
170	15%	21%	0%	3%	**39%**	21%	**60%**
180	15%	21%	0%	3%	**39%**	21%	**60%**
190	15%	21%	0%	3%	**39%**	21%	**60%**
200	15%	21%	0%	3%	**39%**	22%	**60%**
210	14%	21%	0%	3%	**39%**	22%	**60%**
220	14%	21%	0%	3%	**38%**	22%	**60%**
230	14%	21%	0%	3%	**38%**	22%	**60%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

PFC Energy

SB 21 – New Development – Government Take

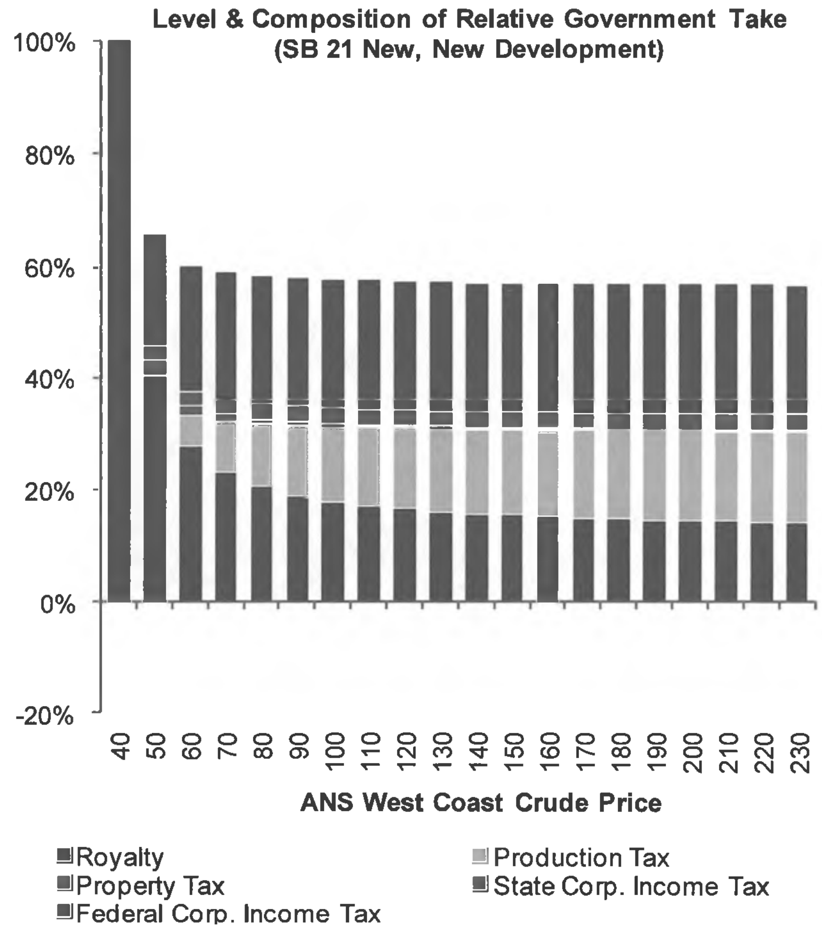


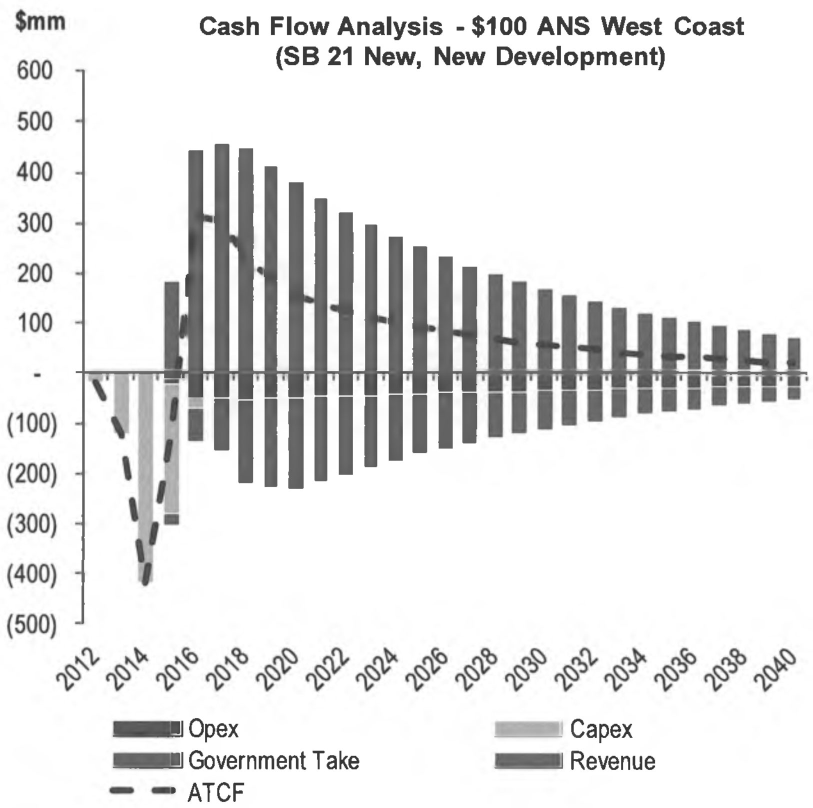
Table 1: Level & Composition of Relative Government Take (SB 21 New, New Development)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	155%	0%	16%	0%	**170%**	0%	**170%**
50	40%	0%	3%	2%	**46%**	20%	**66%**
60	28%	5%	2%	3%	**38%**	23%	**60%**
70	23%	9%	1%	3%	**36%**	23%	**59%**
80	21%	11%	1%	3%	**35%**	23%	**58%**
90	19%	12%	1%	3%	**35%**	23%	**58%**
100	18%	13%	1%	3%	**35%**	23%	**58%**
110	17%	14%	1%	3%	**34%**	23%	**58%**
120	17%	14%	0%	3%	**34%**	23%	**57%**
130	16%	15%	0%	3%	**34%**	23%	**57%**
140	16%	15%	0%	3%	**34%**	23%	**57%**
150	16%	15%	0%	3%	**34%**	23%	**57%**
160	15%	15%	0%	3%	**34%**	23%	**57%**
170	15%	16%	0%	3%	**34%**	23%	**57%**
180	15%	16%	0%	3%	**34%**	23%	**57%**
190	15%	16%	0%	3%	**34%**	23%	**57%**
200	15%	16%	0%	3%	**34%**	23%	**57%**
210	14%	16%	0%	3%	**34%**	23%	**57%**
220	14%	16%	0%	3%	**33%**	23%	**57%**
230	14%	16%	0%	3%	**33%**	23%	**57%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

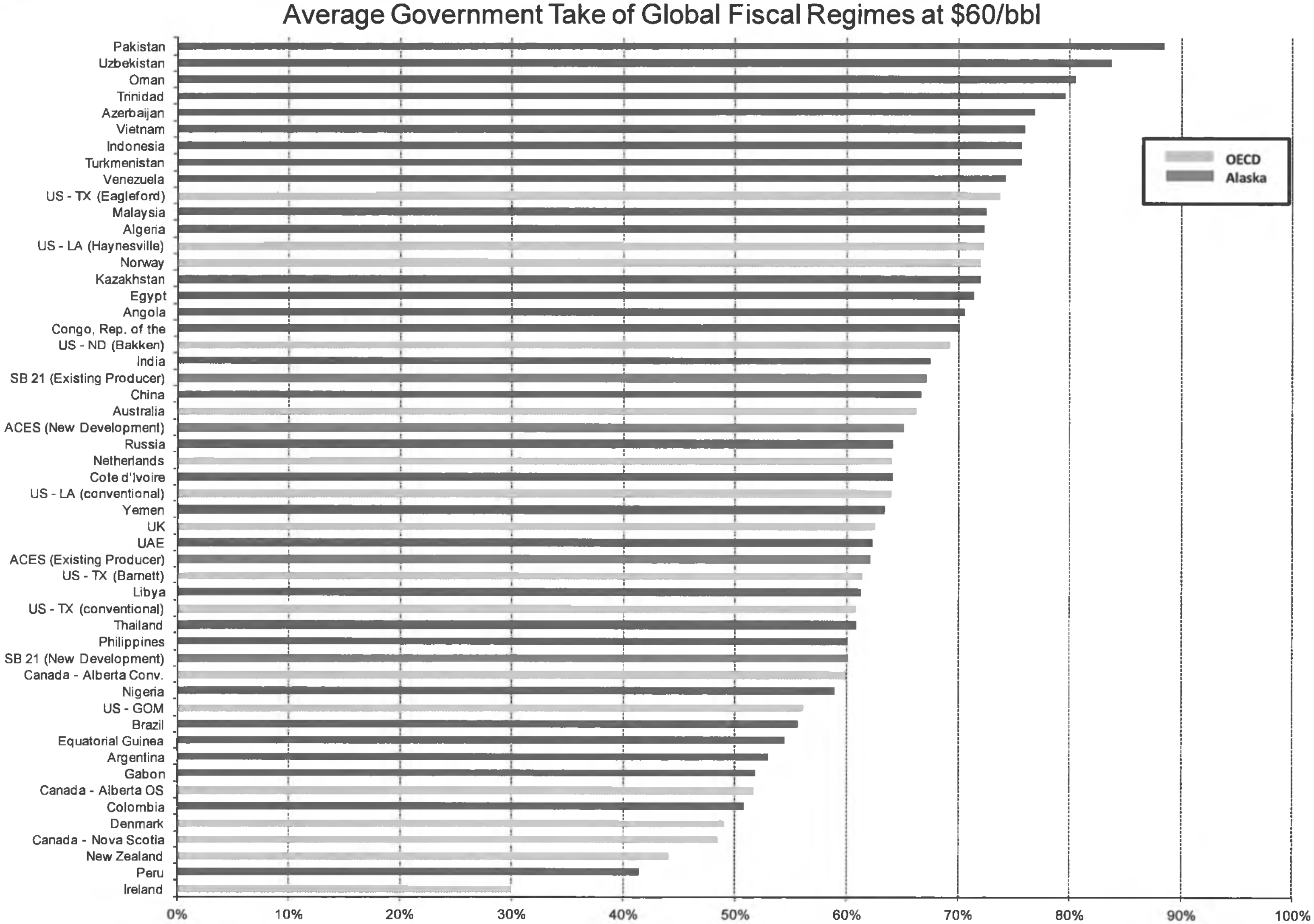
PFC Energy

SB 21 – New Development – Cash Flow Analysis



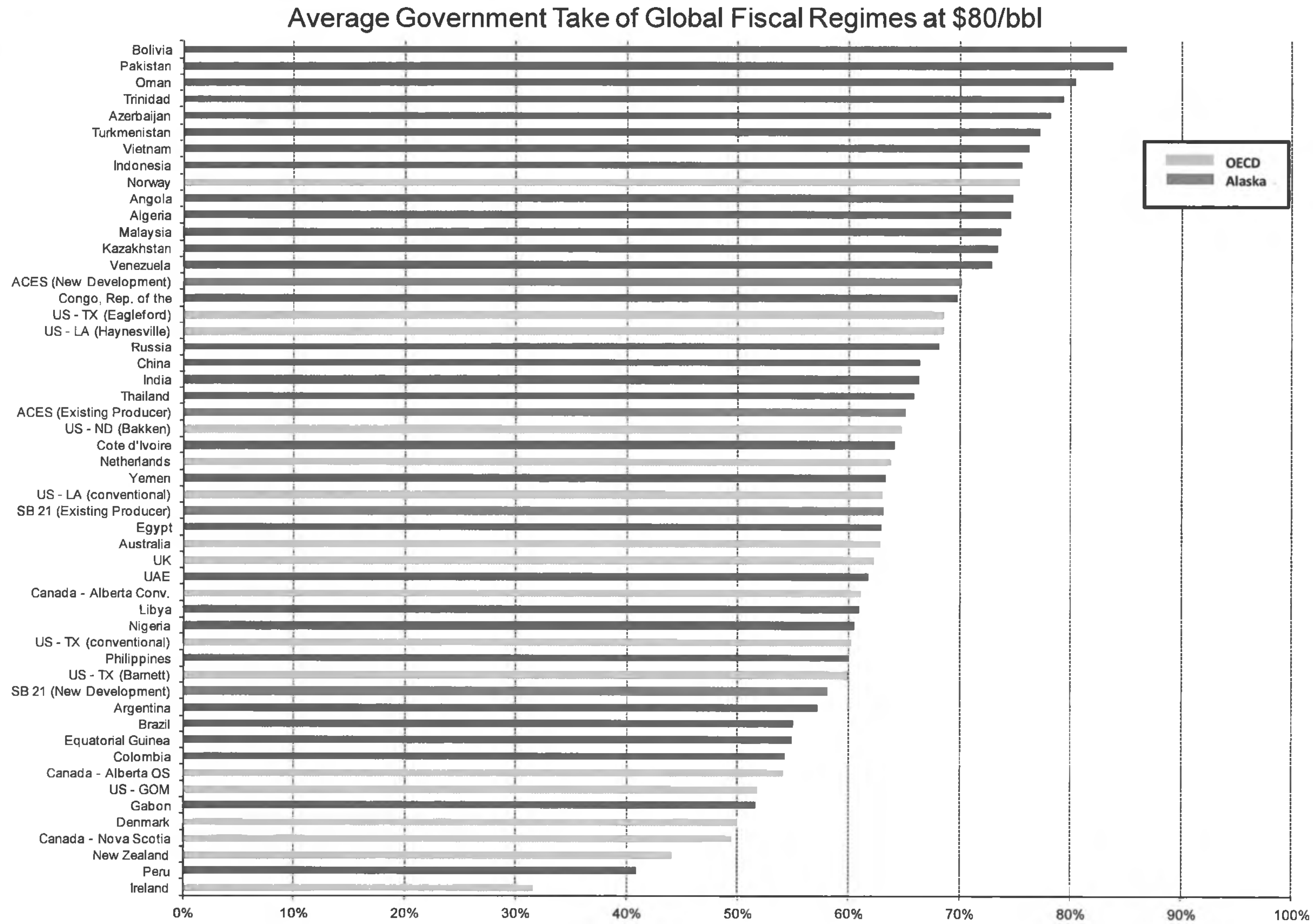
Price	NPV12	NPV/Bbl	IRR
40	(316)	(6.31)	-1.6%
50	(177)	(3.53)	4.9%
60	(64)	(1.29)	9.5%
70	34	0.68	13.3%
80	127	2.55	16.9%
90	219	4.37	20.2%
100	307	6.14	23.3%
110	394	7.89	26.3%
120	481	9.62	29.1%
130	569	11.37	32.0%
140	656	13.12	34.7%

Regime Competitiveness: Average Government Take at $60/bbl

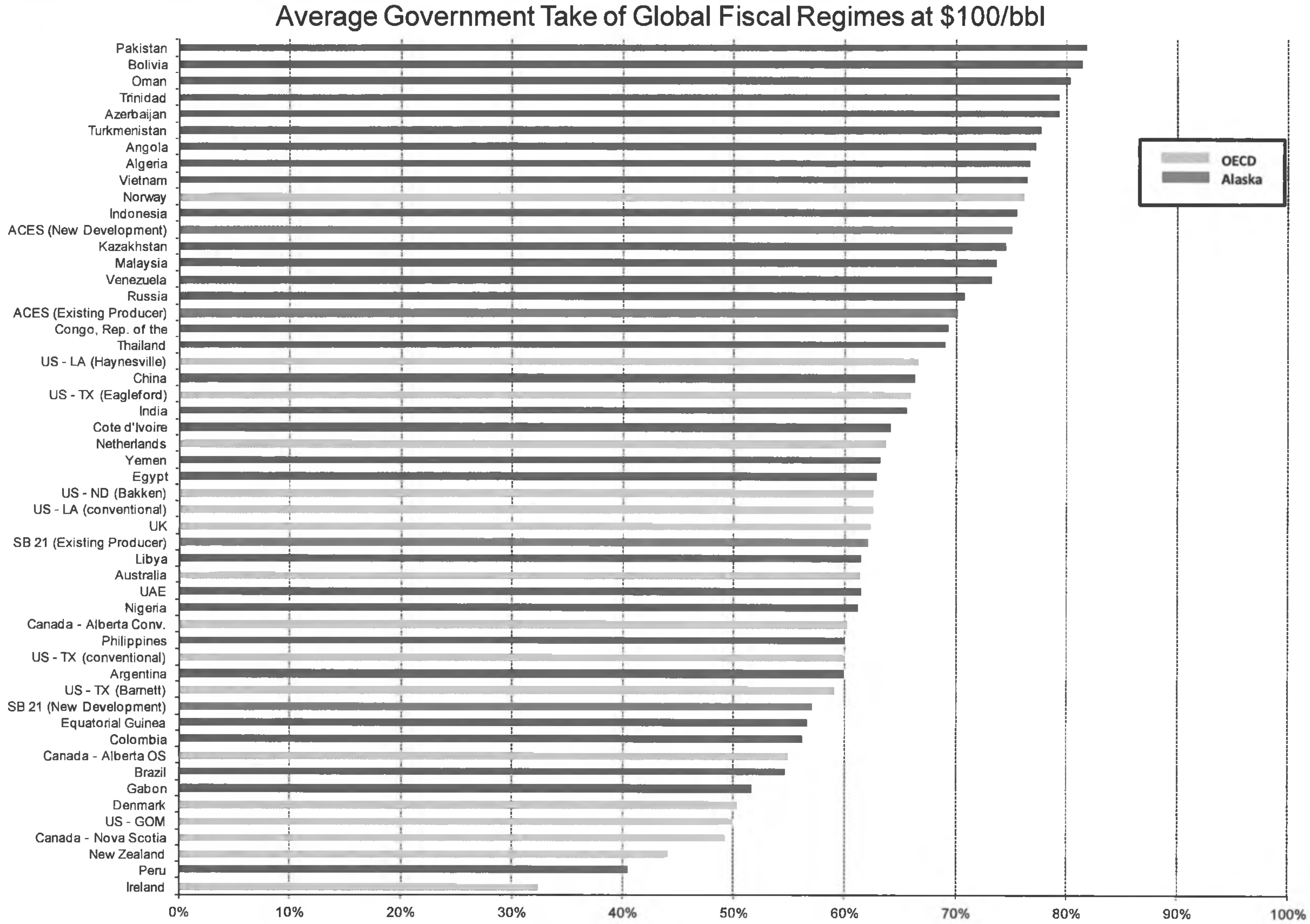


PFC Energy

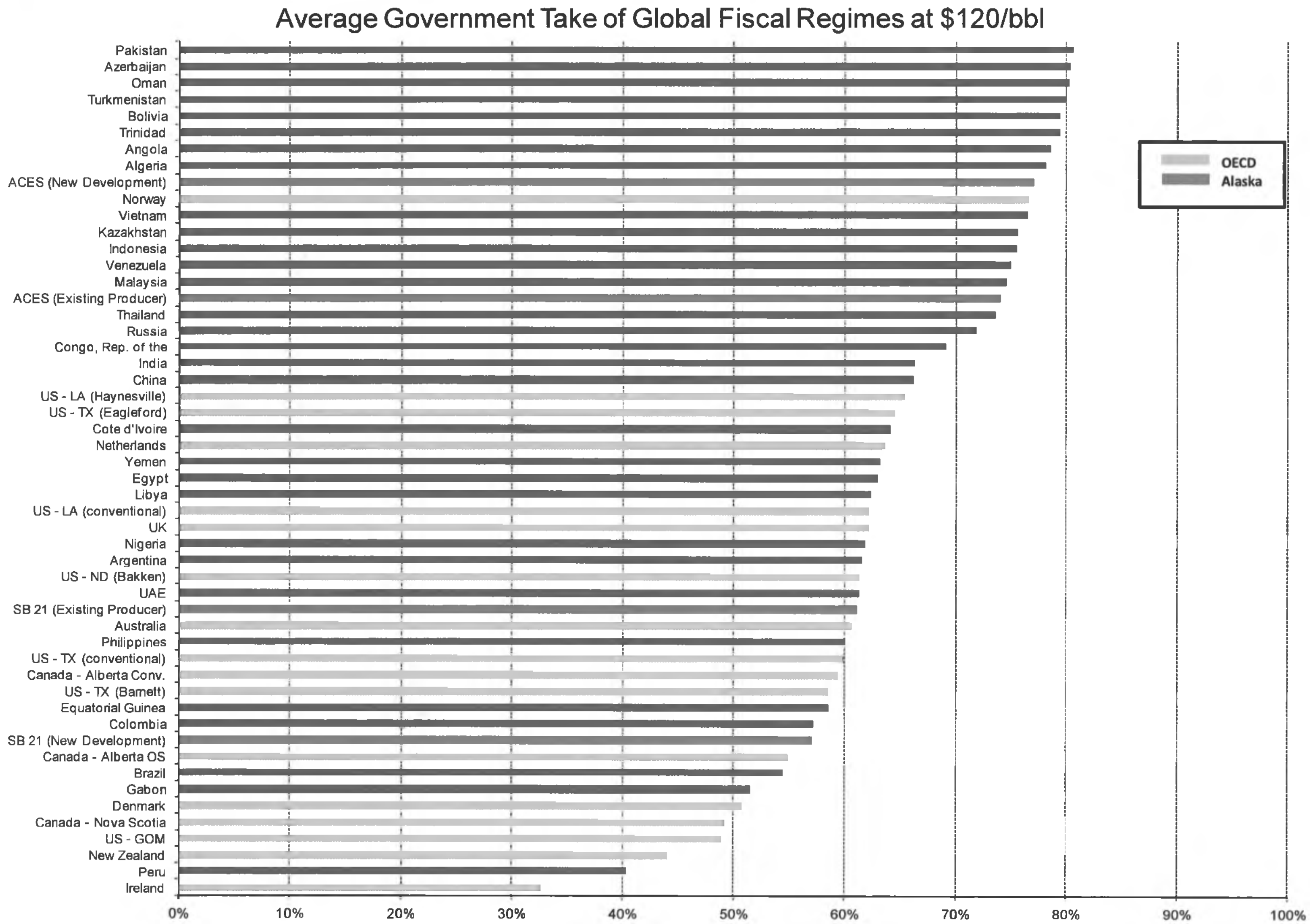
Regime Competitiveness: Average Government Take at $80/bbl



Regime Competitiveness: Average Government Take at $100/bbl

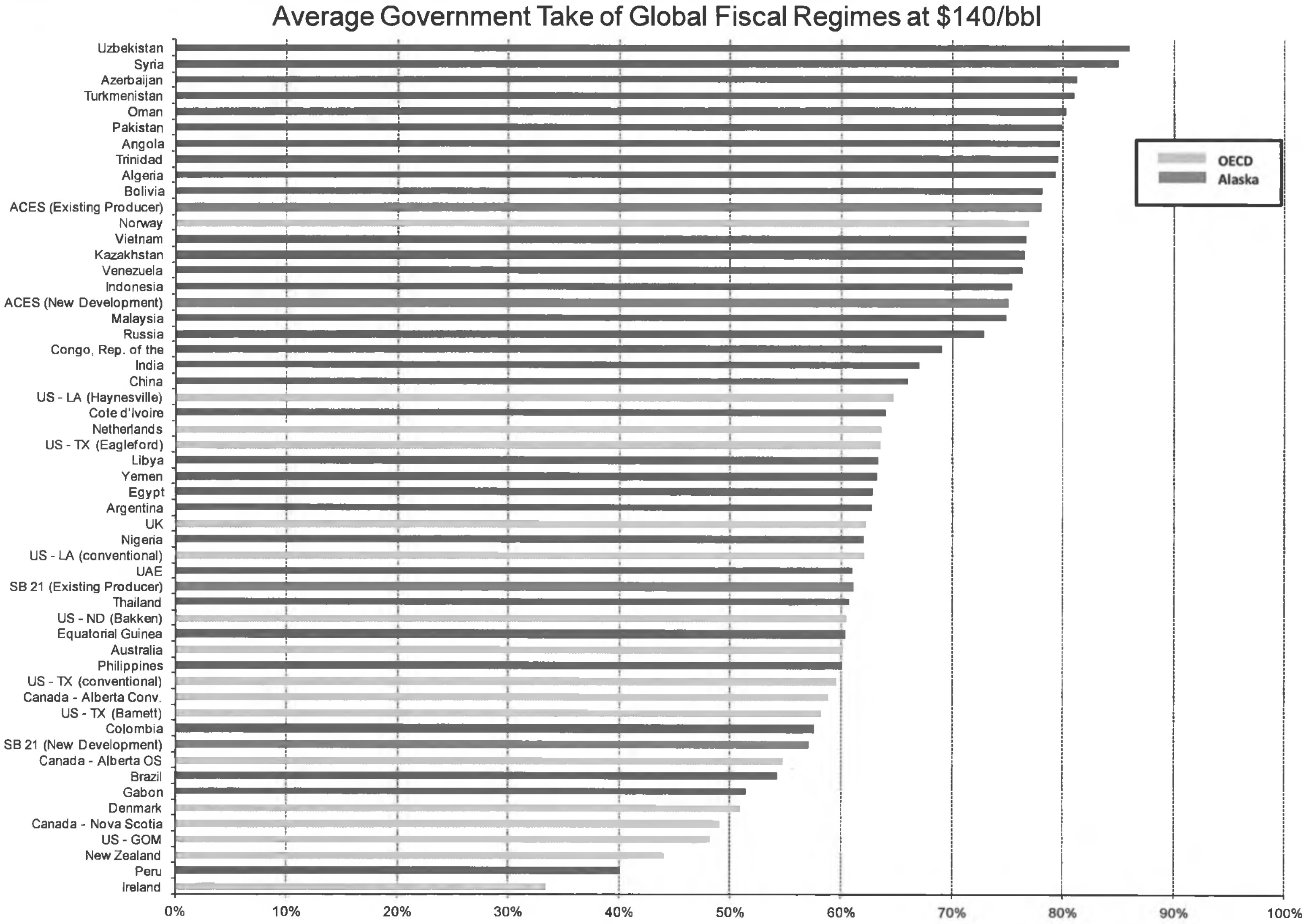


Regime Competitiveness: Average Government Take at $120/bbl



PFC Energy

Regime Competitiveness: Average Government Take at $140/bbl



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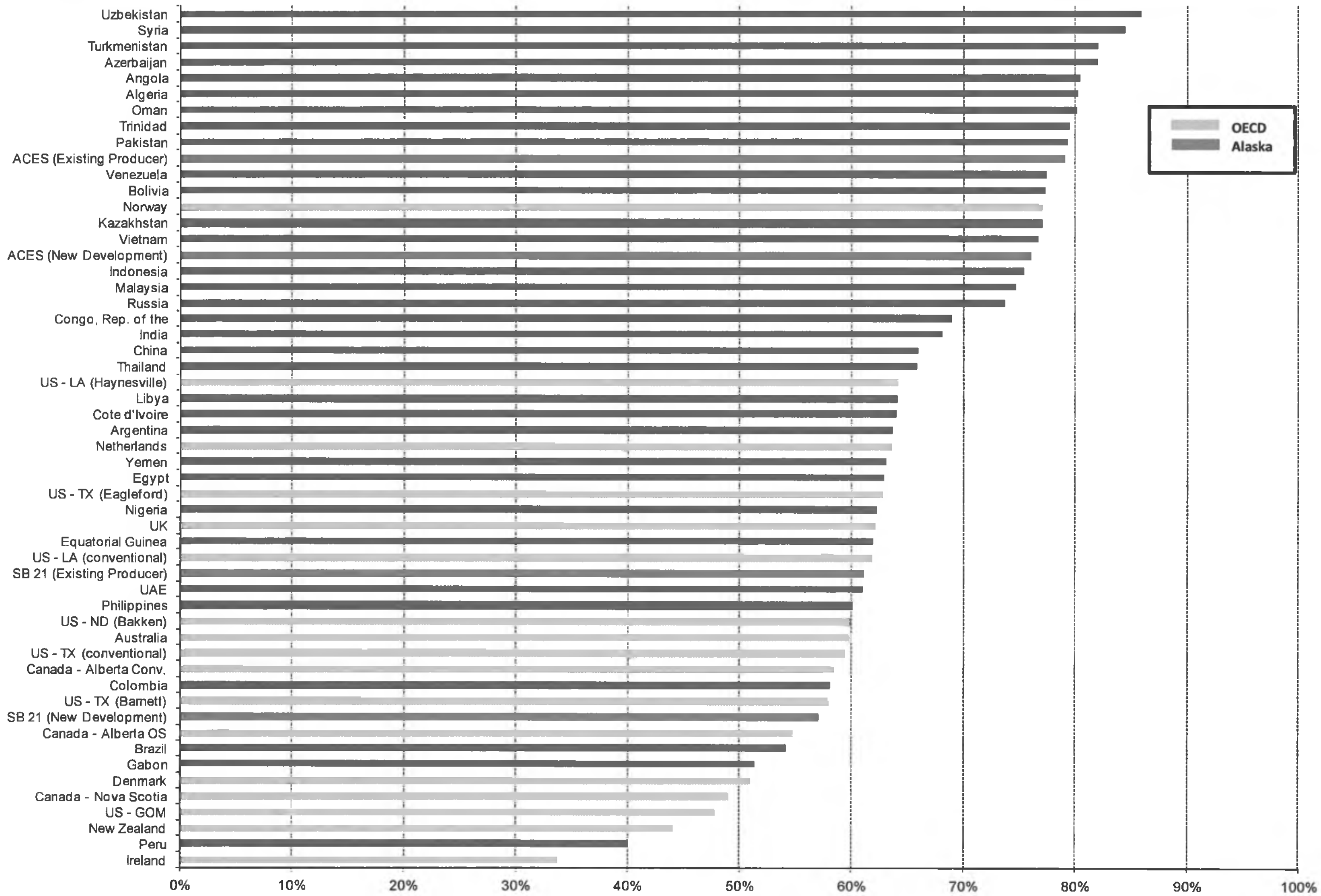
Regime Competitiveness: Average Government Take at $160/bbl

Average Government Take of Global Fiscal Regimes at $160/bbl



PFC Energy

SB21 Prog – Existing Production – Government Take

Includes .01% Progressivity from $30 PTV/bbl to maximum of 35%

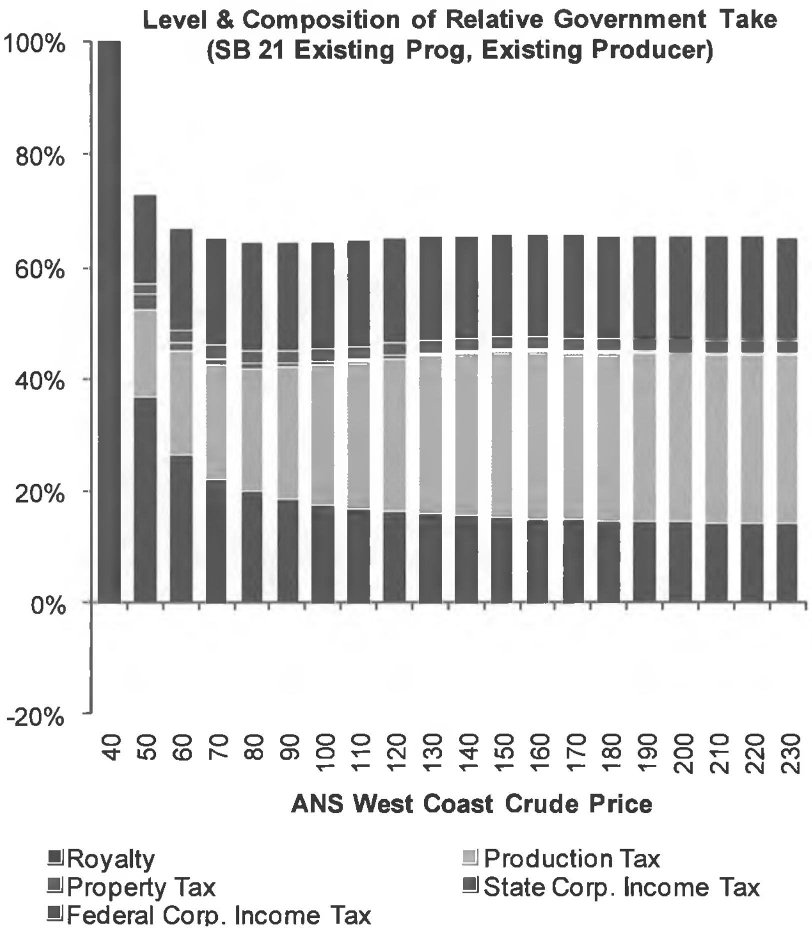


Table 1: Level & Composition of Relative Government Take (SB 21 Existing Prog, Existing Producer)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	104%	21%	11%	1%	**137%**	7%	**144%**
50	37%	16%	3%	2%	**57%**	16%	**73%**
60	26%	18%	2%	2%	**49%**	18%	**67%**
70	22%	20%	1%	2%	**46%**	19%	**65%**
80	20%	22%	1%	2%	**45%**	19%	**65%**
90	19%	23%	1%	2%	**45%**	19%	**64%**
100	18%	25%	1%	2%	**45%**	19%	**65%**
110	17%	26%	1%	2%	**46%**	19%	**65%**
120	16%	27%	0%	2%	**46%**	19%	**65%**
130	16%	28%	0%	2%	**47%**	19%	**66%**
140	16%	29%	0%	2%	**47%**	19%	**66%**
150	15%	29%	0%	2%	**47%**	19%	**66%**
160	15%	30%	0%	2%	**47%**	19%	**66%**
170	15%	30%	0%	2%	**47%**	19%	**66%**
180	15%	30%	0%	2%	**47%**	19%	**66%**
190	15%	30%	0%	2%	**47%**	19%	**66%**
200	15%	30%	0%	2%	**47%**	19%	**66%**
210	14%	30%	0%	2%	**47%**	19%	**65%**
220	14%	30%	0%	2%	**47%**	19%	**65%**
230	14%	30%	0%	2%	**47%**	19%	**65%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

SB 21 Prog – New Development – Government Take

Includes .01% Progressivity from $30 PTV/bbl to maximum of 35%

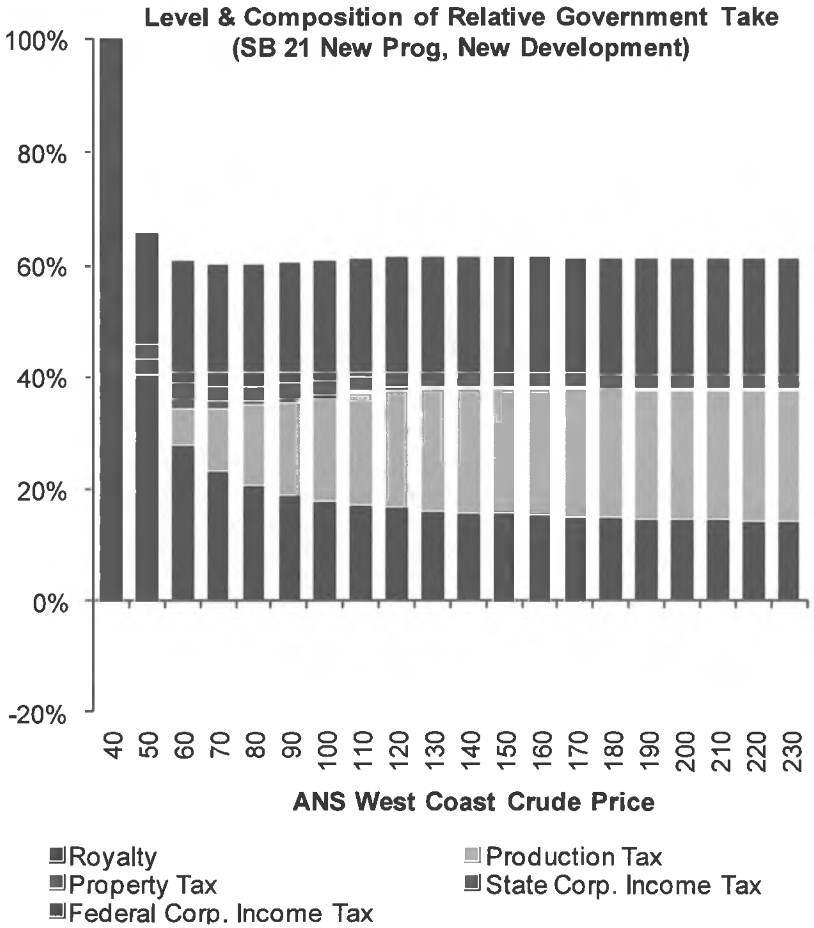


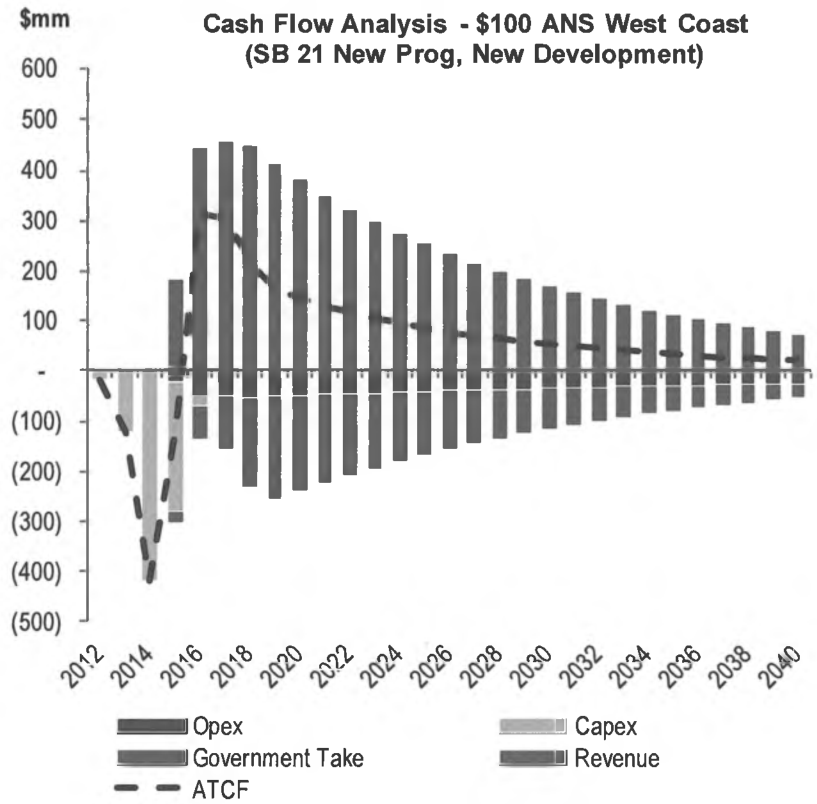
Table 1: Level & Composition of Relative Government Take (SB 21 New Prog, New Development)

Price	Royalty	Production Tax	Property Tax	State Corp. Income Tax	**Total State Take**	Federal Corp. Income Tax	**Total Govt. Take**
40	155%	0%	16%	0%	**170%**	0%	**170%**
50	40%	0%	3%	2%	**46%**	20%	**66%**
60	28%	7%	2%	3%	**39%**	22%	**61%**
70	23%	11%	1%	3%	**38%**	22%	**60%**
80	21%	14%	1%	3%	**38%**	22%	**60%**
90	19%	16%	1%	3%	**39%**	22%	**61%**
100	18%	18%	1%	3%	**39%**	21%	**61%**
110	17%	20%	1%	3%	**40%**	21%	**61%**
120	17%	21%	0%	2%	**41%**	21%	**62%**
130	16%	22%	0%	2%	**41%**	21%	**62%**
140	16%	22%	0%	2%	**41%**	21%	**62%**
150	16%	22%	0%	2%	**41%**	21%	**62%**
160	15%	22%	0%	2%	**41%**	21%	**61%**
170	15%	23%	0%	2%	**40%**	21%	**61%**
180	15%	23%	0%	2%	**40%**	21%	**61%**
190	15%	23%	0%	2%	**40%**	21%	**61%**
200	15%	23%	0%	2%	**40%**	21%	**61%**
210	14%	23%	0%	2%	**40%**	21%	**61%**
220	14%	23%	0%	3%	**40%**	21%	**61%**
230	14%	23%	0%	3%	**40%**	21%	**61%**

Figures reflect percentages of divisible income, and sum horizontally to Total Relative Government Take (undiscounted)

SB 21 Prog – New Development – Cash Flow Analysis

Includes .01% Progressivity from $30 PTV/bbl to maximum of 35%



Price	NPV12	NPV/Bbl	IRR
40	(316)	(6.31)	-1.6%
50	(177)	(3.53)	4.9%
60	(66)	(1.33)	9.4%
70	27	0.55	13.1%
80	114	2.28	16.4%
90	196	3.92	19.5%
100	273	5.47	22.3%
110	348	6.95	25.0%
120	421	8.41	27.6%
130	494	9.87	30.0%
140	570	11.41	32.5%

