SB

49

<TARGET><BILL>SB 49</BILL><SUBJECT>SB
49</SUBJECT><COMM>SRES27</COMM></TARGET>

Senate Resources Committee

Wednesday, March 9

SB 49: Production Tax on Oil and Gas

Contents:

(1) Hearing request

(2) Bill

(3) Fiscal notes from DOR and DNR

(4) Sectional analysis prepared by DOR

(5) DOR's Oil and Gas Production Tax Status Report to the Legislature (1/18/11)

(6) Letters written by DOR in response to specific H RES questions

LIB COPY

State of Alaska

Department of Revenue

Administrative Services Division

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

January 20, 2011

The Honorable Joe Paskvan
The Honorable Tom Wagoner
Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Senators Paskvan and Wagoner:

Senate Bill 49 was read across the floor on January 19, 2011 and transmitted to the Senate Resources Committee for consideration. I respectfully request a hearing to be scheduled at your earliest convenience for the changes to the production tax on oil and gas to be discussed.

Governor Parnell is committed to getting more oil into the pipeline and increasing job opportunities for Alaskans. As oil production declines and as the federal government moves on several fronts to block responsible projects, we must offer more incentives for development of state lands.

Senate Bill 49:

- Establishes a lower base tax rate for areas outside of current fields and units to encourage development of undeveloped leases or properties;
- Caps overall production tax rates to encourage investment at most commodity prices;
- Establishes a bracket system based on existing ACES tax rates;
- Extends tax incentives available in Cook Inlet to the North Slope to encourage in-field drilling in existing units;
- Limits the time for assessment of additional production taxes; and
- Reduces the interest rate on delinquent taxes and refunds.

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

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

Sincerely,

VBlaisdell

Ginger Blaisdell
Director

FISCAL NOTE

STATE OF ALASKA
2011 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: SB 49
(S) Publish Date: 1/19/11

Identifier (file name): LL0007-DOR-TAX-1-13-11
Title: Oil and Gas Production Tax
Dept. Affected: Revenue
Appropriation: Treasury and Taxation
Allocation: Tax Division
Sponsor: Rules Committee
Requester: By Request of the Governor
OMB Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2012**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**
Personal Services				267.0	267.0	267.0	267.0
Travel				10.0	10.0	10.0	10.0
Contractual	115.0			9.4	9.4	9.4	9.4
Supplies				1.0	1.0	1.0	1.0
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**115.0**	**0.0**	**0.0**	**287.4**	**287.4**	**287.4**	**287.4**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES	***	***	***	***	***	***	***

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	115.0	0.0	0.0	287.4	287.4	287.4	287.4
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**115.0**	**0.0**	**0.0**	**287.4**	**287.4**	**287.4**	**287.4**

Estimate of any current year (FY2011) cost

POSITIONS

Full-time	**0.0**	0.00	0	2	2	2	2
Part-time							
Temporary							

Why this fiscal note differs from previous version

This is the first version of the bill.

Prepared by: Cherie Nienhuis, Economist and Bruce Tangeman, Dep. Commissioner
Phone: 269-1019
Division: Tax Division
Date/Time: 1/13/2011; 12:07pm
Approved by: Ginger Blaisdell, Director Administrative Services Division
Department of Revenue
Date: 1/13/11; 12:16pm

(Revised 12/29/2010 OMB)

STATE OF ALASKA
2011 LEGISLATIVE SESSION

BILL NO. SB 49

Analysis

***The revenue impact of this bill is indeterminate.
This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with their potential revenue impact, are discussed below.

1. **The interest rate on delinquent taxes is changed** from the greater of 5 percentage points above the annual rate of interest charged by the 12th Federal Reserve District or 11 percent, to the lesser of 3 percent points above the annual rate of interest charged by the 12th Federal Reservice District or 11 percent. The effective date of this provision is 7/1/11. The Department of Revenue (DOR) does not forecast interest on taxes; therefore this provision has no quantifiable revenue impact. There will be $100,000 in one-time contractor costs to implement this change in our accounting system.

2. **The ANS WC oil price thresholds for the minimum tax are lowered** from the range of $15 to $25 to the range of $12.50 to $20 per barrel. The effective date of this provision is 1/1/2013. The DOR expects no revenue impact from this change since oil prices are forecasted to be above these amounts.

3. **The tax rate is changed and it is calculated annually rather than monthly for production in unitized areas or areas where there has been commercial production.** The tax rates under the bill are bracketed and only the increment of production tax value (PTV) within each bracket is taxed at that bracket's rate. The brackets range from 25% for PTV up to $30 per barrel to 50% for PTV over $92.50 per barrel. The maximum total production tax rate is 50%. The effective date of this provision is 1/1/2013. Using the Fall 2010 forecast assumptions, this provision is expected to result in revenue impacts as follows:
FY 2013: -$382 million
FY 2014: -$961 million
FY 2015: -$1,126 million
FY 2016: -$1,341 million
FY 2017: -$1,423 million

4. **For areas that are not unitized as of 1/1/2011 and where there has been no commercial production, the tax rate has changed and the lease expenditures in those areas may not be applied outside those areas.** The tax rates under the bill are bracketed and only the increment of PTV within each bracket is taxed at that bracket's rate. The brackets range from 15% for PTV up to $30 per barrel to 40% for PTV over $92.50 per barrel. The maximum total production tax rate is 40%. The effective date of this provision is 1/1/2013. Using the Fall 2010 forecast assumptions, this provision is expected to increase revenue slightly in amounts less than $20 million in FY 2013 through FY 2017.

5. **The provision requiring that credits be taken over two years is eliminated**. This provision would result in companies using credits earlier than they would without this change, and except for time value of money impact, it is revenue neutral. The effective date of this provision is 1/1/2012. Using the Fall 2010 forecast assumptions, this provision is expected to decrease revenue in the amount of $250 million in CY 2012 (taken over FY 2012 and FY 2013). Another $100 million in refunds would also be likely sought for credit certificates in FY 2012.

6. **The 40% credit for well lease expenditures is expanded to include qualified expenditures incurred north of 68 degrees North Latitude**. The effective date of this provision is 1/1/2012. The DOR has very limited data upon which to estimate the revenue impact of this provision. We estimate this provision will decrease revenue in the amount of $200 million to $400 million annually. No additional positions will be required, however, there will be a one-time contractual cost of $15,000 for auditor training on well lease expenditures.

7. **The statute of limitations on the assessment of taxes is changed from six to four years after the annual return is filed**. The effective date of this provision is 1/1/2014. The DOR does not forecast assessments of tax upon audit; therefore this provision has no quantifiable revenue impact. Two additional oil and gas auditor IV positions will be required beginning in FY 2014 to implement this provision. These positions are expected to cost $287,400 annually.

FISCAL NOTE

STATE OF ALASKA
2011 LEGISLATIVE SESSION

Fiscal Note Number: 2
Bill Version: SB 49
(S) Publish Date: 1/19/11

LL0007-DNR-DOG-1-13-2011
Title: Oil and Gas Production Tax
Sponsor: Rules Committee
Requester: Governor

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

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2012**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**FY 2016**	**FY 2017**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
CAPITAL EXPENDITURES							
CHANGE IN REVENUES							

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Estimate of any current year (FY2011) cost _____

POSITIONS

Full-time							
Part-time							
Temporary							

Why this fiscal note differs from previous version

Not applicable, initial version

Prepared by: Kevin Banks — Phone: 269-8800
Division: Oil and Gas — Date/Time: 1-13-2011; 2:15 PM
Approved by: Daniel S. Sullivan — Date: 1/13/2011
Natural Resources

(Revised 12/29/2010 OMB)

FISCAL NOTE #2

STATE OF ALASKA
2011 LEGISLATIVE SESSION

BILL NO. SB 49

Analysis

This bill may encourage producers to invest more by allowing them to receive the benefits of credits for that investment more quickly. First, currently under AS 43.55.023(b), only half the 20% qualified capital expenditure (QCE) credit can be taken in any one year. Section 11 of this bill would amend AS 43.55.23(b) to allow the full QCE credit to be taken in one year. Second, under AS 43.55.23(d), a producer that applies to obtain a transferable certificate for expenditures on the North Slope giving rise to a QCE credit or the loss carry-forward credit (AS 43.55.023(a)) will be issued two certificates, each for half the credit amounts, with one of the certificates only good for the next calendar year.

This limitation dilutes the incentive the credit provides to the extent that a producer/investor must wait before receiving the full benefit of the credit. Section 12 of this bill would amend AS 43.55.023(d) to allow the certificates received be for immediate use for North Slope expenditures, just as they are currently for expenditures in Alaska outside the North Slope. Third, Section 17 of the bill makes it easier for a small producer receiving a credit for North Slope expenditures to sell that credit to the State by eliminating the requirement that the producer spend additional money before receiving the credit monies.

In addition to allowing a quicker monetization of a given amount of credits, the bill extends the current 40% credit provided under 43.55.023(l) for well expenditures in Alaska off the North Slope to well expenditures on the North Slope. Currently, the North Slope producers receive a 20% qualified capital expenditure credit for well expenditure capital. Under the amendments provided in Sections 15 and 16 of the bill, producers would receive a 40% credit for those expenditures. This increased credit amount may encourage investment in wells on the North Slope.

This bill has a higher minimum tax rate apply to lower ANS West Coast prices. To the extent investors perceive the possibility that ANS West Coast prices will fall this low, these changes to the minimum tax may discourage investment. Also, by having separate production tax value calculations for "new production" units , the investors in these new units will have less ability to lower tax liability on "old production" units.

This bill lowers the marginal tax rates for existing and new fields by having progressively higher tax rates only apply to incremental production tax value. 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.

State of Alaska

Department of Revenue

Administrative Services Division

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

January 20, 2011

The Honorable Joe Paskvan
The Honorable Tom Wagoner
Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, AK 99801

SB49 Production Tax on Oil and Gas
By Request of the Governor

SECTION ANALYSIS

Sections 1-3: Sections 1-2 are conforming amendments to reflect changes to AS 43.05.225. Section 3 amends AS 43.05.225(1) to provide that the tax rate on delinquent taxes under Title 43 is charged at the lower of three percentage points above the applicable annual federal rate or at the annual rate of 11 percent. This provision is to be effective July 1, 2011.

Section 4-5: Conforming amendment required by amendment to AS 43.05.225, interest rates due on delinquent taxes.

Section 6: Amends AS 43.55.011(e) to levy the annual production tax at the rate of 25 percent plus progressivity for oil and gas from a lease or property containing land that as of December 31, 2010, was or had previously been within a unit or in commercial production. A new tax rate of 15 percent, plus an annual progressivity tax, is levied on oil and gas produced from a lease of property containing land that had not previously been in a unit or in commercial production prior to December 31, 2010. For each category of production, the progressivity tax is levied on an annual basis. This amendment would be effective January 1, 2013, and apply to production after December 31, 2012.

Section 7: AS 43.55.020(f) is amended to lower the threshold prices at which the minimum tax applies, and would apply to production after December 31, 2012.

Section 8: AS 43.55.011(g) is repealed and reenacted to provide an annual incremental progressivity tax for all production. The applicable incremental progressivity tax rate applies only to the fraction of average annual production tax value per BTU equivalent barrel that falls within that incremental rate. For production subject to the 25 percent base rate, progressivity is capped at 25 percent above the base rate, for a maximum rate of 50 percent. For production subject to the 15 percent base rate, progressivity is capped at 25 percent above the base rate, for a maximum rate of 40 percent. This change would be effective January 1, 2013, and apply to production after December 31, 2012.

Section 9: AS 43.55.020, monthly payments of estimated taxes, is repealed and reenacted to account for the annual progressivity calculation and the new tax rate for certain fields.

Section 10: Conforming amendment related to interest rate changes.

Section 11: AS 43.55.023(a) is amended to remove the requirement that tax credits for qualified capital expenditures be applied against taxes or certificated
over two years. This change would be effective January 1, 2012, and would apply to production after December 31, 2011.

Section 12: AS 43.55.023(d) is amended to provide that transferable tax credit certificates will be issued as one certificate. This is to be effective January 1, 2012, for expenditures after December 31, 2011.

Sections 13-14: AS 43.55.023(g) is amended to reflect the interest rate change, and to reflect the repeal of AS 43.55.023(m), related to the issuance of well lease expenditure credit certificates.

Sections 15-16: AS 43.55.023 (*l*) and (n) are amended to expand the 40 percent well lease expenditure credit to qualified expenditures made on leases or properties north of 68 degrees North Latitude. This change is to be effective January 1, 2012, for expenditures after December 31, 2011.

Sections 17 -18: Conforming amendments are made to AS 43.55.028 (e) and (g) to reflect the repeal of AS 43.55.023(m).

Section 19: AS 43.55.075(a) is amended to change the statute of limitations for assessment of additional production taxes from six years to four years after the return is filed. This change is applicable to production after December 31, 2013, for tax liability beginning tax year 2014.

Sections 20: AS 43.55.160(a) is repealed and reenacted to account for changes in the calculation of the progressivity tax, and to account for new tax rates for certain production under AS 43.55.011(e) (2).

Sections 21-23. These sections make conforming amendments to account for interest rate change.

Section 24: AS 43.55.023(m) is repealed, all capital credit certificates, regardless of the location of the exploration, development or production expenditures, will be issued as one certificate.

Section 25: The applicability provision clarifies that sections 11, 12, 15 and 16 apply to expenditures made after December 31, 2011; sections 6-9 and 20 apply to oil and gas produced after December 31, 2012, and section 19 applies to any tax liability for the production of oil and gas after December 31, 2013 and

Section 26: This section provides that the Department of Revenue will have authority to adopt regulations to implement this Act, not to be effective before the effective date of the provisions implemented by this Act.

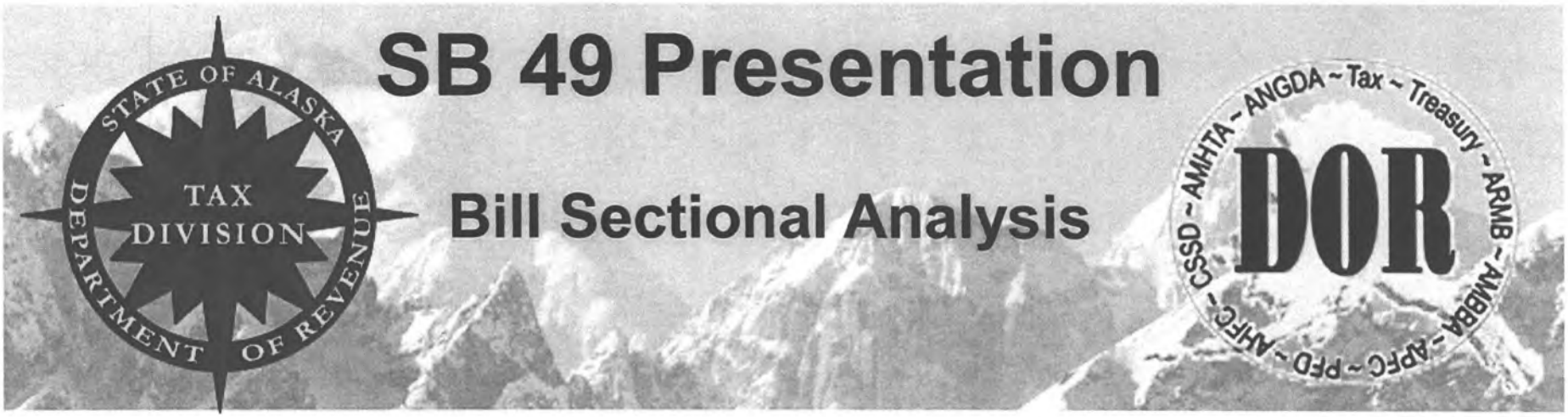
Section 27: The provisions related to the issuance of credit certificates and the expansion of the well lease expenditure credit to the North Slope, sections 11, 12, 14-18, 24 and 25(a), take effect January 12, 2012.

Section 28: The provisions related to new production and the progressivity tax, sections 6-9, 20, and 25(b), take effect January 1, 2013.

Section 29: The provisions related to the statute of limitations for the assessment of production taxes takes effect January 1, 2014.

Section 30: The provisions related to the change in the interest due on delinquent taxes and refunds take effect July 1, 2011.

LIB



Presentation to the
Senate Resources Committee
March 9, 2011
Alaska Department of Revenue

Main proposed changes

Progressivity Rates & Cap	Progressivity defined as discrete brackets, rather than as a continuous function, and applied only to incremental revenue. Maximum progressivity of 25%.	2013
Base Tax Rate	Base tax rate reduction from 25% to 15% for leases or properties neither unitized nor producing as of 12/31/2010.	2013
Tax Credits	Extension of 40% well lease expenditure tax credits to North Slope. Tax credits can be claimed in a single year instead of two years.	2012
Tax Calculation	Yearly tax calculation based on average prices and costs, instead of monthly tax calculation impacted by short term price and cost peaks.	2013

2012 Effective 1/1/2012 for expenditures made before 12/31/2011.

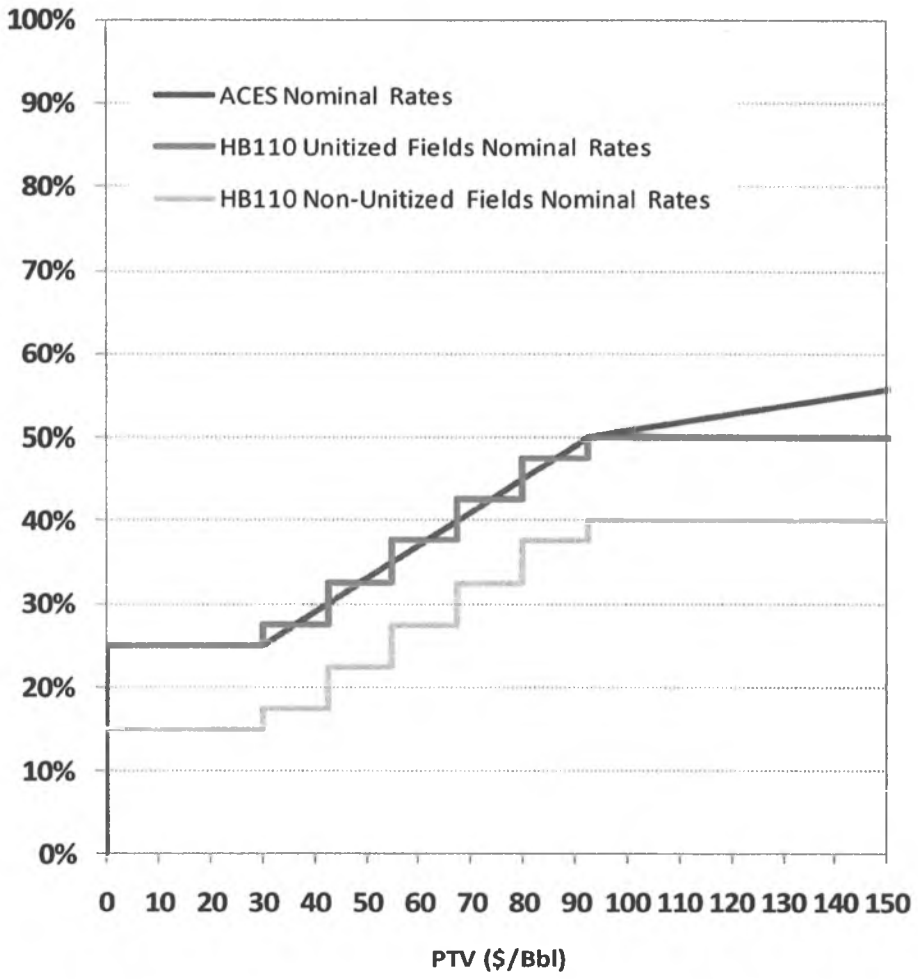
2013 Effective 1/1/2013, applies to production after 12/31/2012.

SB 49
Bill Sectional

Changes to progressivity and maximum tax rate

- **Section 8:** Provides incremental, bracketed progressivity. The applicable progressivity rate applies only to the fraction of the production tax value that falls within the incremental rate. Maximum total tax rate is 50% for production subject to the 25% base rate. Maximum total tax rate is 40% for production subject to the 15% base rate.

Nominal Production Tax Rates



PTV/boe ($/boe)		Tax Bracket (%)	
From	To	Non-Unitized Fields	Unitized Fields
0.0	30.0	15.0%	25.0%
30.0	42.5	17.5%	27.5%
42.5	55.0	22.5%	32.5%
55.0	67.5	27.5%	37.5%
67.5	80.0	32.5%	42.5%
80.0	92.5	37.5%	47.5%
92.5	*and above*	40.0%	50.0%

Conforming amendments for tax rate changes

- **Section 9:** Statute requiring monthly payments is revised to account for annual progressivity calculation and new tax rate for certain fields.
- **Section 20:** AS 43.55.160 repealed and reenacted amended to account for changes in progressivity, and new 15% tax rate. Segments maintained per current statute.

15% base rate for new units

- **Section 6*:** Levy of tax.
  - Rate is 25% + bracketed progressivity for oil and gas from current leases or properties.
  - Rate is 15% + bracketed progressivity for production from lease or property that had not been in a unit or in commercial production prior to Dec 31, 2010.

* Portions of this section discussed elsewhere in presentation

40% well lease expenditure credit extended to North Slope

- **Sections 15-16:** Expands the 40% well lease expenditure credit to qualified expenditures made on the North Slope.
- **Sections 17-18:** Conforming amendments to reflect repeal of AS 43.55.023 (m).

Capital credits can be taken in the year earned

- **Section 11:** Removes requirement that tax credits for qualified capital expenditures be taken over two years.
- **Section 12:** Provides that tax credit certificates will be issued as one certificate.
- **Section 14:** Conforming amendment to reflect repeal of AS 43.55.023 (m), relating to the issuance of well lease expenditure credit certificates.
- **Section 24:** Repeals AS 43.55.023(m), since all capital credit certificates will be issued as one certificate.

Switch from monthly to annual progressivity

- **Section 6*:** Levy of tax.
  - Progressivity would be levied on an annual, rather than a monthly, basis.

* Portions of this section discussed elsewhere in presentation

Strengthens the minimum tax

- **Section 7:** Lowers threshold prices for application of minimum tax.
  - 4% of gross minimum tax would apply when ANS WC price is over $20 (currently $25)
  - Thresholds for 0%, 1%, 2%, 3% tax lowered

Interest rate reduced for delinquent taxes and refunds

- **Sections 1-5:** AS 43.05.225 is amended to reduce interest rates on delinquent taxes and refunds.
  - New rate - federal rate plus 3% or 11 %, whichever is lower.
  - Current rate is federal rate plus 5% or 11%, whichever is higher.
- **Section 10:** Conforming amendment for interest rate change.

Conforming amendments for interest rate change

- **Section 13:** Conforming amendment to reflect interest rate change.
- **Sections 21-23:** Conforming amendments for interest rate change.

Statute of Limitations for production tax assessment reduced

- **Section 19:** Statute of limitations for production tax reduced from 6 years to 4 years, beginning with 2014 tax liability.

Effective dates, applicability, authority for regulations

- **Section 25:** Applicability provision for clarification.
- **Section 26:** Provides DOR authority to adopt regulations to implement the bill.
- **Sections 27-30:** Effective date provisions.

SB 49 Effective Dates

7/1/2011:

Reduced interest rate for overpayment and underpayment of taxes.

1/1/2012:

Credits for expenditures made after this date can be used in one year .

40% Well Lease Expenditure credit extended to North Slope.

1/1/2013:

Annual progressivity, bracketed progressivity, 50% max rate.

Lower tax rate for new leases or properties.

Changes to minimum tax thresholds.

1/1/2014:

Statute of limitations for production tax changed from 6 years to 4 years.

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

Oil and Gas Production Tax
Status Report to the Legislature
Alaska Department of Revenue
January 18, 2011

Report Purpose

In August 2006, the 24th Alaska state legislature approved House Bill 3001, which represented a major restructuring of the state's oil and gas production tax. As part of the legislation, lawmakers asked that the Department of Revenue study the impact of the production tax changes on several criteria and produce a report on or before the first day of the 2011 legislative session on the findings of that study.[1] This report summarizes those findings.

Executive Summary

This report evaluates six elements of Alaska's production tax system since implementation of the Petroleum Profits Tax (PPT) in 2006 and Alaska's Clear and Equitable Share (ACES) in 2007. The six elements and our key findings with respect to each of them are described briefly below.

1. **Revenue Generation/Tax Rate** – State revenues under PPT and ACES exceeded the amount that would have been received under ELF for each of the four fiscal years since implementation of a net profits tax. Although the production tax rate under ACES may be as high as 75%, tax rates in each of the

[1] ***AS 43.55.180 Required Report.*** ***(a)*** *The department shall study*
(1) *the effects of the provisions of this chapter on oil and gas exploration, development, and production in the state, on investment expenditures for oil and gas exploration, development, and production in the state, on the entry of new producers into the oil and gas industry in the state, on state revenue, and on tax administration and compliance, giving particular attention to the tax rates provided under AS 43.55.011 , the tax credits provided under AS 43.55.023 - 43.55.025, and the deductions for and adjustments to lease expenditures provided under AS 43.55.160 - 43.55.170; and*
(2) *the effects of the tax rates under AS 43.55.011 (i) on state revenue and on oil and gas exploration, development, and production on private land, and the fairness of those tax rates for private landowners.*
(b) *The department shall prepare a report on or before the first day of the 2011 regular session of the legislature on the results of the study made under (a) of this section, including recommendations as to whether any changes should be made to this chapter. The department shall notify the legislature that the report prepared under this subsection is available.*

four years were much lower than the maximum rate.

The oil tax rate of 5% of the gross value at the point of production at AS 43.55.011(i) for private landowners has not raised any significant concerns that have been communicated to the Department of Revenue.

2. **Industry Investment** – Investment in the form of capital expenditures has increased in each of the four fiscal years since implementation of the net profits tax, however, it is unclear how much of the capital expenditures were drilling or well-related and how much were maintenance or facilities-related.

3. **Impact on Exploration, Development, and Production –** Exploration has generally increased from 2003, when the EIC credit was implemented, but has dropped off in 2010. Development continues in three relatively new North Slope projects, yet production continues to decline.

4. **Industry Employment and New Entrants –** Industry employment rose steadily from 2006 through 2009, but dipped slightly in 2010. The number of companies filing annual tax returns doubled between 2006 and 2009, indicating interest by companies that are either new or returning to the Alaska oil and gas industry.

5. **Use and Expansion of Tax Credits** – The amount of credits used has increased annually since 2006 and we expect the trend to continue as new credit programs were added in the 2010 legislative session.

6. **Tax Administration and Compliance –** The department continues to write regulations for the new tax system, and the first audits under the net profits tax have been completed. The department has, however, been hampered in its tax reporting and compliance efforts by the lack of a centralized database to house and manage the large volumes of oil and gas data it receives.

7. **Conclusions and Recommendations –** Based on the multiple changes to the tax laws over the past few years, drawing any conclusion about their effect on Alaska's investment climate is difficult. However, what is clear is that production continues to decline. The state should continue to monitor its competitiveness with other oil and gas jurisdictions worldwide and be prepared to change its tax structure as needed.

Overview

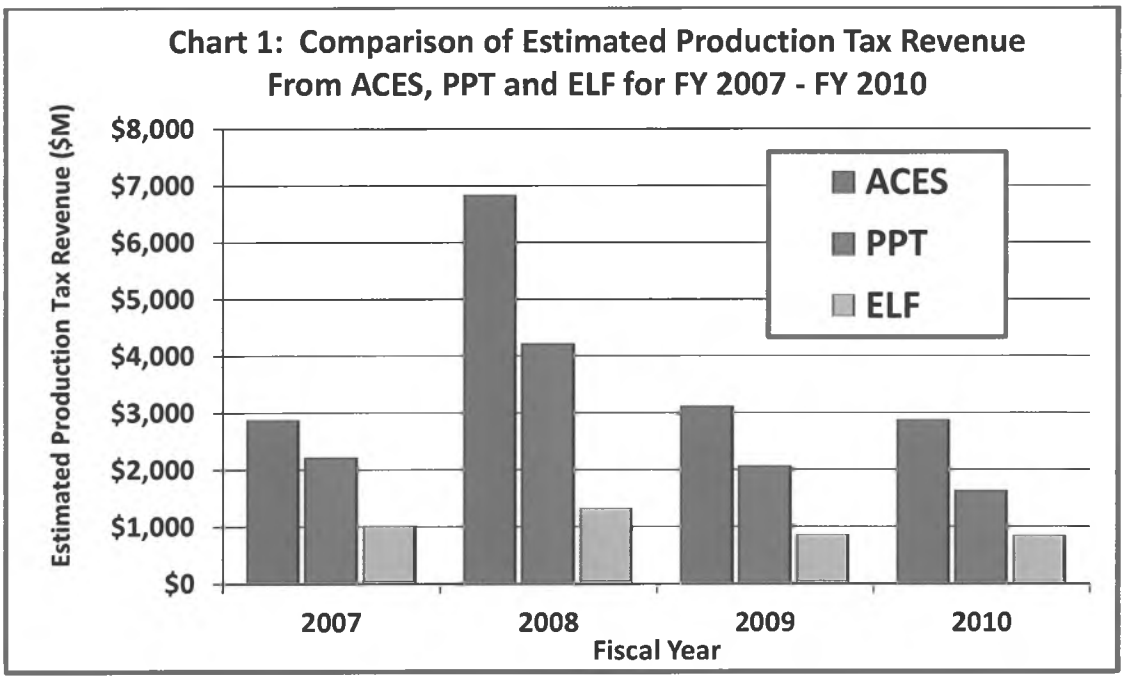
This report reviews and summarizes information gathered over the approximate five-year period since the implementation of the Petroleum Profits Tax (PPT) in 2006, and in 2007, Alaska's Clear and Equitable Share (ACES). The report covers six critical elements for evaluation and a section with conclusions and recommendations, as follows:

1. Revenue Generation/Tax Rate
2. Industry Investment
3. Impact on Exploration, Development and Production
4. Industry Employment and New Entrants
5. Use and Expansion of Tax Credits
6. Tax Administration and Compliance
7. Conclusions and Recommendations

Revenue Generation/Tax Rate

Both PPT and ACES have generated more production tax revenue for the State than would have been received under the previous production tax system, which used the Economic Limit Factor (ELF). In the one year that PPT was in place, FY 2007, the production tax totaled $2.2 billion. That year, the ANS West Coast oil price averaged $61.60 and production on the North Slope averaged 734,000 barrels per day. In contrast, the average oil price one year earlier, in FY 2006, was $62.12, production averaged 840,000 barrels per day, and the production tax under ELF totaled $1.2 billion--$1 billion, or 45% less than collected under PPT. It should be noted that PPT became effective on April 1, 2006, adding two months of tax collections to the FY 2007 total, making FY 2007 effectively a 14-month fiscal year. Regardless, the level of PPT collections above those that would have been collected under ELF, at least at moderately high prices, is significant.

In the three years that ACES has been in place, production tax revenues have increased to higher levels than under PPT. This is largely because ACES has higher base and progressivity tax rates than did PPT, and because one of the credits under PPT – the transition investment expenditure credit – was reduced substantially. The chart below shows production tax revenue collections under PPT and ACES as compared to how production tax revenue collections would have looked under two tax systems that were not in place during those years.



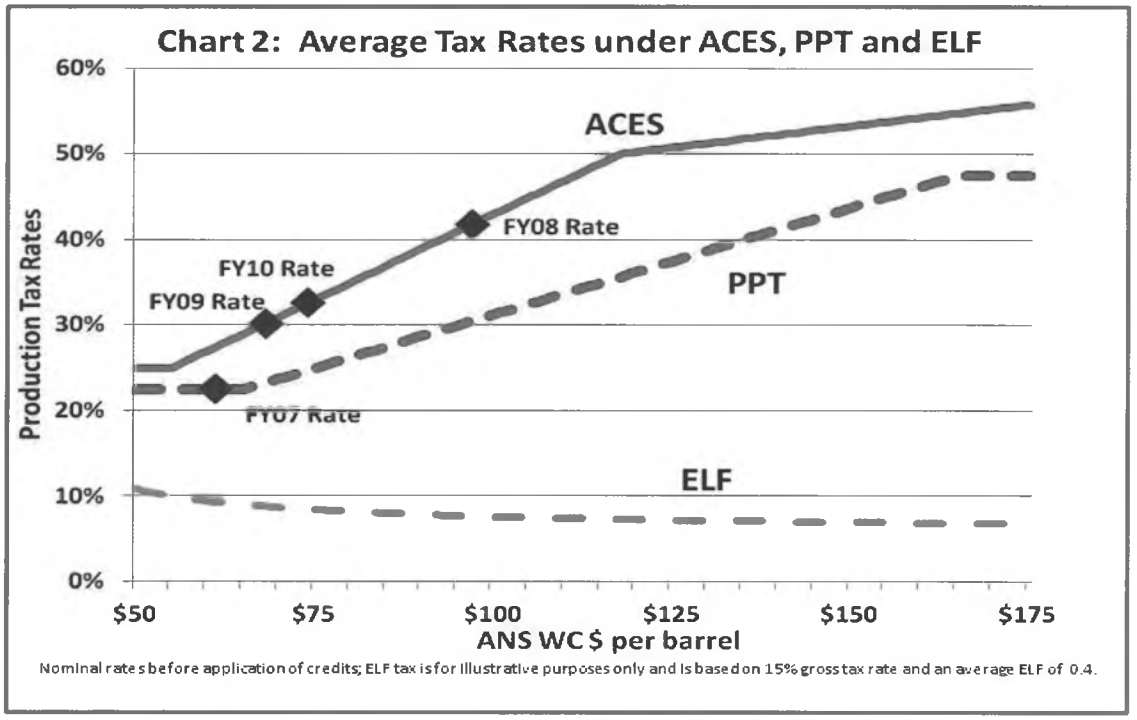
Production tax under both PPT and ACES is calculated on the net profits of oil and gas production, whereas ELF production tax was calculated on the gross profits of oil and gas production. Relative to taxes based on the gross value of production, net profit tax systems generally provide more tax revenue when oil prices are high and less tax revenue when prices are low. The progressive tax mechanism, designed to increase the total tax rate when per-barrel profit exceeds a pre-determined threshold, can increase the tax rate substantially. In addition to the progressive tax rate, the per-barrel profit level where the progressive tax is triggered is important. In the case of ACES, the progressive tax trigger is $30 net profit per barrel, whereas with PPT, the progressive tax trigger was $40 net profit per barrel.

Alaska North Slope (ANS) oil prices over the past four fiscal years were high relative to previous fiscal years. ANS crude prices over the four fiscal years of 2007 through 2010 averaged about $75 per barrel compared to $42 per barrel for the fiscal years of 2003 through 2006. Under ACES, an average price of $75 per barrel would yield an average profit of $50 per barrel, producing a combined base and progressivity tax rate of 33% (25% + [($50-$30)*.004]). The tax under this scenario before credits would be $16.50 per barrel. In contrast, the tax rate under ELF of 15% of the gross value at the point of production, even if the ELF calculated to 1, would yield a production tax of $10.50 per barrel, assuming transport costs of $5 per barrel.

When oil prices are low, however, a net profits-based tax structure would likely provide less production tax revenue than a gross profits-based tax. For example, a tax of 15% on the gross value, regardless of profit, could create a loss for companies producing oil

if profits were equal to or less than the tax. Because PPT and ACES recognize the costs of production in their calculation, a company with no profit would not pay any production tax and would likely get tax credits to offset future tax liabilities. Low oil prices experienced late in the year 2008 and early 2009 generated tax liabilities for many companies operating on the North Slope that were lower than they would have been under the ELF system.

Chart 2 below shows the average tax rates of PPT, ACES and ELF under a range of oil prices. Also shown is the average tax rate in each of the years that a net profits tax has been in place.



The department was also asked to review the tax rate for oil produced from private land of 5% of the gross value at the point of production.[2] The department is not aware of any concerns expressed on behalf of industry or private landowners as to the fairness of this tax.

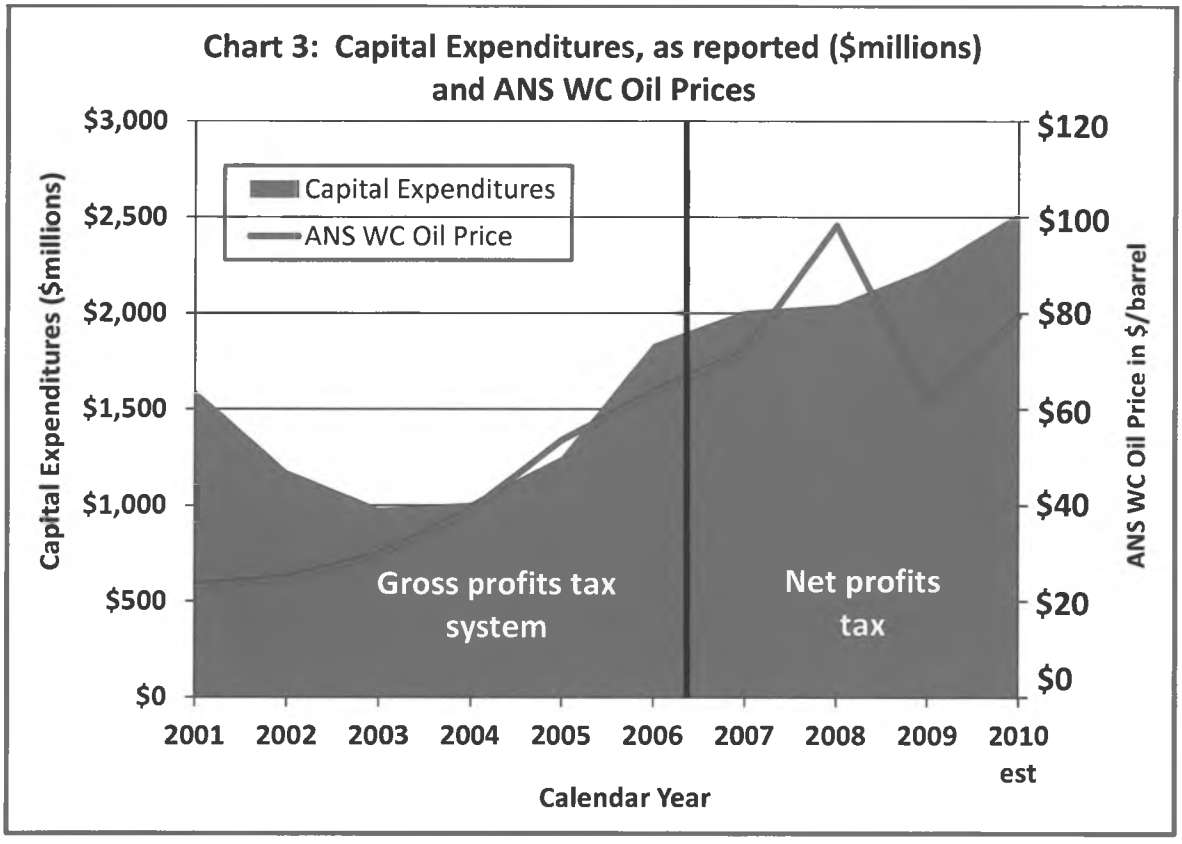
Industry Investment

Investment is an important component in Alaska's oil and gas industry. Producing oil, especially in an arctic environment, requires substantial financial outlays before, during

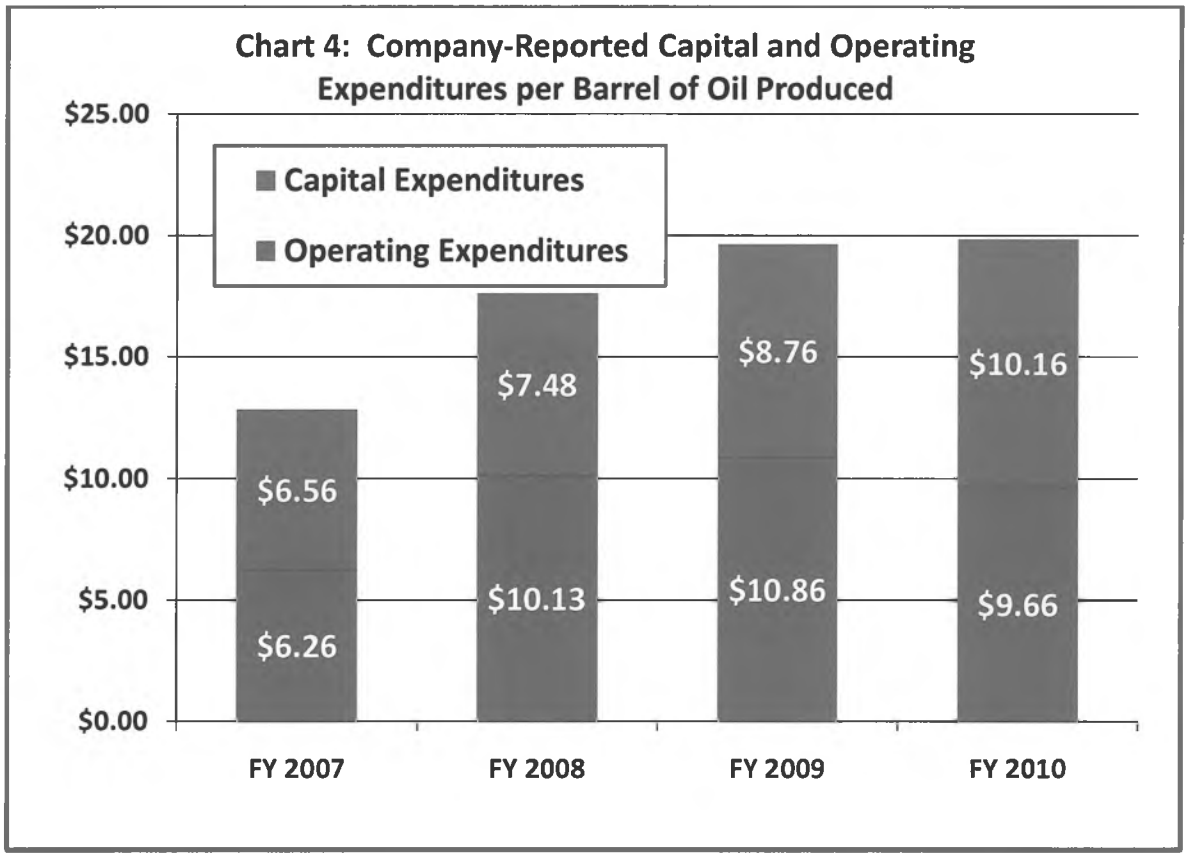
[2] AS 43.55.011(i)

and after producing the oil. In massive oil fields such as Prudhoe Bay, which has been operating for more than 30 years, maintaining and upgrading equipment and facilities is key to continued undisrupted oil production. Companies must also invest in research and new technologies in order to achieve the maximum recoverability of petroleum from the reservoirs they have developed. Because the companies that invest in petroleum projects can and do operate in areas outside of Alaska and the country, Alaska oil projects must compete with other petroleum opportunities throughout the world for those investment dollars.

Industry investment is generally reflected in capital expenditures, as opposed to operating expenditures, which are normally considered day-to-day expenditures for producing oil and gas. Alaska's fiscal system, which gives credits for capital expenditures, theoretically encourages these types of investments. Our review of the past 10 years of data appears to bear this out. Chart 3 below shows company-reported data from tax filings from calendar year 2001 through calendar 2010 (estimated). While capital expenditures over the five-year period (2006 through 2010) since the implementation of a net profits tax with credits for capital expenditures have increased each year, we have limited data as to the nature of the expenditures.

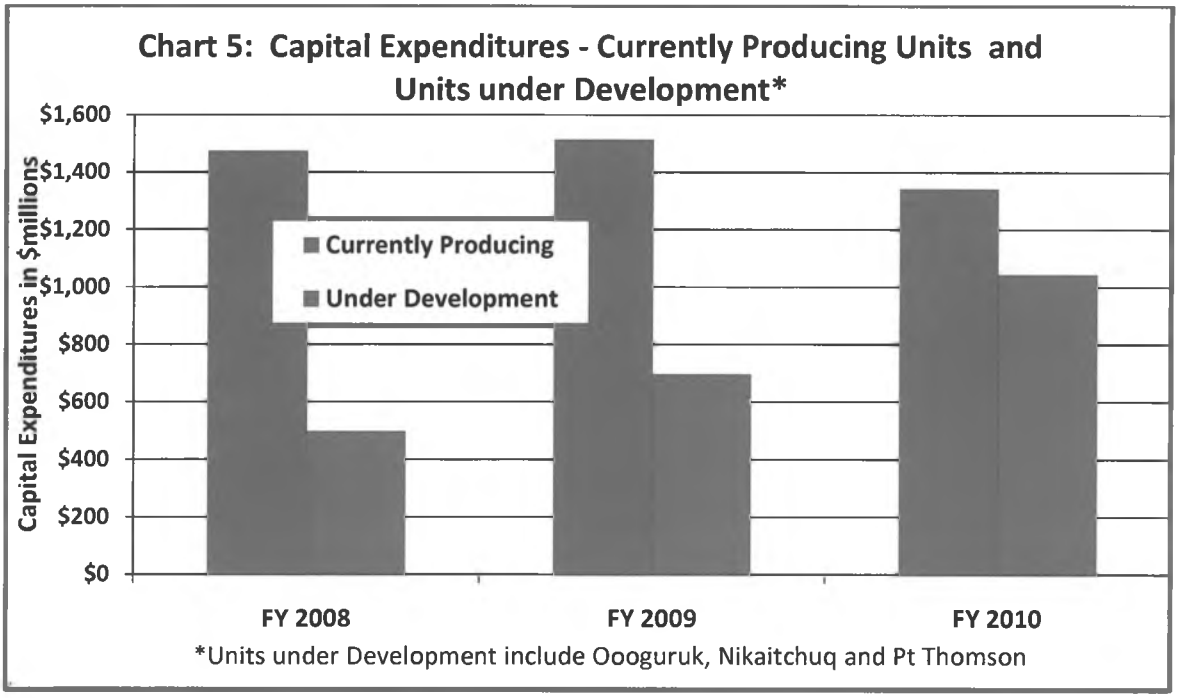


In the context of petroleum basin operations, capital expenditures are generally an indicator of expanding production or enhancing or extending the life of facilities or equipment. Expenditures for drilling wells normally fall into the category of capital expenditures as do expenditures for building housing or processing facilities. The Department of Revenue has extremely limited data from which to determine the nature of the capital expenditure increases. Given the age of North Slope facilities and infrastructure, it is quite possible that much of the capital investment in currently producing properties such as Prudhoe Bay is to extend the life of the facilities or infrastructure. Production on the North Slope continues to decrease, with a 7% decline rate between FY 2009 and FY 2010. The end result is that capital expenditures per barrel of oil produced are rising, while operating expenditures per barrel have leveled off and even decreased somewhat, as shown in Chart 4 below.[3]



[3] The slight decline in capital expenditures per barrel between FY 2007 and FY 2008 can be explained by the fact that FY 2007 included 14 months of expenditures, due to the effective date of the tax change of April 1, 2006.

One trend that has been observed in annual capital expenditures figures is that the proportion of capital spending in units under development has been increasing relative to the total capital expenditures spent on the North Slope. Chart 5 below shows expenditures by currently producing units and units under development over the past three fiscal years.

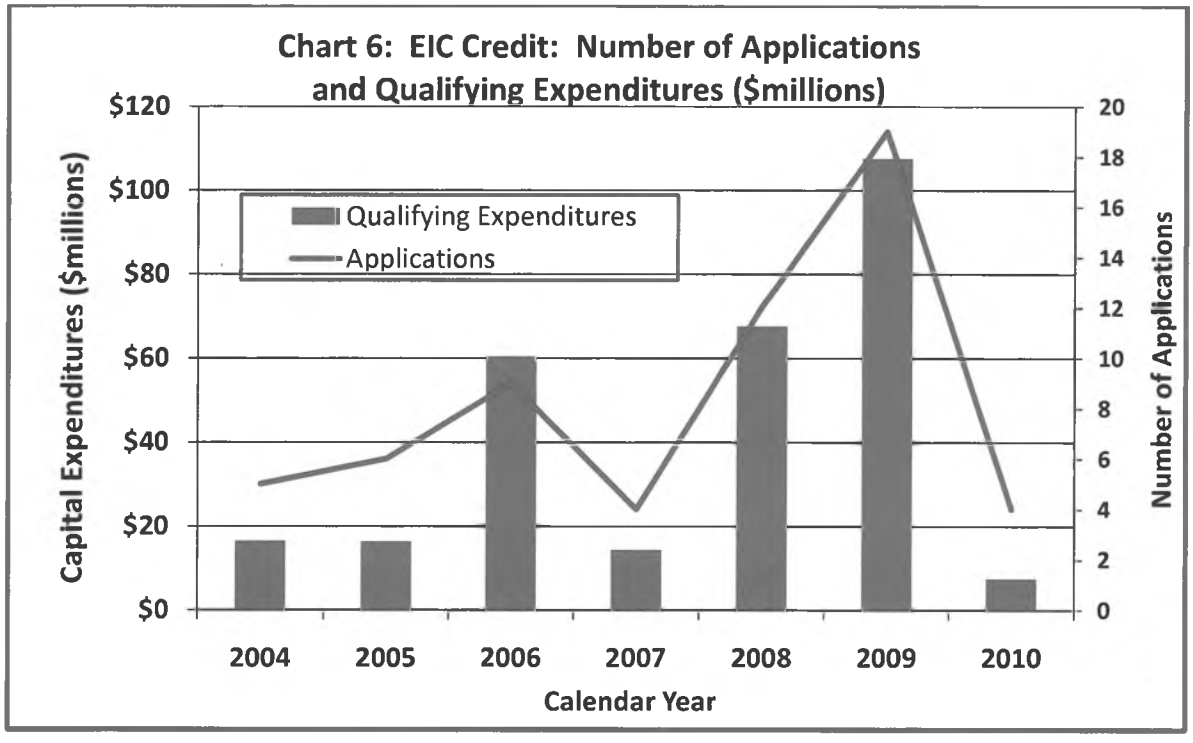


Capital expenditures also earn credits under the new production tax system. The credit system for capital expenditures on the North Slope does not distinguish between types of capital expenditures in existing units. The legislature in 2010 expanded the credit program in Cook Inlet to include an additional 20% credit (total of 40% credit) for lease expenditures related to wellwork. A credit increase of this nature may also prove beneficial to incentivize capital expenditures on drilling and increased wellwork on the North Slope.

Impact on Exploration, Development and Production

As discussed in the previous section, the net profits tax system includes credits for capital expenditures, without distinction as to the nature of the expenditure. The tax system also includes credits for exploration expenditures through its exploration incentive credit (EIC) at AS 43.55.025. This credit was implemented in 2003 and was expanded with the ACES tax changes. If a project meets certain exploration criteria, it may be eligible for 40% credit under the EIC program.

The department began receiving applications under the EIC program in 2004, and the number of applications and amount of qualifying expenditures has generally increased each year peaking in the winter of 2008/2009[4]. The number of applications for EIC credit decreased significantly in 2010, reflecting a decrease in activity for the winter of 2009/2010. Chart 6 shows the number of applications and the expenditures that qualify under the EIC program from 2004 through 2010.

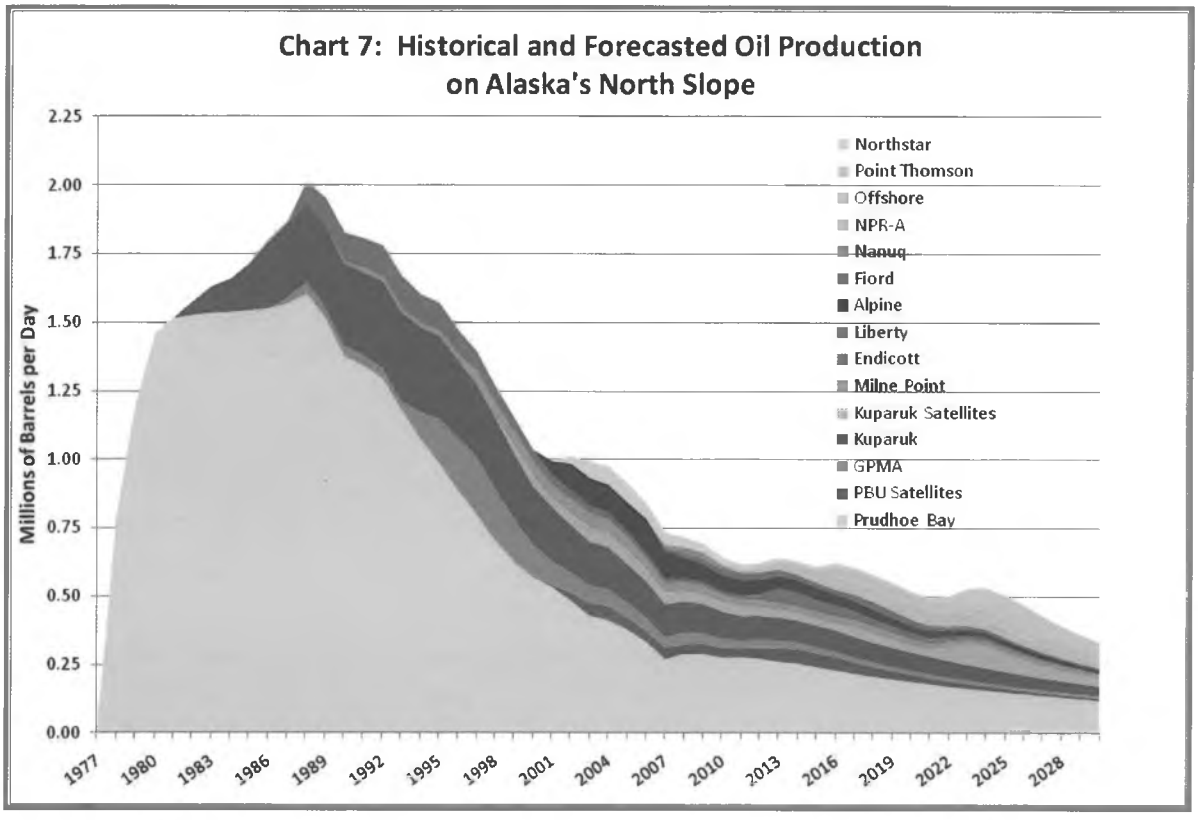


It is much more difficult to measure a tax system's impact on oil development and production from existing fields. The department's production forecasters twice annually create production profiles from limited information about an area's geology, drilling results, and other information exchanged in confidential discussions with operators. The compilation of production profiles for each North Slope field is a challenging task, employing the use of an engineering consultant, generally accepted engineering principles, and special software. The results of this compilation are subject to further revision as projects face delays that are typical in the petroleum industry such as reservoir challenges, permitting difficulties or lack of project funding.

New commercial developments on the North Slope include the Oooguruk Unit, which began production in 2009, and the Nikaitchuq Unit, which is expected to begin production in 2011. The Point Thomson Unit is also under development, expected to

[4] The sharp decrease in 2007 may be due to the tax change to the PPT, which at the time provided credit equal to the lower credit rate of the EIC program, without the reporting requirements.

begin production in 2015. Despite the addition of these developments, North Slope production continues to decline. From FY 2009 to FY 2010, oil production declined 7%; another 4% decline is projected between FY 2010 and FY 2011. Chart 7 below shows historical and projected oil production from the North Slope.

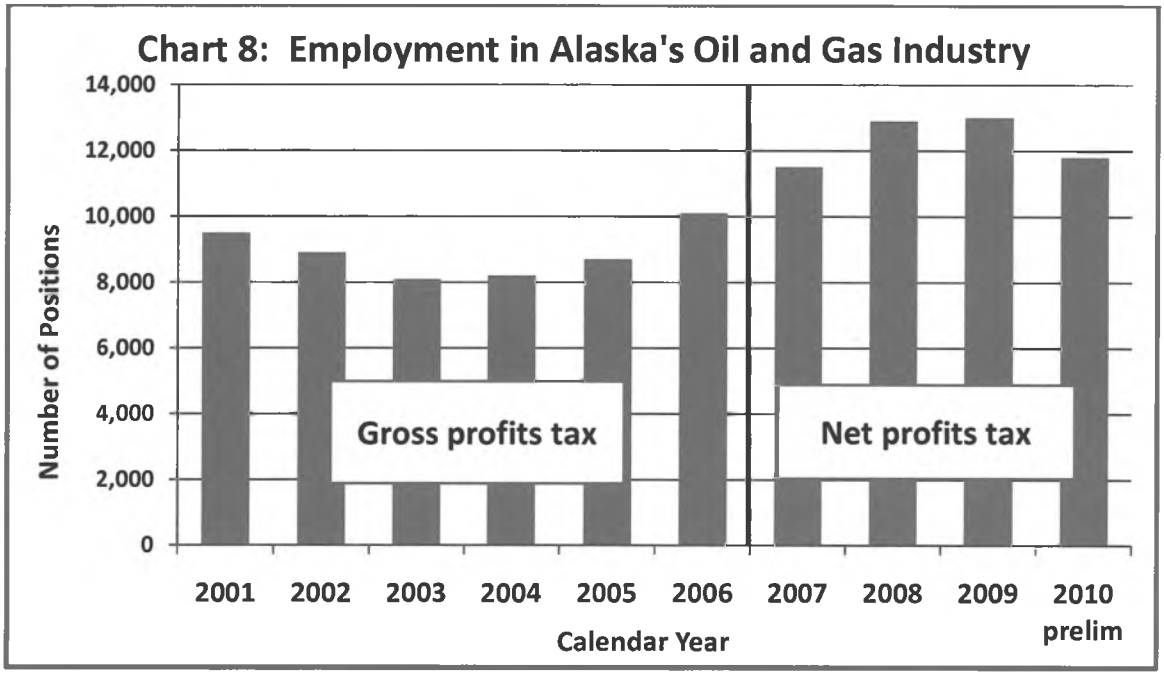


Industry Employment and New Entrants

Employment in the oil and gas sector is another important measure of the health of the oil and gas industry in Alaska. Although oil and gas employment is not the largest category in the state, it is among the most sought-after employment, due to high wages. The Alaska Department of Labor and Workforce Development (DOLWD) reports that in 2009, the average earnings for a person employed in the oil and gas extraction industry was close to $14,000 per month. These earnings are more than 3 times higher than the average earnings for all industries and government in the state of about $4,000 per month.

The department also reports number of employees by industry. Oil industry employment in the state includes jobs with duties that would fall into one of three categories: (1) oil and gas extraction; (2) drilling oil and gas wells; and (3) support activities for oil and gas operations. Officials at DOLWD acknowledge that the definition

is fairly narrow, leaving out important oil-related employment, such as jobs at Alyeska Pipeline Service Company and at refineries in the state. Employment in the oil and gas industry has increased in the years since PPT was implemented, although the department projects a slight decrease in 2010. These data are shown in Chart 8 below.



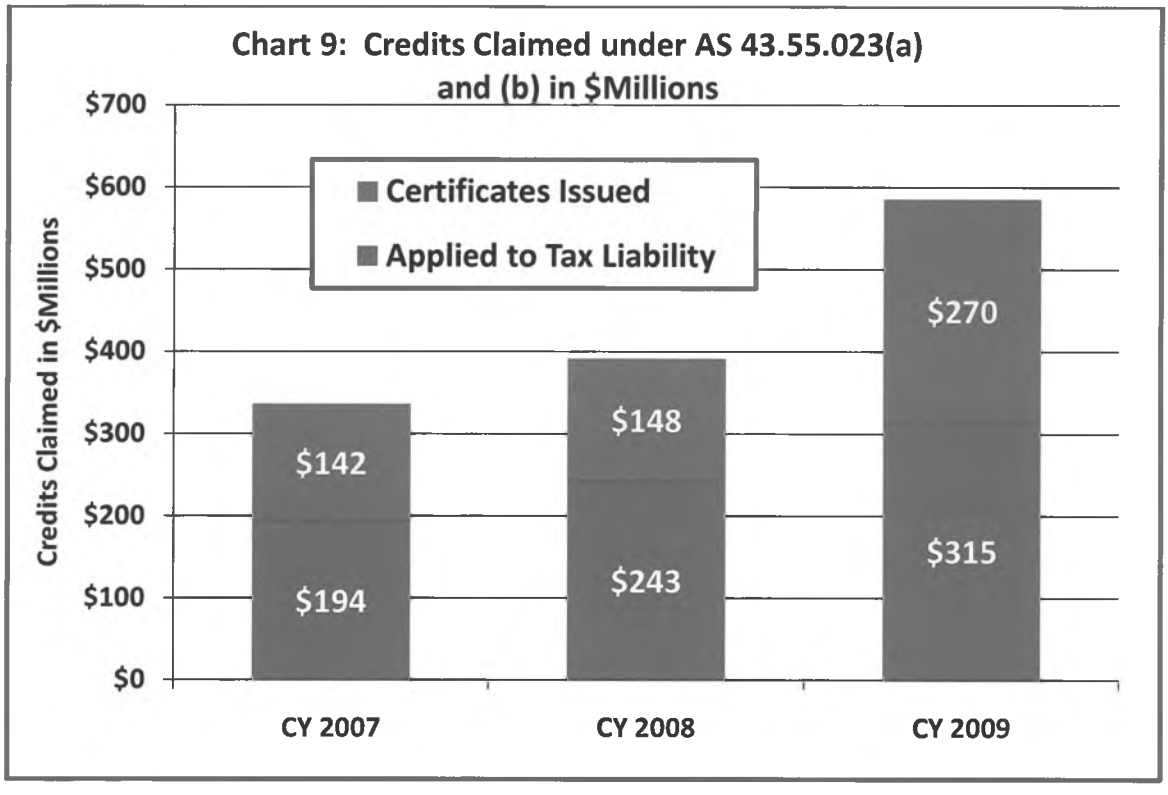
The state has seen new entrants into the Alaska oil and gas industry since the implementation of a net profits production tax. At the most recent lease sale held in October of 2010, a company new to Alaska successfully bid on over 100 tracts of oil and gas property. The steadily increasing number of production tax returns filed annually also indicates companies' new or renewed interest in Alaska's oil and gas opportunities. In 2006, the first year that filings were made under a net profits tax, there were 19 companies filing annual returns. In 2007, the number of companies filing production tax returns totaled 26, and in 2008, 36 companies filed annual production tax returns. The filing for 2009 increased only slightly from 2008, with 39 companies filing returns.

Use and Expansion of Tax Credits

Tax credits have played and continue to play an important role in the net profits production tax system. There are currently five credit programs specific to the oil and gas production tax, and each of the programs have had substantial interest, and in most cases, use from taxpayers. Alaska's tax credit programs are intended to steer spending to certain in-state activities.

The most widely used credits under the production tax system are the qualified capital expenditure credits at AS 43.55.023(a). Tax credits under this program may be applied to production tax to reduce a taxpayer's tax liability. If an oil and gas company has no tax liability, the credit may be carried forward, transferred to another company, or sold to the state. AS 43.55.023(b), credits for carried-forward net operating losses, are also widely used and may also be carried forward, transferred to another company, or sold to the state. Combined, these credits made up over 80% of the credits issued by the DOR Tax Division over the past three years.

Chart 9 below shows the total number of tax credits claimed under AS 43.55.023(a) and (b), categorized by the number of tax credits applied against a tax liability and the number of credits that were issued credit certificates for future use. We note that credits increased in each of the three years shown. The forecast for increased capital expenditures will translate to more credits applied against tax liabilities as well as more credits certificated.



Other credits include Small Producer/New Area Development credits (AS 43.55.024(a) and (c)) and Alternative Credit for Exploration (AS 43.55.025). These credits have seen less use than the credits under .023.

Credits have been expanded – both in credit rate and number of credits available – over the past year. The credit rate under the Qualified Capital Expenditure credit (AS 43.55.023) was increased for well lease expenditures relative to projects in Cook Inlet from 20% to 40%. Credit under the corporate income tax was also increased and extended (AS 43.20.043) for exploration and development of natural gas in Cook Inlet. The credit rate increased from 10% of qualified capital expenditures and qualified services to 25% of these costs and the credit program was extended from 2013 to 2016. For a complete listing of tax credits available against the production tax and other taxes, see the Fall 2010 *Revenue Sources Book*, at:
http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2126f

Tax Administration and Compliance

The numerous changes associated with the shift from a tax on gross value to a tax on profits have been a challenge for the Department of Revenue in a few specific areas. The first order of business under a tax system with a new, different way of calculating the tax is to define the inputs. This has taken place over the past several years in the process of creating, vetting, and implementing regulations. The regulations writing process for the production tax change has been extraordinarily interactive with the taxpayers, incorporating their input in all phases of development. Although this process may have slowed the pace of development, it resulted in more clarity in a complex set of regulations. The regulations writing process continues to date.

The change to a production tax on net profits also posed challenges for the audit staff in the areas of hiring qualified auditors and training auditors for the new demands of the position. The department has had difficulties attracting qualified auditors under the state pay schedule. New and expanded credit programs have also added to their workload. Despite these challenges, the audit staff has completed most of the audits under the PPT system.

The greatest difficulties faced by the department since the implementation of a net profits production tax system are the collection, use, and storage of the huge amounts of data received monthly and annually. As an example, the department receives monthly information from each active oil and gas company regarding the amount of oil and gas produced, the amount spent in operating and capital expenditures, the amount of credits earned and used, and the payment submitted. The department also receives documents pertaining to petroleum sales and netback calculations, most of which are submitted in Adobe Acrobat pdf format, which is not a suitable format for data storage or use. Assembling this data in a useable format is time-intensive and subject to error, as the data are cut and pasted into spreadsheets manually. Further compilations and changes subject the data to additional error and distortion.

The department's access to and use of this important data would be substantially improved if the information were housed in a central database, with access provided to all users of the data. The department believes securing a database will assist in operating more efficiently and effectively as an interface with both taxpayers and the public.

Conclusions and Recommendations

A government's fiscal regime is just one element for oil and gas companies to consider when weighing options for where to invest. Many other elements, such as resource risk, political risk, environmental factors, and availability of labor and equipment, also play a part in companies' decisions about where to invest. It is very difficult to separate these factors in order to determine the extent to which a government's fiscal system influences investment choices.

While it is untenable to blame a tax system for the lack of industry investment, it is equally untenable to claim that the tax system is the reason increased activity or investment occurs. The past three years have seen dramatic swings in oil prices from a high of $134 per barrel to a low of $38 per barrel just 6 months later. An economic recession stifled investment and business activity in the United States and much of the developed world for over a year. The economic activity of the past three years may not have been the best benchmark by which to judge the impact of a tax system.

Nevertheless, it is prudent for state officials to monitor praise for and criticisms of its fiscal systems from both industry and the general population that they serve. High oil prices of recent years have swelled state bank accounts and some have suggested that the state is in the best financial position since statehood. Business periodicals and industry journals report that state is benefitting at the expense of a single industry – petroleum – and that the tax rate under ACES is too high and "takes away the upside" for the oil and gas producers. Criticism is often centered around the marginal tax rate under ACES, under which the government share of each additional dollar of profit may be as high as 93%.

State officials also make efforts to stay informed on the global oil and gas markets and opportunities in other jurisdictions, including how Alaska ranks competitively against them. Among the recent events in government taxation was the royalty modification undertaken by the Canadian province of Alberta. Studies conducted for the Alberta government showed that the royalty changes made in 2007, combined with the recession, the changes in natural gas markets, and other jurisdictions' efforts to attract investment, were making Alberta less competitive for limited petroleum investment

capital. The government responded to this information by changing its royalty structure in a way that the government's share of oil and gas profits would be lower.

The State of Alaska depends heavily on the oil industry, with more than 80% of its unrestricted revenue coming from oil taxes and royalties. State officials should continue to monitor the state's competitiveness in oil and gas opportunities, and be prepared to modify it as the need arises.

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Paul Seaton
State Capitol Room 102
Juneau AK, 99801

February 18, 2011

SUBJECT: Response to Questions regarding House Bill 110 on February 8, 2011

Dear Representative Seaton:

The purpose of this document is to respond to four questions about House Bill 110 submitted by your office via email on February 8, 2011. The questions and answers to those questions follow.

(1) HB 110 proposes a separate tax regime on new fields than on existing fields. Under a scenario where a company is producing oil from an existing field, and simultaneously moves into a new field and begins producing oil from that field please describe the anticipated change in how state Auditors will approach company operations, given the cost and tax differentials between these existing and new fields. Will DOR be requesting additional auditors? How many of these auditors will be Field Auditors as opposed to office Auditors.

The Department does not anticipate a need for additional auditors due to the lower tax rate for new fields. The Department does not make a distinction between "field auditors" and "office auditors". Each auditor visits taxpayer offices as necessary for access to files and information that has to be viewed in the taxpayer's office.

(2) Will the Ugnu heavy oil formation be considered a new field? How will a separate formation within an existing unit be treated by the Department?

The Department uses the concepts of "units" and "participating areas" to distinguish between different oil and gas accumulations for tax purposes. The majority of the Ugnu formation is located within existing units, primarily the Prudhoe Bay, Kuparuk, and Milne Point units. Any production and lease expenditures would be included in information reported for the relevant unit, likely as a new participating area within the unit. Similarly, current viscous oil production is included in information reported for the relevant units. For example, the West Sak participating

area is part of the Kuparuk River Unit, and the Orion participating area is part of the Prudhoe Bay Unit.

To the extent that portions of the Ugnu formation are located outside of existing units, those areas could qualify for the lower tax rates provided for new units in HB 110.

(3) If state net profit taxes on petroleum are reduced by roughly $1 billion, what is the anticipated amount of federal tax that will be paid by companies on this increase in revenue?

The Department's modeling of federal government revenue typically assumes a 35% marginal tax rate for federal corporate income tax. If a $1 billion reduction in state taxes results in a $1 billion increase in taxable income, our modeling would suggest a $350 million increase in federal corporate income tax revenue. If the tax reduction is instead reinvested into additional development in Alaska, as intended, the benefit to the federal government would be reduced or eliminated. The Department plans to present more detailed information related to federal government revenue and total government take at a future bill hearing.

(4) Please create two separate models of the revenue picture for the state. One model should use the current tax structure established under ACES, and the other model use the Governor's proposed tax structure under HB 110. Apply the following assumptions to both models:

- **50% TAPS throughput is oil from New Fields (over a seven-year period TAPS Legacy Field oil is switched over to New Field Oil at a rate of 7% per year so that at the end of the seven years roughly 50% of TAPS throughput is New Field Oil.)**
- **ANS WC price of $90 per barrel (and $50 per barrel) with a cost of $36 per barrel**
- **$15 Billion in capital investment for new infrastructure available for credit**

The Department has developed models that allow us to compare revenues under the current and proposed tax structures. There are a number of assumptions that must be made in addition to the assumptions outlined above. We would like to meet with you to further clarify the scenario before proceeding.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Paul Seaton
The Honorable Eric Feige
Co-Chairs, House Resources Committee
Alaska State Legislature
Juneau AK, 99801

February 21, 2011

SUBJECT: Response to Questions from House Resources Meeting on February 7, 2011

Dear Representatives Seaton and Feige:

The purpose of this document is to respond to the follow-up questions from the House Resources Committee meeting on February 7, 2011. The requests/questions and responses follow.

(1) Provide information about the department's record in forecasting.

The majority of revenue comes from oil production. The department's revenue forecast is driven primarily by two inputs: oil production and oil price. The following discussion briefly discusses the department's history in forecasting these two variables.

Production Forecasting
Recently, inquiries have been made regarding the accuracy and reliability of historical oil production forecasts published by the Department. History has shown that our production forecasts have been overstated for many years. With changes to methodologies and processes in the last two years, the amount by which production forecasts have been overstated has been reduced to 2%. Because of the production forecasting changes made in 2009, it is unfair to compare the last two years to the past. The Department will continue to exercise due diligence and care in the preparation, and review of the production forecasts. The response that follows will examine factors that may have contributed to differences in forecast vs. actual production for Alaska's North Slope (ANS).

The Department of Revenue relies on historical production data as well as both public and private information as the basis for its biannual production forecast. Because forecasts are directly affected by the quality of the input data, the Department of Revenue production forecasts are sensitive to data provided both publicly and privately by the field operators.

It is important to define both what is involved in a production forecast and what is not. In general terms, a forecast is simply an opinion of future oil production. In addition to the quality

of the input data, the uncertainty of the forecast will also depend on the methods employed by the forecaster. Historically, the Department engaged a single contractor to conduct its forecasts until 2009. This contractor relied on a certain method to produce his forecasts. Beginning in 2009 a new contractor was engaged to perform the forecasts and relies on a different methodology to forecast production.

It is also necessary to understand from the outset that, under both current and former methodologies, the production forecasts conducted for and under the directive of the Department have been based only on technically recoverable oil. The forecasts do not include any analysis of whether or not barrels that are technically recoverable are also economically recoverable. This is reasonable given that near term oil production should be relatively certain. Involving an analysis that included economically recoverable barrels would add another layer of complexity and uncertainty to the forecast and require that the department, in essence, predict the future value of a barrel of oil. At the same time this added uncertainty would not provide any cure for near term production overestimates.

As previously mentioned, the accuracy of the forecast will be highly dependent on the methods used by the person making the forecast. In this regard, the current methods employed by the department's staff and contractor have changed significantly from the previous contractor. The result has been that the near term forecasts have been within about 2% of actual production during that same time period.

Perhaps one of the most significant changes in methodology relates to the use of a well-by-well analysis to forecast production and decline curves as used in the current practice, whereas in the past, forecasting had been done on an area-wide or field basis. While the well-by-well basis is more time and labor intensive, the methodology reveals trends that are not observable on an area-wide basis.

Current practice also includes internal staff in addition to the contractor. The department performs in-depth analysis of production trends, forecast to forecast by field, and comparisons of forecasted production to actual, among other analyses.

Another factor that has likely had a material impact and is currently employed in the new methodology is the magnitude of the "b factor" used to calculate the production decline curve. The factor previously used had been as high as 1.4 and has now been reduced to be less than 1.0 in current practice. There is a large body of empirical evidence indicating that “b” factor should never be greater than or equal to 1.0 in any field.

By employing a method of forecasting that adheres to strict and standard petroleum engineering principles the department now excludes barrels that may fall into a high risk area of eventually being brought into future production. For example, both back out barrels and certain recovery projects that have not been tested and proven could be subject to many variables that may or may

not lead to their ultimate production. Accordingly, these volumes are now only included in the department's forecast if they are shown to be in place and have demonstrated a response.

Some factors are beyond the state's control. A standard practice is to go to the producer's and ask when new fields may come on line. A good example is Liberty, which had originally been predicted to begin production in 2011. However, recent events and decisions by the company have delayed start-up until somewhere around 2013. Even though the Liberty pool is in federal waters, facilities are located onshore and production will flow through TAPS and had been included by the state in forecasting total ANS production. When setbacks in timing such as Liberty are unforeseeable, they will by definition, show up as errors in any forecast at a later date.

Below are three additional examples:

1. Aurora Field
   "BP Exploration (Alaska) Inc. said Feb. 23 that production is expected to increase to a peak rate of 15,000 to 20,000 barrels per day as field development continues." *"Aurora field begins production." 2/28/01 Petroleum News*
   - Production at Aurora peaked at an average of 10,447 barrels per day in 2006 according to DNR – just over half of the highest estimate by BP in 2001.

2. Polaris Field
   "BP will develop Polaris with water flood, which is expected to improve total recovery to 15-30 percent of original oil in place, with production rates expected to peak at 12,000-15,000 barrels of oil per day from water injection…" *"BP applies for pool rules for viscous Schrader Bluff Polaris accumulation: Company tells AOGCC western Prudhoe satellite will be developed with water flood, EOR test deferred; initial wells proving up productivity, but hydrate formation causing problems in keeping wells operating; Ugnu sand included." 12/29/02 Petroleum News*
   - Through 2009 production at the Polaris field had not reached the levels predicted by BP in 2002. Specifically, production at the Polaris field peaked at an average of 4,764 barrels per day in 2008 – approximately 60% less than BP predicted in 2002.

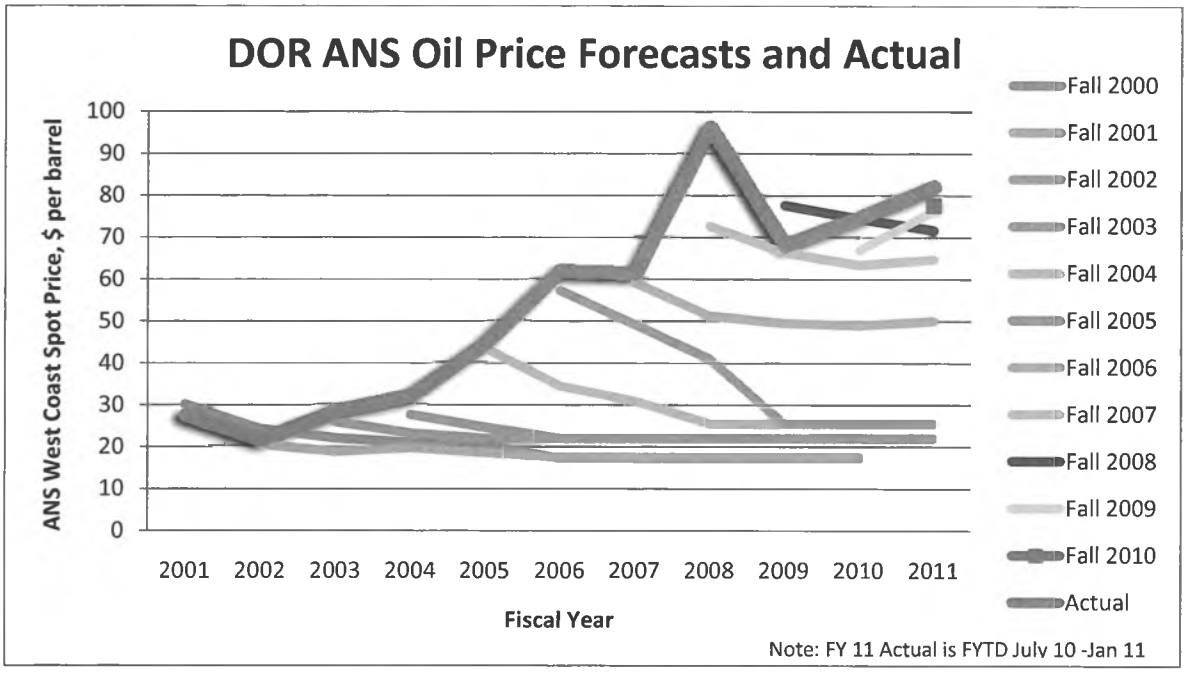
3. West Sak Field
   "The companies said production of West Sak oil is now at about 10,000 barrels per day, and with the Drill Site 1E and 1J project, production is expected to reach approximately 45,000 bpd by 2007." *"$500 million West Sak heavy oil project approved." 8/15/2004 Petroleum News*
   - According to DNR, production at West Sak was just over 11,000 barrels per day in 2004. In 2007 West Sak produced an average of 17,575 barrels per day or less than 40% of the rate forecast by BP in 2004. As of 2009, production at West Sak still has not reached 20,000 barrels a day.

Because the Department of Revenue relies, at least in part, on information provided by the operators of each field in order to forecast production, bias or error inherent in the operator's view of future production often translates into the forecast variances by the Department of Revenue. In short, the forecast is limited by the quality of the data inputs, the methodologies used, and unforeseen events. Incorporating internal staff, the additional in-depth analysis and controls, and sound petroleum engineering methods are steps taken by the department to improve the quality of the production forecast.

Price Forecasting

The chart below shows the DOR fall oil price forecasts from fall 2000 through fall 2010 compared to actual oil prices. The past decade was defined by a swift rise in oil prices from FY 2002 to FY 2007, followed by a sudden spike in FY 2008 and a subsequent crash. The chart shows the rapid rise in price was not anticipated by the department's forecasts. This is on par with other forecasts made during this period. For example, in 2002 the U.S. Energy Information Administration (EIA) forecasted the world oil price would be $23.36 (2000 dollars) in CY 2010. The actual CY 2010 price was $60.56 per barrel (2000 dollars). Moreover, during the previous decade the EIA's forecasts were typically more bullish than other oil price forecasts made by several reputable groups, such as the International Energy Agency, Petroleum Economics Ltd., Natural Resources Canada, and others.

After the price crash, prices remained around $70 to $80 per barrel until last fall when prices began to climb above this range. The price of ANS West Coast (ANS WC) peaked close to $100 per barrel in early February of this year. The department's current ANS WC price projection for FY 2011 is $77.96. As of the end of January, the fiscal-year-to-date price for ANS WC is $82.32.



(2) Provide information about transit pipelines for new developments. Specifically, who would construct them, how much would they cost, and who would pay for them and how?

Oil is transported through gathering lines, transit lines and feeder pipelines before it gets into the Trans-Alaska Pipeline System (TAPS). The owners (producers) of the oil incur the costs of gathering crude oil from the wellhead and getting it to a point where it can be processed and treated to become pipeline quality. Additional lines may need to be constructed from the central processing facility if no infrastructure exists.

An upstream pipeline is the first pipeline to transport oil en route to an interconnection point for delivery to another pipeline. Producers usually provide the gathering lines, central processing facilities and transit lines to the downstream pipelines.

A downstream pipeline receives oil from another pipeline. Producers often have ownership in feeder pipelines and larger lines like TAPS where they provide transportation for others as a common carrier and are subject to RCA and FERC regulations. Rates on such pipelines are designed to recover the cost of providing the transportation service (including a return of and a return on investment) through a tariff paid by the shippers on the line. Shippers nominate volumes and the pipeline company manages the flow.

The cost of a pipeline depends on the location, length of the line and size and quality of the pipe. Costs for a particular system will depend on the specification of those variables. The scope of a

project quantifies those variables from estimates of throughput, reserves, production and life of the field, which are some of the factors that also determine if a find is economic to develop. The range of costs per barrel mile of oil transported is not meaningful without defining the scope of the project.

The Oil and Gas Journal publishes an annual Pipeline Economics Report which includes data on pipeline and compressor station construction costs. Data also includes estimated pipeline costs as presented in applications to FERC. The study is available for purchase through the following link:

http://www.pennenergy.com/index/research-and_data/oil-and_gas/product-display/2130774133/products/pennenergy/research/Petroleum/PipeLines-Transportation-Storage/surveys/us-pipeline-study.html

(3) Provide a discussion on the fiscal impact of switching from a monthly to an annual tax rate calculation.

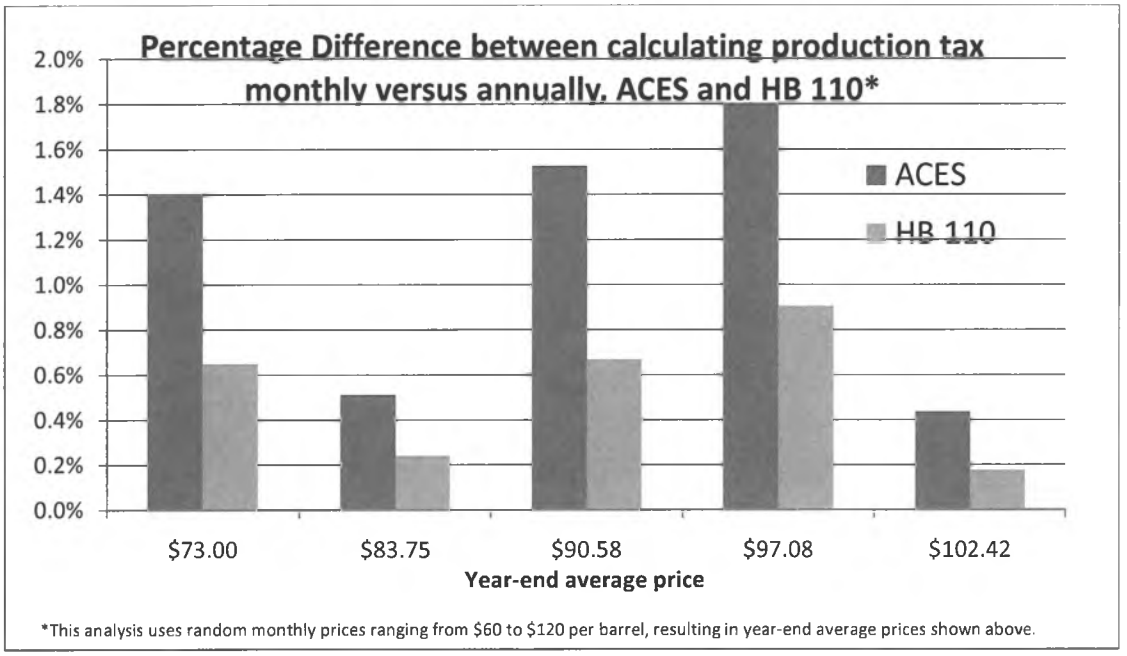
Under current law, ACES is an annual tax with monthly estimated payments based on production levels and oil price in the months the estimate is calculated and on one-twelfth of annualized lease expenditures. The proposal under HB 110 is to change the calculation such that the tax liability is calculated using average annual production levels and an average annual price along with annualized lease expenditures. Estimated monthly production tax payments would still be made under this proposal, but would be "trued up" in the annual tax return when the average annualized figures are known.

The fiscal impact to state revenues of this change alone may be significant in years where there is substantial monthly oil price volatility. A recent example of the extremes in oil price volatility may be found in FY 2009, when oil prices reached $133 per barrel in July and decreased 71% in five months to $37 per barrel in December 2008.

