3/01/12 DEPARTMENT OF REVENUE: RESPONSES TO COMMITTEE QUESTIONS ON OIL AND GAS PRODUCTION TAX

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Senate Resources Committee

Oil and Gas Production Tax

Department of Revenue:

Responses to Committee Questions

March 1, 2012

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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The Honorable Joe Paskvan
Alaska State Senator
State Capitol, Room115
Juneau, Alaska 99801

December 21, 2011

Dear Senator Paskvan,

Thank you for your detailed and thoughtful lists of questions submitted to the Department of Revenue in May and September of this year. As previously discussed, we have been working on the answers to your questions during the interim and are providing them now, as a single package, in advance of the 2012 legislative session. It was very important for me to use the most up-to-date information available and the Fall 2011 Revenue Sources Book (RSB) is what we are using to answer your questions. At the same time as we were preparing the RSB over the past several months, we were also undertaking several other projects that will provide even more information. This will also no doubt lead to good discussions this session.

The analysis contained herein involved the work of numerous individuals on the Department of Revenue team and required large time commitments and custom model runs with significant manual analysis required. Staff were directed to make your request a top priority after completing the Fall 2011 revenue forecast and they should be commended for the time and effort put into this request.

Please don't hesitate to contact me with any additional information requests. We look forward to a constructive and meaningful discussion with you about how to best achieve our mutual goal of increasing oil and gas production in Alaska and incentivizing company investment in exciting and challenging new resources that hold the potential to mitigate the production decline.

Sincerely,

Bryan Butcher
Commissioner

Questions from emails dated May 2, 2011 and May 3, 2011:

1. **Regarding the income statement charts sent on Sunday, May 1:**
   a. **Are the credits from Cook Inlet included within the "Estimated Tax after refunded credits" category?**

      The income statement tables provided on May 1, 2011 included estimates for all production tax credits, including Cook Inlet. Note that our estimates have recently been revised from those provided on May 1, to reflect new information included in the Fall 2011 forecast.

   b. **Are there other credits or deductions which are not reflected in the charts?**

      The income statement tables provided on May 1 are illustrative of all credits and deductions taken. Note that the income statement format is an oversimplification of the tax calculation which in reality is a company-specific calculation. Therefore actual deductions and credits on the company-specific calculations will vary somewhat with those shown on the income statement. Please pay particular attention to the footnotes to the income statement tables to better understand the limitations of the income statement format.

2. **Explain the difference between the $2.572 B in FY11 capital expenditures in the charts and the $2.761B in capital expenditures presented to the Senate Finance Committee on 2/10/11.**

   The $2.572 billion estimate was published in the Fall 2010 RSB and represented a *Fiscal Year* 2011 estimate. The presentation made on February 10, 2011 to the Senate Finance Committee of $2.761 billion represented a *Calendar* Year 2011 estimate.

3. **Provide 5 years of forward-looking capital expenditure estimates as reported by operators in both the fall and the spring of each year, starting with 2005 estimates.**

   See answer to question 4, below.

4. **Provide 5 years of forward-looking capital expenditure estimate as reported by companies with little or no production, starting with 2005 estimates.**

Due to confidentiality requirements, we cannot provide the actual forward-looking capital expenditure estimates that we received from companies. However we can provide the aggregate capital expenditure forecasts prepared by DOR. Our forecast is based primarily on company-provided information that we receive from operators, supplemented as needed by publicly available information, and conversations with non-operators about their spending plans. For the Fall 2011 revenue forecast, we expanded our consultations with non-operators to gain additional confidential information about their capital spending plans, and this information was incorporated into our Fall 2011 revenue forecast.

The table below shows the capital cost forecasts used by DOR in each forecast release for 5 years, beginning with Fall 2006. Prior to Fall 2006, the DOR forecast did not incorporate capital expenditure forecasts because the production tax in place at the time was based on gross value adjusted by an Economic Limit Factor.

Capital Expenditure Estimates - all North Slope Capital Expenditures
All Amounts in $ Millions

Forecast	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
Fall 2006	$ 1,467	$ 1,507	$ 1,548	$ 1,591	$ 1,635					
Spring 2007	$ 1,346	$ 1,896	$ 1,975	$ 1,954	$ 2,031					
Fall 2007		$ 1,502	$ 1,896	$ 1,976	$ 1,962	$ 2,031				
Spring 2008		$ 2,182	$ 2,491	$ 2,829	$ 2,970	$ 3,460				
Fall 2008			$ 2,342	$ 3,009	$ 3,044	$ 2,869	$ 3,122			
Spring 2009			$ 2,123	$ 2,933	$ 2,910	$ 2,505	$ 2,912			
Fall 2009				$ 2,505	$ 2,882	$ 2,924	$ 2,723	$ 2,623		
Spring 2010				$ 2,430	$ 2,945	$ 2,955	$ 2,762	$ 2,674		
Fall 2010					$ 2,572	$ 2,937	$ 3,175	$ 3,019	$ 2,899	
Spring 2011					$ 2,451	$ 2,793	$ 3,135	$ 3,054	$ 2,909	
Fall 2011						$ 2,702	$ 3,018	$ 3,688	$ 3,889	$ 3,323

5. **Regarding the drafting of regulations to receive additional information about credits and categories of expenditures:**

   a. **Provide detail on the types of information DOR/DNR will be requesting.**

   The Department does not have statutory authority to retroactively require a producer or explorer to provide information related to prior years' capital expenditures. The Department is in the process of developing a list of categories for future reporting that would identify various types of capital expenditure categories and reports that would be incorporated into the TRMS project referenced in the question.

Workshops were held October 10, 2011, November 10, 2011, and December 12, 2011 to discuss the appropriate categories to be included and reported.

b. **Provide information about the statutory authority for requesting the information.**

AS 43.55.040(5) and AS 43.55.110 provide the Department with statutory authority for filing of reports under Chapter 55 of Title 43, Revenue and Taxation. This information may be disclosed under AS 43.55.890 if the information is aggregated among three or more producers or explorers and presented in such a manner as to preclude the determination of the affected parties.

6. **Regarding the "effective tax rate":**

a. **Should the "effective tax rate" be based upon the "Estimated Tax after refunded credits" as shown on the income statement charts sent on Sunday, May 1?**

The goal of the "effective tax rate" metrics we have presented on several occasions is to illustrate the overall tax rate that is paid by a typical company currently producing oil on the North Slope at a given oil price. Credits that are refunded are not included in the calculation of the production tax for two reasons: (1) they are not treated as deductions from the production tax in either our state accounting system or state tax system and require special appropriation by the legislature; and (2) they represent payments made to companies that have no production tax liability in the state.

b. **Is not the split of profit oil, defined as the split of PTV, the best way to analyze Alaska's production tax system?**

Several different metrics can be of value in analyzing Alaska's production tax system, and no one piece of information should be taken in isolation.

7. **Provide income statement charts showing all credits for FY12 using the Spring 2011 forecast for oil prices from $40 to $200 per barrel in $5 increments. Hold all other assumptions constant, including assumptions regarding credits.**

Addendum A of this document contains income statement tables as requested with the following changes: (1) In order to use the most recent information

available to DOR, the tables are presented using the Fall 2011 forecast model and assumptions. (2) The tables presented are for FY 2013, so as to use a year with no actual data so as to better illustrate the impacts of changing prices. (3) The tables begin with a $50 oil price.

PLEASE NOTE THAT THESE STATEMENTS ARE SIMPLIFICATIONS, INTENDED TO ILLUSTRATE A VERY COMPLEX SET OF COMPANY-SPECIFIC TAX CALCULATIONS AT VARIOUS PRICES AND SHOULD BE INTERPRETED AS SUCH.

8. **Provide income statement charts for FY10-FY12 using Fall 2010 and Spring 2011 forecasts assuming HB110/SB49 were applicable in those years. Hold all other assumptions constant, including assumptions regarding credits.**

We previously provided income statement illustrations for HB110/SB49 for FY10-12 using Fall 2010 forecast assumptions, in our response to Senate Resources questions dated March 19, 2011. As requested, those tables are provided again (with clarification of the "base tax" and "progressive tax" per our response to Question 11 of your September 22, 2011 letter to DOR), and we also provide the income statement illustrations using the Spring 2011 forecast assumptions. Additionally, in order to provide you with the most current information and forecast assumptions, we have provided information beyond your initial request and added income statement charts for FY11-FY13 using the Fall 2011 forecast assumptions. See Addendum B for all of these charts.

Note that for the well lease expenditure credits extended to the North Slope under HB110/SB49, the tables prepared under the Fall 2010 and Spring 2011 assumptions assumed that the entire amount of the credit would be applied against tax liability. In actuality, only a portion of the well credits would accrue to companies that could apply them against tax liability; this fact is reflected in tables prepared using the Fall 2011 assumptions.

Additionally, we have provided a detailed breakdown of all credits applied against tax liability as well as detail on credits available for refund. We hope you will find this additional information helpful.

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9. **Provide income statement charts or other similar analysis to reflect production tax impact on various types of producers, including incumbent producer and new producer.**

The tables below illustrate one hypothetical example of the production tax impact on new and incumbent producers. In this example, 10,000 barrels per day of production is added through a capital investment of $250 million and operating expenditures of $30 million by both a hypothetical new producer and a hypothetical incumbent producer. The new producer is assumed to have no other production in the state, and the incumbent producer already has production of 100,000 b/d prior to the investment. The tables show the difference in tax paid and in value to the producers in one year of production.

As you will see in the tables, the new producer pays no production tax due to the small producer credit, and receives refundable credits for capital expenditure credits and for net operating loss credits. The incumbent producer benefits from credits for capital expenditures and from the tax rate being lower due to the additional barrels produced. This is just one possible illustration using one possible set of assumptions.

New Producer - Investment in 10,000 b/d Project	
Oil price	$100
Transport costs	$8
Wellhead price	$92
Total production in barrels/day	10,000
Total annual production in barrels	3,650,000
Value of total production	$335,800,000
Royalty	$41,975,000
Value of taxable barrels	$293,825,000
Operating expenditures	$30,000,000
Capital expenditures	$250,000,000
Production tax value	13,825,000
Higher of base tax or minimum tax	11,753,000
Progressive tax	$0
Total tax before credits	11,753,000
Small producer credit	11,753,000
Credit to be refunded	$116,543,750
Total tax after credits	**$0**

Incumbent Producer - Existing Production	
Oil price	$100
Transport costs	$8
Wellhead price	$92
Total production in barrels/day	100,000
Total annual production in barrels	36,500,000
Value of total production	$3,358,000,000
Royalty	$419,750,000
Value of taxable barrels	$2,938,250,000
Operating expenditures	$300,000,000
Capital expenditures	$200,000,000
Production tax value	$2,438,250,000
Base tax (25% * PTV)	$609,562,500
Progressive tax	$451,997,155
Total tax before credits	$1,061,559,655
Credits	$40,000,000
Other credits	$0
Total tax after credits	**$1,021,559,655**

Incumbent Producer - WITH INVESTMENT	
Oil price	$100
Transport costs	$8
Wellhead price	$92
Total production in barrels/day	110,000
Total annual production in barrels	40,150,000
Value of total production	$3,693,800,000
Royalty	$461,725,000
Value of taxable barrels	$3,232,075,000
Operating expenditures	$330,000,000
Capital expenditures	$450,000,000
Production tax value	$2,452,075,000
Base tax (25% * PTV)	$613,018,750
Progressive tax	$390,346,260
Total tax before credits	$1,003,365,010
Credits	$90,000,000
Other credits	$0
Total tax after credits	**$913,365,010**

10. Provide income statement chart for FY12 assuming production of only 250,000 b/d of unconventional oil with capex of $22.33 per barrel, using oil prices from $50 to $150 per barrel in $5 increments. Hold all other assumptions constant.

Addendum C-1 presents an illustration using the income statement format of the production tax calculation for a hypothetical producer with 250,000 barrels per day of production. As requested, these statements are produced from $50 to $150 per barrel in $5 increments. We use the $22.33 per barrel capital expenditure assumption you provided and also use the following assumptions to illustrate an "unconventional" oil concept: $20 / barrel operating expenditure, 15% quality bank discount, 12.5% royalty, and no change in transportation costs from our Fall 2011 forecast for FY 12.

Note that the income statements in this illustration are for a hypothetical producer and project in full production and do not include the massive expenditures that would be required during the development phase for unconventional oil development on this scale. Currently, heavy oil development is in the pilot project stage and years away from potential commercial production.

PLEASE NOTE THAT THESE STATEMENTS ARE SIMPLIFICATIONS, INTENDED TO ILLUSTRATE A VERY COMPLEX SET OF COMPANY-SPECIFIC TAX CALCULATIONS AT VARIOUS PRICES UNDER THIS HYPOTHETICAL SCENARIO AND SHOULD BE INTERPRETED AS SUCH.

11. Provide income statement chart for FY12 assuming FY12 production plus 250,000 b/d of heavy oil (capex of $22.33 per barrel? Not specified). Apply a quality price differential if appropriate. Hold all other assumptions constant.

The illustration in Addendum C-2 provides a hypothetical income statement for FY 12, at the fall 2011 forecast price, with 250,000 barrels per day of heavy oil added. For consistency with our response to question 10, we used the same assumptions and simply added the production to our existing FY 12 income statement as provided in the Fall 2011 Revenue Sources Book.

In addition to our forecasted production and costs for FY12, an additional 250,000 barrels per day of production is assumed. For the additional production we use the $22.33 per barrel capital expenditure assumption you provided for question 10 and also use the following assumptions to illustrate a "heavy" oil concept: $20 / barrel operating expenditure, 15% quality bank discount, 12.5% royalty, and no change in transportation costs from our Fall 2011 forecast for FY 12.

Note that the heavy oil production represents an illustration of a project in full production and does not include the massive expenditures that would be required during the development phase for unconventional oil development on this scale. Currently, heavy oil development is in the pilot project stage and years away from potential commercial production.

PLEASE NOTE THAT THESE STATEMENTS ARE SIMPLIFICATIONS, INTENDED TO ILLUSTRATE A VERY COMPLEX SET OF COMPANY-SPECIFIC TAX CALCULATIONS AT VARIOUS PRICES UNDER THIS HYPOTHETICAL SCENARIO AND SHOULD BE INTERPRETED AS SUCH.

Questions from September 22, 2011 letter to Commissioner Butcher:

1. **What has the recent 100 plus days delivered as to the filling of the high level DOR positions? For example, what is the status of the Director of the Tax Division, Commercial analysts, Audit Master and others? If any difficulty has been encountered in filling these positions, is there any particular identified reason? What are the key positions that currently remain unfilled? How many positions within your department are currently unfilled?**

   Matt Fonder accepted our offer for the Tax Director position and started on October 24th. We have filled both Commercial Analyst positions, one of whom has graciously accepted the responsibilities relating to the Chief Economist. We also have an Acting Assistant Chief Economist in Juneau. We purposely wanted to address these positions prior to recruiting for the final high level position of Audit Master which is still vacant. However, now that we have a better feel for our team and what everyone brings to the table, we are in a better position to begin the recruitment process for the 4th of 4 Audit Masters. We are currently working on this recruitment.

2. **What number of personnel would need to be hired to have DOR fully staffed?**

   "Fully staffed" is certainly a noble goal but for any organization this size, public or private, 0% vacancy is generally unattainable. As of September 27, 2011 we were running just over 6% for the department.

3. **I would like to know how the regulation drafting process is proceeding. What areas have been covered and what areas still need to be rewritten?**

   This response pertains to regulations being drafted for the ACES production tax only and does not address any other regulation projects by the Department.

   Since the passage of ACES the Department has implemented or amended over 70 regulations related to oil and gas production taxes. These include regulations for

lease expenditures and overhead under AS 43.55.165, exploration credits, facility sharing/access, valuation and transportation of gas related to a major gas sale under AGIA, and other miscellaneous and conforming changes. Note that the regulations for the exploration credits under AS 43.55.025 were written prior to the passage of SB 309 and HB 280, respectively, that included the "Jack-up Rig credit" under AS 43.55.025(l) and the "well lease expenditure credit" under AS 43.55.023(l). However, the Department has drafted an Advisory Bulletin (under AS 43.55.110(g)) addressing issues related to the credit under AS 43.55.025(l).

The Department has recently completed the public process for regulation changes required under AS 43.55.011(m) related to what were formerly treated as "excess tax credits" under ceilings required by AS 43.55.011(j), (k), and (o). The Department is currently in discussions with the Department of Law to assess the need for regulations for geological and geophysical exploration, the heating value of gas, information required for forecast reporting requirements, and the well lease expenditure credit.

4. **I understand the implementation of the tax management system may take 3- 5 years. What is currently DOR's knowledge as to the gaps in Alaska's capacity to understand capital expenditures?**

   The Department does not have statutory authority to retroactively require a producer or explorer to provide information related to prior years' capital expenditures. The Department is in the process of developing a list of categories for future reporting that would identify various types of capital expenditure categories and reports that would be incorporated into the TRMS project referenced in the question.

   Workshops were held October 10, 2011, November 10, 2011, and December 12, 2011 to discuss the appropriate categories to be included and reported.

5. **As you know I am most interested in the production tax bill which you are carrying. I have had a number of inquires as to aspects of Alaska's system, including its credits. As DOR is carrying the tax bill, I assume that inquires should be directed to DOR. Please let me know if I am in error or misunderstand as to where I can or should forward my inquiries.**

   You are correct. Please route inquiries through the Commissioner's office. Also to the extent possible we hope that you will share in our goal of keeping future inquiries focused and constructive so that we can best use our staff resources and produce analysis that will be of value in decision making.

6. **Based upon the return of Mr. Dees from vacation in June, possibly the credit issue can be better understood. Please let me know if I may directly contact Mr. Dees, Audit Master, as to credit issues?**

Please route inquiries through the Commissioner's office so that staff time can be allocated and appropriate staff can respond.

7. **I have been trying to obtain the actual bottom line amount of production tax money which Alaska keeps after all credits, whether under ACES, PPT or previous system, what is the actual net dollar amount of production tax money for each year from 2000 until now. I would like to know this both as to calendar and fiscal years if possible. By "all credits" I mean, especially as to ACES, the following credits:**

   - **qualified cap exped, 023(a)(l)**
   - **CFAL, 023(b)**
   - **TIE, 023(i)**
   - **40% Cook Inlet, 023(1)**
   - **new area dev, 024(a)**
   - **small producer, 024(c)**
   - **exploration 30 40, 025**
   - **Cook Inlet jack-up, 025)1)**
   - **CAPEX exploration well, 023(a)(2)**
   - **other credits.**

   The following table presents total production tax for FY 2000 to FY 2011 including an accounting of total credits applied against tax liability. This information is being provided in fiscal year format as our accounting system, Revenue Sources Books, and Annual Reports from which the information is drawn all operated on a fiscal year basis.

Total Production Tax and Tax after all credits, FY 2000 to FY 2011 ($ millions)

Fiscal Year	2000	2001	2002	2003	2004	2005	2006[1]
Production Tax before Credits	$ 703	$ 704	$ 496	$ 599	$ 652	$ 863	$ 1,200
Credits Applied Against Tax Liability	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Tax after credits	$ 703	$ 704	$ 496	$ 599	$ 652	$ 863	$ 1,200
Credits Refunded	NA	NA	NA	NA	NA	NA	NA
Production Tax after refunded credits	$ 703	$ 704	$ 496	$ 599	$ 652	$ 863	$ 1,200

Fiscal Year	2007[1]	2008	2009	2010	2011	Total FY 00-11
Production Tax before Credits	$ 2,764	$ 7,198	$ 3,445	$ 3,288	$ 4,958	$ 26,869
Credits Applied Against Tax Liability	$ 556	$ 375	$ 333	$ 417	$ 405	$ 2,086
Total Tax after credits	$ 2,208	$ 6,823	$ 3,112	$ 2,871	$ 4,553	$ 24,783
Credits Refunded	$ 55	$ 54	$ 193	$ 250	$ 450	$ 1,002
Production Tax after refunded credits	$ 2,153	$ 6,769	$ 2,919	$ 2,621	$ 4,103	$ 23,781

(1) The combined total of tax credits applied against tax liabilities in FY07 include tax credits earned during the months of April and May 2006.

8. **I am interested in first receiving the gross production tax [I guess in the nominal amount] for each fiscal year from 2000 to present. I would then like to have for each year the delineation of the amount of each credit for each year. This would then be followed with the amount kept by Alaska after all credits are accounted for. How could I find in past Revenue books [possibly] a starting point for your nominal production tax? Is there an explanation or method or way to understand the impact of credits on the nominal tax rate, as I am interested in an actual bottom line dollar amount, the credits deducted include both offsets against the tax and payments by the state . If a credit is spread over more than 1 tax reporting year, please identify the gross and the amounts for each year.[I understand that CAPEX is spread over 2 years and that this is shown as credit against tax or for purchase.] To some extent I believe that this is shown in the Revenue Sources book, as to CAP EX anyway.**

The table in Question 7 above shows the amount of production tax revenue collected after all credits have been accounted for. Because production tax credits are often not applied or refunded in the period in which they were earned, we are unable to match credits with the spending that earned them. We can, however, give an estimate of the nominal tax rate for each year by dividing the production tax after all credits by the gross value at the point of production for each year. This analysis would effectively illustrate what an equivalent nominal tax rate on the gross production value would be, much like the tax rates that are applied to the gross value in many states. This information is shown below.

Production Tax as a Percentage of Gross Value at Point of Production (in $millions unless otherwise noted)

Fiscal Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Value at Point of Production	$6 556	$7 145	$5 498	$7 396	$8 544	$11 650	$15 188	$14 608	$20 746	$13 681	$14 157	$16 813
Production tax before credits	$703	$704	$496	$599	$652	$863	$1 200	$2 764	$7 198	$3 445	$3 288	$4 956
Credits applied against tax liability								$656	$375	$333	$417	$405
Production tax after credits against tax liability	$703	$704	$496	$599	$652	$863	$1 200	$2 208	$6 823	$3 112	$2 871	$4 553
Credits refunded								$55	$54	$193	$250	$450
Production Tax after Credits against tax liability and refunded credits	$703	$704	$496	$599	$652	$863	$1 200	$2 153	$6 769	$2 919	$2 621	$4 103
Tax Received/Value at Point of Production												
Before Credits	11%	10%	9%	8%	8%	7%	8%	19%	35%	25%	23%	29%
After Credits applied against tax liability	11%	10%	9%	8%	8%	7%	8%	15%	33%	23%	20%	27%
After credits applied to tax liability and credits refunded	11%	10%	9%	8%	8%	7%	8%	15%	33%	21%	19%	24%

9. **I am interested in receiving this information in a format followed by Fall2010 RSB appendix D. Again, my overriding intent is to receive the actual bottom line amount of production tax money that Alaska actually keeps.**

   The income statement format is an illustration of the production tax calculation only intended to help people understand how the production tax calculation works. Since it is a simplified presentation of a very complex tax system, it does not exactly reflect the "actual bottom line" tax revenue to the state. Refer to our table presented above for the actual production tax revenue before and after credits for each year from FY 2000 to FY 2011, as well as an accounting of production tax after credits refunded.

10. **I am also interested in receiving the responses as to my inquires of May 3, 2011. I am interested in maintaining the parameters as set forth in the email. I need the charts-FY 2010, 2011 and 2012 Fall10 and Spring 11 forecasts depicting SB49/HB 110.**

    Responses to your May 3, 2011 inquiries are included in this response document. Also, to the extent possible, we provided analysis using the Fall 2011 forecast assumptions which reflect the best available and most current information at this time, so as to be most helpful in understanding the tax and making decisions about the tax.

11. **There were 3 charts provided as part of the 3/19/11 DOR letter. Who prepared those charts? What information was relied upon as to rate of progressivity? Why is the rate not shown next to "Progressive Tax" line? [The rate is shown at 7.4%, current tax system, in chart of FY 2011 using Fall 2010 forecast.] [Also, the amount of the progressive tax under the current system is $686.7M] How is Progressive Tax for FY 2011, page 8 of 3/19/11, of $1,029.9 calculated under SB49 analysis? Something does not appear to add up, do you agree? I need an**

explanation of this as the production tax value per barrel is $48.54 under both charts. Is there a reason for the stark increase in progressivity tax under SB49 analysis?

The tables were prepared by staff in our Economics Research Group. The income statement tables were produced using our Fall 2010 revenue forecast assumptions and model, under current law and as modified to reflect the provisions of HB 110 / SB49.

Three income statement format tables were provided showing an illustration of the tax calculation under ACES, in the Fall 2010 Revenue Source Book, Appendix D. At your request, three income statement format tables were provided showing an illustration of the tax calculation under SB 49, in the response dated March 19, 2011 addressing numerous questions and information requests made by members of the Senate Resources committee.

Under ACES, a base tax and progressivity calculation are clearly and separately provided for in statute, with the base tax rate calculated under AS 43.55.011(e), and the progressive surcharge calculated under AS 43.55.011(g).

Under SB 49, there is no longer a distinct "base tax" and "progressivity surcharge" but rather a bracketed tax rate system, with the entire tax calculation provided for under AS 43.55.011(g).

For purposes of preparing the income statement tables, the "progressive tax" shown under ACES represented revenue for the progressive surcharge, over and above the base tax rate. The "progressive tax" line in the SB 49 income statements represented the entire tax for all tax brackets except the first tax bracket. While the total tax was presented correctly in the SB 49 tables, we agree that the breakout between "base tax" and "progressive tax" was confusing. As a result, in the HB 110 / SB 49 income statements provided in this response, the "base tax" represents 25% of production tax value (or 15% for examples of hypothetical production qualifying for the 15% new fields base rate), and "progressivity" represents all tax above and beyond the base rate. This presentation should be easier to understand and more readily comparable to the current tax system.

12. **Could a CAPEX credit under low pricing of oil exceed actual production tax to be received? In other words, could credits, at low oil pricing, overwhelm the tax itself? Does HB 110 / SB49 increase the risk of credits overwhelming the tax? What occurs if credits overwhelm the tax?**

If credits exceed production tax, the state could potentially collect zero production tax in a year at very low oil prices. HB110/ SB49 does not create this scenario, and since the first tax bracket in HB110/SB49 retains the ACES base

rate of 25%, the tax liability before credits under either tax system would be similar when production tax value per barrel is $30 or less. The expansion of the credit system under HB110/SB49 could increase the amount of credits available, however.

The production tax is a company-specific calculation and even at current prices, some companies have expenditures that exceed the value of oil produced (companies with very little production in the state and explorers for example). Such companies, as long as they meet certain criteria, can apply to the state for a transferrable tax credit certificate which can be transferred to another company or refunded by the state. The monies for purchasing tax credit certificates are appropriated annually by the legislature into a sub-fund of the General Fund established for that purpose. Under a low oil price scenario, we would expect that more companies would have low or no production tax liability and those eligible would request refunds for credits. Under such a scenario, many companies would curtail expenditures unless or until oil prices recover.

13. What increase or decrease in OPEX and CAPEX does DOR see between now and 2020? What increase or decrease in downstream costs does DOR see between now and 2020?

The following table presents the Fall 2011 forecast assumptions for total operating expenditures, total capital expenditures, and total downstream costs (ANS Marine Transportation, TAPS tariff, and other downstream costs) for FY 2011 as well as the forecast for FY 2012 through FY 2020. Note that the level of expenditures is based primarily on information provided by operators and non-operators and assumes that oil prices maintain or exceed forecasted levels.

Fiscal Year	2011	2012	2013	2014	2015
Total Operating Expenditures ($ million)	$ 2,614	$ 2,579	$ 2,375	$ 2,375	$ 2,359
Total Capital Expenditures ($ million)	$ 2,317	$ 2,743	$ 3,057	$ 3,726	$ 3,926
Average Downstream Costs ($ / barrel)	$ 7.17	$ 8.72	$ 8.56	$ 8.83	$ 9.15

Fiscal Year	2016	2017	2018	2019	2020
Total Operating Expenditures ($ million)	$ 2,384	$ 2,428	$ 2,664	$ 2,683	$ 2,711
Total Capital Expenditures ($ million)	$ 3,360	$ 2,882	$ 2,499	$ 2,348	$ 2,304
Average Downstream Costs ($ / barrel)	$ 9.55	$ 9.78	$ 10.00	$ 10.35	$ 10.76

14. What spread between WTI and ANS does DOR see between now and 2020? What is the current in-house belief of oil prices for the remainder of this fiscal year?

The differential between WTI and ANS has been volatile over the past year. ANS began the year trading at a modest premium to WTI, and by September 2011 ANS traded as high as $28.60 / barrel over WTI. As of December 9, 2011, ANS traded at a premium of about $8 / barrel over WTI.

To prepare the Fall 2011 revenue forecast, DOR applied a market-based differential estimate to derive ANS prices from our forecast for WTI prices. This produced an estimated differential of $18.41 (ANS premium) for FY 2012. Since preparing this estimate, the differential has narrowed to about $8 / barrel as of December 9, 2011. However, the narrowing has been a result of WTI prices increasing relative to other global crude oils (for example, Brent and Dubai), while ANS prices have remained near forecasted levels and in line with global crude oil prices.

More discussion of the ANS / WTI differential and the outlook and methodology used for the Fall 2011 forecast may be found on page 34 of the Fall 2011 Revenue Sources Book.

15. I would like a HB110/SB49 application prepared upon the May 1, 2011 charts. The income statement approach seems to be most understandable. The charts arise out of the April17, 2011 email from me to Mr. Tangeman.

We previously provided income statement illustrations for HB110/SB49 for FY10-12 using Fall 2010 forecast assumptions, in our response to Senate Resources questions dated March 19, 2011. As requested, those tables are provided again (with a new presentation of the "base tax" and "progressive tax" per our response to Question 11 of your September 22, 2011 letter to DOR with the base tax representing 25% of production tax value), and we also provide the income statement illustrations using the Spring 2011 forecast assumptions. Additionally, in order to provide you with the most current information and forecast assumptions, we have provided information beyond your initial request and added income statement charts for FY11-FY13 using the Fall 2011 forecast assumptions. See Addendum B for all of these charts.

Note that for the well lease expenditure credits extended to the North Slope under HB110/SB49, the tables prepared under the Fall 2010 and Spring 2011 assumptions assumed that the entire amount of the credit would be applied against tax liability. In actuality, only a portion of the well credits would accrue to companies that could apply them against tax liability; this fact is reflected in tables prepared using the Fall 2011 assumptions.

Additionally, we have provided a detailed breakdown of all credits applied against tax liability as well as detail on credits available for refund. We hope you will find this additional information helpful.

PLEASE NOTE THAT THESE STATEMENTS ARE SIMPLIFICATIONS, INTENDED TO ILLUSTRATE A VERY COMPLEX SET OF COMPANY-SPECIFIC TAX CALCULATIONS AT VARIOUS PRICES AND SHOULD BE INTERPRETED AS SUCH.

16. **I would request charts following a Fall2010 RSB appendix D format under proposed HB 110/SB 49, as to the estimated monies, if any, to be received by Alaska assuming 500,000bbl's/day and 700,000 bbl's/day from Shells proposed Chukchi and Beaufort Sea operations.**

We are unable to fulfill your request with the information provided. It is not clear what oil price you would like us to use or what fields/companies are producing the 500,000 barrels per day. If you would like to provide us with more specific information, we will be happy to accommodate your request.

With regard to the Beaufort Sea operations, most of the production would likely be in federal waters and not subject to the production tax. An addition of 700,000 barrels of oil through TAPS should, however, lower the tariff in the range of $2.00 per barrel, providing the state with additional royalty and production tax revenue from barrels produced on state lands.

17. **I would request charts following a Fall2010 RSB appendix D format under proposed HB 110/SB 49, as to the estimated monies, if any, to be received by Alaska assuming 100,000 bbls/day from a hypothetical NPRA development.**

The income statement tables in Addendum D show an illustration of revenue from a hypothetical 100,000 barrel per day development, under HB 110 / SB 49. *As requested, these tables are provided in the income statement format and therefore are for a single year only and only include production tax revenue and do not include property tax, corporate income tax, or shared royalties.*

Addendum D presents an illustration using the income statement format of the production tax calculation under HB 110 / SB 49 for a hypothetical producer with 100,000 barrels per day of production. We prepared these statements at several oil prices: our Fall 2011 forecast for FY 12 ($108.89), and also $75, $100 and $125. We use ongoing capital costs of $10 per barrel and $15 per barrel operating expenditure. We assume a 12.5% royalty. For transportation costs for

this illustration we use the Fall 2011 forecast for FY 12, plus an additional $2 per barrel.

Note that the income statements in this illustration are for a hypothetical producer and project in full production and do not include the significant expenditures that would be required during the development phase for a new NPRA oil development on this scale.

PLEASE NOTE THAT THESE STATEMENTS ARE SIMPLIFICATIONS, INTENDED TO ILLUSTRATE A VERY COMPLEX SET OF COMPANY-SPECIFIC TAX CALCULATIONS AT VARIOUS PRICES UNDER THIS HYPOTHETICAL SCENARIO AND SHOULD BE INTERPRETED AS SUCH.

18. **Over the years, from 2000 to present, what record of underpayment as to the royalty revenue has occurred? In part, please set forth the amounts collected from each year, 2000-present.**

The Department of Revenue does not assess royalty payments or track the underpayment of royalty revenue. Royalty payments fall under the jurisdiction of the Department of Natural Resources. Questions regarding royalty payments should be directed to that department.

19. **Same as question 18, but pertaining to the production tax revenue.**

We do not have an analysis of underpayments for each tax year readily available, however we do have information about total collections from production tax assessments and settlements, which are deposited into the Constitutional Budget Reserve Fund. The following data come from the Tax Division Annual Reports.

Oil and Gas Production Tax to CBRF ($ millions)

Fiscal Year	Amount
2011	62.9
2010	459.8
2009	81.1
2008	47.2
2007	17.5
2006	2.6
2005	21.3
2004	4.2
2003	3.7
2002	24.2
2001	34.8
2000	17.5

20. How does Alaska compare as to other jurisdictions as to the discovering underpayments of a.) royalty monies and b.) production tax monies.

The Department of Revenue has not prepared any analysis regarding underpayments of oil and gas revenues as compared to other jurisdictions.

21. Importantly, I would welcome you alerting me to other areas which are or which will be impacting DOR. As always, you may call me at any time and I certainly welcome the opportunity to meet with you also at any time.

Thank you, I look forward to working with you this session and making progress towards improving Alaska's attractiveness to new oil development.

ADDENDUM A:

FY 2013 Production Tax Estimates – Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions and oil prices from $50 to $200 in $5 increments

These tables are meant to provide an illustration of the production tax calculation under current law, at a range of different ANS prices. Since this is a simplification of the tax calculation, total tax amounts shown here may not exactly match those reported in other analysis. The following notes apply to all the tables in this addendum:

(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. For purposes of this calculation, also includes barrels produced by companies with zero PTV. The effectively taxable volume amount shown here is calculated AT OUR FORECAST PRICE and we do not adjust it between tables.

(2) For purposes of this illustration, to more closely reflect actual tax received by the state, "taxable barrels" shown here exclude barrels produced by companies expected to have zero tax liability.

(3) 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.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

(5) Lease expenditures not included in Tax Revenue Calculation represents lease expenditures made by companies with little to no tax liability.

(6) Estimated Tax after refunded credits represents the total estimated tax revenue minus the amount of credits refunded, which is paid by appropriation through the Production Tax Credit Fund at AS 43.55.028.

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $50 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$50.00	555,227	$27.8
Annual Production (bbl)			
Total		202,657,895	$10,132.9
Royalty, Federal and other barrels[1]		-30,158,081	($1,507.9)
Taxable barrels [2]		172,499,814	$8,625.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$12.88		($2,221.3)
Deductible Capital Expenditures	-$12.53		($2,161.7)
Total Lease Expenditures	-$25.41	172,499,814	($4,382.9)
Production Tax			
Production Tax Value (PTV)			$2,765.0
Base Tax (25%*PTV)			$691.3
Production Tax Value per barrel	$16.03		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$691.3
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($385.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($425.0)
Estimated Total Tax after credits[4]			**$266.3**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($150.0)**
Capital Expenditures			**($860.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($1,010.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($435.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($500.0)**
Estimated Tax after refunded credits [7]			**($233.7)**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $55 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$55.00	555,227	$30.5
Annual Production (bbl)			
Total		202,657,895	$11,146.2
Royalty, Federal and other barrels[1]		-30,158,081	($1,658.7)
Taxable barrels [2]		172,499,814	$9,487.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.09		($2,257.7)
Deductible Capital Expenditures	-$12.98		($2,238.9)
Total Lease Expenditures	-$26.07	172,499,814	($4,496.5)
Production Tax			
Production Tax Value (PTV)			$3,513.9
Base Tax (25%*PTV)			$878.5
Production Tax Value per barrel	$20.37		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$878.5
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($405.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$428.5**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($120.0)**
Capital Expenditures			**($780.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($900.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($410.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($475.0)**
Estimated Tax after refunded credits [7]			**($46.5)**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $60 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$60.00	555,227	$33.3
Annual Production (bbl)			
Total		202,657,895	$12,159.5
Royalty, Federal and other barrels[1]		-30,158,081	($1,809.5)
Taxable barrels [2]		172,499,814	$10,350.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.16		($2,269.8)
Deductible Capital Expenditures	-$13.13		($2,264.6)
Total Lease Expenditures	-$26.29	172,499,814	($4,534.4)
Production Tax			
Production Tax Value (PTV)			$4,338.5
Base Tax (25%*PTV)			$1,084.6
Production Tax Value per barrel	$25.15		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$1,084.6
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($405.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$634.6**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($100.0)**
Capital Expenditures			**($750.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($850.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($410.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($475.0)**
Estimated Tax after refunded credits [7]			**$159.6**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $65 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$65.00	555,227	$36.1
Annual Production (bbl)			
Total		202,657,895	$13,172.8
Royalty, Federal and other barrels[1]		-30,158,081	($1,960.3)
Taxable barrels [2]		172,499,814	$11,212.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.16		($2,269.8)
Deductible Capital Expenditures	-$13.13		($2,264.6)
Total Lease Expenditures	-$26.29	172,499,814	($4,534.4)
Production Tax			
Production Tax Value (PTV)			$5,201.0
Base Tax (25%*PTV)			$1,300.3
Production Tax Value per barrel	$30.15		
Progressive Tax = (0.1% * PTV)			$3.1
Total Tax before credits			$1,303.4
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($410.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$853.4**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($100.0)**
Capital Expenditures			**($750.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($850.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($385.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($450.0)**
Estimated Tax after refunded credits [7]			**$403.4**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $70 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$70.00	555,227	$38.9
Annual Production (bbl)			
Total		202,657,895	$14,186.1
Royalty, Federal and other barrels[1]		-30,158,081	($2,111.1)
Taxable barrels [2]		172,499,814	$12,075.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.16		($2,269.8)
Deductible Capital Expenditures	-$13.13		($2,264.6)
Total Lease Expenditures	-$26.29	172,499,814	($4,534.4)
Production Tax			
Production Tax Value (PTV)			$6,063.5
Base Tax (25%*PTV)			$1,515.9
Production Tax Value per barrel	$35.15		
Progressive Tax = (2.1% * PTV)			$124.9
Total Tax before credits			$1,640.8
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($410.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$1,190.8**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($100.0)**
Capital Expenditures			**($750.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($850.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($385.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($450.0)**
Estimated Tax after refunded credits [7]			**$740.8**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $75 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$75.00	555,227	$41.6
Annual Production (bbl)			
Total		202,657,895	$15,199.3
Royalty, Federal and other barrels[1]		-30,158,081	($2,261.9)
Taxable barrels [2]		172,499,814	$12,937.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.16		($2,269.8)
Deductible Capital Expenditures	-$13.13		($2,264.6)
Total Lease Expenditures	-$26.29	172,499,814	($4,534.4)
Production Tax			
Production Tax Value (PTV)			$6,926.0
Base Tax (25%*PTV)			$1,731.5
Production Tax Value per barrel	$40.15		
Progressive Tax = (4.1% * PTV)			$281.2
Total Tax before credits			$2,012.7
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($415.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$1,562.7**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($100.0)**
Capital Expenditures			**($750.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($850.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($360.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($425.0)**
Estimated Tax after refunded credits [7]			**$1,137.7**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $80 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$80.00	555,227	$44.4
Annual Production (bbl)			
Total		202,657,895	$16,212.6
Royalty, Federal and other barrels[1]		-30,158,081	($2,412.6)
Taxable barrels [2]		172,499,814	$13,800.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.16		($2,269.8)
Deductible Capital Expenditures	-$13.13		($2,264.6)
Total Lease Expenditures	-$26.29	172,499,814	($4,534.4)
Production Tax			
Production Tax Value (PTV)			$7,788.5
Base Tax (25%*PTV)			$1,947.1
Production Tax Value per barrel	$45.15		
Progressive Tax = (6.1% * PTV)			$472.0
Total Tax before credits			$2,419.2
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($415.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$1,969.2**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($100.0)**
Capital Expenditures			**($750.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($850.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($360.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($425.0)**
Estimated Tax after refunded credits [7]			**$1,544.2**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $85 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$85.00	555,227	$47.2
Annual Production (bbl)			
Total		202,657,895	$17,225.9
Royalty, Federal and other barrels[1]		-30,158,081	($2,563.4)
Taxable barrels [2]		172,499,814	$14,662.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.16		($2,269.8)
Deductible Capital Expenditures	-$13.13		($2,264.6)
Total Lease Expenditures	-$26.29	172,499,814	($4,534.4)
Production Tax			
Production Tax Value (PTV)			$8,651.0
Base Tax (25%*PTV)			$2,162.8
Production Tax Value per barrel	$50.15		
Progressive Tax = (8.1% * PTV)			$697.3
Total Tax before credits			$2,860.1
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($415.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$2,410.1**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($100.0)**
Capital Expenditures			**($750.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($850.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($360.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($425.0)**
Estimated Tax after refunded credits [7]			**$1,985.1**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $90 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$90.00	555,227	$50.0
Annual Production (bbl)			
Total		202,657,895	$18,239.2
Royalty, Federal and other barrels[1]		-30,158,081	($2,714.2)
Taxable barrels [2]		172,499,814	$15,525.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.16		($2,269.8)
Deductible Capital Expenditures	-$13.13		($2,264.6)
Total Lease Expenditures	-$26.29	172,499,814	($4,534.4)
Production Tax			
Production Tax Value (PTV)			$9,513.5
Base Tax (25%*PTV)			$2,378.4
Production Tax Value per barrel	$55.15		
Progressive Tax = (10.1% * PTV)			$957.1
Total Tax before credits			$3,335.5
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($415.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$2,885.5**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($100.0)**
Capital Expenditures			**($750.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($850.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$2,485.5**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $95 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$95.00	555,227	$52.7
Annual Production (bbl)			
Total		202,657,895	$19,252.5
Royalty, Federal and other barrels[1]		-30,158,081	($2,865.0)
Taxable barrels [2]		172,499,814	$16,387.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.58		($2,342.6)
Deductible Capital Expenditures	-$14.67		($2,530.0)
Total Lease Expenditures	-$28.25	172,499,814	($4,872.5)
Production Tax			
Production Tax Value (PTV)			$10,037.9
Base Tax (25%*PTV)			$2,509.5
Production Tax Value per barrel	$58.19		
Progressive Tax = (11.3% * PTV)			$1,131.9
Total Tax before credits			$3,641.4
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($415.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$3,191.4**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($30.0)**
Capital Expenditures			**($490.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($520.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$2,791.4**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $100 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$100.00	555,227	$55.5
Annual Production (bbl)			
Total		202,657,895	$20,265.8
Royalty, Federal and other barrels[1]		-30,158,081	($3,015.8)
Taxable barrels [2]		172,499,814	$17,250.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.58		($2,342.6)
Deductible Capital Expenditures	-$14.67		($2,530.0)
Total Lease Expenditures	-$28.25	172,499,814	($4,872.5)
Production Tax			
Production Tax Value (PTV)			$10,900.4
Base Tax (25%*PTV)			$2,725.1
Production Tax Value per barrel	$63.19		
Progressive Tax = (13.3% * PTV)			$1,447.2
Total Tax before credits			$4,172.3
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($415.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$3,722.3**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**($30.0)**
Capital Expenditures			**($490.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($520.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$3,322.3**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $105 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$105.00	555,227	$58.3
Annual Production (bbl)			
Total		202,657,895	$21,279.1
Royalty, Federal and other barrels[1]		-30,158,081	($3,166.6)
Taxable barrels [2]		172,499,814	$18,112.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$11,614.0
Base Tax (25%*PTV)			$2,903.5
Production Tax Value per barrel	$67.33		
Progressive Tax = (14.9% * PTV)			$1,734.1
Total Tax before credits			$4,637.6
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($420.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$4,187.6**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$3,787.6**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $110 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$110.00	555,227	$61.1
Annual Production (bbl)			
Total		202,657,895	$22,292.4
Royalty, Federal and other barrels[1]		-30,158,081	($3,317.4)
Taxable barrels [2]		172,499,814	$18,975.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$12,476.5
Base Tax (25%*PTV)			$3,119.1
Production Tax Value per barrel	$72.33		
Progressive Tax = (16.9% * PTV)			$2,112.4
Total Tax before credits			$5,231.5
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($420.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($450.0)
Estimated Total Tax after credits[4]			**$4,781.5**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$4,381.5**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $115 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$115.00	555,227	$63.9
Annual Production (bbl)			
Total		202,657,895	$23,305.7
Royalty, Federal and other barrels[1]		-30,158,081	($3,468.2)
Taxable barrels [2]		172,499,814	$19,837.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$13,339.0
Base Tax (25%*PTV)			$3,334.7
Production Tax Value per barrel	$77.33		
Progressive Tax = (18.9% * PTV)			$2,525.2
Total Tax before credits			$5,860.0
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($420.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$5,385.0**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$4,985.0**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $120 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$120.00	555,227	$66.6
Annual Production (bbl)			
Total		202,657,895	$24,318.9
Royalty, Federal and other barrels[1]		-30,158,081	($3,619.0)
Taxable barrels [2]		172,499,814	$20,700.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$14,201.5
Base Tax (25%*PTV)			$3,550.4
Production Tax Value per barrel	$82.33		
Progressive Tax = (20.9% * PTV)			$2,972.5
Total Tax before credits			$6,522.9
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($425.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$6,047.9**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$5,647.9**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $125 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$125.00	555,227	$69.4
Annual Production (bbl)			
Total		202,657,895	$25,332.2
Royalty, Federal and other barrels[1]		-30,158,081	($3,769.8)
Taxable barrels [2]		172,499,814	$21,562.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$15,064.0
Base Tax (25%*PTV)			$3,766.0
Production Tax Value per barrel	$87.33		
Progressive Tax = (22.9% * PTV)			$3,454.3
Total Tax before credits			$7,220.3
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($425.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$6,745.3**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($400.0)**
Estimated Tax after refunded credits [7]			**$6,345.3**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $130 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$130.00	555,227	$72.2
Annual Production (bbl)			
Total		202,657,895	$26,345.5
Royalty, Federal and other barrels[1]		-30,158,081	($3,920.6)
Taxable barrels [2]		172,499,814	$22,425.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$15,926.5
Base Tax (25%*PTV)			$3,981.6
Production Tax Value per barrel	$92.33		
Progressive Tax = (24.9% * PTV)			$3,970.6
Total Tax before credits			$7,952.3
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($430.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$7,477.3**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($335.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			($400.0)
Estimated Tax after refunded credits [7]			**$7,077.3**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $135 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$135.00	555,227	$75.0
Annual Production (bbl)			
Total		202,657,895	$27,358.8
Royalty, Federal and other barrels[1]		-30,158,081	($4,071.3)
Taxable barrels [2]		172,499,814	$23,287.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$16,789.0
Base Tax (25%*PTV)			$4,197.2
Production Tax Value per barrel	$97.33		
Progressive Tax = (25.5% * PTV)			$4,278.3
Total Tax before credits			$8,475.5
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($430.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$8,000.5**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$7,625.5**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $140 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$140.00	555,227	$77.7
Annual Production (bbl)			
Total		202,657,895	$28,372.1
Royalty, Federal and other barrels[1]		-30,158,081	($4,222.1)
Taxable barrels [2]		172,499,814	$24,150.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$17,651.5
Base Tax (25%*PTV)			$4,412.9
Production Tax Value per barrel	$102.33		
Progressive Tax = (26% * PTV)			$4,586.3
Total Tax before credits			$8,999.2
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$8,524.2**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$8,149.2**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $145 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$145.00	555,227	$80.5
Annual Production (bbl)			
Total		202,657,895	$29,385.4
Royalty, Federal and other barrels[1]		-30,158,081	($4,372.9)
Taxable barrels [2]		172,499,814	$25,012.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$18,514.0
Base Tax (25%*PTV)			$4,628.5
Production Tax Value per barrel	$107.33		
Progressive Tax = (26.5% * PTV)			$4,903.0
Total Tax before credits			$9,531.5
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$9,056.5**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$8,681.5**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $150 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$150.00	555,227	$83.3
Annual Production (bbl)			
Total		202,657,895	$30,398.7
Royalty, Federal and other barrels[1]		-30,158,081	($4,523.7)
Taxable barrels [2]		172,499,814	$25,875.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$19,376.5
Base Tax (25%*PTV)			$4,844.1
Production Tax Value per barrel	$112.33		
Progressive Tax = (27% * PTV)			$5,228.3
Total Tax before credits			$10,072.4
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$9,597.4**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$9,222.4**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $155 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$155.00	555,227	$86.1
Annual Production (bbl)			
Total		202,657,895	$31,412.0
Royalty, Federal and other barrels[1]		-30,158,081	($4,674.5)
Taxable barrels [2]		172,499,814	$26,737.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$20,239.0
Base Tax (25%*PTV)			$5,059.7
Production Tax Value per barrel	$117.33		
Progressive Tax = (27.5% * PTV)			$5,562.2
Total Tax before credits			$10,622.0
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$10,147.0**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$9,772.0**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $160 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$160.00	555,227	$88.8
Annual Production (bbl)			
Total		202,657,895	$32,425.3
Royalty, Federal and other barrels[1]		-30,158,081	($4,825.3)
Taxable barrels [2]		172,499,814	$27,600.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$21,101.5
Base Tax (25%*PTV)			$5,275.4
Production Tax Value per barrel	$122.33		
Progressive Tax = (28% * PTV)			$5,904.8
Total Tax before credits			$11,180.1
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$10,705.1**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$10,330.1**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $165 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$165.00	555,227	$91.6
Annual Production (bbl)			
Total		202,657,895	$33,438.6
Royalty, Federal and other barrels[1]		-30,158,081	($4,976.1)
Taxable barrels [2]		172,499,814	$28,462.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$21,964.0
Base Tax (25%*PTV)			$5,491.0
Production Tax Value per barrel	$127.33		
Progressive Tax = (28.5% * PTV)			$6,255.9
Total Tax before credits			$11,746.9
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($435.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Total Credits			($475.0)
Estimated Total Tax after credits[4]			$11,271.9
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($2.2)
Capital Expenditures			($407.7)
Total Lease Expenditures not included in Tax Revenue Calculation			($409.9)
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$10,896.9**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $170 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$170.00	555,227	$94.4
Annual Production (bbl)			
Total		202,657,895	$34,451.8
Royalty, Federal and other barrels[1]		-30,158,081	($5,126.9)
Taxable barrels [2]		172,499,814	$29,325.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$22,826.5
Base Tax (25%*PTV)			$5,706.6
Production Tax Value per barrel	$132.33		
Progressive Tax = (29% * PTV)			$6,615.7
Total Tax before credits			$12,322.4
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$11,847.4**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$11,472.4**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $175 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$175.00	555,227	$97.2
Annual Production (bbl)			
Total		202,657,895	$35,465.1
Royalty, Federal and other barrels[1]		-30,158,081	($5,277.7)
Taxable barrels [2]		172,499,814	$30,187.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$23,689.0
Base Tax (25%*PTV)			$5,922.2
Production Tax Value per barrel	$137.33		
Progressive Tax = (29.5% * PTV)			$6,984.2
Total Tax before credits			$12,906.4
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$12,431.4**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$12,056.4**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $180 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$180.00	555,227	$99.9
Annual Production (bbl)			
Total		202,657,895	$36,478.4
Royalty, Federal and other barrels[1]		-30,158,081	($5,428.5)
Taxable barrels [2]		172,499,814	$31,050.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$24,551.5
Base Tax (25%*PTV)			$6,137.9
Production Tax Value per barrel	$142.33		
Progressive Tax = (30% * PTV)			$7,361.2
Total Tax before credits			$13,499.1
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$13,024.1**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$12,649.1**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $185 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$185.00	555,227	$102.7
Annual Production (bbl)			
Total		202,657,895	$37,491.7
Royalty, Federal and other barrels[1]		-30,158,081	($5,579.2)
Taxable barrels [2]		172,499,814	$31,912.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$25,414.0
Base Tax (25%*PTV)			$6,353.5
Production Tax Value per barrel	$147.33		
Progressive Tax = (30.5% * PTV)			$7,746.9
Total Tax before credits			$14,100.4
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$13,625.4**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$13,250.4**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $190 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$190.00	555,227	$105.5
Annual Production (bbl)			
Total		202,657,895	$38,505.0
Royalty, Federal and other barrels[1]		-30,158,081	($5,730.0)
Taxable barrels [2]		172,499,814	$32,775.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$26,276.5
Base Tax (25%*PTV)			$6,569.1
Production Tax Value per barrel	$152.33		
Progressive Tax = (31% * PTV)			$8,141.2
Total Tax before credits			$14,710.3
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$14,235.3**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$13,860.3**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $195 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$195.00	555,227	$108.3
Annual Production (bbl)			
Total		202,657,895	$39,518.3
Royalty, Federal and other barrels[1]		-30,158,081	($5,880.8)
Taxable barrels [2]		172,499,814	$33,637.5
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$27,139.0
Base Tax (25%*PTV)			$6,784.7
Production Tax Value per barrel	$157.33		
Progressive Tax = (31.5% * PTV)			$8,544.1
Total Tax before credits			$15,328.8
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$14,853.8**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$14,478.8**

FY 2013 Production Tax Estimates - Income Statement Format showing ALL Credits using Fall 2011 forecast assumptions with $200 ANS price

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$200.00	555,227	$111.0
Annual Production (bbl)			
Total		202,657,895	$40,531.6
Royalty, Federal and other barrels[1]		-30,158,081	($6,031.6)
Taxable barrels [2]		172,499,814	$34,500.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$28,001.5
Base Tax (25%*PTV)			$7,000.4
Production Tax Value per barrel	$162.33		
Progressive Tax = (32% * PTV)			$8,955.6
Total Tax before credits			$15,956.0
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($440.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Credits			($475.0)
Estimated Total Tax after credits[4]			**$15,481.0**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			**$0.0**
Capital Expenditures			**($370.0)**
Total Lease Expenditures not included in Tax Revenue Calculation			**($370.0)**
Credits to be Refunded [6]			
Qualified Capital Expenditure and NOL Credits (.023)			**($310.0)**
Alternative Credits for Exploration (.025)			**($65.0)**
Total Credits to be Refunded			**($375.0)**
Estimated Tax after refunded credits [7]			**$15,106.0**

ADDENDUM B-1:
FY 2010-FY 2012 Production Tax Estimates - Income Statement Format showing ALL credits Assuming Fall 2010 Forecast assumptions and HB 110/SB 49 tax system

These tables are meant to provide an illustration of the production tax calculation under HB110/SB49 in various years and using various forecast assumptions. Since this is a simplification of the tax calculation, total tax amounts shown here may not exactly match those estimated in other analysis. The following notes apply to all the tables in this addendum:

DOR historical and current revenue models are based on fiscal year data, which is also used for this analysis. To the extent that HB110/SB49 would use calendar year averages for production, price, and costs, the results may differ from that shown in this illustration.