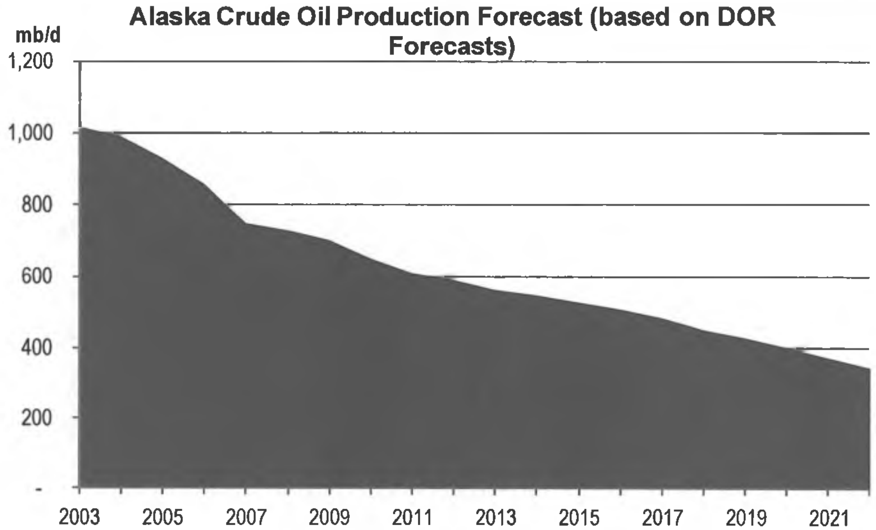
PFC Energy

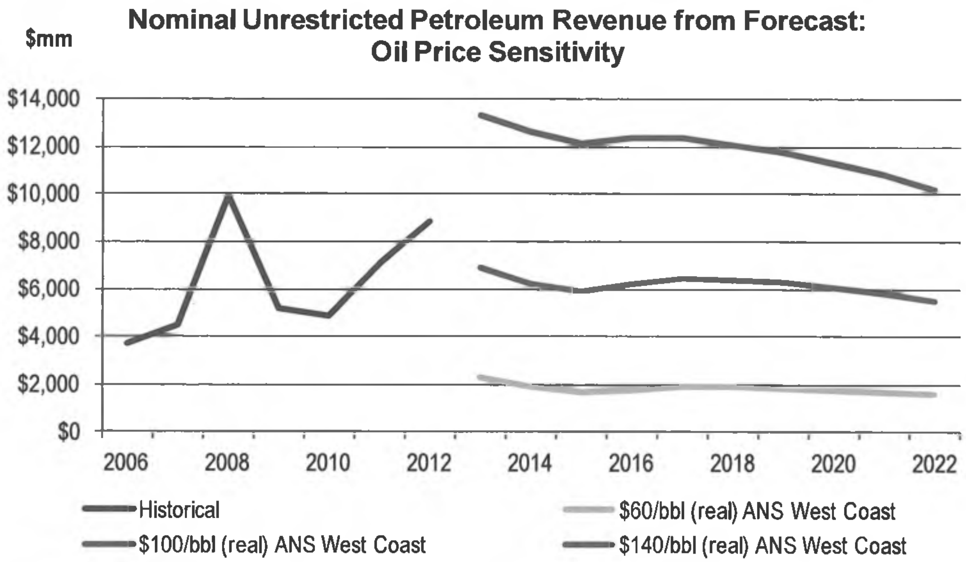
Credits and Deductions

- Current credit system necessary in ACES to offset high government take, but introduces numerous distortions and unintended consequences
- In low price environments, or in the case of significant success attracting new producers to the North Slope, poses significant cashflow risk to the state
- Eliminating 20% capital credit may pose greater issues for smaller, more capital-constrained producers
- If capital credit were to be retained in some form, may be desirable to end ability to claim directly from the state
- While some further targeting of credits may be possible, often difficult to differentiate between maintainance and development spending
- Limiting deductions – for instance in the case of pipeline tariff – also likely to be problematic – added complexity for little gain

Alaska's Future Petroleum Revenues: Sensitivities to Oil Price, Production Decline, and Fiscal Terms

Oil Price is the Major Determinant of Alaska's Future Petroleum Revenue





- The major factor determining Alaska's future petroleum revenue is not oil & gas fiscal terms, or even, in the short run, production levels, but rather something entirely outside Alaska's control: the crude oil price
- Restricting a sensitivity analysis only to the a range of oil prices observed in the last 5 years, and **holding future production constant** (based on DOR forecasts) the potential variation in possible future petroleum revenue is substantial:
  - In a $140/bbl environment, revenue in 2022 under ACES would approach $10bn
  - In a $60/bbl environment, revenue in 2032 under ACES would be as low as $1.8bn

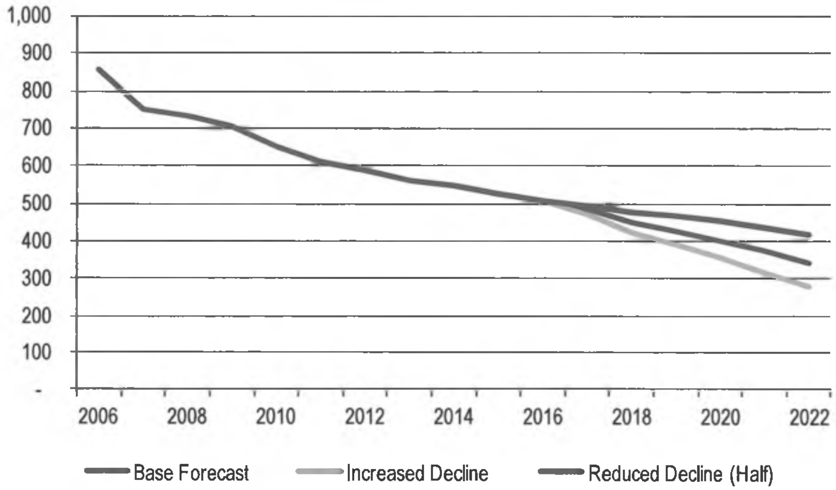
In reality, the potential for variation is even greater than this, since production also responds to price:

- In a sustained high price environment, more projects would be economic, and long-run production would improve
- In a sustained low price environment, fewer projects would be economic and sustaining capital would be lower, resulting in a more rapid decline in long run production

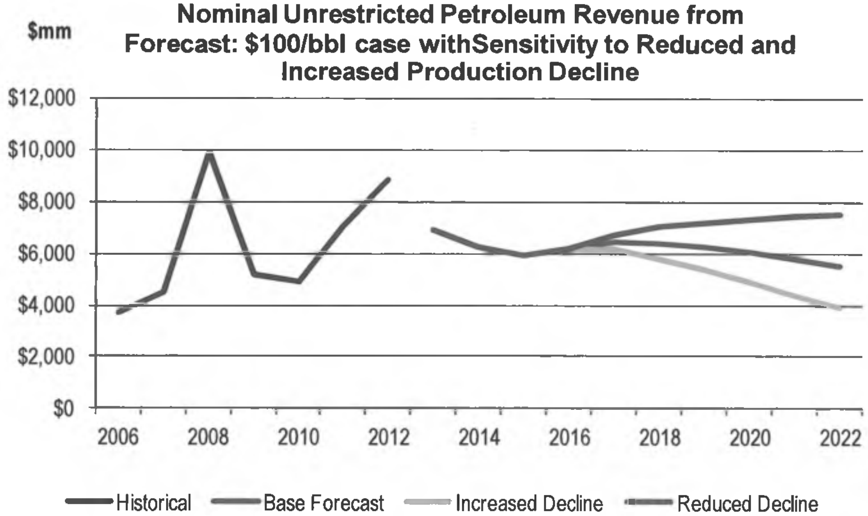
PFC Energy

Decline Rate is the Other Major Determinant

Alaska Crude Oil Production Forecast: Base, Reduced and Increased Decline Cases

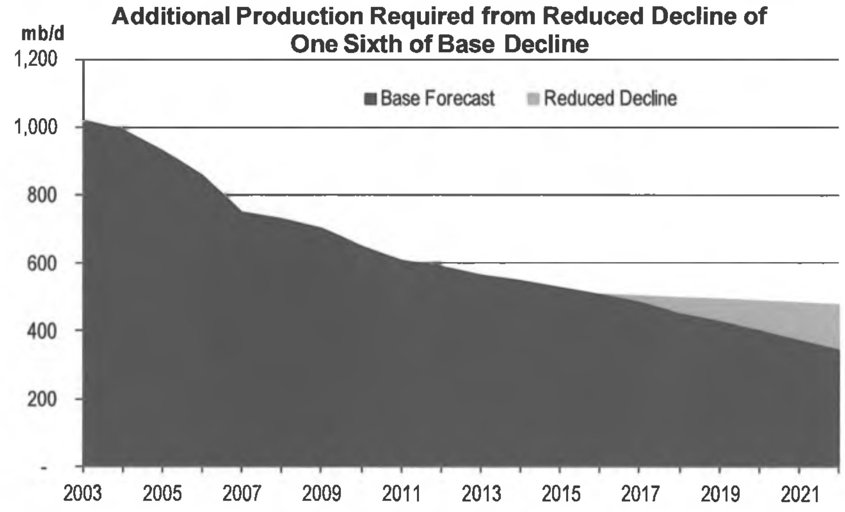


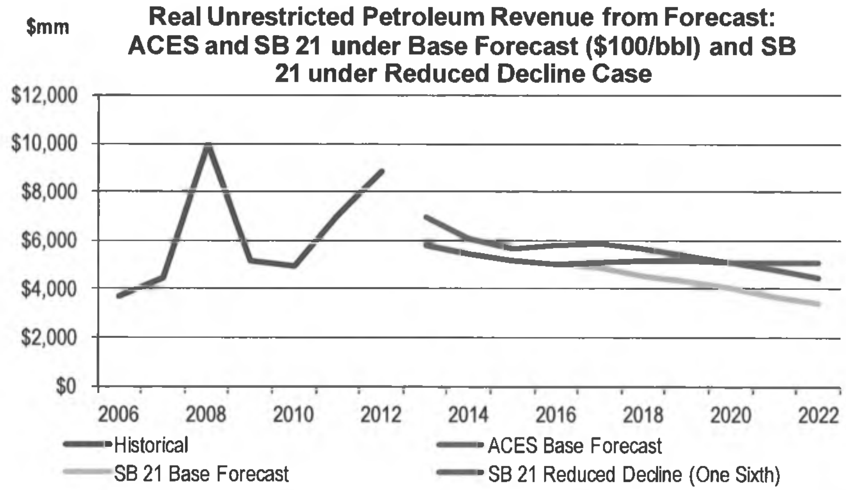
Nominal Unrestricted Petroleum Revenue from Forecast: $100/bbl case withSensitivity to Reduced and Increased Production Decline



- The Base Forecast anticipates an average annual production decline between 2017 and 2022 of **~6%** (including the contribution from new producing areas brought on-stream), yielding production of ~344 mb/d in 2022
- Increasing the average decline rate by half to **9%** in every year from the base case would see production declining to ~280 mb/d in 2032
- Reducing the average decline rate by half to **3%** in every year from the base case would see production of ~419 mb/d in 2032
- In the low decline scenario, more robust production combined with the impact of inflation mean that nominal revenues would continue to grow beyond 2017, reaching ~$7.8 bn at a nominal crude price of $100/bbl
- In the high decline scenario, 2022 nominal revenues would fall well below the $4 bn level anticipated in the Base Forecast case, reaching less than ~$4 bn even with nominal crude prices at $100/bbl

Fiscal Terms Changes and Investment Impacts



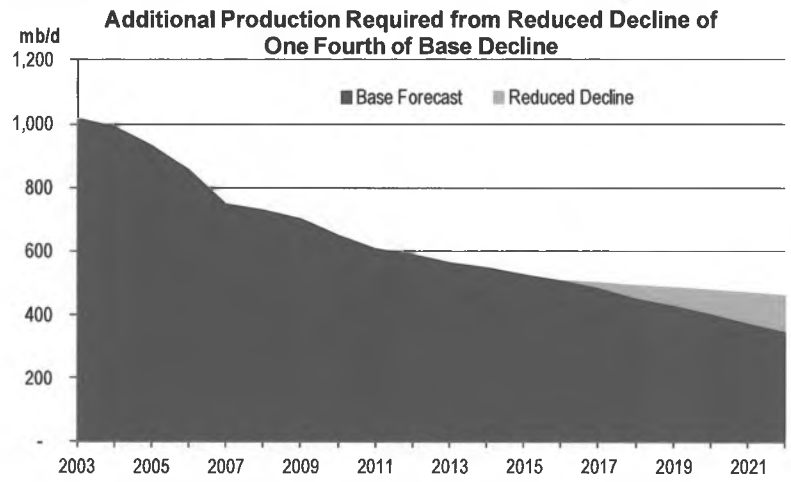


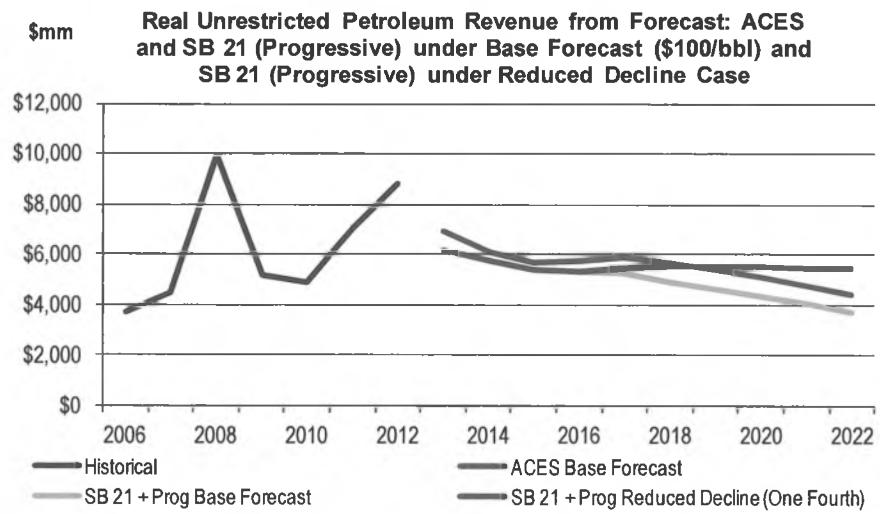
- Even significant changes to fiscal terms, by contrast, have a far smaller impact on future revenues than either oil price or future production declines
  - Under the Base Forecast decline case, at $100/bbl crude oil, SB 21 results in a parallel shift of the revenue curve, reducing the state's petroleum revenue by a little over $1 bn each year
- If an improvement in fiscal terms can stimulate sufficient new investment to stem declines, it has the long run potential to increase revenue, despite the near-term cost of the change
  - To maintain revenues to the state at a steady level in real terms, a reduction in government take such as that under SB 21 would need to spur sufficient investment to **reduce the North Slope base decline from 6%** as currently forecast **to 1%**

Year	2017	2018	2019	2020	2021	2022
Additional Production (mboe/day)	20	48	66	88	111	133

PFC Energy

Fiscal Terms Changes and Investment Impacts





- Re-introducing 0.1% progressivity into SB 21 (to a maximum of 35% Production Tax) would require lower additional production post 2017 to be revenue neutral.
- To maintain revenues to the state at a steady level in real terms, a reduction in government take such as that under SB 21 with 1% progressivity would need to spur sufficient investment to **reduce the North Slope base decline from 6%** as currently forecast **to 2%**

Year	2017	2018	2019	2020	2021	2022
Additional Production (mboe/day)	18	43	59	78	99	118

Fiscal Terms Changes and Investment Impacts

	Year	2017	2018	2019	2020	2021	2022
Incremental Additional Production (mboe/day)	SB 21	-	28	18	22	23	22
	SB 21 + Progressive	-	25	16	19	21	19

- The table shows incremental production needed to added every year for SB21 and SB21 (w/progressivity) regimes.
- SB21 (w/progressivity) would require marginally fewer investments and leads to earlier revenue neutrality

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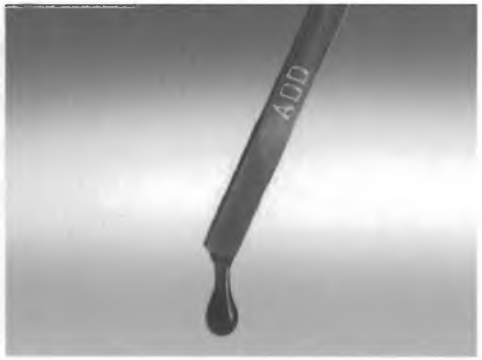
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable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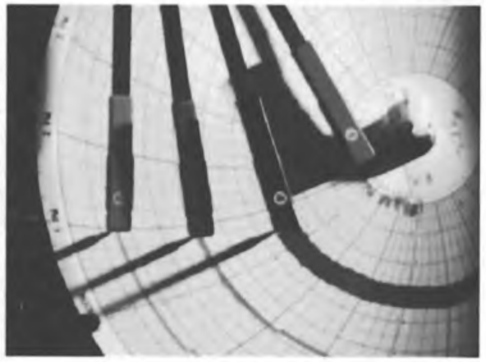
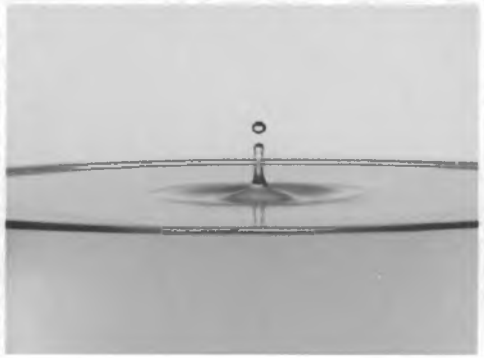




PFC Energy

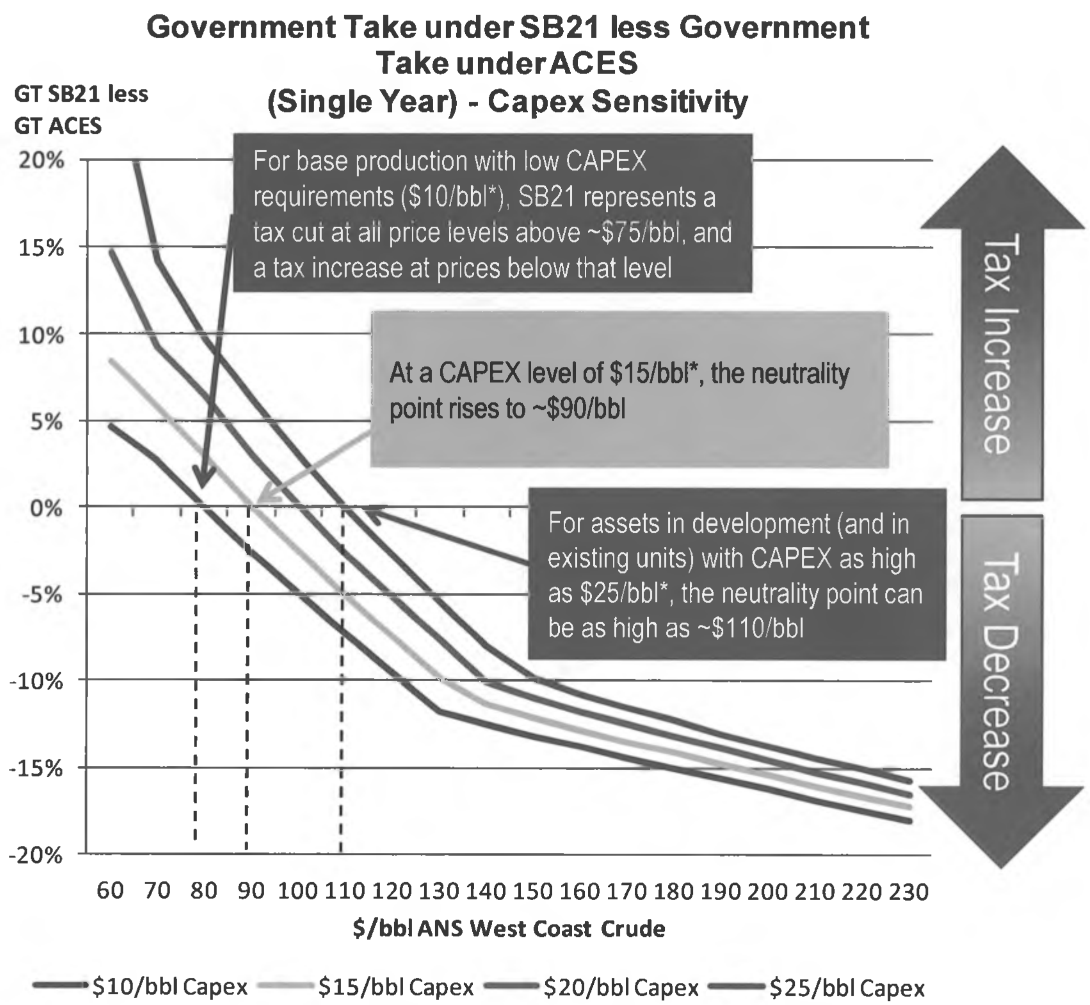
Senate TAPS Throughput Committee

Supplementary Slide to January 31 Presentation

February 4 2013

Janak Mayer
Manager, Upstream
PFC Energy

Government Take under SB21 and ACES – Capex Sensitivity



** All CAPEX figures are in gross bbl terms ($15 per gross bbl is roughly equivalent to DOR 2014 average North Slope forecast of $19.6 per bbl net of royalty, when adjusted for gross/net and for capital expenditures by non-taxable entities)*

- As noted in PFC Energy testimony on 1/31/13, at low oil prices, Relative Government Take under SB 21 is higher than under ACES, due to the impact of low or no progressivity, combined with the elimination of the 20% capital credit under SB 21
- The **oil price level** at which this occurs is highly **sensitive to annual levels of capital spending**, since CAPEX both reduces the oil price level at which progressivity kicks in under ACES, and determines the size of the available capital credit under ACES
- Looking at a **single year of production** also slightly raises this neutrality point, since over many years, inflation reduces the real price level at which progressivity starts under ACES
- For mature, producing assets with a low ongoing CAPEX requirement ($10/bbl), SB21 represents a **reduction in government take at prices below ~$75**, however for capital intensive new developments in existing units, that neutrality **point can be as high as $110/bbl**
- It is thus important to understand that one impact of the removal of the 20% capital credit under SB 21 is that for companies with high development costs relative to overall production, it **can represent a tax increase at current prices**

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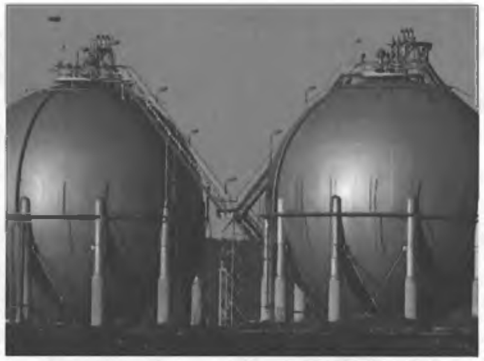

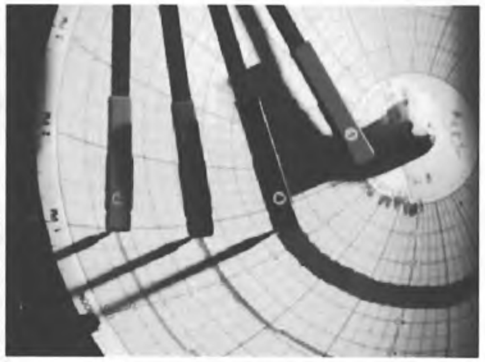

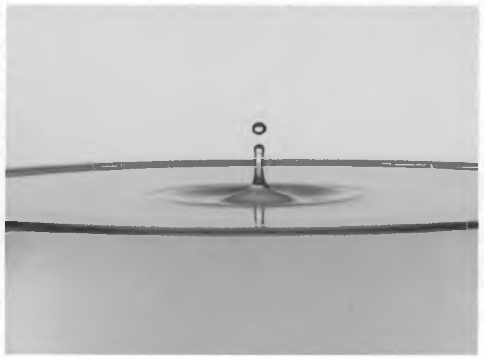

PFC Energy

3521 Andree Dr.
Anchorage, AK 99517

February 4, 2013

RE: Testimony to Senate Special Committee on TAPS Throughput on SB 21

Co-Chairs Micciche and Dunleavy and Senators on the Committee:

My name is Peter J. Stokes a professional petroleum engineer working for Petrotechnical Resources of Alaska.

Thank you for your service and for letting me and other members of the public testify on this important piece of oil tax reform that is needed to increase investment and new production in Alaska.

I live and work in Anchorage. I am on the Board of the Alliance and Chair of the University of Alaska CEM Advisory and Development Council.

I am testifying on behalf of myself, my 3 offspring who work in Anchorage and 2 grandsons and their future.

I grew up on the Kenai Peninsula, went to college in Fairbanks and have worked in oil and gas, starting in Alaska, with jobs in other states and overseas and working for the last 10 years in Anchorage.

I support the Governor's concepts to make Alaska more competitive in attracting increase investments to increase Alaska North Slope production and I urge passage of legislation to make meaningful reforms this year.

Senate Bill 21 is a good start to achieve this goal, but modifications should include:

1) Allow small explorers to continue to sell loss credits generated from exploration prior to production. Taking away this ability will negatively impact those that are currently exploring as it will change the terms which were used to attract exploration funding, it will significantly increase the cost of exploration, and in the unsuccessful case will mean that credits are not redeemable, thus changing the economic risk and rewards of exploration in Alaska.
2) Incentivize development within existing PA's by having the DNR determine a baseline decline for existing production. Any new production above this baseline will be eligible for GRE credit.

Without new exploration and the continued development of new oil within existing PA's, the efforts to increase production into TAPS will likely be reduced.

In summary, I urge you to allow Alaska to become more competitive in investments for new oil production for both explorers and existing producers.

Chairmen and Senators, thank you again for all of your efforts.

I represent the Alaska Trucking Assn. and our members in the transportation industry. Our members are known for their common sense approach, a hard work ethic and a fearless attitude in dealing with the all the obstacles that travel in Alaska brings.

We are extremely concerned with the declining oil production and the flow of TAPS. Alaska has been fortunate to have a projected 20 year pipeline now on it's 35th year. Because of that maintenance is what is currently driving much of the North Slope activity.
Increased production will ensure Alaska a stable future, with dependable state revenue, a growing economy, and profitable producers and support companies.

We agree with the Governor that a new tax plan should be simple and stimulate new production.

We must act now to keep Alaska competitive in what is now a world market. We have the resources. Now is the time to use forward thinking and creative ideas to take control of our future.

We believe that what we do now will set the standard of how business can be done with Alaska. If we get this right, the basic business model will be in place to also attract other development in natural gas, shale gas and oil, and mining. Our resources are our future and we should be in control without federal regulatory overreach.

The tax reform issue has been on the table for three years. We urge you to get a plan done and let's get back to work.

Jim Scherieble
Kenworth Alaska

Lynne Smith

From: Ken Caron <kcaron@gci.net>
Sent: Thursday, January 31, 2013 7:47 AM
To: Sen. Peter Micciche
Subject: Message concerning oil and gas production from concerned citizen

Dear Senator Micciche,

I missed the public hearings held at statewide Legislative Information Offices (LIOs) last Tuesday I would like to make the following comment:

The decline in oil production and the dwindling flow of oil through the Trans Alaskan pipeline is alarming to me. It appears the current legislature has failed to make any headway on increasing the production of State owned oil. Our Governor has a new idea that I believe could stimulate the production of oil on the North Slope, and possibly gas reserves as well. If the legislature hasn't been able to get the job done, please try something new. Give the Governor and (his advisors) a chance to prove their point. It's shortsighted to believe the oil producers won't increase production. If the lower tax levels (for the producers) fail to create greater revenue from increased oil flow or even if the revenue remains the same at least there will be jobs.

The oil companies produce jobs and community income, not just oil & gas products. Thank-you.

Ken Caron – Anchorage / Girdwood

Senate Special Committee on TAPS Throughput
SB 21: Oil & gas production tax.
January 31, 2013
Testimony by Pamela Brodie, P.O. Box 1139, Homer AK 99603 Pamela Brodie

On one side, we hear that we must "fill the pipeline." On the other, we hear that cutting oil industry taxes may do nothing to increase oil production, but it will drastically damage the state's ability to educate our young people and provide necessary services, and may lead to an income tax.

In the late 1980's we had a full pipeline, and oil sold for $10/barrel. Now it sells for around $120/barrel. Yes, those were desperate times -- but what a catastrophic waste of Alaska's precious, limited supply of natural resources to have sold off the maximum possible amount of oil at such a low price.

Oil prices are likely to rise further in the future. We should all be able to agree that the State of Alaska's goal in managing the sale of our limited supply of fossil fuel should be to *maximize total revenue to the state over the life of the supply of that fuel.* We should be able to agree that Alaskans will need the revenue in the future, and we should not use the oil up as fast as possible.

I understand that there must be a minimum flow. I understand that there are increased maintenance costs to a low flow of oil -- but those costs may be worth it. I understand that the calculations are complicated and that the facts and numbers may be in dispute. But we are certainly not going to do the right thing for the state if our goal is to "fill the pipeline," regardless of whether it makes long term economic sense to do.

Every administration is focused on the short term. They have to be. We must depend on the Legislature to protect our interests for the long term.

If the oil companies would increase the pumping of oil in response to a tax cut like SB21, they would tell us so. It would be in their interests to tell us this. But they don't. This is a mighty good indication that they won't. Even it they do increase pumping, it might not be enough to compensate for the lost revenue to the State from cutting taxes. A billion dollars/year or more is an awful lot to compensate for. And once that oil is sold at $120/barrel, it won't be around to sell when the price has risen to $200/barrel or more.

It seems to me extremely unlikely that SB21 is even in the short term interests of the people of Alaska, and almost certainly not in our long term interests. *Please vote against SB 21.* Thank you.

January 30, 2013

Respectfully submitted to the Alaska State Senate regarding SB21

I would like to express my opposition to the passage of SB 21. I do not feel that money should be gambled away from the State's coffers with no promise let alone guarantees that we as a people have purchased anything. We stand to be in the RED from this give away instead of earning the taxes due us to purchase education, health care and general prosperity. If the oil companies earned over 10B here in the state last year, they are not suffering , and if they are they are mismanaged.

ACES was developed as a fair exchange for the use of the oil product we have to sell. It is irresponsible to give away our assets without having anything to show for it. If we are to purchase something, purchase it, pay for it and get it. Do NOT throw it down a bottomless pit to be received at the other end with no recompense.

It is irresponsible to take a budget for a state that has assets and put it into the RED in order to gamble it away into the breeze. Our money should be managed not gambled with.

Mary J Toutonghi

Mary J. Toutonghi,

Soldotna, AK.

-------- Original Message --------
Subject: SB 21
Date: Wed, 30 Jan 2013 11:20:13 -0900
From: Margo Waring <margowaring@ak.net>
To: Senator.Peter.Micciche@akleg.org

Dear Senator,

Please do not support Governor Parnell's Oil Tax bill, SB 21.

I was schooled on this issue when working for Governor Hammond when it was clear that maximizing resources' benefit to Alaskans was more important than oil companies' profits. I also worked for the legislature when the state income tax was repealed. The state's return on oil and the state income tax are historically connected. I believe that SB 21 will have the effect of returning the state income tax as a way to boost revenues lost to oil companies' pockets.

Revenues will fall under SB 21because it eliminates progressivity. This will deprive Alaskans of a fair share of oil revenues, especially when prices rise, as every forecast predicts. For example, in FY'14, this change alone would cost Alaskans $1.6 billion at $110/barrel oil as forecast, $2.4 billion at $120/barrel oil, and $4.1 billion at $140/barrel oil.

Revenues will fall under SB 21 because of the 20% gross revenue exclusion on new oil, creating exceptionally and historically low rates, especially on legacy fields. Under SB 21 the production tax rate for "new" oil would be about 17-18%, slashed from about 40% today. Additionally, the gross revenue exclusion applies to projects in Prudhoe and Kuparuk where infrastructure was paid for long ago and profits are historically high.

Revenues to the state will fall under SB 21 because it removes the 20% capital credit incentive to investment in Alaska and discourages smaller producers/investors who might boost production.

In summary, SB 21 would so significantly reduce revenues that the state will be hard pressed to fill the gap, setting the stage for the return of the income tax and other revenue measures to support state services.

Sincerely,
Margo Waring
11380 N. Douglas Hwy.
Juneau, AK. 99801

Lynne Smith

From: D. Robbins <drobbins.r@gmail.com>
Sent: Wednesday, January 30, 2013 1:03 AM
To: Sen. Mike Dunleavy; Sen. Peter Micciche; Sen. Anna Fairclough; Sen. Lesil McGuire; Sen. Berta Gardner
Subject: RE: SB 21 Oil and Gas Production Tax Cuts

Senators,

RE: SB 21 Oil and Gas Production Tax Cuts

It goes without saying that I know very little about the oil industry. What I do recognize is that SB21 appears to reduce any responsibilities for the oil industry to pay their share of expenses for a product owned by the people of Alaska. We give back to them and expect nothing in return; or at least any expectations that we might have of them are not stated in SB21. That is not sound business sense.

We "repeal this" and we "repeal that" and what do we ask in return? Not a word is mentioned that I can find about "if we do this, then you agree to give us that." We would be seen as fools to make such a deal.

Expectations of what Alaska might stand to benefit from the policy changes outlined in the bill are never mentioned. "We give you this and that, or "forgive this and that tax," and we have no reciprocal expectations.

If I was a grocer and I opened my shop doors for customers but had no one manning the cash register, or prices were unmarked on items I would be out of business in a few days. In Alaska's case, our coffers would soon be bare and our people would be out in the cold.

We are not taking care of our needs now. We continue to flat fund education as the inflation rate rises, resulting in a net cut for education dollars. Our standing in education funding and achievement is not acceptable, but apparently the governor can't seem to figure out that reduced funding, or reduced "take" in oil jargon, has any bearing in that area. He has a heart for multinational oil companies but not for Alaska's children.

There has to be a more sound way for Alaska to do business.

Sincerely,

Doris Robbins

1281 Overhill Dr.
Fairbanks, AK 99709-6753
(907) 374-0597
drobbins@gci.net

--

Lynne Smith

To: LIO Kenai
Subject: RE: Opposition to SB 21

From: Michele Vasquez [mailto:michele.s.simmons@gmail.com]
Sent: Tuesday, January 29, 2013 6:41 PM
To: LIO Kenai
Subject: re: Opposition to SB 21

Hello:

I am unable to attend to public testimony on SB 21, but I want to submit my statement of opposition for the record.

I strongly oppose the governor's bill, SB 21, that would give more tax cuts to oil companies that currently drill or want to drill for oil in Alaska. There is no reason to offer an "incentive" to a company to drill Alaska's oil unless there is an expectation of gain by one or more of our elected officials in terms of political support. We Alaskans don't need to give away our precious oil resource by offering hefty tax cuts to greedy oil companies that make billions in profit and pose such a high risk to the environment in our state. The oil is here; if a company wants to drill it, fine; but it must do so under ACES. Where is the guarantee of an increase in production for such lavish tax cuts? There is no such guarantee. Reject and oppose this outrageous giveaway to oil companies by voting against SB 21.

Sincerely,
Michele Vasquez
Soldotna, AK
907-420-0658

STATE of ALASKA

Bethel Legislative Information Office

PO Box 886
Bethel, Alaska 99559
(907) 543-3541
Fax- 543-3542

Written Testimony for the Record:

TCN: 7887 Committee: STTP

Date: 1/31/2013 Bill Number(s): SB 21

Subject(s): Oil Tax

Please enter my testimony into the record.

Fritz Grenfell
Testifer's name (s):

Representing (opt.)

P.O Box 1427, Bethel, AK 99559
Address

465-4779
Phone

LIO Bethel

From: Fritz Grenfell <fritzgrenfell@yahoo.com>
Sent: Thursday, January 31, 2013 10:13 AM
To: LIO Bethel
Subject: tele conf

i feel the oil companies are holding us hostage, lower taxes more oil in pipe why don' we build a refinery in fbks take our % off and get on with bussiness, fuel is holding us back fritz grenfell pob 1427 bethel ak

Lynne Smith

From: Deanna Geary <truckin_mama@hotmail.com>
Sent: Thursday, January 31, 2013 7:42 PM
To: Lynne Smith
Subject: HB 72/SB 21

I would like to go on record as a resident of the State of Alaska in regard to HB72/SB21.
I see no evidence that makes a correlation between the slow down in getting oil to market and the tax rate that the oil companies now enjoy here in Alaska. In fact, the amount of profits that are reported by the oil companies operating in Alaska prove that they can, and do enjoy the benifit of our oil. We afford them a safe and secure environment in which to conduct business, that should count as a bonus.
I am against lowering the S.O.A.'s tax rate for oil companies.

Thank You, Deanna Geary

KENAI LEGISLATIVE INFORMATION OFFICE

Email: **Kenai.Lio@akleg.gov**

Phone: **907-283-2030** / Fax: **907-283-3075**

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (Oil + Gas Production Tax)

COMMITTEE & DATE: Senate Special Committee Throughput 1/31/13

First of all, I want to tell you how much I appreciate you hearing my comments about the governor's oil tax proposal. I know it's not easy to be in your shoes right now, so thank you for hearing me out.

With all due respect, the governor's oil tax proposal is starting to feel like that movie, "Groundhog Day." Every day, Phil wakes up to Sonny + Cher's "I Got You, Babe", then he meets dippy Ned + steps into a puddle. Despite his fruitless attempts to escape Groundhog Day, he keeps waking up to find that nothing has changed -- he's trapped in a time loop.

Let me be clear - As an Alaskan, I do not support the governor's proposal. I am trying to get out of this time loop -- the same idea over + over + over + over + over again without any fresh ideas. The same question keeps popping up over + over + over + over + over again: How is the State of Alaska going to make up for the revenue that would be lost if this proposal goes through? This is a question that needs to be answered.

(2)

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Phone: **907-283-2030** / Fax: **907-283-3075**

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (oil + gas production tax)

COMMITTEE & DATE:

It seems like if you were going to give away this much money, you would ask for something in return. Perhaps companies who enjoy such a generous tax break would guarantee in writing that they would hire people who actually live in Alaska year-round. Perhaps they would agree to reduce highly paid top CEO's salaries so that their own Alaskan employees would earn higher wages, thereby allowing more money to filter into our states home-based economy. Perhaps the industry would pledge to create renewable energy jobs in Alaska. Perhaps companies would express gratitude that Alaska is a peaceful + safe place to do business (rather than being a dangerous, war-torn nation).

In any case, you need to re-think this plan. As an Alaskan, I vote no on it. We already have a great plan called Alaska's Clear + Equitable Share. That says it all! The oil + resources belong to **us**, the People.

So, the question is, "Is it morning in America yet?"

③

KENAI LEGISLATIVE INFORMATION OFFICE

Email: **Kenai.Lio@akleg.gov**

Phone: **907-283-2030** / Fax: **907-283-3075**

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (oil + gas production tax)

COMMITTEE & DATE:

No. It's Groundhog Day. Maybe the real question should be, "How long are we going to be stuck here in Groundhog Day, re-living the same experience over + over + over + over + over again?"

In the movie, when Phil figured out how to stop stealing money, seducing women, driving recklessly, + getting thrown into jail. When he used the time to learn how to ice skulpt, play the piano, speak French, save lives, help townspeople, + become a better human being, then + only then was the time loop broken.

You are in very respected positions of government. Please vote no on this oil tax proposal. Go back. Take the time to re-think. What's best for the People of Alaska? If you think keeping ACES is the best, great! I completely agree that it is best to keep ACES. If, after putting some thought into the matter, you come up with another plan, please re-present your proposal. I promise to look at it, listen, think about it, + assess what is best for our state.

KENAI LEGISLATIVE INFORMATION OFFICE

4

Email: **Kenai.Lio@akleg.gov**

Phone: **907-283-2030** / Fax: **907-283-3075**

WRITTEN TESTIMONY

NAME: Kate Veh, Soldotna, Alaska

REPRESENTING: Citizen representing myself

BILL # or SUBJECT: SB 21 (oil + gas production tax)

COMMITTEE & DATE:

Then, as an Alaskan, I will say yes or no. This is how democracy works.

Again, please vote no on SB 21 + have a happy Groundhog Day!!

Lynne Smith

From: Kevin Walker <homerkev@gmail.com>
Sent: Saturday, February 02, 2013 9:50 AM
To: Larry Semmens; Rep. Paul Seaton; Sen. Peter Micciche
Subject: Written Testimony for TTP SB21 Hearing and HB 72

Alaska must strive to research and develop energy sources to guarantee our energy security for all future generations. Fossil fuels will eventually be depleted, so the Legislature must develop our very abundant renewable resources such as geothermal, tides, wind, hydro, solar, and other renewable sources.

I have not seen any information that would lead me to support SB21. From what I hear and do see, it will cost the state $20 BILLION ($20,000,000,000). That money would probably set us up with alternative energy sources that would be fueled forever. The oil and gas will run out, and leave our kids and grandkids struggling with few developed alternatives. I can't think of any industry in the world that needs government subsidies less than Oil and Gas. Exxon made what, $44 Billion in profits last year? Do you really think they need more money?

I also understand that these bills will cut taxes on oil companies when oil prices are high, and give away $2 billion per year when oil costs $120/barrel and will create a state budget deficit this year.

To develop sustainable energy in Alaska, I strongly support directing State funds towards the development of alternative power projects such as those begun by HEA and ORPC.
http://alaskarenewableenergy.org/wp-content/uploads/2009/11/ORPC-PowerPoint-Nov-14th-Forum.pdf

Please send me information, or direct me to find some common sense that is written for a layman that may show why the Governor would introduce these bills.