The impact of changing from a monthly to an annual tax calculation is greater under the current ACES tax than it is under the proposed tax structure with bracketed tax rates. This is because the progressive tax under current law is formulaic, and each dollar increase in profit increases the tax rate. Under the proposed HB 110, the tax rate would be bracketed, with the same tax rate applied to a range of profits per barrel. For example, profits of $56 per barrel would be taxed at the same rate as profits of $67 per barrel under the HB 110 proposal. This means of calculating the tax rate provides for less production tax volatility even if it were calculated using monthly values.

We tested this theory by applying a range of monthly prices to forecasted assumptions about production levels and lease expenditure levels, holding these levels flat from month to month, despite potential seasonal variation. With these assumptions, we found that although more

production tax was generated by calculating the production tax monthly than by calculating the tax annually, there was less of a difference in the monthly/annual calculation under the bracketed rates in HB 110 than with the rates currently under ACES, as shown below.



(4) What was the rationale for the $12 million figure for the Small Producer Credit and the $6 million figure for the New Area Development Credit in ACES?

The original PPT proposal in 2006 from then-Governor Frank Murkowski proposed a "standard deduction" of $73 million per year for each taxpayer.

As a deduction under the proposed tax at 20%, the tax savings per taxpayer would have been $14.6 million per year (20% x $73 million). The deduction would have applied to all companies, regardless of how much oil they produced, although there was legislative testimony that indicated that the amount was calculated based on production of 5,000 barrels of oil per day at $40 per barrel (5,000 x $40 x 365).

The tax proposal was heard in several legislative committees and underwent numerous changes in each committee. Among the changes was a shift in the standard deduction provision from a deduction to a credit. The committee substitute from the House Resources Committee changed the provision into a $12 million credit, which closely approximates the $14.6 million in the original proposal.

Although it is unclear how and when the provision was pared down to include only producers with 100,000 barrels of oil equivalent, the credit was generally regarded as an incentive to small producers. Later in the process, likely in one of the special sessions held to consider the tax changes, the New Area Development Credit was added. It is also likely that the amounts were fixed at $12 million and $6 million for ease in applying to the 12 months of a year.

(5) Provide a list of small producers that qualify for the Small Producer credit.

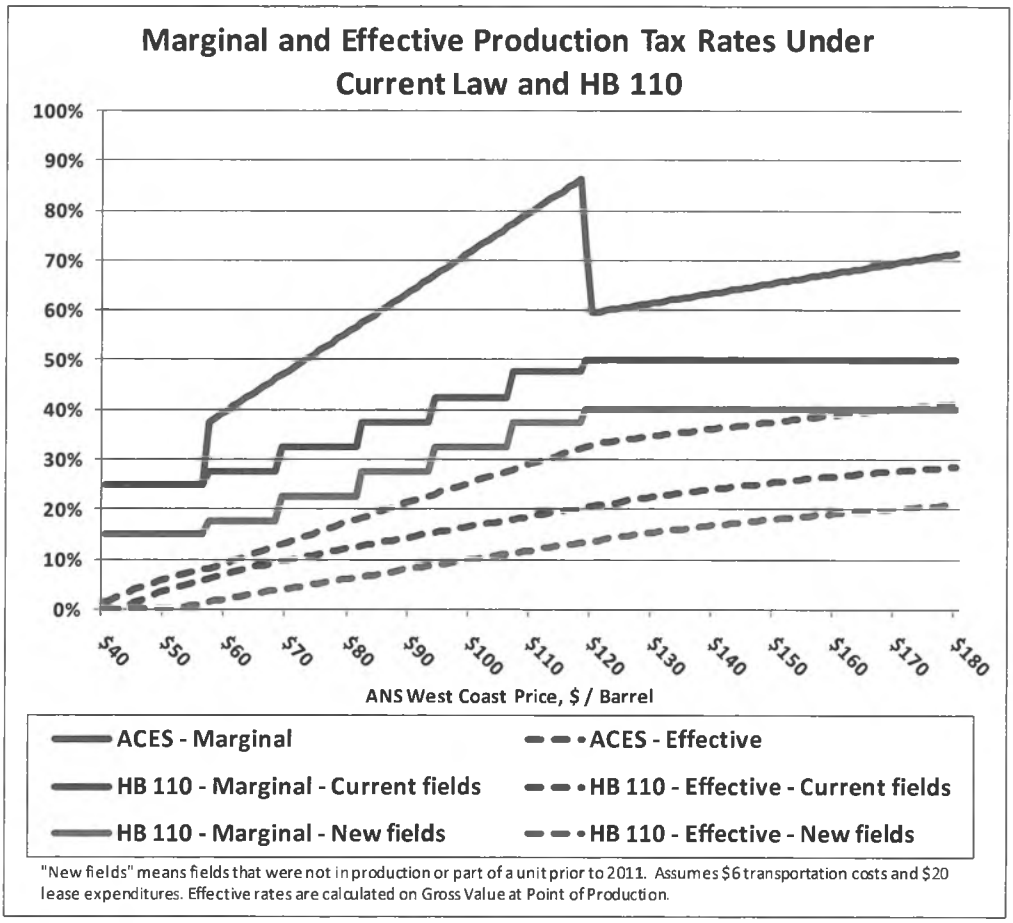
The small producer credit at AS 43.55.024(c) is available to producers who produce less than 100,000 BTU equivalent barrels of oil or gas per day and the credit may only be applied against a tax liability, and not carried forward or certificated. Although the amount of tax liability a producer has and the amount of credit they have earned is considered taxpayer-confidential, the production level of each of the producers is not confidential. Provided below is a list of producers who are currently producing oil and/or gas at levels below 100,000 BTU equivalent barrels per day. Assuming they have a production tax liability, they would be eligible for some or all of the $12 million tax credit.

Companies Currently Eligible for Credit under AS 43.55.024(c)

1. Anadarko Petroleum Corporation
2. Aurora Gas
3. Chevron Corporation
4. Cook Inlet Energy
5. Doyon Limited
6. ENI S.p.A.
7. Marathon Oil Corporation
8. Municipal Light and Power
9. Nana Regional Corporation
10. Pioneer Natural Resources
11. XTO Energy

(6) Provide a figure showing ACES marginal and effective tax rates on same chart.

The chart below shows the marginal and effective tax rates under ACES and HB 110. The marginal tax rate reflects the tax rate on a $1 increase in production tax value. The effective tax rate is the average tax rate assessed on the gross value at the point of production after credits have been applied.



(7) Provide a list of the top ten petroleum producing states that we are competing against for investment.

According to the Energy Information Administration, the following table shows the top ten oil producing states in 2009.

Top Ten Oil Producing States in the U.S.

State	Average Daily Production (thousands of barrels per day)
Texas	1,106
Alaska	645
California	567
North Dakota	218
Louisiana	189
Oklahoma	184
New Mexico	168
Wyoming	141
Kansas	108
Colorado	78

(8) Compare credits offered by other states with Alaska's credits.

This response is composed of two parts. The first part discusses tax incentives in various states and the second part discussed corporate income tax credits in other states.

Many other states offer tax incentives, exemptions, credits, or temporary suspensions, to reduce the tax on certain production. Generally, these tax incentives apply to production from a specified geographic area or a type of well or drilling technique. The incentive may be a reduced tax rate or an exemption from tax for a specified time period. States may exempt production from some wells, such as stripper wells entirely. Incentives may be limited to a certain volume or gross value at the well, or allowed only up to a certain percentage of project recovery costs.

Here are some common types of tax incentives:

Horizontal drilling definition: Some states offer incentives to encourage use of horizontal drilling. Although horizontal wells may have higher drilling costs, they may also have higher recovery rates. North Dakota defines horizontal well as meaning "a well with a horizontal displacement of the well bore drilled at an angle of at least eighty degrees within the productive formation of at least three hundred feet." Other states require an angle of at least 70 degrees, or less of a drilling depth.

Tax rate variation: Adjustable tax rates may apply to all production based on the price of oil or gas, or only to production from new, stripper, or horizontal wells. The reduced tax rate may

apply only up to a certain volume or market price, when that "trigger" volume or market price is reached, some of the tax incentives no longer apply.

Exemptions or reduced rate: A common tax incentive in a gross tax system is to exempt production for certain time, or to allow a reduced rate up to a certain production volume. To qualify, the well may need to be certified as a new, horizontal, or other type of well that qualifies for favored tax treatment.

Demonstration of increased production: This type of incentive can be related to a marginal well, an enhanced-recovery project or any well with declining production. In short, a baseline production amount is established and the operator applies to the tax or other commission for approval of a project designed to increase production. If the well production does increase, the operator may be eligible for a tax refund, exemption or other tax incentive, such as recovery of all or part of the project costs.

The following are some tax incentives in other states[1]:

Louisiana Severance Tax Exemptions, Rates and Suspensions
Oil Full Rate: 12-1/2% of its value at the time and place of severance
Incapable Oil Rate: 6-1/4% of its value. Oil produced from a well is incapable of producing an average of more than twenty-five barrels of oil per day during the entire taxable month and which also produces at least fifty percent salt water per day.

Stripper Oil Rate: 3-1/8% of its value. Oil produced from a well that is incapable of producing an average of more than ten barrels of oil per day during the entire taxable month.

Oil tax deduction allows producers to deduct a $0.25 per barrel for transporting oil or condensate from producing fields to processing facilities.

Tertiary recovery severance tax suspension: Allows crude oil production from a qualified tertiary project not to pay severance tax until the project has reached payout.

Horizontal mining and drilling projects severance tax suspension: Taxed at the special reduced rate of 3.125% of value until the cumulative value of hydrocarbon production from the project equals 2.33 times the private investment invested by the working interest owners.

Horizontal wells severance tax suspension: On any horizontally drilled well or any horizontal recompletions from which production commences after July 31,1994, all severance tax shall be suspended for a period of 24 months or until payout of well cost is achieved, whichever comes

[1] These states have gross tax systems, so upstream costs are not accounted for in determining the wellhead value, although some tax credits may incorporate a determination of exploration and development costs to calculate a project payback.

first. Pay out of well cost shall be the cost of completing the well to commencement of production.

Deep wells severance tax suspension: Wells drilled to a true vertical depth of 15,000 feet or more, where production commences after July 31, 1994 shall be exempt from severance tax for 24 months from the date production begins, or until payout of well cost, whichever comes first.

Texas Severance Tax Incentives

Enhanced Oil Recovery(EOR) Incentive: Oil produced from an approved new enhanced oil recovery project or expansion of an existing project is eligible for a special EOR tax rate of 2.3 percent of the production's market value(one-half of the standard rate) for 10 years after Commission certification of production response. For the expansion of an existing project the reduced rate is applied to the incremental increase in production after response certification.

The two year inactive well incentive: If an oil or gas well has been inactive(i.e., has no more than one month of production) during the preceding two years, any new oil, gas well gas, or casing head gas production may be eligible for up to a 10-year severance tax exemption.

Severance tax relief for marginal oil wells: The bill provides three levels of tax credits on oil production from qualified low-producing oil leases for any given month, depending on Comptroller's average taxable oil prices, adjusted to 2005 dollars, based on applicable price indices of the previous three months. An operator of a qualifying low-producing oil lease would be entitled to: (1) a 25% tax credit if the average taxable oil price were above $25 per barrel but not more than $30; (2) a 50% tax credit if the price were above $22 per barrel but not more than $25, and (3) a 100% tax credit if the price were $22 or less. The bill defines a qualifying low-producing oil lease as a lease that averages, over a 90-day period, less than 15 barrels per day per well or 5% recoverable oil per barrel of produced water per well.

Enhanced Efficiency Equipment Severance Tax Credit: Severance tax credits are available for marginal wells (an oil well that produces 10 barrels of oil or less per day on average during a month) for using equipment that reduces the energy required to produce a barrel of fluid by 10% as compared to alternative equipment.

Oklahoma Severance Tax Incentives

Tertiary Oil Recovery Projects: Any incremental production of crude oil or other liquid hydrocarbons which results from an enhanced recovery project is exempt starting from the project beginning date until project payback is achieved but not to exceed a payback period of 36 months.

Horizontally Drilled Well: The production of oil and gas from a horizontally drilled well producing prior to July 1, 1994, is exempt starting from the project beginning date until project payback is achieved, but not to exceed a payback period of 24 months commencing with the month of initial production.

North Dakota Oil Extraction Tax Incentive
Oil Extraction Tax Incentive for Bakken Horizontal Wells: The first seventy-five thousand barrels of oil produced during the first eighteen months after completion, from a horizontal well drilled and completed in the Bakken formation after June 30, 2007, and before July 1, 2008, is subject to a reduced tax rate of 2% of the gross value at the well of the oil extracted under this chapter.

*The gross production tax rate on gas is subject to a price index change on July 1 each year, the rate through June 30, 2011 is $.0914 per mcf. The gross production tax rate on oil is 5% of the gross value and the oil extraction tax rate is 6.5% of the gross value; 4% if the well qualifies for a reduced rate; 2% from qualifying wells in the Bakken formation; and 0% if the well qualifies for an exemption.

The following list discusses credits that are offered against corporate income tax in several other oil and gas producing states.

- California: **Enhanced Oil Recovery Credit:** Taxpayers are allowed a credit of one third of the federal tax against state tax.[2] This results in a credit of 5% of allowable costs for projects in California. No deductions for costs allowed as a credit; reduce basis in property by amount of the credit. Because federal credit is currently phased out, there is no current California credit. (See federal credits page).
- Oklahoma: **Coal Credit:** For tax years beginning on or after January 1, 2007, the credit shall be Five Dollars ($5.00) for each ton of coal mined, produced, or extracted in, on, under, or through a permit in Oklahoma.[3]
- Wyoming: **The state does not levy a corporate income tax**
- Texas, North Dakota, South Dakota: **No credits for oil & gas**

(9) Provide information about oil tax structure, environmental regulation, and land ownership for other oil producing states in the U.S.

The following discusses oil and gas tax structures in other states. We are in the process of compiling information about environmental regulation and land ownership in other states, and will provide that information to the committee when it is available.

Most state oil and gas severance[4] taxes are imposed on the gross taxable value of oil and natural gas. Under a gross tax, wellhead value is calculated net of transportation, processing and

[2] Cal. Rev. & Tax. Cd. § 23604 Oil recovery credit.
[3] Okla. Stat. § 2357.11 Tax Credit.

manufacturing costs. Generally, costs incurred upstream of the point of production are not deducted or considered when calculating gross taxable value. Gross production taxes can be levied on gross income, with a higher percentage applying as the income level increases. As an example, if gross income attributable from the sale of oil and gas is under $25,000, the tax rate is 2%; if $25, 000 but under $100,000, 3%, and so on. The following table shows the severance tax rates for several of the top oil producing states.

Severance Tax Rates by State	
Wyoming	6%
Texas	4.6%
Oklahoma	7%
North Dakota*	11.5%
Louisiana	12.5%
California	0%
New Mexico	3.75%
Kansas	4.33%

Alaska's severance tax is a net tax on the annual production tax value of oil and gas. Downstream transportation costs are deducted or "netted out" to arrive at a gross value at the point of production. Upstream costs, typically referred to as lease expenditures, are deducted from the gross value at the point of production to arrive at the annual production tax value upon which the tax is levied. If upstream costs are also qualified capital expenditures, they can qualify for a 20 percent credit that can be applied to the production tax liabilities, or redeemed as a certificate. Other credits, such as exploration credits, may also apply.

(10) Discuss the federal tax credits available in Alaska.

The following list presents the primary oil and gas related tax credits that are available against federal corporate income tax. There are also many federal tax credits that are available to all corporations which are not detailed here.

Enhanced Oil Recovery Credit (EOR)

- Credit of 15% of qualified costs against federal tax.
- Credit phases out when price of oil exceeds $28 /bbl (adjusted for inflation).
- No EOR allowed since 2005, because the list price exceeded the inflation adjusted price of oil. The list price for 2009 was $56.39 /bbl

[4] Severance taxes can also be called a mining license tax, net proceeds tax, royalty tax or production. Of course, there may also be property taxes, state income taxes and federal taxes levied on mineral production.

Marginal Well Credit

- Credit up to $3/bbl available only to owner of operating interest.
- Marginal well = oil production not more than 25 bbls/day, and not less than 95% water.
- Credit available only when price of oil less than $18/bbl.

Nonconventional Fuel Source Credit

- Credit up to $3 (adjusted for inflation) per BOE (barrel of oil equivalent, with 5.8 million Btu content)
- Credit completely phased out when inflation adjusted price of oil exceeds $33.46/bbl. List price of oil in 2009 was $56.39 /bbl.
- Credit on oil only from shale or tar sands.
- Credit on synthetic fuels from coal.
- Credit on gas produced only from:
  1. Devonian shale
  2. coal seams
  3. tight formations
  4. biomass
  5. geo pressured brine

(11) Provide a list of credits available from the federal government, and indicate what credits companies operating in Alaska have applied for. Provide examples of federal credits for the examples cited in our presentation (new explorer and existing producer with $200 million exploration program).

As a note on tax administration, corporations claim credits on tax returns when filed. Corporations do not apply for credits prior to filing a return.

No oil companies operating in Alaska have claimed federal corporate income tax credits in recent years because the federal credits have been phased out at current oil prices.

(12) Provide copies and a discussion on the Frazier Institute 2010 Global Petroleum Survey.

The complete Fraser Institute 2010 Global Petroleum Survey is available for free to the public at the following address: http://www.fraseramerica.org/commerce.web/product_files/global-petroleum-survey-2010_US.pdf

The Fraser Institute is an independent, non-profit research organization. The Global Petroleum Survey is based on the responses from managers and executives of petroleum exploration and production companies, and service providers, around the world. 645 professionals, representing 364 companies with a combined budget of $161 billion, contributed to the 2010 survey. Survey respondents rate various jurisdictions on 17 metrics related to investment attractiveness.

(13) If 44% of respondents to the Frasier survey indicated that Alaska's tax regime deters investment, what did the other 56% say?

Following is the detailed breakdown of responses regarding Alaska's tax regime:

- 25% said Alaska's tax regime "encourages investment"
- 31% said Alaska's tax regime "is not a deterrent to investment"
- 25% said Alaska's tax regime "is a mild deterrent to investment"
- 16% said Alaska's tax regime "is a strong deterrent to investment"
- 3% said they "would not invest due to this criterion"

(14) If Alaska modified petroleum taxes so that they were "the most favorable" where would that put AK on the Frazier graph?

The Fraser composite index takes an unweighted average of responses to 17 different factors affecting investment. Therefore, moving to a more favorable tax regime would likely result in a modest improvement in Alaska's composite index score. Also, improving our tax system would demonstrate to companies that Alaska is open for business and is taking steps to partner with industry and actively encourage investment in the state.

One example of a jurisdiction that recently made changes in its fiscal regime is Alberta. Alberta announced changes to its royalty system (Alberta's primary mechanism for receiving revenue from oil and gas) in early 2010. Alberta's composite index score went from 47.46 in 2009 to 36.70 in 2010, and its ranking in the Fraser composite improved from 92 in 2009 to 60 in 2010.

(15) If the state invested in infrastructure development, such as a road to the Umiat area, where would this put Alaska on the Frazier graph?

Quality of infrastructure is one of the 17 factors studied in the Fraser survey. Generally speaking, investing in improved infrastructure, such as roads to resources, would likely improve our score in this area. The impact on the overall perceptions of Alaska would likely depend on whether a road was an isolated investment in a specific project, or part of a broader initiative to improve the attractiveness of Alaska for industry investment.

(16) Please provide statistics on the major producers in Alaska and whether they are currently investing in the five Most Attractive and five Least Attractive jurisdictions on the Frazier graph.

The three largest oil producers in Alaska are currently Conoco Phillips, Exxon Mobil, and BP. As measured by the composite index in the Fraser survey, the five most attractive jurisdictions for investment are South Dakota, Texas, Illinois, Wyoming, and Austria. The five least attractive jurisdictions for investment are Bolivia, Venezuela, Russia, Ukraine, and Iran. To determine areas where the companies are invested, we reviewed Exxon's 2009 Financial &

Operating Review, Conoco's 2009 Fact Book, and BP's 2009 Annual Report. Note that there may be minor investments, or plans for future investments, that are not readily identified.

Among the most favorable jurisdictions, Conoco has investments in the Williston Basin of South Dakota; all three major producers are heavily invested in Texas; Conoco has a 50 percent interest in a refinery in Illinois; Conoco and Exxon both have operations in Wyoming; investments in Austria were not identified.

Among the least favorable jurisdictions, BP had operations in Bolivia that were nationalized in 2008; all the major producers were invested in Venezuela prior to nationalizations in 2007, with Conoco and Exxon pulling out and BP agreeing to joint venture contract terms; all three major producers have significant investments in Russia; investments by the major producers in Ukraine and Iran were not identified.

We hope our responses fully answer your questions. As mentioned above, we are currently compiling additional information to fully respond to request number 9 above, and we will provide that information when it is completed.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

February 23, 2011

The Honorable Eric Feige
State Capitol Room 126
Juneau AK, 99801

The Honorable Paul Seaton
State Capitol Room 102
Juneau AK, 99801

SUBJECT: Response to Modeling Request from Co-Chair Seaton

Dear Representative Feige and Seaton:

Enclosed please find the results of the hypothetical modeling project requested by Co-chair Seaton during the House Resources Committee meeting on February 21, 2011, and earlier by email.

Please pay particular attention to the assumptions and caveats provided in the cover sheet for the analysis. The assumptions used were as requested, and this analysis in no way represents a Department of Revenue forecast or expectation.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Title: Comparison of Revenue under ACES and HB 110 with Requested Volume, Price, and Cost Assumptions*

Preparer: Cherie Nienhuis, Petroleum Economic Policy Analyst and Dan Stickel, Petroleum Economist

Date: 23-Feb-11

Purpose: As requested by Representative Seaton

Data Source: Major ACES tax variables and major proposed variables in HB 110

Key Assumptions:

*Assumptions as requested by requestor, which are neither supported nor condoned by the Department of Revenue.
The following assumptions were dictated:
50% TAPS throughput is oil from New Fields (over a seven-year period TAPS Legacy Field oil is switched over to New Field Oil at a rate of 7% per year so that at the end of the seven years roughly 50% of TAPS throughput is New Field Oil.)
ANS WC price of $90 per barrel, and $50 per barrel
Costs of $36 per barrel
$15 Billion in capital investment for new infrastructure available for credit
With the models, please provide tables below the model, or on a separate page, so we can review the input data.

The following assumptions were made by the Department, to implement the models:
Incremental oil only ocurrs in the HB 110 case
Stated decline rate, and incremental oil additions, continue beyond the first 7 years.
Stated cost of $36 is for incremental oil and includes $7 transportation costs, $19 operating costs, $10 capital costs.
Costs for exising oil are $10 / barrel operating costs, $10 / barrel capital costs, plus $7 / barrel transporation costs ($27 / barrel total)
Simplistic transportation cost model - half of transit costs vary relative to production (costs will increase as throughput declines)
The $15 billion of new infrastructure is exclusive to incremental oil and spread evenly across the first 7 years (appx $2.1 billion per year)
Production decline rate is levied on a compound basis, resulting in smaller absolute declines each year

This analysis does not include assumptions relating to lease expenditure exemptions, or proposed credits. We do not include credits other than the 20% capital credit, and for simplification we assume all credits can be taken in one year.

See assumptions listed on each sheet.

History: None

Disclaimer:

This analysis does not represent a Department of Revenue forecast or expectation. The modeling shown here represents a hypothetical scenario only using assumptions provided by the requestor. Under HB 110, the 15% base tax rate would apply only to oil and gas produced from leases or properties that have not been in a unit as of 1/1/2011 and have never had commercial production. We forecast that the vast majority of additional North Slope production will come from existing units and will not receive the 15% base tax rate.

The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Comparison of Revenue under ACES and HB 110 with Requested Volume, Price, and Cost Assumptions - $90 ANS Scenario

Prepared 02/23/11 by Department of Revenue for Rep Seaton

This analysis does not represent a Department of Revenue forecast or expectation.

These hypothetical assumptions were specifically requested by the requestor and the Department of Revenue does not in any way support the assumptions.
This analysis does not include assumptions relating to lease expenditure exemptions, or proposed credits

KEY INPUTS					
Initial Production (bpd)	600,000		Incremental facilities capital ($ mm)	$	15,000
Decline rate - existing	7%		Years to spread facilities spend	$	7
Oil Price	$90		Incremental Opex / bbl	$	19
Existing Opex / bbl	$ 10		Incremental Capex / bbl	$	10
Existing Capex / bbl	$ 10		Transit costs	$	7

All amounts in $ millions except for all production and amounts labeled as per barrel amounts

ACES Scenario - Existing oil with decline rate

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Base Tax	Progressive Tax	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	600,000	$ 15,905	$ 2,190	$ 2,190	$ 4,380	$11,525	60.14	$2,881	$1,390	$4,271	$ 438	$ -	$3,833	$ -
2	558,000	$ 14,745	$ 2,037	$ 2,037	$ 4,073	$10,671	59.88	$2,668	$1,275	$3,943	$ 407	$ -	$3,536	$ -
3	518,940	$ 13,666	$ 1,894	$ 1,894	$ 3,788	$9,877	59.60	$2,469	$1,169	$3,639	$ 379	$ -	$3,260	$ -
4	482,614	$ 12,662	$ 1,762	$ 1,762	$ 3,523	$9,139	59.29	$2,285	$1,071	$3,355	$ 352	$ -	$3,003	$ -
5	448,831	$ 11,729	$ 1,638	$ 1,638	$ 3,276	$8,452	58.96	$2,113	$979	$3,092	$ 328	$ -	$2,765	$ -
6	417,413	$ 10,861	$ 1,524	$ 1,524	$ 3,047	$7,814	58.61	$1,953	$894	$2,848	$ 305	$ -	$2,543	$ -
7	388,194	$ 10,054	$ 1,417	$ 1,417	$ 2,834	$7,220	58.23	$1,805	$815	$2,620	$ 283	$ -	$2,337	$ -
8	361,021	$ 9,303	$ 1,318	$ 1,318	$ 2,635	$6,667	57.83	$1,667	$742	$2,409	$ 264	$ -	$2,145	$ -
9	335,749	$ 8,605	$ 1,225	$ 1,225	$ 2,451	$6,154	57.39	$1,538	$674	$2,213	$ 245	$ -	$1,967	$ -
10	312,247	$ 7,955	$ 1,140	$ 1,140	$ 2,279	$5,676	56.92	$1,419	$611	$2,030	$ 228	$ -	$1,802	$ -
11	290,389	$ 7,352	$ 1,060	$ 1,060	$ 2,120	$5,232	56.41	$1,308	$553	$1,861	$ 212	$ -	$1,649	$ -
12	270,062	$ 6,790	$ 986	$ 986	$ 1,971	$4,819	55.87	$1,205	$499	$1,703	$ 197	$ -	$1,506	$ -
13	251,158	$ 6,268	$ 917	$ 917	$ 1,833	$4,434	55.28	$1,109	$448	$1,557	$ 183	$ -	$1,374	$ -
14	233,577	$ 5,782	$ 853	$ 853	$ 1,705	$4,077	54.65	$1,019	$402	$1,421	$ 171	$ -	$1,251	$ -
15	217,226	$ 5,330	$ 793	$ 793	$ 1,586	$3,745	53.98	$936	$359	$1,295	$ 159	$ -	$1,137	$ -
16	202,021	$ 4,910	$ 737	$ 737	$ 1,475	$3,436	53.25	$859	$319	$1,178	$ 147	$ -	$1,031	$ -
17	187,879	$ 4,520	$ 686	$ 686	$ 1,372	$3,148	52.47	$787	$283	$1,070	$ 137	$ -	$933	$ -
18	174,728	$ 4,156	$ 638	$ 638	$ 1,276	$2,881	51.62	$720	$249	$969	$ 128	$ -	$842	$ -
19	162,497	$ 3,818	$ 593	$ 593	$ 1,186	$2,632	50.72	$658	$218	$876	$ 119	$ -	$758	$ -
20	151,122	$ 3,504	$ 552	$ 552	$ 1,103	$2,401	49.75	$600	$190	$790	$ 110	$ -	$680	$ -

HB 110 Scenario - Summary Existing + Incremental Production

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	600,000	$ 15,905	$ 4,333	$ 2,190	$ 6,523	$9,382	$ 48.96	$ 3,244	$ 867	$ 536	$ 1,842	$ -
2	600,000	$ 15,905	$ 4,333	$ 2,328	$ 6,661	$9,244	$ 48.24	$ 3,017	$ 867	$ 369	$ 1,782	$ -
3	600,000	$ 15,905	$ 4,333	$ 2,456	$ 6,789	$9,116	$ 47.57	$ 2,806	$ 867	$ 213	$ 1,726	$ -
4	600,000	$ 15,905	$ 4,333	$ 2,576	$ 6,908	$8,996	$ 46.95	$ 2,609	$ 867	$ 68	$ 1,674	$ -
5	600,000	$ 15,905	$ 4,333	$ 2,687	$ 7,019	$8,885	$ 46.37	$ 2,466	$ 867	$ -	$ 1,600	$ -
6	600,000	$ 15,905	$ 4,333	$ 2,790	$ 7,123	$8,782	$ 45.83	$ 2,371	$ 867	$ -	$ 1,505	$ -
7	600,000	$ 15,905	$ 4,333	$ 2,886	$ 7,219	$8,686	$ 45.33	$ 2,283	$ 867	$ -	$ 1,417	$ -
8	600,000	$ 15,905	$ 2,190	$ 2,975	$ 5,165	$10,740	$ 56.05	$ 2,589	$ 438	$ -	$ 2,151	$ -
9	600,000	$ 15,905	$ 2,190	$ 3,058	$ 5,248	$10,657	$ 55.61	$ 2,519	$ 438	$ -	$ 2,081	$ -
10	600,000	$ 15,905	$ 2,190	$ 3,135	$ 5,325	$10,580	$ 55.21	$ 2,455	$ 438	$ -	$ 2,017	$ -
11	600,000	$ 15,905	$ 2,190	$ 3,207	$ 5,397	$10,508	$ 54.84	$ 2,395	$ 438	$ -	$ 1,957	$ -
12	600,000	$ 15,905	$ 2,190	$ 3,274	$ 5,464	$10,441	$ 54.49	$ 2,339	$ 438	$ -	$ 1,901	$ -
13	600,000	$ 15,905	$ 2,190	$ 3,336	$ 5,526	$10,379	$ 54.16	$ 2,287	$ 438	$ -	$ 1,849	$ -
14	600,000	$ 15,905	$ 2,190	$ 3,394	$ 5,584	$10,321	$ 53.86	$ 2,239	$ 438	$ -	$ 1,801	$ -
15	600,000	$ 15,905	$ 2,190	$ 3,447	$ 5,637	$10,267	$ 53.58	$ 2,194	$ 438	$ -	$ 1,756	$ -
16	600,000	$ 15,905	$ 2,190	$ 3,497	$ 5,687	$10,218	$ 53.32	$ 2,153	$ 438	$ -	$ 1,715	$ -
17	600,000	$ 15,905	$ 2,190	$ 3,544	$ 5,734	$10,171	$ 53.08	$ 2,114	$ 438	$ -	$ 1,676	$ -
18	600,000	$ 15,905	$ 2,190	$ 3,587	$ 5,777	$10,128	$ 52.85	$ 2,078	$ 438	$ -	$ 1,640	$ -
19	600,000	$ 15,905	$ 2,190	$ 3,627	$ 5,817	$10,088	$ 52.64	$ 2,044	$ 438	$ -	$ 1,606	$ -
20	600,000	$ 15,905	$ 2,190	$ 3,665	$ 5,855	$10,050	$ 52.45	$ 2,013	$ 438	$ -	$ 1,575	$ -

Comparison of Revenue under ACES and HB 110 with Requested Volume, Price, and Cost Assumptions - $90 ANS Scenario

Prepared 02/23/11 by Department of Revenue for Rep Seaton

This analysis does not represent a Department of Revenue forecast or expectation.

These hypothetical assumptions were specifically requested by the requestor and the Department of Revenue does not in any way support the assumptions.

This analysis does not include assumptions relating to lease expenditure exemptions, or proposed credits

HB 110 Scenario - Existing oil with decline rate

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Base Tax	Progressive Tax	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	600,000	$ 15,905	$ 2,190	$ 2,190	$ 4,380	$11,525	60.14	$2,881	$ 363	$ 3,244	$ 438	$ -	$2,806	$ -
2	558,000	$ 14,792	$ 2,037	$ 2,037	$ 4,073	$10,718	60.14	$2,680	$ 337	$ 3,017	$ 407	$ -	$2,610	$ -
3	518,940	$ 13,756	$ 1,894	$ 1,894	$ 3,788	$9,968	60.14	$2,492	$ 314	$ 2,806	$ 379	$ -	$2,427	$ -
4	482,614	$ 12,793	$ 1,762	$ 1,762	$ 3,523	$9,270	60.14	$2,318	$ 292	$ 2,609	$ 352	$ -	$2,257	$ -
5	448,831	$ 11,898	$ 1,638	$ 1,638	$ 3,276	$8,621	60.14	$2,155	$ 271	$ 2,427	$ 328	$ -	$2,099	$ -
6	417,413	$ 11,065	$ 1,524	$ 1,524	$ 3,047	$8,018	60.14	$2,004	$ 252	$ 2,257	$ 305	$ -	$1,952	$ -
7	388,194	$ 10,290	$ 1,417	$ 1,417	$ 2,834	$7,456	60.14	$1,864	$ 235	$ 2,099	$ 283	$ -	$1,815	$ -
8	361,021	$ 9,570	$ 1,318	$ 1,318	$ 2,635	$6,935	60.14	$1,734	$ 218	$ 1,952	$ 264	$ -	$1,688	$ -
9	335,749	$ 8,900	$ 1,225	$ 1,225	$ 2,451	$6,449	60.14	$1,612	$ 203	$ 1,815	$ 245	$ -	$1,570	$ -
10	312,247	$ 8,277	$ 1,140	$ 1,140	$ 2,279	$5,998	60.14	$1,499	$ 189	$ 1,688	$ 228	$ -	$1,460	$ -
11	290,389	$ 7,698	$ 1,060	$ 1,060	$ 2,120	$5,578	60.14	$1,394	$ 176	$ 1,570	$ 212	$ -	$1,358	$ -
12	270,062	$ 7,159	$ 986	$ 986	$ 1,971	$5,187	60.14	$1,297	$ 163	$ 1,460	$ 197	$ -	$1,263	$ -
13	251,158	$ 6,658	$ 917	$ 917	$ 1,833	$4,824	60.14	$1,206	$ 152	$ 1,358	$ 183	$ -	$1,175	$ -
14	233,577	$ 6,192	$ 853	$ 853	$ 1,705	$4,487	60.14	$1,122	$ 141	$ 1,263	$ 171	$ -	$1,092	$ -
15	217,226	$ 5,758	$ 793	$ 793	$ 1,586	$4,173	60.14	$1,043	$ 131	$ 1,174	$ 159	$ -	$1,016	$ -
16	202,021	$ 5,355	$ 737	$ 737	$ 1,475	$3,880	60.14	$970	$ 122	$ 1,092	$ 147	$ -	$945	$ -
17	187,879	$ 4,980	$ 686	$ 686	$ 1,372	$3,609	60.14	$902	$ 114	$ 1,016	$ 137	$ -	$879	$ -
18	174,728	$ 4,632	$ 638	$ 638	$ 1,276	$3,356	60.14	$839	$ 106	$ 945	$ 128	$ -	$817	$ -
19	162,497	$ 4,307	$ 593	$ 593	$ 1,186	$3,121	60.14	$780	$ 98	$ 879	$ 119	$ -	$760	$ -
20	151,122	$ 4,006	$ 552	$ 552	$ 1,103	$2,903	60.14	$726	$ 91	$ 817	$ 110	$ -	$707	$ -

HB 110 Scenario - Incremental oil to maintain production

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Base Tax	Progressive Tax	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	-	$ -	$ 2,143	$ -	$ 2,143	($2,143)	$ -	($321)	$ -	$ -	$ 429	$ 536	$0	$ 964
2	42,000	$ 1,113	$ 2,296	$ 291	$ 2,587	($1,474)	$ (109.89)	($221)	$ -	$ -	$ 459	$ 369	$0	$ 828
3	81,060	$ 2,149	$ 2,439	$ 562	$ 3,001	($852)	$ (32.92)	($128)	$ -	$ -	$ 488	$ 213	$0	$ 701
4	117,386	$ 3,112	$ 2,571	$ 814	$ 3,385	($274)	$ (7.30)	($41)	$ -	$ -	$ 514	$ 68	$0	$ 583
5	151,169	$ 4,007	$ 2,695	$ 1,048	$ 3,743	$264	$ 5.47	$40	$ -	$ 40	$ 539	$ -	$0	$ 499
6	182,587	$ 4,840	$ 2,809	$ 1,266	$ 4,076	$764	$ 13.11	$115	$ -	$ 115	$ 562	$ -	$0	$ 447
7	211,806	$ 5,615	$ 2,916	$ 1,469	$ 4,385	$1,230	$ 18.18	$184	$ -	$ 184	$ 583	$ -	$0	$ 399
8	238,979	$ 6,335	$ 872	$ 1,657	$ 2,530	$3,805	$ 49.86	$571	$ 66	$ 637	$ 174	$ -	$462	$ -
9	264,251	$ 7,005	$ 965	$ 1,833	$ 2,797	$4,208	$ 49.86	$631	$ 73	$ 704	$ 193	$ -	$511	$ -
10	287,753	$ 7,628	$ 1,050	$ 1,996	$ 3,046	$4,582	$ 49.86	$687	$ 79	$ 767	$ 210	$ -	$557	$ -
11	309,611	$ 8,207	$ 1,130	$ 2,147	$ 3,277	$4,930	$ 49.86	$739	$ 85	$ 825	$ 226	$ -	$599	$ -
12	329,938	$ 8,746	$ 1,204	$ 2,288	$ 3,492	$5,254	$ 49.86	$788	$ 91	$ 879	$ 241	$ -	$638	$ -
13	348,842	$ 9,247	$ 1,273	$ 2,419	$ 3,692	$5,555	$ 49.86	$833	$ 96	$ 929	$ 255	$ -	$675	$ -
14	366,423	$ 9,713	$ 1,337	$ 2,541	$ 3,879	$5,835	$ 49.86	$875	$ 101	$ 976	$ 267	$ -	$709	$ -
15	382,774	$ 10,147	$ 1,397	$ 2,655	$ 4,052	$6,095	$ 49.86	$914	$ 106	$ 1,020	$ 279	$ -	$740	$ -
16	397,979	$ 10,550	$ 1,453	$ 2,760	$ 4,213	$6,337	$ 49.86	$951	$ 110	$ 1,060	$ 291	$ -	$770	$ -
17	412,121	$ 10,925	$ 1,504	$ 2,858	$ 4,362	$6,562	$ 49.86	$984	$ 114	$ 1,098	$ 301	$ -	$797	$ -
18	425,272	$ 11,273	$ 1,552	$ 2,949	$ 4,502	$6,772	$ 49.86	$1,016	$ 117	$ 1,133	$ 310	$ -	$823	$ -
19	437,503	$ 11,597	$ 1,597	$ 3,034	$ 4,631	$6,966	$ 49.86	$1,045	$ 121	$ 1,166	$ 319	$ -	$846	$ -
20	448,878	$ 11,899	$ 1,638	$ 3,113	$ 4,751	$7,148	$ 49.86	$1,072	$ 124	$ 1,196	$ 328	$ -	$868	$ -

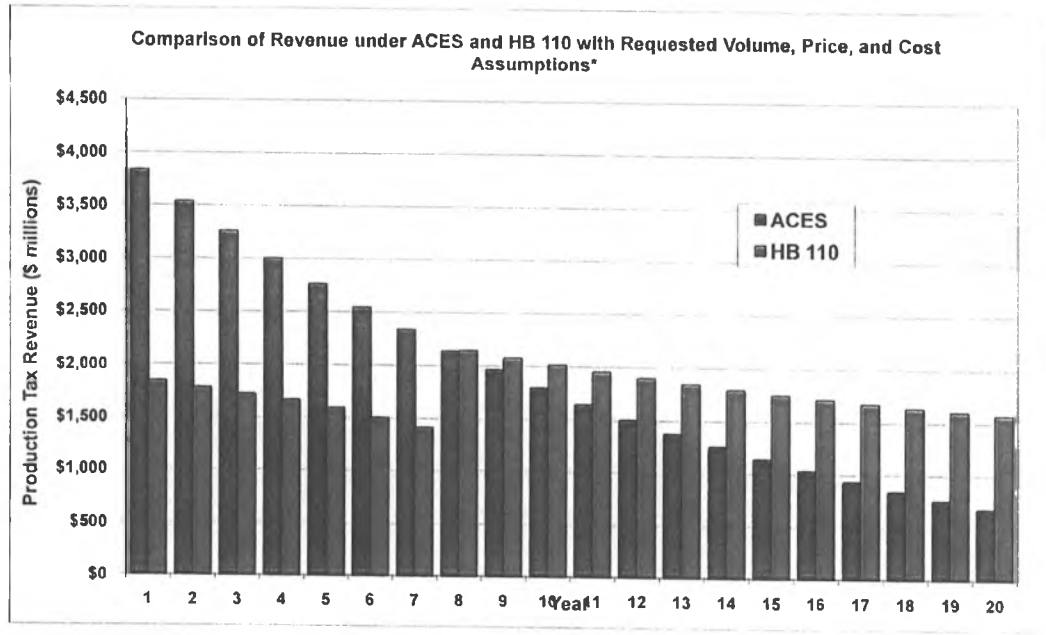
Comparison of Revenue under ACES and HB 110 with Requested Volume, Price, and Cost Assumptions - $90 ANS Scenario

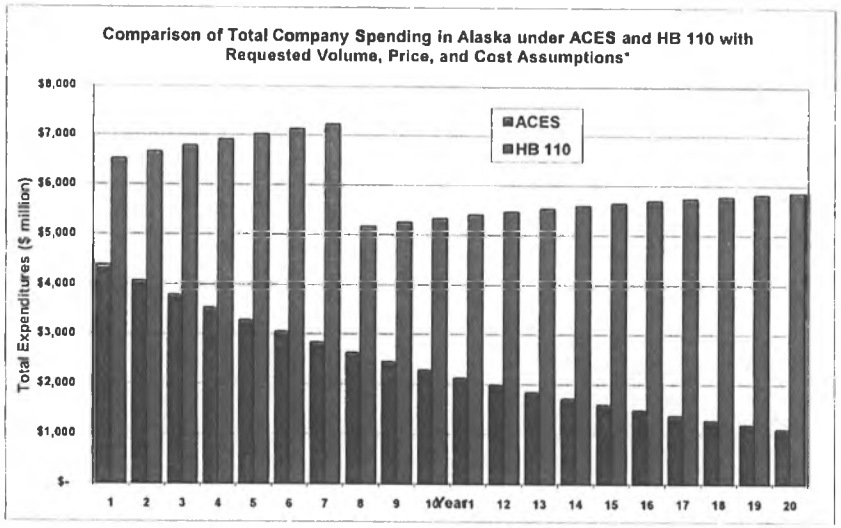
Prepared 02/23/11 by Department of Revenue for Rep Seaton

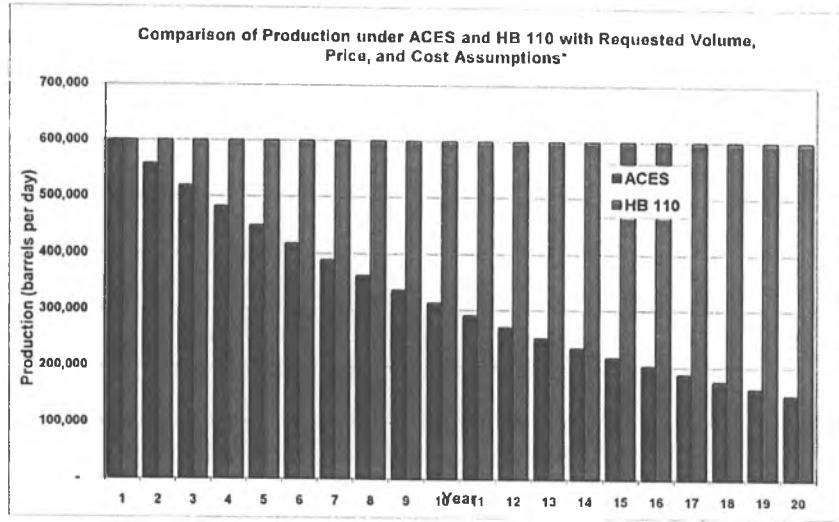
This analysis does not represent a Department of Revenue forecast or expectation.

These hypothetical assumptions were specifically requested by the requestor and the Department of Revenue does not in any way support the assumptions.
This analysis does not include assumptions relating to lease expenditure exemptions, or proposed credits

COMPARISON OF SCENARIOS				
	ACES		HB 110	
Year	Tax Liability	Credits for carry forward or refund	Tax Liability	Credits for carry forward or refund
1	$3,833	$0	$1,842	$0
2	$3,536	$0	$1,782	$0
3	$3,260	$0	$1,726	$0
4	$3,003	$0	$1,674	$0
5	$2,765	$0	$1,600	$0
6	$2,543	$0	$1,505	$0
7	$2,337	$0	$1,417	$0
8	$2,145	$0	$2,151	$0
9	$1,967	$0	$2,081	$0
10	$1,802	$0	$2,017	$0
11	$1,649	$0	$1,957	$0
12	$1,506	$0	$1,901	$0
13	$1,374	$0	$1,849	$0
14	$1,251	$0	$1,801	$0
15	$1,137	$0	$1,756	$0
16	$1,031	$0	$1,715	$0
17	$933	$0	$1,676	$0
18	$842	$0	$1,640	$0
19	$758	$0	$1,606	$0
20	$680	$0	$1,575	$0
Sum	$38,350	$0	$35,271	$0







Comparison of Revenue under ACES and HB 110 with Requested Volume, Price, and Cost Assumptions - $50 ANS Scenario

Prepared 02/23/11 by Department of Revenue for Rep Seaton

This analysis does not represent a Department of Revenue forecast or expectation.

These hypothetical assumptions were specifically requested by the requestor and the Department of Revenue does not in any way support the assumptions.
This analysis does not include assumptions relating to lease expenditure exemptions, or proposed credits

KEY INPUTS					
Initial Production (bpd)		600,000	Incremental facilities capital ($ mm)	$	15,000
Decline rate - existing		7%	Years to spread facilities spend	$	7
Oil Price		$50	Incremental Opex / bbl	$	19
Existing Opex / bbl	$	10	Incremental Capex / bbl	$	10
Existing Capex / bbl	$	10	Transit costs	$	7

All amounts in $ millions except for oil production and amounts labeled as per barrel amounts

ACES Scenario - Existing oil with decline rate

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Base Tax	Progressive Tax	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	600,000	$ 8,240	$ 2,190	$ 2,190	$ 4,380	$3,860	20.14	$965	$0	$965	$ 438	$ -	$527	$ -
2	558,000	$ 7,616	$ 2,037	$ 2,037	$ 4,073	$3,543	19.88	$886	$0	$886	$ 407	$ -	$478	$ -
3	518,940	$ 7,036	$ 1,894	$ 1,894	$ 3,788	$3,248	19.60	$812	$0	$812	$ 379	$ -	$433	$ -
4	482,614	$ 6,497	$ 1,762	$ 1,762	$ 3,523	$2,974	19.29	$743	$0	$743	$ 352	$ -	$391	$ -
5	448,831	$ 5,995	$ 1,638	$ 1,638	$ 3,276	$2,718	18.96	$680	$0	$680	$ 328	$ -	$352	$ -
6	417,413	$ 5,528	$ 1,524	$ 1,524	$ 3,047	$2,481	18.61	$620	$0	$620	$ 305	$ -	$316	$ -
7	388,194	$ 5,094	$ 1,417	$ 1,417	$ 2,834	$2,261	18.23	$565	$0	$565	$ 283	$ -	$282	$ -
8	361,021	$ 4,691	$ 1,318	$ 1,318	$ 2,635	$2,055	17.83	$514	$0	$514	$ 264	$ -	$250	$ -
9	335,749	$ 4,316	$ 1,225	$ 1,225	$ 2,451	$1,865	17.39	$466	$0	$466	$ 245	$ -	$221	$ -
10	312,247	$ 3,966	$ 1,140	$ 1,140	$ 2,279	$1,687	16.92	$422	$0	$422	$ 228	$ -	$194	$ -
11	290,389	$ 3,642	$ 1,060	$ 1,060	$ 2,120	$1,522	16.41	$381	$0	$381	$ 212	$ -	$169	$ -
12	270,062	$ 3,340	$ 986	$ 986	$ 1,971	$1,369	15.87	$342	$0	$342	$ 197	$ -	$145	$ -
13	251,158	$ 3,059	$ 917	$ 917	$ 1,833	$1,226	15.28	$306	$0	$306	$ 183	$ -	$123	$ -
14	233,577	$ 2,798	$ 853	$ 853	$ 1,705	$1,093	14.65	$273	$0	$273	$ 171	$ -	$103	$ -
15	217,226	$ 2,555	$ 793	$ 793	$ 1,586	$970	13.98	$242	$0	$242	$ 159	$ -	$84	$ -
16	202,021	$ 2,330	$ 737	$ 737	$ 1,475	$855	13.25	$214	$0	$214	$ 147	$ -	$66	$ -
17	187,879	$ 2,119	$ 686	$ 686	$ 1,372	$748	12.47	$187	$0	$187	$ 137	$ -	$50	$ -
18	174,728	$ 1,924	$ 638	$ 638	$ 1,276	$649	11.62	$162	$0	$162	$ 128	$ -	$35	$ -
19	162,497	$ 1,743	$ 593	$ 593	$ 1,186	$556	10.72	$139	$0	$139	$ 119	$ -	$20	$ -
20	151,122	$ 1,574	$ 552	$ 552	$ 1,103	$470	9.75	$118	$0	$118	$ 110	$ -	$7	$ -

HB 110 Scenario - Summary Existing + Incremental Production

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	600,000	$ 8,240	$ 4,333	$ 2,190	$ 6,523	$1,717	$ 8.96	$ 965	$ 867	$ 536	$ -	$ 437
2	600,000	$ 8,240	$ 4,333	$ 2,328	$ 6,661	$1,579	$ 8.24	$ 897	$ 867	$ 503	$ -	$ 1,369
3	600,000	$ 8,240	$ 4,333	$ 2,456	$ 6,789	$1,451	$ 7.57	$ 835	$ 867	$ 472	$ -	$ 1,338
4	600,000	$ 8,240	$ 4,333	$ 2,576	$ 6,908	$1,331	$ 6.95	$ 776	$ 867	$ 443	$ -	$ 1,310
5	600,000	$ 8,240	$ 4,333	$ 2,687	$ 7,019	$1,220	$ 6.37	$ 722	$ 867	$ 417	$ -	$ 1,283
6	600,000	$ 8,240	$ 4,333	$ 2,790	$ 7,123	$1,117	$ 5.83	$ 671	$ 867	$ 392	$ -	$ 1,259
7	600,000	$ 8,240	$ 4,333	$ 2,886	$ 7,219	$1,021	$ 5.33	$ 624	$ 867	$ 369	$ -	$ 1,236
8	600,000	$ 8,240	$ 2,190	$ 2,975	$ 5,165	$3,075	$ 16.05	$ 693	$ 438	$ -	$ 255	$ -
9	600,000	$ 8,240	$ 2,190	$ 3,058	$ 5,248	$2,992	$ 15.61	$ 665	$ 438	$ -	$ 227	$ -
10	600,000	$ 8,240	$ 2,190	$ 3,135	$ 5,325	$2,915	$ 15.21	$ 638	$ 438	$ -	$ 200	$ -
11	600,000	$ 8,240	$ 2,190	$ 3,207	$ 5,397	$2,843	$ 14.84	$ 613	$ 438	$ -	$ 175	$ -
12	600,000	$ 8,240	$ 2,190	$ 3,274	$ 5,464	$2,776	$ 14.49	$ 590	$ 438	$ -	$ 152	$ -
13	600,000	$ 8,240	$ 2,190	$ 3,336	$ 5,526	$2,714	$ 14.16	$ 569	$ 438	$ -	$ 131	$ -
14	600,000	$ 8,240	$ 2,190	$ 3,394	$ 5,584	$2,656	$ 13.86	$ 549	$ 438	$ -	$ 111	$ -
15	600,000	$ 8,240	$ 2,190	$ 3,447	$ 5,637	$2,602	$ 13.58	$ 530	$ 438	$ -	$ 92	$ -
16	600,000	$ 8,240	$ 2,190	$ 3,497	$ 5,687	$2,553	$ 13.32	$ 513	$ 438	$ -	$ 75	$ -
17	600,000	$ 8,240	$ 2,190	$ 3,544	$ 5,734	$2,506	$ 13.08	$ 497	$ 438	$ -	$ 59	$ -
18	600,000	$ 8,240	$ 2,190	$ 3,587	$ 5,777	$2,463	$ 12.85	$ 482	$ 438	$ -	$ 44	$ -
19	600,000	$ 8,240	$ 2,190	$ 3,627	$ 5,817	$2,423	$ 12.64	$ 468	$ 438	$ -	$ 30	$ -
20	600,000	$ 8,240	$ 2,190	$ 3,665	$ 5,855	$2,385	$ 12.45	$ 455	$ 438	$ -	$ 17	$ -

Comparison of Revenue under ACES and HB 110 with Requested Volume, Price, and Cost Assumptions - $50 ANS Scenario

Prepared 02/23/11 by Department of Revenue for Rep Seaton

This analysis does not represent a Department of Revenue forecast or expectation.

These hypothetical assumptions were specifically requested by the requestor and the Department of Revenue does not in any way support the assumptions.

This analysis does not include assumptions relating to lease expenditure exemptions, or proposed credits

HB 110 Scenario - Existing oil with decline rate

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Base Tax	Progressive Tax	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	600,000	$ 8,240	$ 2,190	$ 2,190	$ 4,380	$3,860	20.14	$965	$ -	$ 965	$ 438	$ -	$527	$ -
2	558,000	$ 7,663	$ 2,037	$ 2,037	$ 4,073	$3,590	20.14	$897	$ -	$ 897	$ 407	$ -	$490	$ -
3	518,940	$ 7,127	$ 1,894	$ 1,894	$ 3,788	$3,338	20.14	$835	$ -	$ 835	$ 379	$ -	$456	$ -
4	482,614	$ 6,628	$ 1,762	$ 1,762	$ 3,523	$3,105	20.14	$776	$ -	$ 776	$ 352	$ -	$424	$ -
5	448,831	$ 6,164	$ 1,638	$ 1,638	$ 3,276	$2,887	20.14	$722	$ -	$ 722	$ 328	$ -	$394	$ -
6	417,413	$ 5,732	$ 1,524	$ 1,524	$ 3,047	$2,685	20.14	$671	$ -	$ 671	$ 305	$ -	$367	$ -
7	388,194	$ 5,331	$ 1,417	$ 1,417	$ 2,834	$2,497	20.14	$624	$ -	$ 624	$ 283	$ -	$341	$ -
8	361,021	$ 4,958	$ 1,318	$ 1,318	$ 2,635	$2,322	20.14	$581	$ -	$ 581	$ 264	$ -	$317	$ -
9	335,749	$ 4,611	$ 1,225	$ 1,225	$ 2,451	$2,160	20.14	$540	$ -	$ 540	$ 245	$ -	$295	$ -
10	312,247	$ 4,288	$ 1,140	$ 1,140	$ 2,279	$2,009	20.14	$502	$ -	$ 502	$ 228	$ -	$274	$ -
11	290,389	$ 3,988	$ 1,060	$ 1,060	$ 2,120	$1,868	20.14	$467	$ -	$ 467	$ 212	$ -	$255	$ -
12	270,062	$ 3,709	$ 986	$ 986	$ 1,971	$1,737	20.14	$434	$ -	$ 434	$ 197	$ -	$237	$ -
13	251,158	$ 3,449	$ 917	$ 917	$ 1,833	$1,616	20.14	$404	$ -	$ 404	$ 183	$ -	$221	$ -
14	233,577	$ 3,208	$ 853	$ 853	$ 1,705	$1,503	20.14	$376	$ -	$ 376	$ 171	$ -	$205	$ -
15	217,226	$ 2,983	$ 793	$ 793	$ 1,586	$1,397	20.14	$349	$ -	$ 349	$ 159	$ -	$191	$ -
16	202,021	$ 2,774	$ 737	$ 737	$ 1,475	$1,300	20.14	$325	$ -	$ 325	$ 147	$ -	$177	$ -
17	187,879	$ 2,580	$ 686	$ 686	$ 1,372	$1,209	20.14	$302	$ -	$ 302	$ 137	$ -	$165	$ -
18	174,728	$ 2,400	$ 638	$ 638	$ 1,276	$1,124	20.14	$281	$ -	$ 281	$ 128	$ -	$153	$ -
19	162,497	$ 2,232	$ 593	$ 593	$ 1,186	$1,045	20.14	$261	$ -	$ 261	$ 119	$ -	$143	$ -
20	151,122	$ 2,075	$ 552	$ 552	$ 1,103	$972	20.14	$243	$ -	$ 243	$ 110	$ -	$133	$ -

HB 110 Scenario - Incremental oil to maintain production

Year	Production (bpd)	Annual Taxable GVPP	Capital Expenditures	Operating Expenditures	Total Costs	PTV	PTV / barrel	Base Tax	Progressive Tax	Total Tax before Credits	Capital Credits	NOL Tax Credits	Total Tax after Credits	Credits for carry forward or refund
1	-	$ -	$ 2,143	$ -	$ 2,143	($2,143)	$ -	($321)	$ -	$ -	$ 429	$ 536	$0	$ 964
2	42,000	$ 577	$ 2,296	$ 291	$ 2,587	($2,011)	$ (149.89)	($302)	$ -	$ -	$ 459	$ 503	$0	$ 962
3	81,060	$ 1,113	$ 2,439	$ 562	$ 3,001	($1,888)	$ (72.92)	($283)	$ -	$ -	$ 488	$ 472	$0	$ 960
4	117,386	$ 1,612	$ 2,571	$ 814	$ 3,385	($1,773)	$ (47.30)	($266)	$ -	$ -	$ 514	$ 443	$0	$ 958
5	151,169	$ 2,076	$ 2,695	$ 1,048	$ 3,743	($1,667)	$ (34.53)	($250)	$ -	$ -	$ 539	$ 417	$0	$ 956
6	182,587	$ 2,507	$ 2,809	$ 1,266	$ 4,076	($1,568)	$ (26.89)	($235)	$ -	$ -	$ 562	$ 392	$0	$ 954
7	211,806	$ 2,909	$ 2,916	$ 1,469	$ 4,385	($1,476)	$ (21.82)	($221)	$ -	$ -	$ 583	$ 369	$0	$ 952
8	238,979	$ 3,282	$ 872	$ 1,657	$ 2,530	$752	$ 9.86	$113	$ -	$ 113	$ 174	$ -	$0	$ 62
9	264,251	$ 3,629	$ 965	$ 1,833	$ 2,797	$832	$ 9.86	$125	$ -	$ 125	$ 193	$ -	$0	$ 68
10	287,753	$ 3,952	$ 1,050	$ 1,996	$ 3,046	$906	$ 9.86	$136	$ -	$ 136	$ 210	$ -	$0	$ 74
11	309,611	$ 4,252	$ 1,130	$ 2,147	$ 3,277	$975	$ 9.86	$146	$ -	$ 146	$ 226	$ -	$0	$ 80
12	329,938	$ 4,531	$ 1,204	$ 2,288	$ 3,492	$1,039	$ 9.86	$156	$ -	$ 156	$ 241	$ -	$0	$ 85
13	348,842	$ 4,791	$ 1,273	$ 2,419	$ 3,692	$1,098	$ 9.86	$165	$ -	$ 165	$ 255	$ -	$0	$ 90
14	366,423	$ 5,032	$ 1,337	$ 2,541	$ 3,879	$1,154	$ 9.86	$173	$ -	$ 173	$ 267	$ -	$0	$ 94
15	382,774	$ 5,257	$ 1,397	$ 2,655	$ 4,052	$1,205	$ 9.86	$181	$ -	$ 181	$ 279	$ -	$0	$ 99
16	397,979	$ 5,466	$ 1,453	$ 2,760	$ 4,213	$1,253	$ 9.86	$188	$ -	$ 188	$ 291	$ -	$0	$ 103
17	412,121	$ 5,660	$ 1,504	$ 2,858	$ 4,362	$1,297	$ 9.86	$195	$ -	$ 195	$ 301	$ -	$0	$ 106
18	425,272	$ 5,840	$ 1,552	$ 2,949	$ 4,502	$1,339	$ 9.86	$201	$ -	$ 201	$ 310	$ -	$0	$ 110
19	437,503	$ 6,008	$ 1,597	$ 3,034	$ 4,631	$1,377	$ 9.86	$207	$ -	$ 207	$ 319	$ -	$0	$ 113
20	448,878	$ 6,164	$ 1,638	$ 3,113	$ 4,751	$1,413	$ 9.86	$212	$ -	$ 212	$ 328	$ -	$0	$ 116

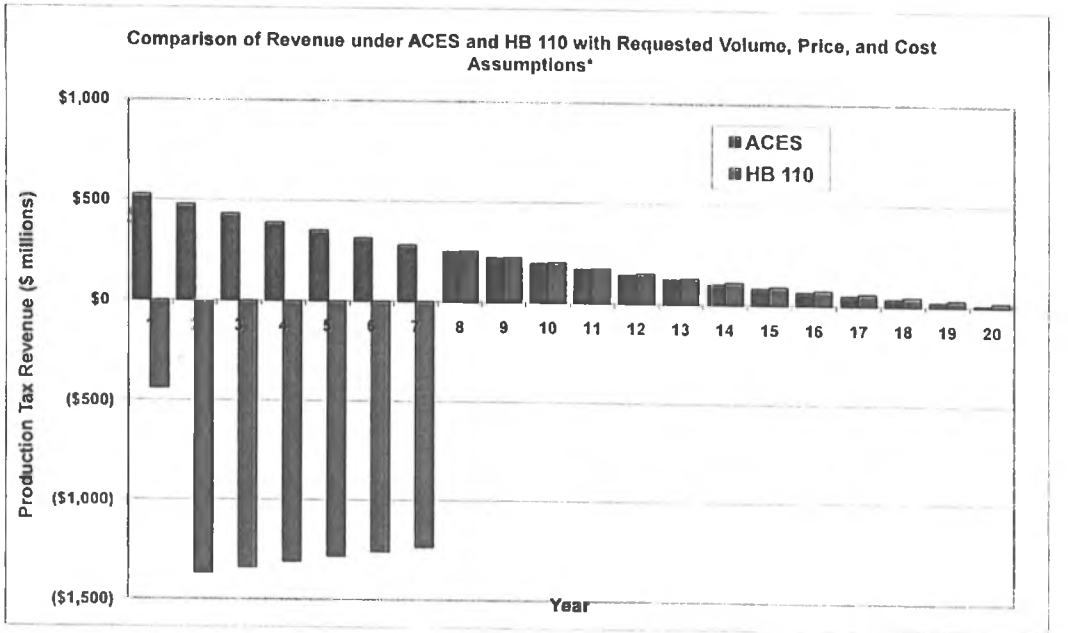
Comparison of Revenue under ACES and HB 110 with Requested Volume, Price, and Cost Assumptions - $50 ANS Scenario

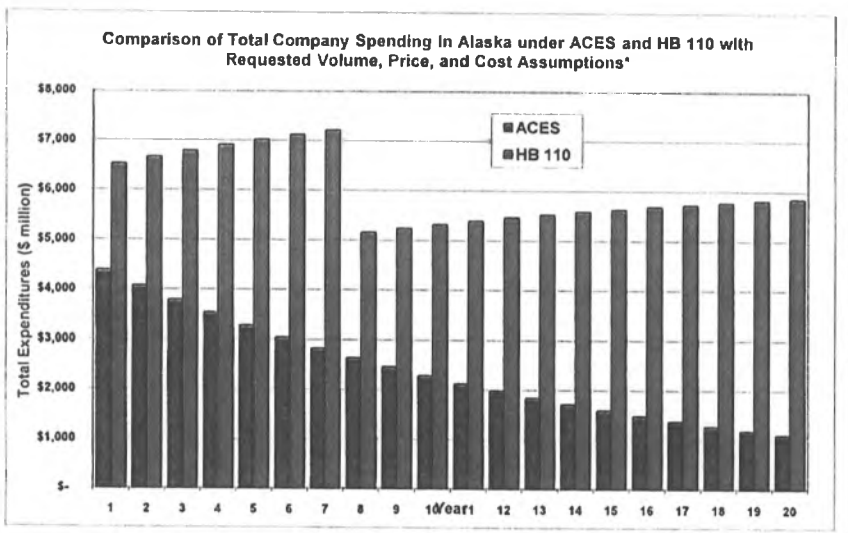
Prepared 02/23/11 by Department of Revenue for Rep Seaton

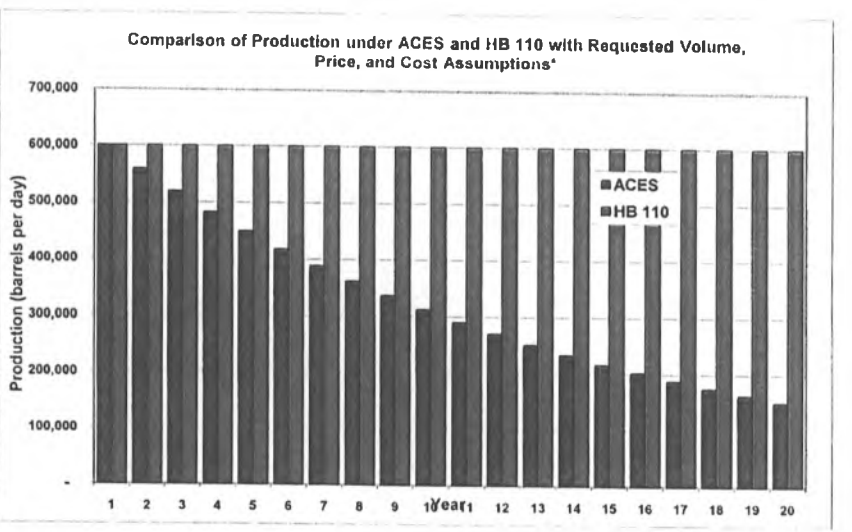
This analysis does not represent a Department of Revenue forecast or expectation.

These hypothetical assumptions were specifically requested by the requestor and the Department of Revenue does not in any way support the assumptions.
This analysis does not include assumptions relating to lease expenditure exemptions, or proposed credits

COMPARISON OF SCENARIOS				
	ACES		HB 110	
Year	Tax Liability	Credits for carry forward or refund	Tax Liability	Credits for carry forward or refund
1	$527	$0	$0	$437
2	$478	$0	$0	$1,369
3	$433	$0	$0	$1,338
4	$391	$0	$0	$1,310
5	$352	$0	$0	$1,283
6	$316	$0	$0	$1,259
7	$282	$0	$0	$1,236
8	$250	$0	$255	$0
9	$221	$0	$227	$0
10	$194	$0	$200	$0
11	$169	$0	$175	$0
12	$145	$0	$152	$0
13	$123	$0	$131	$0
14	$103	$0	$111	$0
15	$84	$0	$92	$0
16	$66	$0	$75	$0
17	$50	$0	$59	$0
18	$35	$0	$44	$0
19	$20	$0	$30	$0
20	$7	$0	$17	$0
Sum	$4,246	$0	$1,568	$8,232







State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Eric Feige
State Capitol Room 126
Juneau AK, 99801

February 23, 2011

The Honorable Paul Seaton
State Capitol Room 102
Juneau AK, 99801

SUBJECT: Response to Questions from House Resources Meeting on February 21, 2011

Dear Representatives Feige and Seaton:

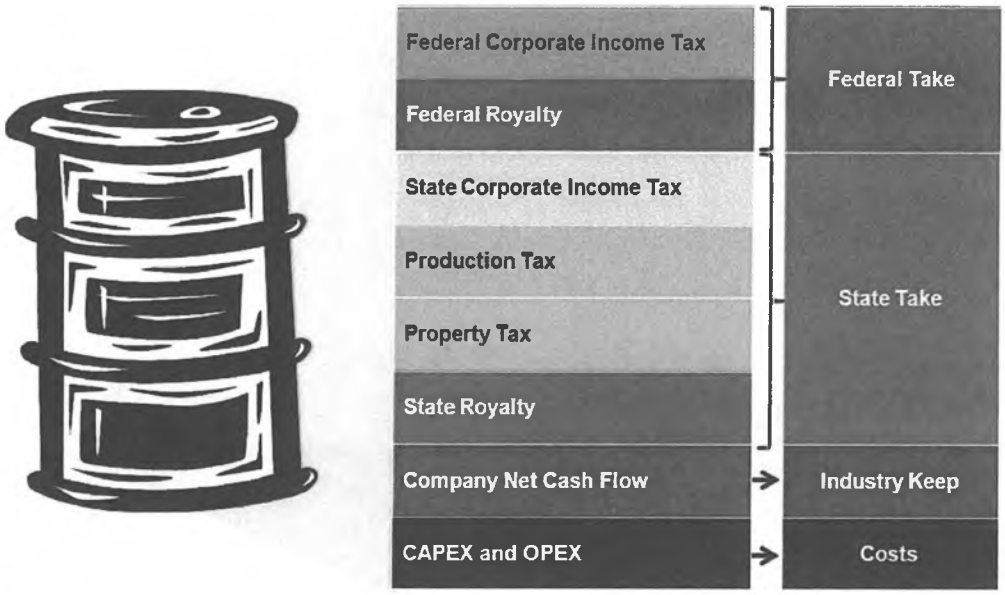
The purpose of this document is to respond to the follow-up questions from the House Resources Committee meeting on February 21, 2011. The requests/questions and responses follow.

1) **Compare effective tax rates to other jurisdictions where major producers are investing.**

   In comparing Alaska to other jurisdictions it is informative to look at total government take, as opposed to just taxes. Total government take includes all aspects of a particular fiscal regime including royalties, corporate income taxes, and production shares. The total government take is calculated as:

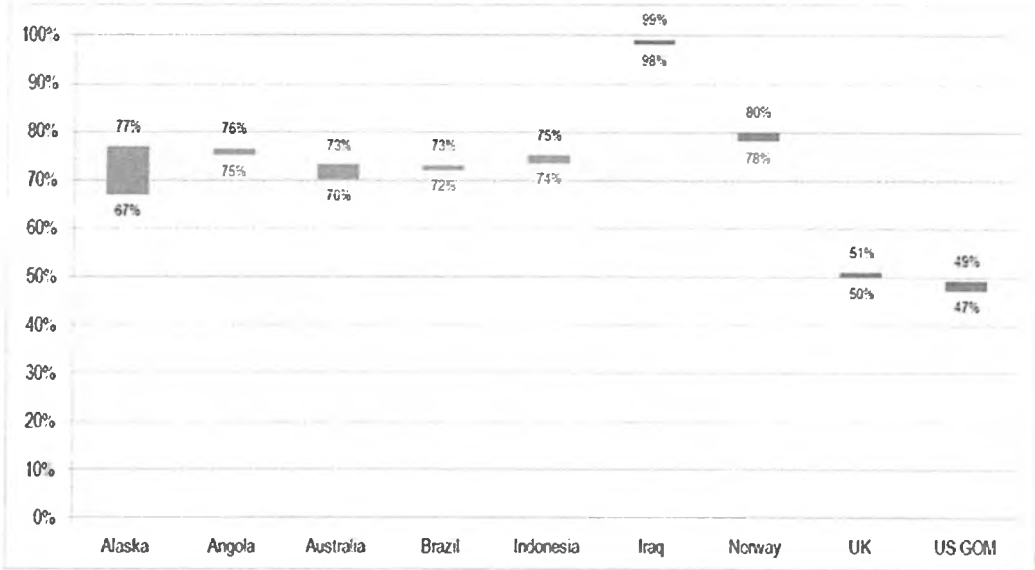
$$\frac{\textit{Federal Take + State Take}}{\textit{Field Revenue – Capex – Opex}}$$

The following graphic illustrates the components that comprise government take.



The following chart, extracted from a presentation given to Senate Finance on 2/22/10, presents total government take at oil prices of $70 and $150, in jurisdictions selected for their ability to attract hydrocarbon investments. The government take calculations are based on a production profile and costs similar to those in Alaska, with the various fiscal systems applied. The chart shows that Alaska's current total government take (about 67% at $70 oil and about 77% at $150 oil) is similar to the government take in a number of these jurisdictions; though significantly higher than the government take in the UK and the US Gulf of Mexico. Although Alaska's government take is similar to some other jurisdictions, Alaska is not currently attracting the desired level of exploration and development.

Remaining NS Oil Profile
Total Government Take



Note: Oil price $70-$150/bbl *Total Government Take - Alaska*

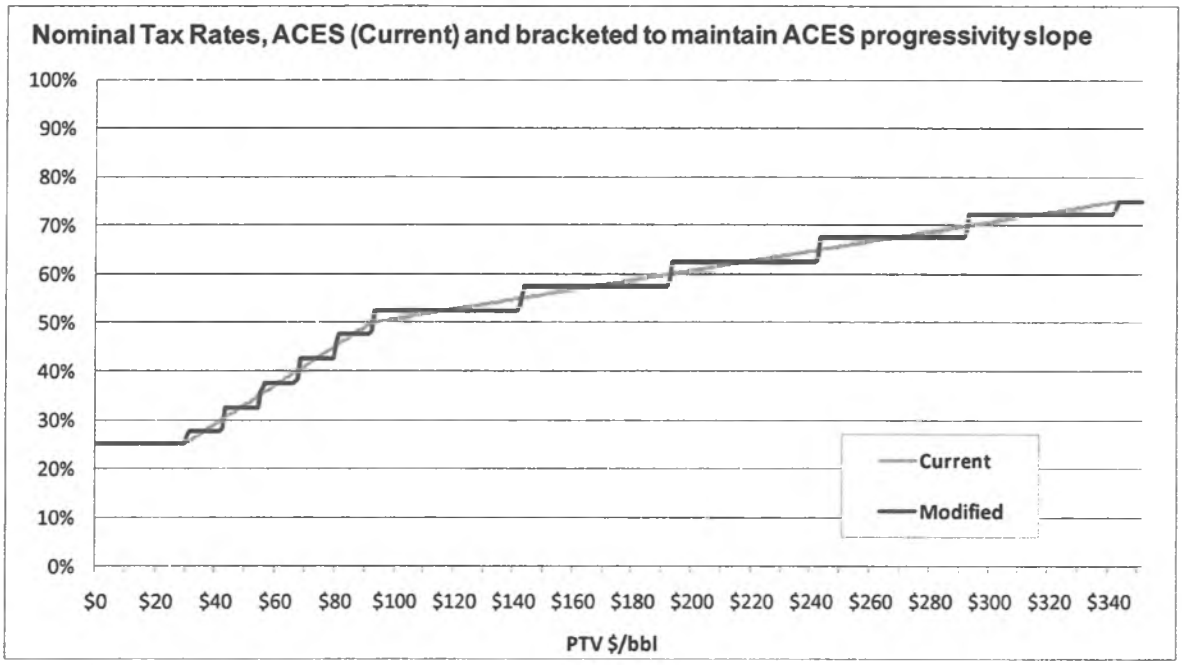
2) How much reinvestment of tax savings would occur if HB 110 passes as written?

The Department cannot say for certain the amount of reinvestment that will occur if HB 110 is enacted. A primary goal of the bill is to improve the investment climate in Alaska. Many companies that are currently producing, or hope to pursue new exploration and development, have testified to the beneficial impact this bill will have in terms of encouraging new investment and production.

3) Provide a slide showing tax rates if we were to maintain the same tax rates as ACES, but bracket progressivity.

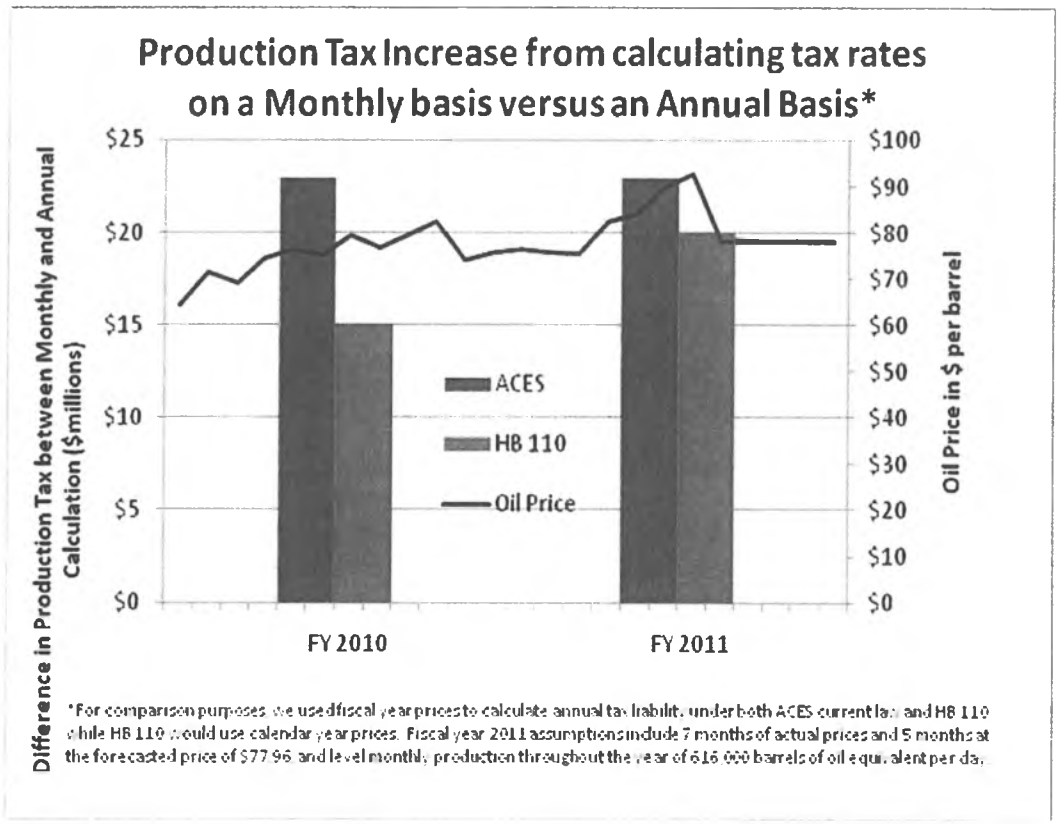
The following table and graph show how a marginal bracket approach could be applied to the production tax, while maintaining the same progressivity slope that exists currently under ACES. HB 110 implements this approach, with the exception that HB 110 caps the total tax rate at 50% compared to 75% under ACES.

Production Tax Value Bracket ($/boe)	Production Tax Rate (%)
0 to 30	25.0%
30 to 42.5	27.5%
42.5 to 55	32.5%
55 to 67.5	37.5%
67.5 to 80	42.5%
80 to 92.5	47.5%
92.5 to 142.5	52.5%
142.5 to 192.5	57.5%
192.5 to 242.5	62.5%
242.5 to 292.5	67.5%
292.5 to 342.5	72.5%
More than 342.5	75.0%



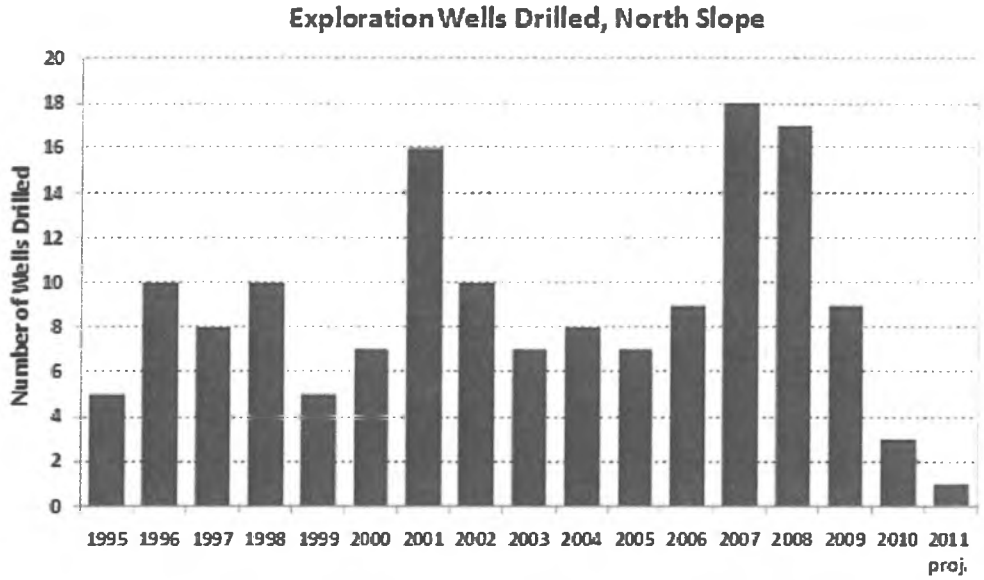
4) **Provide estimates of the revenue impact of switching from monthly to annual progressivity calculation.**

House Bill 110 proposes a change to the production tax rates and with it, a change to the calculation of those rates from a monthly calculation to an annual calculation. Depending on the monthly volatility in oil prices, the tax rate calculated annually may be different than the tax rate calculated monthly, thereby affecting total production tax revenues. Under most scenarios, the annual calculation will yield a lower tax rate and therefore lower production tax revenues than the monthly calculation. The difference in production tax revenue calculated monthly versus annually is much less under HB 110 than it is under ACES, however. We provide the following graph which shows the production tax increase for FY10 and projected for FY11 from calculating the tax rate monthly versus annually for both ACES and for HB 110.



5) **Provide a slide showing exploration wells drilled each year, including prior to 2005.**

The following chart shows exploration wells drilled on the North Slope since 1995, according to the Alaska Oil and Gas Conservation Commission. The Department of Natural Resources currently projects one exploration well for 2011.



Source: Alaska Oil and Gas Conservation Commission and Department of Natural Resources

6) Provide information on the components of federal government take, and explain why the federal government does not reduce their take to encourage exploration.

For production on state land, the primary component of federal government take is the corporate income tax, with a top marginal tax rate of 35%. State taxes are deductible in calculating federal taxable income. If a company is paying at the top marginal tax rate, then of the profit that remains after state taxes and royalties, the federal government receives 35% through the corporate income tax.

The federal government does have certain tax credits that help to encourage development at lower oil prices. These were discussed in the Department's response to questions raised at the February 7, 2011 hearing for HB 110, and that response is included again in its entirety below.

The following list presents the primary oil and gas related tax credits that are available against federal corporate income tax. There are also many federal tax credits that are available to all corporations which are not detailed here.

Enhanced Oil Recovery Credit (EOR)

- Credit of 15% of qualified costs against federal tax.
- Credit phases out when price of oil exceeds $28 /bbl (adjusted for inflation).
- No EOR allowed since 2005, because the list price exceeded the inflation adjusted price of oil. The list price for 2009 was $56.39 /bbl

Marginal Well Credit

- Credit up to $3/bbl available only to owner of operating interest.

- Marginal well = oil production not more than 25 bbls/day, and not less than 95% water.
- Credit available only when price of oil less than $18/bbl.

Nonconventional Fuel Source Credit

- Credit up to $3 (adjusted for inflation) per BOE (barrel of oil equivalent, with 5.8 million Btu content)
- Credit completely phased out when inflation adjusted price of oil exceeds $33.46/bbl. List price of oil in 2009 was $56.39 /bbl.
- Credit on oil only from shale or tar sands.
- Credit on synthetic fuels from coal.
- Credit on gas produced only from:
  1. Devonian shale
  2. coal seams
  3. tight formations
  4. biomass
  5. geo pressured brine

7) Provide our legal opinion regarding whether new information about company spending could be collected by statute, versus by regulation.

Under current statutes, the Department may request taxpayer information needed to provide forecasts and to administer the production tax, including information needed to audit claimed capital credit expenditures. Current statutes authorize the Department to adopt regulations requiring taxpayers to submit more detailed information about capital expenditures.

Under AS 43.05.230 (e), the Department would be able to release information about classification of capital spending only to the extent that it could be compiled as a general statistic that would prevent the identification of a particular return or report.

Under AS 43.55.890, the Department can publish information on qualified capital expenditures, as defined in AS 43.55.023, if aggregated among three or more producers or explorers, by month or calendar year and lease or property, unit, or area of the state.

8) Does Section 20 of the bill allow small producers to "double up" on credits?

Section 20 of HB 110 does not allow small producers to "double up" on credits. Section 20 of HB 110 makes no change to the AS 43.55.024(a) new area development credit or to the .024(c) credits for small producers. House Bill 110 simply cleans up the reporting to address the .024 credits since current AS 43.55.160 does not take into account the fact that for some producers, those credits will sunset in 2016, while for other producers the credit will be available for 9 years after they commence production. The amendments to

AS 43.55.160 in HB 110 simply take this into account, no change is made to how the AS 43.55.024 credits apply.

9) **Provide information about the state revenues and other benefits that would accrue from OCS development.**

The Outer Continental Shelf (OCS) encompasses submerged lands and waters between state jurisdiction and the extent of federal jurisdiction. State jurisdiction in Alaska extends three miles from the coastline. Federal jurisdiction extends 197 miles beyond the state jurisdiction for a total of 200 miles total from the coastline.

Revenue from oil and gas activity in Federal waters within three nautical miles of state waters is subject to Section 1337 (8)(g) of the Outer Continental Shelf Lands Act (OCSLA), which requires 27% of the total revenue to be shared with the state.