(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) New well lease expenditure credits under HB110/SB49 are shown fully deducted against tax liability for consistency with previously presented information using the Fall 2010 and Spring 2011 forecast assumptions. Beginning with estimates using Fall 2011 forecast assumptions, we include a portion of these credits as taken against tax liability, and a portion as available for refund.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

(5) Lease expenditures not included in Tax Revenue Calculation represents lease expenditures made by companies with little to no tax liability.

(6) Estimated Tax after refunded credits represents the total estimated tax revenue minus the amount of credits refunded, which is paid by appropriation through the Production Tax Credit Fund at AS 43.55.028.

FY 2010 Production Tax Estimates - Income Statement showing ALL Credits using Fall 2010 Forecast Assumptions, HB110/SB49 tax system

	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)			$10,128.2
"Base Tax" (25% of PTV)			$2,532.0
Production Tax Value per barrel	$49.69		
"Progressive Tax" (tax over 25% of PTV)			$173.5
Total Tax before credits			$2,705.5
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($322.0)
Small Producer Credits (.024)			($38.0)
Alternative Credits for Exploration (.025)			$0.0
Additional Well Credits per HB110/SB49 [3]			($300.0)
Credits			($650.0)
Estimated Total Tax after credits[4]			**$2,055.5**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($101.3)
Capital Expenditures			($646.7)
Total Lease Expenditures not included in Tax Revenue Calculation			**($748.0)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($229.2)
Alternative Credits for Exploration (.025)			($21.3)
Total Credits to be Refunded			**($250.5)**
Estimated Tax after refunded credits [6]			**$1,805.0**

FY 2011 Production Tax Estimates - Income Statement showing ALL Credits using Fall 2010 Forecast Assumptions, HB110/SB49 tax system

	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% of PTV)			$2,314.4
Production Tax Value per barrel	$48.54		
"Progressive Tax" (tax over 25% of PTV)			$145.8
Total Tax before credits			$2,460.2
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($370.0)
Small Producer Credits (.024)			($30.0)
Alternative Credits for Exploration (.025)			$0.0
Additional Well Credits per HB110/SB49 [3]			($300.0)
Credits			($700.0)
Estimated Total Tax after credits[4]			**$1,760.2**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($76.0)
Capital Expenditures			($584.0)
Total Lease Expenditures not included in Tax Revenue Calculation			**($660.0)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($418.3)
Alternative Credits for Exploration (.025)			($11.7)
Total Credits to be Refunded			**($430.0)**
Estimated Tax after refunded credits [6]			**$1,330.2**

FY 2012 Production Tax Estimates - Income Statement showing ALL Credits using Fall 2010 Forecast Assumptions, HB110/SB49 tax system

	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% of PTV)			$2,419.0
Production Tax Value per barrel	$50.28		
"Progressive Tax" (tax over 25% of PTV)			$172.2
Total Tax before credits			$2,591.2
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($420.0)
Small Producer Credits (.024)			($30.0)
Alternative Credits for Exploration (.025)			$0.0
Additional Well Credits per HB110/SB49 [3]			($300.0)
Credits			($750.0)
Estimated Total Tax after credits[4]			**$1,841.2**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($84.0)
Capital Expenditures			($408.0)
Total Lease Expenditures not included in Tax Revenue Calculation			**($492.0)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($332.5)
Alternative Credits for Exploration (.025)			($67.5)
Total Credits to be Refunded			($400.0)
Estimated Tax after refunded credits [6]			**$1,441.2**

ADDENDUM B-2:
FY 2010-FY 2012 Production Tax Estimates – Income Statement Format showing ALL Credits Assuming Spring 2011 Forecast assumptions and HB 110 / SB 49 tax system

These tables are meant to provide an illustration of the production tax calculation under HB110/SB49 in various years and using various forecast assumptions. Since this is a simplification of the tax calculation, total tax amounts shown here may not exactly match those estimated in other analysis. The following notes apply to all the tables in this addendum:

DOR historical and current revenue models are based on fiscal year data, which is also used for this analysis. To the extent that HB110/SB49 would use calendar year averages for production, price, and costs, the results may differ from that shown in this illustration.

(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) New well lease expenditure credits under HB110/SB49 are shown fully deducted against tax liability for consistency with previously presented information using the Fall 2010 and Spring 2011 forecast assumptions. Beginning with estimates using Fall 2011 forecast assumptions, we include a portion of these credits as taken against tax liability, and a portion as available for refund.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

(5) Lease expenditures not included in Tax Revenue Calculation represents lease expenditures made by companies with little to no tax liability.

(6) Estimated Tax after refunded credits represents the total estimated tax revenue minus the amount of credits refunded, which is paid by appropriation through the Production Tax Credit Fund at AS 43.55.028.

FY 2010 Production Tax Estimates - Income Statement Format Showing ALL Credits using Spring 2011 Forecast Assumptions, HB110/SB49 tax system

	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)			$10,128.2
"Base Tax" (25% of PTV)			$2,532.0
Production Tax Value per barrel	$49.69		
"Progressive Tax" (tax over 25% of PTV)			$173.5
Total Tax before credits			$2,705.5
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($344.0)
Small Producer Credits (.024)			($36.0)
Alternative Credits for Exploration (.025)			($30.0)
Additional Well Credits per HB110/SB49 [3]			($300.0)
Credits			($700.0)
Estimated Total Tax after credits[4]			**$2,005.5**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($101.3)
Capital Expenditures			($646.7)
Total Lease Expenditures not included in Tax Revenue Calculation			**($748.0)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($229.2)
Alternative Credits for Exploration (.025)			($21.3)
Total Credits to be Refunded			**($250.5)**
Estimated Tax after refunded credits [6]			**$1,755.0**

FY 2011 Production Tax Estimates - Income Statement Format Showing ALL Credits using Spring 2011 Forecast Assumptions, HB110/SB49 tax system

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$91.13	605,328	$55.2
Annual Production (bbl)			
Total		220,944,720	$20,134.7
Royalty, Federal and other barrels[1]		-28,560,520	($2,602.7)
Taxable barrels		192,384,200	$17,532.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.07		
TAPS Tariff	-$4.36		
Other	$0.24		
Total Transportation Costs	-$6.19	192,384,200	($1,190.9)
Deductible Lease Expenditures[2]			
Deductible Operating Expenditures	-$12.94		($2,490.0)
Deductible Capital Expenditures	-$9.88		($1,900.0)
Total Lease Expenditures	-$22.82	192,384,200	($4,390.0)
Production Tax			
Production Tax Value (PTV)			$11,951.1
"Base Tax" (25% of PTV)			$2,987.8
Production Tax Value per barrel	$62.12		
"Progressive Tax" (tax over 25% of PTV)			$411.7
Total Tax before credits			$3,399.4
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($390.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			($20.0)
Additional Well Credits per HB110/SB49 [3]			($300.0)
Credits			($750.0)
Estimated Total Tax after credits[3]			**$2,649.4**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($60.0)
Capital Expenditures			($550.0)
Total Lease Expenditures not included in Tax Revenue Calculation			**($610.0)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($418.3)
Alternative Credits for Exploration (.025)			($11.7)
Total Credits to be Refunded			**($430.0)**
Estimated Tax after refunded credits [6]			**$2,219.4**

FY 2012 Production Tax Estimates - Income Statement Format Showing ALL Credits using Spring 2011 Forecast Assumptions, HB110/SB49 tax system

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$94.70	610,460	$57.8
Annual Production (bbl)			
Total		222,817,900	$21,100.9
Royalty, Federal and other barrels[1]		-28,686,445	($2,716.6)
Taxable barrels		194,131,455	$18,384.2
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.05		
TAPS Tariff	-$4.48		
Other	$0.34		
Total Transportation Costs	-$6.19	194,131,455	($1,201.7)
Deductible Lease Expenditures[2]			
Deductible Operating Expenditures	-$12.81		($2,486.0)
Deductible Capital Expenditures	-$12.33		($2,393.0)
Total Lease Expenditures	-$25.13	194,131,455	($4,879.0)
Production Tax			
Production Tax Value (PTV)			$12,303.6
"Base Tax" (25% of PTV)			$3,075.9
Production Tax Value per barrel	$63.38		
"Progressive Tax" (tax over 25% of PTV)			$446.1
Total Tax before credits			$3,522.0
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($415.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			($10.0)
Additional Well Credits per HB110/SB49 [3]			($300.0)
Credits			($765.0)
Estimated Total Tax after credits[3]			**$2,757.0**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($60.0)
Capital Expenditures			($400.0)
Total Lease Expenditures not included in Tax Revenue Calculation			**($460.0)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($317.5)
Alternative Credits for Exploration (.025)			($67.5)
Total Credits to be Refunded			**($385.0)**
Estimated Tax after refunded credits [6]			**$2,372.0**

ADDENDUM B-3:
FY 2011-FY 2013 Production Tax Estimates – Income Statement Format Assuming Fall 2011 Forecast assumptions and HB 110/SB 49 tax system

These tables are meant to provide an illustration of the production tax calculation under HB110/SB49 in various years and using various forecast assumptions. Since this is a simplification of the tax calculation, total tax amounts shown here may not exactly match those estimated in other analysis. The following notes apply to all the tables in this addendum:

DOR historical and current revenue models are based on fiscal year data, which is also used for this analysis. To the extent that HB110/SB49 would use calendar year averages for production, price, and costs, the results may differ from that shown in this illustration.

(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. For purposes of this calculation, also includes barrels produced by companies with zero PTV.

(2) For purposes of this illustration, to more closely reflect actual tax received by the state, "taxable barrels" shown here exclude barrels produced by companies expected to have zero tax liability.

(3) 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.

(4) For new well lease expenditure credits under HB 110/SB49 we include a portion of these credits as taken against tax liability, and a portion as available for refund.

(5) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

(6) Lease expenditures not included in Tax Revenue Calculation represents lease expenditures made by companies with little to no tax liability.

(7) Estimated Tax after refunded credits represents the total estimated tax revenue minus the amount of credits refunded, which is paid by appropriation through the Production Tax Credit Fund at AS 43.55.028.

FY 2011 Production Tax Estimates - Income Statement Format Showing ALL Credits using Fall 2011 Forecast Assumptions, HB110/SB49 tax system

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$94.49	602,723	$56.9
Annual Production (bbl)			
Total		219,993,895	$20,786.7
Royalty, Federal and other barrels[1]		-29,505,505	($2,787.9)
Taxable barrels [2]		190,488,390	$17,998.8
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.45		
TAPS Tariff	-$4.02		
Other	-$0.70		
Total Transportation Costs	-$7.17	190,488,390	($1,365.8)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.22		($2,517.4)
Deductible Capital Expenditures	-$8.52		($1,622.9)
Total Lease Expenditures	-$21.74	190,488,390	($4,140.3)
Production Tax			
Production Tax Value (PTV)			$12,492.6
"Base Tax" (25% of PTV)			$3,123.2
Production Tax Value per barrel	$65.58		
"Progressive Tax" (tax over 25% of PTV)			$489.9
Total Tax before credits			$3,613.1
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			
Small Producer Credits (.024)			
Alternative Credits for Exploration (.025)			
Additional Well Credits per HB110/SB49 [4]			($150.0)
Credits			($550.0)
Estimated Total Tax after credits[5]			**$3,063.1**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($96.6)
Capital Expenditures			($694.1)
Total Lease Expenditures not included in Tax Revenue Calculation			**($790.7)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			
Alternative Credits for Exploration (.025)			
Additional Well Credits per HB110/SB49			
Total Credits to be Refunded			**($450.0)**
Estimated Tax after refunded credits [6]			**$2,613.1**

FY 2012 Production Tax Estimates - Income Statement Format Showing ALL Credits using Fall 2011 Forecast Assumptions, HB110/SB49 tax system

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$108.98	574,373	$62.6
Annual Production (bbl)			
Total		209,646,327	$22,848.2
Royalty, Federal and other barrels[1]		-33,702,389	($3,673.0)
Taxable barrels [2]		175,943,938	$19,175.1
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	175,943,938	($1,534.6)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$14.03		($2,468.1)
Deductible Capital Expenditures	-$10.25		($1,804.0)
Total Lease Expenditures	-$24.28	175,943,938	($4,272.1)
Production Tax			
Production Tax Value (PTV)			$13,368.5
"Base Tax" (25% of PTV)			$3,342.1
Production Tax Value per barrel	$75.98		
"Progressive Tax" (tax over 25% of PTV)			$755.9
Total Tax before credits			$4,098.0
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($355.0)
Small Producer Credits (.024)			($45.0)
Alternative Credits for Exploration (.025)			$0.0
Additional Well Credits per HB110/SB49 [4]			($150.0)
Credits			($550.0)
Estimated Total Tax after credits[4]			**$3,548.0**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($111.3)
Capital Expenditures			($938.7)
Total Lease Expenditures not included in Tax Revenue Calculation			**($1,050.0)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($245.0)
Alternative Credits for Exploration (.025)			($80.0)
Additional Well Credits per HB110/SB49			($100.0)
Total Credits to be Refunded			($325.0)
Estimated Tax after refunded credits [6]			**$3,223.0**

FY 2013 Production Tax Estimates - Income Statement Format Showing ALL Credits using Fall 2011 Forecast Assumptions, HB110/SB49 tax system

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$109.47	555,227	$60.8
Annual Production (bbl)			
Total		202,657,895	$22,185.1
Royalty, Federal and other barrels[1]		-30,158,081	($3,301.4)
Taxable barrels [2]		172,499,814	$18,883.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.70		
TAPS Tariff	-$4.96		
Other	-$0.91		
Total Transportation Costs	-$8.56	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$13.75		($2,372.5)
Deductible Capital Expenditures	-$15.36		($2,648.9)
Total Lease Expenditures	-$29.11	172,499,814	($5,021.5)
Production Tax			
Production Tax Value (PTV)			$12,385.2
"Base Tax" (25% of PTV)			$3,096.3
Production Tax Value per barrel	$71.80		
"Progressive Tax" (tax over 25% of PTV)			$615.0
Total Tax before credits			$3,711.3
Credits against Tax Liability			
Qualified Capital Expenditure Credits (.023)			($410.0)
Small Producer Credits (.024)			($40.0)
Alternative Credits for Exploration (.025)			$0.0
Additional Well Credits per HB110/SB49 [4]			($225.0)
Credits			($675.0)
Estimated Total Tax after credits[4]			**$3,036.3**
Lease Expenditures not included in Tax Revenue Calculation [5]			
Operating Expenditures			($2.2)
Capital Expenditures			($407.7)
Total Lease Expenditures not included in Tax Revenue Calculation			**($409.9)**
Credits to be Refunded			
Qualified Capital Expenditure and NOL Credits (.023)			($335.0)
Alternative Credits for Exploration (.025)			($65.0)
Additional Well Credits per HB110/SB49			($50.0)
Total Credits to be Refunded			**($450.0)**
Estimated Tax after refunded credits [6]			**$2,586.3**

ADDENDUM C-1:

FY 2012 Production Tax Estimates – Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions

These tables are meant to provide an illustration of the production tax calculation under current law in FY 12, for a hypothetical producer with 250,000 barrels per day of unconventional oil production, using a specific set of assumptions. This is a hypothetical only prepared by request. The following notes apply to all the tables in this addendum:

(1) This analysis illustrates the tax calculation for a hypothetical producer for a single year with the following characteristics: 250,000 barrels per day production from state land, 15% quality discount, $22.33 / barrel capex, $20 / barrel opex. No company-specific modeling is included. Importantly, this illustration assumes an operation in full production with the stated costs and does not consider the development phase when large expenditures are made without corresponding production.

(2) For purposes of this illustration, this number reflects a 12.5% royalty only.

(3) For purposes of this illustration, deductible lease expenditures are assumed to be $22.33 / barrel (for all barrels) for capital expenditures and $20 / barrel (for all barrels) for operating expenditures. The per-barrel expenditures shown here reflect expenditures per taxable barrel, for consistency with other income statement presentation, and do not reflect expenditures per all barrels produced.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

(5) At lower prices, credits not applied against tax liability could be carried forward or sold but would not be eligible for refund for a producer with 250,000 barrels per day of production.

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$50.00	250,000	$10.6
Annual Production (bbl)			
Total		91,250,000	$3,878.1
Royalty barrels[2]		-11,406,250	($484.8)
Taxable barrels		79,843,750	$3,393.4
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$0.0
Base Tax (25%*PTV)			$0.0
Production Tax Value per barrel	$0.00		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$0.0
Credits			$0.0
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($407.5)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$55.00	250,000	$11.7
Annual Production (bbl)			
Total		91,250,000	$4,265.9
Royalty barrels[2]		-11,406,250	($533.2)
Taxable barrels		79,843,750	$3,732.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$0.0
Base Tax (25%*PTV)			$0.0
Production Tax Value per barrel	$0.00		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$0.0
Credits			$0.0
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($407.5)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$60.00	250,000	$12.8
Annual Production (bbl)			
Total		91,250,000	$4,653.8
Royalty barrels[2]		-11,406,250	($581.7)
Taxable barrels		79,843,750	$4,072.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$0.0
Base Tax (25%*PTV)			$0.0
Production Tax Value per barrel	$0.00		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$0.0
Credits			$0.0
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($407.5)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$65.00	250,000	$13.8
Annual Production (bbl)			
Total		91,250,000	$5,041.6
Royalty barrels[2]		-11,406,250	($630.2)
Taxable barrels		79,843,750	$4,411.4
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$0.0
Base Tax (25%*PTV)			$0.0
Production Tax Value per barrel	$0.00		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$0.0
Credits			$0.0
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($407.5)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$70.00	250,000	$14.9
Annual Production (bbl)			
Total		91,250,000	$5,429.4
Royalty barrels[2]		-11,406,250	($678.7)
Taxable barrels		79,843,750	$4,750.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$191.7
Base Tax (25%*PTV)			$47.9
Production Tax Value per barrel	$2.40		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$47.9
Credits			($47.9)
Estimated Totai Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($359.6)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$75.00	250,000	$15.9
Annual Production (bbl)			
Total		91,250,000	$5,817.2
Royalty barrels[2]		-11,406,250	($727.1)
Taxable barrels		79,843,750	$5,090.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$531.0
Base Tax (25%*PTV)			$132.8
Production Tax Value per barrel	$6.65		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$132.8
Credits			($132.8)
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($274.8)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$80.00	250,000	$17.0
Annual Production (bbl)			
Total		91,250,000	$6,205.0
Royalty barrels[2]		-11,406,250	($775.6)
Taxable barrels		79,843,750	$5,429.4
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$870.4
Base Tax (25%*PTV)			$217.6
Production Tax Value per barrel	$10.90		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$217.6
Credits			($217.6)
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($189.9)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$85.00	250,000	$18.1
Annual Production (bbl)			
Total		91,250,000	$6,592.8
Royalty barrels[2]		-11,406,250	($824.1)
Taxable barrels		79,843,750	$5,768.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$1,209.7
Base Tax (25%*PTV)			$302.4
Production Tax Value per barrel	$15.15		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$302.4
Credits			($302.4)
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($105.1)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$90.00	250,000	$19.1
Annual Production (bbl)			
Total		91,250,000	$6,980.6
Royalty barrels[2]		-11,406,250	($872.6)
Taxable barrels		79,843,750	$6,108.0
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$1,549.0
Base Tax (25%*PTV)			$387.3
Production Tax Value per barrel	$19.40		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$387.3
Credits			($387.3)
Estimated Total Tax after credits[4]			**$0.0**
Credits Carried Forward [5]			**($20.3)**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$95.00	250,000	$20.2
Annual Production (bbl)			
Total		91,250,000	$7,368.4
Royalty barrels[2]		-11,406,250	($921.1)
Taxable barrels		79,843,750	$6,447.4
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$1,888.4
Base Tax (25%*PTV)			$472.1
Production Tax Value per barrel	$23.65		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$472.1
Credits			($407.5)
Estimated Total Tax after credits[4]			**$64.6**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$100.00	250,000	$21.3
Annual Production (bbl)			
Total		91,250,000	$7,756.3
Royalty barrels[2]		-11,406,250	($969.5)
Taxable barrels		79,843,750	$6,786.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$2,227.7
Base Tax (25%*PTV)			$556.9
Production Tax Value per barrel	$27.90		
Progressive Tax = (0% * PTV)			$0.0
Total Tax before credits			$556.9
Credits			($407.5)
Estimated Total Tax after credits[4]			**$149.4**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$105.00	250,000	$22.3
Annual Production (bbl)			
Total		91,250,000	$8,144.1
Royalty barrels[2]		-11,406,250	($1,018.0)
Taxable barrels		79,843,750	$7,126.1
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$2,567.1
Base Tax (25%*PTV)			$641.8
Production Tax Value per barrel	$32.15		
Progressive Tax = (0.9% * PTV)			$22.1
Total Tax before credits			$663.9
Credits			($407.5)
Estimated Total Tax after credits[4]			**$256.3**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$110.00	250,000	$23.4
Annual Production (bbl)			
Total		91,250,000	$8,531.9
Royalty barrels[2]		-11,406,250	($1,066.5)
Taxable barrels		79,843,750	$7,465.4
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$2,906.4
Base Tax (25%*PTV)			$726.6
Production Tax Value per barrel	$36.40		
Progressive Tax = (2.6% * PTV)			$74.4
Total Tax before credits			$801.0
Credits			($407.5)
Estimated Total Tax after credits[4]			**$393.5**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$115.00	250,000	$24.4
Annual Production (bbl)			
Total		91,250,000	$8,919.7
Royalty barrels[2]		-11,406,250	($1,115.0)
Taxable barrels		79,843,750	$7,804.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$3,245.7
Base Tax (25%*PTV)			$811.4
Production Tax Value per barrel	$40.65		
Progressive Tax = (4.3% * PTV)			$138.3
Total Tax before credits			$949.7
Credits			($407.5)
Estimated Total Tax after credits[4]			**$542.2**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$120.00	250,000	$25.5
Annual Production (bbl)			
Total		91,250,000	$9,307.5
Royalty barrels[2]		-11,406,250	($1,163.4)
Taxable barrels		79,843,750	$8,144.1
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$3,585.1
Base Tax (25%*PTV)			$896.3
Production Tax Value per barrel	$44.90		
Progressive Tax = (6% * PTV)			$213.7
Total Tax before credits			$1,109.9
Credits			($407.5)
Estimated Totai Tax after credits[4]			**$702.4**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$125.00	250,000	$26.6
Annual Production (bbl)			
Total		91,250,000	$9,695.3
Royalty barrels[2]		-11,406,250	($1,211.9)
Taxable barrels		79,843,750	$8,483.4
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$3,924.4
Base Tax (25%*PTV)			$981.1
Production Tax Value per barrel	$49.15		
Progressive Tax = (7.7% * PTV)			$300.6
Total Tax before credits			$1,281.7
Credits			($407.5)
Estimated Total Tax after credits[4]			**$874.2**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$130.00	250,000	$27.6
Annual Production (bbl)			
Total		91,250,000	$10,083.1
Royalty barrels[2]		-11,406,250	($1,260.4)
Taxable barrels		79,843,750	$8,822.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$4,263.7
Base Tax (25%*PTV)			$1,065.9
Production Tax Value per barrel	$53.40		
Progressive Tax = (9.4% * PTV)			$399.1
Total Tax before credits			$1,465.0
Credits			($407.5)
Estimated Totai Tax after credits[4]			**$1,057.5**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$135.00	250,000	$28.7
Annual Production (bbl)			
Total		91,250,000	$10,470.9
Royalty barrels[2]		-11,406,250	($1,308.9)
Taxable barrels		79,843,750	$9,162.1
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$4,603.1
Base Tax (25%*PTV)			$1,150.8
Production Tax Value per barrel	$57.65		
Progressive Tax = (11.1% * PTV)			$509.1
Total Tax before credits			$1,659.9
Credits			($407.5)
Estimated Total Tax after credits[4]			**$1,252.4**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$140.00	250,000	$29.8
Annual Production (bbl)			
Total		91,250,000	$10,858.8
Royalty barrels[2]		-11,406,250	($1,357.3)
Taxable barrels		79,843,750	$9,501.4
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$4,942.4
Base Tax (25%*PTV)			$1,235.6
Production Tax Value per barrel	$61.90		
Progressive Tax = (12.8% * PTV)			$630.7
Total Tax before credits			$1,866.3
Credits			($407.5)
Estimated Total Tax after credits[4]			**$1,458.7**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$145.00	250,000	$30.8
Annual Production (bbl)			
Total		91,250,000	$11,246.6
Royalty barrels[2]		-11,406,250	($1,405.8)
Taxable barrels		79,843,750	$9,840.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$5,281.7
Base Tax (25%*PTV)			$1,320.4
Production Tax Value per barrel	$66.15		
Progressive Tax = (14.5% * PTV)			$763.8
Total Tax before credits			$2,084.2
Credits			($407.5)
Estimated Total Tax after credits[4]			**$1,676.7**
Credits Carried Forward [5]			**$0.0**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 250,000 barrels per day of "Unconventional Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$150.00	250,000	$31.9
Annual Production (bbl)			
Total		91,250,000	$11,634.4
Royalty barrels[2]		-11,406,250	($1,454.3)
Taxable barrels		79,843,750	$10,180.1
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	79,843,750	($696.4)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$22.86		($1,825.0)
Deductible Capital Expenditures	-$25.52		($2,037.6)
Total Lease Expenditures	-$48.38	79,843,750	($3,862.6)
Production Tax			
Production Tax Value (PTV)			$5,621.1
Base Tax (25%*PTV)			$1,405.3
Production Tax Value per barrel	$70.40		
Progressive Tax = (16.2% * PTV)			$908.4
Total Tax before credits			$2,313.7
Credits			($407.5)
Estimated Total Tax after credits[4]			**$1,906.1**
Credits Carried Forward [5]			**$0.0**

ADDENDUM C-2:

FY 2012 Production Tax Estimates – Income Statement Format for illustration of 250,000 barrels per day of "Heavy Oil" using provided assumptions, PLUS existing FY 2012 forecast

This table is meant to provide an illustration of the production tax calculation under current law in FY 12, assuming our Fall 2011 forecast assumptions for FY 12, PLUS 250,000 barrels per day of unconventional oil production, using a specific set of assumptions. This is a hypothetical only prepared by request. The following notes apply to this addendum:

(1) This analysis takes the FY12 income statement from the Fall 2011 RSB and adds and illustration for additional production with the following characteristics: 250,000 barrels per day production from state land, 15% quality discount, $22.33 / barrel capex, $20 / barrel opex. No company-specific modeling is included. Importantly, this illustration assumes an operation in full production with the stated costs and does not consider the development phase when large expenditures are made without corresponding production.

(2) 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. For purposes of this calculation, also includes barrels produced by companies with negative PTV. For the additional production illustration, assumes a 12.5% royalty rate only.

(3) 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. For the additional production, deductible lease expenditures are assumed to be $22.33 / barrel (for all barrels) for capital expenditures and $20 / barrel (for all barrels) for operating expenditures. The per-barrel expenditures shown here reflect expenditures per taxable barrel, for consistency with other income statement presentation, and do not reflect expenditures per all barrels produced.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. 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 - Income Statement Format using Fall 2011 forecast assumptions, PLUS 250,000 barrels per day of "Heavy Oil" using provided assumptions[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$108.98	824,373	$85.7
Annual Production (bbl)			
Total		300,896,327	$31,294.0
Royalty, Federal and other barrels[2]		-45,108,639	($4,728.8)
Taxable barrels[3]		255,787,688	$26,565.2
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other	-$0.85		
Total Transportation Costs	-$8.72	255,787,688	($2,231.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	-$16.78		($4,293.1)
Deductible Capital Expenditures	-$15.02		($3,841.6)
Total Lease Expenditures	-$31.80	255,787,688	($8,134.7)
Production Tax			
Production Tax Value (PTV)			$16,199.5
Base Tax (25%*PTV)			$4,049.9
Production Tax Value per barrel	$63.33		
Progressive Tax = (13.3% * PTV)			$2,159.8
Total Tax before credits			$6,209.7
Total Credits			($807.5)
Estimated Total Tax after credits[4]			**$5,402.2**

ADDENDUM D:

FY 2012 Production Tax Estimates – Income Statement Format for illustration of 100,000 barrels per day of "NPRA Development" under HB110/SB49

These tables are meant to provide an illustration of the production tax calculation under HB110/SB49 in FY 12, for a hypothetical producer with 100,000 barrels per day of NPRA oil production, assuming HB110 / SB49 were in full effect and the development received the 15 percent new fields base rate. The tables are produced at several prices: our FY 12 forecast price, $75, $100, and $125. This is a hypothetical only prepared by request. The following notes apply to all the tables in this addendum:

(1) This analysis illustrates the tax calculation for a hypothetical producer for a single year with the following characteristics: 100,000 barrels per day production from NPRA, $10 / barrel capex, $15 / barrel opex. No company-specific modeling is included. **Importantly, this illustration assumes an operation in full production with the stated costs and does not consider the development phase when large expenditures are made without corresponding production.**

(2) For purposes of this illustration, this number reflects a 12.5% royalty only.

(3) For purposes of this illustration, adds $2 / barrel to Fall 2011 forecast amounts to account for potential feeder pipeline costs.

(4) Deductible lease expenditures are assumed to be $10 / barrel (for all barrels) for capital expenditures and $15 / barrel (for all barrels) for operating expenditures. The per-barrel expenditures shown here reflect expenditures per taxable barrel, for consistency with other income statement presentation, and do not reflect expenditures per all barrels produced.

(5) For illustration purposes, assumes that all provisions of HB 110 / SB 49 are in place and that the development would qualify for the 15 percent new field base rate.

(6) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. 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 - Income Statement Format for illustration of 100,000 barrels per day of "NPRA oil" under HB 110/SB49[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$108.89	100,000	$10.9
Annual Production (bbl)			
Total		36,500,000	$3,974.5
Royalty barrels[2]		-4,562,500	($496.8)
Taxable barrels		31,937,500	$3,477.7
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other[3]	-$2.85		
Total Transportation Costs	-$10.72	31,937,500	($342.4)
Deductible Lease Expenditures[4]			
Deductible Operating Expenditures	-$17.14		($547.5)
Deductible Capital Expenditures	-$11.43		($365.0)
Total Lease Expenditures	-$28.57	31,937,500	($912.5)
Production Tax[5]			
Production Tax Value (PTV)			$2,222.7
"Base Tax" (15% of PTV)			$333.4
Production Tax Value per barrel	$69.60		
"Progressive Tax" (tax over 15% of PTV)			$101.6
Total Tax before credits			$435.0
Credits (including additional well credits)			($104.4)
Estimated Total Tax after credits[6]			**$330.6**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 100,000 barrels per day of "NPRA oil" under HB 110/SB49[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$75.00	100,000	$7.5
Annual Production (bbl)			
Total		36,500,000	$2,737.5
Royalty barrels[2]		-4,562,500	($342.2)
Taxable barrels		31,937,500	$2,395.3
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other[3]	-$2.85		
Total Transportation Costs	-$10.72	31,937,500	($342.4)
Deductible Lease Expenditures[4]			
Deductible Operating Expenditures	-$17.14		($547.5)
Deductible Capital Expenditures	-$11.43		($365.0)
Total Lease Expenditures	-$28.57	31,937,500	($912.5)
Production Tax[5]			
Production Tax Value (PTV)			$1,140.4
"Base Tax" (15% of PTV)			$171.1
Production Tax Value per barrel	$35.71		
"Progressive Tax" (tax over 15% of PTV)			$4.6
Total Tax before credits			$175.6
Credits (including additional well credits)			($104.4)
Estimated Total Tax after credits[6]			**$71.2**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 100,000 barrels per day of "NPRA oil" under HB 110/SB49[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$100.00	100,000	$10.0
Annual Production (bbl)			
Total		36,500,000	$3,650.0
Royalty barrels[2]		-4,562,500	($456.3)
Taxable barrels		31,937,500	$3,193.8
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other[3]	-$2.85		
Total Transportation Costs	-$10.72	31,937,500	($342.4)
Deductible Lease Expenditures[4]			
Deductible Operating Expenditures	-$17.14		($547.5)
Deductible Capital Expenditures	-$11.43		($365.0)
Total Lease Expenditures	-$28.57	31,937,500	($912.5)
Production Tax[5]			
Production Tax Value (PTV)			$1,938.8
"Base Tax" (15% of PTV)			$290.8
Production Tax Value per barrel	$60.71		
"Progressive Tax" (tax over 15% of PTV)			$62.7
Total Tax before credits			$353.6
Credits (including additional well credits)			($104.4)
Estimated Total Tax after credits[6]			**$249.2**

FY 2012 Production Tax Estimates - Income Statement Format for illustration of 100,000 barrels per day of "NPRA oil" under HB 110/SB49[1]

	Price	Barrels	Value ($M)
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$125.00	100,000	$12.5
Annual Production (bbl)			
Total		36,500,000	$4,562.5
Royalty barrels[2]		-4,562,500	($570.3)
Taxable barrels		31,937,500	$3,992.2
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$2.71		
TAPS Tariff	-$5.16		
Other[3]	-$2.85		
Total Transportation Costs	-$10.72	31,937,500	($342.4)
Deductible Lease Expenditures[4]			
Deductible Operating Expenditures	-$17.14		($547.5)
Deductible Capital Expenditures	-$11.43		($365.0)
Total Lease Expenditures	-$28.57	31,937,500	($912.5)
Production Tax[5]			
Production Tax Value (PTV)			$2,737.3
"Base Tax" (15% of PTV)			$410.6
Production Tax Value per barrel	$85.71		
"Progressive Tax" (tax over 15% of PTV)			$200.7
Total Tax before credits			$611.3
Credits (including additional well credits)			($104.4)
Estimated Total Tax after credits[6]			**$506.9**

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
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The Honorable Joe Paskvan
Alaska State Senator
State Capitol, Room115
Juneau, Alaska 99801

December 21, 2011

Dear Senator Paskvan,

Thank you for your detailed and thoughtful lists of questions submitted to the Department of Revenue in May and September of this year. As previously discussed, we have been working on the answers to your questions during the interim and are providing them now, as a single package, in advance of the 2012 legislative session. It was very important for me to use the most up-to-date information available and the Fall 2011 Revenue Sources Book (RSB) is what we are using to answer your questions. At the same time as we were preparing the RSB over the past several months, we were also undertaking several other projects that will provide even more information. This will also no doubt lead to good discussions this session.

The analysis contained herein involved the work of numerous individuals on the Department of Revenue team and required large time commitments and custom model runs with significant manual analysis required. Staff were directed to make your request a top priority after completing the Fall 2011 revenue forecast and they should be commended for the time and effort put into this request.

Please don't hesitate to contact me with any additional information requests. We look forward to a constructive and meaningful discussion with you about how to best achieve our mutual goal of increasing oil and gas production in Alaska and incentivizing company investment in exciting and challenging new resources that hold the potential to mitigate the production decline.

Sincerely,

Bryan Butcher
Commissioner

State of Alaska

Department of Revenue

Commissioner's Office

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November 13, 2009

The Honorable Edward S. Itta
Mayor, North Slope Borough
P.O. Box 69
Barrow, AK 99723

Dear Mayor Itta,

The Department of Revenue has over the years benefited from the assessment assistance provided by the North Slope Borough (NSB) under a Memorandum of Understanding (MOU) authorized under AS 43.56.060(g). Since the MOU's most recent revision in 2006, the Department has undergone a series of internal initiatives to strengthen the protection of taxpayer confidential information. We do not believe the current MOU is consistent with these internal standards. Therefore, please consider this notification that the Department is withdrawing from the agreement effective 30 days from the date of this letter as required in section seven of the MOU.

In light of the recent staff retirements within the NSB, which has left the NSB Audit Group without staff, the Department will now resume performing the appraisal functions that had been previously performed by the NSB under the MOU. As a result, we do not anticipate any negative impacts to the NSB or the state from the termination of the current MOU. Should the opportunity arise in the future to again work together under AS 43.56.060(g), we remain open to developing a new MOU with the NSB consistent with the Department's confidentiality requirements.

In accordance with paragraph 4 of the MOU, please have all AS 43.56 hard copy files stored at the NSB returned to the Department. Likewise, all electronic AS 43.56 files should be copied onto a disk and returned to the Department and subsequently deleted from all NSB computers and servers.

To avoid any confusion regarding the exchange of confidential taxpayer information, the Department will notify AS 43.56 taxpayers that the Department and NSB are no longer exchanging information pursuant to an MOU relating to AS 43.56 assessment matters.

We thank you for the excellent working relationship we have enjoyed with the NSB property assessment staff over the years.

Sincerely,

Marcia Davis

Marcia Davis, Deputy Commissioner

Cc: Randy Hoffbeck, Director, Administration & Financ
Bessie O'Rouke, NSB Attorney
Bonnie Harris, Asst. Attorney General

Sen. Joe Paskvan

From: Tangeman, Bruce E (DOR) <bruce.tangeman@alaska.gov>
Sent: Tuesday, May 03, 2011 4:34 PM
To: Sen. Joe Paskvan
Subject: RE: Questions / May 3, 2011

Follow Up Flag: Follow up
Flag Status: Flagged

Good Afternoon Senator,

I have received the below request as well as the request dated 5/2/11 3:57pm (CORRECTED version). I have been and will continue to pass along your appreciation to the folks in my department who have worked so hard on your requests. I am fortunate to be working with such a terrific group of people.

As you may or may not be aware, we are a fairly lean shop when it comes to this type of detailed economic analysis and back in January I requested of them to "drop everything else & all hands on deck" during the regular 90 day session in order to turn requests around as fast as possible. We've got some folks on vacation and those that are here are catching up on their other day-to-day duties that were "neglected" during the 90 day session.

That being said, we will absolutely get to work on your very detailed requests from 5/2 and 5/3 however I cannot guarantee a turnaround time on these. It may take several weeks but we will keep you posted as to their progress.

Thanks and we'll talk soon.

Bruce Tangeman
Deputy Commissioner
Department of Revenue
(907) 269-0721

From: Sen. Joe Paskvan [mailto:Senator_Joe_Paskvan@legis.state.ak.us]
Sent: Tuesday, May 03, 2011 4:09 PM
To: Tangeman, Bruce E (DOR)
Subject: Questions / May 3, 2011

Hello Bruce,

I very much appreciate the assistance that you and the Department have been providing. Please extend my gratitude to all of your team members.

I have been thinking about the numbers that you sent me on Sunday and, respectfully, would like to submit more questions for you to analyze.

Using the FY12 Production Tax Estimates showing all credits (from the charts transmitted May 1) and also using the Spring 2011 forecast, I request a number of charts be prepared as to prices of $40, $50, $75, $80, $100, $110 to $175 in $5.00 increasing incremental pricing, and $200 per barrel. The chart that I have already been provided shows the calculations based upon a $94.70 price per barrel. The current depicted transportation costs, total lease expenditures, credits against tax liability and credits to be refunded should be held constant in this new analysis. This, I believe, will

change the amount of royalty and production tax value which will then result in a change of the total tax before credits, the estimated tax after credits and the estimated tax after refund amounts. The range of prices will depict the application of the base rate and various levels of progressivity, including the transition beyond $92.50 PTV. (Generally, I am interested in receiving the numbers that apply pursuant to the spectrum of pricing under AS 43.55.011(g), (g)(1) and (g)(2)). Please let me know if this request has been framed in an acceptable manner in order to receive charts at the various pricing levels. Please let me know if you have any questions.

I also request that the 6 charts – FY2010, FY2011 and FY2012 under both the Fall 10 and Spring 11 forecasts provided to me on May 1st – be recalculated assuming HB110/SB49 were applicable for the years 2010, 2011 and 2012. Based upon that assumption, what effect would the tax change have upon the 1) total tax before credits, 2) estimated tax after credits and 3) estimated tax after refund for each of those years. In other words, all values within the charts should remain constant except for the tax rate.

I am also interested in the types of financial information that you can share which might better show the production tax impact upon existing operators with production as compared to operators without production. In particular, I am interested in any internal method for analyzing the production tax impact upon various types of central North Slope operators. Can the 6 charts be adjusted to reflect various types of operators and if so can this adjustment extend to the impact at a spectrum of crude prices?

I also request that, as to the unconventional oil such as heavy oil, a FY2012 Production Tax forecast be prepared solely as to the unconventional oil and assuming 250,000 barrels per day and also assuming a $10/barrel increase in capital expenditure over the current $12.33 rate. The other downstream costs and deductible lease expenditure rates should remain the same. Royalty would, of course, be appropriately adjusted based upon the volume. I request that the individual charts span the range in prices based upon this assumption from $50/ barrel to $150/barrel, in $5/barrel increments.

Lastly, I request that charts at various prices be prepared based upon the assumption above as to heavy oil, as an unconventional oil, and its injection or its blending with 2012 conventional oil throughput. This separate set of charts would combine the 610,460 barrels per day conventional oil, under the FY2012 Production Tax Estimates showing All Credits and using the Spring 2011 forecast assumptions, and the 250,000 barrels per day of heavy oil for tax purposes. If the difference between the quality price differential of the heavy oil can be estimated as compared to the conventional oil pricing, please reflect that price difference in the chart.

Again, I very much appreciate your efforts. Please let me know if you have any questions or comments.

Sincerely,

Joe

Sen. Joe Paskvan

From: Tangeman, Bruce E (DOR) <bruce.tangeman@alaska.gov>
Sent: Tuesday, May 17, 2011 10:10 AM
To: Sen. Joe Paskvan
Cc: Butcher, Bryan D (DOR); Jeff Stepp
Subject: Response times for your questions

Follow Up Flag: Follow up
Flag Status: Flagged

Good Morning Senator,

I wanted to respond to your many questions we have received over the past few weeks. As I stated in my May 3rd response, the Petroleum Economic Analysis group within the Tax Division is a fairly lean shop. This group did a tremendous amount of work during session responding to hundreds of questions we received from both House and Senate committees. At my direction, I requested that they make these responses their #1 priority in order to educate the legislature on one of the Governor's highest priorities - HB110/SB49.

However now that session has come to an end these folks need to catch up with their other priorities that face the Department of Revenue and the State of Alaska such as continuing the audit process and the continued revamping of regulations. We are also in the process of filling several high level positions, including the Director of the Tax Division, Commercial Analysts, and Audit Master that could eventually help address questions such as yours. However at this time I do not have someone I can dedicate solely to addressing these questions and therefore I cannot promise when we will be able to get back to you with responses. Once we are fully staffed I should have a better feel for how we can fully engage our staff to address both the day-to-day business of the State and special requests such as your questions.