Kevin Walker
Homer, Alaska

The Testimony of Jerry McCutcheon

A lifelong Alaskan who fought for Statehood against the Canned Salmon Industry sixty and seventy years ago.

It appears that North Slope Employment will set yet another new record this winter since the construction of TAPS. The growing North Slope employment numbers belie Parnell's allegations about ACES hindering development. ACES with ACES's generous oil tax credits for actual investment is promoting oil and gas development. Development like Alaska has not had since the discovery of Prudhoe Bay.

<u>I don't think those who worked for and passed ACES realize what a marvelous piece work they did for Alaska and Alaska's future when they passed ACES with ACES's very generous oil tax credits for actual investment .</u>

We are Now in the Second Battle for Statehood. Will have Alaskans thrown off the yoke of the Canned Salmon Industry only to take up the yoke of the oil industry?

What is hindering development on the North Slope is the fact that Parnell is trying to take away the oil tax credits for <u>actual</u> investment. One cannot invest and have the Governor out trying to take away the very tax credits on which one is to rely. Several of the small oil companies have said so in the press about the Chenault / Hawker's gasline affects on trying to explore for gas in Cook Inlet.

Bringing gas to Cook Inlet from the North Slope when Cook Inlet has 1.8 trillion cubic feet of proven available gas is just not stupid it is insane. Also there are between 13 and 27 tcf of gas yet to be discovered in the Cook Inlet Basin. DOE, USGS, DNR and others.

ACES should be allowed to run its course for at least a decade without modification unless there is something is glaringly wrong. The only provisions that are needed are further leveling of the playing field for the small oil companies along the lines of Rep. Gara's bill last year, equal access to or new production facilities, TAPS and the Valdez terminal.

Parnell and the republicans are attaching ACES because ACES provides for oil tax credits for the small wildcatter to explore for oil where no one else will go. Parnell wants to change ACES so only those that have production (like the majors) receive the oil tax credits. That eliminates the rank wildcatter and that is very much not in Alaska's best interest. With operation of the law of large numbers and the time value of money Alaska comes out way ahead to gamble with the wildcatter.

Second, a small reservoir may not be worthy of a standalone development, however ACES's oil tax credits allow the developer to capture some multiple of the developer's investment much sooner and progressivity rewards the State for having taken the risk.

Progressivity not only makes those gambles possible but also leads full exploration and production of the oil province. That is one the reasons the majors not only suggested progressivity but also demanded progressivity and oil tax credits druing the Governor Murkowski Administration . Never did the majors wildest dreams think that it would be small oil companies that would capitalize oil tax credits.

The legislature needs to understand that the majors are Elephant hunters and all of the Elephant structures on the Slope were drill decades ago. Elephant hunters do not hunt rabbits; they may take a rabbit if the rabbit is in their backyard.

Alaska not only needs to take bigger share of the risk but also needs start partnering in oil development like Statoil. The Harvard School of Business, business model would very much applaud ACES and taking the risks with the wildcatter. And the Harvard School of Business, business model would strongly suggest that Alaska follow Statoil's lead.

Under Alaska's laws and Constitution there is a duty to produce and it is under those provisions the Governor Murkowski took back Point Thomson. There is 1.8 trillion cubic feet of proven (DNR) available gas in Cook Inlet that is being held off the market to drive up the price of gas.

Theresa Robl

From: Ronald Johnson <rajohnson@alaska.edu>
Sent: Saturday, February 02, 2013 9:27 PM
To: Sen. Mike Dunleavy; Sen. Peter Micciche; Sen. Anna Fairclough; Sen. Lesil McGuire; Sen. Berta Gardner
Cc: Rep. Scott Kawasaki; Rep. Tammie Wilson; Sen. Pete Kelly; Sen. Bill Wielechowski; Gary Miller; drobbins r; Timothy Tilsworth; Jay Dulany; Sam Trivette; Cindy Spanyers; Bob Grove
Subject: SB 21

Three Thoughts re SB 21

1) Pls do a better job of publicizing the off net phone in numbers for public testimony.

2) **Vote no on SB 21**. If you want to change ACES, do it in such a way that industry only gets additional tax breaks after the big players succeed in reducing the rate of decline for the legacy fields. Vague statements ahead of time don't cut it.

3) **Senator Micciche. Recuse yourself** from chairing this committee and voting on legislation that can result in billions of dollars in tax relief to your employer. If what you are doing now is not conflict of interest, I don't know what is.

Pls add this to the public testimony

--
Ron Johnson
Professor Emeritus
Mechanical and Environmental Engineering
Univ of Alaska Fairbanks

2113 Jack St
Fairbanks, AK 99709

Lynne Smith

From: Deborah Brollini <deb_brollini@yahoo.com>
Sent: Thursday, January 31, 2013 6:57 PM
To: Sen. Peter Micciche
Subject: Thank you!

Senator Micciche and TAPS Throughput Committee members,

I want to thank you for taking the time for public testimony, and I appreciate your leadership in reaching out to the public. In addition I would like to thank you for reminding the administration and your consultants that the public is watching and we do not understand terminology. I've been studying oil and gas for five years, and for the first time I will not need a translator this evening to rewatch the PFC presentation today. A huge difference from last session where I needed a tutor.

What I will tell you as someone who is with the public every week... the public blames "big oil" for their high energy costs, and they do not understand how complex our tax structure is, and they are tired of the rhetoric. One thing I hear every week is that we need "a gasline" and that will be our Hail Mary. These Alaskans do not fully understanding that natural gas will never replace oil as a high value revenue source. Your committee has a lot of work to do to find solutions to increasing oil production, and I hope the public will become more informed and engage.

Oil tax reform is a huge decision, and Alaskans from every pocket of this state should have a say. Please do not be discouraged by low public turnout this week. The committee made time to listen, and the public will remember, and they will appreciate the committee's effort.

Regards,

Deborah Brollini, Technical Writer
Alaska Energy Dudes and Divas
Voice: 206-339-7831 | deb_brollini@yahoo.com
http://alaskaenergydudesanddivas.blogspot.com

John Sturgeon - Koncor Forest Product
43 years in timber industry in Ak

During that time I have seen ~~my~~ industry ~~going~~ from a gaint industry in Alaska to the whisper it as today.

At one time Aks timber industry was Alaskas second largest industry generating 10,000 well paying jobs ~~and~~ a billion $'s in revenue. ~~If anyone~~ It was unthingable to us in the timber industry that our decline would be so rapid and so permanant.

Just as the supply of oil in Alaska is not an issue nor ~~was~~ is the supply of timber in Alaska, ~~that can be harvested~~ ~~on a sustained yield.~~ Supply is not the problem.

Infrastructure

Investment climate

The timber industry was wrong when we thought our industry would never all but disappear.

Likewise people who think the oil industry will never go away are wrong.

Once the timber industry declined our infrastructure ~~also~~ disappeared. the businesses such as tire companies, barge services and our skilled workforce moved on. If the oil production declines then infrastructure will also disappear and it will be next to impossible to rebuild it.

And finally even if our timber supply would magically return the investment climate is so bad due to environmental litigation it would be extremely difficult to attract investors.

~~Mat-Su~~ Susitna
State Forest - Goal

- Make timber management a primary use

- Normally State Forest are mandated to manage on a sustained yield basis - However, much of the timber in the Valley is acreage making a sustained yield difficult if not impossible.

Betts Room 105

If ~~a~~ Alaska oil industry doesn't have an attractive investment climate it will have a similar fate.

The go away message is simple —

① It is very possible for the oil industry to leave Alaska if we don't give them an attractive business climate.

② Once the oil infrastructure goes away it will not easily return.

③ And lastly the Timber industry has all but disappeared. Act now to prevent the oil industry from disappearing. Give them a competitive business climate. Give them a competitive tax climate that ~~I support the Gov 4~~ is simple and most important, predictable.

02/05/13 SB 21 - Oil Industry Presenta- tions

<TARGET><BILL>SB 21</BILL><SUBJECT>02-05-13 SB 21 - Oil Industry Presentations</SUBJECT><COMM>STTP28</COMM></TARGET>

AOGA

OIL & GAS:
FUELING
ALASKA'S
ECONOMY

Senate Special Committee on TAPS Throughput

February 5, 2013

Kara Moriarty, Executive Director

Alaska Oil and Gas Association

Purpose

- Serve as single point of contact for Alaskans on the state's oil and gas industry

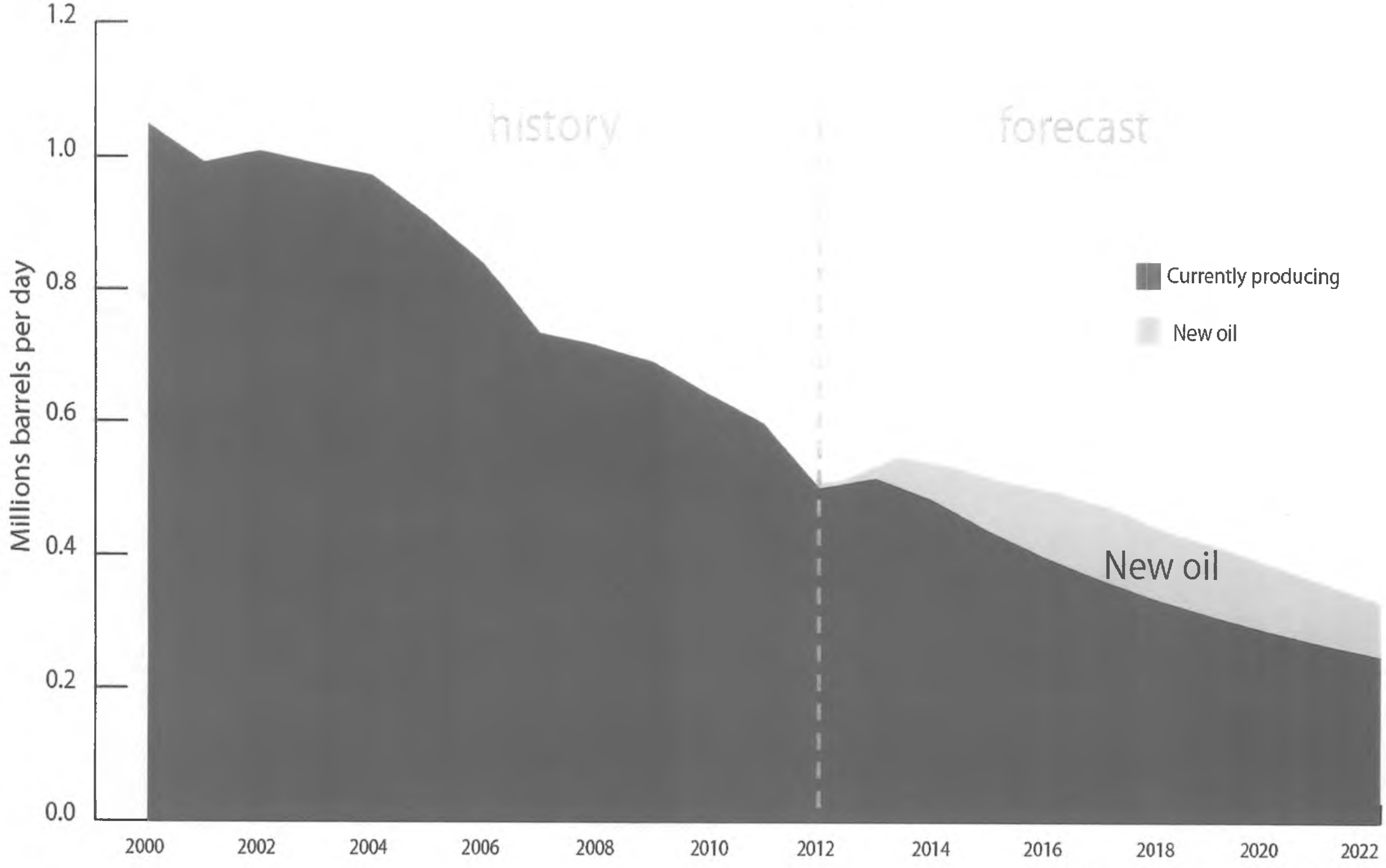
- Provide a forum for discussion and a point of decision on issues that affect the industry

Mission

Long-term viability of the Alaska's Oil & Gas Industry for the benefit of all Alaskans

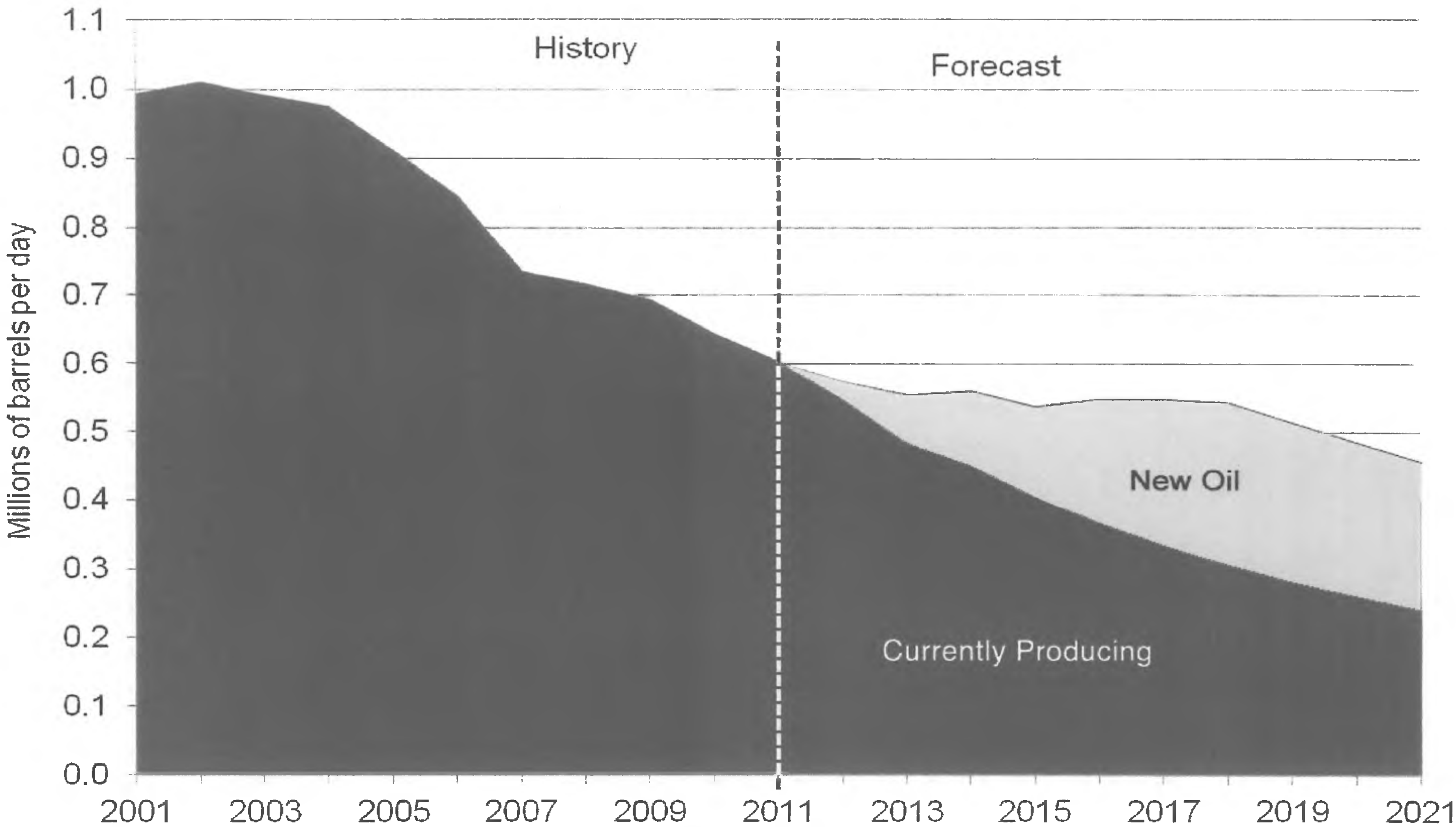
Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



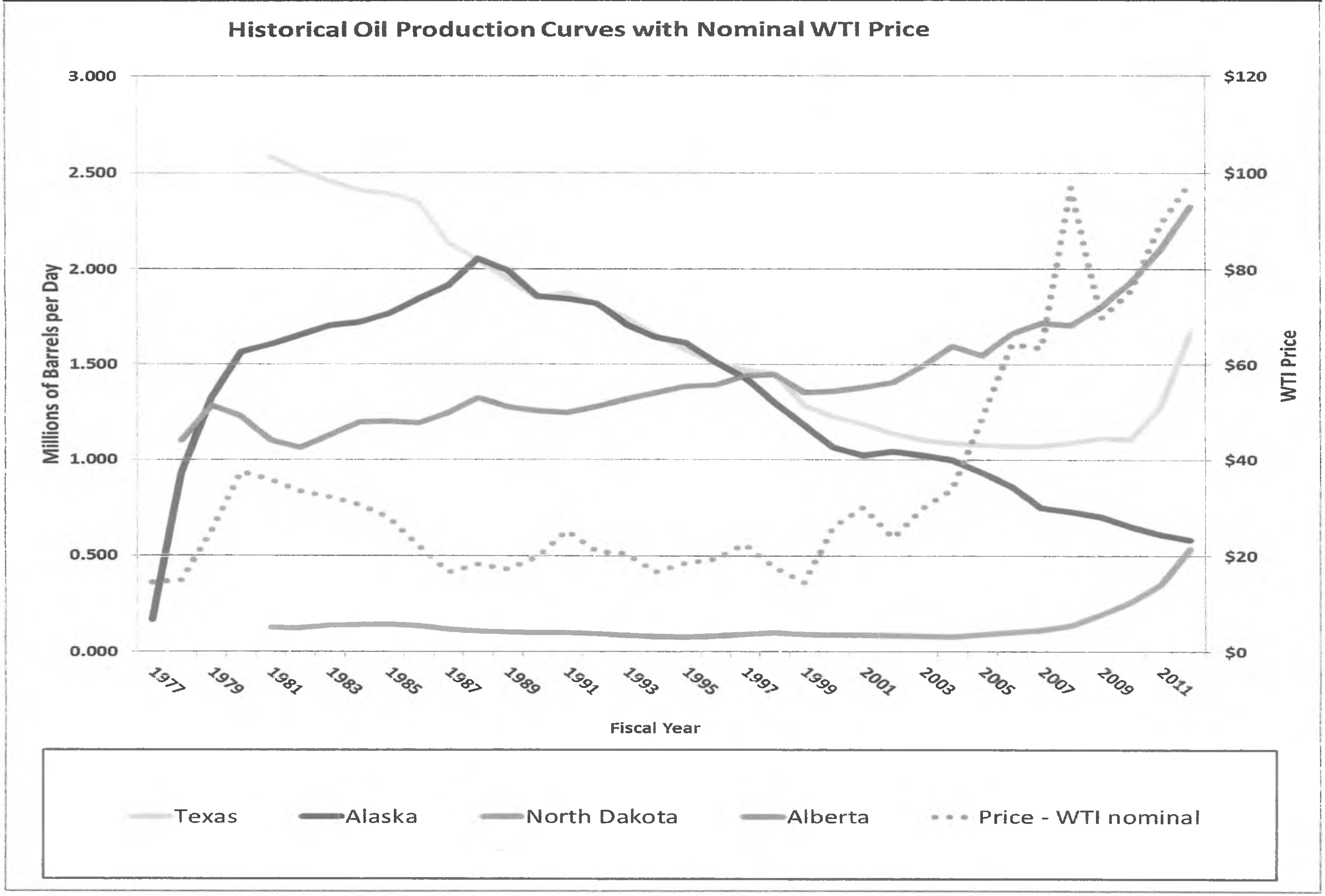
Source: Department of Revenue – Dec. 2012

Production Decline Is Real

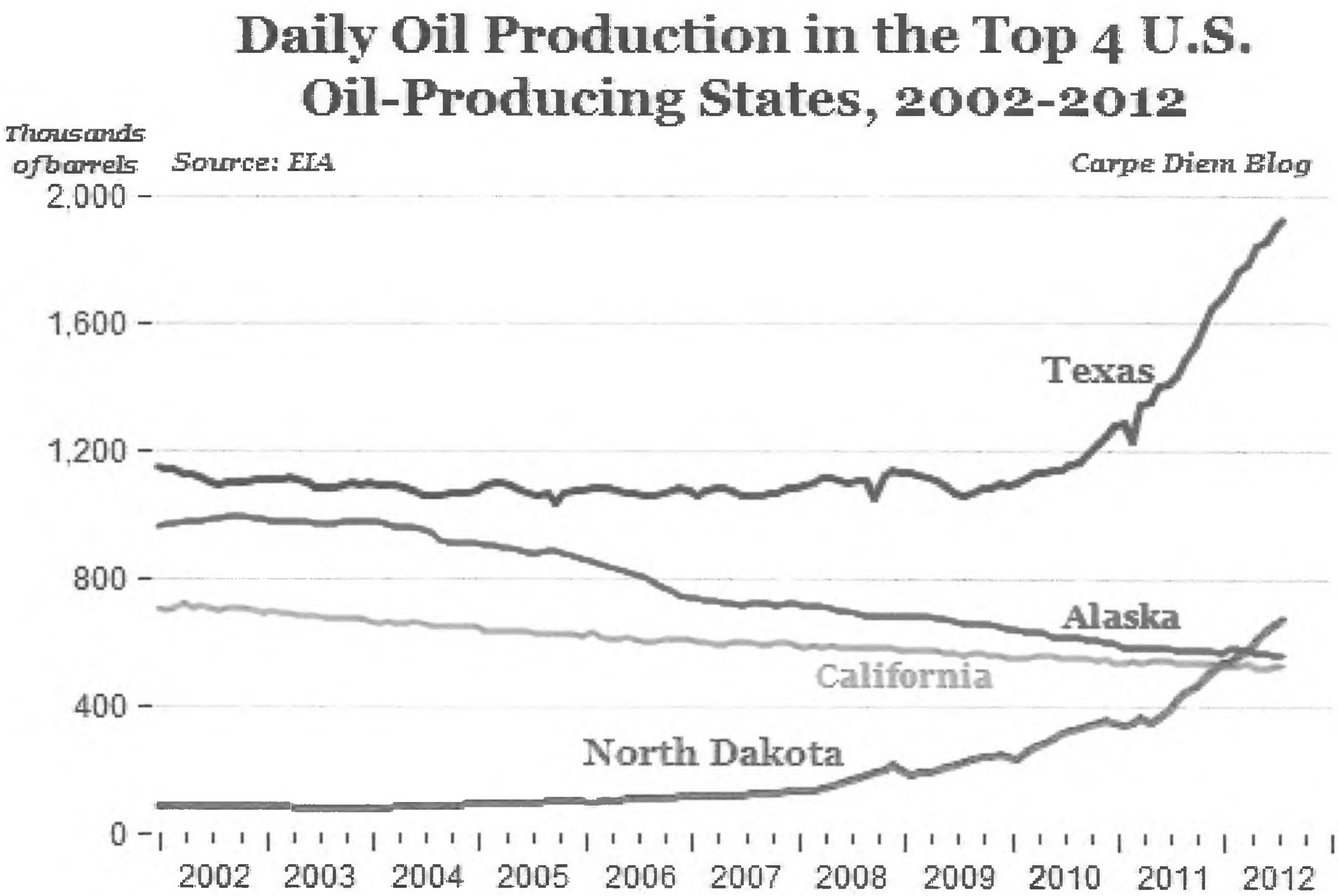


Source: State of Alaska

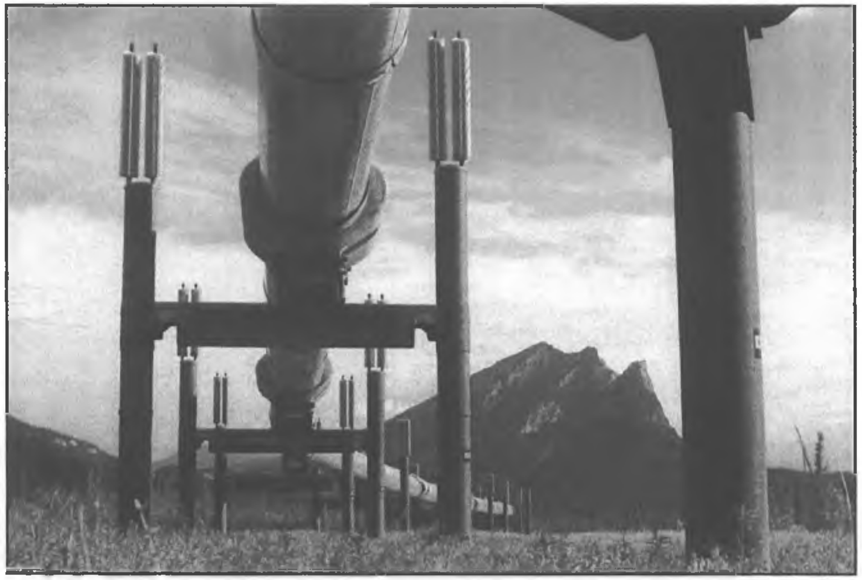
Competition at High Oil Prices



Alaska Headed Out of Medal Contention – 4th



Trans Alaska Pipeline System



- Approximately 11 percent of the nation's domestic oil production carried on TAPS.
- Nearly 17 billion barrels of crude oil transported.
- 20,000+ tankers loaded.
- 547,000 barrels throughput per day, 2012 average.

Refining in Alaska

FLINT HILLS
RESOURCES
Alaska

PETRO STAR INC.
EXCELLENCE IN ENERGY

TESORO

Cook Inlet

Apache

Hilcorp Alaska, LLC

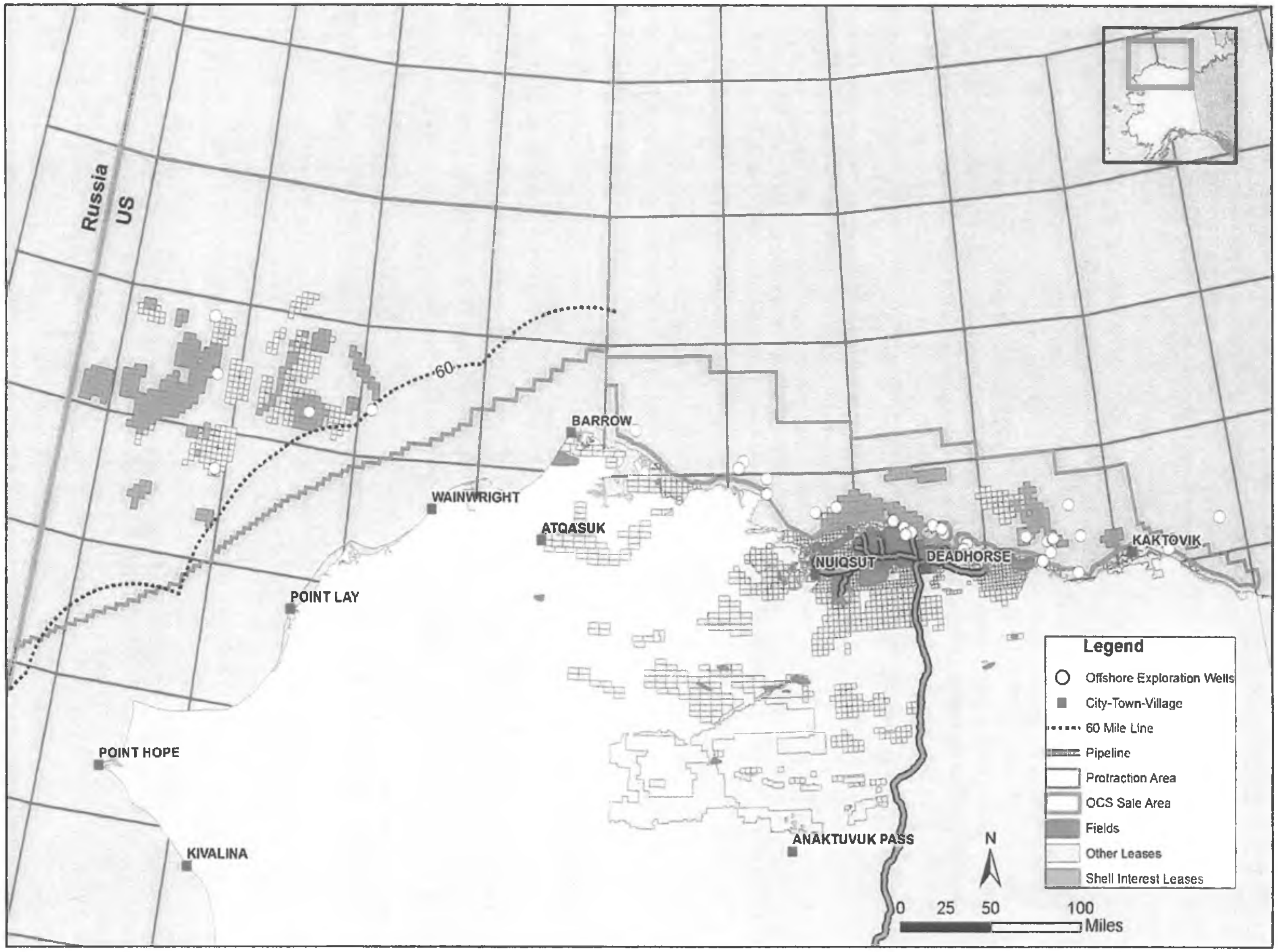
Marathon Oil
Marathon Alaska
Production LLC

TESORO

XTO ENERGY

Arctic Offshore Potential

Statoil



North Slope Onshore

Great Potential:
•40 bbo in Arctic
•5 bbo recoverable in existing fields
•2 bbo potential Unconventional

bp

PIONEER
NATURAL RESOURCES ALASKA

Chevron

eni
petroleum

ExxonMobil

REPSOL

Governor Lays out Principles for Oil Tax Reform

Anchorage Daily News, Jan. 6, 2013:

Reform must:

- Be fair to Alaskans
- Encourage new oil production
- Be simple and restore balance
- Be durable and long-term in nature

AOGA Thoughts on SB 21

- Support the proposed elimination of progressivity
- Concerns with how the bill addresses tax credits
- Support the concept of gross revenue exclusions but should be expanded to fit the majority of projects in legacy fields
- Represents cornerstone for significant and crucial tax reform
- Stand ready to assist in achieving a long-term policy for Alaska

Alaska Oil and Gas Association

AOGA

121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907) 272-1481 Fax: (907) 279-8114
Email: moriarty@aoga.org
Kara Moriarty, Executive Director

ALASKA OIL AND GAS ASSOCIATION STATEMENT ON SENATE BILL 21 FOR SENATE SPECIAL COMMITTEE ON TAPS THROUGHPUT

February 5, 2013

Good Afternoon. For the record, my name is Kara Moriarty and I am the Executive Director of the Alaska Oil and Gas Association, commonly referred to as "AOGA". AOGA is the professional trade association that represents 16 member companies who account for the majority of oil and gas exploration, development, production, transportation and refining of oil and gas onshore and offshore in Alaska. These comments regarding SB 21 have been reviewed by all members and were approved unanimously.

Senate President, Senator Charlie Huggins, outlined the Senate's priorities in an opinion piece published in the *Anchorage Daily News* on January 31. In it he stated "the most pressing issue facing Alaska is the downturn in oil production on Alaska's North Slope." We couldn't agree more. In fact, that is why this committee has been formed; to investigate the causes of oil production decline and make recommendations to turn the tide. We applaud Senator Huggins, you and Governor Parnell for recognizing this as a serious issue.

You have seen this chart over and over, but I think it's important to reflect on this decline. When I was legislative staff in 2000, the first year of this chart, no one was talking about production decline. Instead, everyone was focusing on price, because even though we had a million barrels per day of production, prices hovered between $8-10 that year. The state was facing a $1 billion shortfall, at a time when the budget was significantly less than it is today.

This is the updated forecast from the Department of Revenue (DOR) and you will see that they have employed a new risk modeling into their forecast. In the past, DOR projected that 10 years from now 50% of our oil production would be from new oil. While we applaud DOR for providing a more likely and realistic projection, it is important to note that their forecast for currently producing fields assumes that the current level of investment in producing fields will continue, which is by no means guaranteed.

Regardless, the fact is Alaska's production decline rate has remained at around 6% per year for the last decade, or at least 40,000 barrels a day per year. While we have never said that oil production will return to historic levels of 2 million barrels per day, we continue to argue that this accelerated decline is unacceptable, especially at a time of record and sustaining high oil prices over the last five years.

And just how is our competition reacting to high oil prices? This slide shows the oil price in the green dotted line and production from other regions, including mature basins like ours. Production in Texas started to level off as prices increased, and this was before the shale explosion. And of course, I don't need to remind you about North Dakota on the bottom of the graph that has caught up and surpassed us in production.

But another state that is about to surpass us is California. As this slide says, we are headed out of medal contention. We barely have the bronze and are about to slip to the fourth largest producing state in the United States. In fact, we now supply only 8% of the nation's oil production. I shared similar statistics with you at our legislative luncheon, but I think they bear repeating. In November 2012, the most recent month of statistics on the U.S. Energy Information Agency's website, production in Texas was 2.1 million barrels per day, North Dakota was 731,000 bpd, Alaska was 553,000 and California was nipping at our heels at 533,000. This at a time when we still have world class resources.

As you know, I represent a diverse membership, ranging from companies exploring and operating in Cook Inlet and on the North Slope, to companies hoping to develop Arctic Outer Continental Shelf resources, to three in-state refineries and our lifeline, the Trans-Alaska Pipeline System – or TAPS.

Current production is over 100,000 bpd less than when production from the North Slope began in 1977, so one company in particular that would love to see more oil through TAPS is Alyeska Pipeline Service Company. Because of the dedication and efficiency of their employees, we don't hear about the increasing day to day demands and challenges Alyeska faces in providing safe and reliable transportation of our resources to market, but you are going to hear about them in detail from the president of Alyeska following my presentation.

But it's not just Alyeska. Every single one of my members shares your concern about the decline in TAPS, and for good reason. Two of the three in-state refineries rely solely on North Slope crude, delivered through TAPS, for their refineries. And it is no secret the challenges our refiners face. Low throughput has increased the costs of refining, especially in Interior Alaska. For example, about 20 years ago, the oil when it reached North Pole refineries was about 110 degrees Fahrenheit. Now, it comes in in the mid 30 degree range. So in the refining process of heating oil to over 600 degrees F, the Interior refineries are expending considerably more energy to heat the oil an extra 70 degrees or so due to the drop in throughput, and it is no secret the cost of energy is extremely high in the Interior.

And even though my members in Cook Inlet may seem far removed from this issue, successful operations on the North Slope affect their businesses as well. As skilled workers, especially those with drilling experience have left Alaska for areas that are booming, now that Cook Inlet is starting to experience a boom again, it has been challenging to get drilling equipment and workers back to the Inlet.

As we look to the next generation of oil and gas development, the Arctic OCS is believed to have an estimated 27 billion barrels of oil and 130+ tcf of natural gas. But, even if we have a successful exploration season in 2013, it will be 12-15 years before we see production from the Chukchi Sea. Our pipeline needs to be healthy and viable then, as well as today and the time in between.

My remaining member companies are exploring, producing and operating on the North Slope. These producers of the existing non-legacy fields on the Slope, and the developers of any new fields that may be discovered, need as much production as possible flowing from the legacy fields through TAPS in order to keep the costs affordable to ship their oil from the Slope to its refinery destinations. Unaffordable high transportation costs could cripple the economics of any new fields that might be found, as well as economics of non-legacy fields currently in production.

We have used this analogy before, but it still rings true. The North Slope oil province is like a tree, with the two great legacy fields being its trunk, and with the other fields being branches rising out of the trunk. If one peels the bark off all the way around the trunk and make it unhealthy, all the other branches will become unhealthy too, no matter how robust they might have been if the trunk stayed strong.

Governor Parnell recognizes that as a state, we need increased oil production from all fields because the current throughput is unacceptable. He has identified four "core principles" that "any tax reform proposal must adhere to":

- "First, tax reform must be fair to Alaskans."
- "Second, it must encourage new production."
- "Third, it must be simple, so it restores balance to the system."
- "Fourth, it must be durable for the long term."

AOGA endorses these principles. As you work through this bill and throughout the session, we also encourage you to ask yourselves:

- What is the state's goal and desired outcome?
- Does the state's policy reflect the constitutional mandate of developing the natural resources here for the maximum benefit of Alaskans, both today and tomorrow?
- Is the policy short, mid or long term?
- Will it encourage additional investment across a wide spectrum of projects/companies?
- Will it encourage development through a fair and predictable regulatory environment?
- Will it encourage development through land sales and competitive lease terms?

The challenge facing Alaska is not in having too many companies pursuing the opportunities that they see here, but in having too few. To be effective, any reform measure needs to avoid tax changes that artificially create "winners" and "losers".

Senate Bill 21 takes some positive steps towards the goal of more production; such as the Gross Revenue Exclusion concept and eliminating progressivity, which has led to Alaska being uncompetitive. There are some other provisions that need further consideration in order to fully achieve the goals set out in this legislation.

We support the proposed elimination of progressivity. We have reservations with what the Bill proposes for tax credits – most importantly with the proposed repeal of tax credits for qualified capital expenditures (QCE). The trade-off between repealing progressivity and losing the QCE credit is not beneficial to industry with a rising cost structure and low oil price environment, although it would be helpful with high prices.

We strongly support the GRE (gross revenue exclusions) concept but have concerns over its limited applicability to new fields, only, which is further compounded by the loss of QCE credits as a driver for additional investment. We believe the GRE and tax credit restructuring proposed in the Bill could and should be expanded and better tailored to fit the majority of projects for "legacy" fields that would increase the amount of oil and gas from them.

We also believe the reasons that led the State to create the small-producer tax credit under AS 43.55.024 are still valid, and we are pleased the Bill will extend this credit from 2016 to 2022. But the reasons for creating the exploration tax credits under AS 43.55.025 are also still valid today, and the Bill would be improved by extending these tax credits or making them permanent. Similarly, the Bill would also be improved by addressing the upcoming end of the tax caps for Cook Inlet production and non-Cook Inlet gas sold for in-state use, which will otherwise occur at the end of 2021. Addressing these known issues now, before they become imminent, would strengthen the durability of the reformed tax.

The members of AOGA desire the same outcome that the Governor and the People of Alaska want – more oil in the pipeline providing a solid future for our industry and continued revenues to the State for the benefit of all Alaskans.

Our member companies want to do business in Alaska. Some have been exploring and producing in Alaska for decades, while others have arrived more recently. Both groups have a strong desire to be able to remain in Alaska long-term for their own and the State's mutual benefit.

Overall, the Bill as introduced represents a cornerstone for significant and crucial tax reform. It will take a monumental effort just to replace oil from declining fields with a mixture of new production and new stimulation to legacy fields, and bring the decline to a stop. AOGA stands ready and willing to help Alaskans, the Governor and this Legislature in the remaining work to achieve the four "core principles". We all need to work together to make this happen.

3700 Center Point Drive

Anchorage, AK

February 5, 2013

Testimony to Senate Special Committee on TAPS Throughput (Senate Bill 21)

Co-Chairs Senator Micciche, Senator Dunleavy and Senators on the Committee:

My name is Douglas Smith, President and CEO of LRS Inc and President of the Alaska Industry Alliance.

Thank you for your service to the people of Alaska and working the difficult issue of increasing TAPS production.

The Alliance represents 0ver 400 member companies and 35,000 Alaskan Workers.

LRS is a Hot Oil business with 148 employees working on the North Slope.

I am testifying on behalf of the Alliance.

The alliance supports the framework of SB 21 and the intent of the Governor to make Alaska competitive for additional investment and increased oil production.

Production is down 27% since 2007 despite continued high oil prices

Total Capital spending has been flat since 2008 and when adjusted for inflation a decrease year to year since 2010. For the large producers, and the bulk of where our oil comes from, the capital spend in 2012 is $62 million less and $100 million less when adjusted for inflation.

Some have focused on new entrants to the North Slope and despite capital spending that is equal to 50% of the large producers the group accounts for less than 10% of the production and some of that is inside mature units.

New unit production, those producing after 2003, are less than 5% of daily production. Despite the high investment and limited production gains the new entrants are a key component of Alaska's future and have provided not only additional production but A significant boost to our local economy by spending 100s' of millions in the state while others have reduced spending. These new entrants have more opportunities and our tax policy must continue to support their development efforts. As we try to stem the decline it is the aggregate production gain that matters when discussing the new developments.

The easy oil is gone and the cost to develop new sources of oil is many times that of earlier developments. Alpine was developed for a billion dollars and delivered 80,000 barrels per day but now CD5 will cost a billion dollars and deliver 18,000 barrels under a very different and less profitable tax policy.

In 2005 179 wells were drilled on the North Slope while ANS crude was $51 per barrel. In 2012 we drilled 140 wells, a 25% reduction despite oil prices topping $100. ACES is working if we are harvesting and have given up on the long term potential of our oil resource the pathway to LNG development and the next generation of Alaskans economic prosperity.