According to reports released by the MMS in 2006, the Alaska OCS is estimated to contain at least 50 billion barrels of oil equivalent (BOE) at the 50% confidence level. It is unclear what percentage of the estimated 50 billion BOE of technically recoverable resource would fall within the three to six mile region requiring revenue sharing with the state of Alaska. However, the State of Alaska would likely benefit indirectly from any development in the OCS.

In addition to direct revenue sharing the state would be entitled to from any development within three miles of state waters, the State of Alaska would benefit from OCS development through increased employment, increased throughput on the Trans-Alaska Pipeline System (TAPS), increased property tax payments and multiple other sources of revenue enhancement through the multiplier effect. Specifically, increased TAPS throughput would reduce the tariff on a per barrel basis increasing wellhead value for all production including, taxable production on state lands. Further, increased throughput on TAPS would likely assist in extending the operating life of TAPS allowing for increased recovery of oil in North Slope fields that might not otherwise have been recovered.

10) **Produce an estimate of what the price of oil would have to be to cover the cost of the Governor's proposed FY 12 budget were all the provisions of HB 110 in effect currently.**

The Governor's proposed FY 12 budget, with proposed amendments as of February 16, 2011, includes a total authorization to spend of $5,466.2 million of Unrestricted General Funds, after accounting for transfers and savings.

House Bill 110 is written to gradually phase in the provisions of the production tax changes. As such, our analysis shows that there is little to no direct fiscal impact in FY 12 from the provisions of HB 110 other than agency costs of approximately $100,000 to adjust the Tax Division's accounting system. Under the provisions in HB 110, therefore,

the price of oil would have to average approximately $81 per barrel to provide sufficient unrestricted revenue to cover the Governor's budget for FY 12.

If we assume that all of the provisions of HB 110 are in place prior to the start of FY 12, a price of approximately $90 to $92 per barrel would be needed to provide sufficient unrestricted revenue to cover the Governor's budget for FY 12. This figure is calculated using the bracketed annual tax rates included in HB 110, as well as the annual $200 to $400 million estimate for the well lease expenditure credit (which accounts for the range of oil prices in the result). We did not include estimates for provisions that were revenue neutral or for those that did not have a quantifiable impact on our revenue forecast. Our analysis included adjustments to only production tax and royalty; all other revenues were assumed to be the same as estimated in our Fall 2010 forecast.

11) Provide clarification on how the minimum tax is applied.

In response to discussion in the committee hearing, we would like to provide clarification regarding how the minimum tax under ACES is applied. HB 110 would strengthen the minimum tax by adjusting the price thresholds used in calculating the minimum tax.

Under current law, the production tax is the higher of the minimum tax under AS 43.55.011(f) and the tax under AS 43.55.011(e). At an oil price of $21 per barrel, the tax calculated under AS 43.55.011(e) would likely be zero, as the costs of the oil production would overtake any profit from that production. In that case, the minimum tax under AS 43.55.011(f) would apply. The minimum tax under current law would be 3% of gross value at the point of production, or about $0.42 [3% x ($21-$7 transit costs]. Because HB 110 lowers the threshold so that 4% of gross value applies to oil prices at $20 and above, the minimum tax would be 4% of the gross value at the point of production, or about $0.56 [3% x $21-$7].

12) Modeling request from Co-Chair Seaton

Co-chair Seaton has requested that the Department prepare models of ACES and HB 110, using a specific set up assumptions. The result of this analysis will be provided to the committee separate from this letter.

We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Eric Feige
The Honorable Paul Seaton
Co-Chairs, House Resources Committee
Alaska State House
Juneau AK, 99801

February 23, 2011

SUBJECT: Response to Questions regarding House Bill 110 on February 11, 2011

Dear Representatives Feige and Seaton:

The purpose of this document is to respond to questions that were asked of the Department of Revenue during the department's testimony on House Bill 110 on February 11, 2011. The questions and answers to those questions follow.

(1) Could DOR use the regulations process to require information from producers that would help identify the portion of capital spending that represents investment in new exploration and production, compared to maintaining existing facilities and production?

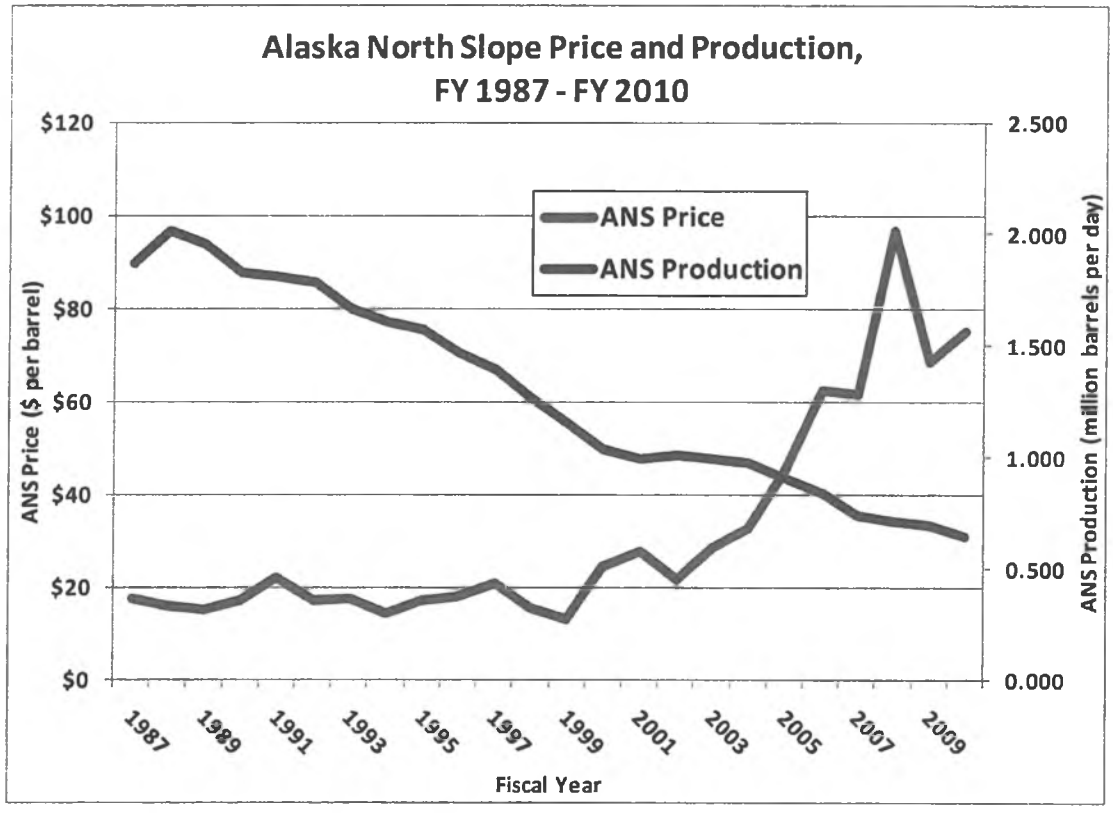
Under current statutes, the Department may request taxpayer information needed to provide forecasts and to administer the production tax, including information needed to audit claimed capital credit expenditures. Current statutes authorize the Department to adopt regulations requiring taxpayers to submit more detailed information about capital expenditures.

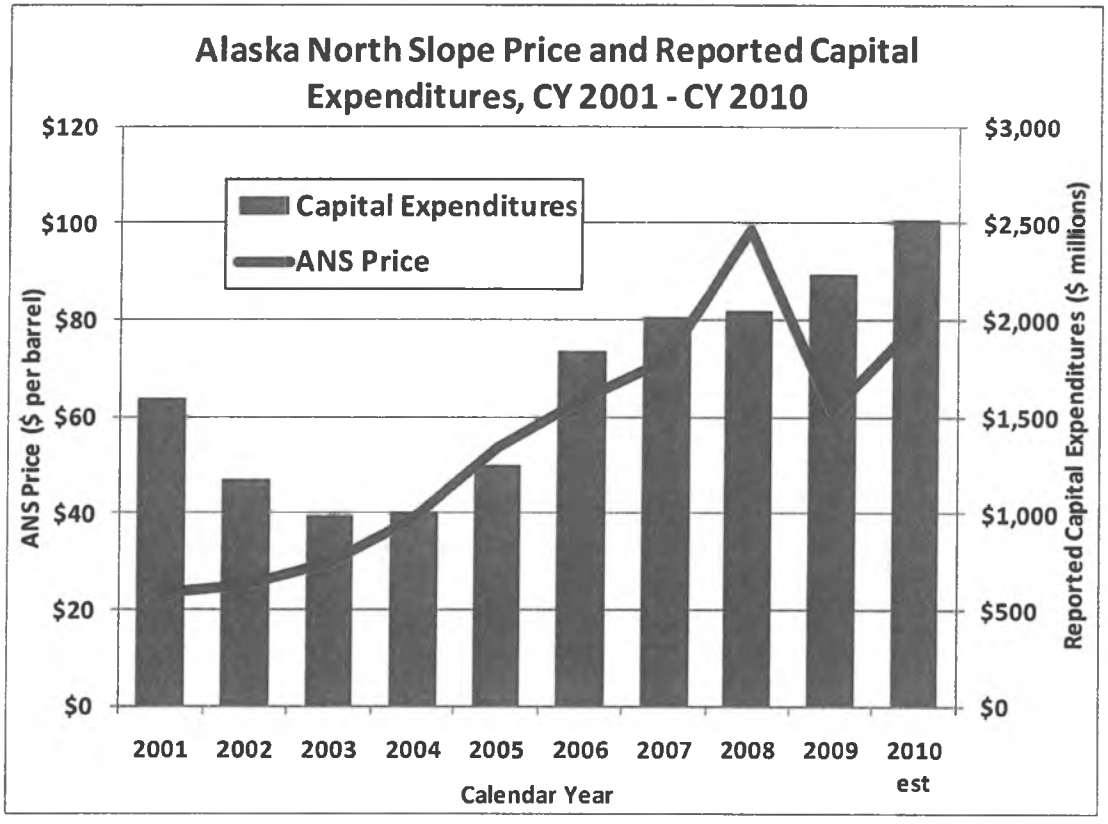
Under AS 43.05.230 (e), the Department would be able to release information about classification of capital spending only to the extent that it could be compiled as a general statistic that would prevent the identification of a particular return or report.

Under AS 43.55.890, the Department can publish information on qualified capital expenditures, as defined in AS 43.55.023, if aggregated among three or more producers or explorers, by month or calendar year and lease or property, unit, or area of the state.

(2) The committee requested statistics comparing the price of oil to historical production and investment in fields

The following two charts present ANS oil prices compared to historical production, and total reported capital expenditures. The Department does not have capital expenditure information for years prior to 2001.





(3) The committee requested information about what companies (other than the "Big 3") have projects that are included in the "under development" and "under evaluation" categories of our production forecast, as well as projects that are not included in our forecast.

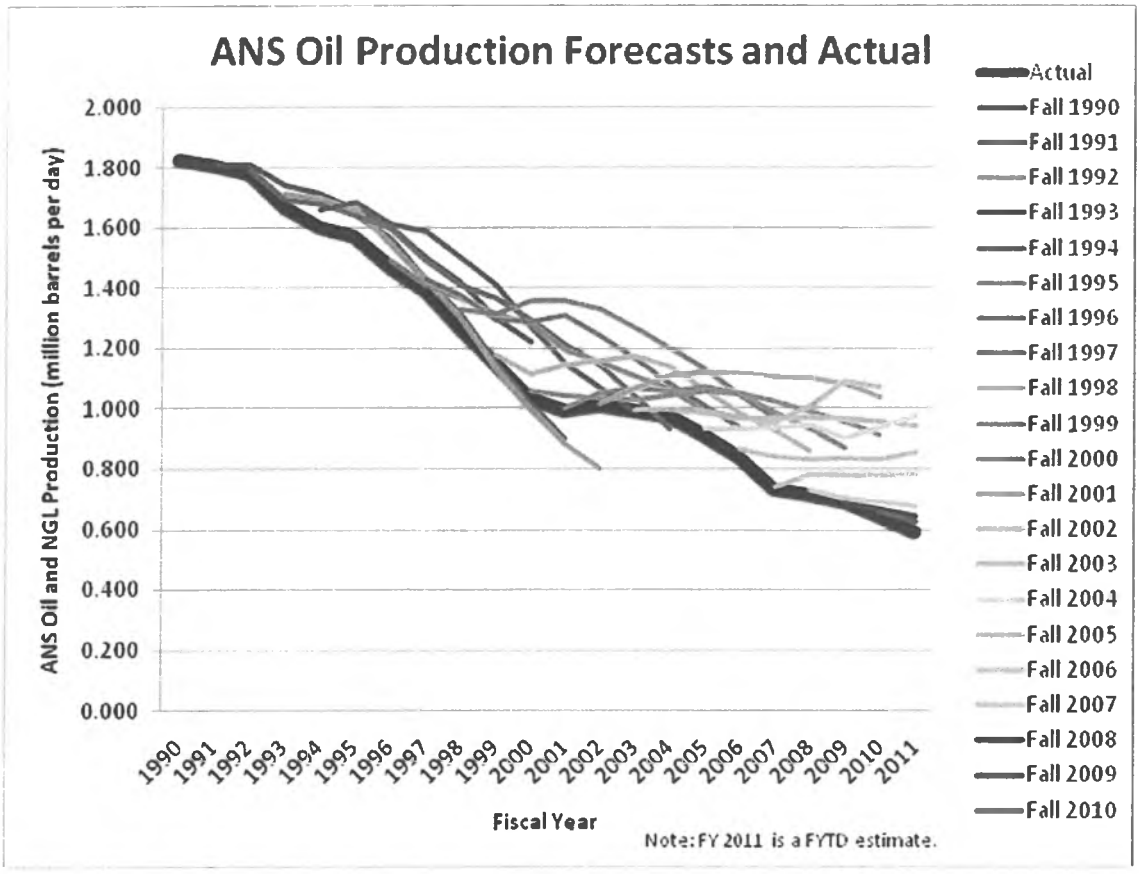
The following projects were identified by our production forecasting consultant as significant projects being pursued by operators other than ConocoPhillips, BP, and ExxonMobil. This list is compiled using public information from the Department of Natural Resources, and reporting in Petroleum News and other media sources.

We include production in our forecast from Badami (operated by Savant), Nikaitchuq (operated by ENI), Oooguruk (operated by Pioneer), and Umiat (operated by Renaissance).

We are not yet including production in our forecast from the Beechy Point Unit (operated by Brooks Range Petroleum), Dewline Unit (operated by Ultrastar), and South Miluveach Unit (operated by Brooks Range Petroleum). We also are not yet including production from Ugnu (various operators), or the Outer Continental Shelf (various operators).

(4) The committee requested a chart showing all DOR's production forecasts since 1990, and actual production.

The chart below shows the Department of Revenue's Alaska North Slope (ANS) production forecasts from fall 1990 to fall 2010. The forecasts are for both oil and natural gas liquids (NGLs).



(5) The committee asked about types of information that other countries require and make available, that we could possibly make available in Alaska.

In 2007, Gaffney, Cline & Associates reviewed reporting and disclosure requirements in other oil and gas producing countries. Their findings were summarized in a memorandum dated October 19, 2007, and a PowerPoint presentation dated October 20, 2007. Both documents will be made available to the committee.

(6) The committee asked if any producers have actually paid the 87% marginal production tax rate.

There was a period of four months in mid-2008 during which oil prices reached levels, when combined with the average level of lease expenditures, produced production tax values for some taxpayers that reached or exceeded the $92.50 per barrel inflection point that is associated with

the 87% marginal production tax rate that has been presented in this committee. The months and associated prices are as follows:

Month. Year	ANS Oil Price ($/bbl)
May 2008	$125.41
June 2008	$133.78
July 2008	$132.87
Aug 2008	$115.98

Although taxpayer confidentiality provisions prohibit DOR from disclosing specific information about any taxpayer, it is fair to say that several taxpayers experienced marginal tax rates at or very near the published 87% rate during these four months.

(7) To Department of Law as well as Revenue: Why is more data available in other countries and based upon existing US laws, why is this information not available to the US. Are there any laws in the U.S. that prevent companies from providing more data?

The data currently made available is based on the statutes and regulations currently in place in Alaska. AS 43.55.890 specifically authorizes the Department to release certain information related to the production tax. Otherwise, the Department may publish aggregated statistics that do not identify a particular project or taxpayer under 43.05.230 (e).

We are not aware of any provisions at the federal level that would prevent Alaska from requiring more information specific to the state.

(8) Provide a break-out of the ANS forecasted production (slide 12 of the DOR 2/11 presentation) that separates production, evaluation, and development by producer.

AS 43.55.890 states, "the department may publish the following information under this chapter, if aggregated among three or more producers or explorers…." Providing production forecast information at the requested level of detail is not allowed under statute.

Sincerely,

Bruce Tangeman
Deputy Commissioner

STATE OF ALASKA

SEAN PARNELL, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

P.O. BOX 111000
JUNEAU, ALASKA 99811-1000
PHONE: (907) 465-2400
FAX: (907) 465-3886

550 WEST 7TH AVENUE, SUITE 1400
ANCHORAGE, ALASKA 99501-3650
PHONE: (907) 269-8431
FAX: (907) 269-8918

February 22, 2011

Senator Thomas H. Wagoner
Senate District Q
Co-Chair: Senate Resources Committee
Alaska State Legislature
State Capitol, #427
Juneau, AK 99801

Dear Senator Wagoner:

Thank you for your letter of February 4, 2011. I appreciate your interest in leasing practices designed to incentivize meaningful exploration and development of state lands and resources.

The Division of Oil and Gas is currently exploring several potential methods for creating just such incentives. Potential changes to our leasing structure must be carefully evaluated for the proper balance of "carrots" and "sticks" to ensure that, while we eliminate non-productive lessees to the greatest degree possible, we do not inadvertently discourage good operators who simply require time to acquire additional resources or information to make exploration and production activities economic.

Options currently available to us under our leasing statute and regulations include the following:

- Various combinations of cash bonus bid, royalty share and net profit share as the bid variables;
- Imposition of a minimum work commitment, made public before the lease sale and which may include penalty provisions if not fulfilled;
- Exploration incentive credits for exploratory wells;
- Exploration incentive credits for geophysical work performed within two years of a lease sale which may be assigned against royalty, rentals or taxes during a limited time period;
- Royalty modification upon application and a definitive finding;
- Lease terms of five to ten years in length;
- Producing leases excepted from statewide acreage limitations;
- Offering tracts in excess of 5,760 acres;
- Immediate, competitive offering of lands returned to the state;
- Rental reductions on returned lands to encourage re-leasing.

Several of these options have been exercised in the past, with varying but less than optimal results. For example, in 1980 the State issued 10-year leases with a work commitment requirement to begin drilling by the end of year five. The leases were terminated, and the State found itself in litigation over requests for extension of the leases. In a current example, 5-year leases were issued, resulting in a premature application for unitization to avoid relinquishment of the leases, on which production may be possible but has not been proven.

Nevertheless, the Division of Oil and Gas is evaluating all available options, as well as possible solutions for which we do not currently have adequate authority, such as changes to our lease qualification requirements. It is our goal to implement the changes we feel will be most effective overall at the earliest opportunity.

The next oil and gas lease sale, on May 24th, will offer the Cook Inlet and Alaska Peninsula lands. While the available timeframe will not allow for radical changes to our leasing structure at this sale, know that all leases that have been relinquished or otherwise returned to the State, including the recently relinquished Cosmopolitan Unit leases, will be offered.

The North Slope, North Slope Foothills and Beaufort Sea lands will be offered in late October, 2011. We believe that the changing industry view of this acreage provides a great opportunity for implementation of changes in our leasing approach based on existing authorities.

I'm happy to discuss this further with you, as is Kevin Banks, Director of the Division of Oil and Gas.

Sincerely,

Daniel S. Sullivan
Commissioner

ALASKA STATE LEGISLATURE

LEGISLATIVE BUDGET AND AUDIT COMMITTEE

Division of Legislative Audit

P.O. Box 113300
Juneau, AK 99811-3300
(907) 465-3830
FAX (907) 465-2347
legaudit@legis.state.ak.us

February 28, 2011

Honorable Members of the
Alaska State Legislature

The Honorable Sean Parnell
Governor
State of Alaska

The Honorable Daniel R. Levinson
Inspector General
Office of the Inspector General
U.S. Department of Health and Human Services

We are pleased to transmit the Single Audit of the State of Alaska for the fiscal year ended June 30, 2010. The audit was conducted in accordance with auditing standards generally accepted in the United States of America; *Government Auditing Standards* issued by the Comptroller General of the United States, and complies with the federal Single Audit Act Amendments of 1996 and the related *OMB Circular A-133* issued by the U.S. Office of Management and Budget.

The report includes an opinion on the basic financial statements of the State of Alaska for FY 10, recommendations on financial and compliance matters, and required auditor's reports on internal controls and compliance, and the Schedule of Expenditures of Federal Awards.

The findings and recommendations included in this report are organized by department and include prior financial/compliance findings not fully corrected by the departments. Our FY 09 Single Audit contained 25 recommendations; this report presents a total of 30 recommendations, eight of which were presented at least in part last year. Included in this year's recommendations are four recommendations made to Alaska Housing Finance Corporation whose audit was performed by other auditors. With your active support and encouragement, we hope to continue seeing improvement in the implementation of these recommendations by the state agencies.

We would again like to acknowledge the professional assistance and cooperation of the Department of Administration's Division of Finance. The division has a strong professional commitment to excellence in the financial accounting and reporting for the State of Alaska. Its continued efforts towards resolving statewide accounting and reporting concerns are commendable.

We would also like to acknowledge the cooperation of all other state agencies involved during the conduct of this audit.

The dedicated staff of the Division of Legislative Audit remains committed to improving the financial accountability of the State of Alaska. Your active involvement is critical to improving that accountability. We are available to assist you in that effort.

Pat Davidson, CPA
Legislative Auditor

DEPARTMENT OF REVENUE

One recommendation was made to the Department of Revenue (DOR) in the *State of Alaska, Single Audit for the Fiscal Year Ended June 30, 2009*. Prior year Recommendation No. 2 is not resolved and is reiterated in this report as Recommendation No. 4.

No new recommendations have been made during the FY 10 statewide single audit.

Recommendation No. 4

DOR's commissioner should ensure staff within its Tax Division implement controls to improve the auditing of oil and gas severance tax revenues.

Prior Finding

In FY 08 and FY 09 significant deficiencies in controls were reported over the auditing of severance tax revenues by DOR's Tax Division. Control deficiencies included insufficient audit oversight, a lack of standard procedures to guide the audit process, inadequate reviews of audits, and untimely reviews and reconciliations of tax returns.

Title 43 of the Alaska Statutes gives DOR the authority to collect tax revenues for the State and to ascertain the correctness of such revenues. The department's main tool for ascertaining the correctness of severance tax revenues is its Tax Division audit section. There are no statutory requirements that DOR's tax auditors conduct their audits in accordance with industry audit standards such as those issued by the American Institute of Certified Public Accountants or the Government Accountability Office. Historically, DOR's audit section has relied upon standard audit programs and supervisor review and oversight to ensure that their audits are timely, accurate and that audit results can withstand the scrutiny of the administrative appeal process and, in some cases, litigation.

With the passage of PPT[2] and ACES[3] legislation, management's controls over the auditing of severance taxes deteriorated. The new laws are more complex to audit. The hiring and retention of experienced, competent audit staff has proven challenging. Delays in drafting PPT and ACES regulations have further disrupted the audit process.

Legislative Audit's Current Position

Significant control deficiencies continued over the auditing of oil and gas severance tax revenues in FY 10. A loss of experienced audit staff during FY 10 compounded the struggles that the audit section was already experiencing.

Our review of DOR's oil and gas severance tax audits and inquiries with DOR staff noted the following deficiencies:

- The division continues to conduct audits without developing standard processes including audit plans and procedures.
- A significant portion of an audit's methodology and results were insufficiently documented.
- The deficiencies in audit documentation forced the tax section to issue a less detailed report than what is issued as part of their standard report format.

[2] *Petroleum Profits Tax* (enacted in August 2006).
[3] *Alaska's Clear and Equitable Share* (enacted in November 2007).

- Audit supervisors did not review and approve audit methodology prior to audits being conducted.
- Audit supervisory reviews were limited, sporadically documented, and only conducted at the end of the audit.

Oil and gas severance taxes, totaling approximately $2.6 billion in FY 10, are a significant source of revenue for the State of Alaska. Insufficient internal controls over the auditing of severance tax revenue may result in the loss of revenue and increase the risk that tax revenue assessments will not hold upon appeal.

We recommend that DOR's commissioner take action to ensure that Tax Division management improves controls over the auditing of severance tax revenues. Specifically, standardized audit processes should be developed and implemented. Auditors also need more oversight and timely feedback during the audit process.

Agency Response – Department of Revenue

Item 1: *The division continues to conduct audits without developing standard processes including audit plans and procedures.*

Response: *We disagree. The division is, and has been, in the process of developing standard processes including audit plans and procedures. Development of standard processes is an ongoing project. As you are aware, the legislature significantly changed the way oil and gas production tax is calculated with the passage of the Petroleum Profits Tax (PPT) in 2006. In 2007, the legislature made further changes to the production tax through the passage of Alaska's Clear and Equitable Share (ACES) legislation. These two major pieces of legislation completely overhauled the production tax scheme and instituted a new tax credit program. The Division has worked diligently over the last four years to implement the changes while continuing to work on audits of tax returns filed under the previous tax structure. Implementation includes not only developing standard processes, but also drafting regulations, hiring and training new auditors, developing tax return forms, establishing tax credit audit and examination procedures, educating taxpayers, and various other duties that accompany the implementation of what is basically a new tax program. You are aware that the oil and gas production tax is administered without automated systems. This means that all processes are performed manually which further strains the Tax Division's limited resources. Although development of standard processes is not yet complete, this does not mean that the Division is not and has not been working on developing those processes.*

Item 2: *A significant portion of an audit's methodology and results were insufficiently documented.*

Response: We agree. The audit in question was started by a highly experienced individual who retired a few months after the audit was opened. The audit was then

transferred to another senior auditor who resigned his position before the audit was completed. The audit was transferred yet again to another senior auditor who had to quickly familiarize himself with all issues within the audit and complete the audit within a short period of time. As stated above, oil and gas production tax audits are conducted without the assistance of automated systems. All audit work, including transaction sampling and testing, is performed manually. Data for this particular audit included over 2 million documents with thousands of transactions per document. During the course of the audit, the auditors manually tested over 1 million transactions. The time it took to perform the manual testing caused the auditor to run out of time to complete proper documentation of audit findings prior to expiration of the statute of limitations. The Tax Division took the position that it was in the best interest of the state to issue the audit with insufficient documentation and with a less detailed audit report than to miss the statute of limitations and, in effect, issue no audit at all. The auditor was instructed to issue the audit, but continue to document audit findings and complete the audit report after the fact. The taxpayer was informed that it would receive a more comprehensive explanation of our adjustments at a later date.

Item 3: *The deficiencies in audit documentation forced the tax section to issue a less detailed report than what is issued as part of their standard report format.*

Response: *We agree. See explanation under Item 2, above.*

Item 4: *Audit supervisors did not review and approve audit methodology prior to audits being conducted.*

Response: *We agree, but disagree that this in an issue. It is not common practice for the Tax Division to approve audit methodology prior to audits being conducted. Audits are assigned to auditors based on their level of experience and their job class. Audits of the largest oil and gas production taxpayers are assigned to Oil and Gas Revenue Auditor IV's (OGRA IV). Under the class specifications, OGRA IV's "serve as lead auditor having complete responsibility for the largest oil and gas production tax . . . audits." The particular audit in question was assigned to an OGRA IV who was required to perform the audit with no day-to-day oversight. Audit methodology is at the auditor's discretion provided, however, that the end result is that the auditor has accurately evaluated tax liabilities. As stated previously in this letter, the Tax Division is still implementing what is essentially a new tax program and specific audit methodology has not yet been defined for these audits.*

Item 5: *Audit supervisory reviews were limited, sporadically documented, and only conducted at the end of the audit.*

Response: *We agree. Audit reviews in all programs are conducted at the end of audits. That is common practice in all audits in the audit profession. We also agree that supervisory reviews were limited and sporadically documented in some of the audits closed during the fiscal year. Again, this was due to the continual implementation of PPT, ACES and the new credit program. Implementation has put a strain on audit resources. Money requested to continue contract audits has been reduced which put further strain on our resources.*

However, management continually communicates with staff on tax issues via meetings and emails, and has discussions about the proper application of statutes and regulations. As a result of the poor documentation of the audit identified in issues 2 and 3, management has instituted the practice of meeting with the audit leads and team members on the largest audits at least once a month to discuss the progress of the audit and any issues that may have arisen that require management input.

The bulk of the findings in the audit report are attributable to:

- *staff turnover, particularly at the supervisory level;*
- *the inability to recruit senior level auditors at current pay levels, despite intensive recruitment efforts over the last two years; this means (1) less experienced auditors are working major audits, and (2) supervisors are having to spend time conducting complex audits, instead of using that time to supervise and developing audit manuals, processes and procedures; and*
- *lack of automated tax processing systems to manage and share information; this dramatically increases the amount of time needed to complete audits and review returns, and thus, siphons resources away from program development.*

As junior auditors in the Production Tax Audit Group gain experience, they will be able to take on more complex and higher volume audit work. This should relieve some of the resource strain, provided these auditors continue working for the Department once they reach senior levels. Over the last three years, great efforts have been made by the Department to obtain an automated tax processing system to manage and share information, but funding for this project has not yet been forthcoming.

Contact Person: *Ginger Blaisdell, Director*
Administrative Services Division
Telephone: (907) 465-2312

Legislative Auditor's Additional Comments

We reviewed DOR's response and nothing in the response persuades us to revise the recommendation.

SB 49
Introduction

Proposed Changes to the Oil & Gas Production Tax

Presentation to the
Senate Resources Committee
Friday, March 11
Alaska Department of Revenue

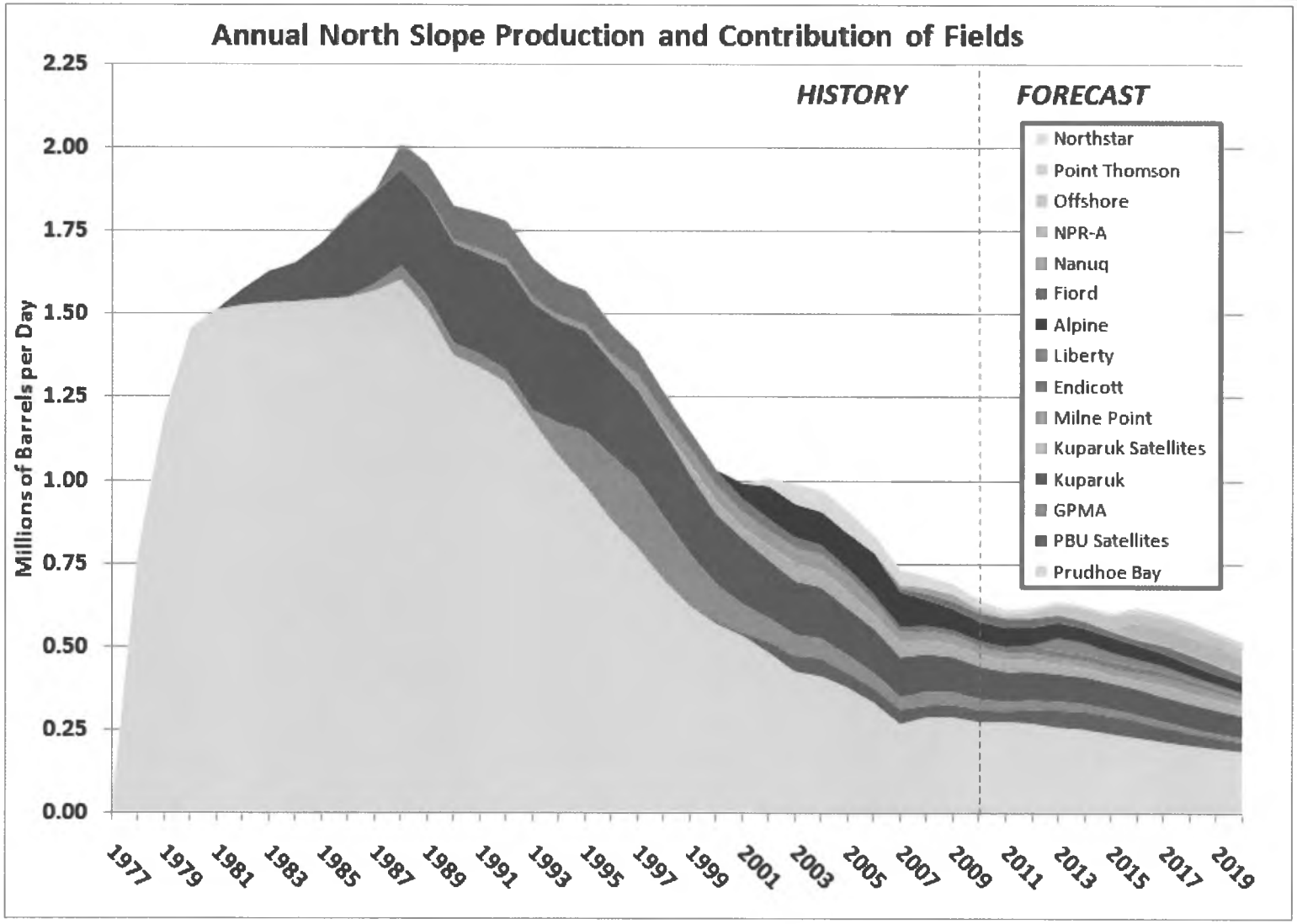
Outline for Presentation

- Goals and Rationale for SB 49
- Production Tax Mechanism
- Components of SB 49

SB 49 Goals

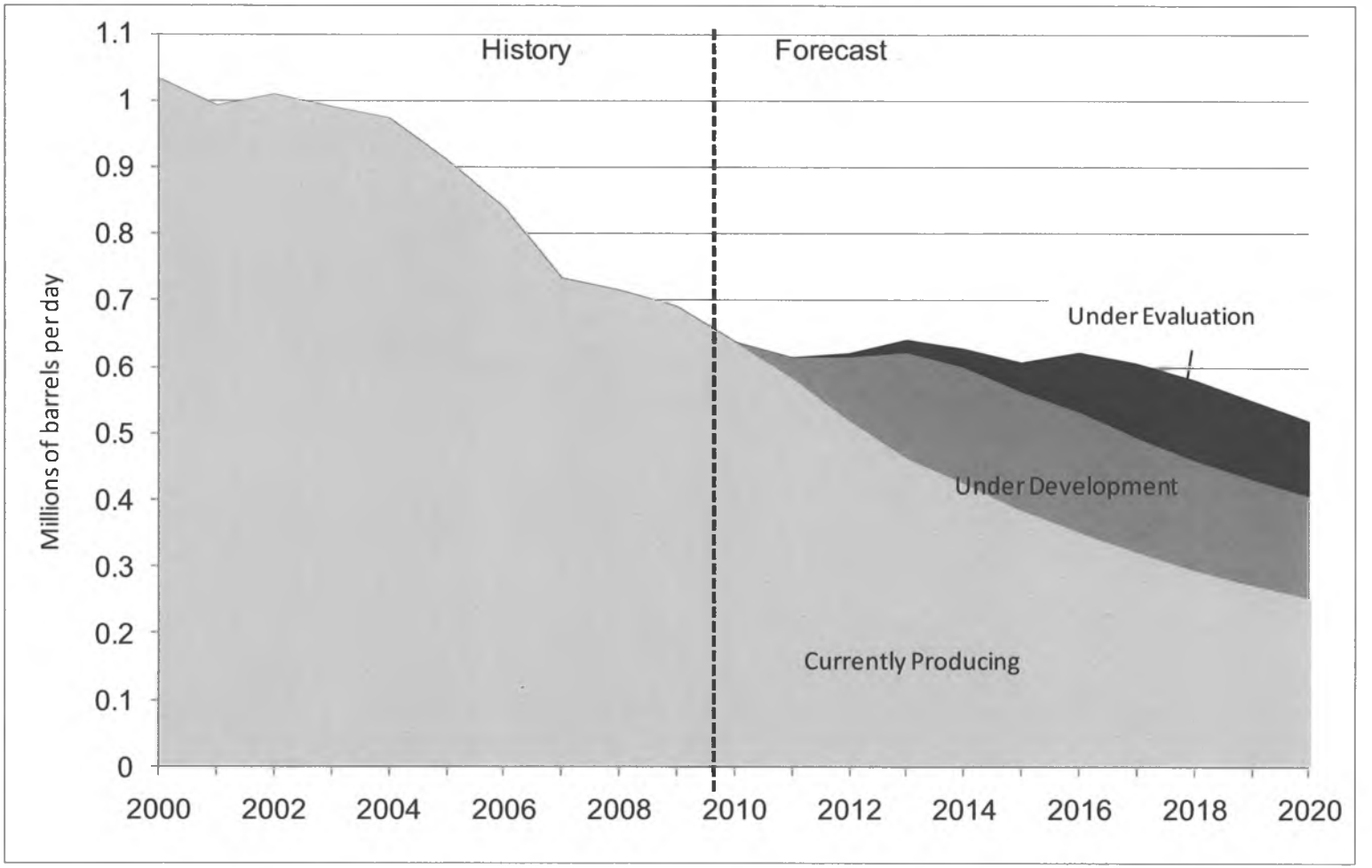
1. Improve investment climate
2. Create jobs for Alaskans
3. Increase production

North Slope Production



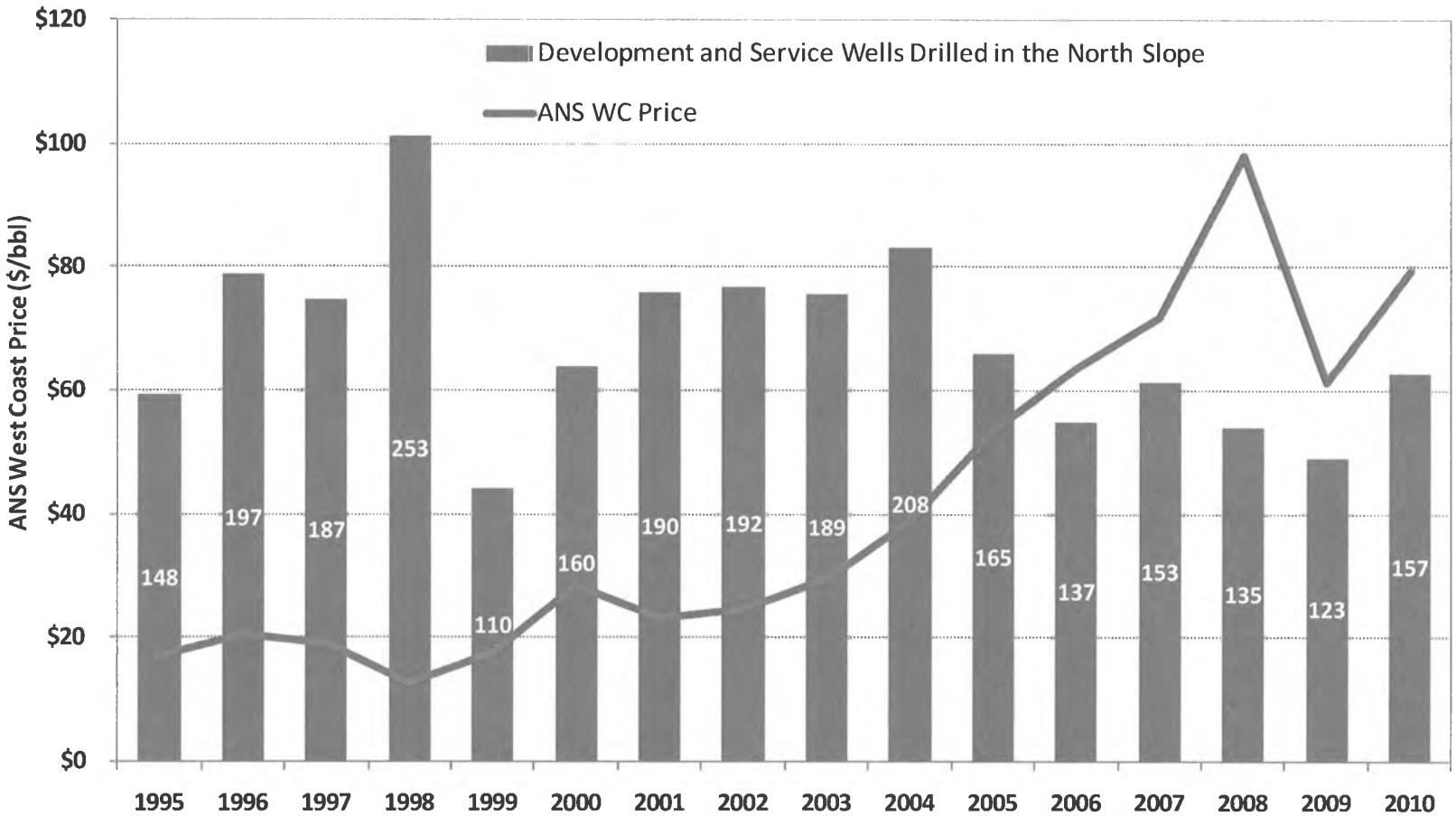
Source: Fall 2010 Revenue Sources Book

Forecasted ANS Production
FY 2010 - 2020



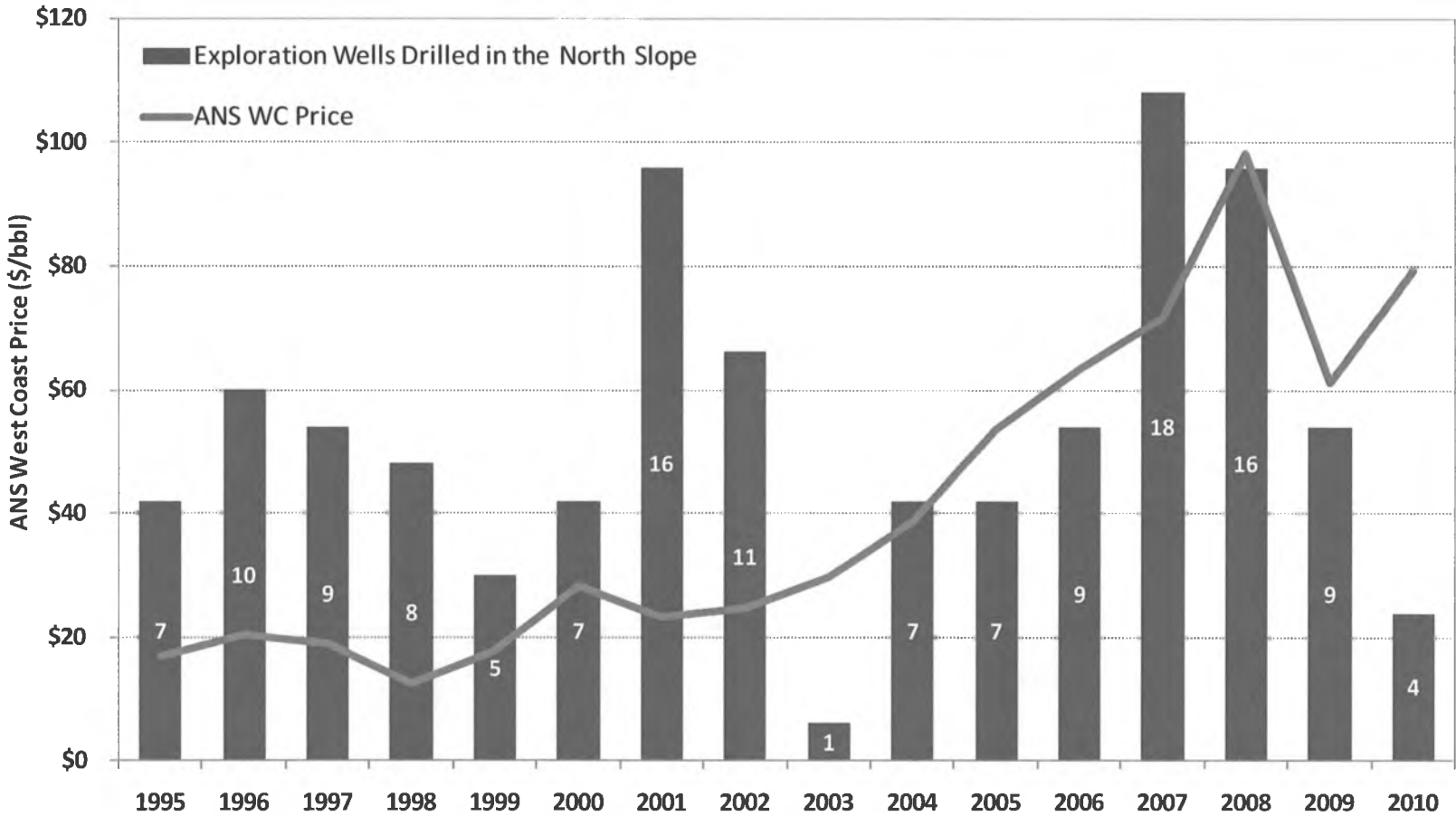
Source: Fall 2010 Revenue Sources Book

North Slope Development Drilling



Source: Alaska Oil and Gas Conservation Commission

North Slope Exploration Drilling

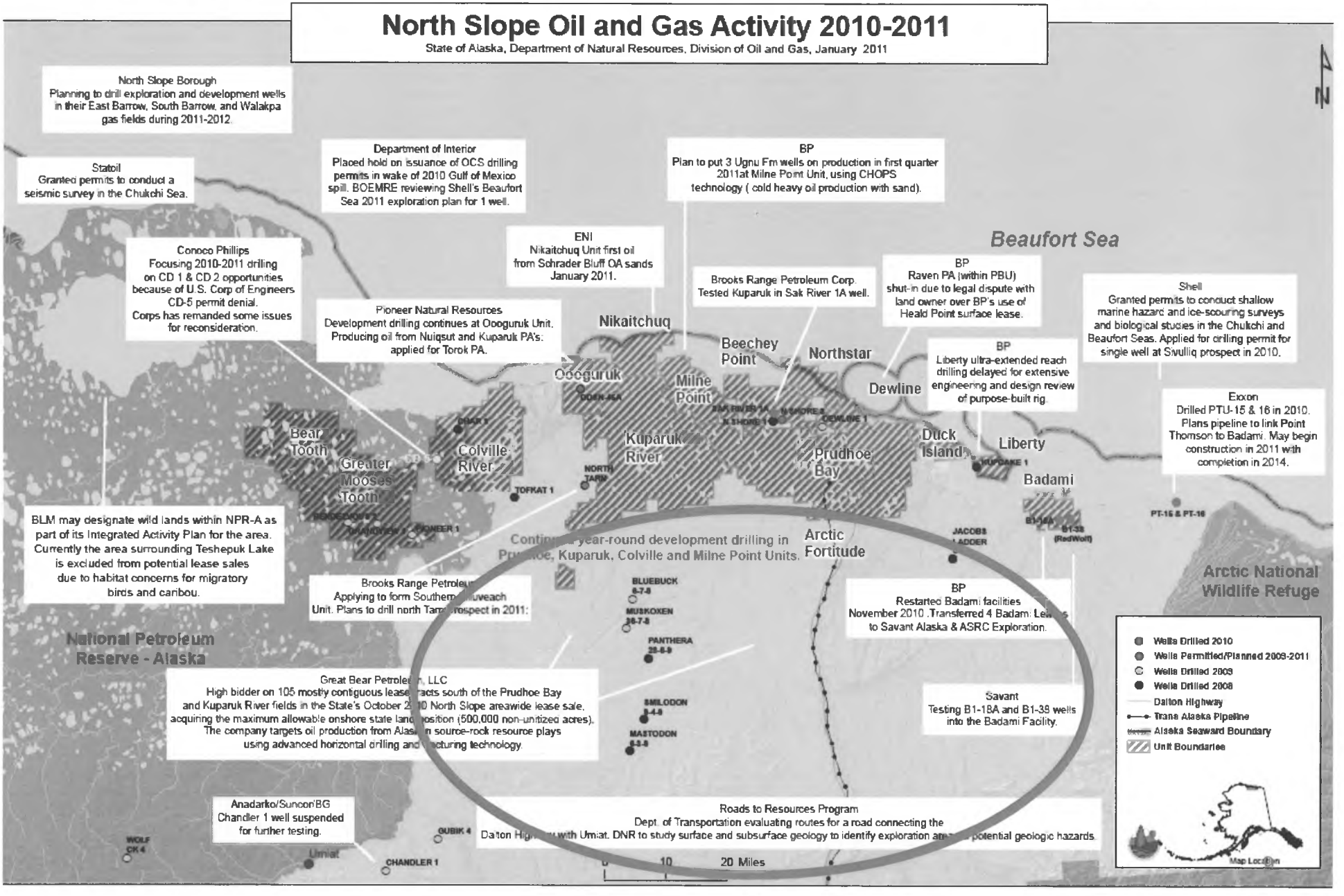


Source: Alaska Oil and Gas Conservation Commission

There's lots of oil left in Alaska…

- Cumulative production through 2010 has been over 16 billion barrels
- Remaining North Slope reserves exceed 5 billion barrels
- Geology-based estimates of total oil volumes are much higher. For instance, we do not include any of the approximately 20 billion barrels in the giant Ugnu deposit, or offshore volumes from the Chukchi or Beaufort Seas, in our forecast

Areas of North Slope are Underdeveloped



How Can We Reverse the Trend?

- Sample Investor Decision Criteria:
  - Prospectivity
  - Geopolitical stability
  - Regulations (access to resources, development permitting, environmental constraints)
  - Operations (existing infrastructure, experienced workforce availability, costs, market proximity)
  - **Tax Regime => SB 49 Focus**

Outline for Presentation

- Goals and Rationale for SB 49
- Production Tax Mechanism
- Components of SB 49

Production Tax Overview

- **Production Tax Value (PTV)** is the market price less transportation costs and allowable lease expenditures
  - Allowable lease expenditures include operating and capital expenditures
- **Base tax rate** of 25% on PTV
- **Progressive Surcharge Rate**
  - Triggered when a company's PTV reaches $30 per barrel
  - $30.00/bbl < PTV < $92.50/bbl = Surcharge adds 0.4% to tax rate for each additional $1 increase in PTV, until combined tax rate reaches 50%
  - $92.50/bbl < PTV < $342.50/bbl = Surcharge adds 0.1% for each additional $1 increase in PTV until combined tax rate reaches the maximum of 75%

Production Tax Overview

How the Tax is Calculated

Production Tax Value (PTV) X Base Tax Rate =	Base Tax
	+
PTV X Progressive Surcharge Rate =	Progressive Surcharge
Pre-Credit Tax Bill	Total Taxes Before Credits
	-
Credits	Credits Applied Against Taxes
Final Tax Bill	**Total Production Taxes Owed**

FY 12 Production Tax Projected

	Per Barrel	Barrels	Value ($ million)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$82.67	622,182	$51.4 / day
Annual Production (bbl)			
Total Annual Production/Value		**227,096,430**	**$18,774.1**
Royalty and Federal barrels		(34,669,890)	($2,866.2)
Taxable barrels		**192,426,540**	**$15,907.9**
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	($2.05)		
TAPS Tariff	($4.67)		
Other	$0.33		
Total Transportation Costs	**($6.39)**	**192,426,540**	**($1,229.6)**
Lease Expenditures			
Deductible Operating Expenditures	($12.86)		($2,474.1)
Deductible Capital Expenditures	($13.14)		($2,528.3)
Total Lease Expenditures	**($26.00)**	**192,426,540**	**($5,002.4)**
Production Tax Value (PTV)	**$50.28**	**192,426,540**	**$9,675.9**
Production Tax			
Base Tax (25%*PTV)			$2,419.0
Progressive Tax Rate = ($50.28-$30) * 0.4% = **8.1%**			
Progressive Tax = (8.1% * PTV)			$785.0
Total Tax Due before credits			**$3,204.0**
Credits Applied Against Taxes			($450.0)
Total Tax after credits			**$2,754.0**

Source: Department of Revenue Fall 2010 Revenue Sources Book, Appendix D
This simple model assumes constant production, price, and expenditures for the entire year; results will differ from our larger model and forecast.
The per-barrel expenditures shown are per taxable barrel and do not reflect expenditures per all barrels produced.

Production Tax Credits Overview

- **Qualified Capital Expenditure Credit** – 20% credit for qualified capital expenditures (40% for well lease expenditures outside North Slope).
- **Carried-Forward Annual Loss Credit** –25% credit for carried-forward annual loss.
- **Small Producer / New Area Development Credit** – Up to $12 million / year for small producers and up to $6 million / year for production outside North Slope and Cook Inlet.
- **Alternative Credit for Exploration** – 30% or 40% of eligible exploration expenditures if certain criteria are met.
- **Cook Inlet Jack-Up Rig Credit** – 80% to 100% credit for first three exploration wells drilled using jack-up rig in Cook Inlet.

Source: Alaska Department of Revenue. Chapter 3 of the Fall 2010 Revenue Sources Book provides detailed information on credits

Outline for Presentation

- Goals and Rationale for SB 49
- Production Tax Mechanism
- Components of SB 49

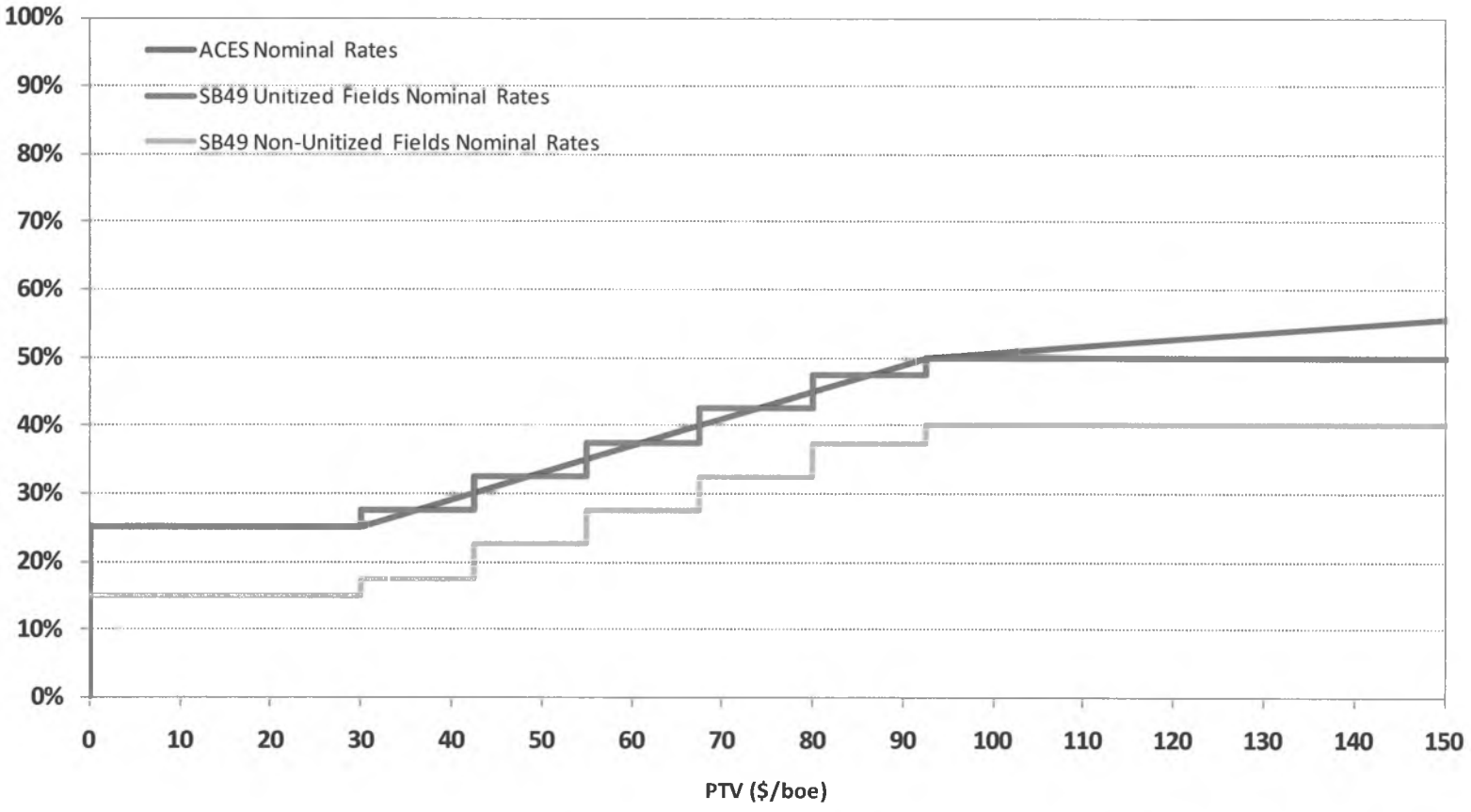
Main proposed changes

Progressivity Rates & Cap	Progressivity defined as discrete brackets, rather than as a continuous function, and applied only to incremental revenue. Maximum progressivity of 25%.	2013
Base Tax Rate	Base tax rate reduction from 25% to 15% for leases or properties properties neither unitized nor producing on or before 12/31/2010.	2013
Tax Credits	Extension of 40% well lease expenditure tax credits to North Slope. Tax credits can be claimed in a single year instead of two years.	2012
Tax Calculation	Yearly tax calculation based on average prices and costs, instead of monthly tax calculation impacted by short term price and cost peaks.	2013

2012 Effective 1/1/2012 for expenditures made before 12/31/2011.

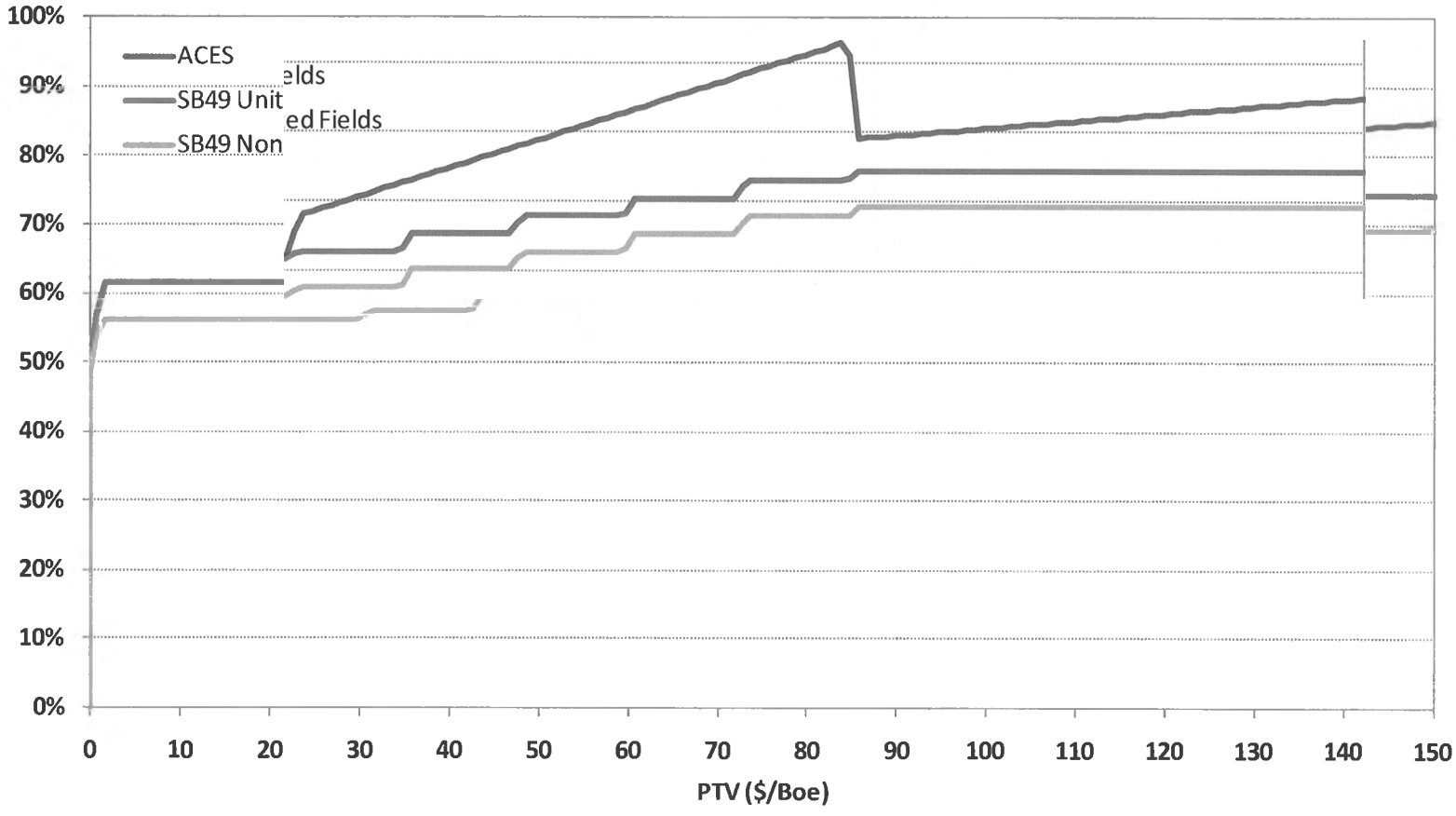
2013 Effective 1/1/2013, applies to production after 12/31/2012.

Nominal Production Tax Rates

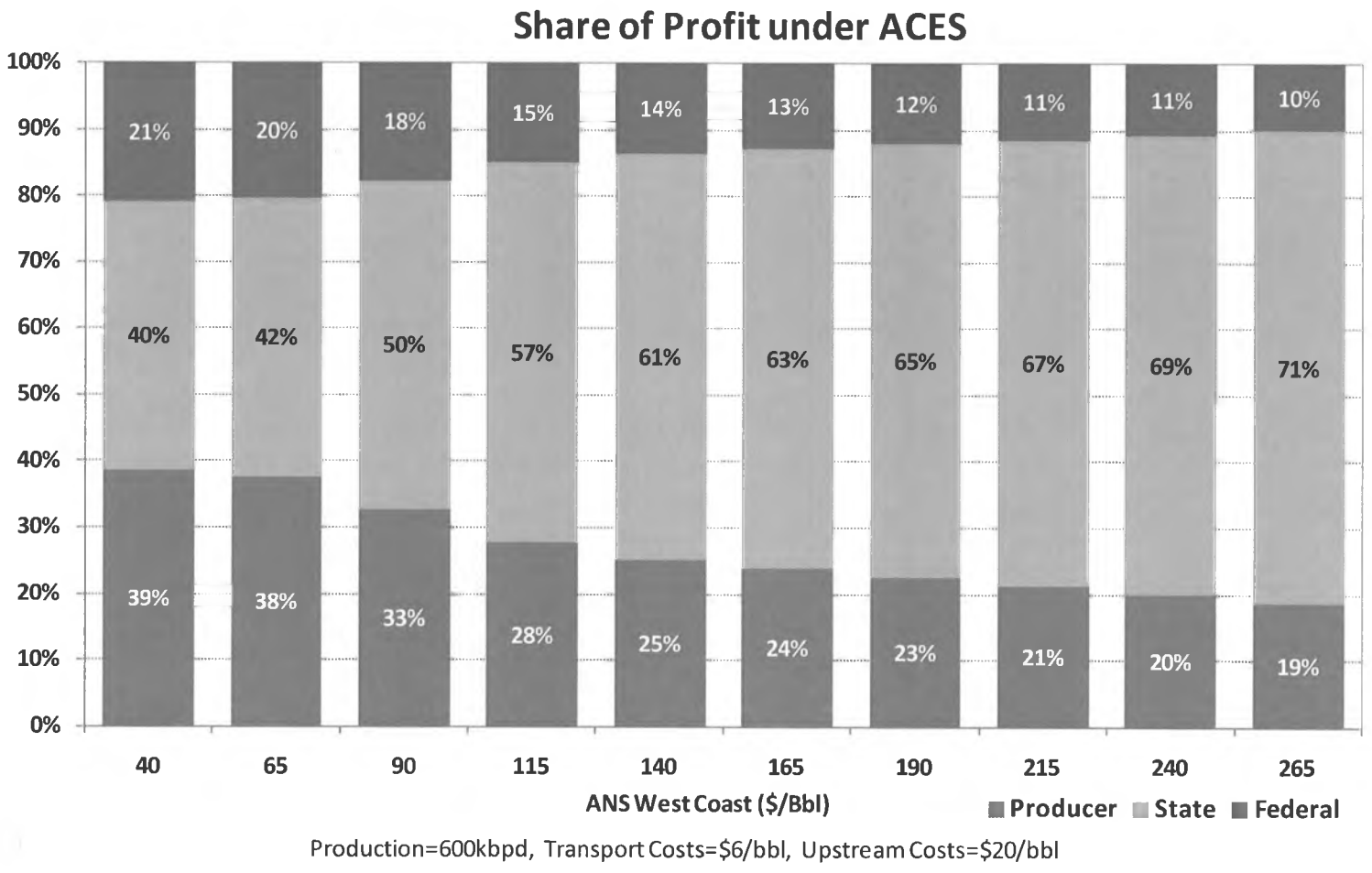


Marginal Government Take

(Incremental Government Take generated by a US$ 1/boe increase in Production Tax Value, with all other conditions remaining unchanged)

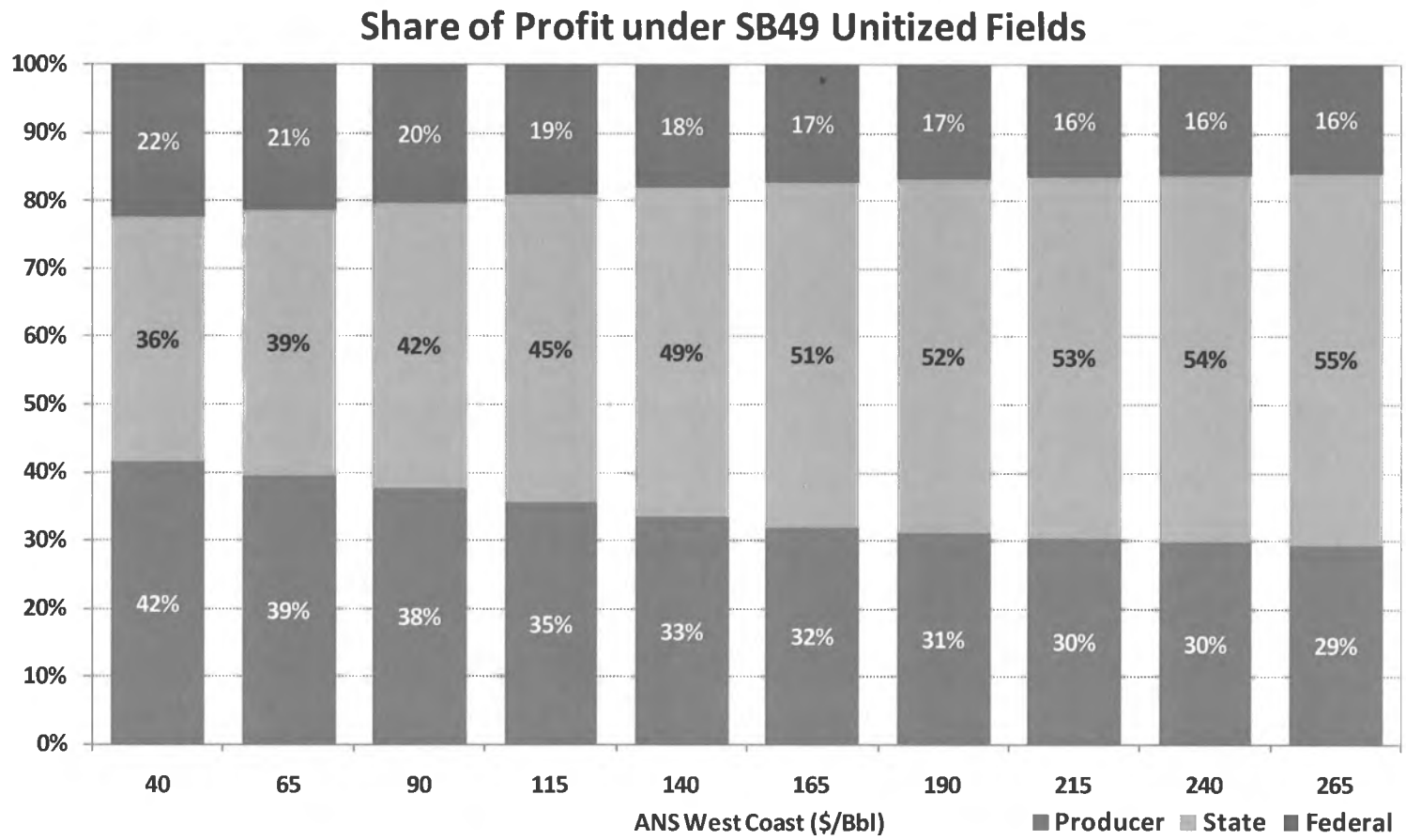


Share of total profit - ACES



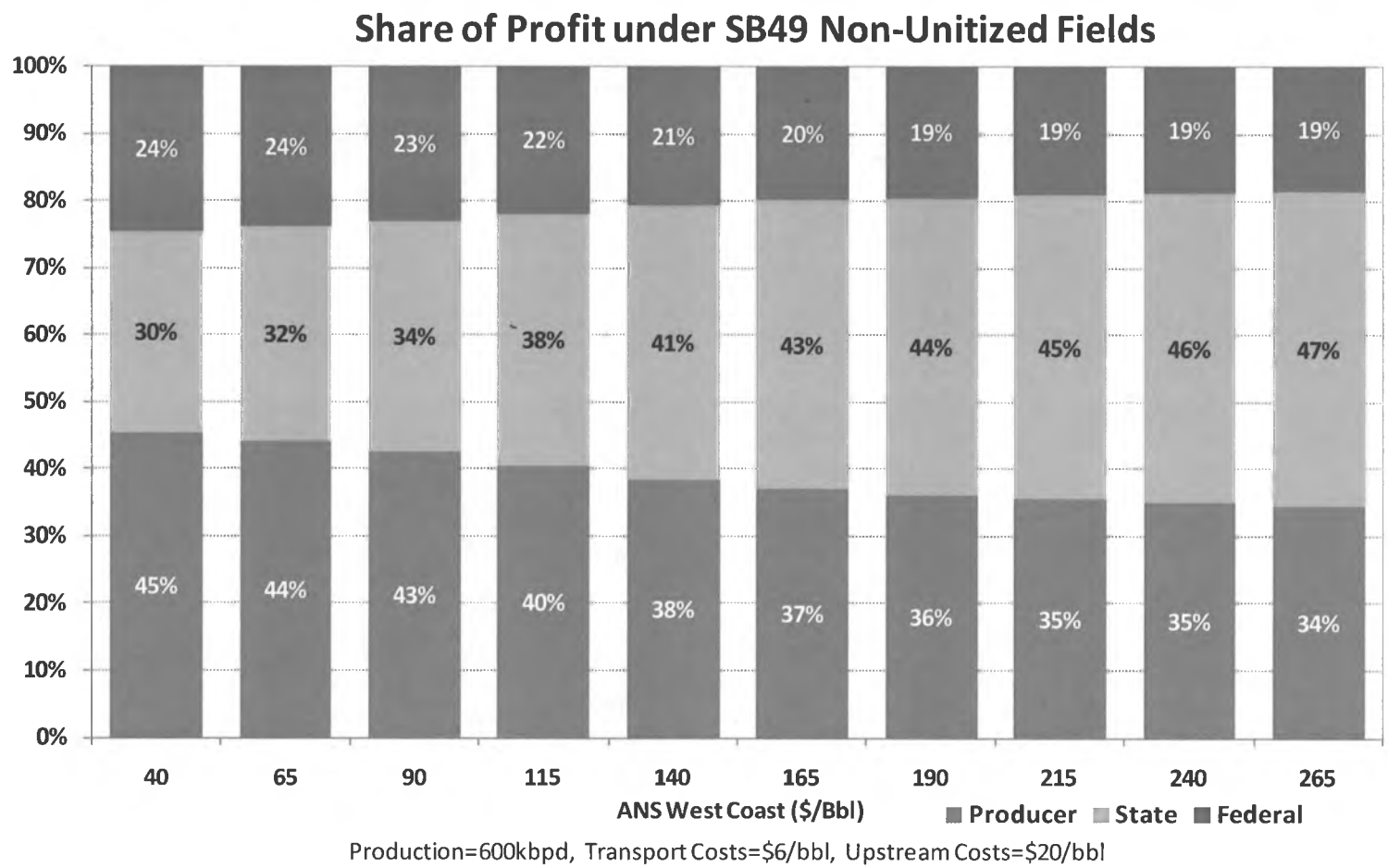
Production=600kbpd, Transport Costs=$6/bbl, Upstream Costs=$20/bbl

Share of total profit
SB49: Unitized Fields



Production=600kbpd, Transport Costs=$6/bbl, Upstream Costs=$20/bbl

Share of total profit
SB49: Non-Unitized Fields



Production=600kbpd, Transport Costs=$6/bbl, Upstream Costs=$20/bbl

SB49 Goals

1. Improve investment climate
2. Create jobs for Alaskans
3. Increase production

Mary Jackson

From: Jeff Stepp
Sent: Monday, March 14, 2011 12:46 PM
To: Andy Moderow; Doug Letch; Genevieve Wojtusik; Jeff Stepp; Katrina Matheny; Mary Jackson; Michael Pawlowski; Michelle Sydeman; Weston Eiler
Subject: Questions asked by Committee Members re: Senate Bill 49 on 3/11/2011

Senate Resources Committee
Questions asked by Committee Members re: Senate Bill 49 on 3/11/2011

1. Please compare royalty rates in Alaska with royalty rates in other states; that is, please compare royalties paid to Alaska as an owner state vs. royalties paid to private land owners in Texas, North Dakota, etc. (Stevens)

2. Slide #3: According to modeling or predictions by the bill sponsor, how many jobs for Alaskans will be created by the passage of SB 49? (Wielechowski)

3. Slide #3: According to modeling or predictions by the bill sponsor, how much will production increase? (Wielechowski)

4. Slide #4: At this point in the life cycle of a mature field, is there an industry norm for the number of new development wells that we might expect to see? (Paskvan)

5. Slide #4: Please explain the standard life cycle of a basin. Please compare the production of Alaska's mature basins with the production of other mature basins. Is the North Slope Production on Slide #4 a normal curve? Would a company build this production decline into a normal investment model? How are investments modeled based on the standard life cycle of a basin? (Stedman)

6. Slide #5: How much of the ANS production that is "under evaluation" is unitized vs. non-unitized? (French)

7. Slide #7: What happened in 2003? (French)

8. Slides #4 – #7: Please compare trends in Alaska with trends in North America and worldwide? (Stedman)

9. Does the Administration believe that there should be, as part of the SB 49 negotiations, a guaranteed increase in exploration and development wells in exchange for the passage of SB 49? (Paskvan)

10. Please explain "duty to produce." (Wielechowski)

11. According to recent ConocoPhillips statements/reports, they have added reserves to their Alaska portfolio. Have those reserves been added to DOR's forecasted ANS production? (Wielechowski)

Jeff Stepp, Legislative Staff
Office of Senator Joe Paskvan
Alaska State Capitol, Room #115
Juneau, AK 99801

email: jeff.stepp@legis.state.ak.us
Direct Line: (907) 465-4747
Office: (907) 465-3709

Fax: (907) 465-4714

Senate District E representing Fairbanks and Fort Wainwright

Mary Jackson

From: Jeff Stepp
Sent: Monday, March 14, 2011 11:29 AM
To: Senate Resources
Cc: Andy Moderow; Doug Letch; Genevieve Wojtusik; Jeff Stepp; Katrina Matheny; Mary Jackson; Michael Pawlowski; Michelle Sydeman; Weston Eiler
Subject: S RES Monday, March 14

Hello Team Resources,

The Committee heard approx 12 of the 23 slides prepared by DOR on Friday. Sen Paskvan asked me to convey that during today's hearing, the DOR will proceed with the presentation that they began on Friday. Therefore, there are no new committee docs for today's Senate Resources hearing.

On Wednesday, the Committee will receive the scheduled presentation by Lenny Dees (Master Auditor, DOR) regarding the oil and gas tax credits.

It appears, then, that the Committee will skip the presentation on the "Oil and Gas Production Tax Status Report to the Legislature" this week; however, it may be re-scheduled for a later date.

Please let me know if you have any questions or comments.

Best,
JS

Mary Jackson

From: Jeff Stepp
Sent: Wednesday, March 16, 2011 1:48 PM
To: Andy Moderow; Doug Letch; Genevieve Wojtusik; Jeff Stepp; Katrina Matheny; Mary Jackson; Michael Pawlowski; Michelle Sydeman; Weston Eiler
Cc: Tangeman, Bruce E (DOR); Bryan Butcher
Subject: SB 49 Back-Up: DOR Slide re Effective Tax Rate on Gross
Attachments: SB 49_Back-Up_DOR Slide re Effective Tax Rate.pdf

Hello All,

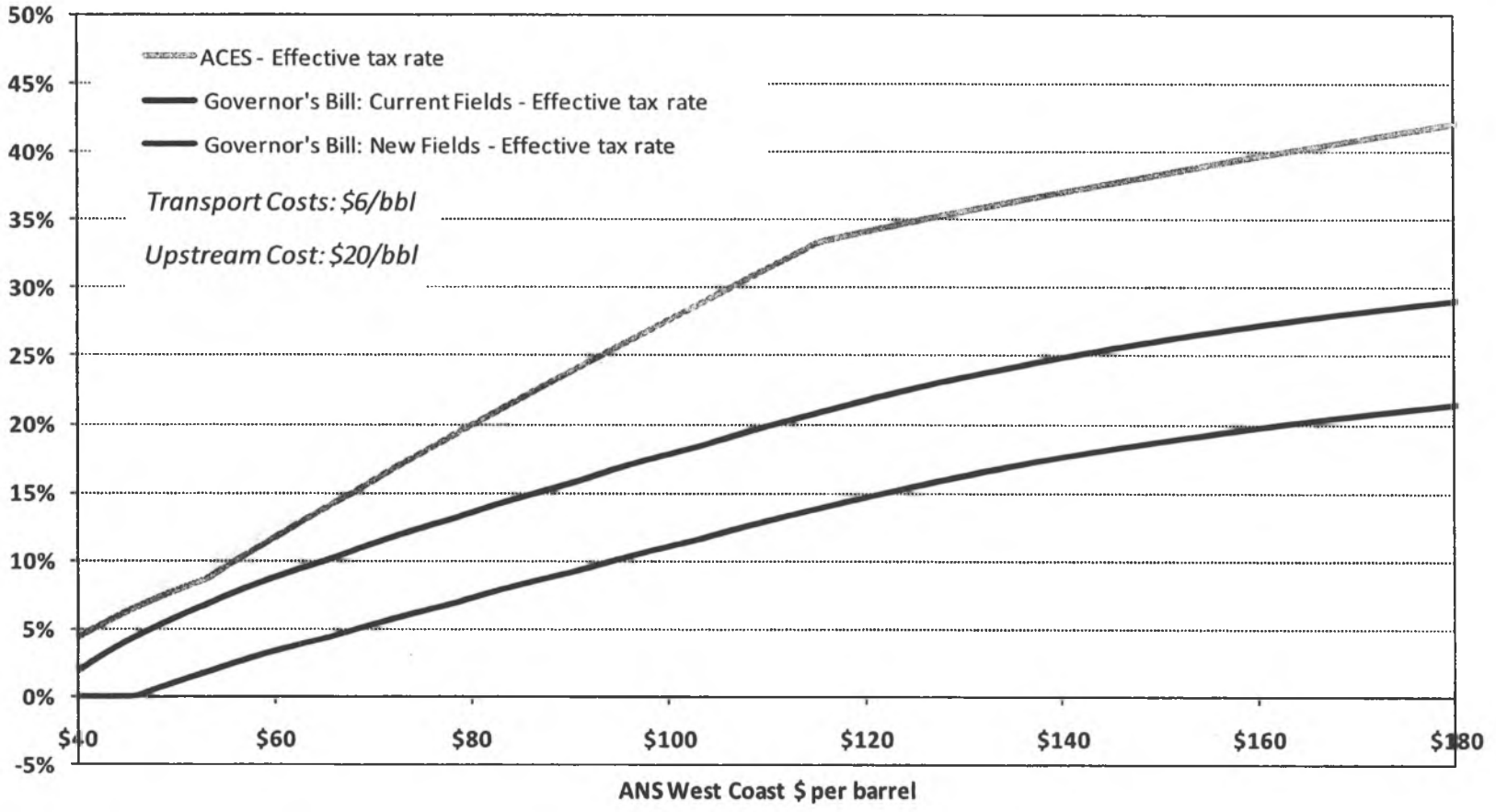
Sen Paskvan was reviewing the attached slide in preparation for this afternoon's Resources Committee hearing. The slide, titled Effective Tax Rate on Gross, was used in a presentation of HB 110 in the House Resources Committee on February 21, 2011.

Sen Paskvan asked me to share the slide with members, as he intends to ask Mr. Dees about this slide today.