Until then, I believe you have some very knowledgeable resources at your disposal such as Legislative Research, Legislative Finance, and the various consultants LB&A has under contract that should be able to address most of your questions.

That being said, HB110/SB49 will continue to be a high priority for the State and I fully expect to continue working closely, as we did all session, with you and your staff during the interim.

Thanks for your time and I look forward to chatting with you soon.

Bruce Tangeman
Deputy Commissioner
Department of Revenue
(907) 269-0721

Sen. Joe Paskvan

From: Tangeman, Bruce E (DOR) <bruce.tangeman@alaska.gov>
Sent: Wednesday, December 14, 2011 5:12 PM
To: Sen. Joe Paskvan
Cc: Jeff Stepp; Butcher, Bryan D (DOR); Brakes, Heather K (GOV)
Subject: Questions Update

Good Afternoon Senator Paskvan,

I wanted to give you a brief update on your questions you have forwarded to DOR. I can appreciate the fact that you may not have received responses as quickly as you would have hoped, but we have put the RSB to bed and are finishing up your responses and should have them for you by late next week and well in advance of session kick-off.

It was very important for me to use the most up-to-date information available and the Fall 2011 Revenue Sources Book (RSB) is what we are using to answer your questions. At the same time as we were neck deep in the RSB compilation we were also undertaking several other projects that will provide even more information. This will also no doubt lead to good discussions this session.

As was done last year, I will be instructing my Tax Division staff to be ready to go DAY ONE of session and that all other issues are to fall in line behind answering questions and providing information. This system certainly lead to a backlog for my staff in their day-to-day duties that required catch-up duty once session was over but I think it was well worth it. As a side note, I'd like to pass along that they certainly appreciated the kind public words you used in describing the service we provided you and your staff with quick responses and always being available last session. You will see the same service this coming session.

Thanks again for your patience Joe and I look forward to working with you this session.

Bruce Tangeman
Deputy Commissioner
Department of Revenue
(907) 269-0721 (w)
(907) 317-1221 (c)

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

SEAN PARNELL, GOVERNOR

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

RECEIVED
JAN 23 2012

January 17, 2012

The Honorable Joseph Paskvan
Alaska State Legislature
State Capitol Room 115
Juneau, AK 99801

Dear Senator Paskvan

Thank you for providing the Department of Natural Resources (DNR) the opportunity to respond to your questions concerning permitting, facility access, new resource developments, and pipeline capacity considerations among other issues important to oil and gas development in Alaska, as outlined in your September 22, 2011, and October 6, 2011, letters. I regret that our response was not more prompt. The breadth of the subject matter and volume of your questions required us to collect information from different divisions within the department and from outside resources. While this response was a top priority for my staff, the demands of processing unit and permit applications, lease sale preparation, task forces, and other daily demands delayed our response.

DNR is making significant strides toward accelerating the rate of bringing new resources online, maintaining production from our legacy fields, and providing new independent operators the means for successful exploration and production. We hope this response will assist you and the legislature in making policy decisions critical to boosting oil production in our state.

I look forward to meeting with you in the coming months.

Sincerely,

Daniel S. Sullivan
Commissioner

Cc: Bill Barron, Director, Division of Oil and Gas

Please find below DNR's responses to the 30 questions from September 22, 2011.

1(a) Q. I would like to have DNR's current knowledge as to the fluid handling capacities of the central North Slope treatment facilities.

A. The following table provides a list of capacities for the central North Slope facilities along with handling limitations to the best of our knowledge.

Unit	Oil and NGLs, standard barrels per day (stb/d)	Gas, million standard cubic feet per day (mmscfd)	Water (bwpd)	Water Injection (bwpd)	Handling Limitations and comments
Badami	35,000	25	12,000	30,000	No Limits
Colville River	140,000	180	100,000	140,000	We know of no limits at this time
Endicott	115,000	455	225,000	245,000	Limited gas and water
Kuparuk					Limited Gas, water, and total fluid handling
CPF-1	170,000	200	250,000	250,000	
CPF-2	160,000	260	250,000	300,000	
CPF-3	85,000	150	100,000	220,000	
Milne Point	75,000	42	99,000		None known for current development
Northstar	77,000	555	30,000		Limited by gas handling, water production is not at limit. Uncertain whether rated capacity is current.
PBU					Limited gas, water handling - Note: cannot add up each facility to obtain total facilities restrictions
FS-1	360,000	2,800	140,000		
FS-2	360,000	1,200	650,000		
FS-3	360,000	1,300	300,000		
GC-1	330,000	2,600	180,000		
GC-2	250,000	1,070	300,000		
GC-3		1,100	275,000		
CGF		8,700			
CCP		7,700			
LPC - Greater Pt. McIntyre	205,000	450	120,000		Limited gas, water, and total fluid. Some wells from Pt. McIntyre flow into GC1
Oooguruk					Production to Kuparuk CPF-3. No known handling limits at Oooguruk.
Nikaitchuq	40,000	unknown	120,000		No limits at this time

1(b) Q: I would like to know the individual ownership interests in all central North Slope treatment facilities.

A: Companies are not required to submit information on ownership interest for treatment facilities to the State; therefore, we have no information to provide for this question. However, facility ownership typically follows working interest ownership percentages. This statement is supported by the fact that operating and capital expenditures on facilities are split amongst partners based on their interest ownership percentages in the field.

1(c) Q: What internal analysis has DNR prepared as to likely continuing near future [next five years or so] constraints as to treatment capacity at particular facilities?

A: To our knowledge, there are no sanctioned projects to increase treatment capacities. The Prudhoe Bay Unit (PBU) Working Interest Owners (WIO) are considering the installation of a gas partial processing plant in the GC2 area, Pad Z, which would partially separate 350 million cubic feet of gas from well production, and compress the gas for gas lift. This will decrease the volume of gas to the central facilities, effectively increasing gas handling, which would be especially beneficial as the Gas-to-Oil Ratios are lower at GC2 as compared to other facilities, and there is potential for increased rates and reserves through drilling of western satellite wells. The increased gas handling will allow for less back-out of oil from existing wells when new wells are brought on line. As noted, however, this project has not been sanctioned and therefore is several years away if in fact it is ever undertaken.

1(d) Q. I would like to know the specifics as to the individual facility constraints as to both water and gas and which facilities are currently constrained as to either the water or the gas or both water and gas, also, as to oil flow downstream of the facility, what line capacity constraints, if any exist?

A. See table above in question 1(a) for the individual facility's status. As noted above, because the facilities are integrated with one another, a significant constraint on oil production to consider is the gas constraints at the central facilities, such as the CCP and the CGF in the Prudhoe Bay Unit.

1(e) Q. What knowledge, if any, as to the construction of new treatment facilities has been conveyed by the oil industry?

A. See answer to question 1(c) above.

1(f) Q. What information does DNR have as to the likely duration of the current constraints in processing capacity of water and gas?

A. With the exception of the potential PBU partial processing plant (not sanctioned), we have no information that the facilities' handling capacities will be increased in the near future.

1(g) Q. The DNR knows of no major gas handling expansion for the Prudhoe Bay area occurring after 1995.

A. That is accurate.

2(a) Q. What information does DNR have as to well shut in as a result of back out facility sharing? [By this I mean conduct both as to inter-company and intra-company conduct.]

A. The operator of each unit is required to submit to the AOGCC a list of all wells that are shut in (SI) for more than one year, and the reasons for SI. We recommend contacting AOGCC for further details on this matter. That said, the annual surveillance reports submitted to the AOGCC are shared with DNR and the operators usually list those wells SI for greater than one year and note those that are shut-in because they are non-competitive either due to water or gas production. However, we have not seen information concerning wells SI due to facility sharing.

2(b) Q. Who is the person at DNR that is most knowledgeable as to back-out agreements and facility sharing agreements?

A. Kevin Banks with the Division of Oil and Gas is the most knowledgeable on these subjects.

3 Q. Other than fluid handling capacities at the treatment facility, what other types of facilities sharing arrangements is the oil industry entering into on the central North Slope? Who within is most knowledgeable as to this area? Can facilities sharing be used as a barrier to development of Alaska's resources?

A. There are other facility sharing agreements, other than fluid handling, on the North Slope. DNR would not necessarily know about other sharing agreements (with the exception of fluid handling agreements as parties need DNR approval to commingle fluids). All facility sharing agreements are confidential. To our knowledge, other services and facilities being shared include gravel roads, drilling pads, grind and inject facilities, gravel mining pits, and power supplies. General, common facility sharing is a routine practice within the industry as a means of decreasing overall operating and capital costs. As noted in testimony by Director Bill Barron in November 2011 House Resource committee hearing on oil development impediments, the Division of Oil and Gas will be encouraging industry to cooperate on developing common needs to reduce costs of operation. The Division of Oil and Gas is likely the most knowledgeable on this subject.

4(a) Q. Ultimate TAPS throughput is associated with the capacities of the treatment facilities on the central North Slope. What internal analysis of the range of throughput reduction is anticipated within the next 5 to 10 years if no additional treatment facilities for conventional oil processing are constructed?

A. DNR does not publish our own predictions. However, DNR reservoir engineers review results of the Department of Revenue's (DOR) published predictions, and they are similar to our own. The following was published by the DOR in their Fall 2011 forecast.

Figure 4-11. Alaska North Slope Production, FY 2011 and Forecasted FY 2012-2021[m] (million barrels per day)

Fiscal Year	Currently Producing	Percent Change from Prior Yr.	Under Development	Under Evaluation	Total ANS	Percent Change from Prior Yr.
2011	0.603	(6.3%)	0.000	0.000	0.603	(6.3%)
2012	0.548	(9.1%)	0.026	0.001	0.574	(4.7%)
2013	0.485	(11.6%)	0.069	0.001	0.555	(3.3%)
2014	0.451	(6.9%)	0.099	0.010	0.561	1.0%
2015	0.406	(10.0%)	0.115	0.017	0.538	(4.1%)
2016	0.369	(9.1%)	0.151	0.029	0.550	2.1%
2017	0.336	(9.1%)	0.179	0.034	0.549	(0.1%)
2018	0.307	(8.5%)	0.171	0.066	0.544	(0.9%)
2019	0.282	(8.1%)	0.166	0.066	0.515	(5.4%)
2020	0.262	(7.4%)	0.164	0.061	0.486	(5.6%)
2021	0.241	(7.7%)	0.161	0.056	0.458	(5.8%)

4(b) Q. Has DNR assessed the engineering or science of a mature oil field as to likely increasing volumes of water and or gas in the next 5 to 10 years?

A. With only a handful of engineers on staff, engineering assessments and studies are rarely undertaken by Department staff. DNR has not undertaken its own assessment of the engineering or science at Prudhoe Bay or Kuparuk. However, some aspects of mature oil fields are well-known. In water-flooded fields, the water-oil ratio will increase over time. Furthermore, the ability to lift the high water cut wells with the existing systems (mostly gas lift) becomes problematic. Similarly, fields such as Prudhoe with gas cap expansion will experience increasing gas-oil ratios. The operators have put a lot of effort into sidetracking wells to areas where oil has been unswept by water or gas, and hence should have lower gas-oil and water-oil ratios at initial production. At some point, as these unswept areas are produced, lower oil rates will result from the well work. The water and gas production rates are constrained by the facilities handling, and hence, with the increasing gas-oil and water-oil ratios, the oil rate decreases.

4(c) Q. Who within DNR is the most knowledgeable in this area?

A. The Division of Oil and Gas has engineers knowledgeable on these subjects; however, we ask that legislative inquiries be directed to the Director's Office or DNR Legislative Liaison Esther Tempel.

5(a) Q. We have had discussions as to the need for revisions to the state's regulations. What is the status of these revisions to the regulations, particularly those related to shale oil development? Is Alaska's DNR fully prepared for a transition to the likely future of unconventional oil development? What DNR additional staffing might need to be addressed and what new areas of staffing should be considered?

A. DNR has established a permitting task force led by Deputy Commissioner Ed Fogels to help streamline the State's permitting process and relieve the current permit backlog. DNR has also established a multi-agency shale oil task force to facilitate and efficiently permit environmentally responsible North Slope shale resource development on State lands. The shale task force is led by the Division of Oil and Gas and includes representatives from DEC, Fish and Game, AOGCC, DMLW, and OPMP. The shale task force is currently identifying regulatory issues and staffing needs to address the increased pace and magnitude of permitting and development inherent in shale oil development. The state is well-positioned from a regulatory and statutory standpoint to manage shale development because the permitting required for conventional wells is applicable to shale development.

DNR is leading the effort to prepare the state for the potential of widespread shale oil development on state lands. The shale task force has been in operation for a mere three months. Although progress has been steady, the scope of their work is large. The shale task force will have more details on staffing needs as it completes its work in March 2012.

5(b) Q. What other areas of interest is DNR considering may participate in the upcoming lease sale?

A. It has been just over a year since the news of shale oil development struck Alaska. News of BP's successful production of heavy oil at Milne Point occurred less than a year ago. DNR representatives have actively marketed the fall lease sale to companies throughout the world. We have two major new players (Shell and Royale Energy) investing in the North Slope with Conoco leasing a number of tracts near Badami and Nordaq moving north to explore Smith Bay. While we were excited by the magnitude of the sale, we have not learned the intentions of the new bidders.

5(c) Q. As to heavy oil development, are regulatory modifications needed or appropriate to this area?

A. Heavy oil permitting has been following the lines of conventional oil development. Current heavy oil development takes place in current operations and participating areas with existing infrastructure. We do not see a need to make regulatory or staffing changes to address the heavy oil development at this time.

6(a) Q. What are DNR's thoughts on quality bank adjustments as to heavy oil?

DNR believes that the litigation process, which involves significant tension between commercially-sophisticated parties, has generally produced a reasonable quality bank compensation formula.

TAPS crudes of different quality are comingled. The TAPS quality bank is a means by which different shippers compensate each other for the fact that the value of the crude that a given shipper's delivery to the line differs from the value that the shipper receives when it receives comingled crude at destination.

From the narrow view of royalty and tax value, the state should be largely indifferent as to the particulars of the quality bank formula. A formula that Shipper A might view as an under-compensation for degradation in its crude quality causes a symmetric over-compensation for Shipper B's crude. Overall, state value should be largely unaffected.

Of course, the state has a broader dynamic interest in ensuring that the quality bank treats all parties fairly, as this promotes maximum efficient development of state resources. The TAPS quality bank litigation has been hard-fought over for many years. The litigation has involved commercial tension between extremely sophisticated parties with detailed knowledge and understanding of how refineries run and value crude oil of different qualities. The state has also participated in this process. In general, the state believes that the process has produced reasonable results and will continue to do so for heavy and viscous oil production.

6(b) Q. What sources of information does DNR look to as to pricing of heavy oil in other jurisdictions?

A. The DNR subscribes to several periodicals that report prices of a number of different crudes. These include Platt's Oilgram News, Oil Daily, and Petroleum Argus.

6(c) Q. What are DNR's thoughts on the magnitude of the operating and capital expenditures needed for heavy oil?

A. Heavy oil development on the North Slope may benefit from the existence of considerable "sunk" infrastructure costs that may be used towards processing and transporting heavy

oil. That said, incremental capital costs are likely to be considerable and DNR is of the general belief that these will be materially greater on a dollar-per-barrel basis than for legacy production on the North Slope. DNR lacks data to offer good estimates on the relative magnitude difference, however. We do not have projections for CapEx and OpEx necessary for heavy oil development.

7. Q. **I would also like similar information, to that requested in the above paragraph, but in the area of shale oil.**

A. DNR's understanding is that an "average" horizontal producing shale oil well in the Bakken has CapEx costs of over $6 million, with annual OpEx around $85,000. Costs in Alaska are expected to considerably exceed these figures. To date, no well has yet been drilled for shale oil in Alaska. Until many such wells have been drilled and produced, the question of costs cannot be answered with a great degree of confidence.

8. Q: **Who within DNR is most knowledgeable in the individual areas of heavy and shale oil production?**

A: The Division of Oil and Gas has several individuals in the Resource Evaluation and Commercial sections knowledgeable in the areas of heavy and shale oil development. To determine the person most suitable to answer questions, please contact the Division of Oil and Gas Director's Office.

9. Q. **What is the drilling activity expected to be between now and summer 2012? Are all drilling rigs currently under contract even if not currently drilling? Are there any rigs which are now idle? What is the type of activity which they are performing? How many exploration wells are anticipated in the drilling season? How many development wells are anticipated in the upcoming drilling season? How many well work-over projects are anticipated?**

See the table in Exhibit A for anticipated exploration activities during the winter 2011-2012 drilling season. This is a list of plan of operations applications submitted to DNR this year. Exploration drilling activities generally cease during the summer months on the North Slope but may continue during the summer in Cook Inlet at locations located near existing infrastructure. The Alaska Oil and Gas Conservation Commission is better equipped to answer questions about the availability of drill rigs and number of exploration and development wells under permit for the upcoming year.

10. Q. **An area of critical importance is in the process of permitting. What percentage of increase or decrease in permit applications has occurred from that which was submitted in 2007, for example, to the 2010 and 2011 time periods, what do you expect for next year? What generally can be said as to the types and numbers of permits which are**

currently being filed? What historical data exists as to the numbers and types of permit applications from, for example, 2000 to present? What historical data exists about the companies submitting those applications? What is the permit application distribution between majors and independents over the past 10 years?

A. Below is a list of Lease and Unit plan of operations applications for independent and major operators in 2007, 2010, and 2011. The change between 2007 and 2010 are not significant; however, the lease plan of operations applications dropped nearly 40% for major operators in 2011 from 2007 and 2010.

Year	*Type of Permit Application*	Operator	Count
2007	*Lease Plan of Operations*	Independent operator	10
2007	*Lease Plan of Operations*	Major operator	86
2007	*Unit Plan of Operations*	Independent operator	6
2007	*Unit Plan of Operations*	Major operator	25
2010	*Lease Plan of Operations*	Independent operator	4
2010	*Lease Plan of Operations*	Major operator	85
2010	*Unit Plan of Operations*	Independent operator	5
2010	*Unit Plan of Operations*	Major operator	23
2011	*Lease Plan of Operations*	Independent operator	6
2011	*Lease Plan of Operations*	Major operator	51
2011	*Unit Plan of Operations*	Independent operator	4
2011	*Unit Plan of Operations*	Major operator	24

A list of submitted applications for plan of operations permits can be found in Exhibit A which details proposed activities for this winter. We are receiving a steady amount of permits applications for exploration work this winter. However, plan of operation approval does not necessarily translate to drilling this winter. At this juncture, we have not received the volume of exploration applications that was projected by companies. Below is a table providing permit counts from 2000-2011 between majors and independents.

Division of Oil & Gas Permitting Activity : 2000 through 2011

Permit type	Operator type	Count
Easements	Independent operators	7
Geothermal Plan of Operations	Independent operators	11
Lease Plan of Operations	Independent operators	81
Multiple Land Use Permit	Independent operators	41
Unit Plan of Operations	Independent operators	41
Lease Plan of Operations	Major operators	644
Multiple Land Use Permit	Major operators	25
Unit Plan of Operations	Major operators	186

11(a) Q. I generally understand that consideration is occurring as to the adding of NGL's downstream of pump station 1 as compared to adding this stream upstream of pump station 1.

A: Currently, NGLs are injected upstream of Skid 50 and flow into Pump Station 1 through the Sadlerochit (Prudhoe) 501 transit oil pipeline. DNR has received no information on plans for studies on injecting NGLs directly into TAPS, downstream of Pump Station 1. Alyeska Pipeline Service Company and the North Slope producers are studying a number of changes to processing facilities and TAPS. A number of screening studies, estimates, conceptual designs, and other efforts are currently being conducted to enhance low-throughput and cold-temperature operations.

Introduction of NGLs into TAPS is not a straight-forward replacement for the same volume of oil. NGLs have a higher vapor pressure and there is probably a limit to the volume able to enter TAPS. Introduction of NGLs into TAPS from the newly-completed Central Gas Facility in Prudhoe during the early 1990s resulted in vapor control problems and required modifications to facilities. Thus, there is still much to learn about this process.

11(b) Q. What potential volumes are considered from NGLs?

A. For the main Prudhoe area, NGLs sold into the pipeline in 2010 averaged 45.6 thousand barrels per day (MSTB/D).

11(c) Q. Does DNR have an estimate to the volumes in barrels of NGLs from the gas volumes from GHX1 and GHX2?

A. As a result of GHX1, peak NGL sales increased by approximately 18,000 barrels per Day (STBD) from additional gas handling of +/- 1.8 billion cubic feet per day (BSCFD)

As a result of GHX2, peak NGL sales increased by approximately 20,000 barrels per Day (STBD) from additional gas handling of +/- 2.0 billion cubic feet per day (BSCFD)

11(d) Q. What percentage, if any, of NGLs which are used for miscible injection are, in the future, not recoverable?

A. We do not have estimates of these volumes. The recovery of remaining NGLs depend upon future depletions plans such as injection of water, lean gas, or CO2 to sweep NGLs remaining.

11(e) Q. What volume of NGLs is necessary for miscible injection?

A. Miscible injection averaged 169 million cubic feet per day (MMSCF/D) in 2010. Of these volumes, 24.7% consisted of propane and about 2.2% were heavier end hydrocarbons. Not all of the propane volumes can be stabilized as liquids. Only volumes of NGLs that cannot be sold into TAPS, due to vapor pressure restrictions, are used for miscible injection. It is likely that if more miscible gas volumes were available, they would be used to increase recovery in Prudhoe, including the satellite pools.

11(f) Q. What additional oil volume is currently extracted because of NGL miscible injection?

A. As noted above, propanes and heavier components comprise about 27% of the gas volume of MI, or 46.6 MMscfd. We do not have this volume in barrels, and as also stated above, these volumes cannot be stabilized into oil for TAPS.

12. Q. Has DNR analyzed the potential volume of liquids which can be transported by TAPS if a GTL processing plant was located on the central North Slope?

A. DNR has no definitive information on this issue. The ability for TAPS to transport hydrocarbon liquids depends upon the type of hydrocarbons that a GTL plant will produce. Light hydrocarbons (such as NGLs) can create vapor-pressure problems. Heavy oils can create excessive pressure loss and require additional pumps or pump stations. Theoretically, TAPS can ship the same volume of artificially produced hydrocarbon liquid as naturally produced oil, if the liquid is tailored to have physical characteristics similar to current North Slope production. The current limit of TAPS facilities is 1.4MM BOPD, with injection of large amounts of Drag Reducing Agent.

13. Q. Has DNR analyzed the potential range of volumes of heavy oil which would flow through TAPS?

A. No. Heavy oil throughput is really a question of how aggressively BP and Conoco Philips pursue new viscous development. We could see these levels stay flat at current rates, decline, or increase. Ultimately, heavy oil development will depend on price, success of ongoing pilot projects, availability of diluents such as NGLs, perhaps TAPS heating situation, and other factors relevant to a company's investment strategy.

Current total production for existing developed "viscous" oil is 36,000 BOPD, with a peak of 44,000 BOPD in 2008. Online wells have stayed relatively steady since 2008. Note these are "viscous" Schrader Bluff/West Sak pools, not the "heavy" Ugnu formation which is in current pilot testing at Milne Point and Kuparuk.

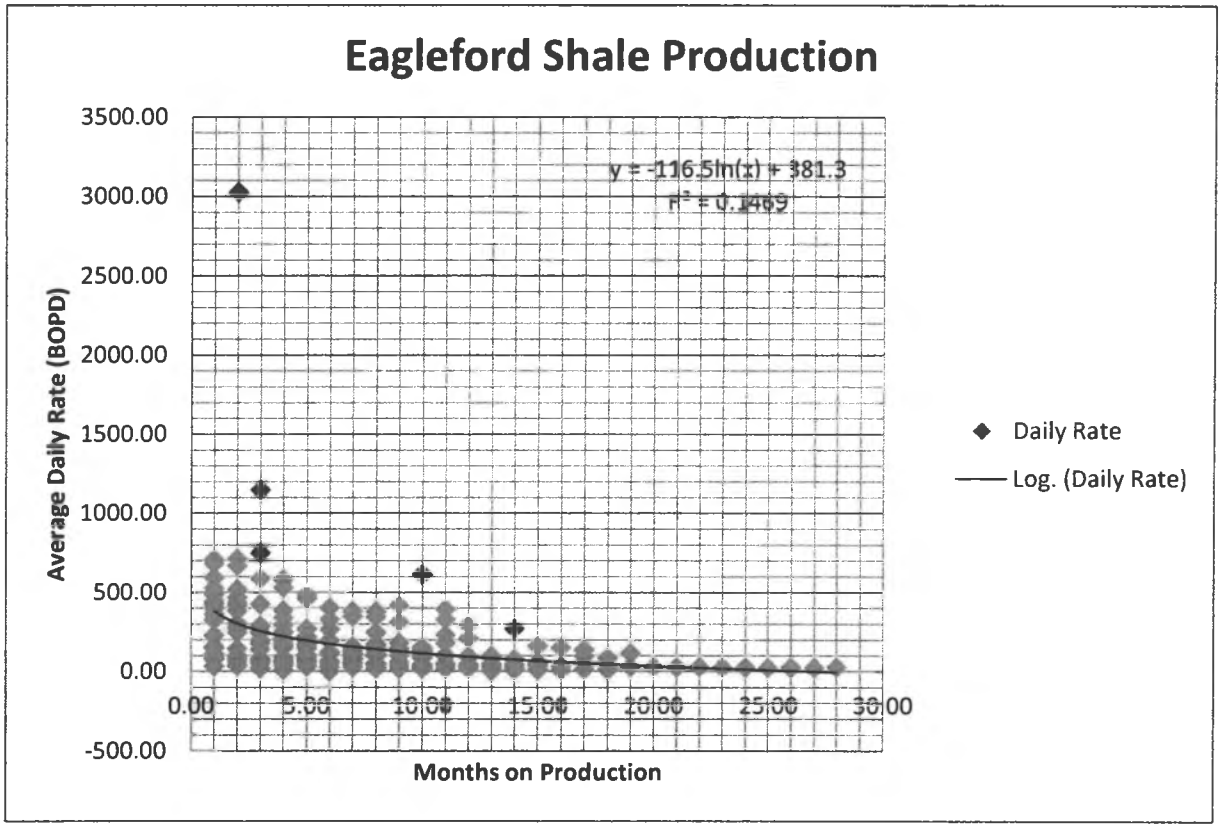
14. Q Has DNR analyzed the potential ranges of volumes of the oil obtained from the Chukchi/Beaufort from Shell's current plans that would travel through TAPS?

A. No. We do not have resource volumes or production forecasts for all of Shell's OCS oil prospects. Some have known, discovered resources (Sivulliq/Hammerhead) and others (Torpedo, etc.) are still undrilled, undiscovered, hypothetical barrels. Burger in the Chukchi has known gas and is prospective for oil or condensate liquids, but whether it will ship via TAPS is uncertain.

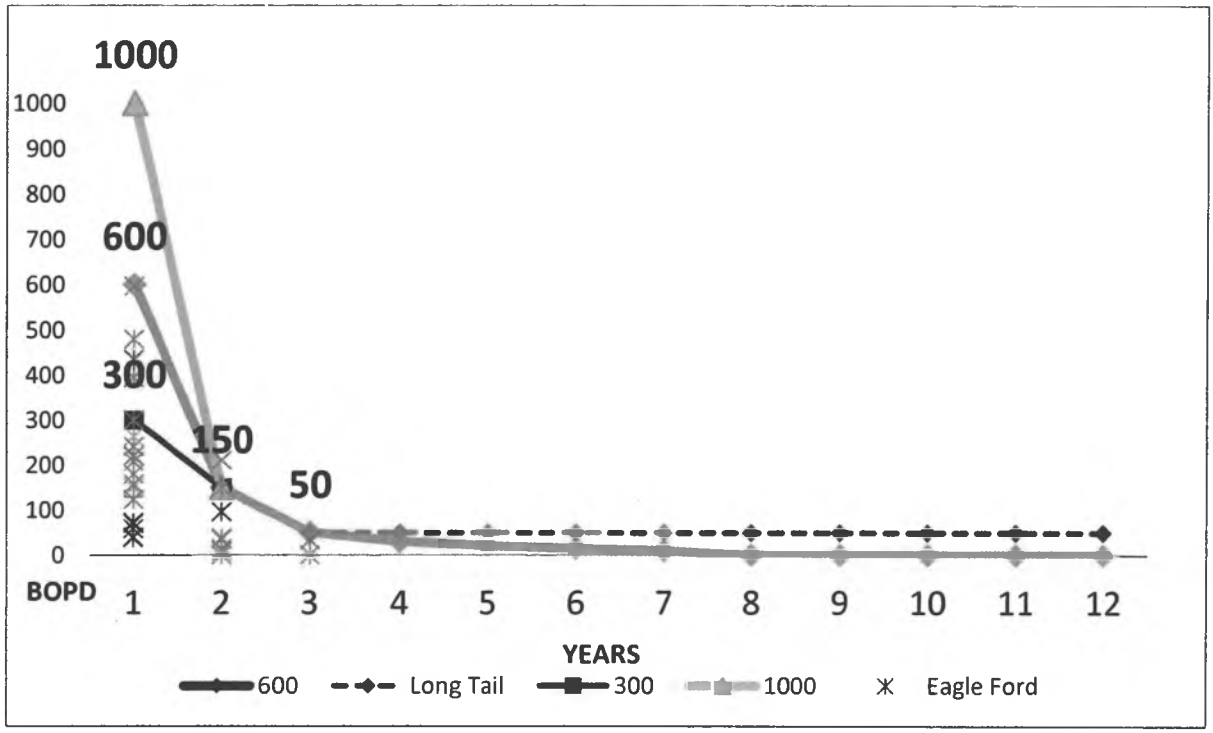
15. Q. Has DNR analyzed the potential volumes of Shale oil from Alaska's source rocks that may travel through TAPS assuming the successful implementation of shale oil extraction in Alaska?

A. DNR's analysis regarding the potential of the Alaskan shale resource play has centered on production of oil wells in the Eagle Ford Shale in Texas. The Eagle Ford was selected because the primary target of the current Alaskan operator, Great Bear, is the Shublik shale which has been compared to the Eagle Ford formation as an analogue.

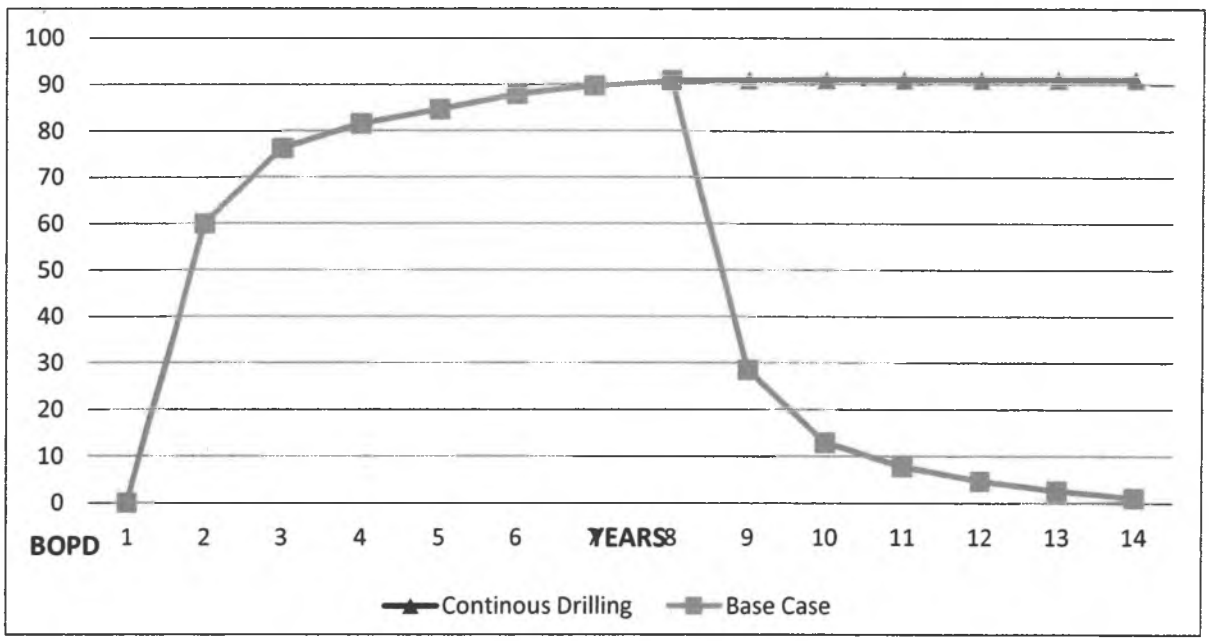
The central question around any shale development is whether or not the characteristics of the shale itself will allow hydraulic fracturing and production of hydrocarbons in commercially successful volumes. Until testing of the Alaskan source rocks occurs, the true potential will not be known. If the Eagle Ford is a true indicator of potential oil production of the Shublik, production could mirror data from the Texas Railroad Commission website. Research conducted by DNR and University of Alaska graduate students indicated that for Eagle Ford certified oil wells, production was as follows: First month production was between 80 and 700 BOPD for a first month average. The oldest well of the data set was at 24.5 BOPD after 28 months.



With this data, the Division of Oil and Gas commercial team developed the following single well dual lateral production profiles:



The commercial team then built up the following production profile based on a six-rig drilling program with year-on-year development within the lease term of 10 years and drilling for 7 years or continuing beyond the lease term with all leases held by at least one well:



This case shows a rate of 90,000 BOPD rate potential assuming all wells produce with the same rate initially which will most likely not be true. The rate will increase with more rigs

drilling the wells. Twelve rigs would result in a potential 180,000 BOPD added to the pipeline.

It is important to understand that these numbers are based on year-on-year "assembly line" type of development with all wells being equal in the production arena. While the assembly line type of development can be within the control of the state and the operators, the production is not, especially when data is studied for any other shale resource currently in production. The case also studies a single interval, not three as proposed in the highest Great Bear estimates. Prior to any tests being completed on the Shublik interval, all production data discussed above are only educated guesses as tests may find actual production to be lower or higher.

16 **Q. Has DNR analyzed the range of volumes of conventional oil from Conoco Phillips Colville River development assuming the bridge crossing is approved?**

A. Although there are no public numbers available, DNR believes that a wide range of possible oil reserves can be estimated for the proposed CD-5 pad based on the performance of the Alpine field consisting of the CD-1 and CD-2 pads and the two satellite areas: the Fiord CD-3 pad and the Nanuq CD-4 pad. DNR sees the possibility of 25-200 MM BOPD being recovered from CD-5 with peak production of 10-100 thousand barrels per day based on what we have seen at the first four pads.

17. **Q. What strategic planning would be needed to increase TAPS throughput capacity above 1.1 million bbl's/day should oil volumes, both conventional and unconventional, need to be transported by TAPS?**

A. TAPS capacity can be increased above 1.1 million BOPD. However, increases beyond 1.4 million BOPD or significant increases in unconventional oil (heavy oil or NGLs) may require modifications. The capacities of the facilities and the mainline are addressed independently:

Mainline: The mainline appears sufficient for rates of 1.1 million BOPD. It has flowed at rates up to 2.1 million BOPD. However, this was not a TAPS physical limit, but a maximum created by North Slope production decisions and regulatory approvals. Since that time, Alyeska has de-rated the maximum allowable pressure in certain locations. Alyeska would likely have to repair or replace specific pipe defects to increase pressure in these sections again. Typical mainline modifications can be made within a year of funding.

Facilities: The new Strategic Reconfiguration (SR) facilities can pump 1.14 million BOPD with no modifications. Simulations performed by Alyeska indicate that with large volumes of Drag Reducing Agent, the SR facilities can transport up to 1.4 million BOPD.

Alyeska designed each SR pump station for future expansion by allowing room to add one additional pump, motor, turbine, and variable frequency device (VFD).

Legacy Pump Stations with higher capacities are still online at Pump Station (PS) 01 and PS07. Part or all of abandoned legacy pump stations still exist at PS02, PS03, PS04, PS06, PS08 and PS09. PS05 contains piping to add more pumps.

Extensive production of non-conventional oil or NGLs may require additional pumps at existing pump stations or new pump stations. Adding redundant equipment to increase reliability would require more equipment. Typical major facility modifications can be made in two to five years at existing sites and three to five years at new sites or sites requiring air permits.

18. Q. **What are DNR's thoughts as to the additional fluid handling treatment facilities needed within the next 5-10 years? I am interested in this information both as to conventional and unconventional oil and state and federal land developments.**

A. It is likely that, as new discoveries are made or opportunities are found within existing fields, operators will continue to build or expand facilities as needed. The need for incremental oil processing facilities on the North Slope will be driven by the exploration and development activities being undertaken today. At present, we do not know the projected results of those efforts. Without an assessment of incremental production, we cannot estimate the amount of incremental facilities needed.

19. Q. **Do you agree that Alaska's current production tax credits provide for both the CAPEX deduction of costs and credit of 20% as they relate to fluid handling, both treatment facility upgrades and construction?**

A. We would agree with this assessment for all of the geographic areas listed, with the exception of Chukchi and Beaufort Sea oil. Production from the Outer Continental Shelf (OCS) is not on land within the geographic boundaries of the state, and therefore not subject to the state production tax. Accordingly, costs associated with developing OCS acreage do not receive deductions or credits under Alaska's current production tax system.

20. Q. **Does DNR acknowledge that if additional treatment facilities had been constructed on the central North Slope, for example in 2005, that 1) TAPS throughput would exceed the current throughput and 2) assuming excess capacity at the newer constructed facility that would provide motivation for exploration, especially by independent oil companies?**

A. With regard to (1): There are areas on the North Slope where processing facility constraints require operators to make optimization decisions about which wells to shut in (e.g. those with the highest ratios of gas to oil production) and which to keep in production. If there were more gas and water handling facilities available then the economics of keeping marginal wells online would improve. All else equal, that would lead to increased production.

That said, this says nothing about the economics of constructing additional facilities or debottlenecking existing facilities to increase their capacity. The economics of those decisions are not known by the DNR, as we do not know the cost of incremental facilities or the benefits of augmenting or accelerating production by bringing additional wells online.

With regard to (2): If there was excess capacity at newer constructed facilities, and such capacity was made available at commercially reasonable terms, then additional exploration could be facilitated. The key issues here are the relative costs of fluid processing at a large facility versus a possibly much smaller modular facility, and the commercial terms by which excess capacity might be made available. DNR does not currently have adequate estimates of these relative costs, in part because the model of using smaller modular processing facilities has not yet been developed on the North Slope.

21. **Q. What analysis has DNR done as to why it took approximately 30 years for the first independent to produce any oil from the central North Slope? Who at DNR is most knowledgeable as to potential impediments to independent production of Alaska's resources?**

A. DNR has conducted no formal analysis or finding concerning this question. Any, or a large, number of potential factors invite speculation, including: high costs of unaffiliated transportation (TAPS and OPA-90 compliant tankers); the pace of technology diffusion associated with Arctic operation acumen; comparatively lower historical oil prices; the high costs of exploration and development in an Arctic environment; smaller apparent remaining oil fields to develop; or costs of complying with environmental sensitivities.

Additional questions as to potential impediments to independent production of Alaska's resources should be directed to Bill Barron, Director of the Division of Oil and Gas.

22. **Q. Please set forth: a) the types of non-public information and b) the types of public information which DNR has which would qualify the oil production benefits of future gas and water handling capacity investments as stated June 8th 2011.**

A. Projections to quantify benefits of gas and water handling capacity investment are based on AOGCC's production data, which is publicly available, and aspects of a company's plan of development that are non-confidential. DNR receives confidential data in the plans of development submitted to the Division of Oil and Gas that can be helpful in determining benefits of investment; however, we are unable to make projections based on this information for fear that our interpolation will reveal confidential data. DNR does not receive company information critical for developing projections such as optimization records, reservoir models, or cost and price information. Thus, we are limited in what benefits of adding handling capacity we can project.

23(a) Q. How many BCF of gas does the central North Slope consume in a years' time and set forth the benefit to Alaska in either royalty or tax revenues which Alaska receives for that gas?

A. The State's share of gas produced and sold off unit (royalty-bearing gas) in 2010 was 3.52 BCF. The State received $11,676,308 for that gas. Non-royalty bearing gas for in unit consumption was 450 BCF in 2010.

23(b) Q. Has there been a royalty inventory as to any gas volumes used on the central North Slope?

A. DNR has not initiated a royalty inventory at this time.

24(a) Q. What water oil ratio does DNR anticipate at Prudhoe Bay from 2010 (at, I believe approximately 4: 1 water oil ratio) to 2020?

A. At the current rate of drilling, sidetrack, and work-overs, we estimate an average field-wide water-to-oil ratio of approximately 6 to 7:1 on average for Prudhoe Bay (Ivishak Initial Participating Area plus western satellite development).

24(b) Q. Will those increasing water oil ratios over the next decade reduce throughput from Prudhoe Bay?

A. Yes, increasing water-to-oil ratios will reduce oil throughput from the water-flood areas. Work-over or sidetracks of wells to reduce water will have diminishing rate impacts over time. In addition, artificial lift using gas lift will become increasingly inefficient.

25. Q. How is NGL processing for sales into TAPS accounted for in royalty?

A. NGLs are valued as oil, except that DL-1 leases subject to the 1995 Gas Settlement Agreement pay a higher field cost deduction.

26. Q. Does DNR agree that throughput in 2006-2007 occurred due to corrosion and shut down issues?

A. We are unable to comment on these issues because they are the subject of litigation scheduled for trial.

27. Q: Well work-over activity in the central North Slope has been high in recent years. Is it generally accurate that the activity will likely increase production volumes from the wells for years to come, but subject to the treatment facility constraints?

A: Rig or non-rig work-overs have proven to be the most cost effective method of maintaining the highest production rates of current reserves. To state that the activity increases production volumes and will for years to come is not exactly correct. The activity returns most wells to their highest possible production rates by fixing an issue that is typically mechanical in a well. In a few cases, the work-over activity will access new reserves. For the most part, this work maintains or accelerates the production of current reserves. It is important to caution that production volumes from a well will not be perpetually increased through work-over activities as the reserves are diminished over time. The comment on production increase being constrained by treatment facility limitations is generally correct. If the production of the newly-fixed well is not impacted, there is typically another less competitive well or wells that are backed out of the system to make room for the increased production.

28. Q. Does DNR agree that oil throughput at Prudhoe Bay is constrained by the ability of field operators to process and re-inject associated natural gas?

A. Yes, gas processing is a significant facility constraint in Prudhoe Bay. While new wells could be drilled with lower GORs, other high GOR wells have to be shut-in because of the gas processing limitation.

29. Q. As of the early 1990's, does DNR agree that Prudhoe Bay was past the point where well drilling could stave off a falling oil rate?

A. Yes. The Prudhoe Bay Unit WIOs had a very aggressive drilling program in 1986-1992. In addition, a major gas handling expansion (GHX-1) occurred in the late 1980s which helped stem decline. Significant delay in the production plateau would have been difficult.

Please find below DNR's responses to the 11 questions from October 6, 2011.

1(a) Q. The Charter of Development dated December 1999 contains facility requirements. Who is the person most knowledgeable at DNR as to paragraphs F and G?

A. A number of DNR staff is familiar with certain aspects of the Charter. We ask that inquiries be directed to DOG Director Bill Barron to identify the staff member with the most knowledge on a specific aspect of the Charter.

1(b) Q. Specifically, what are the past and current understandings of terms as to:

a. Non-discriminatory, just and reasonable?
See response below

b. Allowing access to existing unit facilities?
See response below

c. Reasonable commercial terms?

A. For question (a) – (c), we have asked the Department of Law to provide interpretations on contract terms for you.

d. Further, who are the qualified producers under G?

A. At this time, it appears that qualified producers counted under paragraph G would be the following: ASRC, Doyon, Murphy Exploration, Petro-Hunt, Pioneer, Savant, and NANA Corporation. However, we are not privy to the assets of each of these corporations.

e. What leasehold production has been purchased by Charter signers?

A. Production has been purchased from the Northstar, Nikaitchuq, Colville River, Oooguruk, and Badami units.

f. What accounting as to the 30,000 bbls/day exists?

A. There has not been an official accounting of the volume; however, the Division of Oil and Gas has current information on production sold by qualified producers.

g. Has the 30,000 bbls/day been reached?

A. From our information, it appears that less than half that amount is currently being sold by qualified producers.

h. What policy background exists as to the inclusion of these paragraphs in the Charter?

A. The merger of BP and ARCO would have led to the entire North Slope being operated by a single entity. There were concerns from the Federal Trade Commission on the potential effect of the merger on the downstream crude oil market and the petroleum products market on the US West Coast. The State provided its position in paragraph F (1) of the Charter agreement. To our knowledge, the State has never intervened to ensure that BP and ConocoPhillips have complied with the Charter in a facility access dispute or in purchases of crude from smaller producers. Furthermore, DNR has not been asked by interested parties to invoke the Charter for access to facilities operated by BP and ConocoPhillips.

i. What if anything has been accomplished by paragraphs F and G?

A. Most notably, the provisions of the Charter were effective in helping Pioneer negotiate a facility sharing agreement with Conoco for the Oooguruk unit production. UltraStar has also come to terms with BP on a framework for access to drill sites and for future use of Lisburne facilities for the Dewline unit. We presume the Charter was instrumental in negotiating the UltraStar agreement, but we cannot confirm this fact.

2(a) Q. Since 1995 has any treatment facility, other than ENI's, been built?

A. Alpine facility installation in 1999-2000. Expansion of processing facilities has occurred since 1995 which is detailed in the answer to question 5 below.

2(b) Q. What are the ENI treatment facility capacities?

A. ENI's treatment facility capacity is around 40,000 barrels of oil per day of heavy crude with sand and 120,000 barrels of water per day.

2(c) Q. What current end throughput comes from ENI's facility?

A. The current end throughput, to the best of our knowledge, is 6-7000 BOPD and 100 BWPD.

2(d) Q. Is there spare capacity at the ENI facility?

A. There appears to be spare capacity at the ENI facility based on the numbers above.

2(e) Q. Is any spare capacity expected to be used by ENI alone?

A. Treatment facilities could reduce oil production reaching TAPS if facilities reaching fluid limits are not augmented and well workovers and new drilling are not employed in a field to access new lower GOR and WOR reserves. Otherwise, operators have been employing smaller-scale facilities additions/debottlenecking to address fluid handling, for example:

- Milne Point processing expansions in 1996
- Alpine expanded water handling
- Prudhoe Bay Unit
  - GC2 water handling debottlenecking and miscible gas lines to the West End of PBU
  - Prudhoe GPMA LPC – installed miscible injection (MI) pump. Increased water handling.
  - MI is also being sent to Pt. McIntyre from PBU via conversion of a water line to an MI line
  - Seawater injection started back up and water being injected into Prudhoe gas cap. This is proving to increase reservoir energy, decrease decline, and reduce GORs
  - Water injection into Lisburne gas cap to reduce GORs
- Oooguruk Unit processes production through sharing at KRU CPF3. New drill sites, lines for injection of water and gas lift were installed.

6. **Q. Do you agree that without more fluid treatment capacity, oil throughput is constrained?**

A. Oil throughput constraint is not solely a fluid treatment issue as gas separation is also a factor. In some fields fluid treatment may constrain throughput; however, with proper resource management, most fields are able to adapt to decreasing GORs and overcome constraints without additional fluid treatment capacity.

7. **Q. For how many years have treatment facility constraints affected oil throughput volumes?**

A. We are unable to provide a timeline on purported constraints. Continuous debottlenecking and drilling or work overs are used to stem throughput decline which inhibit our ability to track these issues. Debottlenecking and work overs are actions of a prudent operator decreasing constraint occurrences. It appears that some of the fields such as Badami and Nikaitchuq may not be limited for some time. Proper resource management helps to limit gas and water processing constraints.

8. **Q. Can treatment facility access be used in a manner harmful to Alaska's interests? If so, how?**

A. It is unclear how increased access by third parties to treatment facilities, under commercially reasonable terms, could bring harm to Alaska's interests. The Division is not aware of any development that has not proceeded simply because reasonable third party access terms could not be negotiated.

9. **Q. Can a company's internal conduct as to back outs of volumes be used in a manner harmful to Alaska? If so, how?**

A. This question is difficult to answer without clarification on what is meant by "a company's internal conduct as to backout volumes." We request more specifics or information in order to answer this question properly.

10. **Q. Do Alaska's credits allow for expansion of and construction of treatment handling facilities? By this I mean: Does both deduction from gross and credit [20%] to bottom line currently exist? It is my belief that the current tax system allows for both deduction and credit as to treatment handling facilities.**

A. Generally, capital expenditures for expanding or constructing new treatment facilities would generally count as permissible lease expenditures under ACES, and so would allow a working interest owner to both deduct the expenses and qualify for a qualified capital expenditure credit. For more information on this topic, we suggest contacting the Department of Revenue which is responsible for administering the production tax system.

11(a) Q. As to fluid volume handling, what are the percentages of access by company at each facility? The total at each facility should equal 100%.

11(b) Q. Of all operators at central North Slope, who have entered into back out agreements?