We are 3 years into a rigorous debate on our tax policy while production continues to decline and some Senators tell us that ACES is working. Senator Wielechowski who wants to debate the Governor on oil tax policy along with Senator Ellis would like to bring back Gaffney, Cilne and Associates who worked on ACES to advise legislators. That group produced graphics in 2007 that show Capex for drilling at 3.7 billion from 2008 to 2012 and incremental oil of over 200,000 barrels per day by 2012. Given the inaccuracy of that forecast of how our oil and gas investment and corresponding production has turned out I would not listen to the Senators in question or the consultants they would like to have advise legislators on tax policy. The work provided by econ One and PFC Energy is comprehensive and provides the information necessary along with testimony to move forward with legislative decisions.

We cannot waste more valuable time on fool hearted follies or consultants that steered us into this path of declining investment while our oil producing peers have seen extraordinary growth, prosperity and increased production. Despite an aging field environment Texas has seen a production increase in the last 10 years while our production has dropped 40%. It is long overdue to correct our tax policy and make Alaska competitive for the investment needed to sustain our oil production for the long term.

Senate Bill 21 is a good start to achieve this goal however we suggest the following considerations:

1) Ensure our tax policy adjustments do not increase taxes in the range where producers will stress test the economics of investment opportunities, thought to be in the $80 -$85 range.
2) Ensure our tax policy does not disincentive development within existing PA's where the largest production improvement opportunities exist.
3) Oil policy must support the new entrants like Pioneer and ENI who are producing oil into TAPS and spending millions in our state economy. Our policy must encourage them to continue that investment trend.
4) A new tax policy must make Alaska competitive for investment but protect Alaskans interest. A fair and balanced approach will be durable.

We urge you to act fairly but expeditiously on this legislation and allow Alaska to become more competitive in investments for new oil production.

Chairmen and Senators, thank you again for all of your efforts.

Senate Special Committee on TAPS Throughput

SB21

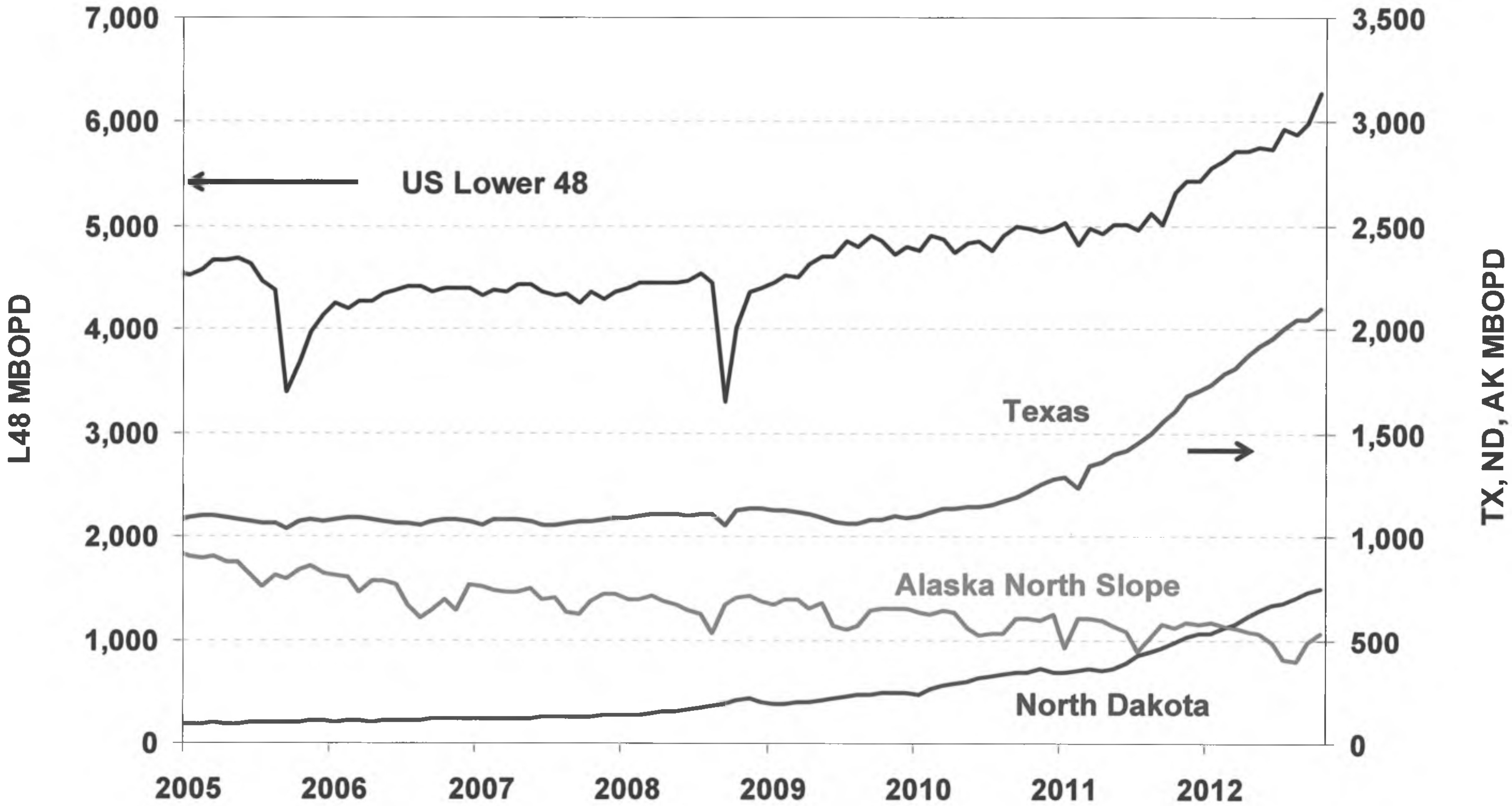
Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska

February 5, 2013

Topics

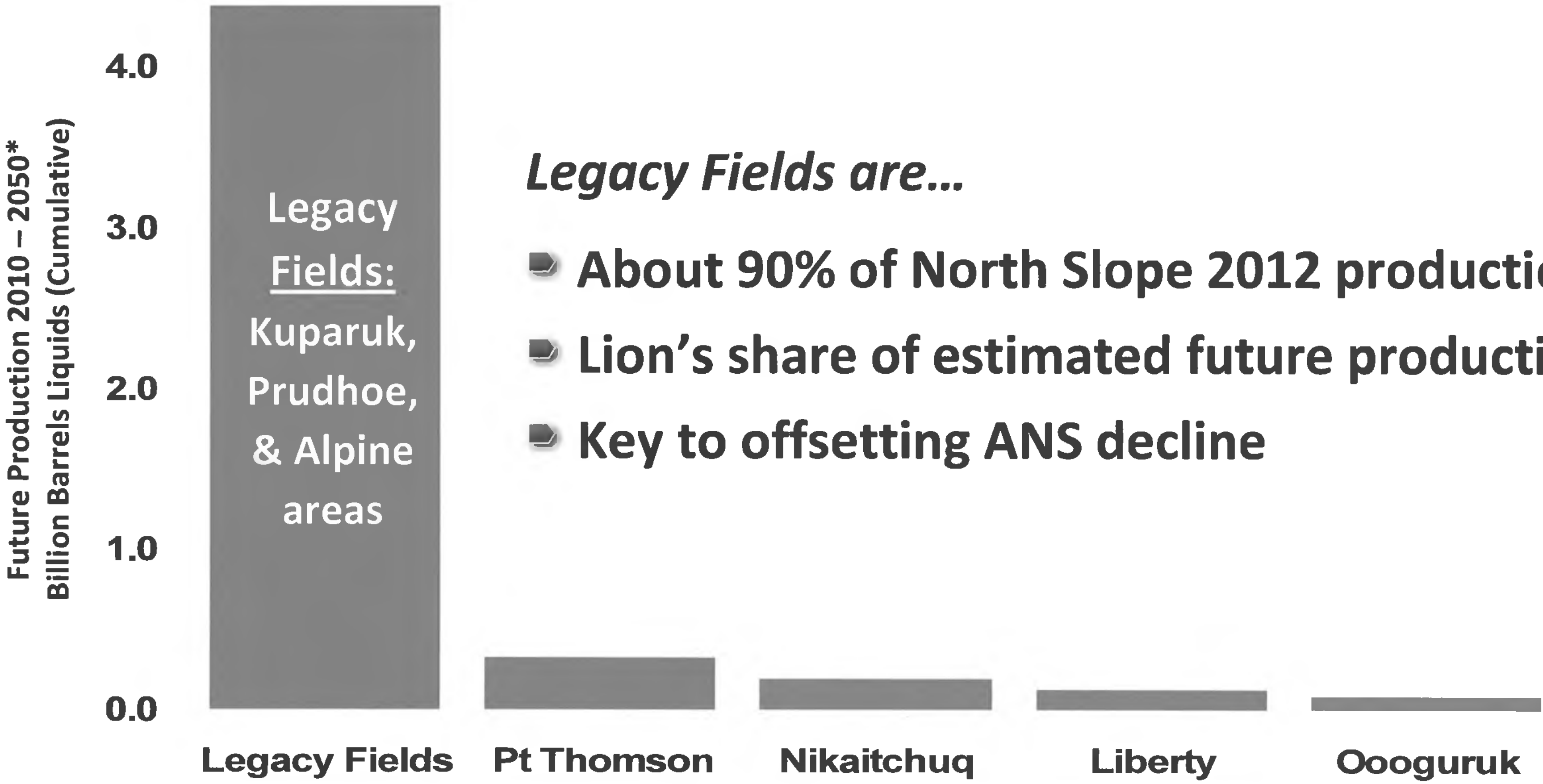
- Alaska's Production Challenge
- Investment Considerations and Alaska's Cost Environment
- ACES and SB21
- Observations

Alaska Decline Continues While Lower 48 Continues to Increase



Source: U.S. Energy Information Administration

Alaska Legacy Fields Still Provide Significant Opportunity

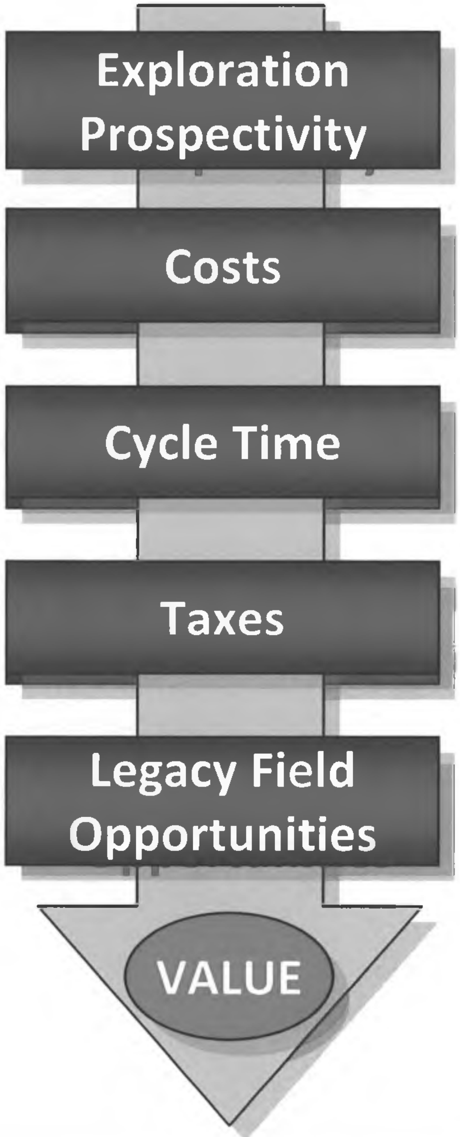


Legacy Fields are…

- **About 90% of North Slope 2012 production**
- **Lion's share of estimated future production**
- **Key to offsetting ANS decline**

*Source: DOR 2009 production forecast 2010 – 2050 volumes

Investment Criteria: How Alaska Ranks



- Expected field size/maturity
- Crude quality

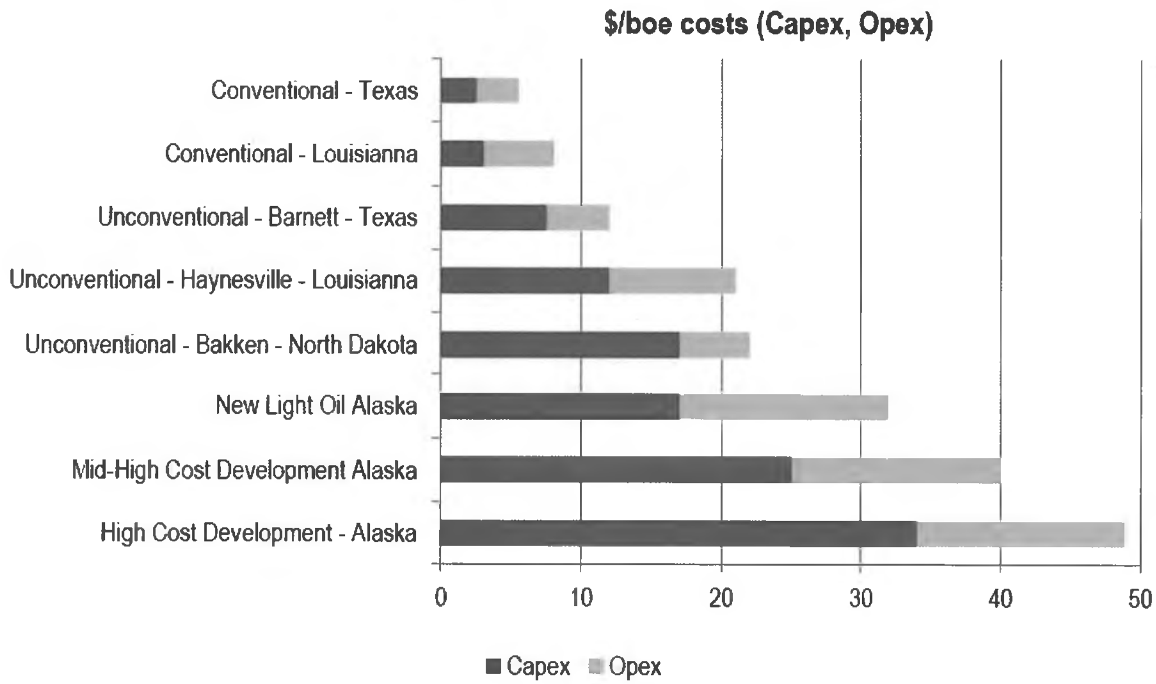
- Exploration, development & production cost
- Transportation costs to market

- Time to production
- Permitting/regulatory environment

- Tax rates given challenged location
- Tax rates compared to other states & countries

- Billions of barrels left to be developed
- Significant production volumes

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



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

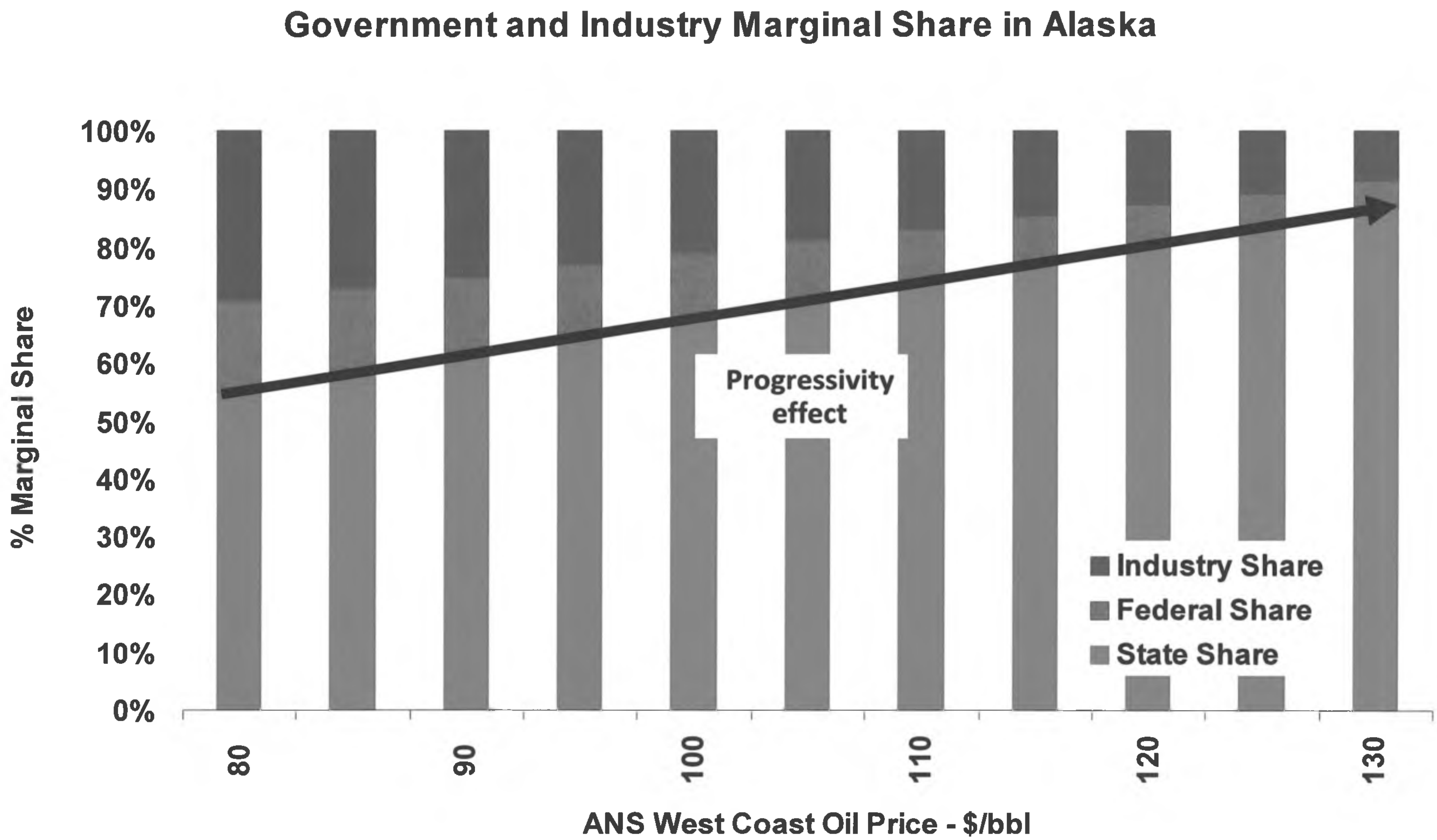
"Easy Oil" In the Legacy Fields Is Gone

- Challenged oil remains
  - Complex, high cost wells
  - Smaller reserve targets
  - Isolated fault blocks, flank oil
  - Satellites and viscous oil
  - Most new wells produce oil AND water
  - Facilities handling ~ three times as much water as oil
- **A billion dollars does not go as far as it used to...**
  - 2000 Alpine development: ~80,000 BOPD
  - 2012 CD-5 Drillsite: ~18,000 BOPD

Initial Alpine Development

CD-5 Type Development

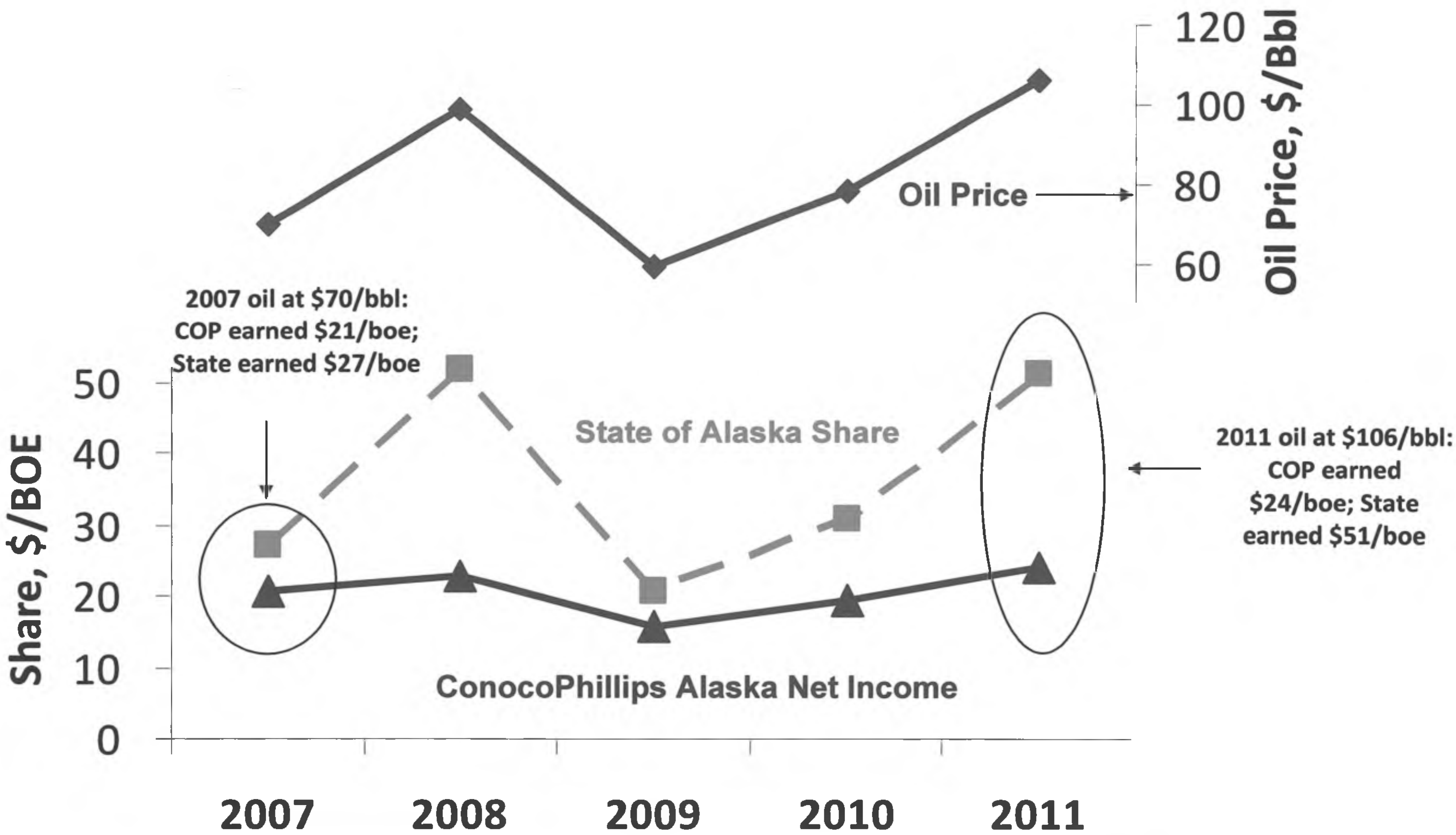
ACES Marginal Industry Share



Based on Fall 2012 Revenue Sources Book data for FY2014

ConocoPhillips

Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska

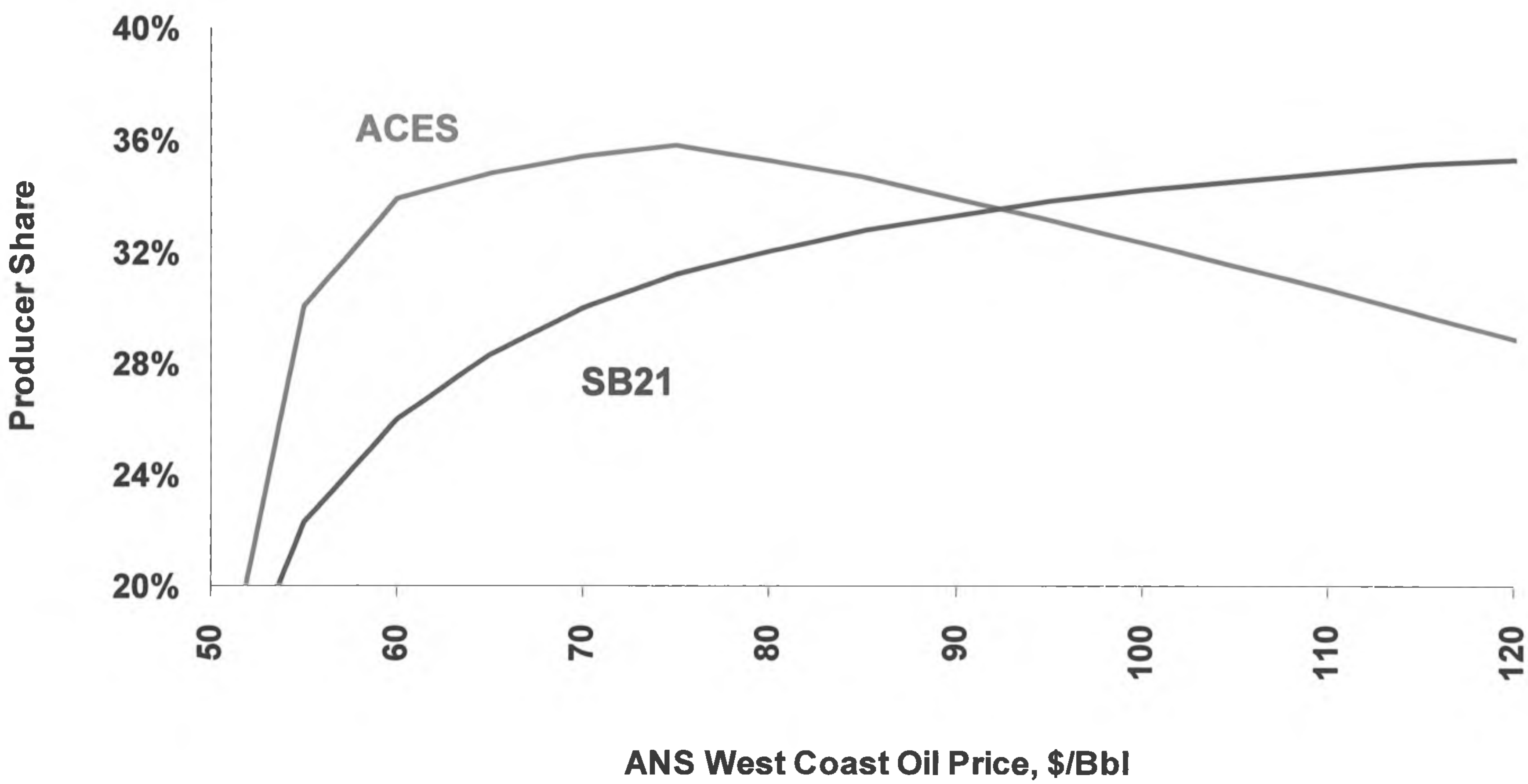


ACES progressivity takes the upside

Source: ConocoPhillips 10-K, 2007-2011; State share is royalties (estimated), production tax, ad valorem tax and state income tax, oil prices are average realized prices by ConocoPhillips on the West Coast

ConocoPhillips

Producer Share under SB21



Observations

- ACES
  - Progressivity takes the upside and discourages investment
  - Tax credit investment incentives positive, but do not offset the negative effects of ACES progressivity

- SB21 Positive Elements
  - Positive step to improve Alaska's business climate
  - Solves the high marginal tax problem
  - Makes Alaska more competitive at $100+ prices

- SB21 Areas for Improvement
  - Bill does not contain sufficient investment incentives for legacy fields to offset Alaska's high cost environment
  - Does not encourage investment relative to ACES in a downward trending oil price environment

Basis shows 3 Barrett documents - they are all contained in this one document

Trans Alaska Pipeline System

Declining Throughput Challenges
Senate Special Committee on TAPS Throughput
February 5, 2013
Presented by Tom Barrett, President

About TAPS

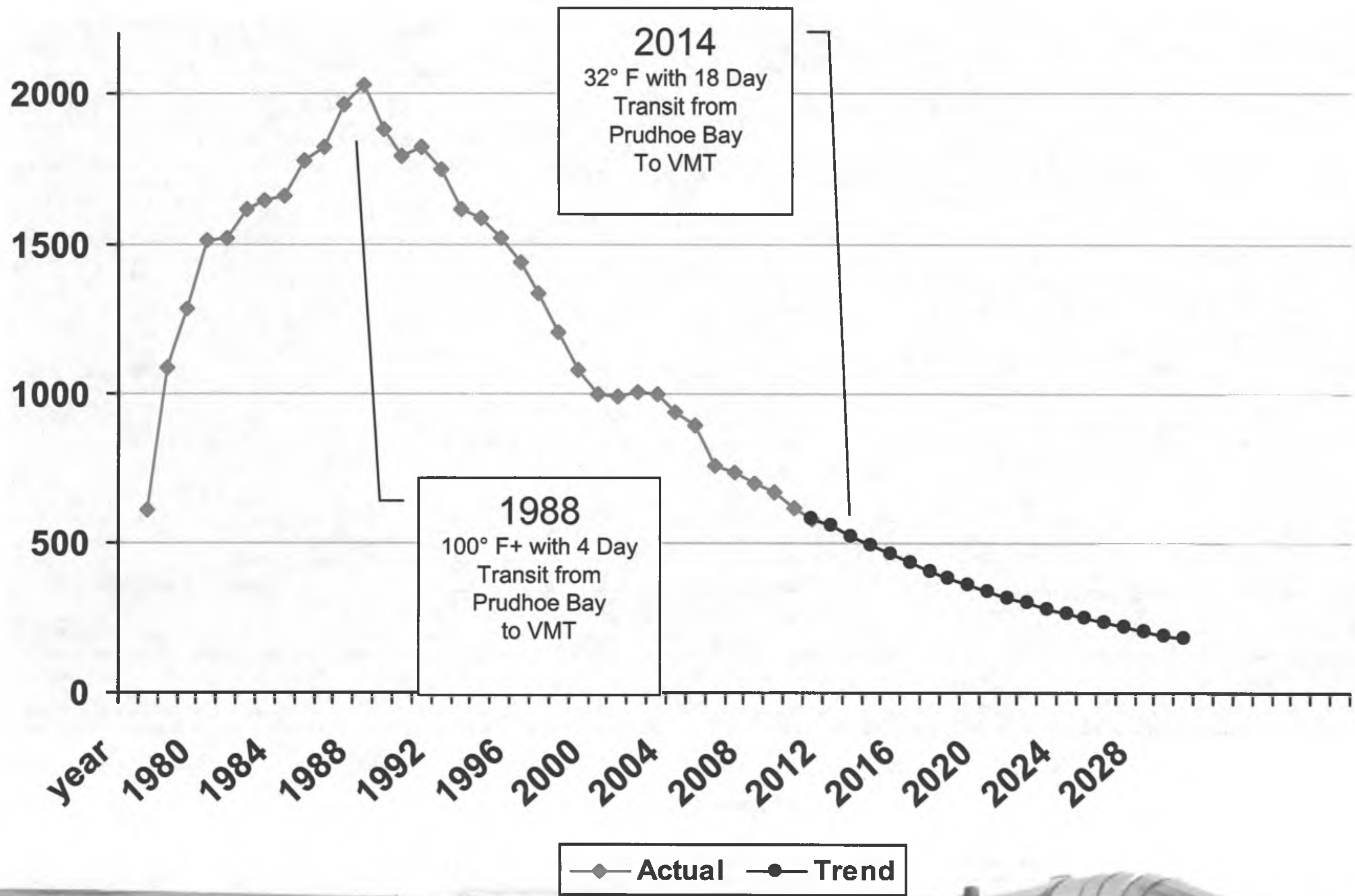
TAPS was designed as a warm oil pipeline.

- Designed to move 1.5 million barrels per day.
- Peak production of 2.1 million barrels per day (1988).

Circumstances have changed.

- Throughput and temperatures continue to decline.
- At 580K barrels/day, segments of crude oil in the pipe will be below 32F during the winter months.

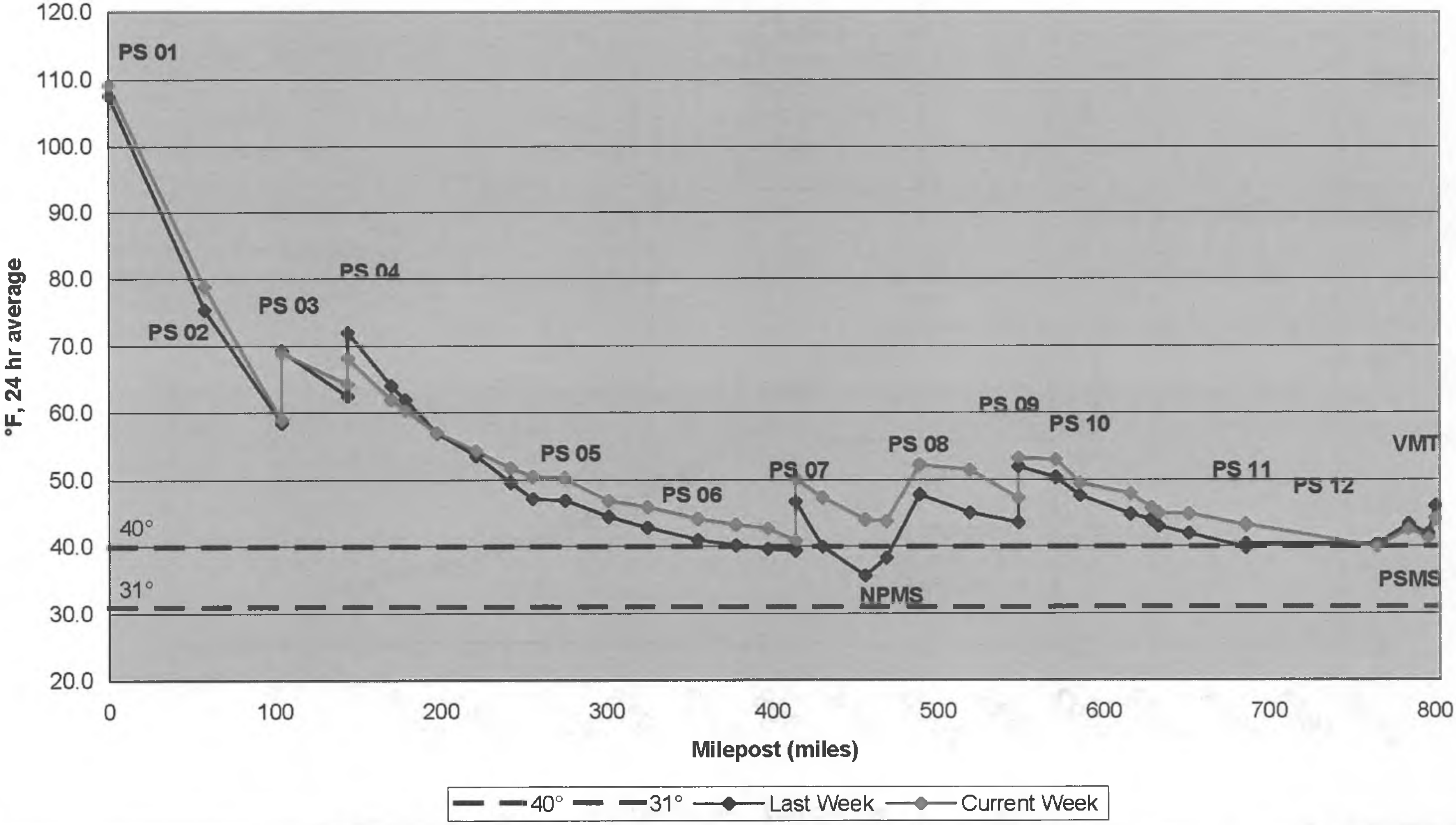
Steadily Declining Throughput



Adjusted Pipeline Temperatures

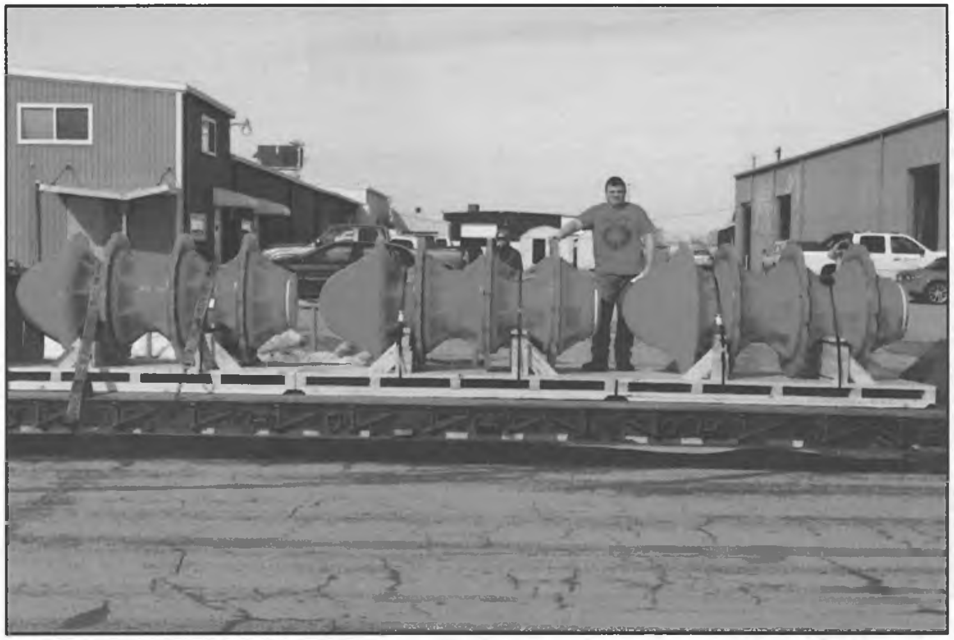
24 Hour Average Adjusted Temperatures for January 27 and February 3, 2013

The adjusted temperatures have an offset applied to the values based on the temperature data gathered from PDL (Pipeline Data Logger) runs.



Alyeska pipeline

TAPS scraper pigs



Taking action today, preparing for tomorrow

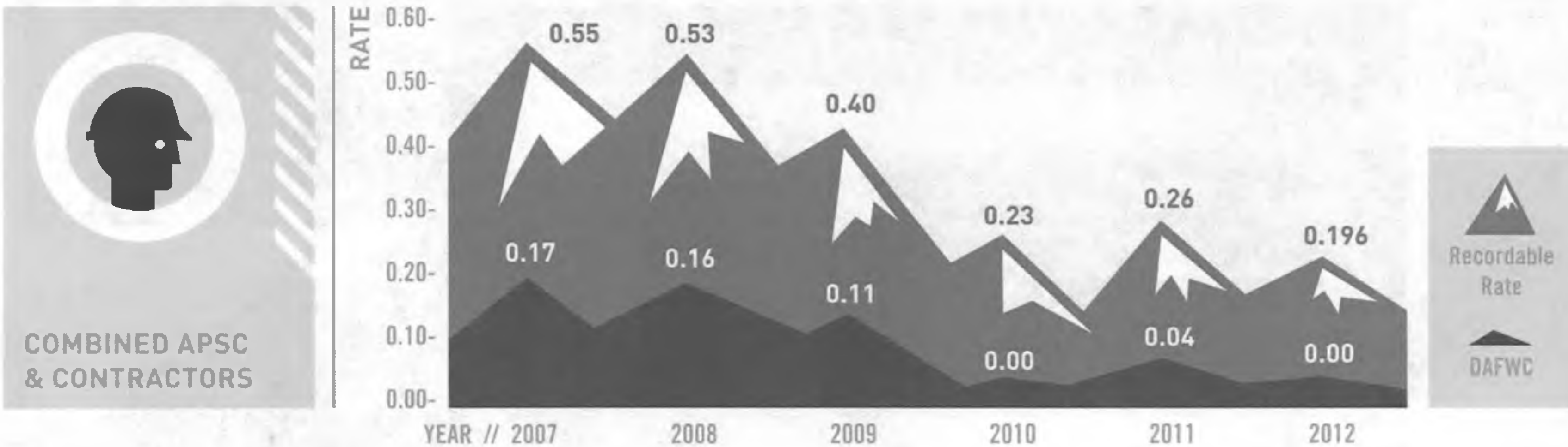
Recirculation pipe installation at PS4

www.alyeska-pipe.com Alyeska pipeline

Determination, ingenuity, partnership

2012 Alyeska's BEST safety year on record

OCCUPATIONAL SAFETY



99.8 % reliability delivered for the State of Alaska

"We didn't know it couldn't be done."

Declining throughput: a continuum of challenges

The trans-Alaska pipeline transformed Alaska's economy and strengthened the nation's energy infrastructure. The pipeline today transports some 11 percent of the nation's domestic crude production and remains the backbone of Alaska's economy, delivering about 90 percent of unrestricted general fund revenue.

More than 2 million barrels a day (BPD) once surged through the Trans Alaska Pipeline Systems (TAPS). Since peak flow in the late 1980s, TAPS throughput has dropped. Today it is declining more than 5 percent per year. Less oil means slower-moving oil. Slower oil means colder oil. And the slower and colder the oil, the more complicated the challenges for Alyeska Pipeline Service Company, the pipeline's operator.

The best long-term solution is more oil. In the meantime, daily throughput is already lower than it was at pipeline startup in 1977.

Water/ice

Crude oil naturally contains small amounts of water. As crude slows and cools, water will begin to separate out from the oil and accumulate at the bottom of the pipeline, increasing the risk of corrosion. This happens today during shutdowns, when water accumulates at low points. As water drops out and everything cools, the risk of ice-related problems also increases.