Best,
Jeff

Effective Tax Rates on Gross Current law and HB 110

Effective Tax Rate based on Gross Value (After Credits)



PRODUCTION TAX CREDITS

PRESENTED TO THE SENATE RESOURCES COMMITTEE

MARCH 16, 2011

Overview

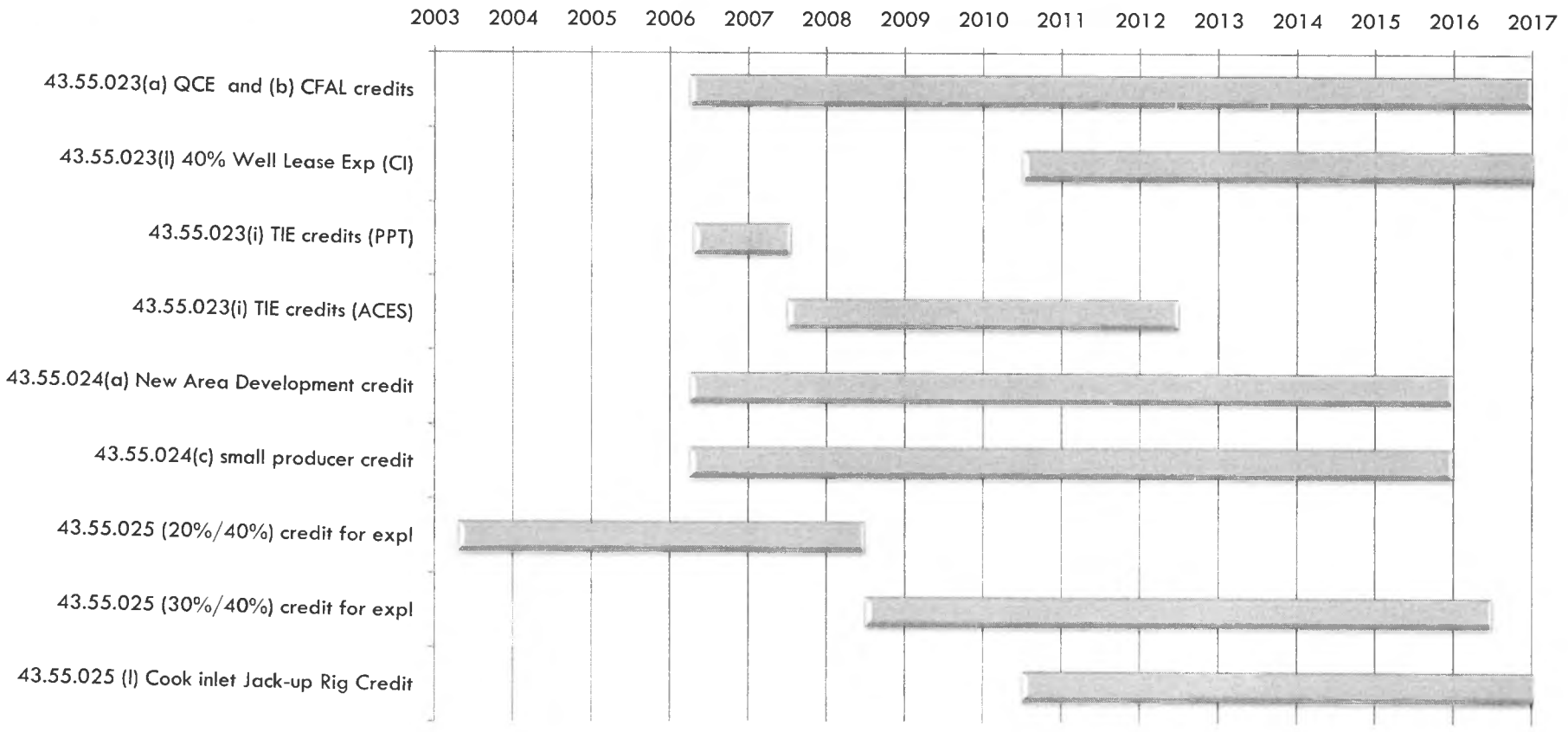
- **Types of Production Tax Credits**
- Credits Applied Against Production Tax Liability
- Transferable Tax Credit Certificates
- Cash Refunds History

Types of Production Tax Credits

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

- Capital Expenditure Credits
- Alternative Tax Credits for Oil and Gas Exploration
- Net Operating Loss ("NOL") Carry Forward Credits
- Transitional Investment Expenditure ("TIE") Credit
- Additional Nontransferable Tax Credits
- Well Lease Expenditures Credit
- Cook Inlet Jack-up Rig Credit

Timelines for Production Tax Credits



Types of Production Tax Credits

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

- **20%** of qualified capital expenditures (QCE)
- QCE include drilling, construction of facilities, new equipment, etc.
- Same expenditures may also qualify for NOL Carry Forward Credit
- Same expenditures do ***not*** qualify for exploration credit
- Must be spread over 2 years (except for expenditures incurred south of 68 degrees North latitude – effective July 1, 2010)
- Credits may be cashed or transferred

Types of Production Tax Credits

Exploration Credits

- Two Main Types
  - Capital Credit for Exploration Activity 43.55.023(a)(2) **(20%)**
  - Alternative Tax Credits for Oil and Gas Exploration 43.55.025 **(30%-40%)**

Types of Production Tax Credits

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

- **20%** of qualifying expenditures related to geologic and geophysical exploration, or in connection with an exploration well
- Requires that data be submitted to DNR
- Must be spread across 2 years (except for expenditures incurred south of 68 degrees North latitude – effective July 1, 2010)
- Same expenditures may also qualify for NOL Carry Forward Credits
- Credits may be cashed or transferred

Types of Production Tax Credits

Exploration Credits

- Two Main Types
  - Capital Credit for Exploration Activity under 43.55.023(a)(2) **(20%)**
  - Alternative Tax Credits for Oil and Gas Exploration under 43.55.025 **(30%-40%)**

Types of Production Tax Credits

Alternative Tax Credits for Oil and Gas Exploration - 43.55.025

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

Types of Production Tax Credits

NOL Carry Forward Credit - 43.55.023(b)

- **25%** of net operating loss
- Applied against tax liability in following year
- Credit based on adjusted lease expenditures which include both operating and capital expenses
- Includes capital expenditures which also qualify for qualified capital expenditure credit under 43.55.023(a)(1) and exploration credit under 43.55.023(a)(2)
- Credits may be cashed or transferred

Types of Production Tax Credits

Transitional Investment Expenditure (TIE) Credits

43.55.023(i)

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

Types of Production Tax Credits

Additional Nontransferable Tax Credit- 43.55.024**(a)**

- Referred to as "New Area Development" credit
- Up to $6 million
- Available for companies producing from leases or properties outside of Cook Inlet and North Slope
- Credit can only be applied against tax liability
- Expires 2016 or 9 years after first commercial oil or gas production if before May 1, 2016
- Credits may ***not*** be cashed or transferred or carried forward

Types of Production Tax Credits

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

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

Types of Production Tax Credits

Well Lease Expenditure Credit - 43.55.023(l)

- 40% of well lease expenditures incurred in the state south of 68 degrees north latitude
- Must be intangible drilling costs or seismic work conducted within the boundaries of a exploration or production unit
- Credit may be applied against tax liability, or certificated and cashed or transferred to another taxpayer

Types of Production Tax Credits

Cook Inlet Jack-Up Rig Credit - 43.55.025(l)

- Credit of 100%/90%/80% of up to $25 million each of exploration expenditures for first 3 unaffiliated persons drilling wells using the same jack up rig penetrating and evaluating prospects in the pre-Tertiary zone.
- Taxpayer obtaining credit may not claim .023 credit for same expenditure
- 50% of credit to be repaid over 10 year period if well yields sustained production

Overview

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

Credits Applied Against Production Tax Liability

Credits may be redeemed in two ways:

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

- Capital Expenditure and Capital Exploration Credits split over two years (except south of 68 degree North latitude – eff. July 1, 2010)
- NOL , TIE, Small Producer and Alternative Tax Credits for Oil and Gas Exploration may all be applied against tax liability in total in a single year

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

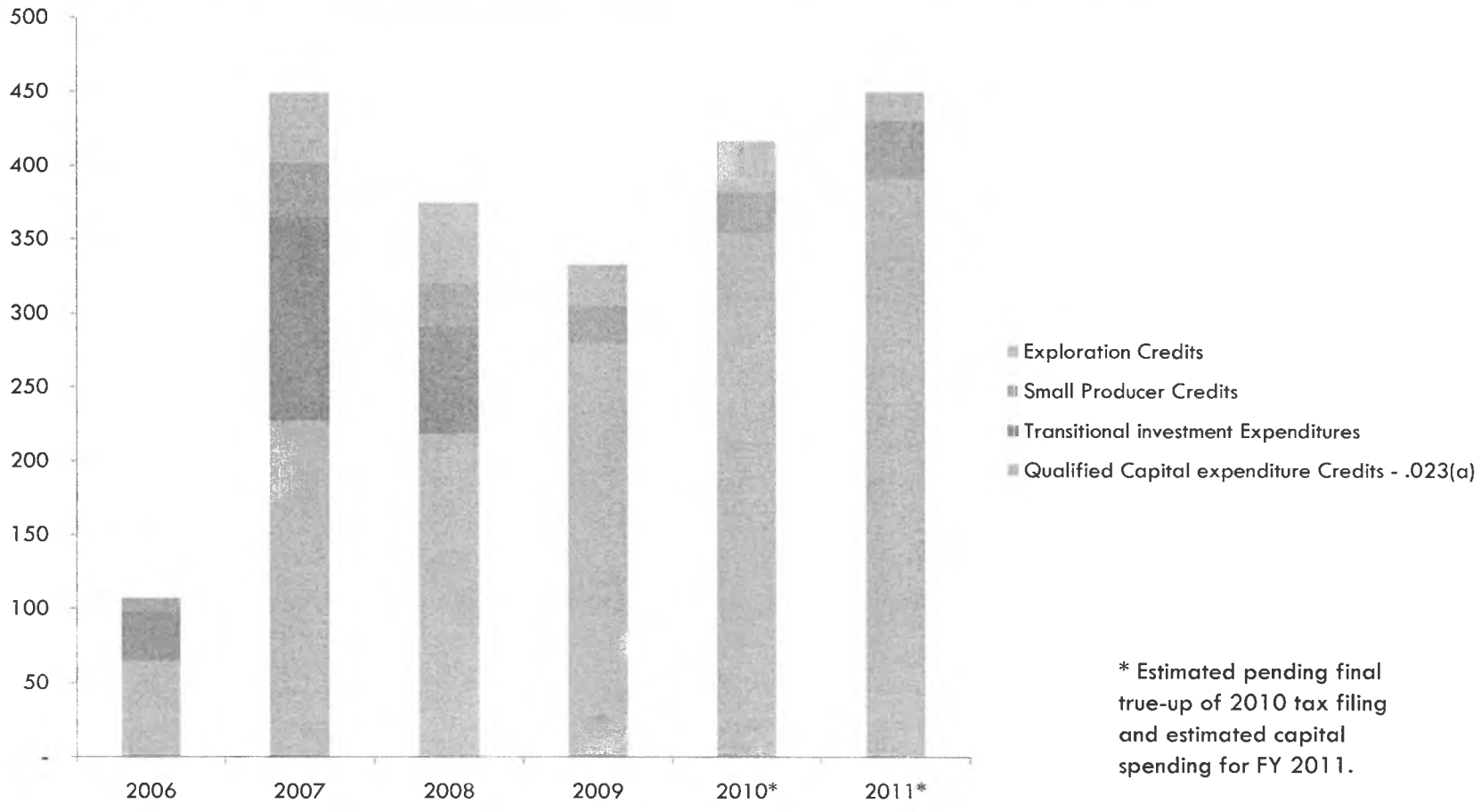
- Capital Expenditure, Capital Exploration, NOL, and Alternative Tax Credits for Oil and Gas Exploration are convertible to tax certificates
- Capital Expenditure, Capital Exploration and NOL Tax Credit Certificates must be applied over two years (except south of 68 degrees North latitude – passed 2010)
- Alternative Tax Credits for Oil and Gas Exploration Certificates can be used in single year

Production Tax Credits Applied Against Tax Liability (Fiscal Year)

	2006	2007	2008	2009	2010*	2011*	Total
Capital Expenditure Credit	65	227	219	280	349	391	1,535
TIE Credits	33	138	73	0	0	0	243
Small Producer Credits	9	37	30	26	28	40	169
Exploration Credits	1	47	55	28	34	20	185
Totals	107	449	375	333	417	450	2,131

* Estimated

Production Tax Credits Applied Against Tax Liability (Fiscal Year)



* Estimated pending final true-up of 2010 tax filing and estimated capital spending for FY 2011.

Overview

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

Transferable Tax Credit Certificates

Companies may also claim tax credits by applying for a Transferable Tax Credit Certificate (TTCC)

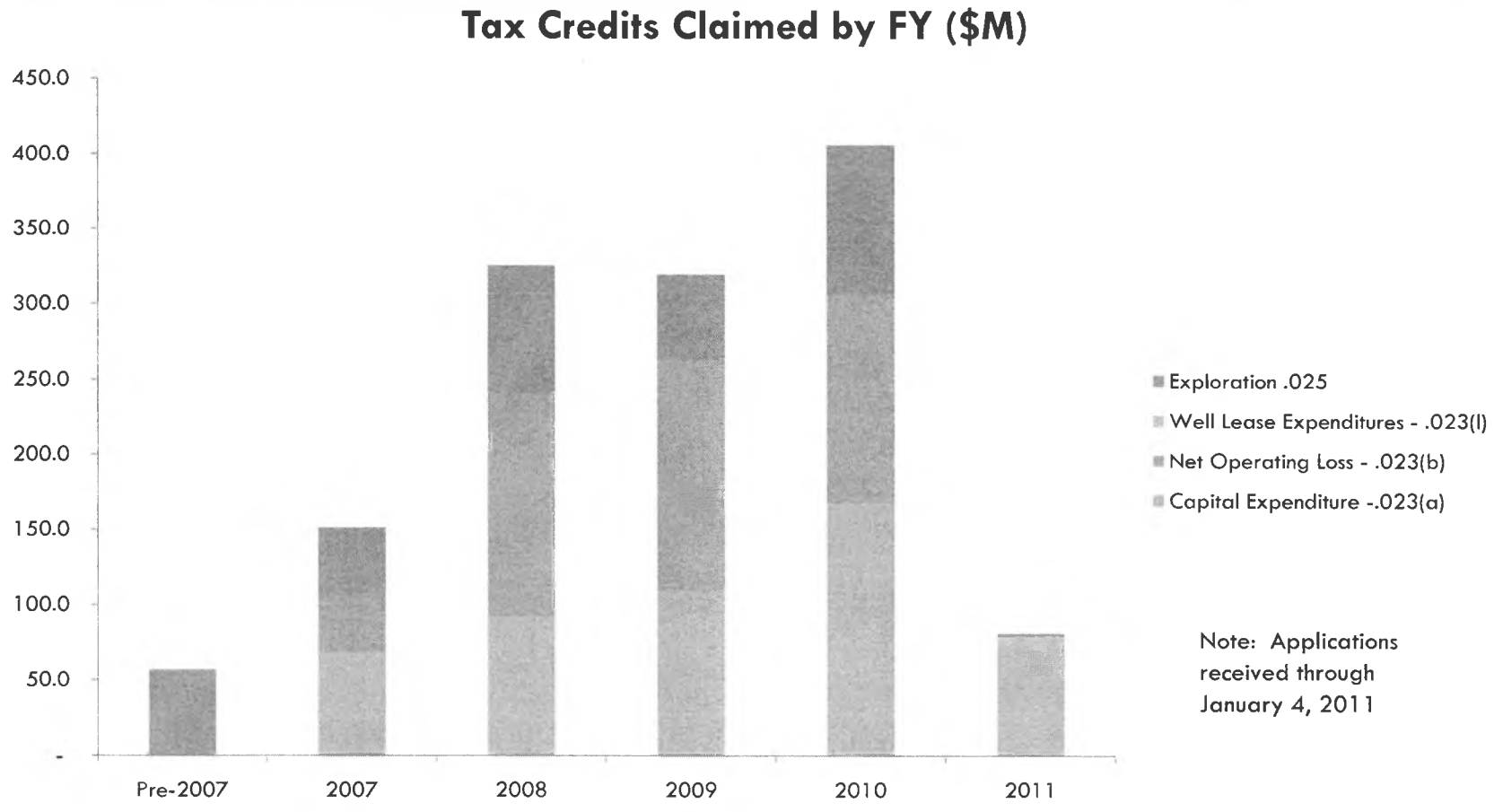
- Available to companies (explorers) with no tax liability to which credits can be applied
- Tax Credit Certificates under 43.55.023(a) and (b) must be split or applied over two years (except credits issued for expenditures incurred south of 68 degrees North latitude effective July 1, 2010)
- May be transferred to another taxpayer or cashed with the state

Production Tax Credits Under AS 43.55 Claimed by FY ($M)

Credit Type	Pre-2007	2007	2008	2009	2010	2011*	Total
Capital Expenditure - .023(a)		68.2	91.7	109.6	168.0	72.8	510.3
Net Operating Loss .023(b)		38.1	148.5	153.5	138.7	.2	479.0
Well Lease Expenditure - .023(l)						5.8	5.8
Exploration -.025	48.3	44.9	85.5	56.6	99.5	2.4	337.2
Total	48.3	151.3	325.6	319.7	406.2	81.3	1332.4

* Applications received through January 4, 2011.

Transferable Tax Credit Certificates



Transferable Tax Credit Certificate Activity by Fiscal Year ($M)

	Pre-2007	2007	2008	2009	2010	2011*	Total
Issued	16.2	99.9	130.8	308.2	361.3	191.5	1,107.9
Refunded		(54.6)	(54.1)	(193.1)	(250.5)	(299.3)	(851.6)
Transferred/ Applied to Taxes	(12.3)	(40.0)	(46.6)	(20.0)	(1.2)	(62.7)	(182.8)
Activity by year	3.9	5.2	30.1	95.1	109.6	(170.4)	
Transferable Tax Credit Certificates Outstanding	3.9	9.1	39.2	134.2	243.9	73.4	73.4

*Payment activity through February 4, 2011.

Overview

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

Cash Refunds History

Cash Refunds Governed by AS 43.55.028:

- To cash must be usable against tax liability
- Must show subsequent (24 months) QCEs or lease bids equal to cash sought (repealed in 2010)
- Have a zero tax owed in current and past years
- Have no more than 50,000 BOE/d

Cash Refunds History

Tax Credits Purchased

By fiscal year ($M)

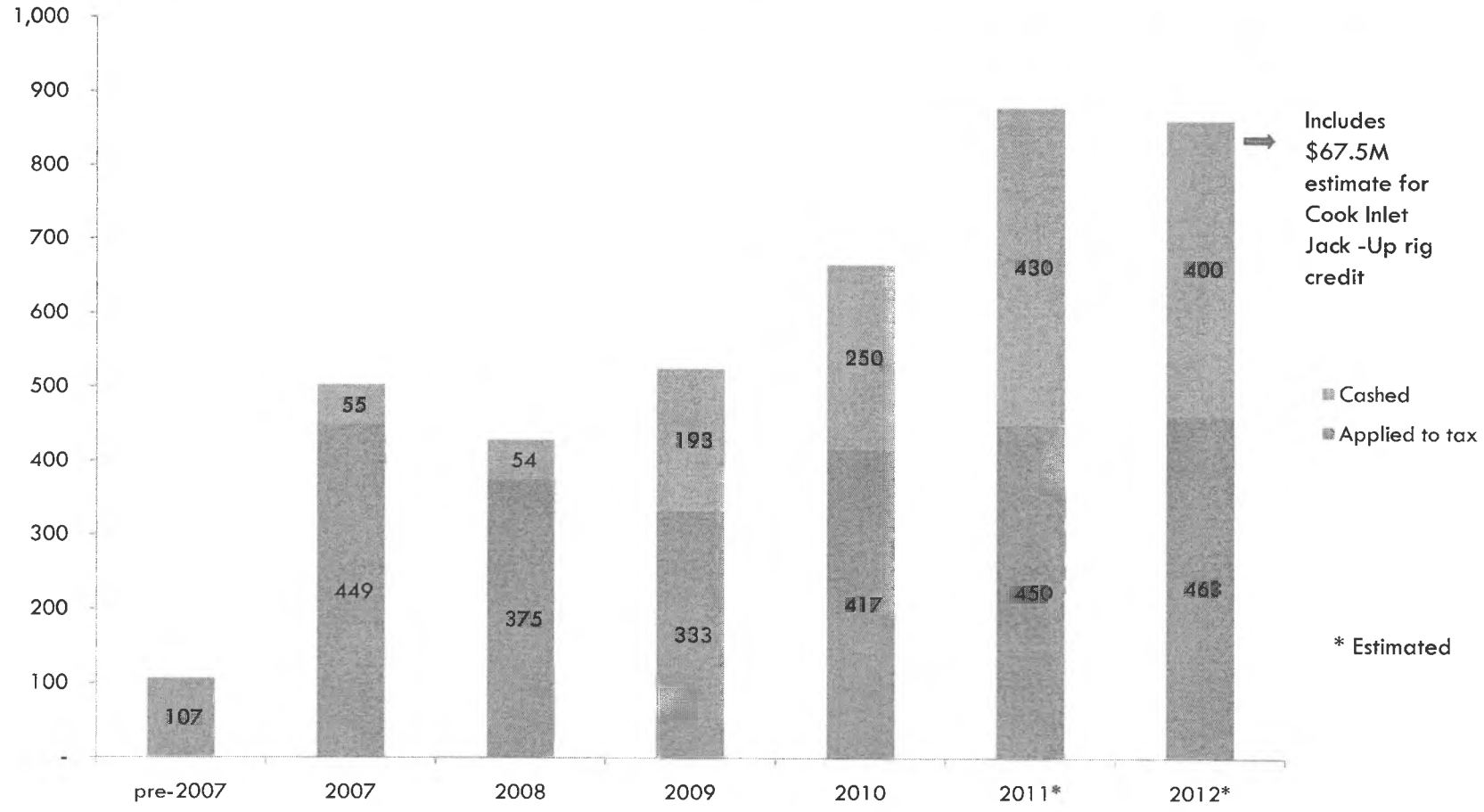
2007	$ 54.6
2008	54.1
2009	193.1
2010	250.5
2011 (thru 02/04/11)	299.3
TOTAL	$851.6

Cash Refunds History

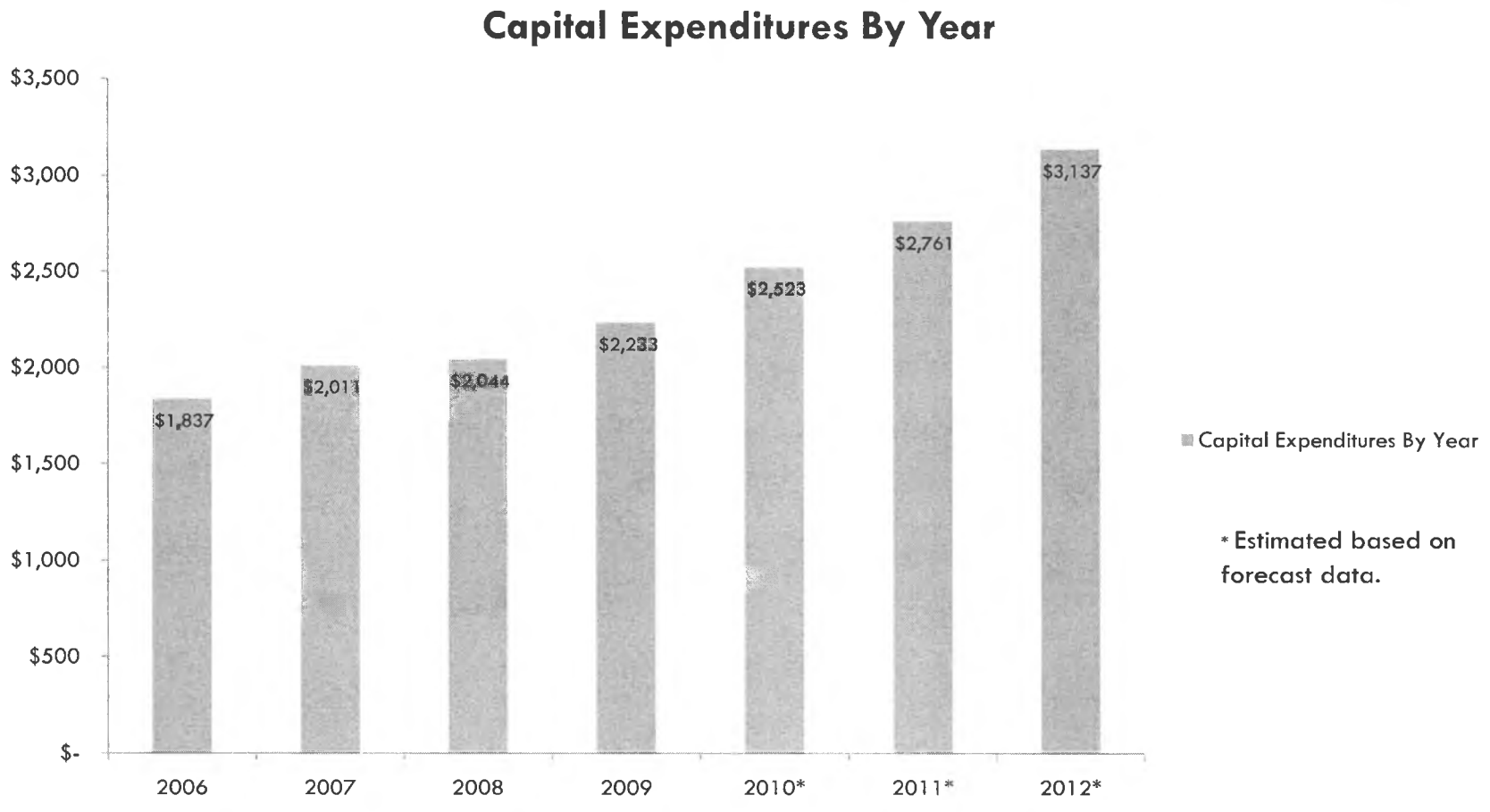
Oil & Gas Tax Credit Fund

Appropriations -	$ 904	M
Tax Credit Purchases (TC Fund)	(772)	M
Tax Credit Purchases (GF)	(79)	M
Interest Earned	22	M
Balance	$ 75	M

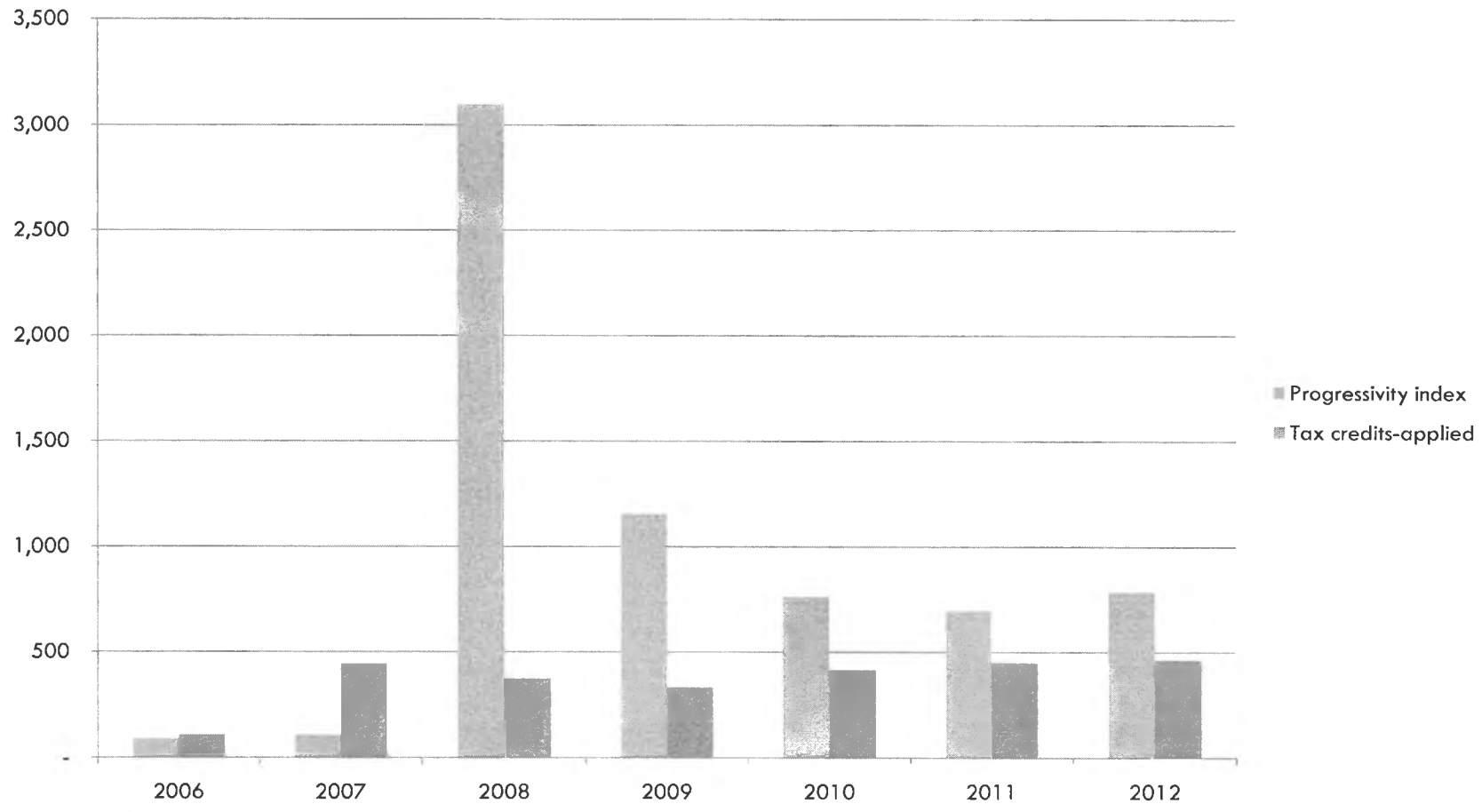
Impact of Production Tax Credits
Total State Stimulus



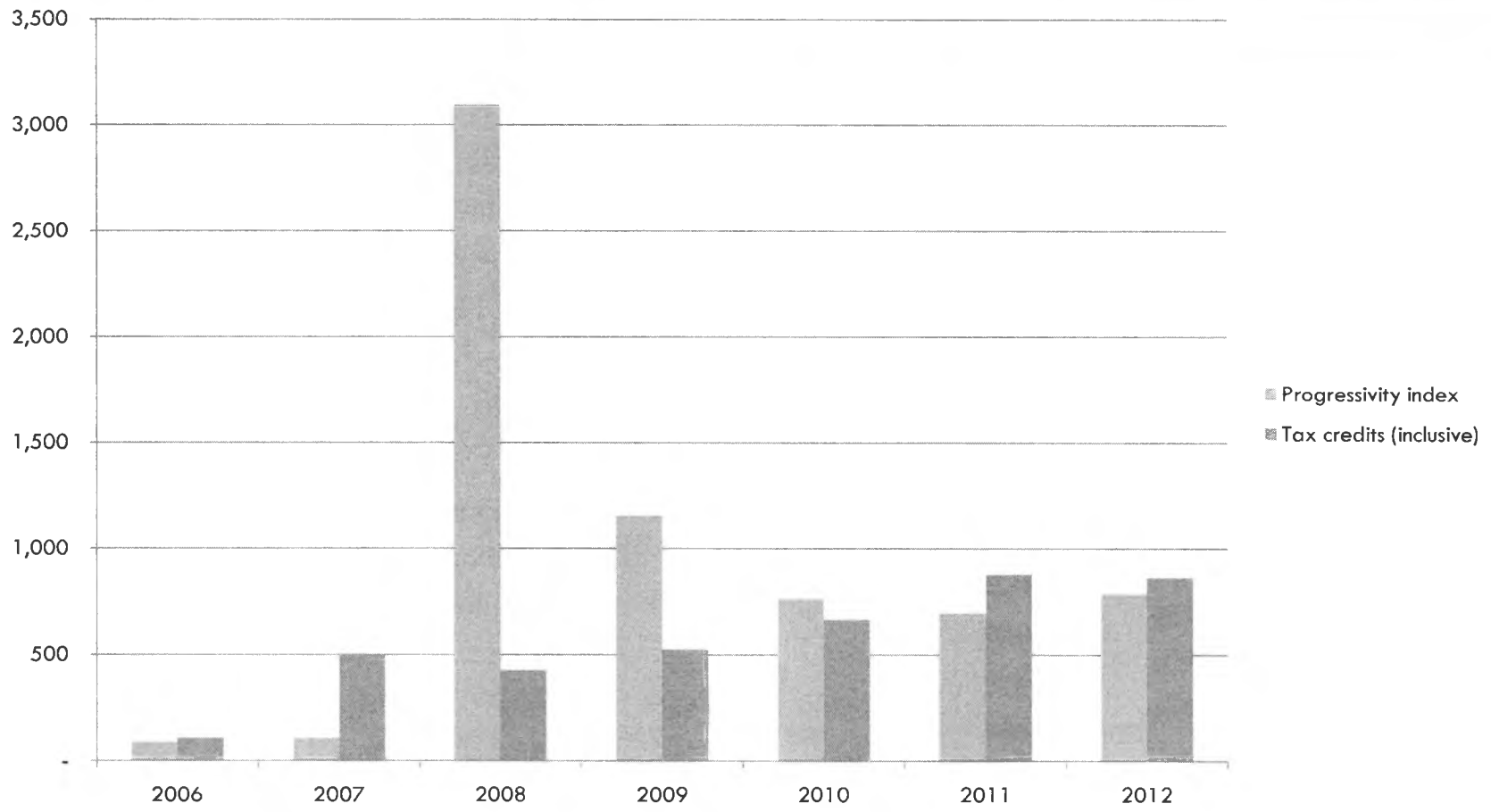
Capital Expenditures by Year ($M)



Progressivity Index versus Production Tax Credits Applied



Progressivity Index versus Total Production Tax Credits



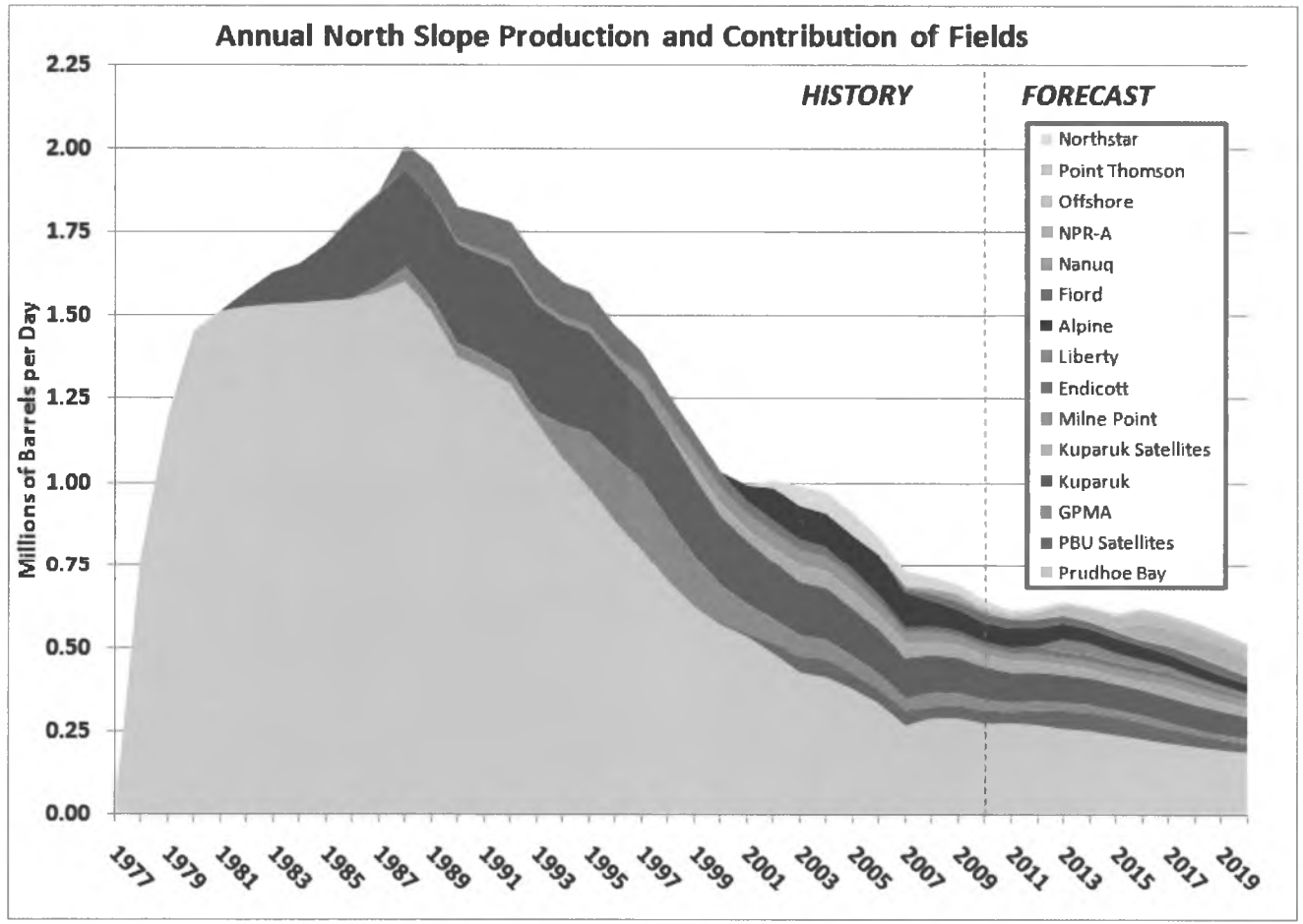
GCA
Gaffney, Cline & Associates

Issues In Considering SB49

Senate Resources Committee
March 18, 2011

A Question Of Nature or Nurture ?

GCA
Gaffney, Cline & Associates



Source: Fall 2010 Revenue Sources Book

Fiscal System Design

GCA
Gaffney, Cline & Associates

- **2 Parts *Art* to every 1 Part *Science***
- **What works well for one state/country does not necessarily work for another**
  - Over time it may actually no longer work optimally where it once did
- **Influencing factors include (but not limited to):**
  - GDP & GDP/Capita
  - Energy as % of GDP
  - Infrastructure Availability
  - Infrastructure Capacity
  - Competition from elsewhere
  - Hydrocarbon Basin Maturity
  - Skilled Local Labor Force
  - H S & E
  - Institutional Capacity

The "Pressure" to Change

GCA
Gaffney, Cline & Associates

- Fiscal system change occurs generally because:
  a) Governments want their perceived fair share; or
  b) Attract Investment/Industry

★ *The two are not always the same or even nearly the same*

- Request for change justified by:
  - 'Objective' Calculations – model results based on a large number of assumptions
  - 'Subjective' Calculations – experts assessing major changes in direction or behavior

Creating "Best" Fiscal Systems

GCA
Gaffney, Cline & Associates

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

- **There are far more systems in place than there are countries with petroleum legislation**
  - Many areas of similarity
  - Many areas of difference
  - Different 'vintages' can be active at the same time

Where is Alaska today?

GCA
Gaffney, Cline & Associates

1. Production continues to decline despite unprecedented prices
2. TAPS (either operational limit or economic limit)
3. Heavy oil potential under assessment
4. New plays on the verge of being unlocked?
5. New resources viewed by some as "stranded"
   - Access to infrastructure
6. Logistical challenges and high costs remain
7. Long lead times to bring on new fields
8. Players
   - Incumbents and new entrants

Future Scenarios for Alaska

GCA
Gaffney, Cline & Associates

Hard to predict the future in a nice tidy narrow range

- Requires many assumptions that leads to '*noise*' and time and focus taken away from discussing and understanding root causes and the real issues
- Lack of planning data

What are the possible upside/downside scenarios to consider in looking to change ACES?

- Upside – Reduced taxes leads to investment in new resources and technologies that keep TAPS flowing through 2050
- Downside – Reduced taxes, still no new fields brought on line, TAPS reaches limit in the 2020's

The Importance Of Oil To Alaska

GCA
Gaffney, Cline & Associates

- **Alaska (2010)**
  - Oil taxes and royalties accounted for almost 90% of unrestricted General Fund revenue

- **Big 3 (2010)**
  - Alaska profits and production accounted for 5% - 30% of their "economy"

Alaska remains very important to the big oil companies .... but the relative importance to them is much, much less than it is to the State

Some Big Questions ...

GCA
Gaffney, Cline & Associates

- Is it necessary to change ACES ?

  Will I get +/- the same investment and production anyway if I do not ?

  If I get more investment and production, how much more ?

  Will TAPS obtain oil from "somewhere" to keep flowing, regardless ?

  How long can I "delay" before being comfortable that I know the likely outcome ?

  What can I influence ? How ?

Some (Very High Level) Metrics ...

GCA
Gaffney, Cline & Associates

- **Difference between 3% and 6% decline**
  - 1.5 to 2 billion barrels (TAPS threshold dependent)
- **150,000 Bopd for 20 years**
  - 1 billion barrels
- **Delays cost money; value halves ...**
  - In 7 years at 10% discount rate
  - In 15 years at 5% discount rate
- **$100 a barrel (market price) worth to State approximately (undiscounted)**
  - $40 under ACES
  - $30 under SB49 (area dependent)
- **$150 a barrel (market price)**
  - $75 under ACES
  - $55 under SB49 (area dependent)

Some (Very High Level) Metrics ...

GCA
Gaffney, Cline & Associates

- **Put another way, at $100/Bbl**
  - Getting 150,000 Bopd for 20 years that you might not have got is worth ~$30 billion to the State
  - Changing to SB49 if you would have got it anyway costs $10-15Bn
- **At $150/Bbl**
  - Getting 150,000 Bopd for 20 years that you might not have got is worth ~$50-60 billion to the State
  - Changing to SB49 if you would have got it anyway costs $15-25Bn

- **Delaying 150,000 Bopd by 10 years (halve value; i.e. discounted)**
  - ~$20 – 40 Bn ?

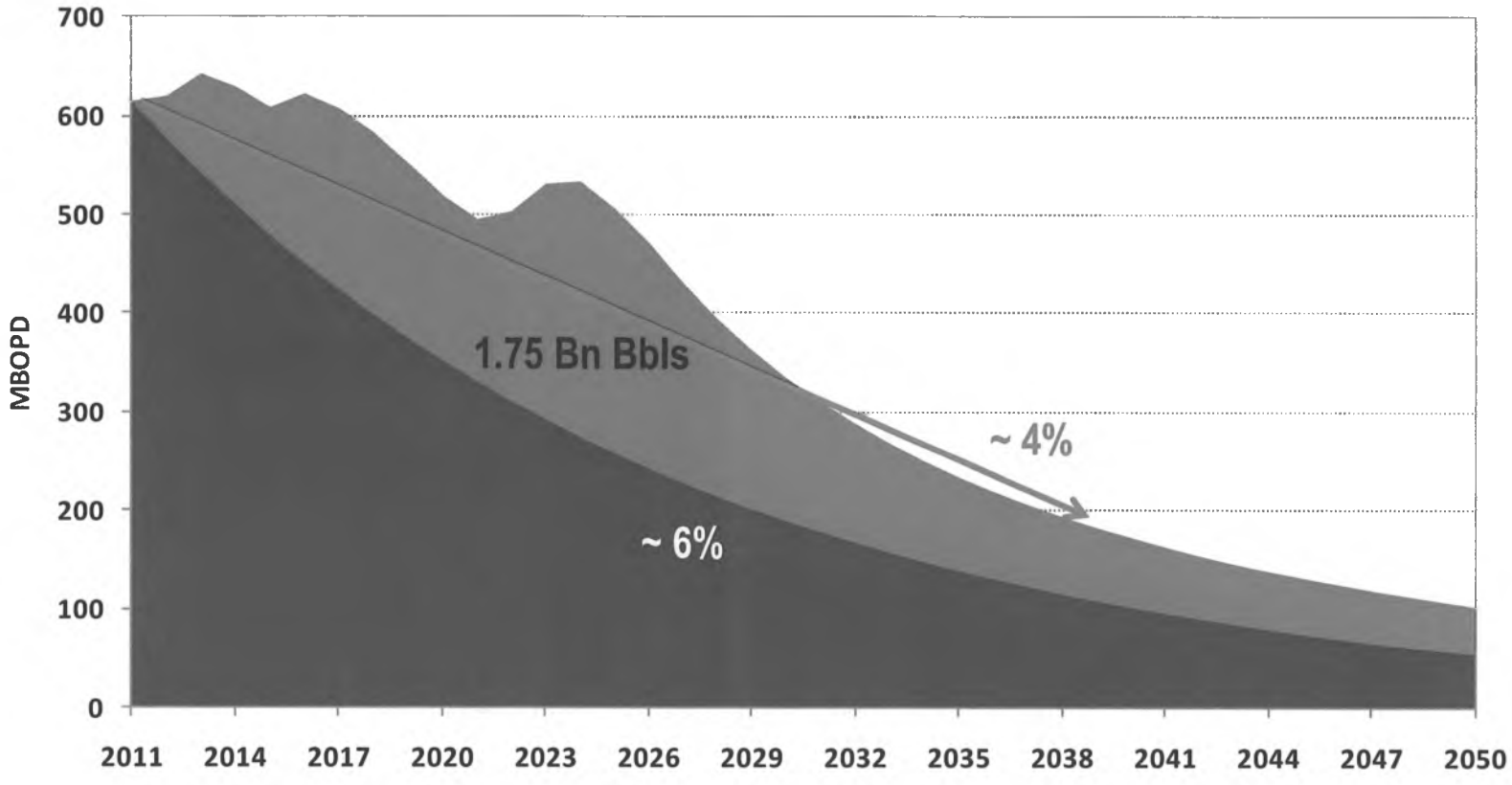
Based On Cash Flow Model

GCA
Gaffney, Cline & Associates

- **Examine the "what if" economic impacts (for example) to try and assess some possible "goalposts"**
  - Change fiscal take and limit long term decline to 3% - 4% (DoR 2010 Fall Profile)
  - Do Nothing and decline is actually around 6%
  - Do Nothing and still limit long term decline to 3% - 4%

Continued 6% Decline and DOR Fall 2010 Forecast

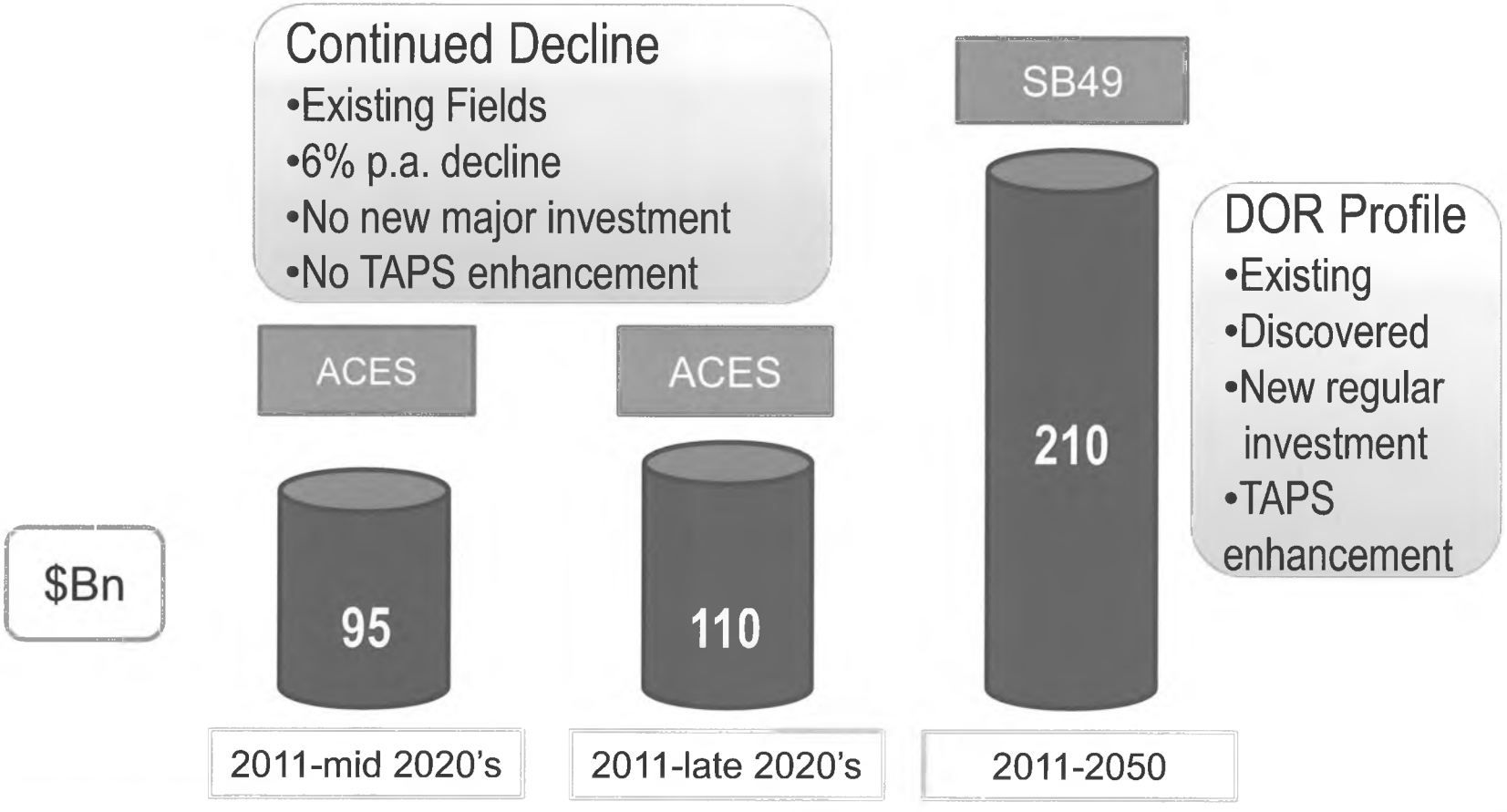
GCA
Gaffney, Cline & Associates



State Undiscounted Cash Flow

GCA
Gaffney, Cline & Associates

~$100 + Bn Potential Gain….



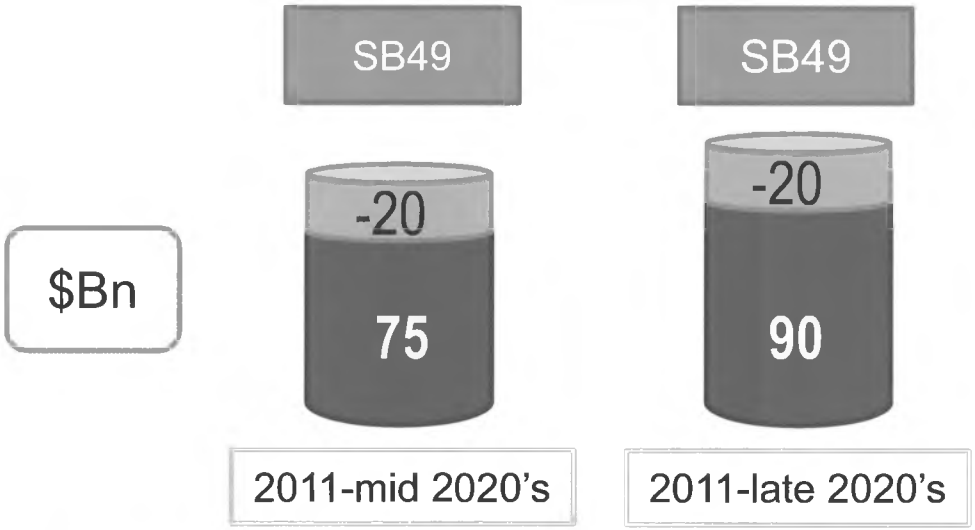
* DOR price & cost forecasts

State Undiscounted Cash Flow

GCA
Gaffney, Cline & Associates

~$20-50 Bn Potential Downside….

Assumes:
- Make change to SB49
- Still no new investment
- No TAPS enhancement



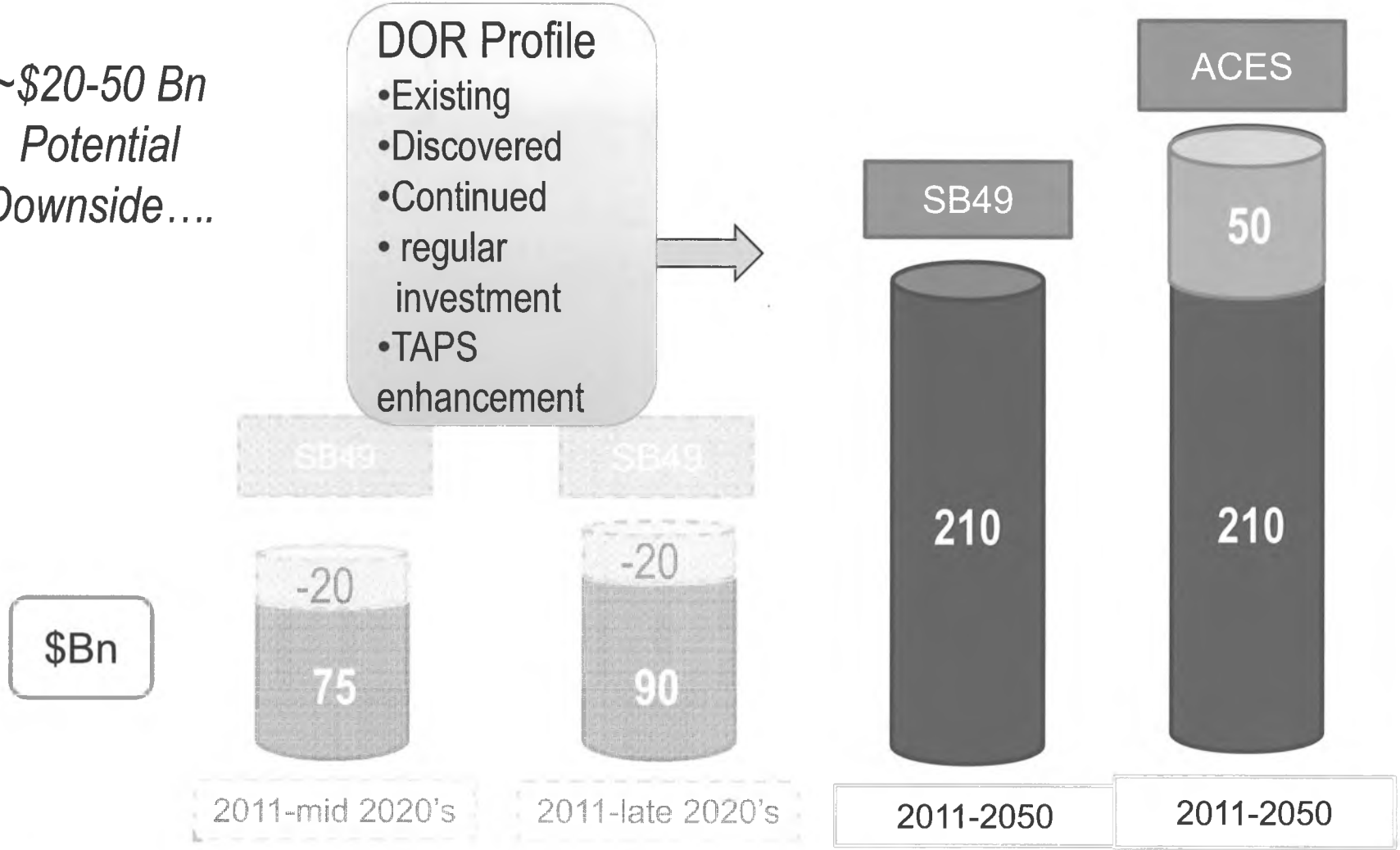
* DOR price & cost forecasts

State Undiscounted Cash Flow

GCA
Gaffney, Cline & Associates

~$20-50 Bn Potential Downside….

DOR Profile
- Existing
- Discovered
- Continued
- regular investment
- TAPS enhancement



* DOR price & cost forecasts

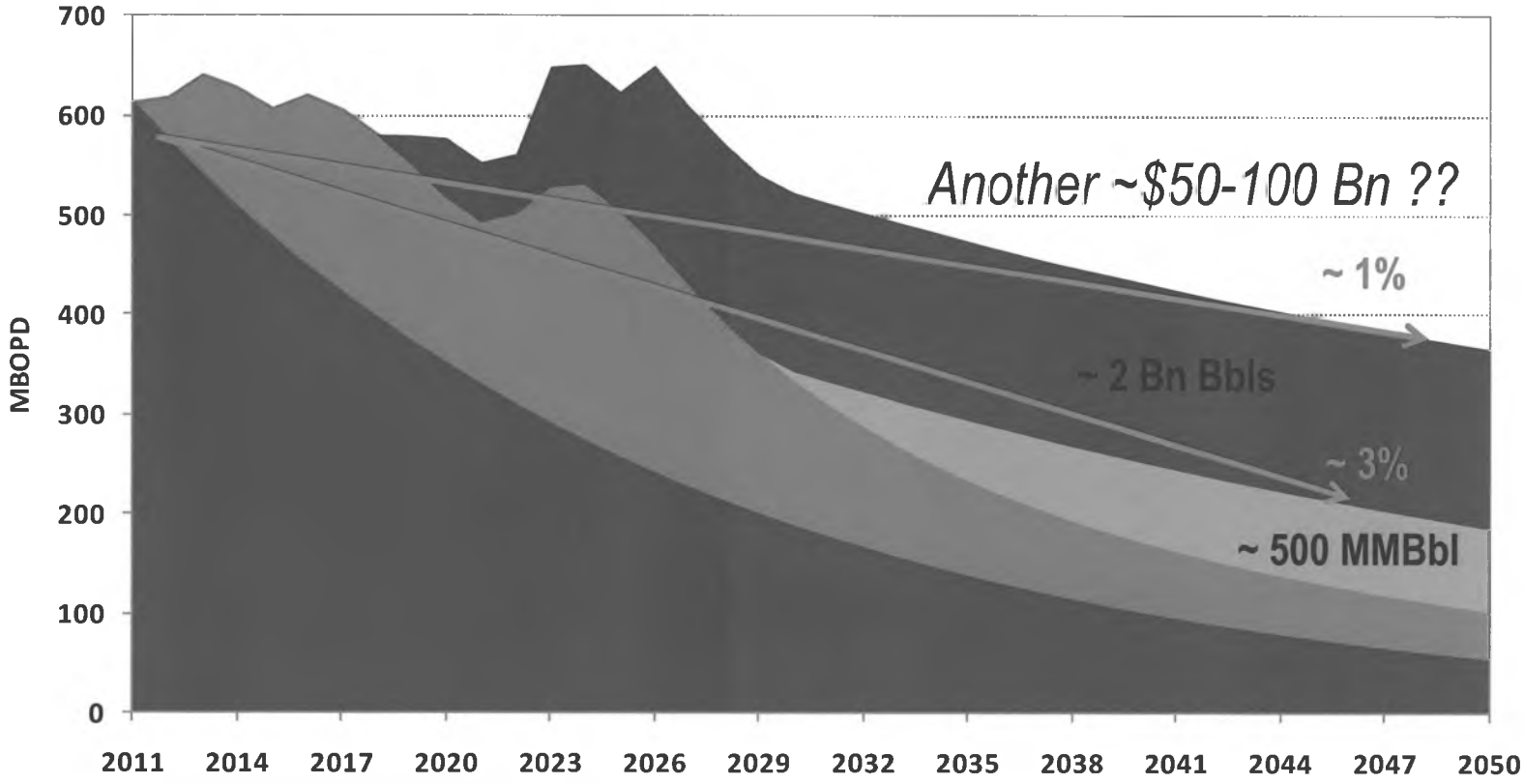
How To Consider The Options

GCA
Gaffney, Cline & Associates

- Examine the "what if" economic impacts of (for example) to try and assess some possible "goalposts"
  - Do Nothing and still limit long term decline to 3% - 4%
  - Do Nothing and decline is actually around 6%
  - Change fiscal take and limit long term decline to 3% - 4%
- **The prize of achieving 3% decline ..**
  - …. or better

Potentially Better Still

GCA
Gaffney, Cline & Associates



Ongoing Infield and Exploratory Drilling ….

… Heavy Oil and Non-Conventional Resources ?

Illustrative Potential Capital Requirements

GCA
Gaffney, Cline & Associates

	Bn Bbls	Cost Range ($/Bbl)		Capex ($Bn)	
DOR Fall 2010	5	14		68	
Conventional Oil, Existing Field Areas	1	10	15	10	15
Conventional Oil, New Areas	2	15	25	30	50
Heavy Oil	4	20	40	80	160
If All of the Above (Beyond DOR Forecast)				**120**	**225**

…. and then there are unconventional resources ….

Available Investment Capital

GCA
Gaffney, Cline & Associates

- **Producer spending can be put in three categories:**
  - Mandatory – loss of license if they don't
  - Should – monetary penalties / loss of production if they don't
  - Discretionary – used to "balance the books"
- **How much of the lack of new discretionary spending in Alaska is because the 'tax is too high' versus significant spending being directed to the top two categories above?**
  - Projects not viable
  - Better alternatives elsewhere at present

Conclusion

GCA
Gaffney, Cline & Associates

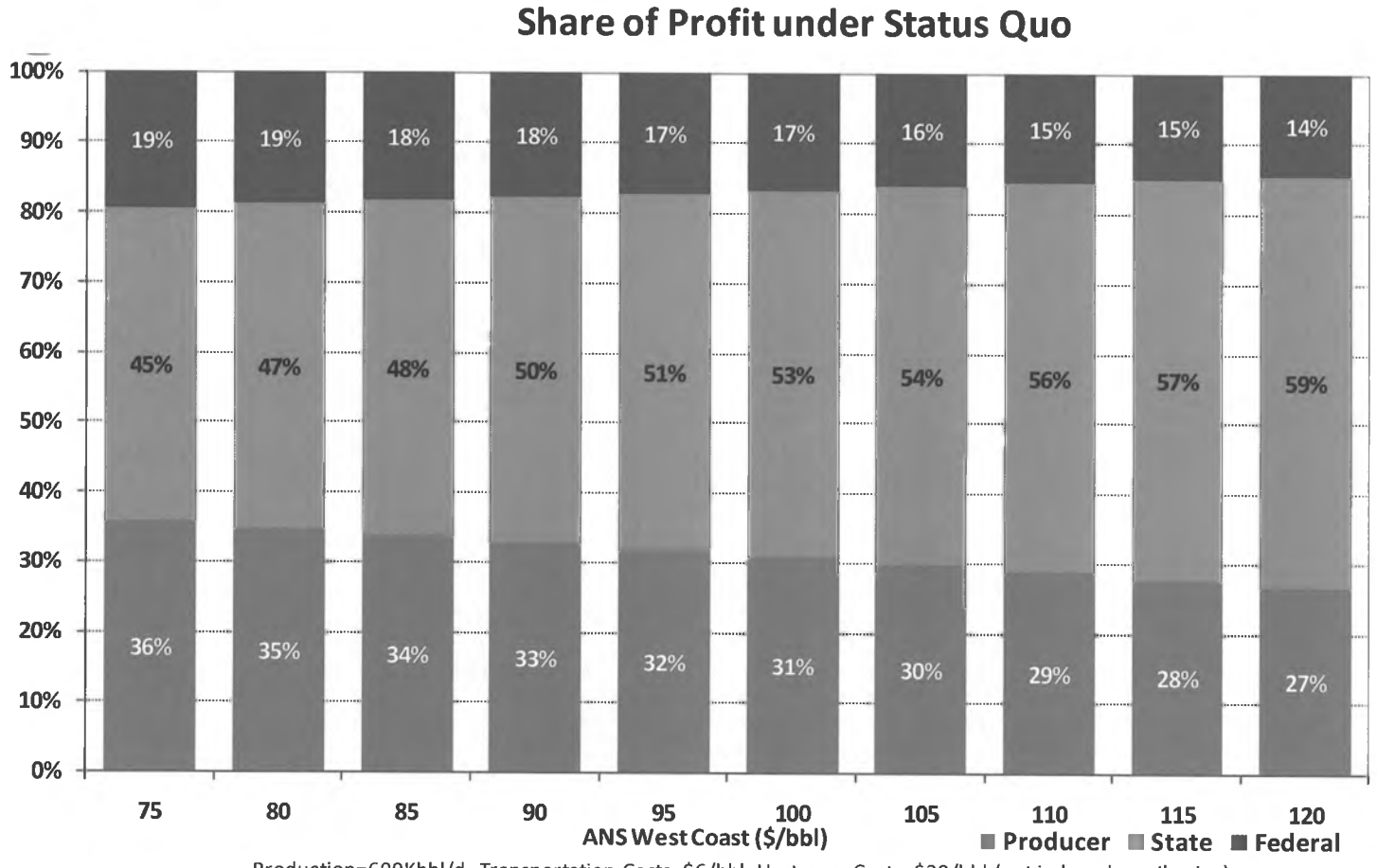
- Hard to predict the future in a nice tidy narrow range
- Potential impact of early pipeline shutdown significant to all parties, but most significant by far to the State
- Production Tax one of the possible levers the State can use to incentivize further investments and help extend the life of TAPS

Profit share graph Assumptions

Assumptions	Value	Unit
Transportation Costs	6.00	$/bbl
Royalty Rate	12.5%	
Upstream CAPEX	10.00	$/bbl
Upstream OPEX	10.00	$/bbl
Total Upstream Costs	**20.00**	**$/bbl**
Daily Production	600,000	bbl/d
Property Tax (% of CAPEX)	2.00%	
Total Allowable Costs	**20.20**	**$/bbl**

- ANS West Coast Price range
  - from $75/bbl to $120/bbl in increments of $5/bbl
- Costs are constant through price range

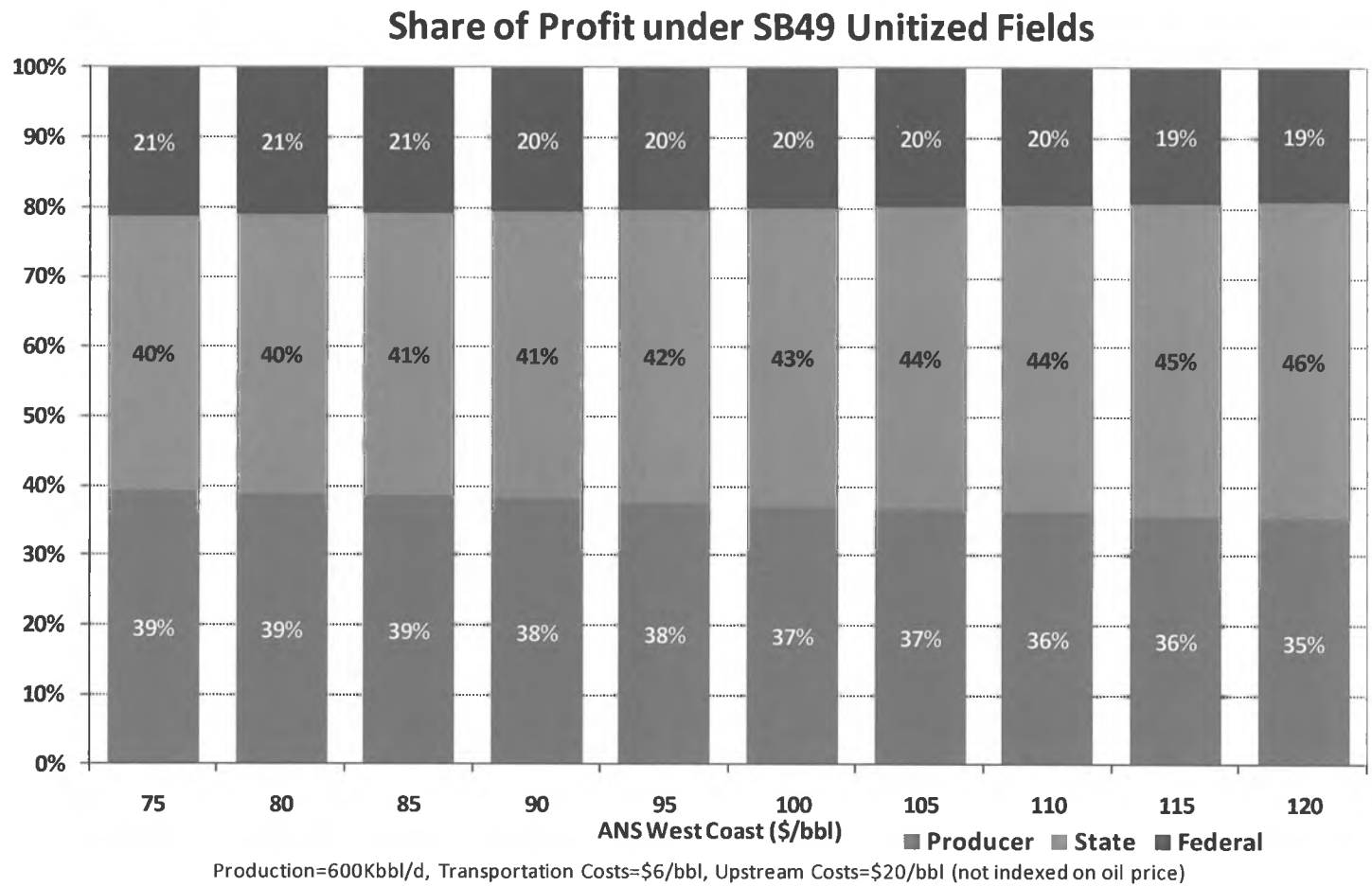
Profit Share under Status Quo



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures

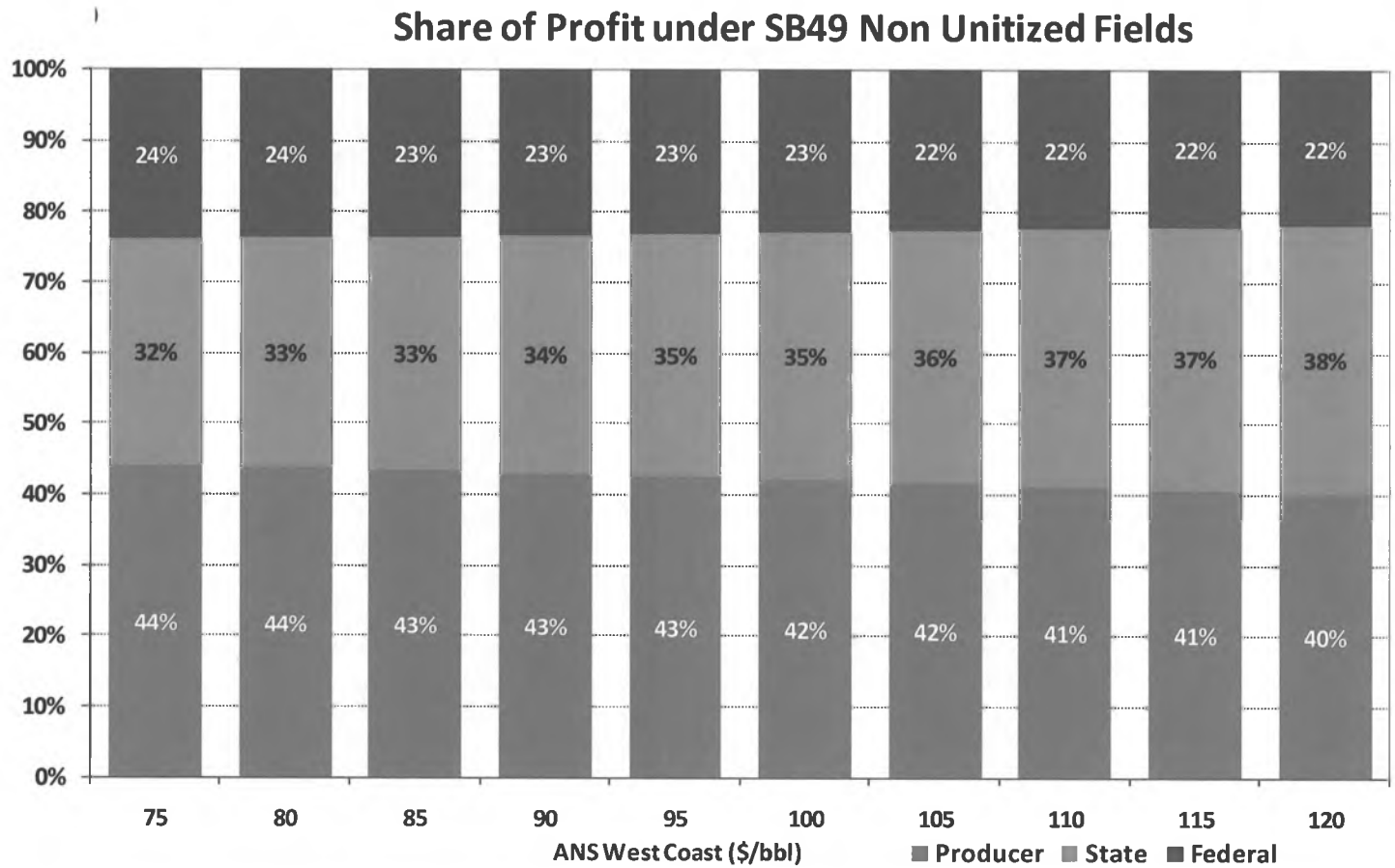
Profit Share under SB49 Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures

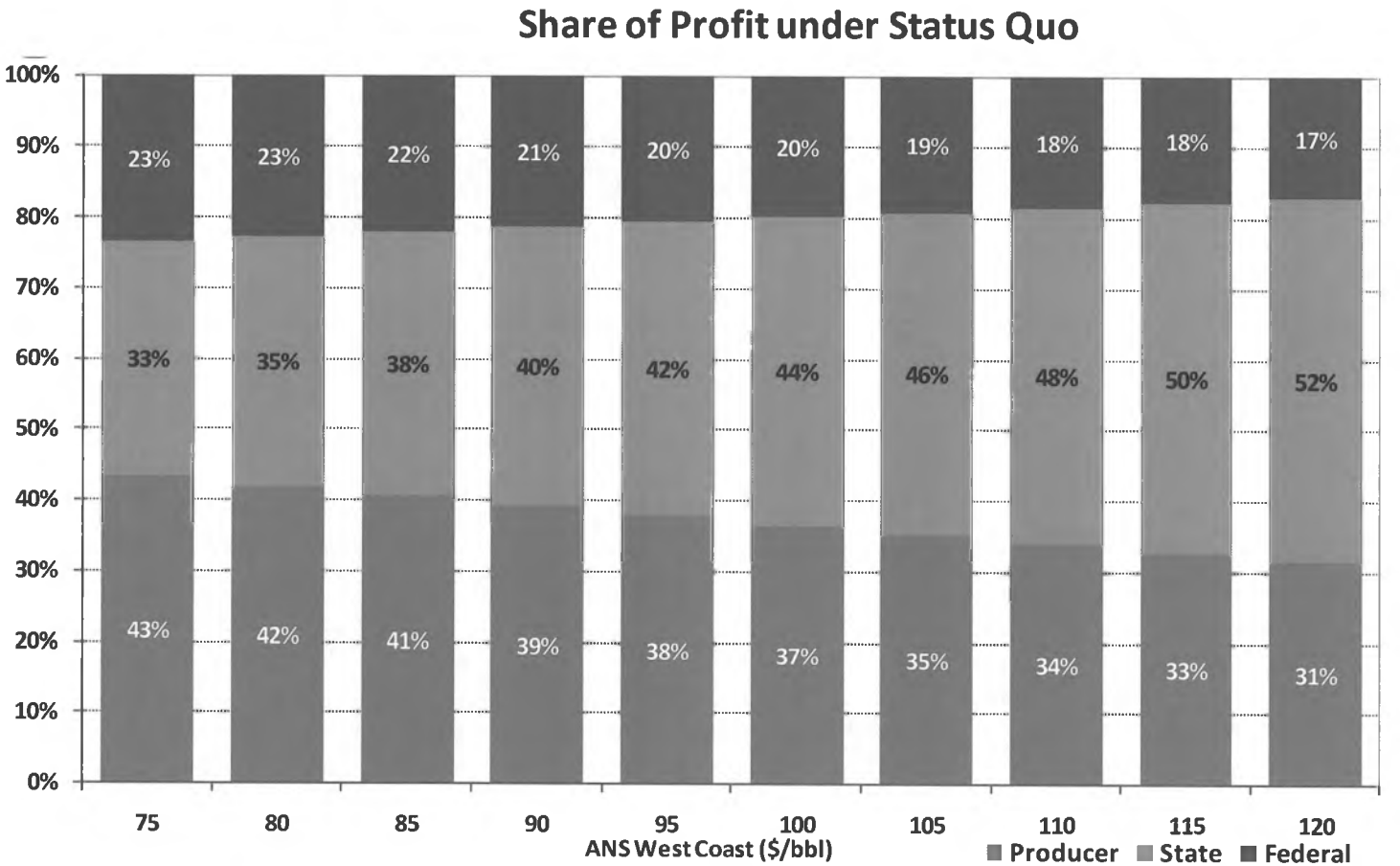
Profit Share under SB49
Non-Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures

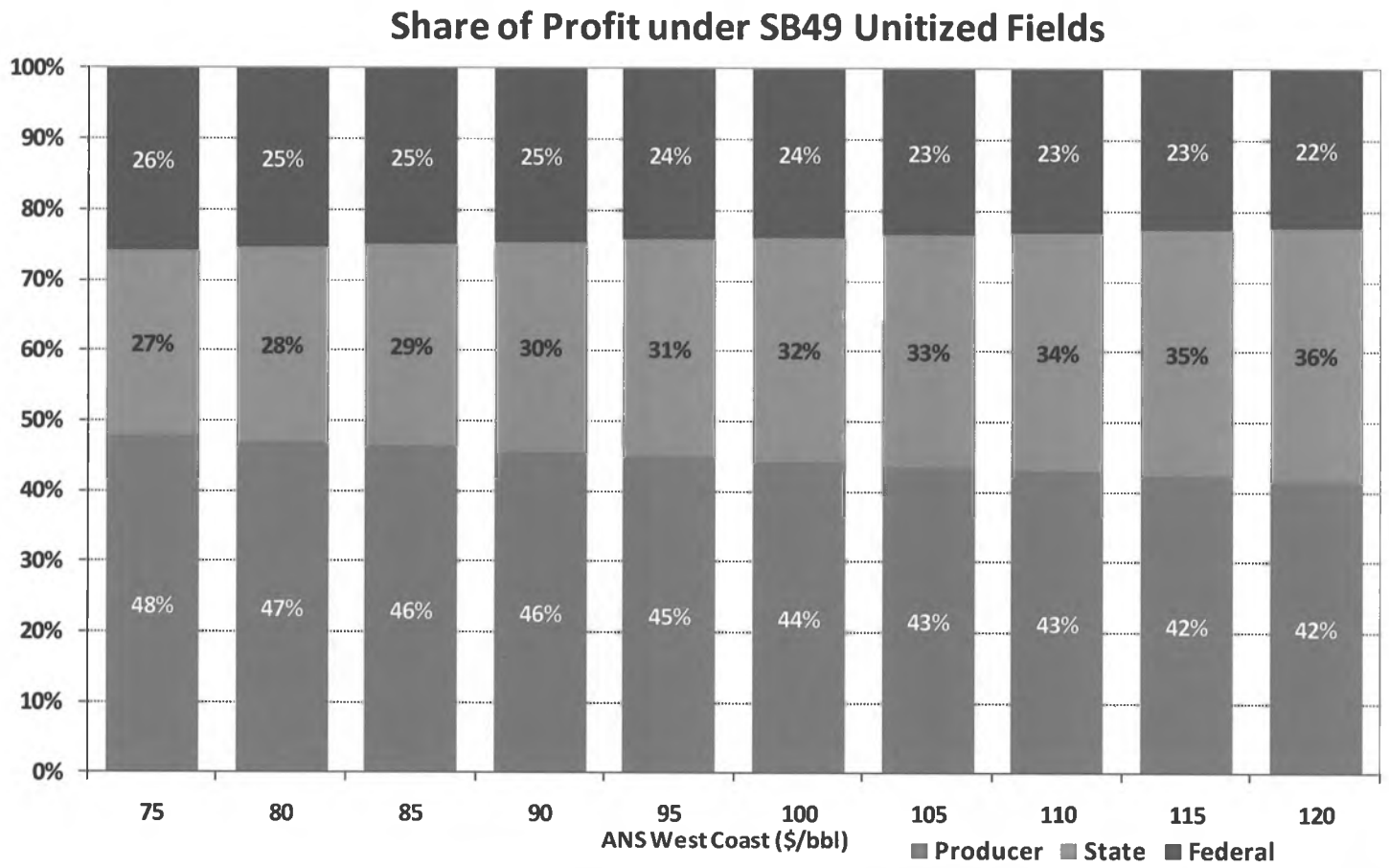
Profit minus Royalty Share under Status Quo



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit minus Royalty: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures (minus) Royalty

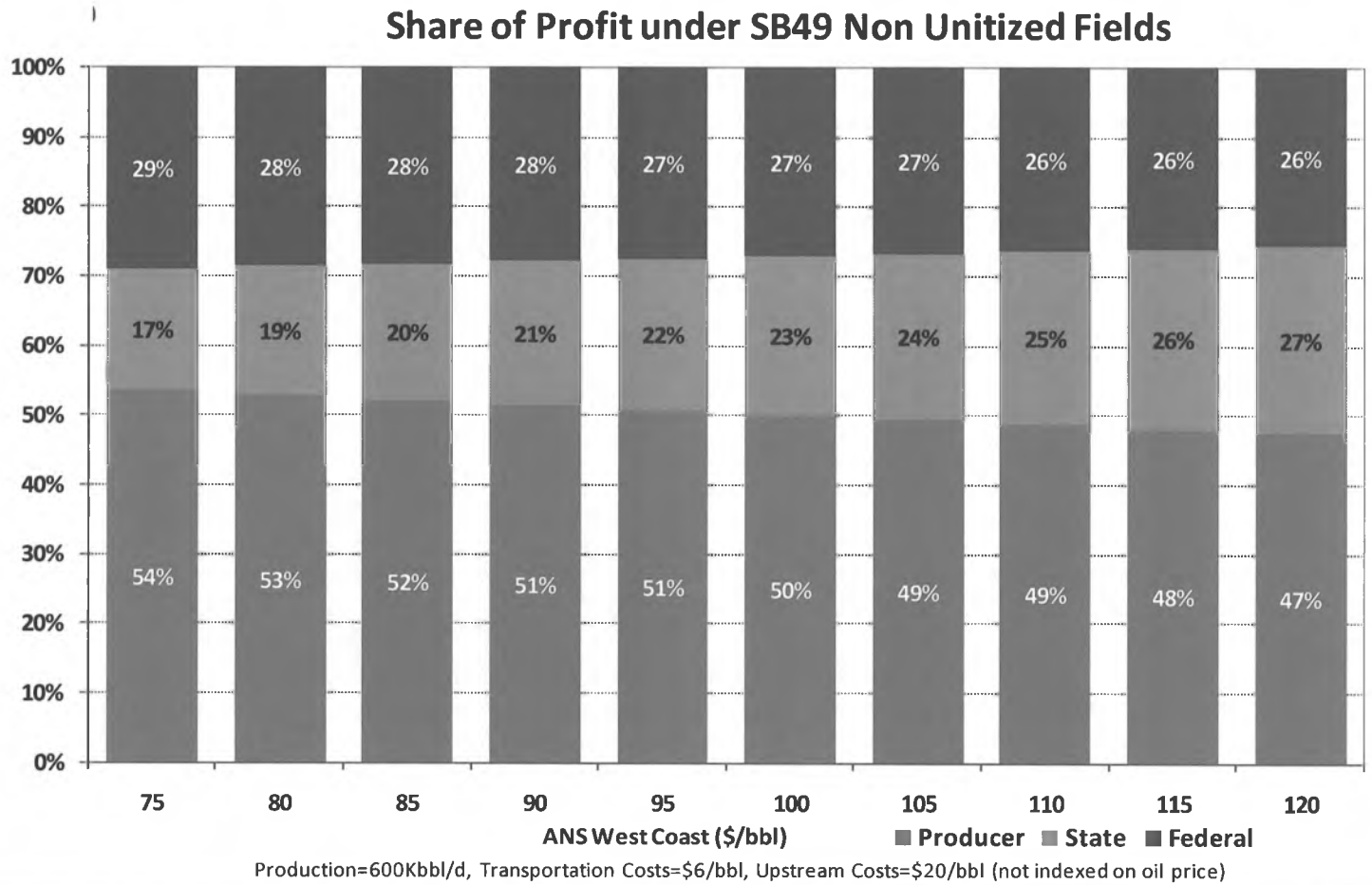
Profit minus Royalty Share under SB49 Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit minus Royalty: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures (minus) Royalty

Profit minus Royalty Share under SB49 Non-Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit minus Royalty: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures (minus) Royalty

Presentation to the Senate Resources Committee April 1, 2011 Alaska Department of Revenue

ACES Status Report

- **Overview of the Publication**
- **What We Know**

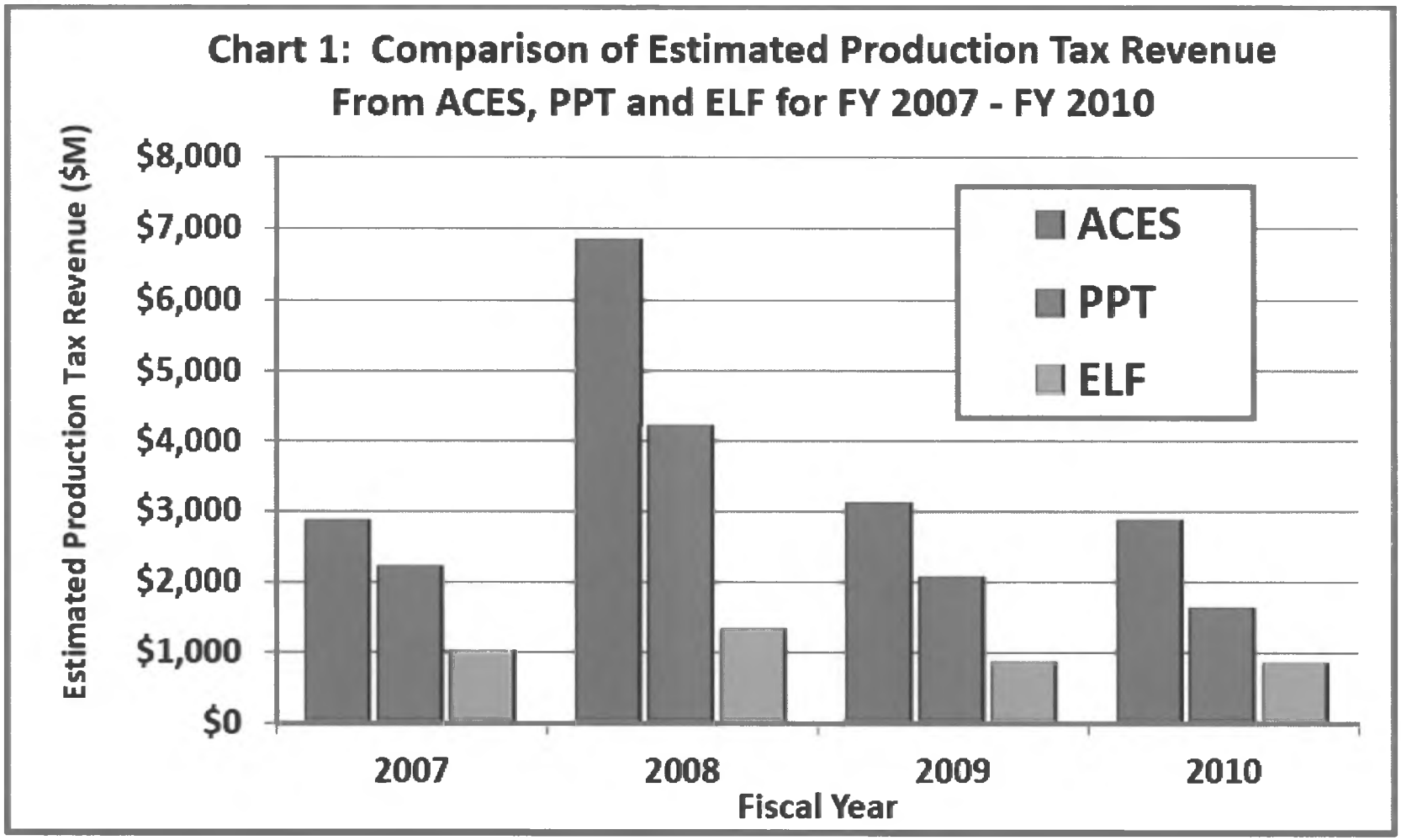
➢ ***Required report to the legislature under AS 43.55.180***

➢ ***Released January 18, 2011***

Overview of ACES Status Report

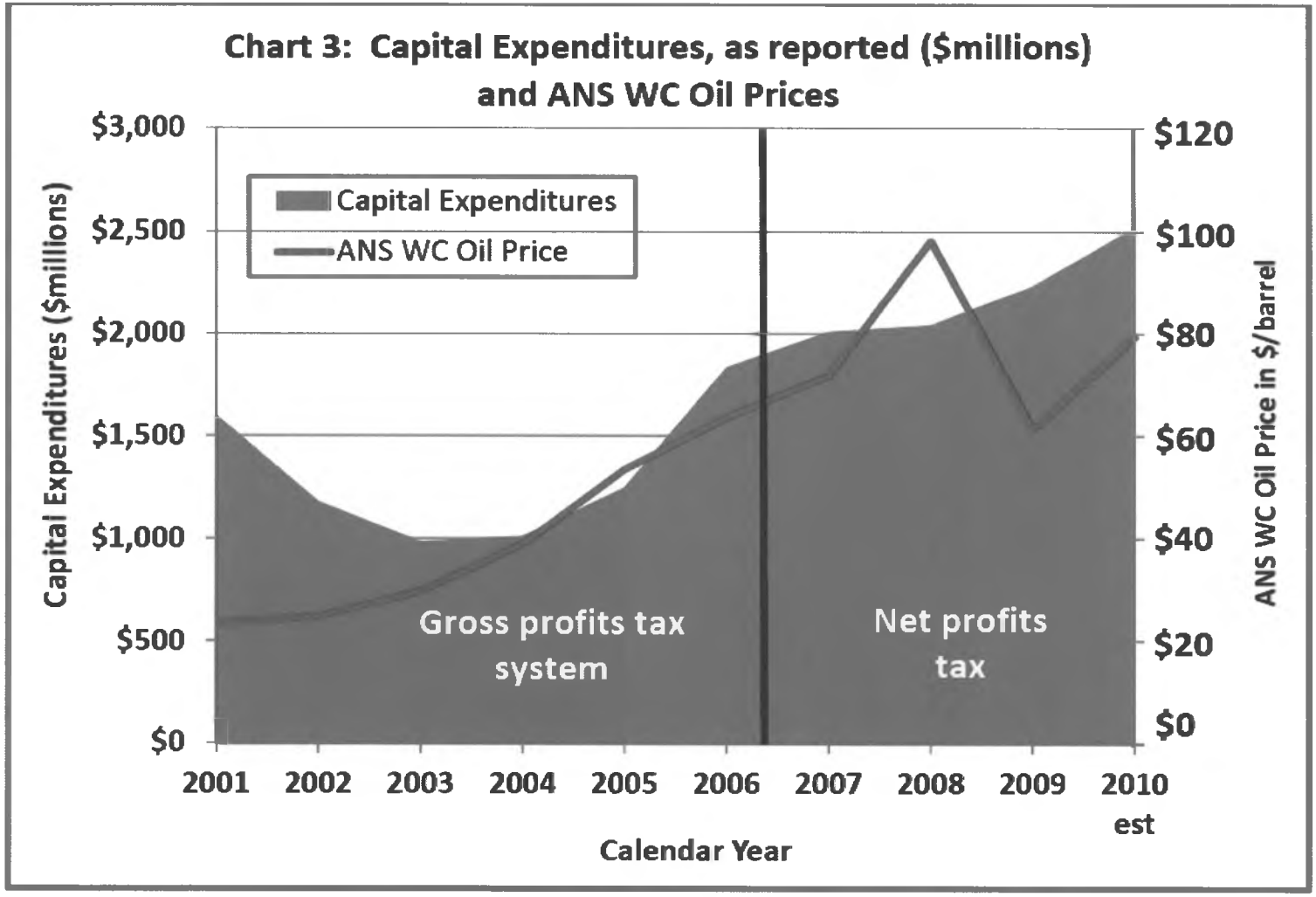
1. **Revenue Generation / Tax Rate**
2. **Industry Investment**
3. **Impact on Exploration, Development, Production**
4. **Industry Employment and New Entrants**
5. **Use and Expansion of Tax Credits**
6. **Tax Administration and Compliance**
7. **Conclusions and Recommendations**

What We Know:
State Revenue Has Increased



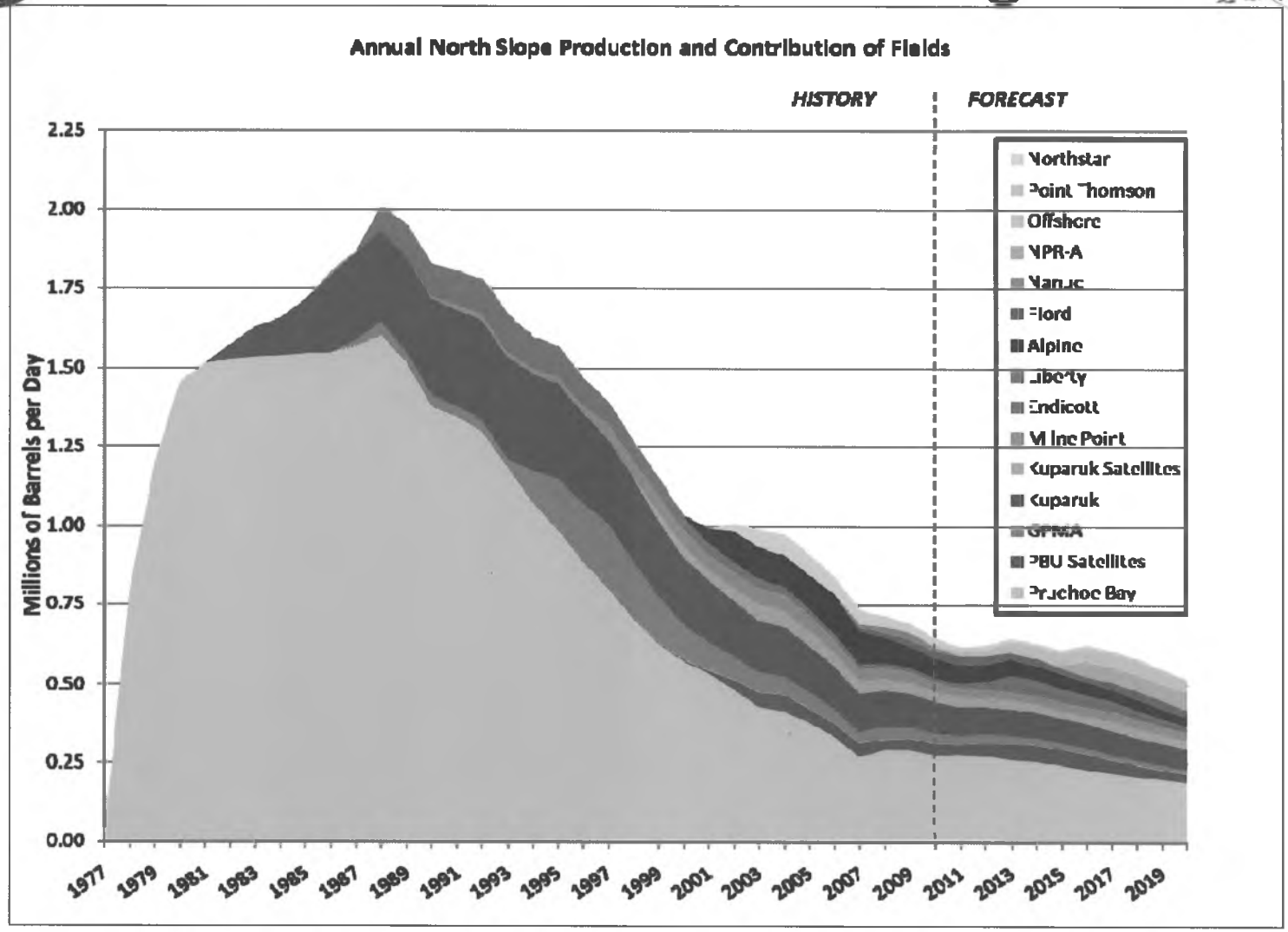
Source: Oil & Gas Tax Status Report 2011

What We Know: Companies are spending more



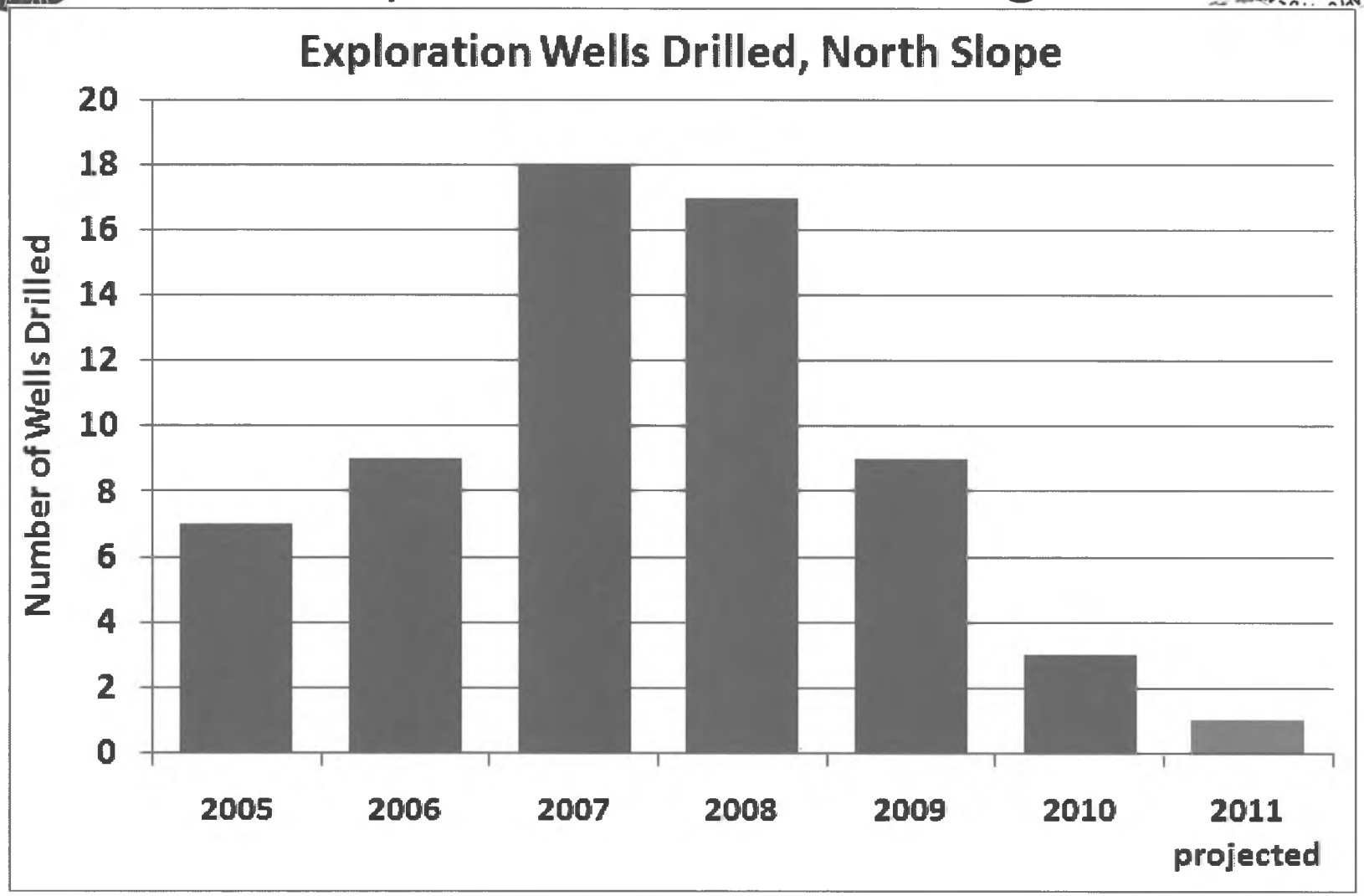
Source: Oil & Gas Tax Status Report 2011

What We Know: Production Is Declining



Source: Oil & Gas Tax Status Report 2011, and Fall 2010 Revenue Sources Book

What We Know: Exploration is Declining



Source: Alaska Oil & Gas Conservation Commission and Alaska Department of Natural Resources

Conclusion

- **Cannot conclusively identify the ACES impact compared to all the other factors in recent years**
- **We know we have more revenue in the short term**
- **We know oil production keeps declining**
- **We know there is little exploration taking place**

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Joe Paskvan
Alaska State Senator
State Capitol, Room 115
Juneau, AK 99801

March 15, 2011

The Honorable Thomas Wagoner
Alaska State Senator
State Capitol Room 427
Juneau AK, 99801

SUBJECT: Response to Questions from SB 49 Bill Sectional Presentation in Senate Resources on March 9, 2011 and March 11, 2011

Dear Senators Paskvan and Wagoner:

The purpose of this document is to respond to the follow-up questions raised by the Senate Resources Committee meeting during our presentation of the SB 49 bill sectional on March 9, 2011 and March 11, 2011. The requests/questions and responses follow. In addition, several policy issues were raised for future discussion, and we look forward to discussing these issues with the committee as the hearing process continues.