11(c) Q. Of all operators at central North Slope, who have entered into sharing agreements?

11(d) Q. As to those agreements, please identify the payer and payee and the volumes and facility percentages.

11(e) Q. What are the highest percentages of a facility's capacity which has been subject to an agreement?

11(f) Q. What companies have internally engaged in back out type conduct?

A. [*This response addresses all the questions posed in 11 above*]
We noted in an earlier question that back out and facility sharing agreements between two separate units are confidential. There are numerous in-unit agreements that DNR receives on a voluntary basis; however, industry is very hesitant to provide these documents. For the state to continue to receive these documents, there must be a degree of trust that the agreements will not become public unless absolutely necessary. Therefore, answering the questions above will lead DNR breaching our duty of

confidentiality or the possibility industry will discontinue their practice of providing in-unit agreements to DNR.

Company	Project Name	Project Type	Project Description	Received Date
Buccaneer	**Cook Inlet Exploratory Drilling**	**Exploration**	Buccaneer plans to conduct a four well, offshore exploratory drilling program in upper Cook Inlet at its proposed locations on the following State of Alaska oil and gas leases: Alaska Division of Land (ADL) 17595-2 (Southern Cross Unit #1), ADL 391108 (Southern Cross Unit #2), ADL 391270 (Northwest Cook Inlet Unit #1), and ADL 391611 (Northwest Cook Inlet Unit #2). **Purpose:** (To explore for oil & gas). **Proposed start-up date:** 07/01/2011 **Expected Completion Date**: 08/31/2013	**7/11/2011**
Cook Inlet Energy, LLC	**Otter Prospect Gas Exploration Well**	**Exploration**	An exploratory drilling program. **Purpose:** to test the Lower Miocene Sterling and Beluga formations and Upper Oligocene - Lower Miocene Tyonek formation that CIE has named the "Otter Prospect" . **Proposed start-up date:** 10/01/2011; **Expected Completion Date:** 9/30/2012	**8/10/2011**
Nuna Exploration	**2011-2012 North Slope Exploration Wells**	**Exploration**	PNRA proposes to drill and test two exploration wells with associated activities as described in the POO. **Proposed start-up date:** 11/1/2011; **Expected Completion Date:** 5/31/2012	**8/10/2011**
UltraStar Exploration, LLC	**North Dewline #1 Well**	**Exploration**	Directionally drill one onshore well from an ice pad off lease. Dependent on rig availability. **Purpose:** To assess oil and gas reserves within oil and gas leases held by UltraStar. **Proposed start-up date:** 12/01/2011 **Expected Completion Date:** 04/30/2012	**8/18/2011**
Great Bear	**Great Bear 2011-2012 E&E Program**	**Exploration**	Exploration & Evaluation Program (E&E Program) which includes up to 4 vertical wells for coring samples and potential laterals with hydraulic fracture stimulation, with the possibility for two additional wells, if required. **Purpose:** To prove the unconventional resource play. **Proposed start-up date:** 11/01/2011 **Expected Completion Date:** Summer/Fall 2012	**9/14/2011**
Repsol	**Repsol**	**Exploration**	Single vertical well and, time permitting, up to two sidetracks from an ice pad. **Purpose**: is to primarily assess oil reserves within leases operated by Repsol. **Proposed start-up date:** 11/01/2011 **Expected Completion Date:** 05/31/2012	**9/16/2011**

Repsol	**Repsol**	**Exploration**	Single vertical well and, time permitting, up to two sidetracks from an ice pad. Purpose: is to primarily assess oil reserves within leases operated by Repsol. **Proposed start-up date:** 11/01/2011 **Expected Completion Date:** 05/31/2012 **Well Names to Drill:** Qugruk No. 3, Kachemach No. 1	**9/16/2011**
Brooks Range Petroleum Corporation	**2011-2012 Mustang Exploration Program**	**Exploration**	BRPC requests the following modifications - to re-enter & complete North Tarn 1A well at the North Tarn Pad, and if successful, drlill up to 3 additional wells from the same pad; and possibly perform a short term production flow test(s); use Nabors rig 7ES during the 2011-2012 drilling season; update exploration activity timeframes - ice road & pad construction (pre-packing) may commence as soon as November 2011, with drilling activities scheduled for completion by the end of the winter tundra travel season (April-May2012). **Purpose:** to find significant hydrocarbons during drilling and then test and confirm flow rates and reservoir characteristics. **Proposed start-up date:** 11/1/2011 **Expected Completion Date:** 08/31/2011	**9/21/2011**
ConocoPhillips Alaska, Inc.	**Shark Tooth No. 1**	**Exploration**	CPAI proposes to build approximately 4 miles of ice road, an ice pad and to drill a single appraisal well, approximately 2 miles east of Drill Site 2L in the south-west area of the Kuparuk River Unit (KRU). **Purpose:** To provide additional reservoir information in this area and narrow uncertainty around reservoir description parameters including oil-water contact, sand quality and thickness, and oil viscosity **Proposed start-up date:** 01/01/2012 **Expected Completion Date:** 04/30/2012	**10/13/2011**
NordAq Energy Inc.	**Tiger Eye North No. 1 Exploration Project**	**Exploration**	NordAq proposes an exploratory drilling program for one well, Tiger Eye North #1, which will be drilled in summer 2012. **Purpose:** (To explore for oil & gas). **Proposed start-up date:** 11/01/2011 **Expected Completion Date:** 09/15/2012	**10/26/2011**
CGGVeritas	**Tabasco 3D Seismic**	**Geophysical**	**Project Description:** CGGVeritas plans to acquire a multi-client 3D seismic program on the North Slope this winter 2012 on behalf of the CGGVeritas Multi-Client & New Ventures Division. **Purpose:** To shoot approximately 200-300 square miles of 3D Seismic . **Proposed start-up date:** December 15, 2011; **Expected Completion Date:** May 31, 2012; **PROGRAM NAME:** Tabasco North 3D and Tabasco South 3D.	**10/24/2011**

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL & GAS

SEAN PARNELL, GOVERNOR

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February 9, 2012

Senator Joseph Paskvan
Senate Resources Committee Co-chair
State Capitol Room 115
Juneau AK, 99801

Senator Thomas Wagoner
Senate Resources Committee Co-Chair
State Capitol Room 427
Juneau AK, 9980

Dear Senators:

I wanted to take this opportunity to thank you both for inviting me to testify before the Senate Resources Committee on February 3, 2012. The committee is trying to understand a very complex subject matter, and I am pleased that the Division has been called upon to provide the factual basis for crafting solutions to perceived facility issues. This correspondence allows me to reiterate a few of the more salient aspects of my testimony and present to the committee an updated table on Capacities of North Slope Facilities from page 11 of my February 3rd slide package (enclosed). It is crucial that we all operate under a similar framework and understanding of reservoir dynamics and facility capabilities; therefore, I offer the bulleted information below to clarify the main points of my testimony. Please keep in mind the underlying pretext of my comments involved the issue of third party access to existing process facilities.

- The Prudhoe and Kuparuk units are experiencing typical reservoir depletion which requires handling and processing of increasing amounts of water and gas, decisions on facility management, effective well utilization, and complex reservoir management.
- Facilities are designed to meet a wide range of production profiles with varying water-oil and gas-oil ratios (WOR and GOR, respectively). As the reservoir matures, reservoir management and facility debottlenecking for water and gas handling, water and/or gas injection to maintain reservoir pressure, well workovers, and new infield development drilling is required.
- Pipeline capacity is available throughout most of the North Slope, thus companies with new oil discoveries will need to negotiate to share the existing transport facilities.
- Corporate culture and size of a discovery typically dictate decisions whether to build new process facilities or enter into commercial agreements to access existing facilities.
- Statutory changes for facility access will be difficult and likely ineffective due to the complexity and idiosyncrasies of each field's physical assets, reservoir management approach, and commercial conditions.

Again, thank you for the opportunity and I look forward to future discussions.

Sincerely,

W.C. Barron
Director

Cc: Daniel Sullivan, Commissioner Department of Natural Resources
Joseph Balash, Deputy Commissioner, Department of Natural Resources
Senator Hollis French
Senator Lesil McGuire
Senator Bert Stedman
Senator Gary Stevens
Senator Bill Wielechowski, Senate Resources Committee Vice-Chair

Enclosed: *Capacities of North Slope Facilities.doc*

Capacity of North Slope Facilities						
Unit	**Oil and NGLs, standard barrels per day (stb/d)**	**Gas, million standard cubic feet per day (mmscfd)**	**Water (bwpd)**	**Water Injection (bwpd)**	**Handling Limitations, and comments**	**Field/Facility Startup**
Badami	35,000	25	12,000	30,000	No Limits	Aug 1998
Colville River	140,000	180	100,000	140,000	We know of no limits at this time	Nov 2000, expansions in 2004 and 2005
Endicott	115,000	455	225,000	245,000	Limited gas and water	Jul 1986
Kuparuk					Limited Gas, water, & total fluid handling	
CPF-1	170,000	200	250,000	250,000	Rates currently below referenced limits	Dec 1981
CPF-2	160,000	260	250,000	300,000	Rates currently below referenced limits; may be nearing water limits	Jun 1983
CPF-3	85,000	150	100,000	220,000	Rates currently below referenced limits	Jun 1985
Milne Point	75,000	42	99,000		None known for current development	Jul 1983
Northstar	77,000	555	30,000		Limited by gas handling, water production is not at limit. Uncertain whether rated capacity is current.	Oct 2001
PBU					Limited gas, water handling - Note: cannot add up each facility to obtain total field restrictions. SI wells to maintain field limits.	
FS-1	360,000	2,800	140,000		Limited gas and water handling	Jun 1977
FS-2	360,000	1,200	650,000		Possible water handling limit	Jun 1977

FS-3	360,000	1,300	300,000		Note: FS-3 and GC-3 production can be diverted to either/both gathering center. Combined FS-3 and GC-3 at gas handling limits	Mar 1979
GC-1	330,000	2,600	180,000		High GORs - some wells not competitive at field level.	May 1977
GC-2	250,000	1,070	300,000		Limited gas and water handling	Jun 1977
GC-3		1,100	275,000		Note: FS-3 and GC-3 production can be diverted to either/both gathering center. Combined FS-3 and GC-3 at gas handling limits	Apr 1978
CGF		8,700			Limited by gas handling. Note, while "Design" capacity is 8.7 BCF/D peak, actual operating capacity around 7.5 BCFD average yearly at the plant inlet, with peaks of around 8.2 BCFD.	Jun 1977 Full Start, (NGL initial prod 1980, expansions in 1986, 1990, and 1994)
CCP		8,700			Actual Injection Peaks at 7.2-7.8 BCFD. Limited by CGF gas handling capacity	Jun 1977 Expansions in 1986, 1990, and 1994, Peak NGL Rate 97,000/day in 1996
LPC - Greater Pt. McIntyre	205,000	450	120,000		Limited gas, water, and total fluid. Some wells from Pt. McIntyre flow into GC1	Dec 1986
Oooguruk					Production to Kuparuk CPF-3. No known handling limits at Oooguruk.	Jun 2008
Nikaitchuq	40,000	unknown	120,000		No limits at this time	Jan 2011

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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The Honorable Hollis French
Alaska State Senator
State Capitol, Room 417
Juneau, AK 99801

February 13, 2012

Dear Senator French:

Thank you for your email on January 30, following up with questions you have from the Senate Resources committee.

1. *Today in committee your slide #3 told us that Texas is BOOMING (your caps). Imagine how I felt to read in your department's recent publication "Alaska's Oil and Gas Fiscal Regime" on page 4 that "Oil production in Texas is up slightly". Which is it?*

   After decades of a production decline remarkably similar to Alaska's, Texas has flattened out their decline curve and begun to increase production. This activity has resulted in thousands of new jobs and has played a large role in pulling Texas out of the nationwide recession. Defining what is considered a boom is subjective. In my opinion, if we can achieve in Alaska what has been achieved in Texas over the last few years, I would consider that a boom.

2. *Last week I asked you about whether the new production in Texas was conventional or shale oil. You replied that is was conventional. You have been asked to document that assertation. Please share your documentation with me as well.*

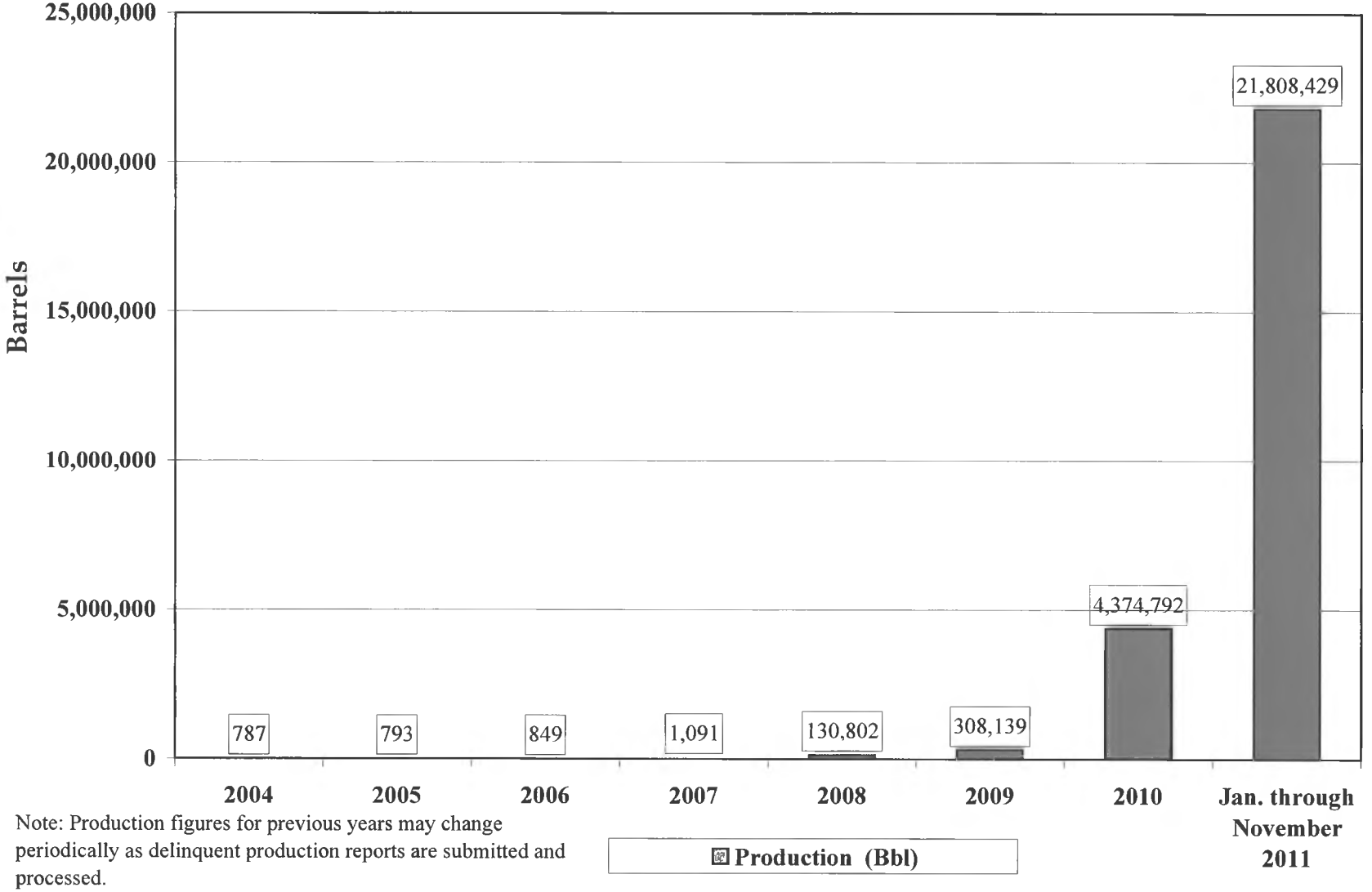
   Comments made recently about the flattening of the decline curve having resulted from conventional oil are a result of our face to face discussions with the Railroad Commission of Texas, the Texas equivalent of AOGCC. The majority of shale oil being produced in Texas is from the Eagle Ford shale play. Attached you will find a year to year summary of shale oil production from Eagle Ford from 2004 through November, 2011. This information may be found on-line at http://www.rrc.state.tx.us/eagleford/EagleFordOilProduction.pdf . As you can see, the biggest jump in production occurred in 2011, which was not included in DOR's slide presented to you in Senate Resources on January 27, 2012.

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

Sincerely,

Bryan Butcher
Commissioner

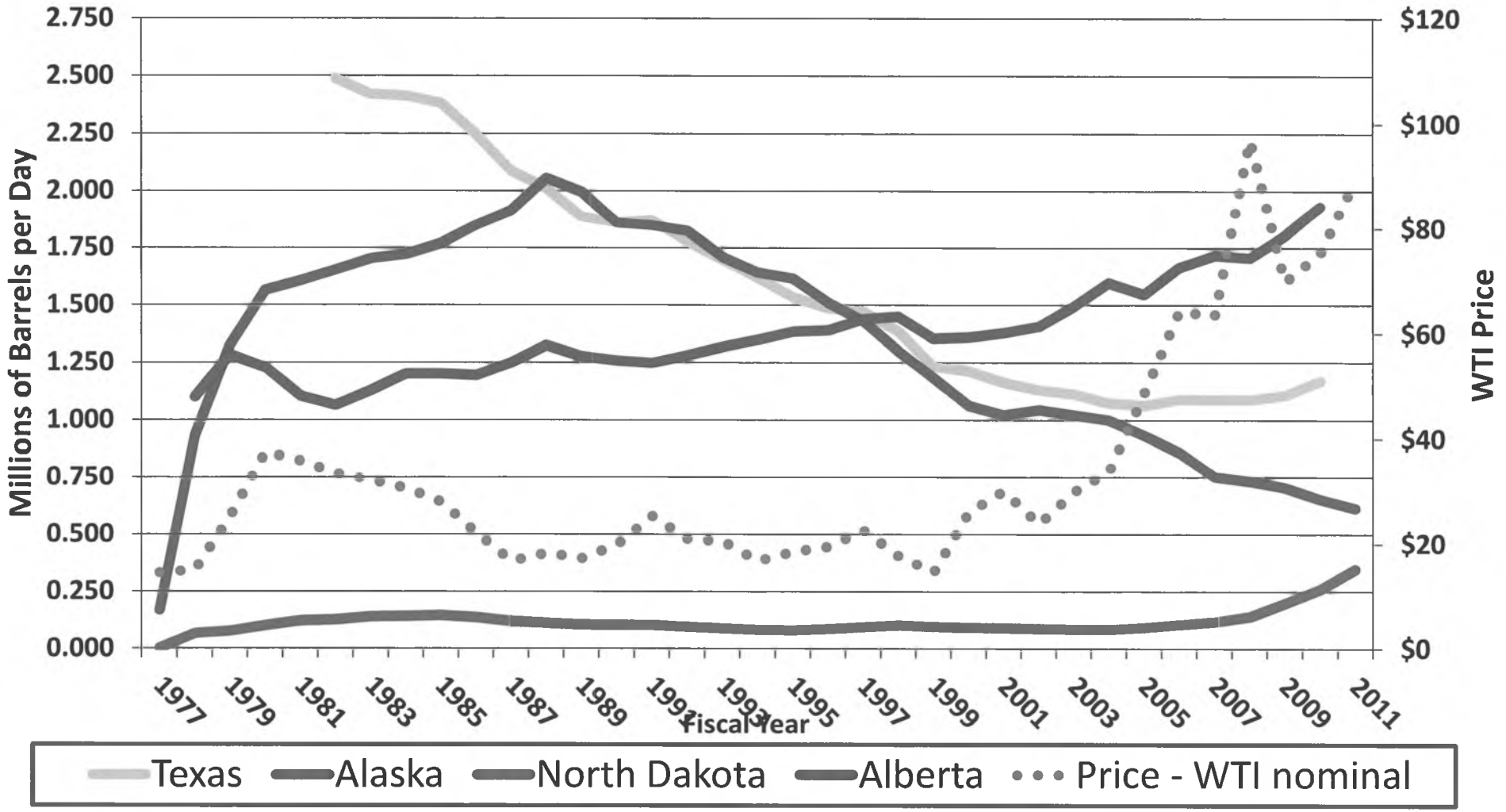
Texas Eagle Ford Shale
Oil Production
2004 through November 2011



Note: Production figures for previous years may change periodically as delinquent production reports are submitted and processed.

Historical Oil Production:

How Did Our Competition Fare When Prices Spiked?



Alaska Department of Revenue

Date	Oil (BBL)	Casinghead (MCF)	GW Gas (MCF)	Condensate (BBL)	
Jan-93	50,410,883	109,240,003	368,487,412	2,868,768	
Feb-93	45,634,807	100,315,316	333,803,869	2,635,625	
Mar-93	50,288,197	112,470,511	370,855,621	2,912,724	
Apr-93	48,194,383	108,833,723	357,648,663	2,829,670	
May-93	49,330,072	111,948,174	364,967,997	2,961,272	
Jun-93	47,325,888	108,375,587	355,754,561	2,806,981	
Jul-93	48,402,757	112,725,162	368,052,666	2,820,234	560,175,224
Aug-93	48,495,965	113,445,090	361,159,467	2,873,056	
Sep-93	46,676,980	108,095,830	354,101,464	2,880,129	
Oct-93	48,174,274	111,399,790	369,469,246	3,154,330	
Nov-93	46,684,142	105,183,018	359,436,905	3,010,380	
Dec-93	47,998,045	108,261,339	372,968,218	3,127,598	
Jan-94	47,559,087	103,588,382	371,962,703	3,258,257	
Feb-94	42,761,629	93,939,019	338,543,186	2,942,935	
Mar-94	47,216,646	105,889,097	378,809,303	3,289,080	
Apr-94	45,253,940	102,156,321	367,339,947	3,256,350	
May-94	46,481,636	103,217,072	380,074,210	3,331,047	
Jun-94	44,470,123	101,971,226	369,522,229	3,163,677	
Jul-94	45,651,191	104,876,650	385,926,314	3,190,125	527,630,849
Aug-94	45,406,572	103,726,890	387,528,313	3,225,722	
Sep-94	43,864,046	100,334,526	369,094,963	3,120,514	
Oct-94	45,177,641	102,139,134	374,996,690	3,168,542	
Nov-94	43,930,284	97,897,556	376,193,990	3,208,258	
Dec-94	45,225,529	99,205,361	393,977,720	3,378,847	
Jan-95	44,769,396	97,922,016	386,797,930	3,369,920	
Feb-95	40,530,039	89,357,270	351,660,260	3,063,593	
Mar-95	44,492,958	98,660,854	385,485,716	3,299,473	
Apr-95	42,888,214	95,463,285	376,917,475	3,140,929	
May-95	43,732,241	97,852,080	391,974,723	3,226,111	
Jun-95	41,962,738	93,150,340	375,128,378	3,023,749	
Jul-95	43,015,328	95,955,495	383,712,358	3,084,630	507,229,632
Aug-95	42,905,303	94,446,314	384,858,313	3,070,852	
Sep-95	41,555,275	91,978,762	376,863,211	2,964,995	
Oct-95	43,386,365	94,761,673	387,338,704	3,109,813	
Nov-95	42,147,523	91,870,145	380,018,682	3,089,429	
Dec-95	43,143,510	92,984,905	390,595,711	3,230,991	
Jan-96	42,869,137	91,473,292	394,590,594	3,322,378	
Feb-96	40,094,489	85,625,846	373,488,881	3,142,721	
Mar-96	43,274,774	92,489,085	402,131,972	3,389,804	
Apr-96	41,544,145	91,308,796	388,392,145	3,253,991	
May-96	42,552,997	94,780,851	402,606,771	3,367,951	
Jun-96	40,740,786	91,502,856	387,455,505	3,198,347	
Jul-96	41,788,129	94,887,830	403,936,453	3,261,825	492,980,731

Aug-96	41,607,796	94,095,097	402,175,138	3,190,269	
Sep-96	40,516,299	90,264,848	391,627,977	3,129,738	
Oct-96	42,195,694	94,151,389	408,811,420	3,330,974	
Nov-96	40,678,069	88,829,427	400,490,096	3,237,084	
Dec-96	41,896,364	89,450,716	421,340,026	3,452,256	
Jan-97	41,238,982	86,003,115	414,908,428	3,438,150	
Feb-97	38,133,744	78,917,770	377,642,194	3,133,614	
Mar-97	42,138,722	88,748,217	416,556,246	3,432,572	
Apr-97	40,565,996	86,311,533	398,246,673	3,313,723	
May-97	41,879,880	89,908,133	406,973,417	3,285,217	
Jun-97	40,341,056	86,573,448	388,374,829	3,185,841	
Jul-97	41,710,723	90,006,734	401,944,271	3,221,346	484,319,182
Aug-97	41,404,796	89,027,622	401,527,066	3,207,608	
Sep-97	40,353,013	85,992,746	390,924,353	3,121,789	
Oct-97	41,753,155	88,209,755	408,403,138	3,333,095	
Nov-97	40,489,849	82,285,165	401,569,762	3,348,842	
Dec-97	41,359,688	83,557,575	413,261,658	3,481,091	
Jan-98	41,484,256	84,508,939	411,669,113	3,467,247	
Feb-98	37,503,314	76,537,915	375,805,531	3,123,752	
Mar-98	41,048,736	84,263,848	413,796,757	3,503,844	
Apr-98	39,252,278	81,515,824	402,645,173	3,300,949	
May-98	39,986,368	84,839,198	412,912,374	3,302,668	
Jun-98	37,973,006	82,900,535	398,165,655	3,099,334	
Jul-98	38,333,668	84,572,119	412,172,028	3,293,516	426,480,737
Aug-98	38,300,860	83,233,372	416,871,948	3,579,032	
Sep-98	36,651,510	79,729,972	399,262,417	3,264,479	
Oct-98	37,439,325	80,553,716	411,902,551	3,426,606	
Nov-98	35,874,870	76,279,936	399,708,428	3,296,289	
Dec-98	35,645,248	74,107,356	401,221,625	3,232,161	
Jan-99	35,510,034	75,675,374	405,332,533	3,350,129	
Feb-99	32,041,306	69,079,010	366,501,044	2,936,937	
Mar-99	35,073,530	74,850,472	401,215,018	3,206,716	
Apr-99	33,794,135	73,715,300	385,417,871	3,064,441	
May-99	34,590,335	75,782,691	396,128,152	2,996,758	
Jun-99	33,225,916	74,184,170	383,402,393	2,896,703	
Jul-99	34,276,330	76,861,171	396,207,036	2,927,729	407,371,803
Aug-99	34,066,441	76,096,512	393,106,095	2,839,147	
Sep-99	33,270,396	73,216,156	385,906,600	2,845,136	
Oct-99	34,747,638	74,728,161	403,033,540	2,985,521	
Nov-99	33,729,389	71,951,298	394,975,448	3,106,569	
Dec-99	34,750,904	72,598,056	405,889,097	3,312,640	
Jan-00	34,757,643	73,151,024	406,471,170	3,309,094	
Feb-00	32,759,546	69,134,724	380,318,890	3,057,733	
Mar-00	34,685,003	74,792,104	411,425,735	3,228,974	
Apr-00	33,409,498	73,138,392	398,752,544	3,043,115	
May-00	34,107,063	74,153,188	414,088,435	3,031,344	
Jun-00	32,811,952	73,050,309	403,750,917	2,980,521	

Jul-00	33,717,365	75,688,056	414,692,209	2,984,025	390,144,695
Aug-00	33,746,259	75,494,464	414,251,140	3,046,110	
Sep-00	32,578,391	73,145,294	400,207,646	2,960,029	
Oct-00	33,652,340	73,167,136	415,919,939	3,186,189	
Nov-00	32,338,212	69,491,602	402,638,705	3,163,280	
Dec-00	32,554,940	69,494,319	421,288,572	3,365,853	
Jan-01	33,143,747	71,731,678	420,555,401	3,428,622	
Feb-01	29,922,315	64,864,188	381,364,957	3,130,902	
Mar-01	32,987,442	71,331,809	422,566,211	3,499,134	
Apr-01	31,741,116	71,442,394	408,035,999	3,341,273	
May-01	32,542,176	73,411,685	423,976,609	3,224,485	
Jun-01	31,220,392	73,009,965	409,756,198	3,107,222	
Jul-01	32,034,928	74,812,091	420,838,153	3,197,562	372,997,390
Aug-01	32,019,127	74,204,186	421,747,154	3,174,675	
Sep-01	30,834,035	71,602,352	410,712,464	3,114,131	
Oct-01	32,236,848	73,176,738	424,025,917	3,340,132	
Nov-01	30,739,745	69,845,489	408,237,193	3,323,766	
Dec-01	31,764,783	70,383,290	422,830,870	3,564,394	
Jan-02	31,845,735	70,237,201	419,019,231	3,631,557	
Feb-02	28,673,519	63,658,080	378,149,833	3,285,983	
Mar-02	31,498,312	71,037,945	418,554,245	3,404,923	
Apr-02	30,285,455	69,166,656	405,194,795	3,367,749	
May-02	31,225,661	70,850,062	417,998,453	3,370,745	
Jun-02	29,839,242	69,737,649	403,297,385	3,136,187	
Jul-02	30,607,151	71,985,305	417,238,580	3,268,871	361,712,229
Aug-02	30,676,792	71,122,237	416,011,791	3,292,214	
Sep-02	29,699,919	70,332,118	398,436,756	3,204,511	
Oct-02	30,596,406	69,686,073	415,808,708	3,383,161	
Nov-02	29,935,899	67,026,508	399,237,951	3,297,489	
Dec-02	30,854,075	70,643,146	409,977,175	3,397,728	
Jan-03	30,834,596	69,194,691	408,134,894	3,500,664	
Feb-03	27,874,342	63,586,763	372,815,887	3,170,741	
Mar-03	30,939,101	69,908,627	422,167,254	3,638,657	
Apr-03	29,874,043	68,812,305	406,620,962	3,398,006	
May-03	30,573,954	71,322,344	424,675,355	3,456,703	
Jun-03	29,245,951	68,523,848	411,795,697	3,313,724	
Jul-03	30,143,033	72,066,529	427,274,208	3,428,752	355,814,518
Aug-03	30,159,655	72,128,815	426,862,585	3,368,774	
Sep-03	29,460,536	70,322,574	414,084,817	3,381,189	
Oct-03	30,572,435	71,056,110	427,170,169	3,498,957	
Nov-03	29,470,069	67,978,940	413,939,894	3,379,627	
Dec-03	30,273,633	73,241,712	429,709,032	3,703,802	
Jan-04	30,095,903	75,758,180	430,938,707	3,701,486	
Feb-04	28,226,668	70,546,029	403,197,322	3,473,469	
Mar-04	30,157,682	76,476,100	430,908,165	3,600,576	
Apr-04	29,019,005	73,963,629	420,145,506	3,442,323	
May-04	29,801,770	77,350,146	434,395,350	3,421,758	

Jun-04	28,434,129	75,044,260	418,264,403	3,274,501	
Jul-04	29,412,483	78,585,847	434,617,157	3,349,931	350,191,783
Aug-04	29,512,847	78,970,845	433,711,001	3,325,463	
Sep-04	28,736,912	77,373,935	420,458,030	3,286,343	
Oct-04	29,586,737	80,367,138	438,221,376	3,503,637	
Nov-04	28,652,719	77,121,992	424,367,577	3,418,822	
Dec-04	29,667,679	78,408,024	435,037,648	3,616,111	
Jan-05	29,962,056	55,050,907	440,727,586	3,772,911	
Feb-05	27,187,915	50,976,837	404,012,631	3,525,280	
Mar-05	30,153,217	60,423,002	451,706,648	3,878,329	
Apr-05	28,994,237	56,128,361	440,606,274	3,710,884	
May-05	29,696,799	58,110,559	451,759,221	3,741,033	
Jun-05	28,628,182	56,126,800	437,558,785	3,463,012	
Jul-05	29,293,674	57,301,984	458,159,799	3,589,341	347,158,617
Aug-05	29,366,976	57,716,463	463,080,949	3,639,737	
Sep-05	27,952,501	52,706,946	431,005,094	3,195,196	
Oct-05	29,544,016	56,775,060	466,963,656	3,624,049	
Nov-05	28,748,575	54,956,988	457,724,424	3,633,899	
Dec-05	29,413,807	55,550,451	472,299,208	3,838,925	
Jan-06	29,704,766	57,771,973	473,093,910	3,920,658	
Feb-06	26,907,758	51,212,473	425,902,292	3,529,468	
Mar-06	29,750,235	57,925,920	476,668,004	3,933,364	
Apr-06	28,660,651	56,487,430	463,760,098	3,717,294	
May-06	29,423,019	57,539,913	482,386,048	3,728,018	
Jun-06	28,392,639	55,657,578	465,431,657	3,543,635	
Jul-06	29,224,395	57,267,246	482,847,581	3,685,508	344,453,305
Aug-06	29,093,672	56,832,051	486,527,604	3,700,237	
Sep-06	28,460,070	57,705,210	473,987,298	3,651,243	
Oct-06	29,575,238	58,824,926	490,646,432	3,853,798	
Nov-06	28,657,237	56,170,289	477,632,882	3,843,024	
Dec-06	29,429,280	58,535,986	495,614,280	3,966,995	
Jan-07	28,868,316	57,272,894	489,145,682	3,911,101	
Feb-07	26,489,647	53,085,325	453,265,114	3,690,190	
Mar-07	29,291,322	59,402,965	515,646,695	4,196,909	
Apr-07	28,466,896	56,926,606	499,999,565	4,001,665	
May-07	29,092,873	59,707,532	523,694,198	4,134,255	
Jun-07	27,804,359	57,892,624	515,041,609	3,923,400	
Jul-07	28,854,805	60,532,902	532,711,007	3,966,211	347,418,838
Aug-07	28,906,389	60,982,584	541,929,168	4,063,759	
Sep-07	28,136,753	58,985,550	527,228,383	3,931,461	
Oct-07	29,114,723	61,524,088	551,224,992	4,105,497	
Nov-07	28,366,639	58,804,611	543,761,444	4,137,063	
Dec-07	29,398,206	59,730,189	569,056,241	4,304,973	
Jan-08	29,456,966	59,844,078	569,542,795	4,453,055	
Feb-08	27,842,638	57,915,392	541,995,118	4,173,345	
Mar-08	29,865,456	62,540,912	588,171,329	4,676,304	
Apr-08	28,959,208	61,574,650	572,759,578	4,427,836	

May-08	29,881,601	64,783,439	600,160,143	4,505,566	
Jun-08	28,635,454	62,097,022	582,828,781	4,265,193	
Jul-08	29,964,810	65,835,274	603,743,854	4,443,463	353,438,970
Aug-08	29,977,614	65,403,945	611,529,452	4,424,510	
Sep-08	27,992,720	54,955,861	560,025,674	3,665,475	
Oct-08	30,404,293	64,092,416	618,750,094	4,463,880	
Nov-08	29,803,191	63,983,314	605,019,515	4,420,714	
Dec-08	30,513,715	64,431,032	623,102,126	4,594,885	
Jan-09	30,415,304	64,658,367	625,816,513	4,681,529	
Feb-09	27,361,156	57,290,372	560,702,863	4,136,756	
Mar-09	30,134,398	64,410,165	620,837,116	4,501,249	
Apr-09	28,995,316	64,143,695	587,146,542	4,286,232	
May-09	29,554,495	66,156,646	596,492,632	4,167,179	
Jun-09	28,321,958	64,427,336	569,749,640	3,786,262	
Jul-09	29,012,101	66,803,831	579,951,613	3,908,183	351,644,267
Aug-09	29,178,867	65,806,771	574,811,215	3,864,706	
Sep-09	28,657,021	65,475,881	542,706,316	3,739,691	
Oct-09	29,501,845	66,500,954	557,976,643	3,943,842	
Nov-09	28,881,115	65,858,101	540,881,601	4,082,915	
Dec-09	29,418,318	65,873,455	555,381,895	4,299,450	
Jan-10	29,567,497	66,389,022	557,906,862	4,413,750	
Feb-10	27,149,472	61,234,825	512,121,686	4,175,407	
Mar-10	30,496,226	68,993,042	576,796,942	4,679,579	
Apr-10	29,608,326	68,185,924	547,150,824	4,423,406	
May-10	30,696,387	72,054,543	573,083,751	4,696,247	
Jun-10	29,477,092	67,916,948	546,235,800	4,430,938	
Jul-10	30,832,155	70,720,903	563,406,844	4,470,981	305,315,543
Aug-10	31,109,469	71,682,518	563,029,486	4,591,741	
Sep-10	30,511,774	70,652,877	543,820,256	4,430,829	
Oct-10	31,850,859	73,503,789	555,127,493	4,586,541	
Nov-10	30,840,136	70,879,218	533,866,372	4,557,492	
Dec-10	32,018,590	73,908,593	543,234,413	4,667,383	
Jan-11	31,542,694	72,074,230	525,344,791	4,590,189	
Feb-11	26,465,698	60,141,910	444,547,428	3,928,850	
Mar-11	31,141,010	71,754,674	510,632,980	4,405,900	
Apr-11	29,003,158	66,049,970	476,974,404	3,799,668	

BBL/YR	FY 94	FY 95	FY 96	FY 97	FY 98
MMBL/D	5.6E+08	527630849	507229632	492980731	484319182
	1.534727	1.44556397	1.389670225	1.35063214	1.326901868

BBL/YR	FY 99	FY 00	FY 01	FY 02	FY 03
MMBL/D	4.26E+08	407371803	390144695	372997390	361712229
	1.16844	1.116087132	1.068889575	1.021910658	0.990992408

BBL/YR	FY 04	FY 05	FY 06	FY 07	FY 08
MMBL/D	3.56E+08	350191783	347158617	344453305	347418838
	0.974834	0.959429542	0.951119499	0.943707685	0.951832433

BBL/YR	FY 09	FY 10	FY 11
MMBL/D	3.53E+08	351644267	305315543
	0.968326	0.963408951	0.83648094

Source: Texas Railroad Commission
http://www.rrc.state.tx.us/data/index.php

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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The Honorable Joe Paskvan
The Honorable Tom Wagoner
Co-Chairs, Senate Resources Committee
Alaska State Senate
State Capitol, Room 119
Juneau, AK 99801

February 14, 2012

Re: Response to Questions from Senate Resources Hearing on January 27, 2012

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 to the committee on January 27, 2012. The requests/questions and responses follow.

1) **Provide details on how the Department studies "Project Economics" per slide 4.**

The Department does not perform project economics on individual projects included in our production forecast. In the Department's view, the economic viability of the projects and development included in the production forecast is implied by the individual company's inclusion in their production forecast submission.

2) **Identify what projects are in the "under development" and "under evaluation" categories, to the extent possible.**

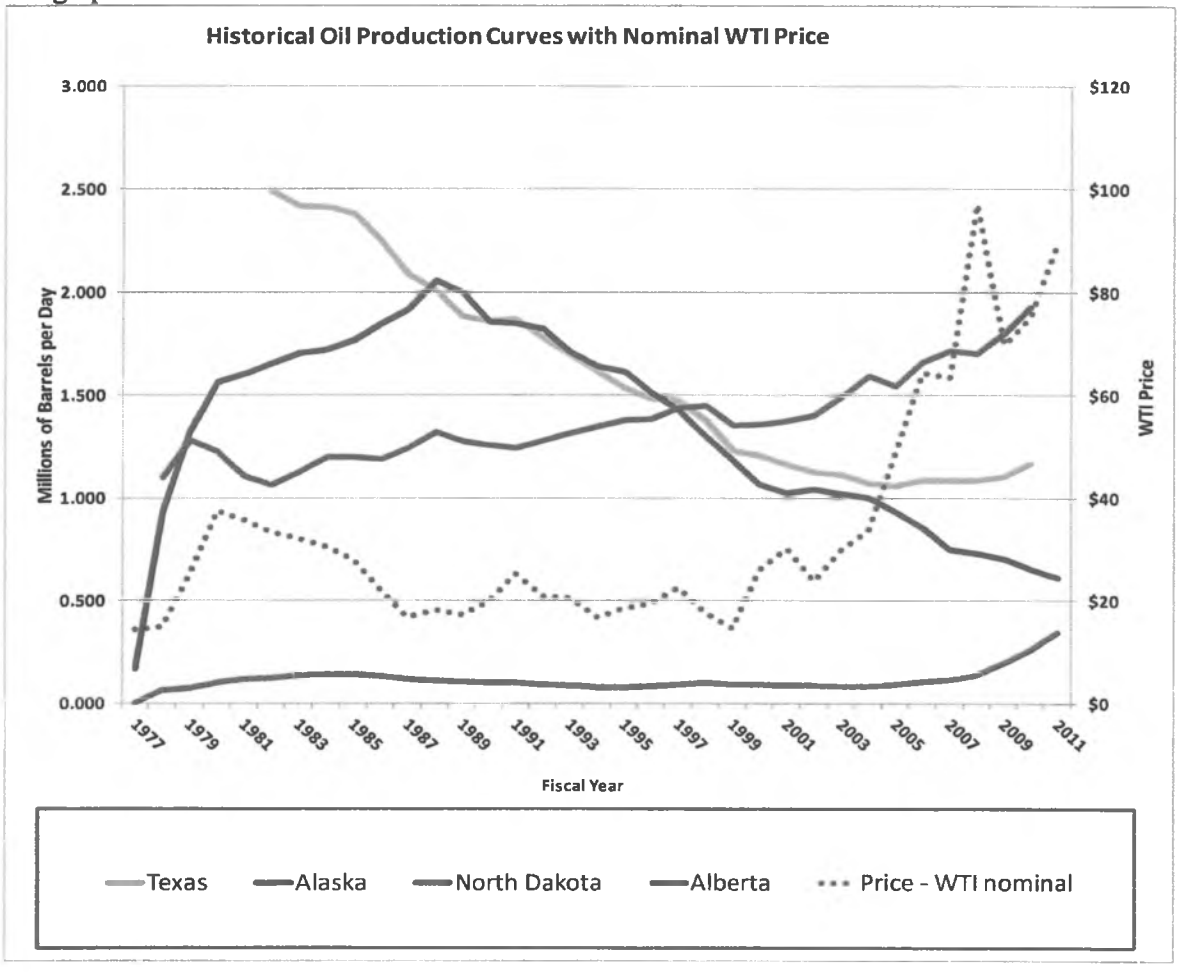
From the Department's Fall 2011 Revenue Sources Book, pg 41, located online here: *http://www.tax.alaska.gov//programs/documentviewer/viewer.aspx?2443f*

"Examples of production currently under development include the Nanuq and Alpine West satellites at Alpine, the Borealis and Orion satellites at Prudhoe Bay, development drilling at Liberty, Oooguruk and Nikaitchuq, and ongoing development drilling at Prudhoe Bay and Kuparuk."

"Under Evaluation: Examples include longer term Orion drilling, long-term production from Pt. Thomson and associated satellites, and pools within NPR-A."

3) Provide data to support information provided to the Senate Resources Committee on the production increases / decreases in Texas and other jurisdictions compared to Alaska

See graph with notes and sources below.



Notes and Sources

- Alaska production is from the same sources used in publication of the RSB and includes NGLs and non-state volumes at Northstar.
- North Dakota Production was provided by the North Dakota Pipeline Authority.
- Texas, Oklahoma and California production is all from the EIA. Texas oil production includes volumes from the Eagle Ford and Barnett shale plays.
- Alberta and Saskatchewan production is from the Canadian Association of Petroleum Producers and includes both oil sands and heavy oil production. Also, please note the

Alberta data was adjusted from two separate sources at CAPP per conversations with individuals at CAPP in Alberta and may not match the data online exactly.
- Alaskan production and ND production are in Fiscal Years (FY). All other production is in Calendar Year (CY).

4) Provide estimates for Prudhoe and Kuparuk recovery rates compared to Texas, Oklahoma, and North Dakota

Recovery rates are estimates that vary with the resource, reservoir, and recovery types. Further, recovery rates vary both over time, and from one field to another. The recovery rate for Prudhoe Bay as outlined in the attachment, "Prudhoe Lisburne Fact sheet" was originally expected to be 40% but has increased to over 60% due to new technologies. Kuparuk recovery is expected to exceed 40%. Publicly available estimates for recovery factors in the Bakken in North Dakota range from 3% to 50%. The Department was unable to obtain recovery rates, or estimated recovery rates for Texas or Oklahoma. Estimated recovery rates for individual fields in Texas and Oklahoma will vary with the resource, reservoir and recovery types.

5) Provide an estimate of revenue under the 300,000 barrels per day scenario like Slide 7 of the Senate Resources presentation of January 27, 2012, using HB 110.

As currently written, most of the provisions of HB 110 would take effect on January 1, 2013, meaning that HB 110 would be in place for only half of FY 2013. However, in order to be responsive to your question, we have calculated the revenue as if HB 110 were in effect for the entirety of FY 2013. With that assumption, and an assumption of $300 million for well lease expenditure credits, plus all the assumptions included in slide 7, we estimate total GF unrestricted revenue to be $3.2 billion.

Using the same assumptions in slide 7 of the presentation, a total of GF unrestricted revenue in FY 2013 of $3.2 billion would translate out to a revenue to budget shortfall of $3.23 billion. Based on high level assumptions regarding income and sales in the state, this amount could hypothetically be filled by one of the following: (1) every Alaska resident paying the state $4,500; (2) a statewide sales tax of up to 48%; or (3) a statewide flat income tax of up to 18%.

6) Provide monetary value of 100% deduction for capital expenditures for all years shown on slides 13 and 14

The following table illustrates the approximate benefit of 100% deduction of capital expenditures in FY 2007-FY 2011 and forecasted FY 2012. To estimate these values, we calculate the statewide tax liability using the "income statement" approach, under status quo (with 100% deduction for capital expenditures in the year the expenditure was made), and under ACES with an alternative deduction for capital expenditures. Two alternatives are shown:

1. The first assumes a 10-year depreciation schedule for capital expenditures beginning in FY 2007. For this presentation we assume that in FY 2007, the only deduction would be for 1/10th of that year's spending. In FY 2008, the deduction would be 1/10th of that year's spending plus 1/10th of the prior year's spending, and so on. This attempts to illustrate the impact of a depreciation schedule for capital expenditures had such a schedule been put in place for the net profits tax when it was first enacted.
2. The second alternative assumes that no deduction at all is allowed for capital expenditures in calculating production tax and so all capital expenditures were removed from the tax calculation.

Note that our calculations use yearly and statewide averages instead of company-specific monthly calculations, and therefore are approximate. The capital expenditure numbers used are company-reported capital expenditures before exclusions. Also, note that this analysis considers only companies with tax liability, and the value of being able to deduct capital expenditures in calculating tax due – it does not consider the value of the Net Operating Loss Carry forward credit to companies without a tax liability.

See table on the following page and also attached "Prudhoe Lisburne Fact sheet."

I hope these answers fully address your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Estimated monetary value of 100% deduction for capital expenditures, FY 2007 - FY 2011 and forecast FY 2012 ($M)

Current Production Tax Calculation - using 100% deduction for capital expenditures in the year earned						
Fiscal Year	2007	2008	2009	2010	2011	2012
Taxable barrels	277,972,233	226,024,764	218,438,995	203,816,365	190,488,390	175,943,938
Gross Value at Point of Production	16,026	20,403	13,513	14,039	16,633	17,641
Deductible Operating Expenses	2,228	1,897	2,050	2,169	2,517	2,468
Deductible Capital Expenses	1,446	1,914	1,750	1,742	1,623	1,804
Production Tax Value	12,352	16,592	9,713	10,128	12,493	13,368
PTV / Barrel	$ 44.43	$ 73.41	$ 44.46	$ 49.69	$ 65.58	$ 75.98
tax rate	23.6%	42.4%	30.8%	32.9%	39.2%	43.4%
Total Tax before credits	**2,916.1**	**7,028.9**	**2,990.1**	**3,329.8**	**4,901.3**	**5,800.9**

Alternative Production Tax Calculation - using 10-year depreciation of capital expenditures beginning FY 2007						
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Fiscal Year	2007	2008	2009	2010	2011	2012
Taxable barrels	277,972,233	226,024,764	218,438,995	203,816,365	190,488,390	175,943,938
Gross Value at Point of Production	16,026	20,403	13,513	14,039	16,633	17,641
Deductible Operating Expenses	2,228	1,897	2,050	2,169	2,517	2,468
Deductible Capital Expenses	145	336	511	685	847	1,028
Production Tax Value	13,653	18,170	10,952	11,185	13,268	14,145
PTV / Barrel	$ 49.12	$ 80.39	$ 50.14	$ 54.88	$ 69.65	$ 80.39
tax rate	24.8%	45.2%	33.1%	35.0%	40.9%	45.2%
Total Tax before credits	**3,383.2**	**8,204.4**	**3,620.0**	**3,909.2**	**5,421.5**	**6,387.2**
Est Benefit of 100% CapEx Deduction vs Depreciation *	**467.1**	**1,175.5**	**629.9**	**579.4**	**520.3**	**586.4**

This benefit decreases over time as more years are included in the calculation.