Wax

ANS Crude oil naturally contains up to 2 percent wax by volume. There are two issues with wax: First, when the pipe walls are colder than 70 degrees and colder than the oil, wax crystals gravitate to the pipe wall and stick to it. Second, wax precipitates out of the crude oil. Less turbulence, cooler crude temperature and slower flow all may result in more wax sticking to pipe walls and more wax dropping out of the oil and settling in the pipeline. Wax deposits must be removed by running cleaning pigs.

Less throughput = more challenges

Less oil → slower flow → crude spends more time in pipe, and less turbulence
Slower flow/less turbulence → more wax may accumulate in the pipe, requiring more frequent 'pig' cleaning
More time in pipe → Crude loses heat → higher risk of ice problems, more wax forms

- TAPS is currently moving an average of 548,000 BPD (2012 daily average)
- Challenges are immediate
- No hard and fast thresholds; a continuum of challenges requires corresponding actions to address them
- Ultimately may need shift to intermittent flow

The pipeline today

Alyeska and its owner companies have analyzed the risks, options and challenges of declining throughput. Some mitigations are already in place, while engineers are validating other potential steps through laboratory and field tests.

Transitional fix: more heat, more pigs

For the immediate future, Alyeska is adding heat to keep the crude warm and to prevent small amounts of water from freezing in the line. The cleaning pig program has been modified – with frequent pigging and redesigned pigs as needed – to keep the pipe clean of wax.

Heat is added through recirculation at Pump Stations 3, 4 and 9. Pump Station 7, which was previously decommissioned, is now back online to recirculate oil. Infrastructure for recirculating oil at that station is also enhanced. A schedule is in place for adding more heat as the crude continues to cool due to declining throughput.

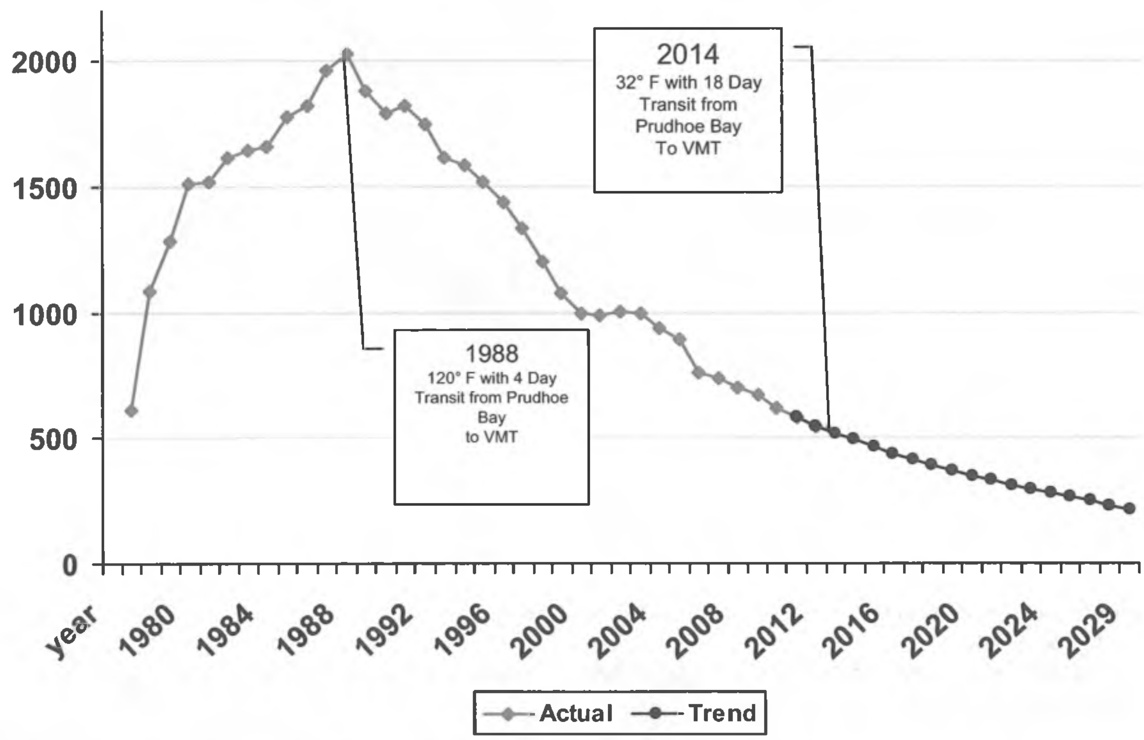
Longer term: cold dry flow

As throughput further declines, continuing to add ever more heat would create new problems. At some point – teams are researching this now – it appears the most effective approach will be to operate the line in a "cold-dry flow" state.

With cold-dry flow, most of the water is removed from the crude before it enters the pipeline and the system runs much cooler. Since the purpose of heat is mainly to prevent ice formation, eliminating most of the water eliminates the need for elaborate heating systems.

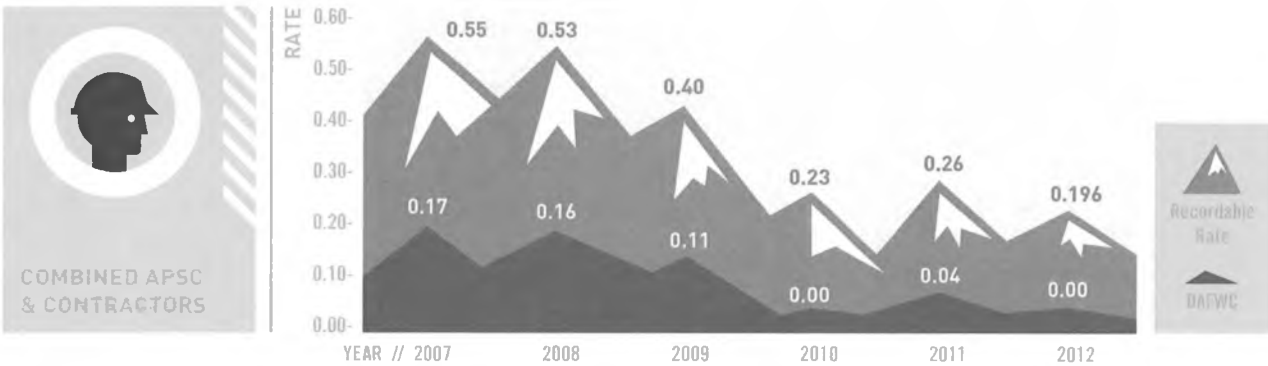
Once the cold dry flow system has been validated through field and laboratory testing, a transition phase will shift the system from heat-dependent operations to cold-dry flow.

Work is in progress to determine how best to manage wax accumulation.



2012 Alyeska's BEST safety year on record

OCCUPATIONAL SAFETY



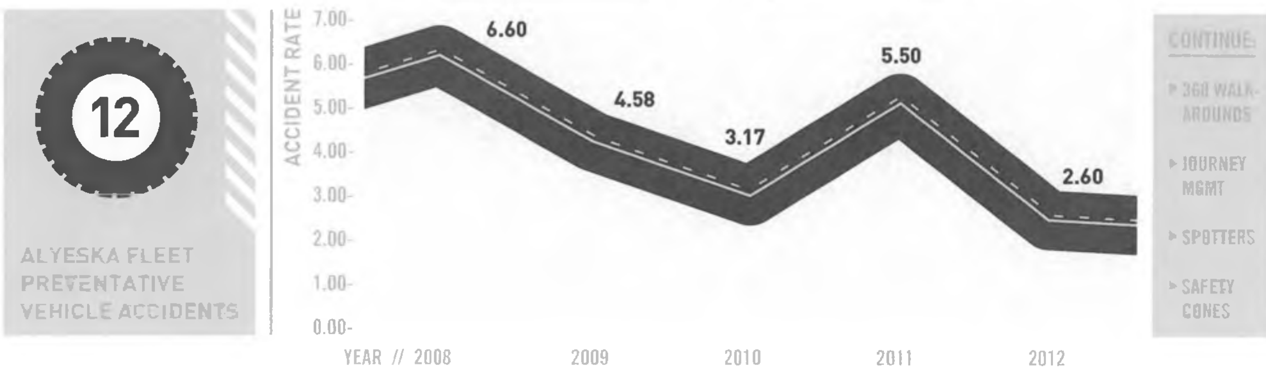
3 PART CONTRACTOR SAFETY IMPROVEMENT STRATEGY

ADOPTED IN 2012 & CONSISTS OF FOCUSED ACTION

- Reinforce *SAFETY CULTURE* expectations and accountabilities for TAPS Contractors
- Improve *LPS STEWARDSHIP* by Contractor and Labor Union leadership
- Increase *SAFETY ACCOUNTABILITY* for Contractor work on TAPS.

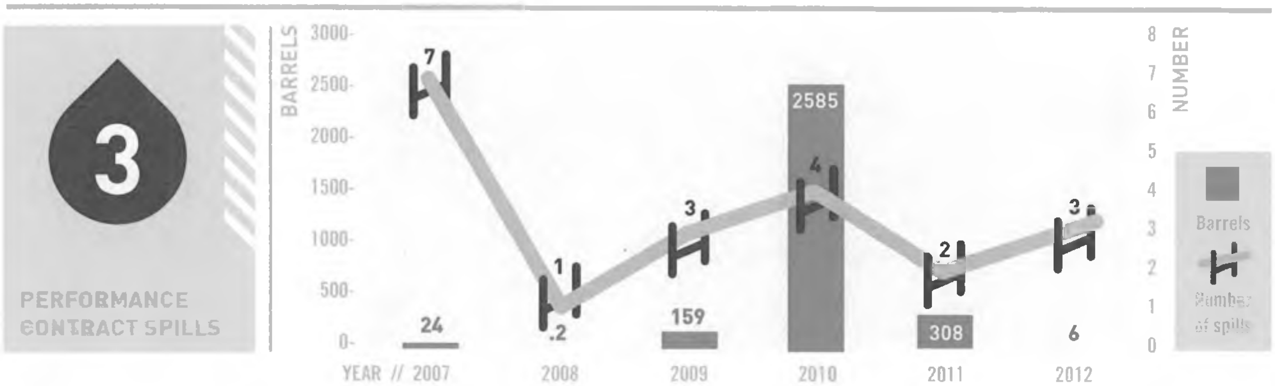
CONTINUE:
- HazRec
- LPS Behaviors

VEHICLE SAFETY



There were twelve PVA's incurred with the Alyeska vehicle fleet. All but one of the incidents were low speed impacts and relatively minor damage. One of the incidents involved a contractor operated Alyeska vehicle departing the roadway at highway speeds.

ENVIRONMENTAL



There were 3 "Performance Contract" spills. The total amount of petroleum product released was the lowest since 2008 (6 barrels).

JAN 2013 DATE

THE LINE

COLD OPERATIONS NEWSLETTER

www.alyeska-pipe.com

Alyeska pipeline 35 YEARS DELIVERING EXCELLENCE

PRESIDENT'S MESSAGE

As I write this, we are coming up on the 2012 Winter Solstice. The hours of dark are long, and deep cold is upon us. It is -51 degrees in Fairbanks today, and -31 degrees in Prudhoe Bay, with a wind chill to -49. We are just coming out of a stretch of early winter storms that challenged our inventory management at the Valdez Marine Terminal. With typical Alyeska grit, the employees and contractors of Alyeska Pipeline Service Company managed the Trans Alaska Pipeline System and kept oil moving safely through these conditions. I know this professionalism will stay strong as our six-month winter season continues.

The fact is, we know about operating a pipeline in a cold, challenging arctic climate. We've done this successfully for the past 35 years. But it has never been harder than it is today. With technical challenges from declining throughput, we are operating in new territory every day. Issues caused by declining flow – slower moving oil, more wax and water dropout, tank roofs to shovel – are becoming harder to manage in the cold winter months. We're taking steps to address these issues and we will have to increase these efforts if flow continues to decline.

People on TAPS, whose focus and hard work make our winter operations successful, deserve our thanks. Since pipeline startup, our employees have worked very hard every day to safely move oil. We will continue to apply innovation and technology to continue that legacy, regardless of what the future brings.

TOM BARRETT
President

Tom Barrett speaks with Brendan LaBelle-Hamer, Pipeline Area Manager, and John Baldridge, Senior Pipeline Operations Director, during a visit to Pump Station 1.

PIPELINE 101

RECIRCULATION

In cold months, adding heat to cooling crude oil helps keep oil flowing. Alyeska engineers have modified or adjusted the Trans Alaska Pipeline System's pumping equipment to recirculate oil. Oil enters pump stations through the pipeline and is pushed downstream by the station's pumping equipment. With recirculation, the oil is looped back through the pumps several times. Recirculation adds energy to the flow of oil, and energy adds heat to the system. Oil enters TAPS at approximately 110 degrees and loses heat due to less velocity and longer travel time in the pipeline. With lower and lower throughput, recirculation is necessary to prevent freezing conditions in the pipeline. More oil equals more heat. Less oil means less heat, increased maintenance and cost, and the need for recirculation. See the featured story inside this newsletter to learn about recirculation work at Pump Station 7.

PIPELINE RELIABILITY

DECEMBER 2012 RELIABILITY FACTOR

TAPS reliability factor for December 2012 **100.00%**

TAPS reliability factor for year 2012 **99.79%**

Barrels pumped from Pump Station 1

December throughput: 18,069,567 BBLS*
Average: 582,899 BPD**
Year 2012: 200,518,904 BBLS*
Average: 547,866 BPD**
*BBLS (barrels) = 42 Gallons **BPD = Barrels Per Day

VOICE FROM THE PIPELINE

Advice from Pump Station 7, where winter installation of recirculation equipment require extensive work outdoors: "Stay hydrated! We have to order two pallets of bottled water a week for the people working outside. The temperature change is hard. It can drop 20 degrees in 20 miles. Lots of contractors have never experienced freezing temperatures, much less -20 or -30 degrees. Hand protection is the biggest problem. You can spend $100 on a pair of supposed arctic gloves and they're not worth a dime. Our guys have learned to build Taj Mahals out of Visqueen so the portable heaters can keep the outdoor work areas a little warmer. People's attitudes really depend on the meals; a good cook is worth their weight in gold."

FACTOID ▸

On Jan. 14, 1988, the highest daily throughput was recorded on TAPS – 2,145,297 barrels.

JAN 2013 DATE

THE LINE

COLD OPERATIONS NEWSLETTER

Alyeska pipeline 35 YEARS DELIVERING EXCELLENCE

www.alyeska-pipe.com

HEADLINE STORY

COLD WEATHER OPERATIONS ARE ESSENTIAL IN KEEPING TAPS RUNNING SAFELY AND EFFICIENTLY

To other Alaskans, "cold weather operations" means dusting off shovels and snow-blowers, and unpacking down coats for the winter ahead. For Alyeska employees, it means keeping TAPS running safely as oil transits the 800-mile pipeline during the coldest months of the year.

Throughput continues to decline and winter poses increasing challenges to a pipeline that was constructed to move a warm product quickly. Today, crude oil slowly moves through the frigid interior of the state, and it gradually cools. Without action by Alyeska, cold oil could create a host of different problems, from frost heaves to ice formation in the line. Ice could damage pumps and valves in facilities along the pipeline corridor.

To combat the problems caused by diminished flow rates and temperature, Alyeska employees are working to keep the pipeline running in a steady state during winter operations. This requires careful coordination of project work and other factors to minimize shutdowns during winter.

Alyeska also adds heat at strategic points along the pipeline. For two years, crude oil has recirculated at several pump stations, creating friction and heat as it travels through piping multiple times. At Pump Stations 4 and 7, teams installed additional piping and new valves that function partly open. These drag valves create significant friction; this system is called

IN THE FIELD

PUMP STATION 7 AIDS COLD WEATHER OPS

Formerly on stand-by status, Pump Station 7, located approximately 50 miles north of Fairbanks, has assumed an important role in cold weather operations. Not needed to pump oil under normal operating conditions, the ability to add heat to the pipe as it travels through Pump Station 7 is an important tool in moving oil through the Interior of Alaska during stretches of cold weather.

Pump Station 7 can add heat to the pipeline's crude oil stream using an existing "legacy" pump. The mechanical energy provided by the pump converts to heat energy through pressure reducing valves. The recirculation system only operates when certain conditions, including temperature and throughput, increase the need for heat.

During recirculation, a portion of the crude stream passes through drag valves that produce a pressure drop to develop heat. That same crude oil then flows through a full head pump that adds more heat with friction and increases the pressure. The crude oil goes through yet another drag valve, dropping the pressure again and producing additional heat before the oil re-enters the pipeline.

"The main challenge we have encountered is the inclement weather, as most of the work occurs outdoors," said Lori Howard, Pump Station 5 and 7 supervisor. "The project crew has done an outstanding job meeting the challenges to safely complete the work required to operate Pump Station 7 in a manual mode while the automation portion of the project is being finished."

"enhanced recirculation." More friction means TAPS is running less efficiently, but what the pipeline loses in efficiency, it gains in heat.

"Keeping TAPS running safely and efficiently during the long Alaska winter requires incredible coordination and focus," said Betsy Haines, Oil Movements Director. "Our team is up to the challenge, but getting more oil in the pipe is the best solution to many of the issues created by colder oil temperatures."

OUR PEOPLE

DEBORAH HUGHES, OPERATIONS ENGINEER OPERATIONS CONTROL CENTER (OCC)

Deborah Hughes works in the Operations Control Center (OCC) in Anchorage as an Operations Engineer. She has worked for Alyeska for two years.

Does OCC have a role in cold weather operations? How?

Yes, OCC plays a critical role in cold weather operations. OCC is tasked with maintaining bulk crude oil temperature as warm as reasonably possible. The goal is to keep crude oil from reaching the freezing temperature of the entrained water that is present in oil. Operations engineering uses a thermal model to provide recommendations to the OCC controllers on how much heat should be added to the system at each location along TAPS. The controllers are able to adjust recycle rates to add the desired amount of heat.

What are some of the challenges to cold weather operations for OCC?

The main challenge of cold weather operations for OCC is that it is not always possible to recycle enough to add the desired amount of heat at each location. When a mainline pump or turbine generator is offline, it directly affects the maximum recycle rates at a pump station, which in turn causes crude oil temperatures to drop. Other challenges include dealing with issues that are out of OCC's control. Colder than usual ambient temperatures and pipeline throughput both have a huge effect on crude oil temperatures.

Looking ahead, do you see these challenges becoming more or less common? How?

I think the challenges related to cold weather operations and low flow will be increasing in the next few years. Each year as throughput decreases, the crude oil temperatures will be decreasing as well. In addition, scraper pigging operations are going to be more and more of a challenge as throughput declines.

JAN 2013 DATE

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COLD OPERATIONS NEWSLETTER

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02/07/13 SB 21 - Proposed Amendments and Letter of Intent

<TARGET><BILL>SB 21</BILL><SUBJECT>02-07-13 SB 21 - Proposed Amendments and Letter of Intent</SUBJECT><COMM>STTP28</COMM></TARGET>

28-GS1647\A.1
Bullock
2/2/13

AMENDMENT #1

OFFERED IN THE SENATE BY SENATOR GARDNER

TO: SB 21

1 F 1Y 4N (Gardner)
2 F 1Y 4N (Gardner)
3 F 1Y 4N (Gardner)
4 F 1Y 4N (Gardner)
5 - not offered

Page 9, line 30, through page 11, line 3:

Delete all material.

Renumber the following bill sections accordingly.

Page 11, line 29, through page 12, line 17:

Delete all material.

Renumber the following bill sections accordingly.

Page 13, line 15, through page 16, line 25:

Delete all material.

Renumber the following bill sections accordingly.

Page 18, line 14, through page 19, line 4:

Delete all material.

Renumber the following bill sections accordingly.

Page 23, line 15:

Delete "Sections 2, 5, 6, 22 - 24, and 26"

Insert "Sections 2, 5, 6, 16 - 18, and 20"

Page 23, line 17:

Delete "Sections 3 and 21"

Insert "Sections 3 and 15 of this Act"

Page 23, line 18:

Delete "Sections 7, 11, 13, 14, and 25"

Insert "Section 7 - 10 and 19"

Page 23, lines 20 - 21:

Delete all material.

Page 23, line 24:

Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

Insert "Sections 3, 7 - 10, 12, 15, and 19"

Page 23, line 31:

Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

Insert "Sections 1, 2, 5, 6, 16 - 18, and 20"

Page 24, line 2:

Delete "sec. 30"

Insert "sec. 24"

28-GS1647\A.4
Bullock
2/1/13

AMENDMENT #2

OFFERED IN THE SENATE BY SENATOR GARDNER

TO: SB 21

Page 23, line 3, following "section,":

Insert "for the first seven years immediately following the commencement of production subject to tax under AS 43.55.011(e),"

28-GS1647\A.5
Bullock
2/1/13

AMENDMENT #3

OFFERED IN THE SENATE BY SENATOR GARDNER

TO: SB 21

Page 10, line 19, through page 11, line 3:

Delete all material.

Renumber the following bill sections accordingly.

Page 11, line 29:

Delete "sec. 11"

Insert "sec. 9"

Page 13, line 15, through page 16, line 25:

Delete all material.

Renumber the following bill sections accordingly.

Page 18, line 14, through page 19, line 4:

Delete all material.

Renumber the following bill sections accordingly.

Page 23, line 15:

Delete "Sections 2, 5, 6, 22 - 24, and 26"

Insert "Sections 2, 5, 6, 18 - 20, and 22"

Page 23, line 17:

Delete "Sections 3 and 21"

Insert "Sections 3 and 17 of this Act"

Page 23, line 18:

Delete "Sections 7, 11, 13, 14, and 25"

Insert "Sections 7, 9, 11, 12, and 21"

Page 23, line 20:

Delete "Sections 9, 10, 12, 15, and 20 of this Act apply"

Insert "Section 10 of this Act applies"

Page 23, line 24:

Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

Insert "Sections 3, 7, 9, 11, 12, 14, 17, and 21"

Page 23, line 31:

Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

Insert "Sections 1, 2, 5, 6, 10, 18 - 20, and 22"

Page 24, line 2:

Delete "sec. 30"

Insert "sec. 26"

28-GS1647\A.6
Bullock
2/5/13

AMENDMENT #4

OFFERED IN THE SENATE BY SENATOR GARDNER

TO: SB 21

Page 1, line 2, following "**rate;**":

Insert "**relating to the minimum tax on oil and gas production;**"

Page 2, following line 18:

Insert a new bill section to read:

"* **Sec. 3.** AS 43.55.011(f) is repealed and reenacted to read:

(f) Except for oil and gas subject to (i) of this section and gas subject to (o) of this section, the provisions of this subsection apply to oil and gas produced from each lease or property within a unit or nonunitized reservoir that has cumulatively produced 1,000,000,000 BTU equivalent barrels of oil or gas by the close of the most recent calendar year and from which the average daily oil and gas production from the unit or nonunitized reservoir during the most recent calendar year exceeded 100,000 BTU equivalent barrels. Notwithstanding any contrary provision of law, a producer may not apply tax credits to reduce its total tax liability under (e) of this section for oil and gas produced from all leases or properties within the unit or nonunitized reservoir below 10 percent of the total gross value at the point of production of that oil and gas. If the amount of tax calculated by multiplying the tax rate in (e) of this section by the total production tax value of the oil and gas taxable under (e) of this section produced from all of the producer's leases or properties within the unit or nonunitized reservoir is less than 10 percent of the total gross value at the point of production of that oil and gas, the tax levied by (e) of this section for that oil and gas is equal to 10 percent of the total gross value at the point of production of that oil and gas. In this subsection, "total gross value at the point of production" means the gross value at the point of production as adjusted by AS 43.55.160(f), if applicable."

Renumber the following bill sections accordingly.

Page 5, line 27:

Delete "sec. 4"

Insert "sec. 5"

Page 6, line 19, through page 7, line 5:

Delete all material and insert:

"(B) for oil and gas produced from leases or properties subject to AS 43.55.011(f), **10 percent of the gross value at the point of production of that oil and gas** [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 THE 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 THE OIL AND GAS 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];"

Page 9, line 30:

Delete "sec. 7"

Insert "sec. 8"

Page 11, line 29:

Delete "sec. 11"

Insert "sec. 12"

Page 23, line 15:

Delete "Sections 2, 5, 6, 22 - 24, and 26"

Insert "Sections 2, 3, 6, 7, 23 - 25, and 27"

Page 23, line 17:

Delete "Sections 3 and 21"

Insert "Sections 4 and 22 of this Act"

Page 23, line 18:

Delete "Sections 7, 11, 13, 14, and 25"

Insert "Sections 8, 12, 14, 15, and 26"

Page 23, line 20:

Delete "Sections 9, 10, 12, 15, and 20"

Insert "Sections 10, 11, 13, 16, and 21"

Page 23, line 24:

Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

Insert "Sections 4, 8, 12, 14, 15, 18, 22, and 26"

Page 23, line 31:

Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

Insert "Sections 1, 2, 3, 6, 7, 10, 11, 13, 16, 21, 23 - 25, and 27"

Page 24, line 2:

Delete "sec. 30"

Insert "sec. 31"

28-GS1647\A.7
Nauman/Bullock
2/5/13

AMENDMENT #5

OFFERED IN THE SENATE BY SENATOR GARDNER

TO: SB 21

Page 1, lines 1 - 2:

Delete "**relating to appropriations from taxes paid under the Alaska Net Income Tax Act;**"

Page 1, line 12, through page 2, line 18:

Delete all material and insert:

"* **Section 1.** 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) **of a** [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 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 **of a** [PER] BTU equivalent barrel of the taxable oil and gas for the month is not more than **$62.50** [$92.50], the tax rate is 0.4 percent multiplied by the number that represents the difference between that average monthly production tax value **of a** [PER] BTU equivalent barrel and $30; [OR]

(2) if the producer's average monthly production tax value **of a** [PER] BTU equivalent barrel of the taxable oil and gas for the month is more than **$62.50 but not more than** $92.50, the tax rate is the sum of **13** [25] percent and the product of **0.3** [0.1] percent multiplied by the number that represents the difference between the average monthly production tax value **of a** [PER] BTU equivalent barrel and

$62.50; or

(3) if the producer's average monthly production tax value of a BTU equivalent barrel of the taxable oil and gas for the month is more than $92.50, the tax rate is the sum of 22 percent and the product of 0.1 percent multiplied by the number that represents the difference between the average monthly production tax value of a BTU equivalent barrel and $92.50, except that the sum determined under this paragraph may not exceed **35** [50] percent."

Renumber the following bill sections accordingly.

Page 5, line 27:

Delete "sec. 4"

Insert "sec. 3"

Page 6, lines 11 - 13:

Delete "[THE SUM OF] 25 percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"

Insert "the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by"

Page 6, lines 26 - 28:

Delete "[THE SUM OF] 25 percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"

Insert "the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by"

Page 7, lines 9 - 11:

Delete "[THE SUM OF] 25 percent **of** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"

Insert "the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by"

Page 7, lines 19 - 21:

Delete "[THE SUM OF] 25 percent **<u>of</u>** [AND THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY]"

Insert "the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g) multiplied by"

Page 8, line 25, through page 9, line 11:

Delete all material.

Renumber the following bill sections accordingly.

Page 9, line 30:

Delete "sec. 7"

Insert "sec. 5"

Page 11, line 29:

Delete "sec. 11"

Insert "sec. 9"

Page 21, line 10, though page 22, line 31:

Delete all material and insert:

"* **Sec. 20.** AS 43.55.160(a), as amended by sec. 19 of this Act, is amended to read:

(a) Except as provided in (b) **<u>and (f)</u>** of this section, for the purposes of

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

(A) oil and gas produced from leases or properties in the state that include land north of 68 degrees North latitude, other than gas produced before 2022 and used in the state;

(B) 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

(i) gas produced before 2022 and used in the state; or

(ii) oil and gas subject to AS 43.55.011(p);

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

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

(E) gas produced before 2022 from each lease or property in the state outside the Cook Inlet sedimentary basin and used in the state, other than gas subject to AS 43.55.011(p);

(F) oil and gas subject to AS 43.55.011(p) produced from leases or properties in the state;

(G) oil and gas produced from leases or properties in the state no part of which is north of 68 degrees North latitude, other than oil or gas described in (B), (C), (D), (E), or (F) of this paragraph;

(2) AS 43.55.011(g), the monthly production tax value of the taxable

(A) oil and gas produced during a month from leases or properties in the state that include land north of 68 degrees North latitude is the gross value at the point of production of the oil and gas taxable under AS 43.55.011(e) and produced by the producer from those leases or properties, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil and gas produced by the producer from those leases or properties, as adjusted under AS 43.55.170; this subparagraph does not apply to gas subject to AS 43.55.011(o);

(B) oil and gas produced during a month from leases or properties in the state outside the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North latitude, is the gross value at the point of production of the oil and gas taxable under AS 43.55.011(e) and produced by the producer from those leases or properties, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to the oil and gas produced by the producer from those leases or properties, as adjusted under AS 43.55.170; this subparagraph does not apply to gas subject to AS 43.55.011(o);

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

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

(E) gas produced during a month from a lease or property outside the Cook Inlet sedimentary basin and used in the state is the gross value at the point of production of that gas taxable under AS 43.55.011(e) and produced by the producer from that lease or property, less 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar year applicable to that gas produced by the producer from that lease or property, as adjusted under AS 43.55.170."

Renumber the following bill sections accordingly.

Page 23, line 1:

Delete "a new subsection"

Insert "new subsections"

Page 23, following line 10:

Insert a new subsection to read:

"(g) A separate annual production tax value must be calculated under (a)(1) of this section for

(1) oil and gas produced from leases or properties in the state that include land north of 68 degrees North latitude, other than gas produced before 2022 and used in the state;

(2) 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, during a calendar year before or during the last calendar year under AS 43.55.024(b) for which the producer could take a tax credit under AS 43.55.024(a); this paragraph does not apply to

(A) gas produced before 2022 and used in the state; or

(B) oil and gas subject to AS 43.55.011(p);

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

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

(5) gas produced before 2022 from each lease or property in the state outside the Cook Inlet sedimentary basin and used in the state, other than gas subject to AS 43.55.011(p);

(6) oil and gas subject to AS 43.55.011(p) produced from leases or properties in the state;

(7) oil and gas produced from leases or properties in the state no part of which is north of 68 degrees North latitude, other than oil or gas described in (2), (3), (4), (5), or (6) of this subsection."

Page 23, line 12:

Delete "AS 43.55.011(g), 43.55.023(i), and 43.55.160(c) are"

Insert "AS 43.55.023(i) is"

Page 23, line 15:

Delete "Sections 2, 5, 6, 22 - 24, and 26"

Insert "Sections 1, 4, 20, 21, and 23"

Page 23, line 17:

Delete "Sections 3 and 21"

Insert "Sections 2 and 19 of this Act"

Page 23, line 18:

Delete "Sections 7, 11, 13, 14, and 25"

Insert "Sections 5, 9, 11, 12, and 22"

Page 23, line 20:

Delete "Sections 9, 10, 12, 15, and 20"

Insert "Sections 7, 8, 10, 13, and 18"

Page 23, line 24:

Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

Insert "Sections 2, 5, 9, 11, 12, 15, 19, and 22"

Page 23, line 31:

Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

Insert "Sections 1, 4, 7, 8, 10, 13, 18, 20, 21, and 23"

Page 24, line 2:

Delete "sec. 30"

Insert "sec. 27"

ALASKA STATE LEGISLATURE
Trans Alaska Pipeline Throughput Committee

Sen. Peter Micciche, Co-Chair

State Capitol Building, Room 125
Juneau, AK 99801 – 1182
Phone (907) 465-2828
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Shows Sen. Gardner's amendments

LETTER OF INTENT

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput was formed specifically to evaluate solutions designed to reverse or significantly reduce the historical decline in the quantity of oil produced from leases or properties north of 68 degrees North latitude and shipped through the Trans Alaska Pipeline System. The Committee recognizes that oil revenue is extremely important to the State of Alaska and currently funding over 90% of Alaska's essential services and critical infrastructure including education, public safety, health and social services and transportation. The Committee is also aware that projected declines in the Trans Alaska Pipeline System throughput may compound the operational and cost issues that could jeopardize the viability and safe operation of the Trans Alaska Pipeline System.

The Committee was the first to consider SENATE BILL 21 "An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

The Committee held six meetings with the intent of framing the discussion around SB 21 through a lens of evaluating direct impacts to the TAPS production decline. The Committee process was designed for fairness and equal participation by majority and minority members. The Committee included expert consultant, agency, the Alaskan public and industry testimony in the process through many productive hours and publicly-available meetings evaluating the potential positive and negative effects on production through revised Alaska oil tax policy. Most importantly, the Committee provided over five hours of Committee time for public testimony from every LIO in the state, as well as telephonically from any location. Every Alaskan that chose to address the Committee was warmly welcomed and given the opportunity to share their support and/or concerns.

The Committee has arrived at several key findings after completing the process of evaluating SB 21 and the effects of oil tax on production. They include:

- Regarding oil revenue that funds the vast majority of governmental functions for the people of Alaska, there are many factors in which the State has little control, including the price of North Slope oil. Total government take through oil taxation is the only lever under the control of the people of Alaska.
- The ACES tax structure has likely contributed to advancing the decline of oil production and throughput in TAPS, primarily due to a lack of competitiveness with other OECD producing regions.
- When evaluating with increased production as a primary objective, ACES credits should have been more specifically directed toward projects resulting in production and less toward general spending.
- Specific incentives and a competitive oil tax regime in Alaska will likely result in additional production-related spending.
- There has been a direct correlation in other OECD producing regions between production-related spending and increased production.
- Current fiscal spending policies appear to have an adverse effect on the business climate and willingness to invest in the State of Alaska. Policies must deliver the clear message to the business community that Alaska will not continue taxing to fund unsustainable levels of government spending.
- Although SB 21 is an adequate platform from which a respectful dialogue can begin, in the current form the bill may not adequately provide production credit incentives and opportunities; a level revenue proportion for Alaskans; and protections for Alaska hire and re-investment.

The Committee's intent to pass the bill to the Senate Resources Committee in the original form for further processing is in no way an expression of support by Committee members for SB 21 in current form. In fact, most members have expressed concern for key concepts that would require revision prior to supporting the bill as it moves through the legislative process.

Key concerns being passed through this letter with an expectation of consideration moving forward will be communicated in two sections. The first section below includes throughput-related Committee recommendations:

- Evaluate providing a guarantee of investment in Alaska and a further incentive for stemming production decline from leases or properties north of 68 degrees North latitude by fixing the amount of production used in determining the reasonable transportation costs to determine transportation deduction costs for pipelines and gas treatment plants under the Oil and Gas Production Tax and Oil Surcharge, AS 43.55, so that producers receive a benefit for increased oil production and throughput in the Trans Alaska Pipeline System but incur a corresponding limitation on deductions due to throughput declines after December 31, 2015.
- Evaluate expanding the application of the Gross Revenue Exclusion in units formed before 2003 (Legacy Areas). The Senate Resources Committee should specifically inquire about expansions of existing Participating Areas, increasing recovery factors in

existing Participating Areas, and Participating Areas that contain oil with an API gravity of 20 degrees or less.

- Evaluate specific production-related credits allowed under ACES for inclusion in SB 21 as a direct incentive for costs that deliver production. Require that credits are charged against actual production to eliminate currently-existing negative revenue liability to the State.

The Committee is united in several philosophies that are also recommendations to be considered in SB 21, not related to throughput, including:

- Firm incentives for Alaska Hire and Alaska Purchase,
- Evaluating significant and specific incentives for unconventional and heavy oil,
- Evaluating a production credit system for producers willing to provide propane fuels for the people of rural Alaska in areas unlikely to receive natural gas distribution if/when a natural gas pipeline is constructed, and
- Evaluating employing progressivity as a tool to level the proportion of take for Alaskans across the various oil price environments.

Although not supported unanimously by the Committee, yet in the spirit of fairness for all Committee members, the Minority Committee member has requested the following considerations to be passed onto the Senate Resource Committee:

- Evaluate a time limit into the future for the 20% Gross Revenue Exclusion.
- Evaluate removing the Net Operating Loss provision in SB 21.
- Evaluate adding a 10% minimum gross tax at the gross value at the point of production.
- Consider bracketing progressivity at varying rates as the price of oil varies.

The Senate Special Committee on Trans Alaska Pipeline System (TAPS) Throughput will continue to convene to identify and evaluate additional mitigation solutions for operational and regulatory TAPS production-related obstacles in the future. The Committee looks forward to the constructive dialogue and additional processing that will occur within the Legislature related to SB 21 the remainder of this session.

Respectfully submitted to the Senate Resource Committee on February 7, 2013,

Sen. Peter A. Micciche, Co-Chair

Sen. Mike Dunleavy, Co-Chair

ALASKA STATE LEGISLATURE

Trans Alaska Pipeline Throughput Committee

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Respectfully submitted to the Senate Resources Committee on February 7, 2013,

Sen. Peter A. Micciche, Co-Chair

Sen. Mike Dunleavy, Co-Chair

SENATE COMMITTEE REPORT
First Committee of Referral

DATE: 1/16/13

FURTHER: Resources
Finance

Date of 5-Day Notice: 1/17/13
(in accordance with Uniform Rule 23)

DATE TURNED IN TO OFFICE: 2/8/13

Senate Special Committee on Trans Alaska Pipeline System Throughput considered SENATE BILL NO. 21

SB 21-OIL AND GAS PRODUCTION TAX

"An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

and recommends:

[ ] be **replaced** with **CS** ________ (________) *[ ] Same Title* *[ ] New Title*

[ ] adopt **previous CS** ________ (________) *[ ] Same Title* *[ ] New Title*

[ ] attached amendment(s)

[X] adopt TTP Letter of Intent

[ ] further referral to ________ Committee

Dept Abbr.	
ADM	LWF
CED	LAW
COR	LEG
CRT	MVA
EED	DNR
DEC	DPS
DFG	REV
GOV	DOT
DHS	UA

Previous FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #
REV		✓		1
DNR		✓		2

PREVIOUS FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #

[ ] **APPROPRIATION - no fiscal note**

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
Berta Gardner	GARDNER				X
Anna I. Fairclough	FAIRCLOUGH				✓
Lesil L. McGuire	McGuire				✓
CO-CHAIR: [signature]	Dunleavy			X	
CO-CHAIR: [signature]	MICCICHE				✓

THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

COMMISSIONER'S OFFICE
Bryan Butcher, Commissioner

333 Willoughby Avenue, 11th Floor
PO Box 110400
Juneau, Alaska 99811-0400
Main: 907.465.2300
Fax: 907.465.2389

February 7, 2013

The Honorable Berta Gardner
Alaska State Senator
State Capitol, Room 417
Juneau, AK 99801-1182

Dear Senator Gardner:

I am writing in response to your February 1, 2013 letter with questions that arose during the Econ One Research presentation. I have worked with Mr. Pulliam and our economic research staff to answer your questions below. Please see questions in italics and our responses immediately below the questions.

1. *In recent years in Alaska there has been discussion about the majors being in "harvest mode." Is there any reason to believe that this characterization is incorrect?*

   Alaska's majors (defined here as CP, EM and BP) continue to develop their properties, which have billions of additional recoverable barrels in reserves. In addition, they are expanding (in the case of Conoco at CD-5 and Exxon and BP at Pt. Thompson) and have attempted to develop new fields (e.g., Liberty for BP) but have met with technical challenges. In addition, they have invested in recent years in updating older facilities in aging fields, facilities that will enable these fields to produce for many years to come. These activities are not consistent with companies that are in "harvest mode."

2. *Slide 26: Producer spending (in red) between 2007 and 2012 is roughly level while "all other" spending (in green) is doubled over the same period. We don't really know if producers were doing new work or maintenance work, but does the green portion indicate that ACES was successful in bringing new participants to Alaska?*

   Capital spending by large producers (red) grew by approximately $250 million between 2007 and 2012. At the same time, capital spending by all others (green) grew by approximately $320 million. The growth in "all others" over this period overlaps with the development of Oooguruk and Nikaitchuq by Pioneer Natural Resources and ENI, though the (green) spending in Chart 26 encompasses additional companies.

   Pioneer Natural Resources is the operator at Oooguruk and has a 70% working interest, which it acquired in 2002 during the ELF period. ENI holds the remaining 30%, which it acquired through the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005, also during the ELF period. The project was sanctioned in January 2006.

   ENI is the operator of Nikaitchuq. ENI acquired a 30% interest in Nikaitchuq with the purchase of the Alaskan assets of Armstrong Oil & Gas in August 2005. ENI acquired the remaining 70% interest in the Unit from Anadarko in March 2007. Anadarko in turn acquired its interest from Kerr-McGee.

KMG/Armstrong, ENI's predecessor in interest at Nikaitchuq, began drilling exploration and appraisal wells in the 2003-2004 season and drilled six wells prior to 2006. ENI sanctioned development of Nikaitchuq in February 2008 after receiving royalty relief approval from DNR in the second half of 2007.

ENI also owned interests in the North Tarn field (Mustang), which it acquired from Armstrong in August 2005. ENI farmed out its interests in these properties in 2010 to Brooks Range and a group of independents. Brooks Range and its partners are actively trying to advance Mustang and other projects as well.

With these background facts in mind, I do not believe that the rise in spending by "all others" shown in Slide 26 indicates that ACES (or its provisions) brought new participants to Alaska.