1) What is the definition of a unit?

The term "unit" is defined for production tax purposes under AS 43.55.900 (23):

(23) "unit" means a group of tracts of land that is
(A) subject to a cooperative or a unit plan of development or operation that has been certified by the commissioner of natural resources under AS 38.05.180(p);
(B) subject to a cooperative or a unit plan of development or operation that has been certified by the United States Secretary of the Interior under 30 U.S.C. 226(m);
(C) subject to an agreement of the owners of interests in the tracts of land to validly integrate their interests to provide for the unitized management, development, and operation of the tracts of land as a unit, within the meaning of AS 31.05.110(a); or
(D) within the unit area of a unit created by order of the Alaska Oil and Gas Conservation Commission under AS 31.05.110(b)

In addition, if requested, the Department of Natural Resources is prepared to provide the committee with a brief presentation explaining the concepts of leases, units, and participating areas in more detail.

2) **Provide slides from a prior presentation by Gaffney, Cline & Associates that show Internal Rate of Return and Return on Investment statistics for infield drilling.**

The model developed for BP's infill drilling program, and the Gaffney, Cline & Associates presentation to the House Oil & Gas committee, were released by the previous administration on October 30, 2007. The model and presentation are both available in the "Gasoline & Tax Issues: 2004-2010 – ACES" section of the Legislative Budget & Audit Committee web site at the following address: http://lba.legis.state.ak.us/.

3) **What are the "gaps" in data collected by the Department?**

15 AAC 55.345 sets out procedures for applying certain tax credits. The regulation is already in place, and requires a producer or explorer filing a claim to set out "the information required by the department on a form prescribed by the department". The department has not yet revised the form to include the types of information that has been requested during the current legislative session. Initial proposals are to include requests for the following types of information:

- Exploration costs
  - G&G (geophysics and geology) costs
  - Exploration wells
- Development Wells
  - In-field drilling
  - Workover
  - Operations CapEx
- Facilities
  - Repairs
  - Upgrades
  - New Equipment
  - Operations CapEx

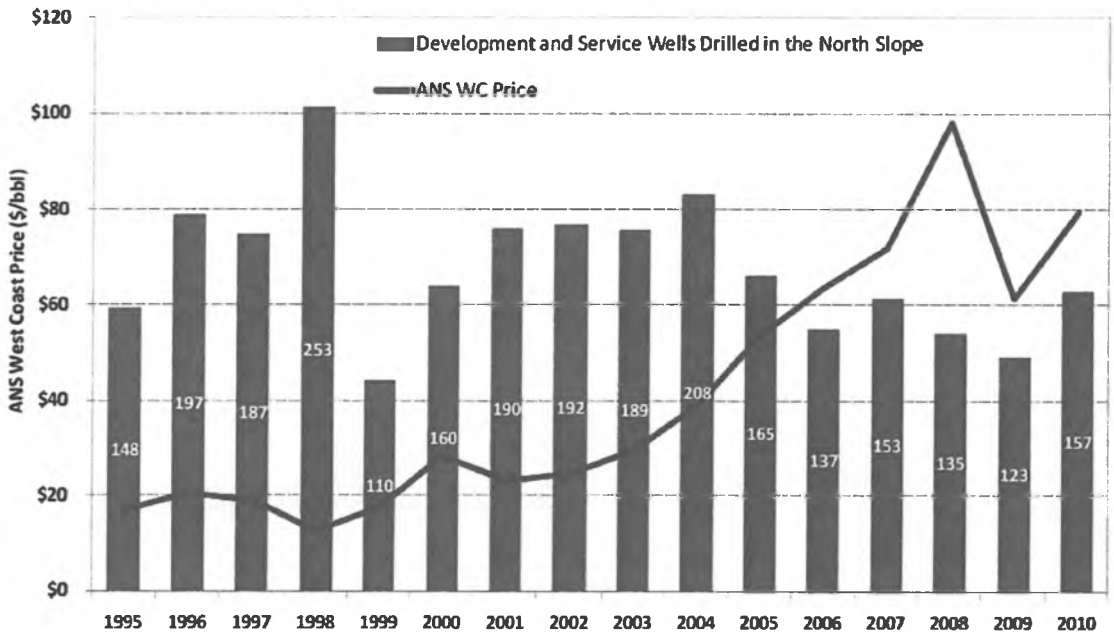
4) **How effective has the 40% well lease expenditure credit been in Cook Inlet?**

The 40% credit for well lease expenditures in Cook Inlet was created with legislation passed in the 2010 session. Given the short time in which the credit has been in place, it is not yet possible to gauge the effectiveness of the credit other than anecdotally.

5) **Provide information about the number of in-field wells drilled last year compared to prior years.**

The following chart shows the number of development and service wells drilled on the North Slope annually from 1995 to 2010. This information is part of the Department's

presentation to the committee dated March 11, 2011.



Source: Alaska Oil and Gas Conservation Commission

6) Have the minimum tax thresholds ever been triggered?

Under current law, a company's tax liability under ACES is the higher of the tax calculated under AS 43.55.011(e) and the minimum tax, as calculated under AS 43.55.011(f). The minimum tax thresholds are based on the average ANS West Coast crude oil price over the entire calendar year, with the highest tax rate—4%--being applied when the average price of ANS WC crude is greater than $25 per barrel. Therefore, the minimum tax in effect since ACES was implemented in 2007 is 4% of the gross value at the point of production.

Although some companies would calculate a higher value under the minimum tax than under the ACES tax at .011(e), they have been allowed to offset their tax liabilities with credits. To date, we are not aware of any companies that had an annual tax liability under the minimum tax.

7) Provide information about the historical amounts of interest payments for delinquent taxes and refunds under AS 43.05.225 (1).

The following table presents total interest collected under AS 43.05.225 (1) for FY 2008, FY 2009, and FY 2010. These amounts include both interest paid to the state for delinquent taxes, and interest paid by the state for delinquent refunds. All the amounts shown below are positive revenues to the state: typically, the state has collected more in interest than it has paid out.

The Department does not have an estimate of the change in interest due to the lower interest rate provisions in SB 49. Compiling such an estimate would require manually examining and recalculating the interest for hundreds of tax returns or more.

Total Interest by Year (Positive revenue to the state - $ millions)

Fiscal Year	General Fund	CBRF	Total
FY 2008	$7.1	$219.1	$226.2
FY 2009	$5.2	$27.9	$33.1
FY 2010	$78.6	$85.6	$164.3
Total FY 08- FY 10	$90.9	$332.6	$423.5

8) **Provide information about the number of companies available each year for audit (either submitting returns or credit applications).**

The requested information was included in the "Oil and Gas Production Tax Status Report to the Legislature" released on January 18, 2011. On page 11 of that publication, we reported the following:

"In 2006, the first year that filings were made under a net profits tax, there were 19 companies filing annual returns. In 2007, the number of companies filing production tax returns totaled 26, and in 2008, 36 companies filed annual production tax returns. The filing for 2009 increased only slightly from 2008, with 39 companies filing returns."

9) **Provide information about what the oil industry is investing in, in Alaska.**

Department of Revenue Audit Master Lennie Dees will share available information in his presentation to the committee on tax credits, currently planned for Wednesday, March 16.

10) **Provide an analysis where the $3 billion in cumulative production tax credits have been used.**

Department of Revenue Audit Master Lennie Dees will share available information in his presentation to the committee on tax credits, currently planned for Wednesday, March 16.

We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Joe Paskvan
State Capitol Room 115
Juneau AK, 99801

March 19, 2011

The Honorable Thomas Wagoner
State Capitol Room 427
Juneau AK, 99801

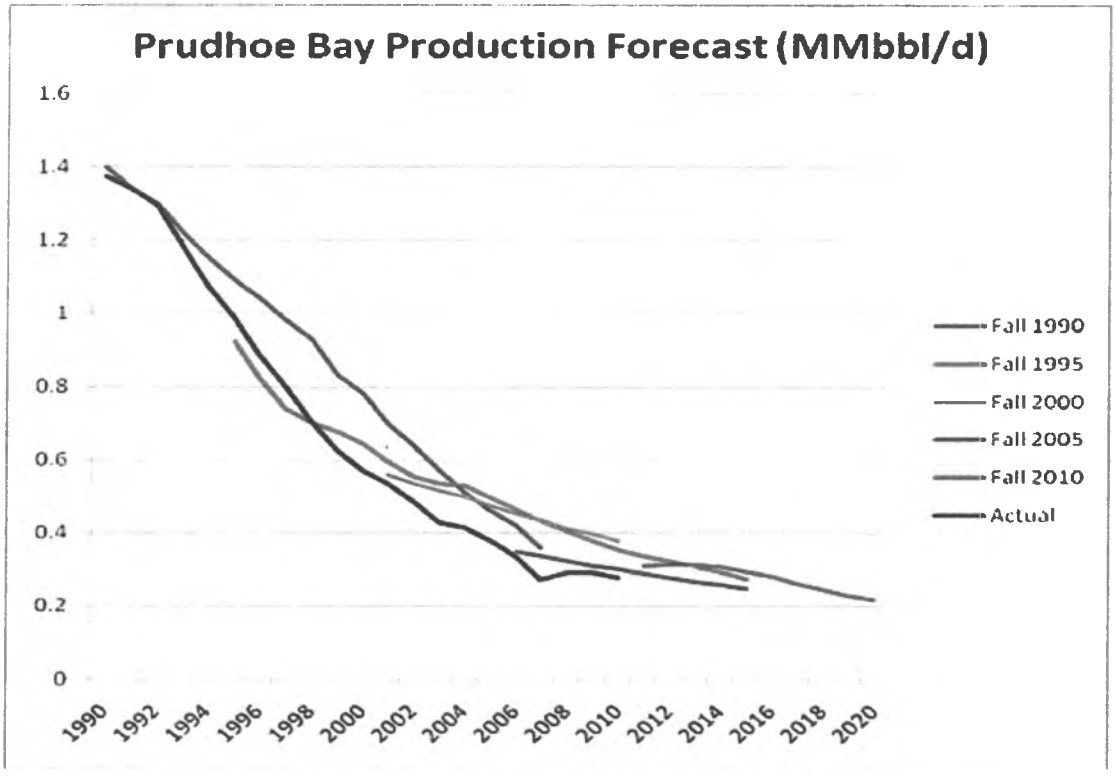
SUBJECT: Response #2 to Questions from SB 49 Bill Sectional Presentation in Senate Resources on March 11 and 14, 2011, and Tax Credits Presentation on March 16, 2011.

Dear Senators Paskvan and Wagoner:

The purpose of this document is to respond to the remaining follow-up questions raised by the Senate Resources Committee meeting during our presentation of the SB 49 bill introduction on March 11 and 14, 2011, and during our tax credits presentation on March 16, 2011. The requests/questions and responses follow. We have provided responses for many other questions from these meetings at a prior date.

1) **Provide the Department's previous forecasts for Prudhoe Bay production in 5-year increments (2010, 2005, 2000, etc).**

   Historical production forecasts can be found online in the Fall Revenue Sources Book: http://www.tax.alaska.gov/programs/sourcebook/index.aspx



- These forecasts include Prudhoe Bay production only.
- These forecasts exclude Greater Point McIntyre Area (GPMA) production.
- Forecast volumes include NGLs.

2) Explain the concept of "duty to produce."

"Duty to Produce" refers to a more common expression, "duty to develop" that is the implied covenant of an oil and gas lease in the primary term of a lease. The lessor (usually the State) grants the lion share of the value of the hydrocarbons produced from the lease and the oil company lessee is committed to develop the land, reasonably produce any hydrocarbons found, and use their expertise to market the production for the mutual benefit of both the royalty owner (the State) and producer (lessee).

The duty to develop is implied unless the lease explicitly requires it. Depending on the factual circumstances and the language of the lease, the commitment to develop the lease is met if the lessee is working under an approved plan of exploration, development, or operations. Depending on the specific wording in the lease, the lessee also may be complying with its obligation to develop and produce if it is producing either oil or gas but not both.

3) **Can we look at a possible correlation between declines in exploration in 2003 and 2010, and the economic downturns in 2001 and 2008. Is Alaska's decline in exploration in those years similar to other states after removing gas exploration wells?**

Rig counts, which constitute a proxy for drilling activity, have been impacted by the recent economic downturns, affecting the United States mostly in 2002 / 2003 and in 2008 / 2009.

The following two charts represent the evolution of the number of active rigs drilling for oil targets both onshore and offshore (gas rigs are excluded from this count) in:

- Selected states and the total US since 2002
- Global regions and international total since 2002

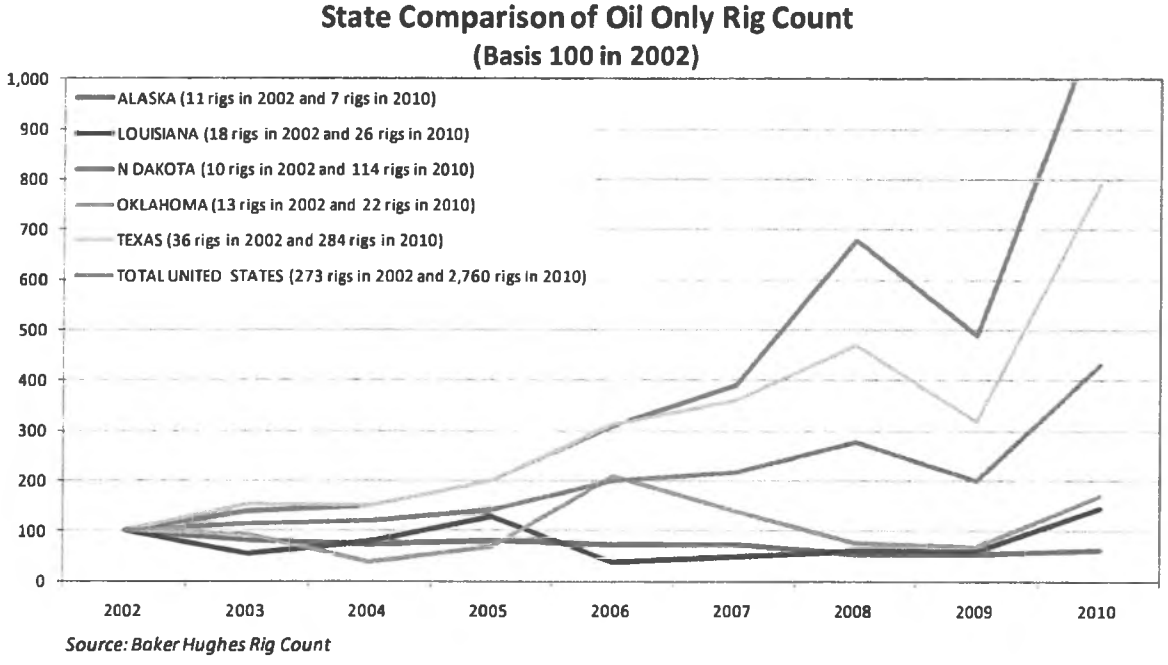
Baker Hughes, which publishes rig counts, did not differentiate oil from gas rigs prior to 2002. Please note that such rig count includes rigs drilling exploration wells and rigs drilling development wells (no differentiation between these types of wells is made in the data set).

These charts display the relative change in rig counts (consistently with previous information provided to the Committee) over the past decade, using 2002 as a base year (the rig count for each series for any given year is represented relative to the rig count for that series in year 2002. For example, if the rig count was to go from 8 in 2002 to 16 in 2010, this would be reflected in the chart by a line going from 100 in 2002 to 200 in 2010).

United States

No trend common to all states trend can be observed during the 2002 to 2004 time period. Alaska and Oklahoma rigs counts both decreased during this period, while North Dakota increased both years. Louisiana rig count decreased slightly in the first year, and then increased in the second year, but did not return to year 2002 levels. Texas experienced the opposite, increasing in year one, then dropping marginally in year two. Overall, the total United States oil only rig count increased slightly over the two year period.

During the 2008 to 2009 period, activity in all states either remained the same or declined, and from 2009 to 2010, activity in all states increased. Overall, the US rig count dropped by close to 27% between 2008 and 2009 (from 276 oil rigs in 2008 to 201 in 2009) and more than doubled between 2009 and 2010. It is noteworthy that from 2009 to 2010, the Alaska rig count increased by 17%, while all other states presented here typically increased by more than doubled.

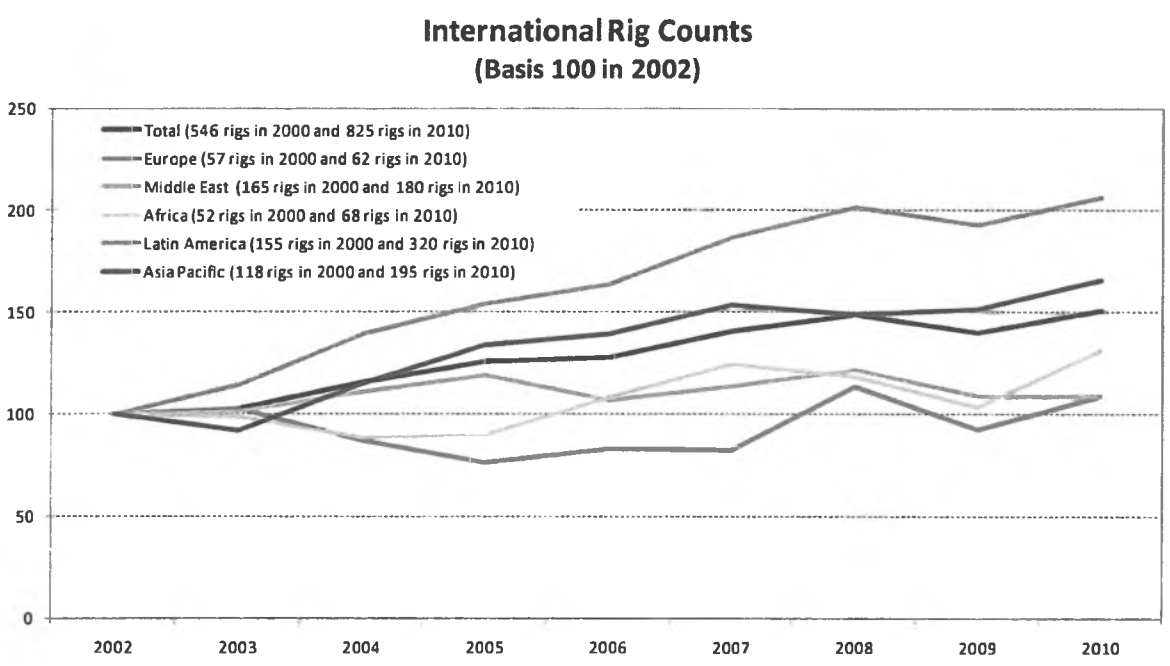


Source: Baker Hughes Rig Count

International

As was the case for the United States, there is no common directly observable trend across geographic areas during the 2002 to 2004 time period. The Middle East and Latin America both increased rig count over the two year period. Africa is the only region which decreased rig count both years; although the overall decrease, 2002 relative to 2004, was only 12%. Europe increased by one rig between 2002 and 2003, then decreased marginally between 2003 and 2004. Asia Pacific decreased initially, and then increased between 2003 and 2004 for an overall increase of 14%. The total rig count internationally increased both years, for an overall increase of 15%.

During the 2008 to 2010 time period, Europe, Africa and Latin America all decreased rig count in 2009 and increased again in 2010. The Middle East decreased in year one and remained the same in year two. The only region to increase both years was Asia Pacific, with an overall increase of 11%. The total rig count internationally followed the majority of the regions, decreasing in year one, and increasing again in year two, and in addition, 2010 rig count surpassed the 2008 count.



4) **Provide information about companies that are working together on exploration wells shown in the exploration wells slide.**

The source of the data on the exploration wells graph presented in committee was AOGCC. They make public certain details about drilling activities in the state. Along with the well data, AOGCC provides the name of the operator of the well. We provide a copy of the well data, along with the name of the operator of each well, as an attachment to this letter. Neither the Department of Revenue nor the Department of Natural Resources maintains information about the other companies that may have worked with the operators on these wells.

5) **How do drilling agreements work when companies are working together? If one company pulls out of a project, is the project typically cancelled?**

Companies working together in established units, commonly referred to as working interest owners (WIOs), operate those units under guidelines contained in unit operating agreements. These unit operating agreements contain provisions regarding the operation of the unit, as well as voting rights of each WIO. Many unit operating agreements have options for WIOs to "opt out" of a project that the operator proposes. If this is the case, then WIOs that do not want to participate in a project may opt not to do so. Provisions of each of the unit operating agreements are distinct for each unit, however, may treat this particular issue differently.

6) **Compare royalty rates in Alaska with royalty rates in other states; that is, compare royalties paid in Alaska as an owner state to royalties paid to private land owners in Texas, North Dakota, etc.**

Oil and gas leasing in Alaska differs from that in many states due to the fact that the state of Alaska owns the mineral rights under most of the oil and gas-prone land. In other petroleum-rich states, such as Texas and Oklahoma, a large percentage of the land leased for petroleum development is private land, wherein the private landowners also hold the mineral rights. A company that wants to lease rights to the minerals often pays a bonus, rent, and/or royalties to the owner of those minerals. In Alaska, the owner is often the state; in other states, the owner is often a private individual.

Private ownership of petroleum minerals in states like Texas, Oklahoma, and Louisiana, can be as much as 97%, according to a source within the Alberta Department of Energy.[1] In these states, petroleum developers often must negotiate with private landowners to lease rights to the minerals under their property. The terms of the negotiation can vary, but often contain a royalty provision. Our research shows that private landowners have been successfully negotiating royalties of 1/16 share (6.25%) up to 4/16 share (25%) in more recent leasing activities. The terms of the lease will likely be subject to the potential of the resource base, and the economic viability of the petroleum development project.

7) **Please show SB 49 compared to our revenue forecast in the "income statement" format for FY 2010, FY 2011, and FY 2012.**

The production tax estimates for FY 2012, FY 2011, and FY 2012 under SB 49 are shown in the "income statement" format on the following pages.

[1] "A Comparison of United States and Alberta Royalty Systems," Barry Rodgers, Alberta Department of Energy, July 17, 2006, available online at http://pnwer.dataweb.com/tables/jointables/meetingparticipantjoin/files/presentation/PNWERPresentation.pdf

FY 2010 Production Tax Estimates - SB49

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$74.90	643,517	$48.2
Annual Production (bbl)			
Total		234,883,705	$17,592.8
Royalty, Federal and other barrels[1]		-31,067,340	($2,326.9)
Taxable barrels		203,816,365	$15,265.8
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.21		
TAPS Tariff	-$3.81		
Other	$0.00		
Total Transportation Costs	-$6.02	203,816,365	($1,227.0)
Deductible Lease Expenditures[2]			
Deductible Operating Expenditures	-$10.64		($2,168.7)
Deductible Capital Expenditures	-$8.55		($1,742.0)
Total Lease Expenditures	-$19.19	203,816,365	($3,910.7)
Production Tax			
Production Tax Value (PTV)			$10,128.1
Base Tax (25%*PTV)			$1,528.6
Production Tax Value per barrel	$49.69		
Progressive Tax			$1,176.9
Total Tax before credits			$2,705.5
Credits (includes $300M in well lease exp credit)			($650.0)
Estimated Total Tax after credits[3]			$2,055.5

Notes: DOR revenue historical and current models are based on fiscal year data, which is also used for this analysis. SB49 would use calendar year averages for production, price, and costs, and the results may differ slightly from that shown in this analysis. (1) Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property and barrels used in production. (2) Deductible Lease Expenditures represents our best estimate of lease expenditures that are applicable to currently producing fields that are likely to produce a tax liability for the company or companies producing them. The per-barrel expenditures reflect expenditures **per taxable barrel** and do not reflect expenditures per all barrels produced. (3) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, and constant expenditures for the entire year. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

FY 2011 Production Tax Estimates - SB49

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$77.96	615,902	$48.0
Annual Production (bbl)			
Total		224,804,230	$17,525.7
Royalty, Federal and other barrels[1]		-34,100,490	($2,658.5)
Taxable barrels		190,703,740	$14,867.3
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.07		
TAPS Tariff	-$4.17		
Other	$0.24		
Total Transportation Costs	-$6.00	190,703,740	($1,144.2)
Deductible Lease Expenditures[2]			
Deductible Operating Expenditures	-$12.99		($2,477.0)
Deductible Capital Expenditures	-$10.43		($1,988.4)
Total Lease Expenditures	-$23.42	190,703,740	($4,465.4)
Production Tax			
Production Tax Value (PTV)			$9,257.6
Base Tax (25%*PTV)			$1,430.3
Production Tax Value per barrel	$48.54		
Progressive Tax			$1,029.9
Total Tax before credits			$2,460.2
Credits (includes $300M in well lease exp credit)			($700.0)
Estimated Total Tax after credits[3]			**$1,760.2**

Notes: DOR revenue historical and current models are based on fiscal year data, which is also used for this analysis. SB49 would use calendar year averages for production, price, and costs, and the results may differ slightly from that shown in this analysis. (1) Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property and barrels used in production. (2) Deductible Lease Expenditures represents our best estimate of lease expenditures that are applicable to currently producing fields that are likely to produce a tax liability for the company or companies producing them. The per-barrel expenditures reflect expenditures **per taxable barrel** and do not reflect expenditures per all barrels produced. (3) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, and constant expenditures for the entire year. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

FY 2012 Production Tax Estimates - SB49

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$82.67	622,182	$51.4
Annual Production (bbl)			
Total		227,096,430	$18,774.1
Royalty, Federal and other barrels[1]		-34,669,890	($2,866.2)
Taxable barrels		192,426,540	$15,907.9
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.05		
TAPS Tariff	-$4.67		
Other	$0.33		
Total Transportation Costs	-$6.39	192,426,540	($1,229.6)
Deductible Lease Expenditures[2]			
Deductible Operating Expenditures	-$12.86		($2,474.1)
Deductible Capital Expenditures	-$13.14		($2,528.3)
Total Lease Expenditures	-$26.00	192,426,540	($5,002.4)
Production Tax			
Production Tax Value (PTV)			$9,675.9
Base Tax (25%*PTV)			$1,443.2
Production Tax Value per barrel	$50.28		
Progressive Tax			$1,148.2
Total Tax before credits			$2,591.4
Credits (includes $300M in well lease exp credit)			($750.0)
Estimated Total Tax after credits[3]			**$1,841.4**

Notes: DOR revenue historical and current models are based on fiscal year data, which is also used for this analysis. SB49 would use calendar year averages for production, price, and costs, and the results may differ slightly from that shown in this analysis. (1) Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property and barrels used in production. (2) Deductible Lease Expenditures represents our best estimate of lease expenditures that are applicable to currently producing fields that are likely to produce a tax liability for the company or companies producing them. The per-barrel expenditures reflect expenditures per **taxable barrel** and do not reflect expenditures per all barrels produced. (3) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, and constant expenditures for the entire year. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

8) **Please recast the fiscal note analysis using flat oil prices of $100, $110, and $120 instead of the Department's forecast oil prices.**

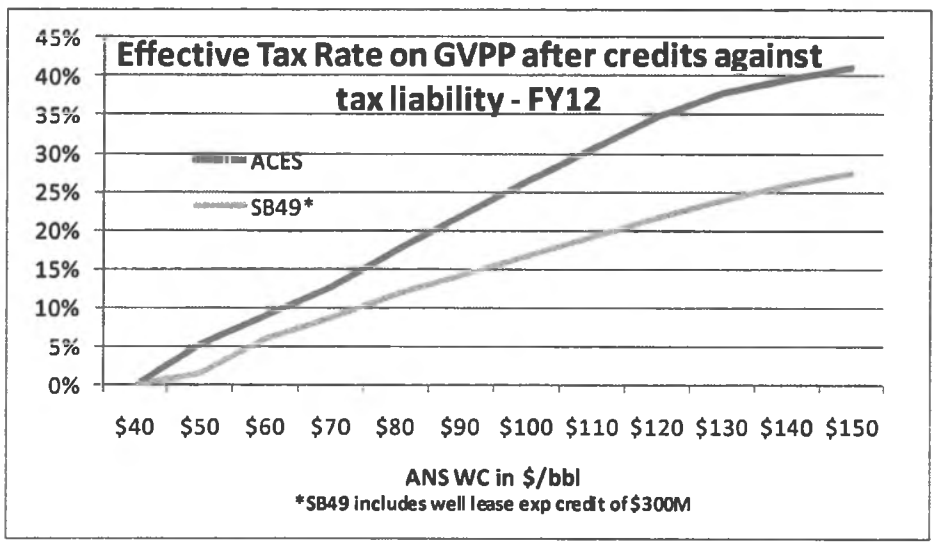
Revenue Impact of Progressivity Portion of SB49, at Requested Oil Prices (in $millions)					
ANS WC Price in $/bbl	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
$100	$669	$1,335	$1,260	$1,336	$1,272
$110	$948	$1,884	$1,787	$1,880	$1,799
$120	$1,269	$2,518	$2,394	$2,505	$2,405

9) **Provide a 5-year forecast for capital expenditures and the credits derived from those expenditures.**

Estimated Capital Expenditures and Credits, FY 2011 - FY 2015 in $millions					
	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Forecasted Capital Expenditures	$2,572	$2,936	$3,175	$3,019	$2,899
Total Forecasted Credits*	$665	$675	$675	$650	$625

*Total Forecasted Credits includes both credits likely to be used against tax liabilities and credits for which transferable tax credit certificates will be issued, without regard to the requirement that use of the credits must be split between two years.

10) **Provide a chart of effective tax rates under current law and SB 49 using forecasted transportation costs, lease expenditures, and credits for FY 2012.**



11) Provide information to show whether the $1.1 billion in credits paid to explorers has led to any production.

The $1.1 billion in tax credits referenced above is the estimated amount of credits for which credit certificates have been issued. A large portion of those certificates have been issued to companies developing the Oooguruk and Nikaitchuq units. Both of those units are now in production, with the Oooguruk unit producing about 10,000 barrels per day, and the Nikaitchuq unit began production in February of this year. That production could be attributed to a portion of the $1.1 billion in credit certificates issued.

12) Provide a breakout of the types of capital expenditures in as much detail as possible.

Types of capital expenditures provided on documents provided by oil and gas producing companies include the following categories:

- Exploration Drilling
- Appraisal Drilling
- Well Tie Ins
- Wellwork
- Facility Capacity Upgrades
- Facility – Integrity
- Seismic Acquisition & Test
- Major Accident Review
- Waterflood Optimization
- Roads, Pads and Runway
- Facility Siting Mitigation
- Fire and Gas / Automation
- Chemical Storage
- Infrastructure

We do not have any more detail about types of capital expenditures for current expenditures.

We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Attachment A: Exploratory Wells, Well Name, and Well Operator

Year	Operator	Well Name	API Well Number
1995			
	ARCO ALASKA INC	ALPINE 1	50-103-20211-00-00
		ALPINE 1A	50-103-20211-01-00
		FIORD 3	50-103-20210-00-00
		FIORD 3A	50-103-20210-01-00
	BP EXPLORATION (ALASKA) INC	BADAMI 4	50-629-22532-00-00
		BADAMI 5	50-629-22533-00-00
		MILNE PT UNIT KR E-13	50-029-22536-00-00
		PRUDHOE BAY UN NIA NK-27	50-029-22547-00-00
1996			
	ARCO ALASKA INC	ALPINE 3	50-103-20234-00-00
		BERGSCHRUND 2	50-103-20232-00-00
		NANUK 1	50-103-20238-00-00
		NEVE 1	50-103-20231-00-00
		TEMPTATION 1	50-103-20233-00-00
		TEMPTATION 1A	50-103-20233-01-00
	BP EXPLORATION (ALASKA) INC	NORTH MILNE POINT 2	50-029-22653-00-00
		SOURDOUGH 3	50-089-20026-00-00
	CONOCOPHILLIPS ALASKA INC	ALPINE 1B	50-103-20211-02-00
		BERGSCHRUND 2A	50-103-20232-01-00
1997	ARCO ALASKA INC	TARN 2	50-103-20247-00-00
		TARN 3	50-103-20248-00-00
		TARN 3A	50-103-20248-01-00
		TARN 4	50-103-20249-00-00
	BP EXPLORATION (ALASKA) INC	PETE'S WICKED 1	50-029-22737-00-00
		PRUDHOE BAY UN MDS E-100	50-029-22819-00-00
		PRUDHOE BAY UN NIA NK-41	50-029-22778-00-00
		PRUDHOE BAY UN PTM P1-09	50-029-22704-00-00
	CONOCOPHILLIPS ALASKA INC	KUPARUK RIV UNIT 2F-18	50-029-22720-00-00
		WEST GOLDHILL 2F-20	50-029-22739-00-00
1998	ARCO ALASKA INC	KALUBIK 2	50-103-20252-00-00
		KALUBIK 3	50-103-20251-00-00
		NUIQSUT 1	50-103-20253-00-00
	BP EXPLORATION (ALASKA) INC	DUCK IS UNIT MPI 2-56/EID	50-029-22863-00-00
		DUCK IS UNIT MPI 2-56A/EID	50-029-22863-01-00
		PRUDHOE BAY UN BORE 02-01	50-029-22866-00-00
		PRUDHOE BAY UN BORE L-100	50-029-22858-01-00
		PRUDHOE BAY UN BORE L-101	50-029-22865-00-00
		PRUDHOE BAY UN MDS E-101	50-029-22909-00-00
		PRUDHOE BAY UN NWE 01-01	50-029-22858-00-00
1999	ARCO ALASKA INC	FIORD 4	50-103-20289-00-00
		FIORD 5	50-103-20292-00-00
		MELTWATER SOUTH 1	50-287-20014-00-00
	BP EXPLORATION (ALASKA) INC	PRUDHOE BAY UN POL V-200	50-029-22937-00-00

Source: AOGCC

Attachment A: Exploratory Wells, Well Name, and Well Operator

		RED DOG 1	50-089-20027-00-00
2000	ARCO ALASKA INC	CLOVER A	50-103-20310-00-00
		MELTWATER NORTH 2	50-103-20321-00-00
		MELTWATER NORTH 2A	50-103-20321-01-00
	BP EXPLORATION (ALASKA) INC	WEST GWYDYR 1	50-029-22954-00-00
	CONOCOPHILLIPS ALASKA INC	MELTWATER NORTH 1	50-103-20326-00-00
		NANUK 2	50-103-20332-00-00
		SPARK 1	50-103-20313-00-00
2001	CONOCOPHILLIPS ALASKA INC	ATLAS 1	50-103-20360-00-00
		ATLAS 1A	50-103-20360-01-00
		COLVILLE RIV UNIT CD2-33	50-103-20381-00-00
		COLVILLE RIV UNIT CD2-33A	50-103-20381-01-00
		KUPARUK RIV UNIT 3S-26	50-103-20361-01-00
		MOOSE TOOTH C	50-103-20315-00-00
		NANUQ 3	50-103-20365-00-00
		NIGLIQ 1	50-103-20370-00-00
		NIGLIQ 1A	50-103-20370-01-00
		PALM 1	50-103-20361-00-00
		RENDEZVOUS 2	50-103-20363-00-00
		RENDEZVOUS A	50-103-20316-00-00
		SILVERTIP 1J-14	50-029-22990-00-00
		SPARK 1A	50-103-20313-01-00
	CONOCOPHILLIPS COMPANY	TRAILBLAZER A-01	50-103-20364-00-00
		TRAILBLAZER H-01	50-103-20369-00-00
2002	ANADARKO PETROLEUM CORPO	ALTAMURA 1	50-103-20403-00-00
	BP EXPLORATION (ALASKA) INC	PRUDHOE BAY UN NWE 04-01	50-029-23072-00-00
	CONOCOPHILLIPS ALASKA INC	CIRQUE 3	50-103-20399-00-00
		CIRQUE 4	50-103-20404-00-00
		GRIZZLY 1	50-287-20015-00-00
		HEAVENLY 1	50-287-20016-00-00
		HUNTER A	50-103-20405-00-00
		LOOKOUT 1	50-103-20359-00-00
		LOOKOUT 2	50-103-20410-00-00
		MITRE 1	50-103-20409-00-00
		NANUQ 5	50-103-20414-00-00
2003	CONOCOPHILLIPS ALASKA INC	OBERON 1	50-103-20443-00-00
	PIONEER NATURAL RESOURCES A	IVIK 1	50-703-20436-00-00
		NATCHIQ 1	50-703-20438-00-00
		OOOGURUK 1	50-703-20437-00-00
2004	ANADARKO PETROLEUM CORPO	HOT ICE 1	50-103-20451-00-00
	CONOCOPHILLIPS ALASKA INC	CARBON 1	50-103-20477-00-00
		PLACER 1	50-103-20481-00-00
		PLACER 2	50-103-20488-00-00
		SCOUT 1	50-103-20479-00-00
		SPARK 4	50-103-20480-00-00
	KERR-MCGEE OIL & GAS CORP	NIKAITCHUQ 1	50-629-23193-00-00

Source: AOGCC

Attachment A: Exploratory Wells, Well Name, and Well Operator

		NIKAITCHUQ 2	50-629-23199-00-00
	TOTAL E&P USA INC	CARIBOU 26-11 1	50-279-20009-00-00
2005	CONOCOPHILLIPS ALASKA INC	IAPETUS 2	50-103-20506-00-00
		KOKODA 1	50-279-20011-00-00
		KOKODA 5	50-279-20012-00-00
		KUPARUK RIV U WSAK 1Q-101	50-029-23282-00-00
		KUPARUK RIV U WSAK 3J-101	50-029-23283-00-00
	KERR-MCGEE OIL & GAS CORP	ATARUQ 2	50-103-20508-00-00
		ATARUQ 2A	50-103-20508-01-00
		KIGUN 1	50-629-23239-01-00
		NIKAITCHUQ 3	50-629-23242-00-00
		NIKAITCHUQ 4	50-629-23241-00-00
		TUVAAQ ST 1	50-629-23239-00-00
2006	CONOCOPHILLIPS ALASKA INC	ANTIGUA 1	50-029-23299-00-00
		COLVILLE RIV QANN CD2-404	50-103-20530-00-00
		KUPARUK RIV UNIT 1H-NORTH	50-029-23294-00-00
		KUPARUK RIV UNIT 1H-SOUTH	50-029-23296-00-00
		KUPARUK RIV UNIT 1R-EAST	50-029-23295-00-00
	ENI US OPERATING CO INC	OLIKTOK POINT I-1	50-029-23324-00-00
	FEX LIMITED PARTNERSHIP	AKLAQ 2	50-279-20014-00-00
	PIONEER NATURAL RESOURCES A	CRONUS 1	50-103-20523-00-00
		HAILSTORM 1	50-029-23287-00-00
2007	ANADARKO PETROLEUM CORPO	JACOB'S LADDER C	50-029-23330-00-00
	BP EXPLORATION (ALASKA) INC	MILNE PT UNIT LIVIANO 1	50-029-23343-00-00
		MILNE PT UNIT LIVIANO 1A	50-029-23343-01-00
		MILNE PT UNIT PESADO 1	50-029-23345-00-00
		MILNE PT UNIT PESADO 1A	50-029-23345-01-00
		MT ELBERT 1	50-029-23302-00-00
	BROOKS RANGE PETROLEUM	SAK RIVER 1	50-029-23336-00-00
	CONOCOPHILLIPS ALASKA INC	INTREPID 2	50-023-20036-00-00
		NOATAK 1	50-279-20013-00-00
	ENI US OPERATING CO INC	MAGGIORE 1	50-029-23342-00-00
		OLIKTOK POINT I-2	50-029-23326-00-00
		ROCK FLOUR 2	50-029-23335-00-00
		ROCK FLOUR 3	50-029-23341-00-00
	FEX LIMITED PARTNERSHIP	AKLAQ 6	50-279-20019-00-00
		AKLAQYAAQ 1	50-279-20018-00-00
		AMAGUQ 2	50-279-20017-00-00
2008	ANADARKO PETROLEUM CORPO	GUBIK 3	50-287-20017-00-00
		JACOB'S LADDER C-A	50-029-23330-01-00
	BROOKS RANGE PETROLEUM	NORTH SHORE 1	50-029-23340-00-00
		TOFKAT 1	50-103-20567-00-00
		TOFKAT 1A	50-103-20567-01-00
		TOFKAT 1B	50-103-20567-02-00
	CONOCOPHILLIPS ALASKA INC	CHAR 1	50-103-20564-00-00
		SPARK DD-9	50-103-20569-00-00
	SAVANT ALASKA LLC	KUPCAKE 1	50-029-23382-00-00
	UNION OIL CO OF CALIFORNIA	MASTODON 6-3-9	50-287-20023-00-00

Source: AOGCC

Attachment A: Exploratory Wells, Well Name, and Well Operator

		PANTHERA 28-6-9	50-223-20023-00-00
		SMILODON 9-4-9	50-223-20022-00-00
2009	ANADARKO PETROLEUM CORPO	CHANDLER 1	50-287-20022-00-00
		GUBIK 4	50-287-20025-00-00
		WOLF CK 4	50-119-20002-00-00
	CONOCOPHILLIPS ALASKA INC	GRANDVIEW 1	50-103-20594-00-00
		PIONEER 1	50-103-20595-00-00
	PIONEER NATURAL RESOURCES /	OOOGURUK ODST-45A	50-703-20577-01-00
	ULTRASTAR EXPLORATION LLC	DEWLINE 1	50-029-23408-00-00
	UNION OIL CO OF CALIFORNIA	BLUEBUCK 6-7-9	50-223-20024-00-00
		MUSKOXEN 36-7-8	50-287-20024-00-00
2010	BROOKS RANGE PETROLEUM	SAK RIVER 1A	50-029-23336-02-00
	EXXONMOBIL CORPORATION	PTU 15	50-089-20030-00-00
		PTU 16	50-089-20031-00-00
	SAVANT ALASKA LLC	BADAMI UNIT B1-38	50-029-23407-00-00

Source: AOGCC

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

March 21, 2011

The Honorable Joe Paskvan
The Honorable Tom Wagoner
Co-Chairs, Senate Resources Committee
Alaska State Senate
Juneau, AK 99801

The Honorable Eric Feige
The Honorable Paul Seaton
Co-Chairs, House Resources Committee
Alaska State House
Juneau, AK 99801

The Honorable Bill Stoltze
The Honorable Bill Thomas
Co-Chairs, House Finance Committee
Alaska State House
Juneau, AK 99801

SUBJECT: Corrected Well Data from Alaska Oil & Gas Conservation Commissioner (AOGCC)

Dear State Legislators:

It has been brought to our attention that the drilling activity charts presented by the Department of Revenue on the basis of AOGCC data contained some inaccuracies. Simply put, we received different sets of data from different people within AOGCC and we realized there was a problem because the data sets didn't match. It has to do with what is and is not included as you work through the well data. Once we realized there was a problem, we worked with AOGCC to determine the correct data and it is enclosed herein. These updated slides have been based on AOGCC data and their staff have cross-checked the numbers with their internal, confidential database. What has not changed is the fact that exploration is down in 2010 and that only one exploration well is expected in 2011 by the Alaska Department of Natural Resources.

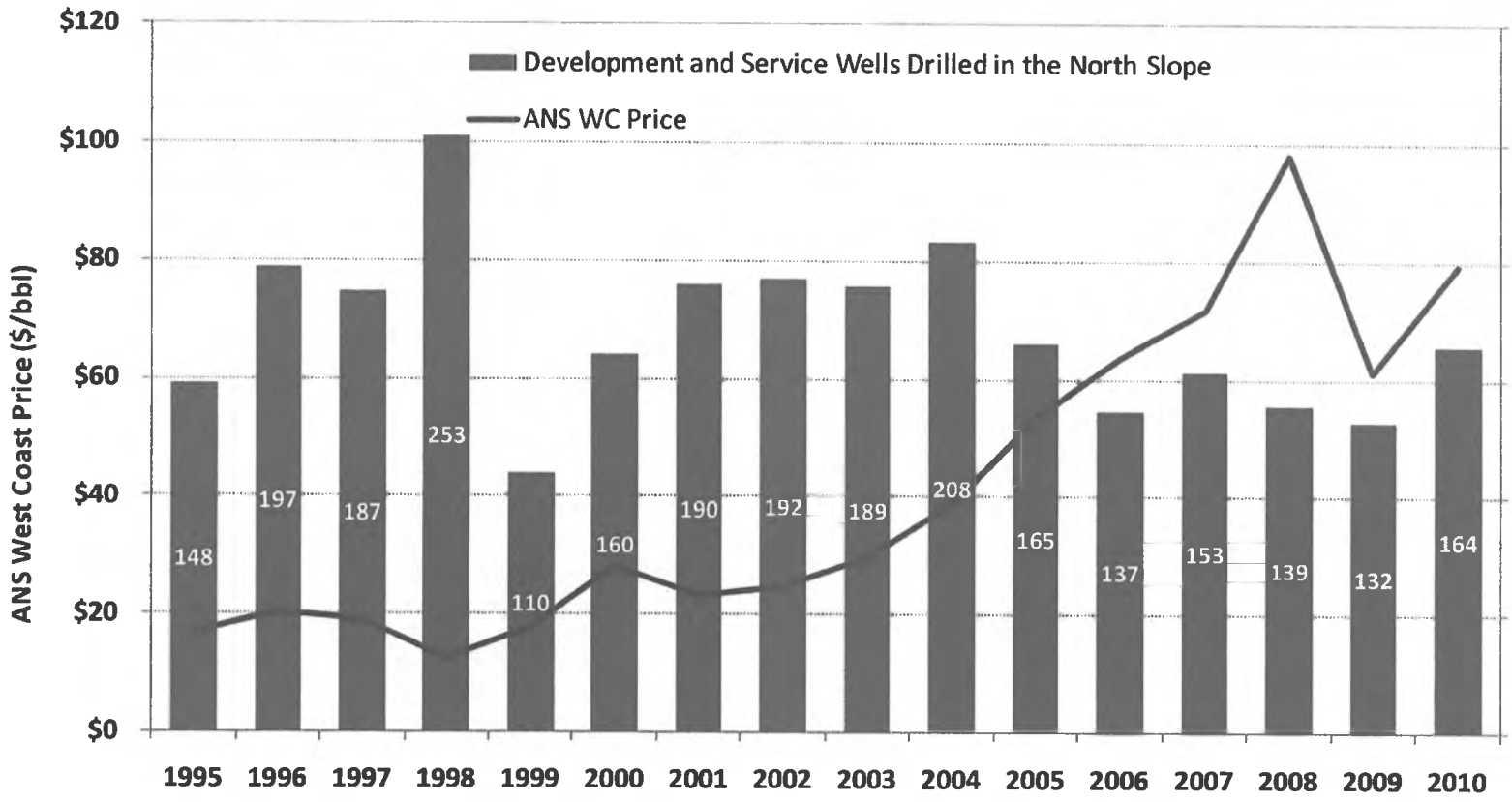
We would like to apologize for this error and provide assurance to the committees that we will be more diligent in cross checking information before providing it to any legislative body.

Sincerely,

Bruce Tangeman
Deputy Commissioner

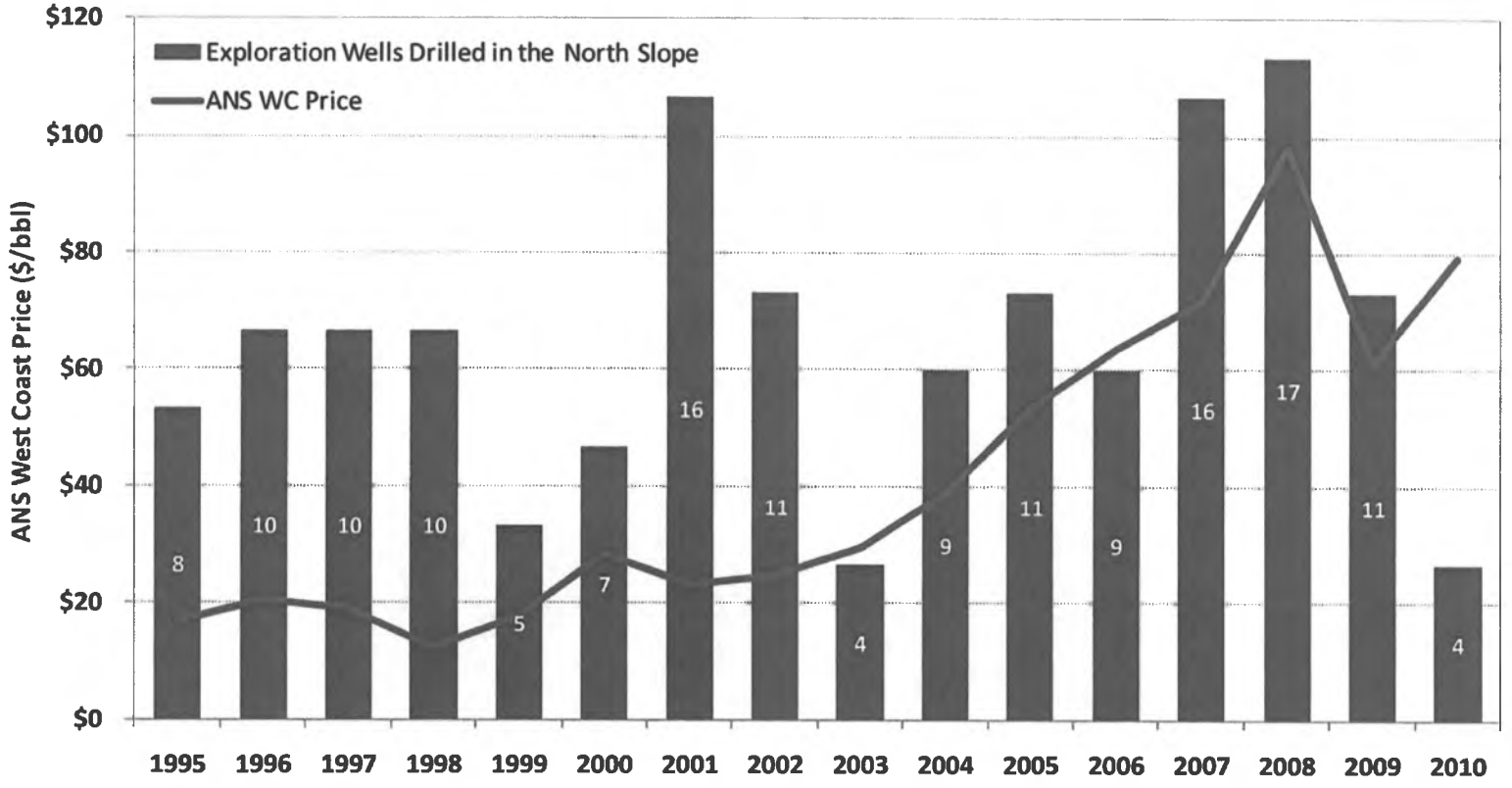
Enclosure

North Slope Development Drilling



Source: Alaska Oil and Gas Conservation Commission

North Slope Exploration Drilling



Source: Alaska Oil and Gas Conservation Commission

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

March 22, 2011

The Honorable Joe Paskvan
Co-Chair, Senate Resources Committee
State Capitol Room 115
Juneau AK, 99801

The Honorable Thomas Wagoner
Co-Chair, Senate Resources Committee
State Capitol Room 427
Juneau AK, 99801

SUBJECT: AK Industry Information Disclosure

Dear Co-Chairs Paskvan and Wagoner:

The purpose of this document is to respond to a follow-up question raised by members of the Senate Resources Committee. Please see the enclosed spreadsheet titled 'Alaska Oil and Gas Industry Submittal and Disclosure Summary'.

Please feel free to contact me for any further details.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Enclosure

cc: Senate Resources Committee

Alaska Oil and Gas Industry Information Submittal and Disclosure Summary

Compiled with Input from DOR, DNR, DOLWD & AOGCC, March 22,2011

Type of Data	Agency Receiving Data	Agencies With Which Data May be Shared	Reason for Data Submission (Citation)	Submittal Timeframe	Publication and Public Access	Form of Reported Info.
EXPLORATION AND APPRAISAL						
Joint Operating Agreements	DNR-DOG	Public portions of unit operating agreements; confidential portions may be shared with DOR under AS38.05.035(a)(12)	Required for unitization under AS 38.05.180(p), or for approval of drillling or development contracts under AS 38.05.180(t); 11 AAC 83.301 - 11 AAC 83.395; 11 AAC 83.400	With the application to unitize	generally public, but portions may be entitled to confidentiality	Varies
Work Programs and Budgets	AOGCC: Proposed work programs only, no budget information	DNR-DOG authorized personnel upon request (confidential wells on state lands only)	20 AAC 25.005, 20 AAC 25.010, 20 AAC 25.015, 20 AAC 25.105, 20 AAC 25.280	Prior to work (as much notice as possible)	Records for exploratory and stratigraphic test wells / wellbores are held confidential for 25-months, then released to the public record (excluding those few that have been granted extended confidential status by DNR's Commissioner). Public records are available through the AOGCC library and	Printed (AOGCC library); scanned records (Internet)
	DNR-DOG (Unit Section): Plans of Exploration; no budget	Some is public; confidential may be shared with DOR under AS38.05.035(a)(12)	11 AAC 83.301 - 11 AAC 83.395;	With application to unitize and periodically after that	generally public, but portions may be entitled to confidentiality	
	DNR-DOG (Permitting Section): Plan of Operations, no budget DNR-DOG (Leasing Section): Exploration License, work commitment	Plan of Operations - Public document, all agencies	Permit Application (11 AAC 83.158 and 346)		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
Seismic	DNR-DOG (Permitting Section)	Public document, all agencies	Permit Application (11 AAC 96.210)		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
	DNR-DOG	Confidential seismic remains in DOG possession at all times; other authorized DNR personnel may view data as needed.	Entitled to seismic on state lands through MLUP permit requirements (AAC 96.210) , tax credit requirements (AS 43.55.025 and .023(a)(2)) and exploration license requirements (11 AAC 82.981); Entitled to seismic on fed or private lands if issuing these tax credits; also obtains advanced processing datasets in units upon request to evaluate unit & PA formation, expansion or support for operator-requested unit actions (AAC 83.306, etc.)	Statute: notify DNR w/in 30 days of completion of processing. Reality: MLUP data may take months.	Data receiving tax credits will be publicly released after 10 yrs, subject to private landowner approval (public access system to be determined). MLUP and unit request data remain confidential indefinitely.	Formerly included paper, now electronic, in industry-standard formats
Daily Drilling Reports	AOGCC	DNR-DOG authorized personnel upon request (confidential wells on state lands only)	Maintnence of accurate well history records (20 AAC 25.070)	30 days after completion, suspension or abandonment of well/wellbore	See "Work Programs and Budgets", above	Printed (AOGCC library); scanned records (Internet)
Logs & Wellbore Surveys	AOGCC	DNR-DOG has its own specific well log data submittal requirements; other logs disclosed to DNR-DOG authorized personnel upon request (confidential wells on state lands only)	AS 31.05.030, 20 AAC 25.071 (Reason: accurate well records)	90 days after completion, suspension or abandonment of well/wellbore	See "Work Programs and Budgets", above	Printed (AOGCC library); scanned records (Internet)
Well Tests	AOGCC	DNR-DOG authorized personnel upon request (confidential wells on state lands only)	Maintnence of accurate well history records (20 AAC 25.071)	30 days after completion, suspension or abandonment of well/wellbore	See "Work Programs and Budgets", above	Printed (AOGCC library); scanned records (Internet)
Cuttings and Conventional Core Chips	AOGCC	DNR-DOG authorized personnel upon request (confidential wells on state lands only)	Maintnence of accurate well history records (20 AAC 25.071)	Cuttings: 30 days after completion, suspension or abandonment of well/wellbore; Core chips: 30 days after the conventional core is	See "Work Programs and Budgets", above. Cuttings and core chips are available at the Geologic Materials Center.	Rock samples
Geological Models and Maps	AOGCC and DNR: Supplied by Unit Operator	DNR-DOG upon request (non-confidential information only)	Field and pool regulation and classification (20 AAC 25.520) and regulation of underground injection of fluids (20 AAC 25.460)	Non-confidential information available upon publication of AOGCC order; confidential information not available for release	AOGCC library (public records only)	Printed (AOGCC library)
	DNR-DOG (Permitting Section): Project area map	Public document, all agencies	Permit Application (11 AAC 83.158 and 346)		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
	DNR-DOG: possibly with unit application; Participating Area applications	May be shared with DOR under AS38.05.035(a)(12)	11 AAC 83.301 - 11 AAC 83.395	with application to unitize or application to form PA	entitled to confidentiality	
All data collected in drilling and evaluating wells, including interpretive, value-added, and wellbore seismic data not reported to AOGCC	DNR-DOG	Confidential well data remains in DOG possession at all times; other authorized DNR personnel may view data as needed.	Receives comprehensive datasets for wells on state leases through Lease Plan of Operations (AAC 83.158); also on fed and private lands if issuing tax credit (AS 43.55.025 and 023(a)(2)).	varies, but prompt	Data submitted under Plan of Ops remains confidential indefinitely; tax credit well data to be released after AOGCC well confidentiality expires, subject to federal primacy and private landowner approval (public access to be determined).	Varies

Alaska Oil and Gas Industry Information Submittal and Disclosure Summary

Compiled with Input from DOR, DNR, DOLWD & AOGCC, March 22,2011

Type of Data	Agency Receiving Data	Agencies With Which Data May be Shared	Reason for Data Submission (Citation)	Submittal Timeframe	Publication and Public Access	Form of Reported Info.
DEVELOPMENT						
Development Plans with Opex and Capex Projections	AOGCC: proposed work programs only, no budget or opex/capex information	Development and service well information submitted to AOGCC is not confidential	20 AAC 25.005, 20 AAC 25.010, 20 AAC 25.015, 20 AAC 25.105, 20 AAC 25.280	Prior to work (as much notice as possible)	AOGCC library and Internet (public records only)	Printed (AOGCC library); scanned records (Internet)
	DNR-DOG (Unit Section): Plans of Development	Some is public; confidential may be shared with DOR under AS38.05.035(a)(12)	11 AAC 83.301 - 11 AAC 83.395;	With application to unitize and periodically after that	generally public, but portions may be entitled to confidentiality	
	DNR-DOG (Permitting Section): Plan of Operations	Public document, all agencies	Permit Application (11 AAC 83.158 and 346)			
Construction Progress Reports	DNR-DOG (Permitting Section): (limited)	Public document, all agencies	Status-Completion Reports	semi-annual (May and Nov, and at project completion)	Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
Seismic	DNR-DOG	Confidential seismic remains in DOG possession at all times; other authorized DNR personnel may view data as needed.	Entitled to seismic on state land thru MLUP permit (11 AAC 96.210), tax credits (AS 43.55.025 and .023(a)(2)), exploration license (11 AAC 82.981) & on fed or private lands if issuing these tax credits; also obtains advanced processing datasets in units upon request to evaluate unit & PA formation and expansion requests (AAC 83.306, etc.)	Quarterly	Data receiving tax credits will be publicly released after 10 yrs, subject to private landowner approval (public access system to be determined). MLUP and unit request data remain confidential indefinitely.	Formerly included paper, now electronic, in industry-standard formats
Daily Drilling Reports	AOGCC	Development and service well information is not confidential	20 AAC 25.070 (Reason: accurate well history records)	30 days after completion, suspension or abandonment of well/wellbore	AOGCC library and Internet (public records only)	Printed (AOGCC library); scanned records (Internet)
Logs & Wellbore Surveys	AOGCC and DNR-DOG (most units)	Development and service well information submitted to AOGCC is not confidential; Logs, tops, etc. submitted to DNR are not shared with other agencies	AOGCC: AS 31.05.030, 20 AAC 25.071; DNR: unit agreements.	90 days after completion, suspension or abandonment of well/wellbore	AOGCC: library and Internet (public records only); DNR submissions are not released to public	Printed (AOGCC library); scanned records (Internet)
Well Tests	AOGCC	Development and service well information submitted to AOGCC is not confidential	20 AAC 25.071 (Reason: accurate well records)	30 days after completion, suspension or abandonment of well/wellbore	AOGCC library and Internet (public records only)	Printed (AOGCC library); scanned records (Internet)
Cuttings and Conventional Core Chips	AOGCC	Development and service well information submitted to AOGCC is not confidential	20 AAC 25.071 (Reason: accurate well records)	Cuttings: 30 days after completion, suspension or abandonment of well/wellbore; Core chips: 30 days after the conventional core is	Samples for development or service well/wellbores are not confidential; available at the Geologic Materials Center.	Rock samples
Reservoir Characterization	AOGCC	DNR-DOG upon request (non-confidential information only)	20 AAC 25.520 (Reason: field and pool regulation and classification) and 20 AAC 25.460 (Reason: regulation of underground injection of fluids)	Non-confidential information available upon publication of AOGCC order; confidential information not available for release.	AOGCC library and Internet (public records only)	Printed (AOGCC library); scanned records (Internet)
	DNR-DOG	Some is public; confidential may be shared with DOR under AS38.05.035(a)(12)	11 AAC 83.301 - 11 AAC 83.395	with application to unitize or application to form PA	May be entitled to confidentialtiy	
Interpretive Reservoir Studies, Models, Maps, Etc.	DNR-DOG	Confidential studies, maps, etc. remain in DOG possession at all times; other authorized DNR personnel may view data as needed.	Support for operator-requested unit actions (AAC 83.306, etc.); Include a wide variety of interpretive info not specific to individual wells	varies, but prompt	This information submitted to DNR remains indefinitely confidential	n/a
PRODUCTION / OPERATIONS						
Production	AOGCC	Regular production information is not confidential; database transfer to DNR completed monthly	20 AAC 25.230 (Reason: regular production records are public-domain)	One-month reporting lag	Internet (regular production data; AOGCC statistical report)	Downloadable database in MS Access format; downloadable ASCII text file; production charts
	DNR-DOG	Production data is generally public	AS 38.05.180(x)		Production data is generally public	
	DNR-DOG (Permitting Section): Plan of Operations	Public document, all agencies	Permit Application (11 AAC 83.158 and 346)		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
	DOR	DNR/Upon Request/Under Confidentiality Agreement.	AS 43.55.040	Daily & Monthly	Only released in aggregated form.	Received via email, fax, PDF, excel spreadhseet and plain text.
Injection	AOGCC	Regular injection information is not confidential; database transfer to DNR completed monthly	20 AAC 25.432 (Reason: regular injection records are public-domain)	One-month reporting lag	Internet (regular injection data; AOGCC statistical report)	Downloadable database in MS Access format; downloadable ASCII text file; production charts
	DNR-DOG: Plan of Operations, storage	Public Data - All Agencies	AS 38.05.180(x); Permit Application (11 AAC 83.158)		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
Facility Maps and Studies	DNR-DOG (Permitting Section)	Public document, all agencies	Permit Application (11 AAC 83.158 and 346)		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
Safety and Environmental Reports	DNR-DOG (Permitting Section)	Public document, all agencies	Corrective action plans		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
	DNR-PSIO	Generally PSIO can openly share the non-confidential information with liaison agencies. Caveat: most of what operators share with PSIO is confidential and typically PSIO is given a presentation by operators and not allowed to take any information, other than hand-written notes.	Receives some information regarding root causes of incidents and corrective actions - typically plays into discussions of operator quality management/business practices and operations (AO 234 ; DOG leases)	Varies on operator and their willingness to cooperate and share information with PSIO.	Little, but varies.	Varies, but typically in presentation/discussion format and PSIO is not allowed to take any information, other than hand-written notes.
Work Programs and Budgets	DNR-DOG: (Permitting Section): No budget	Public document, all agencies	Permit Application (11 AAC 83.158 and 346)		Public Document, as Public Noticed	electronic filing not required (may be submitted as PDF
	DNR-PSIO	Generally PSIO can openly share the non-confidential information with liaison agencies. Caveat: most of what operators share with PSIO is confidential and typically PSIO is given a presentation by operators and not allowed to take any information, other than hand-written notes.	Some information received regarding quality management/business practices and operations - typically in response to an incident involving infrastructure failure (AO 234; DOG leases)	Varies on operator and their willingness to cooperate and share information with PSIO.	Little, but varies.	Varies, but typically in presentation/discussion format and PSIO is not allowed to take any information, other than hand-written notes.

Alaska Oil and Gas Industry Information Submittal and Disclosure Summary

Compiled with Input from DOR, DNR, DOLWD & AOGCC, March 22,2011

Type of Data	Agency Receiving Data	Agencies With Which Data May be Shared	Reason for Data Submission (Citation)	Submittal Timeframe	Publication and Public Access	Form of Reported Info.
BUDGET / EXPENDITURE / COST DATA						
Sales Price and Netback Costs	DOR, Tax Division	AS 38.05.036(c) and AS 43.55.230 specify the information DOR can share with DNR.	Administering the production tax (e.g. this is used in determining the gross value at point of production).	Supplied to DOR monthly (one-month lag) and in annual filings.	Some data in this category may be disclosed to the public provided it is properly aggregated and allowed to be released under 43.05.230 and 43.55.890.	Summarized data sent to DOR in Excel monthly information report. Detailed information provided in various formats.
Sales Contracts	DOR, Tax Division	AS 38.05.036(c) and AS 43.55.230 specify the information DOR can share with DNR.	Administering the production tax (e.g. this is used in determining the gross value at point of production).	Supplied to DOR monthly (one-month lag) and in annual filings.	Some data in this category may be aggregated and used in calculations that are subsequently disclosed to the public.	Contracts provided in PDF or Word documents.
Tax Credit Information (applications for tax credit certificates, credits claimed against tax liability)	DOR, Tax Division	AS 38.05.036(c) and AS 43.55.230 specify the information DOR can share with DNR.	Administering the production tax (e.g. calculating the tax liability or issuing tax credit certificates.)	Credit applications are received throughout the year. Credit information is received by DOR on monthly information report (one-month lag) and in annual filings.	Some data in this category may be disclosed to the public provided it is properly aggregated and allowed to be released under 43.05.230 and 43.55.890.	Credit information submitted through credit application forms (PDF files) and monthly information report (Excel file).
Opex- Projections	DOR, Tax Division	AS 38.05.036(c) and AS 43.55.230 specify the information DOR can share with DNR.	Used in forecasting production tax revenue.	Supplied to DOR twice a year (fall and spring)	Some data in this category is aggregated and used in the DOR forecast of total ANS expenditures, which is published in RSB.	Copies of communications with WIOs is provided (PDF copies of letters).
Capex- Projections	DOR, Tax Division	AS 38.05.036(c) and AS 43.55.230 specify the information DOR can share with DNR.	Used in forecasting production tax revenue.	Supplied to DOR twice a year (fall and spring)	Some data in this category is aggregated and used in the DOR forecast of total ANS expenditures, which is published in RSB.	Copies of communications with WIOs is provided (PDF copies of letters).
Opex- Actual	DOR, Tax Division	AS 38.05.036(c) and AS 43.55.230 specify the information DOR can share with DNR.	Administering the production tax (e.g. this is used in determining the production value).	Summarized opex data is supplied to DOR monthly (one-month lag) with limited breakdown of expense types. Details sometimes included in back-up files.	43.55.890 allows for lease expenditures to be disclosed to the public when aggregated among 3 or more companies.	Summarized data sent to DOR through Excel monthly reporting form. Supplemental detailed information provided in various formats.
Capex- Actual	DOR, Tax Division	AS 38.05.036(c) and AS 43.55.230 specify the information DOR can share with DNR.	Administering the production tax (e.g. this is used in determining the production tax value).	Summarized capex data is supplied to DOR monthly (one-month lag) with limited breakdown of expense type. Details sometimes included in back-up files.	43.55.890 allows for qualified capital expenditures to be disclosed to the public when aggregated among 3 or more companies.	Summarized data sent to DOR through Excel monthly reporting form. Detailed information provided in various formats.
ABANDONMENT						
Abandonment Plan and Budget	AOGCC: Well abandonment plan only, no budget information	DNR-DOG authorized personnel upon request (non-confidential wells and confidential wells on state lands only)	20 AAC 25.105 (Reason: accurate well records)	30 days after completion, suspension or abandonment of well/wellbore	Records for development or service well/wellbores are not confidential. Records for exploratory and stratigraphic test wells are held confidential for 25-months, then released to the public record (excluding those few that have been granted extended confidential status by DNR's Commissioner). Public records are available through the AOGCC library and Internet.	Printed (AOGCC library); scanned records (Internet)
	DNR-DOG (Permitting Section): Plan only DNR-DOG (Leasing Section): List of wells/infrastructure on lease	Public document, all agencies	Permit Application (11 AAC 83.158 and 346)		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
Progress Reports	AOGCC (well abandonment operations only, no budget information)	DNR-DOG authorized personnel upon request (non-confidential wells and confidential wells on state lands only)	20 AAC 25.070 (Reason: accurate well records)	30 days after completion, suspension or abandonment of well/wellbore	See "Abandonment Plan and Budget", above	Printed (AOGCC library); scanned records (Internet)
	DNR-DOG (Permitting Section)	Public document, all agencies	Status-Completion Reports		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
Environmental Clean-up Assessment	AOGCC	DNR-DOG authorized personnel upon request (non-confidential wells and confidential wells on state lands only)	Wellsite clearance inspection: physical condition of site only, does not include chemical sampling, analysis or reporting (Onshore: 20 AAC 25.170; Offshore: 20 AAC 25.172)	Upon completion of Inspection	See "Abandonment Plan and Budget", above	Printed (AOGCC library); scanned records (Internet)
	DNR-DOG (Permitting Section)	Public document, all agencies	Status-Completion Reports		Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
WORKFORCE / LABOR						
Unemployment Insurance Contributions	DOLWD-Employment Security Division	Disclore to certain agencies under AS 23.20.110.	AS 23.20.110	Quarterly	No	Electronic
Reports of Occupational Injury	DOLWD-Division of Workers' Compensation	Any government agency under 23.30.107(b)(1)	AS 23.30.070	Within 10 days of knowledge of occupational in	Not public - 23.30.107(b)	07-6101
Proof of Coverage (workers' comp insurance)	DOLWD-Division of Workers' Compensation	Information is public.	23.30.085	Within 10 days of policy issuance	Yes	Electronic
Reports of Occupational Fatality or Hospitalization	DOLWD-AKOSH Enforcement	Except for confidential data, information may be shared with PSIO and federal OSHA	AS 18.60.058	Immediately after each incident, but no less than 8 hours after employer awareness	Upon completion of investigation	Not consistent in every case - Potentially Public Records Act Disclosure and/or Press Release
Company Performance Reports and Self-Evaluation	DOLWD-AKOSH Consultation and Training	Only with employer consent - otherwise confidential	Voluntary Protection Program	Annual	No	N/A
Training and Development	DNR-DOG (Permitting Section)	Public document, all agencies	Data sumbitted voluntarily (not required)	Varies	Public Document, as Public Noticed	electronic filing not required (may be submitted as adobe .pdf)
Northstar Alaska Hire Quarterly Report	DOLWD-Commissioner's Office	Information is public.	Measure Alaska Residency as required by lease agreement.	Quarterly	Yes	Printed

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

March 22, 2011

The Honorable Joe Paskvan
Co-Chair, Senate Resources Committee
State Capitol Room 115
Juneau AK, 99801

The Honorable Thomas Wagoner
Co-Chair, Senate Resources Committee
State Capitol Room 427
Juneau AK, 99801

SUBJECT: Response #1 to Questions from SB 49 Bill Sectional Presentation in Senate Resources on March 11 and 14, 2011, and tax credits presentation on March 16, 2011.

Dear Co-Chairs Paskvan and Wagoner:

The purpose of this document is to respond to the follow-up questions raised by the Senate Resources Committee meeting during our presentation of the SB 49 bill introduction on March 11 and 14, 2011, and during our tax credits presentation on March 16, 2011. The requests/questions and responses follow. As noted in this document, there are a handful of remaining questions which we will provide answers to at a later date.

QUESTIONS FROM BILL INTRODUCTION PRESENTATION

1) **Discuss whether / how North Slope reserve additions recently reported by Conoco Phillips are included in our production forecast.**

   The Department of Revenue considers technically recoverable oil in the production forecast. Updated estimates of original oil in place (OOIP) and technically recoverable reserves are discussed with the individual operators on at least an annual basis and will be considered in future forecasts.

2) **What is the forecasted production decline over the next decade?**

The Department of Revenue's Fall 2010 production forecast, which includes producing, under development and under evaluation, projects an average decline rate of 2.1% per year from FY 2010 through FY 2020. The under evaluation portion is the most speculative and could greatly affect the production curve if it were not realized.