Alternative Production Tax Calculation - with no deduction for capital expenditures						
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Fiscal Year	2007	2008	2009	2010	2011	2012
Taxable barrels	277,972,233	226,024,764	218,438,995	203,816,365	190,488,390	175,943,938
Gross Value at Point of Production	16,026	20,403	13,513	14,039	16,633	17,641
Deductible Operating Expenses	2,228	1,897	2,050	2,169	2,517	2,468
Deductible Capital Expenses	-	-	-	-	-	-
Production Tax Value	13,798	18,506	11,463	11,870	14,116	15,172
PTV / Barrel	$ 49.64	$ 81.87	$ 52.48	$ 58.24	$ 74.10	$ 86.23
tax rate	24.9%	45.7%	34.0%	36.3%	42.6%	47.5%
Total Tax before credits	**3,437.0**	**8,466.2**	**3,896.2**	**4,308.3**	**6,019.0**	**7,205.9**
Est Benefit of 100% CapEx Deduction vs no CapEx Deduction	**520.9**	**1,437.3**	**906.1**	**978.5**	**1,117.8**	**1,405.1**

Amounts in $ millions except for tax rate

Amounts shown here are illustrations using "income statement" approach, not precise company-specific calculations

FY 2007-2008 taken from DOR forecast models, FY 2009+ taken from "Income Statement" sheets

Depreciation example assumes 10-year depreciation with 2007 being the first year. In 2007, only 10% of 2007 capex is deducted. In 2008, the deduction is 10% of 2007 plus 10% of 2008, and so on.

FY 2007 tax is PPT and represents 14 months of production, FY 2008-on are ACES

GREATER PRUDHOE BAY

After more than 30 years of production, Prudhoe Bay remains the largest oil field in North America and ranks among the 20 largest fields ever discovered. When production started at the Prudhoe Bay field the recovery rate of the 25 billion barrels of oil in place was expected to reach 40 percent. Today, using new technologies that estimate has increased to more than 60 percent.

The initial producing area of Prudhoe Bay field has produced more than 12 billion barrels, of which BP's net cumulative production is approximately 4.6 billion barrels of oil equivalent (BOE). Production from the Prudhoe Bay initial producing area averaged approximately 314,000 BOE per day in 2008. The Energy Information Administration estimates the field also contains an estimated recoverable 26 trillion cubic feet of natural gas in an overlying gas cap and in solution with the oil.

Prudhoe Bay produces from the Sadlerochit sandstone formation, nearly 9,000 feet below sea level. The oil bearing column is 500 feet thick in some areas. The Greater Prudhoe Bay Area, which includes the fields of Prudhoe Bay, its satellite fields and the Greater Point McIntyre Area fields, in total produce about 392,000 BOE per day. Cumulative production has exceeded 13 billion barrels; BP's net share is 4.8 billion barrels.

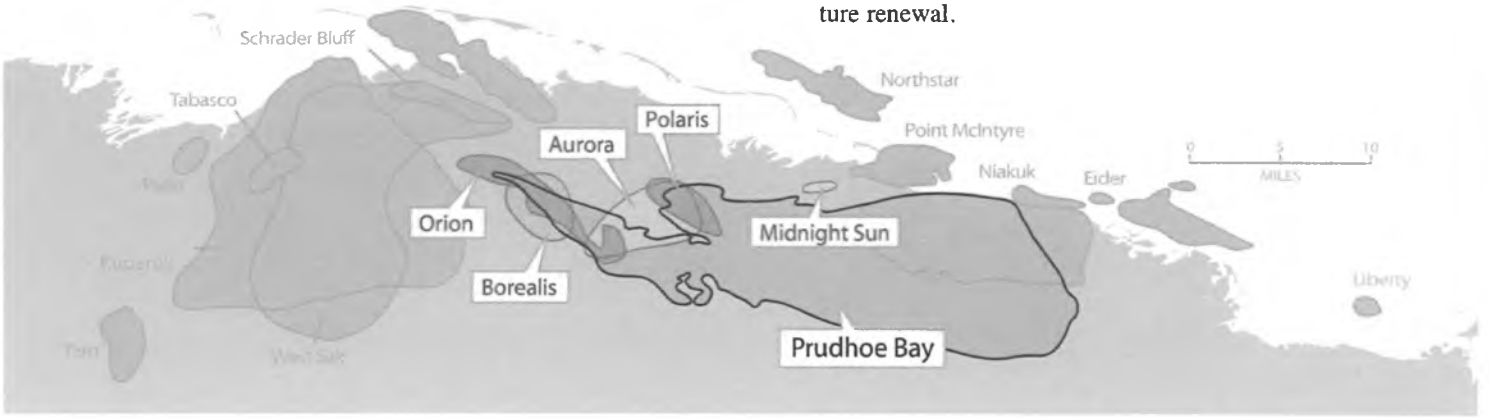
BP's net production from Greater Prudhoe Bay Area averages approximately 98,000 barrels of oil equivalent per day (BOED). Prudhoe Bay was discovered in 1968 and came on-stream June 20, 1977. Production averaged more than 1.5 million barrels of oil and gas liquids per day for more than a decade.

Prudhoe Bay satellites

Satellite fields are smaller accumulations of oil that can often be developed using existing infrastructure. The average daily production from Prudhoe Bay satellites is about 45,700 barrels of oil equivalent per day. BP's net share of that production is about 8,600 barrels. There are five satellite fields currently producing and the liquids are processed through the field's main facilities. Aurora and Borealis satellite fields produce from similar formations. Midnight Sun produces from a sandstone formation at 8,000 feet below sea level. Orion and Polaris fields both produce the difficult heavy oil from the Schrader Bluff formation, at depths of 4,000 to 5,000 feet below sea level. By using advanced drilling technologies we are growing this important resource. The Prudhoe Bay satellite fields have produced more than 118 million barrels of oil equivalent. BP's net cumulative production is approximately 23.4 million barrels of oil equivalent.

Prudhoe Bay renewal

BP completed replacing 16-miles of oil transit lines and put these lines into service in late 2008. The project included rebuilding the main Prudhoe Bay oil delivery system, pigging modules, corrosion inhibitor injection facilities, state-of-the-art leak detection, metering facilities and all the affiliated electrical and emergency systems. This $500 million project incorporates the best technology and materials to ensure safe operations. BP will continue to invest in safe, reliable and efficient operations through infrastructure renewal.



GREATER POINT MCINTYRE

The Greater Point McIntyre Area encompasses Point McIntyre field and the nearby satellite fields of West Beach, North Prudhoe Bay, Niakuk and Western Niakuk. The Lisburne Production Center processes fluids from Point McIntyre Area fields and the Lisburne field. Production averaged about 40,900 barrels per day in 2008. Cumulative production from the Greater Point McIntyre area is 717 million barrels of oil equivalent. BP's cumulative net production is approximately 165 million barrels of oil equivalent.

Point McIntyre

Located seven miles north of Prudhoe Bay, the Point McIntyre field was discovered in 1988 and came on-line in 1993. Point McIntyre contained an estimated 900 million barrels of oil in place, of which about 500 million barrels is recoverable with existing technology. The field's production peaked in 1996 at 170,000 barrels per day. Production averaged about 27,000 barrels per day in 2008. BP produces the field from two gravel drill site pads. Production rates are maintained through drilling new wells, enhanced oil recovery methods and upgrades to facilities.

Drill rig at Point McIntyre.

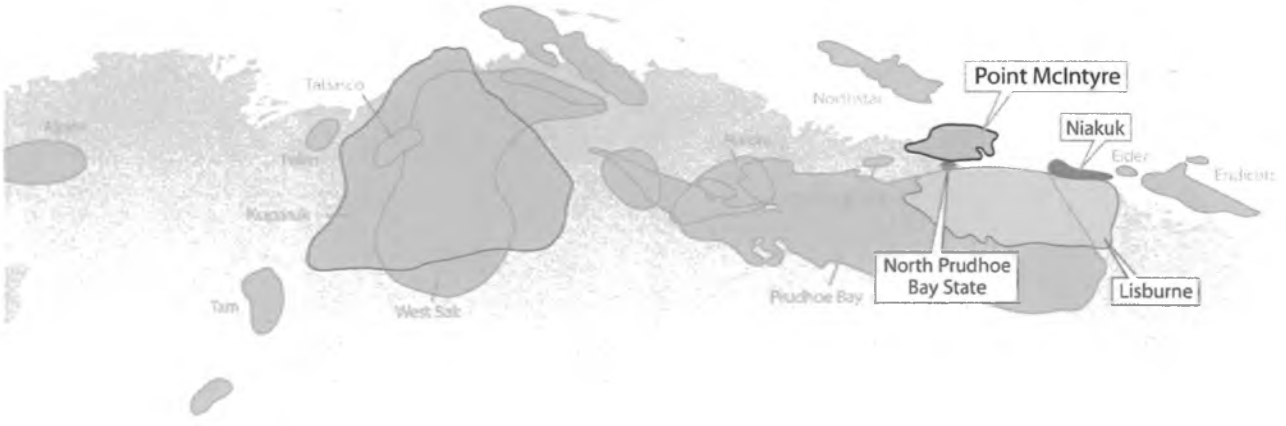
Niakuk and Western Niakuk

The Niakuk fields lie offshore and contain about 300 million barrels of original oil in place. Production in 2008 averaged about 5,500 barrels per day from the lower Cretaceous Kuparuk River formation, a structurally and stratigraphically complex formation.

Lisburne Processing Center

Lisburne

The Lisburne field is a complex, fractured carbonate reservoir that lies underneath and adjacent to the main Ivishak reservoir at Prudhoe Bay. The field was discovered in 1968 along with the Prudhoe Bay field and came on-stream in late 1986. The field contained an estimated 1.8 billion barrels of oil in place. Production averaged about 8,400 barrels per day in 2008. Cumulative production from the Lisburne field is is nearly 189 million barrels of oil equivalent. BP's cumulative net production from the field is approximately 44 million barrels of oil equivalent. Horizontal drilling technology using coiled tubing drilling, along with geosciences techniques to identify fracture and fault locations, have increased production rates in recent years.



The Niakuk and Western Niakuk fields lie offshore of the Prudhoe Bay.

Oil Fields	Point McIntyre	Niakuk	Lisburne
Owners	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%	BP (Operator) ~26% ConocoPhillips ~36% ExxonMobil ~36% Chevron ~2%
Field Data			
Participating Field Area	10,834 acres	6,443 acres	79,929 acres
Original Oil in Place	0.8 billion barrels	0.2 billion barrels	1.8 billion barrels
Original Gas in Place	0.9 trillion SCF	0.1 trillion SCF	0.3 trillion SCF
Cumulative Oil Production	Gross Field	Gross Field	Gross Field
Production (12/31/08) (millions of barrels of oil equivalent)	434	91.3	188.5
Current Rates (12/31/08)	Gross Field	Gross Field	Gross Field
Oil (thousands BOE/day)	27	5.5	8.4
Number of Wells			
Oil Producers	61	18	79
Gas Injection	1	0	4
Water Injection	9	7	0
WAG Injection*	6	0	0

** Water Alternating Gas Injector*

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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February 16, 2012

The Honorable Joe Paskvan
The Honorable Tom Wagoner
Co-Chairs, Senate Resources Committee
Alaska State Senate
State Capitol, Room 119
Juneau, AK 99801

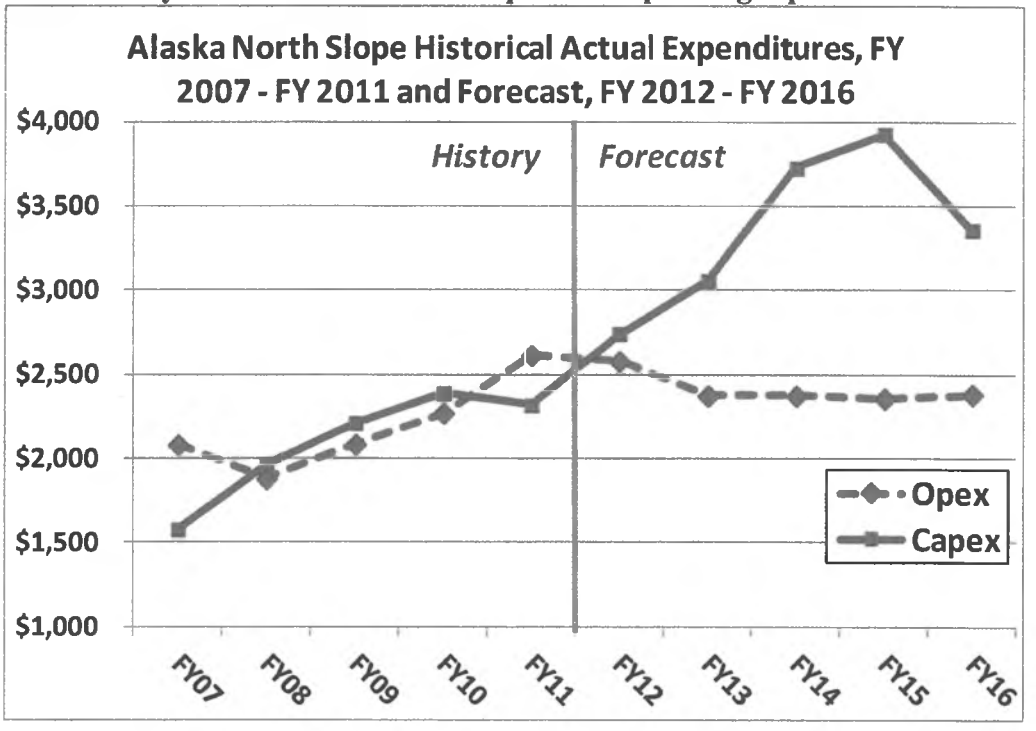
Re: Response to questions from Senate Resources Hearing on February 10, 2012

The purpose of this document is to respond to the follow-up questions raised by the Senate Resources Committee meeting on February 10, 2012.
The requests/questions and responses follow.

1) **Provide details on Texas reserves tax.**

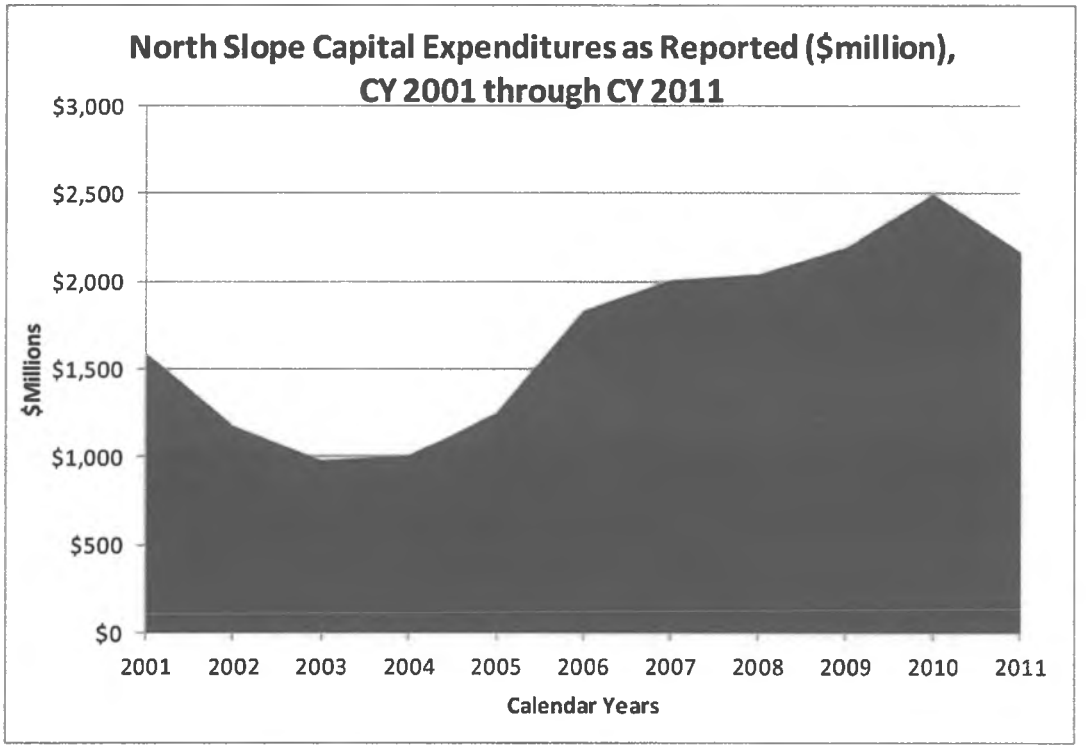
The Texas fiscal system is discussed on page 37 of our publication "Alaska's Oil and Gas Fiscal Regime – A Closer Look from a Global Perspective." Texas includes oil and gas reserves in their property tax calculation; property taxes are assessed at 2.5 percent, levied on the fair market value of reserves as determined by discounted present value. This rate reflects a statewide percent average for counties and school districts.

2) **Add several years of forecasts to our capital and operating expenditure slide.**



3) Provide expenditure history beginning in 2000 or as far back as we have it

Slide 6 of our presentation includes the 5 fiscal years of actual operating and capital expenditure information, subsequent to the enactment of a net profits tax, based on company submitted annual returns and monthly information forms. This slide, which is included above with extended forecast information per the committee's request, represents the extent of our complete data for total lease expenditures. We do not have complete operating expenditure information prior to FY 2007.
For capital expenditures, we do have data on a calendar year basis beginning with 2001. That information was provided to the committee in Chart 3 of the "Oil & Gas Tax Status Report 2011" dated January 18, 2011 and has been updated here for your convenience.



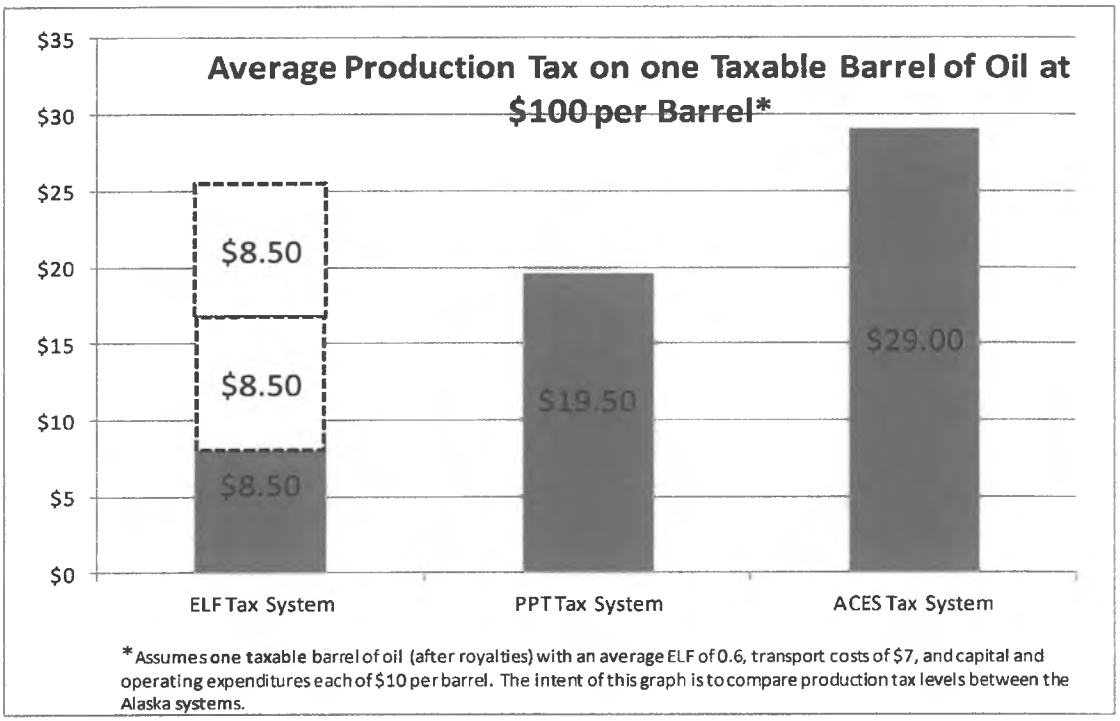
4) Provide calculations for how we arrive at $29 tax per barrel at $100 and provide the tax per barrel chart on Slide 10 with PPT included.

The illustration presented to the Senate Resources Committee was primarily intended to show how the production tax under the ELF system compares to the production tax under the ACES system at today's oil prices. The tax calculation was simplified for a wider audience by removing reference to royalties. The calculation as indicated in the slide presented for the Senate Resources Committee assumes that the barrel is a "taxable" barrel. If we had included royalties in the calculation, the numbers would have been slightly lower, but the effect would have been the same—that is, at $100 per barrel, the ACES tax was triple the amount it would have been under the ELF tax system.

The following calculations show how the $29 in tax per taxable barrel (without the impact of royalties) is calculated under ACES at $100 per barrel. We also include the calculations under ELF and PPT per the request of the committee. As noted, this example assumes transportation costs of $7 per barrel, and capital and operating expenditures each of $10 per taxable barrel. The calculation for the PPT assumes that TIE credits add credits equal to 10% of the capital expenditures. These assumptions are in line with the level of expenditures in place when ACES was implemented in FY 2008.

Again, the high-level simplistic analysis is intended to show how the tax burden changed from ELF to PPT to ACES. As shown, PPT more than doubled the tax burden compared to the ELF system, while ACES more than tripled it.

Tax Calculations - One TAXABLE barrel				
	ELF	**PPT**	**ACES**	
Destination Value	$100.00	$100.00	$100.00	
Value at Wellhead	$93.00	$93.00	$93.00	
Prod Tax Value	--	$73.00	$73.00	
Base tax rate	15.0%	22.5%	25.0%	
Progressive tax rate	--	8.3%	17.2%	
Total tax rate	15.0%	30.8%	42.2%	
Average ELF (2006)	0.6	--	--	
Tax before credits	$8.37	$22.45	$30.81	
Credits**	--	$3.00	$2.00	
Tax after credits (rounded)	$8.50	$19.50	$29.00	
**PPT tax calculation assumes TIE credits of $1 per barrel				



5) Provide information on Cook Inlet and how SB 309 impacted activity at different prices, credits, and tax rates. Provide examples of what SB 309 has done to incentivize activity.

SB 309 (2010), which was later incorporated into HB 280 (2010), "The Cook Inlet Recovery Act," expanded the alternative tax credit for oil and gas exploration under AS 43.55.025 and changed the existing Gas Exploration and Development credit under AS 43.20.043. SB 309 created what is commonly referred to as the "Cook Inlet Jack-up Rig Credit," which offers a credit to the first three unaffiliated persons that drill an offshore exploration well for the purposes of discovering oil or gas in Cook Inlet that penetrates and evaluates a prospect in the pre-Tertiary zone using a jack-up rig. Following the bill's passage, Furie Operating Alaska (formerly Escopeta) used a jack-up rig to begin drilling the KLU No. 1 well in Cook Inlet in September 2011. Escopeta cited the Jack-up Rig Credit as incentive to drilling the KLU No. 1 well. A second company, Buccaneer Alaska, expects to have a jack-up rig in Cook Inlet in April 2012 and begin drilling May.

SB 309 also increased the existing Gas Exploration and Development credit under AS 43.20.043. It increased the credit from 10% to 25% of qualified expenditures beginning January 1, 2010 and increased the amount of corporate income tax liability the credit can offset from 50% to 75%. While these changes are an incentive for natural gas exploration and development in Cook Inlet, the amount of Gas Exploration and Development credits applied against corporate income tax liability cannot be reported due to taxpayer confidentiality constraints.

Senate Bill 309 and the natural gas storage credit provisions in HB 280 have expanded the incentives for developing both oil and gas in Cook Inlet. There has been a resurgence of interest and activity in Cook Inlet that may be at least partially attributable to the incentives provided. However, the department cannot determine with any certainty the exact impact that oil or gas prices, credits, and tax rates would have had on Cook Inlet activity.

6) **How many wells have come back into production due to high prices in Texas that were previously shut in?**

We contacted the Oil and Gas Division of the Railroad Commission of Texas to assist with this request. They compared two snapshots of their wellbore database, one as of 1/31/2012 and one as of 1/31/2007.

Of the 90,174 wellbores wells that were inactive as of 1/31/2007, 19,028 are now plugged, 15,271 have been returned to active operation or worked over, and 55,875 remain in inactive status.

Note: this is a comparison of two snapshots in time. If a well had returned to active operation and then became inactive again, or if a well had returned to active operation and then been plugged, those would not show up in the data. One cannot point to high oil prices as the sole factor in play here. For example, in 2009 Texas adopted additional requirements associated with an operator's inactive well inventory; the resulting cleanup of records as well as restoration of wells to activity to avoid those requirements may have also contributed (in an indeterminable degree) to the shift.

7) **Provide backup for Alaska's 26.8% effective tax rate in slide 11**

The 26.8% effective tax rate was calculated by the Montana Department of Revenue as follows:

Oil and Gas Revenue Collected divided by the Value of Oil and Natural Gas Produced = $6,900,000,000/$25,741,800,390 = 26.8%

Based on the total revenue the Montana Department of Revenue included, it appears that they incorporated only the production tax and the petroleum property tax into their totals and did not include state petroleum royalties or corporate income tax.

I hope these answers fully address your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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The Honorable Bert Stedman
The Honorable Lyman Hoffman
Co-Chairs, Senate Finance Committee
Alaska State Senate
Juneau, AK 99801

February 16, 2012

Re: Response to questions from Senate Finance Hearing on February 2, 2012

Dear Senators Stedman and Hoffman:

The purpose of this document is to respond to the follow-up questions raised by the Senate Finance Committee meeting on February 2, 2012.
The requests/questions and responses follow.

1) **Provide what information the Department of Revenue (DOR) has about facilities constraining oil production (i.e. lack of gas or water handling capacity).**

Most of the facilities on the slope are constrained by either available gas handling or water handling capacity or both. Gas handling constraints are the reason we see the large swings when comparing summer to winter production. This is because of ambient temperature fluctuations. Gas compressors are powered by gas turbines whose efficiency and power output vary significantly with the ambient temperatures. Colder ambient temperatures yield high horsepower outputs and increased gas compression capacities. Well oil production on the slope is optimized to an incremental GOR (gas oil ratio) and WOR (water oil ratio) based on facility handling constraints.

The department accounts for facility handling constraints in its production forecast on an individual well basis. The well history will include when the well was producing versus when the well was shut in based on facility handling constraints. In fitting a decline curve, the shut in periods of time are factored in and reflected in the forecast.

2) **Provide further breakdown of FY 13 / 14 / 15 expenditure forecasts as much as possible.**

The Department of Revenue is seeking clarification from the Department of Law on the extent to which it can disclose information about expenditure forecasts provided by companies.

3) **What amount of expenditures is made by oil companies that are not deductible for purposes of the ACES tax?**

The amount of expenditures that are not deductible for the ACES tax is not reported to the Department of Revenue. There are several expenditures that are specifically excluded from qualifying as lease expenditures under ACES at AS 43.55.165(e), such as costs for dismantlement, removal, surrender or abandonment of a facility, pipeline, or other property used for producing oil and/or gas. Costs for deferred maintenance are also disallowed as well as a limitation on capital expenditures (the "$.30 haircut" under AS 43.55.165(e)(18)).

Regulations detailing qualified lease expenditures are written to conform to allowable costs as provided for under most joint operating agreements (JOAs). Most JOAs (as well as our lease expenditures) allow direct costs of production as well as an allowance for overhead expenses. The state allows a fixed percentage of 4.5% of direct costs as an overhead allowance that may be deducted as lease expenditures. The statutes provide that only those costs that are related to exploring for, developing, or producing oil or gas may be deducted as lease expenditures. Therefore, expenditures that are related to research and development type costs are not allowed as lease expenditures since they are not expenditures related to exploring for, developing, or producing oil or gas.

4) **How much production do the credits the state has issued translate out to?**

Based on our understanding of the question, the intent is to translate production tax credits in each year to a certain amount of production for each year. To illustrate this concept, we present total credits in each year relative to lease expenditures per barrel in each year. The resulting calculation illustrates the number of barrels for which the costs would be covered by the total credits in each fiscal year. When viewing this data, note that many credits are issued to companies that are not producing oil, and also that many if not most credits represent investments in future production as opposed to current year production.

Illustration of Amount of Production that would be paid for by tax credits, FY 2007-FY 2012

	FY 2007 / Pre-2008 [1]	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Total Credits [2] ($ million)	$673	$509	$641	$773	$863	$533
Total Lease Expenditures ($ million)	$3,659	$3,848	$4,297	$4,659	$4,931	$5,322
ANS Production, bpd	734,000	716,000	693,000	644,000	603,000	574,000
Lease Expenditures per Barrel of Total Production	$13.70	$14.70	$17.00	$19.80	$22.40	$25.30
Total Credits / Lease Expenditures per Barrel	49,124,000	34,626,000	37,706,000	39,040,000	38,527,000	21,067,000

(1) To simplify this analysis all "pre-2008" credits are shown relative to FY 2007 production.
(2) Includes both tax credit certificates and credits applied against production tax liability. FY 2011 and FY 2012 are estimated pending final true-ups.

5) Provide history of year-forward forecasts (ie 2011 forecast for FY 12, 2010 forecast for FY 11, etc).

The following table presents the Fall forecasts for lease expenditures for the following year (ie Fall 2007 forecast for FY 2008, etc), for Fall 2007 through Fall 2011 forecasts. We also include the actual lease expenditures for the first four years.

Year-forward lease expenditure forecasts and actuals

Forecast	Year Forecasted	Forecast Opex ($ millions)	Actual Opex ($ millions)	Forecast Capex ($ millions)	Actual Capex ($ millions)	Forecast Total ($ millions)	Actual Total ($ millions)
Fall 2007	FY 2008	$ 2,149	$ 1,881	$ 2,188	$ 1,967	$ 4,337	$ 3,848
Fall 2008	FY 2009	$ 2,153	$ 2,085	$ 2,373	$ 2,212	$ 4,526	$ 4,297
Fall 2009	FY 2010	$ 1,996	$ 2,270	$ 2,505	$ 2,389	$ 4,501	$ 4,659
Fall 2010	FY 2011	$ 2,553	$ 2,614	$ 2,572	$ 2,317	$ 5,125	$ 4,931
Fall 2011	FY 2012	$ 2,579		$ 2,743		$ 5,322	

Source: Fall 2007-Fall 2011 Revenue Sources Book "Basic Data" tables

6) Break out credit for Cook Inlet.

See attached S FIN 2.2.12 credits.pdf

7) Update credit slides with FY 2013 projections.

See attached S FIN 2.2.12 credits.pdf

8) Provide information about the basis of our 10-year property tax forecast.

Property taxes are difficult to forecast for a variety of reasons. As such, in forecasting petroleum property taxes, the Department has adopted a simple model which takes the previous year assessed tax value, and projects it forward with assumptions that depreciation slightly offsets appreciation. This is a conservative estimate. The state's petroleum property tax forecast is outlined at the top of page 27 of the Department's Fall 2011 Revenue Sources Book.

9) Show municipal and state shares each year.

The property tax forecast is limited to the state's share. The Department does not forecast municipal property taxes. However, the Department does acquire current fiscal year property tax by municipality. The breakdown can be found on page 43 of the Department's Fall 2011 Revenue Sources Book. It is the Department's understanding that certain municipalities may conduct their own property tax forecasts, but the Department does not receive or review those forecasts.

10) Compare our forecast to expectations based on the Gleason decision.

The Department has not performed further property tax forecasting based on Judge Gleason's recent decision. Judge Gleason's decision is not yet "final" at the Superior Court level, and will likely get appealed to the Alaska Supreme Court for a final determination

11) Provide a history for CBRF (slide 4) of starting balance and fund flows.

See attached document named S FIN 2.2.12 CBRF Analysis Chart.pdf, which has been prepared in response to a question regarding the Constitutional Budget Reserve Fund cash flows. We started in 1991 with the appropriation into the CBRF. Each of the blue bars represents either a contribution or withdrawal into the CBRF. The investment income (represented by the green line) plus the cumulative amount contributed (represented by the light blue fill) equals the net asset value (represented by the black dotted line). We have also placed the various tax structures and price of oil on the graph so that a historical construct can be made around the CBRF inflow and outflows.

12) Provide a history of monthly cash flows for PCE… appropriations, earnings, payments out, and rates of return.

See attached document named S FIN 2.2.12 PCE Analysis – FY11 & FY12.pdf, which shows the monthly contributions, withdrawals and income or loss to the Power Cost Equalization fund along with rates of return. This information is updated monthly on the Department of Revenue's website http://www.dor.alaska.gov/treasury/programs/programs/other/ifr/index.aspx?2012

13) Make a recommendation for changes to PCE payout rates and rates of return.

The Power Cost Equalization Endowment (PCE) provides ongoing funding to assist in stabilizing electricity rates throughout the state as well as to make grants to improve state utility performance. The key operating assumptions set in statute are for the commissioner of revenue to invest the endowment to achieve at least a seven percent nominal return over time and for the endowment to provide for annual disbursements of seven percent based on the past 36 month endowment balance.

Since the PCE's expected long term return of 7% is equal to the 7% disbursement level, the fund and the purchasing power of disbursements can be expected to diminish with inflation over time absent additional state support. Many endowments are structured to payout current benefits while protecting future purchasing power to provide a similar level of future benefits. Funds are generally designed to accomplish this by targeting a rate of return that exceeds the payout level by the expected inflation rate.

The addition of $400 million to the PCE in July of 2011 provides the state with an opportunity to protect the endowment against inflation without requiring an increase in risk or a reduction from recent appropriations.

The endowment targets a nominal rate of return of at least 7% which necessitates a relatively high level of risk. This level of risk and return is reasonable since it is consistent with the long term ability of the endowment to bear risk.

To protect the endowment from inflation, I recommend decreasing the appropriation level. The long term expectation for inflation is 3%. Since the target return is 7%, this leaves 4% for appropriation. Over the long term, a 4% real rate of return for appropriation should be achievable.

As a result of the recent $400 million infusion, a 4% appropriation should result in disbursements increasing by 30% from $22.9 million in FY2011 to an estimated $29.8 million in FY2014. The additional capital is averaging into the appropriation calculation over a three year period between FY2012 and FY2014. To avoid a reduction in the level of recent appropriations, I would recommend transitioning to the 4% rate by fixing the appropriations for FY2012 and FY2013 at $25 million and $27.3 million. The following table provides the recent appropriations, the 4% estimates, and the recommendation:

Fiscal Year	(a) 36 Month Average Value	(b) Appropriation	(c) 4% Calculation	(d) Recommendation
FY2008	301,024,639	21,071,725		
FY2009	340,491,397	23,834,398		
FY2010	338,189,252	23,673,248		
FY2011	327,150,521	22,900,536		
FY2012 est.	*468,541,379*		*18,700,000*	*25,000,000 fixed $*
FY2013 est.	*606,523,926*		*24,300,000*	*27,300,000 fixed $*
FY2014 est.	*744,575,228*		*29,800,000*	*29,800,000 4%*

Protecting the Power Cost Equalization Endowment from the impact of long term inflation will help preserve the purchasing power of the endowment and allow for future benefits to increase with inflation. The current disbursement model is likely to result in either decreasing future disbursements or the need for additional state support. The state has a unique opportunity this fiscal year to move toward inflation-proofing this endowment without increasing risk or decreasing the level of recent appropriations.

14) Provide a report about the PF earnings reserve account over the past 5 years, balances, and how it was invested.

See attached document named S FIN 2.2.12 APFC earnings reserve.pdf

I hope the answers fully address your questions.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Enclosures

Production Tax Credits

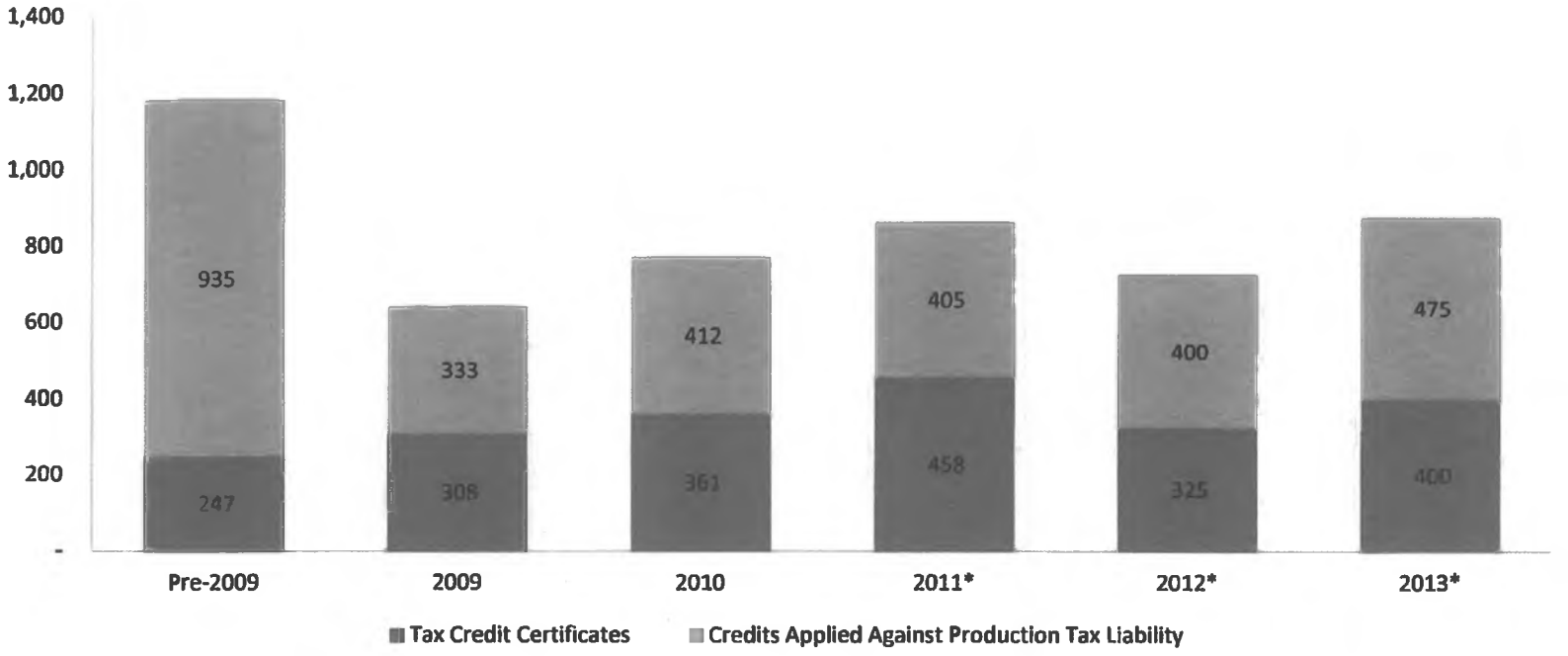
Total Production Tax Credit Impact through FY 2013 ($M)

	Pre-2009	2009	2010	2011*	2012*	2013*	Total
Tax Credit Certificates	247	308	361	458	325	400	2,099
Credits Applied Against Production Tax Liability	935	333	412	405	400	475	2,961
Total by Year	1,182	641	773	863	725	875	5,060

***Estimated pending final true-ups**

Production Tax Credits

By Fiscal year ($M)



* Estimates pending final true-ups

Transferable Tax Credits Certificates Claimed by Fiscal Year ($M)

Credit Type	Pre-2008	2008	2009	2010	2011	2012*	Total
Capital Expenditure - .023(a)(1)	52.3	78.4	66.9	114.9	160.7	83.4	556.7
Capital Expenditure Exploration - .023(a)(2)	15.9	13.3	42.6	34.7	4.6	0.4	111.5
Carried Forward Annual Loss .023(b)	38.1	148.5	153.8	140.4	188.6	8.3	677.7
Well Lease Expenditure - .023(l)					9.4	23.8	33.2
Exploration -.025	93.2	85.5	56.6	99.5	2.4	2.5	339.7
Total	199.6	325.7	320.0	389.5	365.7	118.4	1,718.9

* through December 2011

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

	Pre-2008	2008	2009	2010	2011	2012*	Total
Issued	116.0	130.8	308.0	361.3	458.0	132.9	1,507.1
Refunded	(54.6)	(54.1)	(193.1)	(250.5)	(450.2)	(273.5)	(1276.1)
Transferred/ Applied to Taxes	(52.3)	(62.7)	(46.6)	(20.0)	(7.4)	0	(189.0)
Activity by year	9.1	14.0	68.3	90.8	.3	(140.5)	
Transferable Tax Credit Certificates Outstanding	9.1	23.1	91.5	182.3	182.6	42.0	42.0

* through December 2011

Credits Applied Against Production Tax Liability, by Fiscal Year ($M)

	Pre-2009	2009	2010	2011*	2012*	2013*	Total
Capital Exp Credit AS 43.55.023(a) & (l)	511	278	342	345	360	415	2,252
TIE Credits AS 43.55.023(i)	244	0	0	0	0	0	244
Small Producer Credits AS 43.55.024	77	27	27	41	35	35	242
Exploration Credits AS 43.55.025	103	28	42	19	5	25	222
Totals	935	333	412	405	400	475	2,961

*estimated pending final true-up

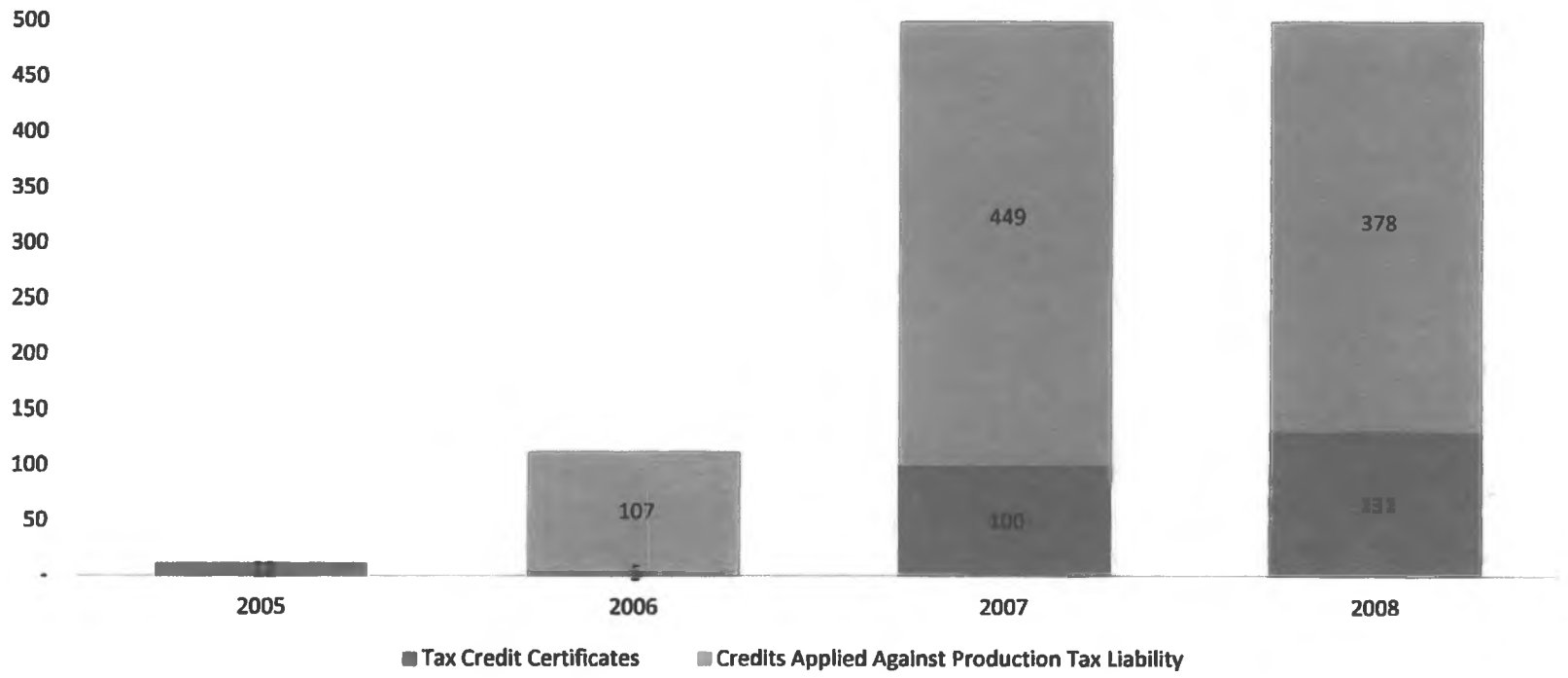
Production Tax Credits

Fiscal Years 2005 – 2008
($M)

	2005	2006	2007	2008	Total
Tax Credit Certificates	11	5	100	131	247
Credits Applied Against Production Tax Liability		107	449	378	935
Total by Year	11	112	549	509	1,182

Production Tax Credits

Fiscal Years 2005 – 2008
($M)



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

February 20, 2012

Dear Senator Paskvan:

I am writing in response to your recent questions regarding the "Gas Partial Processing Plant," and specifically, your requests for information on:

1) Whether BP has applied for a tax credit for this project; and
2) If so, provide the details including the amount of credits rewarded.

The provisions of Alaska statutes 40.25.100 and 43.05.230(a) require the Department to hold information provided in returns or reports confidential. These statutes are taken seriously by all Department staff. Generally speaking, the Department is required to keep all taxpayer information that it receives confidential. Alaska statute 43.05.230(f) makes it a crime for an individual to release such information, punishable by up to a $5,000 fine, or two years in jail, or both.

I hope our response fully answers your question.

Sincerely,

Bruce Tangeman
Deputy Commissioner

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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The Honorable Joe Paskvan
Alaska State Senator
State Capitol, Room115
Juneau, Alaska 99801

February 21, 2012

Re: Memo dated January 28, 2012.

Dear Senator Paskvan:

This letter is in response to the memo you sent to me on January 28, 2012, with questions regarding Alaska's hypothetical income statement using Department of Revenue price, production, and tax and credit forecasts. Below, I have itemized your requests and questions and my responses based on enumerated paragraphs from your memo.

Paragraph 3: "I request charts/slides for FY 11, FY12 and FY13 in the income statement format [i.e. in a similar format to Fall 2011 RSB D-1a, D-1b, and D-1c] showing in a new column to the right side of the current Value column the 25% private royalty load and the 10% gross production tax load. I would like the royalty amount to appear in the same horizontal line as Alaska's royalty and I would also like to have the gross production tax to appear on the same horizontal line as Total Tax before credits. For each year, the same revenue earned in Alaska is to be used such that the 25% and 10% load is applied for FY11 on revenue [$million] of $20,786.7, for FY12 on revenue of $22,848.2 and for FY13 on revenue of $22,185.1."

Response: Figures 1 through 3, attached to the end of this letter, are modifications on figures D-1a, D-1b, and D-1c, from the *Fall 2011 Revenue Sources Book* (RSB), as requested. I added a column on each figure where calculations of hypothetical royalty and gross tax are shown.

I am concerned with the assertion in your January 28 memo that the royalty rates in North Dakota and Texas are 25 and 35 percent, respectively. These values are the extreme high values of a range you may have seen in the comparison table in DOR's publication titled *Alaska's Oil and Gas Fiscal Regime* (January 2012).[1]

[1] Alaska Department of Revenue, 2012, Alaska's Oil and Gas Fiscal Regime – A Closer Look from a Global Perspective. Table 6-2 provides minimum and maximum ranges of values for fiscal term elements for twelve jurisdictions that comprise Alaska's fiscal regime peer group.

I believe that if, for simplicity, you want to model a single royalty rate and a single severance tax rate, it is prudent to use values similar to those recommended by PFC Energy and others in their *World Rating of Oil and Gas Fiscal Terms (2011)*, which quotes a royalty rate of 18.75 percent and severance tax rate of 11.5 percent used for modeling North Dakota and a royalty rate of 25 percent and severance tax rate of 4.6 percent for modeling Texas. I use assumptions for your request that are more representative of fiscal terms for North Dakota[2].

Paragraph 4: "My very rough calculations using, for example, FY11 revenue show royalty at $5,196.6 [I have not factored in federal royalty monies] and gross resource tax at $2,078.6 for a total of $7,275.2. Is this accurate?"

Response: It appears that the value you calculated, $5,196.6 million, is the value of royalty production assuming price and gross annual production equals the values seen in the Fall 2011 RSB D-1a, but using a 25 percent royalty rate.

Your gross tax calculation is incorrect. In most states, the royalty interest in oil produced from a state, federal or municipal oil and gas lease is exempt from severance tax. Almost all of Alaska's oil and gas are produced from leases that would qualify in most states for royalty oil exemption from severance tax. I would recommend assuming all royalty production is exempt from severance tax in your hypothetical example, since that is the case in Alaska, and that is the way that I have done the calculation in the tables provided with this letter.

Paragraph 5: "In FY11, FY12, FY13 charts/slides, I would like to also show for each year the credits for potential purchase as shown on page 31 of Fall 2011 RSB. This results, for example, in a reduction from $4,501.28 to $4,051.28 in FY11 at the bottom line."

Response: Figures 1 through 3, attached to the end of this letter, include the requested modifications.

Paragraph 6: "The no OPEX or CAPEX deduction or credits are not to be factored into the far right hand column as North Dakota does not have deductions or credits. Is this correct?"

Response: North Dakota does not offer direct OPEX or CAPEX deductions or credits.

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[2] PFC Energy, Van Meurs Corp., and Rodgers Oil & Gas Consulting, 2011, World Rating of Oil and Gas Terms: Volume 1, North America, Annex C. A detailed breakdown and description of North Dakota's fiscal terms is provided on pages 100 – 105 of Annex C. A detailed breakdown and description of Texas' fiscal terms is provided on pages 114 – 116 of Annex C.

Paragraph 7: "On a different topic, how many barrels are excluded under the footnote 2 to the income statement? Also, what models, as discussed in footnote 4, can be shared with Senate Resources?"

Response: Regarding Footnote 2, disclosing production attributed to companies expected to have zero tax liability would violate DOR confidentiality constraints. Regarding Footnote 4, we shared an ACES and HB110 revenue model with you on March 17, 2011. This model is still a good tool to apply to these issues. The "larger models" referred to in Footnote 4 include confidential taxpayer information and cannot be made public.

Paragraph 8: "I also request that DOR prepare a chart/slide using the FY13 income statement depiction but changing only one variable which is to increase the ANS Oil Price to $110.46. This is a $1/bbl increase as to FY13, D-1c in Fall 2011 RSB."

Response: Figure 4 provides the change as requested.

I hope this letter fully addresses your needs on these issues. Please remember that the original estimates in figures D-1a, D-1b, and D-1c of the RSB are simplifications of complicated tax and credit calculations and do not accurately reflect Department of Revenue expectations. Calculations based on modifying these figures are subject to the same accuracy issues. The modifications are provided here at your request and do not reflect Department of Revenue expectations.

Sincerely,

Bryan Butcher
Commissioner

Figure 1. FY 2011 production tax estimate, reproduced from Fall 2011 RSB Figure D-1a Income Statement. Modified by adding column with hypothetical calculations (highlighted) added at the request of Senator Paskvan.

			As reported in Fall 2011 RSB	Per Paskvan Request
	Price	**Barrels**	**Value ($MM)**	**Value ($MM)**
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$94.49	602,723	$56.9	$56.9
Annual Production (bbl)				
Total		219,993,895	$20,786.7	$20,786.7
Royalty, Federal and other barrels[1]		-29,505,505	($2,787.9)	
Hypothetical Royalty at 18.75%, 100% Exempt bbls.		-41,248,855		($3,897.5)
Taxable Value[2]			$17,998.8	$16,889.2
Downstream (Transportation) Costs ($/bbl)				
ANS Marine Transportation	($2.45)			
TAPS Tariff	($4.02)			
Other	($0.70)			
Total Transportation Costs on Taxable Barrels	($7.17)	190,488,390	($1,365.8)	
Deductible Lease Expenditures[3]				
Deductible Operating Expenditures	($13.22)		($2,517.4)	
Deductible Capital Expenditures	($8.52)		($1,622.9)	
Total Lease Expenditures on Taxable Barrels	($21.74)	190,488,390	($4,140.3)	
Hypothetical Gross Production Tax				
Hypothetical Gross Tax at 11.5%				$1,688.9
Current Net Production Tax				
Production Tax Value (PTV)			$12,492.6	
Base Tax (25%*PTV)			$3,123.2	
Production Tax Value per barrel	$65.58			
Progressive Tax = (14.2% * PTV)			$1,778.1	
Total Tax before credits			$4,901.2	
Credits Used Against Tax Liability ($MM)			($400.0)	
Estimated Total Tax After Credits Against Taxes[4]			**$4,501.2**	
Credits for Potential Purchase ($MM)			($450.0)	
Estimated Total State Revenue After Credits			**$4,051.2**	
Hypothetical Royalty + Production/Severance Tax			**($6,839.1)**	**($5,586.4)**

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. For purposes of this calculation, also includes barrels produced by companies with negative PTV.

(2) For purposes of this illustration, to more closely reflect actual tax received by the state, "taxable value" shown here excludes the value of barrels produced by companies expected to have zero tax liability.

(3) 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.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Figure 2. FY 2012 production tax estimate, reproduced from Fall 2011 RSB Figure D-1b Income Statement. Modified by adding column with hypothetical calculations (highlighted) added at the request of Senator Paskvan

			As reported in Fall 2011 RSB	Per Paskvan Request
	Price	**Barrels**	**Value ($MM)**	**Value ($MM)**
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$108.98	574,373	$62.6	$62.6
Annual Production (bbl)				
Total		219,993,895	$23,975.8	$23,975.8
Royalty, Federal and other barrels[1]		-29,505,505	($3,215.6)	
Hypothetical Royalty at 18.75%, 100% Exempt bbls.		-41,248,855		($4,495.5)
Taxable Value[2]			$20,760.2	$19,480.3
Downstream (Transportation) Costs ($/bbl)				
ANS Marine Transportation	($2.71)			
TAPS Tariff	($5.16)			
Other	($0.85)			
Total Transportation Costs on Taxable Barrels	($8.72)	190,488,390	($1,661.4)	
Deductible Lease Expenditures[3]				
Deductible Operating Expenditures	($13.22)		($2,517.4)	
Deductible Capital Expenditures	($8.52)		($1,622.9)	
Total Lease Expenditures on Taxable Barrels	($21.74)	190,488,390	($4,140.3)	
Hypothetical Gross Production Tax				
Hypothetical Gross Tax at 11.5%				$1,948.0
Current Net Production Tax				
Production Tax Value (PTV)			$14,958.4	
Base Tax (25%*PTV)			$3,739.6	
Production Tax Value per barrel	$78.53			
Progressive Tax = (19.4% * PTV)			$2,903.5	
Total Tax before credits			$6,643.1	
Credits Used Against Tax Liability ($MM)			($400.0)	
Estimated Total Tax After Credits Against Taxes[4]			**$6,243.1**	
Credits for Potential Purchase ($MM)			($450.0)	
Estimated Total State Revenue After Credits			**$5,793.1**	
Hypothetical Royalty + Production/Severance Tax			**($9,008.8)**	**($6,443.5)**

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. For purposes of this calculation, also includes barrels produced by companies with negative PTV.

(2) For purposes of this illustration, to more closely reflect actual tax received by the state, "taxable value" shown here excludes the value of barrels produced by companies expected to have zero tax liability.

(3) 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.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Figure 3. FY 2013 production tax estimate, reproduced from Fall 2011 RSB Figure D-1c Income Statement. Modified by adding column with hypothetical calculations (highlighted) added at the request of Senator Paskvan

			As reported in Fall 2011 RSB	Per Paskvan Request
	Price	**Barrels**	**Value ($MM)**	**Value ($MM)**
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$109.47	555,227	$60.8	$60.8
Annual Production (bbl)				
Total		202,657,895	$22,185.1	$22,185.1
Royalty, Federal and other barrels[1]		-30,158,081	($3,301.4)	
Hypothetical Royalty at 18.75%, 100% Exempt bbls.		-37,998,355		($4,159.7)
Taxable Value[2]			$18,883.7	$18,025.4
Downstream (Transportation) Costs ($/bbl)				
ANS Marine Transportation	($2.70)			
TAPS Tariff	($4.96)			
Other	($0.91)			
Total Transportation Costs on Taxable Barrels	($8.56)	172,499,814	($1,477.0)	
Deductible Lease Expenditures[3]				
Deductible Operating Expenditures	($13.75)		($2,372.5)	
Deductible Capital Expenditures	($15.36)		($2,648.9)	
Total Lease Expenditures on Taxable Barrels	($29.11)	172,499,814	($5,021.5)	
Hypothetical Gross Production Tax				
Hypothetical Gross Tax at 11.5%				$1,802.5
Current Net Production Tax				
Production Tax Value (PTV)			$12,385.2	
Base Tax (25%*PTV)			$3,096.3	
Production Tax Value per barrel	$71.80			
Progressive Tax = (16.7% * PTV)			$2,070.7	
Total Tax before credits			$5,167.0	
Credits Used Against Tax Liability ($MM)			($450.0)	
Estimated Total Tax After Credits Against Taxes [4]			**$4,717.0**	
Credits for Potential Purchase ($MM)			($400.0)	
Estimated Total State Revenue After Credits			**$4,317.0**	
Hypothetical Royalty + Production/Severance Tax			**($7,618.5)**	**($5,962.3)**

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. For purposes of this calculation, also includes barrels produced by companies with negative PTV.

(2) For purposes of this illustration, to more closely reflect actual tax received by the state, "taxable value" shown here excludes the value of barrels produced by companies expected to have zero tax liability.

(3) 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.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

Figure 4. Hypothetical FY 2013 calculation, similar to Figure 3 (above), but with average ANS price set at $110.46, all other input elements remain as shown in Figure 3. Produced at the request of Senator Paskvan.

			As reported in Fall 2011 RSB
	Price	**Barrels**	**Value ($MM)**
Avg ANS Oil Price ($/bbl) & Daily Production (bbls)	$110.46	555,227	$61.3
Annual Production (bbl)			
Total		202,657,895	$22,385.6
Royalty, Federal and other barrels[1]		-30,158,081	($3,331.3)
Taxable Value[2]			$19,054.3
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	($2.70)		
TAPS Tariff	($4.96)		
Other	($0.91)		
Total Transportation Costs on Taxable Barrels	($8.56)	172,499,814	($1,477.0)
Deductible Lease Expenditures[3]			
Deductible Operating Expenditures	($13.75)		($2,372.5)
Deductible Capital Expenditures	($15.36)		($2,648.9)
Total Lease Expenditures on Taxable Barrels	($29.11)	172,499,814	($5,021.5)
Current Net Production Tax			
Production Tax Value (PTV)			$12,555.8
Base Tax (25%*PTV)			$3,139.0
Production Tax Value per barrel	$72.79		
Progressive Tax = (17.1% * PTV)			$2,148.9
Total Tax before credits			$5,287.9
Credits Used Against Tax Liability ($MM)			($450.0)
Estimated Total Tax After Credits Against Taxes [4]			**$4,837.9**
Credits for Potential Purchase ($MM)			($400.0)
Estimated Total State Revenue After Credits			**$4,437.9**
Hypothetical Royalty + Production/Severance Tax			**($7,769.2)**

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. For purposes of this calculation, also includes barrels produced by companies with negative PTV.

(2) For purposes of this illustration, to more closely reflect actual tax received by the state, "taxable value" shown here excludes the value of barrels produced by companies expected to have zero tax liability.

(3) 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.

(4) Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company specific information. Variations in these assumptions captured in larger revenue models will produce different results that differ from the estimates in the simple model above.

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
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February 28, 2012

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

SUBJECT: Response to Questions from Senate Resources Meeting on February 27, 2012

Dear Senators Paskvan and Wagoner:

Thank you for the opportunity to provide our follow-up responses from the Senate Resources Committee meeting on February 27, 2012. The questions and responses follow.

1.) **Is the 30 cents per barrel capital expenditures exclusion included in the snapshot model charts presented?**

For purposes of the charts presented we did not separately break out the 30 cents / barrel exclusion. Please remember that charts and analysis presented in committee represent volume-weighted data that has been aggregated to a high level to identify trends in how various tax schemes impact North Slope operations. This is a high-level comparison that makes simplifying assumptions allowing the user to compare different fiscal regimes and the conclusions and outcomes of the model are the same whether or not this specific provision is broken out.

2.) **What would the FY 12 revenue impact be if amendment B.5 was in effect for the full year?**

For FY 2012, based on our Fall 2011 forecast assumptions, the provisions of amendment B.5 (bracketed progressivity with 50% maximum tax rate) would impact revenue by approximately $1.7 billion if in effect for the full year.

3.) **What would the difference be between amendment B.5 and CSSB 192, for FY 12, at $150 per barrel?**

If the provisions of CSSB 192 were in effect for the full year in FY 2012, and assuming our Fall 2011 forecast assumptions except for a constant ANS price of $150 per barrel, we would expect approximately $9.90 billion in production tax revenue. Under the provisions of amendment B-5 and the same assumptions, we would expect approximately $7.15 billion in production tax revenue, for a difference of approximately $2.75 billion.

4.) What is the revenue impact of amendment B.18?

Using the Fall 2011 oil price, production, and cost levels, production tax values for the next several years do not exceed roughly $72 per barrel. Therefore, the progressivity rates in this amendment do not have a dramatic impact on production tax revenues. Our modeling results regarding the impact of amendment B.18 over the term of the fiscal note are as follows:

Revenue Impact of Amendment B.18 FY13 - FY18 ($millions)	
FY 2013	$27.00
FY 2014	$7.00
FY 2015	$0.00
FY 2016	$0.00
FY 2017	$0.00
FY 2018	$1.50

5.) Provide charts for amendment B.8 and amendment B.18 similar to charts we provided for bracketed progressivity amendments.

See attached slides.

6.) Provide marginal tax rates for each of the proposals shown in the presentation.

See attached slides.

We hope our responses fully answer your questions.

Sincerely,

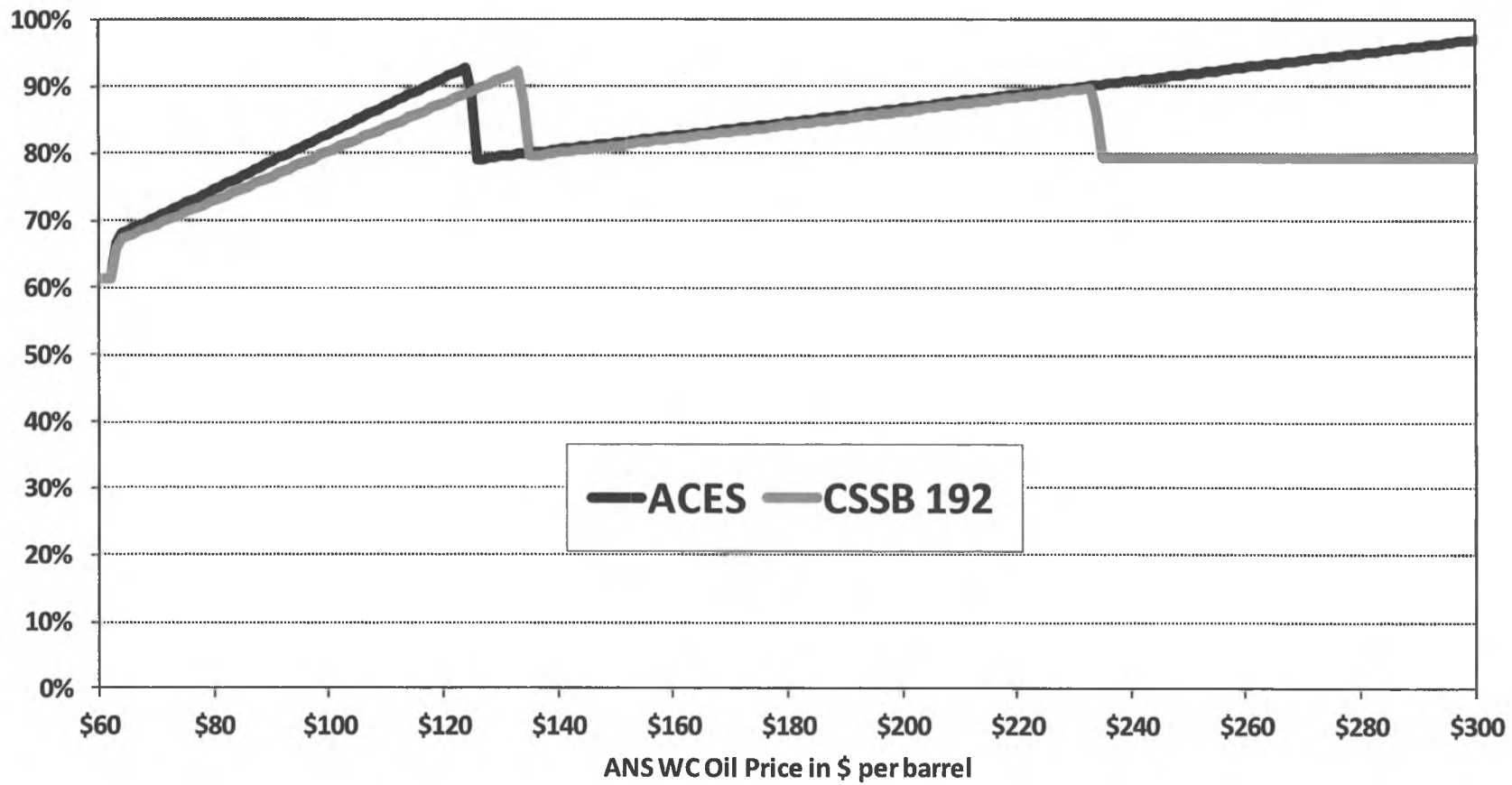
Bruce Tangeman
Deputy Commissioner

Enclosures

Marginal Government Take

(includes all federal and state taxes)

ACES and CSSB 192 \B

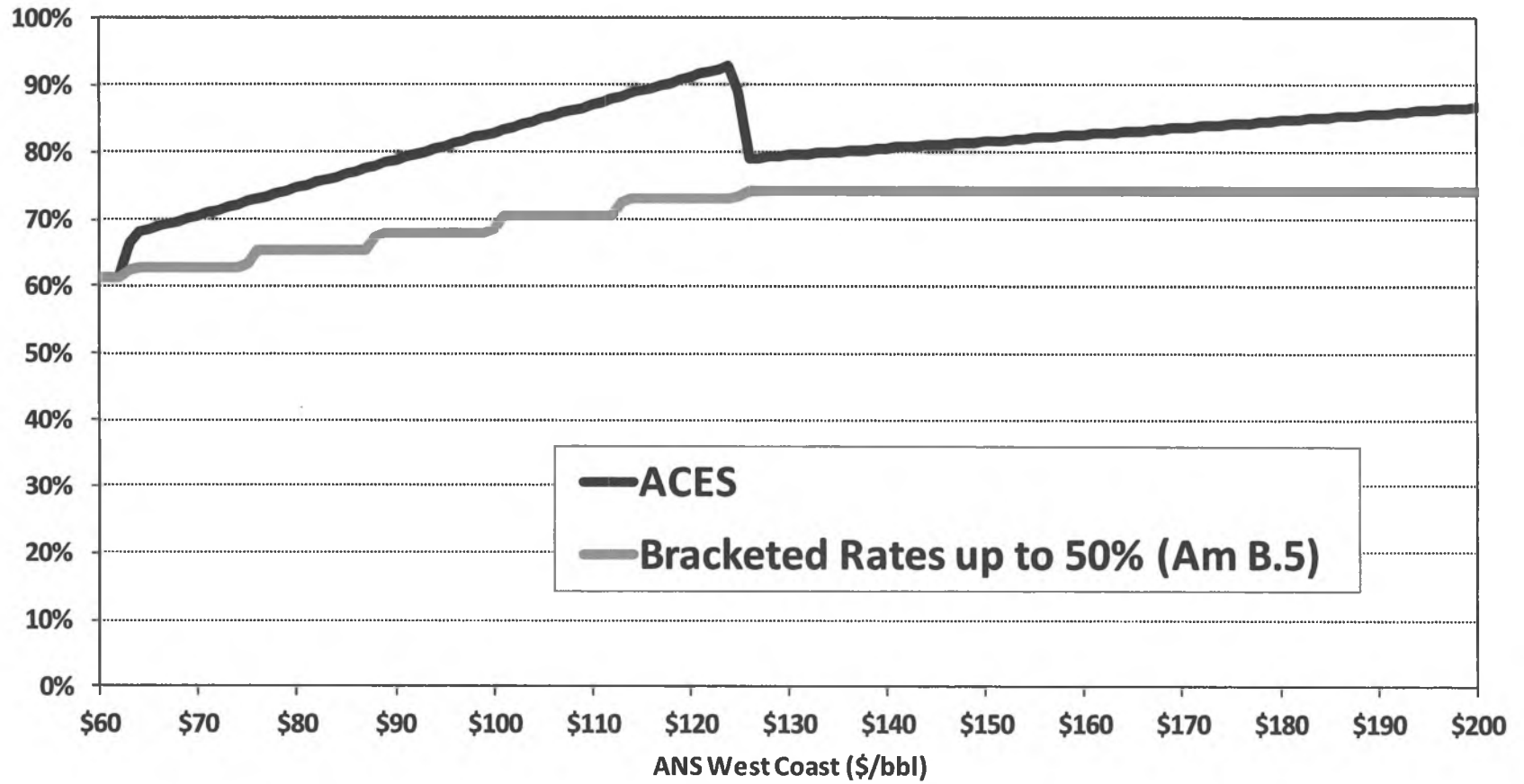


Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Marginal Government Take

(includes all federal and state taxes)

ACES and Bracketed Rates up to 50% (Am B.5)

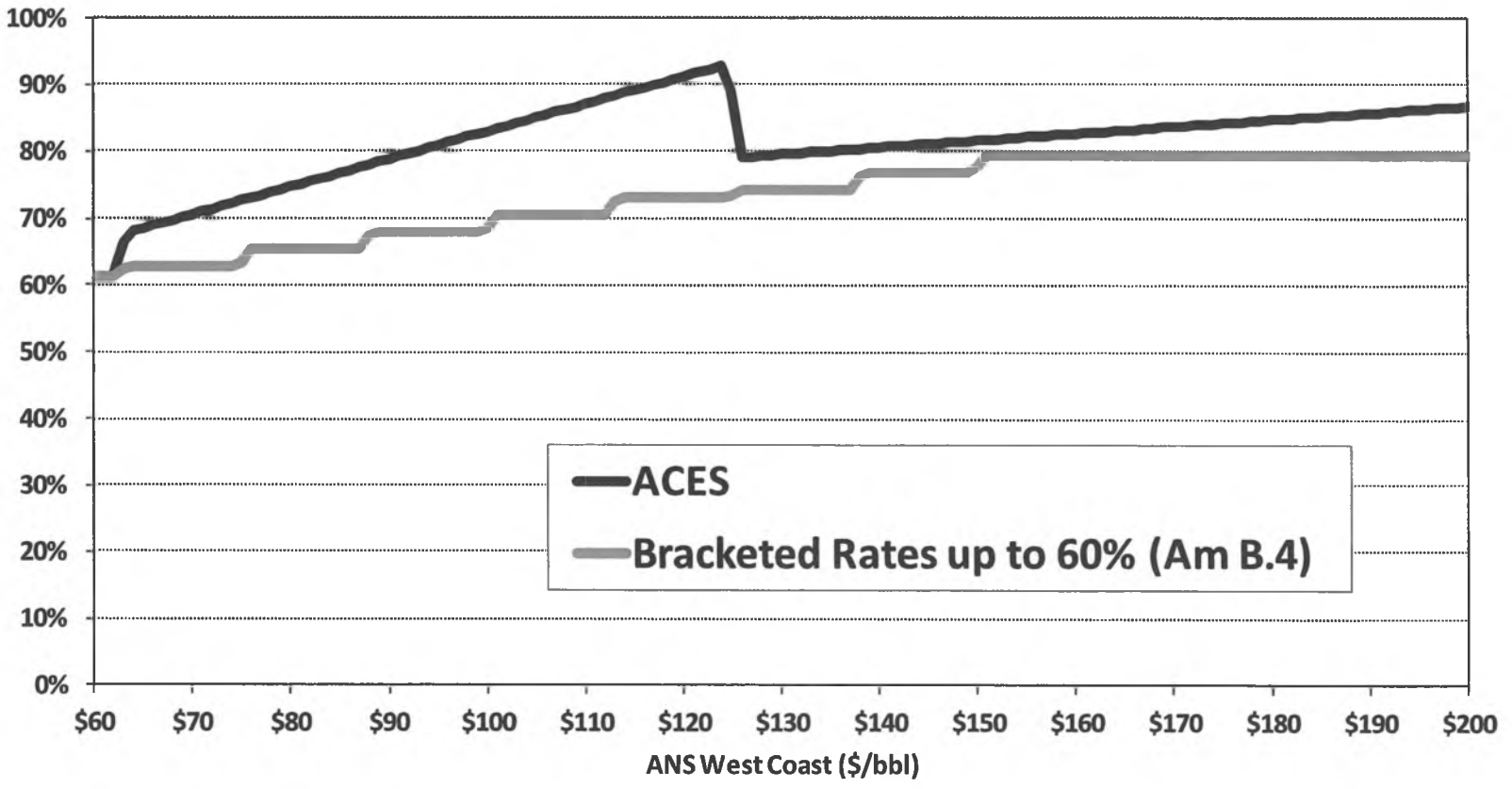


Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Marginal Government Take

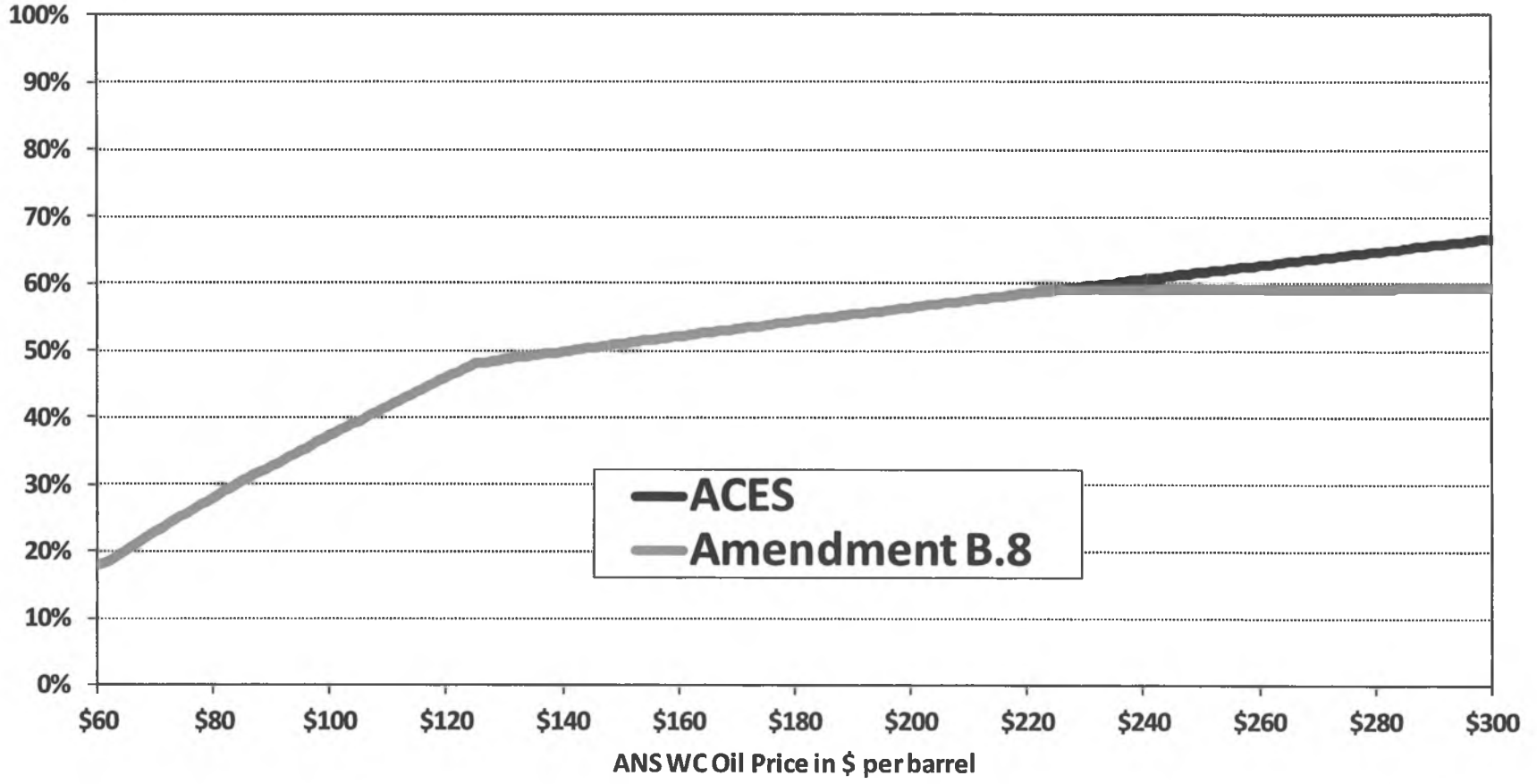
(includes all federal and state taxes)

ACES and Bracketed Rates up to 60% (Am B.4)



Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Effective Production Tax Rates:
ACES and Am B.8 (ACES capped at 60%)

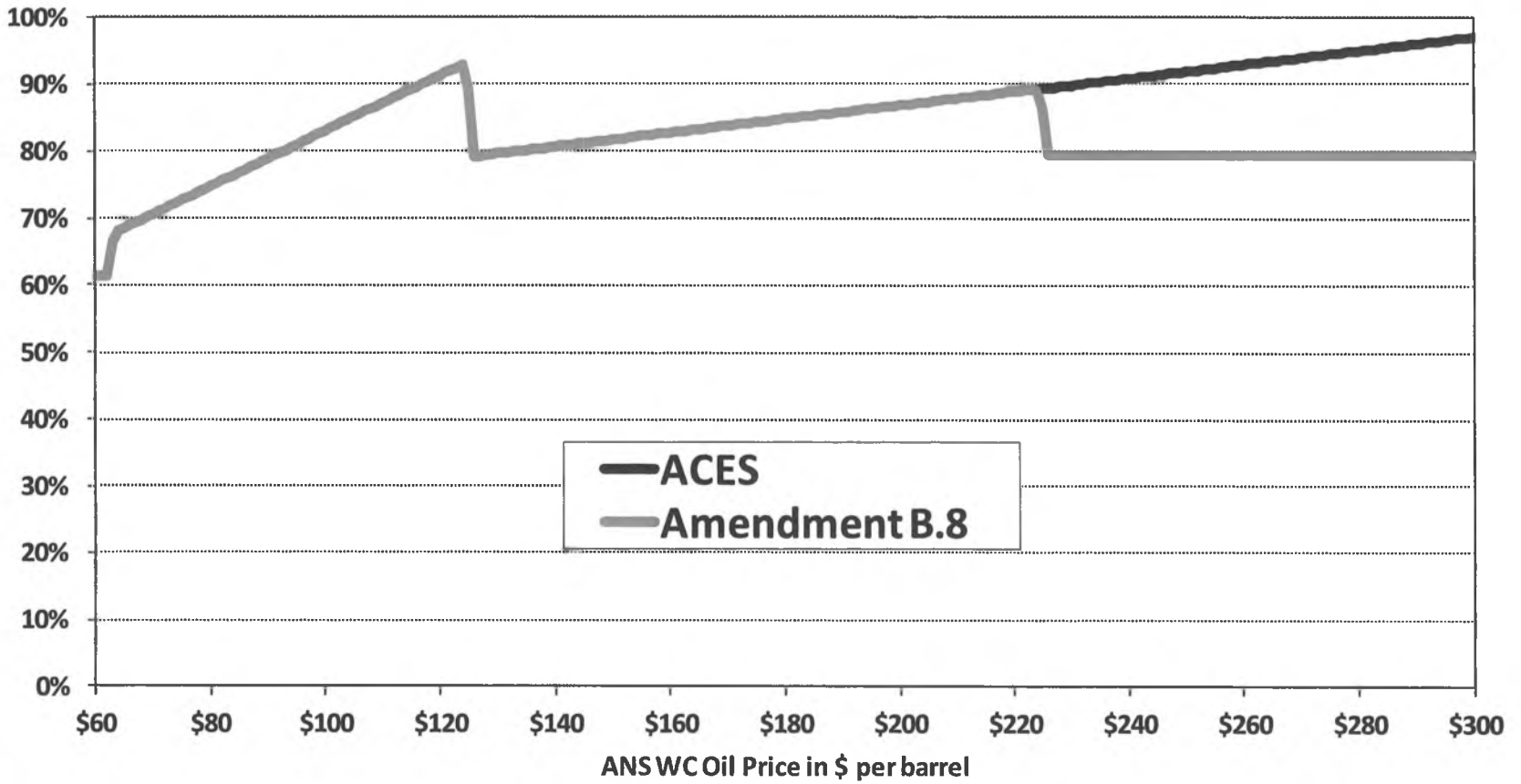


Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Marginal Government Take

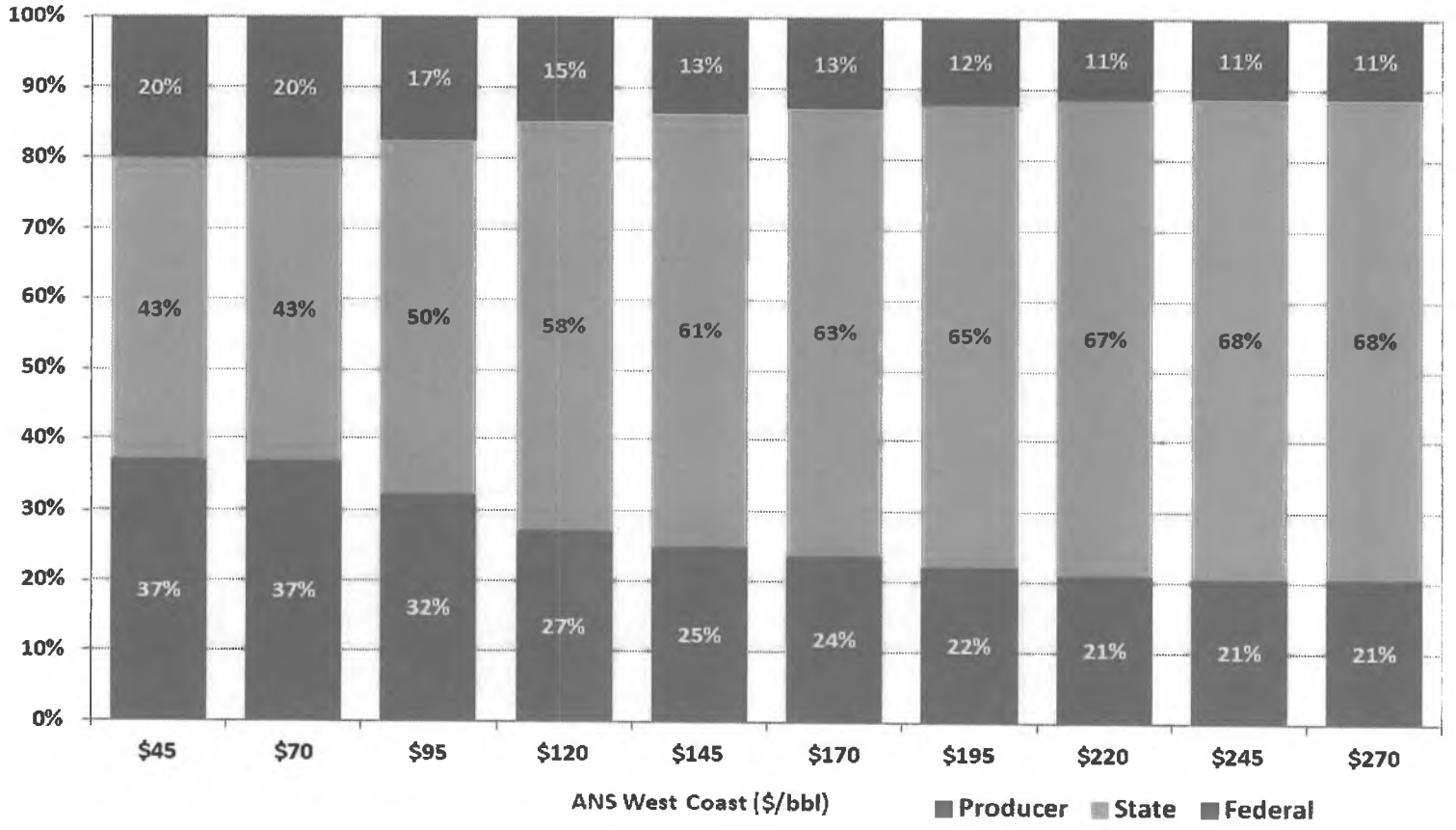
(includes all federal and state taxes)

ACES and Am B.8 (ACES capped at 60%)



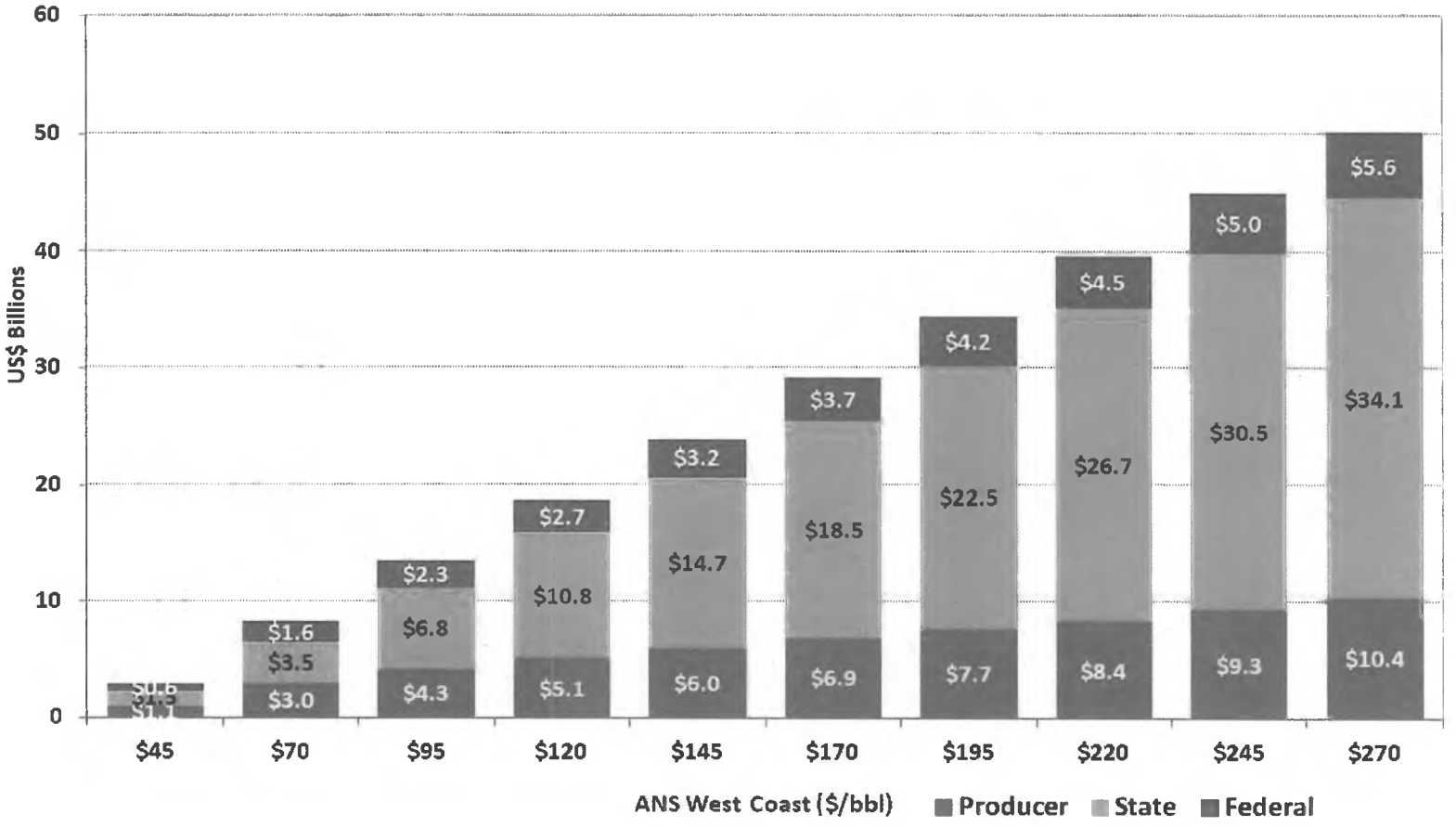
Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Share of Profit under Amendment B.8 (ACES capped at 60%)



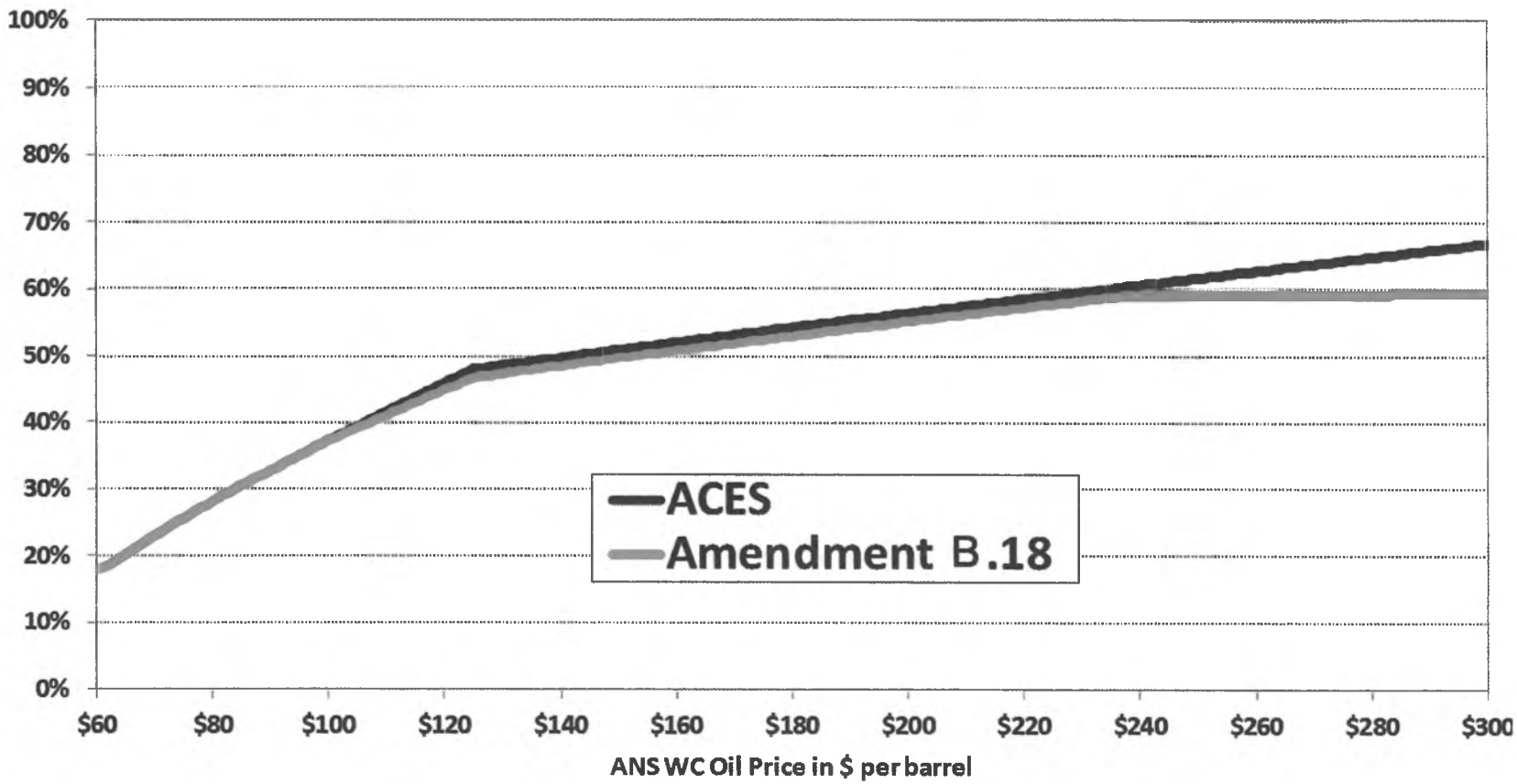
Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Absolute Profit under Amendment B.8 (ACES capped at 60%)



Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Effective Production Tax Rates:
ACES and Am B.18 (ACES capped at 60%, 0.35% progressivity from $67.50 to $92.50 PTV)

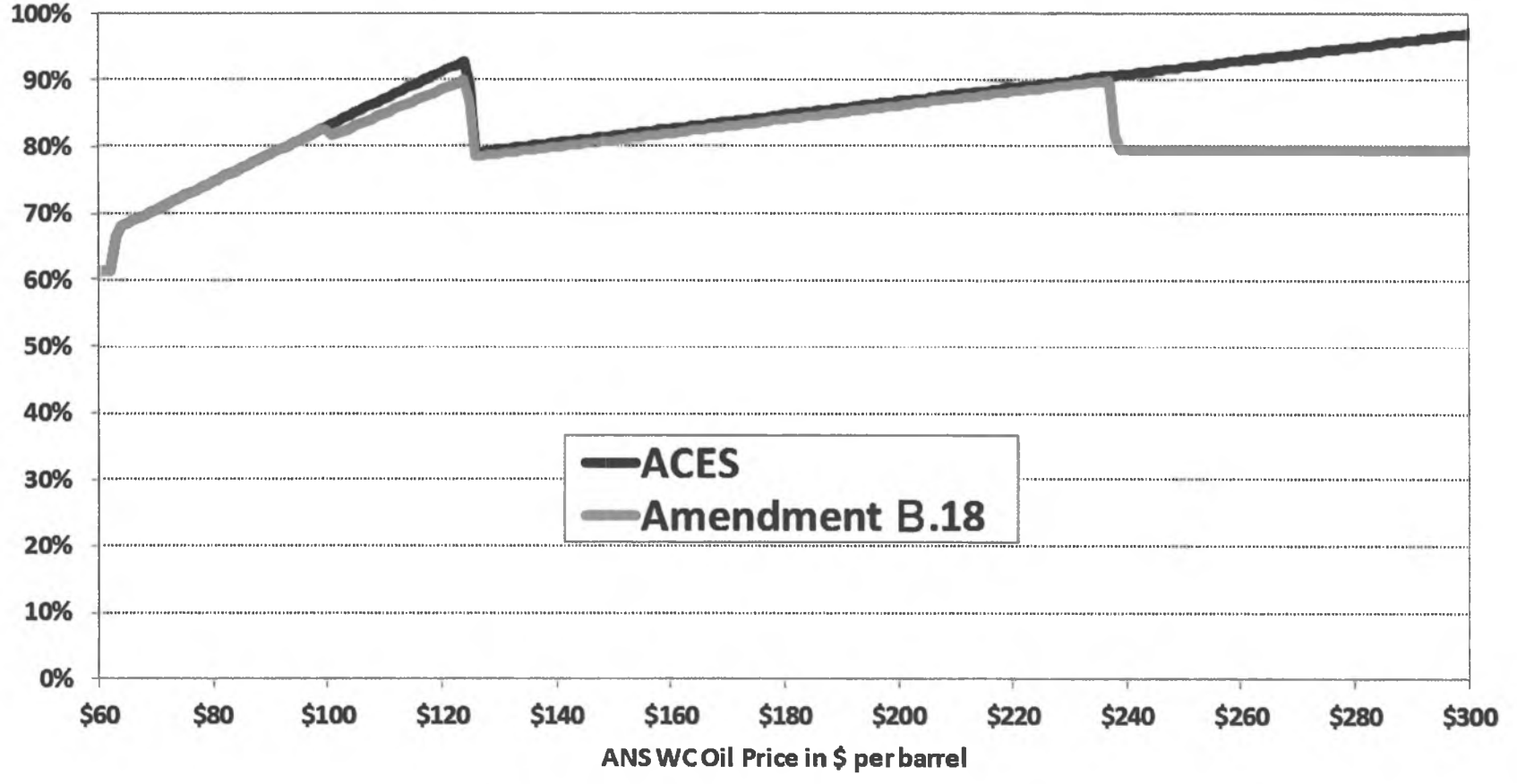


Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Marginal Government Take

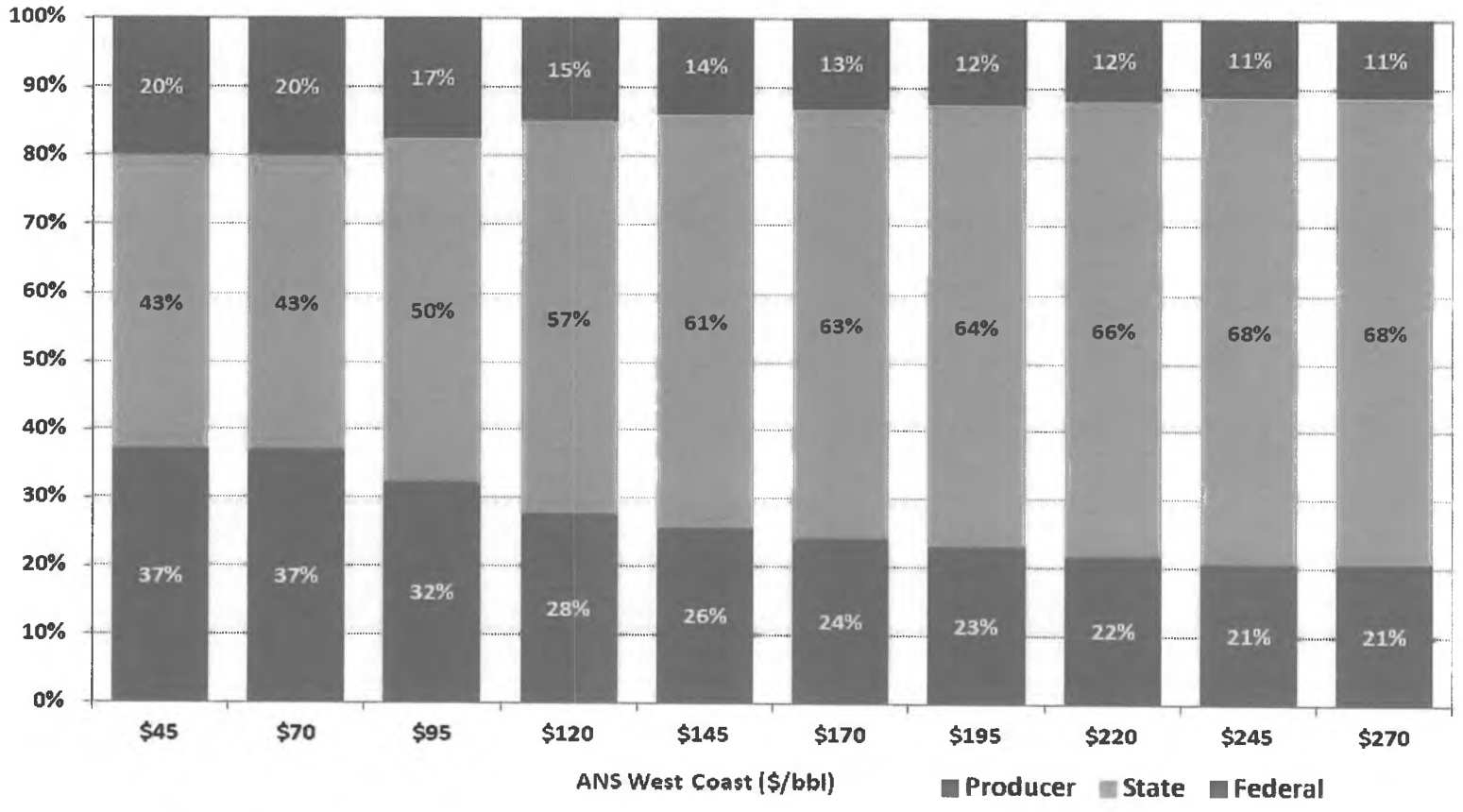
(includes all federal and state taxes)

ACES and Am B.18 (ACES capped at 60%, 0.35% progressivity from $67.50 to $92.50 PTV)



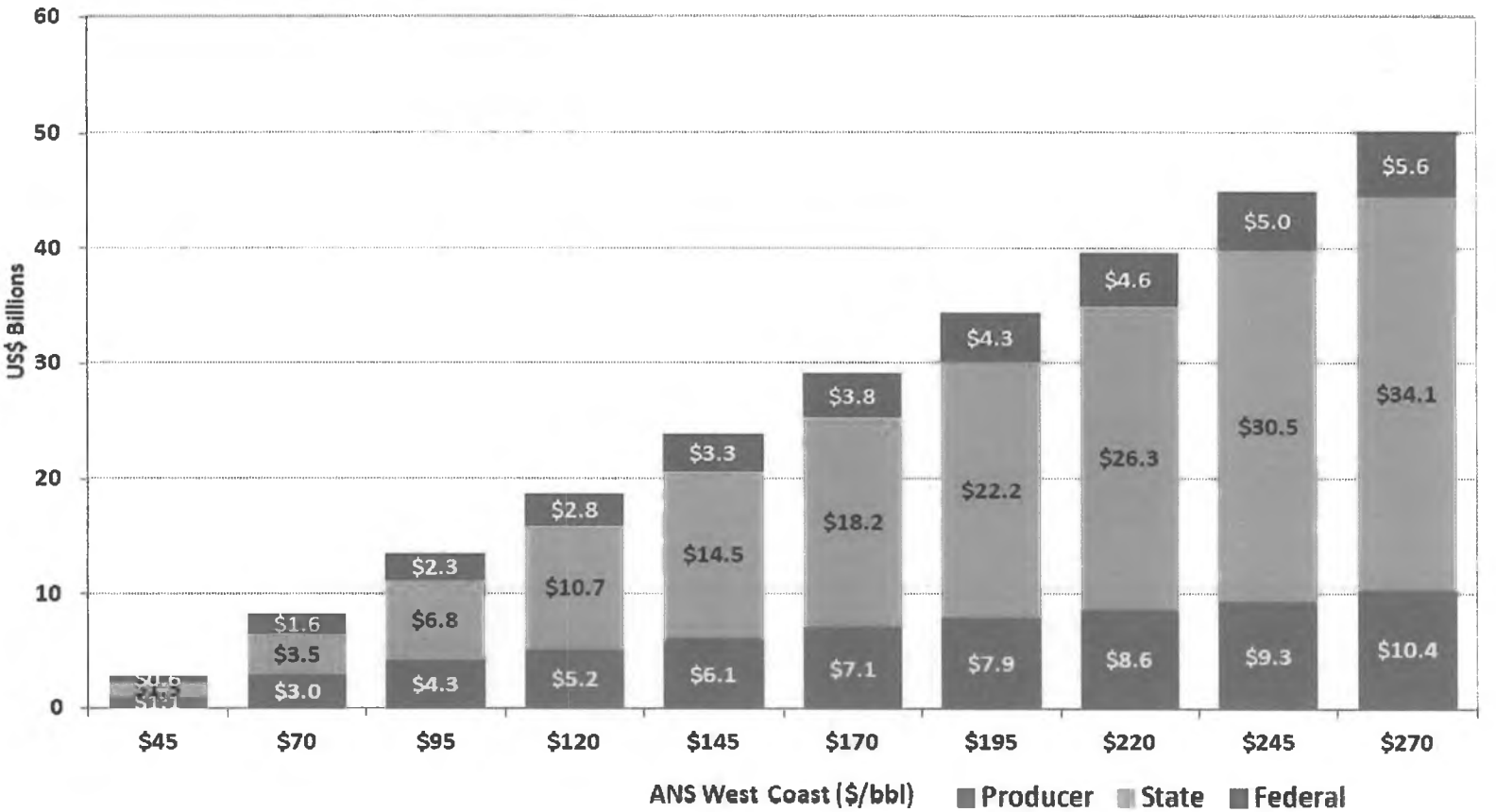
Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Share of Profit under Amendment B.18 (ACES capped at 60%, 0.35% progressivity from $67.50 to $92.50 PTV)



Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Absolute Profit under Amendment B.18 (ACES capped at 60%, 0.35% progressivity from $67.50 to $92.50 PTV)



Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

J. Scott Jepsen
Vice President, External Affairs

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Phone: (907) 265-1650
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ConocoPhillips
Alaska, Inc.

February 29, 2012

The Honorable Joe Paskvan
Co-Chairman, Senate Resources Committee
Alaska State Legislature
Alaska State Capitol, Room 115
Juneau, AK 99801-1182

Dear Senator Paskvan:

Thank you for your letter dated February 22, 2012. We are happy to clarify the statements that we made regarding the net income and payments to governmental authorities for ConocoPhillips Company and its wholly owned subsidiaries (including ConocoPhillips Alaska, Inc.) operating in Alaska ("CPA"), as well as our analysis of the data in the Alaska Department of Revenue Fall 2011 Revenue Source Book (RSB).

Let me first address CPA's tax and royalty payments in comparison to our reported net income. For the years 2007 through 2011, CPA earned total net income of $9.83 billion. During that same time period, we paid a total of approximately $21 billion in royalties and taxes (taxes include payments to local governments, the State of Alaska, and the federal government). For the year 2011, CPA earned $1.98 billion and paid a total of approximately $5 billion in taxes and royalties. Of this $5 billion, approximately $4 billion (taxes and royalties) was paid to the State of Alaska alone. All of the tax numbers come directly from the 10-K forms that CPA has filed with the Securities and Exchange Commission. The value of the royalty payments has been estimated using our actual royalty rate of 13.6%. These figures form the basis for our statement that in Alaska, we pay approximately twice as much in taxes and royalties as we earn.

Your letter also attempts to understand our comments in the context of the industry as a whole as portrayed by the RSB for FY2011. I believe that the following discussion will help in understanding why industry earnings as a whole track CPA's government payments to earnings ratio.

When we consider the tax burden in Alaska, we take into account all of the taxes we pay. The additional burdens that were excluded in your analysis do make a significant difference with respect to the industry's tax burden as well as the tax revenue for state and local

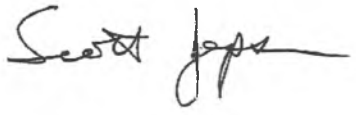
governments. Using the RSB, the industry paid $542 million in state income taxes and $476 million in property taxes (state share $110 million, local share $366 million). The total of these additional burdens is over $1 billion more in taxes to the industry than in your analysis.

There are two other areas that differ between our analysis and yours. First, we have used a federal tax rate of 35% which corresponds to our federal tax rate. Second, it appears that $850 million of tax credits were deducted from the calculated production tax to determine the production tax paid after credits. From the large producer perspective, $400MM applies to the producers' tax liability. The other $450 million is identified as "Credits for Potential Purchase" earned by those parties who do not generate sufficient production tax liability to utilize the credits. The production tax paying producers do not receive the benefit of the "Credits for Potential Purchase" unless the credits are purchased at some nominal discount, in which case the value realized by the purchaser is a small fraction of the tax credit itself. Including these adjustments, the production tax paying producers paid approximately $11 billion dollars in taxes and royalties with after tax cash flow of approximately $4.7 billion dollars. This results in a ratio of tax and royalty payments to earnings of about 2.3. Excluding federal tax payments, the ratio of state taxes and royalty to earnings is about 1.8.

As a sensitivity, we have looked at the case where ANS crude is priced at $120/bbl (versus $94.49/bbl in the RSB) with all other assumptions in the RSB remaining the same. The $120/bbl case demonstrates one of the key problems with ACES – as prices increase, industry sees very little of the uplift. At $120/bbl, our model estimates total government share and royalties is about 3 times industry's share, and state severance tax alone is about 1.5 times the industry total share. In absolute terms, with a price increase from $94.49/bbl to $120/bbl, we estimate industry's share increases about $700MM while the state's share (taxes and royalties) increases by approximately $4.5 billion.

I appreciate your desire to understand the basis for our statements as well as to understand our perspective regarding the reasons that we believe substantial changes are needed to ACES to attract more investment by the industry. I hope this response to your letter has helped in this regard as well as in understanding the basis for our comments regarding the ratio of taxes and royalties to profits. Please feel free to contact me if you have additional questions.

Respectfully,



J. Scott Jepsen

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
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Fax: (907) 465-2389

March 1, 2012

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

RE: DOR "Access to Information" Power Point Presentation

Dear Senators Paskvan and Wagoner:

Thank you for the opportunity to provide our follow-up responses from the Senate Resources Committee meeting on February 23, 2012. The questions/comments and responses follow.

1.) **Clarification about Slide 6 demonstrating that the difference between the DOR assessed TAPS values and Superior Court values was due to information that did not exist before the trial.**

To clarify Slide 6 from the Department's Power Point presentation to your committee on February 23, 2012, on the subject matter of, "Access to Information."

The fourth bullet point of Slide 6 stated in part:

> "TAPS assessments by DOR (not SARB) were $4.5 billion in 2007…"

The fifth bullet point of Slide 6 stated in part:

"Using information under the de novo provisions at trial in 2011 that was not actually in existence in 2007, the Superior Court ruled TAPS value at $8.9 billion in 2007…"

Questions from the committee, as well as the Department's responses to those questions, were framed in the context of Alaska North Slope (ANS) reserve estimates. The information this slide is referring to, however, is TAPS replacement cost data and not ANS reserves data. The Department's statements in relation to Slide 6 therefore should be taken only in the context of TAPS replacement cost data and not in the context of a position on ANS reserves.

Slide 6 is simply meant to demonstrate that TAPS assessed value as determined by the Superior Court continues to most closely agree with the Department's assessments relative to the values

argued by the Municipalities and the TAPS Owners. In the recent 2011 TAPS property tax trial covering tax years 2007 – 2009, the biggest discrepancy between the Department's and court's assessed value occurred in tax year 2007. The main reason for the discrepancy was the court's reliance on TAPS replacement cost data that was in existence in 2011, but did not actually exist in 2007 when the Department did the original assessment.

It is also important to clarify that this TAPS replacement cost data did not exist in 2007, as opposed to being in the possession of the TAPS owners and not provided to the Department. Rather, this TAPS replacement cost data was information the Municipalities commissioned after the 2007 TAPS assessment. It was provided to the Department to consider for the 2008 TAPS assessment. The Department did in 2008 rely on this data, and did so before the tax year was under litigation. The Department continues to consider and rely on this data in its TAPS assessments, irrespective of the ongoing TAPS litigation.

2.) **Why was the FY 2016 production forecast reduced by 79,000 barrels per day from Spring 2011 to Fall 2011, and can we release the supporting documents from producers based on court order that any production with 3 or more companies be made public?**

- In response to your question regarding the 79,000 BPD difference between DOR's Spring 2011 forecast and Fall 2011 forecast for FY 2016:
    - In our spring forecast, we included the Umiat, Orion, Nikaitchuq, and Liberty fields;
    - Between the release of our spring forecast and the compilation of info for our fall forecast, there were changes in all of the fields listed above which caused DOR to reduce its estimates (changes re: deferred plans, reduced scope, and reduced reserves).

3.) **Provide backup for bullet 3 on slide 10, explaining why the cooperative agreement with the North Slope Borough was ended. Provide the letter from Marsha Davis regarding ending the North Slope Borough cooperative agreement for property tax.**

Please see attached letter from Deputy Commissioner Marcia Davis re: the ending of the North Slope Borough cooperative agreement for property tax.

Sincerely,

Bruce Tangeman
Deputy Commissioner

Enclosure

State of Alaska

Department of Revenue

Commissioner's Office

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November 13, 2009

The Honorable Edward S. Itta
Mayor, North Slope Borough
P.O. Box 69
Barrow, AK 99723

Dear Mayor Itta,

The Department of Revenue has over the years benefited from the assessment assistance provided by the North Slope Borough (NSB) under a Memorandum of Understanding (MOU) authorized under AS 43.56.060(g). Since the MOU's most recent revision in 2006, the Department has undergone a series of internal initiatives to strengthen the protection of taxpayer confidential information. We do not believe the current MOU is consistent with these internal standards. Therefore, please consider this notification that the Department is withdrawing from the agreement effective 30 days from the date of this letter as required in section seven of the MOU.

In light of the recent staff retirements within the NSB, which has left the NSB Audit Group without staff, the Department will now resume performing the appraisal functions that had been previously performed by the NSB under the MOU. As a result, we do not anticipate any negative impacts to the NSB or the state from the termination of the current MOU. Should the opportunity arise in the future to again work together under AS 43.56.060(g), we remain open to developing a new MOU with the NSB consistent with the Department's confidentiality requirements.

In accordance with paragraph 4 of the MOU, please have all AS 43.56 hard copy files stored at the NSB returned to the Department. Likewise, all electronic AS 43.56 files should be copied onto a disk and returned to the Department and subsequently deleted from all NSB computers and servers.

To avoid any confusion regarding the exchange of confidential taxpayer information, the Department will notify AS 43.56 taxpayers that the Department and NSB are no longer exchanging information pursuant to an MOU relating to AS 43.56 assessment matters.

We thank you for the excellent working relationship we have enjoyed with the NSB property assessment staff over the years.

Sincerely,

Marcia Davis

Marcia Davis, Deputy Commissioner

Cc: Randy Hoffbeck, Director, Administration & Financ
Bessie O'Rouke, NSB Attorney
Bonnie Harris, Asst. Attorney General

State of Alaska
Department of Revenue

Commissioner Bryan Butcher

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The Honorable Bert Stedman
State Capitol Room 516
Juneau AK, 99801

March 20, 2012

The Honorable Lyman Hoffman
State Capitol Room 518
Juneau AK, 99801

SUBJECT: Response to Questions from Senate Finance Meeting on March 14, 2012

Dear Senators Stedman and Hoffman:

Thank you for your questions and the opportunity to provide our follow-up responses from the Senate Finance Committee meeting on March 14, 2012. The questions and responses follow.

1. **Reproduce slide 5 using total lease expenditures for all companies.**

   Please see slide 1 attached.

2. **Can you run another slide #5 that shows the production tax revenue in dollars on the Y axis and the ANS WC Oil price in $ per barrel on the X axis but only from $60 to $140 instead of going all the way out to $300.**

   Please see slide 2 attached, with the X axis out to $200 per barrel.

3. **Reproduce slides 21-23 using 25% and 20% federal CIT rates.**

   Please see slides 3-8 attached.

4. **Reproduce slides 21-23 using total lease expenditures for all companies.**

   Please see slides 9-11 attached.

5. **Reproduce slides 21-23 showing total dollars to state, federal, and producer.**

   Please see slides 12-14 attached.

6. **For slide 27, what gross tax rate would generate an equal amount of production tax at $120 / barrel for each tax system?**

   Using FY 2012 assumptions of $8.72 in transport costs, opex of $14.03 per taxable barrel, and capex of $10.25 per taxable barrel, we calculated the following "equivalent" gross tax for ANS WC oil price of $120 per barrel.

   ACES Tax System: 35%
   HB 110 Brackets only: 24%

7. **For slide 29, provide share of profit charts, both as percent and dollar value.**

   Please see slides 15-20 attached.

8. **Reproduce slide 24 using total lease expenditures for all companies.**

   Please see slide 21 attached.

9. **Provide administration's position regarding continuing separate tax treatment for gas produced in Cook Inlet and gas used in state.**

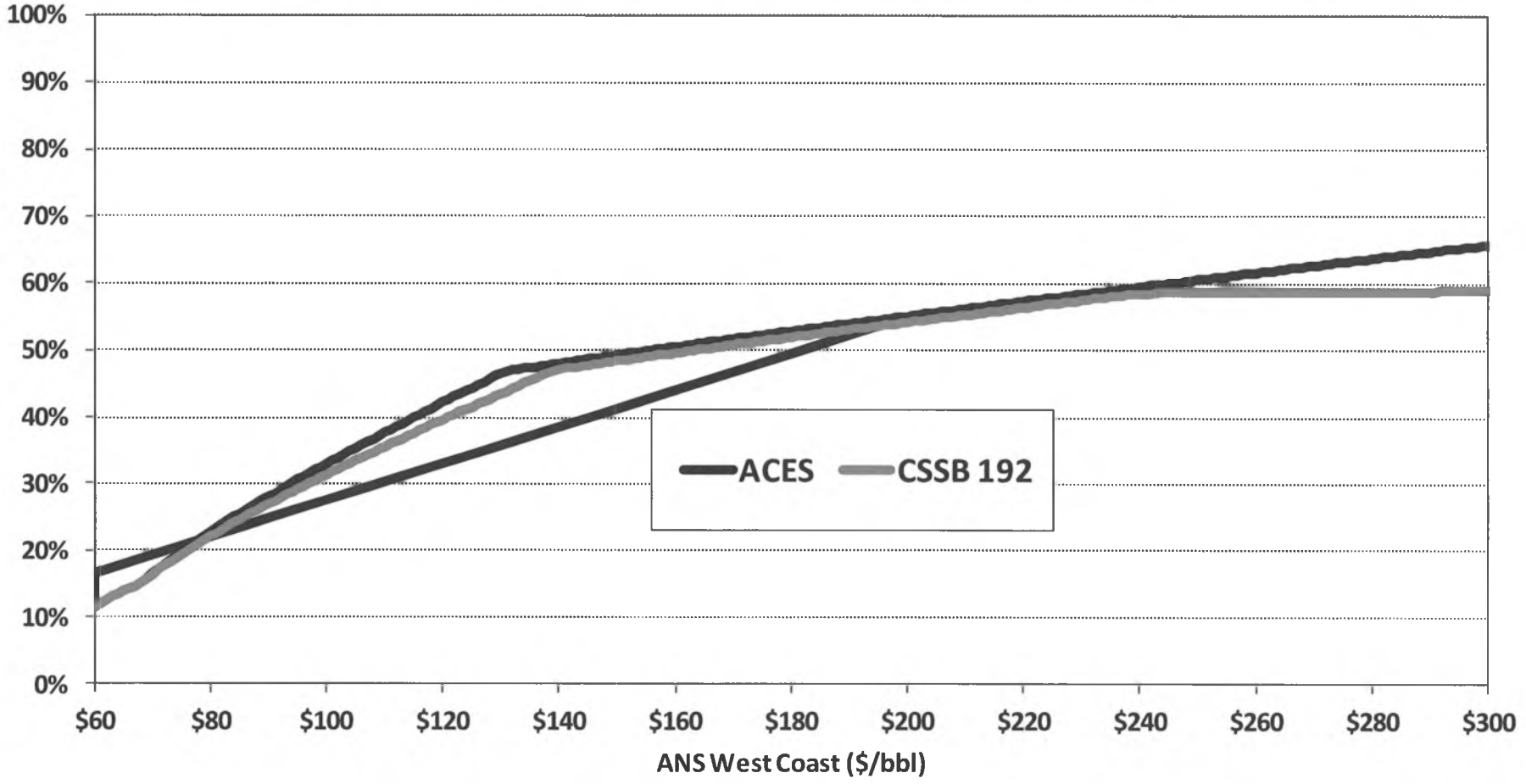
   The administration has not proposed making any changes to the current gas tax structure during this legislative session. The Governor has stated that he wants to address oil taxes this session to make Alaska more competitive for company investment that would lead to additional oil production. The Governor has also stated that he wants to address gas taxes in a future legislative session, in the context of a more concrete proposal for major gas sales.

We hope our responses fully answer your questions.

Sincerely,

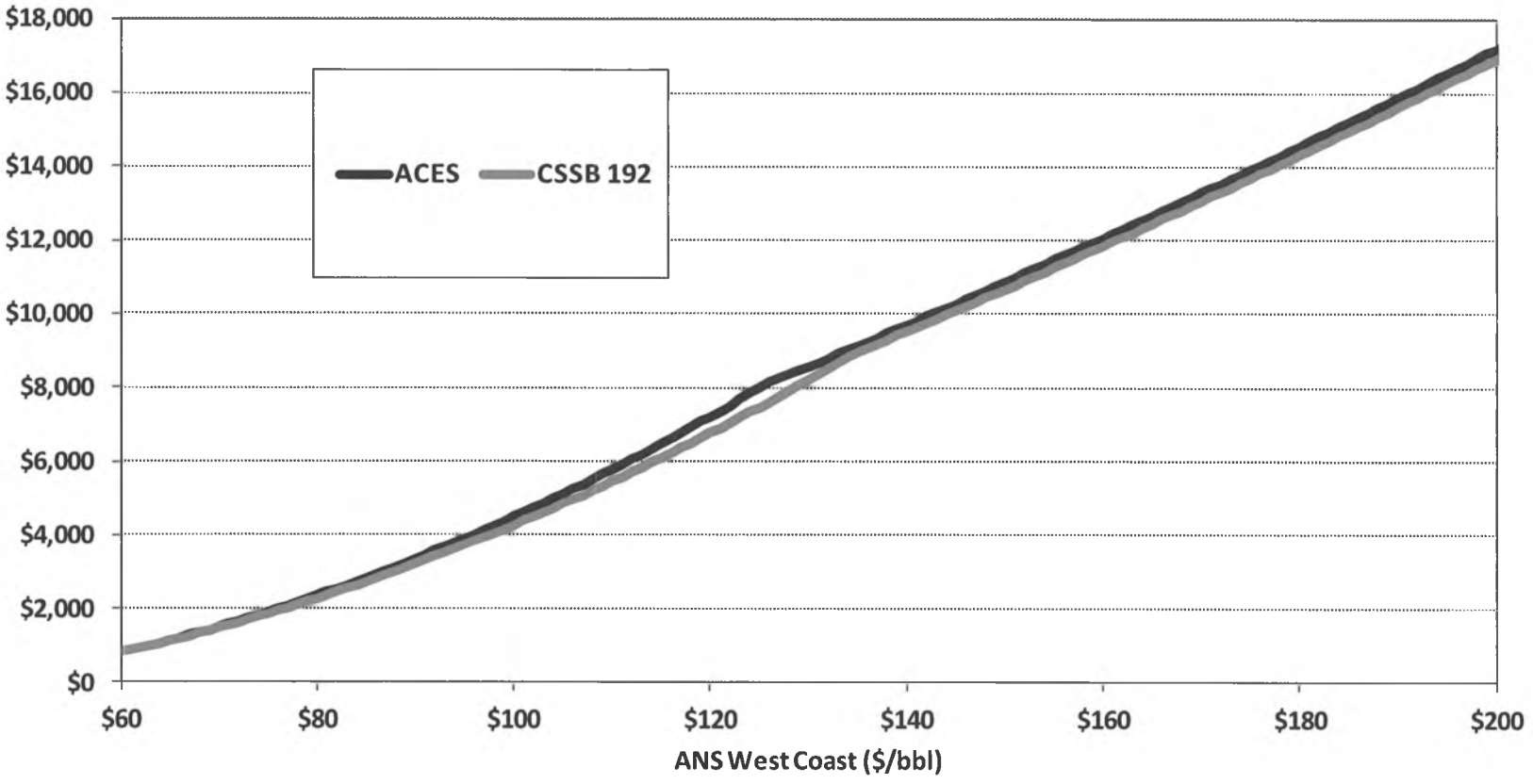
Bruce Tangeman
Deputy Commissioner

Effective Production Tax Rates: ACES and CSSB 192 (progressivity only) using Total Lease Expenditures for all Companies



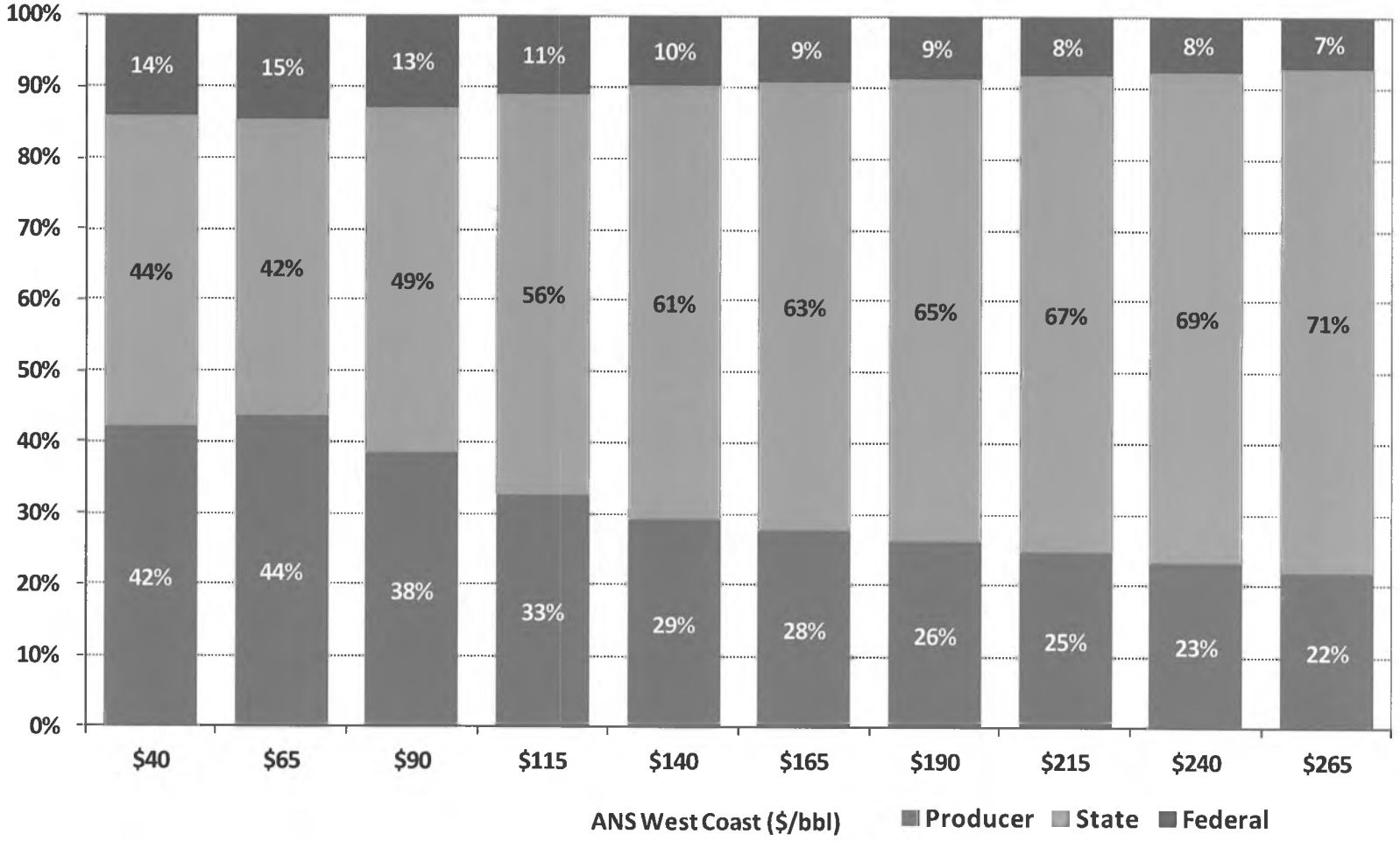
Assumes FY 2012 expenditures for all companies regardless of whether they have a tax liability: Transport costs of $8.72/ bbl, Opex of $14.06 per taxable barrel, and Capex of $14.95 per taxable barrel.

Production Tax Revenue after credits: ACES and CSSB 192 (progressivity only)



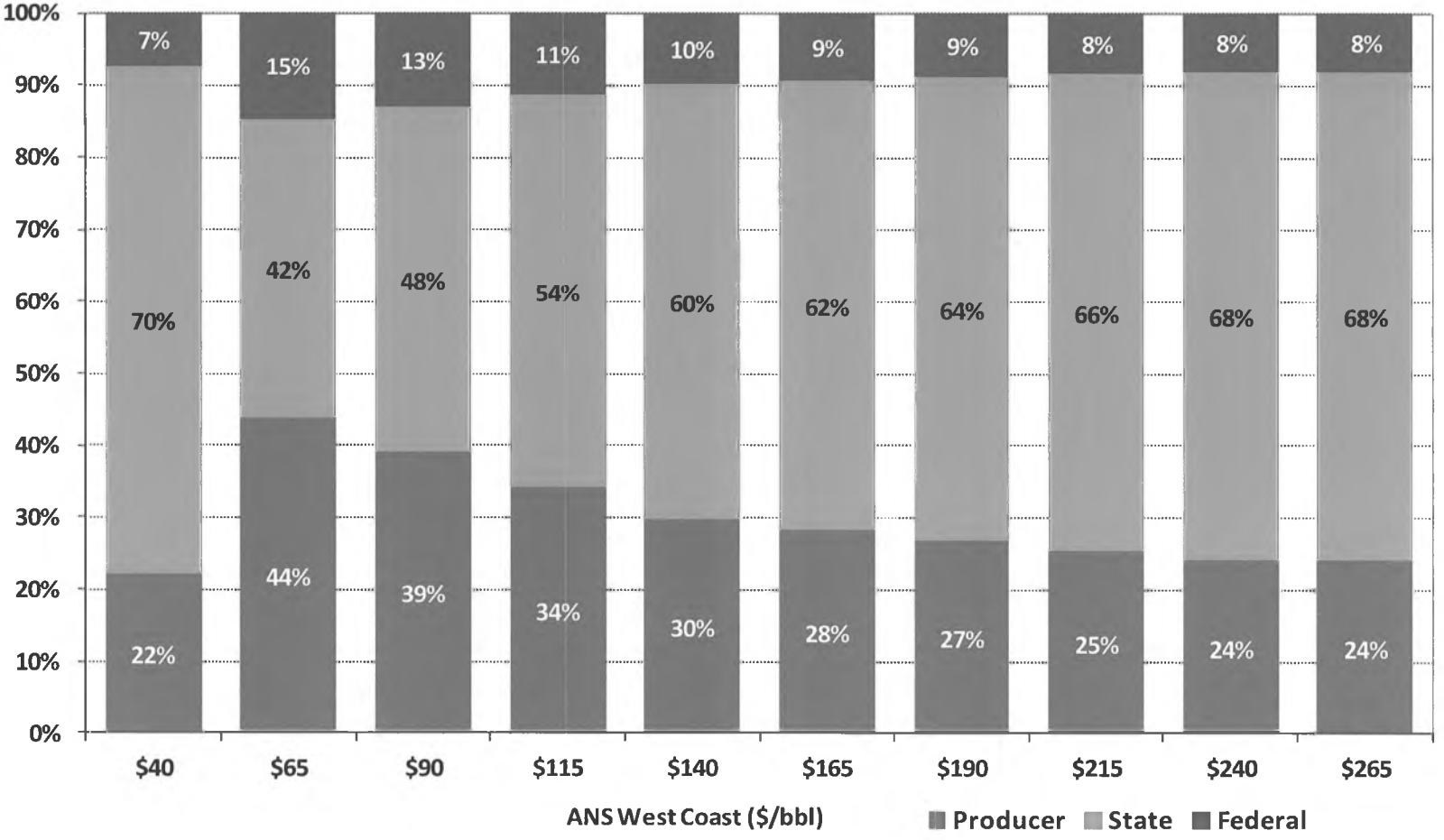
Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Share of Profit under ACES with 25% federal CIT



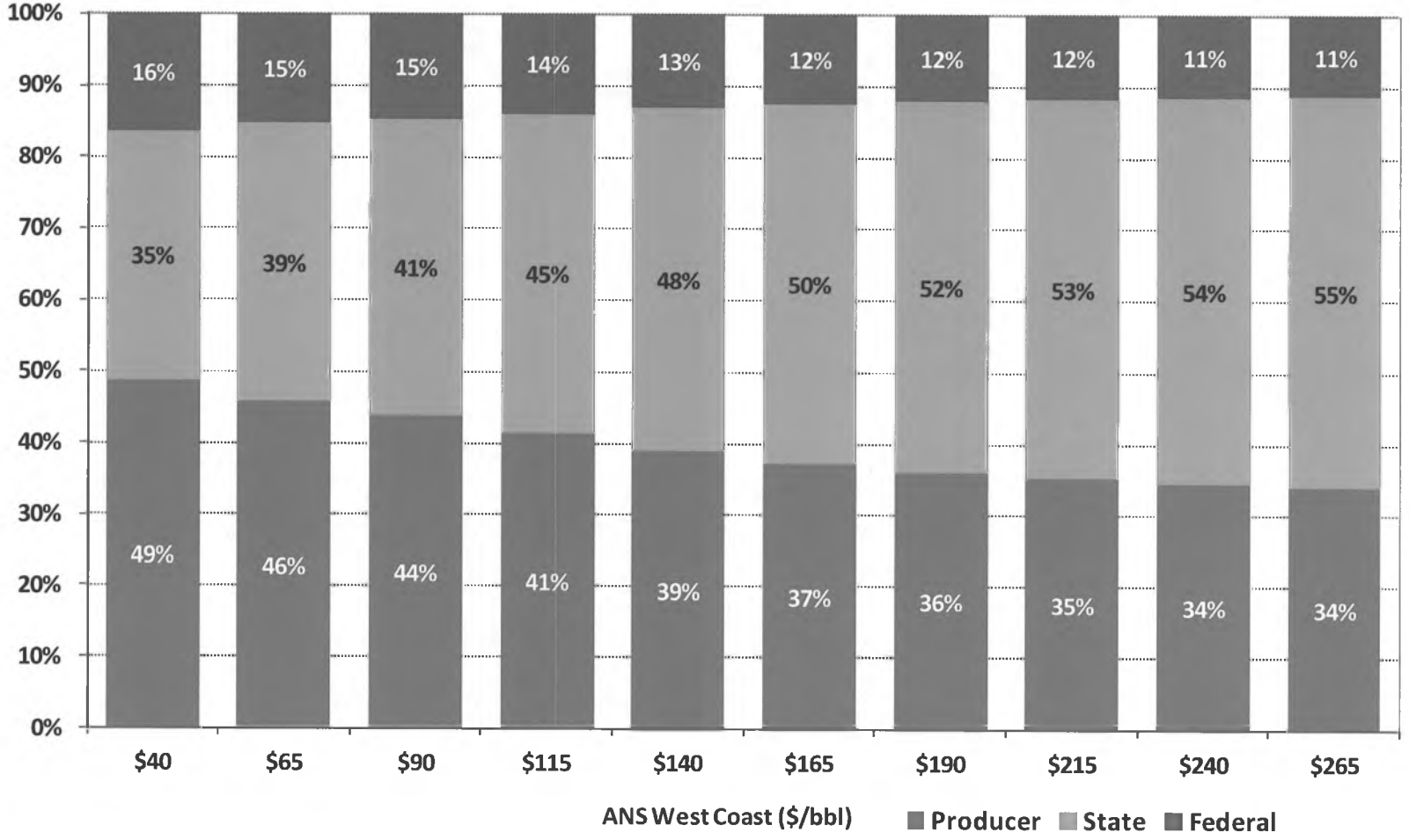
Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Share of Profit under CSSB 192 with 25% federal CIT



Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.
Assumes that 80% of production is impacted by 10% gross minimum tax with no credits allowed against gross tax.

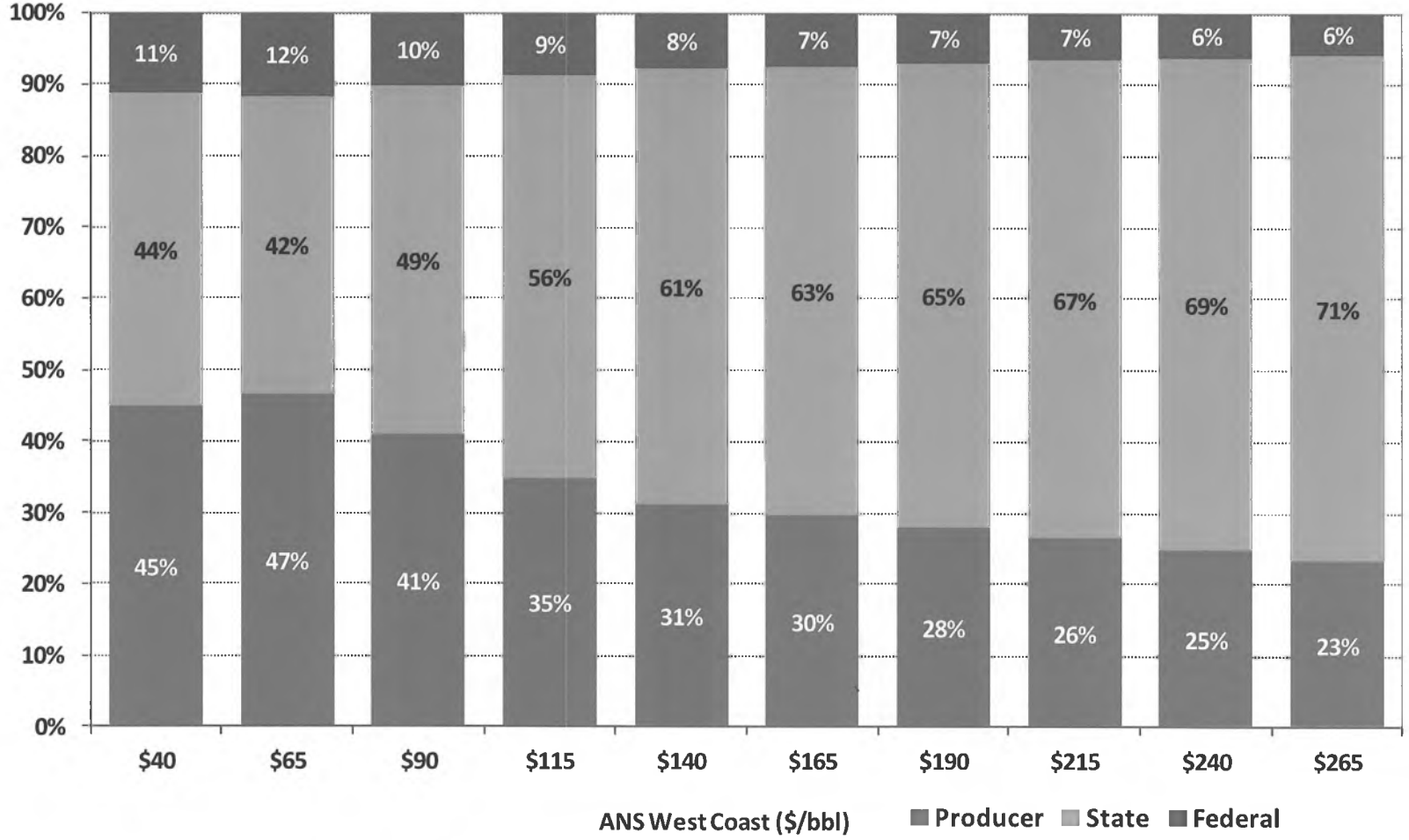
Share of Profit under CS HB 110 (FIN) with 25% federal CIT



Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.

Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Share of Profit under ACES with 20% federal CIT



Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
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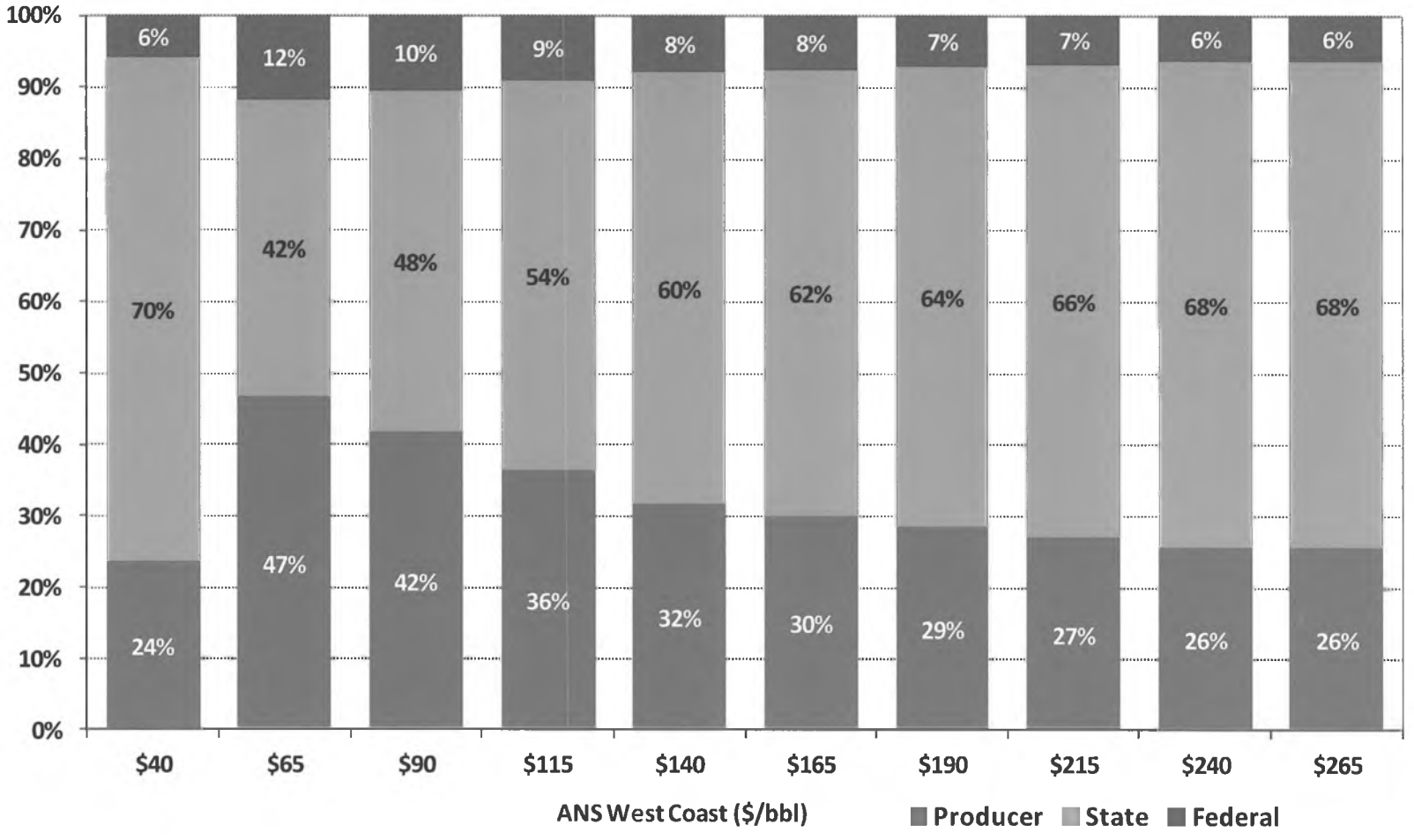
Share of Profit under CSSB 192 with 20% federal CIT



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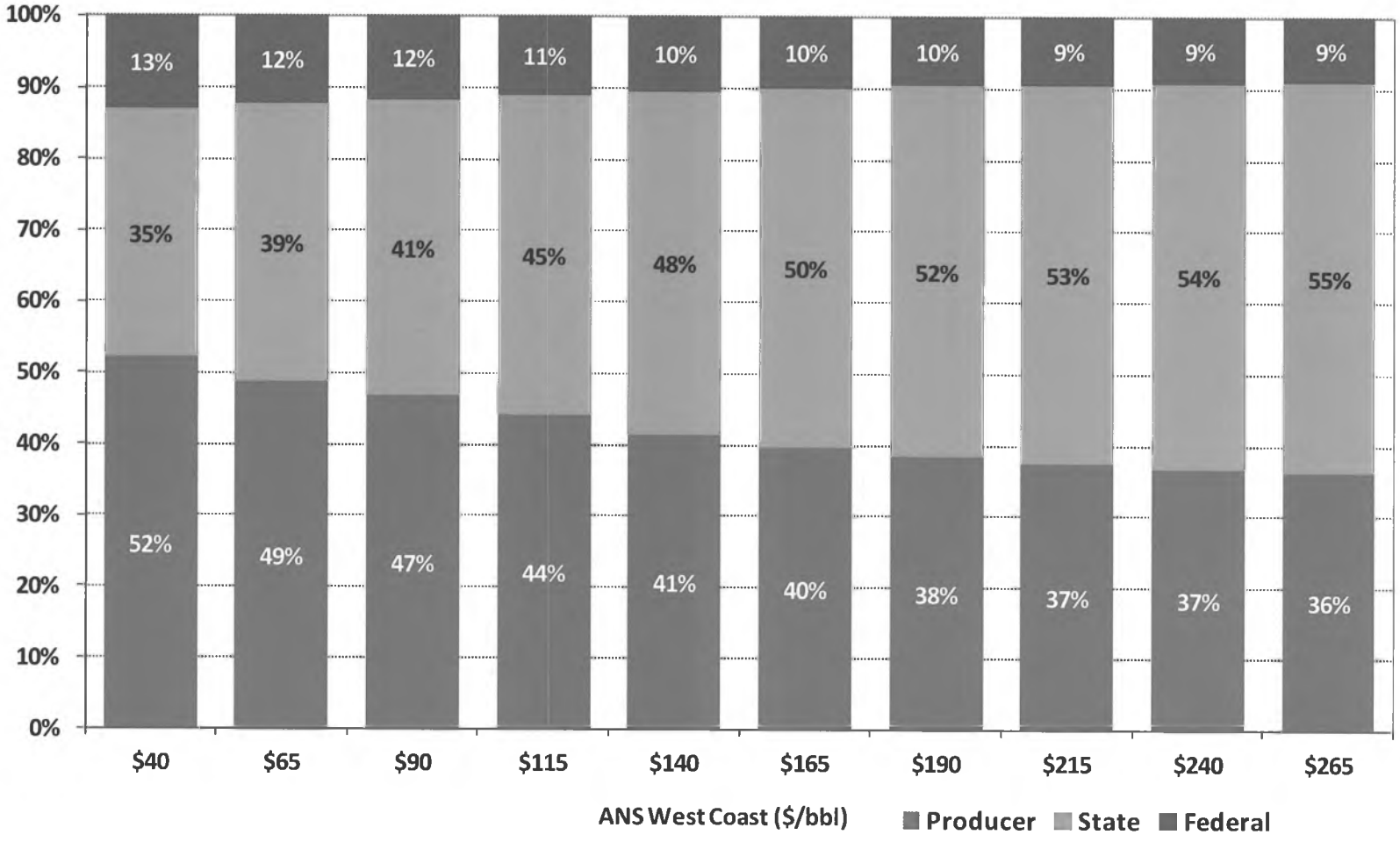

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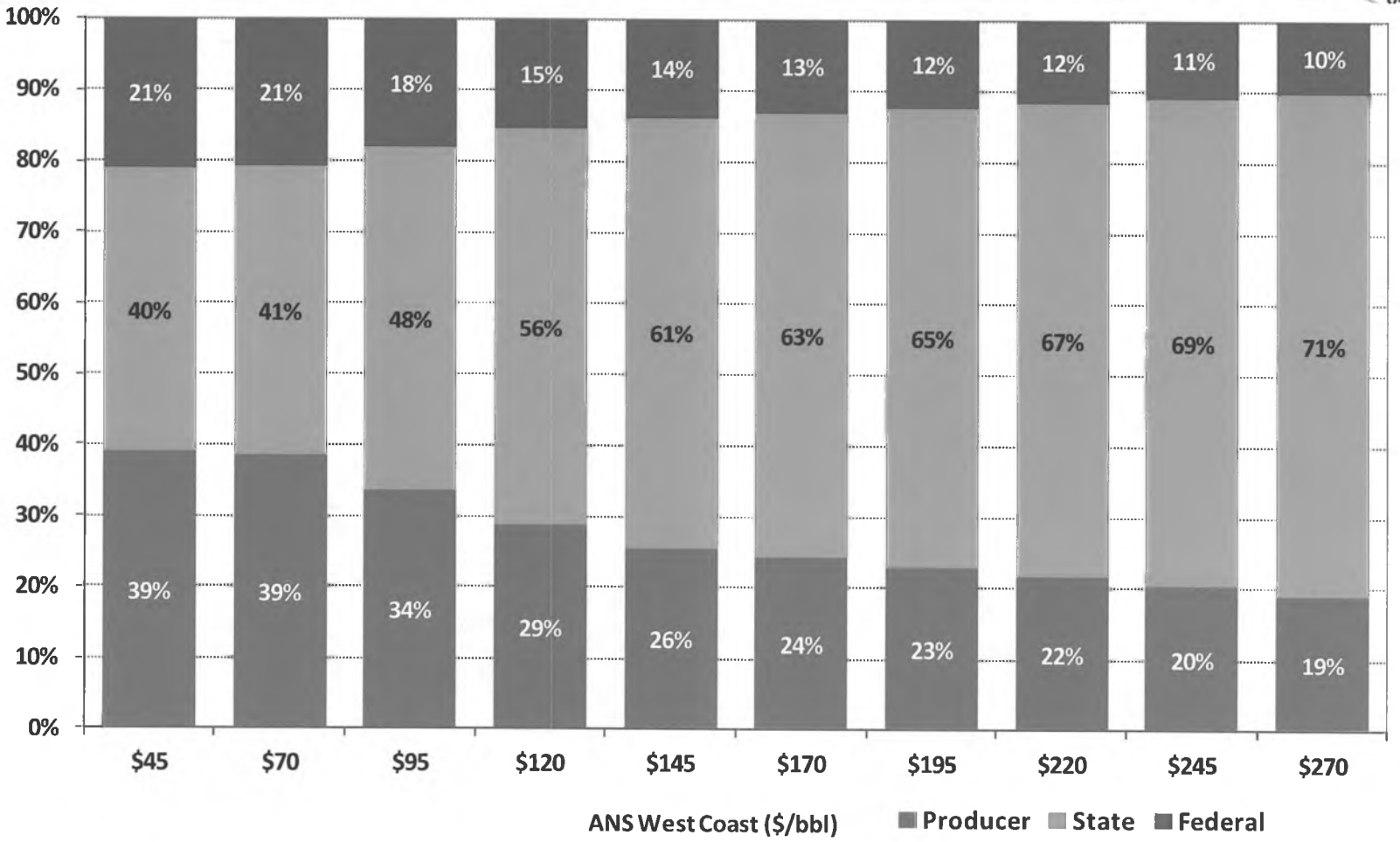
Assumes FY 2012 Transport costs of $8.72/ bbl, Opex of $14.03 per taxable barrel, and Capex of $10.25 per taxable bbl.

Share of Profit under ACES

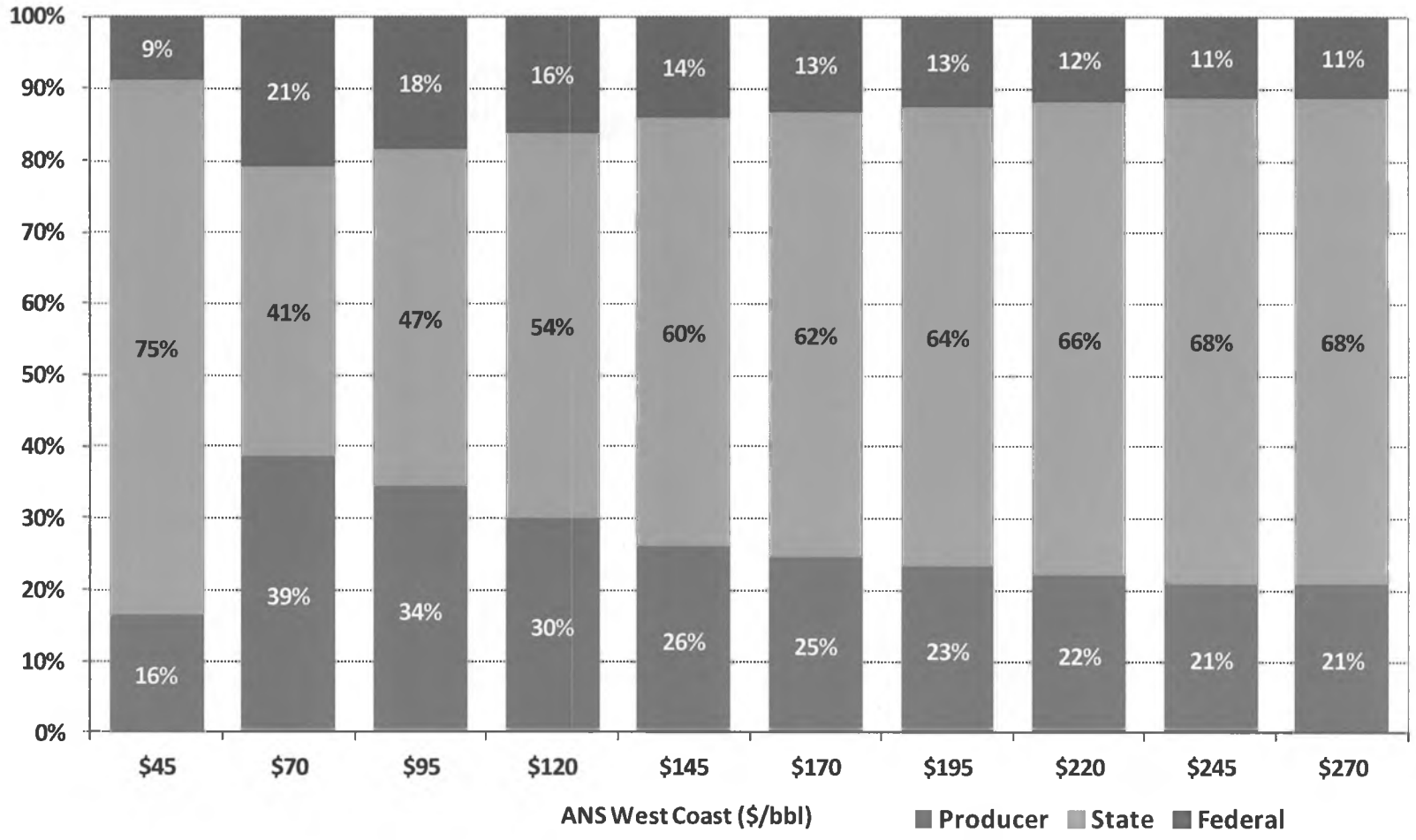
Using total lease expenditures for all companies



Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
Assumes FY 2012 expenditures for all companies regardless of whether they have a tax liability: Transport costs of $8.72/ bbl, Opex of $14.06 per taxable barrel, and Capex of $14.95 per taxable barrel).

Share of Profit under CSSB 192

Using total lease expenditures for all companies



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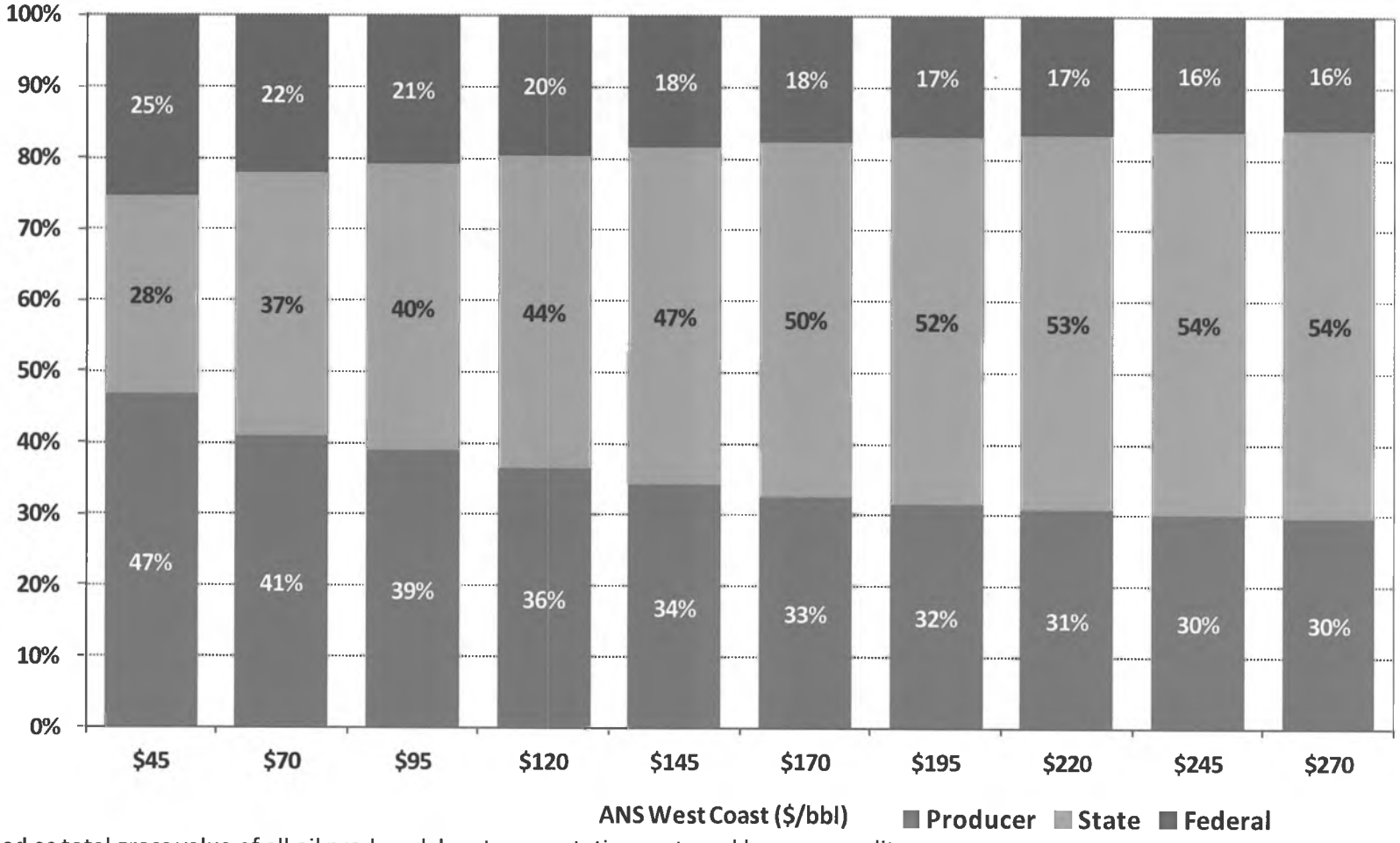
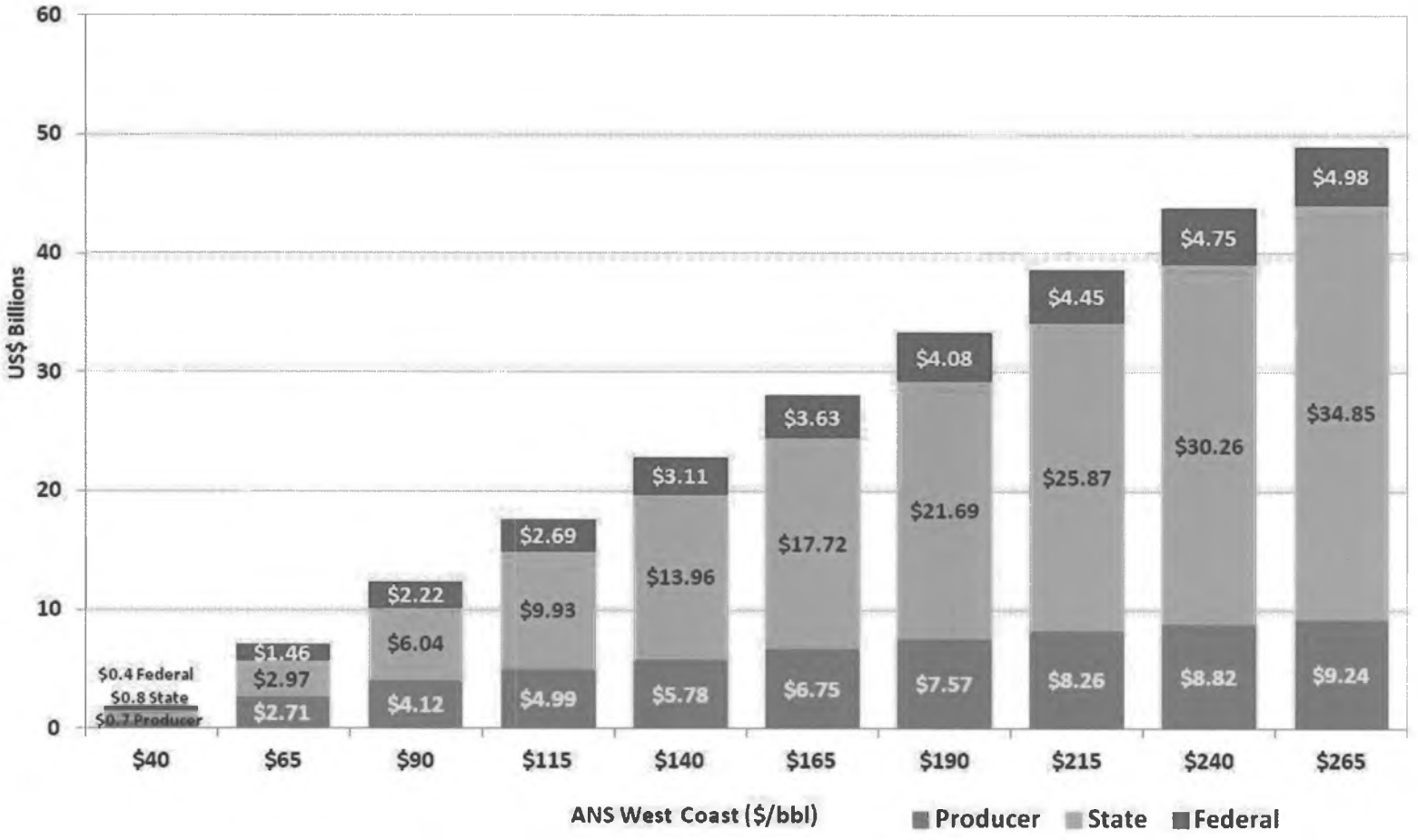
Share of Profit under CS HB 110 (FIN)

Using total lease expenditures for all companies



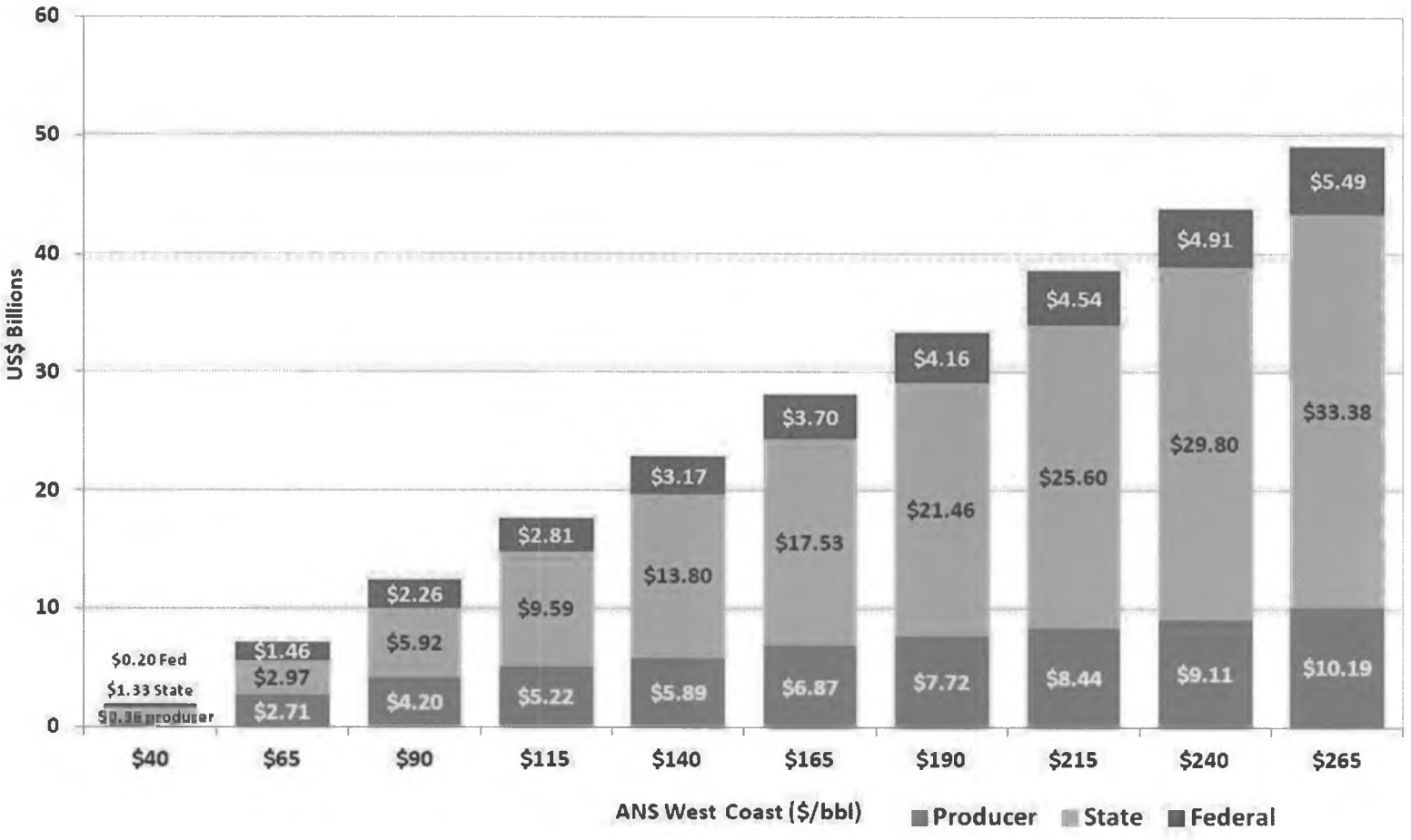
Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
Assumes FY 2012 expenditures for all companies regardless of whether they have a tax liability: Transport costs of $8.72/ bbl, Opex of $2579 million ($12.30 per total barrel), and Capex $2743 million ($13.08 per total barrel).

Absolute Profit Split under ACES



Profit defined as total gross value of all oil produced, less transportation costs and lease expenditures.
Assumes FY 2012 production of .574 mmb/d, transport costs of $8.72/bbl, opex of $14.03 per taxable barrel, and capex of $10.25 per taxable bbl.

Absolute Profit Split under CSSB 192



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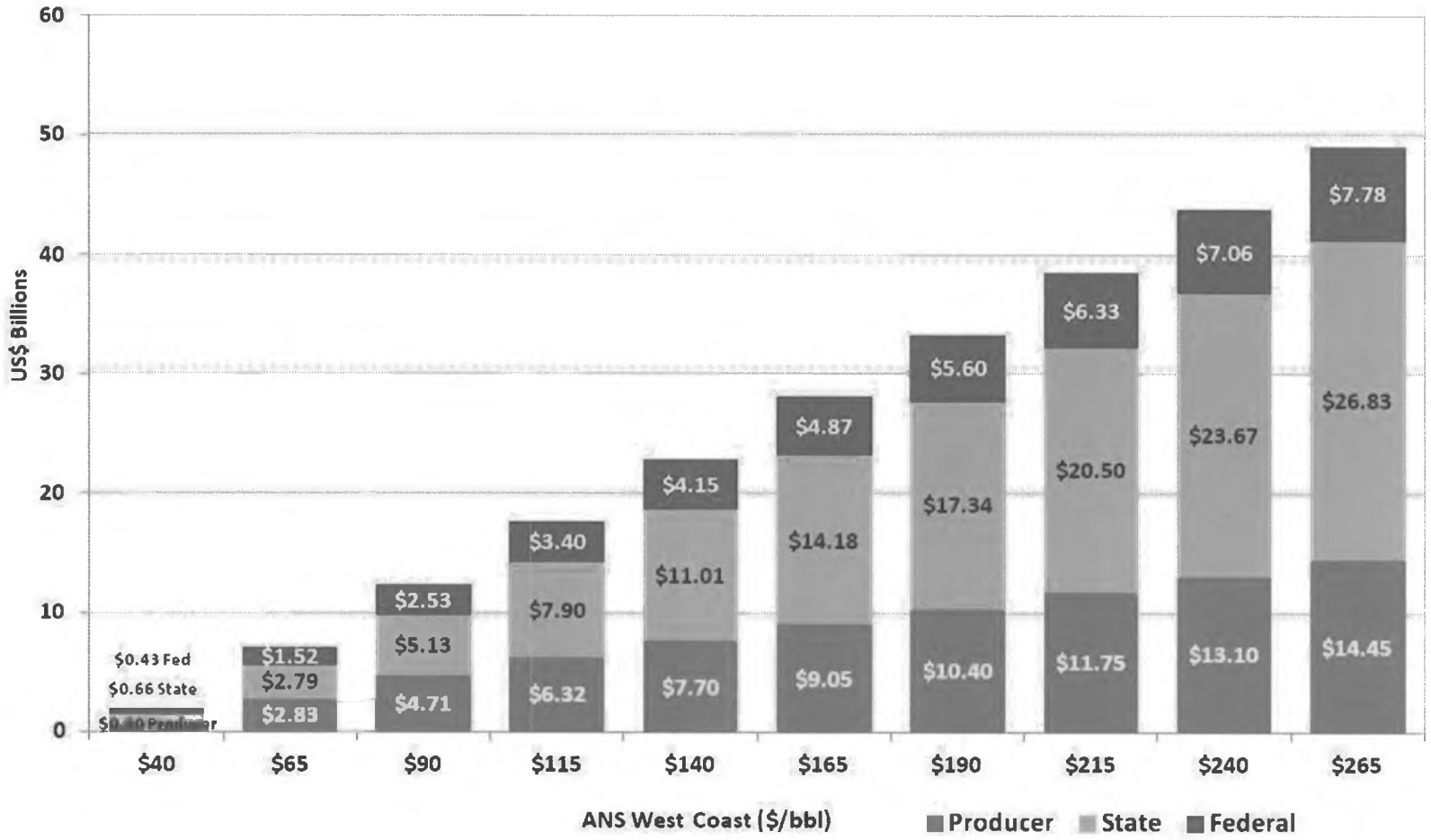
Absolute Profit Split under CSHB 110(FIN)



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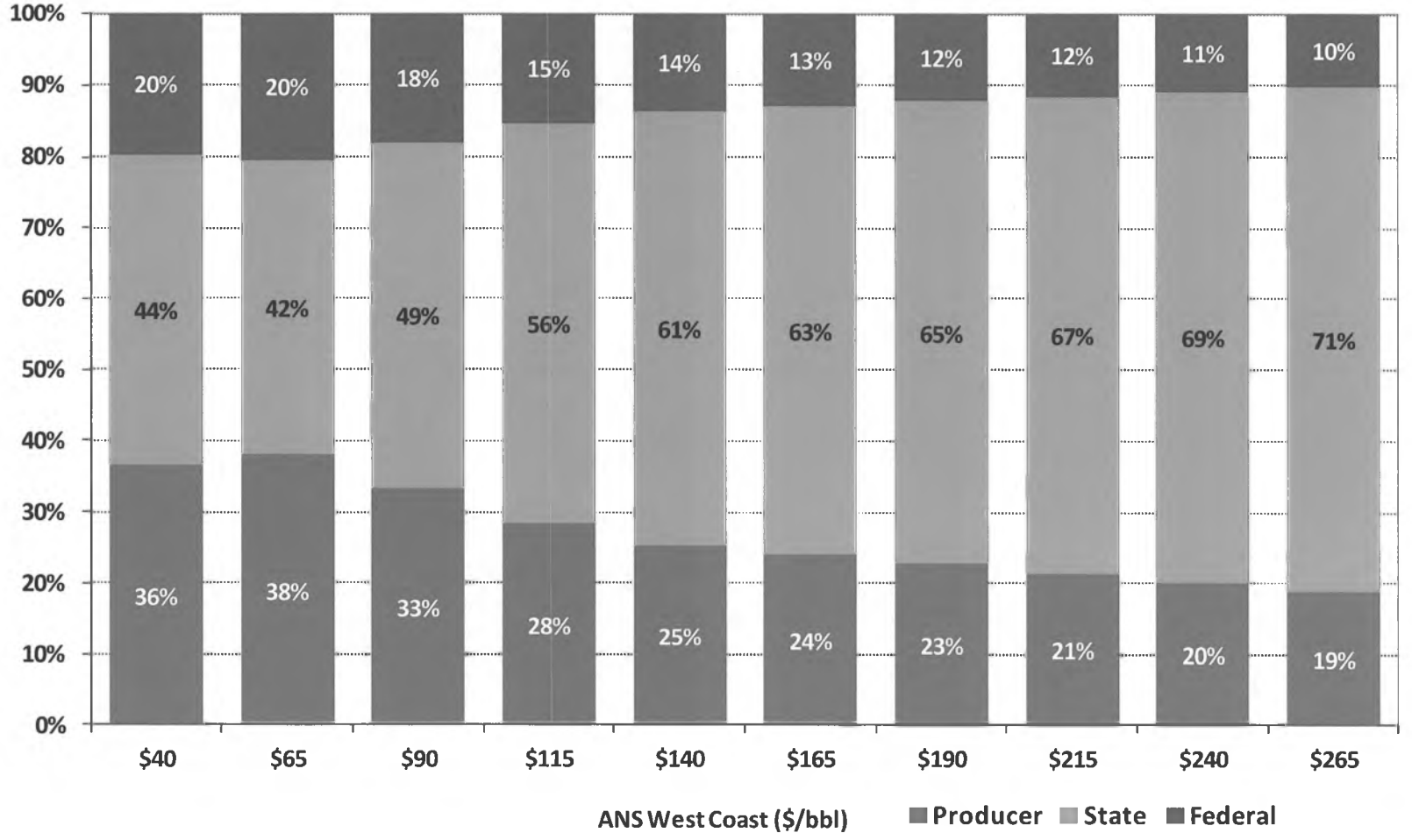
Share of Profit under ACES



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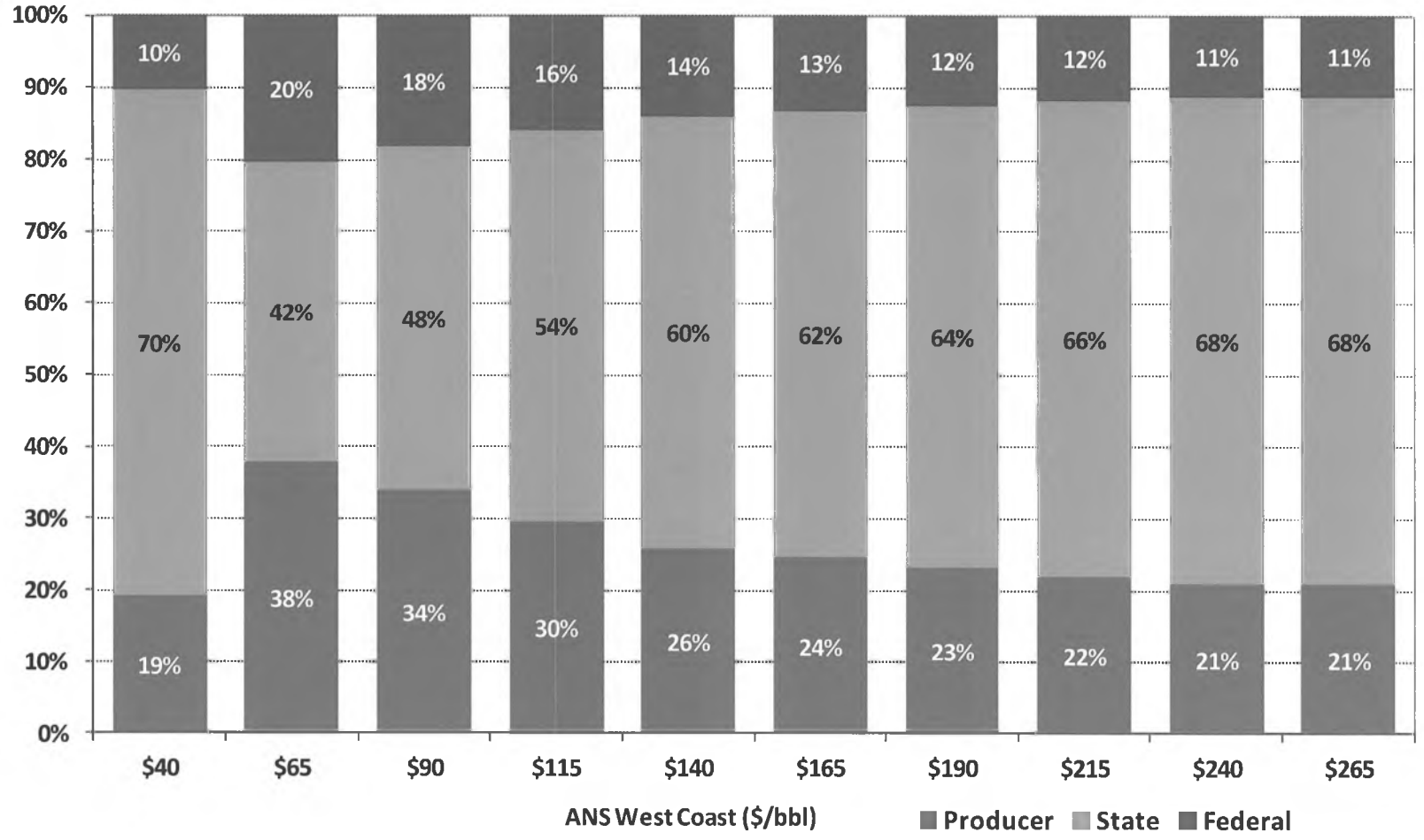

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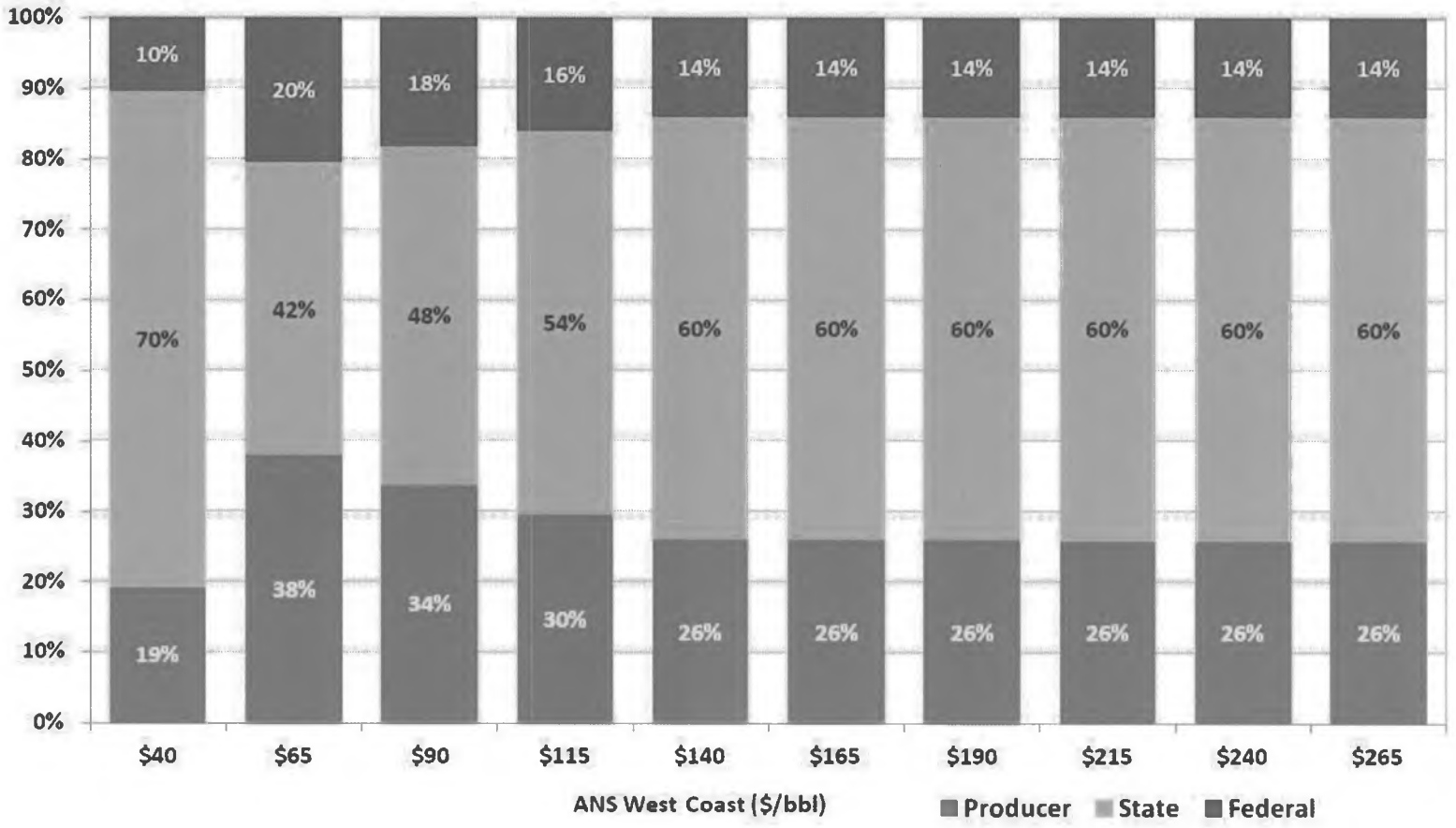
Share of Profit under CSSB 192 with 50% Maximum Tax Rate



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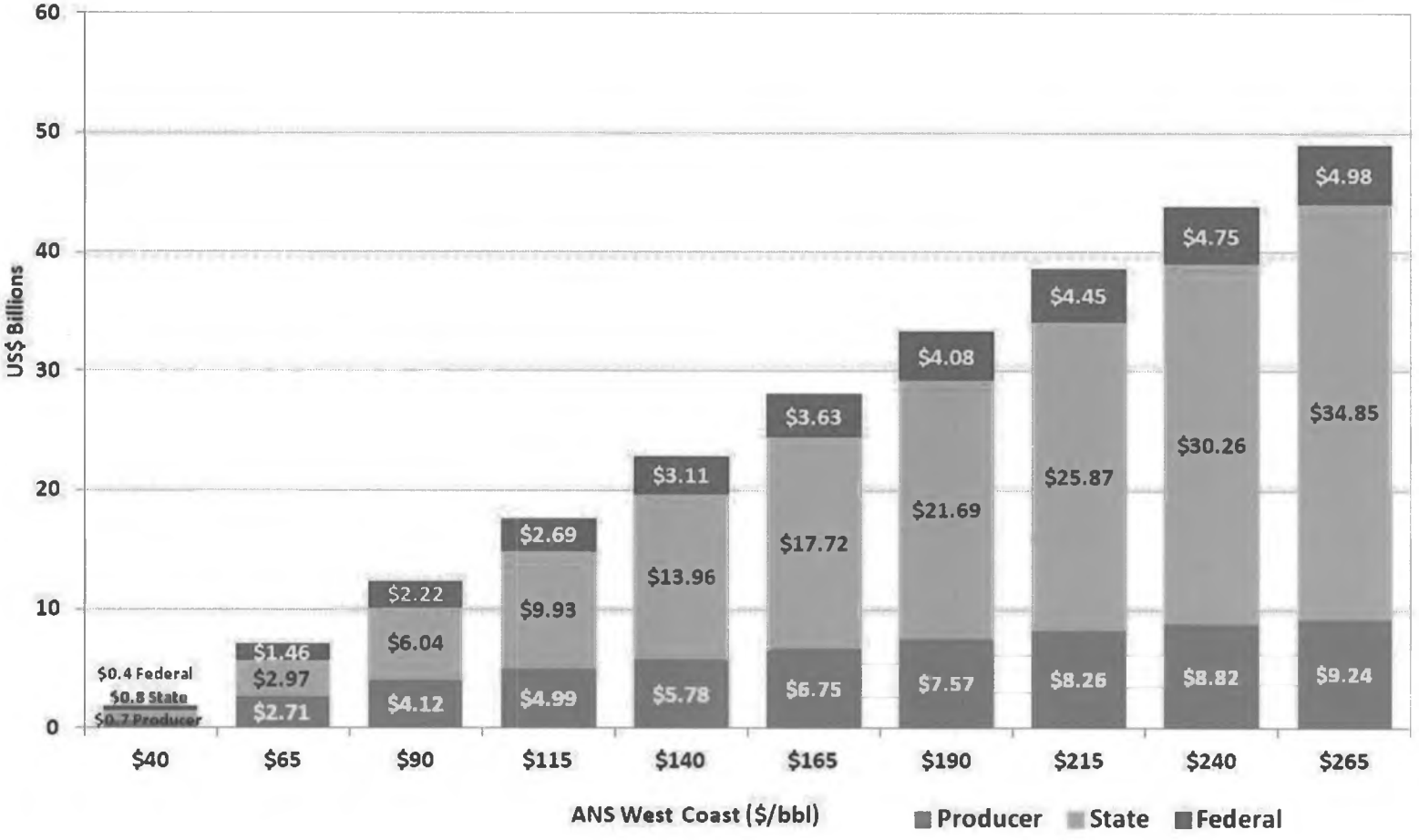
Absolute Profit Split under ACES



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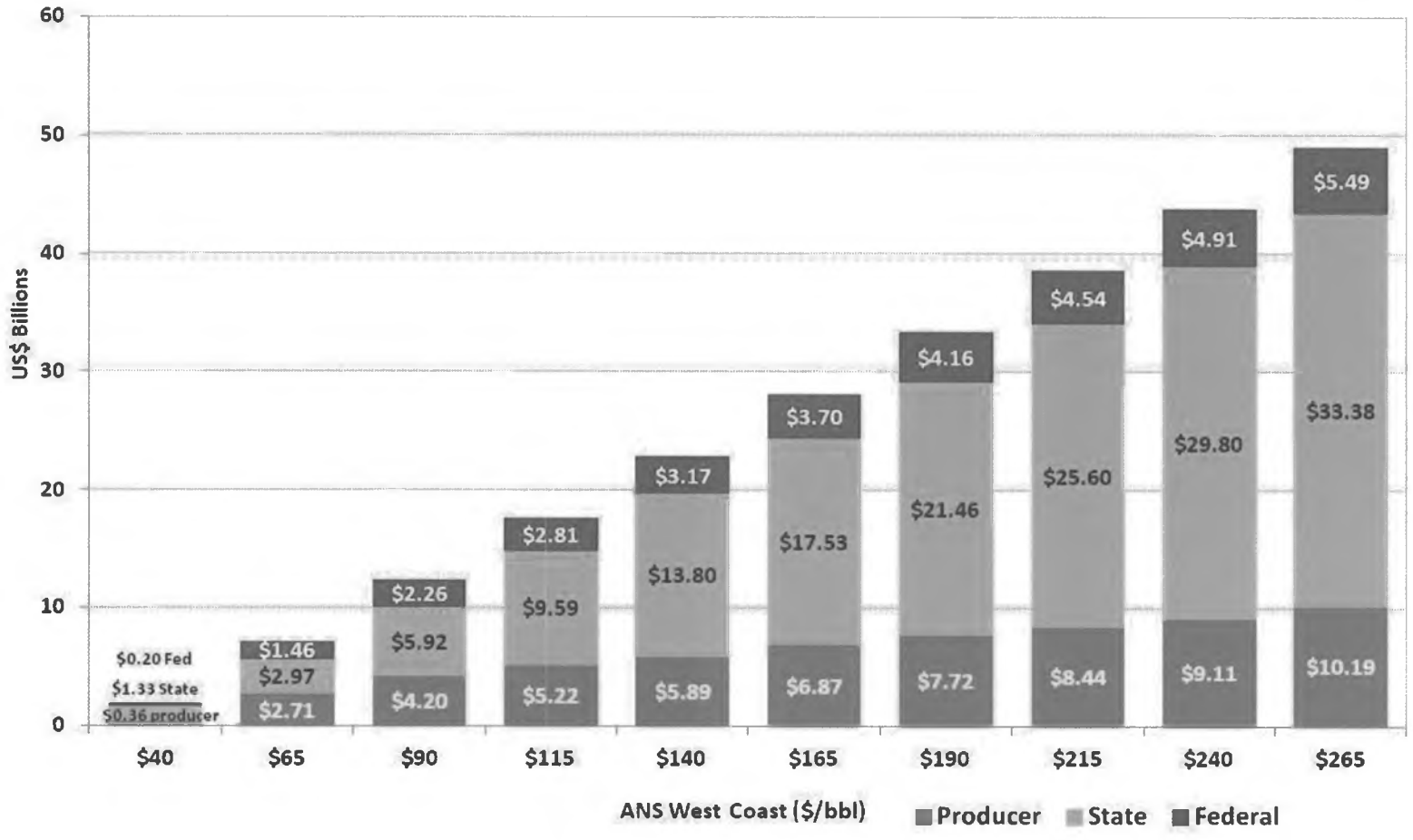

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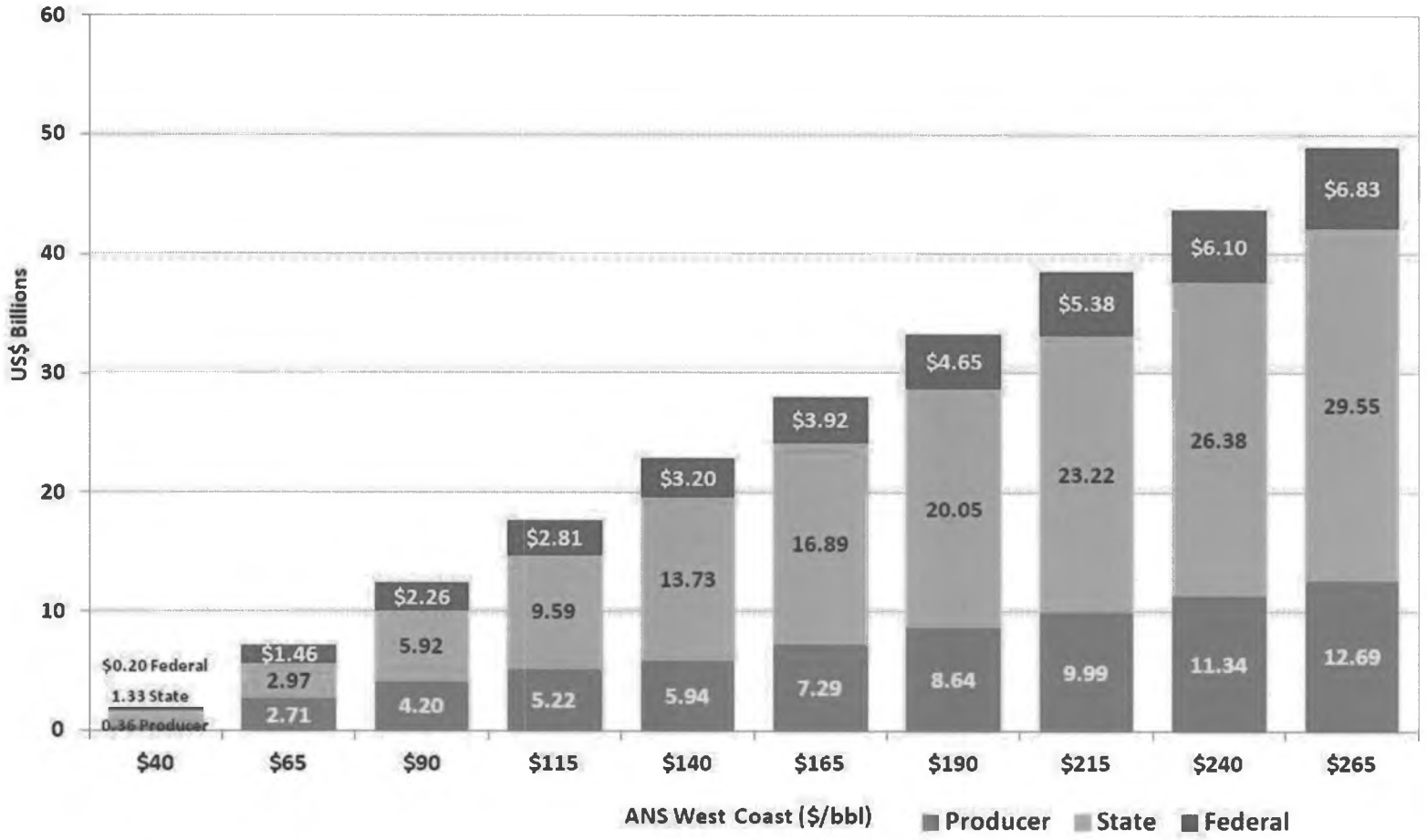

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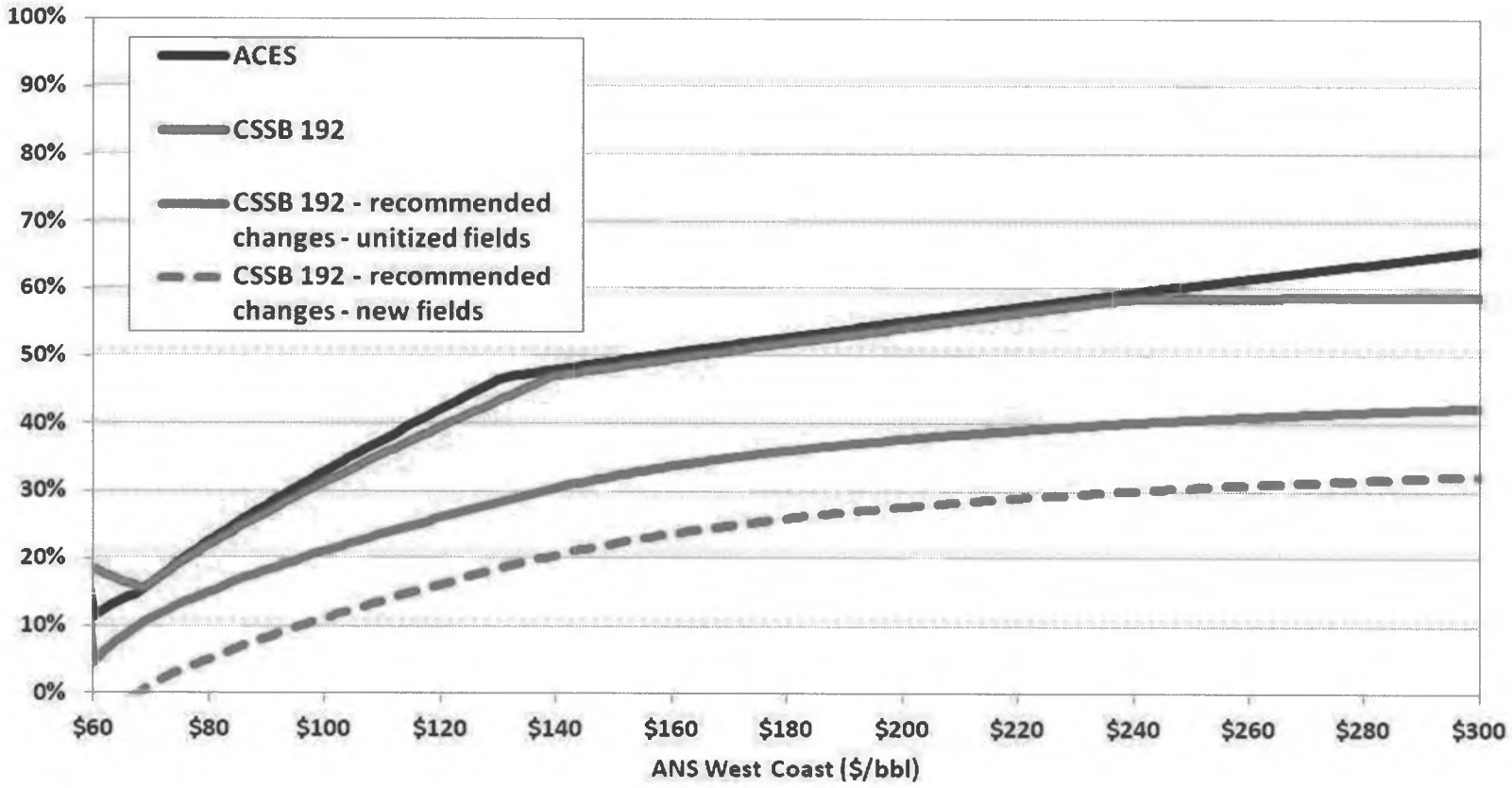
Effective Production Tax Rate (Post-Credits) using Total Lease Expenditures for all companies



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