3. *Slide 27: Does this slide show that spending for new units increased 2 ½ times under ACES?*

   Slide 27 shows that spending for units not in production as of 2003 (Oooguruk, Nikaitchuq, Pt. Thomson and others) increased from $426 million in 2007 to $1,091 million in 2012. 2012 spending was approximately 2.5 times the level of 2007 spending. This represents an increase of approximately 150% during the period in which ACES has been in effect.

4. *Slide 38: This is an area profile for Australia. Can you explain why both employment and capital spending increased dramatically during the period 2002-2011 but Drilling/Development dropped beginning in 2006?*

   This slide shows employment and capital spending growing through 2011, while drilling is declining from 2006 forward. I believe these inverse trends are likely the result of two factors. First, the employment data from Australia includes mining operations, not just petroleum operations. We do not have a separate breakout for petroleum employment in Australia. Second, much of the capital spending in Australia has been related to LNG development which will include significant spending on facilities rather than drilling.

5. *Slide 43: Employment is climbing as spending holds steady. Why is this?*

   Slide 43 shows a significant growth in Alaska employment beginning in 2006, flattening between 2008 and 2011 and increasing by approximately 5% in 2012 (see also slide 34). The purpose of this slide is to benchmark employment changes in Alaska against other areas. We do not have 2012 comparative data for regions other than the lower-48. The top right panel shows employment growth in the rest of the US rose by a greater amount than the 5% we enjoyed in Alaska in 2012.

   Chart 34 shows both Alaska spending (top right) and employment (bottom left) over time. The 5% employment growth between 2011 and 2012 is not matched by a similar increase in capital spending. I do not know the reason for this. I do note that we see the reverse happening between 2007 and 2008, with spending rising by a larger amount than employment. Finally, I'd note that I would not necessarily expect to see a match between capital spending and employment changes. Capital reflects spending on facilities and wells. A component of this will show up in Alaska employment, but some portion will not, as the spending (e.g., engineering, fabrication) may take place outside the state.

6. *Slide 45: Attractiveness of Investments: We talked a bit about the role of various factors such as prospectivity, stability, Internal Rates of Return. What other factors might be considered?*

   This slide begins the section on investment analysis. Slide 48 lists the measures or "metrics" we examined in our analysis. I believe these are the significant financial measures that companies consider when making investment decisions. In addition to the measures listed in Slide 48, companies will consider prospectivity, political and fiscal stability, contractual obligations, permitting and access, and environmental and regulatory issues. Companies will also consider whether the project and/or area fits with their overall corporate strategy and operations and their ability of management to adequately focus on the project and/or area. All of these issues matter, though they are not all readily quantifiable. This is why we focused our comparisons on the US, Canada, North Sea and Australia as they share many of the same "non-quantifiable" qualities and are areas in which many of the North Slope producers are active.

7. *Slide 47-52: ACES incumbents have very high IRR. Is it fair to say that this means it is almost impossible to NOT make money under the status quo? If so, why are projects being delayed?*

   The higher IRRs for ACES incumbents result entirely from the "buy-down" effect. Additional investment under ACES allows an incumbent to "buy-down" its tax rate on existing production. Under the ACES system a producer can earn those higher IRRs, but only if it reinvests in Alaska to buy down its tax rate. It cannot earn those returns if it chooses to distribute its profits to shareholders, which is vitally important to management, not to mention shareholders. In this sense, the profits (and associated higher IRRs) are somewhat "captive" and may not be viewed as being of same quality (i.e., comparable) to profits earned in other jurisdictions where no such strings are attached.

   I believe that this is one reason why projects "are delayed" or not started at all, even though the IRRs are so high. Higher IRRs are a good thing, ceteris peribus (meaning all else equal). The challenge here is that all else is not equal, as discussed above.

   Another reason is that IRR does not tell the whole story. IRR is just one measure that investors look at. IRR is an investment decision tool, but should not be used to compare mutually exclusive projects, only to decide whether a single project is worth investing in. Moreover, IRRs are not appropriate for comparing projects with different risk characteristics.

   It is also important to note that IRR assumes reinvestment of interim cash flows in projects with equal rates of return (the reinvestment can be the same project or a different project). Therefore, IRR overstates the annual equivalent rate of return for a project whose interim cash flows are reinvested at a rate lower than the calculated IRR. This presents a problem, especially for high IRR projects, since there is frequently not another project available in the interim that can earn the same rate of return as the first project.

   When the calculated IRR is higher than the true reinvestment rate for interim cash flows, the measure will overestimate, sometimes very significantly, the annual equivalent return from the project. The formula assumes that the company has additional projects, with equally attractive prospects, in which to invest the interim cash flows. This is likely to be the case for the high IRRs indicated for Alaska incumbents.

In short, IRR is one factor, but should not be viewed in isolation. IRR calculations that vary greatly from most other opportunities should probably be taken with "a grain of salt."

8. *Can you show us these IRR slides with a line for SB21 for both incumbent and new participants?*

   Charts 62-66 show the same analysis as Charts 49-53 and include SB21.

9. *Slide 47: You indicate development costs of $16/bbl in Eagle Ford and $19 in Bakken. We have heard that development costs were significantly higher than that. A recent study using data from the North Dakota Industrial Commission in July 2012 found that the breakeven price for the "average" well in the Bakken formation is $80-$90/barrel, with an average decline of 40% in the first year. Can you explain the difference between "development costs" and "break-even price"?*

   Breakeven price refers to the price of oil in the market that is necessary for an investor to "breakeven" on its investment. Here breakeven would include recovering costs, including the cost of capital. Development costs (indicated at $19/bbl in Slide 47) are the investment that one hopes to break even on. So when the ND Commission says the breakeven price is $80-90/bbl it means that oil prices must be in this range for a producer to plus recover its development costs, including its cost of capital (i.e., a return on capital), operating costs, royalties and taxes.

10. *Slide 49: The cash margins are 2017-2022. This cells looks are cash during the 1st 5 years of production (under SB21 tax would be lower). What would it look like during development when both Incumbents and New Producers have lost the ACES credits and deductions?*

    The bottom left box shows margins per-barrel of production. It is cash generation divided by production. It's not possible to look at this metric during development as there is no production (i.e., denominator) during that period. Charts 59 and 60 do show producer cash flows under ACES and SB21. The first 5 years shown in these charts are the period of development.

11. *Slide 50: NPV-12 for ACES Incumbent is higher than NPV-l2 for Bakken at prices below $120. Does this mean that using NPV as a measure tells us that under ACES, oil development on the North Slope is more profitable here than in North Dakota?*

    Profit is an accounting concept while Net Present Value is an economic concept. A higher Net Present Value for a given project means that at the specified discount rate (in this case 12%) the project creates more value than a project with a lower Net Present Value. Slide 50 shows that the Net Present Value at a 12% discount rate creates more value to the ACES incumbent at prices below $120. As discussed above for slides 49-53 in the context of IRR, much of the higher NPV associated with the ACES incumbent is due to the tax buy-down on existing production. The ACES New Participant line shows a "break-even" NPV with the Bakken at about $100/bbl. The difference between these two reflects the impact of the buy-down for the incumbent.

    The slide shows that ACES Incumbent has a higher NPV than Bakken until about $120/bbl, and a similar NPV to Eagle Ford at prices below $100/bbl. The New Participant has a higher NPV than Bakken until about $100/bbl, but a lower NPV than Eagle Ford at all price levels.

12. *Slide 52: NPV and IRR for ACES are higher than for Norway but reversed for Cash Margins for 2017-2022. What would this comparison look like if it included the years 2007-2017? And, what is the relative importance of NPV/IRR vs Cash Margins in decision-making?*

    The relationships seen in this chart should not change if one looked at 2007-2017 instead, with the potential exception of Canada, where fiscal terms did change during this period. The analysis is based on fiscal terms in place currently, which would apply going forward. NPV, IRR, and Cash Margins are all relevant metrics to producers. Which is more relevant is probably a good question for the producers. I do believe, however, that once a project's IRR is greater than the producer's hurdle rate, differences between IRRs across projects are likely to be viewed as less relevant for the reasons discussed above. I also expect that producers would view NPV as more relevant than IRR for purposes of comparison. Cash margins are important to producers, but they would not likely trump NPV on their own. Put another way, high cash margins, combined with negative NPV's would not lead to investment. PI is also relevant, and would be used to aide management rank projects where budgets or other constraints don't allow them to undertake everything at once, which is common.

13. *Slide 53: Same questions for Canada Oil Sands*

    See answer to question #12.

14. *Page 56: The Gross Revenue Exclusion is forever? Was there consideration of doing a 7 year exclusion as we did in the "middle earth" legislation last session?*

    Yes, consideration was given to a 7-year GRE as well as the life-of-recovery GRE proposed in SB21. Including the GRE for the life of recovery enhances the investment metrics relative to a 7-year GRE. It also encourages continuing investment and recovery from new fields and removes the potential that oil recovery may be "inefficiently" front loaded in a new project.

15. *Slide 57: Does the phrase "eliminates incentives for gold-plating" also mean "eliminates incentive to reinvest Alaskan profits in Alaska"?*

    The term "eliminates incentives for gold plating" refers to the fact that under ACES, the State effectively subsides the majority of capital spending for incumbent producers. As prices rise, that subsidy increases and can exceed 100% of the expenditure. This subsidy reduces a producer's incentive to efficiently manage costs. The term "gold plating" is a term of art that describes this situation.

    I don't think there is any way to read the phrase as also meaning "eliminates incentives to reinvest in Alaska." In my view SB21 will increase producer's incentives to invest in Alaska. Reducing the government's take on the producer's investment will leave the producer with a greater share of the profits from its investment. That greater share is what will enhance their incentive to reinvest (and continue to earn a greater share of the profits).

Along this line of reasoning, the State should not fear that producers will be encouraged to "take their profits elsewhere." If producers can keep a greater share of what they invest in Alaska, they will be encouraged to reinvest in Alaska, and less tempted to reinvest their profits elsewhere. The structure of SB21 enhances the producer's incentives to invest, and reinvest in Alaska relative to ACES.

16. *Slide 58: May we please see this chart extended to $200 oil?*

We have attached a revised Slide 58 showing prices up to $200/bbl as requested. In addition to the price extension, we have shown the figures for the 5-year period FY 2015 - 2019 rather than FY2014-18 as FY 2014 is a transition year.

17. *Slides 59 & 60: Under SB2l, the NPV of the governor's proposal is nearly identical for a new producer ($318m) as an existing producer ($319). It would seem that these numbers should not be quite so close, since the incumbent gets the value of their spending in years 1 as a 25% tax reduction, whereas the new producer must hold their Net Operating Loss credit for several years. Is it the 15% interest payment that makes up the difference?*

Yes, new producers who don't have a tax liability would not be able to deduct their losses during development under SB21. New producers can carry forward their losses, which are increased by 15% per year, and deduct them against their tax liability once production begins. The 15% increase helps to keep their NPV equivalent to that of the incumbent that has the ability to deduct the loss against current tax liabilities.

18. *How many taxpayers were filing for oil and gas credits on the North Slope for each of the years 2002-2012?*

On the following page is a table that shows the number of companies in each year that either (1) applied for tax credit certificates for credits earned under AS 43.55.023 or AS 43.55.025 on the North Slope, or (2) applied credits earned on the North Slope under AS 43.55.023, .024, or .025 against their tax liabilities in the specified years. This analysis captures the vast majority of companies on the North Slope earning tax credits applicable to the ACES production tax.

With respect to the analysis below, we note that the tax credit under AS 43.55.025 was implemented in 2003. Tax credits under AS 43.55.023 and .024 were implemented with PPT and subsequently expanded with ACES in 2006 and 2007, respectively. The expansion of credits available through PPT and ACES was a large contributing factor to the number of companies earning credits under these programs.

Number of taxpayers filing for oil and gas credits on the North Slope, CY 2002 - 2012	
Calendar Year	**Number of Companies**
2002	0
2003	0
2004	3
2005	1
2006	13
2007	20
2008	26
2009	33
2010	33
2011	30
2012*	36

*2012 totals subject to true-up filings due March 31, 2013
Above data reflects number of companies that either applied for tax credit certificates from activity on the North Slope or applied credits against their tax liability for oil and gas production on the North Slope
Includes credits under AS 43.55.023, .024, and .025.

19. *The comparisons used in the presentation rely on jurisdictions where much of the development is shale or gas. Can we please see some of the same comparisons using the locations worldwide where British Petroleum, ConocoPhillips and Exxon are producing and making new investments in conventional oil?*

Within OECD countries, these companies are making significant investments in conventional oil production in the North Sea, the U.S. Gulf and Offshore Eastern Canada. The analysis includes North Sea conventional production (both U.K. and Norway). We will look at adding comparisons with the U.S. Gulf and Eastern Canada offshore.

20. *Barry Pulliam testified that Alaska is viewed as unfriendly to business. Do you think that is an accurate view?*

Mr. Pulliam stated that Alaska is viewed as "a high tax, not always friendly place to do business." Mr. Pulliam did not say Alaska is "unfriendly to business." There would seem to be little doubt that Alaska is a "high tax" jurisdiction, particularly at current prices. Mr. Pulliam testified that Alaska has a very challenging physical environment on the North Slope, which is certainly not a "friendly" place to do business. He also mentioned the challenges associated with permitting new projects such as CD-5, a project that filed its first permits more than 5 years before receiving approval. He also stated that permitting practices by the State of Alaska itself were generally viewed positively by business. In addition, he mentioned the challenges associated with offshore development in the aftermath of the Gulf Horizon incident. In addition to these issues, producers are challenged by environmental lawsuits (e.g., Shell) that seek to delay or discourage development. These are all examples of how Alaska can be viewed as a place that is not <u>always</u> friendly to do business. DOR agrees with Mr. Pulliam's characterization.

21. *During his presentation of SB21 to the Legislature, Commissioner Butcher and Chair Micciche had a conversation about fairness being sharing profits of our oil with 1/3 to state, 1/3 to federal government and 1/3 to producers. Do you think a total government take of 2/3 is a reasonable goal?*

The administration is seeking a balance of providing enough profit to entice producers to bring Alaska's resources to market and simultaneously maintaining as much of those benefits as possible for Alaskans in accordance with our constitution. Attempting to capture too great a percentage of those benefits results in leaving resources in the ground as producers seek out better opportunities. With this balance in mind, the administration believes that the total government take should not exceed 2/3 of the profits from oil production. However, given investment alternatives available in other areas, this should be viewed as an upper limit on government take rather than a goal.

22. *What about contractual obligations to develop? We saw with Point Thompson that the duty to develop is enforceable. What do you think about the obligations/duty to develop as a factor in development decision-making?*

Contractual obligations certainly play a role in decision making. The primary lease term is really focused on prudent exploration and delineation. Upon unitization the State has a greater opportunity to leverage operators into development. While over the last decade unitization has been used as a tool to 'extend leases' this paradigm is fundamentally changing and development activities and obligations are becoming standard requirements in new unit approvals. The business decisions for 'explorers' is different than that of 'producers'. Successful exploration doesn't automatically result in development and production. If the economic environment isn't conducive to long term exposure of significant capital funds then developments aren't progressed. This is really a failed opportunity for the industry and the State.

23. *In terms of managing risk, are oil companies more concerned about risk at the low end or about high end?*

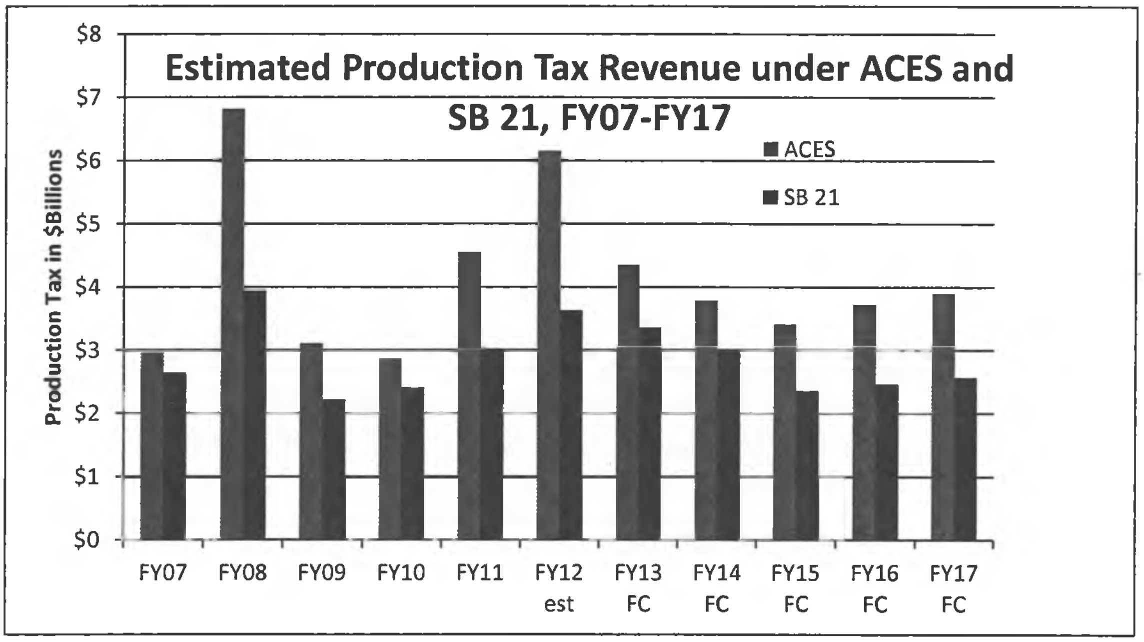
"Risk" is uncertainty. Uncertainty makes projects more "risky." Producers plan around a set of expected prices, but those expected prices may not prove to be correct. They also examine their economics at lower than expected prices (downside risk) and higher than expected prices (upside risk). They are concerned with both. They don't want to be in a situation where downside risk will cause a project will lose money. And, they will be less willing to take on this downside risk if their exposure to upside risk is limited. High progressivity removes much of the upside risk that might otherwise compensate for downside risk.

24. *What do we know about their hurdle rates or reasonable profits?*

We do not know what a specific company's hurdle rate or view of a reasonable profit is. Mr. Pulliam used a 12% discount rate in his analysis, which is widely viewed as reflecting producer's cost of capital in OECD countries. A hurdle rate would not be below the cost of capital. As an economic matter, we would expect producers to view a "reasonable" profit as one that is at least as good as its alternatives. Assuming all factors equal, if a producer can invest all the funds it has available and earn a 20% rate of return for example, it would likely view other opportunities as providing a reasonable profit as long as they also provided this type of return.

25. *In the 1/17/13 presentation "North Slope Oil Production History & Forecast" page 3 shows a forecast for General Fund Unrestricted Revenues for the Years 2012-2017. Can we please see that forecast (and history) for the years 2007-2017 under ACES, HB110 and SB21?*

Below is a chart showing the estimated production tax revenue under ACES and under SB 21, FY 2007 through FY 2017. What is not shown in this chart is the estimated savings from the state's general fund under SB 21 for not having to refund certain credits. From FY 2007 through FY 2012, that amount was approximately $1.2 billion. From FY 2013 through FY 2017, another savings of approximately $1.2 billion would be anticipated under SB 21, for a total savings over the 10-year period of about $2.4 billion.



I hope that you find this information helpful. I look forward to working together in our continuing efforts through the remainder of this legislative session.

Sincerely,

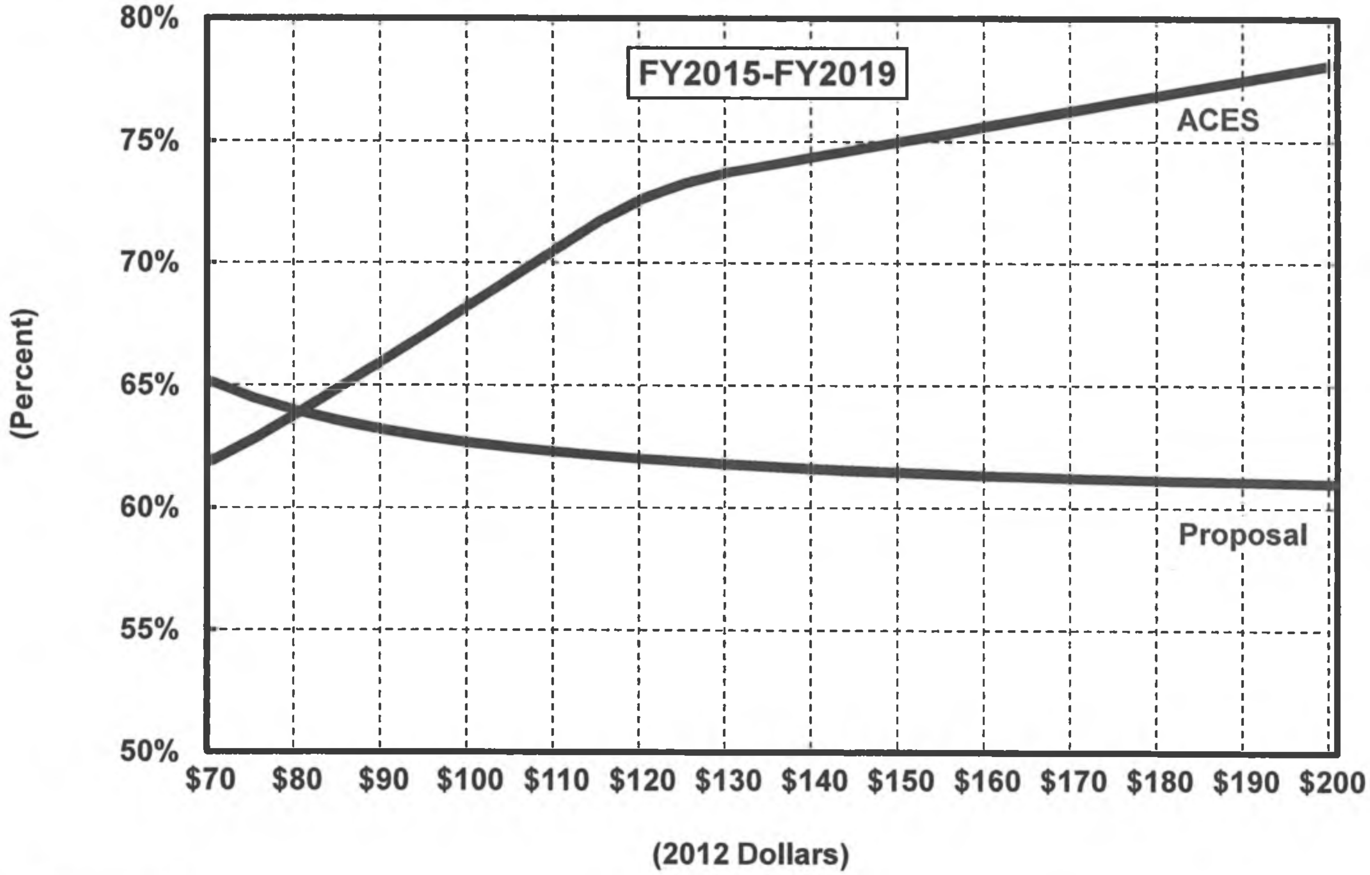
Bruce Tang

Bruce Tangeman
Deputy Commissioner

Enclosure: revised slide #58

Key Aspects of Administration's Proposal (cont'd)

- **Average Government Take Moves From Progressive to Relatively Neutral Under Proposal**



02/26/13 & 03/05/13 SB 59 - Oil and Gas Exploration and Development Areas

<TARGET><BILL>SB 59</BILL><SUBJECT>02-26-13 and 03-05-13 SB 59 - Oil and Gas Exploration and Development Areas</SUBJECT><COMM>STTP28</COMM></TARGET>

SENATE COMMITTEE REPORT
First Committee of Referral

DATE: 2/19/13

FURTHER: Resources
Finance

Date of 5-Day Notice: ____________________
(in accordance with Uniform Rule 23)

DATE TURNED
IN TO OFFICE: 3/5/13

Senate Special Committee on Trans Alaska Pipeline System Throughput considered SENATE BILL NO. 59

SB 59 OIL & GAS EXPLORATION/DEVELOPMENT AREAS

"An Act relating to approval for oil and gas or gas only exploration and development in a geographical area; and providing for an effective date."

and recommends:

[ ] be **replaced** with **CS** ________________________ (__________) *[ ] Same Title* *[ ] New Title*

[ ] adopt **previous CS** ________________________ (__________) *[ ] Same Title* *[ ] New Title*

[ ] attached amendment(s)

[ ] adopt ________________________ Letter of Intent

[ ] further referral to ________________ Committee

Dept Abbr.	
ADM	LWF
CED	LAW
COR	LEG
CRT	MVA
EED	DNR
DEC	DPS
DFG	REV
GOV	DOT
DHS	UA

NEW FISCAL NOTE(S)

Dept.	Fiscal	Indet.	Zero	FN #

PREVIOUS FISCAL NOTE(S)

Dept.	Fiscal	Indet.	Zero	FN #
DNR	✓			1

[ ] **APPROPRIATION - no fiscal note**

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	DO PASS	DO NOT PASS	NO REC	AMEND
Berta Gardner	Gardner			X	
Kevin McGuire	McGuire	✓			
CO-CHAIR: P. Micciche	MICCICHE	✓			
CO-CHAIR:					

THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Natural Resources

Office of the Commissioner

550 West 7th Avenue, Suite 1400
Anchorage, Alaska, 99501-3650
Phone: 907.269.8431
Fax: 907.269.8918

February 19, 2013

The Honorable Peter Micciche, Co-Chair
The Honorable Mike Dunleavy, Co-Chair
Senate Special Committee on TAPS Throughput
State Capitol Rooms 125 and 510
Juneau, AK 99801

Dear Senator Micciche and Senator Dunleavy:

The Department of Natural Resources (DNR) respectfully requests a hearing in the Senate Special Committee on TAPS Throughput on SB 59, "An Act relating to approval for oil and gas or gas only exploration and development in a geographical area; and providing for an effective date."

The purpose of this legislation is to clarify that oil and gas exploration and development approvals can be made for all or part of an oil and gas lease sale area, without regard to lease boundaries. This statutory change will help the Division of Oil and Gas (DO&G) do its business more efficiently and should enable the public to be better served by making the process for approving oil and gas exploration and development more certain and timely.

A copy of Governor Parnell's transmittal letter, the bill, a briefing paper, sectional analysis, and fiscal notes accompany this request.

Your favorable consideration of this request is appreciated. If you need any additional information, please contact Esther Tempel, Legislative Liaison for the Department of Natural Resources at 907-465-4730 or Robert Pawlowski, Legislative & Policy Advisor for the Division of Oil and Gas at 907-269-8802.

Sincerely,

Daniel S. Sullivan
Commissioner

Cc: Heather Brakes, Legislative Director, Office of the Governor
Bill Barron, Director, Division of Oil & Gas

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Governor Sean Parnell
STATE OF ALASKA

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February 18, 2013

The Honorable Charlie Huggins
President of the Senate
Alaska State Legislature
State Capitol, Room 111
Juneau, AK 99801-1182

Dear President Huggins,

Under the authority of Article III, Section 18 of the Alaska Constitution, I am transmitting a bill relating to approval for oil and gas or gas only exploration and development in a geographical area. This bill will reduce the time required to get oil into production and flowing through TAPS, while protecting Alaska's environment.

Under current procedures, the Department of Natural Resources (DNR) grants lease exploration and development approval in conjunction with individual plans of operation for a lease or project. As such, a separate public notice is required for each approval, often resulting in repetitive approvals within the same geographical area. In order to streamline the State's permitting process, this bill allows DNR to comprehensively evaluate oil and gas exploration and development in a geographical area, and define the criteria by which specific projects are evaluated and approved. Approvals made under the provisions of this bill are valid for up to ten years as specified by DNR's Director of the Division of Lands.

Creating economic opportunity in Alaska requires a clear, predictable, and timely permitting process that encourages resource development while protecting the environment. I urge your prompt and favorable action on this measure to create a streamlined permitting process in the interests of increasing oil throughput and growing Alaska's economy.

Sincerely,

Sean Parnell
Governor

Enclosure

SB 59: Oil & Gas Exploration/Development Areas
Briefing Paper

For the Senate Special Committee on TAPS Throughput • February 19, 2013

SB 59 will consolidate the Department of Natural Resources' exploration and development approvals and streamline its plans of operations approval process, while still protecting the environment and providing for public participation. The right to explore and develop oil and gas is granted through a lease that has been through an extensive public disposal process. A lease is subject to mitigation measures, multiple agency permits, and plans of operations approval. Exploration and development approvals are made in conjunction with individual plans of operations for a lease or project and include a separate public notice for each approval. Many approvals are repetitive, subject to the same mitigation measures, and within the same geographical area.

SB 59 will allow the department to comprehensively evaluate oil and gas exploration and development in a geographical area, without regard to lease boundaries, and define the criteria by which specific projects are evaluated and approved. The initial comprehensive review of a geographical area gives the public, government agencies and industry an opportunity to participate and identify exploration and development considerations for all subsequent projects. Projects may then move forward within the defined parameters and subject to the lease mitigation measures without additional public review following the geographical area approval process.

Approvals covering a broader area would both create efficiencies in the exploration and development review process and provide for the department to look at the overall effects of exploration and development across multiple leases. This bill will still protect the public interest by requiring public notice and an opportunity to comment under AS 38.05.945. Further, it provides certainty to the oil and gas industry that exploration and development projects may proceed within defined parameters.

This bill will:

- Create efficiencies by streamlining oil and gas exploration and development approval processes;
- Protect the public interests by requiring public notice and the opportunity to comment during the approval process for a geographical area;
- Enable a review of the effects of exploration and development across multiple leases;
- Allow project approvals to be consolidated into a comprehensive decision;
- Provide certainty to oil and gas operators, industry and the public when projects receive approval; and,
- Promote the state's interests through implementing effective approval processes.

SB 59: Oil & Gas Exploration/Development Areas
Sectional Analysis

For the Senate Special Committee on TAPS Throughput • February 19, 2013

Section 1 of SB 59 adds a new subsection (o) to AS 38.05.035 that allows the director to approve exploration or development for all or part of an area previously approved for oil and gas or gas only leasing under best interest findings as required under AS 38.05.035(e).

This section preserves the right for the public to comment by requiring the Department of Natural Resources to provide public notice.

If the approval is granted, exploration and development activities would be valid for a period of up to 10 years as specified by the director and the lessee can begin exploration or development only if it receives other authorizations as required by state or federal law.

This approval process would apply only to lands DNR previously described as areawide lease sales in its five-year program of proposed oil and gas or gas only lease sales.

Section 2 of SB 59 establishes an immediate effective date.

FISCAL NOTE

STATE OF ALASKA
2013 LEGISLATIVE SESSION

Bill Version	**SB 59**
Fiscal Note Number	1
(S) Publish Date	2/19/13

Identifier (file name)	LL0970-DNR-DOG-1-14-13	Dept. Affected	Natural Resources
Title	Oil and Gas Exploration and Development Approval	Appropriation	Oil and Gas
		Allocation	Oil and Gas
Sponsor	Rules by Request of the Governor		
Requester	Governor	OMB Component Number	439

Expenditures/Revenues (Thousands of Dollars)

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

	FY14 Appropriation Requested	Included in Governor's FY14 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	**FY14**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**
Personal Services	80.0						
Travel	3.0						
Services	48.8						
Commodities	2.2						
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	**134.0**	**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	134.0						
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
	TOTAL	**134.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

POSITIONS							
Full-time							
Part-time							
Temporary	1						

CHANGE IN REVENUES							

Estimated SUPPLEMENTAL (FY13) operating costs 0.0 *(separate supplemental appropriation required)*
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY14) costs 0.0 *(separate capital appropriation required)*
(discuss reasons and fund source(s) in analysis section)

ASSOCIATED REGULATIONS

Does the bill direct, or will the bill result in, regulation changes adopted by your agency? No

If yes, by what date are the regulations to be adopted, amended, or repealed? N/A Discuss details in analysis section.

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

Initial version, not applicable.

Prepared by	Bill Barron	Phone	269-8800
Division	Oil and Gas	Date/Time	1/14/13 5:00 PM
Approved by	Daniel S. Sullivan, Commissioner	Date	1/14/2013
	Department of Natural Resources		

(Revised 11/5/2012 OMB)

FISCAL NOTE ANALYSIS #1

STATE OF ALASKA **BILL NO.** SB 59

2013 LEGISLATIVE SESSION

Analysis

This bill will allow the Department of Natural Resources to approve oil and gas exploration and development for a geographic area, without regard to individual lease boundaries.

To implement this bill would require one non-permanent position (NRSIII) to prepare exploration approvals for existing oil and gas lease sale areas, contractual services for legal support, public outreach and notice, and travel for public meetings. On-going exploration and development approvals would be accomplished using existing staff as a result of efficiencies gained through implementing this bill.

SB 59: OIL & GAS EXPLORATION AND DEVELOPMENT APPROVALS BY GEOGRAPHICAL AREA

Senate Special Committee on TAPS Throughput

February 26, 2013

Department of Natural Resources

- Dan Sullivan, Commissioner
- William C. Barron, Director, DO&G
- Wendy Woolf, DO&G

SB 59 – "An Act relating to approval for oil and gas or gas only exploration and development in a geographical area; and providing for an effective date."

What does SB 59 do?

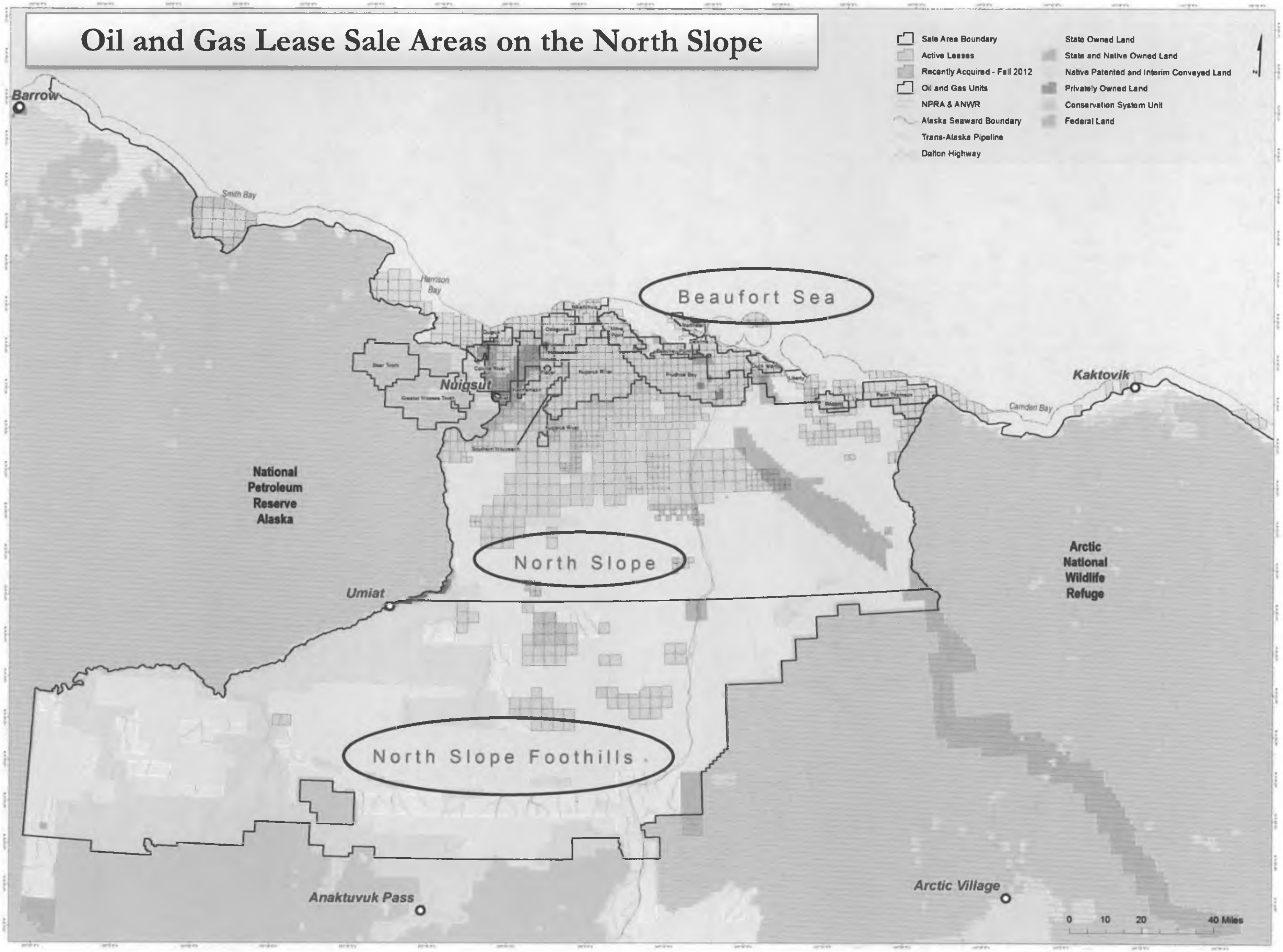
- It clarifies the Department of Natural Resources can authorize oil and gas exploration and development activities within a geographical area.
- It preserves public notice and review at the beginning of an exploration or development phase.
- It ensures certainty when an approval has been granted for exploration or development activities.

How does this benefit the public?

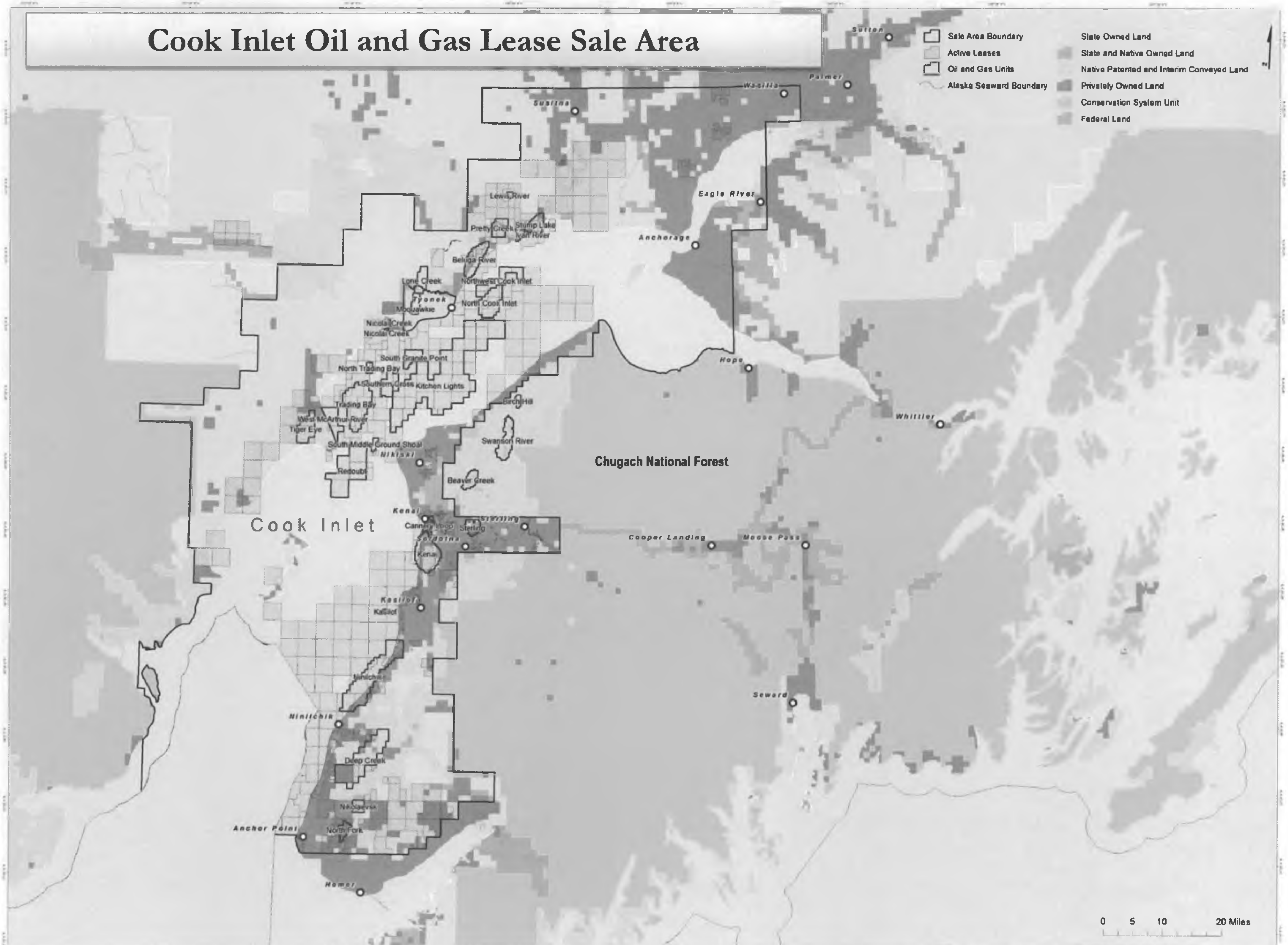
- It allows the public to comprehensively evaluate oil and gas activities within a geographical area.
- It provides an opportunity for input at the beginning of an exploration or development phase.
- It safeguards environmental concerns through special stipulations and conditions.

How does this benefit industry?

- It allows a project to be planned within approved parameters and conditions.
- It provides certainty that plans of operations meeting those defined criteria can proceed.
- It ensures predictable project approvals for subsequent exploration or development activity.