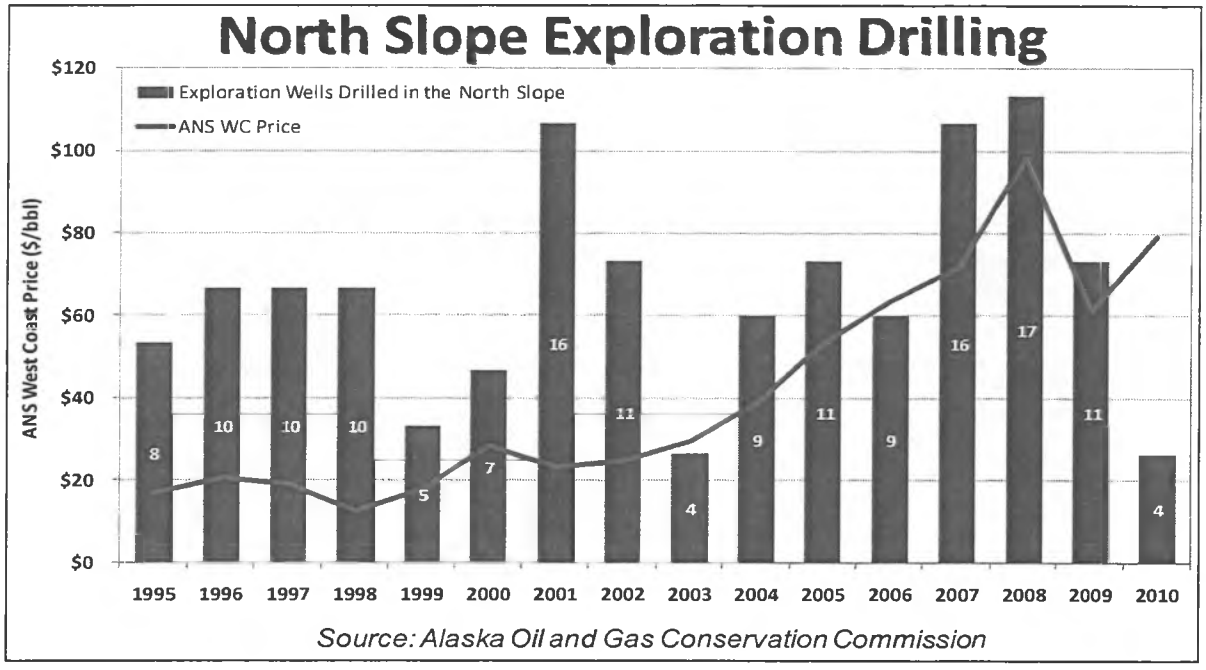
3) **What part of the Department's production forecast comes from areas that are not currently unitized?**

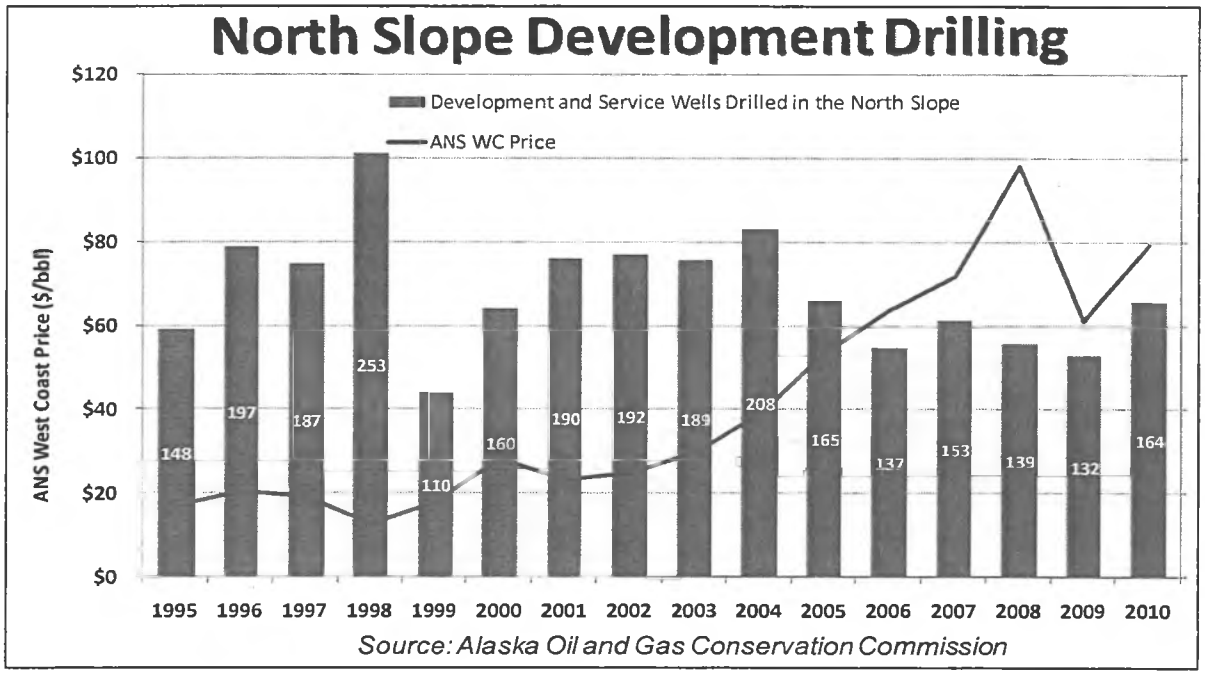
The vast majority of production in our forecast comes from areas that are currently unitized. Through FY 2020, the only production in our forecast that comes from an area that is not currently in a unit is a portion of the forecast production from the NPR-A. In general, production from areas that are not yet unitized does not have the level of certainty required to be included in our production forecast. In order to be included, a field must at least be "under evaluation," meaning it is a technically viable project where engineering, cost, risk and reward are all being actively evaluated. Most of the oil outside existing units does not yet meet these criteria.

4) Why was only one exploration well drilled in 2003?

It has been brought to our attention that the drilling activity charts presented by the Department of Revenue on the basis of AOGCC data contained some inaccuracies. Corrected exploration and development drilling activity charts are included below.

Several factors may have contributed to the decline in exploration drilling in 2003, including the economic downturn at the beginning of that decade, merger and acquisition activity impacting companies active in Alaska, and changes in corporate strategy.





5) **Compare trends in the number of exploration and development wells drilled in Alaska, to trends in the U.S. or worldwide.**

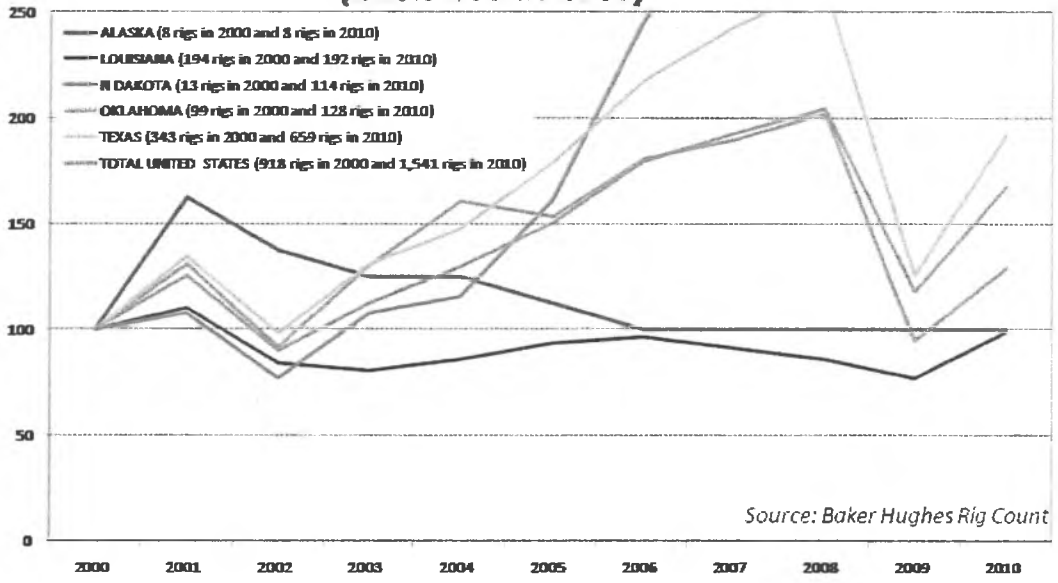
The number of active rigs can be used to compare oil and gas activity levels in various jurisdictions. The following charts show trends in rig counts in the United States, and internationally. These charts display the relative change in rig counts over the past decade using 2000 as a base year (the rig count for each series for any given year is represented relative to the rig count for that series in year 2000 – for example, if the rig count was to go from 8 in 2000 to 16 in 2010, this would be reflected in the chart by a line going from 100 in 2000 to 200 in 2010). These statistics include oil and gas rigs, active both onshore and offshore. No differentiation is made between exploration and development rigs in this context.

In summary, one can observe over the 2000 to 2010 period:

- A relatively flat rig count in Alaska
- The impacts of the recent recessions and of the "shale boom" in other US States
- Rig count in Europe remaining relatively stable
- Rig count in other areas, including the US, typically increasing by over 50%

Alaska and States with over 100 rigs in 2010

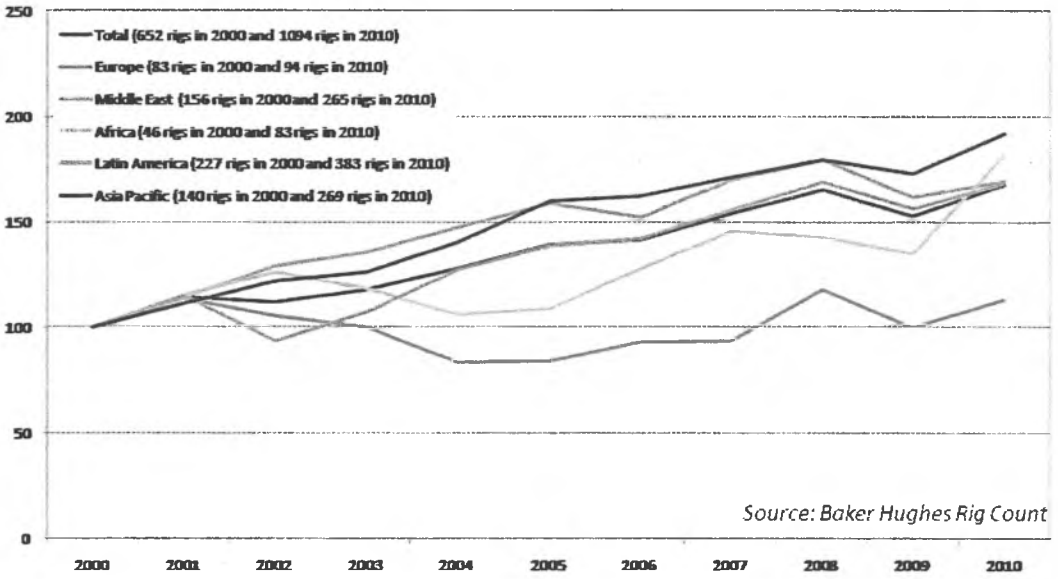
(basis 100 in 2000)



Notes: Includes oil and gas rigs (reflects impact of shale gas boom), as well as onshore and offshore (State + Federal). Selected States have over 100 active rigs in 2010 (except Alaska)

International Rig Counts

(basis 100 in 2000)



Notes: Includes oil and gas rigs, as well as onshore and offshore.

6) **Provide information about the "normal" number of development wells drilled in a mature oil field.**

The definition of an "elephant" oil field varies substantially in practical use, but typically refers to very large oil fields with total oil resources estimated in the hundreds of millions to billions of barrels. Prudhoe Bay is an "elephant" oil field with estimates from BP of more than 25 billion barrels of OOIP. More than 1,100 producing wells have been drilled in the Prudhoe Bay field as well as more than a hundred injection wells.

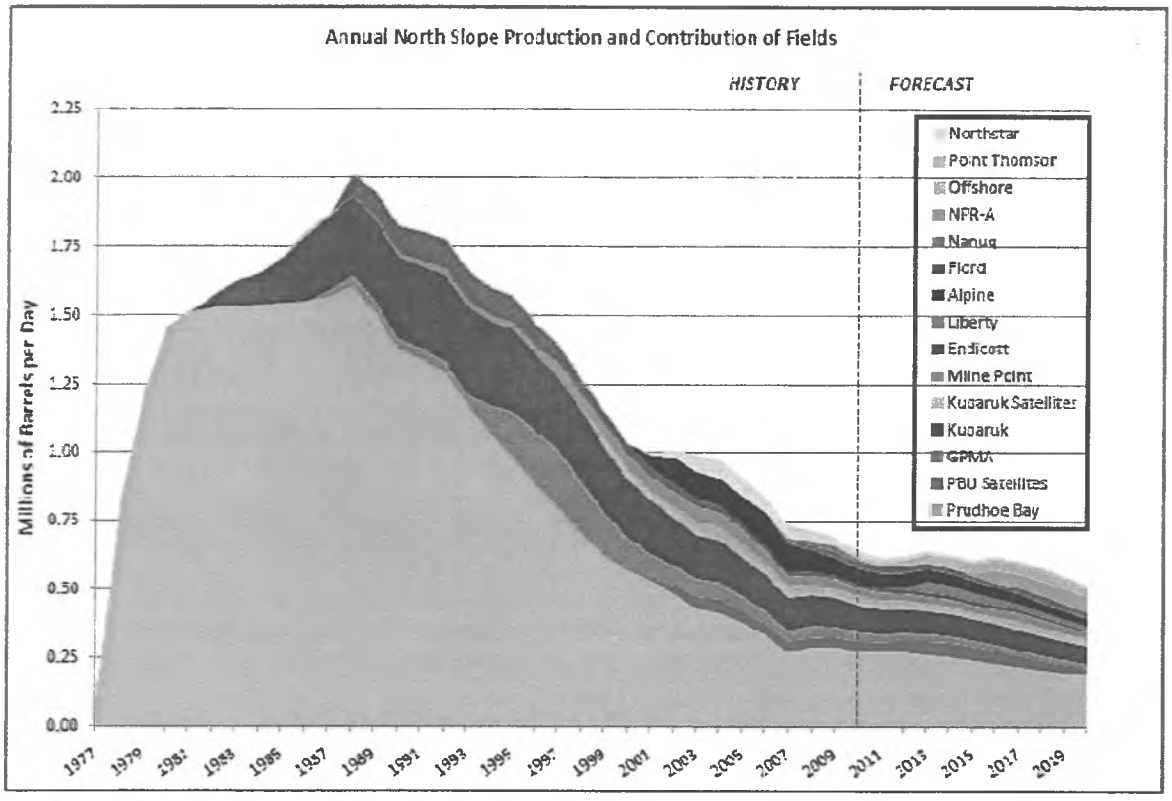
Unfortunately, it would be difficult to estimate a "normal" number of producing wells in a normal or hypothetical field as the development program will depend on the geology and the physical characteristics of the oil, among other factors. For example, looking at AOGCC data, Prudhoe Bay has seen an average of between 40 and 60 new producing "wells/penetrations" completed each year since 2000. While Kuparuk has seen an average of between 8 and 10 new producing "wells/penetrations" completed each year in that same time. In both cases, the productivity of the wells seem to be decreasing with time.

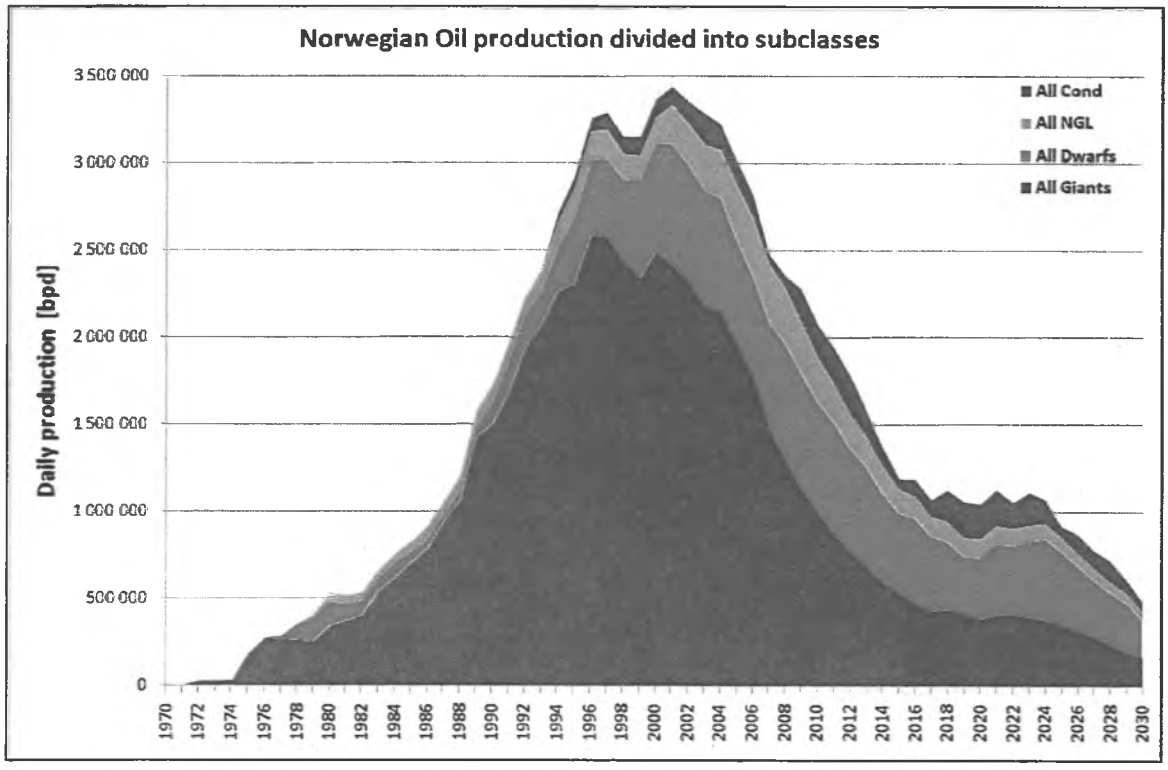
More public Prudhoe Bay statistics can be found at the following web address: http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/A/abp_wwd_alaska_prudhoe_bay_fact_sheet.pdf

7) **Provide information about the pattern of natural decline in exploration of a mature oil basin, and how Alaska's mature basins compare. Also explain how a company would typically model investments in a mature oil basin.**

Following are graphs of the Alaska North Slope (ANS) and Norway's historical and forecasted production. Norway is not as mature as ANS. Norway's production peaked in 2000 at approximately 3.5MMBPD and is currently declining at an average rate of 13% ten years after peaking. ANS peaked in 1988 at 2.011MMBPD and is currently declining at a rate of 4.3%. For comparison, ten years after ANS peaked the decline rate was 9.1%.

Bob George of Gaffney, Cline and Associates testified before the committee on March 18, 2011. In his testimony, Mr. George addressed this question and explained that a company would typically assume a production path not unlike that of Alaska's in modeling investments in a mature oil basin, with a fast ramp up, a plateau period, and a period of decline. However Mr. George also noted that there are multiple opportunities in Alaska that could allow the state to return to growing production, including heavy oil, new discoveries, and increased development of known resources.


Annual North Slope Production and Contribution of Fields
HISTORY
FORECAST
Millions of Barrels per Day
2.25
2.00
1.75
1.50
1.25
1.00
0.75
0.50
0.25
0.00
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
Northstar
Point Thomson
Offshore
NPR-A
Nanuq
Fiord
Alpine
Liberty
Endicott
Milne Point
Kuparuk Satellites
Kuparuk
GPMA
PBU Satellites
Prudhoe Bay


Norwegian Oil production divided into subclasses
Daily production [bpd]
3 500 000
3 000 000
2 500 000
2 000 000
1 500 000
1 000 000
500 000
0
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
All Cond
All NGL
All Dwarfs
All Giants

8) **Does the Department of Revenue have access to drilling plans and / or plans of development when preparing their production forecast, and how far out do those planning documents go?**

Yes, the Department of Revenue has access to drilling plans and plans of development (PODs) when preparing the production forecast. In the near term, about one or two years out, the operators are usually very specific, sharing drilling schedules, budgets, production forecasts, etc. with us. In the time up to five years, some of the operators usually have a "plan" for future development that is somewhat less specific that may include anticipated wells, some budget information and perhaps anticipated production. Beyond five years, some of the operators will have a general plan that may just include the prospective field and a very general time estimate of the start of the field. The Department of Revenue does consider the Plans of Development submitted by the operators to the Department of Natural Resources.

9) **What would the revenue reductions have been each year since the passage of ACES, if the provisions of SB 49 had been in place instead?**

The following table provides the estimated impact of SB 49 using historical Department of Revenue models, which are set up to provide revenue forecasts by fiscal year. SB 49 as proposed would use calendar year prices to determine the average price for calculating progressivity and then allocate the revenue to fiscal years. This structural difference might cause the impacts to be slightly more in one year and less in the next, but the revenue impact should be the same over time.

Note also that this table does not reflect production level increases that would likely have been experienced had SB 49 been implemented during these years.

Production Tax Revenue under ACES and the Estimated Impact of HB 110/SB 49 on Production Tax Revenue in Prior Years*

(in $billions)

Year	Production Tax Revenue under ACES	Impact of Tax Rate Change	Impact of Well Lease Exp Credit	**Total Estimated Impact**	Estimated Production Tax Revenue under HB 110/SB 49
FY 2008	$6.81	-$2.06	-$0.30	**-$2.36**	$4.45
FY 2009	$3.10	-$0.99	-$0.30	**-$1.29**	$1.81
FY 2010	$2.86	-$0.60	-$0.30	**-$0.90**	$1.96

***Notes regarding this analysis**

This analysis considers revenue impacts of only those provisions of HB 110 and SB 49 that can be reasonably quantified and that are not considered revenue neutral over time (such as the elimination of the credit split). Additionally, because historical models are maintained on a fiscal year basis, fiscal year inputs such as prices, production and costs were used for this analysis, even though annual tax calculations in HB 110 and SB 49 are based on calendar year inputs. For the well lease expenditure credit, we chose a median of the range of $200 to $400 million per year as stated in the fiscal note.

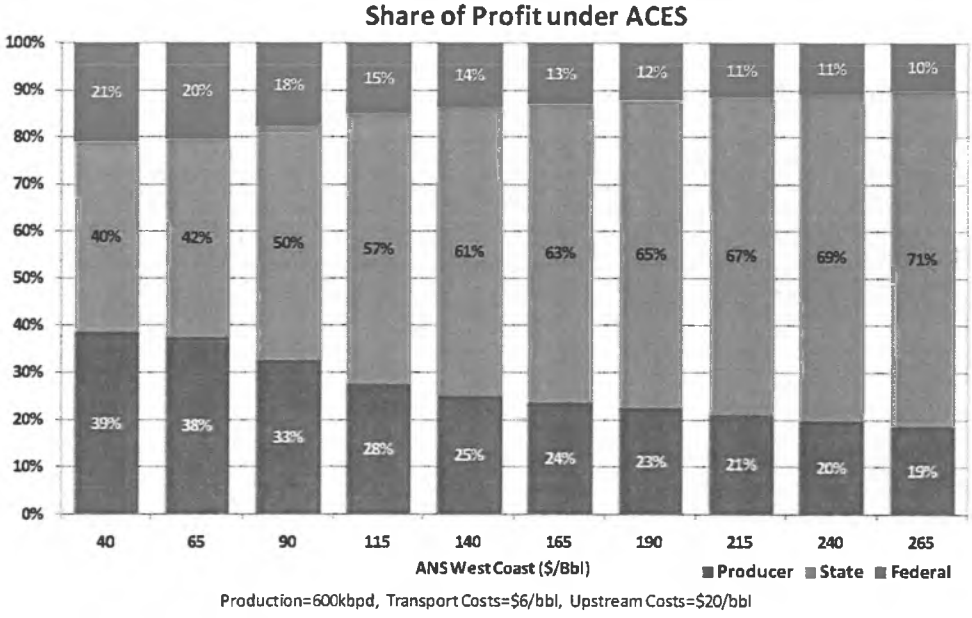
This analysis does not consider the likely production increases had HB 110/SB 49 been in effect.

10) Please provide the numbers, and assumptions, behind the profit share graph on slide 20 as presented.

The chart uses a range of possible ANS West Coast prices, with no change in costs across the range. The chart assumes production on state land. Following are the assumptions used in producing the chart. The chart as presented in committee is also included below.

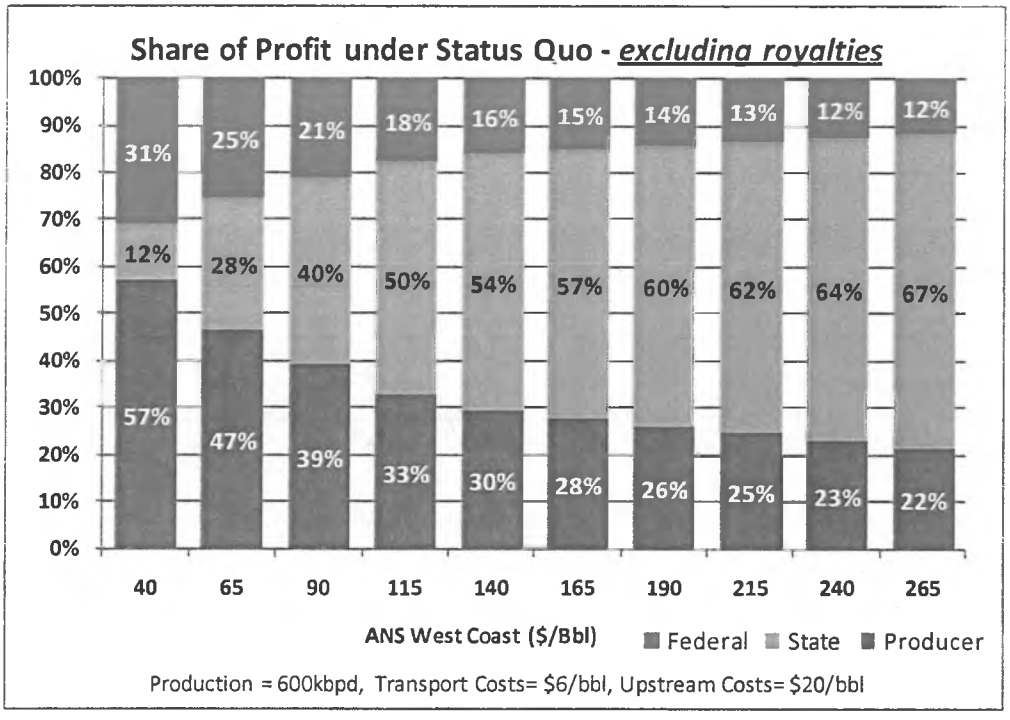
Assumptions	Value	Unit
Transportation Costs	6.00	$/bbl
Royalty Rate	12.5%	
Upstream CAPEX	10.00	$/bbl
Upstream OPEX	10.00	$/bbl
Total Upstream Costs	20.00	$/bbl
Daily Production	600,000	Kbbl/d
Property Tax (% of CAPEX)	2.00%	

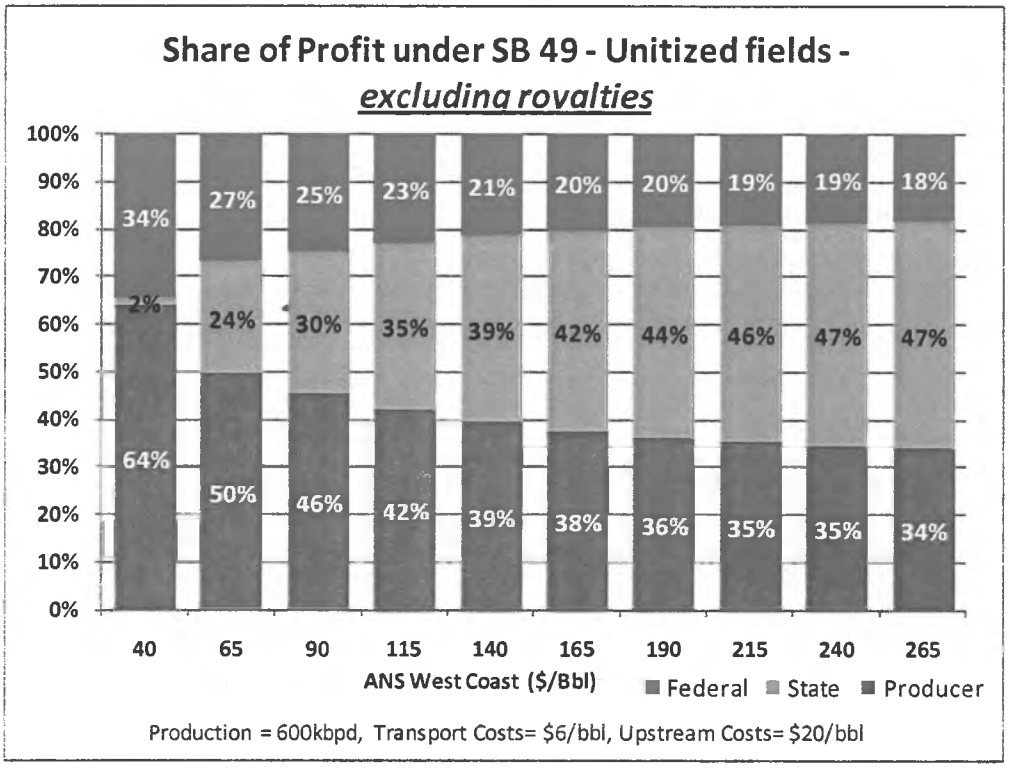
Share of total profit - ACES



11) Please reproduce the profit share graph on slide 20 without including state royalty.

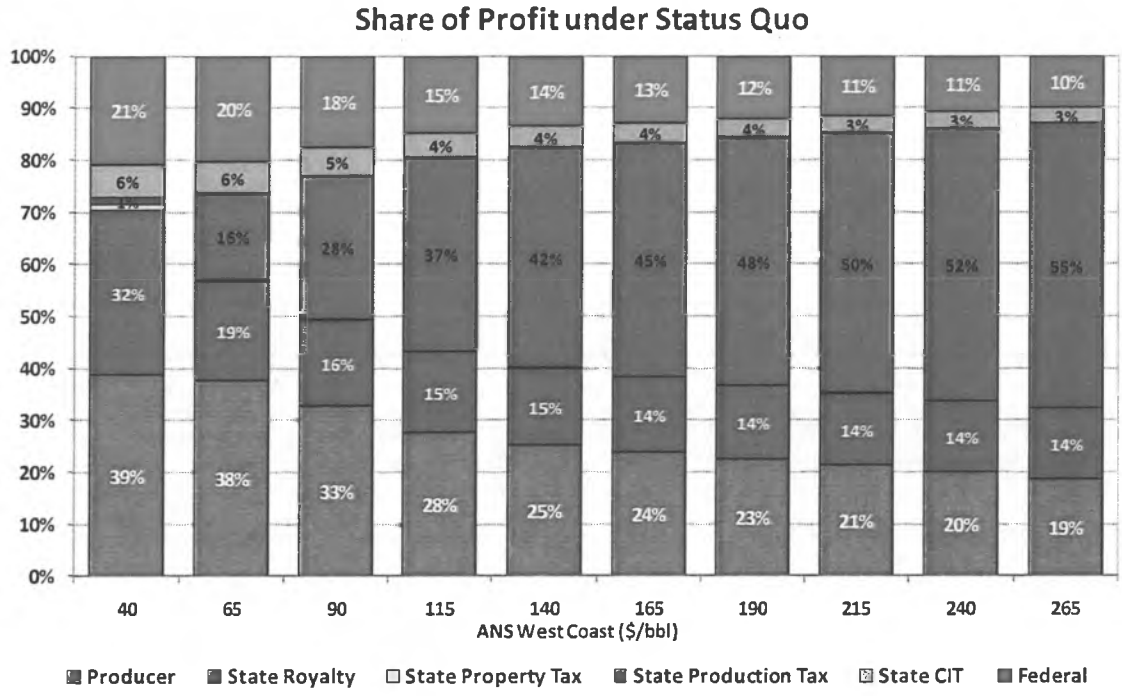
The following charts show the distribution of profit (excluding royalty) at various oil prices, under both status quo and SB 49. Royalty is an integral part of the state's fiscal system and we maintain that it should be included in the analysis of distribution of profit.

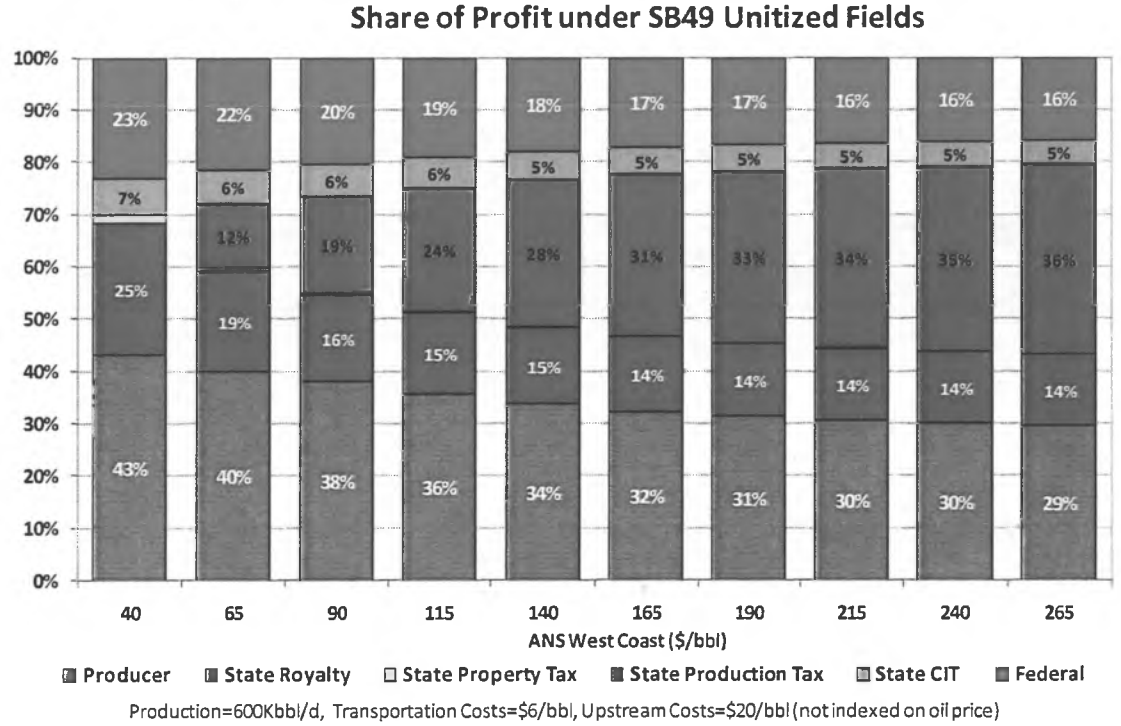




12) Please reproduce the profit share graph on slide 20, including royalty, with the state share broken down into the various components.

The following charts show the distribution of profit at various oil prices, including detailed breakdown of the components of state take, under both status quo and SB 49.





13) Explain why the profit shares on the share graph on slide 20 and 21 are different than shares of gross value.

Profit and gross value are two different numbers – one includes costs to produce oil and one does not. The concept of "profit" used in the "share of profit" slides represents the wellhead value of oil (which excludes transportation costs), less lease expenditures (operating and capital costs). The concept of "gross value at point of production" represents the value at the entry point into a common carrier pipeline (such as TAPS) and excludes only transportation costs.

14) Provide the model used to produce the profit share graph on slide 20.

The Department has prepared a one-year snapshot model designed to illustrate the impacts of SB49 on the state, federal and producer takes for a certain production rate, under fixed oil price and cost assumptions. Department staff are available to meet with interested legislators who wish to manipulate this model.

QUESTIONS FROM TAX CREDITS PRESENTATION

15) What is the difference between an exploration well and a development well?

Following are definitions of different types of wells, from the AOGCC:

- "Exploratory Well" means a well drilled to discover or to delineate a pool
- "Development Well" means a well drilled to a known productive pool
- "Service Well" means a well used for injecting water, gas, or other fluids into a reservoir or producing formation in pressure maintenance, enhanced recovery, or storage operations, for disposing of oil field wastes, or for conducting other operations in support of oil or gas production
- "Stratigraphic Test Well" means a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas

16) Explain the difference between the $85.5 million in exploration credits for FY 2008 shown in today's presentation, and a lower number ($38.5 million) provided in an earlier presentation.

The table used in the earlier presentation incorrectly excluded 3 applications for exploration credit claims totaling $47 million submitted and received during FY 2008. The data was omitted from a report obtained out of the database used to track credit applications. The error was discovered as we reconciled the eventual credits paid or refunded by the state to the applications received.

17) Will the Department be revising its estimate for credits taken in 2011 based on the recent announcement that Repsol will be investing in an exploration program on the North Slope?

The Department will not be revising the estimate for credits taken in FY 2011 based on Repsol's recent announcement about its North Slope investment plans. The Department may, however, revise estimates for FY 2012 and later years' expenditures and credits, pending further information gathered during our extensive fall forecasting process. As part of our fall forecast, we review plans of development, and we meet individually with oil and gas explorers and developers in order to gain a better understanding of their projects. This will also give us the opportunity to inquire about spending plans, and whether or not the projects will likely meet the criteria for credit under one of our exploration tax credits or other credits. Assuming company plans proceed as intended, we will likely incorporate these new estimates into our Fall 2011 forecast.

We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

OUTSTANDING QUESTIONS

The following questions remain from the Senate Resources hearings on March 11, 14, and 16, 2011. We are working on these questions and will respond at a future date.

1) **Provide the Department's previous forecasts for Prudhoe Bay production in 5-year increments (2010, 2005, 2000, etc)**

2) **Explain the concept of "duty to produce".**

3) **Can we look at a possible correlation between declines in exploration in 2003 and 2010, and the economic downturns in 2001 and 2008. Is Alaska's decline in exploration in those years similar to other states after removing gas exploration wells?**

4) **Provide information about companies that are working together on exploration wells shown in the exploration wells slide.**

5) **How do drilling agreements work when companies are working together? If one company pulls out of a project, is the project typically cancelled?**

6) **Compare royalty rates in Alaska with royalty rates in other states; that is, compare royalties paid in Alaska as an owner state to royalties paid to private land owners in Texas, North Dakota, etc.**

7) **Please show SB 49 compared to our revenue forecast in the "income statement" format for FY 2010, FY 2011, and FY 2012.**

8) **Please recast the fiscal note analysis using flat oil prices of $100, $110, and $120 instead of the Department's forecast oil prices.**

9) **Explain the difference between the $85.5 million in exploration credits for FY 2008 shown in today's presentation, and a lower number ($38.5 million) provided in an earlier presentation.**

10) **Provide a 5-year forecast for capital expenditures and the credits derived from those expenditures.**

11) **Provide a chart of effective tax rates under current law and SB 49 using forecasted transportation costs, lease expenditures, and credits for FY 2012.**

12) **Provide modeling to show whether the $1.1 billion in credits paid to explorers has led to any production.**

13) **Provide a breakout of the types of capital expenditures in as much detail as possible.**

State of Alaska

Department of Revenue

Commissioner's Office

SEAN PARNELL, GOVERNOR

550 West 7th Avenue, Suite 1820

Anchorage, Alaska 99501

Phone: (907) 269-0080

Fax: (907) 276-3338

March 25, 2011

Senator Joe Paskvan
State Capitol Room 115
Juneau AK, 99801

Re: Answers to questions posed March 17, 2011

Dear Senator Paskvan:

The purpose of this document is to respond to the questions you raised in our meeting with you on March 17, 2011. The requests/questions and responses follow.

1. **Prepare a version of the FY 2011 income statement that replaces the "credits applied against tax liability" with "total credits earned" regardless of when or how those credits are used.**

   Please see income statement for FY 2011 on the following page.

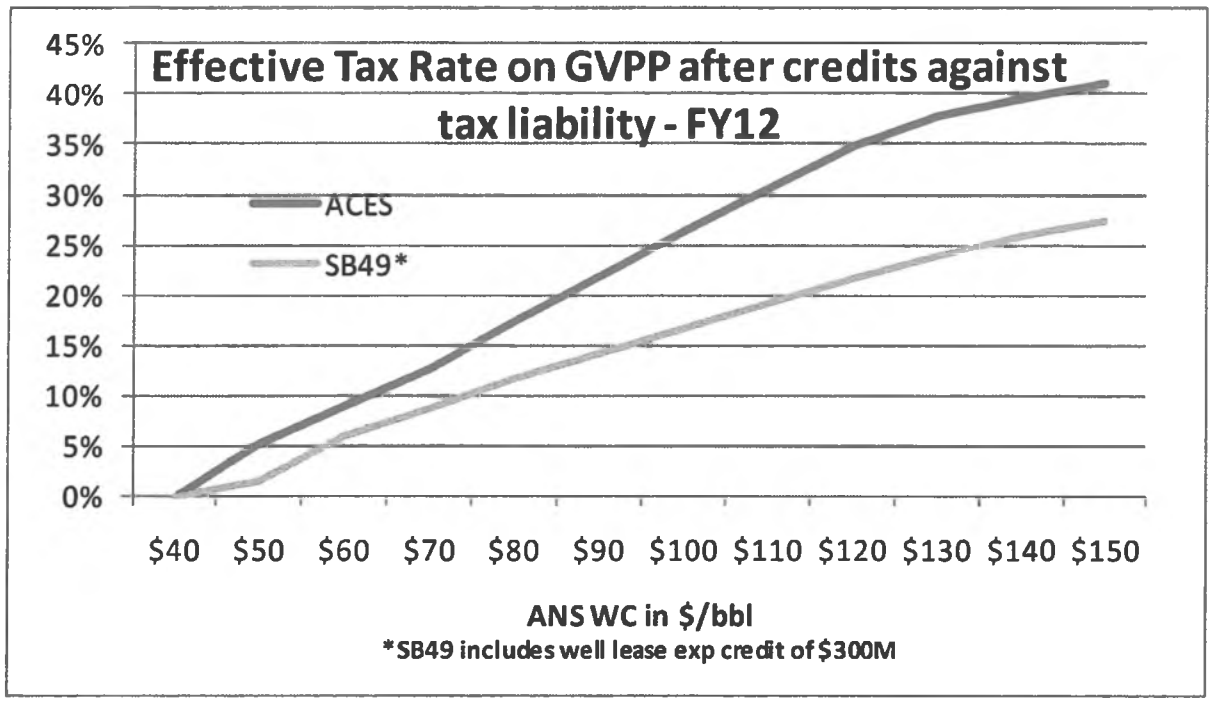
FY 2011 Production Tax Estimates with Total Credits earned[4]

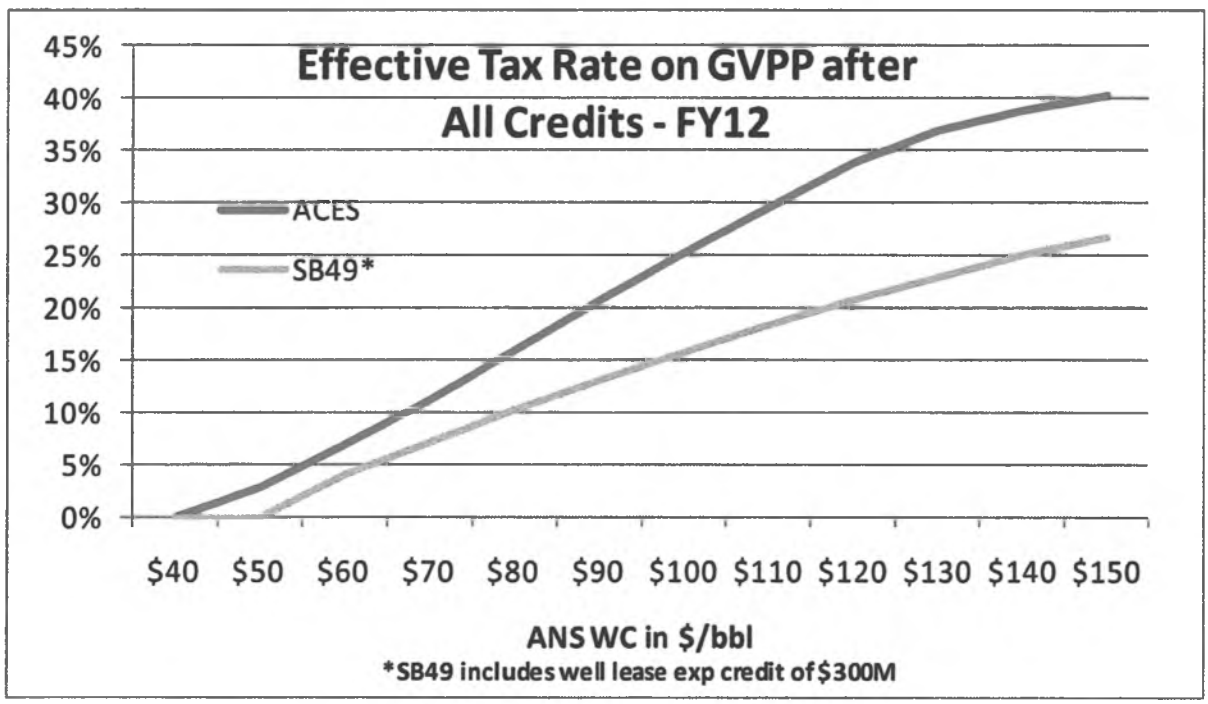
	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$77.96	615,902	$48.0
Annual Production (bbl)			
Total		224,804,230	$17,525.7
Royalty, Federal and other barrels[1]		-34,100,490	($2,658.5)
Taxable barrels		190,703,740	$14,867.3
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.07		
TAPS Tariff	-$4.17		
Other	$0.24		
Total Transportation Costs	-$6.00	190,703,740	($1,144.2)
Lease Expenditures			
Total Operating Expenditures	-$13.39		($2,553.0)
Total Capital Expenditures	-$13.49		($2,572.0)
Deductible Operating Expenditures[2]	-$12.99		($2,477.0)
Deductible Capital Expenditures[2]	-$10.43		($1,988.4)
Total Deductible Lease Expenditures	-$23.42	190,703,740	($4,465.4)
Production Tax			
Production Tax Value (PTV)			$9,257.6
Base Tax (25%*PTV)			$2,314.4
Production Tax Value per barrel	$48.54		
Progressive Tax = (7.4% * PTV)			$686.7
Total Tax before credits			$3,001.1
Credits			
Credits applied against tax liability			($400.0)
Estimated Total Tax after credits[3]			**$2,601.1**
Total credits earned (including not applied against tax)[4]			($665.0)
Total Tax before credits less total credits earned[4]			$2,336.1

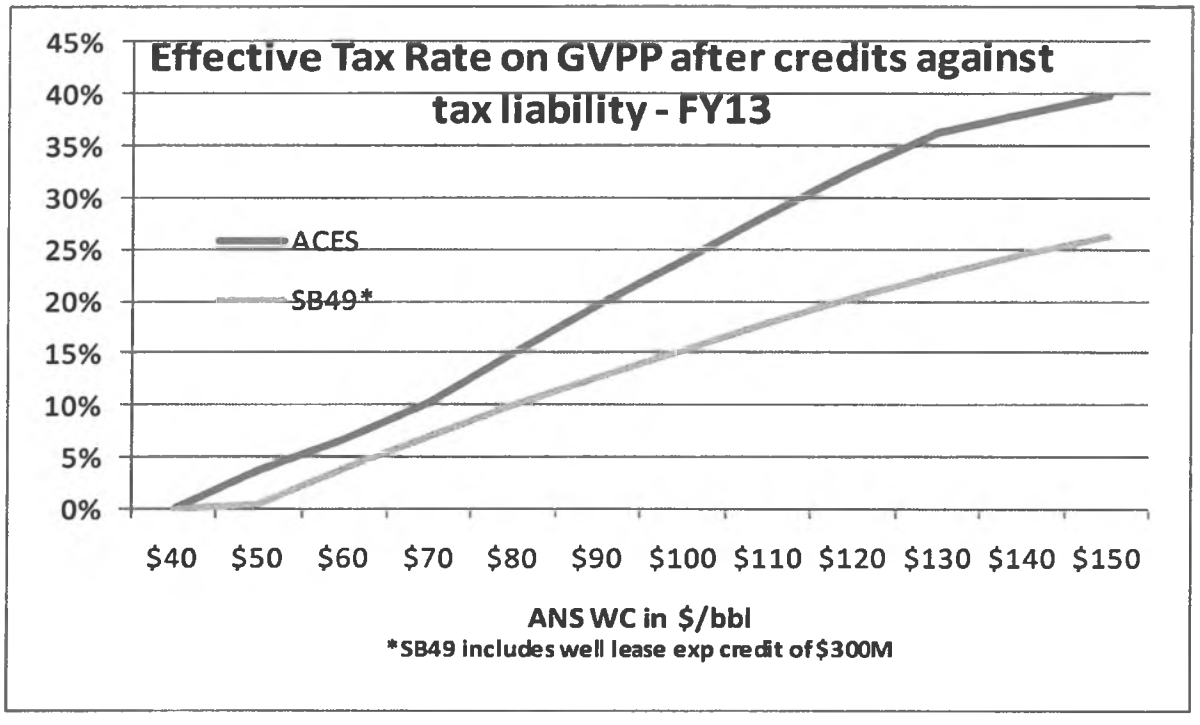
Notes: (1) Royalty, Federal and other barrels represents our best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property and barrels used in production.
(2) Deductible Lease Expenditures represents our best estimate of lease expenditures that are applicable to currently producing fields that are likely to produce a tax liability for the company or companies producing them. The per-barrel expenditures reflect expenditures **per taxable barrel** and do not reflect expenditures per all barrels produced.
(3) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, and constant expenditures for the entire year. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.
(4) Total credits earned is shown by request and is intended to reflect the net exposure to the state from all production tax credit activity in a year without regard to when and how the credits are applied or redeemed.

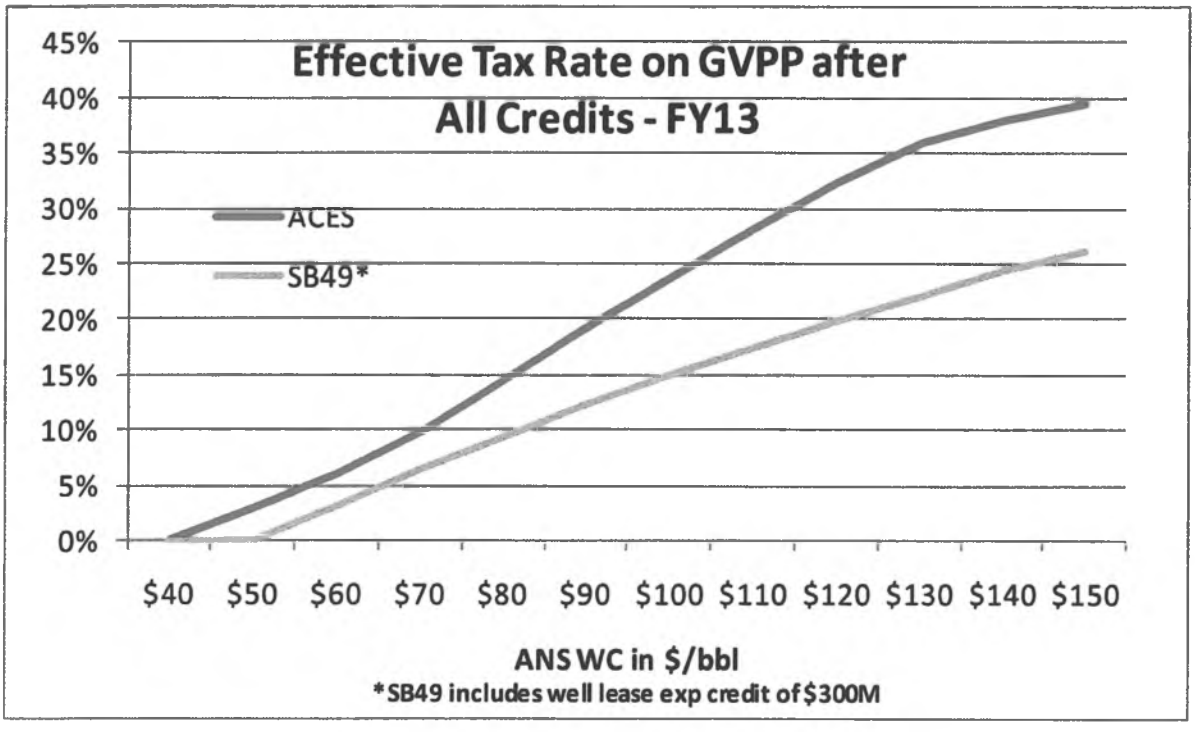
2. **Prepare slides showing effective tax rates on gross (after credits) for ACES and SB 49, for FY 2012-2016. Prepare similar slides showing effective tax rate on gross after all credits – including those used against tax liability and those which will likely be certificated – for ACES and SB 49 for the same years.**

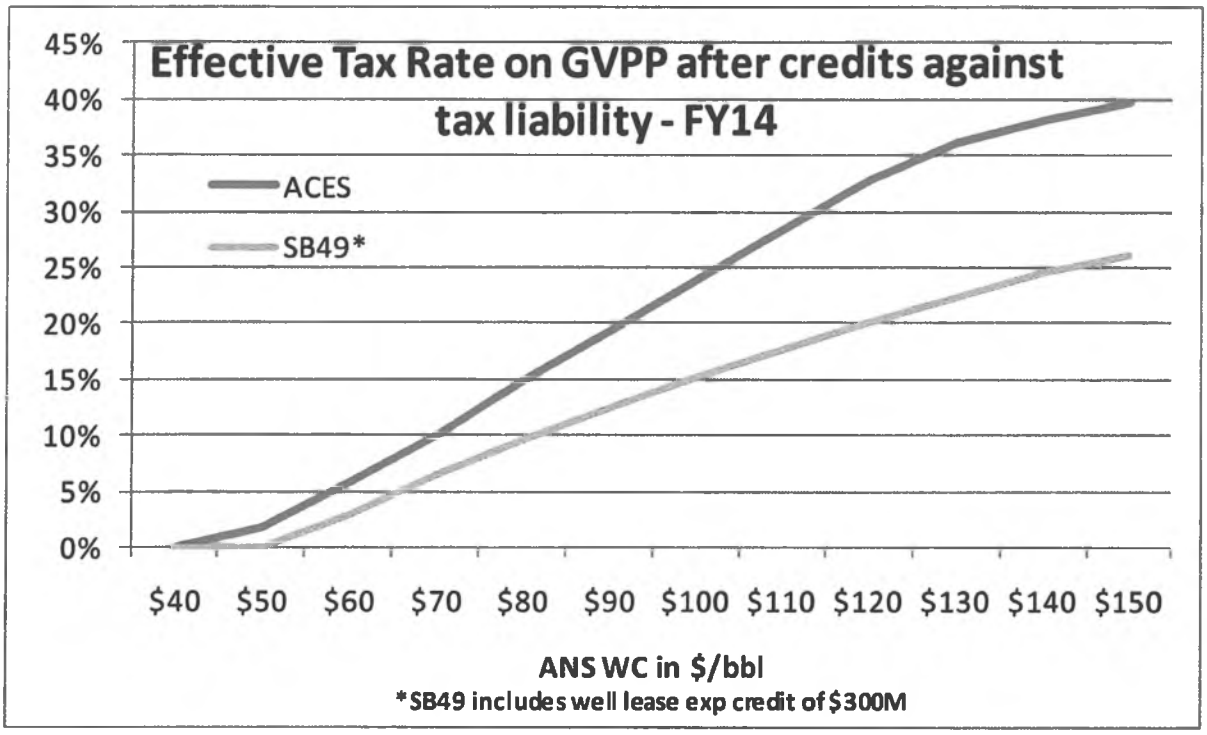
   See the following pages for the slides requested in question number 2.

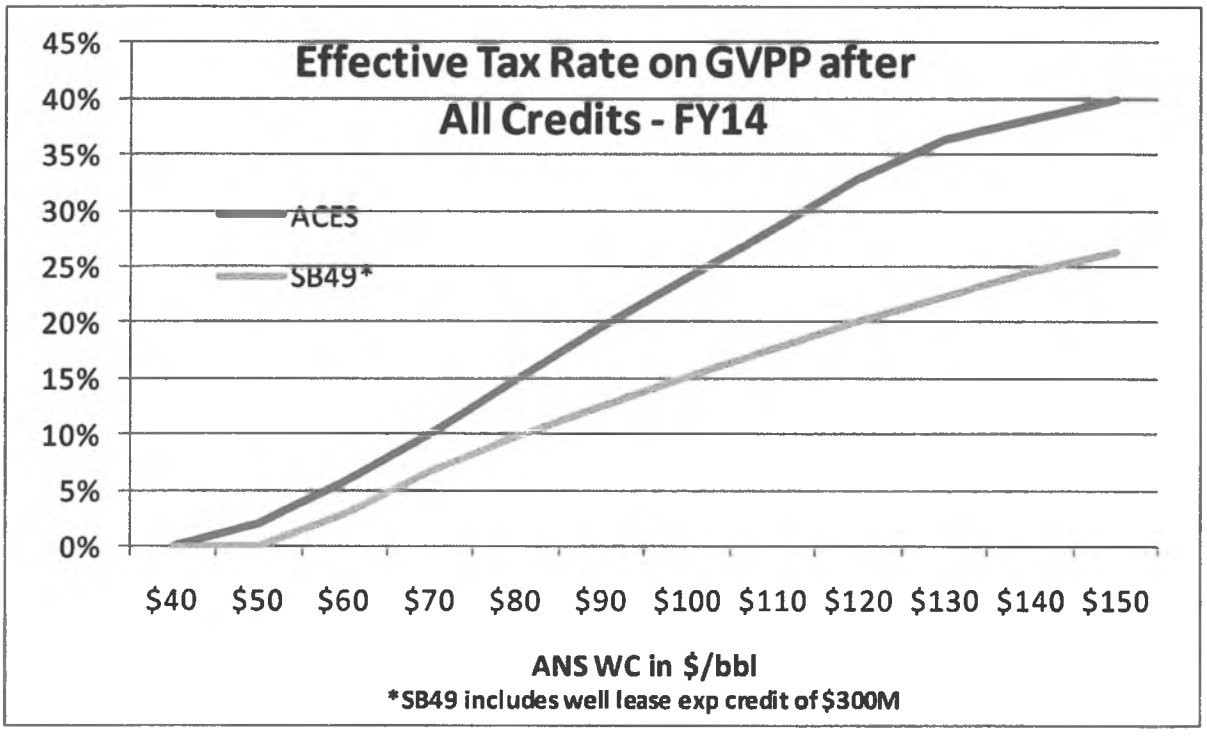

Effective Tax Rate on GVPP after credits against tax liability - FY12
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M

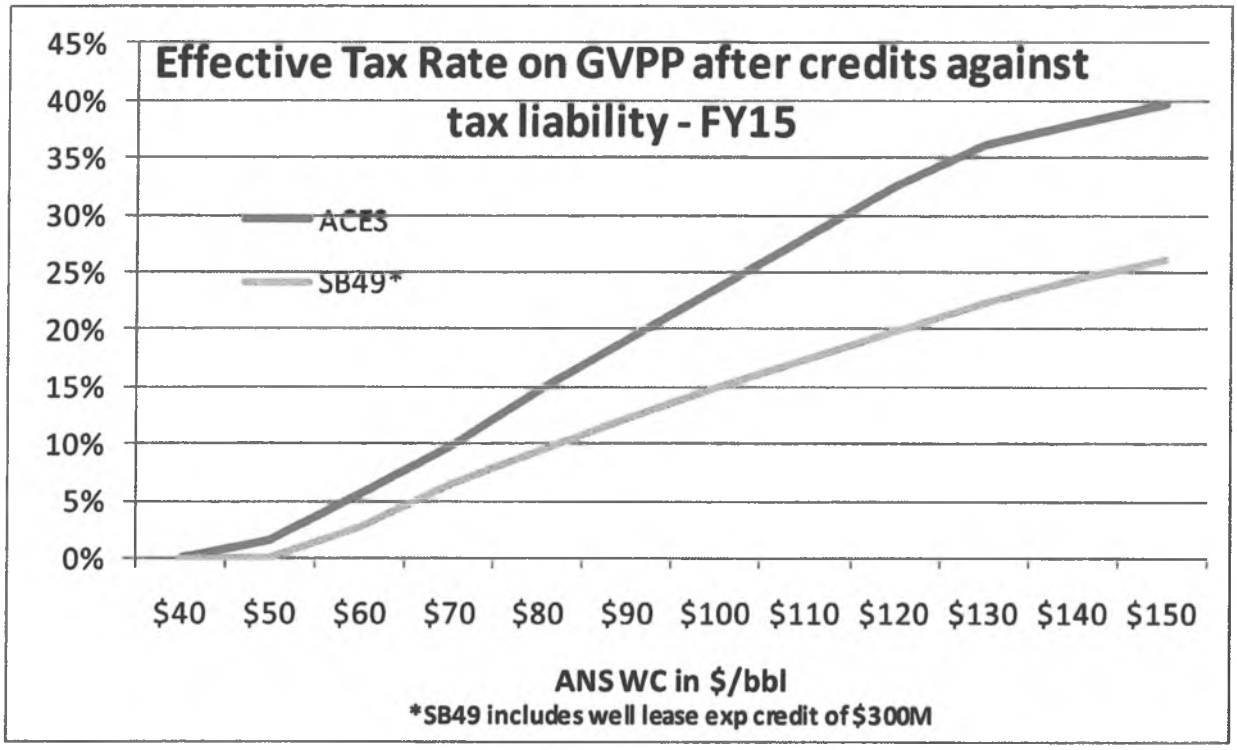

Effective Tax Rate on GVPP after All Credits - FY12
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M

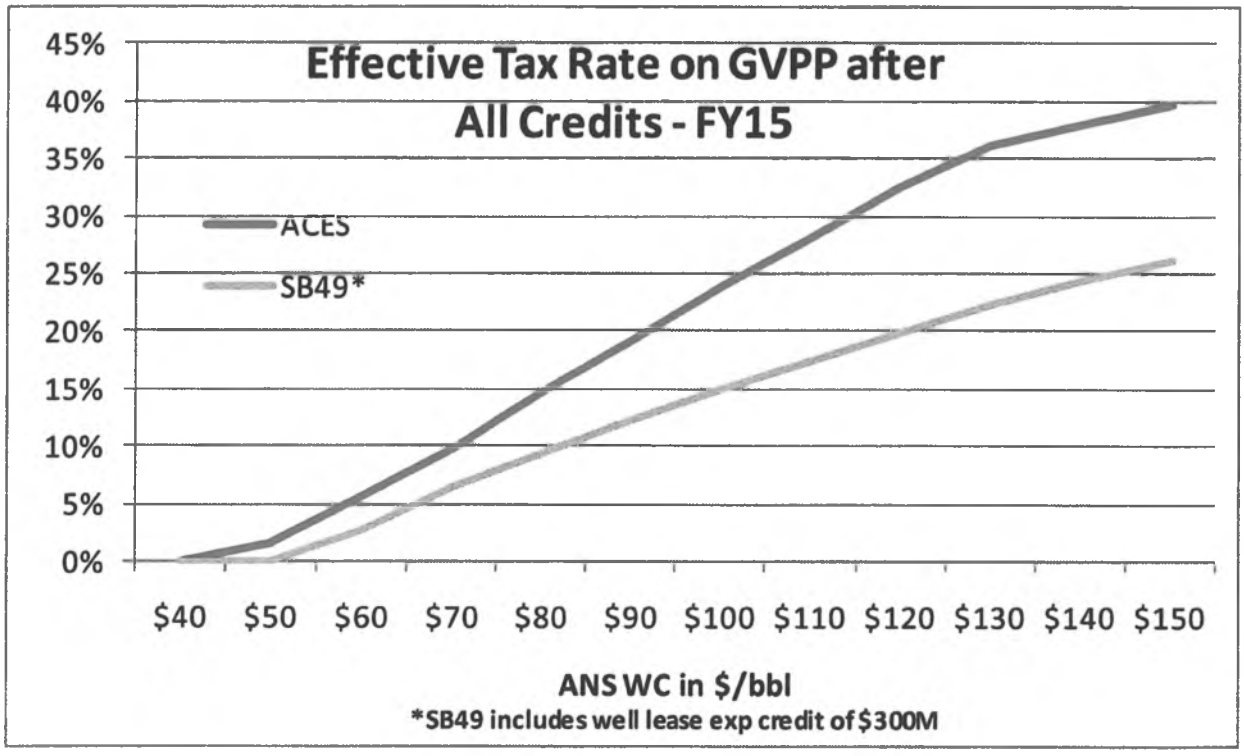

Effective Tax Rate on GVPP after credits against tax liability - FY13
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M

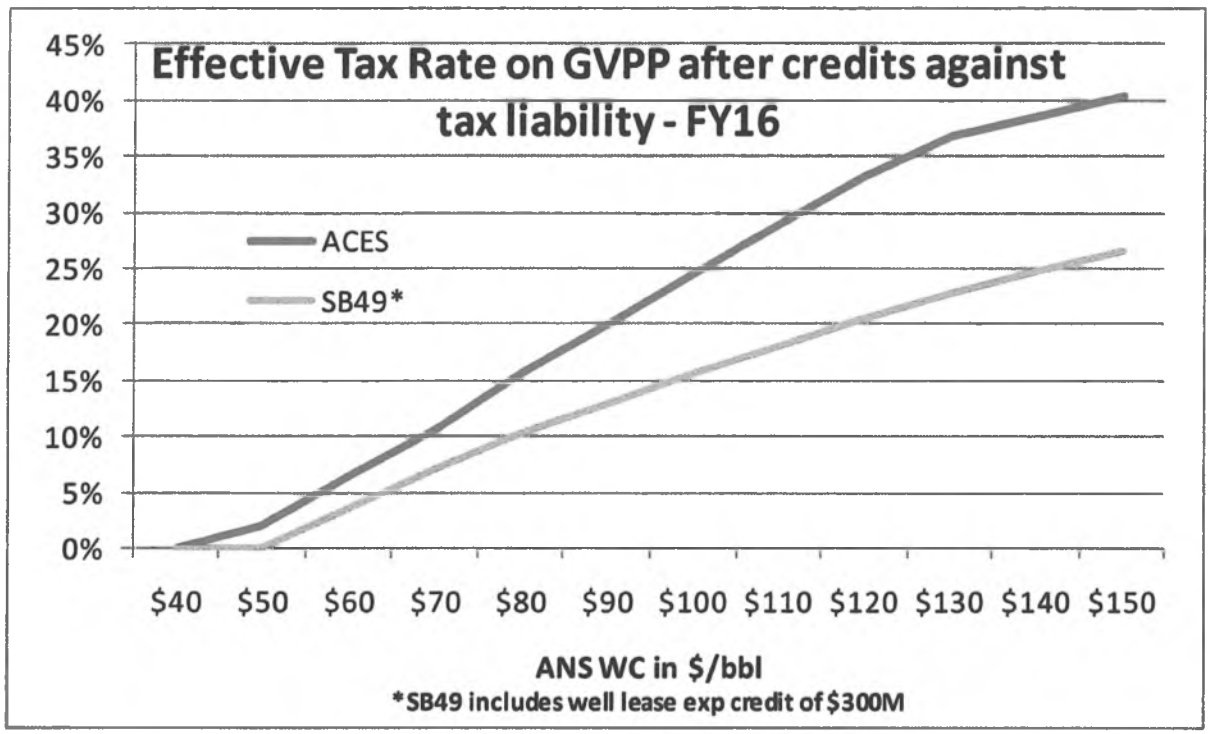

Effective Tax Rate on GVPP after All Credits - FY13
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M

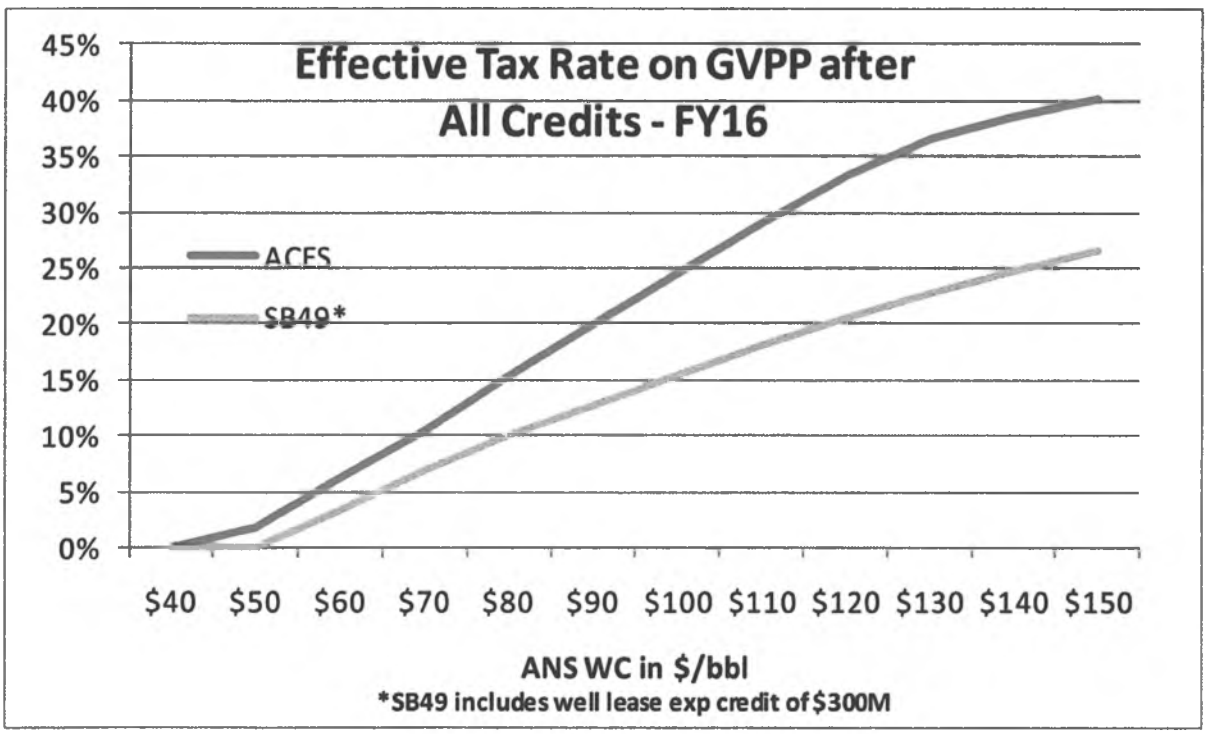

Effective Tax Rate on GVPP after credits against tax liability - FY14
ACES
SB49*
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M


Effective Tax Rate on GVPP after All Credits - FY14
ACES
SB49*
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M


Effective Tax Rate on GVPP after credits against tax liability - FY15
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M

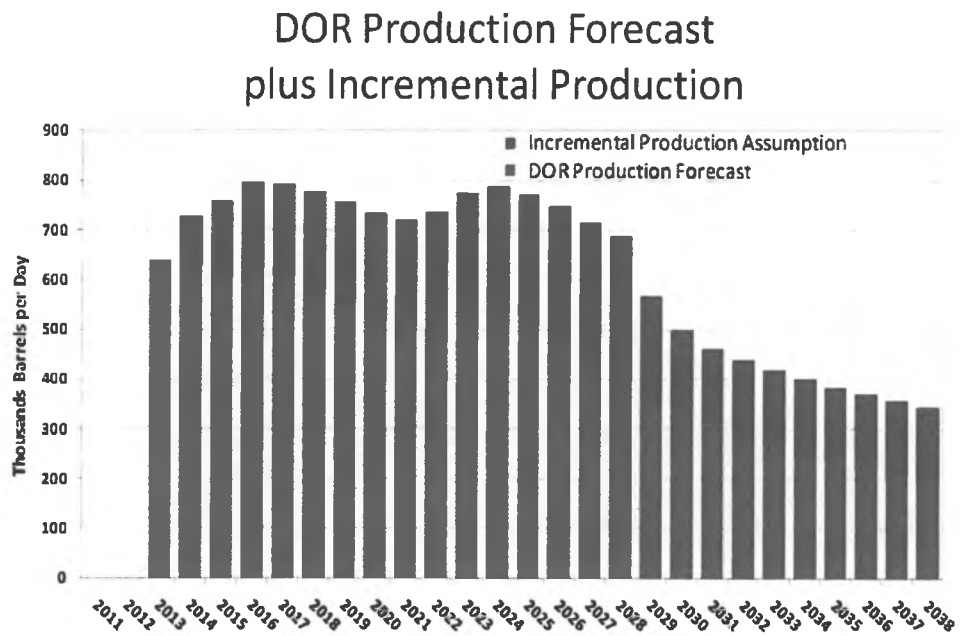

Effective Tax Rate on GVPP after All Credits - FY15
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M


Effective Tax Rate on GVPP after credits against tax liability - FY16
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M


Effective Tax Rate on GVPP after All Credits - FY16
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
ACES
SB49*
$40 $50 $60 $70 $80 $90 $100 $110 $120 $130 $140 $150
ANS WC in $/bbl
*SB49 includes well lease exp credit of $300M

3. Provide the analysis of the Great Bear scenario that was prepared for the House Resources Committee.

The following charts have been prepared to illustrate the potential impact of incremental production on state revenue. This illustration does not constitute a "best case scenario" but rather one single potential outcome out of a very wide range of possible production and price scenarios. The assumptions used are based on the Fall 2010 production and price forecasts and on recent industry testimony and as such, can be considered as neither excessively optimistic nor conservative. This scenario does not represent a Department of Revenue forecast or expectation. The analysis assumes that following the enactment of HB 110, incremental production beyond what is included in the Department's current production forecast would come from state lands. For this analysis, production included in the Department's forecast is assumed to be taxed at a 25% base rate and a maximum progressivity of 25% under HB 110. For illustration purposes, incremental production has been assumed to follow a profile similar to that presented by Great Bear Petroleum, as described in their 18th February, 2011 testimony[1]. This incremental production is assumed to come from currently non-unitized fields, which under HB 110, would be taxed at a 15% base rate and a maximum progressivity of 25%.

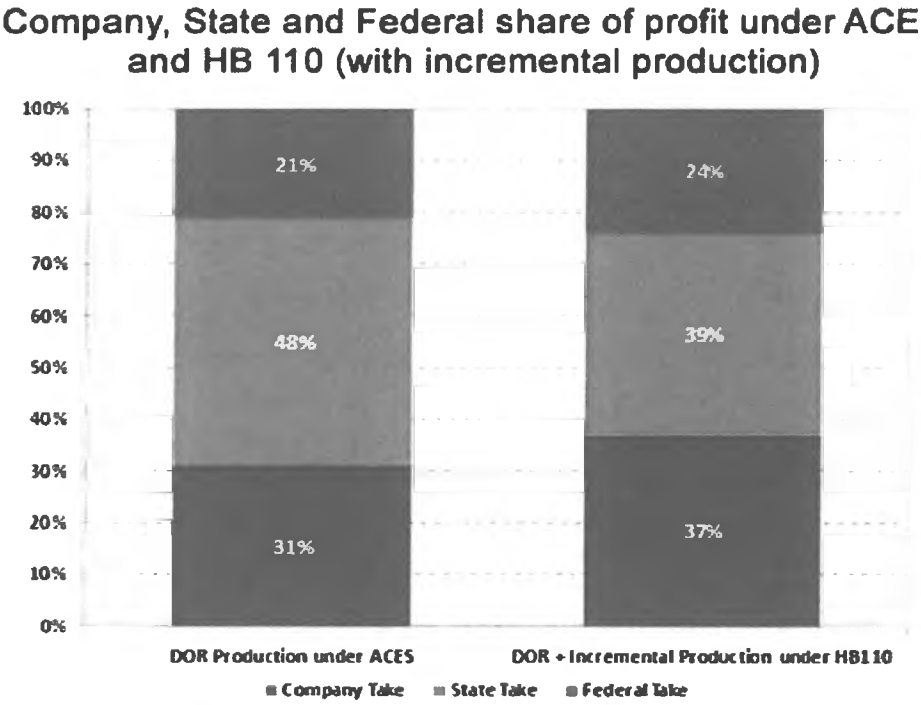


Source: DOR Production Profile; Fall 2010 Revenue Sources Book.
Incremental Production: Great Bear Petroleum; 18 February, 2011.

Overall, the enactment of HB 110 under this set of assumptions would reduce the "State Take" (all state revenues including production tax, royalty, corporate income tax and property tax) from

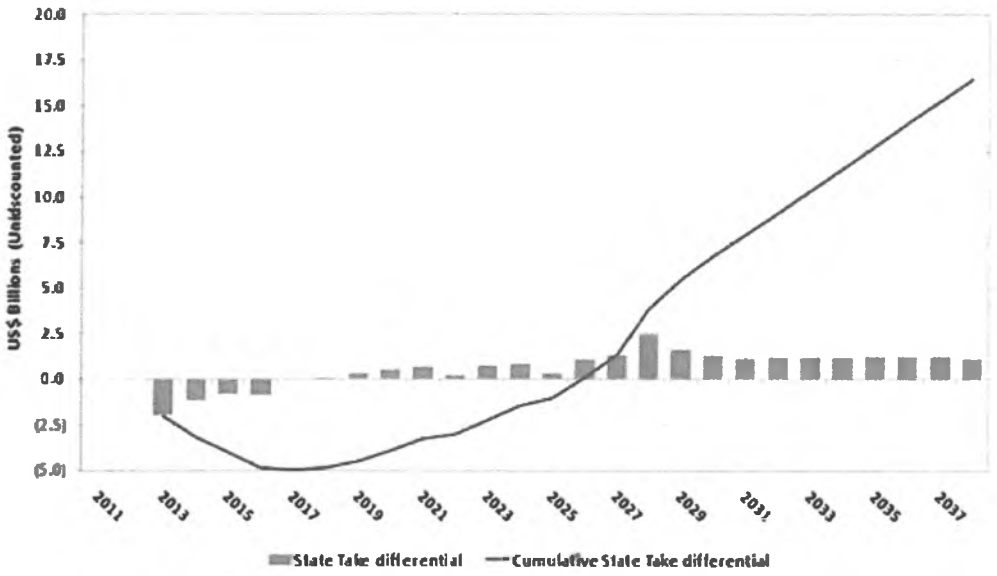
[1] Production starts in 2014 with 295 thousand barrels per day peak in 2028. Note: Great Bear Petroleum labels this as a 'Potential Oil Production Profile' and lists certain assumptions used in the preparation of this profile in their testimony.

48% to 39% of profits. Overall "Government Take", which also includes federal corporate income taxes, would be reduced from 69% to 63%.



However, while the relative State Take decreases under HB 110, it is applied to a "larger pie", which includes the assumed incremental production. Over the 2013 to 2038 period, total state revenue under HB 110, with the incremental production, would be $17 billion higher than it would be under ACES with no incremental production.

Additional state revenue under HB 110



Note: State Take for DOR + Incremental Production under HB110 minus State Take for DOR Production under ACES

Under the assumptions used, state revenue under HB 110, with the incremental production, would be higher than under the status quo beginning in 2018. Cumulative state revenue under the HB110 scenario starts exceeding what would have been received under ACES in 2026. As stated earlier, this is but one many potential scenarios as incremental production could conceivably be greater, or lower, than assumed for the purpose of this illustration.

We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99800-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

April 5, 2011

The Honorable Joe Paskvan
Alaska State Senator
State Capitol, Room 115
Juneau, AK 99801

The Honorable Thomas Wagoner
Alaska State Senator
State Capitol, Room 427
Juneau, AK 99801

Re: Response to Questions from Senate Resources Hearing on April 1, 2011

Dear Senators Paskvan and Wagoner:

The purpose of this document is to respond to the follow-up questions raised by the Senate Resources Committee meeting during our presentation of the Oil & Gas Production Tax Status Report on April 1, 2011. The requests/questions and responses follow.

1) **Provide information about the Department's use of contract auditors and the possibility of using contract auditors when positions cannot be filled.**

   We have used and are currently using contract auditors to perform some of the audits on the AS 43.55.025 alternative credit for oil and gas exploration applications.

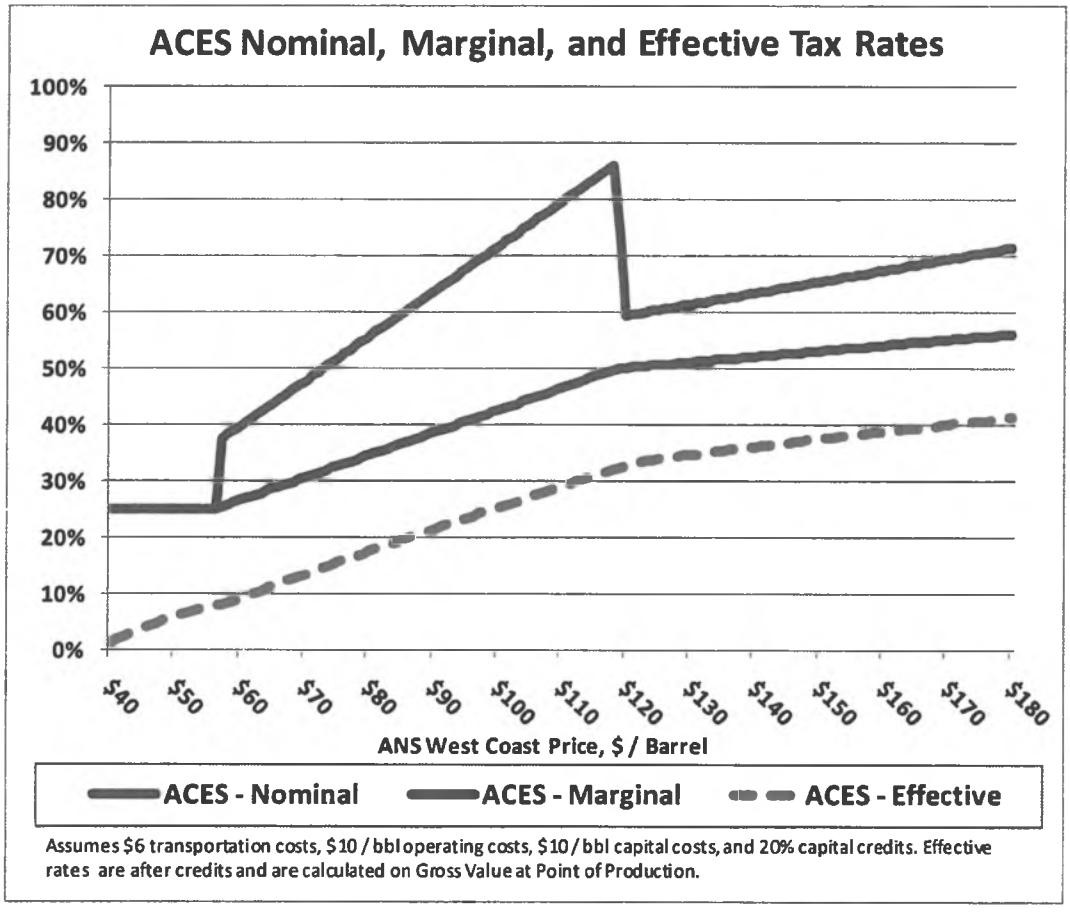
   We have also used and will use contract auditors to perform the annual AGIA reimbursement audit of the licensee as required by AS 43.90.220. These audits are calendar year end audits performed and completed within the next tax year.

   We have not used contract auditors for other uses, due to lack of available funding.

2) **What are the nominal and effective tax rates under ACES when the price for ANS oil is $100 per barrel?**

The following chart compares nominal, marginal, and effective tax rates under ACES at a range of oil prices. For this analysis we assumed $6 per barrel transportation costs, $10 per barrel operating costs, $10 per barrel capital costs, and credits in the amount of 20% of capital costs.

Based on this analysis, at an ANS price of $100 per barrel, the nominal tax rate is 42.6%, the marginal tax rate is 71.8%, and the effective tax rate on gross value is 25.3%.



We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska

Department of Revenue

Commissioner's Office

SEAN PARNELL, GOVERNOR

550 West 7th Avenue, Suite 1820

Anchorage, Alaska 99501

Phone: (907) 269-0080

Fax: (907) 276-3338

The Honorable Joe Paskvan
Alaska State Senator
State Capitol, Room 115
Juneau, AK 99801

April 6, 2011

Re: Answers to questions posed April 4, 2011

Dear Senator Paskvan:

The purpose of this document is to respond to the questions posed in an email from Jeff Stepp of your office dated April 4, 2011. The requests/questions and responses follow.

1. **For the years 2005 – 2011*, how much (gross dollars) are the capital expenditures by operators with production tax liability?**
2. **For the years 2005 – 2011*, how much are the capital expenditures by operators with some production tax liability but whose liability for that tax was reduced to zero with credits?**
3. **For the years 2005 – 2011*, how much are the capital expenditures by operators with no production and, therefore, no tax liability?**
4. **What is the specific number of companies that fit into each of the above categories in each of the years?**
5. **What is the total number of operators reporting taxes in each of those years (2005 – 2011*)?**
6. **Please identify the names of the operators in each of the categories in each of the years.**
7. **For the years 2005 – 2011*, name the operators filing reports.**

The Department of Revenue began receiving capital and operating expenditure data with the passage of PPT, which became effective in FY 2007. The department has since that time received monthly information forms and annual tax returns from oil and gas companies in the state. The department has a relatively solid data set for FY 2007 through FY 2010, and can provide information about those years. The data are limited to expenditures on the North Slope. Due to confidentiality constraints, we can provide information only about companies with production and companies with no production. We cannot disclose taxpayer-specific information, therefore we cannot provide answers to questions 5 – 8.

The table below provides the information we could compile for questions 1 – 4 above.

North Slope Capital Expenditures and Number of Companies with and without production, FY07 - FY10

Fiscal Year	North Slope Capital Expenditures by Companies with Production	Number of Companies with Production - North Slope	North Slope Capital Expenditures by Companies with No Production	Number of Companies with No Production - North Slope	North Slope Capital Expenditures - All Companies	Total Number Companies - North Slope
2007	$1,713,888,686	5	$388,085,401	13	$2,101,974,087	18
2008	$1,494,140,538	6	$477,661,229	18	$1,971,801,768	24
2009	$2,108,129,331	8	$103,848,115	12	$2,211,977,446	20
2010	$2,336,081,390	9	$52,611,147	11	$2,388,692,537	20

8. What is the amount of credits refunded for FY05 – FY 11, and what are the forecasted credits refunded for FY12 and forward?

Credits became refundable with the passage of PPT beginning in FY 2007. The amounts of credits refunded in each of the years since then, and forecasted for FY 2012 is shown below. We do not attempt to estimate refundable credits on a forecast basis further out than one year from the current date.

FY 2007 = $54.6 million
FY 2008 = $54.1 million
FY 2009 = $193.1 million
FY 2010 = $250.5 million
FY 2011 = $430.0 million
FY 2012 = $400.0 million
TOTAL = $1,382 million

We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Joe Paskvan
Alaska State Senator
State Capitol, Room 115
Juneau, AK 99801

April 6, 2011

Re: Answers to questions posed on April 5, 2011

Dear Senator Paskvan:

The purpose of this document is to respond to the questions posed on April 5, 2011. The requests/questions and responses follow.

Is it accurate to say that "the production tax rate under ACES may be as high as 75% (Oil & Gas Tax Status Report, p. 1)" when the price of a barrel of crude is approximately $400? Also, to confirm, are you talking about the nominal, marginal, or effective tax rate in that line?

This statement would be accurate. 75% is the maximum nominal tax rate for production tax only, and applies when the production tax value is greater than $342.50 per barrel.

On page 1 – page 2 of the January 17, 2011 Oil and Gas Production Tax Status Report, the report says that, "tax rates in each of the four years were much lower than the maximum rate." What was the corresponding tax rate in each of those four years?

Chart 2, on page 5 of the report, shows the average nominal tax rate paid in FY 07, 08, 09, and 10. The average nominal tax rates paid in each year were as follows: FY 2007, 22.5% (under PPT); FY 2008, 41.8%; FY 2009, 30.2%; and FY 2010, 32.6%.

The Oil & Gas Tax Status Report 2011 says that "the government share of each additional dollar of profit may be as high as 93% (page 14)." Please provide the back-up numbers to support that statement.

The maximum marginal rate under the current fiscal system has been quoted as either 87% or 93%. Both these numbers are correct, but refer to different things.

The maximum marginal rate of 87% refers to the percentage of the incremental taxable revenue (defined as the taxable revenue generated by a US$ 1/bbl increase in ANS

West Coast price with all other conditions remaining unchanged) that is captured by the State through the production tax only.

The calculation of this ACES maximum marginal rate is illustrated in Appendix A using the data presented by the Department of Revenue (DoR) to Senate Finance Committee on 25 January 2011 for FY2010.

Assuming an ANS West Coast price of US$ 116.71/bbl (leading to a Production tax Value per barrel (PTV/bbl) of US$ 91.50 in this example), the taxable barrels revenue would be US$ 23,787 million (MM) and the production tax before credit would be US$ 9,250MM.

Assuming an ANS West Coast price US$ 1 higher of US$ 117.71/bbl (with PTV/bbl rising commensurately to US$ 92.50), the taxable barrels revenue would be US$ 23,991MM and the production tax before credit would be US$ 9,427MM.

The ACES marginal rate is calculated by dividing the incremental production tax (US$ 177MM) by the incremental taxable revenue (US$ 204MM) generated by the US$ 1 oil price increase. In this case, the marginal rate is 87%, which is the maximum marginal rate for ACES.

Figure 1: ACES Marginal Rate Calculation

ACES Marginal Rate	116.71$/bbl case	117.71$/bbl case	Incremental
Taxable barrels Revenue ($MM)	23,787	23,991	204
Production Tax ($MM)	9,250	9,427	177
Marginal Tax Rate	*(Production Tax / Taxable Barrels)*		87%

Others have referred to 93% as the correct marginal rate. This is correct if one considers all the taxes a producer needs to pay i.e. the Production Taxes plus Royalty and State and Federal Income Taxes. This is illustrated in Appendix B using simplified assumptions.

Using the same assumptions, with ANS West Coast Price increasing from US$ 116.71/bbl to US$ 117.71/bbl, Royalty increases from US$ 3,626MM to US$ 3,657MM, Production Tax increases from US$ 9,250MM to US$ 9,427MM and Income Tax increases from US$ 3,997MM to US$ 4,008MM.

The marginal government rate of 93% is calculated by dividing the total incremental state and federal government take (US$ 219MM) by the incremental total revenue (US$ 235MM) generated by the US$ 1 oil price increase. Because each taxable element is calculated on different base amounts the total revenue has been used for consistency in the percent marginal rate calculation.

Figure 2: Government Marginal Rate Calculation

Government Marginal Rate	116.71$/bbl case	117.71$/bbl case	Incremental
Total Revenue ($MM)	27,413	27,648	235
Government Take ($MM)	16,873	17,092	219
Marginal Tax Rate	*(Gov't Take / Total Revenue)*		93%

In other words, the maximum marginal rate of 93% refers to the percentage of the incremental revenue that is captured by both State and Federal Governments. Note that at extreme prices over $300 / barrel, it is possible for the marginal rate to go even higher.

Appendix A

Note: data and assumptions below as per DoR presentation to Senate Finance Committee on 25 January 2011 for FY2010 save for the oil price which has been modified to illustrate where the ACES marginal rate is at its highest.

Figure A1: Production Tax assuming average ANS West Coast Price of US$ 116.71/bbl

Income Statement Type Summary	Per barrel	Barrels	Value ($million)
ANS West Coast & Daily Production	116.71	643,517	75
Annual Production	116.71	234,883,705	27,413
Royalty and federal barrels	116.71	(31,066,756)	(3,626)
Taxable barrels		**203,816,949**	**23,787**
Transportation Costs	-6.02	203,816,949	(1,227)
Deductible Opex	-10.64	203,816,949	(2,169)
Deductible Capex	-8.55	203,816,949	(1,743)
Total Lease Expenditures	-19.19	203,816,949	(3,911)
Production Tax Value (PTV)	91.50	203,816,949	18,649
Base Tax = 25%*PTV			4,662
Progressive Tax = ([91.5-30]*0.4%=24.6%)*PTV			4,588
Total Production Tax Due Before Credits			**9,250**
Credits Applied Against Production Taxes			(350)
Total Production Tax After Credits			8,900

Figure A2: Production Tax assuming average ANS West Coast Price of US$ 117.71/bbl (US$ 1/bbl increment)

Income Statement Type Summary	Per barrel	Barrels	Value ($million)
ANS West Coast & Daily Production	117.71	643,517	76
Annual Production	117.71	234,883,705	27,648
Royalty and federal barrels	117.71	(31,066,756)	(3,657)
Taxable barrels		**203,816,949**	**23,991**
Transportation Costs	(6.02)	203,816,949	(1,227)
Deductible Opex	(10.64)	203,816,949	(2,169)
Deductible Capex	(8.55)	203,816,949	(1,743)
Total Lease Expenditures	(19.19)	203,816,949	(3,911)
Production Tax Value (PTV)	92.50	203,816,949	18,853
Base Tax = 25%*PTV			4,713
Progressive Tax = ([92.5-30]*0.4%=25%)*PTV			4,713
Total Production Tax Due Before Credits			**9,427**
Credits Applied Against Production Taxes			(350)
Total Production Tax After Credits			9,077

Appendix B

Note: These calculations are based on commonly used assumptions, such as 41% corporate income tax rate, for illustration purposes. Property taxes are not specified as these have no impact on marginal rates.

Figure B1: Government take assuming average ANS West Coast Price of US$ 116.70/bbl

Simplified Tax Summary	Value ($million)
Royalty and federal barrels ($MM)	3,626
Production Tax ($MM)	9,250
Income Tax (41%) ($MM)	3,997
Total Government Take	16,873

Figure B2: Government take assuming average ANS West Coast Price of US$ 117.70/bbl (US$ 1/bbl increment)

Simplified Tax Summary	Value ($million)
Royalty and federal barrels ($MM)	3,657
Production Tax ($MM)	9,427
Income Tax (41%) ($MM)	4,008
Total Government Take	17,092

We hope our responses fully answer your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Title:	**Tax and Credit Report as Requested**
Preparer:	Cherie Nienhuis, Petroleum Economic Policy Analyst
Date:	4-Apr-11
Purpose:	To answer specific questions from Senator Paskvan about the production tax
Data Source:	DOR forecast models
Key Assumptions:	All assumptions included in forecast models
History:	None
Disclaimer:	The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Tax and Credit Report as Requested

	FY 2010	FY 2011	FY 2012
GVPP	$14,039	$13,723	$14,678
Total Lease Expenditures	$4,659	$5,125	$5,494
PTV (all expenditures)*	$9,380	$8,598	$9,184
Tax after credits applied against tax liability	$2,871	$2,615	$2,738
Credits Earned by type			
Capex credits (.023a)	$465	$500	$575
NOL credits (.023b)	$210	$120	$55
Small producer credit (.024c)	$35	$40	$40
Exploration credit (.025)	$5	$5	$5
Total credits earned*	$715	$665	$675

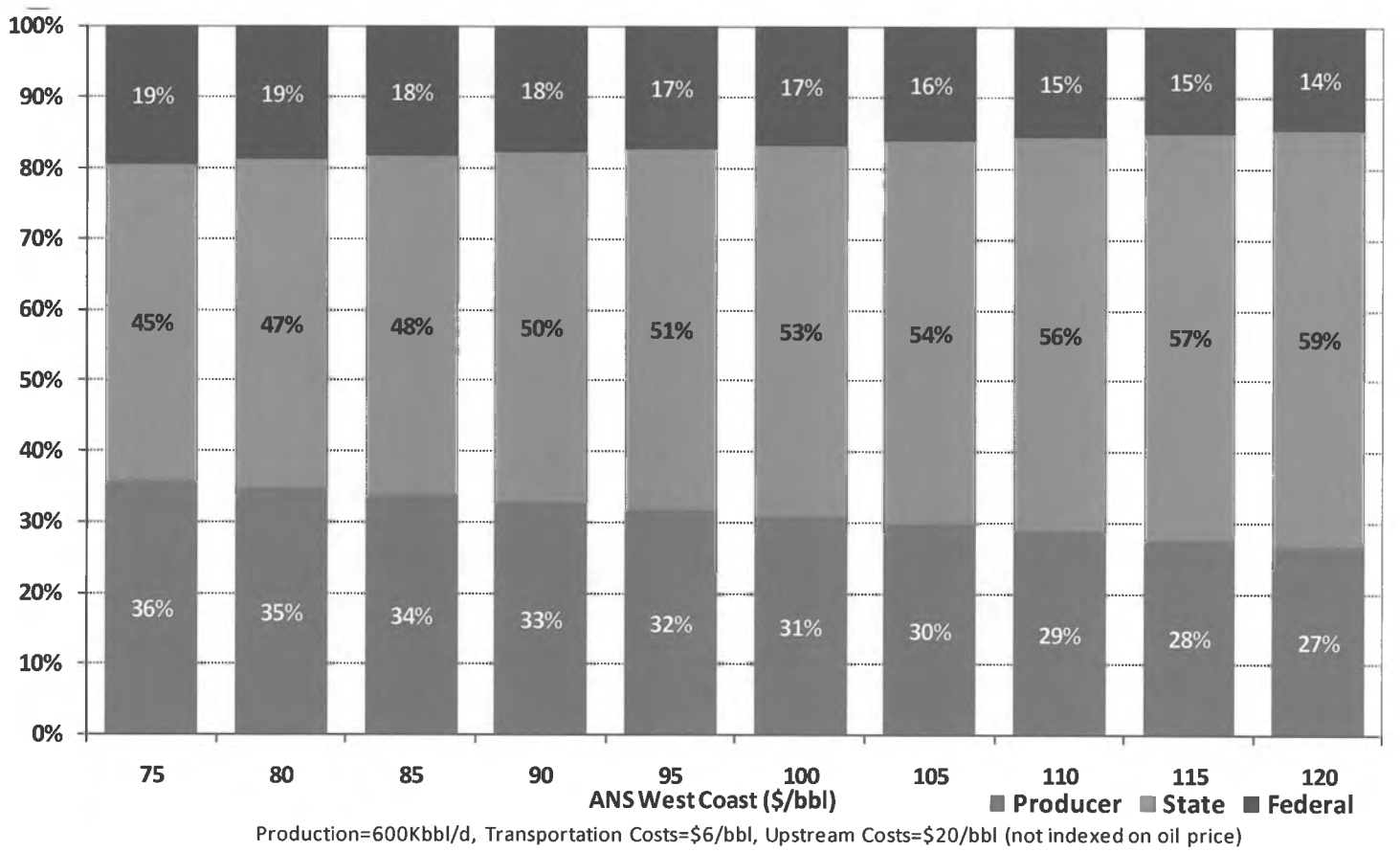
*PTV will not match published numbers because this report shows all expenditures, regardless of whether they were made by a company with a production tax liability.
**Total credits earned is an estimate of credits earned based on expenditures in the year; this estimate is not a forecast of credits to be used against tax liability in these years.
This analysis uses Fall 2010 assumptions

Profit share graph Assumptions

Assumptions	Value	Unit
Transportation Costs	6.00	$/bbl
Royalty Rate	12.5%	
Upstream CAPEX	10.00	$/bbl
Upstream OPEX	10.00	$/bbl
Total Upstream Costs	**20.00**	**$/bbl**
Daily Production	600,000	bbl/d
Property Tax (% of CAPEX)	2.00%	
Total Allowable Costs	**20.20**	**$/bbl**

- ANS West Coast Price range
  - from $75/bbl to $120/bbl in increments of $5/bbl
- Costs are constant through price range

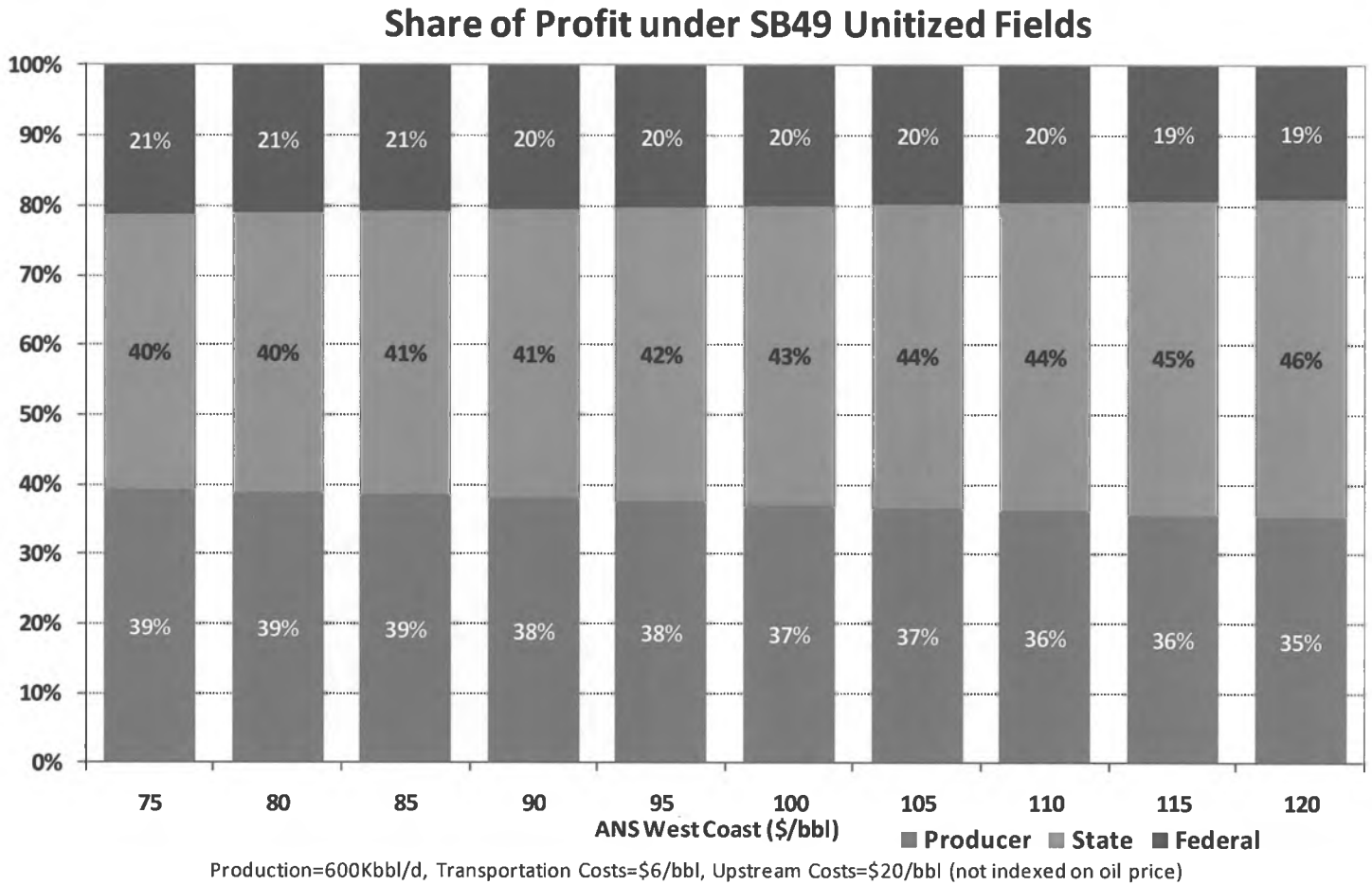
Profit Share under Status Quo



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures

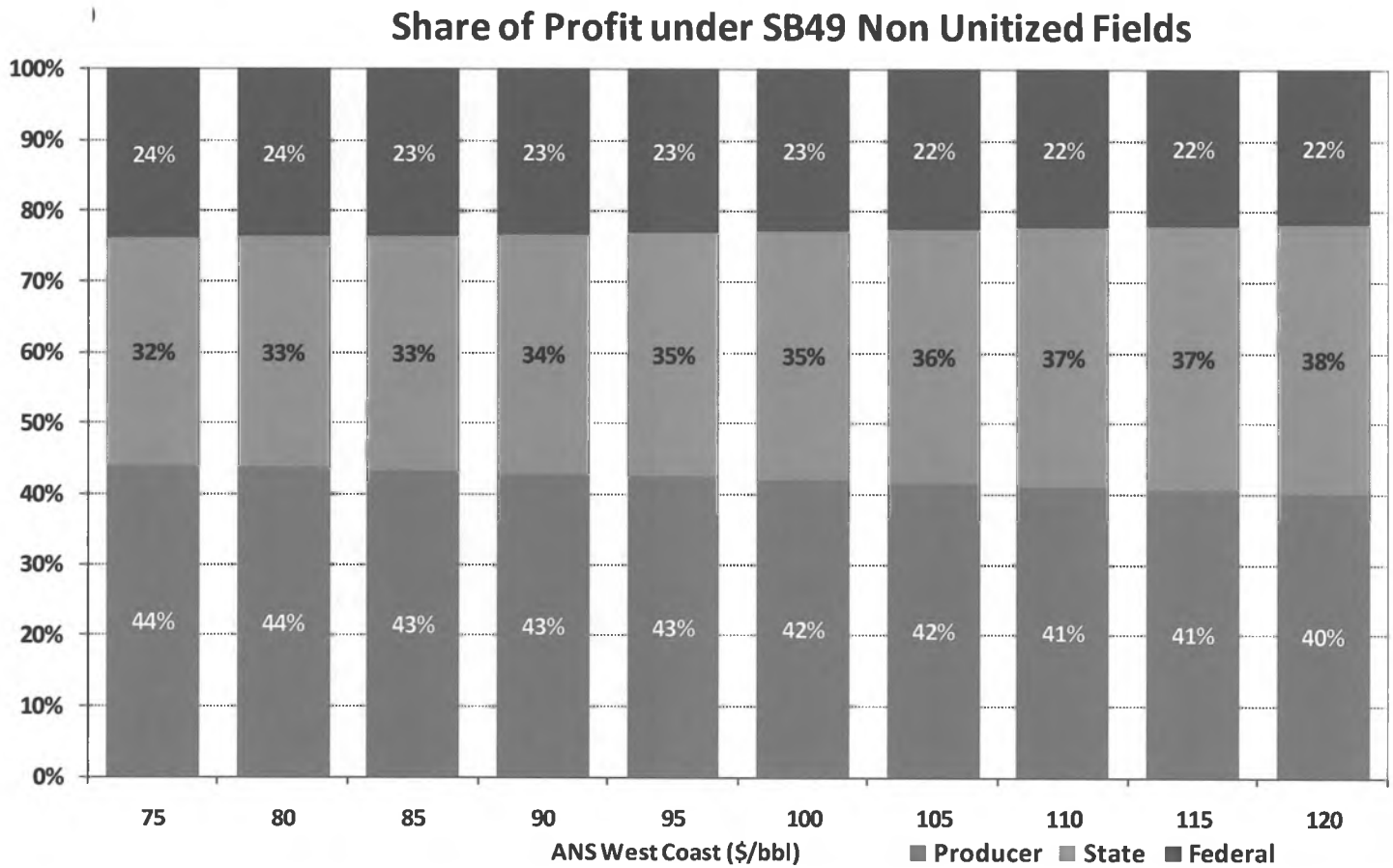
Profit Share under SB49 Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures

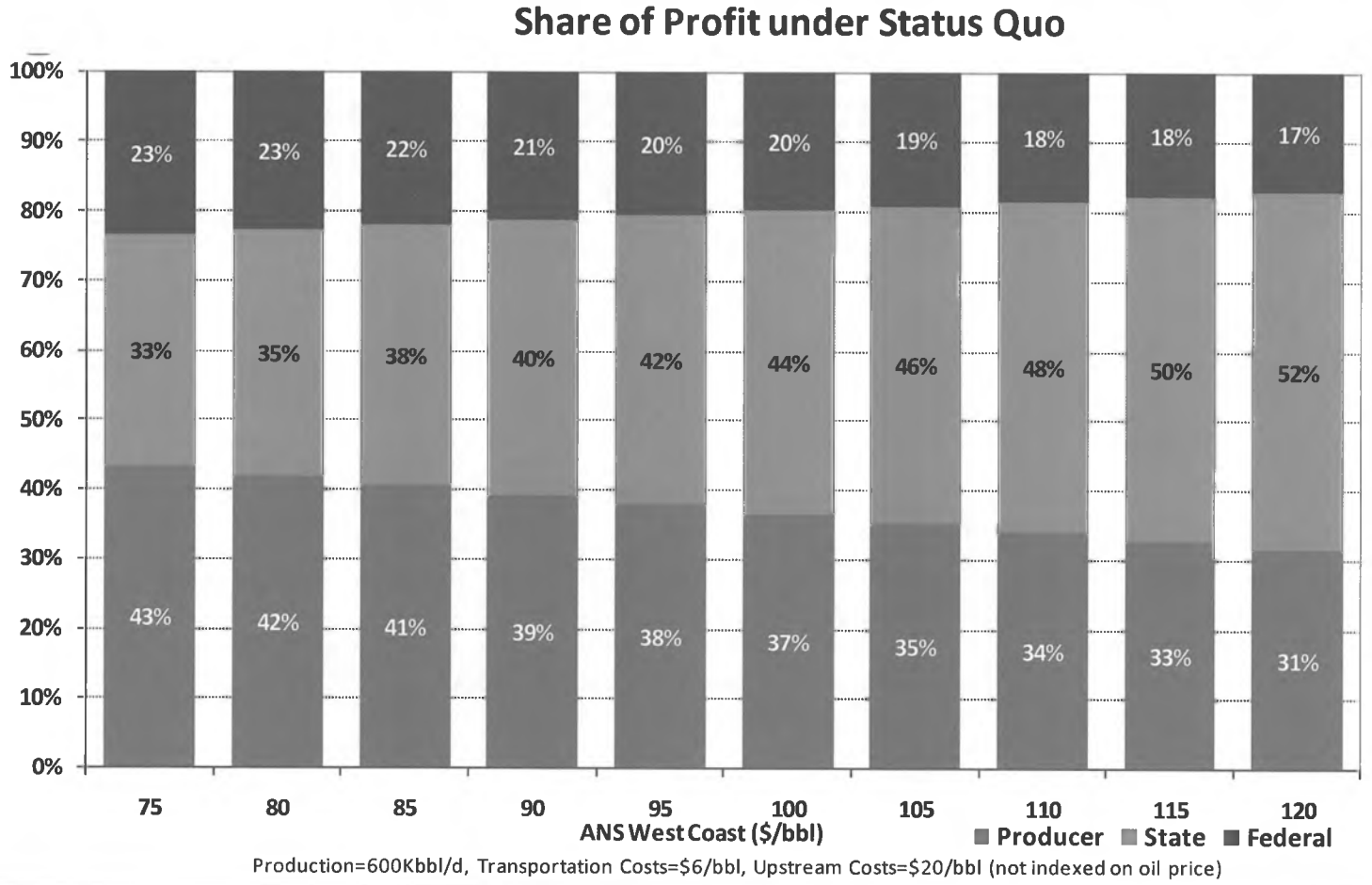
Profit Share under SB49
Non-Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures

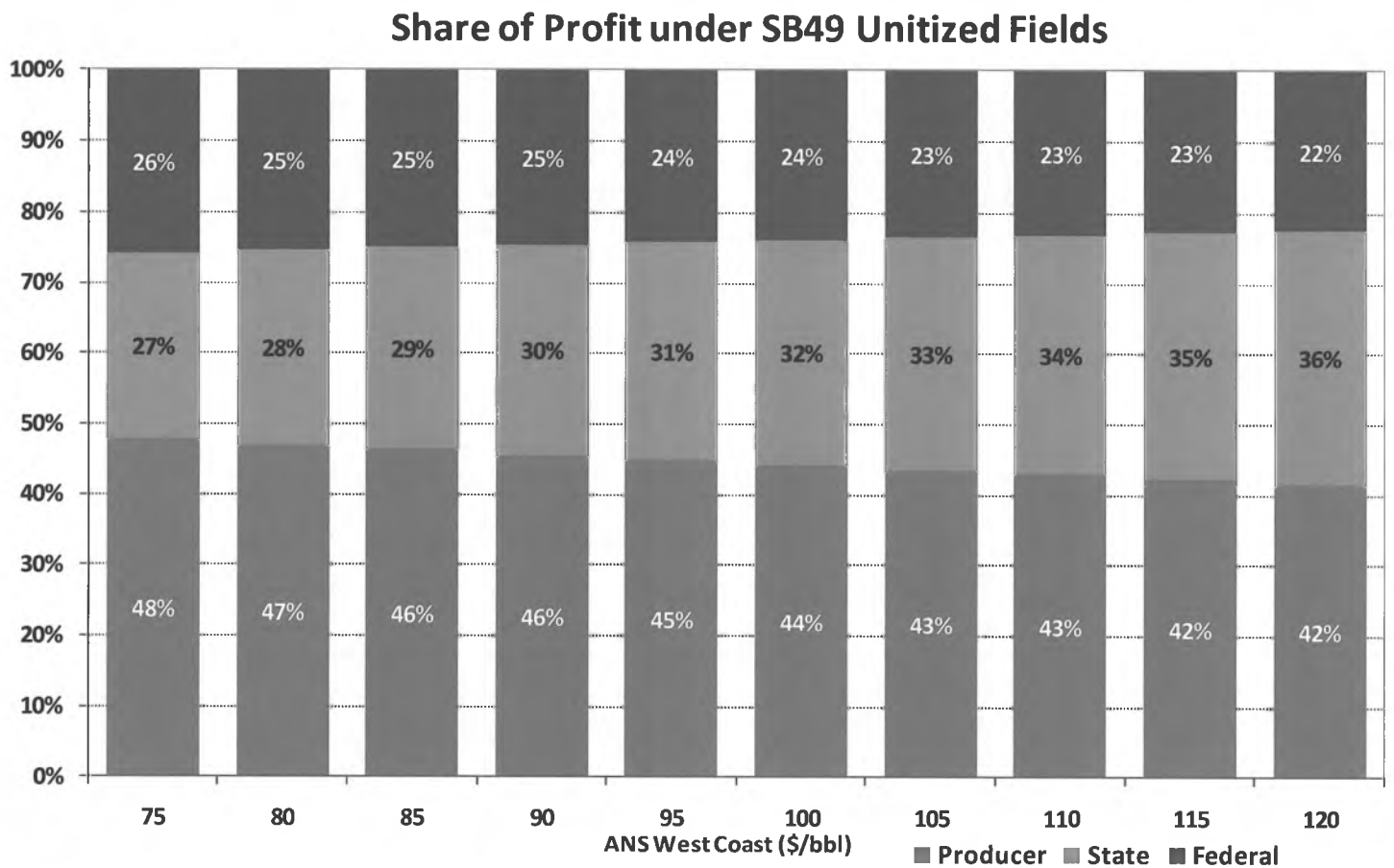
Profit minus Royalty Share under Status Quo



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit minus Royalty: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures (minus) Royalty

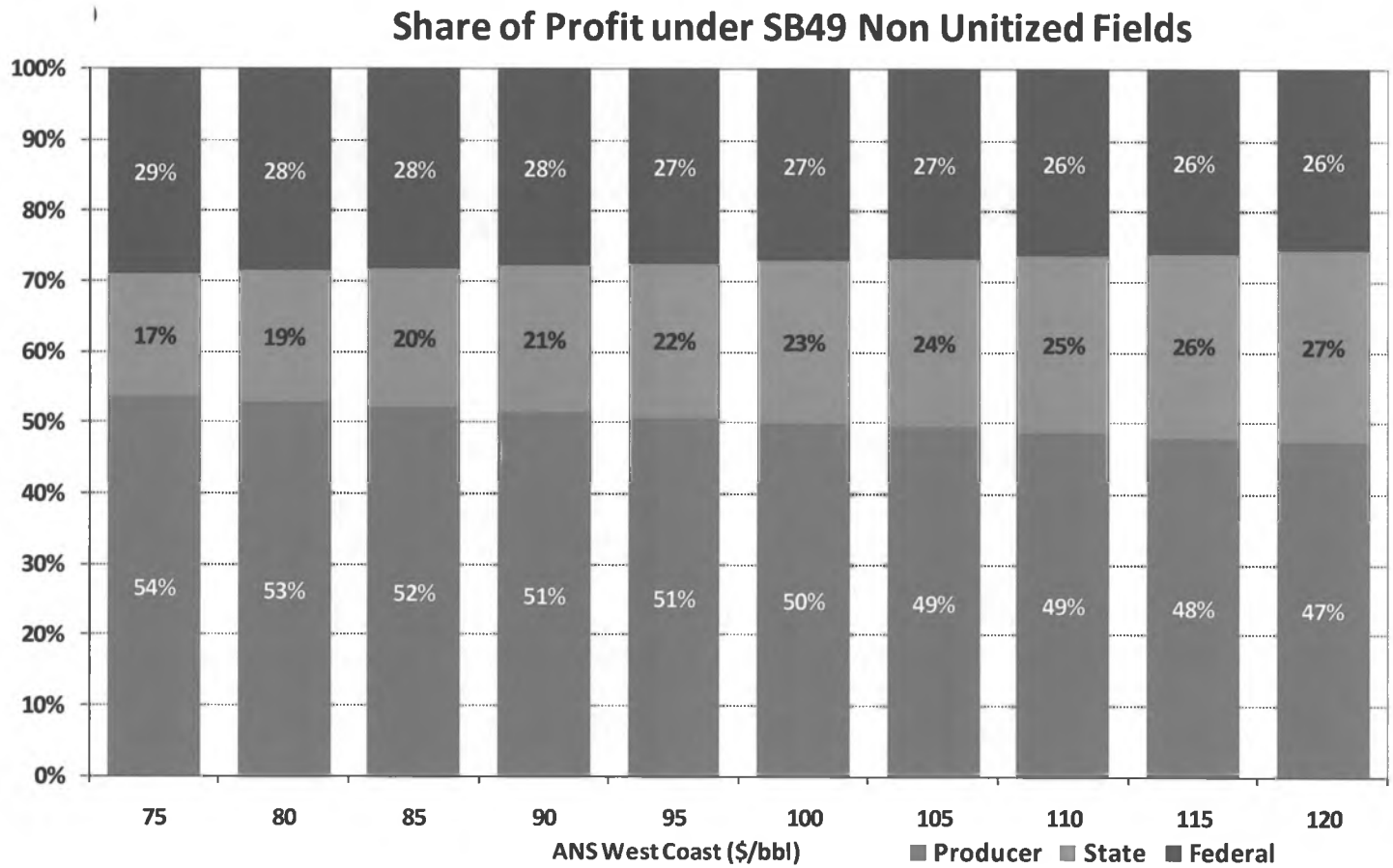
Profit minus Royalty Share under SB49 Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit minus Royalty: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures (minus) Royalty

Profit minus Royalty Share under SB49 Non-Unitized Fields



Production=600Kbbl/d, Transportation Costs=$6/bbl, Upstream Costs=$20/bbl (not indexed on oil price)

Profit minus Royalty: Gross Value at Market (minus) Transportation Costs (minus) Lease Expenditures (minus) Royalty

LEGISLATIVE RESEARCH SERVICES

Alaska State Legislature
Division of Legal and Research Services
State Capitol, Juneau, AK 99801

(907) 465-3991 phone
(907) 465-3908 fax
research@legis.state.ak.us

Memorandum

TO: Senator Resources Committee
FROM: Chuck Burnham, Legislative Analyst
DATE: March 29, 2011
RE: *Review of Selected Claims Made by the Supporters of SB 49*
LRS Report 11.245

You asked that we review certain claims made in a publication by the "Make Alaska Competitive Coalition" regarding the state's oil taxes and the impact of those taxes on investments and jobs. Specifically, you wanted us to examine the veracity of that organization's claims that Alaska's current oil tax structure is "driving away business" and motivating petroleum industry employers to move jobs out of Alaska. You were particularly interested in learning about variables other than taxation that impact the decisions of petroleum producing companies as to where and when to invest their resources.

Summary

We address your request, in part, through an analysis of the Fraser Institute's 2010 *Global Petroleum Survey*, which garnered responses from 645 respondents representing 345 companies regarding 133 oil producing jurisdictions.[1] To our knowledge, it is the largest publicly-available survey of its kind. In hearings for HB 110 (the companion bill to SB 49) before the House Resources Committee, representatives of the Governor's administration referred to elements of the survey as evidence of Alaska's competitive disadvantage in attracting investment from the oil and gas industry, and to support the claim that state taxes on the industry need to be reduced. It appears that in using the results of the survey to support those views, the Administration, industry groups, and other advocates of cutting oil taxes, such as the "Make Alaska Competitive Coalition," may have oversimplified and/or misinterpreted the survey results and the degree of negativity it reflects on Alaska.

Our analyses of the data collected by the survey, and of reports published by the Alaska Department of Revenue, suggest that a minority of industry officials hold negative views of Alaska's overall attractiveness for investment. With specific regard to taxation, a majority of survey respondents found Alaska's system attracts or has no impact on investment. These respondents combined with those who find the state's tax regime to be nothing more than a "mild deterrent," leave fewer than twenty percent of survey respondents who view taxes to be a significant barrier to investment in the state.

We located no research that definitively concludes that Alaska's petroleum taxation system, or that of other jurisdictions, is the primary driver of industry investment. Clearly, taxation is an important variable that impacts business decisions; however, it is equally clear that it is but one among many such significant variables. The massive expansion in petroleum exploration and production in North Dakota, where the oil tax system is viewed relatively favorably by industry (and has been for years), clearly demonstrates how variables other than taxation can drive increased investment.

[1] It is important to note that while 645 individuals responded to the survey, none of those individuals has sufficient knowledge of every variable in each of the 133 jurisdictions to provide responses to questions on those areas. Therefore, the number of responses for any given area on any specific variable is likely well below the number of overall respondents to the survey. In order to be included in the survey report, a jurisdiction was required to have garnered at least five responses for all seventeen variables. At least eleven jurisdictions were excluded due to lack of response. We contacted the authors of the survey to determine how many respondents are represented in the information on Alaska presented in their report to get a clearer picture of the extent of industry opinion represented therein; however, the Fraser Institute considers that information to be confidential. Dr. Gerry Angevine, lead researcher on the survey, suggested that the number of responses was "more than five but fewer than 200." Without knowing the precise number of individuals who provided responses on Alaska, we cannot discuss the accuracy of the survey's findings on the state with any authority. It is an established fact of statistical sampling practice, however, that as a sample grows smaller relative to the entire population being examined, the margin of error increases and, therefore, confidence in the survey's results decreases. Dr. Angevine can be reached via email at *gerry.angevine@fraserinstitute.org*.

As you know, in advocating for lower taxes on the petroleum industry in the state, the MACC has made a number of claims regarding oil and gas jobs in Alaska. Primary among those claims, in this case published on its website, is the following:

> Exploration jobs are down: Department of Labor statistics show jobs in the oil industry has shed 1,700 jobs over the last two years.

In a television commercial funded by the MACC, which is currently in broadcast circulation on a number of stations, the narrator makes the following statement:

> Alaska has lost almost 2,000 oil industry jobs, while North Dakota added 25,000.[2]

The advertisement provides a timeframe for neither the Alaska job losses, nor for the North Dakota gains; however, we assume that it approximates the same two-year time-period cited in the MACC's other media on the topic. The commercial does not directly claim that oil explorers and producers have transferred jobs directly from Alaska to North Dakota, but that appears to be the intended implication. Our final assumption on these claims is that the MACC is referring to the two-year period from November 2008 to November 2010—the most recent two-year period for which the Alaska Department of Labor and Workforce Development (DOLWD) has compiled data.

Our review of data on "oil and gas" employment compiled by the DOLWD suggests that, in the course of the past two years, roughly 2,000 jobs in that sector were "lost." However, that calculus is only true if one selects the month with the highest level of employment and compares it to the month with the lowest level of employment. Looking at the entire period in question, Alaska experienced a reduction of about 1,300 oil and gas jobs (11/2008-11/2010). However, selecting a given month in one year and comparing it to a month in another year produces highly volatile results. For example, by simply choosing the two-year period from February 2008-February 2010, instead of the period the MACC chose, job losses are reduced to only 400. We believe a more appropriate means of comparison is to use *average annual employment*, which eliminates a degree of the volatility that accompanies selectively comparing monthly employment. Using annual measures, Alaska lost approximately 700 oil and gas jobs over the three years 2008-2010. Nevertheless, the number of such jobs in the state remains above the ten-year average, and an argument can be made that the decline is part of a normal cycle of increases and decreases in what has historically been a volatile industry sector with regard to numbers of employees.[3]

Determining whether jobs are leaving Alaska for North Dakota, or any other petroleum producing jurisdiction, is not possible with the data available to us. As we detail below, among the points that are clear is that, relative to overall petroleum production levels, Alaska's oil and gas workforce has always been smaller than those of other oil producing areas.

To be clear, we take no position on the Governor's tax proposals, nor is it our intention to disparage the *Global Petroleum Survey* or to impugn the motives of the Administration and others who have used it to support their position. Rather, this report is meant to examine claims that have been made by those supporting tax cuts from a perspective that has not yet been presented to the Legislature, and to review some of the numerous variables besides taxation that impact the decisions of oil and gas industry executives in the course of their determining where to invest and expand or decrease workforces.

Fraser Institute *Global Petroleum Survey*

The Fraser Institute—a Canada-based research organization—conducts an annual *Global Petroleum Survey* to measure the views of executives, managers, and other influential members of petroleum exploration and production companies regarding the barrier to investment of petroleum-producing areas. It does so by asking those executives to rate jurisdictions on seventeen variables divided among three broader topics as follows:

[2] The commercial "Change Our Economic Tune" is available on the MACC website at *http://www.makealaskacompetitive.com/ads-photographs/*.

[3] Employment figures for 2010 are preliminary. Data are from the Alaska Department of Labor and Workforce Development, Research and Analysis, *http://laborstats.alaska.gov/*. The Department defines oil and gas jobs as those related to oil and gas extraction, drilling oil and gas wells, and support activities of oil and gas operations, as delineated by the North American Industry Classification System.

Commercial Environment	Regulatory Climate	Geopolitical Risk / Stability
Fiscal terms	Cost of regulatory compliance	Political stability
Taxation regime	Uncertainty regarding regulatory issues (interpretation, enforcement)	Security of personnel and assets
Trade barriers	Uncertainty regarding environmental regulation	Disputed land claims
Quality of infrastructure	Labor regulations, employment agreements, and local hiring requirements	Uncertainty over what lands can be protected as wilderness, parks, etc.
Labor availability	Regulatory duplications and inconsistencies	Socio-economic agreement / community development conditions
	Legal system	Quality of geological database

For each of these seventeen variables, respondents were asked to choose one of the following responses for each jurisdiction with which they were familiar:

1—Encourages investment
2—Is not a deterrent to investment
3—Is a mild deterrent to investment
4—Is a strong deterrent to investment
5—Would not invest due to this criterion

Survey Reporting Methodology

In the "Survey Methodology" section of their report, the authors of the *Global Petroleum Survey* begin with the following explanation:

> The survey is designed to identify the provinces, states, and countries with the highest barriers to investment in oil and gas exploration and production.[4]

As this quote indicates, the survey is intended to identify the *worst* jurisdictions for petroleum investment as perceived by the industry. This is reflected in the scoring mechanism, which effectively considers only the three levels of *negative* response. That is, for each of the seventeen variables and jurisdictions for which a sufficient level of response was received, the authors measured the proportion of responses that indicated a "mild deterrent to investment," "strong deterrent to investment," and those that indicated that the respondent "would not invest" due to a given criterion. For each variable, the jurisdiction with the highest proportion of negative responses was given a score of "100," with other jurisdictions listed in descending order of negative responses received. The authors included numerous bar graphs based on this method, with the least attractive area reflected by the highest bar on the far right of the graph and the least negative area represented on the far left of the graph by the shortest bar.

There is nothing inherently wrong, in our view, with this methodology, and the survey report provides interesting data. Problems can arise, however, in readers' interpretation of survey data as they are presented graphically in the Fraser Institute report. Further, it can be argued whether response number 3—indicating that a variable is "a mild deterrent to investment"—should be included and generally given the same weight in graphic representations as the other clearer and more definitive negative responses 4 and 5, which indicate that a variable is a "strong deterrent," and one that wholly precludes investment in an area, respectively. Finally, the debate over HB 110 is primarily about oil taxes. As we've outlined,

[4] Gerry Angevine, Ph.D. and Miguel Cervantes, "Global Petroleum Survey 2010," Fraser Institute, p. 7. The entire report can be accessed online at *http://www.fraserinstitute.org/publicationdisplay.aspx?id=16223&terms=global+petroleum+survey*. The Fraser Institute describes itself as an "independent non-partisan research and educational organization."

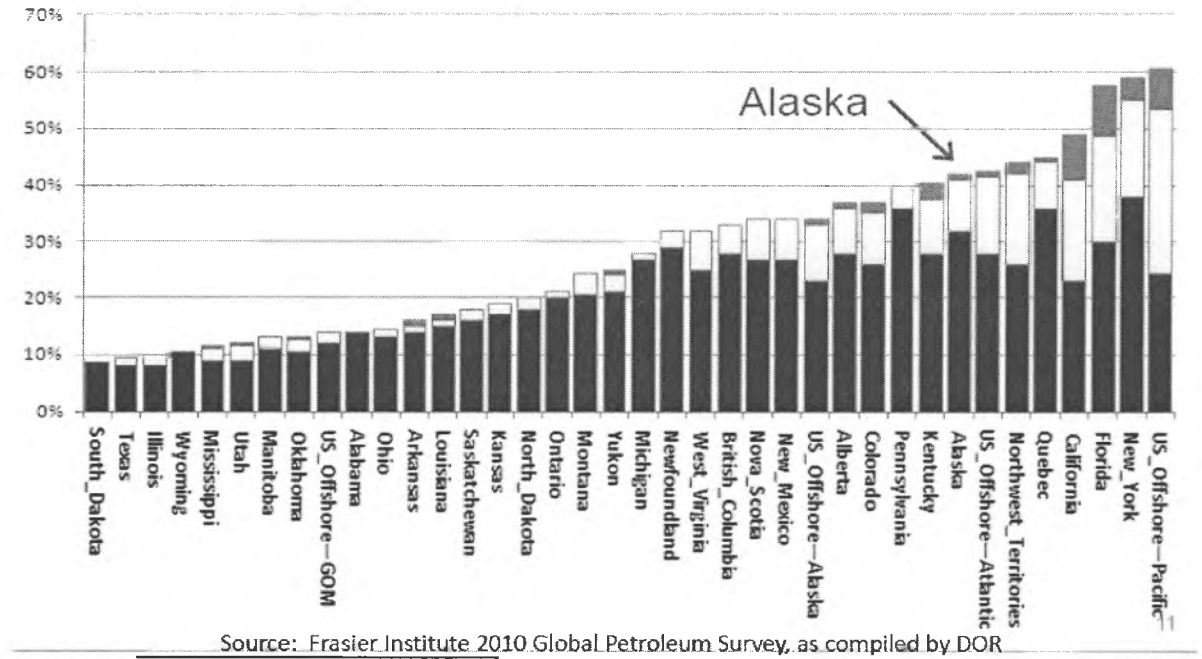
the *Global Petroleum Survey* measured sentiment on 17 variables. Taxation was but one of these variables, none of which were given more "weight" than another in determining the overall attractiveness of a given area. It is very difficult, therefore, to determine the degree to which Alaska would improve its standing as a region for investment were its tax structure to be changed in the manner sought in HB 110. We discuss each of these potentially problematic issues below.

Problems of Interpretation

Figure 1 (following page) is a graph produced by the Alaska Department of Revenue, using data from the *Global Petroleum Survey*, which was included in a February 7, 2011, presentation introducing HB 110 to the House Resources Committee.[5] The graph is generally in the same style as those included in the Fraser Institute's report on the survey except, of course, the particular emphasis on Alaska. The bars of the graph in Figure 1 have up to three color-coded sections. The bottom section, in dark blue, represents the "mildly deterrent" responses. The middle tan section reflects responses indicating a tax regime strongly deters investment; while the top section, in green, shows the proportion of respondents who indicate that they would not invest in a jurisdiction.

As you can see, of the 38 jurisdictions in North America for which survey responses were received, the "US Offshore Pacific" is viewed most negatively, while South Dakota is seen as the area with the fewest negatives for investment. Alaska is shown in position 31, near the "least attractive" far right of the graph. The reader sees that the "Alaska" bar reaches over half-way to the top of the graph, while Florida, New York, and U.S. Offshore are one line of delineation from the top. This gives the impression that these jurisdictions are viewed nearly universally as unattractive places for petroleum investment. One must keep in mind, however, that only the negative responses to survey questions are reflected in the bars of the graph. Looking at the far-left, vertical, or "Y," axis of the graph, it becomes clear that the uppermost line of delineation equates to 70 percent of responses being negative. Therefore, the *worst* jurisdictions for investment were identified as such in about 60 percent of responses, while Alaska was viewed negatively by slightly over 40 percent. Said another way, the overall attractiveness of Alaska to petroleum investment was not viewed as even a minor deterrent in almost 60 percent of responses. To put this in context, about three in ten respondents viewed South Dakota—the state with the lowest proportion of negative responses on taxation—as being more attractive than Alaska, while two in ten found that North Dakota—the state with the fastest growing levels of oil exploration and production—presents fewer negatives than Alaska.

Figure 1: Excerpt from Alaska Department of Revenue Presentation to House Resources, Feb. 7, 2011



Source: Frasier Institute 2010 Global Petroleum Survey, as compiled by DOR

[5] Slides for the presentation are available online at *http://www.legis.state.ak.us/basis/get_documents.asp?session=27&bill=HB110.*

There is no denying that to the extent that Alaska is viewed negatively impacts investment in the state, the survey data are troubling. Our point here is that the differences among the states in overall negative ratings—and particularly between Alaska and states legitimately competing for petroleum investment dollars—may not be as dramatic as some interpretations of the graphic portions of both the survey and presentations by the Administration on HB 110 have suggested.[6]

"Mild Deterrent"

As we mentioned, the meanings of four of the possible responses to questions in the *Global Petroleum Survey* are obvious: Responses 1 and 2 indicate that a given variable encourages investment and does not deter investment, respectively; while responses 4 and 5 state that a variable strongly discourages investment and causes a company to forego investment completely. Between these responses is the, to our ears, less definitive language of response 3, which indicates that a variable is a "mild deterrent" to investment. The survey report does not provide a precise definition for this term, so we presume it to follow the common definition of something that may be rather easily overcome or outweighed by other considerations.

Again, we understand that the survey was designed to measure the level of negativity that members of the oil and gas industry associate with petroleum-producing jurisdictions and do not take issue with that approach. We do, however, believe that the data collected through the survey could have been reported in a fashion that more clearly identifies issues that are fundamental problems as opposed to those that either may be easily addressed or are not serious obstacles. In other words, the survey report provides no "weight" to the relative importance of the variables reviewed.[7] Similarly, negative responses could have been weighted to provide a more nuanced understanding of the severity of that sentiment on a given variable by assigning higher values to the two most negative responses. The larger point is that we believe it legitimate to question whether industry players would be discouraged from an otherwise promising investment by a variable that is "mildly deterrent." We believe it reasonable to conclude that the answer to that question is no, at least with respect to a single mildly deterrent variable having the impact of driving away investment.

In light of that conclusion, we compiled Table 1 (following page), which shows the proportions of each of the 5 possible responses on the issue of taxation regime for all of the states an provinces covered by the survey. We include an additional column that combines the results for responses 1-3. Therefore, this column can be viewed as including all responses that characterized the taxation regimes as mildly deterrent, not a deterrent, or encouraging investment.

[6] For this report we leave aside the question of whether it is legitimate to compare and rank Alaska's attractiveness to investors with states that have a minute fraction of its proven oil and gas reserves.

[7] To be fair, the bar graphs of the Fraser Institute's survey color code the proportion of the bars represented by the three levels of negativity (the presentation by DOR to House Resources does so as well, but does not provide a key to the coding).

Table 1: Petroleum Industry Views on Tax Systems from the 2010 *Global Petroleum Survey*

	1	2	3	1 - 3	4	5
States						
Alabama	25%	58%	17%	100%	0%	0%
Alaska	25%	31%	25%	81%	16%	3%
Arkansas	36%	43%	21%	100%	0%	0%
California	8%	41%	26%	75%	21%	5%
Colorado	15%	50%	23%	88%	13%	0%
Florida	10%	40%	10%	60%	30%	10%
Illinois	14%	86%	0%	100%	0%	0%
Kansas	20%	67%	13%	100%	0%	0%
Kentucky	0%	71%	29%	100%	0%	0%
Louisiana	24%	58%	13%	95%	2%	2%
Michigan	20%	50%	30%	100%	0%	0%
Mississippi	41%	47%	12%	100%	0%	0%
Montana	19%	63%	16%	98%	3%	0%
New Mexico	35%	39%	22%	96%	4%	0%
New York	13%	38%	33%	84%	17%	0%
North Dakota	32%	52%	16%	100%	0%	0%
Ohio	0%	83%	17%	100%	0%	0%
Oklahoma	24%	62%	12%	98%	0%	3%
Pennsylvania	11%	56%	26%	93%	7%	0%
South Dakota	29%	57%	14%	100%	0%	0%
Texas	36%	55%	8%	99%	1%	1%
Utah	38%	56%	6%	100%	0%	0%
West Virginia	30%	30%	40%	100%	0%	0%
Wyoming	24%	64%	12%	100%	0%	0%
Provinces						
Alberta	25%	42%	27%	94%	5%	2%
British Columbia	19%	65%	16%	100%	0%	0%
Manitoba	17%	72%	10%	99%	0%	0%
Newfoundland	10%	65%	23%	98%	3%	0%
N.W. Territories	20%	60%	20%	100%	0%	0%
Nova Scotia	17%	59%	17%	93%	7%	0%
Ontario	18%	53%	29%	100%	0%	0%
Quebec	16%	47%	37%	100%	0%	0%
Saskatchewan	19%	66%	15%	100%	0%	0%
Yukon	18%	73%	9%	100%	0%	0%

Notes and Source: This table show's responses to a question regarding the impression of petroleum industry executives in the Fraser Institute's 2010 Global Petroleum Survey. The column "1 - 3" is an aggregate of responses in columns 1, 2, and 3, and represents the proportion of responses indicating that the tax system of a given jurisdiction encourages investment, does not deter investment, or is a mild deterrent to investment, respectively.

As you can see, 16 percent of those responding to questions on Alaska's tax system found that variable to be a strong deterrent (response 4), while three percent indicated that taxes preclude investment (response 5). Among these 35 jurisdictions, these negatives are relatively high; however, collectively those negative responses represent fewer than two out of ten respondents. By contrast, the aggregate of responses for those that see the tax system as, at worst, a mild deterrent, was 81 percent, and a majority—56 percent—view the tax system as encouraging or having no impact on investment.

Assuming that the *Global Petroleum Survey* is a reasonably accurate reflection of sentiments in the petroleum industry, those who claim that Alaska's taxes are "driving away business" must be referring to the business of the roughly 19 percent of industry leaders who view those taxes as a serious deterrent. If that is the case, an important question for the Legislature is the extent to which it will benefit the state to cut taxes or offer incentives to win over that proportion of the industry. Of course, it is possible that cuts and credits may increase the efforts of industry players who do not hold a negative view of Alaska's taxes as well; however, members of the industry have generally declined to definitively confirm or deny the extent to which this is the case or, for that matter, whether any level of tax cuts or credits will increase their activities in the state. In the current debate over petroleum taxes in Alaska, it appears that one of the few firm conclusions that can be reached is that, with the data available and information presented thus far to the Legislature, the calculus for determining the mix of taxes and credits that are optimum to attract investment to the state is extremely challenging.

Variables Other than Taxation—The North Dakota Boom

As we mentioned, the researchers who compiled the *Global Petroleum Survey* asked industry leaders questions on seventeen variables, all of which, the researchers identify as important in the making of investment decisions. Although this point is fairly obvious, it is important to keep it in mind when considering HB 110/SB 49 because the focus of those bills is almost exclusively on taxation and credits.

The importance of any of the variables considered in the survey (and indeed those not considered) relative to other variables in the investment decision-making process depends largely on the very precise circumstances of the company, region, project, geology, and value of the commodity being sought, among other factors. For example, an oil producer may be offered very attractive fiscal and taxation terms, low costs of regulatory compliance, few barriers to trade, and favorable labor agreements by the country of Sudan but decline to pursue investment strictly out of concern about security and the political stability of the government. Conversely, Canada's Northwest Territories may offer generous exploration credits and other attractive terms but industry may be discouraged by aboriginal land claims and stringent environmental regulation. More likely than either of these examples, however, is that industry executives carefully weigh *all* variables when making long-term plans for development, and that it is rare for any one or two variables to be *the* determining factor in deciding where to invest. A review of the recent experience of North Dakota may be an instructive insight into how a confluence of variables brings investment to an area.

North Dakota

As you know, North Dakota has experienced an oil boom in recent years, and is frequently identified by the Make Alaska Competitive Coalition and others as a major competitor for industry investment.[8] That state's production tax on oil is 5 percent of the wellhead value plus an extraction tax of 6.5 percent, which may be reduced or eliminated if oil prices fall below a statutory minimum "trigger," which stands at $46.79 per barrel for FY 2011. If the average price of a barrel of oil remains above the trigger price for any consecutive five-month period, the 6.5 percent rate applies; however, if the price falls below the trigger for five-consecutive months, the rate is reduced or the tax suspended for certain wells based on their type or age. Generally, at recent oil prices, these taxes are lower than in Alaska; however, North Dakota's tax system is not viewed by industry as the most attractive. Respondents to the *Global Petroleum Survey* collectively ranked the state 13th among the 38 jurisdictions in North American that were reviewed.

Given that relatively low levels of taxation have existed in North Dakota for years, one would expect that the recent oil boom was driven by the discovery of a major new oil field. However, the existence of very large petroleum deposits in North Dakota has been common knowledge since the early 1950s. Much of this petroleum lies in the shale strata of the geological areas known as the "Bakken" formation and, to a lesser extent, the "Three Forks" formation. These areas encompass most of the western third of North Dakota and smaller portions of eastern Montana and southeastern Saskatchewan Province. Estimates

[8] According to the U.S. Energy Information Administration, the current oil boom moved North Dakota from the seventh-highest petroleum producing state in the U.S. in 2009, to the fourth highest in 2010. In 2009, an average of 53 rigs and roughly 4,500 wells were in operation; by the fall of 2010, over 140 rigs were operating on nearly 5,200 wells (*https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp*). Over the next 20 years the North Dakota Oil and Gas Division foresees 2,140 new wells per year replacing depleted wells, requiring the operation of up to 165 rigs at any given time. Recent rig counts bear out that estimate, as the NDOGD lists 170 rigs in the state as of February 14, 2011. Rig counts are available online at *https://www.dmr.nd.gov/oilgas/riglist.asp*.

of the volume of the area's oil deposit range widely, from around 38 billion barrels (BBbl) to 500 BBbl; likewise, approximations of the portion of this petroleum that is recoverable range widely from 3 percent to 50 percent. Relatively conservative estimates put the amount of recoverable oil between 3 BBbl and 5 BBbl.[9]

So, why, in light of low taxes and a large oil field near extensive pipeline infrastructure in a stable, secure area, is it only in recent years that oil production has exploded in North Dakota? In fact, the Bakken spawned previous "oil booms" in the 1960s and early 1980s, but the easily recoverable oil in the area was exhausted in just a few years in each of those cases. The recent growth in exploration and production was spawned by technological advancements in horizontal well drilling and hydraulic fracturing ("fracking") techniques, which have facilitated access to reserves in the formation's mostly high-density rock structures.[10] As a result, even at the low-end estimates of reserves and recoverable oil, the amount of economically recoverable product in the formation will engender substantial oil and gas production for many years, but only if petroleum prices remain high enough to support these more expensive extraction methods.[11] According to a presentation by the Director of the North Dakota Oil and Gas Division (NDOGD), current levels of drilling and production are sustainable at oil prices above $50 per barrel.

In light of the above information, claims that petroleum industry investment in North Dakota, at the expense of such investment in Alaska, is occurring primarily due to differences in tax structure appear to be problematic. To the contrary, it is clear that the rapid expansion of oil and gas production in North Dakota was initiated by advances in oil recovery technologies. To be sure, many other variables in the state must be viewed as favorable to the industry members doing business there; however, even had the oil tax rate in North Dakota been zero, in the absence of technological improvements, its petroleum resources would still be locked deep underground. It is also worth noting that despite North Dakota's relatively low oil tax rates, the petroleum industry is aggressively lobbying the state Legislature for tax cuts.[12]

Alaska Department of Revenue Oil and Gas Production Tax Status Report

Pursuant to AS § 43.55.180, the Department of Revenue (DOR) is required to annually provide a report to the Legislature describing the effects of the state's petroleum production tax system on oil and gas development, exploration, production, revenue, and a number of other variables. In the summary for the most recent such report, published January 18, 2011, the DOR makes the following comments:

> **Industry Investment** – Investment in the form of capital expenditures has increased in each of the four fiscal years since implementation of the net profits tax, however, it is unclear how much of the capital expenditures were drilling or well-related and how much were maintenance or facilities-related.
>
> **Impact on Exploration, Development, and Production** – Exploration has generally increased from 2003, when the EIC credit was implemented, but has dropped off in 2010. Development continues in three relatively new North Slope projects, yet production continues to decline.
>
> **Industry Employment and New Entrants** – Industry employment rose steadily from 2006 through 2009, but dipped slightly in 2010. The number of companies filing annual tax returns doubled

[9] More information on attempts to estimate the Bakken's reserves is published by the State of North Dakota at *http://www.nd.gov/ndic/ic-press/bakken-form-06.pdf*.

[10] Ben Casselman,"Oil Industry Booms—In North Dakota," *The Wall Street Journal* online edition, February 26, 2010, *http://online.wsj.com/article/SB10001424052748703795004575087623756596514.html*.

[11] Hydraulic fracturing is a resource intensive process that significantly increases the cost of petroleum recovery. It is also a controversial technique that has raised concerns among certain members of the public, environmental groups, and regulators. The U.S. Environmental Protection Agency is currently studying the process and its consequences. More information is available on the EPA website at *http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydrowhat.cfm*. The Canadian province of Quebec recently placed a moratorium on the procedure in order to further study its environmental impacts (*http://ca.finance.yahoo.com/news/Does-shale-gas-industry-capress-5532805.html?x=0*)

[12] Dale Wetzel, "North Dakota Oil Pressing for Tax Cuts," *Bloomberg News*, February 1, 2010, *http://www.bloomberg.com/news/2011-02-01/north-dakota-oil-industry-pressing-for-tax-cuts.html*.

between 2006 and 2009, indicating interest by companies that are either new or returning to the Alaska oil and gas industry.

Use and Expansion of Tax Credits – The amount of credits used has increased annually since 2006 and we expect the trend to continue as new credit programs were added in the 2010 legislative session.

The DOR cautions that multiple changes to the tax laws in recent years makes drawing conclusions about impacts on investment in Alaska difficult, and warns that production continues to decline. Nonetheless, these recent statements, made by the agency that is the primary advocate for the Governor's tax proposals before the Legislature, do not support the claim that the state's oil taxes are "driving away business." As we have said, this report is not intended to in any way deny that Alaska faces significant challenges to increasing oil production and maintaining current revenue levels. However, the publicly available evidence on Alaska's taxation system, some of which we have reviewed in this report, does not appear to support the level of certainty that some supporters of cutting taxes have displayed in claiming that the tax system is the exclusive culprit in driving away industry investment.[13]

The Context of Recent Job Losses

As we mentioned, based on annual averages, Alaska saw a reduction of 700 oil and gas jobs between 2008 and the preliminary total for 2010; however, if one selects the month of highest employment over that two-year period—December 2008, with 13,700 jobs—and subtracts the month in which the fewest number of oil and gas employees were working—September 2010, with 11,600 jobs—a claim of job losses totaling roughly 2,100 jobs can be made. Comparing annual averages with monthly totals begins to illustrate the problems with such a claim. That is, the number of oil and gas jobs in Alaska is a highly volatile measure, which, since 2001, has regularly increased or decreased by 200-600 jobs per month. As a result, selecting data on the extremes in a given pairing of months can be misleading in the larger context of industry employment. Further, as Table 2 (following page) shows, the most recent two-year period is one of historically volatile levels of both oil prices and related employment in Alaska, which followed a steep, years-long expansion in that workforce—an increase of 34 percent from 2001-2007.[14] While it is true that the oil and gas workforce has decreased overall in the past two years, the 12,100 preliminary average for of such jobs in 2010 is 19.3 percent above the cumulative average annual employment of 10,145 since the year 2000.

[13] The entire report is available online at *http://www.revenue.state.ak.us/2011%20OG%20Tax%20Report%201-18-2011%20on%20Letterhead.pdf*.

[14] The reasons for this expansion, and their relative impacts, are subjects of significant debate. Although we make comparisons in this report with employment, production, and oil prices, we draw no firm conclusions on their relationships. In recent years, a number of maintenance issues, accidents, production activities requiring additional manpower, and other factors have been present that likely contributed to greater demand for oil field workers. The extent to which each of these variables led to increases in the workforce, however, remains unclear.

Table 2: Average Annual Alaska Oil and Gas Jobs and North Slope Oil Price and Production, 2001-2010

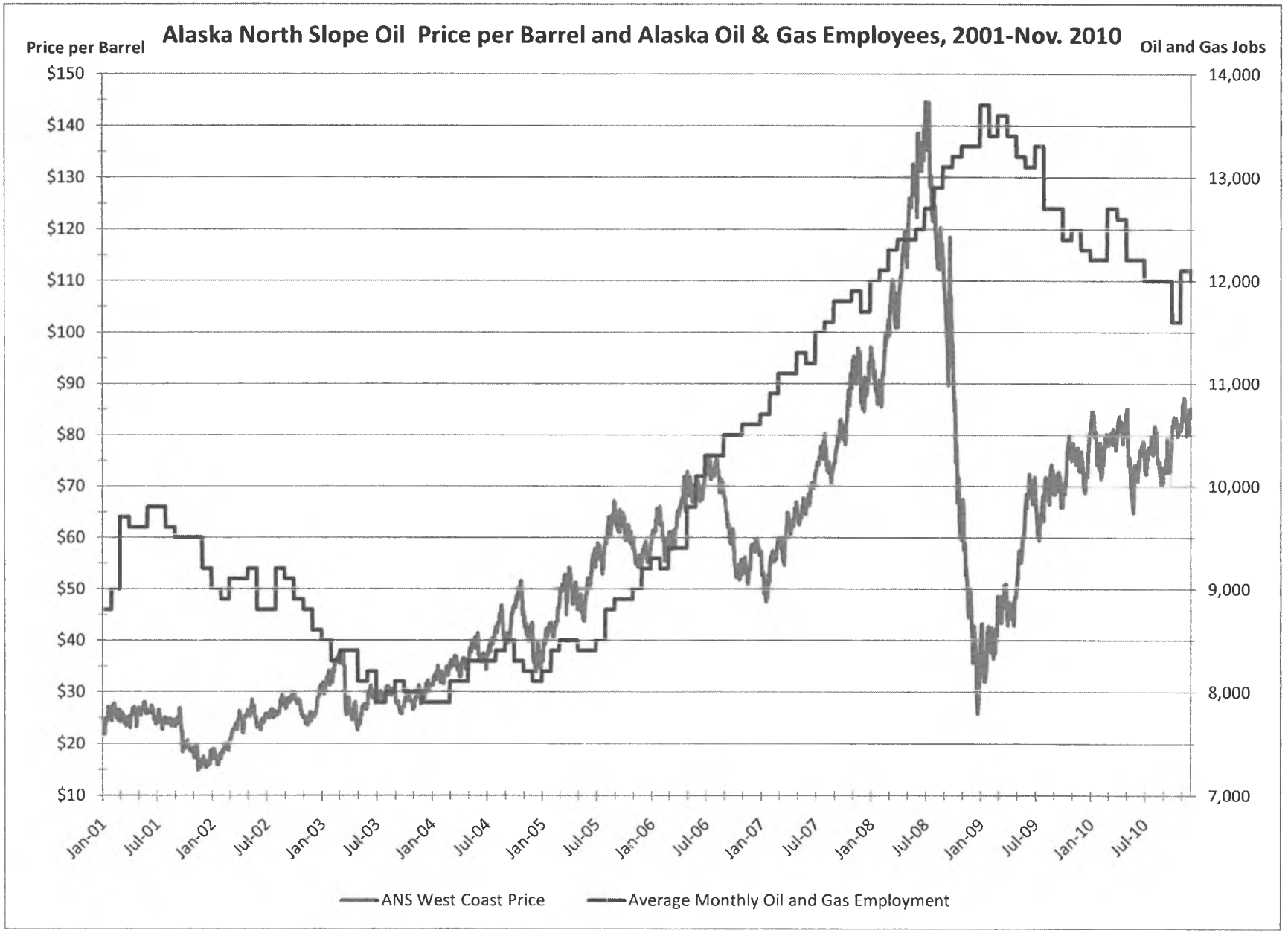
Year	Annual Oil & Gas Employment[1]	ANS for West Coast Delivery[2] (nominal $ per barrel)	ANS Production[2] (barrels per day)
2000	8,800	$28.40	997,821
2001	9,500	$23.23	993,844
2002	8,900	$24.81	996,856
2003	8,100	$29.57	988,950
2004	8,200	$38.86	939,170
2005	8,700	$53.59	889,498
2006	10,100	$63.65	758,957
2007	11,500	$71.54	737,206
2008	12,800	$98.40	705,681
2009	12,900	$61.00	671,845
2010	12,100	$77.93	619,044
Overall Average	**10,145**	**$51.91**	**845,352**

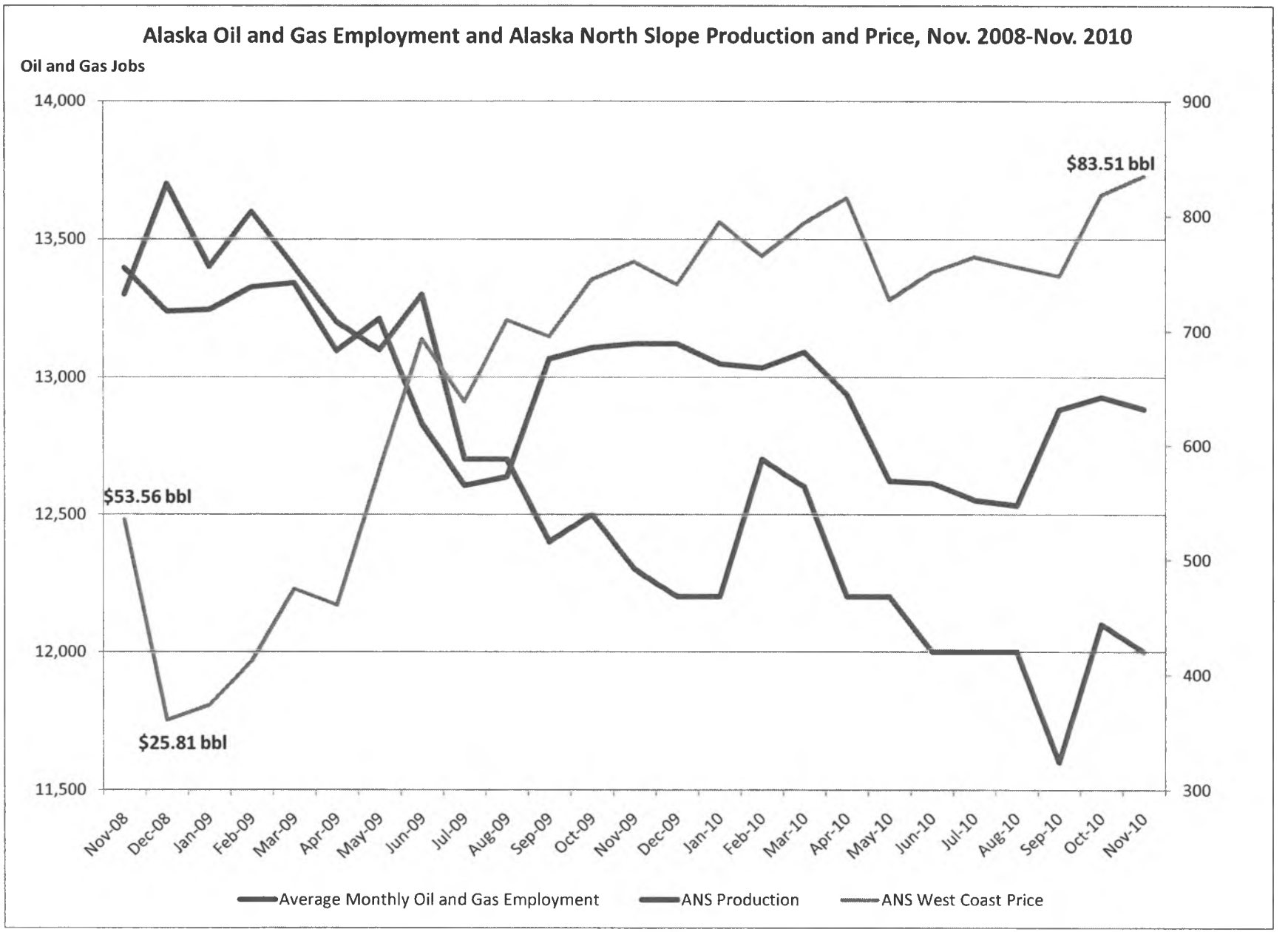
Notes and Sources: 1) 2010 employment figures are preliminary. Alaska Department of Labor and Workforce Development, Research and Analysis, *http://laborstats.alaska.gov/*. The Department defines oil and gas jobs as those related to oil and gas extraction, drilling oil and gas wells, and support activities of oil and gas operations, as delineated by the North American Industry Classification System.
2) Alaska North Slope oil prices and production levels are annual averages we calculated based on information from an online database on the website of the Alaska Department of Revenue at *http://www.tax.alaska.gov/programs/oil/dailyoil/dailyoil.aspx*. Please note that because these figures are based on daily prices and production, they may differ somewhat from figures published elsewhere derived from a different methodology.

The data in Table 1 are annual averages that, while useful, do not fully capture the volatility of the daily and monthly changes that occur. The data lines in Figure 1 (following page) are based on daily oil prices and monthly employment levels, and provide better insight into the volatility of these variables and the dramatic changes they have undergone in recent years.

As you can see in Figure 2 (following page), both Alaska North Slope (ANS) oil prices (blue line, left vertical axis) and oil and gas employment (red line, right vertical axis) began an extended period of increases in early 2005. Oil prices suffered a relatively brief swoon in mid-2006 but initiated another steep climb in early 2007 that ultimately saw per barrel prices climb from the mid-$40 range to over $144 in July of 2008. Over that two-year period, oil and gas employment expanded by approximately 2,000 jobs—roughly equal to the decrease between December 2008 and September 2010.

Figure 3 (page 12) represents the same variables as Figure 1, but for only the two most recent years of data, and includes an overlay of the price of ANS oil. As you can see, oil production and employment trended down over this period while prices generally moved higher. Beyond showing the relationship between these variables, the graph illustrates again their significant degree of volatility.


Alaska North Slope Oil Price per Barrel and Alaska Oil & Gas Employees, 2001-Nov. 2010
Price per Barrel
Oil and Gas Jobs
$150
$140
$130
$120
$110
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
14,000
13,000
12,000
11,000
10,000
9,000
8,000
7,000
Jan-01
Jul-01
Jan-02
Jul-02
Jan-03
Jul-03
Jan-04
Jul-04
Jan-05
Jul-05
Jan-06
Jul-06
Jan-07
Jul-07
Jan-08
Jul-08
Jan-09
Jul-09
Jan-10
Jul-10
ANS West Coast Price
Average Monthly Oil and Gas Employment


Alaska Oil and Gas Employment and Alaska North Slope Production and Price, Nov. 2008-Nov. 2010
Oil and Gas Jobs
14,000
13,500
13,000
12,500
12,000
11,500
900
800
700
600
500
400
300
$83.51 bbl
$53.56 bbl
$25.81 bbl
Nov-08
Dec-08
Jan-09
Feb-09
Mar-09
Apr-09
May-09
Jun-09
Jul-09
Aug-09
Sep-09
Oct-09
Nov-09
Dec-09
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Average Monthly Oil and Gas Employment
ANS Production
ANS West Coast Price

We do not intend to imply through these figures and discussion that the causal relationships between prices, production, and/or oil and gas employment are clear or reducible to a simple graph, nor are we suggesting that price and production are the only variables that impact employment—they are not. That there is some relationship is obvious; however, equally apparent is that many other variables influence employment levels. In 2008, the DOLWD dedicated an issue of its *Alaska Economic Trends* magazine to the oil industry in the state, and included substantial discussion of the industry workforce and the various issues that have had significant impacts on employment levels over the years.[15] We review a number of the significant points in that article below.

According to Neal Fried, Economist III with DOLWD and the primary author of the *Trends* issue on the state's oil industry, despite comprising 29 percent of Alaska's gross state product in 2007, the petroleum industry provided just four percent of the state's jobs. Nonetheless, these jobs are important both because of their high average wages and due to their obvious importance to the state's most vital industry. Mr. Fried describes the levels of oil and gas employment in Alaska since 1991, when the industry had 10,700 workers, as having "fluctuated from year to year, with an overarching declining trend accompanied by periods of recovery."[16] The following excerpts from Mr. Fried's article outline a number of these fluctuations, and provide some of the reasons that they occurred:

> Other factors aside from production levels and prices explain the changing size of the oil industry's work force, both nationally and in Alaska. Dramatic improvements in technology in the last decade have had a powerful effect on employment levels . . . According to the Federal Reserve Bank of Dallas, the national oil and gas industry was the leader in productivity gains throughout the 1990s and continues to be an above-average performer. In other words, the oil industry has been able to perform more work using fewer workers.
>
> One of the largest contractions in Alaska's oil industry work force took place from 1991 to 1992. BP, along with other oil industry employers and contractors, went through a period of major restructuring and consolidation in response to declining oil prices. The downsizing cost the industry 1,300 jobs – a record one-year loss. Weak oil prices and other factors buffeted the industry again in 1995, when Atlantic Richfield Co. made major cuts to the size of its work force. By 1998, employment in Alaska's oil patch began to recover with the development of the Alpine, Tarn and Badami fields, the drilling at West Sak, and preliminary work at North Star, Liberty and other fields. Oil prices plunged from nearly $19 per barrel in 1997 to $13 in 1998 and record job losses followed. For the first time since 1983, Alaska's oil industry employment fell below 8,000 and the losses reverberated throughout the state's economy.
>
> Finally, in 2000, recovery kicked in and by 2001, oil industry employment reached a 10-year high, nearly 2,000 jobs higher than the industry's nadir in 1999. The near concurrent development of both the Alpine and North Star oil fields were the two major reasons for the upswing in activity. What gave the oil industry's employment numbers some extra loft was the construction of large oil modules in Kenai and Anchorage. Before that, they were built in the Lower 48 or overseas. The year 2000 marked a historic event: Alaska's largest oil industry employer and discoverer of Prudhoe Bay, Atlantic Richfield, disappeared from the scene when it sold its assets to BP and ConocoPhillips. The sale was a signal to many observers that Alaska's oil industry was moving into its very "mature" stage of development, and – barring any major field discoveries, the opening of ANWR for exploration or construction of a gas line – the industry's employment trajectory was most likely on a permanent downward sloping curve.
>
> The following four years appeared to reinforce that view. With most of the work completed on the North Star and Alpine fields, oil industry employment began to fall steeply in 2001 and then hover

[15] *Trends* is a monthly publication that studies a wide variety of issues that impact Alaska's economy. Previous issues of the publication, including the September 2008 issue on the oil industry, can be accessed online at *http://labor.alaska.gov/trends/*.

[16] *Trends*, September 2008, p. 6.

> at the 8,000 level through 2004. What made that peculiar was the fact that the price of oil was recovering nicely from its 2001 low of $23 a barrel to $39 in 2004. Even so, it appeared as if Alaska's oil work force was entering an era of stagnation and enduring decline. Finally, and possibly due to four years of above average oil prices that by 2005 had more than doubled from the 2001 low, the oil industry began to stir again in 2005. Unlike many earlier recoveries, this one wasn't tied to one or two projects. Instead, there were a lot of smaller ones: continued work on heavy oil in West Sak, an increase in the production of viscous oil, the repair of Prudhoe Bay production wells, work around Alpine, the building of new connecting pipelines, and the continued development of a number of satellite fields.
>
> Then in early 2006, a section of BP's pipeline sprung a leak. It eventually turned out to be the largest oil spill in the North Slope's history. Soon afterward, BP discovered additional corrosion problems, forcing the company to shut down the pipeline for a short period. The spill and corrosion led BP to spend more than $260 million in 2007 and 2008 to replace 16 miles of pipeline in Prudhoe Bay and up-grade the company's facilities. Undoubtedly, that helped turbo-charge Prudhoe Bay employment numbers in late 2006 and early 2007.

Again, we are not suggesting that recent decreases in oil industry employment are not a cause for some concern. We do note, however, that according to the DOLWD, oil and gas workers represented 4.1 percent of claimants for unemployment insurance, which is roughly equal to the portion of the overall Alaska workforce comprised by the oil and gas sector.[17] Further, as the above excerpt makes clear, regular fluctuations and occasional dramatic changes are the norm, rather than the exception, in oil and gas employment levels in Alaska. To be clear, such volatility is not seen in Alaska alone. According to the North Dakota Department of Commerce, that state's oil and gas worker turnover, or "replacement," rate for 2010 was 34 percent, and similar turnover levels are expected through in coming years.[18]

Oil and Gas Jobs Moving to Other States

As we mentioned, we are aware of no publicly available data that show oil and gas jobs have been transferred directly from Alaska to North Dakota or any other state. It is true that, on the whole, such employment has decreased over the past two years in Alaska, while North Dakota has seen a large increase due to rapidly expanding production in the Bakken formation in the western third of the state. However, the growth in the North Dakota industry's employment, while quite dramatic, does not appear to reach the levels suggested by the MACC.

According to data published by the North Dakota Petroleum Council, direct employment in its oil and gas industry increased 264 percent, from 5,051 to 18,328, between 2005 and 2009.[19] A study prepared for the North Dakota Department of Commerce reports that industry employment is expected to continue to rise through 2011, to approximately 20,500 workers, and remain at that level through 2015. To be sure, a quadrupling of the oil and gas workforce since 2005 is nothing short of a boom for the industry; however, the roughly 15,000 jobs added in that time period fall well short of the 25,000 jobs that the MACC cites. Since 2009, growth in North Dakota oil and gas employment slowed compared to the 2005-2009 period, adding fewer than 2,000 jobs over the past two years—roughly comparable to the number that the MAAC claims Alaska has lost.[20]

When measured by the amount of oil produced per employee, Alaska's oil industry is the most efficient in the U.S.—typically by a wide margin. For example, preliminary data from the U.S. Energy Information Administration show that, in 2010, North

[17] "Unemployment Insurance Claimant Characteristics 2010," Alaska Department of Labor and Workforce Development

[18] North Dakota employment figures are from "North Dakota Oil and Gas Workforce Needs and Skills Study," prepared by Electronic Media for the North Dakota Department of Commerce, December 2010, *http://www.commerce.nd.gov/uploads%5Cresources%5C315%5Coil-and-gas-executive-summary.pdf*.

[19] The North Dakota Petroleum Council represents and advocates for over 250 companies in states the oil and gas industry. More information on the group and its activities is available online at *http://www.ndoil.org/?id=25&ncid=4&nid=162*.

[20] "North Dakota Oil and Gas Workforce Needs and Skills Study," p. 1.

Dakota produced an estimated 122,471,000 barrels of oil and employed an average of 19,070 oil and gas employees.[21] This equates to per employee production of about 6,422 barrels for that year. By contrast, an average of 12,100 oil field workers in Alaska produced 224,840,000 barrels of oil, or about 18,580 per worker—nearly three times the per employee rate of production in North Dakota. In other words, because North Dakota's oil production is derived from a much higher and more geographically dispersed number of wells, the state needs far more workers than Alaska to produce its oil. Therefore, in that state, it appears that the number of workers employed is more directly tied to production than is the case in Alaska.

According to labor economist Neal Fried, this disparity is typical between Alaska and other states. In his 2008 *Trends* article, Mr. Fried compared production levels and numbers of employees in Alaska to those of seven other oil production states. In every case, Alaska workers were more efficient, sometimes to a stunning degree. For instance, Colorado produced 23,903,000 barrels of oil in 2007 and had 18,913 oil and gas employees. That same year Alaska produced ten-times the amount of oil with about 6,700 fewer employees.[22]

Compared to the per employee oil production rate in Alaska for 2007, the 2010 rate decreased by over 5,000 barrels, or nearly 20 percent. By contrast, over the same time period, overall oil production has decreased by about 17 percent, but average annual oil and gas employment in the state has increased over 5 percent. Again, we believe the complex interplay of these variables with the many other factors that help determine oil and gas employment levels in the state belie simplistic attempts to explain changes in those levels or claims that jobs have been "moved" to another jurisdiction.

We hope this is helpful. If you have questions or need additional information, please let us know.

[21] The U.S. Department of Energy, Energy Information Administration, provides a wide variety of data on its website at *http://www.eia.gov/*. Oil production data are available at *http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm*.

[22] Neal Fried, *Trends*, September 2008, p. 11. Please note that the oil and gas employees in other states have produced much more natural gas than Alaska, which mitigates the differences in per worker production levels somewhat. Even controlling for gas production, however, Alaska appears to have higher levels of efficiency that other areas.

State of Alaska

Department of Revenue

Commissioner's Office

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

January 14, 2010

Honorable Governor Parnell,

Recently you requested a review of Alaska's oil and gas production tax, and recommendations for how the production tax could be improved. Enclosed for your review is analysis of Alaska's oil and gas production tax (otherwise referred to as "ACES"), which was compiled at my request by the Department of Revenue's technical staff. The ACES Status Report evaluates whether ACES is meeting its intended goals of providing a fair share of revenue to the state while encouraging investment in new oil and gas exploration and development activities.

Based on the report, I am recommending a collection of potential amendments to ACES and its associated Exploration Incentive Credit (EIC) program. The amendments are primarily intended to accomplish two things: 1. Further incentivize drilling and other production enhancing activities; and 2. Address a number of provisions of ACES that may keep explorers from enjoying the full intended value of the capital credit program.

The status report shows that ACES successfully allowed the state to share in the benefits of high oil prices while accommodating fluctuations in production costs and oil prices. ACES adjusted when oil prices tumbled and kept oil operations in Alaska highly profitable relative to other oil provinces. With respect to the impact that the new production tax has had on investment activity, the report is positive, but ultimately inconclusive. While the overall level of taxation increased with ACES, it distributed the impact of that tax burden in a way designed to incentivize investment in new exploration and development. Since ACES passed the legislature, overall spending on oil and gas activities on the North Slope has increased. However, given only two and a half years of experience, during which time oil prices climbed to $140 per barrel then plunged to under $30 per barrel, it would be premature to attribute the increased level of oil company investment to the success of ACES.

Oil taxes are clearly an important factor in industry investment decisions. However, it is misleading to isolate their influence from other key factors, such as world oil prices, geologic potential, access to land, resources and markets, costs of infrastructure and support services, and the legal and regulatory framework. As noted in the report, the true merit of Alaska's current fiscal system can only be determined when it is evaluated in conjunction with these other variables. The scope of the status report, and the limited timeframe since ACES passed, do not allow for such a comprehensive analysis and definitive conclusions.

In addition to documenting several promising trends in industry spending activity, the report notes a number of discrete policy issues associated with the production tax where improvement can be made. These warrant your consideration as potential amendments to the ACES framework.

1. **Increase Credits for All Well-Related Activity to 30%:** The Capital Credit and Exploration Incentive Credit (EIC) programs have been identified as influential in spurring exploration activities. However, the EIC program's 30% credits are only available to wells located more than 3 miles from all existing wells. The state has a significant interest in also incentivizing infill drilling and other well work that will increase oil production, particularly for heavy oil. I therefore recommend expanding the EIC program so that all expenditures related to drilling and well work that add new production or increase the efficiency of existing production will qualify for the 30% EIC credit under AS 43.55.025 regardless of a well's location relative to existing wells.

2. **Increase Access to Capital Credits for New Explorers:** Small producers are currently required to invest in new activities during subsequent years in order to obtain direct payment from the state for previously earned tax credits. This is not an issue for existing producers because they simply deduct credits from their current tax bill and do not need to seek direct payment from the state. Deleting this provision would make the tax credits more accessible to smaller explorers, level the playing field between new and existing operators, and eliminate an unfair double standard.

3. **Accelerate Capital Credit Usage**: Companies currently can only use half of their capital credits in the year they are earned, and the other half the following year. This is true whether the credits are applied against a tax liability or purchased by the state. Taxpayers would see increased value in the credits if they could apply the entire credit in the first year. In addition, this would ease the cost of administering these credits.

4. **Waive Interest on Late Tax Payments Due to Drafting of Regulations**: The ACES regulations, including those defining 'allowable lease expenditures' are being finalized this month. Under the statutes, these regulations are to be applied retroactively to various dates in 2007. To the extent additional taxes are due as a result of the application of the new regulations, such payments would be subject to interest and possibly penalties. While the department can waive penalties, it cannot waive interest charges. A statutory change is required in order to permit the waiver of interest.

I am confident you will find the ACES Status Report informative and interesting. Please consider my recommendations to improve the effectiveness and fair administration of ACES and the EIC program. I look forward to continuing to work with you to encourage additional oil and gas development while preserving Alaska's equitable share of oil and gas profits.

Sincerely,

Patrick S. Galvin
Commissioner

Alaska's Clear and Equitable Share (ACES)
Status Report
Alaska Department of Revenue
January 14, 2010

Introduction

In November 2007, the Alaska Legislature passed House Bill 2001, known as Alaska's Clear and Equitable Share (ACES). ACES made modifications to the prior production tax called the Petroleum Profits Tax (PPT), enacted in 2006. The changes made first with PPT and later with ACES represented substantial production tax reform in that the basis of the tax shifted from the *gross value* to the *net value* of oil and gas production. The gross tax which had been in place prior to the PPT is generally referred to as the Economic Limit Factor (ELF).

This report was prepared at the request of the Commissioner of Revenue in order to evaluate whether ACES is meeting its intended goals of providing a fair share of oil and gas revenue to the state, and encouraging investment in the exploration and development of new oil and gas resources in Alaska.

Following are the key findings of this report:

1) State revenues under ACES in FY 2009 exceeded amounts which would have been generated under either the PPT or ELF systems. The crossover point at which ACES is projected to provide more revenue than ELF is $51 per barrel west coast price in FY 2010.

2) Activation of the progressive surcharge is estimated to occur when west coast sales prices reach $56 per barrel.

3) Capital spending on the North Slope totaled over $2.2 billion in FY 2009 an increase over FY 2008. This is nearly the highest level of capital spending in nominal dollars since oil production began in the state.

4) The impact of the production tax modifications on industry investment cannot be clearly determined due to the influence of other factors and given the limited timeframe during which ACES has been in place.

5) Operating costs have risen since the enactment of PPT and ACES, but the impact of these cost increases to state tax revenues was moderated by the "standard deduction" provision of ACES, which expired December 31, 2009.

6) Increased reporting requirements, particularly of forward looking expenditure information, has greatly enhanced the accuracy of the Department's revenue forecasting efforts.

7) The Department has made significant progress in implementing ACES regulations, but there will be challenges to both the department and taxpayers as the regulations are implemented. Preliminary audits of taxpayers under the new profits-based system (formerly PPT) have begun, consistent with the normal audit timeframe.

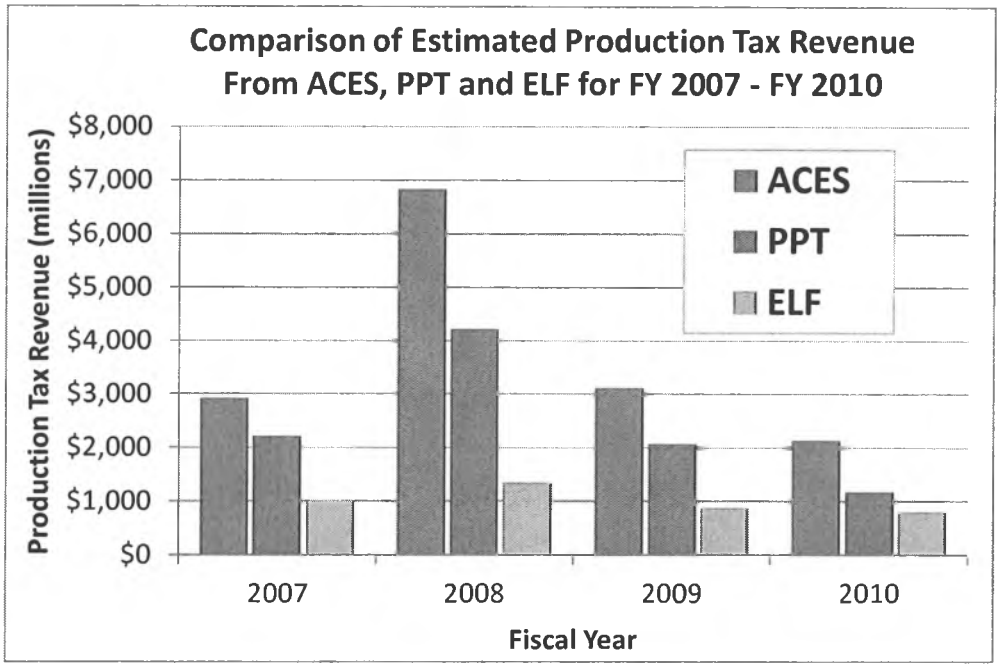
Comparison of Revenues under ACES, PPT and ELF

The net tax structure – first enacted under PPT (2006) and later with ACES (2007) – represents a significant change from the oil and gas tax structure used for much of Alaska's history. Under the earlier tax, known as the Economic Limit Factor (ELF), production tax was levied on oil and gas producing properties, regardless of whether operations were profitable. The current production tax structure requires companies to pay tax only when they are making profits from oil and gas production in the state. In addition, tax credits are provided for capital expenditures, with higher credits available for certain oil and gas exploration investments.

Since its enactment in 2007, ACES has generated more state revenue than would have been generated under either PPT or ELF. In FY 2008, a period of very high oil prices and profits, ACES generated $6.8 billion in production tax revenue, compared with $4.2 billion which would have been received under PPT and $1.3 billion which would have been received under ELF. In fiscal year 2009, during which west coast oil prices average $68.34, ACES generated just over $3.1 billion. This compares with roughly $2 billion that would have been generated under PPT and $858 million under the earlier ELF system.

Figure A compares revenue from ACES, PPT and ELF for FY 2007-2010. The FY 2009 revenues are preliminary. Estimates for FY 2010 are based on the Department's fall 2009 forecast of an average west coast oil price of $66.93 per barrel.

Figure A[1]



The progressive feature in ACES means that the state receives more production tax revenue when oil prices are high relative to underlying costs. Similarly, it significantly lessens the state's share of revenues when per-barrel margins decline. This effect was illustrated in 2008, when oil prices reached a high of $140 per barrel in July, bringing in $900 million in production tax for the month, and later plunged to below $30 per barrel in December, producing a total of $50 million in production tax for the month. Over the course of the full year, ANS crude oil averaged over $92 per barrel, resulting in five times more revenue than would have been realized under the ELF system.

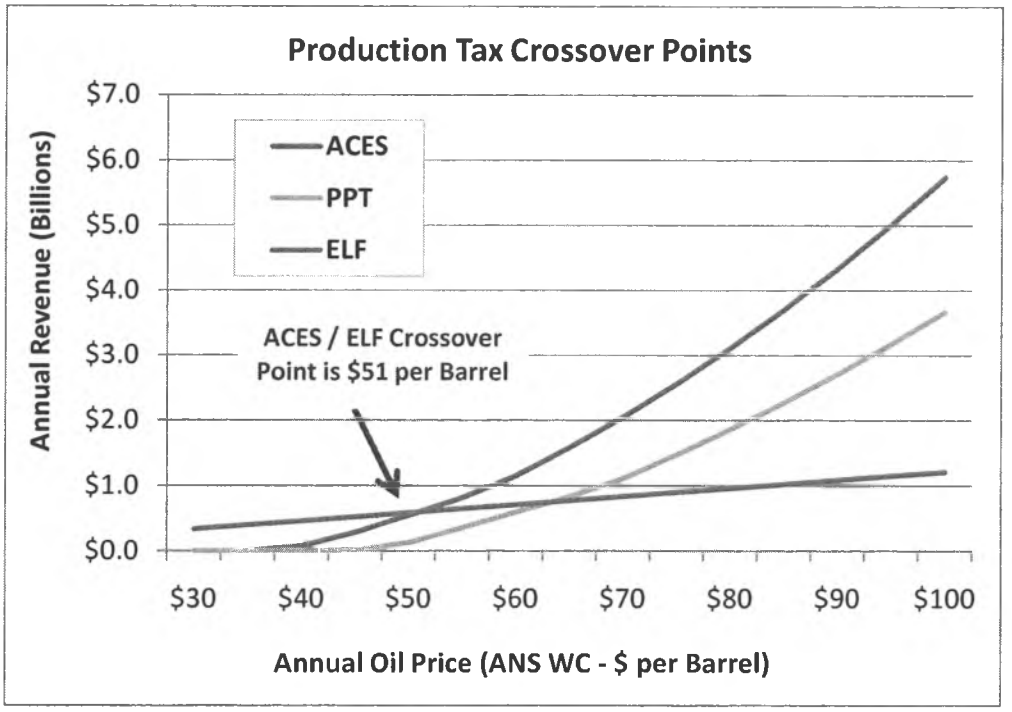
Figure B shows estimated revenues that would be received under ACES, ELF and PPT at various oil prices.[2] The oil price crossover point at which the state receives more revenue under ACES than the ELF system is roughly $51 per barrel. The crossover point has increased over prior

[1] Production tax revenue includes surcharges but does not include any settlements which go to the Constitutional Budget Reserve Fund. FY 2007 PPT revenue includes true-up payments for the period of April 2006 through December 2006. FY 2007 ACES revenue assumes similar true-up payments for comparison purposes. For FY 2007 - FY 2009, assumes actual data for oil price, production, costs and other variables. For FY 2010, assumes oil price, production, costs and other variables as of the fall 2009 forecast. Costs under PPT for FY 2010 for Prudhoe Bay and Kuparuk are based on aggregated company forecasts. For ACES only, assumes that standard deduction would apply for all of FY 2007-FY 2009 and first half of FY 2010. Actual tax revenue, as opposed to modeled revenue, is used for PPT in FY 2007 and ACES in FY 2008-FY 2009.

[2] This analysis assumes a constant oil price for the entire year, production of 655,000 barrels per day, deductible lease expenditures of $20 per barrel and transit costs of $6 per barrel.

years because lease expenditures, which are deductible under ACES, have increased since ACES was passed. It is expected that lease expenditures will decrease as costs decline in delayed response to the decline in oil prices from their 2008 levels.

Figure B[3]



Lease Expenditures

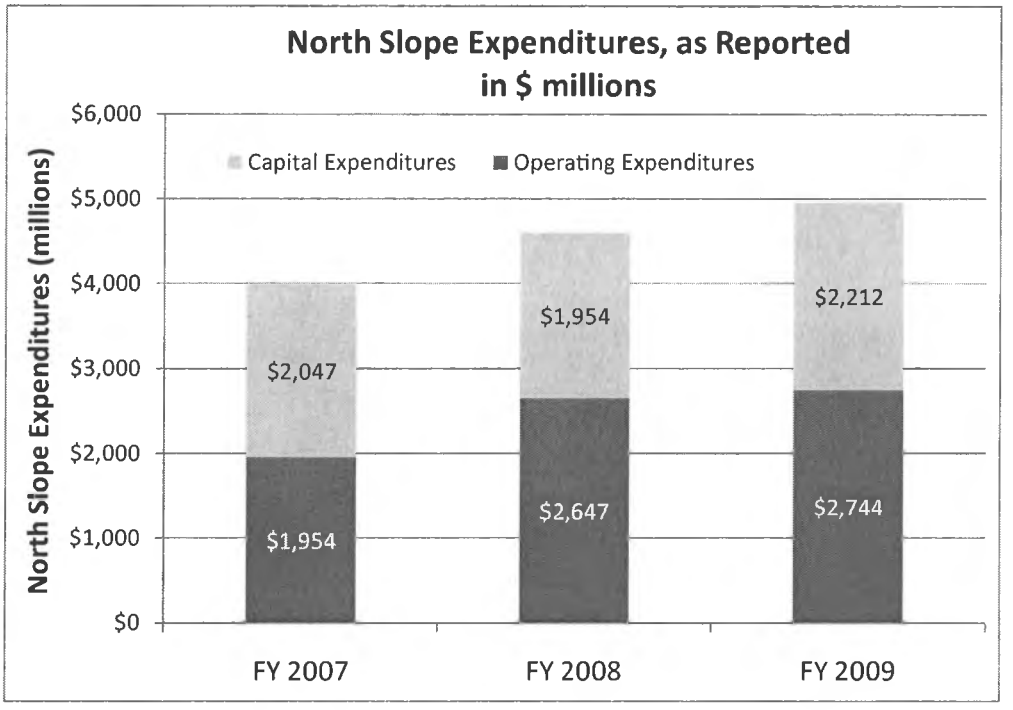
With the introduction of the net tax, it became necessary for the state to identify and forecast allowable lease expenditures for purposes of the tax calculation. Prior to the passage of PPT, the department had not been required to track or audit oil and gas production costs in Alaska. Some early cost data had been acquired directly from producing companies and through preliminary examination of federal tax returns. However, even during the debate over PPT, the state did not have access to comprehensive, Alaska-specific data that would enable policymakers to analyze the effects of the proposed tax over the life of a project. With much more information now being provided under the new tax structure, the department is developing a better understanding of oil and gas costs in Alaska, which will significantly benefit future policy deliberations.

[3] Assumes fixed operating and capital cost of $20 per barrel.

Lease expenditures fall into two general categories that constitute the major deductions under the ACES tax system. Operating expenditures are the costs to operate an oil or gas production facility on a day-to-day basis. These include labor, heat and light for the facilities, and some well work and minor equipment repairs. Capital expenditures are costs incurred to enhance or improve the reserve base, level of production, or facilities. Drilling is one of the most common forms of capital costs, as is facility construction or expansion.

Figure C shows the operating and capital expenditures, as reported on company tax returns and monthly reports, for their North Slope operations, from FY 2007 through FY 2009. Note that the graph represents all reported expenditures for all North Slope properties, regardless of whether or not they are subject to the "standard deduction" provisions of AS 43.55.165(j).

Figure C[4]



Operating Expenditures

Operating costs have risen significantly in recent years for the oil and gas industry worldwide. This has often been linked to the corresponding rise in oil prices beginning around 2002. Projects around the world that were once marginally economic have become viable, increasing the demand for limited supplies of engineering, procurement and construction services, as well

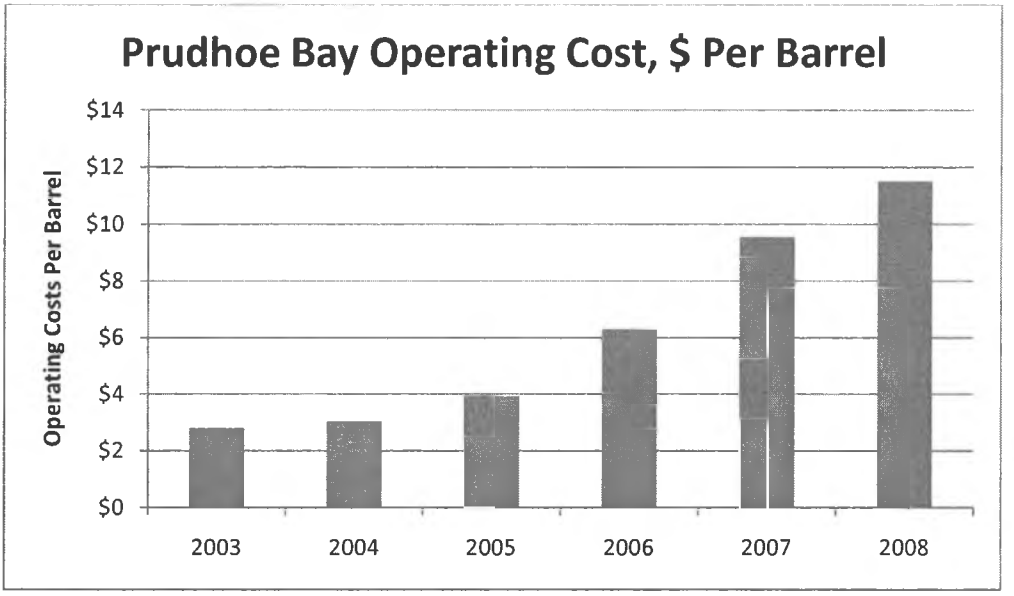
[4] Operating expenditures includes total reported costs, not standard deduction; FY 2007 estimated based on incomplete reporting

as raw materials. Cambridge Energy Research Associates (CERA) reports the upstream operating cost index rose for oil and gas field operations roughly 67% between 2002 and the end of 2008.[5] Meanwhile, the global capital cost index rose over 100% during the same period.[6]

Alaska-specific information obtained through public sources and shared in confidence during the Stranded Gas Development Act negotiations and through ACES reporting shows similar trends on the North Slope. Estimates of operating costs prior to PPT ranged from $3 to $5 per barrel. More recent information indicates that operating costs on the North Slope have doubled, and in some cases nearly tripled. Following the Prudhoe Bay corrosion incidents in 2006, operating expenditures on major repairs increased. However, since that time, the proportion of total operating expenditures directed to major repairs does not appear to have been a key driver in the growth of total operating expenditures.

Figure D shows the upward trend in per-barrel operating costs at Prudhoe Bay from 2003 to 2008. The chart shows a dramatic increase over the six-year period, consistent with cost increases seen in the oil and gas sector worldwide.

Figure D



The recent downturn of the global economy has started to push operating costs back down again. In June of 2009, CERA reported that worldwide, operating costs had declined 8 percent

[5] IHS CERA Upstream Operating Cost Index (UOCI), http://www.ihsindexes.com (Accessed December 11, 2009)
[6] IHS CERA Upstream Capital Cost Index (UOCI), http://www.ihsindexes.com (Accessed December 11, 2009)

over the previous 6 months.[7] The most recent information reported to the department under the new ACES requirements shows this trend to also be developing on the North Slope.

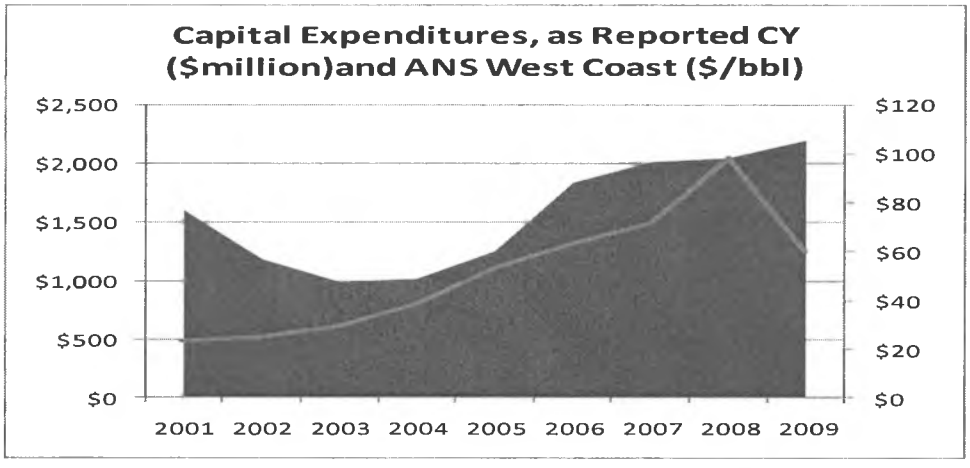
Much of this change can once again be linked to recent trends in oil prices. Lower oil prices led to a slackening of worldwide project activity, driving down the costs of transportation and various consumables. Despite this correlation, however, operating costs have not fallen at the same rate as oil prices. While the department anticipates that per-barrel operating costs will continue to decline under the lower oil price forecast for FY 2009 and FY 2010, they are expected to remain relatively high compared with those from five or more years ago.

Capital Expenditures

Capital expenditures have also increased since PPT and ACES were enacted. While capital expenditures on pipeline repairs at Prudhoe Bay increased after the Prudhoe Bay corrosion incidents in 2006, the majority of growth in capital expenditures is attributable to drilling, seismic and other projects. As shown below, capital spending on the North Slope in CY 2009 was roughly twice the level in either 2003 or 2004. At least some of this increase is due to new development activities. Two major developments – Oooguruk and Nikaitchuq – have gone forward despite recent oil price setbacks. Development of the Point Thomson field is also underway.

Figure E shows historical capital expenditures from CY 2001 to 2009 as reported by oil and gas producing companies operating on the North Slope.

Figure E



[7] IHS CERA: "*Period of Sustained Cost Escalation for Upstream Oil and Gas Facilities Comes to an End,*" June 5, 2009. http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10388 (Accessed December 11, 2009)

In order to forecast North Slope lease expenditures, the department receives forward looking spending projections from taxpayers, and also consults a variety of information sources, including unit forecasts, plans of development, and federal partnership returns. These data give the department significantly better insight into future development plans, as well as trends in operating and capital expenditures.

This information shows a variety of changes on the North Slope in the years ahead. There is continuing development of newer fields like Oooguruk, Nikaitchuq, and Point Thomson. Growth in capital expenditures at many major North Slope units (i.e. Prudhoe Bay, Kuparuk, Colville River and others) appear to slow slightly or decline in the next year or two and re-surge thereafter to the level of the recent past or higher. This trend is consistent with indicators of worldwide industry activity which show a dramatic drop in capital expenditures from the high levels experienced in 2008. This suggests that recent economic contraction may have caused some North Slope development projects to be delayed as producers hope to form a better idea of where the economy and oil prices may be headed.

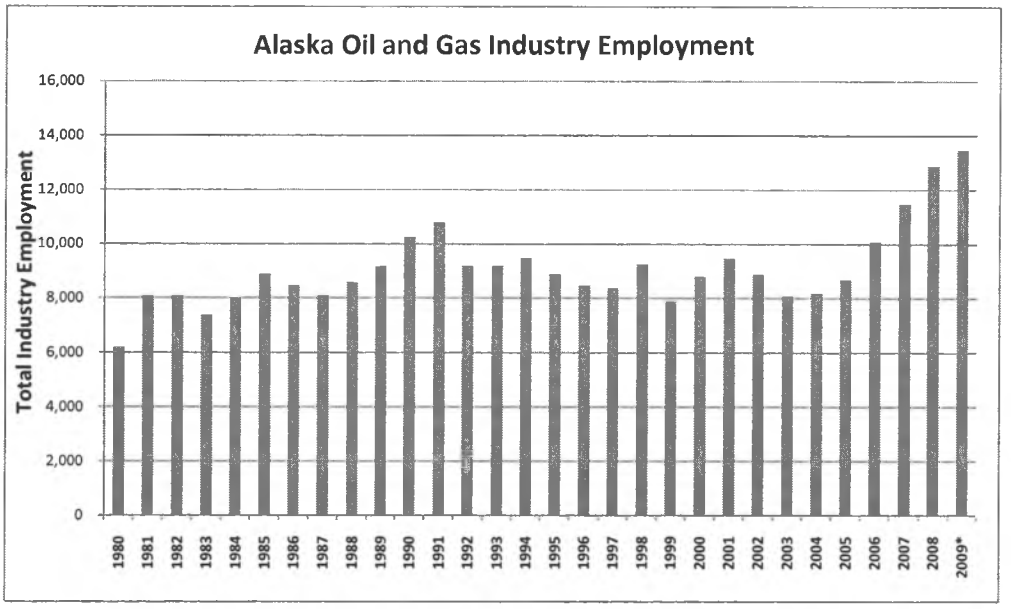
It would be presumptuous to solely attribute the rise in expenditures to the success of the investment incentives found in ACES. Many factors beyond tax policy drive oil and gas investment decisions. However, one of Alaska's new explorers, Savant Alaska, stated in a recent Petroleum News article that ACES had assisted in their development efforts at Badami. "ACES was an important component for Savant in considering investment in Alaska. It definitely had its intended consequence with us." [8]

Industry Employment

Employment in the industry has also increased steadily since the implementation of PPT and ACES, with 2009 forecast to be the highest in state history. It is important to note that this occurred concurrent with a steady rise in the oil prices, which has generally shown a strong correlation with industry activity.

[8] Kay Cashman quoting Savant's Chief Operating Officer Greg Vigil, "Savant Accelerates Badami Drilling Plan," *Petroleum News*, Volume 14, No. 3, January 18, 2009.

Figure F[9]



Flexibility of Tax Burden Evidenced

The increased revenues generated under ACES represent an increased tax burden on Alaska's oil and gas industry. However, there is evidence that ACES effectively adjusts that burden when oil prices drop and profit margins are squeezed. In 2009, a period of relatively low oil prices in comparison to recent years, 35 percent of ConocoPhillips total reported exploration and production profit in the first quarter of the year (Q1), 55 percent in Q2, and 36 percent in Q3, came from its Alaska operations, which only account for 12 percent of the company's worldwide production.[10]

ACES Structure and Tax Rate

The ACES tax consists of a base rate of 25% plus a progressive surcharge, which is triggered when a company's net profits — also known as "production tax value"— exceed $30 per barrel. Beyond this point, the base tax rate is increased by 0.4% for each additional $1 increase in per-barrel production tax value. Using current estimated transportation and production costs of roughly $26 per barrel, the surcharge would begin to be applied when west coast oil prices reach $56 per barrel. When the combined base rate and progressive surcharge reach 50%

[9] Data from Alaska Department of Labor and Workforce Development, Research and Analysis Section (January 11, 2010). Includes nonagricultural wage and salary data and excludes the self-employed. *Estimates for 2009 are preliminary.

[10] ConocoPhillips, Form 10-Q Quarterly Reports Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, March 31, 2009, June 30, 2009 and September 30, 2009.

(approximately $92.50 per-barrel profit or $118.50 West Coast price) the progressive surcharge is lessened to 0.1% for each additional $1 increase in per-barrel production tax value. The maximum nominal tax rate is 75%, which would apply at a profit rate of $342.50 per barrel or $368.50 West Coast price.

As with any tax, ACES may be evaluated using a variety of different metrics, including "effective," "nominal" and "marginal" tax rate comparisons. While each of these can be helpful under the appropriate circumstances, each is also subject to certain limitations. It is important when using these metrics to understand their relative value and how they reflect upon the objectives of the tax system.

The "effective tax rate" is the share of the total gross taxable value at the point of production that is paid in production taxes after credits are applied. It is a good universal measure of the sharing of total petroleum value that can be compared to gross value-based tax systems.

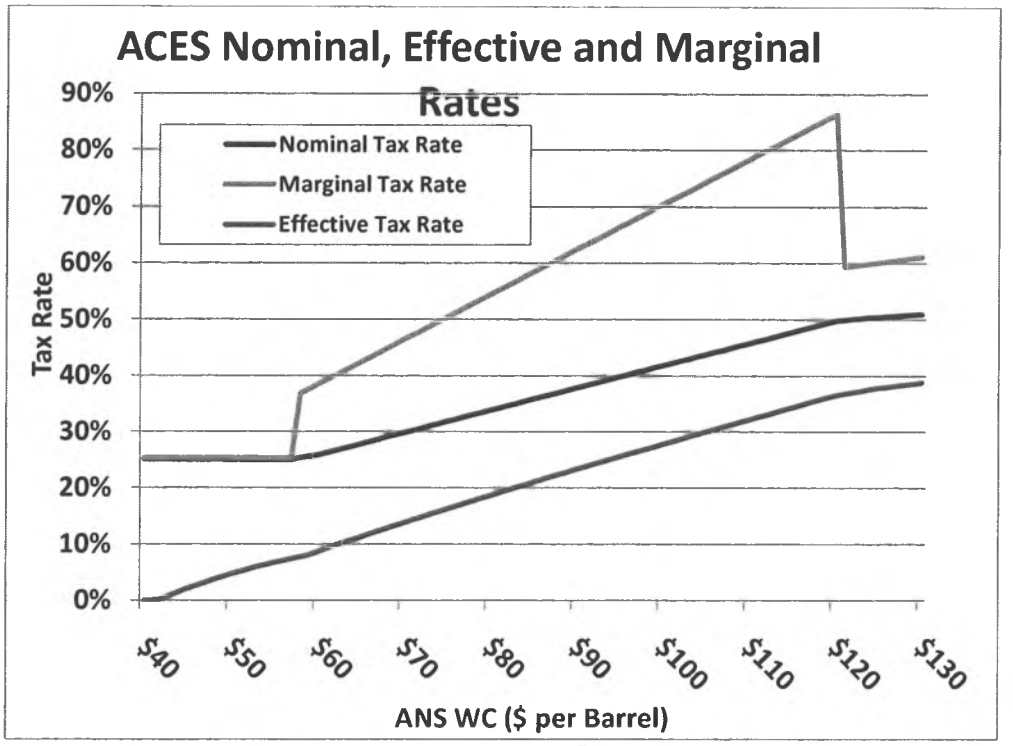
The "nominal tax rate" is the statutory tax rate as applied to the net value of oil and gas production. It does not account for credits or other tax benefits which ultimately impact a company's bottom line. Under ACES, the nominal tax rate varies with the per-barrel profitability. In addition to a base tax rate of 25%, ACES levies a progressive surcharge that can raise the combined nominal tax rate to 75% at extreme price levels.

The "marginal tax rate" is the rate theoretically applied to each dollar increase in oil price. In the case of ACES, the marginal tax rate is 25% until per barrel profit reaches $30 per barrel (about $56 per barrel in west coast spot price under the current cost structure), at which point it increases for every additional dollar up to a marginal tax rate of 87% when the profit reaches $92.50 per barrel (about $118.50 per barrel on the west coast). Following this peak, the marginal tax rate drops off significantly as the profit level continue to rise. With a net based tax system, this metric shows a company the impact of making additional investment, because each dollar they invest is "subsidized" by the government based on the amount of marginal tax they have avoided paying on that dollar.

Each of these metrics has their limitations when considered in isolation from other metrics, or when only one data point on the curve is presented. For example, a marginal tax rate of up to 87% initially sounds excessive. However, at that same price level, the effective tax rate (the tax burden) is less than 40%. The marginal rate of 87% actually represents the state's "portion" of any new investment made at such high prices.

Figure G shows the nominal, effective and marginal tax rates under ACES using a wide range of west coast spot prices.

Figure G



Production Tax Administration and Implementation

The passage of ACES presented significant challenges for tax administration and implementation because it involved comprehensive structural changes to the tax on the heels of the prior year's legislative changes through PPT. These challenges are experienced both on the taxpayer and on the state side.

Tax Credit Successes and Difficulties

The increased spending levels reported earlier in this document, may be due in part to the expansion of capital and exploration credits provided under ACES for reinvestment in the state. Credits can be applied against tax liabilities, sold to other companies or, for companies producing less than 50,000 boe/day, can be purchased by the state. Nearly $550 million in credits were claimed in FY 2009. Approximately $193 million was paid to oil and gas companies

to purchase oil and gas tax credits, while an additional $350 million in tax credits were used to offset tax liabilities.

Some administrative difficulties have arisen due to the requirement that the 20% capital credit be spread out over two years. It has taken a substantial amount of time and resources to develop a database with which the division can track the issuance and staged application of these credits for each taxpayer. This detailed tracking was made necessary by the transferability and use of the credits, and some confusion by taxpayers and their transferees regarding how the credits could be applied. In addition, the two-year spread in the application of the capital credits diminishes their value to taxpayers who look for quick return of their investment dollars. Finally, one of the reasons for the two-year spread in credits was to assist the department in forecasting future revenues. However, the department has found that the information provisions in ACES have been extremely valuable and successful in improving the volume and quality of spending projection data provided to the department by operators. This forward looking spending information has been much more valuable to the revenue forecasting process than the two-year spread in credits.

The Department has also received feedback regarding the reinvestment requirements for new explorers. Under current law, companies generally receive a financial benefit of over 45 percent of exploration expenditures incurred in the state. However, a new entrant to Alaska (with no production to immediately apply the credit against) can only get full value for their expenditures by applying to the state for cash payment for their credits earned. In order to receive such a payment, the company must continue to make expenditures in future years. Although this provision was originally created to support new explorers, it appears to be a limiting factor for companies that have fewer financial resources and are only considering a single exploration investment. In application, this requirement creates a "double standard" where new entrants to Alaska are provided less value for their credits compared to incumbent companies.

"Standard Deduction" provision at AS 43.55.165(j)

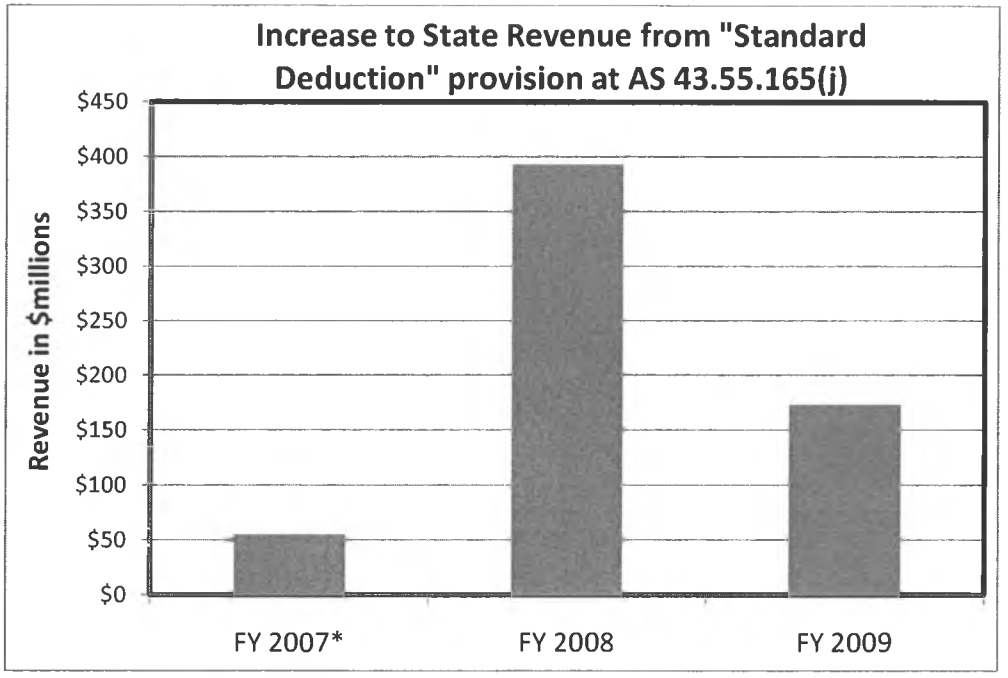
The ACES tax reform made modifications to the deductibility of operating expenditures for certain fields on the North Slope. Alaska Statute 43.55.165(j) limited the deduction of operating expenditures at leases or properties that have produced a cumulative 1 billion barrels of oil and NGLs since the lease or property began oil production. The Prudhoe Bay Unit and the Kuparuk River Unit are subject to these provisions based on their cumulative production. The provision, coined the "standard deduction," limits the deduction of operating expenditures to the amount deducted on the first PPT returns, filed April 1, 2007, for calendar year 2006 expenditures, adjusted annually. This provision, which was effective through December 31,

2009, was intended to moderate the risk associated with adopting a profits based tax without substantial historical data on which to rely for future cost estimates.

Based on company-reported expenditure data, the provision has resulted in a substantially greater tax liability to the state during the time it has been in place. The total liability in FY 2008 was substantially larger than the liability for FY 2009 due to the higher tax rate in FY2008 because of higher net profits realized due to high oil prices.

Figure H shows the increased revenue to the state from the standard deduction from FY 2007 through FY 2009.

Figure H[11]



Regulations

The ACES tax included new restrictions and guidance on allowable lease expenditures, requiring complex regulations. The department has actively sought industry input on the structure of the regulations to ensure they continue to achieve their intended purposes, while avoiding undue burdens for either side. The process has included numerous public workshops pertaining to credit regulation, conforming regulatory changes required by ACES, lease expenditures, facility sharing costs and transportation costs. As a result, the regulation drafting process has been

[11] *Standard Deduction was only in place for half of FY 2007.

lengthy and complex. However, the regulations to define allowable lease expenditures are expected to be finalized this month.

Under the statute the regulations are retroactive to various 2007 dates. To the extent additional taxes are due, taxpayers would be required to pay interest on what would now be late tax payments. The department has discretion to waive any penalties for late payments. However, a statutory change would be needed in order for the department to provide a waiver from interest payments.

Reporting and Revenue Forecasting

ACES requires that companies exploring for or producing oil and gas in the state submit a monthly information report to the department. This report includes estimated data on production volumes, the value of the production, and the operating and capital expenditures related to production. The monthly report is used primarily by state economists to monitor company production and spending. Included with the monthly report is an estimate of taxes owed and credits earned. Twice annually, companies are asked to provide the department with forward-looking expenditure information, along with future production plans to aid the department in providing the legislature with state revenue forecasts.

These reports, in combination with the monthly information reports and the annual tax returns, have significantly enhanced the quality of the department's revenue forecasts.

Audit Compliance

The ACES legislation extended from three to six years, the period in which the department is required to assess production taxes owed. The extension was seen as necessary to assure proper tax assessments, particularly given the complexity of overlapping ELF, PPT and ACES tax laws. The new tax law also included funding for four new "Audit Masters" within the department. The department is still experiencing significant difficulties recruiting and filling audit positions. The department has successfully recruited three Audit Masters, and these individuals have been placed within sections of the Tax Division to assist with implementation and administration of the tax. The recruitment of the fourth Audit Master, and Oil and Gas Revenue Auditors is ongoing.

During 2008, the department's auditors began auditing tax returns that were submitted for calendar year 2006 under the PPT program.

Conclusion

The ACES production tax has been effective in allowing the state to share in the benefits of high oil profitability. It has also responded well to lower oil prices by reducing state tax burden on Alaska's oil and gas producers. Over $2 billion in new capital investment was reported in fiscal year 2009 reaching near-record levels. While these and other indicators suggest that the profits-based tax system has supported North Slope exploration and development, it would be misleading to suggest that ACES alone influences the level of investment. While tax is recognized as being an important factor in investment decisions, it is not the primary determinant. Long-term price forecasts, as well as the resources themselves, have proven to be much more significant drivers of industry activity.

The department is continuing to analyze ACES to identify opportunities to improve the tax framework in order to support additional exploration and development in the state, while not harming the state's revenue base.

The new reporting requirements under ACES are helping the department develop a better understanding of industry expenditures and activity, and have assisted in the state's revenue forecasting efforts. Development of new tax regulations is progressing, though several challenges remain for both the state and taxpayers. Numerous workshops have been held to solicit industry input and these will continue as the department continues to work through outstanding issues. In 2008, the production tax audit group began auditing taxpayers who submitted annual returns for CY 2006 under PPT.

Overall, the information reviewed by the department indicates that ACES is performing as expected when it was passed by the Legislature in 2007. The economic provisions are resulting in the revenue levels anticipated, and the investment incentives appear to distribute the increased tax burden in a fashion that continues to encourage reinvestment, though the experience with the credit program could be improved for new explorers. Challenges remain in the implementation by the department, but they are manageable and the department is positioned to meet those challenges.

Final Findings and Determination

For

Nikaitchuq Development
Royalty Modification
Application

Commissioner of the Department of Natural Resources

APPROVAL
OF MODIFICATION OF ROYALTY
FOR LEASES:
ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583, 390615, 390616 and 391283

January 11, 2008

Table of Contents

7. Economic Analysis and Internal Decision Process: Final Findings and Determination For Nikaitchuq Royalty Modification Application (CONFIDENTIAL under AS 38.05.180(j) and "Deliberative Process Privilege")
8. Public Comments

I. INTRODUCTION AND BACKGROUND

A. Introduction

On October 16, 2007, Eni US Operating Co. Inc. (Eni), as operator of the Nikaitchuq Unit (NU), on behalf of its affiliate Eni Petroleum US LLC, 100 percent working interest owner of the subject leases, submitted an application to the commissioner of the State of Alaska Department of Natural Resources (ADNR) for modification of royalty under AS 38.05.180(j)(1)(A) (Attachment 1). On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for 30 days ending January 7, 2008. ADNR hereby issues its Final Findings and Determination as required under AS 38.05.

Eni has applied for royalty modification on 12 leases which overlie the Schrader Bluff and the Sag River reservoirs. However, the Sag River reservoir was withdrawn from the application at the request of Eni. Eni requests that the fixed royalty rates of

- 12.5 percent on the Net Profit Share (NPS) lease, ADL 391283, and
- 16.66667 percent on the 11 leases (ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616)

be reduced to the minimum rate allowed, 5.0 percent, with an annual sliding-scale royalty percentage adjustment based on the level of Alaska North Slope West Coast (ANSWC) crude oil price. The 30 percent net profit share rate on ADL 391283 is to remain unchanged. Attachment 2 depicts the Nikaitchuq Unit boundaries and leases subject to this royalty modification application.

This Final Findings and Determination responds to the royalty modification application as required under AS 38.05.180(j)(8). Part I summarizes the royalty modification application and process. Part II reviews the history of the Nikaitchuq Unit formation and development, and Eni's royalty modification application. Part III reviews the state's authority to carry out royalty modification. Part IV reviews the requirements and terms of royalty modification pursuant to this application. Part V contains ADNR's analysis of the application under the royalty modification criteria. Part VI is the Final Findings and Determination.

B. Royalty Modification Procedure

This Final Findings and Determination is the first step in a process contemplated in AS 38.05.180(j) that could result in an authorization to modify the royalty terms for certain leases. The commissioner published the Preliminary Findings and Determination, gave public notice of a 30-day public comment period (Attachments 3 and 4), and offered to appear before the Legislative Budget and Audit Committee to provide a review of the

Findings and Determination and the administrative process. The commissioner will keep the submitted data confidential under AS 38.05.035(a)(9) at the request of the lessee or lessees making application for the royalty reduction. This Final Findings and Determination by ADNR regarding royalty modification is final and not appealable. With the Applicant's concurrence, ADNR will amend the subject leases to conform to the terms of this royalty modification Final Findings and Determination.

II. SUMMARY OF ENI'S APPLICATION FOR ROYALTY MODIFICATION

A. Unit and Lease Summary

ADNR approved the formation of the Nikaitchuq Unit effective April 29, 2004. At that time, Kerr-McGee Oil & Gas Corp. (KMG) held 70 percent of the working interest and Armstrong Oil & Gas Inc. (Armstrong) held 30 percent. The unit originally consisted of eight leases covering 12,968 offshore acres in the shallow waters of Harrison Bay in the Beaufort Sea, approximately three miles north of Oliktok Point. The Kuparuk River Unit (KRU) lies to the south, and the Milne Point Unit (MPU) lies to the east of the Nikaitchuq Unit. The Tuvaaq Unit, formed in August 2004, was adjacent to the western boundary of the original Nikaitchuq Unit. Effective October 5, 2007, ADNR approved the first expansion of the Nikaitchuq Unit, termination of the Tuvaaq Unit and the contraction of the Kuparuk River Unit. The Nikaitchuq Unit expanded to include all of the Tuvaaq Unit leases, the Kigun lease, formerly committed to the KRU, and two additional leases acquired by ENI at the 2004 Beaufort Sea Sale.

All 12 leases in the Eni royalty modification application are committed to the expanded Nikaitchuq Unit. (See lease map in Attachment 2.)

The ownership of the Nikaitchuq Unit has changed significantly since formation. Eni acquired Armstrong's 30 percent WIO of Nikaitchuq Unit in August 2005. In August 2006, Anadarko Petroleum Co. (Anadarko) acquired KMG, including KMG's 70 percent WIO in Nikaitchuq Unit, and became Nikaitchuq Unit operator. Eni subsequently acquired the remaining 70 percent Nikaitchuq Unit ownership from the operator, Anadarko, in March 2007, and became the 100 percent WIO and operator of Nikaitchuq Unit.

On January 11, 2006, KMG submitted an application for royalty modification under AS 38.05.180(j)(1)(A) for 14 leases of which 12 are the subject of this application.[1] KMG's application requested that the royalty rate for the 14 leases be modified from their respective existing fixed royalty rates of 16.67 percent and 12.5 percent to a fixed royalty rate of 5 percent. Effective October 31, 2006, the ADNR issued the Final Findings and Determination of the Commissioner of the Department of Natural Resources for the Nikaitchuq Development Royalty Modification Application denying KMG's application for royalty modification.

[1] The KMG application included ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, 388583, 390615, and 390616.

B. Project Development History

In the 2003-2004 and 2004-2005 exploration/appraisal drilling programs KMG/Armstrong encountered accumulations of hydrocarbons in the area of the then-proposed Nikaitchuq Unit. A total of six wells were drilled in the Nikaitchuq area in the 2004 and 2005 winter drilling seasons; two additional wells were drilled in 2006.

The planned development includes:

- Construction of a gravel pad with drilling, gathering and production facilities on Oliktok Point near the existing ConocoPhillips Alaska Inc. seawater treatment facility.
- Construction of a gravel drilling island near Spy Island tied back via a 3.8-mile subsea flow line and utility bundle to Oliktok Point for fluid processing.
- Construction of a +/-14-mile pipeline from Oliktok Point to a tie-in near KRU DS-1Y pad for connection to the Kuparuk Transportation common carrier pipeline.
- Consideration of future modifications required to adjust facility configuration to accommodate actual results of well performance.
- A total of 73 wells drilled between 2008 and 2011, of which 31 are expected to be producers.
- First oil expected in 2010.

Development studies indicate that extended reach horizontal producing and injection wells required for pressure maintenance are needed to economically recover the hydrocarbons in place. The planned development would permit a relatively small "footprint" for centralized facilities and minimal well pads, thereby reducing environmental impacts to the region. Initial drilling will be from a 313,000-square-foot pad to be constructed at Oliktok Point. Existing roads will be utilized for access. The production facilities will be located on the same pad. Later, a small gravel island is to be constructed within the barrier islands for future drilling. A subsea bundle containing a three-phase production line and multiple utility lines will be constructed to connect the gravel island to Oliktok Point to transport production and provide fuel, secondary recovery fluid, and power to the gravel island.

C. Eni Royalty Modification Request

On October 16, 2007, Eni submitted an application (Attachment 3) to the ADNR commissioner for modification of royalty on 12 leases, ADLs: 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616 and ADL 391283 under AS 38.05.180(j)(1)(A). In accordance with 11 AAC 88.105, 11 AAC 83.185, and 11 AAC 05.010(a)(10)(H) Eni submitted a complete application with the required $250.00 filing fee.

The Eni application for royalty modification submitted on October 16, 2007, requests a 5.0 percent fixed royalty if the Alaska North Slope West Coast (ANSWC) crude oil price falls below an ANSWC price equivalent to the U.S. Department of Interior, Minerals Management Service (MMS) NYMEX West Texas Intermediate (WTI) oil price threshold for royalty modification for OCS August 2004-2006 deepwater oil leases in the Gulf of Mexico (GOM).[2] Eni proposes a sliding-scale royalty rate in any month after production start-up (expected in 2010) that would range between 5.0 and 16.6667 percent, depending on the average monthly price of ANSWC crude oil. An ANSWC monthly (nominal) price below the Alaska Department of Revenue (ADOR) *Spring 2007 Revenue Sources* forecast between 2010 (the year of first production) and 2017 shown in Figure II.1 (below) would trigger a reduced royalty rate from original fixed lease rates of 12.5 percent and 16.6667 percent, respectively. The amount of the reduction in royalty percentage would depend on (a) the original lease rate (either 12.5 percent or 16.6667 percent) and (b) the extent to which the actual future oil price falls below the ADOR forecast threshold.[3]

The original fixed royalty rate of 16.6667 percent for ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583, 390615, and 390616 and 12.5 percent with 30 percent net profit for ADL 391283 would be subject to the sliding scale modification in a low commodity price environment to a level at or above a floor of 5 percent. The 30 percent net profit share to the State attached to ADL 391283 would be unchanged under the Eni royalty modification proposal.

The Eni application also would provide full royalty relief at a reduced rate of 5 percent for all leases regardless of oil price if monthly production is below 4,000 barrels of oil per day for the first 10 years following the effective date of the royalty modification decision.

---

[2] ADNR estimates threshold to be $42.53 per barrel in 2010 based on a 2007 NYMEX WTI price of $42.64 assuming a 94 percent basis adjustment to ANSWC and 2 percent price escalation pursuant to the ENI proposal. See: MMS, *Price Thresholds and Annual Market Prices for MMS Deepwater and Deep Depth Oil and Gas Royalty Relief Programs*, Deep Water Oil, Economics Division at www.mms.gov/econ/DWRRAPrice1.htm.

[3] Under the Eni proposal, the royalty percentage rate adjustment would be approximately ¾ percentage point per $1 change in ANSWC price for leases with a 16.6667 percent base royalty rate and ½ percentage point per $1 change in ANSWC price for leases with a 12.5 percent base royalty rate. After 2017, the ADOR ANSWC price forecast is inflated by the monthly change in the Producer Price Index (PPI).

III. SUMMARY OF ROYALTY MODIFICATION AUTHORITY AS 38.05.180(j)(1)(A), (2), (3), (4)(A), (5)

A. General Royalty Modification Requirements

AS 38.05.180(j)(1)(A) authorizes the DNR commissioner to provide for royalty modification on individual leases, leases unitized as described in (p) of this section (AS 38.05.180), leases subject to an agreement described in (s) or (t) of this section (AS 38.05.180), or interests unitized under AS 31.05 to allow for production from an oil or gas field or pool if:

1. the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;
2. the field or pool has not previously produced oil or gas for sale; and
3. oil or gas production from the field or pool would not otherwise be economically feasible.
4. Under AS 38.05.180(j)(2), the commissioner may not grant a royalty modification unless the lessee or lessees requesting the royalty modification make a clear and convincing showing that a royalty modification meets the three requirements set out above and is in the best interests of the state.

B. General Royalty Modification Terms

1. Under AS 38.05.180(j)(3) the royalty modification terms must provide for an increase or decrease or other modification of the state's royalty share by a sliding-scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs.
2. Under AS 38.05.180(j)(4)(A) a modification to royalty may not be granted for the field or pool if the royalty modification would result in a royalty rate of less than 5 percent in amount or value of the production removed or sold from a lease or leases covering the field or pool.
3. Under AS 38.05.180(j)(5) a royalty reduction must include an explicit condition that the royalty reduction is not assignable without the prior written approval, which may not be unreasonably withheld, by the commissioner. The commissioner shall, in the preliminary and final findings and determinations, set out the conditions under which the royalty reduction may be assigned and may not grant a royalty reduction without an explicit condition that the royalty reduction is not transferable.

IV. DISCUSSION OF ROYALTY MODIFICATION CRITERIA

A. Leases Are Eligible For Consideration

The leases meet the requirements for consideration and all eleven subject leases proposed for royalty modification are committed in entirety to the Nikaitchuq Unit. AS 38.05.180(j)(1) allows modification of royalty for individual leases and unitized leases.

B. Reservoir Delineation: Discussion of Reservoir Geology and Engineering

1. Introduction to reservoir delineation.

The commissioner may grant royalty modification to allow for production from an oil or gas field or pool if the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner.

The area within the Nikaitchuq Unit for which royalty relief is sought lies offshore in the Beaufort Sea in the vicinity of Spy Island, approximately three miles north of Oliktok Point. The Nikaitchuq Unit is north of and contiguous with the northern edge of the KRU and the Milne Point Unit (MPU). The KRU is operated by ConocoPhillips and produces from the Cretaceous Kuparuk River Formation and shallower Schrader Bluff Formation. The BP-operated MPU field lies to the south-southeast of the Nikaitchuq Unit and produces oil from the Schrader Bluff, Kuparuk, and Triassic Sag River formations. The western edge of the proposed Nikaitchuq Unit is adjacent to the recently expanded Oooguruk Unit (OU) operated by Pioneer. Production from the OU is expected from the Kuparuk and Jurassic Nuiqsut sandstones.

Within the Nikaitchuq Unit, potential commercially recoverable reserves have been tested in both the Cretaceous Schrader Bluff and the Triassic Sag River formations.

Based upon the submitted application and the planned initial development, the request for royalty modification at Nikaitchuq is limited to the OA sand of the Schrader Bluff Formation. For the purpose of this application, the OA sand is defined in Kerr McGee Nikaitchuq #1 (API No. 50629231930000), completed in 2004, as the interval between 5034 feet measured depth (4127 feet subsea true vertical depth) and 5090 feet measured depth (4170 feet subsea true vertical depth).

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Although upside potential may also exist within the shallower Schrader Bluff N sand interval, the current lack of core, well test, or fluid data from this interval increases the risk and precludes it from being deemed delineated and included as part of this application. ENI plans to gather more data to thoroughly evaluate the N sand during the course of developing the deeper OA sand.

The Sag River Formation contains lighter oil than the Schrader; however, it is plagued with poor quality reservoir rock. The development potential is marginal at best unless there are significant advances in stimulation or enhanced oil recovery technology. Delineation of the Sag River Formation at Nikaitchuq to date has revealed limited reserves and similar test results to the analog at MPU where wells within the Sag River Formation consistently show initial flush production followed by steep decline within the first year. ENI is still evaluating the development potential of this interval and, as such, it has been excluded from this application.

2. Exploration History of the Area

Two key early exploration wells lie within several miles of the Nikaitchuq development area. The Unocal East Harrison Bay State #1 well lies near the northwest corner of the KRU, to the southwest of the Nikaitchuq Unit. The well was drilled in February 1977 to a measured depth of 9,809 feet, bottoming in argillite basement. The East Harrison Bay State #1 well logs appear to contain about 15 feet of oil-bearing Kuparuk Formation that appears cemented in the upper half. The Jurassic section looks silty on logs. The ARCO Kalubik #3 well, drilled in February 1998, lies to the south-southwest of the Nikaitchuq area. The well bottomed in the Jurassic at a measured depth of 7,000 feet. The well encountered a 40-foot-thick measured depth (MD) interval of Kuparuk C sandstone that appears on electric logs as oil-bearing, but siderite cemented in the upper 10 feet of the interval. On well logs the Jurassic interval contains silt with a 12-foot silty sand developed around 6,565 feet MD. The well was plugged and abandoned on March 6, 1998.

3. Drilling History

The first major exploration activity in the area in the early 1970s targeted the Ivishak Formation following the discovery of the prolific Ivishak Formation in Prudhoe Bay State #1 in 1967. The Hamilton Brothers Milne Point #18-1 was one of the early wells drilled on the Milne Point structure in 1970 in search of Ivishak and Lisburne objectives. This well encountered about 50 feet of tight oil-saturated sandstone that was not tested and a section of Kuparuk sandstone that tested at a rate of 875 BOPD. This discovery led to increased industry interest in the Milne Point area and led to exploration and delineation drilling for Kuparuk reserves. In the early 1980s the Sag River was cored in the Conoco Milne Point Unit #C-1 well and contained bleeding oil and gas. The Sag River Sandstone was also cored in the MPU #L-1 well and contained no visible porosity or staining and appeared tight on wire line logs.

In the early 1990s about a dozen wells were drilled to the west-southwest of the Nikaitchuq area with Jurassic sandstones and Kuparuk C sandstones as targets. The ARCO Kalubik #1 well encountered approximately 160 feet of productive Nuiqsut and Nechelik sandstone that tested approximately 336 BOPD (un-stimulated). In addition, the well penetrated an 85-foot section of Sag River Sandstone with calculated log porosities in the range of 15 to 22 percent. The Thetis Island #1 well also encountered an 80-foot section of porous Sag River sandstone with log-calculated porosities in the range of 16-24 percent. A pay section of Nuiqsut sandstone was also encountered that tested at an average rate of 120 BOPD with a high rate of 650 BOPD. Both the Kalubik #1 well and Thetis Island #1 well drilled through Brookian sandstones that contained mud log hydrocarbon shows.

In the late 1990s BP drilled several dedicated Sag River Sandstone test wells, including MPU #C-23, #K-33, #E-13A, 3F-33, #F-33A, and #F-73A. Alaska Oil and Gas Conservation Commission (AOGCC) production data indicate that several Milne Point wells have produced oil out of the Sag River Sandstone and two oil producing wells MPU F-33A and K-33, are currently shut-in. MPU #C-23 produced 378,012 barrels of oil between 1996 and 2001. MPU #F-33 produced 314,276 barrels of oil between September 1996 and May 1999 and was subsequently plugged and abandoned. MPU #K-33 has produced approximately 93,241 barrels of oil since 1997. MPU #E-13A produced 366,665 barrels of oil between 1995 and April 2001. MPU #F-33A produced approximately 661,099 barrels of oil since April of 2001. MPU #F-73A produced 13,430 and is now a water-alternating-gas injection (WAGIN) well. BP estimated the original oil-in-place (OOIP) at 62 MM STB oil and the reservoir area about 8500 acres based upon seismic and log data during an AOGCC Conservation Order hearing in May 1998. AOGCC reservoir data indicate that the oil commonly recovered from the Sag River sandstone has an API oil gravity of about 37 degrees. Total production from the MPU Sag River Sandstone has been 1,834,131 barrels of oil and 1,875,668 MSCF gas through October 2007. MPU Sag River recovery is less than 3 percent to date based on OOIP. The original GOR ranged from 784 – 974 SCF/STB. Production from the Sag River pool at MPU has been intermittent with extended shut-in periods since June 1999.

Between 2004 and 2005, Kerr McGee (KMG) drilled six wells in the Nikaitchuq and Tuvaaq Units. Initially, the primary exploration target was the Sag River Formation; the Kuparuk Formation was a secondary target. Although the wells did not encounter reservoir quality sand in the Kuparuk, the well logs indicated that sands in the shallower Schrader Bluff Formation were prospective. KMG then adjusted the exploration program to thoroughly evaluate the Schrader Bluff Formation. Three of the six wells tested oil from the viscous Schrader Bluff or Sag River formations. In 2006/2007 KMG drilled two additional pre-development wells from Oliktok Point to further delineate and test the Schrader Bluff sandstone. The two wells are currently suspended.

4. Schrader Bluff Formation Tests

KMG Nikaitchuq #4

Approximately 3,000 feet of gross horizontal Schrader Bluff OA sand was drilled in this well, with approximately 2,270 feet of horizontal or lateral net pay, from a 30-foot true-vertical-depth net pay thickness. A two-week production test was performed on the well using an electric submersible pump (ESP) to aid in producing the 16–17 API crude. The well tested at rates up to 1,200 barrels of oil per day during periods of the initial test. Permeability estimated from the test was greater than 350 millidarcies and was confirmed from the analysis of the flow tests conducted on a whole core obtained from the well.

KMG Tuvaaq #1

The well was not tested. It penetrated 30 feet net pay Schrader Bluff OA Sand and 12 feet net Schrader Bluff N sand. There were no cores taken at Tuvaaq. Schrader Bluff N sand was interpreted to be oil-filled here and at Kigun #1 appeared unconsolidated with permeability estimated from 100-1000 millidarcies and porosity 25-35 percent.

KMG Kigun #1

The well was not tested. It penetrated 29 feet net pay Schrader Bluff OA sand and 30 feet net N sand. An MDT tool run sampled the Schrader Bluff OA fluids which were 18 degree API, GOR 59 SCF/STB and viscosity of 82 cp at 87 degree reservoir temperature. (Contamination of the samples with oil-based mud caused concern about the reliability of the sample estimates and properties.) Schrader Bluff OA sand core data indicated 25 percent to 38 percent porosity and up to 1,000 millidarcies permeability in the sandstone intervals.

KMG Oliktok Point I-1 KMG Oliktok Point I-2

These two wells were drilled by KMG during the 2006/2007 drilling season as pre-development wells to further test and delineate the Schrader Bluff reservoir. These wells have been suspended. Results from these wells are currently held confidential under AS 38.05.035(a)(9).

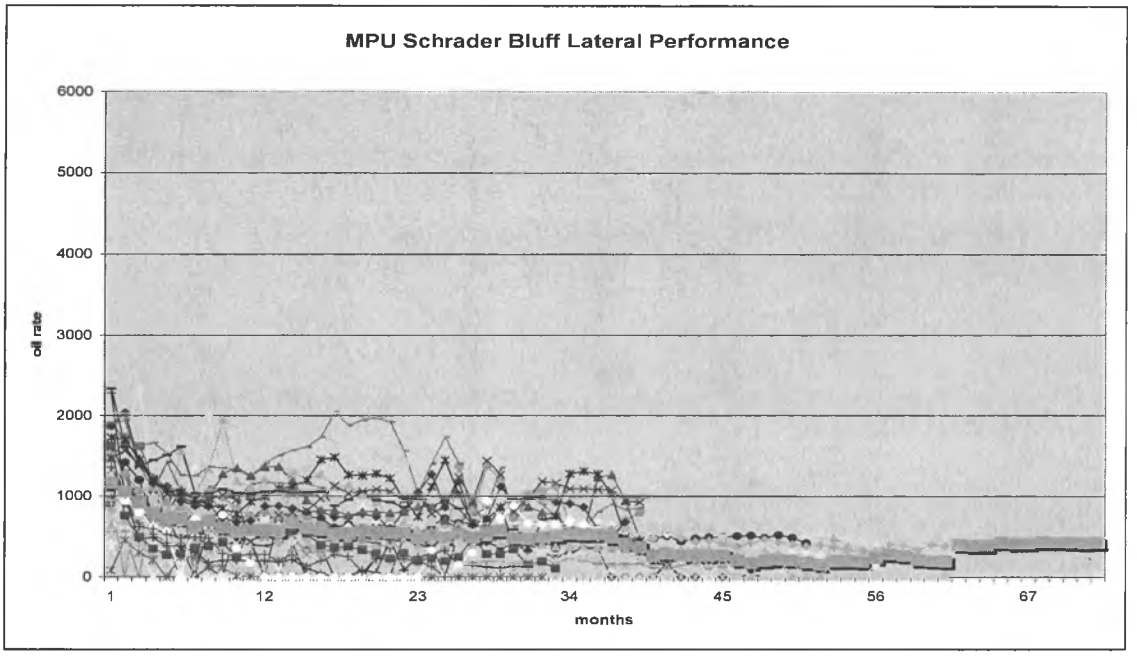
5. Analog Schrader Bluff Formation Performance

Milne Point Unit (MPU) Schrader Bluff Pool (Figure 1), Kuparuk River Unit (KRU) West Sak Pool (Figure 2) and Prudhoe Bay Unit (PBU) Polaris and Orion pools – Figure 3, represent analog Schrader Bluff Formation horizontal well performance. Each of the pools was developed initially with vertical or slanted completions. More recently a number of horizontal lateral and multi-lateral wells have been completed in each of these pools. MPU and KRU Schrader Bluff wells show a distinct, lower rate performance than the newer developed Polaris and Orion Pool wells. A significant portion of the performance difference is likely due to differences in fluid quality. Within the Schrader Bluff Formation / West Sak, developments oil gravities can vary between 15-24 degrees API and viscosity can vary between 5-130 centipoise. To date, development has been limited to those areas with higher API Gravity and lower viscosity. Later Schrader Bluff Formation developments are building on earlier techniques by going from vertical to

horizontal and multilaterals wells. The horizontal and multilaterals should consistently outperform the older wells because more formation is exposed and the completions are more efficient.

The wells in each Schrader Bluff Formation pool exhibit early flush production for six to 12 months. The PBU Schrader Bluff completions show slightly higher initial rate profiles followed by relatively steep decline. The average MPU Schrader Bluff completion (heavy bright green points and line) declined from 1200 bopd to 500 bopd at 12 to 40 months. KRU West Sak lateral completions have performed similar to MPU Schrader Bluff.

Figure 1. MPU Schrader Bluff Formation lateral performance and average performance (heavy green).



6. Reservoir delineation determination.

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Figure 2. KRU West Sak sands lateral performance and average performance (heavy orange).

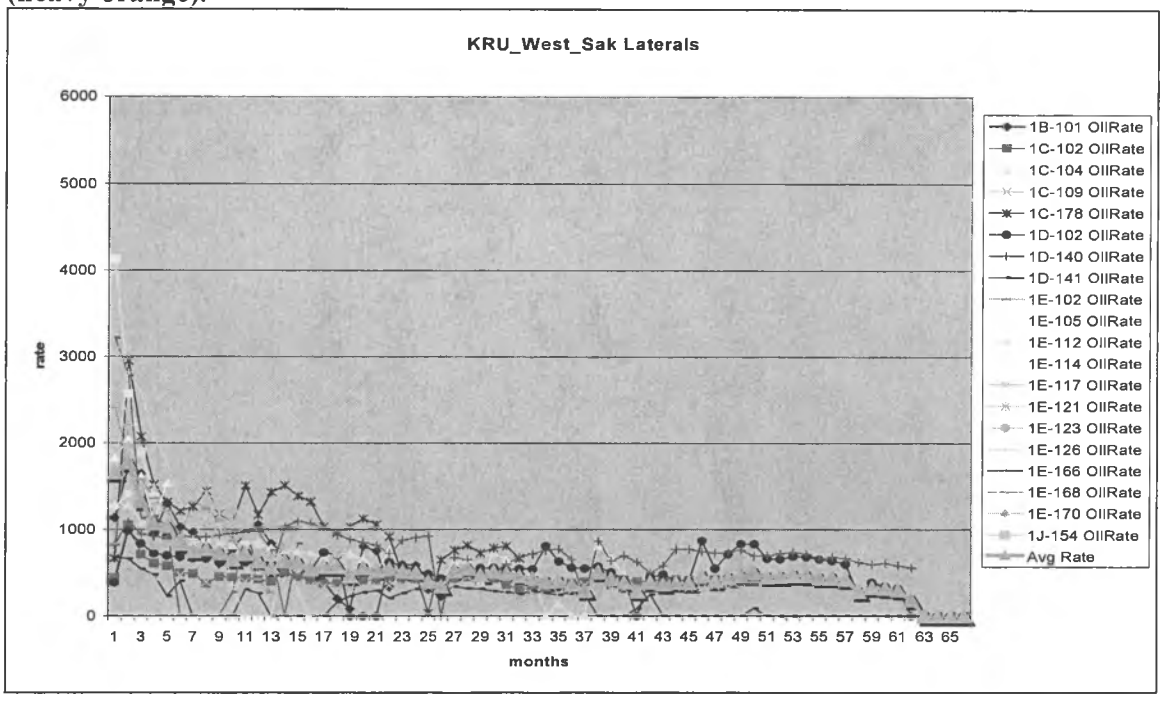
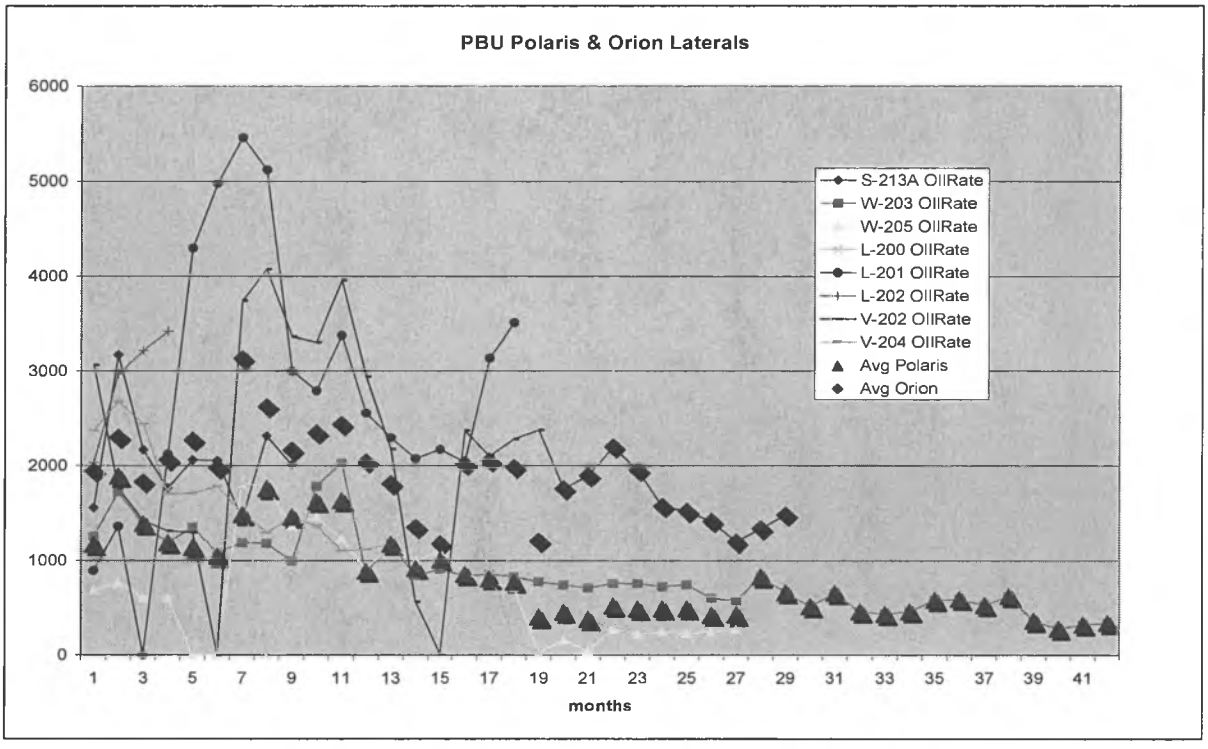


Figure 3. PBU Polaris and Orion Schrader Bluff Formation initial performance.



ENI stated that their plan is to develop Nikaitchuq Schrader Bluff Formation with horizontal wells. Their prognosis of performance can be compared to the analogs by evaluating average Schrader Bluff well performance from initial completion to date. There are up to seven years of production history for the various Schrader Bluff Formation horizontal and lateral wells. Orion appears to be more productive so far but the long term performance has yet to be defined. ENI appears to estimate their development will improve on the previous KRU and MPU Schrader Bluff completions by using the latest technology, namely very long horizontal and or multi-lateral completions. ENI's cases align reasonably with the MPU Schrader Bluff and KRU West Sak and PBU Polaris average performance. PBU Orion performance is notably better than ENI's high case average rates. Analyses of oil samples taken within the OA sand in the Nikaitchuq area demonstrate measured oil viscosities of 95–188 centipoise. This is heavier than the average viscosity of production from existing KRU, MPU and PBU Schrader Bluff developments. In addition, the Nikaitchuq development will include construction of a new standalone facility. The KRU, MPU, and PBU Schrader Bluff pools had existing infrastructure and production from other formations to support the additional development. Both of these factors increase the risk and make this project more economically challenged compared to existing heavy oil developments.

C. No Previous Sale of Produced Oil or Gas

The pools underlying the leases have not previously produced oil or gas for sale.

D. Economic Analysis

ADNR used its own in-house probabilistic economic model (ADNR Model) for the Nikaitchuq development to independently assess the financial performance and ultimate economic effects of a royalty modification for both Eni and for the State of Alaska. Eni shared with the state portions of its proprietary economic model, but the state chose to use its own model that incorporated many input assumptions provided by Eni.[4]

ADNR closely examined the assumptions and methods currently in use by the U.S. Minerals Management Service (MMS) for the Deep Water Royalty Relief Program. The MMS has developed an in-house proprietary probabilistic economic model for Royalty Suspension Viability Program. ADNR adopted an approach similar to that of the MMS by applying the quantitative results from the ADNR model to a prudent-investor decision framework. The ADNR decision framework is confidential. It is designed to replicate the kind of analytical framework used by industry for making prudent oil and gas investment decisions under uncertain conditions involving significant capital outlays and lengthy project life cycles.

[4] Eni has submitted financial and technical data and analyses and requested that they be held confidential in accordance with AS 38.05.035(a)(9). Thus this section does not discuss any confidential information concerning Eni's geologic, engineering and cost data. These documents are included and discussed in detail in the confidential *Economic Analysis and Internal Decision Process*, (Attachment 6).

The prudent investor standard is maintained throughout the project evaluation process. Under this standard, ADNR incorporates a collection of project performance benchmarks that are consistent with industry norms.

To obtain royalty relief the applicant must show by clear and convincing evidence that without royalty modification the project is not economically feasible. Nikaitchuq is an offshore, heavy oil prospect with relatively high expected exploration and development costs and low expected production possibilities. The final analysis of Nikaitchuq project development conducted by ADNR pursuant to the Eni royalty modification application suggests that, under reasonable assumptions about future oil prices and without some form of royalty relief, this project would not be sanctioned for funding and development.

In its simplest form, the ADNR Model describes project cash-flows for the Nikaitchuq development over a 50-year time horizon. The ADNR Model incorporates expected investment, production, price, revenue, and cost. It incorporates fiscal system attributes, including state and federal tax, state production tax (including the recent ACES legislation)[5], and royalty obligations, as well as other important commercial relationships, such as facility sharing and pipeline transportation charges.

The ADNR in-house model is flexible enough to allow ADNR to evaluate the effects of changes to the fiscal system. The model provides a platform for systematic evaluation of the effect of a change to the royalty rate. The model calculates the changes to the various financial metrics that result from a change in the royalty rate. These metrics include annual and cumulative discounted and undiscounted cash flow, years to payout, net present value (NPV), expected monetary value (EMV), and internal rate of return (IRR) on investment, as well as state revenues. Also, ADNR used its model to carry out sensitivity analysis of key driver assumptions and to characterize certain price, production, and cost variables in terms of probability distributions to evaluate how uncertainty among these drivers affects key project metrics and state revenues.

Eni furnished ADNR with 200 realizations of project production that depict the range of values and probabilities for the many reservoir factors that that determine ultimate reservoir recovery (e.g., aerial and vertical extent, rock characteristics, fluid composition and properties). These 200 Eni realizations represent the universe of possible resource recovery outcomes for ADNR's Monte Carlo analysis that fit the well-test data. The ADNR model samples repeatedly from this universe of production realizations, as well as from volatility inherent in price formation, as characterized in the mean reversion price model (see below), to generate a distribution of net present value (NPV) outcomes for the Nikaitchuq project. The central tendency (mean and median) and dispersion (variance) of the NPV outcomes depict project performance uncertainty and speak to the dimensions of ADNR's prudent-investor decision framework mentioned above.

ADNR incorporated the applicant's input data into its model along with its own assumptions about the path of uncertain future prices to derive independent results for the

[5] See HB2001 (11/15/2007).

economic feasibility of the Nikaitchuq project. The ADNR Model examines a range of possible inputs to derive a P50, or median, outcome from a Monte Carlo simulation. The P50 result is the value where 50 percent of the outcomes lay below this point and 50 percent of the outcomes lay above the P50 outcome. The ADNR Model uses Palisades Software's "@Risk" Monte Carlo software application to run the simulations and determine risk-weighted outcomes reported in the confidential supplement to this *Final Findings and Determination* (Attachment 7).

Calculating risk weighted outcomes is critical to a full analysis of a project. The probabilistic rate profile, determined based on the applicant's reservoir simulation results, is combined with pricing to determine the project revenue stream. Annual Alaska North Slope West Coast (ANSWC) crude oil prices were generated from an Ornstein-Uhlenbech type Mean-Reversion price model[6] with parameters estimated as described by Schwartz, (1997)[7] using annual price data for ANSWC crude as reported by Platt's. The starting ANSWC delivered price used in the model is $67 per barrel, the average price for 2007. The risk weighted cost profiles are then matched to the revenue stream generated by the probabilistic price and production models. This yields an NPV distribution. The mean of the NPV distribution is the EMV for the entire project that incorporates uncertainty and can be compared "apples-to-apples" with other versions of the project.

ADNR analyzed various senarios to explore Nikaitchuq project performance with and without royalty modification. DNR approves royalty modification only when it believes a project will not go forward without it. This means that the impact to royalty revenues to the state is the difference between the royalty revenues with royalty modification as was prescribed in the DNR decision and zero. Even under low price scenarios, ADNR determined that the state can expect to receive an additional $100 million over the life of the project.

If it is assumed that the project could have gone forward without royalty modification (again, not what ADNR assumes) the impact would be as indicated in Table 1. This table presents several possible price scenarios and the indicated change to the state royalty cash flow stream.

In Table 1 the scenarios labeled "$43 and Above (Sustained)" and "$40 Sustained" simply use a flat price deck for "Alaska North Slope West Coast" (ANSWC) crude oil (before inflation) for the life of the project, the price does not vary from year-to-year. An oil price of $40 is always just below the $42.64 royalty modification threshold and thus results in 5 percent royalty rates for every barrel of oil produced from the reservoir for the life of the project and the greatest negative impact to overall state royalty revenues.

---

[6] Dixit & Pindyck, 1994, http://www.puc-rio.br/marco.ind/sim_stoc_proc.html#mc-mrd.

[7] The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging", Schwartz, E., Journal of Finance, 1997, Volume 52, issue 3, 923-973

Table 1. Change in Alaska royalty revenues if royalty modification were not necessary and project produced oil without royalty modification.

Price Scenario	Impact on State of Alaska Royalty Revenue ("With Royalty Modification Per Decision" Minus "Without Royalty Modification", 5% discount rate)
$43 and Above (Sustained)	$0 million
DNR Price Model	($39 million)
$40 Sustained	($160 million)

The "DNR Price Model" scenario does not use a constant or "sustained" price for the life of the project (i.e. flat price deck) as is the case with the other two scenarios in Table 1. We use a forward-looking, Monte Carlo-based "mean-reversion" model, as discussed above. This price model creates a price forecast where oil price fluctuates over time, simulating real-life price variability similar to what history has shown. The price for 2007, $67 per barrel ANSWC, was taken from U.S. Energy Information Agency's most recent price projection for West Texas Intermediate (WTI) crude, and adjusted for ANS-WTI basis by taking the previous 12-month average difference between these two prices. The model reverts to DNR's expected mean value of $53 per barrel, over time.

The ADNR has determined that under ADNR's price and discounting assumptions, the project attributes furnished by Eni, and the existing lease royalty rates in effect prior to this *Final Finding and Determination* (16.6667 percent fixed royalty rate and the 12.5 percent fixed royalty with 30 percent NPS for ADL 391283), the Nikaitchuq project does not meet prudent-investor standards for economic feasibility. ADNR concludes further that the royalty modification terms and conditions stipulated in Section IV.B would improve project economics. Eni represents that royalty modification would make project sanction more likely.

V. PUBLIC COMMENTS

On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for thirty days, ending January 7, 2008 (Attachments 3 and 4).

No comments were received from the public.

VI. STATE'S PROPOSED ROYALTY MODIFICATION

A. Royalty Modification Requirements for the Nikaitchuq Project

1. Eni's application for royalty modification on ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616, and ADL 391283 meets the requirements for consideration under AS 38.05.180(j)(1). Eni has paid the filing fee and submitted a complete application for the royalty modification including financial and technical data that meet the requirements of 11 AAC 88.105, 11 AAC 83.185, 11 AAC 05.010(a)(10)(H), and AS 38.05.180(j)(6).

2. The Schrader Bluff pool has been sufficiently delineated to the satisfaction of the commissioner for the purpose of considering royalty modification; this pool has not previously produced oil or gas for sale.

3. Eni has shown that oil or gas production from the Schrader Bluff pool would not otherwise be economically feasible.

4. Eni has made a clear and convincing showing that a modification of royalty meets the requirements of 38.05.180(j)(1)(A), and is in the best interests of the state.

B. Royalty Modification Terms for the Nikaitchuq Project

1. Royalty modification pursuant to the terms herein is granted to Eni US Operating Co. Inc. (Eni), as operator and 100 percent working interest owner of the Nikaitchuq project (Project), on ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, 390616, and 391283. Royalty modification is denied for ADL 388580 because there was no apparent resource allocated to this lease.

2. Only production from Nikaitchuq Unit's Schrader Bluff OA reservoir, as delineated under this Findings and Determination, shall be eligible for royalty modification. To receive royalty modification on production, the lease must be committed to an approved participating area within six years of the date of Project sanction. After six years, any subject lease or portion of a subject lease not committed to an approved participating area for the Nikaitchuq Schrader Bluff OA reservoir shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

3. If the Project, not materially changed from that set out in the October 16, 2007, royalty modification application, is not sanctioned by all working interest owners by February 28, 2008, this royalty modification decision is rescinded.

4. Within 30 days following the date of Project sanction, the working interest owners shall provide ADNR with the Project sanction documents, approvals for expenditure, and other documents supporting the technical and financial data submitted with Project sanction documents excluding any proprietary data. ADNR agrees to keep all such data confidential.

5. If six years following the date of Project sanction total actual Project spending starting December 1, 2007, does not meet $822 million in nominal dollars, then this royalty modification is rescinded. If 11 years following the date of Project sanction total actual Project spending does not meet $1.398 billion in nominal dollars, then this royalty modification is rescinded. The ADNR may audit the working interest owners' spending on this Project to determine compliance any time between the sixth and the 13th year following Project sanction. If at either cost threshold juncture this royalty modification is rescinded, then Eni will refund to the State of Alaska the difference between the royalty which would have been due at the royalty rates that were in effect immediately prior to the effective date of this Findings and Determination and the royalty due at the modified royalty rate, with interest as set forth in AS 38.05.135(d).

6. The NPS lease regulations set out in 11 AAC 83.201 – 11 AAC 83.295 remain in full force and effect for ADL 391283, except that the cost to the applicant for the application for royalty modification will not be included in any NPS lease Development Account balance.

7. (a) Nikaitchuq royalty modification mechanism implemented as follows:

   i. Original lease rates are 12.5 percent for ADL 391283 and 16.67 percent for ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, and 390616.

   ii. For the first 25 years following the date of first sustained production, when Alaska North Slope West Coast ("ANS WC") delivered crude prices are below the threshold price per barrel as adjusted by inflation, then production from the Nikaitchuq Schrader Bluff OA reservoir on the subject lease will pay a 5 percent royalty. The ANS WC crude price for the month of production is the average assessment by Platt's Oilgram Price Report and Reuters online data providing service, of the spot price for ANS delivered on the West Coast. The average assessment of the spot price for ANS by each reporting service is the average of the midpoints of the high and low closing assessments for the spot price for ANS for all days during the month of production for which closing assessments are

reported. The threshold price shall start at $42.64 per barrel. This threshold price will be adjusted annually for inflation starting on May 1, 2008, and shall be adjusted on each May 1 thereafter. The inflation adjustment shall be (1 + inflation rate) multiplied by the previous year's inflation-adjusted threshold price. The inflation rate shall be determined by taking the previous year's annual implicit price deflator for GDP (initially, for the year 2007) as reported by the end of April of each year, dividing that deflator by the two-years-previous annual implicit price deflator (initially, for the year 2006), and then subtracting 1. The source of the inflation data shall be the Department of Commerce Bureau of Analysis (BEA) U.S. Economic Accounts-GDP. National Income and Productions Account (NIPA) Table 1.1.9. When the monthly ANS WC oil price is above the threshold, royalty rates for production attributable to such month(s) shall return to the original lease royalty rates.

iii. This royalty modification shall be terminated 25 years following the date of first sustained production and at that time royalty rates shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

(b) For the 18th through the 120th months after first commercial production from the Nikaitchuq Schrader Bluff OA reservoir, if production from all of the subject leases averages below 4,000 barrels of oil per day for any previous twelve month period, full royalty modification rates of 5 percent shall be in effect for all production from the Nikaitchuq Schrader Bluff OA reservoir, regardless of oil price. Provided, however, nothing in this provision shall prevent Eni from applying for royalty modification under AS 38.05.180 (j)(1)(B)or (C).

8. In the determination of royalty value of oil or gas from any of its properties, Eni shall waive any rights to a transportation deduction for the pipeline constructed pursuant to the Easement granted on ADL 417493. This waiver shall remain in effect even if such pipeline is converted to a common carrier.

9. If any working interest owner should contract to use any processing facilities at any time for production from the reservoirs delineated and leases covered in this Findings and Determination, that working interest owner shall furnish ADNR the facilities contract, including information regarding the fee structure and volumes processed unless such contract prevents disclosure of such information. This information will be kept confidential by ADNR. The working interest owner shall also furnish produced oil, water, and gas volumes on a monthly basis broken down by individual working interest owner.

10. Should any third party petition the Nikaitchuq Unit facility owners to contract for use of any unit facilities, the cost of use shall be based on market rates. Any

resulting contract covering facilities access or use shall be shared with the ADNR. ADNR agrees to keep all such information confidential.

11. This royalty modification is not assignable without prior written approval of the ADNR commissioner, which shall not be unreasonably withheld. The assignee must be fit, willing, and able to satisfy all of the duties and obligations attached to this royalty modification and all other lease terms.

12. If at any time royalty modification is rescinded, the terms and conditions of this Findings and Determination shall terminate, with two exceptions. First, the provisions of Term 8 shall survive the termination of royalty modification. Second, all obligations to keep information confidential that was submitted pursuant to this Findings and Determination shall survive the termination of royalty modification.

VI. PROPOSED FINDINGS AND DETERMINATION

After detailed consideration where all the materials presented by the applicant were reviewed and incorporated into our analysis, the ADNR has determined that Eni meets the necessary requirements and that royalty modification for the Nikaitchuq development project is warranted under the terms established in Section IV of this finding and determination.

1/11/08

Thomas E. Irwin
Commissioner

Date

cc: Kevin Banks, Director, Division of Oil and Gas
Antony Scott, Senior Commercial Analyst, Division of Oil and Gas
Jeff Landry, Department of Law