Oil and Gas Lease Sale Areas on the North Slope
Sale Area Boundary
Active Leases
Recently Acquired - Fall 2012
Oil and Gas Units
NPRA & ANWR
Alaska Seaward Boundary
Trans-Alaska Pipeline
Dalton Highway
State Owned Land
State and Native Owned Land
Native Patented and Interim Conveyed Land
Privately Owned Land
Conservation System Unit
Federal Land
Barrow
Smith Bay
Harrison Bay
Beaufort Sea
Nuiqsut
Kaktovik
Camden Bay
National Petroleum Reserve Alaska
North Slope
Arctic National Wildlife Refuge
Umiat
North Slope Foothills
Anaktuvuk Pass
Arctic Village
0
10
20
40 Miles



Cook Inlet Oil and Gas Lease Sale Area
Sale Area Boundary
Active Leases
Oil and Gas Units
Alaska Seaward Boundary
State Owned Land
State and Native Owned Land
Native Patented and Interim Conveyed Land
Privately Owned Land
Conservation System Unit
Federal Land
Sutton
Palmer
Wasilla
Susitna
Eagle River
Anchorage
Hope
Whittier
Chugach National Forest
Cook Inlet
Lewis River
Pretty Creek
Stump Lake
Ivan River
Beluga River
Lone Creek
Northwest Cook Inlet
Tyonek
Moquawkie
North Cook Inlet
Nicolai Creek
South Granite Point
North Trading Bay
Southern Cross
Kitchen Lights
Trading Bay
West McArthur River
Tiger Eye
Birch Hill
Swanson River
South Middle Ground Shoal
Nikiski
Redoubt
Beaver Creek
Kenai
Cannery Loop
Sterling
Soldotna
Cooper Landing
Moose Pass
Kasilof
Ninilchik
Seward
Deep Creek
Nikolaevsk
North Fork
Anchor Point
Homer
0 5 10 20 Miles

Oil and Gas Lease Sale Process

- **Proposed Areawide Oil and Gas Lease Sale**
  Public Notice and Opportunity to Comment
  Evaluate Statutory Criteria
  Develop Mitigation Measures
- **Final Finding of the Director to Lease Oil and Gas**
  - **Exploration Phase**
    Public Notice and Opportunity to Comment
  - **Development Phase**
    Public Notice and Opportunity to Comment
  - **Transportation (Pipelines)**
    Public Notice and Opportunity to Comment

Life of an Oil and Gas Lease

Year 0
- Final Finding of the Director – Areawide Oil and Gas Lease Sale
  - Lease Issued (10-Year Term)

Lessee develops exploration plans

Year 4
- Lease Plan of Operations – Seismic Program (multiple leases)
  - Public Notice and Comment Period

Year 5
- Lease Plan of Operations – Exploration Well
  - Public Notice and Comment Period

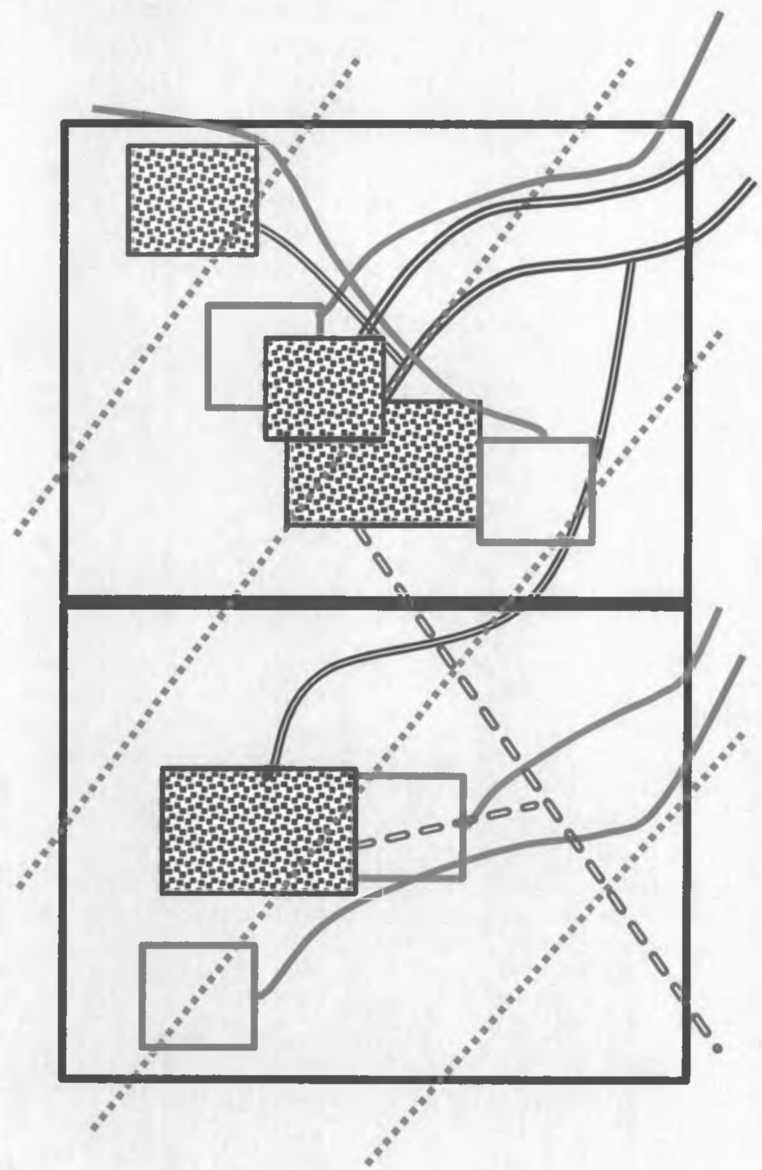
Year 6
- Lease Plan of Operations – Exploration Well
  - Public Notice and Comment Period

Discovery – Lessee formulates development plan

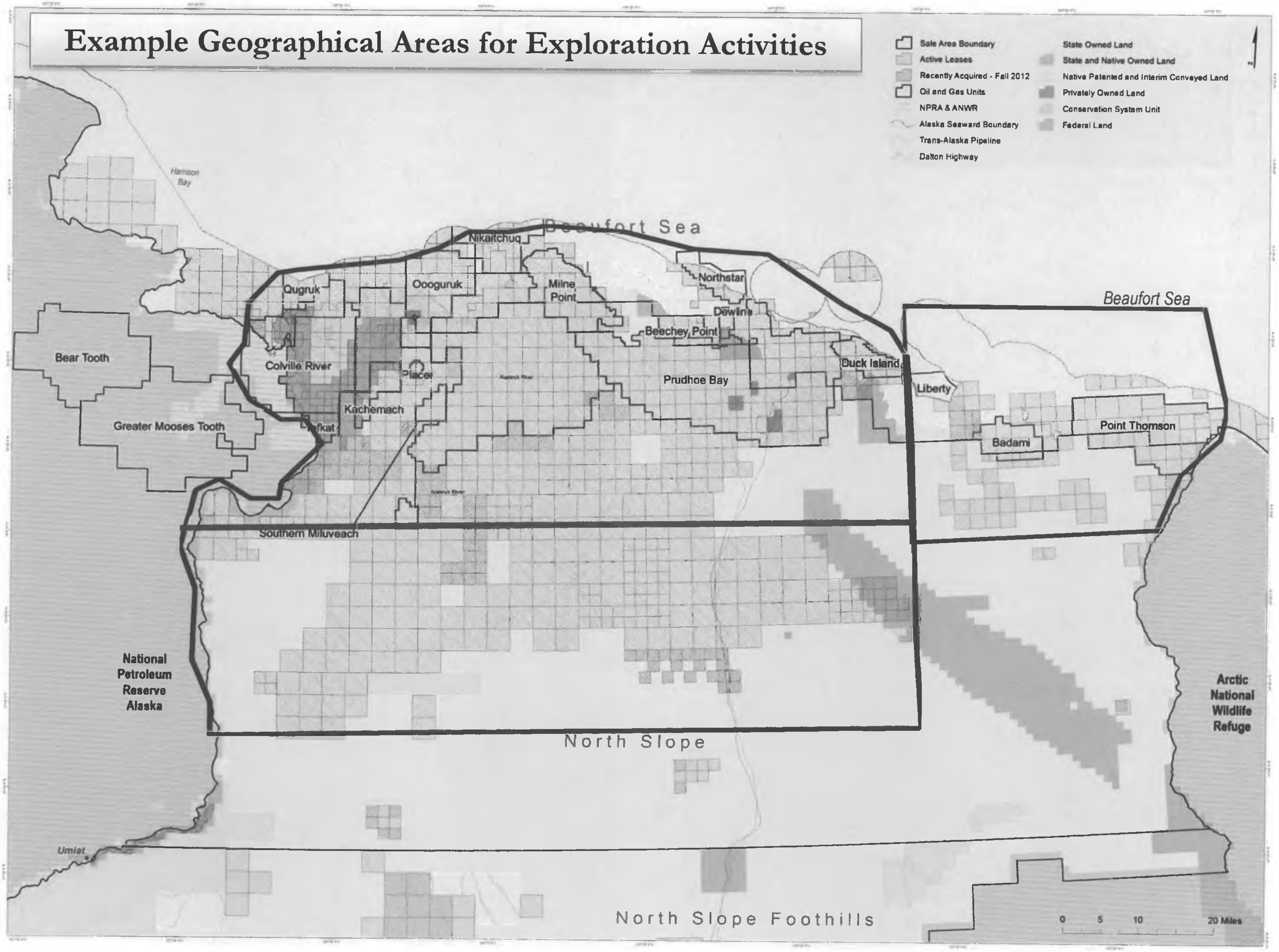
Year 7
- Lease Plan of Development – Conceptual Development Plan

Year 8
- Lease Plan of Operations – Initial Development Plans
  - Public Notice and Comment Period
- Lease Plan of Operations – Modified Development Plans
  - Public Notice and Comment Period
- Pipeline Application (AS 38.05.850 or AS 38.35)
  - Public Notice and Comment Period

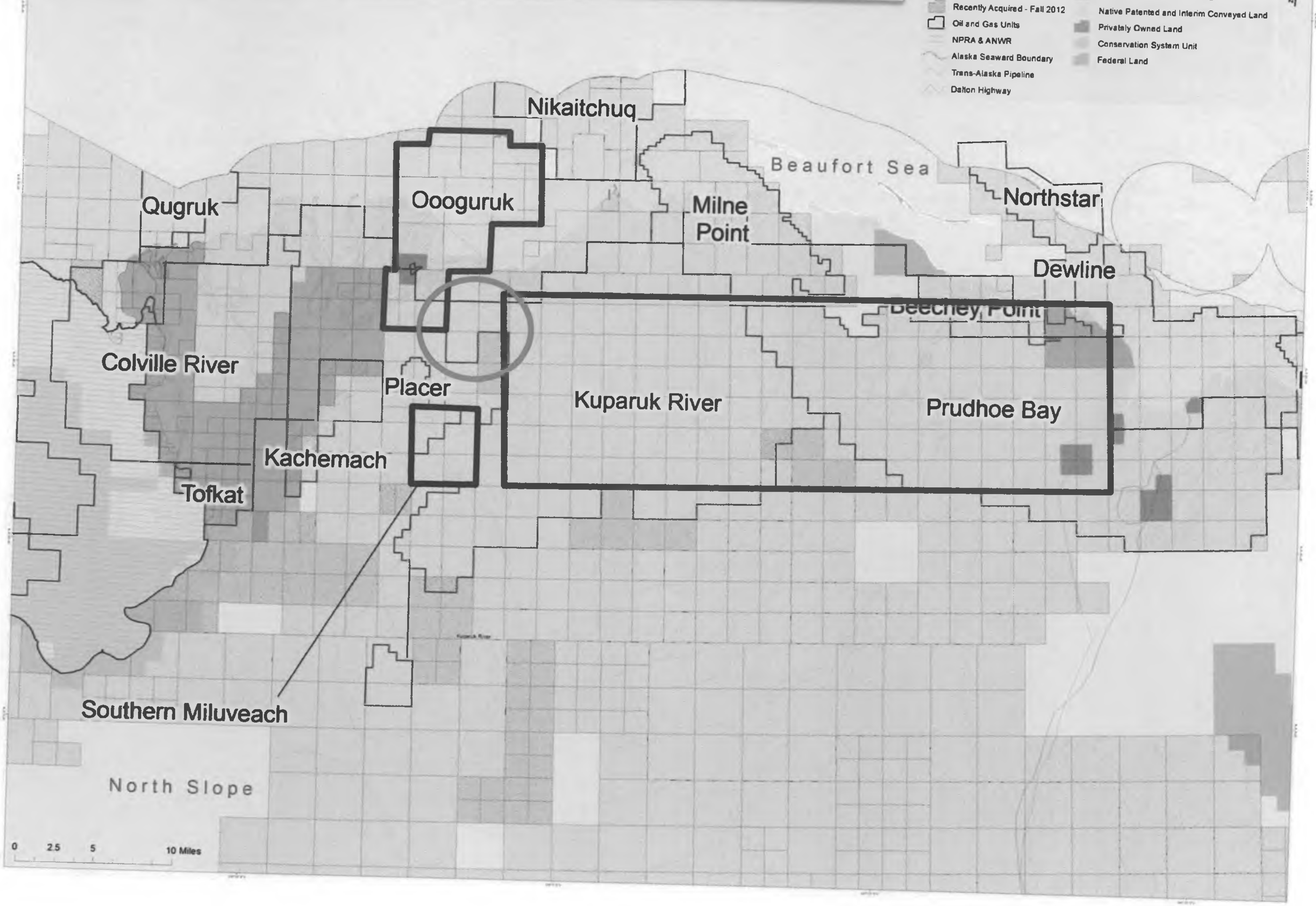
Year 10
- Production
- Lease Plan of Operations – Additional Development Plans
  - Public Notice and Comment Period

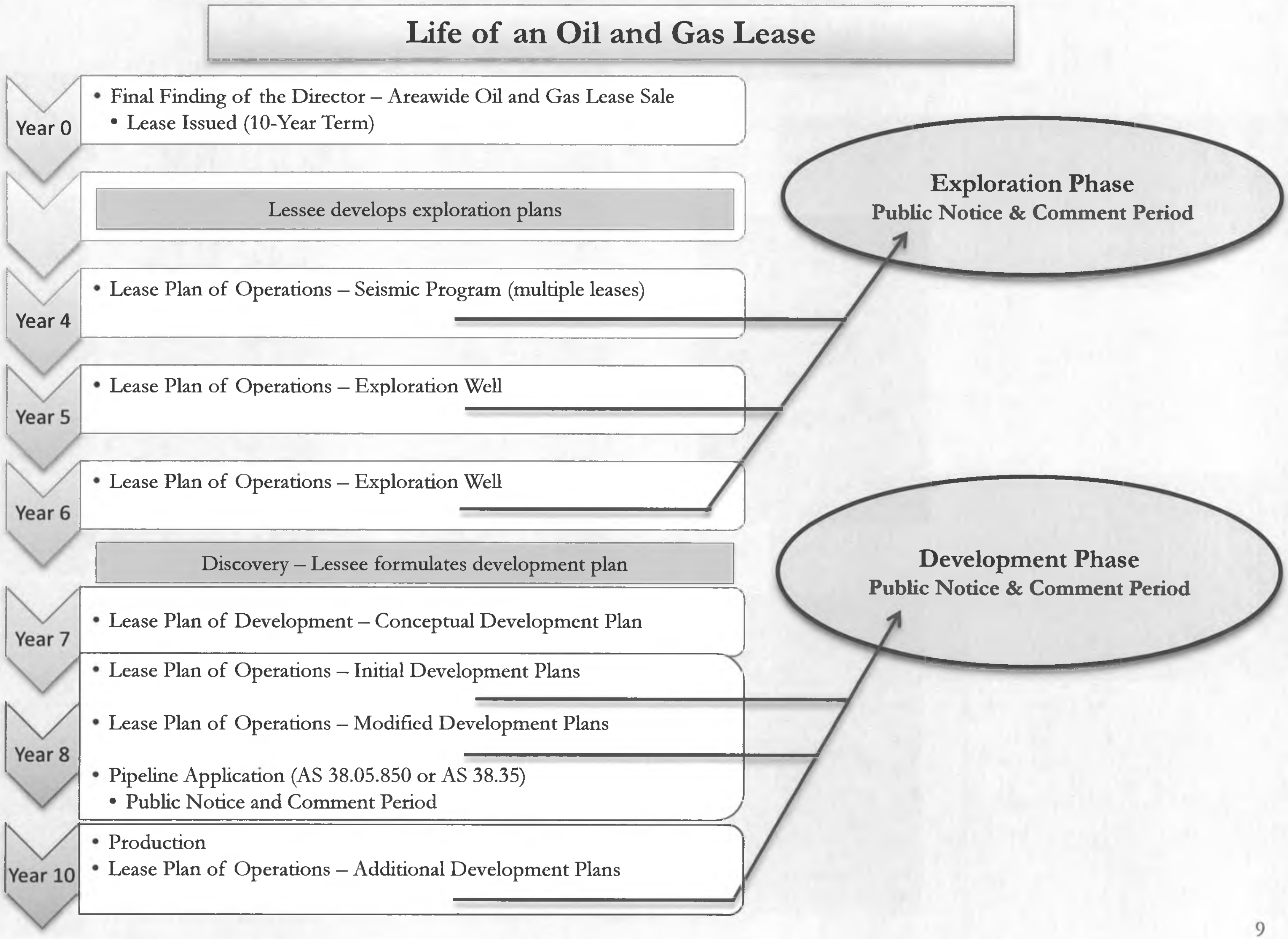


Example Geographical Areas for Exploration Activities



Example Geographical Areas for Development Activities




Life of an Oil and Gas Lease
Year 0
• Final Finding of the Director – Areawide Oil and Gas Lease Sale
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Lessee develops exploration plans
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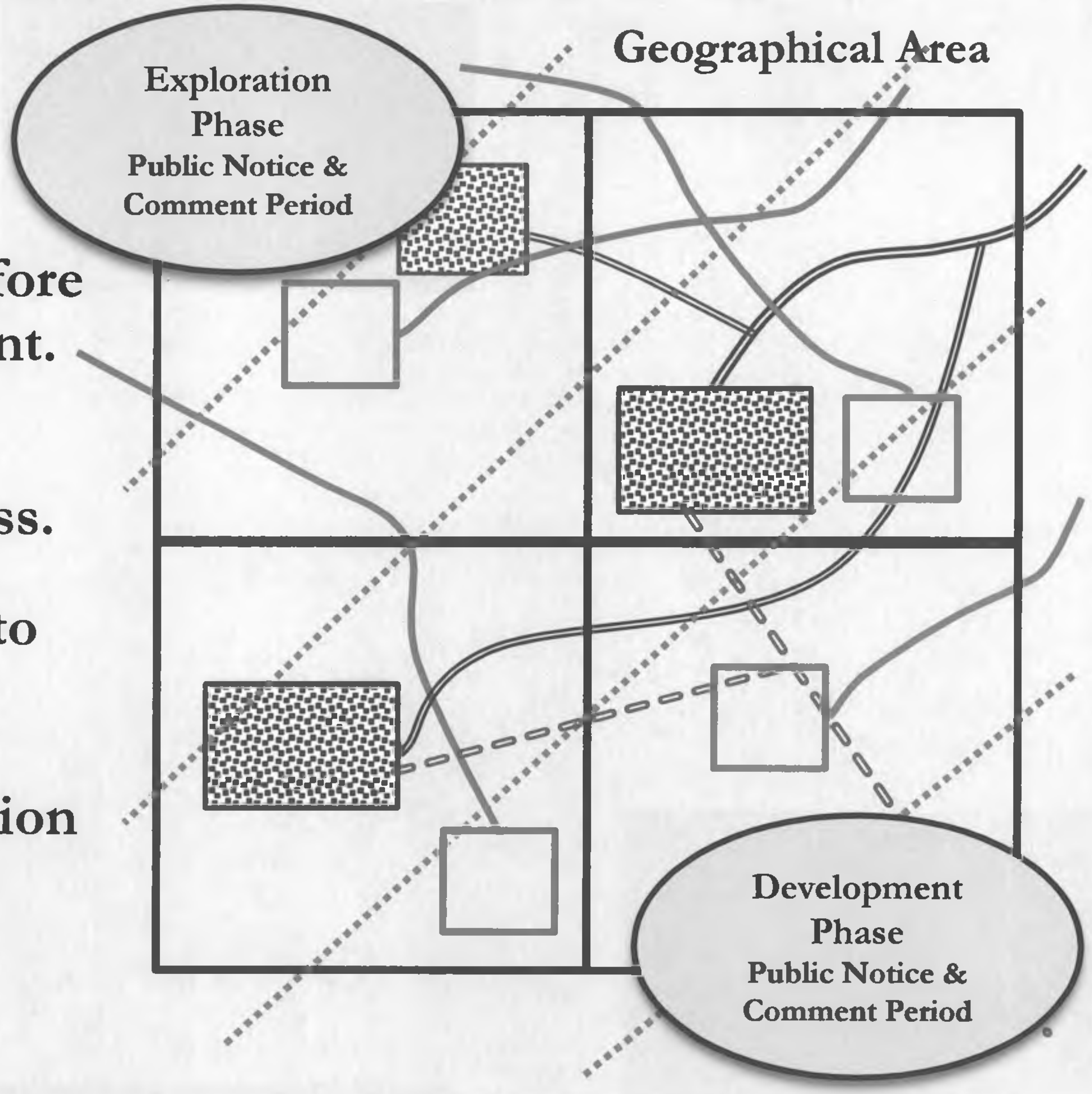
• Lease Plan of Development – Conceptual Development Plan
Year 8
• Lease Plan of Operations – Initial Development Plans
• Lease Plan of Operations – Modified Development Plans
• Pipeline Application (AS 38.05.850 or AS 38.35)
• Public Notice and Comment Period
Year 10
• Production
• Lease Plan of Operations – Additional Development Plans
Exploration Phase
Public Notice & Comment Period
Development Phase
Public Notice & Comment Period

Results

- **SB 59 provides for a comprehensive review before exploration or development.**
- **SB 59 preserves public participation in the process.**
- **SB 59 allows stipulations to be approved before a company develops site specific plans for exploration or development activities.**



Questions?

STATEWIDE PERMITTING REFORM

Senate Special Committee on TAPS Throughput Committee

February 26, 2013

Department of Natural Resources

- Dan Sullivan, Commissioner

IMPORTANCE *of* PERMITTING REFORM *for* ALASKA'S COMPETITIVENESS

Permitting reform has bipartisan, national and local recognition and support

- Permitting reform is a bipartisan effort as policymakers realize the economic benefits of allowing large-scale development projects to proceed in a responsible, timely manner
- States as politically diverse as California, Massachusetts, Indiana, and Kansas are fully engaged in modernizing their permitting processes
- The Federal government also recognizes the issues and has undertaken initiatives to reduce costs, simplify the system, and eliminate redundancy and inconsistency
- Last year (February 2012), *The Economist* ran a cover story called "Over-regulated America" in which it concluded that "America needs a smarter approach to regulation" that will "mitigate a real danger: that regulation may crush the life out of America's economy"
- In *Newsweek* (June 2011), President Bill Clinton lamented that it can take three years or more to permit major economic development projects. One of his top recommendations to put Americans back to work was to speed up the regulatory approval process and grant state waivers on environmental rules to hasten start times on construction projects

IMPORTANCE *of* PERMITTING REFORM *for* ALASKA'S COMPETITIVENESS

Permitting reform is a national issue affecting U.S. competitiveness

- Potential investors sometimes express reluctance to pursue projects in the U.S. and Alaska because of the ever-present risk of permitting delays and litigation
- In 2012, the investment firm Behre Dolbear Group, which undertakes an annual global survey of mineral sector investment, ranked the United States last (tied with Papua New Guinea) out of 25 countries in the category of "permitting delays"
  - "Permitting delays are the most significant risk to mining projects in the United States"
  - States are negatively impacted by federal rules that they are bound to enforce resulting in a 7- to 10-year waiting period before mine development can begin
  - Australia is one of the countries with the fewest permitting delays
- Contrast Alcan Highway construction

BEHRE DOLBEAR
BEHRE DOLBEAR GROUP INC.
MINERALS INDUSTRY ADVISORS

2012 RANKING OF COUNTRIES FOR MINING INVESTMENT
WHERE *"NOT TO INVEST"*

Since 1999, the Behre Dolbear Group Inc. has compiled annual political risk assessments of the key players in the global mining industry. Over time, our assessment indicates a positive correlation between the growth of a nation's wealth and the prosperity of its mining industry – only when a country recognizes its critical need to adapt, and restructures burdensome policy, will it truly optimize this economic potential.

While our perspective is often considered provocative, it is our intent to highlight countries whose policies and business conditions promote investment growth in the mining sector. Behre Dolbear welcomes continued feedback from our clients and industry professionals alike. Both positive and negative dialogue enables Behre Dolbear to improve its assessment.

This year's survey, as it has in the past, concentrates on specific countries, regional issues, and notable trends. Geology and mineral potential were not considered, as the fact that exploration, development, and mining activity are occurring confirms the existence of such potential. Only factors relevant to "political risk" have been considered. We do not make an effort to include mitigating factors such as economic returns or an investor's relevant experience in a particular country as part of our ranking.

The Behre Dolbear Group of companies is comprised of more than 150 professionals based out of 12 offices around the globe. The views expressed herein reflect the collective responses to our annual internal survey. Our professionals' opinions are valued as they have the unique opportunity to conduct business and evaluate investments within many different countries. In 2011, Behre Dolbear completed 220 projects in over 55 countries. Our global reach through the depth and diversity of our international involvement continuously builds our perspective on the industry. Our rankings in this annual survey are also based in part on confidential sources and public databases. Behre Dolbear ... *Economic Freedom* (a Wall Street Journal/...

> *"Permitting delays are a global issue."*
> – Behre Dolbear, 2012 Ranking of Countries for Mining Investment: Where "Not to Invest"

IMPORTANCE *of* PERMITTING REFORM *for* ALASKA'S COMPETITIVENESS

Jobs and the Environment are Undermined by Permitting Delays and Overregulation

- While an overly burdensome regulatory system can discourage investments and job creation, it can also undermine, not enhance, environmental protection
- When companies forgo investing in places like Alaska and the U.S.—places with very high environmental standards—because of regulatory delays, it can result in passing energy and mineral investment to nations with substandard environmental regulations and little capacity or desire to protect the environment
  - Last year the Associated Press estimated that 5 to 20 million tons of oil leaked a year in Russia. At even the lower end, that would be the equivalent of a Deepwater Horizon blowout about every two months
  - Russia experienced approximately 18,000 oil pipeline ruptures in 2010 – the figure in the U.S. for the same year was 341
- The global environment would be much better off if hydrocarbons and other natural resources were produced in countries with the highest environmental standards rather than some of the lowest

IMPORTANCE *of* PERMITTING REFORM *for* ALASKA'S COMPETITIVENESS

Timely, predictable, and efficient permitting is critical to other statewide strategies

<u>Secure Alaska's Future: Oil</u>

I. Increase production by making Alaska more competitive

II. Ensure the permitting process is structured and efficient

III. Facilitate and incentivize the next phase of North Slope development

IV. Promote Alaska's resources and positive investment climate to world markets

<u>Secure Alaska's Future: Strategic & Critical Minerals</u>

I. Undertake a statewide assessment of Alaska's strategic mineral potential—millions budgeted for this project

II. Provide support for the development of known or highly prospective strategic mineral occurrences throughout Alaska through infrastructure partnerships and incentives

III. Improve the structure and efficiency of permitting processes in order to expedite mineral development, including strategic minerals

IV. Deepen partnership and cooperation with the federal government, local governments, Native corporations, and other potential new entrants to encourage domestic exploration, development, and processing of REEs and other strategic minerals

V. Attract new investment and markets for Alaska's abundant mineral resources

Statewide Permitting Reform

- Strategy -

Objective:

Improve the State of Alaska's permitting processes in order to advance the public interest by ensuring projects are permitted in a timely, predictable and efficient manner while safeguarding the environment.

DNR has been working with a team from DEC, ADF&G, and LAW to develop and advance strategies that aim to:

I. Improve agencies' internal permitting structure to create a more efficient, timely, and certain process

II. Enhance coordination within different state departments and with different entities and stakeholders throughout the state

III. Seek input from the public about the permitting process including input from municipalities, industry and non-governmental organizations

IV. Improve coordination between the state and the federal government—federal permitting issues have a strong influence on state projects

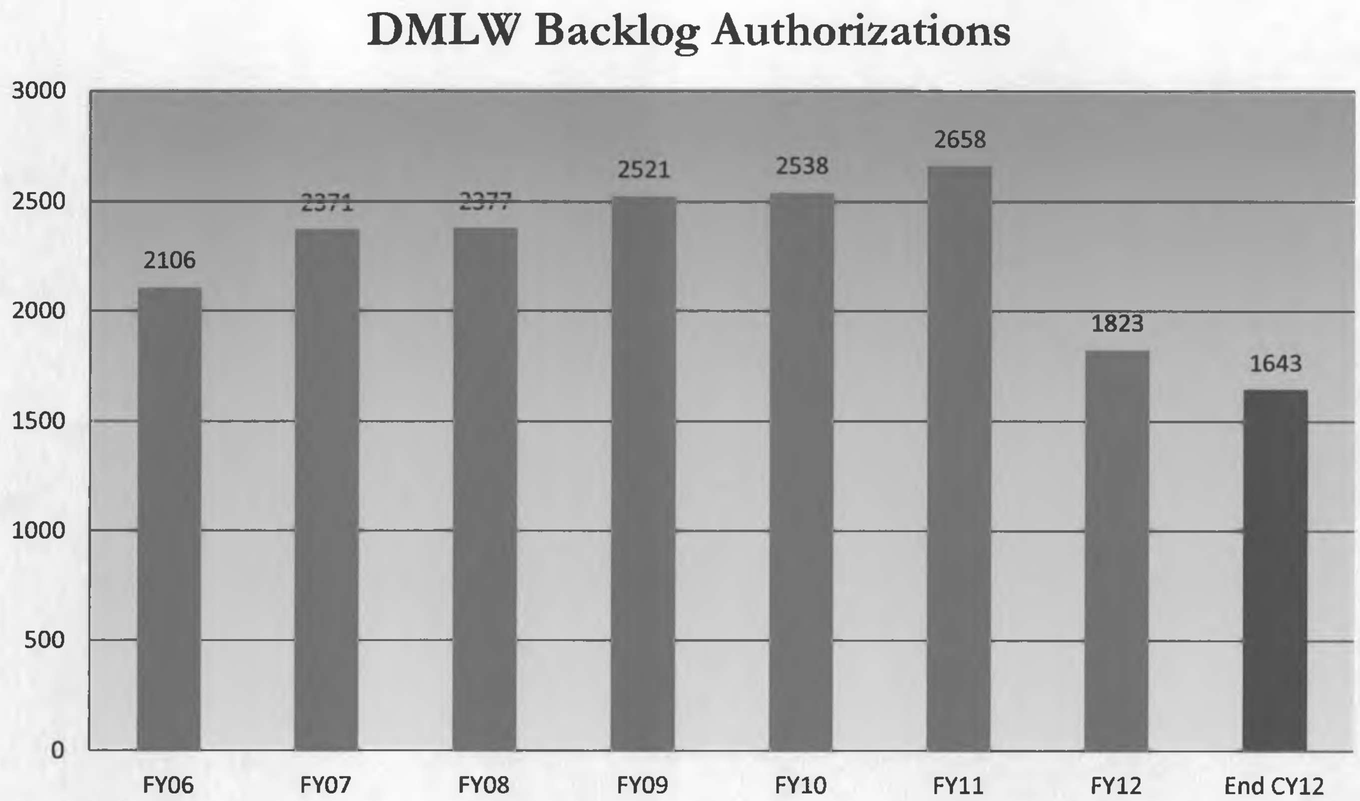
V. Anticipate and plan for permitting the next phases of resource development, e.g. the Shale Oil Task Force

STATEWIDE PERMITTING REFORM
- SIGNIFICANT PROGRESS MADE -

- In FY12, the Legislature provided approximately $2.7 million in operating funds for the Division of Mining, Land & Water to create efficiency, timeliness and certainty in the permitting process
- We utilized capital funding from FY12 ($2.5M for the Unified Permit Project and Document Management) to focus on business management software and services
- In FY13, the Legislature approved the continuation of FY12 operating funds as part of the ongoing base for permitting and an additional $950.0 to cover increased personnel costs and fill vacant positions focused on permitting
  - FY13 capital budget included $3.3M to continue work on the Unified Permit Project, including the continuation of IT strategies and Business Process Management
- We reclassified and updated over 50 position descriptions
- Since the beginning of FY12, the backlog has been reduced by 38.2% (1,015 authorizations)
- We have conducted public meetings statewide for input on state permitting processes
- We are evaluating internal processes to identify and fix inefficiencies

STATEWIDE PERMITTING REFORM

- SIGNIFICANT PROGRESS MADE -



STATEWIDE PERMITTING REFORM
- SIGNIFICANT PROGRESS MADE -

2012 Statutory Changes – HB361

- The Division of Mining, Land and Water identified over 30 statutory changes that would help reduce applicant costs, create efficiencies, reduce redundancies, and reduce opportunities for legal challenges
- During the 2012 Legislative session, the Governor introduced HB 361, which included the highest priority changes related to leasing and disposal programs that would help reduce the permitting burden on the applicant and free more time for staff to work on processing applications
- The Legislature passed HB 361 and it has been signed by the Governor

STATEWIDE PERMITTING REFORM
- 2013 LEGISLATURE -

2013 Statutory Changes – SB26

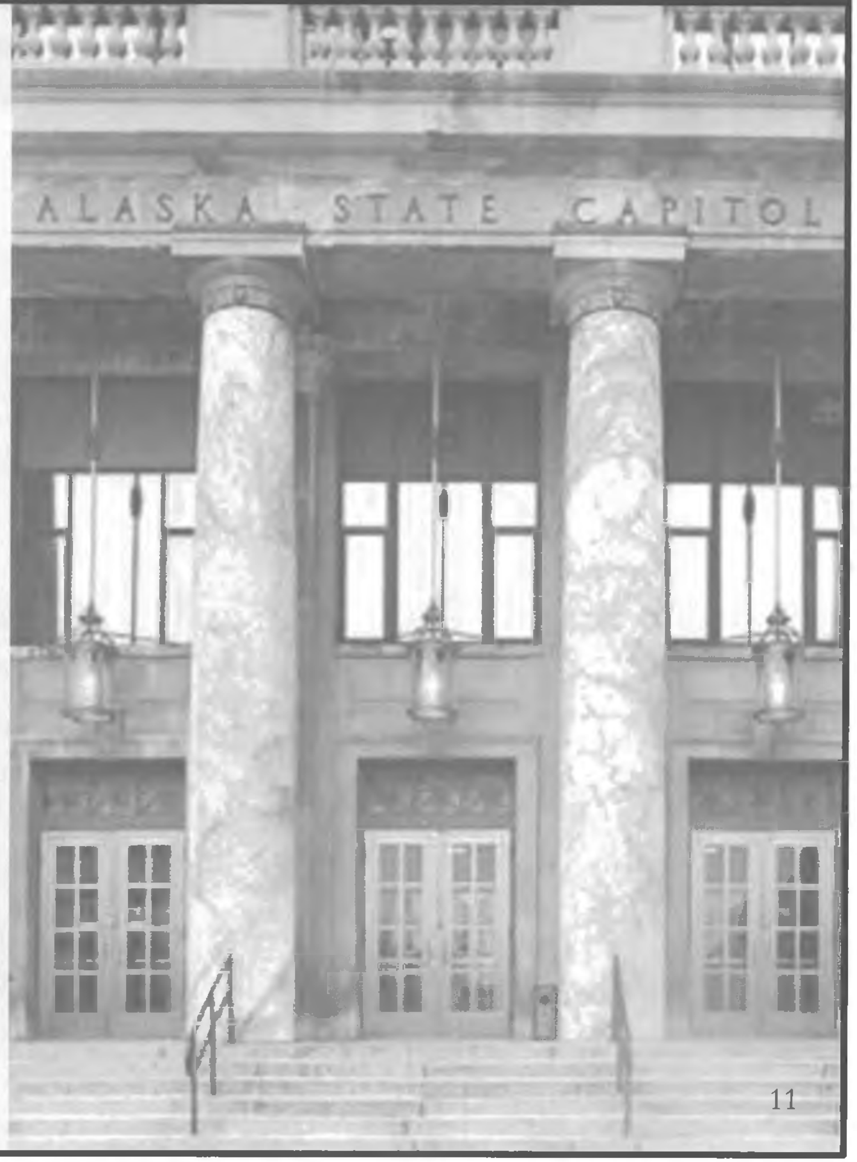
- Building on the success of 2012, the Division of Mining, Land and Water has identified additional statutory changes that would help streamline permitting requirements for the public to use and enjoy Alaska's land and resources
- Governor Parnell has introduced HB 77, which would reform and streamline procedures for obtaining, issuing, and appealing permits, leases, best interest findings, and other DNR authorizations
- It would allow DNR to establish a general permit for an activity on state land unlikely to cause significant and irreparable harm to the State
- It would prevent non-agency entities from being able to apply directly for a reservation of water; this does not affect holders of, or applicants for, standard water rights, temporary water use permits or water removals

STATEWIDE PERMITTING REFORM

- 2013 LEGISLATURE -

2013 Statutory Changes – SB27

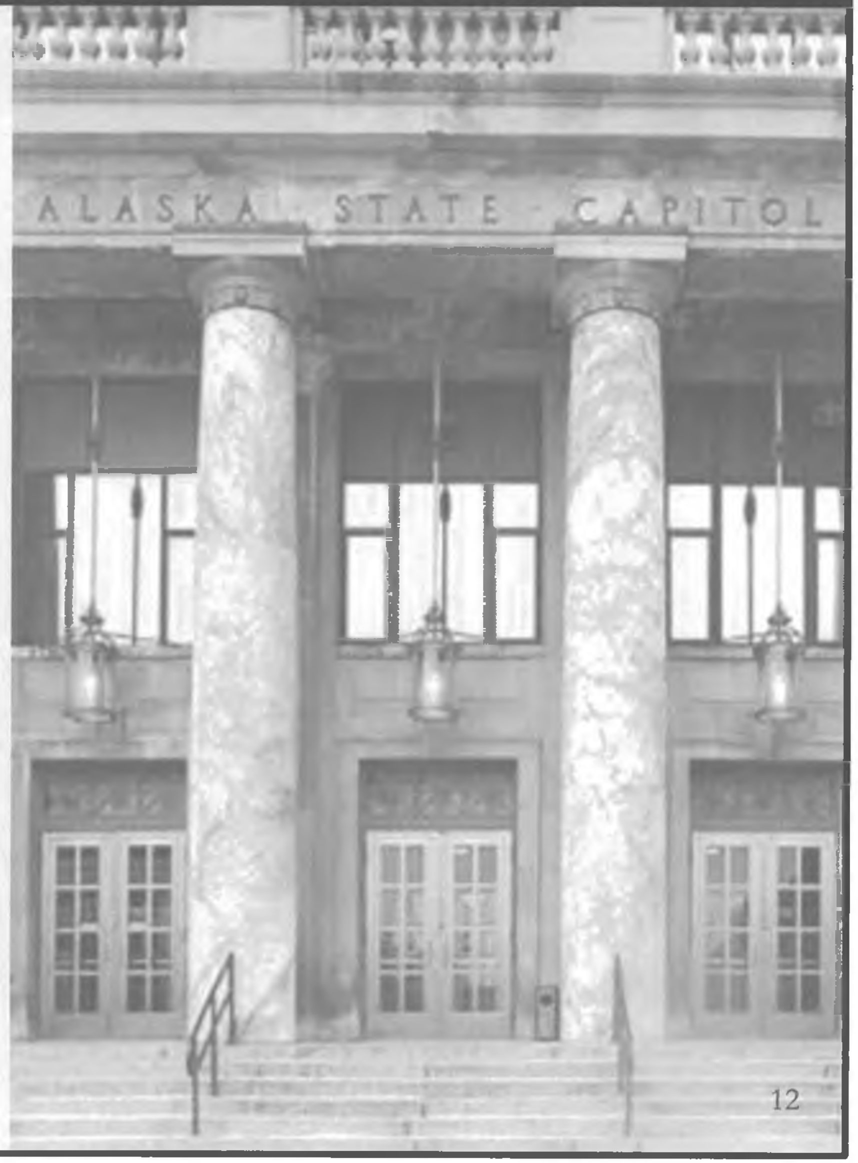
- Section 404 of the Clean Water Act (CWA) requires a permit from the Corps of Engineers for discharge of dredged or fill material into waters of the U.S.
- Purpose is to provide the State authority to evaluate and, potentially, assume primacy for permitting of dredge and fill activities in waters and wetlands in the State, as provided for in the CWA
- State primacy would still be subject to federal oversight and must be as stringent as the current federal program, but should help ensure funding and staffing for the program, provide greater state participation and control, enable the State to focus resources where most needed, and better insulate the program from national politics



Statewide Permitting Reform
- 2013 Legislature -

2013 Statutory Changes – SB 59

- SB 59 – Oil and Gas Exploration/Development Areas
- SB 59 will
  - Create efficiencies by streamlining oil and gas exploration and development approval processes
  - Protect the public interest by requiring public notice and the opportunity to comment during the approval process for a geographical area
  - Enable a review of the effects of exploration and development across multiple leases
  - Allow project approvals to be consolidated into a comprehensive decision
  - Provide certainty to oil and gas operators, industry and the public when projects receive approval
  - Promote the State's interests through implementing effective approval processes



Brooks Range Petroleum

March 1, 2013

Commissioner Dan Sullivan
Department of Natural Resources
550 W. 7th Ave, Suite 1260
Anchorage, AK 99501-3557

Dear Commissioner Sullivan:

Brooks Range Petroleum Company (BRPC) is a strong supporter of the Parnell Administration's efforts to streamline and improve the permitting process while maintaining high environmental standards. Permitting reform is, after all, critical to turn around the TAPS throughput decline. Indeed, a permitting process with unnecessary layers that do nothing to safeguard the environment only undermines the ability of companies to move projects forward in a timely and cost effective manner.

BRPC believes SB 59 provides a substantial improvement to the DNR permitting process. The current permitting process around Plans of Operation, Exploration, and Development is inefficient and cumbersome. SB 59 will remedy these shortcomings because it will consolidate the Department of Natural Resources' exploration and development approvals and streamline its approval process, while still protecting the environment and providing for public participation. SB 59's changes will reduce the permitting process by months, which is especially critical because exploration companies only have a few short months to operate during the North Slope exploration season.

Thank you again for your leadership on this issue and your efforts to make Alaska more competitive.

Sincerely,

Barton J. Armfield
Chief Operating Officer
Brooks Range Petroleum Corporation

Cc: Joe Balash

SB 59 – Public Testimony – Lisa Weissler
March 1, 2013

Dear Senate TTP Committee Members:

SB 59 undercuts a legal commitment made to Alaskans through legislation passed in 2001 – that they would have the opportunity to review and comment on oil and gas exploration and development project activities in or near their communities before exploration or development could proceed.

The 2001 legislation was passed in response to an Alaska Supreme Court decision that required the Department of Natural Resources (DNR) to prepare a comprehensive best interest finding for each phase of a project. For oil and gas projects, the phases are lease sale disposal, exploration, development and transportation. The legislation amended AS 38.05.035(e) with the stated intent of making it clear that no best interest finding is required after the lease disposal phase but that "public notice and the opportunity to comment shall be provided at each phase of the project."[1]

Under AS 38.05.035(e)(1)(C), a best interest finding may be limited in scope to those facts and issues that pertain soley to the disposal phase of a project. This is known as a "phased review." At the lease sale disposal phase in a phased review, the potential future effects of oil and gas project activities are discussed in general terms and for the entire disposal area. Project specific effects are addressed later when details of an activity and its location are known.

DNR may do a phased review for an oil and gas disposal when "before the next phase of the project may proceed, public notice and the opportunity to comment are provided under regulations adopted by the department..."[2]

The best interest findings issued for DNR's five areawide oil and gas lease sale disposals are done as phased reviews. As stated in a 2011 areawide lease sale best interest finding, "In the case of oil and gas, DO&G cannot determine with any specificity or definition at the lease sale phase if, when, where, how, or what kind of exploration, development or production might ultimately occur as the result of a lease sale."[3]

The finding explains that the public notice and comment condition for a phased review of the oil and gas disposal is met because "before the next phase of the project may proceed, ADNR provides public notice and the opportunity to comment on proposed plans of operations in the lease sale area." [Emphasis added]. The finding further states, "The effects of future exploration, development, and production will be considered at each subsequent phase, when various government agencies and the public review applications for specific proposed activities at specific locations."

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[1] Section 1, Legislative Purpose, CSSB 156(RES) 2001
[2] AS 38.05.035(e)(1)(C)(ii)
[3] North Slope Foothills Areawide Sale Best Interest Finding – excerpt attached.

SB 59 – Public Testimony – Lisa Weissler
March 1, 2013

Under SB 59, Alaskans will no longer have the opportunity to comment on proposed plans of operation for specific project activities that may occur in or near their community. They will be required to comment on oil and gas exploration and development without knowing the "when, where, how, or what kind of exploration, development or production might ultimately occur" in a potentially vast sale area – from 2 million acres in the Beaufort Sea region to 7.6 million acres in the North Slope Foothills.[4]

In addition, SB 59 provides that a general exploration or development approval is good for ten years and an approved lease activity that is initiated during that ten years is authorized for the entire lease term, a term that could extend for decades. Decades without an official means for Alaskans to convey to state regulators the site specific concerns they may have with an oil and gas exploration or development project that affects their community.

People may still be able to comment on site-specific permits issued for an oil and gas activity. However, such permits address only a particular part of a project and are more limited in scope than a plan of operations that provides comprehensive details on the entire project and its effects. It should also be noted that other legislation is being proposed that will limit public involvement for site-specific permits. SB 26/HB 77 authorizes the commissioner to issue general permits for a broad range of activities that may include oil and gas exploration and development project activities. Like the general approvals proposed in SB 59, a general permit has broad application and limits the opportunity for people to comment on concerns specific to their community. They may not even have notice that an activity is about to occur.

For example, in September 2012, Homer residents were surprised to learn about a company's plans to drill in the midst of their community because the leases had been issued ten years ago. Fortunately, the people of Homer will still have opportunities to provide input about their local concerns as the company applies for various state authorizations, including plans of operation.

Now imagine how surprised, and upset, people will be when drilling rigs show up in their neighborhood and learn that their opportunity to comment on the activity is long gone, that the only time for public involvement was back when a general exploration or development approval was issued, potentially a decade earlier. This is what will happen if SB 59 is enacted – with even more consequences if the administration's other permitting bill, SB 26/HB 77, passes.

There is a reason for public notice. It is to let people know that there will be activity in their area. There is a reason for public comment. It is so state regulators can learn about issues of concern to an affected community that may be located far from where the regulator is based, and so those concerns are addressed through the authorization process. With Alaska's vast size, DNR should welcome local involvement, rather than trying to limit public participation in project reviews.

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[4] The other three areawide lease sale areas are: Alaska Peninsula, 5.8 million acres; Cook Inlet, 4.2 million acres; North Slope, 5.1 million acres.

SB 59 – Public Testimony – Lisa Weissler
March 1, 2013

On March 26, 2013, in a Senate TTP committee hearing on SB 59, DNR described industry applicants as "customers." But Alaska is not a business that serves industry. Alaska is a sovereign state whose government has a duty to regulate industry and represent the public interest. While there may be a need to simplify the permitting process, it should not be done at the expense of public involvement in state government decision-making. Alaskans are the state's true customers and should be treated as such. Honor the commitment made to Alaskans in 2001. Please say "no" to SB 59.

Thank you for your consideration.

Sincerely,

Lisa Weissler
340 Highland Drive
Juneau, AK 99801
907-723-5902
lisaweissler@gmail.com
Business website: http://changingtides.com

ATTACHMENT

SB 59 – Public Testimony – Lisa Weissler
March 1, 2013

ATTACHMENT

Excerpt: North Slope Foothills Areawide Final Best Interest Finding, 2011 – pages 2-3 to 2-5:

D. Phased Review

Phased review recognizes that some disposals of oil and gas, or of gas only, may result in future development that cannot be predicted or planned with any certainty or specificity at the initial lease sale phase, and that any future development will be subject to detailed review before it takes place. In the case of oil and gas, DO&G cannot determine with any specificity or definition at the lease sale phase if, when, where, how, or what kind of exploration, development or production might ultimately occur as the result of a lease sale. Although advances in technology, unpredictable market changes, and specific infrastructure requirements for possible production cannot be foreseen, new developments or improvements in any or all of these areas may occur.

Phasing allows the review and finding for a lease sale to focus only on the issues pertaining to the lease sale phase and reasonably foreseeable, significant effects of a lease sale. Additional authorizations are required for exploration, development, production, and other phases. When a project is multi-phased, review of issues that would require speculation about future factors may be deferred until permit authorization is sought at the exploration, development, and production phases. A discussion of governmental and public involvement at these later phases can be found in Chapter Seven.

Under AS 38.05.035(e)(1)(C), the Director may, if the project for which the proposed disposal is sought is a multiphased development, limit the scope of an administrative review and finding for the proposed disposal to the applicable statutes and regulations, facts, and issues identified above that pertain solely to the disposal phase of the project when:

> (i) the only uses to be authorized by the disposal are part of that phase;
> <u>**(ii)** the disposal is a disposal of oil and gas, or of gas only, and, before the next phase of the project may proceed, **public notice and the opportunity to comment are provided**</u> unless the project is subject to a consistency review under AS 46.40 and public notice and the opportunity to comment are provided under AS 46.40.096(c);
> (iii) the department's approval is required before the next phase may proceed; and,
> (iv) the department describes its reasons for a decision to phase. [Emphasis added]

The conditions under which phasing may occur have been met in this best interest finding for the North Slope Foothills areawide oil and gas lease sales. Accordingly, the review of activities in the lease sale area is of a multi-phased development. The Director, in making this finding, has limited the scope of the finding to the applicable statutes and regulations, facts, and issues that pertain solely to the lease sale phase of oil and gas activities and the reasonably foreseeable significant effects of a lease sale.

Condition (i) is met because the only uses authorized are part of the lease sale phase. The lease gives the lessee, subject to the provisions of the lease, the right to conduct geological and geophysical exploration for oil, gas, and associated substances within the leased area and the right to drill for, extract, remove, clean, process, and dispose of any oil, gas, or associated substances that may underlie the lands described by the lease. While the lease gives the lessee the right to conduct these activities, the lease itself does not authorize any exploration or development activities by the lessee on leased tracts.

Condition (ii) is met because the lease sale is of oil and gas or gas only, **and before the next phase of the project may proceed, ADNR provides public notice and the opportunity to comment on proposed plans of operations in the lease sale area.** Additionally, any plan of operations in the lease sale area that is within the coastal zone is subject to consistency with the ACMP standards, including public notice and opportunity to comment under AS 46.40. [Emphasis added]

Condition (iii) is met because ADNR's approval is required before the next phase (in this case exploration) may proceed. See Chapter Six for a discussion of post-leasing phases. Before exploration activities can occur on leased lands, the lessee must secure all applicable authorizations. Additional authorizations must also be secured for any subsequent development or production on the lease.

The plans of operation must identify the specific measures, design criteria, construction methods, and standards that will be employed to meet the provisions of the lease. A plan of operations is subject to extensive technical review by a number of local, state, and federal agencies. Oil and gas exploration, development, or production-related activities will be permitted only if proposed operations comply with all local, state, and federal laws and the provisions of the lease.

Condition (iv) is met because ADNR describes above the reasons for its decision to phase. The effects of future exploration, development, and production will be considered at each subsequent phase, when various government agencies **and the public review applications for specific proposed activities at specific locations.** However, this finding does discuss, in general terms, the potential effects that may occur with oil and gas exploration, development, production, and transportation within the lease area as well as proposed measures to be imposed as terms of the lease, subsequent permits, and plan of operations to mitigate possible adverse effects. [Emphasis added]

4 March 13

ELECTRONIC TRANSMISSION

Commissioner Daniel Sullivan
Alaska Department of Natural Resources
550 West 7th Avenue; Suite 1400
Anchorage, AK 99501-3554

Dear Commissioner Sullivan:

Linc Energy Operations, Inc. (Linc) is actively working to progress its oil and gas development projects in the Cook Inlet and on the North Slope. For this reason, Linc supports the Parnell Administration's efforts to improve the permitting process while at the same time, maintaining the state's high environmental standards. A more efficient permitting process will play a critical role in lowering costs, attracting investment and, ultimately, increasing oil and gas production in the Cook Inlet and on the North Slope.

Currently, projects are often delayed while waiting to receive authorizations from DNR on their Plans of Operations, Exploration or Development. Linc was pleased to see that the Parnell Administration introduced SB 59, which will improve the DNR permitting process by consolidating DNR's exploration and development approvals. Our assessment of the bill is that SB 59's changes will likely reduce the permitting process timeline by months; and, over the life of a project, this could help move projects more quickly from exploration and into development and production. In the end, this type of efficient and well organized approach benefits all Alaskans, as more production will be brought on line without reducing environmental standards or saddling projects with unnecessary and costly delays.

Linc appreciates your willingness to identify ways to improve the permitting process and believes SB 59's changes could have a material impact on Linc's ability to timely develop its Alaska assets.

Sincerely,

Corri A. Feige

Corri A. Feige
General Manager – Alaska

Cc:/ Deputy Commissioner Joe Balash, ADNR

LINC ENERGY OPERATIONS, INC

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Anchorage, AK 99503

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04/08/14 Presentation: Alaska Oil and Gas Conservation Commission Overview and Issues

<TARGET><BILL></BILL><SUBJECT>04-08-14 Presentation Alaska Oil and Gas Conservation Commission Overview and Issues</SUBJECT><COMM>STTP28</COMM></TARGET>

Good afternoon. My name is Cathy Foerster and I am the chair and engineering commissioner of the Alaska Oil and Gas Conservation, or AOGCC.

Thank you for the opportunity to share with you the mission of and pressing issues before the AOGCC.

The AOGCC is an independent quasi-judicial body located in downtown Anchorage.

Although located within the executive branch, by statute the AOGCC is independent. This means that we do not report to any department within the executive branch but certainly we're held to the same administrative requirements of any other state department. Why? So that, when the DNR comes before us, they are held in no higher standing than any other applicant.

By statute, we have three commissioners. One must be a petroleum geologist. Currently that is Dan Seamount. One must be a petroleum engineer. That is me, and I am currently the Chair. And one is a public member who must have training and experience relevant to the oil and gas industry. That position is currently vacant.

On staff we have positions for 2 geologists, 6 engineers, 7 field inspectors, and several IT, data management, and administrative support staff. I said "have positions for" because we currently have 1 engineer and we are currently trying to add 1 additional field inspector position.

If you want to know our issues, here's a big one. We draw our staff from the same talent pool as industry and it's very difficult for us to compete with them on compensation. The last two engineers that left our agency went to industry, where each got a signing bonus, about a 20 percent raise, and an all-expense-paid move to Texas, which took them closer to family. We can't compete with that; so we have pretty much a constant struggle to keep positions filled.

AOGCC Mission

- Prevent hydrocarbon waste
- Protect correlative rights
- Promote greater ultimate recovery
- Protect underground fresh water
- Protect human safety

The AOGCC mission is to prevent hydrocarbon waste, to protect correlative rights, to promote greater ultimate recovery, to protect underground fresh water, and to protect human safety.

The AOGCC exercises the police powers of the State of Alaska and has jurisdiction throughout the State of Alaska including offshore state waters for conventional oil and gas, coalbed methane, shale gas, shale oil, and geothermal resource exploration and development.

Also, if a well is being drilled for other purposes but we have reason to suspect that it will encounter unanticipated hydrocarbons or other hazardous substances, our statutes give us the authority to assert jurisdiction. In fact we did that in 2012 for a CIRI underground coal gasification project.

Our authority covers resource management and conservation, drilling and well work operations, well integrity and well safety systems, custody transfer metering, and eventually well abandonment.

Typical AOGCC Approvals

- Drilling
- Sundry Wellwork
- Underground Injection
- Conservation Orders
- Other

All wells drilled in the State of Alaska for oil, gas, or geothermal resource exploration and development must receive a drilling permit from our agency.

Also, remedial or recompletion wellwork on an existing well requires a permit from us for.

The AOGCC has primacy for administering the EPA's Class II underground injection control program in Alaska, and we do our own independent review, approval, and monitoring of injection into Class I wells.

We have statewide rules covering all of our requirements, but whenever an operator wants pool-specific rules, they submit a request to us and those rules are addressed in conservation orders.

And there is a wide variety of other approvals we address, such as granting exceptions and variances from existing rules.

We stay very busy. In the new millennium we have approved over 2900 drilling permits, over 5900 sundry well work permits, over 1200 injection orders, conservation orders and other decisions and orders.

Major Issues before the AOGCC

- Increased Cook Inlet activity
- Increased North Slope activity
- Hydraulic fracturing regulation
- Suspended, orphaned, and BLM legacy well clean-up
- North Slope gas sales

We try to stay a quiet little agency, but there are several important issues before us. This is a list of the major issues currently before us. I will discuss each in some detail.

Cook Inlet Activity

- Offshore exploration
- Hilcorp and CIE
- Increased inspections, incidents and investigations
- Disputes among operators and land owners

Offshore drilling in the post-Macondo world is clearly one of the hottest topics before us. Thanks in no small way to the good work of the Legislature, new operators are coming to the Inlet. Furie (previously called Escopeta) and Buccaneer have brought jack-up rigs to the Inlet and have been exploring for the past few seasons.

On the downside, both of these companies have required much more than normal regulatory oversight. But on the upside, both are making meaningful discoveries.

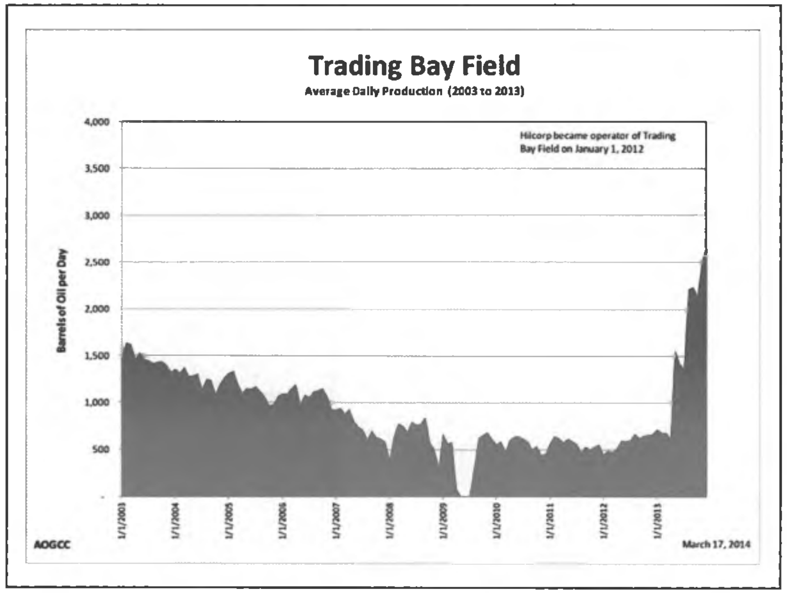
Hilcorp purchased Unocal and Marathon's interests and is very aggressively investing in restoring production in these fields.

And Cook Inlet Energy is also actively drilling exploratory and development wells in the Inlet

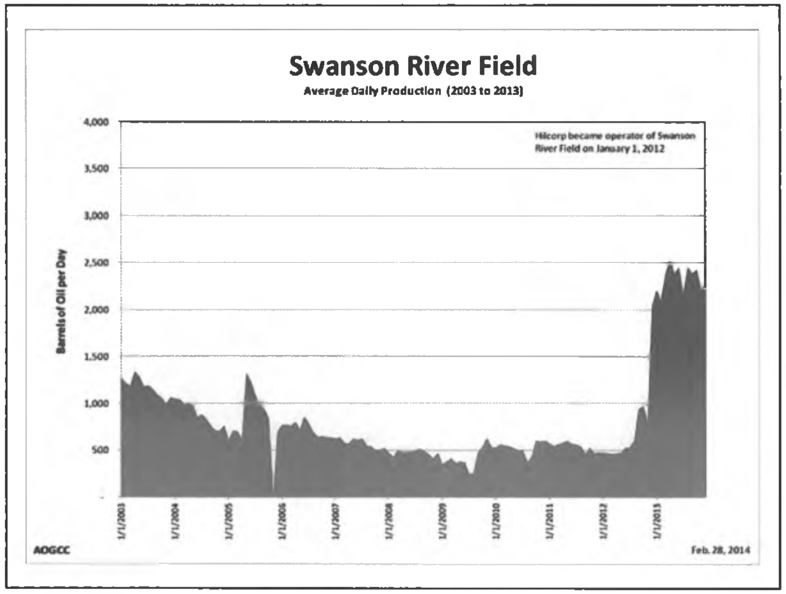
This increased activity level in the Inlet has kept us very busy. We are reviewing an unusually high number of custody transfer metering applications. Our field inspectors are conducting more inspections and safety system tests. The new operators are having difficulty compying with our regulations; so inspections and incident investigations are also up. And we are currently involved in adjudicating some very heated disputes among operators and land owners.

As Senator Micciche hears from his constituents, our modest inspection staff is being stretched thin. The result is that we have to choose between waiving witness on critical safety systems testing or causing delays for the operators. We are working hard to strike an appropriate balance but the long-term solution clearly involves identifying, recruiting, hiring, and retaining more qualified field inspectors.

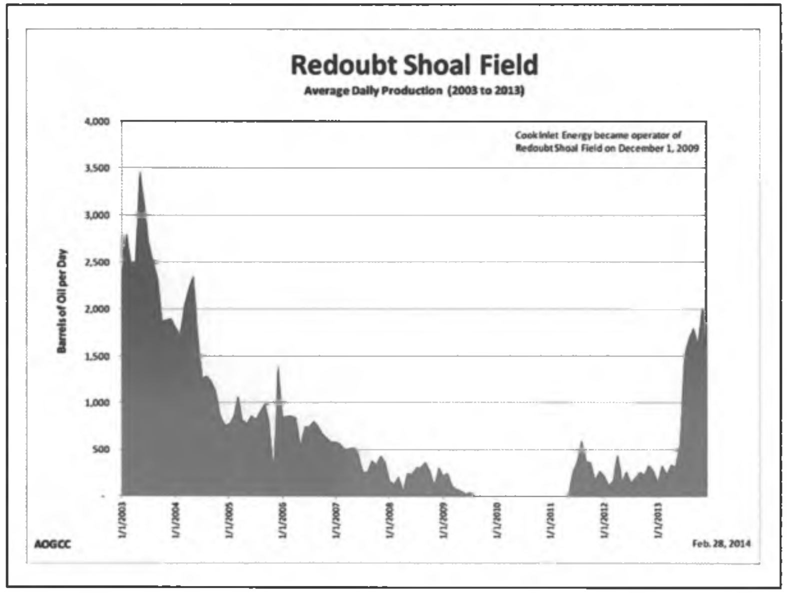
In the big picture, the increased activity is all very positive, as the increased production on the next three slides shows.



The uptick in production is due to Hilcorp's aggressive wellwork and drilling program.



Again, the uptick in production is due to Hilcorp's aggressive wellwork and drilling program.



And this increase is due to the work of Cook Inlet Energy.

North Slope Activity

- Winter exploration drilling
- Increased work in old fields
- Viscous oil
- CD-5
- Pt Thomson
- Great Bear

Also in no small part due to the work of the Legislature, North Slope activity is also up.

We're into the winter exploration season. Conoco is drilling one exploratory well and Repsol is drilling 5 this season. As with new operators in the Inlet, Repsol is putting a regulatory strain on our field inspectors as well as our engineers and geologists in the office.

Activity in the legacy fields is also up. For example, over the past year Prudhoe Bay has experienced a 35 % increase in well work activity and Kuparuk has experienced an 18 % increase. Drilling activity is also up in both fields but I was not able to extract those numbers in time for this presentation. Perhaps the best news is that Prudhoe Bay and Kuparuk annual decline appear to be slowing. The last time I looked at the rolling 12-month decline numbers, Prudhoe was at 2% and Kuparuk was at 4%, compared to their usual decline of 6%.

Both Conoco and BP continue to work at unlocking the enormous potential of viscous oil on the Slope.

And Conoco is working toward development of CD-5, an expansion of its Colville development.

We're expecting renewed well work activity, possibly next year, from Exxon as it moves toward start-up of its Pt Thomson gas cycling pilot.

And we're hopeful that, as Great Bear completes its evaluation of the exploratory data it gathered, they will be back with positive results and a plan to bring Alaska into the shale business.

Hydraulic Fracturing

- Increased public interest
- Fracturing not new to Alaska
- Regulations in place, recently updated

Hydraulic fracturing has recently become a topic of interest. We've been hydraulically fracturing wells in Alaska for over 40 years. About one quarter of Alaska's wells have been hydraulically fractured. And the AOGCC has been regulating these operations since they began. The AOGCC just completed a multi-year effort to modify its regulations, first to keep up with technology advances, second to address fracturing fluids disclosure and water quality monitoring, and third to gather all of our regulatory requirements into a section titled hydraulic fracturing to make it easier for the public to see THAT we are and HOW we are regulating hydraulic fracturing. Hydraulic fracturing is a commonly used and well understood oilfield production enhancement practice, but one that carries a lot of mystique around it. Let me just offer to do my best to answer any questions that you or your constituents might have about it.

States like Texas and Oklahoma have thousands of orphaned wells; Alaska has only a handful. But we don't want to let down our guard and let this become a problem for our state; so we have a constant effort to hold operators accountable for properly plugging and abandoning wells that have no further utility. The only operator we have a major problem with is the Federal Government – I think you're all familiar with the BLM ~~legacy~~ travesty wells.

The bad news is that they're still a problem, and one that generally doesn't get better with time.

The good news is that, thanks to you guys and Senator Murkowski, Congress has given the BLM $50million to apply to their clean-up. The even better news is that they are working closely and cooperatively with AOGCC and ADEC to ensure that the clean-up meets state standards, which are significantly higher than their own.

North Slope Gas Sales

- Prevent hydrocarbon waste
- Ensure greater ultimate recovery of total hydrocarbons

And, of course, the AOGCC has a small but important role in the seemingly-never-ending question of North Slope Gas Sales.

Remembering that early slide outlining our mission, the AOGCC is charged by statute to prevent hydrocarbon losses and ensure greater ultimate recovery of total hydrocarbons.

Those two charges have enormous implications for North Slope gas sales. In the world of petroleum engineering it is a simple truism that taking gas from an oil field puts ultimate oil recovery at risk. Prudhoe Bay is an oil field with about 2 billion barrels left to produce and Pt Thomson is also an oil field by technical definition and by the legal definition of the state of Alaska.

So the AOGCC is responsible for determining when and how much gas can be taken from those oil fields so that waste does not occur and greater ultimate recovery is achieved.

North Slope Gas Sales

- Prevent hydrocarbon waste
- Ensure greater ultimate recovery of total hydrocarbons

AOGCC developed white papers describing our role in gas offtake determination, the concerns we have with Prudhoe Bay, and the concerns we have with Pt Thomson. They're kind of long (and probably a bit boring) so I won't go through them here but all three are included for your use, perhaps as a sedative.

In addition to the field-specific issues discussed in those papers, there are a few other issues to mention. First, it is possible that the best use of the Pt Thomson gas will be to inject it into the Prudhoe Bay gas cap to get an added half billion barrels (approximate guess) out of the Prudhoe Bay reservoir. Second, as Conoco and BP work to find ways to unlock the huge potential viscous oil resource, it is highly likely that gas will be part of the solution. Third, if we build it, they will come. I.e., the USGS estimates roughly 150TCF of undiscovered gas on the North Slope. If there is the reality of a market for that gas, then the exploration work needed to realize those discoveries will likely result.

The last thought I want to leave you with is that the monkey is on the operator's back to demonstrate to the AOGCC that selling the gas from Prudhoe Bay and Pt Thomson is the best answer for preventing waste and ensuring greater ultimate recovery. So, we are looking to BP, Conoco, and Exxon to do that. And I doubt they'd spend the big bucks to build a line if they didn't think they could.

Role of the Alaska Oil and Gas Conservation Commission in Approving Pool Rules for the Point Thomson Field

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas production rates should be allowed from North Slope oil fields. As part of this process, the AOGCC will evaluate ExxonMobil's proposed plan to develop the Point Thomson Field as a gas field rather than as an oil field. Generally, the most total hydrocarbon recovery from a retrograde condensate field would be achieved by conducting gas cycling operations to produce condensate (a liquid hydrocarbon that is considered "oil" under the Commission's governing law) until all of the economically recoverable liquid hydrocarbons have been produced. Only then should the gas be sold. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Point Thomson is the largest proven yet still undeveloped field in Alaska. It is also one of the most difficult to develop and manage properly because the majority of the resources are contained in what is called a retrograde condensate reservoir. Retrograde condensate reservoirs around the world tend to be deeper and have higher pressures and temperatures than conventional reservoirs. These abnormally high temperatures and pressures cause the fluids in the reservoir to have unusual properties. Thus, a retrograde condensate reservoir acts differently than a typical oil field such as Prudhoe Bay or a typical gas field such as the Kenai Gas Field. The differences in behavior are technically complex and difficult to describe, understand, and address; yet understanding and addressing these differences are essential to evaluating whether a plan of development satisfies the conservation requirements administered by the Commission.

A conventional oil reservoir is typically filled with a liquid hydrocarbon that has some solution gas in it. In such a reservoir all the fluid exists as a liquid, but as it is brought to the surface its pressure drops and some of its solution gas is released. The same thing happens underground. As the pressure decreases in the reservoir, gas in the oil comes out of solution. To understand how this works, think of a bottle of soda. Before the bottle is opened, its contents are under pressure and it appears that there is just liquid in the bottle. However when the cap is removed, the pressure in the bottle is reduced and bubbles will start to form and float to the surface of the soda.

Conversely, a conventional gas reservoir is typically filled with hydrocarbon gas. The gas may have a small amount of hydrocarbon liquid, called condensate, vaporized in it. This condensate will not drop out as a liquid in the reservoir because the temperature is too high. However it will separate from the gas when the gas is brought to the surface where the temperature is lower. This is similar to what happens when someone blows warm breath onto a cold window and watches it fog up. The water that exists as a vapor inside the warm lungs turns to condensation as it hits the cold window.

Retrograde condensate reservoirs do not behave in the same ways that conventional oil and gas reservoirs do. Dropping the pressure in the reservoir does not cause gas to form from oil, as is the case in a conventional oil reservoir. Nor does vaporized condensate remain a vapor, as is the case in a conventional gas reservoir. Rather, for a retrograde condensate reservoir, as the pressure decreases, liquids drop out of the gas in the reservoir.

When a retrograde condensate field is produced like a conventional gas field, the gas is produced and sold at high rates. Initially a large amount of condensate is produced with the gas. However the reservoir pressure drops quickly and condensate production drops dramatically because condensate is dropping out in the reservoir instead of at the surface. To further the problem, condensate that drops out in the reservoir is much more difficult to produce than that which remains entrained as a vapor in the gas. The liquid tends to build up and clog the pore spaces in the reservoir rock. Also, since this reservoir has never been exposed to liquid before, the rock acts as a sponge and some of the condensate will be immobilized and never come out. To make things worse, once the condensate comes out of the gas, very little of it will return to a gaseous state even if the reservoir pressure is later increased. In other words this is a problem that you can't fix after you cause it; it's like unringing a bell.

In addition to lost condensate recovery, if the reservoir pressure is reduced too quickly, the gas recovery will also decrease. The condensate that clogs up the reservoir and won't come out also blocks the gas from coming out. This is similar to an air filter on a car. When the filter is new, air will flow through it freely, but as it gets older the pores in the filter begin to clog with dirt (as the pores in the reservoir would clog with condensate) and the air will not flow through as well. Eventually no air at all will flow.

So what's the answer? To maximize condensate production from a retrograde condensate reservoir, it is necessary to keep the reservoir pressure high until the condensate has been recovered. Often this is accomplished through a process known as "gas cycling." In this process hydrocarbon gas is produced, the condensate is removed and sold, and the now-lean gas is injected back into the reservoir to maintain pressure and to sweep more condensate to the surface. As this process continues, the gas produced slowly becomes leaner and the yield of condensate decreases. Eventually the gas is stripped of most of the liquids and it is safe to sell the gas. This method delays gas sales, but it results in greater ultimate recovery of both liquid and gaseous hydrocarbons.

Another method used to develop retrograde condensate fields is to inject a substitute gas such as nitrogen or carbon dioxide either to replace or to supplement the produced gas for pressure maintenance. Unfortunately, there is currently no substitute gas available to Point Thomson.

These are just a few of the more common methods used for developing retrograde condensate fields and each has advantages and disadvantages that must be considered. Primary depletion as a gas field is the least efficient and results in the lowest hydrocarbon recovery. However, it is the simplest and cheapest method for the operator since it does not require an investment in equipment to recycle the gas. Gas cycling yields greater hydrocarbon recovery but may be less attractive to the operator because it has a higher up-front development cost for compression and it has low up-front cash flow due to the deferral of gas sales. Injection of outside substances has the possibility of maximizing both condensate recovery and cash flow, but it is the most expensive method because in addition to compression equipment it requires the purchase of a substitute gas.

Selection of an optimal method of development must consider all of the unique aspects of the reservoir in question, as well as the practicality and applicability of the various development methods.

The operator of the Point Thomson Unit has indicated that the only development scenario that makes sense is to develop Point Thomson as if it were a normal gas field, which would likely result in significant loss of condensate. Since the AOGCC must determine whether this development option is consistent with good oilfield engineering practices and will result in greater ultimate recovery, the agency is working with an outside consultant who has extensive retrograde condensate reservoir expertise. The AOGCC and its consultant are evaluating different development options and developing a sound technical basis for conservation orders relative to the development plan that is ultimately proposed by the operator of the Point Thomson Unit.

Role of the Alaska Oil and Gas Conservation Commission in Establishing Allowable Gas Offtake Rate for Prudhoe Bay

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas production rates should be allowed from Prudhoe Bay and other North Slope oil fields. Considering only the laws of science, these decisions are very simple; to prevent waste and insure a greater ultimate hydrocarbon recovery, produce all of the oil in a reservoir first and then "blow down" its gas cap only when there is no commercially recoverable oil left. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Before considering other factors, it is essential first to understand the science. Extracting gas from an oil field like Prudhoe Bay triggers a series of events. First, the pressure in the gas cap decreases and becomes lower than the pressure in the oil-bearing part of the reservoir. As driven by the laws of physics, the reservoir then works to get back to equilibrium, i.e., the same pressure throughout. To do this, some oil, which is at a higher pressure, moves up into the lower pressure gas cap and the pressure in the oil-bearing part of the reservoir drops. This process continues as the pressure throughout the reservoir equalizes at a lower pressure than before. And as more gas is withdrawn, the process repeats, causing more oil to move into the gas cap and also causing the reservoir pressure to decrease further.

Both the movement of oil into the gas cap and the decrease in reservoir pressure jeopardize oil reserves.

Let's look at movement of oil into the gas cap first. Think about what happens when you drain the oil from your car or when you pour cooking oil into a measuring cup. When you empty the container, some of the oil sticks to it and will not come off. That is what happens to oil when it moves into the gas cap, a part of the reservoir that has never contained oil but has always only held gas. However, because that container is porous rock rather than glass or plastic, the amount of oil that sticks is much greater. The previously "dry" reservoir rock becomes coated with oil. Although some of this oil can be produced, a substantial portion (in some fields over 20 to 30 per cent) sticks to the rock and will never come out. In short, producing gas without replacing the gas cap fluids will cause some oil to stick to the reservoir rock and result in a decrease of ultimate recovery of oil.

Now let's look at decreasing reservoir pressure. Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids – both the active product and the carrier gas -- are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen. Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir. Typically operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they "blow down" the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oil field this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to suck water up a straw than it is molasses.

In summary, looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercial oil remaining to be produced WILL cause a portion of the oil resources to be lost and, thus, the gas cap in an oil reservoir should only be "blown down" when no more commercially recoverable oil remains.

The explanation above assumes that all of the gas can be recovered after all of the oil has been produced, and for most Lower 48 scenarios this is a reasonable assumption. However, for the North Slope, there will be a trade-off between leaving oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors.

For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas production. As this infrastructure ages, two things happen: 1) the cost to operate the equipment increases, and 2) components break and must be repaired or replaced. The later in time the gas is produced the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas will be left stranded.

The minimum rate at which TAPS can operate will also impact the balance between losing oil and stranding gas. Although the gas will have its own line which will operate independently of TAPS, continued operation of the TAPS line will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical.

These and other factors will complicate the gas off take rate and timing decisions for North Slope fields. The AOGCC is charged with preventing waste and insuring the greater ultimate recovery by making sure that the operators act in accordance with good oilfield engineering practices. In executing this responsibility, the AOGCC must be cognizant of the balance between oil recovery optimization and gas recovery optimization. This will be no trivial task.

Role of the Alaska Oil and Gas Conservation Commission in North Slope Gas Sales

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope natural gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has an important responsibility in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas offtake rates should be allowed from North Slope fields, most notably the Prudhoe Oil Pool and the Pt. Thomson gas condensate reservoirs.

There are over 35 trillion cubic feet of gas reserves within these two fields. However, hundreds of millions of barrels of oil and condensate could be lost if gas offtake from these fields is not correctly managed.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after the liquid hydrocarbon reserves have been depleted. Until then, the gas that is produced is used to promote liquid production in various ways (including being reinjected so that it can provide the energy needed to get the liquid hydrocarbons to the surface and providing a source of gas for miscible injectant used in enhanced oil recovery operations). And that is exactly what is happening right now at Prudhoe Bay and other North Slope fields.

The North Slope gas sales project will ultimately involve trade-offs between oil and gas recovery. The documents *Role of the Alaska Oil and Gas Conservation Commission in Establishing an Allowable Gas Offtake Rate for Prudhoe Bay* and *Role of the Alaska Oil and Gas Conservation Commission in Managing Development of the Point Thomson Field* explain these trade-offs. This document explains the process the AOGCC is using to insure greater ultimate total hydrocarbon recovery, i.e., recovery of both oil and gas, as the North Slope gas project moves forward.

Normally, the operator of an oil or gas field applies to the AOGCC for "Pool Rules." These are specific rules that stipulate how to develop the reservoir in a way that maximizes oil and gas recovery. However, the Point Thomson Owners have not yet applied to the AOGCC for Pool Rules.

Nor have the Prudhoe Owners applied for amendment of current pool rules to allow for a higher gas offtake rate. The existing Prudhoe gas offtake rate was set in 1977 at 2.7 billion standard cubic feet (BCF) of gas per day. After deducting gas used as fuel and in enhanced recovery operations, this leaves about 2 BCF of gas per day available for sales. However, the gas sales scenarios that are being discussed publicly could require increasing the Prudhoe gas offtake allowable.

Normally the AOGCC would wait for an application from the Owners before performing the reservoir studies necessary to establish or increase gas offtake rates. However, that would delay the AOGCC's decision-making such that it could disrupt the timetable for a potential gas pipeline project. (The AOGCC needs to complete its evaluations and make its rulings for both

Prudhoe Bay and Pt Thomson so the Owners have approved gas offtake allowables that they can use in the "open season" process that is required under the Federal Energy Regulatory Commission ("FERC") regulations. The current draft version of the Alaska Stranded Gas Fiscal Contract requires the Producers to apply to the AOGCC within 6 months of the effective date of the contract for issuance of pool rules to authorize the field gas offtake rate for Point Thompson.)

Therefore, the AOGCC has chosen a proactive approach. There are two ways the Commission might take a proactive role with respect to such studies. One would be to conduct or arrange for consultants to conduct independent reservoir studies. The other would be to participate with the Owners and operators in their reservoir simulation studies, so that questions can be answered and adjustments can be made up front. Assuming adequate cooperation on the part of the Owners, the latter approach has significant advantages: lower cost to the State of Alaska, less time required to complete evaluation of the studies, more complete and accurate input data, and use of proven, probably more sophisticated reservoir evaluation tools.

In 2005 the Commission held hearings to inquire whether the gas offtake rate from Prudhoe should be updated. The AOGCC decided that, although the 1977 allowable was based on the best available data at the time, the appropriate gas offtake allowable must now be redetermined using the almost thirty years worth of reservoir description and performance information that has become available since 1977. Further, the Prudhoe Owners and the AOGCC established principles by which to perform collaborative studies. The report of the inquiry and the resultant study principles were issued by the AOGCC on December 5, 2005.

The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Prudhoe study. The Prudhoe Owners have agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. A data room has been set up in BP's Anchorage offices, equipped with computers and software allowing review of the simulator results. The Owners have voluntarily offered to make the data room information available. The information meets the standards of AS 31.05.035(d) and 20 AAC 25.537(b) entitling it to be held confidential during this study period.

This study process began in January 2006, and is anticipated to be complete by the end of this year. Following this study period, either the Owners will submit an application to amend the Prudhoe gas offtake allowable or the AOGCC will call for a hearing. In either case, the AOGCC will hold public hearings to review the development plans associated with the proposed gas sales. The Owners will be required to submit for the record reservoir studies that best reflect a reasonable range of offtake options and their effects. The AOGCC may request (including by subpoena) any other pertinent information that has been used in the study but is not included in the Owners' submission of evidence in the hearings. Claims of confidentiality for evidence in the hearings will be determined by the AOGCC during the course of the hearings under governing law.

On April 26, 2006 the AOGCC and the Pt. Thomson Owners agreed upon a similar process for studying the allowable gas offtake from that field. The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. AOGCC staff and consultants will have access to a data room in ExxonMobil's Houston offices. The data room will include reservoir engineering, geologic and simulation information and will be equipped with computers and software allowing review of the simulator results. The study will begin before September 2006 and will last up to six months. The Point Thomson Owners have indicated they plan to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate.