

**SB 192
(FILE 2)
AMENDMENTS
AND
ANALYSIS**

<TARGET><BILL>SB 192</BILL><SUBJECT>SB 192 (FILE 2)
AMENDMENTS AND
ANALYSIS</SUBJECT><COMM>SRES27</COMM></TARGET>

Senate Resources Committee

SB192 Amendments

Jeff Stepp, Office of Senator Paskvan

Simple Bracketed Progressivity Example

The following example takes the PTV for FY 2012 from the Fall 2011 Revenue Sources Book and calculates the severance taxes levied and the nominal rate under amendments B.4 and B.5.

Note: The tax levied, and nominal rates under B.4 and B.5 are the same because the PTV is not high enough to trigger the additional brackets added by amendment B.4.

ANS Oil Price \$109.33

Production Tax Value \$75.98

*Source: Fall 2011 Revenue Sources Book p. 103

Base Tax	Tax Rate 25%	Tax Levied \$19.00	Amendment Progressive Tax Rate Amendment Nominal Tax Rate	5.65% 30.65%
Progressive Tax	18.40%	\$13.98	ACES Progressive Tax Rate ACES Nominal Tax Rate	18.40% 43.40%
Brackets				
30-42.50	2.50%	\$0.31		
42.50-55.00	7.50%	\$0.94		
55.00-67.50	12.50%	\$1.56		
67.50-80.00	17.50%	\$1.48		
80-92.50	22.50%	NA		
92.50-105.00	25%	NA		
105-117.50	30%	NA		
Above 117.50	35%	NA		
Total		\$4.30		

Prepared by Michael Pawlowski, Aide to Senator McGuire
Feb. 25, 2012

DRAFT

Prepared as Draft by Dept. of Revenue

Amendment 27-LS1305\M.14 – Bullock 2/21/12

- Tax rate is changed to use bracketed progressivity.
- The tax rates under the amendment are bracketed and only the increment of production tax value (PTV) within each bracket is taxed at that bracket's rate. The brackets range from 25% for PTV up to \$30 per barrel to 60% for PTV over \$117.50 per barrel. The maximum total production tax rate is 60%. The effective date of this provision is 1/1/2013.
- Same rates as HB 110 for existing production, with two additional brackets added: 55% for PTV from \$105 to \$117.50 / barrel, and 60% for PTV over \$117.50 / barrel.
- No distinction between existing units and "new" production
- Under our Fall 2011 forecast assumptions, the addition of the 2 additional brackets would have NO CHANGE on revenue this decade compared to bracketing with a 50% maximum rate, because our forecast prices and production tax values are expected to be below \$92.50 each year. We are forecasting PTV per taxable barrel in the \$65-\$70 range over this time period.
- The following presents the estimated fiscal impact, based on Fall 2011 forecast assumptions and no change in production.

Fiscal Year	Revenue Impact (\$ millions)
FY 2013*	(\$700)
FY 2014	(\$1,300)
FY 2015	(\$1,100)
FY 2016	(\$1,150)
FY 2017	(\$1,050)
FY 2018	(\$1,150)

*provisions in place for half of
FY 2013

Committee Substitute for Senate Bill 192 Oil and Gas Production Tax Values

Amendments

1. B.17 (McGuire) Competitiveness Review Board
2. B.6 (McGuire) Inflation Adjusting the \$30
3. B.11 (Wielechowski/French) Changes to Oil and Gas Leasing Laws
4. B.12 (Wielechowski/French) State Directed Financial Investment (SDFI)
5. B.14 (Wielechowski) Re-instituting Separate Accounting
6. B.15 (Wielechowski/French) Requiring Info About Use of Tax Credits
7. B.16 (French) Oil Information System
8. B.4 (McGuire) Progressivity Bracketed – 35% top bracket
9. B.5 (McGuire) Progressivity Bracketed – 25% top bracket
10. B.7 (McGuire) Adjusted base rate plus bracketed progressivity and in-field development credit for new fields
11. B.8 (Wielechowski/French) Simple Progressivity
12. B.9 (Wielechowski/French) Rewarding Increased Production
13. B.10 (Wielechowski/French) Capping Credits to Avoid Gold Plating
14. B.13 (Wielechowski/French) Establishing a Gross Minimum Tax
15. B.1 (Wagoner) Extends the Sunset of the Small Producer/New Area Development Credit from 2016 to 2021
16. B.2 (Wagoner) Gross Value at the Point of Production Tax Holiday
17. B.3 (Wagoner) Tax Credit Based on the Capital Cost of Developing New Oil and Gas Production

27-LS1305\B
Bullock
2/23/12

CS FOR SENATE BILL NO. 192(RES)
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-SEVENTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the oil and gas production tax; and providing for an effective date."**

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

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

4 (g) For each month of the calendar year for which the producer's average
5 monthly production tax value under AS 43.55.160(a)(2) **for a** [PER] BTU equivalent
6 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes of
7 (e)(2) of this section is determined by multiplying the monthly production tax value of
8 the taxable oil and gas produced during the month by the tax rate calculated as
9 follows:

10 (1) if the producer's average monthly production tax value **for a** [PER]
11 BTU equivalent barrel of the taxable oil and gas for the month is not more than
12 **\$101.43** [\$92.50], the tax rate is **0.35** [0.4] percent multiplied by the number that
13 represents the difference between that average monthly production tax value **for a**
14 [PER] BTU equivalent barrel and \$30; or

15 (2) if the producer's average monthly production tax value **for a** [PER]

1 BTU equivalent barrel of the taxable oil and gas for the month is more than **\$101.43**
2 [\$92.50], the tax rate is the sum of 25 percent and the product of 0.1 percent multiplied
3 by the number that represents the difference between the average monthly production
4 tax value for a [PER] BTU equivalent barrel and **\$101.43** [\$92.50], except that the
5 sum determined under this paragraph may not exceed **35** [50] percent.

6 * **Sec. 2.** This Act takes effect January 1, 2013.

ALASKA STATE LEGISLATURE



Senate Bipartisan Working Group Press Release

For Immediate Release: February 24, 2012

Senate Bipartisan Working Group Principles on Oil Development

Group issues statement as members begin discussions on amending Senate Bill 192

JUNEAU- To clarify our objectives, the Senate Bipartisan Working Group has developed the following statement as members begin discussions on how to amend Senate Bill 192 in the Senate Resources Committee today at 3:30pm:

❖ **We Want**

- Increased Oil Production
- More Jobs for Alaskans
- Sustainable State Revenue Over the Long Term

❖ **We Believe**

- Alaska's oil profits **must** be shared fairly between industry and the State across a wide range of oil prices, geologies, and viscosities
- Any significant reduction to Alaska's current share of oil profits **must** directly induce commercial investment, increase oil production, and create a competitive investment environment
- Industry and the State **must** work in partnership to recruit, train, and hire more Alaska residents
- Factual evidence and analysis **must** guide our debate

For more information on this statement, please call Senate Bipartisan Working Group Press Secretary Carolyn Kuckertz at (907) 465-3803 or Carolyn_Kuckertz@legis.state.ak.us.

###

Senate Resources Committee
Joe Paskvan, Co-Chair / February 24, 2012

Let's call the meeting to order.

Let the record reflect that it is _____ p.m. on Friday, February 24.

Let the record reflect that there is a quorum. Present are

- Co-Chair Wagoner
- Senator Stedman
- Senator Stevens
- Senator Wielechowski
- Senator French
- Senator McGuire
- And myself, Senator Paskvan

During this hearing, the Senate Resources Committee will first adopt a Committee Substitute for Senate Bill 192 which relates to the Oil and Gas Production Tax Rates.

We will also begin to hear the amendments that are being proposed by the Committee members. Today and tomorrow at 1pm, the amendments will be discussed conceptually. This will be an open and transparent process. There will be no motion to move an amendment there will be no vote on any amendment, either today or tomorrow. After additional consideration and discussion, amendments may or may not be included in a forthcoming CS.

I have not asked the Administration to prepare an analysis of any of these amendments, at this time.

I have reviewed the amendments and very much appreciate the dedication and effort displayed by the Committee members. The ideas that we will hear are interesting and have merit. Ultimately, we are required to determine what legislation will advance from this Committee and I look forward to an informative dialogue for the next couple of days.

Let me begin by presenting the Committee Substitute for Senate Bill 192.

May I please have a motion to bring the CS for SB 192, Version B, before this Committee?

LEGAL SERVICES

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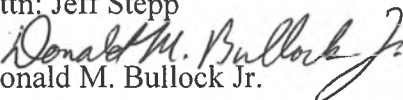

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

February 24, 2012

SUBJECT: Amendments received for SB 192 now drafted for
CSSB 192(RES), draft version B
(Work Order Nos. 27-LS1305\B.1 - B.16)

TO: Senator Joe Paskvan
Chair of the Senate Resources Committee
Attn: Jeff Stepp

FROM: 
Donald M. Bullock Jr.
Legislative Counsel
and
Emily Nauman 
Legislative Counsel

You have a draft version of CSSB 192(RES), Work Order No. 27-LS1305\B. The previous version of the bill, the introduced version, is SB 192, Work Order No. 27-LS1305\M. Sixteen amendments were filed with you in preparation for the Senate Resources Committee meeting today, February 24, 2012 at 3:30 p.m. We understand you may introduce CSSB 192(RES), draft version B as the committee's working draft.

Today we reviewed the list of amendments that had been submitted to you that were prepared to SB 192. To facilitate the work of the committee and in consultation with you, the amendments that you have in your possession have been redrafted to amend CSSB 192(RES), draft version B. Because you may not request that an amendment be drafted for another member of the legislature without his or her consent, the enclosed amendments are blank where the name of the sponsor would normally appear.

Therefore, to assist the committee and the Senators that have provided you with the amendments for the original version of the bill, the table below lists the work order for each amendment as drafted to SB 192 and the new work order number for the same amendment as drafted to CSSB 192(RES), draft version B. There are no substantive changes in the amendments to the CS; however, each amendment now is identified as an amendment to the CS, and page and line numbers referenced in the amendments have been changed as necessary.

The list below does not include the names of the sponsors that submitted the amendments for SB 192. You may wish to distribute the new amendments to each sponsor after CSSB 192(RES), draft version B is adopted as the working draft for the committee. It

would be helpful if the sponsors had time to look at the new versions of the amendments to ensure that they are satisfied with the new version and to add each sponsor's name.

Work Order No. for Amendment to SB 192	Work Order Number for Amendment to CSSB 192(RES), Draft Version "B"
27-LS1305\M.18	27-LS1305\B.1
27-LS1305\M.17	27-LS1305\B.2
27-LS1305\M.24	27-LS1305\B.3
27-LS1305\M.14	27-LS1305\B.4
27-LS1305\M.13	27-LS1305\B.5
27-LS1305\M.15	27-LS1305\B.6
27-LS1305\M.16	27-LS1305\B.7
27-LS1305\M.2	27-LS1305\B.8
27-LS1305\M.23	27-LS1305\B.9
27-LS1305\M.3	27-LS1305\B.10
27-LS1305\M.25	27-LS1305\B.11
27-LS1305\M.22	27-LS1305\B.12
27-LS1305\M.1	27-LS1305\B.13
27-LS1305\M.5	27-LS1305\B.14
27-LS1305\M.8	27-LS1305\B.15
27-LS1305\M.26	27-LS1305\B.16

DMB:plm
12-128.plm

Enclosures

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "**establishing the Oil and Gas Competitiveness Review Board;**"

3

4 Page 2, following line 5:

5 Insert new bill sections to read:

6 **** Sec. 2.** AS 44.99 is amended by adding new sections to read:

7 **Article 6. Oil and Gas Competitiveness Review Board.**

8 **Sec. 44.99.600. Oil and Gas Competitiveness Review Board established.** (a)

9 The Oil and Gas Competitiveness Review Board is established.

10 (b) The board shall consist of nine members as follows:

11 (1) one senator appointed by the president of the senate;

12 (2) one representative appointed by the speaker of the house of
13 representatives;

14 (3) five members of the public appointed by the governor, including
15 one member who is a petroleum engineer, one member who is a geologist, one
16 member who is an economist, and one member who is a member of an environmental
17 or conservation group;

18 (4) the commissioner of natural resources or the commissioner's
19 designee; and

20 (5) the commissioner of revenue or the commissioner's designee.

21 (c) The senator and representative appointed to the board under (b)(1) and (2)
22 of this section shall be cochairs.

23 (d) Each legislative member serves for the duration of the legislature during

1 which the member is appointed. Each public member serves for three years. An
2 individual who has served on the board may be reappointed.

3 (e) A vacancy on the board shall be filled in the manner of the original
4 appointment.

5 (f) A member of the board may be removed and replaced at the discretion of
6 the person appointing that member.

7 (g) The public members of the board serve without compensation but shall
8 receive per diem and travel expenses authorized for boards and commissions under
9 AS 39.20.180.

10 (h) The board may enter into contracts for professional services and may
11 employ staff for administrative support for the board.

12 **Sec. 44.99.610. Duties.** The duties of the board include the following:

13 (1) review historical, current, and potential levels of investment in the
14 state's oil and gas sector;

15 (2) identify factors that affect investment in oil and gas exploration,
16 development, and production in the state, including tax structure, rates, and credits;
17 royalty requirements; infrastructure; workforce availability; and regulatory
18 requirements;

19 (3) review the competitive position of the state to attract and maintain
20 investment in the oil and gas sector in the state as compared to the competitive
21 position of other regions with oil and gas resources;

22 (4) in order to facilitate the work of the board, establish procedures to
23 accept and keep confidential information that is beneficial to the work of the board,
24 including the creation of a secure data room and confidentiality agreements to be
25 signed by individuals having access to the confidential information;

26 (5) make written findings and recommendations, together with
27 suggested legislation, to the Alaska State Legislature before December 1 of each year,
28 or as soon thereafter as practicable, regarding

29 (A) changes to the state's regulatory environment that would be
30 conducive to encouraging increased investment while protecting the interests
31 of the people of the state and the environment;

1 (B) changes to the state's fiscal regime that would be conducive
 2 to increased and ongoing long-term investment in and development of the
 3 state's oil and gas resources; and

4 (C) alternative means for increasing the state's ability to attract
 5 and maintain investment in and development of the state's oil and gas
 6 resources.

7 **Sec. 44.99.620. Information to be provided to board.** (a) The commissioner
 8 of natural resources, the commissioner of revenue, the commissioner of environmental
 9 conservation, and other commissioners and state agencies that have responsibility for
 10 and maintain information related to oil and gas investment and activity in the state
 11 shall, at the request of the board, provide information required by the board to carry
 12 out the duties described in AS 44.99.610.

13 (b) At the request of the board, and except for information that is confidential
 14 under AS 43.05.230, a commissioner may disclose to the board information that is
 15 otherwise confidential after each member of the board and each staff member for the
 16 board with access to the information signs a confidentiality agreement prepared by the
 17 commissioner making the disclosure. Information that is confidential under
 18 AS 43.05.230 may not be disclosed to the board.

19 **Sec. 44.99.630. Definition.** In AS 44.99.600 - 44.99.630, "board" means the
 20 Oil and Gas Competitiveness Review Board.

21 * **Sec. 3.** AS 44.99.600, 44.99.610, 44.99.620, and 44.99.630 are repealed June 30, 2021."
 22

23 Renumber the following bill section accordingly.

24
 25 Page 2, line 6:

26 Delete "This"

27 Insert "Section 1 of this"

28
 29 Page 2, following line 6:

30 Insert a new bill section to read:

31 **"* Sec. 5.** Except as provided in sec. 4 of this Act, this Act takes effect immediately under

1 AS 01.10.070(c)."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 6:

2 Delete "\$30"

3 Insert "the greater of \$30 or the amount determined under (p) of this section
4 [\$30]"

5

6 Page 1, line 14:

7 Delete "\$30"

8 Insert "the greater of \$30 or the amount determined under (p) of this section
9 [\$30]"

10

11 Page 2, following line 5:

12 Insert a new bill section to read:

13 **** Sec. 2.** AS 43.55.011 is amended by adding a new subsection to read:

14 (p) For a calendar year after 2013, the \$30 amount in (g) of this section shall
15 be adjusted by the commissioner as soon as practicable before the start of the calendar
16 year for which the tax will be determined according to changes in the Consumer Price
17 Index for all urban consumers for the Anchorage metropolitan area compiled by the
18 United States Department of Labor, Bureau of Labor Statistics. The \$30 amount in (g)
19 of this section shall be adjusted based on the increase, if any, between the consumer
20 price index for January through June of 2011 and for January through June of the year
21 immediately preceding the year for which the \$30 amount in (g) of this section is
22 being adjusted."

23

1 Renumber the following bill section accordingly.

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "Act":

2 Insert "relating to oil and gas or gas only leasing; requiring that a minimum work
3 commitment be included in each oil and gas and gas only lease and that a proposed plan
4 of development be included in an application for an oil and gas or gas only lease;"

5

6 Page 1, following line 2:

7 Insert new bill sections to read:

8 **** Section 1.** AS 38.05.180(h) is amended to read:

9 (h) The commissioner **shall** [MAY] include terms in **a** [ANY] lease **that**
10 **impose** [IMPOSING] a minimum work commitment on the lessee **to implement the**
11 **plan of development submitted by the lessee with a bid for an oil and gas or gas**
12 **only lease. The terms of the minimum work commitment must** [. THESE TERMS
13 SHALL BE MADE PUBLIC BEFORE THE SALE, AND MAY] include appropriate
14 penalty provisions to take effect in the event the lessee does not fulfill the minimum
15 work commitment. If it is demonstrated that a lease has been proven unproductive by
16 actions of adjacent lease holders, the commissioner may set aside a work commitment.
17 The commissioner may waive for a period not to exceed one two-year period any term
18 of a minimum work commitment if the commissioner makes a written finding either
19 that conditions preventing drilling or exploration were beyond the lessee's reasonable
20 ability to foresee or control or that the lessee has demonstrated through good faith
21 efforts an intent and ability to drill or develop the lease during the term of the waiver.

22 *** Sec. 2.** AS 38.05.180(x) is amended to read:

23 (x) A lessee conducting or permitting any exploration for, or development or

1 production of, oil or gas on state land shall provide the commissioner access to all
2 noninterpretive data obtained from that lease; **shall provide the commissioner access**
3 **to all information necessary to perform an economic analysis under (ii)(2) of this**
4 **section, including the capital, operating, production, and development costs and**
5 **an estimate of total reserves;** and shall provide copies of that data **and information,**
6 as the commissioner may request. The confidentiality provisions of AS 38.05.035
7 apply to the information obtained under this subsection.

8 * **Sec. 3.** AS 38.05.180 is amended by adding new subsections to read:

9 (hh) The commissioner shall require each bidder for an oil and gas lease or gas
10 only lease and each lessee applying for an extension or renewal of an oil and gas lease
11 or gas only lease to submit a plan of development for exploring, developing, and
12 producing from the lease within the period of the lease or the extension or renewal of
13 the lease. The commissioner shall review each plan of development and determine if
14 the proposed plan of development is reasonably expected to develop the lease in the
15 best interest of the state. The plan of development shall be included in a lease along
16 with penalties for failing to comply with the plan of development and other terms of
17 the lease. A bidder may not be a "qualified bidder" for the purposes of (f)(1) of this
18 section if the commissioner finds that the bidder has not submitted a proposed plan of
19 development that is in the best interest of the state or that the person that submitted the
20 plan of development is not reasonably capable of implementing the plan.

21 (ii) The commissioner shall

22 (1) review each oil and gas lease or gas only lease each year for the
23 purpose of determining whether a lease is being developed in the best interest of the
24 state, whether the lessee is complying with the plan of development applicable to the
25 lease, and whether revision of a development plan, including the planned rate of
26 development, would provide the maximum benefit to the people of the state;

27 (2) every five years, perform an economic analysis on each
28 participating area and determine whether the participating area is capable of increased
29 production in paying quantities over the current rate of production or plan of
30 development;

31 (3) enforce the terms of each oil and gas lease or gas only lease,

1 including imposing any applicable penalty or other remedy for noncompliance, within
 2 a reasonable time after finding that a lessee is out of compliance with the terms of the
 3 lease;

4 (4) submit a report to the legislature before the first day of each regular
 5 session that lists each oil and gas or gas only lessee that is found to be out of
 6 compliance and the action by the commissioner to bring the lessee back into
 7 compliance or to terminate the lease.

8 (jj) For the purposes of (hh) and (ii) of this section, a plan of development for
 9 a cooperative or unit under (p) of this section is the plan of development for a lease
 10 within the cooperative or unit, except where a different plan of development is
 11 established for a lease within the cooperative or unit.

12 (kk) For purposes of (ii) of this section,

13 (1) "participating area" means that part of an oil and gas lease unit area
 14 to which production is allocated in the manner described in a unit agreement;

15 (2) "production in paying quantities" means production in quantities
 16 sufficient to yield a return in excess of drilling, development, and operating costs."
 17

18 Page 1, line 3:

19 Delete "**Section 1**"

20 Insert "**Sec. 4**"

22 Page 2, line 6:

23 Delete all material and insert:

24 "*** Sec. 5.** The uncodified law of the State of Alaska is amended by adding a new section to
 25 read:

26 **APPLICABILITY.** Section 1 of this Act and AS 38.085.180(hh), enacted by sec. 3 of
 27 this Act, apply to a proposed lease sale and the renewal or extension of a lease on or after the
 28 effective date of secs. 1 and 3 of this Act.

29 *** Sec. 6.** Section 4 of this Act takes effect January 1, 2013.

30 *** Sec. 7.** Except as provided in sec. 6 of this Act, this Act takes effect July 1, 2013."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "relating to participation by the Alaska Industrial Development and Export
3 Authority in the development of oil and gas resources in the state;"

4

5 Page 2, following line 5:

6 Insert new bill sections to read:

7 "* **Sec. 2.** AS 44.88.080 is amended by adding a new paragraph to read:

8 (32) to acquire an interest in a project as necessary or appropriate to
9 provide working or venture capital for an oil or natural gas development project under
10 AS 44.88.650 - 44.88.660, whether by purchase, gift, or lease;

11 * **Sec. 3.** AS 44.88 is amended by adding new sections to read:

12 **Sec. 44.88.650. Acquisition of interest in businesses.** (a) The authority may
13 acquire, through purchase or other means, an interest in an in-state asset of a
14 corporation or other business entity that has a lease interest in an oil or natural gas
15 field in the state that has been explored, but only if the authority determines the
16 leaseholder has made reasonable efforts to obtain financing from the private sector to
17 develop the lease and those efforts have, in whole or part, been unsuccessful. The
18 authority shall exercise due diligence in acquiring an interest in an in-state asset of a
19 business entity under this section.

20 (b) If the authority acquires an interest in an in-state asset of a business entity
21 under this section, the authority may use the authority's assets, as appropriate, to aid in
22 the development of the oil or natural gas field in which the business entity has a lease
23 interest.

1 **Sec. 44.88.660. Alaska resource development fund.** (a) The Alaska resource
2 development fund is established in the authority for the purpose of developing oil and
3 gas resources, and consists of appropriations to the fund. The authority shall manage
4 the fund and may create separate accounts within it. Income of the fund or of
5 enterprises of the authority shall be separately accounted for and may be appropriated
6 to the fund.

7 (b) The authority may use money from the fund to carry out the fund's
8 purposes set out in (a) of this section.

9 * **Sec. 4.** AS 44.88.900(9) is amended to read:

10 (9) "project" means

11 (A) a plant or facility used or intended for use in connection
12 with making, processing, preparing, transporting, or producing in any manner,
13 goods, products, or substances of any kind or nature or in connection with
14 developing or utilizing a natural resource, or extracting, smelting, transporting,
15 converting, assembling, or producing in any manner, minerals, raw materials,
16 chemicals, compounds, alloys, fibers, commodities and materials, products, or
17 substances of any kind or nature;

18 (B) a plant or facility used or intended for use in connection
19 with a business enterprise;

20 (C) commercial activity by a business enterprise;

21 (D) a plant or facility demonstrating technological advances of
22 new methods and procedures and prototype commercial applications for the
23 exploration, development, production, transportation, conversion, and use of
24 energy resources;

25 (E) infrastructure for a new tourism destination facility or for
26 the expansion of a tourism destination facility; in this subparagraph, "tourism
27 destination facility" does not include a hotel or other overnight lodging facility;

28 (F) a plant or facility, other than a plant or facility described in
29 (D) of this paragraph, for the generation, transmission, development,
30 transportation, conversion, or use of energy resources;

31 (G) a plant or facility that enhances, provides for, or promotes

1 economic development with respect to transportation, communications,
2 community public purposes, technical innovations, prototype commercial
3 applications of intellectual property, or research;

4 (H) a plant or facility used or intended for use as a federal
5 facility, including a United States military, national guard, or coast guard
6 facility;

7 **(I) development of an oil and gas lease by providing**
8 **working or venture capital in exchange for an equity interest;**

9 * **Sec. 5.** The uncodified law of the State of Alaska is amended by adding a new section to
10 read:

11 ANALYSIS AND REPORT ON ALASKA RESIDENT INVESTMENT PROGRAM.
12 The Alaska Industrial Development and Export Authority shall research the possibility of
13 creating a program through which a resident of the state could invest the resident's permanent
14 fund dividend or other funds in an in-state oil or gas asset acquired by the authority under
15 AS 44.88.650 and report its findings to the legislature on December 31, 2012."

16
17 Renumber the following bill section accordingly.

18
19 Page 2, line 6:

20 Delete "This"

21 Insert "Section 1 of this"

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1 following "tax;":

2 Insert "relating to the oil and gas corporate income tax; relating to the credits
3 against the oil and gas corporate income tax; making conforming amendments;"
4

5 Page 1, following line 2:

6 Insert new bill sections to read:

7 "* Section 1. AS 29.60.599(1) is amended to read:

8 (1) "barrel," when used with reference to oil, means the quantity of
9 oil contained in 42 United States gallons of 231 cubic inches each, measured at a
10 temperature of 60 degrees Fahrenheit and an absolute pressure of 14.65 pounds a
11 square inch [HAS THE MEANING GIVEN IN AS 43.20.072];

12 * Sec. 2. AS 41.09.010(b) is amended to read:

13 (b) An exploration incentive credit extended under (a) of this section may be
14 applied against

15 (1) a payment or obligation against which a credit authorized by
16 AS 38.05.180(i) may be claimed;

17 (2) taxes payable under AS 43.20 or AS 43.21, as applicable; and

18 (3) oil and gas bonus payments due the state under AS 38.05.180(f).

19 * Sec. 3. AS 43.20.011 is amended by adding a new subsection to read:

20 (g) For purposes of calculating the tax under (e) of this section, the taxable
21 income of a corporation engaged in the production or transportation of crude oil or
22 natural gas shall be determined in accordance with AS 43.21.

23 * Sec. 4. AS 43.20.073(f) is amended to read:

1 (f) This section does not apply to taxpayers subject to AS 43.21
 2 [AS 43.20.072 ENGAGED IN

3 (1) THE PRODUCTION OF OIL OR GAS FROM A LEASE OR
 4 PROPERTY IN THE STATE; OR

5 (2) THE TRANSPORTATION OF OIL OR GAS BY REGULATED
 6 PIPELINE IN THE STATE].

7 * **Sec. 5.** AS 43.21 is amended by adding new sections to read:

8 **Article 1. Determination of Taxable Income.**

9 **Sec. 43.21.200. Application.** This chapter applies to every corporation doing
 10 business in the state that derives income from the production of oil or gas from a lease
 11 or property in the state or from the pipeline transportation of oil or gas in the state. The
 12 tax calculated under this chapter is measured by the total taxable income of the
 13 corporation during the tax period as defined by AS 43.21.210 - 43.21.240 and is
 14 calculated at the rates established under AS 43.20.011(e).

15 **Sec. 43.21.210. Determination of taxable income from oil and gas**
 16 **production.** (a) The taxable income of a corporation from the production of oil and
 17 gas from a lease or property in the state is the corporation's net income as calculated
 18 by the department in accordance with this section.

19 (b) Gross income of a corporation from oil and gas production is the gross
 20 value at the point of production of oil or gas produced from a lease or property in the
 21 state. The department shall by regulation determine a uniform method of establishing
 22 the gross value at the point of production. For the purpose of determining the gross
 23 value at the point of production under this subsection, the department shall use
 24 AS 43.55.150 for the determination of transportation costs.

25 (c) Net income from oil and gas production shall be determined by the
 26 department by deducting from gross income the following:

27 (1) royalties paid in kind or in value;

28 (2) taxes imposed under AS 43.55 that are actually paid or incurred by
 29 the corporation on the production from a lease or property in the state;

30 (3) taxes imposed under AS 29.45.080 - 29.45.090 and AS 43.56 that
 31 are actually paid or incurred by the corporation on property used directly in the

1 production of oil or gas from a lease or property in the state, including property used
2 in production, gathering, treatment, or preparation of the oil or gas for pipeline
3 transportation, but only if those property tax payments were due and payable only
4 after the date of commercial production from the lease or property with which the
5 property was associated;

6 (4) the direct costs incurred by or for the corporation in operating the
7 lease or property, including the direct costs of producing, gathering, treating, or
8 preparing the oil or gas for pipeline transportation, but net of any payments received
9 for those activities and not including any indirect cost or overhead expense;

10 (5) depreciation, using the percentage depletion basis under 26 U.S.C.
11 613 (Internal Revenue Code) or another reasonable method as the department may by
12 regulation establish, on property used directly in the production, gathering, treatment,
13 or preparation of the oil or gas for pipeline transportation, including amortization of
14 capitalized interest for investments in that property at a rate not to exceed the average
15 cost to the taxpayer of borrowed capital during the year in which the interest is
16 capitalized;

17 (6) the amortization of lease acquisition payments and taxes paid or
18 incurred under AS 29.45.080, 29.45.090, or AS 43.56, including capitalized interest,
19 for or on producing properties before the commencement of commercial production
20 from the lease or property for which the property is being used;

21 (7) interest expense of the corporation, not capitalized during
22 construction, that was paid or incurred in connection with property in the state;
23 however, unless (f) of this section applies, the interest expense may not exceed that
24 portion of the total interest paid by the consolidated business of which the corporation
25 is a part, determined by multiplying the total interest by a fraction, the numerator of
26 which is the value of the corporation's real and tangible personal property used
27 directly in the production of oil or gas from a lease or property in the state and the
28 denominator of which is the value of all real and tangible personal property of the
29 consolidated business; in this paragraph, "total interest paid by the consolidated
30 business" does not include interest expense arising from intercompany obligations
31 within the consolidated business except to the extent that the interest expense reflects a

1 pass-through of interest on a third-party borrowing by the parent or other member of
2 the consolidated business with the purpose, expressed at the time of the third-party
3 borrowing, of financing Alaska business activity of the taxpayer corporation;

4 (8) expenses incurred by the corporation after December 31, 2012, of
5 unsuccessful exploration of oil or gas in the state, including the acquisition costs of
6 abandoned properties, dry hole costs, and the costs of geologic and geophysical
7 exploration related to those abandoned properties;

8 (9) general overhead or administrative expense incurred by the
9 corporation attributable to deriving income from the production of oil or gas from a
10 lease or property in the state to the extent, except as provided in (f) of this section, that
11 the general overhead or administrative expense does not exceed that portion of the
12 total general overhead or administrative expense incurred by the consolidated business
13 of which the corporation is a part, determined by multiplying the total general
14 overhead or administrative expense by a fraction, the numerator of which is the value
15 of the corporation's real and tangible personal property used directly in the production
16 of oil or gas from a lease or property in the state and the denominator of which is the
17 value of all real and tangible personal property of the consolidated business;

18 (10) the amount of income from the production of oil and gas from a
19 lease or property that is divided among the regional Native corporations under 43
20 U.S.C. 1606(i) (sec. 7(i), Alaska Native Claims Settlement Act, P.L. 92-203).

21 (d) Deductions from gross income under this section may not include
22 expenses previously deducted on a return filed under AS 43.20.

23 (e) If a corporation subject to this chapter shares the production or proceeds of
24 the production from a lease or property through a working interest, royalty interest,
25 overriding royalty interest, production payment, net profit interest, joint venture, or
26 other agreement, the department shall allocate the deductions from gross income
27 between the corporation and the persons with whom the corporation has the agreement
28 in accordance with the terms of the agreement.

29 (f) If a corporation demonstrates to the satisfaction of the department that the
30 corporation paid or incurred actual expenses for interest or for general overhead or
31 administration attributable to deriving income from the production of oil or gas from a

1 lease or property in the state in an amount greater than the amount determined under
2 (c)(7) or (9) of this section, the department may allow the corporation to deduct the
3 greater amount.

4 **Sec. 43.21.220. Determination of income from oil and gas pipeline**
5 **transportation.** (a) Except as provided in (c) of this section, taxable income
6 attributable to the transportation of oil in a pipeline engaged in interstate commerce in
7 this state shall be determined by the department and shall be the amount reported or
8 that would be required to be reported to the Federal Energy Regulatory Commission or
9 its successors as net operating income, less those portions of interest and general
10 overhead or administrative expense attributable to the pipeline transportation of oil in
11 the state, except that taxable income shall also include taxes on or measured by
12 income. The department shall establish regulations governing the determination of
13 interest and general overhead or administrative expense attributable to pipeline
14 transportation of oil in the state.

15 (b) Except as provided in (c) of this section, taxable income attributable to the
16 transportation of natural gas in a pipeline engaged in interstate commerce in this state
17 shall be determined by the department and shall be the amount reported or that would
18 be required to be reported to the Federal Energy Regulatory Commission as net
19 operating income, less that portion of interest and general overhead or administrative
20 expense attributable to pipeline transportation in the state, except that the taxable
21 income shall also include taxes on or measured by income. The department shall
22 establish regulations governing the determination of interest and general overhead or
23 administrative expense attributable to pipeline transportation of natural gas in the
24 state.

25 (c) Taxable income attributable to the transportation of oil or natural gas in
26 this state of a corporation not under the jurisdiction of the Federal Energy Regulatory
27 Commission, or of a corporation under the jurisdiction of the Federal Energy
28 Regulatory Commission but not reporting the operation of pipelines in the state
29 separately from the operation of pipelines elsewhere, shall be determined by the
30 department and shall be based on an amount equal to the amount that would have been
31 reported to the Federal Energy Regulatory Commission under (a) of this section in the

1 case of oil pipelines, or under (b) of this section, in the case of natural gas pipelines,
2 had the corporation been, in fact, under the jurisdiction of the Federal Energy
3 Regulatory Commission for the taxable year and required to report on the operation of
4 pipelines in the state separately from the operation of pipelines elsewhere.

5 **Sec. 43.21.230. Determination of income from activities other than oil and**
6 **gas production or pipeline transportation.** (a) Taxable income of a corporation
7 subject to this chapter from activities in this state other than the production of oil or
8 gas from a lease or property in the state or the pipeline transportation of oil or gas in
9 the state shall be determined in accordance with the method established in art. IV of
10 AS 43.19.010 and in AS 43.20.071, as modified by (b) - (d) of this section.

11 (b) The total taxable income of a consolidated business is its entire income
12 less the portion of that entire income attributable to worldwide production and pipeline
13 transportation of oil and gas. In this subsection, for a member of a consolidated
14 business who is

15 (1) required to file under the Internal Revenue Code, "entire income"
16 means the taxpayer's taxable income as the term is used in AS 43.20.011 - 43.20.065;

17 (2) not required to file under the Internal Revenue Code, "entire
18 income" means an income determination prepared in accordance with generally
19 accepted accounting principles, except that a taxpayer may elect to report income as
20 the income would be determined under (1) of this subsection.

21 (c) The numerator and denominator of the property factor, of the payroll
22 factor, and of the sales factor shall be calculated without reference to that portion of
23 property, payroll, or sales directly related to the production of oil or gas from a lease
24 of property in the state or the pipeline transportation of oil or gas in the state.

25 (d) The value attributed to vessels transporting Alaska oil or gas of a
26 consolidated business that are not owned or effectively owned by the consolidated
27 business shall be excluded from the property factor.

28 **Sec. 43.21.240. Applicability of tax to a consolidated business.** The
29 provisions of this chapter apply to a consolidated business whether or not the taxpayer
30 is the parent or controlling corporation.

31 **Article 2. Calculation of Tax; Returns.**

1 **Sec. 43.21.300. Assessment of income and tax.** (a) The department shall
2 assess taxable income and the amount of tax payable on that taxable income. The
3 amount of the tax payable shall be determined using the tax rates in AS 43.20.011(e).

4 (b) On or before August 15 of each year, the department shall send to every
5 corporation taxable under this chapter a notice of assessment showing the amount of
6 income taxable under this chapter for the previous year and the amount of tax payable
7 on that taxable income.

8 (c) For purposes of this chapter, the department may combine taxable income
9 of corporations subject to tax under this chapter who are part of the same consolidated
10 business.

11 (d) If the methods of allocation and apportionment provided in this chapter do
12 not fairly represent the extent of a corporation's business activity in the state, the
13 corporation may petition for or the department may require, in respect to all or any
14 part of the corporation's business activity, if reasonable, the employment of any
15 method authorized under art. IV, sec. 18, AS 43.19.010 (Multistate Tax Compact), to
16 carry out an equitable allocation and apportionment of the corporation's income. The
17 commissioner shall include in the annual report required in AS 43.21.410 a report on
18 all relief granted under this subsection, including, for each case, a statement of the
19 changes in tax liability resulting from the granting of relief, the tax years involved, and
20 a description of the method of determining taxable income that was substituted for the
21 methods provided in this chapter.

22 **Sec. 43.21.320. Credits.** A credit under AS 43.20.043, 43.20.044, or 43.20.046
23 may also be applied against the tax levied under this chapter, unless a credit for the
24 same expenditure has been taken against a tax levied under AS 43.20 or AS 43.55.

25 **Sec. 43.21.330. Returns.** On or before April 15 of each year, a corporation
26 subject to tax under this chapter shall submit a return in a form prescribed by the
27 department setting out information required by the department to determine taxable
28 income. For purposes of this chapter, the department may require corporations subject
29 to tax under this chapter that are part of the same consolidated business to file a single
30 return.

31 **Sec. 43.21.340. Payment of tax.** The tax levied under this chapter is payable

1 to the department on or before September 30 of each year or in installments, including
2 prepayments of estimated tax, at the times and under the conditions the department
3 may by regulation require. The tax is payable on the due date set out in this section
4 even though the assessment is under appeal or the validity, enforceability, or
5 application of this chapter or any provision of this chapter is challenged before the
6 department or in the courts.

7 **Article 3. Administrative Matters.**

8 **Sec. 43.21.400. Regulations.** The department shall adopt regulations in
9 accordance with AS 44.62 (Administrative Procedure Act) as appropriate to
10 administer and enforce this chapter.

11 **Sec. 43.21.410. Public reporting.** (a) The commissioner shall compile and
12 transmit to the legislature an annual report of state revenue and the implementation of
13 taxation policies under this chapter. The report must include total aggregate income
14 tax paid by corporations subject to this chapter and aggregate income and deductions
15 by category, classified so as to prevent the identification of particular returns or
16 reports.

17 (b) The legislative auditor shall notify the legislature on or before the first day
18 of each regular session that the annual report reviewing the actions of the department
19 in administering this chapter is available.

20 **Sec. 43.21.420. Information disclosure.** Notwithstanding AS 43.05.320, the
21 department shall disclose to a legislator, on request, information collected from a
22 taxpayer to the extent that

- 23 (1) the taxpayer is a publicly traded company;
24 (2) the information has been filed in a quarterly, annual, or other
25 periodic report to the United States Securities Exchange Commission; and
26 (3) the information has been made public by the United States
27 Securities Exchange Commission.

28 **Sec. 43.21.499. Definitions.** Unless the context requires otherwise, the
29 definitions contained in AS 43.55.900 are applicable to this chapter. In addition, in this
30 chapter,

- 31 (1) "consolidated business" means a corporation or group of

1 corporations having more than 50 percent common ownership, direct or indirect, or a
 2 group of corporations in which there is common control, either direct or indirect, as
 3 evidenced by an arrangement, contract, or agreement;

4 (2) "Internal Revenue Code" has the meaning given in AS 43.20.340."
 5

6 Page 1, line 3:

7 Delete "**Section 1**"

8 Insert "**Sec. 6**"
 9

10 Page 2, line 6:

11 Delete all material and insert:

12 "* **Sec. 7.** AS 43.82.210(a) is amended to read:

13 (a) If the commissioner approves an application and proposed project plan
 14 under AS 43.82.140, the commissioner may develop proposed terms for inclusion in a
 15 contract under AS 43.82.020 for periodic payment in lieu of one or more of the
 16 following taxes that otherwise would be imposed by the state or a municipality on the
 17 qualified sponsor or member of a qualified sponsor group as a consequence of
 18 participating in an approved qualified project:

19 (1) oil and gas production taxes and oil surcharges under AS 43.55;

20 (2) oil and gas exploration, production, and pipeline transportation
 21 property taxes under AS 43.56;

22 (3) **oil and gas corporate income tax under AS 43.21**; [REPEALED]

23 (4) Alaska net income tax under AS 43.20;

24 (5) municipal sales and use tax under AS 29.45.650 - 29.45.710;

25 (6) municipal property tax under AS 29.45.010 - 29.45.250 or
 26 29.45.550 - 29.45.600;

27 (7) municipal special assessments under AS 29.46;

28 (8) a comparable tax or levy imposed by the state or a municipality
 29 after June 18, 1998;

30 (9) other state or municipal taxes or categories of taxes identified by
 31 the commissioner.

1 * **Sec. 8.** AS 43.20.072 is repealed.

2 * **Sec. 9.** The uncodified law of the State of Alaska is amended by adding a new section to
3 read:

4 APPLICABILITY. AS 43.21, added by sec. 5 of this Act, applies to taxable income
5 earned or received after December 31, 2012.

6 * **Sec. 10.** The uncodified law of the State of Alaska is amended by adding a new section to
7 read:

8 REGULATIONS. (a) The Department of Revenue may adopt regulations necessary to
9 implement AS 43.21, added by sec. 5 of this Act. The regulations take effect under AS 44.62
10 (Administrative Procedure Act), but not before the effective date of the law implemented by
11 regulation.

12 (b) The Department of Revenue shall provide by regulation for a transition for a
13 corporation subject to tax under AS 43.20 before December 31, 2012, to avoid double
14 taxation of the same income or double deduction of the same expense of the corporation as a
15 result of becoming subject to tax under AS 43.21, added by sec. 5 of this Act.

16 * **Sec. 11.** Section 10 of this Act takes effect immediately under AS 01.10.070(c).

17 * **Sec. 12.** Except as provided in sec. 11 of this Act, this Act takes effect January 1, 2013."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "**relating to information concerning oil and gas taxes, including information**
3 **about expenditures that must be provided in order to claim an oil and gas production**
4 **tax credit for those expenditures, and relating to the disclosure of that information;**"

5

6 Page 2, line 6:

7 Delete all material and insert:

8 "*** Sec. 2.** AS 43.55.030(a) is amended to read:

9 (a) A producer that produces oil or gas from a lease or property in the state
10 during a calendar year, whether or not any tax payment is due under AS 43.55.020(a)
11 for that oil or gas, shall file with the department on March 31 of the following year a
12 statement, under oath, in a form prescribed by the department, giving, with other
13 information required by the department under a regulation adopted by the
14 department, the following:

15 (1) a description of each lease or property from which oil or gas was
16 produced, by name, legal description, lease number, or accounting codes assigned by
17 the department;

18 (2) the names of the producer and, if different, the person paying the
19 tax, if any;

20 (3) the gross amount of oil and the gross amount of gas produced from
21 each lease or property, and the percentage of the gross amount of oil and gas owned by
22 the producer;

23 (4) the gross value at the point of production of the oil and of the gas

1 produced from each lease or property owned by the producer and the costs of
2 transportation of the oil and gas;

3 (5) the name of the first purchaser and the price received for the oil and
4 for the gas, unless relieved from this requirement in whole or in part by the
5 department;

6 (6) the producer's qualified capital expenditures, as defined in
7 AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other
8 payments or credits under AS 43.55.170;

9 (7) the production tax values of the oil and gas under AS 43.55.160;

10 (8) any claims for tax credits to be applied; [AND]

11 (9) calculations showing the amounts, if any, that were or are due
12 under AS 43.55.020(a) and interest on any underpayment or overpayment; **and**

13 **(10) for each expenditure that is the basis for a credit claimed**
14 **under AS 43.55.023 or 43.55.025, a description of the expenditure, a detailed**
15 **description of the purpose of the expenditure, and a description of the lease or**
16 **property for which the expenditure was incurred; notwithstanding**
17 **AS 43.05.230(a), information submitted under this paragraph may be disclosed to**
18 **the public and shall be disclosed to the legislature in a report submitted within 10**
19 **days after the convening of the next regular legislative session following the date**
20 **a statement is filed under this section.**

21 * **Sec. 3.** AS 43.55.030(e) is amended to read:

22 (e) An explorer or producer that incurs a lease expenditure under
23 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
24 year but does not produce oil or gas from a lease or property in the state during the
25 calendar year shall file with the department on March 31 of the following year a
26 statement, under oath, in a form prescribed by the department, giving, with other
27 information required **by the department under a regulation adopted by the**
28 **department**, the following:

29 (1) the producer's qualified capital expenditures, as defined in
30 AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other
31 payments or credits under AS 43.55.170; [AND]

1 (2) if the explorer or producer receives a payment or credit under
2 AS 43.55.170, calculations showing whether the explorer or producer is liable for a
3 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount; **and**

4 **(3) for each expenditure that is the basis for a credit claimed under**
5 **this chapter, a description of the expenditure, a detailed description of the**
6 **purpose of the expenditure, and a description of the lease or property for which**
7 **the expenditure was incurred; notwithstanding AS 43.05.230(a), information**
8 **submitted under this paragraph may be disclosed to the public and shall be**
9 **disclosed to the legislature in a report submitted within 10 days after the**
10 **convening of the next regular legislative session following the date a statement is**
11 **filed under this section.**

12 * **Sec. 4.** Sections 2 and 3 of this Act take effect July 1, 2012.

13 * **Sec. 5.** Section 1 of this Act takes effect January 1, 2013."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "Act":

2 Insert "**relating to the duties of the Alaska Oil and Gas Conservation Commission;**
3 **relating to a petroleum information management system; relating to the duties of the**
4 **Department of Natural Resources, the Department of Revenue, and the Department of**
5 **Labor and Workforce Development that relate to providing the Alaska Oil and Gas**
6 **Conservation Commission with certain information relating to oil and gas;"**

7

8 Page 1, following line 2:

9 Insert new bill sections to read:

10 * **Section 1.** AS 31.05.030 is amended by adding a new subsection to read:

11 (n) The commission shall develop and maintain the petroleum information
12 management system required under AS 31.05.031.

13 * **Sec. 2.** AS 31.05 is amended by adding a new section to read:

14 **Sec. 31.05.031. Petroleum information management system.** (a) The
15 commission shall develop and maintain an electronic petroleum information
16 management system to collect, secure, distribute, store, retrieve, and archive
17 information related to oil and gas exploration, development, and production in the
18 state. The purposes of the petroleum information management system are to improve
19 the administration of the oil and gas production tax and to facilitate exploration,
20 development, and production of oil and gas resources. The petroleum information
21 management system shall be accessible by the public.

22 (b) To the extent the information is available and is not confidential, the
23 petroleum information management system must include the following information:

- 1 (1) unit and joint operating agreements;
- 2 (2) state oil and gas exploration licenses and oil and gas leases;
- 3 (3) for exploration activities,
 - 4 (A) exploration work programs and budgets;
 - 5 (B) seismic data;
 - 6 (C) drilling reports;
 - 7 (D) logs;
 - 8 (E) well tests;
 - 9 (F) geological models and maps;
- 10 (4) for development activities,
 - 11 (A) development plans with operating and capital expenditure
 - 12 projections;
 - 13 (B) construction progress reports;
 - 14 (C) drilling reports;
 - 15 (D) reservoir characterization;
- 16 (5) for production activities,
 - 17 (A) production work programs and budgets;
 - 18 (B) oil and gas sales, revenue, and pricing;
 - 19 (C) transportation agreements;
 - 20 (D) production data;
 - 21 (E) injection data;
 - 22 (F) operating and capital expenditures;
 - 23 (G) facility maps and studies;
- 24 (6) for abandonment of oil and gas wells, leases, and production and
- 25 transportation facilities,
 - 26 (A) abandonment plans and budgets;
 - 27 (B) progress reports;
- 28 (7) for oil and gas related employment information,
 - 29 (A) the number of resident and nonresident hires for each year;
 - 30 (B) training opportunities; and
- 31 (8) other information the commission determines necessary and

1 relevant to the oil and gas production tax and to the exploration, development, and
2 production of oil and gas resources.

3 (c) The Department of Natural Resources, the Department of Revenue, and the
4 Department of Labor and Workforce Development, in consultation with the
5 commission, shall provide information described in (b) of this section that is not
6 confidential and within each department's control to the commission for inclusion in
7 the petroleum information management system. The information provided by a
8 department under this subsection shall be in a form suitable for the commission to
9 include in the petroleum information management system.

10 * **Sec. 3.** AS 31.05.093(c) is amended to read:

11 (c) The commission shall determine the regulatory cost charges levied under
12 this section so that the total amount to be collected approximately equals the
13 appropriations made for the operating costs of the commission under this chapter for
14 the fiscal year. **For the purpose of determining the regulatory costs charges under**
15 **this subsection, the operating costs for the petroleum information management**
16 **system (AS 31.05.031) may not be included in the operating costs of the**
17 **commission.**"

18
19 Page 1, line 3:

20 Delete "**Section 1**"

21 Insert "**Sec. 4**"

22
23 Page 2, following line 5:

24 Insert a new bill section to read:

25 "*** Sec. 5.** The uncodified law of the State of Alaska is amended by adding a new section to
26 read:

27 IMPLEMENTATION OF THE PETROLEUM INFORMATION MANAGEMENT
28 SYSTEM; RECOMMENDATION FOR STATUTORY CHANGES. The Alaska Oil and Gas
29 Conservation Commission shall develop and implement a work plan for the development of
30 the petroleum information management system required by AS 31.05.031, enacted by sec. 2
31 of this Act, so that the system is operational before January 1, 2014."

1

2 Renumber the following bill section accordingly.

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1:

2 Delete "oil and gas production tax"

3 Insert "tax rates applicable to oil and gas production when the average production
4 tax value for a BTU equivalent barrel of oil and gas is more than \$30"

5

6 Page 1, line 3, through page 2, line 6:

7 Delete all material and insert:

8 **** Section 1.** AS 43.55.011(g) is repealed and reenacted to read:

9 (g) For each month of the calendar year for which the producer's average
10 monthly production tax value under AS 43.55.160(a)(2) for each BTU equivalent
11 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes of
12 (e)(2) of this section is determined by multiplying the monthly production tax value of
13 the taxable oil and gas produced during the month by the following tax rates, as
14 applicable:

15 (1) if the producer's average monthly production tax value of a BTU
16 equivalent barrel of the taxable oil and gas for the month is not more than \$42.50, the
17 tax rate is 2.5 percent of the difference between that average monthly production tax
18 value of a BTU equivalent barrel and \$30;

19 (2) if the producer's average monthly production tax value of a BTU
20 equivalent barrel of the taxable oil and gas for the month is more than \$42.50 but not
21 more than \$55, the tax rates are

22 (A) 2.5 percent on the first \$12.50 of monthly production tax
23 value for each BTU equivalent barrel that is greater than \$30; and

1 (B) 7.5 percent of the monthly production tax value for each
2 BTU equivalent barrel that is greater than \$42.50;

3 (3) if the producer's average monthly production tax value of a BTU
4 equivalent barrel of the taxable oil and gas for the month is more than \$55 but not
5 more than \$67.50, the tax rates are

6 (A) 2.5 percent on the first \$12.50 of monthly production tax
7 value for each BTU equivalent barrel that is greater than \$30;

8 (B) 7.5 percent of the next higher \$12.50 of monthly
9 production tax value for each BTU equivalent barrel; and

10 (C) 12.5 percent of the monthly production tax value for each
11 BTU equivalent barrel that is greater than \$55;

12 (4) if the producer's average monthly production tax value of a BTU
13 equivalent barrel of the taxable oil and gas for the month is more than \$67.50 but not
14 more than \$80, the tax rates are

15 (A) 2.5 percent on the first \$12.50 of monthly production tax
16 value for each BTU equivalent barrel that is greater than \$30;

17 (B) 7.5 percent of the next higher \$12.50 of monthly
18 production tax value for each BTU equivalent barrel;

19 (C) 12.5 percent of the next higher \$12.50 of monthly
20 production tax value for each BTU equivalent barrel;

21 (D) 17.5 percent of the monthly production tax value for each
22 BTU equivalent barrel that is greater than \$67.50;

23 (5) if the producer's average monthly production tax value of a BTU
24 equivalent barrel of the taxable oil and gas for the month is more than \$80 but not
25 more than \$92.50, the tax rates are

26 (A) 2.5 percent on the first \$12.50 of monthly production tax
27 value for each BTU equivalent barrel that is greater than \$30;

28 (B) 7.5 percent of the next higher \$12.50 of monthly
29 production tax value for each BTU equivalent barrel;

30 (C) 12.5 percent of the next higher \$12.50 of monthly
31 production tax value for each BTU equivalent barrel;

1 (D) 17.5 percent of the next higher \$12.50 of monthly
2 production tax value for each BTU equivalent barrel; and

3 (E) 22.5 percent of the monthly production tax value for each
4 BTU equivalent barrel that is greater than \$80;

5 (6) if the producer's average monthly production tax value of a BTU
6 equivalent barrel of the taxable oil and gas for the month is more than \$92.50 but not
7 more than \$105, the tax rates are

8 (A) 2.5 percent on the first \$12.50 of monthly production tax
9 value for each BTU equivalent barrel that is greater than \$30;

10 (B) 7.5 percent of the next higher \$12.50 of monthly
11 production tax value for each BTU equivalent barrel;

12 (C) 12.5 percent of the next higher \$12.50 of monthly
13 production tax value for each BTU equivalent barrel;

14 (D) 17.5 percent of the next higher \$12.50 of monthly
15 production tax value for each BTU equivalent barrel;

16 (E) 22.5 percent of the next higher \$12.50 of monthly
17 production tax value for each BTU equivalent barrel; and

18 (F) 25 percent of the monthly production tax value for each
19 BTU equivalent barrel that is greater than \$92.50;

20 (7) if the producer's average monthly production tax value of a BTU
21 equivalent barrel of the taxable oil and gas for the month is more than \$105 but not
22 more than \$117.50, the tax rates are

23 (A) 2.5 percent on the first \$12.50 of monthly production tax
24 value for each BTU equivalent barrel that is greater than \$30;

25 (B) 7.5 percent of the next higher \$12.50 of monthly
26 production tax value for each BTU equivalent barrel;

27 (C) 12.5 percent of the next higher \$12.50 of monthly
28 production tax value for each BTU equivalent barrel;

29 (D) 17.5 percent of the next higher \$12.50 of monthly
30 production tax value for each BTU equivalent barrel;

31 (E) 22.5 percent of the next higher \$12.50 of monthly

1 production tax value for each BTU equivalent barrel;

2 (F) 25 percent of the next higher \$12.50 of monthly production
3 tax value for each BTU equivalent barrel; and

4 (G) 30 percent of the monthly production tax value for each
5 BTU equivalent barrel that is greater than \$105;

6 (8) if the producer's average monthly production tax value of a BTU
7 equivalent barrel of the taxable oil and gas for the month is more than \$117.50, the tax
8 rates are

9 (A) 2.5 percent on the first \$12.50 of monthly production tax
10 value for each BTU equivalent barrel that is greater than \$30;

11 (B) 7.5 percent of the next higher \$12.50 of monthly
12 production tax value for each BTU equivalent barrel;

13 (C) 12.5 percent of the next higher \$12.50 of monthly
14 production tax value for each BTU equivalent barrel;

15 (D) 17.5 percent of the next higher \$12.50 of monthly
16 production tax value for each BTU equivalent barrel;

17 (E) 22.5 percent of the next higher \$12.50 of monthly
18 production tax value for each BTU equivalent barrel;

19 (F) 25 percent of the next higher \$12.50 of monthly production
20 tax value for each BTU equivalent barrel;

21 (G) 30 percent of the next higher \$12.50 of monthly production
22 tax value for each BTU equivalent barrel; and

23 (H) 35 percent of the monthly production tax value for each
24 BTU equivalent barrel that is greater than \$117.50.

25 * **Sec. 2.** The uncodified law of the State of Alaska is amended by adding a new section to
26 read:

27 APPLICABILITY. Section 1 of this Act applies to oil and gas produced after
28 December 31, 2012.

29 * **Sec. 3.** The uncodified law of the State of Alaska is amended by adding a new section to
30 read:

31 TRANSITION: REGULATIONS. The Department of Revenue may adopt regulations

1 to implement this Act. The regulations take effect under AS 44.62 (Administrative Procedure
2 Act), but not before the effective date of the provision of this Act implemented by the
3 regulation.

4 * **Sec. 4.** Section 1 of this Act takes effect January 1, 2013.

5 * **Sec. 5.** Except as provided in sec. 4 of this Act, this Act takes effect immediately under
6 AS 01.10.070(c)."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1:

2 Delete "**oil and gas production tax**"

3 Insert "**tax rates applicable to oil and gas production when the average production**
4 **tax value for a BTU equivalent barrel of oil and gas is more than \$30**"

5

6 Page 1, line 3, through page 2, line 6:

7 Delete all material and insert:

8 **** Section 1.** AS 43.55.011(g) is repealed and reenacted to read:

9 (g) For each month of the calendar year for which the producer's average
10 monthly production tax value under AS 43.55.160(a)(2) for each BTU equivalent
11 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes of
12 (e)(2) of this section is determined by multiplying the monthly production tax value of
13 the taxable oil and gas produced during the month by the following tax rates, as
14 applicable:

15 (1) if the producer's average monthly production tax value of a BTU
16 equivalent barrel of the taxable oil and gas for the month is not more than \$42.50, the
17 tax rate is 2.5 percent of the difference between that average monthly production tax
18 value of a BTU equivalent barrel and \$30;

19 (2) if the producer's average monthly production tax value of a BTU
20 equivalent barrel of the taxable oil and gas for the month is more than \$42.50 but not
21 more than \$55, the tax rates are

22 (A) 2.5 percent on the first \$12.50 of monthly production tax
23 value for each BTU equivalent barrel that is greater than \$30; and

1 (B) 7.5 percent of the monthly production tax value for each
2 BTU equivalent barrel that is greater than \$42.50;

3 (3) if the producer's average monthly production tax value of a BTU
4 equivalent barrel of the taxable oil and gas for the month is more than \$55 but not
5 more than \$67.50, the tax rates are

6 (A) 2.5 percent on the first \$12.50 of monthly production tax
7 value for each BTU equivalent barrel that is greater than \$30;

8 (B) 7.5 percent of the next higher \$12.50 of monthly
9 production tax value for each BTU equivalent barrel; and

10 (C) 12.5 percent of the monthly production tax value for each
11 BTU equivalent barrel that is greater than \$55;

12 (4) if the producer's average monthly production tax value of a BTU
13 equivalent barrel of the taxable oil and gas for the month is more than \$67.50 but not
14 more than \$80, the tax rates are

15 (A) 2.5 percent on the first \$12.50 of monthly production tax
16 value for each BTU equivalent barrel that is greater than \$30;

17 (B) 7.5 percent of the next higher \$12.50 of monthly
18 production tax value for each BTU equivalent barrel;

19 (C) 12.5 percent of the next higher \$12.50 of monthly
20 production tax value for each BTU equivalent barrel;

21 (D) 17.5 percent of the monthly production tax value for each
22 BTU equivalent barrel that is greater than \$67.50;

23 (5) if the producer's average monthly production tax value of a BTU
24 equivalent barrel of the taxable oil and gas for the month is more than \$80 but not
25 more than \$92.50, the tax rates are

26 (A) 2.5 percent on the first \$12.50 of monthly production tax
27 value for each BTU equivalent barrel that is greater than \$30;

28 (B) 7.5 percent of the next higher \$12.50 of monthly
29 production tax value for each BTU equivalent barrel;

30 (C) 12.5 percent of the next higher \$12.50 of monthly
31 production tax value for each BTU equivalent barrel;

1 (D) 17.5 percent of the next higher \$12.50 of monthly
2 production tax value for each BTU equivalent barrel; and

3 (E) 22.5 percent of the monthly production tax value for each
4 BTU equivalent barrel that is greater than \$80;

5 (6) if the producer's average monthly production tax value of a BTU
6 equivalent barrel of the taxable oil and gas for the month is more than \$92.50, the tax
7 rates are

8 (A) 2.5 percent on the first \$12.50 of monthly production tax
9 value for each BTU equivalent barrel that is greater than \$30;

10 (B) 7.5 percent of the next higher \$12.50 of monthly
11 production tax value for each BTU equivalent barrel;

12 (C) 12.5 percent of the next higher \$12.50 of monthly
13 production tax value for each BTU equivalent barrel;

14 (D) 17.5 percent of the next higher \$12.50 of monthly
15 production tax value for each BTU equivalent barrel;

16 (E) 22.5 percent of the next higher \$12.50 of monthly
17 production tax value for each BTU equivalent barrel; and

18 (F) 25 percent of the monthly production tax value for each
19 BTU equivalent barrel that is greater than \$92.50.

20 * **Sec. 2.** The uncodified law of the State of Alaska is amended by adding a new section to
21 read:

22 APPLICABILITY. Section 1 of this Act applies to oil and gas produced after
23 December 31, 2012.

24 * **Sec. 3.** The uncodified law of the State of Alaska is amended by adding a new section to
25 read:

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

30 * **Sec. 4.** Section 1 of this Act takes effect January 1, 2013.

31 * **Sec. 5.** Except as provided in sec. 4 of this Act, this Act takes effect immediately under

1 AS 01.10.070(c)."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax":

2 Insert "rate; relating to monthly installment payments of the oil and gas
3 production tax; relating to oil and gas production tax credits, including qualified capital
4 credits for exploration, development, and production"
5

6 Page 1, line 3, through page 2, line 6:

7 Delete all material and insert:

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

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

14 [(1)] the annual production tax value of the taxable oil and gas
15 (1) produced from a lease or property not described in (2) of this
16 subsection as calculated under AS 43.55.160(a)(1) multiplied by 25 percent, and the
17 sum, over all months of the calendar year, of the tax amounts determined under
18 (g)(1) of this section; and

19 (2) produced during the first seven consecutive years after the
20 start of sustained production or produced during the first seven years after the
21 effective date of this bill section, whichever is later, from a lease or property
22 containing land that was not or previously had not been within a unit or in
23 commercial production as of December 31, 2008, as calculated under

1 **AS 43.55.160(a)(1) multiplied by 15 percent, and** the sum, over all months of the
 2 calendar year, of the tax amounts determined under **(g)(2)** [(g)] of this section; **in this**
 3 **paragraph, "sustained production" has the meaning given in AS 43.55.025(l).**

4 * **Sec. 2.** AS 43.55.011(g) is repealed and reenacted to read:

5 (g) For each month of the calendar year for which the producer's average
 6 monthly production tax value under AS 43.55.160(a)(2) for each BTU equivalent
 7 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes

8 (1) of (e)(1) of this section is determined by multiplying the monthly
 9 production tax value of the taxable oil and gas produced during the month by the tax
 10 rate calculated as follows:

11 (A) if the producer's average monthly production tax value of a
 12 BTU equivalent barrel of the taxable oil and gas for the month is not more than
 13 \$92.50, the tax rate is 0.4 percent multiplied by the number that represents the
 14 difference between that average monthly production tax value of a BTU
 15 equivalent barrel and \$30; or

16 (B) if the producer's average monthly production tax value of a
 17 BTU equivalent barrel of the taxable oil and gas for the month is more than
 18 \$92.50, the tax rate is the sum of 25 percent and the product of 0.1 percent
 19 multiplied by the number that represents the difference between the average
 20 monthly production tax value of a BTU equivalent barrel and \$92.50, except
 21 that the sum determined under this subparagraph may not exceed 50 percent;

22 (2) of (e)(2) of this section is determined by multiplying the monthly
 23 production tax value of the taxable oil and gas produced during the month by the
 24 following tax rates, as applicable:

25 (A) if the producer's average monthly production tax value of a
 26 BTU equivalent barrel of the taxable oil and gas for the month is not more than
 27 \$42.50, the tax rate is 2.5 percent of the difference between that average
 28 monthly production tax value of a BTU equivalent barrel and \$30;

29 (B) if the producer's average monthly production tax value of a
 30 BTU equivalent barrel of the taxable oil and gas for the month is more than
 31 \$42.50 but not more than \$55, the tax rates are

1 (i) 2.5 percent on the first \$12.50 of monthly production
2 tax value for each BTU equivalent barrel that is greater than \$30; and

3 (ii) 7.5 percent of the monthly production tax value for
4 each BTU equivalent barrel that is greater than \$42.50;

5 (C) if the producer's average monthly production tax value of a
6 BTU equivalent barrel of the taxable oil and gas for the month is more than
7 \$55 but not more than \$67.50, the tax rates are

8 (i) 2.5 percent on the first \$12.50 of monthly production
9 tax value for each BTU equivalent barrel that is greater than \$30;

10 (ii) 7.5 percent of the next higher \$12.50 of monthly
11 production tax value for each BTU equivalent barrel; and

12 (iii) 12.5 percent of the monthly production tax value
13 for each BTU equivalent barrel that is greater than \$55;

14 (D) if the producer's average monthly production tax value of a
15 BTU equivalent barrel of the taxable oil and gas for the month is more than
16 \$67.50 but not more than \$80, the tax rates are

17 (i) 2.5 percent on the first \$12.50 of monthly production
18 tax value for each BTU equivalent barrel that is greater than \$30;

19 (ii) 7.5 percent of the next higher \$12.50 of monthly
20 production tax value for each BTU equivalent barrel;

21 (iii) 12.5 percent of the next higher \$12.50 of monthly
22 production tax value for each BTU equivalent barrel;

23 (iv) 17.5 percent of the monthly production tax value
24 for each BTU equivalent barrel that is greater than \$67.50;

25 (E) if the producer's average monthly production tax value of a
26 BTU equivalent barrel of the taxable oil and gas for the month is more than
27 \$80 but not more than \$92.50, the tax rates are

28 (i) 2.5 percent on the first \$12.50 of monthly production
29 tax value for each BTU equivalent barrel that is greater than \$30;

30 (ii) 7.5 percent of the next higher \$12.50 of monthly
31 production tax value for each BTU equivalent barrel;

1 (iii) 12.5 percent of the next higher \$12.50 of monthly
2 production tax value for each BTU equivalent barrel;

3 (iv) 17.5 percent of the next higher \$12.50 of monthly
4 production tax value for each BTU equivalent barrel; and

5 (v) 22.5 percent of the monthly production tax value for
6 each BTU equivalent barrel that is greater than \$80;

7 (F) if the producer's average monthly production tax value of a
8 BTU equivalent barrel of the taxable oil and gas for the month is more than
9 \$92.50, the tax rates are

10 (i) 2.5 percent on the first \$12.50 of monthly production
11 tax value for each BTU equivalent barrel that is greater than \$30;

12 (ii) 7.5 percent of the next higher \$12.50 of monthly
13 production tax value for each BTU equivalent barrel;

14 (iii) 12.5 percent of the next higher \$12.50 of monthly
15 production tax value for each BTU equivalent barrel;

16 (iv) 17.5 percent of the next higher \$12.50 of monthly
17 production tax value for each BTU equivalent barrel;

18 (v) 22.5 percent of the next higher \$12.50 of monthly
19 production tax value for each BTU equivalent barrel; and

20 (vi) 25 percent of the monthly production tax value for
21 each BTU equivalent barrel that is greater than \$92.50.

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

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

25 (1) an installment payment of the estimated tax levied by
26 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each
27 month of the calendar year on the last day of the following month; except as otherwise
28 provided under (2) of this subsection, the amount of the installment payment is the
29 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be
30 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount
31 of the installment payment may not be less than zero:

1 (A) for oil and gas produced from leases or properties in the
 2 state outside the Cook Inlet sedimentary basin but not subject to
 3 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
 4 greater of

5 (i) zero; or

6 (ii) the **applicable tax rates in AS 43.55.011(e) and (g)**
 7 **applied to** [SUM OF 25 PERCENT AND THE TAX RATE
 8 CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)
 9 MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
 10 producer's adjusted lease expenditures for the calendar year of
 11 production under AS 43.55.165 and 43.55.170 that are deductible for
 12 the leases or properties under AS 43.55.160 from the gross value at the
 13 point of production of the oil and gas produced from the leases or
 14 properties during the month for which the installment payment is
 15 calculated;

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

18 (i) zero;

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

23 (iii) the **applicable tax rates in AS 43.55.011(e) and**
 24 **(g) applied to** [SUM OF 25 PERCENT AND THE TAX RATE
 25 CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)
 26 MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
 27 producer's adjusted lease expenditures for the calendar year of
 28 production under AS 43.55.165 and 43.55.170 that are deductible for
 29 those leases or properties under AS 43.55.160 from the gross value at
 30 the point of production of the oil and gas produced from those leases or
 31 properties during the month for which the installment payment is

1 calculated;

2 (C) for oil and gas produced from each lease or property
3 subject to AS 43.55.011(j), (k), or (o), the greater of

4 (i) zero; or

5 (ii) the **applicable tax rates in AS 43.55.011(e) and (g)**

6 **applied to** [SUM OF 25 PERCENT AND THE TAX RATE
7 CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)
8 MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
9 producer's adjusted lease expenditures for the calendar year of
10 production under AS 43.55.165 and 43.55.170 that are deductible under
11 AS 43.55.160 for oil or gas, respectively, produced from the lease or
12 property from the gross value at the point of production of the oil or
13 gas, respectively, produced from the lease or property during the month
14 for which the installment payment is calculated;

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

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

29 (A) the applicable tax rate for oil provided under
30 AS 43.55.011(i), multiplied by the gross value at the point of production of the
31 oil taxable under AS 43.55.011(i) and produced from the lease or property

1 during the month; and

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

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

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

11 (g) The issuance of a transferable tax credit certificate under (d) **of this**
12 **section** or **former** (m) of this section or the purchase of a certificate under
13 AS 43.55.028 does not limit the department's ability to later audit a tax credit claim to
14 which the certificate relates or to adjust the claim if the department determines, as a
15 result of the audit, that the applicant was not entitled to the amount of the credit for
16 which the certificate was issued. The tax liability of the applicant under
17 AS 43.55.011(e) and 43.55.017 - 43.55.180 is increased by the amount of the credit
18 that exceeds that to which the applicant was entitled, or the applicant's available valid
19 outstanding credits applicable against the tax levied by AS 43.55.011(e) are reduced
20 by that amount. If the applicant's tax liability is increased under this subsection, the
21 increase bears interest under AS 43.05.225 from the date the transferable tax credit
22 certificate was issued. For purposes of this subsection, an applicant that is an explorer
23 is considered a producer subject to the tax levied by AS 43.55.011(e).

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

25 (l) A producer or explorer may apply for a tax credit for a well lease
26 expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE]
27 after **December 31, 2012, and before January 1, 2023** [JUNE 30, 2010], as follows:

28 (1) notwithstanding that a well lease expenditure incurred in the state

29 (A) south of 68 degrees North latitude may be a deductible
30 lease expenditure for purposes of calculating the production tax value of oil
31 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken

1 under (a) of this section, AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or
 2 AS 43.55.025, a producer or explorer that incurs a well lease expenditure in the
 3 state south of 68 degrees North latitude may elect to apply a tax credit against a
 4 tax levied by AS 43.55.011(e) in the amount of 40 percent of that expenditure;

5 **(B) north of 68 degrees North latitude and outside of a unit**
 6 **or in commercial production before December 31, 2008, may be a**
 7 **deductible lease expenditure for purposes of calculating the production**
 8 **tax value of oil and gas under AS 43.55.160(a), unless a credit for that**
 9 **expenditure is taken under (a) of this section, AS 38.05.180(i),**
 10 **AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or explorer that**
 11 **incurs a well lease expenditure in the state north of 68 degrees North**
 12 **latitude and outside of a unit or in commercial production before**
 13 **December 31, 2008, may elect to apply a tax credit against a tax levied by**
 14 **AS 43.55.011(e) in the amount of 40 percent of that expenditure;** [A TAX
 15 CREDIT UNDER THIS PARAGRAPH MAY BE APPLIED FOR A SINGLE
 16 CALENDAR YEAR;]

17 (2) a producer or explorer may take a credit for a well lease
 18 expenditure **under this subsection** incurred [IN THE STATE SOUTH OF 68
 19 DEGREES NORTH LATITUDE] in connection with geological or geophysical
 20 exploration or in connection with an exploration well only if the producer or explorer

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

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

25 * **Sec. 6.** AS 43.55.023(l) is repealed and reenacted to read:

26 (l) A producer or explorer may apply for a tax credit for a well lease
 27 expenditure incurred in the state south of 68 degrees North latitude after December 31,
 28 2022, as follows:

29 (1) notwithstanding that a well lease expenditure incurred in the state
 30 south of 68 degrees North latitude may be a deductible lease expenditure for purposes
 31 of calculating the production tax value of oil and gas under AS 43.55.160(a), unless a

1 credit for that expenditure is taken under (a) of this section, AS 38.05.180(i),
2 AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a
3 well lease expenditure in the state south of 68 degrees North latitude may elect to
4 apply a tax credit against a tax levied by AS 43.55.011(e) in the amount of 40 percent
5 of that expenditure; a tax credit under this paragraph may be applied for a single
6 calendar year;

7 (2) a producer or explorer may take a credit for a well lease
8 expenditure incurred in the state south of 68 degrees North latitude in connection with
9 geological or geophysical exploration or in connection with an exploration well only if
10 the producer or explorer

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

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

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

16 (n) For the purposes of (l) [AND (m)] of this section, a well lease expenditure
17 [INCURRED IN THE STATE SOUTH OF 68 DEGREES NORTH LATITUDE] is a
18 lease expenditure that is

19 (1) directly related to an exploration well, a stratigraphic test well, a
20 producing well, or an injection well other than a disposal well, [LOCATED IN THE
21 STATE SOUTH OF 68 DEGREES NORTH LATITUDE,] if the expenditure is a
22 qualified capital expenditure and an intangible drilling and development cost
23 authorized under 26 U.S.C. (Internal Revenue Code), as amended, and 26 C.F.R.
24 1.612-4, regardless of the elections made under 26 U.S.C. 263(c); in this paragraph, an
25 expenditure directly related to a well includes an expenditure for well sidetracking,
26 well deepening, well completion or recompletion, or well workover, regardless of
27 whether the well is or has been a producing well; or

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

30 * **Sec. 8.** AS 43.55.028(e) is amended to read:

31 (e) The department, on the written application of a person to whom a

1 transferable tax credit certificate has been issued under AS 43.55.023(d) or **former**
 2 **AS 43.55.023(m)** [(m)] or to whom a production tax credit certificate has been issued
 3 under AS 43.55.025(f), may use available money in the oil and gas tax credit fund to
 4 purchase, in whole or in part, the certificate if the department finds that

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

8 (2) [REPEALED

9 (3) REPEALED

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

12 (3) [(5)] the applicant's total tax liability under AS 43.55.011(e), after
 13 application of all available tax credits, for the calendar year in which the application is
 14 made is zero;

15 (4) [(6)] the applicant's average daily production of oil and gas taxable
 16 under AS 43.55.011(e) during the calendar year preceding the calendar year in which
 17 the application is made was not more than 50,000 BTU equivalent barrels; and

18 (5) [(7)] the purchase is consistent with this section and regulations
 19 adopted under this section.

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

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

29 * **Sec. 10.** AS 43.55.023(m) is repealed.

30 * **Sec. 11.** The uncodified law of the State of Alaska is amended by adding a new section to
 31 read:

1 APPLICABILITY. (a) Sections 4, 5, 7, and 10 of this Act apply to expenditures
2 incurred after December 31, 2012.

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

4 (c) Section 6 of this Act applies to expenditures incurred after December 31, 2022.

5 * **Sec. 12.** The uncodified law of the State of Alaska is amended by adding a new section to
6 read:

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

11 * **Sec. 13.** Sections 1 - 5, 7 - 10, and 11(a) and (b) of this Act take effect January 1, 2013.

12 * **Sec. 14.** Sections 6 and 11(c) of this Act take effect January 1, 2023.

13 * **Sec. 15.** Except as provided in secs. 13 and 14 of this Act, this Act takes effect
14 immediately under AS 01.10.070(c)."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 3, through page 2, line 5:

2 Delete all material and insert:

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

4 (g) For each month of the calendar year for which the producer's average
5 monthly production tax value under AS 43.55.160(a)(2) **for a** [PER] BTU equivalent
6 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes of
7 (e)(2) of this section is determined by multiplying the monthly production tax value of
8 the taxable oil and gas produced during the month by the tax rate calculated as
9 follows:

10 (1) if the producer's average monthly production tax value **for a** [PER]
11 BTU equivalent barrel of the taxable oil and gas for the month is not more than
12 \$92.50, the tax rate is 0.4 percent multiplied by the number that represents the
13 difference between that average monthly production tax value **for a** [PER] BTU
14 equivalent barrel and \$30; or

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

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "**providing for a reduction in production tax value for certain oil;**"

3

4 Page 2, following line 5:

5 Insert new bill sections to read:

6 "* **Sec. 2.** AS 43.55.160(a) is amended to read:

7 (a) Except as provided in (b) of this section **and subject to an adjustment**
8 **under AS 43.55.162**, for the purposes of

9 (1) AS 43.55.011(e), the annual production tax value of the taxable

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

18 (B) oil and gas produced during a calendar year from leases or
19 properties in the state outside the Cook Inlet sedimentary basin, no part of
20 which is north of 68 degrees North latitude, is the gross value at the point of
21 production of the oil and gas taxable under AS 43.55.011(e) and produced by
22 the producer from those leases or properties, less the producer's lease
23 expenditures under AS 43.55.165 for the calendar year applicable to the oil and

1 gas produced by the producer from those leases or properties, as adjusted under
2 AS 43.55.170; this subparagraph does not apply to gas subject to
3 AS 43.55.011(o);

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

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

16 (E) gas produced during a calendar year from a lease or
17 property outside the Cook Inlet sedimentary basin and used in the state is the
18 gross value at the point of production of that gas taxable under
19 AS 43.55.011(e) and produced by the producer from that lease or property, less
20 the producer's lease expenditures under AS 43.55.165 for the calendar year
21 applicable to that gas produced by the producer from that lease or property, as
22 adjusted under AS 43.55.170;

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

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

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

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

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

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

29 * **Sec. 3.** AS 43.55 is amended by adding a new section to read:

30 **Sec. 43.55.162. Adjustment to production tax value for increasing oil**
31 **production.** (a) The production tax value of oil delivered to and transported by the

1 Trans Alaska Pipeline System, as calculated under AS 43.55.160(a)(1)(A) and (B) and
2 AS 43.66.160(a)(2)(A) and (B), may be reduced by an amount determined by the
3 department under this section.

4 (b) A producer shall report to the department the total adjusted amount of
5 annual oil production and adjusted amount of the average daily statewide oil
6 production delivered by the producer for transport to the Trans Alaska Pipeline
7 System for both the calendar year immediately preceding the year for which the tax is
8 being determined and the year for which the tax is being determined. The report shall
9 be filed at the time the statement required under AS 43.55.030(a) is filed.

10 (c) When calculating the

11 (1) adjusted amount of the average daily statewide production under
12 (b) of this section, the producer shall exclude from the calculation the days on which
13 the rate of production is significantly reduced and the volume of production on those
14 days for which the rate of production is significantly reduced; for the purposes of this
15 paragraph, the rate of production is significantly reduced when the production of oil
16 delivered by the producer to the Trans Alaska Pipeline System for the day is less than
17 one-half of the average daily production for the year calculated by dividing the total
18 oil production that is produced by the producer and delivered to the Trans Alaska
19 Pipeline System for the year by the number of days in the year;

20 (2) adjusted amount of total annual oil production that is delivered by
21 the producer to the Trans Alaska Pipeline System, the producer shall multiply the
22 adjusted amount of average daily production determined under (1) of this subsection
23 by the number of days in the applicable calendar year; and

24 (3) adjusted amount of total annual oil production that is delivered by
25 the producer to the Trans Alaska Pipeline System for the year for which the tax is
26 being determined under (2) of this subsection, the producer may not include the
27 amount of production resulting from the purchase, merger, or other acquisition of
28 another producer and any production attributable to the producer from a unit in which
29 the producer did not participate in the calendar year immediately preceding the year
30 for which the tax is being determined; however, the increased production that may not
31 be included by a producer under this paragraph may be included in the adjusted

1 amount of total annual oil production for the year when determining the amount by
2 which production increases in the next succeeding year.

3 (d) After receiving a report by the producer under (b) of this section, the
4 department may reduce the production tax value determined under

5 (1) AS 43.55.160(a)(1)(A) and (B) by \$10 for each barrel of oil
6 delivered by the producer to the Trans Alaska Pipeline system during the year for
7 which the tax is being determined that exceeds the adjusted total annual production for
8 the calendar year immediately preceding the year for which the tax is being
9 determined; and

10 (2) AS 43.55.160(a)(2)(A) and (B) by \$10 for each barrel of oil
11 delivered to the Trans Alaska Pipeline System for each month in the year for which
12 the tax is being determined that exceeds 1/12 of the number of barrels by which the
13 adjusted total annual production for the year for which the tax is being determined
14 exceeds the adjusted total annual production for the calendar year immediately
15 preceding the year for which the tax is being determined.

16 (e) The department shall notify the producer of the amount of tax reduction
17 allowed as a result of a reduction in production tax value determined by the
18 department under (d) of this section. At the request of the producer, the department
19 may refund any amount due to the producer as a result of the reduction in production
20 tax value or credit the amount of the tax reduction against the liability of the taxpayer
21 for a tax due under this title.

22 (f) A tax reduction that results from a reduction in the production tax value
23 under this section may not be considered when a producer is required to calculate and
24 pay any amount due under AS 43.55.020(a). However, at the request of the producer, a
25 credit allowed under (e) of this section may be applied against a payment due under
26 AS 43.55.020(a) for a period after the department determines the amount of reduction
27 in the production tax value.

28 (g) The department may adopt regulations specifying the information that
29 must be included in the report filed by a producer under (b) of this section and other
30 regulations necessary for the administration of this section.

31 * **Sec. 4.** The uncodified law of the State of Alaska is amended by adding a new section to

1 read:

2 APPLICABILITY. The reduction in production tax value under AS 43.55.162,
3 enacted by sec. 10 of this Act, applies to qualifying oil produced after December 31, 2012. In
4 this section, "qualifying oil" means oil delivered to the Trans Alaska Pipeline System the
5 production tax value of which is calculated under AS 43.55.160(a)(1)(A) and (B) and
6 43.55.160(a)(2)(A) and (B)."

7

8 Renumber the following bill section accordingly.

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "**limiting the amount of certain tax credits applicable to the oil and gas**
3 **production tax;**"

4

5 Page 2, following line 5:

6 Insert new bill sections to read:

7 "* **Sec. 2.** AS 43.55.023(a) is amended to read:

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

10 (1) except as limited by (p) of this section, notwithstanding that a
11 qualified capital expenditure may be a deductible lease expenditure for purposes of
12 calculating the production tax value of oil and gas under AS 43.55.160(a), unless a
13 credit for that expenditure is taken under AS 38.05.180(i), AS 41.09.010,
14 AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a qualified capital
15 expenditure may also elect to apply a tax credit against a tax levied by
16 AS 43.55.011(e) in the amount of 20 percent of that expenditure; however, not more
17 than half of the tax credit may be applied for a single calendar year;

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

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

23 (B) submits to the Department of Natural Resources all data

1 that would be required to be submitted under AS 43.55.025(f)(2).

2 * **Sec. 3.** AS 43.55.023(d) is amended to read:

3 (d) Except as limited by (i) **and (p)** of this section, a person that is entitled to
4 take a tax credit under this section that wishes to transfer the unused credit to another
5 person or obtain a cash payment under AS 43.55.028 may apply to the department for
6 transferable tax credit certificates. An application under this subsection must be in a
7 form prescribed by the department and must include supporting information and
8 documentation that the department reasonably requires. The department shall grant or
9 deny an application, or grant an application as to a lesser amount than that claimed and
10 deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the
11 year following the calendar year in which the qualified capital expenditure or carried-
12 forward annual loss for which the credit is claimed was incurred; (2) the date the
13 statement required under AS 43.55.030(a) or (e) was filed for the calendar year in
14 which the qualified capital expenditure or carried-forward annual loss for which the
15 credit is claimed was incurred; or (3) the date the application was received by the
16 department. If, based on the information then available to it, the department is
17 reasonably satisfied that the applicant is entitled to a credit, the department shall issue
18 the applicant two transferable tax credit certificates, each for half of the amount of the
19 credit. The credit shown on one of the two certificates is available for immediate use.
20 The credit shown on the second of the two certificates may not be applied against a tax
21 for a calendar year earlier than the calendar year following the calendar year in which
22 the certificate is issued, and the certificate must contain a conspicuous statement to
23 that effect. A certificate issued under this subsection does not expire.

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

25 (l) **Except as limited by (p) of this section, a** [A] producer or explorer may
26 apply for a tax credit for a well lease expenditure incurred in the state south of 68
27 degrees North latitude after June 30, 2010, as follows:

28 (1) notwithstanding that a well lease expenditure incurred in the state
29 south of 68 degrees North latitude may be a deductible lease expenditure for purposes
30 of calculating the production tax value of oil and gas under AS 43.55.160(a), unless a
31 credit for that expenditure is taken under (a) of this section, AS 38.05.180(i),

1 AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a
 2 well lease expenditure in the state south of 68 degrees North latitude may elect to
 3 apply a tax credit against a tax levied by AS 43.55.011(e) in the amount of 40 percent
 4 of that expenditure; a tax credit under this paragraph may be applied for a single
 5 calendar year;

6 (2) a producer or explorer may take a credit for a well lease
 7 expenditure incurred in the state south of 68 degrees North latitude in connection with
 8 geological or geophysical exploration or in connection with an exploration well only if
 9 the producer or explorer

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

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

14 * **Sec. 5.** AS 43.55.023 is amended by adding a new subsection to read:

15 (p) The amount of credit for a capital expenditure under (a) or (l) of this
 16 section for an expenditure that is also a lease expenditure under AS 43.55.165 is
 17 reduced by the amount necessary so that the tax benefit percentage is not more than 65
 18 percent of the capital expenditure. The amount of credit for a capital expenditure
 19 under (a) or (l) of this section that may not be taken because of the limitation in this
 20 subsection may not be applied in a later calendar year under (c) of this section and
 21 may not be included in an application for a tax credit certificate under (d) of this
 22 section. In this subsection, "tax benefit percentage" means the sum of the average
 23 monthly tax rate under AS 43.55.011(e) and (g) for the calendar year in which the
 24 credit is taken and the percentage of the capital expenditure that may be taken as a
 25 credit under (a) or (l) of this section.

26 * **Sec. 6.** AS 43.55.025(a) is amended to read:

27 (a) Subject to the terms and conditions of this section **and except as limited**
 28 **by (n) of this section**, a credit against the production tax levied by AS 43.55.011(e) is
 29 allowed for exploration expenditures that qualify under (b) of this section in an
 30 amount equal to one of the following:

31 (1) 30 percent of the total exploration expenditures that qualify only

1 under (b) and (c) of this section;

2 (2) 30 percent of the total exploration expenditures that qualify only
3 under (b) and (d) of this section;

4 (3) 40 percent of the total exploration expenditures that qualify under
5 (b), (c), and (d) of this section;

6 (4) 40 percent of the total exploration expenditures that qualify only
7 under (b) and (e) of this section; or

8 (5) 80, 90, or 100 percent, or a lesser amount described in (l) of this
9 section, of the total exploration expenditures described in (b)(1) and (2) of this section
10 and not excluded by (b)(3) and (4) of this section that qualify only under (l) of this
11 section.

12 * **Sec. 7.** AS 43.55.025 is amended by adding a new subsection to read:

13 (n) The amount of credit for an exploration expenditure under (a)(1) - (4) of
14 this section for an expenditure that is also a lease expenditure under AS 43.55.165 is
15 reduced by the amount necessary so that the tax benefit percentage is not more than 65
16 percent of the exploration expenditure. The amount of credit for an exploration
17 expenditure under (a)(1) - (4) of this section that may not be taken because of the
18 limitation in this subsection may not be transferred, conveyed, or sold under (g) of this
19 section. In this subsection, "tax benefit percentage" means the sum of the average
20 monthly tax rate under AS 43.55.011(e) and (g) for the calendar year in which the
21 credit is taken and the percentage of the exploration expenditure that may be taken as a
22 credit under (a)(1) - (4) of this section."

23
24 Renumber the following bill section accordingly.

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "**relating to the minimum tax on oil and gas production; relating to the**
3 **availability of funds from the oil and gas production tax for appropriation to the**
4 **community revenue sharing fund;**"

5

6 Page 1, following line 2:

7 Insert new bill sections to read:

8 **"* Section 1.** AS 29.60.850(b) is amended to read:

9 (b) Each fiscal year, the legislature may appropriate to the community revenue
10 sharing fund an amount equal to **the lesser of** 20 percent of the money received by the
11 state during the previous calendar year under AS 43.55.011(g) **or the difference**
12 **between the amount of money received by the state during the previous calendar**
13 **for oil and gas production subject to AS 43.55.011(f) and 25 percent of the**
14 **production tax value determined under AS 43.55.160 for oil and gas production**
15 **subject to AS 43.55.011(f) produced during the previous calendar year, except the**
16 **difference may not be less than zero.** The amount **appropriated** may not exceed

17 (1) \$60,000,000; or

18 (2) the amount that, when added to the fund balance on June 30 of the
19 previous fiscal year, equals \$180,000,000.

20 *** Sec. 2.** AS 43.55.011(f) is repealed and reenacted to read:

21 (f) Except for oil and gas subject to (i) of this section and gas subject to (o) of
22 this section, the provisions of this subsection apply to oil and gas produced from each
23 lease or property within a unit or nonunitized reservoir that has cumulatively produced

1 1,000,000,000 BTU equivalent barrels of oil or gas by the close of the most recent
 2 calendar year and from which the average daily oil and gas production from the unit or
 3 nonunitized reservoir during the most recent calendar year exceeded 100,000 BTU
 4 equivalent barrels. Notwithstanding any contrary provision of law, a producer may not
 5 apply tax credits to reduce its total tax liability under (e) and (g) of this section for oil
 6 and gas produced from all leases or properties within the unit or nonunitized reservoir
 7 below 10 percent of the total gross value at the point of production of that oil and gas.
 8 If the amount of tax calculated by multiplying the tax rates in (e) and (g) of this
 9 section by the total production tax value of the oil and gas taxable under (e) and (g) of
 10 this section produced from all of the producer's leases or properties within the unit or
 11 nonunitized reservoir is less than 10 percent of the total gross value at the point of
 12 production of that oil and gas, the tax levied by (e) and (g) of this section for that oil
 13 and gas is equal to 10 percent of the total gross value at the point of production of that
 14 oil and gas."

15
 16 Page 1, line 4:

17 Delete "**Section 1**"

18 Insert "**Sec. 3**"

19
 20 Renumber the following bill sections accordingly.

21
 22 Page 2, following line 5:

23 Insert a new bill section to read:

24 "*** Sec. 4.** AS 43.55.020(a) is amended to read:

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

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

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

3 (A) for oil and gas produced from leases or properties in the
4 state outside the Cook Inlet sedimentary basin but not subject to
5 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
6 greater of

7 (i) zero; or

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

16 (B) for oil and gas produced from leases or properties subject
17 to AS 43.55.011(f), **10 percent of the gross value at the point of production**
18 **of that oil and gas** [THE GREATEST OF

19 (i) ZERO;

20 (ii) ZERO PERCENT, ONE PERCENT, TWO
21 PERCENT, THREE PERCENT, OR FOUR PERCENT, AS
22 APPLICABLE, OF THE GROSS VALUE AT THE POINT OF
23 PRODUCTION OF THE OIL AND GAS PRODUCED FROM ALL
24 LEASES OR PROPERTIES DURING THE MONTH FOR WHICH
25 THE INSTALLMENT PAYMENT IS CALCULATED; OR

26 (iii) THE SUM OF 25 PERCENT AND THE TAX
27 RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)
28 MULTIPLIED BY THE REMAINDER OBTAINED BY
29 SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE
30 EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION
31 UNDER AS 43.55.165 AND 43.55.170 THAT ARE DEDUCTIBLE

1 FOR THOSE LEASES OR PROPERTIES UNDER AS 43.55.160
2 FROM THE GROSS VALUE AT THE POINT OF PRODUCTION
3 OF THE OIL AND GAS PRODUCED FROM THOSE LEASES OR
4 PROPERTIES DURING THE MONTH FOR WHICH THE
5 INSTALLMENT PAYMENT IS CALCULATED];

6 (C) for oil and gas produced from each lease or property
7 subject to AS 43.55.011(j), (k), or (o), the greater of

8 (i) zero; or

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

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

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

1 (A) the applicable tax rate for oil provided under
2 AS 43.55.011(i), multiplied by the gross value at the point of production of the
3 oil taxable under AS 43.55.011(i) and produced from the lease or property
4 during the month; and

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

9 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any
10 credits applied as allowed by law, that exceeds the total of the amounts due as
11 installment payments of estimated tax is due on March 31 of the year following the
12 calendar year of production."
13

14 Renumber the following bill section accordingly.

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "relating to certain additional nontransferable oil and gas production tax
3 credits;"

4

5 Page 2, following line 5:

6 Insert a new bill section to read:

7 "* **Sec. 2.** AS 43.55.024(d) is amended to read:

8 (d) A producer may not take a tax credit under (c) of this section for any
9 calendar year after the later of

10 (1) **2021** [2016]; or

11 (2) if the producer did not have commercial oil or gas production from
12 a lease or property in the state before April 1, 2006, the ninth calendar year after the
13 calendar year during which the producer first has commercial oil or gas production
14 before May 1, **2021** [2016], from at least one lease or property in the state."

15

16 Renumber the following bill section accordingly.

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, line 1, following "tax;":

2 Insert "**relating to an adjustment to the gross value at the point of production for**
3 **oil production from certain leases or properties; relating to the determination of the**
4 **production tax value of oil and gas;**"

5

6 Page 2, following line 5:

7 Insert new bill sections to read:

8 "* **Sec. 2.** AS 43.55.160(a) is amended to read:

9 (a) Except as provided in (b) of this section **and subject to an adjustment**
10 **under AS 43.55.162.** for the purposes of

11 (1) AS 43.55.011(e), the annual production tax value of the taxable

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

20 (B) oil and gas produced during a calendar year from leases or
21 properties in the state outside the Cook Inlet sedimentary basin, no part of
22 which is north of 68 degrees North latitude, is the gross value at the point of
23 production of the oil and gas taxable under AS 43.55.011(e) and produced by

1 the producer from those leases or properties, less the producer's lease
2 expenditures under AS 43.55.165 for the calendar year applicable to the oil and
3 gas produced by the producer from those leases or properties, as adjusted under
4 AS 43.55.170; this subparagraph does not apply to gas subject to
5 AS 43.55.011(o);

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

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

18 (E) gas produced during a calendar year from a lease or
19 property outside the Cook Inlet sedimentary basin and used in the state is the
20 gross value at the point of production of that gas taxable under
21 AS 43.55.011(e) and produced by the producer from that lease or property, less
22 the producer's lease expenditures under AS 43.55.165 for the calendar year
23 applicable to that gas produced by the producer from that lease or property, as
24 adjusted under AS 43.55.170;

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

26 (A) oil and gas produced during a month from leases or
27 properties in the state that include land north of 68 degrees North latitude is the
28 gross value at the point of production of the oil and gas taxable under
29 AS 43.55.011(e) and produced by the producer from those leases or properties,
30 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
31 calendar year applicable to the oil and gas produced by the producer from

1 those leases or properties, as adjusted under AS 43.55.170; this subparagraph
2 does not apply to gas subject to AS 43.55.011(o);

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

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

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

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

31 * **Sec. 3.** AS 43.55 is amended by adding a new section to read:

1 **Sec. 43.55.162. Adjustments to the gross value at the point of production**
2 **for certain oil.** (a) If the volume of taxable oil produced by a producer during a
3 calendar year from leases or properties described in AS 43.55.160(a)(1)(A) is greater
4 than the annual target volume of taxable oil production determined under this section
5 for the calendar year, the gross value at the point of production for the taxable oil
6 produced during

7 (1) the calendar year for the purpose of determining the annual
8 production tax value under AS 43.55.160(a)(1), shall be reduced by a percentage equal
9 to the percentage by which the volume of taxable oil produced during the calendar
10 year exceeds the target volume of production for the calendar year; and

11 (2) a calendar month for the purpose of determining the production tax
12 value for the calendar month under AS 43.55.160(a)(2), shall be reduced by a
13 percentage equal to the percentage by which the volume of taxable oil produced
14 during the calendar month exceeds the target volume of production for the calendar
15 month.

16 (b) Subject to adjustment under (e) of this section, the target volume of taxable
17 oil production by a producer for a calendar year equals the volume of taxable oil
18 produced by the producer from leases or properties described in
19 AS 43.55.160(a)(1)(A) during the calendar year immediately preceding the calendar
20 year for which the tax is being determined, multiplied by the applicable factor
21 determined under (c)(1) - (4) of this section.

22 (c) For the purpose of determining the target volume of taxable oil production
23 under (b) of this section, for a producer having taxable oil production from a lease or
24 property described in AS 43.55.160(a)(1)(A)

25 (1) during the calendar year immediately preceding the calendar year
26 for which the tax is being determined and the fourth calendar year preceding the
27 calendar year for which the tax is being determined, the factor is equal to the cube root
28 of the ratio of the volume of taxable oil produced by the producer from the leases or
29 properties described in AS 43.55.160(a)(1)(A) during the calendar year immediately
30 preceding the calendar year for which the tax is being determined to the volume of
31 taxable oil produced from the leases or properties described in AS 43.55.160(a)(1)(A)

1 during the fourth calendar year preceding the year for which the tax is being
2 determined;

3 (2) during the calendar year immediately preceding the calendar year
4 for which the tax is being determined and the third calendar year preceding the
5 calendar year for which the tax is being determined, but not during the fourth year
6 preceding the calendar year for which the tax is being determined, the factor is equal
7 to the square root of the ratio of the volume of taxable oil produced by the producer
8 from the leases or properties described in AS 43.55.160(a)(1)(A) during the calendar
9 year immediately preceding the year for which the tax is being determined to the
10 volume of taxable oil produced from the leases or properties described in
11 AS 43.55.160(a)(1)(A) during the third calendar year preceding the calendar year for
12 which the tax is being determined;

13 (3) during the calendar year immediately preceding the calendar year
14 for which the tax is being determined and the second calendar year preceding the year
15 for which the tax is being determined, but not during the third or fourth calendar years
16 preceding the year for which the tax is being determined, the factor is equal to the ratio
17 of the volume of taxable oil produced by the producer from the leases or properties
18 described in AS 43.55.160(a)(1)(A) during the calendar year immediately preceding
19 the calendar year for which the tax is being determined to the volume of taxable oil
20 produced from the leases or properties described in AS 43.55.160(a)(1)(A) during the
21 second calendar year preceding the calendar year for which the tax is being
22 determined;

23 (4) during the calendar year immediately preceding the year for which
24 the tax is being determined but not during the second, third, or fourth calendar years
25 preceding the calendar year for which the tax is being determined, the factor is equal
26 to one.

27 (d) The target volume of taxable oil production by a producer for a calendar
28 month is equal to 1/12 of the annual target volume of taxable oil production for the
29 calendar year, except as otherwise provided in (e)(4) of this section.

30 (e) For purposes of this section, for a producer that produced taxable oil
31 during a calendar year from a lease or property described in AS 43.55.160(a)(1)(A),

1 (1) if the producer did not produce taxable oil from a lease or property
2 described in AS 43.55.160(a)(1)(A) during the calendar year immediately preceding
3 the calendar year for which the tax is being determined, there is no target volume of
4 taxable oil production for the calendar year or calendar month during the year and no
5 reduction in the gross value at the point of production for that oil production for the
6 purposes of AS 43.55.160(a)(1) for the year for which the tax is being determined,
7 unless the production of taxable oil during the entire calendar year was interrupted
8 because of force majeure;

9 (2) if the producer did not produce taxable oil from a lease or property
10 described in AS 43.55.160(a)(1)(A) during the calendar year immediately preceding
11 the calendar year for which the tax is being determined because the production of
12 taxable oil during the entire calendar year was interrupted because of force majeure,
13 the target volume of taxable oil production for the current year must be determined
14 under (c) of this section based on the fourth, third, or second preceding calendar year,
15 as applicable, in which the producer produced taxable oil from a lease or property
16 described in AS 43.55.160(a)(1)(A);

17 (3) for a producer that produced taxable oil from leases or properties
18 described in AS 43.55.160(a)(1)(A) during a prior year that would have been used in
19 the applicable calculation under (b) of this section, except that there was no taxable oil
20 production for 30 days or more during that calendar year because the producer first
21 produced taxable oil from those leases or properties during that calendar year or
22 because production from the leases or properties was interrupted by force majeure for
23 30 days or more during that calendar year, the producer's volume of taxable oil
24 production from leases or properties described in AS 43.55.160(a)(1)(A) during that
25 prior year is multiplied by a fraction, the numerator of which is the number of days
26 during that prior year and the denominator of which is the number of days during that
27 prior year on which the producer had oil production from a lease or property described
28 in AS 43.55.160(a)(1)(A);

29 (4) for a producer that has production of taxable oil that is interrupted
30 by force majeure for 30 days or more during the year for which the tax is being
31 determined, the target volume of taxable oil production for the current year that would

1 otherwise be applicable shall be reduced by a percentage equal to the percentage of
2 days during the year that the production was interrupted, and the producer's monthly
3 target volume of taxable oil production for the current year is the target volume of
4 taxable oil production for the current year determined under this paragraph divided by
5 a fraction, the numerator of which is the number of days during the year when the
6 producer had production from leases or properties described in AS 43.55.160(a)(1)(A),
7 and the denominator of which is 30.4375.

8 (f) The determination of the adjustment to the gross value at the point of
9 production in this section is based on the location of a lease or property within the area
10 described in AS 43.55.160(a)(1)(A) and is made without regard as to whether taxable
11 oil is produced from a particular lease or property during more than one year.

12 (g) The negligence or recklessness of a producer or operator that prevents the
13 production of taxable oil does not constitute force majeure. However, if there is a
14 sufficient cause for the cessation of production because of force majeure, the
15 negligence or recklessness of the producer, the operator, or the producer and operator
16 does not prohibit treating the inability to produce oil or the suspension of oil
17 production as having been caused by force majeure for the purposes of this section.

18 (h) In this section, "force majeure" means a cause beyond the reasonable
19 ability of a producer, an operator, or a producer and operator of a lease or property to
20 avoid or control that prevents the producer from producing oil or having oil produced
21 for the producer from the lease or property for a period of 24 or more consecutive
22 hours; "force majeure" includes an act of God, war, martial law, insurrection,
23 terrorism, sabotage, government restriction, order of a court or an administrative or
24 regulatory body having jurisdiction over the lease or property or production from the
25 lease or property, a strike or other labor action, or a failure or omission on the part of a
26 third-party supplier, contractor, subcontractor, carrier, or other third party."
27

28 Renumber the following bill section accordingly.

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "B"

1 Page 1, following "tax;":

2 Insert "**providing for a tax credit applicable to the oil and gas production tax**
3 **based on the capital cost of developing new oil and gas production;**"

4

5 Page 1, following line 2:

6 Insert a new bill section to read:

7 **"* Section 1.** AS 43.20.043(g) is amended to read:

8 (g) A taxpayer that obtains a credit for a qualified capital investment or cost
9 incurred for qualified services under this section may not also claim a tax credit or
10 royalty modification for the same qualified capital investment or cost incurred for
11 qualified services under AS 38.05.180(i), AS 41.09.010, AS 43.55.023, [OR]
12 43.55.025, or 43.55.026. However, a taxpayer may elect not to obtain a credit under
13 this section in order to qualify for a credit provided under AS 38.05.180(i),
14 AS 41.09.010, AS 43.55.023, [OR] 43.55.025, or 43.55.026."

15

16 Page 1, line 3:

17 Delete "**Section 1**"

18 Insert "**Sec. 2**"

19

20 Page 2, line 6:

21 Delete all material and insert:

22 **"* Sec. 3.** AS 43.55 is amended by adding a new section to read:

23 **Sec. 43.55.026. Development cost credit.** (a) This section applies to a credit

1 for a qualified development expenditure incurred before 2018 and before the start of
2 sustained production that is taxable under AS 43.55.011(e). The qualified development
3 expenditure must be incurred for development outside of the Cook Inlet sedimentary
4 basin and outside of the Point Thomson unit established under AS 38.05.180(p) as the
5 area of the Point Thomson unit existed on December 31, 2010. The qualified
6 development expenditure must be for the development of a

7 (1) lease or property that, as of December 31, 2010, contains land that
8 is not or previously had not been within a unit or is not or had not previously been
9 involved directly in sustained production; or

10 (2) pool that, as of December 31, 2010, is not directly involved in or
11 had not previously been involved directly in sustained production.

12 (b) The total amount of the credits under this section is equal to 100 percent of
13 the qualified development expenditures that are incurred after the completion of the
14 first well drilled that discovers a pool capable of commercial production from the lease
15 or property and before the start of sustained production, less the amount of credits
16 taken under AS 43.55.023(a) and (b). In consultation with the Alaska Oil and Gas
17 Conservation Commission, the department shall determine the date

18 (1) on which the first well drilled discovered a pool capable of
19 production; and

20 (2) of the start of sustained production from the pool, lease, or
21 property.

22 (c) A credit under this section may be applied against the tax levied by
23 AS 43.55.011(e) for the pool, lease, or property that is the basis for the credit until the
24 credit for qualified development expenditures has been fully applied.

25 (d) A qualified development expenditure that is taken as a credit under this
26 section may not be used as an expenditure for which a credit may be taken under
27 AS 43.20.043. A credit under AS 43.55.023 may not be taken against the tax levied by
28 AS 43.55.011(e) for the pool, lease, or property that is the basis for a credit during the
29 same month in which a credit is taken under this section.

30 (e) A credit or portion of a credit under this section is not transferable and may
31 not be used to reduce a person's tax liability under AS 43.55.011(e) to below zero for

1 any calendar year.

2 (f) The department shall adopt regulations describing the procedures for
3 determining the amount of the credit, record keeping, verification of the accuracy of
4 the credit claimed, allocating expenditures to a pool eligible for a credit under (a)(2) of
5 this section, and other regulations necessary to administer this section.

6 (g) If a pool, lease, or property for which a credit may be taken under this
7 section subsequently becomes a part of a unit, or a pool that is in a unit first begins
8 sustained production after December 31, 2010, the credit may be applied only against
9 the tax levied by AS 43.55.011(e) for the production of oil and gas attributable to the
10 pool, lease, or property that qualified for the credit. For the purpose of applying the
11 credit, the tax shall be allocated to the pool, lease, or property that qualified for the
12 credit in proportion to the volume of production from that pool lease or property
13 within the unit.

14 (h) In this section,

15 (1) "pool" has the meaning given in AS 31.05.170;

16 (2) "qualified development expenditure" means an expenditure, other
17 than an expenditure for exploring for new oil or gas reserves, that may be recognized
18 as a qualified capital expenditure as defined in AS 43.55.023;

19 (3) "sustained production" has the meaning given in AS 43.55.025(*l*).

20 * **Sec. 4.** AS 43.55.180(a) is amended to read:

21 (a) The department shall study

22 (1) the effects of the provisions of this chapter on oil and gas
23 exploration, development, and production in the state, on investment expenditures for
24 oil and gas exploration, development, and production in the state, on the entry of new
25 producers into the oil and gas industry in the state, on state revenue, and on tax
26 administration and compliance, giving particular attention to the tax rates provided
27 under AS 43.55.011, the tax credits provided under AS 43.55.023 - 43.55.026
28 [AS 43.55.023 - 43.55.025], and the deductions for and adjustments to lease
29 expenditures provided under AS 43.55.160 - 43.55.170; and

30 (2) the effects of the tax rates under AS 43.55.011(i) on state revenue
31 and on oil and gas exploration, development, and production on private land, and the

1 fairness of those tax rates for private landowners.

2 * **Sec. 5.** Section 2 of this Act takes effect January 1, 2013.

3 * **Sec. 6.** Except as provided in sec. 5 of this Act, this Act takes effect immediately under

4 AS 01.10.070(c)."

Committee Substitute for Senate Bill 192 Oil and Gas Production Tax Values**Version E (3/1/12)****Amendments**

- E.1 (formerly B.1) Extends the Sunset of the Small Producer/New Area Development Credit from 2016 to 2021 (Wagoner)
- E.2 (formerly B.2) Gross Value at the Point of Production Tax Holiday (Wagoner)
- E.3 (formerly B.3) Tax Credit Based on the Capital Cost of Developing New Oil and Gas Production (Wagoner)
- E.6 (formerly B.6) Inflation Adjusting the \$30 (McGuire)
- E.9 (formerly B.10) Capping Credits to Avoid Gold Plating (Wielechowski/French)
- E.10 (formerly B.11) Changes to Oil and Gas Leasing Laws (Wielechowski/French)
- E.11 (formerly B.12) State Directed Financial Investment (SDFI) (Wielechowski/French)
- E.12 (formerly B.14) Re-instituting Separate Accounting (Wielechowski)
- E.13 (formerly B.15) Requiring Info About Use of Tax Credits (Wielechowski/French)
- E.14 (formerly B.17) Competitiveness Review Board (McGuire)
- E.16 (formerly B.4) Progressivity Bracketed – 35% top bracket
- E. 18 (formerly B.8) Simple Progressivity (Wielechowski/French)
- E.19 (formerly B.18) Simple Progressivity 2 (Wielechowski / French)

Amendment Forthcoming

- E.17 (formerly B.7) Adjusted base rate plus bracketed progressivity and in-field development credit for new fields (McGuire)
-

A M E N D M E N T

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, line 1, following "tax;":

2 Insert "**relating to certain additional nontransferable oil and gas production tax**
3 **credits;**"

4

5 Page 10, following line 22:

6 Insert a new bill section to read:

7 **** Sec. 11.** AS 43.55.024(d) is amended to read:

8 (d) A producer may not take a tax credit under (c) of this section for any
9 calendar year after the later of

10 (1) **2021** [2016]; or

11 (2) if the producer did not have commercial oil or gas production from
12 a lease or property in the state before April 1, 2006, the ninth calendar year after the
13 calendar year during which the producer first has commercial oil or gas production
14 before May 1, **2021** [2016], from at least one lease or property in the state."

15

16 Renumber the following bill sections accordingly.

17

18 Page 21, line 9:

19 Delete "sec. 13"

20 Insert "sec. 14"

A M E N D M E N T

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 17, line 28, through page 20, line 1:

2 Delete all material and insert:

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

4 **Sec. 43.55.162. Adjustments to the gross value at the point of production**
5 **for certain oil.** (a) If the volume of taxable oil produced by a producer during a
6 calendar year from leases or properties described in AS 43.55.160(a)(1)(A) is greater
7 than the annual target volume of taxable oil production determined under this section
8 for the calendar year, the gross value at the point of production for the taxable oil
9 produced during

10 (1) the calendar year for the purpose of determining the annual
11 production tax value under AS 43.55.160(a)(1), shall be reduced by a percentage equal
12 to the percentage by which the volume of taxable oil produced during the calendar
13 year exceeds the target volume of production for the calendar year; and

14 (2) a calendar month for the purpose of determining the production tax
15 value for the calendar month under AS 43.55.160(a)(2), shall be reduced by a
16 percentage equal to the percentage by which the volume of taxable oil produced
17 during the calendar month exceeds the target volume of production for the calendar
18 month.

19 (b) Subject to adjustment under (e) of this section, the target volume of taxable
20 oil production by a producer for a calendar year equals the volume of taxable oil
21 produced by the producer from leases or properties described in
22 AS 43.55.160(a)(1)(A) during the calendar year immediately preceding the calendar
23 year for which the tax is being determined, multiplied by the applicable factor

1 determined under (c)(1) - (4) of this section.

2 (c) For the purpose of determining the target volume of taxable oil production
3 under (b) of this section, for a producer having taxable oil production from a lease or
4 property described in AS 43.55.160(a)(1)(A)

5 (1) during the calendar year immediately preceding the calendar year
6 for which the tax is being determined and the fourth calendar year preceding the
7 calendar year for which the tax is being determined, the factor is equal to the cube root
8 of the ratio of the volume of taxable oil produced by the producer from the leases or
9 properties described in AS 43.55.160(a)(1)(A) during the calendar year immediately
10 preceding the calendar year for which the tax is being determined to the volume of
11 taxable oil produced from the leases or properties described in AS 43.55.160(a)(1)(A)
12 during the fourth calendar year preceding the year for which the tax is being
13 determined;

14 (2) during the calendar year immediately preceding the calendar year
15 for which the tax is being determined and the third calendar year preceding the
16 calendar year for which the tax is being determined, but not during the fourth year
17 preceding the calendar year for which the tax is being determined, the factor is equal
18 to the square root of the ratio of the volume of taxable oil produced by the producer
19 from the leases or properties described in AS 43.55.160(a)(1)(A) during the calendar
20 year immediately preceding the year for which the tax is being determined to the
21 volume of taxable oil produced from the leases or properties described in
22 AS 43.55.160(a)(1)(A) during the third calendar year preceding the calendar year for
23 which the tax is being determined;

24 (3) during the calendar year immediately preceding the calendar year
25 for which the tax is being determined and the second calendar year preceding the year
26 for which the tax is being determined, but not during the third or fourth calendar years
27 preceding the year for which the tax is being determined, the factor is equal to the ratio
28 of the volume of taxable oil produced by the producer from the leases or properties
29 described in AS 43.55.160(a)(1)(A) during the calendar year immediately preceding
30 the calendar year for which the tax is being determined to the volume of taxable oil
31 produced from the leases or properties described in AS 43.55.160(a)(1)(A) during the

1 second calendar year preceding the calendar year for which the tax is being
2 determined;

3 (4) during the calendar year immediately preceding the year for which
4 the tax is being determined but not during the second, third, or fourth calendar years
5 preceding the calendar year for which the tax is being determined, the factor is equal
6 to one.

7 (d) The target volume of taxable oil production by a producer for a calendar
8 month is equal to 1/12 of the annual target volume of taxable oil production for the
9 calendar year, except as otherwise provided in (e)(4) of this section.

10 (e) For purposes of this section, for a producer that produced taxable oil
11 during a calendar year from a lease or property described in AS 43.55.160(a)(1)(A),

12 (1) if the producer did not produce taxable oil from a lease or property
13 described in AS 43.55.160(a)(1)(A) during the calendar year immediately preceding
14 the calendar year for which the tax is being determined, there is no target volume of
15 taxable oil production for the calendar year or calendar month during the year and no
16 reduction in the gross value at the point of production for that oil production for the
17 purposes of AS 43.55.160(a)(1) for the year for which the tax is being determined,
18 unless the production of taxable oil during the entire calendar year was interrupted
19 because of force majeure;

20 (2) if the producer did not produce taxable oil from a lease or property
21 described in AS 43.55.160(a)(1)(A) during the calendar year immediately preceding
22 the calendar year for which the tax is being determined because the production of
23 taxable oil during the entire calendar year was interrupted because of force majeure,
24 the target volume of taxable oil production for the current year must be determined
25 under (c) of this section based on the fourth, third, or second preceding calendar year,
26 as applicable, in which the producer produced taxable oil from a lease or property
27 described in AS 43.55.160(a)(1)(A);

28 (3) for a producer that produced taxable oil from leases or properties
29 described in AS 43.55.160(a)(1)(A) during a prior year that would have been used in
30 the applicable calculation under (b) of this section, except that there was no taxable oil
31 production for 30 days or more during that calendar year because the producer first

1 produced taxable oil from those leases or properties during that calendar year or
2 because production from the leases or properties was interrupted by force majeure for
3 30 days or more during that calendar year, the producer's volume of taxable oil
4 production from leases or properties described in AS 43.55.160(a)(1)(A) during that
5 prior year is multiplied by a fraction, the numerator of which is the number of days
6 during that prior year and the denominator of which is the number of days during that
7 prior year on which the producer had oil production from a lease or property described
8 in AS 43.55.160(a)(1)(A);

9 (4) for a producer that has production of taxable oil that is interrupted
10 by force majeure for 30 days or more during the year for which the tax is being
11 determined, the target volume of taxable oil production for the current year that would
12 otherwise be applicable shall be reduced by a percentage equal to the percentage of
13 days during the year that the production was interrupted, and the producer's monthly
14 target volume of taxable oil production for the current year is the target volume of
15 taxable oil production for the current year determined under this paragraph divided by
16 a fraction, the numerator of which is the number of days during the year when the
17 producer had production from leases or properties described in AS 43.55.160(a)(1)(A),
18 and the denominator of which is 30.4375.

19 (f) The determination of the adjustment to the gross value at the point of
20 production in this section is based on the location of a lease or property within the area
21 described in AS 43.55.160(a)(1)(A) and is made without regard as to whether taxable
22 oil is produced from a particular lease or property during more than one year.

23 (g) The negligence or recklessness of a producer or operator that prevents the
24 production of taxable oil does not constitute force majeure. However, if there is a
25 sufficient cause for the cessation of production because of force majeure, the
26 negligence or recklessness of the producer, the operator, or the producer and operator
27 does not prohibit treating the inability to produce oil or the suspension of oil
28 production as having been caused by force majeure for the purposes of this section.

29 (h) In this section, "force majeure" means a cause beyond the reasonable
30 ability of a producer, an operator, or a producer and operator of a lease or property to
31 avoid or control that prevents the producer from producing oil or having oil produced

1 for the producer from the lease or property for a period of 24 or more consecutive
2 hours; "force majeure" includes an act of God, war, martial law, insurrection,
3 terrorism, sabotage, government restriction, order of a court or an administrative or
4 regulatory body having jurisdiction over the lease or property or production from the
5 lease or property, a strike or other labor action, or a failure or omission on the part of a
6 third-party supplier, contractor, subcontractor, carrier, or other third party."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, following "tax;":

2 Insert "providing for a tax credit applicable to the oil and gas production tax
3 based on the capital cost of developing new oil and gas production;"
4

5 Page 4, following line 28:

6 Insert a new bill section to read:

7 "* **Sec. 5.** AS 43.20.043(g) is amended to read:

8 (g) A taxpayer that obtains a credit for a qualified capital investment or cost
9 incurred for qualified services under this section may not also claim a tax credit or
10 royalty modification for the same qualified capital investment or cost incurred for
11 qualified services under AS 38.05.180(i), AS 41.09.010, AS 43.55.023, [OR]
12 43.55.025, or 43.55.026. However, a taxpayer may elect not to obtain a credit under
13 this section in order to qualify for a credit provided under AS 38.05.180(i),
14 AS 41.09.010, AS 43.55.023, [OR] 43.55.025, or 43.55.026."
15

16 Renumber the following bill sections accordingly.
17

18 Page 10, following line 22:

19 Insert a new bill section to read:

20 "* **Sec. 12.** AS 43.55 is amended by adding a new section to read:

21 **Sec. 43.55.026. Development cost credit.** (a) This section applies to a credit
22 for a qualified development expenditure incurred before 2018 and before the start of
23 sustained production that is taxable under AS 43.55.011(e). The qualified development

1 expenditure must be incurred for development outside of the Cook Inlet sedimentary
2 basin and outside of the Point Thomson unit established under AS 38.05.180(p) as the
3 area of the Point Thomson unit existed on December 31, 2010. The qualified
4 development expenditure must be for the development of a

5 (1) lease or property that, as of December 31, 2010, contains land that
6 is not or previously had not been within a unit or is not or had not previously been
7 involved directly in sustained production; or

8 (2) pool that, as of December 31, 2010, is not directly involved in or
9 had not previously been involved directly in sustained production.

10 (b) The total amount of the credits under this section is equal to 100 percent of
11 the qualified development expenditures that are incurred after the completion of the
12 first well drilled that discovers a pool capable of commercial production from the lease
13 or property and before the start of sustained production, less the amount of credits
14 taken under AS 43.55.023(a) and (b). In consultation with the Alaska Oil and Gas
15 Conservation Commission, the department shall determine the date

16 (1) on which the first well drilled discovered a pool capable of
17 production; and

18 (2) of the start of sustained production from the pool, lease, or
19 property.

20 (c) A credit under this section may be applied against the tax levied by
21 AS 43.55.011(e) for the pool, lease, or property that is the basis for the credit until the
22 credit for qualified development expenditures has been fully applied.

23 (d) A qualified development expenditure that is taken as a credit under this
24 section may not be used as an expenditure for which a credit may be taken under
25 AS 43.20.043. A credit under AS 43.55.023 may not be taken against the tax levied by
26 AS 43.55.011(e) for the pool, lease, or property that is the basis for a credit during the
27 same month in which a credit is taken under this section.

28 (e) A credit or portion of a credit under this section is not transferable and may
29 not be used to reduce a person's tax liability under AS 43.55.011(e) to below zero for
30 any calendar year.

31 (f) The department shall adopt regulations describing the procedures for

1 determining the amount of the credit, record keeping, verification of the accuracy of
 2 the credit claimed, allocating expenditures to a pool eligible for a credit under (a)(2) of
 3 this section, and other regulations necessary to administer this section.

4 (g) If a pool, lease, or property for which a credit may be taken under this
 5 section subsequently becomes a part of a unit, or a pool that is in a unit first begins
 6 sustained production after December 31, 2010, the credit may be applied only against
 7 the tax levied by AS 43.55.011(e) for the production of oil and gas attributable to the
 8 pool, lease, or property that qualified for the credit. For the purpose of applying the
 9 credit, the tax shall be allocated to the pool, lease, or property that qualified for the
 10 credit in proportion to the volume of production from that pool lease or property
 11 within the unit.

12 (h) In this section,

13 (1) "pool" has the meaning given in AS 31.05.170;

14 (2) "qualified development expenditure" means an expenditure, other
 15 than an expenditure for exploring for new oil or gas reserves, that may be recognized
 16 as a qualified capital expenditure as defined in AS 43.55.023;

17 (3) "sustained production" has the meaning given in AS 43.55.025(I)."
 18

19 Renumber the following bill sections accordingly.
 20

21 Page 20, following line 29:

22 Insert a new bill section to read:

23 **"* Sec. 18.** AS 43.55.180(a) is amended to read:

24 (a) The department shall study

25 (1) the effects of the provisions of this chapter on oil and gas
 26 exploration, development, and production in the state, on investment expenditures for
 27 oil and gas exploration, development, and production in the state, on the entry of new
 28 producers into the oil and gas industry in the state, on state revenue, and on tax
 29 administration and compliance, giving particular attention to the tax rates provided
 30 under AS 43.55.011, the tax credits provided under AS 43.55.023 - 43.55.026
 31 [AS 43.55.023 - 43.55.025], and the deductions for and adjustments to lease

1 expenditures provided under AS 43.55.160 - 43.55.170; and

2 (2) the effects of the tax rates under AS 43.55.011(i) on state revenue
3 and on oil and gas exploration, development, and production on private land, and the
4 fairness of those tax rates for private landowners."
5

6 Page 21, line 9:

7 Delete "sec. 13"

8 Insert "sec. 15"
9

10 Page 21, line 13:

11 Delete all material and insert:

12 **"* Sec. 21.** Sections 5, 12, and 18 of this Act take effect immediately under
13 AS 01.10.070(c).

14 *** Sec. 22.** Except as provided in sec. 21 of this Act, this Act takes effect January 1, 2013."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

- 1 Page 6, line 1:
2 Delete "\$30"
3 Insert "the greater of \$30 or the amount determined under (q) of this section
4 [\$30]"
5
6 Page 6, line 13:
7 Delete "\$30"
8 Insert "the greater of \$30 or the amount determined under (q) of this section
9 [\$30]"
10
11 Page 7, line 6:
12 Delete "a new subsection"
13 Insert "new subsections"
14
15 Page 7, line 9:
16 Delete "\$30"
17 Insert "the greater of \$30 or the amount determined under (q) of this section"
18
19 Page 7, line 19:
20 Delete "\$30"
21 Insert "the greater of \$30 or the amount determined under (q) of this section"
22
23 Page 8, following line 6:

1 Insert a new subsection to read:

2 "(q) For a calendar year after 2013, the \$30 amount in (g) of this section shall
3 be adjusted by the commissioner as soon as practicable before the start of the calendar
4 year for which the tax will be determined according to changes in the Consumer Price
5 Index for all urban consumers for the Anchorage metropolitan area compiled by the
6 United States Department of Labor, Bureau of Labor Statistics. The \$30 amount in (g)
7 of this section shall be adjusted based on the increase, if any, between the consumer
8 price index for January through June of 2011 and for January through June of the year
9 immediately preceding the year for which the \$30 amount in (g) of this section is
10 being adjusted."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, line 1, following "tax;":

2 Insert "**limiting the amount of certain tax credits applicable to the oil and gas**
3 **production tax;**"

4

5 Page 10, following line 22:

6 Insert new bill sections to read:

7 "*** Sec. 11.** AS 43.55.023(a) is amended to read:

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

10 (1) **except as limited by (p) of this section,** notwithstanding that a
11 qualified capital expenditure may be a deductible lease expenditure for purposes of
12 calculating the production tax value of oil and gas under AS 43.55.160(a), unless a
13 credit for that expenditure is taken under AS 38.05.180(i), AS 41.09.010,
14 AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a qualified capital
15 expenditure may also elect to apply a tax credit against a tax levied by
16 AS 43.55.011(e) in the amount of 20 percent of that expenditure; however, not more
17 than half of the tax credit may be applied for a single calendar year;

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

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

23 (B) submits to the Department of Natural Resources all data

1 that would be required to be submitted under AS 43.55.025(f)(2).

2 * **Sec. 12.** AS 43.55.023(d) is amended to read:

3 (d) Except as limited by (i) **and (p)** of this section, a person that is entitled to
4 take a tax credit under this section that wishes to transfer the unused credit to another
5 person or obtain a cash payment under AS 43.55.028 may apply to the department for
6 transferable tax credit certificates. An application under this subsection must be in a
7 form prescribed by the department and must include supporting information and
8 documentation that the department reasonably requires. The department shall grant or
9 deny an application, or grant an application as to a lesser amount than that claimed and
10 deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the
11 year following the calendar year in which the qualified capital expenditure or carried-
12 forward annual loss for which the credit is claimed was incurred; (2) the date the
13 statement required under AS 43.55.030(a) or (e) was filed for the calendar year in
14 which the qualified capital expenditure or carried-forward annual loss for which the
15 credit is claimed was incurred; or (3) the date the application was received by the
16 department. If, based on the information then available to it, the department is
17 reasonably satisfied that the applicant is entitled to a credit, the department shall issue
18 the applicant two transferable tax credit certificates, each for half of the amount of the
19 credit. The credit shown on one of the two certificates is available for immediate use.
20 The credit shown on the second of the two certificates may not be applied against a tax
21 for a calendar year earlier than the calendar year following the calendar year in which
22 the certificate is issued, and the certificate must contain a conspicuous statement to
23 that effect. A certificate issued under this subsection does not expire.

24 * **Sec. 13.** AS 43.55.023(l) is amended to read:

25 (l) **Except as limited by (p) of this section, a** [A] producer or explorer may
26 apply for a tax credit for a well lease expenditure incurred in the state south of 68
27 degrees North latitude after June 30, 2010, as follows:

28 (1) notwithstanding that a well lease expenditure incurred in the state
29 south of 68 degrees North latitude may be a deductible lease expenditure for purposes
30 of calculating the production tax value of oil and gas under AS 43.55.160(a), unless a
31 credit for that expenditure is taken under (a) of this section, AS 38.05.180(i),

1 AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or explorer that incurs a
 2 well lease expenditure in the state south of 68 degrees North latitude may elect to
 3 apply a tax credit against a tax levied by AS 43.55.011(e) in the amount of 40 percent
 4 of that expenditure; a tax credit under this paragraph may be applied for a single
 5 calendar year;

6 (2) a producer or explorer may take a credit for a well lease
 7 expenditure incurred in the state south of 68 degrees North latitude in connection with
 8 geological or geophysical exploration or in connection with an exploration well only if
 9 the producer or explorer

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

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

14 * **Sec. 14.** AS 43.55.023 is amended by adding a new subsection to read:

15 (p) The amount of credit for a capital expenditure under (a) or (l) of this
 16 section for an expenditure that is also a lease expenditure under AS 43.55.165 is
 17 reduced by the amount necessary so that the tax benefit percentage is not more than 65
 18 percent of the capital expenditure. The amount of credit for a capital expenditure
 19 under (a) or (l) of this section that may not be taken because of the limitation in this
 20 subsection may not be applied in a later calendar year under (c) of this section and
 21 may not be included in an application for a tax credit certificate under (d) of this
 22 section. In this subsection, "tax benefit percentage" means the sum of the average
 23 monthly tax rate under AS 43.55.011(e) and (g) for the calendar year in which the
 24 credit is taken and the percentage of the capital expenditure that may be taken as a
 25 credit under (a) or (l) of this section.

26 * **Sec. 15.** AS 43.55.025(a) is amended to read:

27 (a) Subject to the terms and conditions of this section **and except as limited**
 28 **by (n) of this section**, a credit against the production tax levied by AS 43.55.011(e) is
 29 allowed for exploration expenditures that qualify under (b) of this section in an
 30 amount equal to one of the following:

31 (1) 30 percent of the total exploration expenditures that qualify only

1 under (b) and (c) of this section;

2 (2) 30 percent of the total exploration expenditures that qualify only
3 under (b) and (d) of this section;

4 (3) 40 percent of the total exploration expenditures that qualify under
5 (b), (c), and (d) of this section;

6 (4) 40 percent of the total exploration expenditures that qualify only
7 under (b) and (e) of this section; or

8 (5) 80, 90, or 100 percent, or a lesser amount described in (l) of this
9 section, of the total exploration expenditures described in (b)(1) and (2) of this section
10 and not excluded by (b)(3) and (4) of this section that qualify only under (l) of this
11 section.

12 * **Sec. 16.** AS 43.55.025 is amended by adding a new subsection to read:

13 (n) The amount of credit for an exploration expenditure under (a)(1) - (4) of
14 this section for an expenditure that is also a lease expenditure under AS 43.55.165 is
15 reduced by the amount necessary so that the tax benefit percentage is not more than 65
16 percent of the exploration expenditure. The amount of credit for an exploration
17 expenditure under (a)(1) - (4) of this section that may not be taken because of the
18 limitation in this subsection may not be transferred, conveyed, or sold under (g) of this
19 section. In this subsection, "tax benefit percentage" means the sum of the average
20 monthly tax rate under AS 43.55.011(e) and (g) for the calendar year in which the
21 credit is taken and the percentage of the exploration expenditure that may be taken as a
22 credit under (a)(1) - (4) of this section."

23
24 Renumber the following bill sections accordingly.

25
26 Page 21, line 9:

27 Delete "sec. 13"

28 Insert "sec. 19"

A M E N D M E N T

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, line 1, following "tax;":

2 Insert "relating to oil and gas or gas only leasing; requiring that a minimum work
3 commitment be included in each oil and gas and gas only lease and that a proposed plan
4 of development be included in an application for an oil and gas or gas only lease;"
5

6 Page 4, following line 28:

7 Insert new bill sections to read:

8 **** Sec. 5.** AS 38.05.180(h) is amended to read:

9 (h) The commissioner shall [MAY] include terms in a [ANY] lease that
10 impose [IMPOSING] a minimum work commitment on the lessee to implement the
11 plan of development submitted by the lessee with a bid for an oil and gas or gas
12 only lease. The terms of the minimum work commitment must [. THESE TERMS
13 SHALL BE MADE PUBLIC BEFORE THE SALE, AND MAY] include appropriate
14 penalty provisions to take effect in the event the lessee does not fulfill the minimum
15 work commitment. If it is demonstrated that a lease has been proven unproductive by
16 actions of adjacent lease holders, the commissioner may set aside a work commitment.
17 The commissioner may waive for a period not to exceed one two-year period any term
18 of a minimum work commitment if the commissioner makes a written finding either
19 that conditions preventing drilling or exploration were beyond the lessee's reasonable
20 ability to foresee or control or that the lessee has demonstrated through good faith
21 efforts an intent and ability to drill or develop the lease during the term of the waiver.

22 *** Sec. 6.** AS 38.05.180(x) is amended to read:

23 (x) A lessee conducting or permitting any exploration for, or development or

1 production of, oil or gas on state land shall provide the commissioner access to all
2 noninterpretive data obtained from that lease; **shall provide the commissioner access**
3 **to all information necessary to perform an economic analysis under (ii)(2) of this**
4 **section, including the capital, operating, production, and development costs and**
5 **an estimate of total reserves;** and shall provide copies of that data **and information,**
6 as the commissioner may request. The confidentiality provisions of AS 38.05.035
7 apply to the information obtained under this subsection.

8 * Sec. 7. AS 38.05.180 is amended by adding new subsections to read:

9 (hh) The commissioner shall require each bidder for an oil and gas lease or gas
10 only lease and each lessee applying for an extension or renewal of an oil and gas lease
11 or gas only lease to submit a plan of development for exploring, developing, and
12 producing from the lease within the period of the lease or the extension or renewal of
13 the lease. The commissioner shall review each plan of development and determine if
14 the proposed plan of development is reasonably expected to develop the lease in the
15 best interest of the state. The plan of development shall be included in a lease along
16 with penalties for failing to comply with the plan of development and other terms of
17 the lease. A bidder may not be a "qualified bidder" for the purposes of (f)(1) of this
18 section if the commissioner finds that the bidder has not submitted a proposed plan of
19 development that is in the best interest of the state or that the person that submitted the
20 plan of development is not reasonably capable of implementing the plan.

21 (ii) The commissioner shall

22 (1) review each oil and gas lease or gas only lease each year for the
23 purpose of determining whether a lease is being developed in the best interest of the
24 state, whether the lessee is complying with the plan of development applicable to the
25 lease, and whether revision of a development plan, including the planned rate of
26 development, would provide the maximum benefit to the people of the state;

27 (2) every five years, perform an economic analysis on each
28 participating area and determine whether the participating area is capable of increased
29 production in paying quantities over the current rate of production or plan of
30 development;

31 (3) enforce the terms of each oil and gas lease or gas only lease,

1 including imposing any applicable penalty or other remedy for noncompliance, within
 2 a reasonable time after finding that a lessee is out of compliance with the terms of the
 3 lease;

4 (4) submit a report to the legislature before the first day of each regular
 5 session that lists each oil and gas or gas only lessee that is found to be out of
 6 compliance and the action by the commissioner to bring the lessee back into
 7 compliance or to terminate the lease.

8 (jj) For the purposes of (hh) and (ii) of this section, a plan of development for
 9 a cooperative or unit under (p) of this section is the plan of development for a lease
 10 within the cooperative or unit, except where a different plan of development is
 11 established for a lease within the cooperative or unit.

12 (kk) For purposes of (ii) of this section,

13 (1) "participating area" means that part of an oil and gas lease unit area
 14 to which production is allocated in the manner described in a unit agreement;

15 (2) "production in paying quantities" means production in quantities
 16 sufficient to yield a return in excess of drilling, development, and operating costs."
 17

18 Renumber the following bill sections accordingly.

19
 20 Page 21, line 8, following "APPLICABILITY":

21 Insert "(a)"

22
 23 Page 21, line 9:

24 Delete "sec. 13"

25 Insert "sec. 16"

26
 27 Page 21, following line 12:

28 Insert a new subsection to read:

29 "(b) Section 5 of this Act and AS 38.085.180(hh), enacted by sec. 7 of this Act, apply
 30 to a proposed lease sale and the renewal or extension of a lease on or after the effective date
 31 of secs. 5 and 7 of this Act."

1

2 Page 21, line 13:

3 Delete all material and insert:

4 "* **Sec. 21.** Sections 5 - 7 of this Act take effect July 1, 2013.

5 * **Sec. 22.** Except as provided in sec. 21 of this Act, this Act takes effect January 1, 2013."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 2, line 10, following "gas;":

2 Insert "relating to participation by the Alaska Industrial Development and Export
3 Authority in the development of oil and gas resources in the state;"

4
5 Page 20, following line 29:

6 Insert new bill sections to read:

7 **** Sec. 16.** AS 44.88.080 is amended by adding a new paragraph to read:

8 (32) to acquire an interest in a project as necessary or appropriate to
9 provide working or venture capital for an oil or natural gas development project under
10 AS 44.88.650 - 44.88.660, whether by purchase, gift, or lease.

11 *** Sec. 17.** AS 44.88 is amended by adding new sections to read:

12 **Sec. 44.88.650. Acquisition of interest in businesses.** (a) The authority may
13 acquire, through purchase or other means, an interest in an in-state asset of a
14 corporation or other business entity that has a lease interest in an oil or natural gas
15 field in the state that has been explored, but only if the authority determines the
16 leaseholder has made reasonable efforts to obtain financing from the private sector to
17 develop the lease and those efforts have, in whole or part, been unsuccessful. The
18 authority shall exercise due diligence in acquiring an interest in an in-state asset of a
19 business entity under this section.

20 (b) If the authority acquires an interest in an in-state asset of a business entity
21 under this section, the authority may use the authority's assets, as appropriate, to aid in
22 the development of the oil or natural gas field in which the business entity has a lease
23 interest.

1 **Sec. 44.88.660. Alaska resource development fund.** (a) The Alaska resource
2 development fund is established in the authority for the purpose of developing oil and
3 gas resources, and consists of appropriations to the fund. The authority shall manage
4 the fund and may create separate accounts within it. Income of the fund or of
5 enterprises of the authority shall be separately accounted for and may be appropriated
6 to the fund.

7 (b) The authority may use money from the fund to carry out the fund's
8 purposes set out in (a) of this section.

9 * **Sec. 18.** AS 44.88.900(9) is amended to read:

10 (9) "project" means

11 (A) a plant or facility used or intended for use in connection
12 with making, processing, preparing, transporting, or producing in any manner,
13 goods, products, or substances of any kind or nature or in connection with
14 developing or utilizing a natural resource, or extracting, smelting, transporting,
15 converting, assembling, or producing in any manner, minerals, raw materials,
16 chemicals, compounds, alloys, fibers, commodities and materials, products, or
17 substances of any kind or nature;

18 (B) a plant or facility used or intended for use in connection
19 with a business enterprise;

20 (C) commercial activity by a business enterprise;

21 (D) a plant or facility demonstrating technological advances of
22 new methods and procedures and prototype commercial applications for the
23 exploration, development, production, transportation, conversion, and use of
24 energy resources;

25 (E) infrastructure for a new tourism destination facility or for
26 the expansion of a tourism destination facility; in this subparagraph, "tourism
27 destination facility" does not include a hotel or other overnight lodging facility;

28 (F) a plant or facility, other than a plant or facility described in
29 (D) of this paragraph, for the generation, transmission, development,
30 transportation, conversion, or use of energy resources;

31 (G) a plant or facility that enhances, provides for, or promotes

1 economic development with respect to transportation, communications,
2 community public purposes, technical innovations, prototype commercial
3 applications of intellectual property, or research;

4 (H) a plant or facility used or intended for use as a federal
5 facility, including a United States military, national guard, or coast guard
6 facility;

7 **(I) development of an oil and gas lease by providing**
8 **working or venture capital in exchange for an equity interest;**

9 * **Sec. 19.** The uncodified law of the State of Alaska is amended by adding a new section to
10 read:

11 ANALYSIS AND REPORT ON ALASKA RESIDENT INVESTMENT PROGRAM.

12 The Alaska Industrial Development and Export Authority shall research the possibility of
13 creating a program through which a resident of the state could invest the resident's permanent
14 fund dividend or other funds in an in-state oil or gas asset acquired by the authority under
15 AS 44.88.650 and report its findings to the legislature on December 31, 2012."

16
17 Renumber the following bill sections accordingly.

18
19 Page 21, line 13:

20 Delete "This Act takes"

21 Insert "Sections 1 - 15, 20, and 21 of this Act take"

A M E N D M E N T

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, line 1 following "tax;":

2 Insert "relating to the oil and gas corporate income tax; relating to the credits
3 against the oil and gas corporate income tax; making conforming amendments;"

4

5 Page 2, following line 11:

6 Insert a new bill section to read:

7 **** Section 1.** AS 29.60.599(1) is amended to read:

8 (1) "barrel," when used with reference to oil, means the quantity of
9 oil contained in 42 United States gallons of 231 cubic inches each, measured at a
10 temperature of 60 degrees Fahrenheit and an absolute pressure of 14.65 pounds a
11 square inch [HAS THE MEANING GIVEN IN AS 43.20.072];

12

13 Renumber the following sections accordingly.

14

15 Page 2, line 12:

16 Delete "Section 1"

17 Insert "Sec. 2"

18

19 Page 4, following line 28:

20 Insert new bill sections to read:

21 **** Sec. 6.** AS 41.09.010(b) is amended to read:

22 (b) An exploration incentive credit extended under (a) of this section may be
23 applied against

1 (1) a payment or obligation against which a credit authorized by
2 AS 38.05.180(i) may be claimed;

3 (2) taxes payable under AS 43.20 or AS 43.21, as applicable; and

4 (3) oil and gas bonus payments due the state under AS 38.05.180(f).

5 * **Sec. 7.** AS 43.20.011 is amended by adding a new subsection to read:

6 (g) For purposes of calculating the tax under (e) of this section, the taxable
7 income of a corporation engaged in the production or transportation of crude oil or
8 natural gas shall be determined in accordance with AS 43.21.

9 * **Sec. 8.** AS 43.20.073(f) is amended to read:

10 (f) This section does not apply to taxpayers subject to AS 43.21
11 [AS 43.20.072 ENGAGED IN

12 (1) THE PRODUCTION OF OIL OR GAS FROM A LEASE OR
13 PROPERTY IN THE STATE; OR

14 (2) THE TRANSPORTATION OF OIL OR GAS BY REGULATED
15 PIPELINE IN THE STATE].

16 * **Sec. 9.** AS 43.21 is amended by adding new sections to read:

17 **Article 1. Determination of Taxable Income.**

18 **Sec. 43.21.200. Application.** This chapter applies to every corporation doing
19 business in the state that derives income from the production of oil or gas from a lease
20 or property in the state or from the pipeline transportation of oil or gas in the state. The
21 tax calculated under this chapter is measured by the total taxable income of the
22 corporation during the tax period as defined by AS 43.21.210 - 43.21.240 and is
23 calculated at the rates established under AS 43.20.011(e).

24 **Sec. 43.21.210. Determination of taxable income from oil and gas**
25 **production.** (a) The taxable income of a corporation from the production of oil and
26 gas from a lease or property in the state is the corporation's net income as calculated
27 by the department in accordance with this section.

28 (b) Gross income of a corporation from oil and gas production is the gross
29 value at the point of production of oil or gas produced from a lease or property in the
30 state. The department shall by regulation determine a uniform method of establishing
31 the gross value at the point of production. For the purpose of determining the gross

1 value at the point of production under this subsection, the department shall use
2 AS 43.55.150 for the determination of transportation costs.

3 (c) Net income from oil and gas production shall be determined by the
4 department by deducting from gross income the following:

5 (1) royalties paid in kind or in value;

6 (2) taxes imposed under AS 43.55 that are actually paid or incurred by
7 the corporation on the production from a lease or property in the state;

8 (3) taxes imposed under AS 29.45.080 - 29.45.090 and AS 43.56 that
9 are actually paid or incurred by the corporation on property used directly in the
10 production of oil or gas from a lease or property in the state, including property used
11 in production, gathering, treatment, or preparation of the oil or gas for pipeline
12 transportation, but only if those property tax payments were due and payable only
13 after the date of commercial production from the lease or property with which the
14 property was associated;

15 (4) the direct costs incurred by or for the corporation in operating the
16 lease or property, including the direct costs of producing, gathering, treating, or
17 preparing the oil or gas for pipeline transportation, but net of any payments received
18 for those activities and not including any indirect cost or overhead expense;

19 (5) depreciation, using the percentage depletion basis under 26 U.S.C.
20 613 (Internal Revenue Code) or another reasonable method as the department may by
21 regulation establish, on property used directly in the production, gathering, treatment,
22 or preparation of the oil or gas for pipeline transportation, including amortization of
23 capitalized interest for investments in that property at a rate not to exceed the average
24 cost to the taxpayer of borrowed capital during the year in which the interest is
25 capitalized;

26 (6) the amortization of lease acquisition payments and taxes paid or
27 incurred under AS 29.45.080, 29.45.090, or AS 43.56, including capitalized interest,
28 for or on producing properties before the commencement of commercial production
29 from the lease or property for which the property is being used;

30 (7) interest expense of the corporation, not capitalized during
31 construction, that was paid or incurred in connection with property in the state;

1 however, unless (f) of this section applies, the interest expense may not exceed that
2 portion of the total interest paid by the consolidated business of which the corporation
3 is a part, determined by multiplying the total interest by a fraction, the numerator of
4 which is the value of the corporation's real and tangible personal property used
5 directly in the production of oil or gas from a lease or property in the state and the
6 denominator of which is the value of all real and tangible personal property of the
7 consolidated business; in this paragraph, "total interest paid by the consolidated
8 business" does not include interest expense arising from intercompany obligations
9 within the consolidated business except to the extent that the interest expense reflects a
10 pass-through of interest on a third-party borrowing by the parent or other member of
11 the consolidated business with the purpose, expressed at the time of the third-party
12 borrowing, of financing Alaska business activity of the taxpayer corporation;

13 (8) expenses incurred by the corporation after December 31, 2012, of
14 unsuccessful exploration of oil or gas in the state, including the acquisition costs of
15 abandoned properties, dry hole costs, and the costs of geologic and geophysical
16 exploration related to those abandoned properties;

17 (9) general overhead or administrative expense incurred by the
18 corporation attributable to deriving income from the production of oil or gas from a
19 lease or property in the state to the extent, except as provided in (f) of this section, that
20 the general overhead or administrative expense does not exceed that portion of the
21 total general overhead or administrative expense incurred by the consolidated business
22 of which the corporation is a part, determined by multiplying the total general
23 overhead or administrative expense by a fraction, the numerator of which is the value
24 of the corporation's real and tangible personal property used directly in the production
25 of oil or gas from a lease or property in the state and the denominator of which is the
26 value of all real and tangible personal property of the consolidated business;

27 (10) the amount of income from the production of oil and gas from a
28 lease or property that is divided among the regional Native corporations under 43
29 U.S.C. 1606(i) (sec. 7(i), Alaska Native Claims Settlement Act, P.L. 92-203).

30 (d) Deductions from gross income under this section may not include
31 expenses previously deducted on a return filed under AS 43.20.

1 (e) If a corporation subject to this chapter shares the production or proceeds of
2 the production from a lease or property through a working interest, royalty interest,
3 overriding royalty interest, production payment, net profit interest, joint venture, or
4 other agreement, the department shall allocate the deductions from gross income
5 between the corporation and the persons with whom the corporation has the agreement
6 in accordance with the terms of the agreement.

7 (f) If a corporation demonstrates to the satisfaction of the department that the
8 corporation paid or incurred actual expenses for interest or for general overhead or
9 administration attributable to deriving income from the production of oil or gas from a
10 lease or property in the state in an amount greater than the amount determined under
11 (c)(7) or (9) of this section, the department may allow the corporation to deduct the
12 greater amount.

13 **Sec. 43.21.220. Determination of income from oil and gas pipeline**
14 **transportation.** (a) Except as provided in (c) of this section, taxable income
15 attributable to the transportation of oil in a pipeline engaged in interstate commerce in
16 this state shall be determined by the department and shall be the amount reported or
17 that would be required to be reported to the Federal Energy Regulatory Commission or
18 its successors as net operating income, less those portions of interest and general
19 overhead or administrative expense attributable to the pipeline transportation of oil in
20 the state, except that taxable income shall also include taxes on or measured by
21 income. The department shall establish regulations governing the determination of
22 interest and general overhead or administrative expense attributable to pipeline
23 transportation of oil in the state.

24 (b) Except as provided in (c) of this section, taxable income attributable to the
25 transportation of natural gas in a pipeline engaged in interstate commerce in this state
26 shall be determined by the department and shall be the amount reported or that would
27 be required to be reported to the Federal Energy Regulatory Commission as net
28 operating income, less that portion of interest and general overhead or administrative
29 expense attributable to pipeline transportation in the state, except that the taxable
30 income shall also include taxes on or measured by income. The department shall
31 establish regulations governing the determination of interest and general overhead or

1 administrative expense attributable to pipeline transportation of natural gas in the
2 state.

3 (c) Taxable income attributable to the transportation of oil or natural gas in
4 this state of a corporation not under the jurisdiction of the Federal Energy Regulatory
5 Commission, or of a corporation under the jurisdiction of the Federal Energy
6 Regulatory Commission but not reporting the operation of pipelines in the state
7 separately from the operation of pipelines elsewhere, shall be determined by the
8 department and shall be based on an amount equal to the amount that would have been
9 reported to the Federal Energy Regulatory Commission under (a) of this section in the
10 case of oil pipelines, or under (b) of this section, in the case of natural gas pipelines,
11 had the corporation been, in fact, under the jurisdiction of the Federal Energy
12 Regulatory Commission for the taxable year and required to report on the operation of
13 pipelines in the state separately from the operation of pipelines elsewhere.

14 **Sec. 43.21.230. Determination of income from activities other than oil and**
15 **gas production or pipeline transportation.** (a) Taxable income of a corporation
16 subject to this chapter from activities in this state other than the production of oil or
17 gas from a lease or property in the state or the pipeline transportation of oil or gas in
18 the state shall be determined in accordance with the method established in art. IV of
19 AS 43.19.010 and in AS 43.20.071, as modified by (b) - (d) of this section.

20 (b) The total taxable income of a consolidated business is its entire income
21 less the portion of that entire income attributable to worldwide production and pipeline
22 transportation of oil and gas. In this subsection, for a member of a consolidated
23 business who is

24 (1) required to file under the Internal Revenue Code, "entire income"
25 means the taxpayer's taxable income as the term is used in AS 43.20.011 - 43.20.065;

26 (2) not required to file under the Internal Revenue Code, "entire
27 income" means an income determination prepared in accordance with generally
28 accepted accounting principles, except that a taxpayer may elect to report income as
29 the income would be determined under (1) of this subsection.

30 (c) The numerator and denominator of the property factor, of the payroll
31 factor, and of the sales factor shall be calculated without reference to that portion of

1 property, payroll, or sales directly related to the production of oil or gas from a lease
2 of property in the state or the pipeline transportation of oil or gas in the state.

3 (d) The value attributed to vessels transporting Alaska oil or gas of a
4 consolidated business that are not owned or effectively owned by the consolidated
5 business shall be excluded from the property factor.

6 **Sec. 43.21.240. Applicability of tax to a consolidated business.** The
7 provisions of this chapter apply to a consolidated business whether or not the taxpayer
8 is the parent or controlling corporation.

9 **Article 2. Calculation of Tax; Returns.**

10 **Sec. 43.21.300. Assessment of income and tax.** (a) The department shall
11 assess taxable income and the amount of tax payable on that taxable income. The
12 amount of the tax payable shall be determined using the tax rates in AS 43.20.011(e).

13 (b) On or before August 15 of each year, the department shall send to every
14 corporation taxable under this chapter a notice of assessment showing the amount of
15 income taxable under this chapter for the previous year and the amount of tax payable
16 on that taxable income.

17 (c) For purposes of this chapter, the department may combine taxable income
18 of corporations subject to tax under this chapter who are part of the same consolidated
19 business.

20 (d) If the methods of allocation and apportionment provided in this chapter do
21 not fairly represent the extent of a corporation's business activity in the state, the
22 corporation may petition for or the department may require, in respect to all or any
23 part of the corporation's business activity, if reasonable, the employment of any
24 method authorized under art. IV, sec. 18, AS 43.19.010 (Multistate Tax Compact), to
25 carry out an equitable allocation and apportionment of the corporation's income. The
26 commissioner shall include in the annual report required in AS 43.21.410 a report on
27 all relief granted under this subsection, including, for each case, a statement of the
28 changes in tax liability resulting from the granting of relief, the tax years involved, and
29 a description of the method of determining taxable income that was substituted for the
30 methods provided in this chapter.

31 **Sec. 43.21.320. Credits.** A credit under AS 43.20.043, 43.20.044, or 43.20.046

1 may also be applied against the tax levied under this chapter, unless a credit for the
2 same expenditure has been taken against a tax levied under AS 43.20 or AS 43.55.

3 **Sec. 43.21.330. Returns.** On or before April 15 of each year, a corporation
4 subject to tax under this chapter shall submit a return in a form prescribed by the
5 department setting out information required by the department to determine taxable
6 income. For purposes of this chapter, the department may require corporations subject
7 to tax under this chapter that are part of the same consolidated business to file a single
8 return.

9 **Sec. 43.21.340. Payment of tax.** The tax levied under this chapter is payable
10 to the department on or before September 30 of each year or in installments, including
11 prepayments of estimated tax, at the times and under the conditions the department
12 may by regulation require. The tax is payable on the due date set out in this section
13 even though the assessment is under appeal or the validity, enforceability, or
14 application of this chapter or any provision of this chapter is challenged before the
15 department or in the courts.

16 **Article 3. Administrative Matters.**

17 **Sec. 43.21.400. Regulations.** The department shall adopt regulations in
18 accordance with AS 44.62 (Administrative Procedure Act) as appropriate to
19 administer and enforce this chapter.

20 **Sec. 43.21.410. Public reporting.** (a) The commissioner shall compile and
21 transmit to the legislature an annual report of state revenue and the implementation of
22 taxation policies under this chapter. The report must include total aggregate income
23 tax paid by corporations subject to this chapter and aggregate income and deductions
24 by category, classified so as to prevent the identification of particular returns or
25 reports.

26 (b) The legislative auditor shall notify the legislature on or before the first day
27 of each regular session that the annual report reviewing the actions of the department
28 in administering this chapter is available.

29 **Sec. 43.21.420. Information disclosure.** Notwithstanding AS 43.05.320, the
30 department shall disclose to a legislator, on request, information collected from a
31 taxpayer to the extent that

1 (1) the taxpayer is a publicly traded company;

2 (2) the information has been filed in a quarterly, annual, or other
3 periodic report to the United States Securities Exchange Commission; and

4 (3) the information has been made public by the United States
5 Securities Exchange Commission.

6 **Sec. 43.21.499. Definitions.** Unless the context requires otherwise, the
7 definitions contained in AS 43.55.900 are applicable to this chapter. In addition, in this
8 chapter,

9 (1) "consolidated business" means a corporation or group of
10 corporations having more than 50 percent common ownership, direct or indirect, or a
11 group of corporations in which there is common control, either direct or indirect, as
12 evidenced by an arrangement, contract, or agreement;

13 (2) "Internal Revenue Code" has the meaning given in AS 43.20.340."
14

15 Renumber the following sections accordingly.

16
17 Page 20, following line 29:

18 Insert new bill sections to read:

19 **** Sec. 21.** AS 43.82.210(a) is amended to read:

20 (a) If the commissioner approves an application and proposed project plan
21 under AS 43.82.140, the commissioner may develop proposed terms for inclusion in a
22 contract under AS 43.82.020 for periodic payment in lieu of one or more of the
23 following taxes that otherwise would be imposed by the state or a municipality on the
24 qualified sponsor or member of a qualified sponsor group as a consequence of
25 participating in an approved qualified project:

26 (1) oil and gas production taxes and oil surcharges under AS 43.55;

27 (2) oil and gas exploration, production, and pipeline transportation
28 property taxes under AS 43.56;

29 (3) **oil and gas corporate income tax under AS 43.21; [REPEALED]**

30 (4) Alaska net income tax under AS 43.20;

31 (5) municipal sales and use tax under AS 29.45.650 - 29.45.710;

1 (6) municipal property tax under AS 29.45.010 - 29.45.250 or
2 29.45.550 - 29.45.600;

3 (7) municipal special assessments under AS 29.46;

4 (8) a comparable tax or levy imposed by the state or a municipality
5 after June 18, 1998;

6 (9) other state or municipal taxes or categories of taxes identified by
7 the commissioner.

8 * **Sec. 22.** AS 43.20.072 is repealed."
9

10 Renumber the following bill sections accordingly.

11
12 Page 21, line 4:

13 Delete "sec. 3"

14 Insert "sec. 4"

15
16 Page 21, line 8, following "APPLICABILITY.":

17 Insert "(a)"
18

19 Page 21, line 9:

20 Delete "sec. 13"

21 Insert "sec. 18"
22

23 Page 21, following line 12:

24 Insert new material to read:

25 "(b) AS 43.21, added by sec. 9 of this Act, applies to taxable income earned or
26 received after December 31, 2012.

27 * **Sec. 25.** The uncodified law of the State of Alaska is amended by adding a new section to
28 read:

29 REGULATIONS. (a) The Department of Revenue may adopt regulations necessary to
30 implement AS 43.21, added by sec. 9 of this Act. The regulations take effect under AS 44.62
31 (Administrative Procedure Act), but not before the effective date of the law implemented by

1 regulation.

2 (b) The Department of Revenue shall provide by regulation for a transition for a
3 corporation subject to tax under AS 43.20 before December 31, 2012, to avoid double
4 taxation of the same income or double deduction of the same expense of the corporation as a
5 result of becoming subject to tax under AS 43.21, added by sec. 9 of this Act.

6 * **Sec. 26.** Section 25 of this Act takes effect immediately under AS 01.10.070(c)."
7

8 Renumber the following bill section accordingly.
9

10 Page 21, line 13:

11 Delete "This"

12 Insert "Except as provided in sec. 26 of this Act, this"

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, line 1, following "tax;":

2 Insert "relating to information concerning oil and gas taxes, including information
3 about expenditures that must be provided in order to claim an oil and gas production
4 tax credit for those expenditures, and relating to the disclosure of that information;"

5

6 Page 10, following line 22:

7 Insert new bill sections to read:

8 **"* Sec. 11.** AS 43.55.030(a) is amended to read:

9 (a) A producer that produces oil or gas from a lease or property in the state
10 during a calendar year, whether or not any tax payment is due under AS 43.55.020(a)
11 for that oil or gas, shall file with the department on March 31 of the following year a
12 statement, under oath, in a form prescribed by the department, giving, with other
13 information required by the department under a regulation adopted by the
14 department, the following:

15 (1) a description of each lease or property from which oil or gas was
16 produced, by name, legal description, lease number, or accounting codes assigned by
17 the department;

18 (2) the names of the producer and, if different, the person paying the
19 tax, if any;

20 (3) the gross amount of oil and the gross amount of gas produced from
21 each lease or property, and the percentage of the gross amount of oil and gas owned by
22 the producer;

23 (4) the gross value at the point of production of the oil and of the gas

1 produced from each lease or property owned by the producer and the costs of
2 transportation of the oil and gas;

3 (5) the name of the first purchaser and the price received for the oil and
4 for the gas, unless relieved from this requirement in whole or in part by the
5 department;

6 (6) the producer's qualified capital expenditures, as defined in
7 AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other
8 payments or credits under AS 43.55.170;

9 (7) the production tax values of the oil and gas under AS 43.55.160;

10 (8) any claims for tax credits to be applied; [AND]

11 (9) calculations showing the amounts, if any, that were or are due
12 under AS 43.55.020(a) and interest on any underpayment or overpayment; **and**

13 **(10) for each expenditure that is the basis for a credit claimed**
14 **under AS 43.55.023 or 43.55.025, a description of the expenditure, a detailed**
15 **description of the purpose of the expenditure, and a description of the lease or**
16 **property for which the expenditure was incurred; notwithstanding**
17 **AS 43.05.230(a), information submitted under this paragraph may be disclosed to**
18 **the public and shall be disclosed to the legislature in a report submitted within 10**
19 **days after the convening of the next regular legislative session following the date**
20 **a statement is filed under this section.**

21 * **Sec. 12.** AS 43.55.030(e) is amended to read:

22 (e) An explorer or producer that incurs a lease expenditure under
23 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
24 year but does not produce oil or gas from a lease or property in the state during the
25 calendar year shall file with the department on March 31 of the following year a
26 statement, under oath, in a form prescribed by the department, giving, with other
27 information required **by the department under a regulation adopted by the**
28 **department**, the following:

29 (1) the producer's qualified capital expenditures, as defined in
30 AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other
31 payments or credits under AS 43.55.170; [AND]

1 (2) if the explorer or producer receives a payment or credit under
 2 AS 43.55.170, calculations showing whether the explorer or producer is liable for a
 3 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount; **and**

4 **(3) for each expenditure that is the basis for a credit claimed under**
 5 **this chapter, a description of the expenditure, a detailed description of the**
 6 **purpose of the expenditure, and a description of the lease or property for which**
 7 **the expenditure was incurred; notwithstanding AS 43.05.230(a), information**
 8 **submitted under this paragraph may be disclosed to the public and shall be**
 9 **disclosed to the legislature in a report submitted within 10 days after the**
 10 **convening of the next regular legislative session following the date a statement is**
 11 **filed under this section.**"

12
 13 Renumber the following bill sections accordingly.

14
 15 Page 21, line 9:

16 Delete "sec. 13"

17 Insert "sec. 15"

18
 19 Page 21, following line 12:

20 Insert a new bill section to read:

21 **"* Sec. 20. Sections 11 and 12 of this Act take effect July 1, 2012."**

22
 23 Renumber the following bill section accordingly.

24
 25 Page 21, line 13:

26 Delete "This"

27 Insert "Except as provided in sec. 20 of this Act, this"

A M E N D M E N T

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 2, line 10, following "gas;":

2 Insert "**establishing the Oil and Gas Competitiveness Review Board;**"

3

4 Page 20, following line 29:

5 Insert new bill sections to read:

6 **"* Sec. 16.** AS 44.99 is amended by adding new sections to read:

7 **Article 6. Oil and Gas Competitiveness Review Board.**

8 **Sec. 44.99.600. Oil and Gas Competitiveness Review Board established.** (a)

9 The Oil and Gas Competitiveness Review Board is established.

10 (b) The board shall consist of nine members as follows:

11 (1) one senator appointed by the president of the senate;

12 (2) one representative appointed by the speaker of the house of
13 representatives;

14 (3) five members of the public appointed by the governor, including
15 one member who is a petroleum engineer, one member who is a geologist, one
16 member who is an economist, and one member who is a member of an environmental
17 or conservation group;

18 (4) the commissioner of natural resources or the commissioner's
19 designee; and

20 (5) the commissioner of revenue or the commissioner's designee.

21 (c) The senator and representative appointed to the board under (b)(1) and (2)
22 of this section shall be cochairs.

23 (d) Each legislative member serves for the duration of the legislature during

1 which the member is appointed. Each public member serves for three years. An
2 individual who has served on the board may be reappointed.

3 (e) A vacancy on the board shall be filled in the manner of the original
4 appointment.

5 (f) A member of the board may be removed and replaced at the discretion of
6 the person appointing that member.

7 (g) The public members of the board serve without compensation but shall
8 receive per diem and travel expenses authorized for boards and commissions under
9 AS 39.20.180.

10 (h) The board may enter into contracts for professional services and may
11 employ staff for administrative support for the board.

12 **Sec. 44.99.610. Duties.** The duties of the board include the following:

13 (1) review historical, current, and potential levels of investment in the
14 state's oil and gas sector;

15 (2) identify factors that affect investment in oil and gas exploration,
16 development, and production in the state, including tax structure, rates, and credits;
17 royalty requirements; infrastructure; workforce availability; and regulatory
18 requirements;

19 (3) review the competitive position of the state to attract and maintain
20 investment in the oil and gas sector in the state as compared to the competitive
21 position of other regions with oil and gas resources;

22 (4) in order to facilitate the work of the board, establish procedures to
23 accept and keep confidential information that is beneficial to the work of the board,
24 including the creation of a secure data room and confidentiality agreements to be
25 signed by individuals having access to the confidential information;

26 (5) make written findings and recommendations, together with
27 suggested legislation, to the Alaska State Legislature before December 1 of each year,
28 or as soon thereafter as practicable, regarding

29 (A) changes to the state's regulatory environment that would be
30 conducive to encouraging increased investment while protecting the interests
31 of the people of the state and the environment;

1 (B) changes to the state's fiscal regime that would be conducive
 2 to increased and ongoing long-term investment in and development of the
 3 state's oil and gas resources; and

4 (C) alternative means for increasing the state's ability to attract
 5 and maintain investment in and development of the state's oil and gas
 6 resources.

7 **Sec. 44.99.620. Information to be provided to board.** (a) The commissioner
 8 of natural resources, the commissioner of revenue, the commissioner of environmental
 9 conservation, and other commissioners and state agencies that have responsibility for
 10 and maintain information related to oil and gas investment and activity in the state
 11 shall, at the request of the board, provide information required by the board to carry
 12 out the duties described in AS 44.99.610.

13 (b) At the request of the board, and except for information that is confidential
 14 under AS 43.05.230, a commissioner may disclose to the board information that is
 15 otherwise confidential after each member of the board and each staff member for the
 16 board with access to the information signs a confidentiality agreement prepared by the
 17 commissioner making the disclosure. Information that is confidential under
 18 AS 43.05.230 may not be disclosed to the board.

19 **Sec. 44.99.630. Definition.** In AS 44.99.600 - 44.99.630, "board" means the
 20 Oil and Gas Competitiveness Review Board.

21 * **Sec. 17.** AS 44.99.600, 44.99.610, 44.99.620, and 44.99.630 are repealed June 30, 2021."
 22

23 Renumber the following bill sections accordingly.

24
 25 Page 21, following line 12:

26 Insert a new bill section to read:

27 "** **Sec. 20.** Sections 16 and 17 of this Act take effect immediately under AS 01.10.070(c)."
 28

29 Renumber the following bill section accordingly.

30
 31 Page 21, line 13:

1

Delete "This"

2

Insert "Except as provided in sec. 20 of this Act, this"

A M E N D M E N T

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, lines 2 - 9:

2 Delete "providing that the tax rate applicable to the production of oil as the
3 average production tax value of oil, gas produced in the Cook Inlet sedimentary basin,
4 and gas produced outside of the Cook Inlet sedimentary basin and used in the state
5 increases above \$30 shall be 0.35 percent multiplied by the number that represents the
6 difference between that average monthly production tax value and \$30, or the sum of 25
7 percent and the product of 0.1 percent multiplied by the number that represents the
8 difference between that average monthly production tax value and \$101.43, except that
9 the total rate determined in the calculation may not exceed 35 percent;"

10 Insert "relating to the tax rate applicable to oil production as the average
11 production tax value of oil, gas produced in the Cook Inlet sedimentary basin, and gas
12 produced outside of the Cook Inlet sedimentary basin and used in the state increases
13 above \$30, \$42.50, \$55, \$67.50, \$80, \$92.50, \$105, and \$117.50;"

14

15 Page 5, line 28, through page 7, line 5:

16 Delete all material and insert:

17 **** Sec. 7.** AS 43.55.011(g) is repealed and reenacted to read:

18 (g) For each month of the calendar year for which the producer's average
19 monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent
20 barrel of taxable oil and gas is more than \$30, the amount of tax for purposes of
21 (e)(2)(A) of this section is determined by multiplying the monthly production tax
22 value of the taxable oil produced during the month, gas produced during the month
23 from a lease or property in the Cook Inlet sedimentary basin, and gas produced during

1 the month from a lease or property outside the Cook Inlet sedimentary basin and used
2 in the state by the following tax rates, as applicable:

3 (1) if the producer's average monthly production tax value under
4 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil and gas for the
5 month is not more than \$42.50 under AS 43.55.160(a)(2)(A) - (E), the tax rate is 2.5
6 percent of the difference between that average monthly production tax value of a BTU
7 equivalent barrel and \$30;

8 (2) if the producer's average monthly production tax value under
9 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the taxable oil and gas for
10 the month is more than \$42.50 but not more than \$55 under AS 43.55.160(a)(2)(A) -
11 (E), the tax rates are

12 (A) 2.5 percent on the first \$12.50 of monthly production tax
13 value for each BTU equivalent barrel that is greater than \$30; and

14 (B) 7.5 percent of the monthly production tax value for each
15 BTU equivalent barrel that is greater than \$42.50;

16 (3) if the producer's average monthly production tax value under
17 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the taxable oil and gas for
18 the month is more than \$55 but not more than \$67.50 under AS 43.55.160(a)(2)(A) -
19 (E), the tax rates are

20 (A) 2.5 percent on the first \$12.50 of monthly production tax
21 value for each BTU equivalent barrel that is greater than \$30;

22 (B) 7.5 percent of the next higher \$12.50 of monthly
23 production tax value for each BTU equivalent barrel; and

24 (C) 12.5 percent of the monthly production tax value for each
25 BTU equivalent barrel that is greater than \$55;

26 (4) if the producer's average monthly production tax value under
27 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the taxable oil and gas for
28 the month is more than \$67.50 but not more than \$80 under AS 43.55.160(a)(2)(A) -
29 (E), the tax rates are

30 (A) 2.5 percent on the first \$12.50 of monthly production tax
31 value for each BTU equivalent barrel that is greater than \$30;

1 (B) 7.5 percent of the next higher \$12.50 of monthly
2 production tax value for each BTU equivalent barrel;

3 (C) 12.5 percent of the next higher \$12.50 of monthly
4 production tax value for each BTU equivalent barrel; and

5 (D) 17.5 percent of the monthly production tax value for each
6 BTU equivalent barrel that is greater than \$67.50;

7 (5) if the producer's average monthly production tax value under
8 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the taxable oil and gas for
9 the month is more than \$80 but not more than \$92.50 under AS 43.55.160(a)(2)(A) -
10 (E), the tax rates are

11 (A) 2.5 percent on the first \$12.50 of monthly production tax
12 value for each BTU equivalent barrel that is greater than \$30;

13 (B) 7.5 percent of the next higher \$12.50 of monthly
14 production tax value for each BTU equivalent barrel;

15 (C) 12.5 percent of the next higher \$12.50 of monthly
16 production tax value for each BTU equivalent barrel;

17 (D) 17.5 percent of the next higher \$12.50 of monthly
18 production tax value for each BTU equivalent barrel; and

19 (E) 22.5 percent of the monthly production tax value for each
20 BTU equivalent barrel that is greater than \$80;

21 (6) if the producer's average monthly production tax value under
22 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the taxable oil and gas for
23 the month is more than \$92.50 but not more than \$105 under AS 43.55.160(a)(2)(A) -
24 (E), the tax rates are

25 (A) 2.5 percent on the first \$12.50 of monthly production tax
26 value for each BTU equivalent barrel that is greater than \$30;

27 (B) 7.5 percent of the next higher \$12.50 of monthly
28 production tax value for each BTU equivalent barrel;

29 (C) 12.5 percent of the next higher \$12.50 of monthly
30 production tax value for each BTU equivalent barrel;

31 (D) 17.5 percent of the next higher \$12.50 of monthly

1 production tax value for each BTU equivalent barrel;

2 (E) 22.5 percent of the next higher \$12.50 of monthly
3 production tax value for each BTU equivalent barrel; and

4 (F) 25 percent of the monthly production tax value for each
5 BTU equivalent barrel that is greater than \$92.50;

6 (7) if the producer's average monthly production tax value under
7 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the taxable oil and gas for
8 the month is more than \$105 but not more than \$117.50 under AS 43.55.160(a)(2)(A)
9 - (E), the tax rates are

10 (A) 2.5 percent on the first \$12.50 of monthly production tax
11 value for each BTU equivalent barrel that is greater than \$30;

12 (B) 7.5 percent of the next higher \$12.50 of monthly
13 production tax value for each BTU equivalent barrel;

14 (C) 12.5 percent of the next higher \$12.50 of monthly
15 production tax value for each BTU equivalent barrel;

16 (D) 17.5 percent of the next higher \$12.50 of monthly
17 production tax value for each BTU equivalent barrel;

18 (E) 22.5 percent of the next higher \$12.50 of monthly
19 production tax value for each BTU equivalent barrel;

20 (F) 25 percent of the next higher \$12.50 of monthly production
21 tax value for each BTU equivalent barrel; and

22 (G) 30 percent of the monthly production tax value for each
23 BTU equivalent barrel that is greater than \$105;

24 (8) if the producer's average monthly production tax value under
25 AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the taxable oil and gas for
26 the month is more than \$117.50 under AS 43.55.160(a)(2)(A) - (E), the tax rates are

27 (A) 2.5 percent on the first \$12.50 of monthly production tax
28 value for each BTU equivalent barrel that is greater than \$30;

29 (B) 7.5 percent of the next higher \$12.50 of monthly
30 production tax value for each BTU equivalent barrel;

31 (C) 12.5 percent of the next higher \$12.50 of monthly

1 production tax value for each BTU equivalent barrel;

2 (D) 17.5 percent of the next higher \$12.50 of monthly
3 production tax value for each BTU equivalent barrel;

4 (E) 22.5 percent of the next higher \$12.50 of monthly
5 production tax value for each BTU equivalent barrel;

6 (F) 25 percent of the next higher \$12.50 of monthly production
7 tax value for each BTU equivalent barrel;

8 (G) 30 percent of the next higher \$12.50 of monthly production
9 tax value for each BTU equivalent barrel; and

10 (H) 35 percent of the monthly production tax value for each
11 BTU equivalent barrel that is greater than \$117.50;

12 (9) for purposes of this subsection, the average monthly production tax
13 value under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil and
14 gas is calculated by

15 (A) adding all of the monthly production tax values determined
16 under AS 43.55.160(a)(2)(A) - (E); and

17 (B) dividing the sum calculated under (A) of this paragraph by
18 the total amount, in BTU equivalent barrels, of

19 (i) taxable oil produced by the producer during the
20 month;

21 (ii) taxable gas produced by the producer during the
22 month from a lease or property in the Cook Inlet sedimentary basin;
23 and

24 (iii) taxable gas produced by the producer during the
25 month from a lease or property outside the Cook Inlet sedimentary
26 basin and used in the state."

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 2, line 1, following "tax":

2 Insert "rate; relating to oil and gas production tax credits, including qualified
3 credits for exploration, development and production"
4

5 Page 4, line 29, through page 5, line 9:

6 Delete all material and insert:

7 "* Sec. 5. AS 43.55.011(e) is repealed and reenacted to read:

8 (e) There is levied on the producer of oil or gas a tax for all oil and gas
9 produced each calendar year from each lease or property in the state, less any oil and
10 gas the ownership or right to which is exempt from taxation or constitutes a
11 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
12 this section, the tax is equal to the sum of the annual production tax value of the
13 taxable oil and gas

14 (1) produced from a lease or property not described in (2) of this
15 subsection as calculated under AS 43.55.160(a)(1) multiplied by 25 percent, and the
16 sum, over all months of the calendar year, of the tax amounts determined under (g)(1)
17 and (p) of this section, as applicable; and

18 (2) produced during the first seven consecutive years after the start of
19 sustained production or produced during the first seven years after the effective date of
20 this subsection, whichever is later, from a lease or property containing land that was
21 not or previously had not been within a unit or in commercial production as of
22 December 31, 2008, as calculated under AS 43.55.160(a)(1) multiplied by 15 percent,
23 and the sum, over all months of the calendar year, of the tax amounts determined

1 under (g)(2) and (p) of this section, as applicable; in this paragraph, "sustained
2 production" has the meaning given in AS 43.55.025(l)."
3

4 Page 5, line 28, through page 7, line 5:

5 Delete all material and insert:

6 **"* Sec. 7.** AS 43.55.011(g) is repealed and reenacted to read:

7 (g) For each month of the calendar year for which the producer's average
8 monthly production tax value calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU
9 equivalent barrel of taxable oil produced during the month, gas produced during the
10 month from a lease or property in the Cook Inlet sedimentary basin, and gas produced
11 during the month from a lease or property outside the Cook Inlet sedimentary basin
12 and used in the state is more than \$30, the tax is calculated as follows:

13 (1) the amount of tax for purposes of (e)(1) of this section is determined
14 by multiplying the value calculated under AS 43.55.160(a)(2)(A) - (E) by the tax rate
15 calculated as follows:

16 (A) if the producer's average monthly production tax value
17 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the
18 taxable oil and gas for the month is not more than \$92.50, the tax rate is 0.4
19 percent multiplied by the number that represents the difference between that
20 average monthly production tax value of a BTU equivalent barrel and \$30; or

21 (B) if the producer's average monthly production tax value
22 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the
23 taxable oil and gas for the month is more than \$92.50, the tax rate is the sum of
24 25 percent and the product of 0.1 percent multiplied by the number that
25 represents the difference between the average monthly production tax value
26 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel and
27 \$92.50, except that the sum determined under this subparagraph may not
28 exceed 50 percent;

29 (2) the amount of tax for purposes of (e)(2) of this section is
30 determined by multiplying the monthly production tax value calculated under
31 AS 43.55.160(a)(2)(A) - (E) of the taxable oil and gas produced during the month by

1 the following tax rates, as applicable:

2 (A) if the producer's average monthly production tax value
3 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the
4 taxable oil and gas for the month is not more than \$42.50, the tax rate is 2.5
5 percent of the difference between that average monthly production tax value of
6 a BTU equivalent barrel and \$30;

7 (B) if the producer's average monthly production tax value
8 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the
9 taxable oil and gas for the month is more than \$42.50 but not more than \$55,
10 the tax rates are

11 (i) 2.5 percent on the first \$12.50 of monthly production
12 tax value calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU
13 equivalent barrel that is greater than \$30; and

14 (ii) 7.5 percent of the monthly production tax value
15 calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU equivalent
16 barrel that is greater than \$42.50;

17 (C) if the producer's average monthly production tax value
18 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the
19 taxable oil and gas for the month is more than \$55 but not more than \$67.50,
20 the tax rates are

21 (i) 2.5 percent on the first \$12.50 of monthly production
22 tax value calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU
23 equivalent barrel that is greater than \$30;

24 (ii) 7.5 percent of the next higher \$12.50 of monthly
25 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
26 each BTU equivalent barrel; and

27 (iii) 12.5 percent of the monthly production tax value
28 calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU equivalent
29 barrel that is greater than \$55;

30 (D) if the producer's average monthly production tax value
31 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the

1 taxable oil and gas for the month is more than \$67.50 but not more than \$80,
2 the tax rates are

3 (i) 2.5 percent on the first \$12.50 of monthly production
4 tax value calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU
5 equivalent barrel that is greater than \$30;

6 (ii) 7.5 percent of the next higher \$12.50 of monthly
7 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
8 each BTU equivalent barrel;

9 (iii) 12.5 percent of the next higher \$12.50 of monthly
10 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
11 each BTU equivalent barrel;

12 (iv) 17.5 percent of the monthly production tax value
13 calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU equivalent
14 barrel that is greater than \$67.50;

15 (E) if the producer's average monthly production tax value
16 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the
17 taxable oil and gas for the month is more than \$80 but not more than \$92.50,
18 the tax rates are

19 (i) 2.5 percent on the first \$12.50 of monthly production
20 tax value calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU
21 equivalent barrel that is greater than \$30;

22 (ii) 7.5 percent of the next higher \$12.50 of monthly
23 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
24 each BTU equivalent barrel;

25 (iii) 12.5 percent of the next higher \$12.50 of monthly
26 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
27 each BTU equivalent barrel;

28 (iv) 17.5 percent of the next higher \$12.50 of monthly
29 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
30 each BTU equivalent barrel; and

31 (v) 22.5 percent of the monthly production tax value

1 calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU equivalent
2 barrel that is greater than \$80;

3 (F) if the producer's average monthly production tax value
4 calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of the
5 taxable oil and gas for the month is more than \$92.50, the tax rates are

6 (i) 2.5 percent on the first \$12.50 of monthly production
7 tax value calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU
8 equivalent barrel that is greater than \$30;

9 (ii) 7.5 percent of the next higher \$12.50 of monthly
10 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
11 each BTU equivalent barrel;

12 (iii) 12.5 percent of the next higher \$12.50 of monthly
13 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
14 each BTU equivalent barrel;

15 (iv) 17.5 percent of the next higher \$12.50 of monthly
16 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
17 each BTU equivalent barrel;

18 (v) 22.5 percent of the next higher \$12.50 of monthly
19 production tax value calculated under AS 43.55.160(a)(2)(A) - (E) for
20 each BTU equivalent barrel; and

21 (vi) 25 percent of the monthly production tax value
22 calculated under AS 43.55.160(a)(2)(A) - (E) for each BTU equivalent
23 barrel that is greater than \$92.50;

24 (3) for purposes of this subsection, the average monthly production tax
25 value calculated under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of
26 taxable oil and gas is calculated by

27 (A) adding all of the monthly production tax values determined
28 calculated under AS 43.55.160(a)(2)(A) - (E); and

29 (B) dividing the sum calculated under (A) of this paragraph by
30 the total amount, in BTU equivalent barrels, of

31 (i) taxable oil produced by the producer during the

1 month;

2 (ii) taxable gas produced by the producer during the
3 month from a lease or property in the Cook Inlet sedimentary basin;
4 and

5 (iii) taxable gas produced by the producer during the
6 month from a lease or property outside the Cook Inlet sedimentary
7 basin and used in the state."
8

9 Page 8, line 19, following "percent":

10 Insert ", or 15 percent, as applicable under AS 43.55.011(e),"

11

12 Page 8, line 20:

13 Delete "AS 43.55.011(g)"

14 Insert "AS 43.55.011(g)(1) or (2), as applicable"

15

16 Page 8, line 22, following "percent":

17 Insert ", or 15 percent, as applicable under AS 43.55.011(e),"

18

19 Page 9, line 1, following "percent":

20 Insert ", or 15 percent, as applicable under AS 43.55.011(e),"

21

22 Page 9, line 2:

23 Delete "AS 43.55.011(g)"

24 Insert "AS 43.55.011(g)(1) or (2), as applicable"

25

26 Page 9, line 4, following "percent":

27 Insert ", or 15 percent, as applicable under AS 43.55.011(e)"

28

29 Page 9, line 10:

30 Following "percent":

31 Insert ", or 15 percent, as applicable under AS 43.55.011(e),"

1

Delete "AS 43.55.011(g)"

2

Insert "AS 43.55.011(g)(1) or (2), as applicable"

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

1 Page 1, line 5:

2 Delete "0.35"

3 Insert "0.4"

4

5 Page 1, line 8:

6 Delete "\$101.43"

7 Insert "\$92.50"

8

9 Page 6, line 9:

10 Delete "\$101.43 [\$92.50], the tax rate is 0.35 [0.4]"

11 Insert "\$92.50, the tax rate is 0.4"

12

13 Page 6, line 16:

14 Delete "\$101.43 [\$92.50]"

15 Insert "\$92.50"

16

17 Page 6, line 20:

18 Delete "\$101.43 [\$92.50]"

19 Insert "\$92.50"

AMENDMENT

OFFERED IN THE SENATE

TO: CSSB 192(RES), Draft Version "E"

- 1 Page 1, line 5:
2 Delete "**0.35**"
3 Insert "**0.4**"
4
5 Page 1, line 6:
6 Delete "**25**"
7 Insert "**15**"
8
9 Page 1, line 7:
10 Delete "**0.1**"
11 Insert "**0.35**"
12
13 Page 1, line 8:
14 Delete "**\$101.43**"
15 Insert "**\$67.50, or the sum of 23.75 percent and the product of 0.1 percent**
16 **multiplied by the number that represents the difference between the average monthly**
17 **production tax and \$92.50**"
18
19 Page 6, line 9:
20 Delete "**\$101.43**"
21 Insert "**\$67.50**"
22 Delete "**0.35** [0.4]"
23 Insert "0.4"

1

2 Page 6, line 16:

3 Delete "\$101.43 [\$92.50]"4 Insert "\$67.50 but is not more than \$92.50"

5 Delete "25"

6 Insert "15 [25]"

7

8 Page 6, line 17:

9 Delete "0.1"

10 Insert "0.35 [0.1]"

11

12 Page 6, line 20:

13 Delete "\$101.43 [\$92.50]"14 Insert "\$67.50; or

15 (3) if the producer's average monthly production tax value of a
16 BTU equivalent barrel of taxable oil and gas for the month is more than \$92.50,
17 the tax rate is the sum of 23.75 percent and the product of 0.1 percent multiplied
18 by the number that represents the difference between the average monthly
19 production tax value of a BTU equivalent barrel and \$92.50"

20

21 Renumber the following paragraph accordingly.

Library



CSSB 192\B and Proposed Amendments



*Presentation to the
Senate Resources Committee
Department of Revenue
February 27, 2012*



Presentation Organization



- Modeling and discussion of CSSB 192\B
- Modeling and discussion of amendments



CS SB 192\B

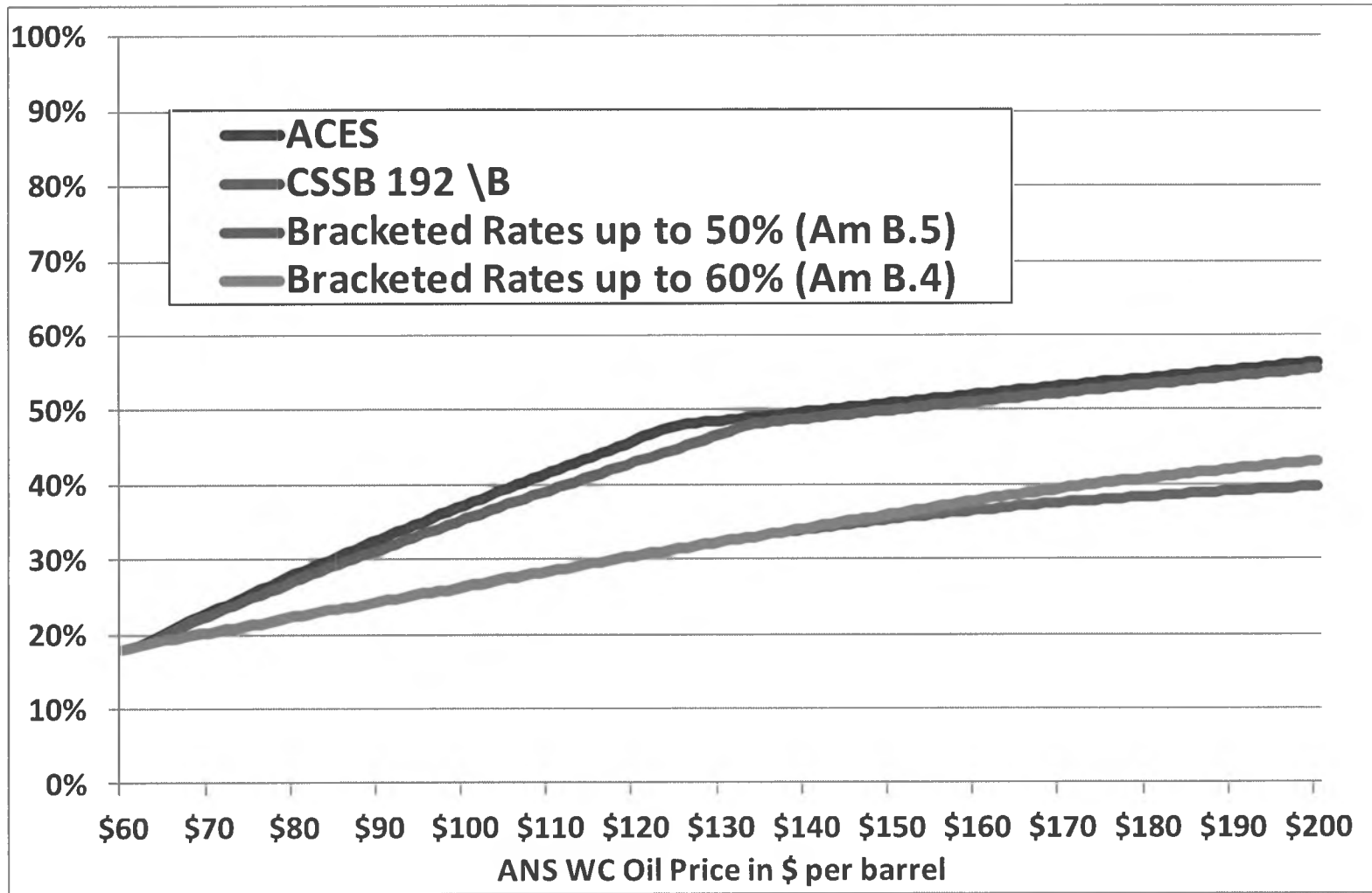


What the CS does as currently written

1. Changes the progressivity rate over \$30 / barrel production tax value from 0.4% to 0.35%
2. Changes the trigger point that slows the rate of progressivity to 0.1%, from \$92.50 to \$101.43 / barrel production tax value
3. Changes the maximum production tax rate from 75% to 60% (would apply over \$201.43 / barrel production tax value)
4. Provides a modest reduction in taxes compared to our Fall 2011 forecast



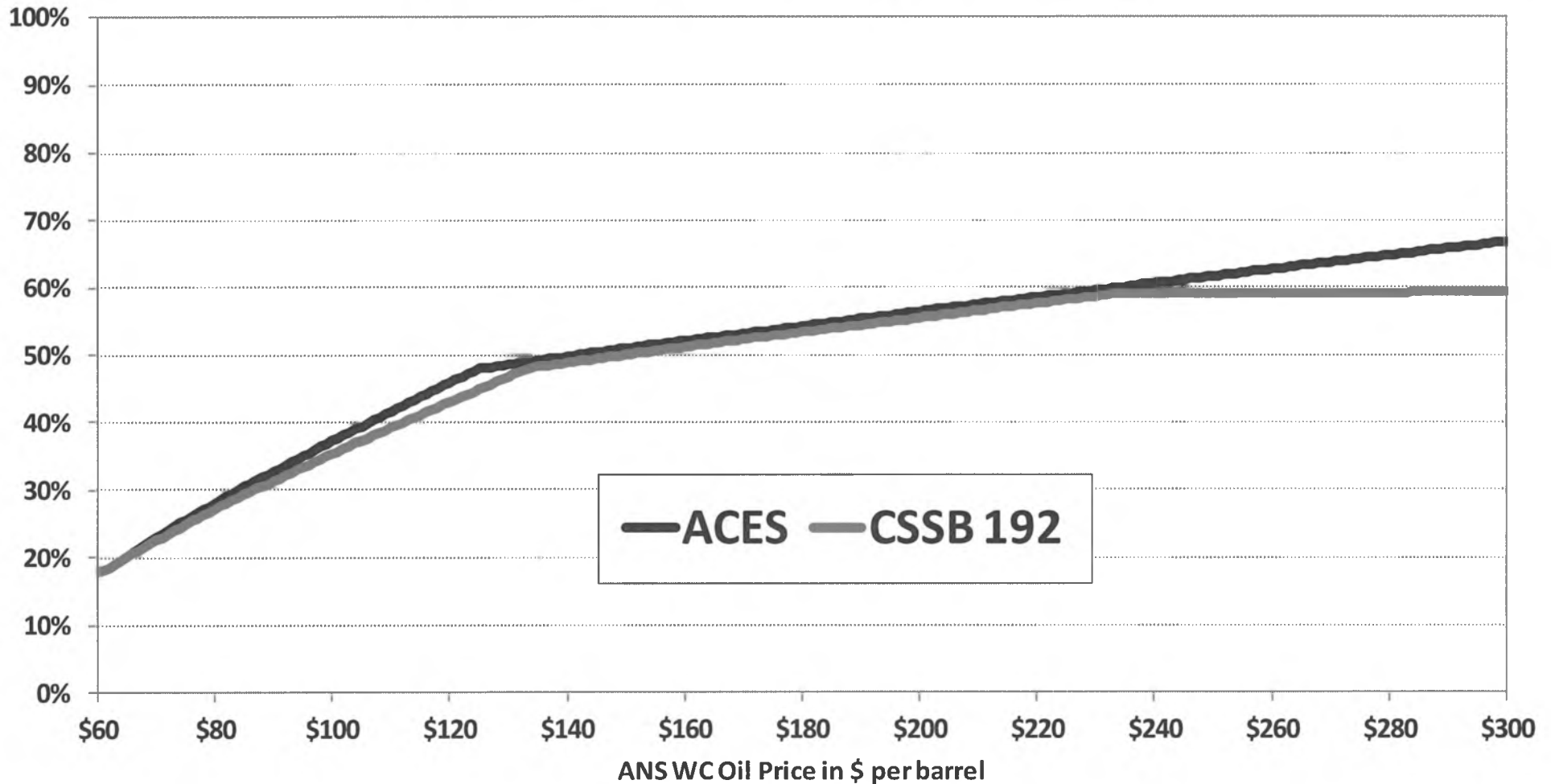
Effective Production Tax Rates: Comparisons



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



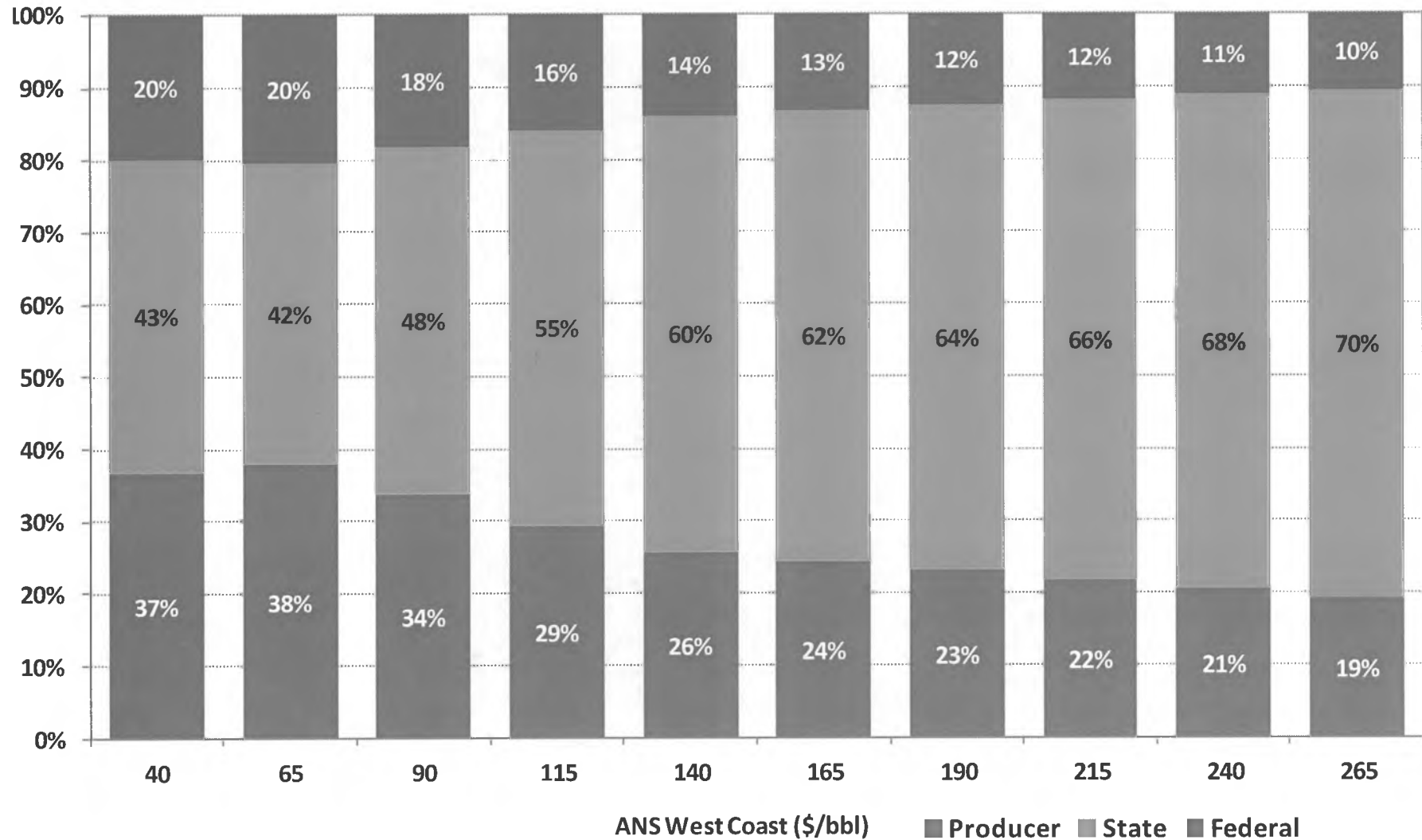
Effective Production Tax Rates: ACES and CSSB 192\B



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



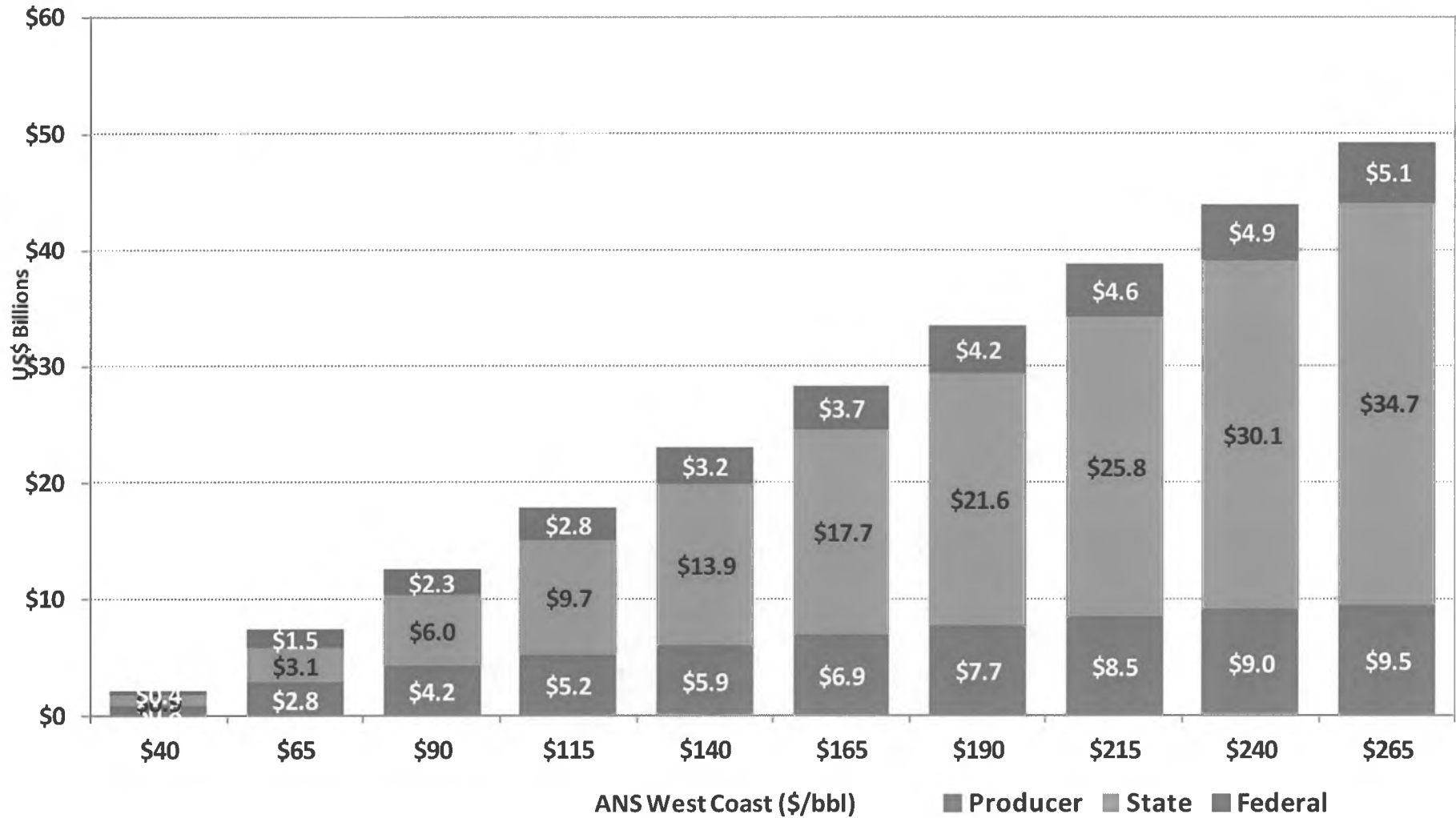
Share of Profit under CSSB 192\B



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



Absolute Profit under 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.



Amendment B.5

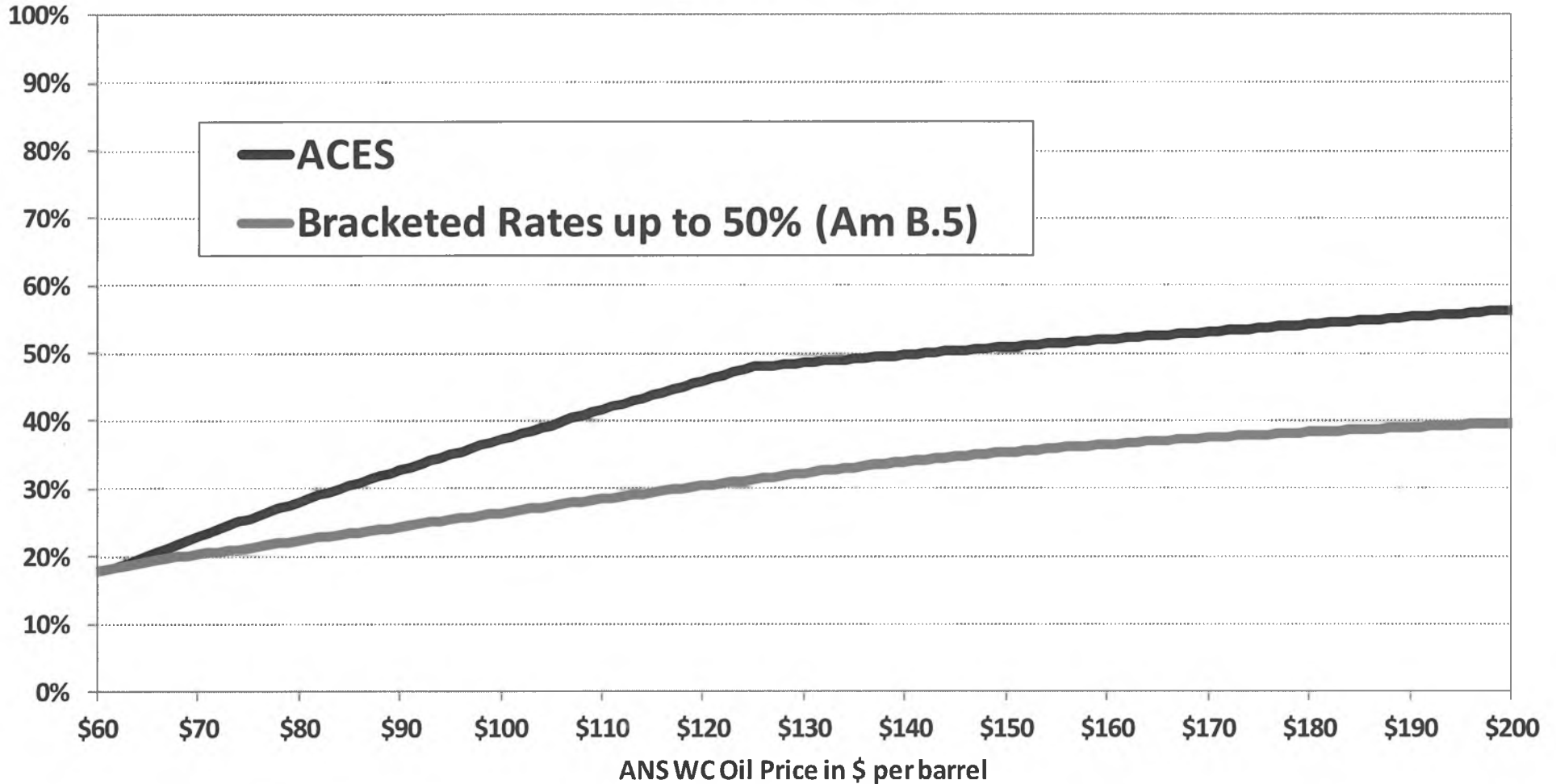


Progressivity bracketed – 25% top bracket

1. Provides “tax brackets” for progressivity, with the progressively higher rate only applying to the value within that tax bracket
2. Generally follows existing progressivity slope
3. Top bracket is 25% progressivity (50% tax rate)
4. Maximum production tax rate of 50% (would apply over \$92.50 / barrel production tax value)



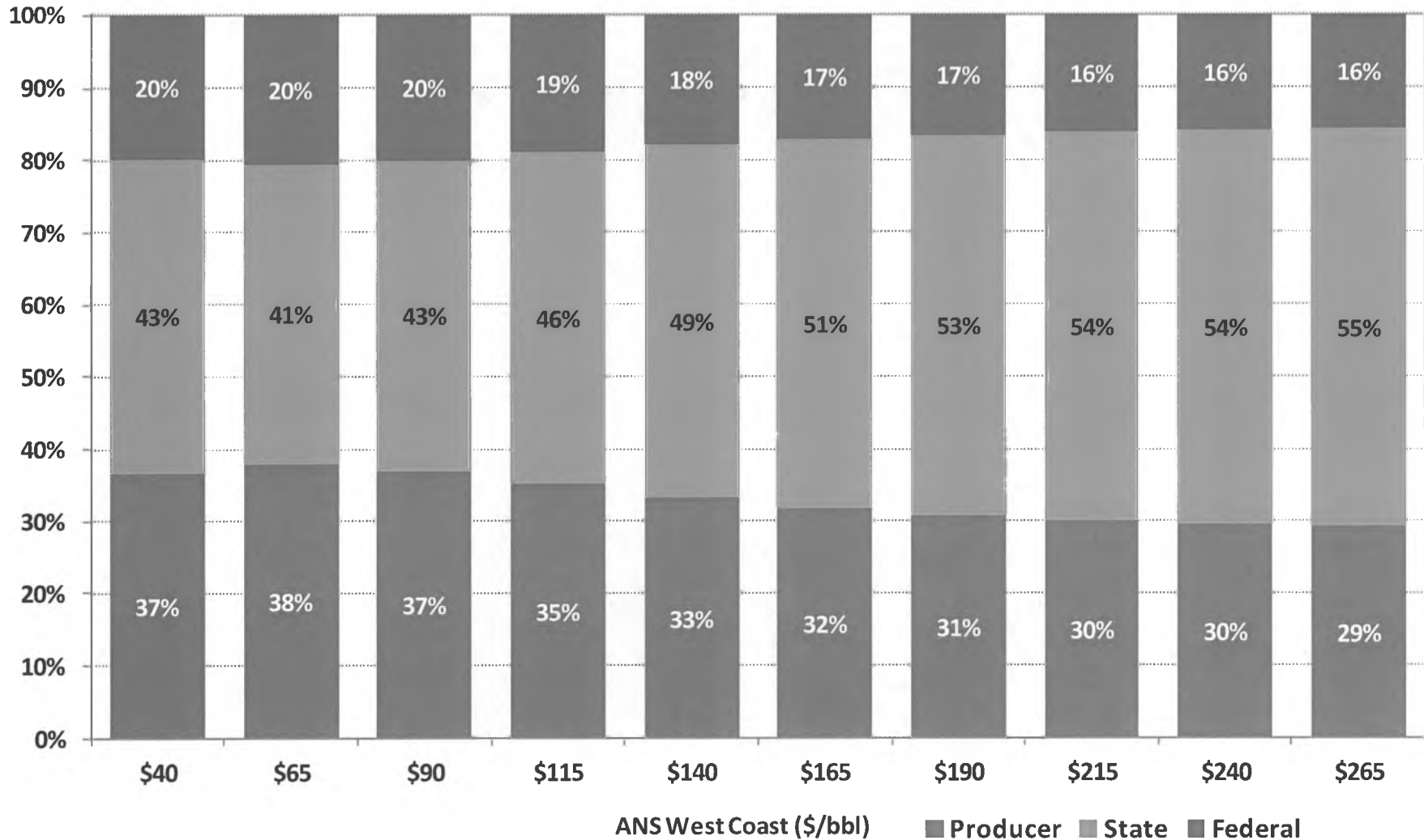
Effective Production Tax Rates: ACES and Bracketed Rates up to 50% (Am B.5)



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



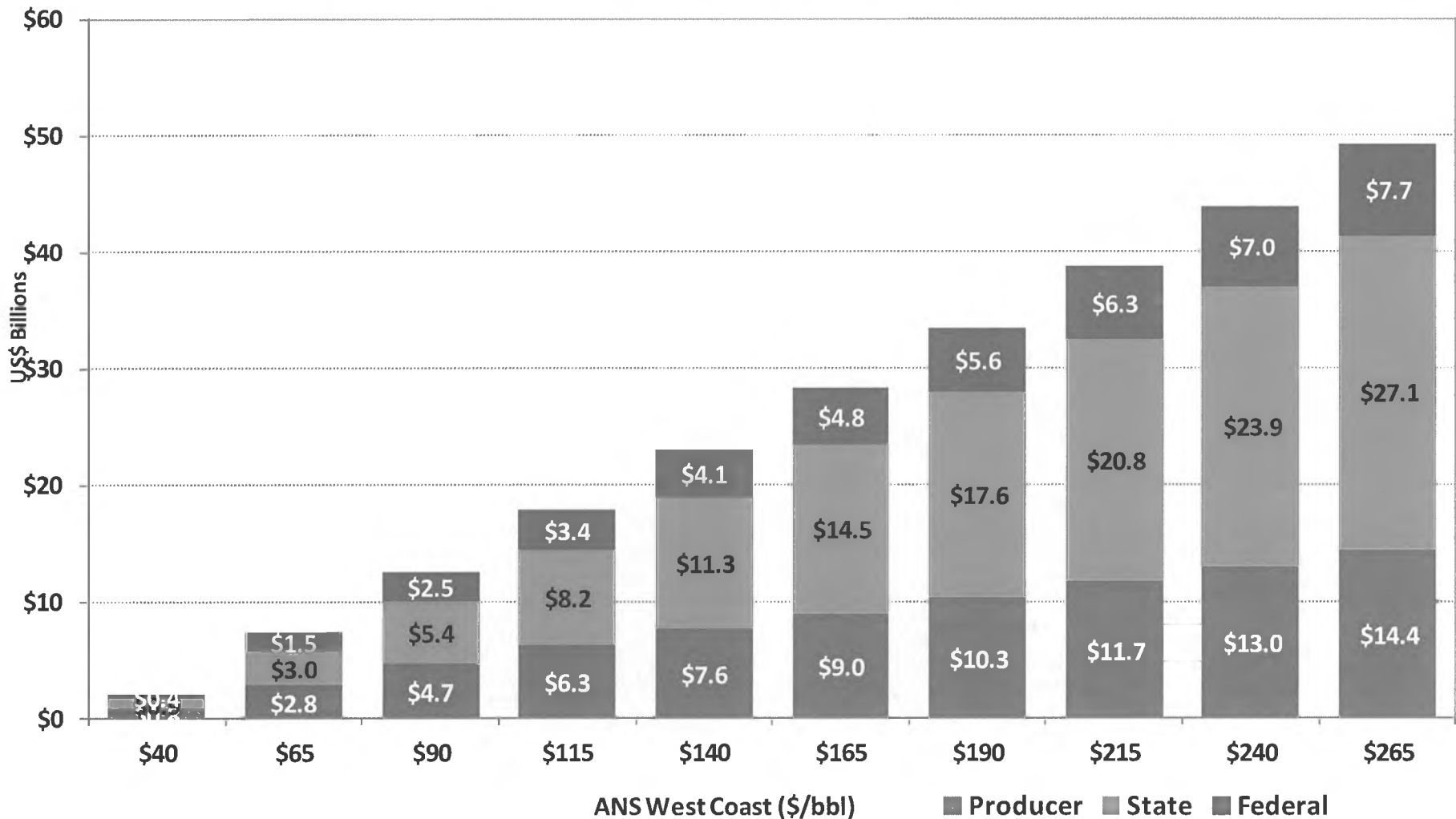
Share of Profit under Bracketed Rates up to 50% (Am B.5)



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



Absolute Profit under 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.



Amendment B.4

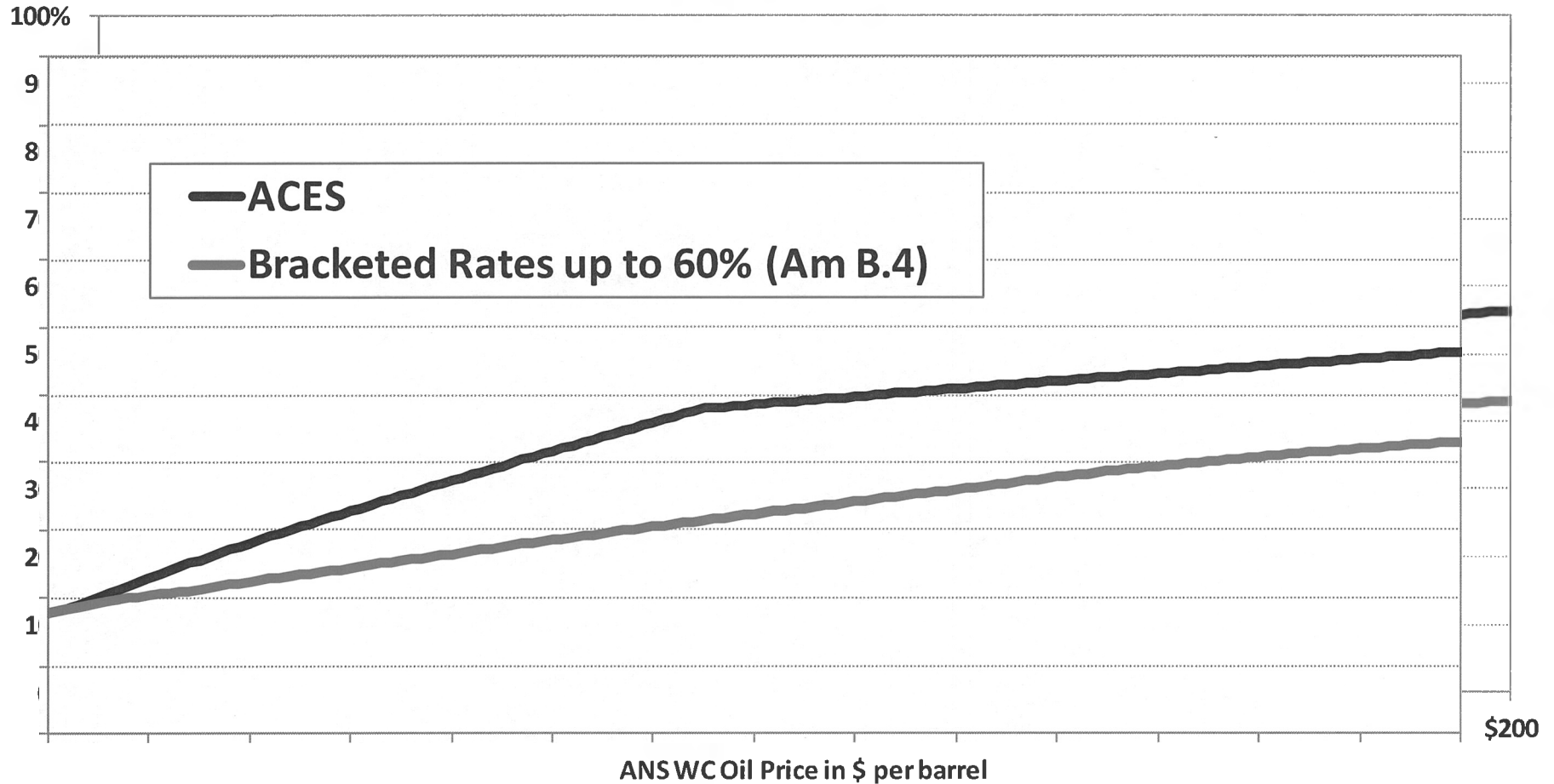


Progressivity bracketed – 35% top bracket

1. Provides “tax brackets” for progressivity, with the progressively higher rate only applying to the value within that tax bracket
2. Generally follows existing progressivity slope
3. Top bracket is 35% progressivity (60% tax rate)
4. Maximum production tax rate of 60% (would apply over \$92.50 / barrel production tax value)



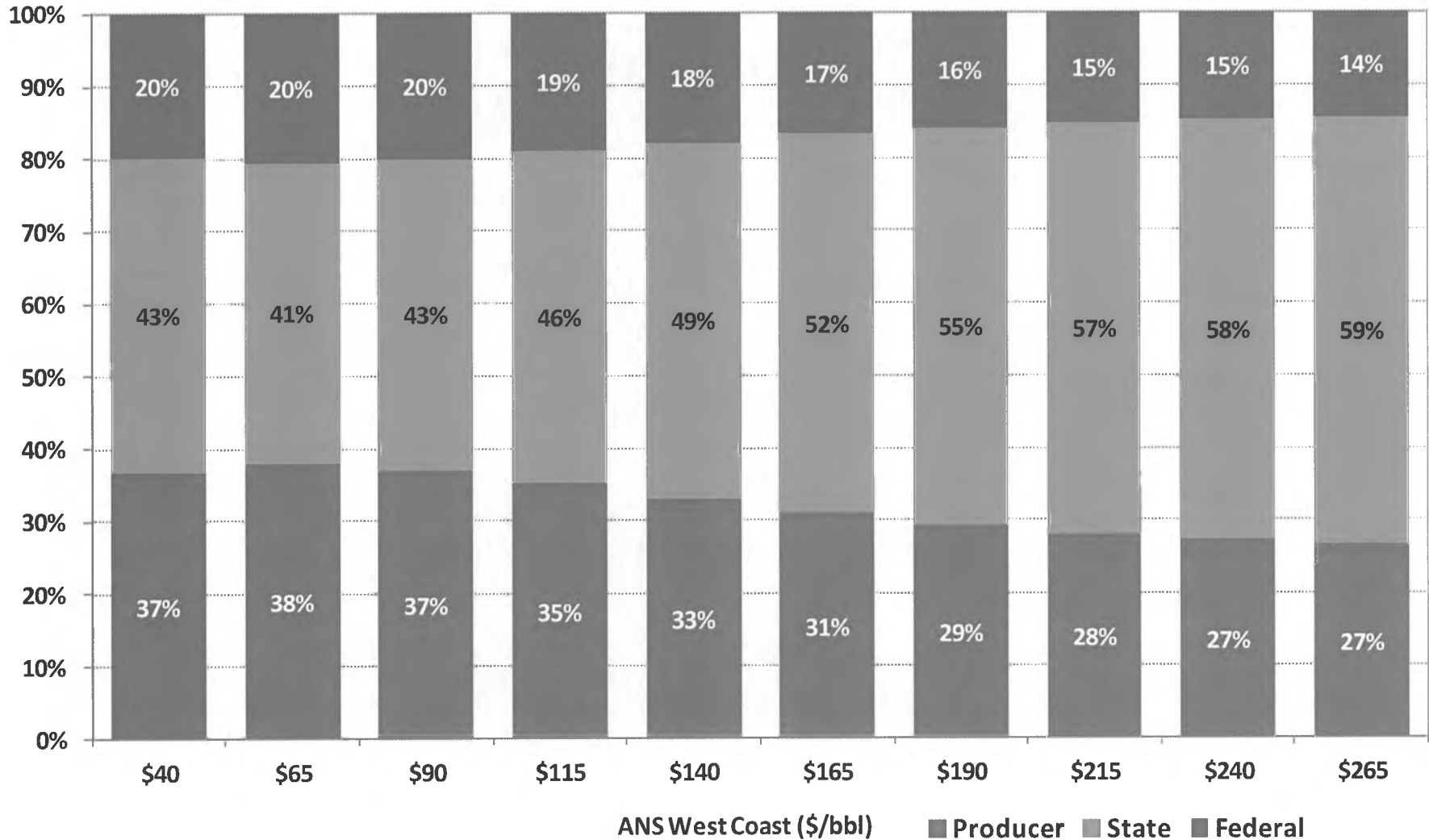
Effective Production Tax Rates: ACES and Bracketed Rates up to 60% (Am B.4)



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



Share of Profit under 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.



Absolute Profit under 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.



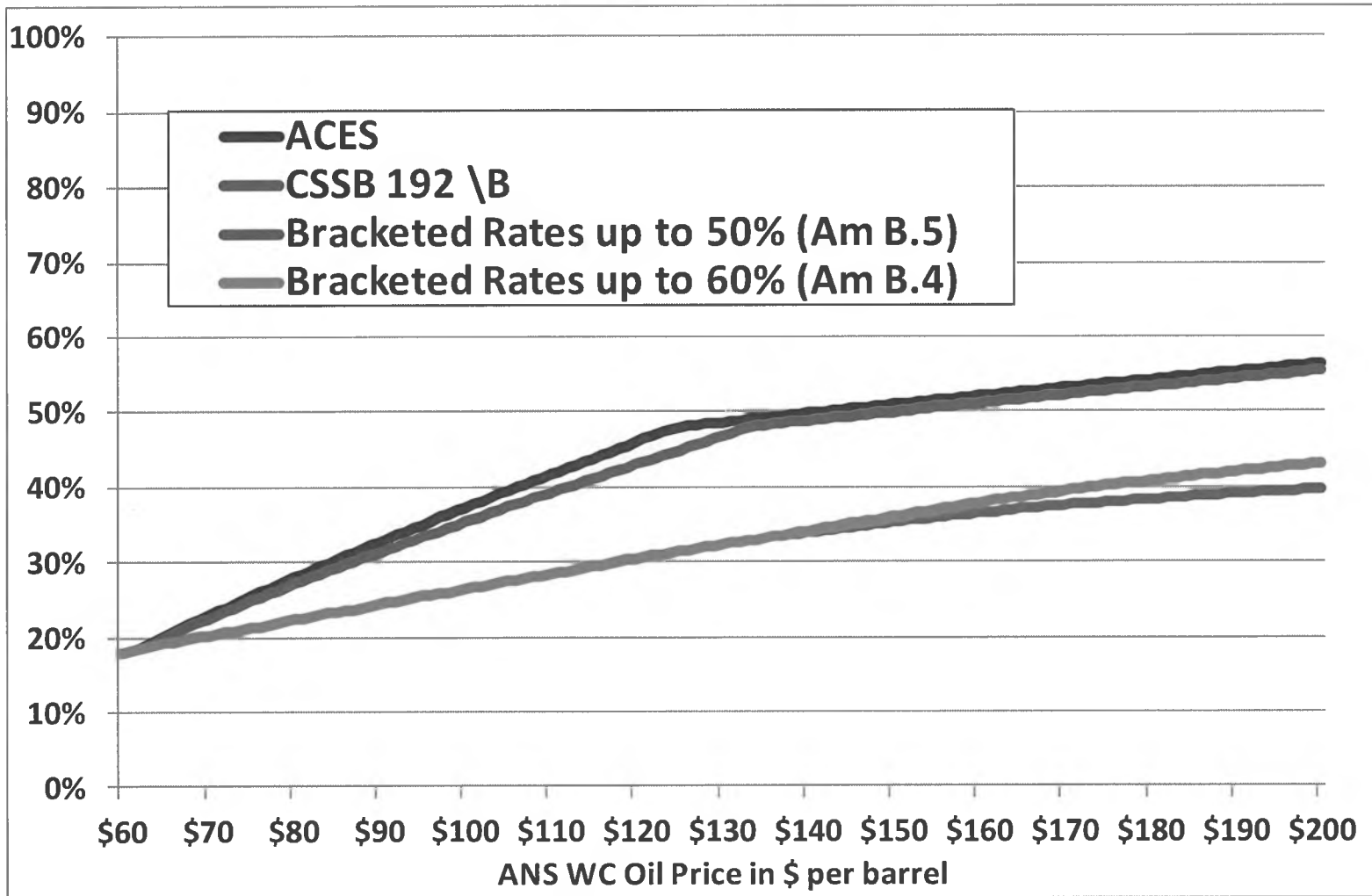
Bracketed progressivity

Bracket	Base Rate	Progressivity Rate	Total Rate
\$0-\$30	25%	0%	25%
\$30-\$42.50	25%	2.5%	27.5%
\$42.50-\$55	25%	7.5%	32.5%
\$55-\$67.50	25%	12.5%	37.5%
\$67.50-\$80	25%	17.5%	42.5%
\$80-\$92.50	25%	22.5%	47.5%
\$92.50-\$105*	25%	25%	50%
\$105-\$117.50	25%	30%	55%
\$117.50+*	25%	35%	60%

* Under Amendment B.5, 25% is the maximum progressivity rate for a total production tax rate of 50%. Under amendment B.4, 35% is the maximum progressivity rate for a total production tax rate of 60%.



Effective Production Tax Rates: Comparisons



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



Questions ?

Alaska Senate Resources Committee:

Analysis of CSSB192 and Amendments

February 27, 2012

Janak Mayer
Manager, Upstream & Gas
PFC Energy

Senate Resources Committee
Joe Paskvan, Co-Chair / February 29, 2012

Let's call the meeting to order.

Let the record reflect that it is _____ p.m. on Wednesday, February 29.

Let the record reflect that there is a quorum. Present are

- Co-Chair Wagoner
- Senator Stedman
- Senator Stevens
- Senator Wielechowski
- Senator French
- Senator McGuire
- And myself, Senator Paskvan

During this hearing, we are joined again by PFC Energy.

According to their website, "PFC Energy is a global consulting firm specializing in the oil and gas industry. Our clients are oil and gas operators, national oil companies, service companies, investors, governments and other stakeholders."

PFC Energy presented testimony – focusing mostly on progressivity – to the Senate Resources Committee on February 16 and 17.

Subsequently, the Committee requested additional information and modeling from PFC – and we are pleased that Janak and Jerry were able to join us today.

The Committee acknowledges that a significant amount of information was requested and we appreciate that the work was completed in time for today's hearing.

Welcome back, Janak Meyer, and welcome also Jerry Kepes (keppus). Please introduce yourselves for the public record and then begin your testimony.

Committee Substitute for Senate Bill 192 Oil and Gas Production Tax Values

Amendments

1. B.17 (McGuire) Competitiveness Review Board
2. B.6 (McGuire) Inflation Adjusting the \$30
3. B.11 (Wielechowski/French) Changes to Oil and Gas Leasing Laws
4. B.12 (Wielechowski/French) State Directed Financial Investment (SDFI)
5. B.14 (Wielechowski) Re-instituting Separate Accounting
6. B.15 (Wielechowski/French) Requiring Info About Use of Tax Credits
7. B.16 (French) Oil Information System
8. B.4 (McGuire) Progressivity Bracketed – 35% top bracket
9. B.5 (McGuire) Progressivity Bracketed – 25% top bracket
10. B.7 (McGuire) Adjusted base rate plus bracketed progressivity and in-field development credit for new fields
11. B.8 (Wielechowski/French) Simple Progressivity
12. B.9 (Wielechowski/French) Rewarding Increased Production
13. B.10 (Wielechowski/French) Capping Credits to Avoid Gold Plating
14. B.13 (Wielechowski/French) Establishing a Gross Minimum Tax
15. B.1 (Wagoner) Extends the Sunset of the Small Producer/New Area Development Credit from 2016 to 2021
16. B.2 (Wagoner) Gross Value at the Point of Production Tax Holiday
17. B.3 (Wagoner) Tax Credit Based on the Capital Cost of Developing New Oil and Gas Production

18. B.18 Simple Progressivity II

PFC Presentation: Requested Analysis on Progressivity Caps

Slide #9: If they use a higher production forecast (e.g, the Spring 2011 forecast), how does that impact these projections?

Production Sensitivity Analysis:

1. Are FY13 cost forecasts sensitive to production volumes?
 2. Can you run the charts with Spring '11 forecast numbers?
 3. How much would these tax rates change, based on your best estimate, with different cost and production forecasts?
-

PFC Presentation: Analysis of CS SB 192 and Amendments

Slide #5: Is this telling us that Ugnu, as a high cost development, needs \$95/bbl to breakeven (blue line) under ACES?

My recollection is that a year ago, under ACES, BP was saying Ugnu needed \$60/bbl to breakeven. That number increased to \$70-75/bbl as a result of the pilot test. Why \$95?



Alaska Senate Resources Committee:

Analysis of CSSB192 and Amendments

29

February 27, 2012

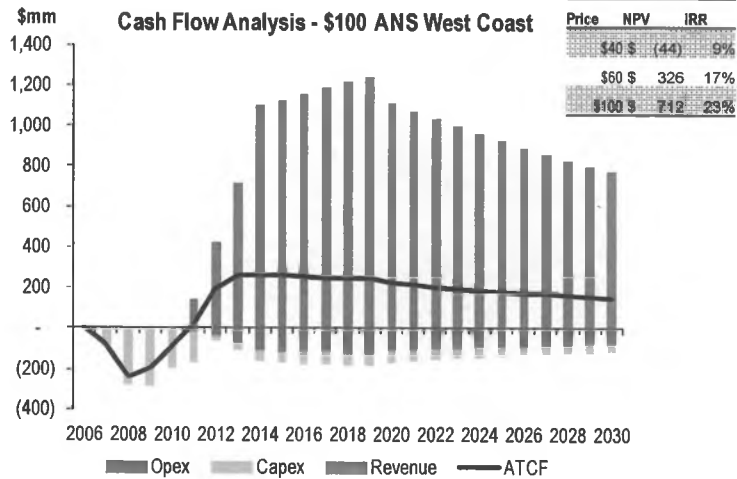
Janak Mayer
Manager, Upstream & Gas
PFC Energy

Cost Assumptions Underlying Development-Forward Analysis

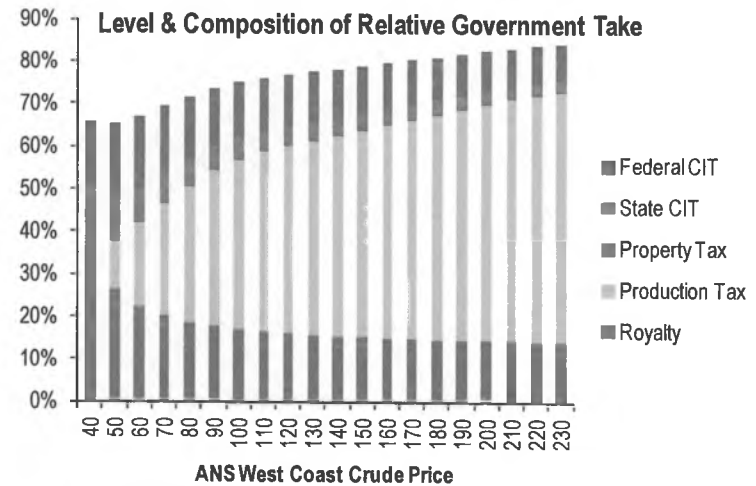
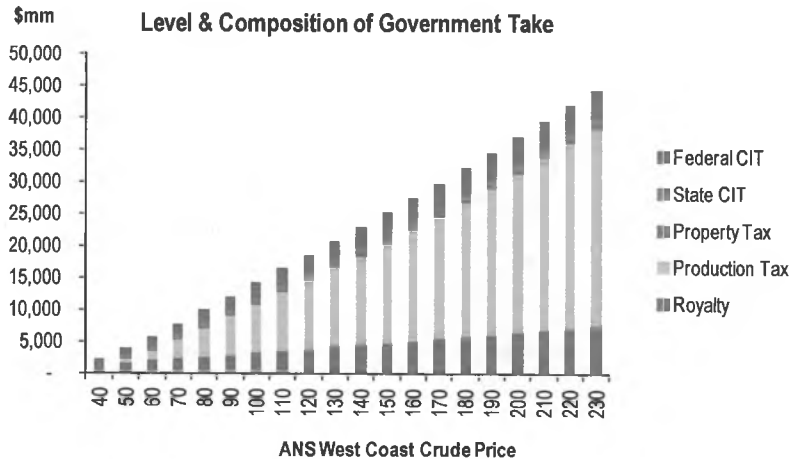
- Development-forward analysis has been undertaken by looking economics for a generic example **low-cost field development**. Cost examples underpinning the modeled scenarios are:
 - \$10 per flowing bbl operating expenditures
 - \$5 per bbl reserves initial development capital expenditures
 - \$5 per flowing bbl ongoing capital expenditures
 - \$7.40 per flowing bbl transportation costs
- These assumptions are broadly in keeping with actual reported costs for lower-cost production from the North Slope. They are in total higher than the calendar year 2010 costs reported by DOR for the Prudhoe Bay Unit, which are:
 - 1,314mm operating expenditures (~\$11.89 per flowing bbl)
 - \$561mm capital expenditures (includes both maintenance and additional new development ~\$5.08 per flowing bbl)
- Development-forward analysis has also been undertaken by looking economics for a generic example **high-cost field development**. Cost examples underpinning the modeled scenarios are:
 - \$17 per flowing bbl operating expenditures
 - \$15 per bbl reserves initial development capital expenditures
 - \$1 per flowing bbl ongoing capital expenditures
 - \$7.40 per flowing bbl transportation costs

High
Cost
New
Field

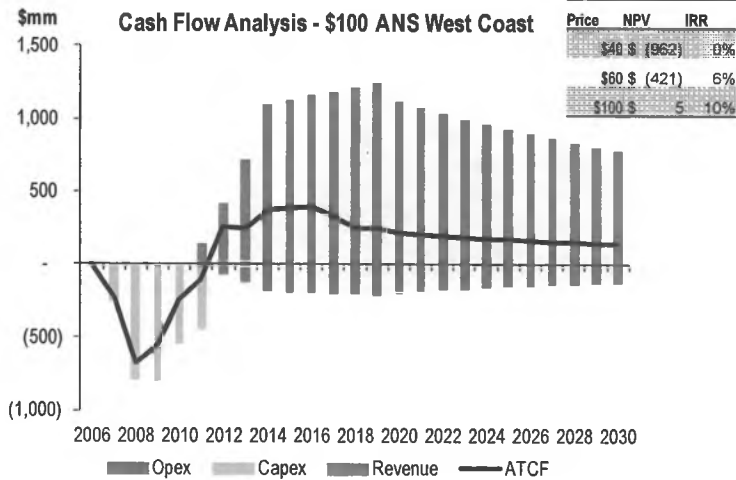
ACES (low cost development)



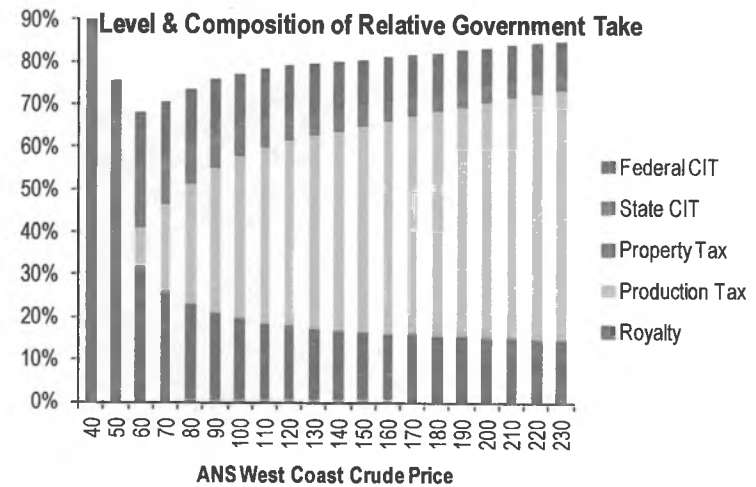
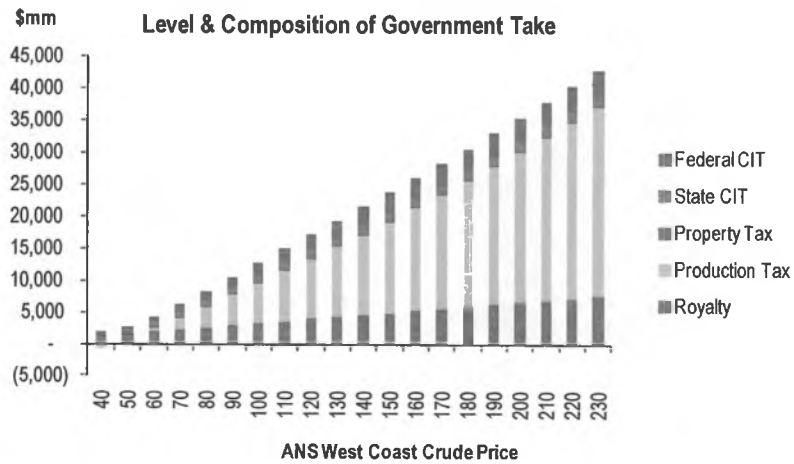
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	37%	1%	10%	4%	51%	15%	66%
50	26%	11%	6%	4%	48%	17%	65%
60	22%	20%	4%	4%	50%	17%	67%
70	20%	26%	3%	4%	54%	16%	70%
80	19%	32%	3%	4%	57%	14%	72%
90	18%	37%	2%	4%	60%	14%	74%
100	17%	40%	2%	3%	62%	13%	75%
110	16%	42%	2%	3%	64%	13%	76%
120	16%	44%	2%	3%	65%	12%	77%
130	16%	46%	1%	3%	66%	12%	78%
140	15%	47%	1%	3%	67%	12%	78%
150	15%	49%	1%	3%	68%	11%	79%
160	15%	50%	1%	3%	69%	11%	80%
170	15%	51%	1%	3%	70%	11%	81%
180	15%	53%	1%	3%	71%	10%	81%
190	15%	54%	1%	3%	72%	10%	82%
200	14%	55%	1%	2%	73%	9%	83%
210	14%	57%	1%	2%	74%	9%	83%
220	14%	58%	1%	2%	75%	9%	84%
230	14%	59%	1%	2%	76%	8%	84%



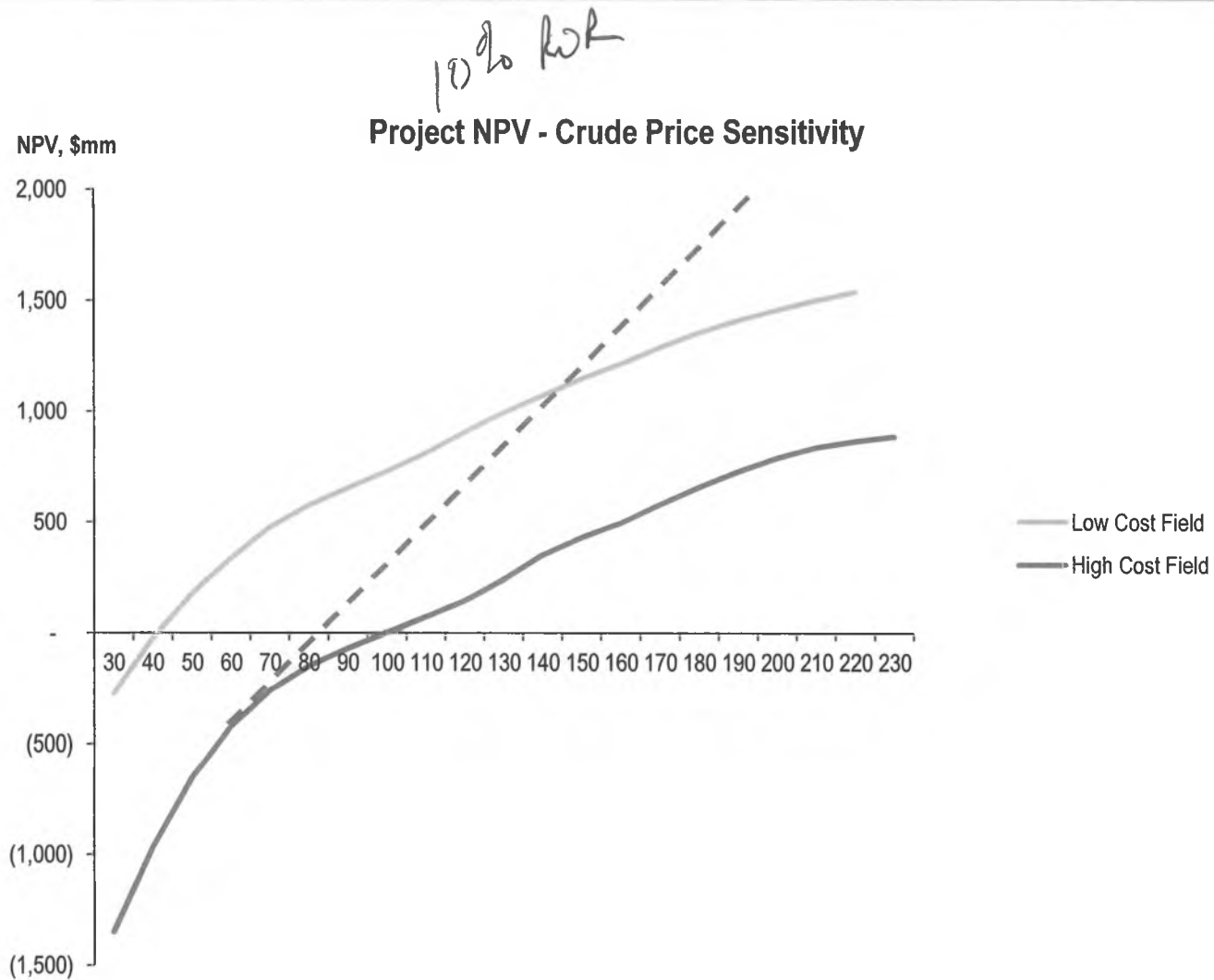
ACES (high cost development)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	136%	-90%	73%	0%	119%	0%	119%
50	46%	-8%	20%	2%	60%	8%	68%
60	32%	10%	11%	3%	56%	12%	68%
70	26%	20%	8%	3%	58%	13%	71%
80	23%	28%	6%	3%	61%	13%	74%
90	21%	34%	5%	3%	63%	12%	76%
100	20%	38%	4%	3%	65%	12%	77%
110	19%	41%	4%	3%	67%	12%	78%
120	18%	44%	3%	3%	68%	11%	79%
130	17%	45%	3%	3%	68%	11%	80%
140	17%	47%	3%	3%	69%	11%	80%
150	16%	48%	2%	3%	70%	11%	81%
160	16%	50%	2%	3%	71%	10%	81%
170	16%	51%	2%	3%	72%	10%	82%
180	16%	53%	2%	2%	73%	9%	82%
190	15%	54%	2%	2%	74%	9%	83%
200	15%	55%	2%	2%	75%	9%	83%
210	15%	57%	2%	2%	76%	8%	84%
220	15%	58%	1%	2%	76%	8%	85%
230	15%	59%	1%	2%	77%	8%	85%



ACES Impact on high cost development economics



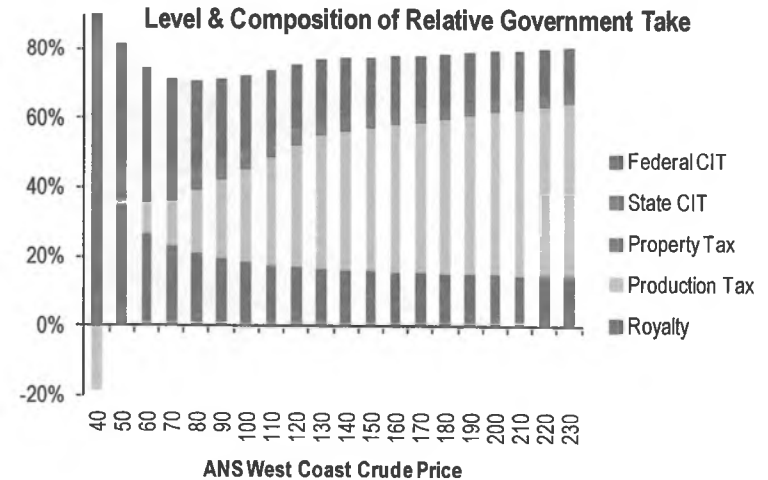
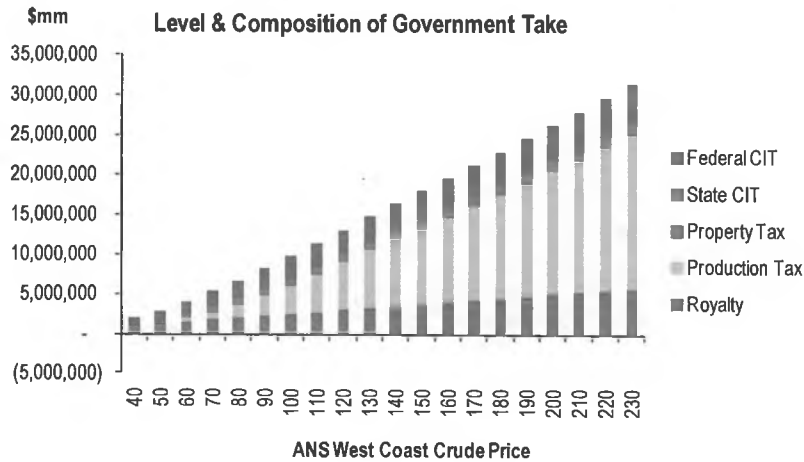
Analysis Using DOR FY2013 Estimated Average Costs

- As requested, an alternate analysis of ACES and the various potential maximum production tax rates has also been performed using DOR FY2013 forecast North Slope cost and production figures
 - By using a 'snapshot' of costs and production for a given year, the analysis inherently no longer presents a development-forward lifecycle analysis, since it combines initial development capex for some projects with ongoing spending on others
 - As a result, such an analysis should be performed only as a snapshot of a single year
 - As such, such an analysis represents a high-level approximation of Government Take in that particular year, not over the actual lifecycle of a particular asset type
 - Such an analysis also does not account for the 'bracket-creep' or 'stealth-tax' effect of inflation over time
- DOR FY2013 cost forecasts are:
 - \$13.75 per taxable barrel operating expenditures
 - \$15.36 per taxable barrel capital expenditures
 - \$8.56 per taxable barrel transportation costs
- On a per-flowing-barrel basis, these equate to:
 - \$11.71 /bbl operating expenditures
 - \$13.07 /bbl capital expenditures
 - \$7.29 /bbl transportation costs
- On the following slides, the ACES system, along with ACES with maximum production tax levels set at 50%, 55%, 60%, 65% and 70% has been analyzed, using these cost figures

ACES (FY 2013 – DOR Estimate Inputs)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	\$ 985,712	\$ (290,533)	\$ 93,820	\$ 198,851	\$ 987,849	758,947	1,746,797
50	\$ 1,232,140	\$ 43,155	\$ 93,820	\$ 315,721	\$ 1,684,835	1,205,000	2,889,836
60	\$ 1,478,568	\$ 474,404	\$ 93,820	\$ 424,395	\$ 2,471,187	1,619,776	4,090,962
70	\$ 1,724,995	\$ 969,137	\$ 93,820	\$ 527,737	\$ 3,315,690	2,014,198	5,329,888
80	\$ 1,971,423	\$ 1,715,090	\$ 93,820	\$ 609,977	\$ 4,390,310	2,328,079	6,718,389
90	\$ 2,217,851	\$ 2,599,043	\$ 93,820	\$ 680,625	\$ 5,591,338	2,597,717	8,189,056
100	\$ 2,464,279	\$ 3,620,995	\$ 93,820	\$ 739,680	\$ 6,918,774	2,823,113	9,741,887
110	\$ 2,710,707	\$ 4,780,946	\$ 93,820	\$ 787,144	\$ 8,372,617	3,004,266	11,376,883
120	\$ 2,957,135	\$ 6,078,897	\$ 93,820	\$ 823,016	\$ 9,952,868	3,141,176	13,094,044
130	\$ 3,203,563	\$ 7,500,215	\$ 93,820	\$ 848,525	\$ 11,646,123	3,238,535	14,884,658
140	\$ 3,449,991	\$ 8,540,576	\$ 93,820	\$ 906,034	\$ 12,990,421	3,458,029	16,448,450
150	\$ 3,696,419	\$ 9,615,437	\$ 93,820	\$ 960,645	\$ 14,366,321	3,666,462	18,032,783
160	\$ 3,942,847	\$ 10,724,798	\$ 93,820	\$ 1,012,358	\$ 15,773,823	3,863,835	19,637,658
170	\$ 4,189,275	\$ 11,868,659	\$ 93,820	\$ 1,061,174	\$ 17,212,927	4,050,147	21,263,074
180	\$ 4,435,703	\$ 13,047,019	\$ 93,820	\$ 1,107,091	\$ 18,683,633	4,225,398	22,909,031
190	\$ 4,682,131	\$ 14,259,880	\$ 93,820	\$ 1,150,110	\$ 20,185,941	4,389,588	24,575,529
200	\$ 4,928,559	\$ 15,507,240	\$ 93,820	\$ 1,190,232	\$ 21,719,850	4,542,718	26,262,568
210	\$ 5,174,986	\$ 16,789,100	\$ 93,820	\$ 1,227,455	\$ 23,285,362	4,684,787	27,970,149
220	\$ 5,421,414	\$ 18,105,461	\$ 93,820	\$ 1,261,781	\$ 24,882,475	4,815,796	29,698,271
230	\$ 5,667,842	\$ 19,456,321	\$ 93,820	\$ 1,293,208	\$ 26,511,191	4,935,744	31,446,934

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	46%	0%	4%	65%	14%	79%
200	15%	47%	0%	4%	66%	14%	79%
210	15%	48%	0%	3%	66%	13%	80%
220	15%	49%	0%	3%	67%	13%	80%
230	15%	50%	0%	3%	68%	13%	81%



Summary of ACES, CSSB192 and Analyzed Amendments

ACES			
Is Production Tax Bracketed?	No		
Are oil and gas assessed separately?	No		
Rates for non-bracketed system:		75% maximum	
<= 30	\$ 30.00 PTV/BOE	25% base	
> 30 but <= 92.5	\$ 92.50 PTV/BOE	0.40% progressivity	
> 92.5		0.10% progressivity	

CSSB 192			
Is Production Tax Bracketed?	No		
Are oil and gas assessed separately?	No		
Rates for non-bracketed system:		60% maximum	
<= 30	\$ 30.00 PTV/BOE	25% base	
> 30 but <= 101.43	\$ 101.43 PTV/BOE	0.35% progressivity	
> 101.43		0.10% progressivity	

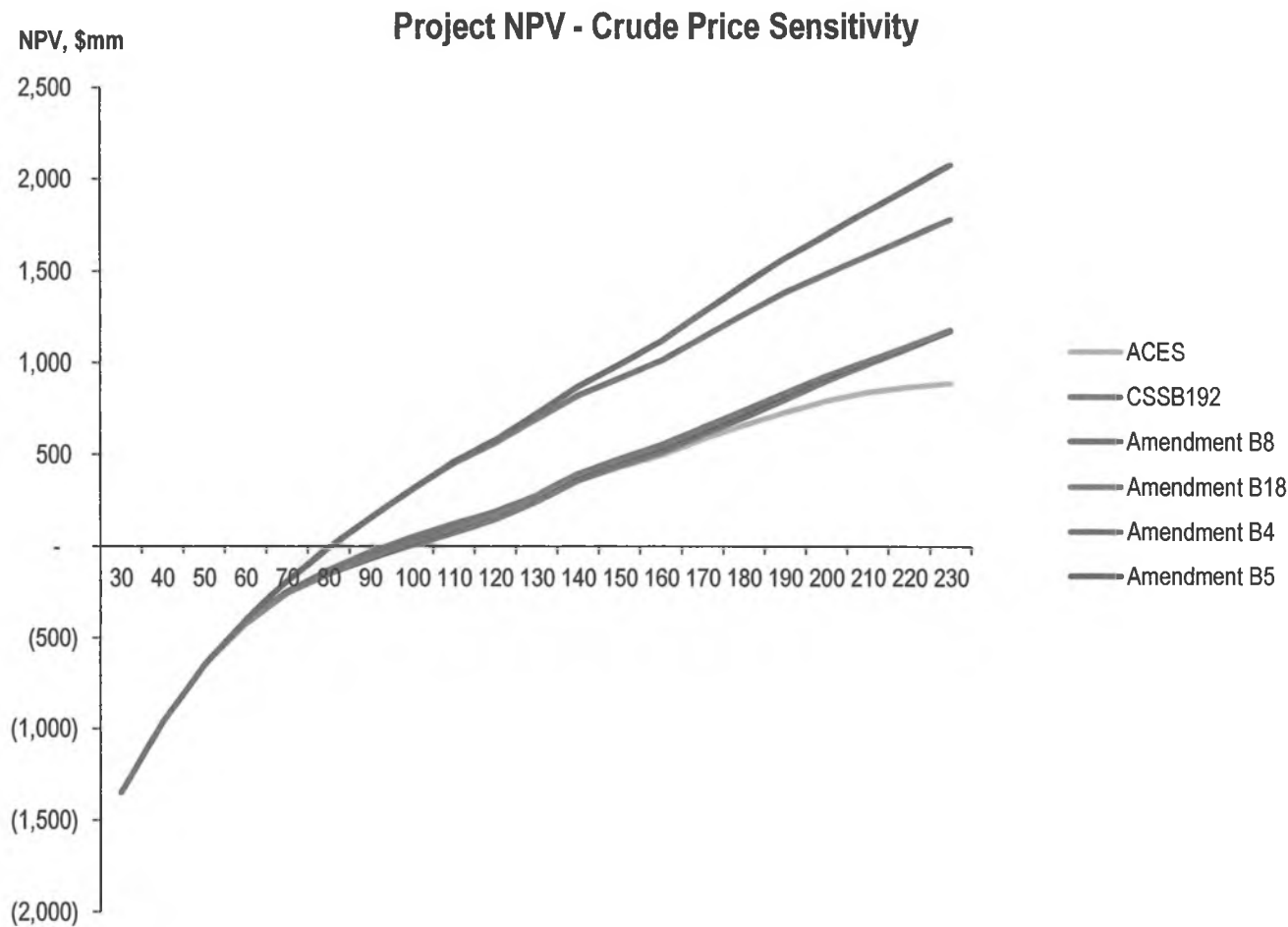
Amendment B8			
Is Production Tax Bracketed?	No		
Are oil and gas assessed separately?	No		
Rates for non-bracketed system:		60% maximum	
<= 30	\$ 30.00 PTV/BOE	25% base	
> 30 but <= 92.5	\$ 92.50 PTV/BOE	0.40% progressivity	
> 92.5		0.10% progressivity	

Amendment B18			
Is Production Tax Bracketed?	No		
Are oil and gas assessed separately?	No		
Rates for non-bracketed system:		60% maximum	
<= 30	\$ 30.00 PTV/BOE	25% base	
> 30 but <= 67.5	\$ 67.50 PTV/BOE	0.40% progressivity	
> 67.5 but <= 92.5	\$ 92.50 PTV/BOE	0.35% progressivity	
> 92.5		0.10% progressivity	

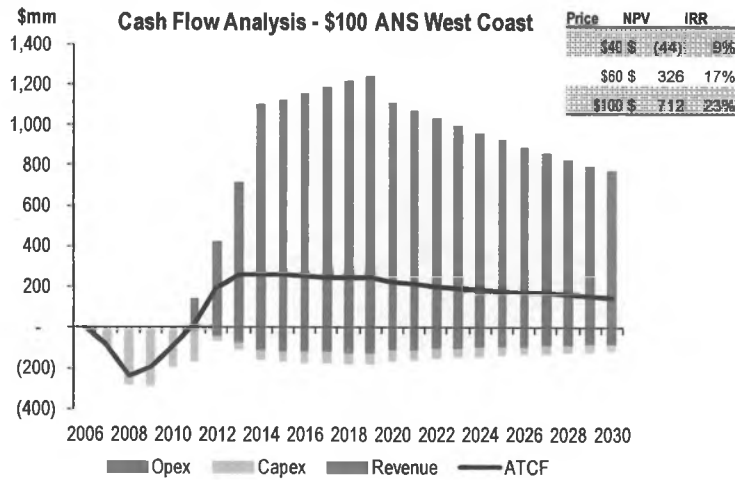
Amendment B4			
Is Production Tax Bracketed?	Yes		
Are oil and gas assessed separately?	No		
Rates for bracketed system:		25% base	
<= 30.00	\$ 30.00 PTV/BOE	0.0%	
> 30.00 but <= 42.50	\$ 42.50 PTV/BOE	2.5%	
> 42.50 but <= 55.00	\$ 55.00 PTV/BOE	7.5%	
> 55.00 but <= 67.50	\$ 67.50 PTV/BOE	12.5%	
> 67.50 but <= 80.00	\$ 80.00 PTV/BOE	17.5%	
> 80.00 but <= 92.50	\$ 92.50 PTV/BOE	22.5%	
> 92.50 but <= 105.00	\$ 105.00 PTV/BOE	25.0%	
> 105.00 but <= 117.50	\$ 117.50 PTV/BOE	30.0%	
> 117.50		35.0%	

Amendment B5			
Is Production Tax Bracketed?	Yes		
Are oil and gas assessed separately?	No		
Rates for bracketed system:		25% base	
<= 30.00	\$ 30.00 PTV/BOE	0.0%	
> 30.00 but <= 42.50	\$ 42.50 PTV/BOE	2.5%	
> 42.50 but <= 55.00	\$ 55.00 PTV/BOE	7.5%	
> 55.00 but <= 67.50	\$ 67.50 PTV/BOE	12.5%	
> 67.50 but <= 80.00	\$ 80.00 PTV/BOE	17.5%	
> 80.00 but <= 92.50	\$ 92.50 PTV/BOE	22.5%	
> 92.50	PTV/BOE	25.0%	

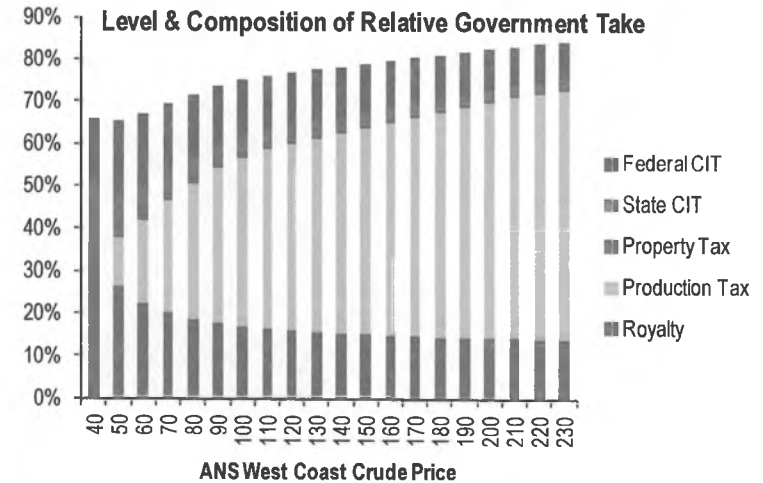
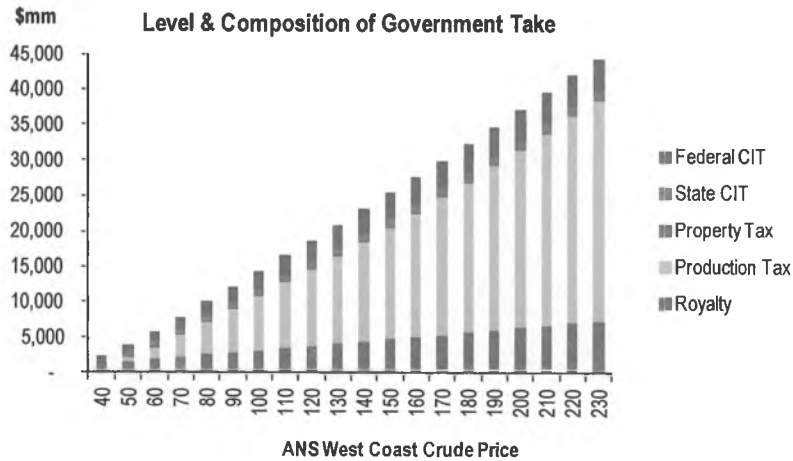
Impact of different amendment cases on high cost development economics



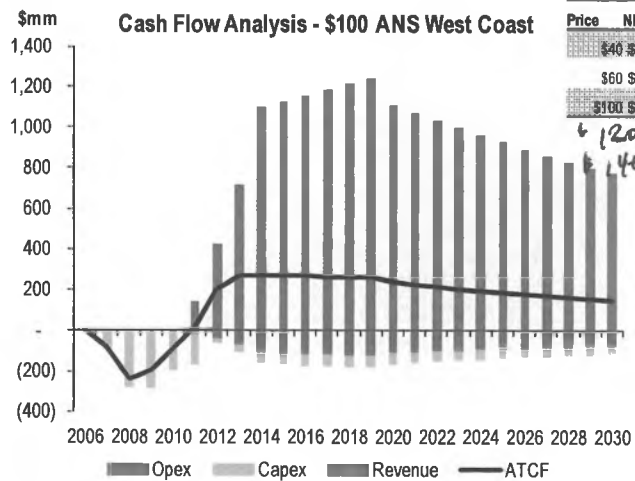
ACES (low cost development)



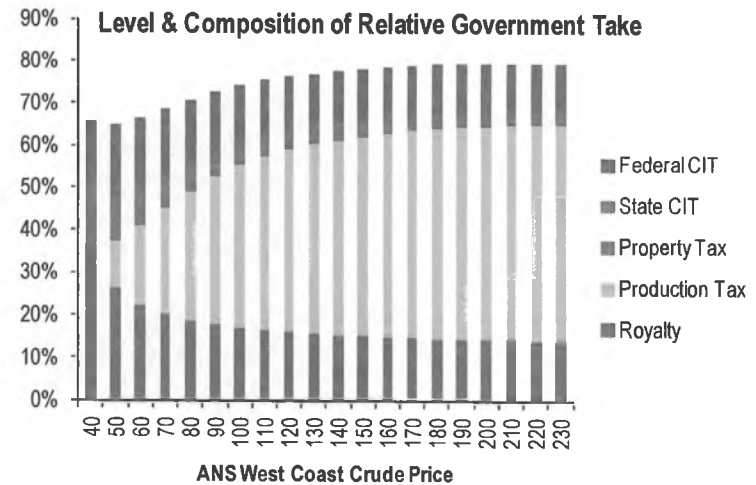
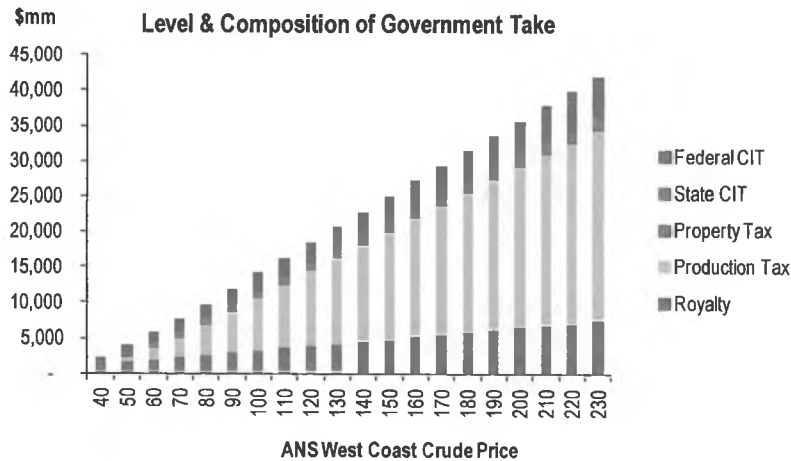
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	37%	1%	10%	4%	51%	15%	66%
50	26%	11%	6%	4%	48%	17%	65%
60	22%	20%	4%	4%	50%	17%	67%
70	20%	26%	3%	4%	54%	16%	70%
80	19%	32%	3%	4%	57%	14%	72%
90	18%	37%	2%	4%	60%	14%	74%
100	17%	40%	2%	3%	62%	13%	75%
110	16%	42%	2%	3%	64%	13%	76%
120	16%	44%	2%	3%	65%	12%	77%
130	16%	46%	1%	3%	66%	12%	78%
140	15%	47%	1%	3%	67%	12%	78%
150	15%	49%	1%	3%	68%	11%	79%
160	15%	50%	1%	3%	69%	11%	80%
170	15%	51%	1%	3%	70%	11%	81%
180	15%	53%	1%	3%	71%	10%	81%
190	15%	54%	1%	3%	72%	10%	82%
200	14%	55%	1%	2%	73%	9%	83%
210	14%	57%	1%	2%	74%	9%	83%
220	14%	58%	1%	2%	75%	9%	84%
230	14%	59%	1%	2%	76%	8%	84%



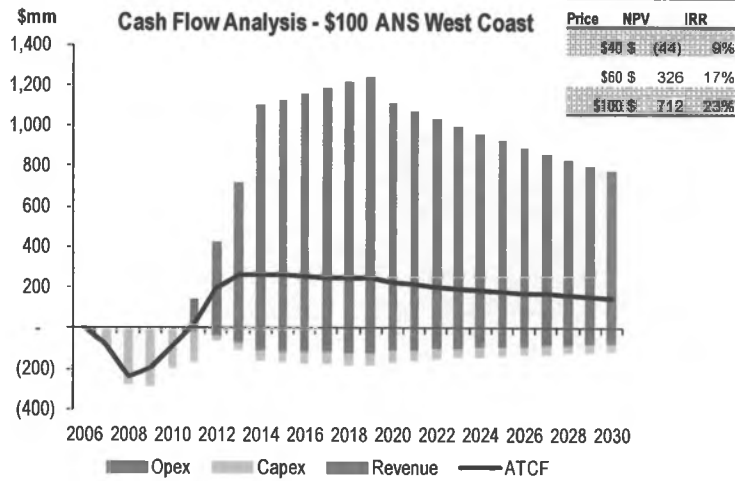
CSSB 192 (low cost development)



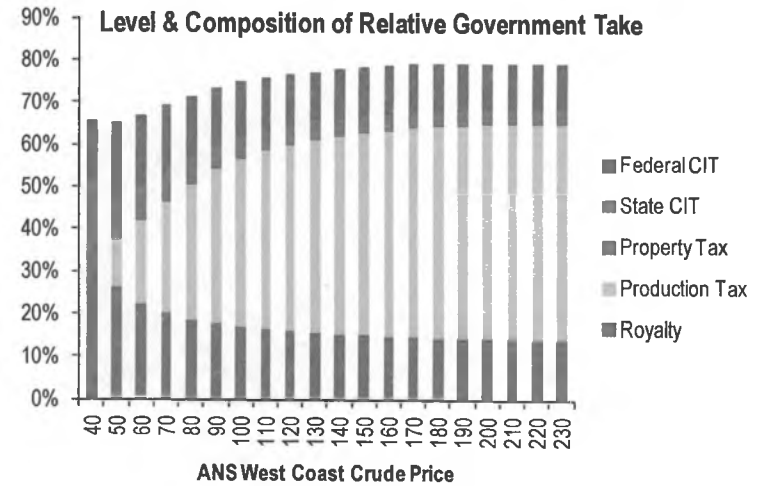
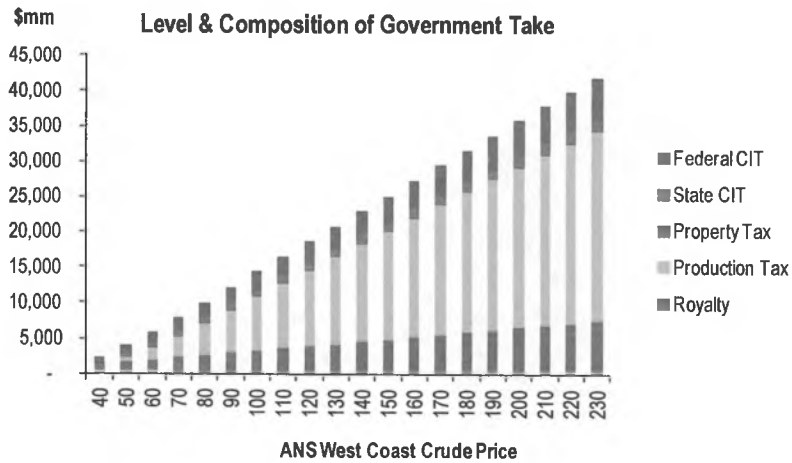
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	37%	1%	10%	4%	51%	15%	66%
50	26%	11%	6%	4%	48%	17%	65%
60	22%	19%	4%	4%	50%	17%	66%
70	20%	25%	3%	4%	53%	16%	69%
80	19%	31%	3%	4%	56%	15%	71%
90	18%	35%	2%	4%	59%	14%	73%
100	17%	38%	2%	4%	61%	14%	74%
110	16%	41%	2%	3%	63%	13%	76%
120	16%	43%	2%	3%	64%	12%	76%
130	16%	45%	1%	3%	65%	12%	77%
140	15%	46%	1%	3%	66%	12%	78%
150	15%	47%	1%	3%	67%	12%	78%
160	15%	48%	1%	3%	67%	12%	79%
170	15%	49%	1%	3%	68%	11%	79%
180	15%	49%	1%	3%	68%	11%	79%
190	15%	50%	1%	3%	68%	11%	79%
200	14%	50%	1%	3%	68%	11%	79%
210	14%	51%	1%	3%	69%	11%	80%
220	14%	51%	1%	3%	69%	11%	80%
230	14%	51%	1%	3%	69%	11%	79%



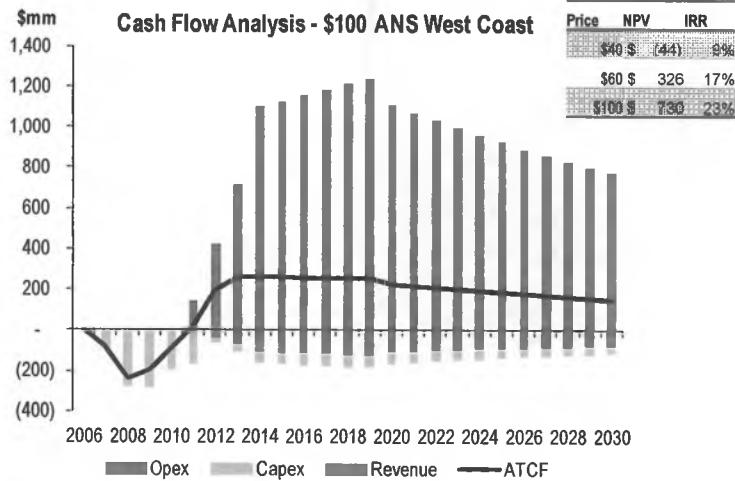
Amendment B8 (low cost development)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	37%	1%	10%	4%	51%	15%	66%
50	26%	11%	6%	4%	48%	17%	65%
60	22%	20%	4%	4%	50%	17%	67%
70	20%	26%	3%	4%	54%	16%	70%
80	19%	32%	3%	4%	57%	14%	72%
90	18%	37%	2%	4%	60%	14%	74%
100	17%	40%	2%	3%	62%	13%	75%
110	16%	42%	2%	3%	64%	13%	76%
120	16%	44%	2%	3%	65%	12%	77%
130	16%	45%	1%	3%	66%	12%	78%
140	15%	47%	1%	3%	66%	12%	78%
150	15%	48%	1%	3%	67%	12%	79%
160	15%	49%	1%	3%	68%	11%	79%
170	15%	49%	1%	3%	68%	11%	79%
180	15%	50%	1%	3%	68%	11%	79%
190	15%	50%	1%	3%	68%	11%	79%
200	14%	50%	1%	3%	69%	11%	80%
210	14%	51%	1%	3%	69%	11%	80%
220	14%	51%	1%	3%	69%	11%	80%
230	14%	51%	1%	3%	69%	11%	79%

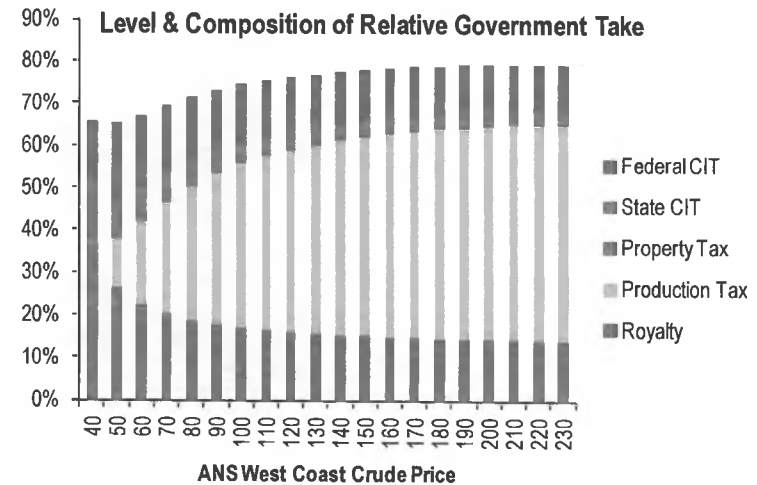
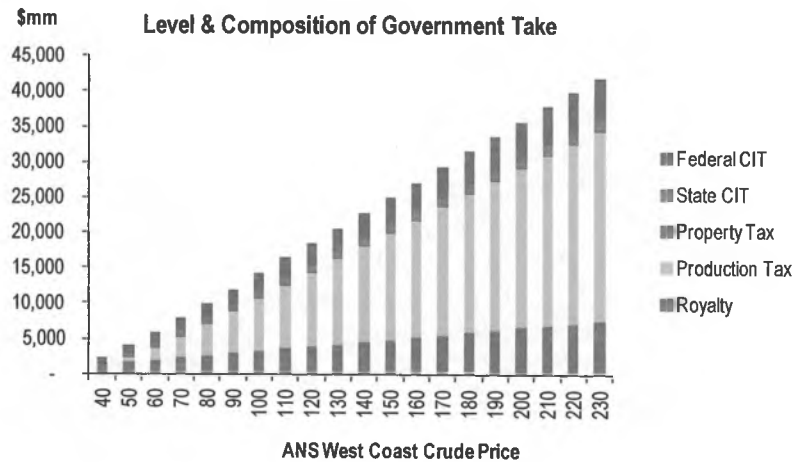


Amendment B18 (low cost development)

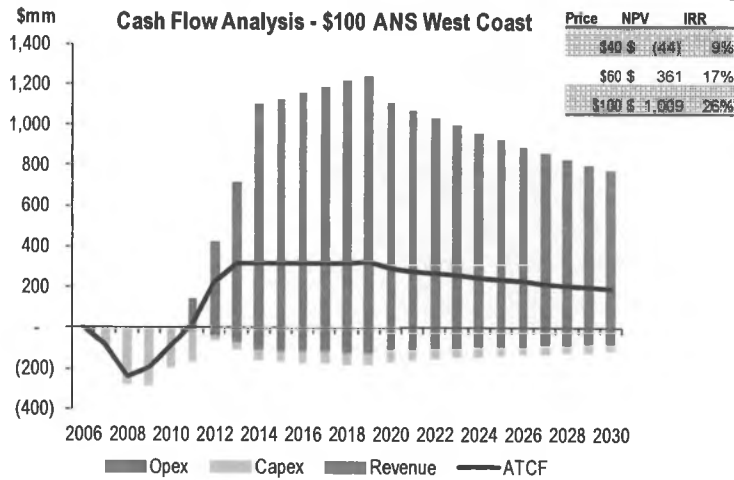


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	37%	1%	10%	4%	51%	15%	66%
50	26%	11%	6%	4%	48%	17%	65%
60	22%	20%	4%	4%	50%	17%	67%
70	20%	26%	3%	4%	54%	16%	69%
80	19%	32%	3%	4%	57%	15%	71%
90	18%	36%	2%	4%	59%	14%	73%
100	17%	39%	2%	4%	61%	13%	75%
110	16%	41%	2%	3%	63%	13%	76%
120	16%	43%	2%	3%	64%	13%	76%
130	16%	44%	1%	3%	65%	12%	77%
140	15%	46%	1%	3%	66%	12%	78%
150	15%	47%	1%	3%	66%	12%	78%
160	15%	48%	1%	3%	67%	12%	78%
170	15%	49%	1%	3%	67%	11%	79%
180	15%	49%	1%	3%	68%	11%	79%
190	15%	50%	1%	3%	68%	11%	79%
200	14%	50%	1%	3%	68%	11%	79%
210	14%	51%	1%	3%	69%	11%	79%
220	14%	51%	1%	3%	69%	11%	80%
230	14%	51%	1%	3%	69%	11%	79%

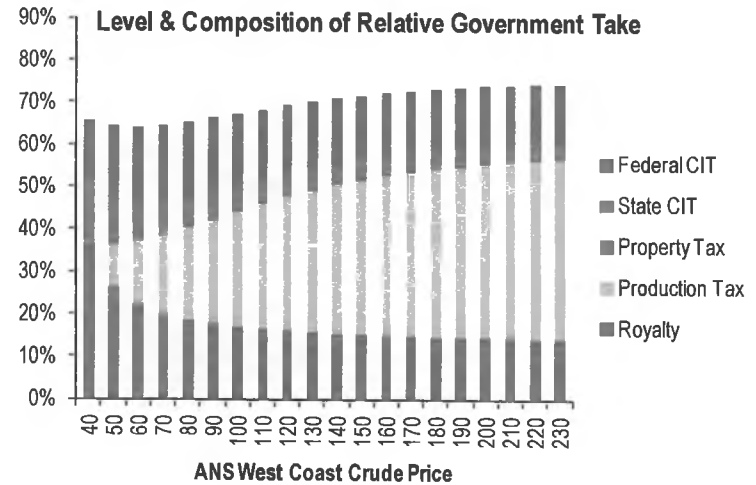
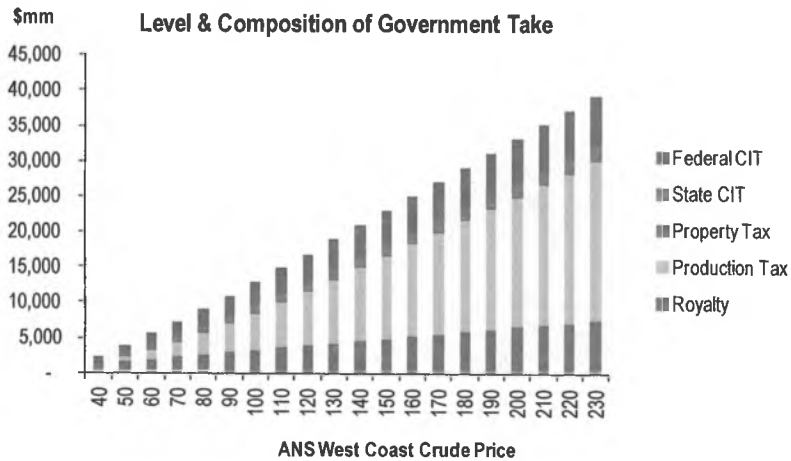
60% straight back



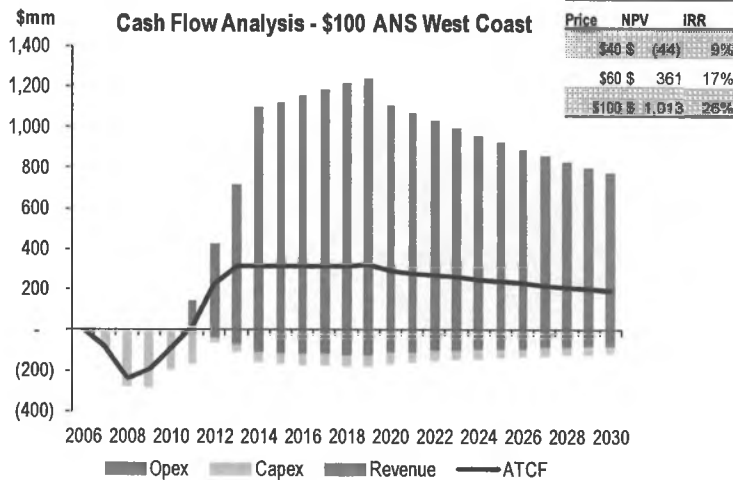
Amendment B4 (low cost development)



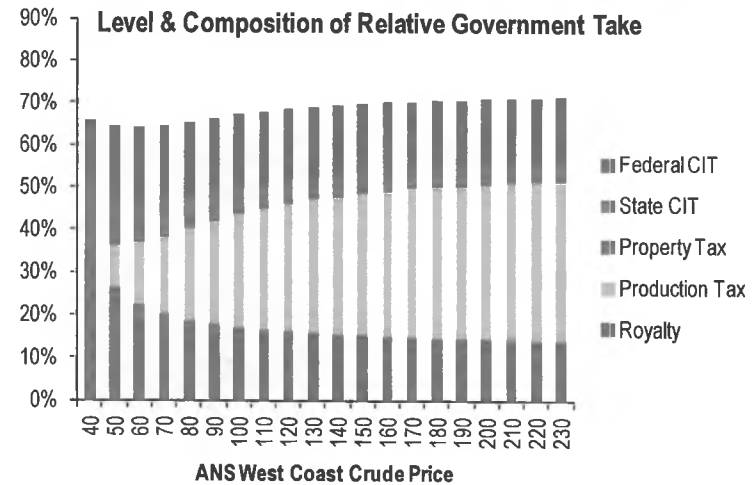
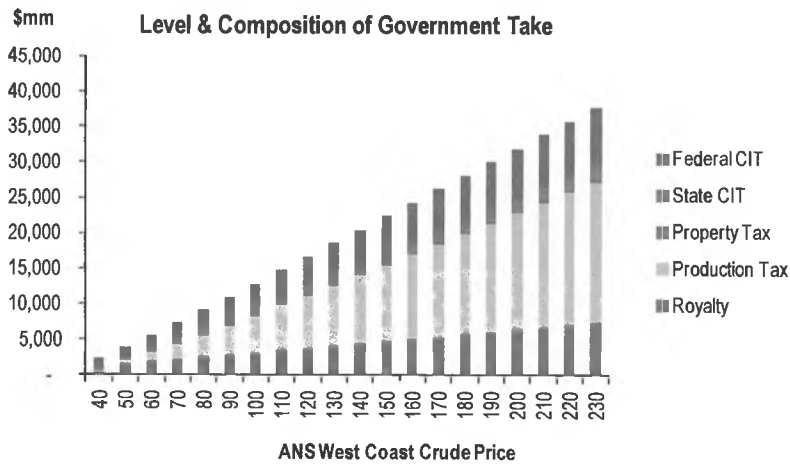
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	37%	1%	10%	4%	51%	15%	66%
50	26%	10%	6%	5%	47%	17%	64%
60	22%	15%	4%	5%	46%	18%	64%
70	20%	18%	3%	5%	47%	18%	65%
80	19%	22%	3%	5%	48%	18%	65%
90	18%	24%	2%	5%	49%	17%	66%
100	17%	27%	2%	4%	50%	17%	68%
110	16%	29%	2%	4%	52%	16%	68%
120	16%	32%	2%	4%	53%	16%	69%
130	16%	33%	1%	4%	55%	16%	70%
140	15%	35%	1%	4%	56%	15%	71%
150	15%	36%	1%	4%	57%	15%	72%
160	15%	38%	1%	4%	58%	15%	72%
170	15%	39%	1%	4%	58%	15%	73%
180	15%	40%	1%	4%	59%	14%	73%
190	15%	40%	1%	4%	59%	14%	74%
200	14%	41%	1%	4%	60%	14%	74%
210	14%	42%	1%	4%	60%	14%	74%
220	14%	42%	1%	4%	61%	14%	74%
230	14%	43%	1%	4%	61%	13%	75%



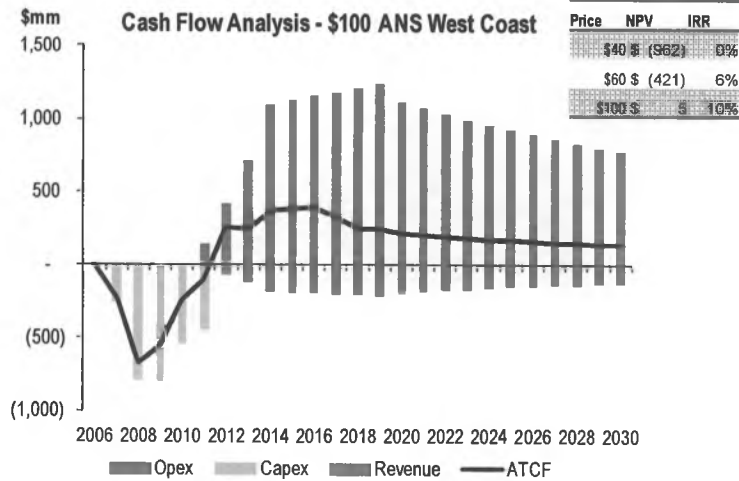
Amendment B5 (low cost development)



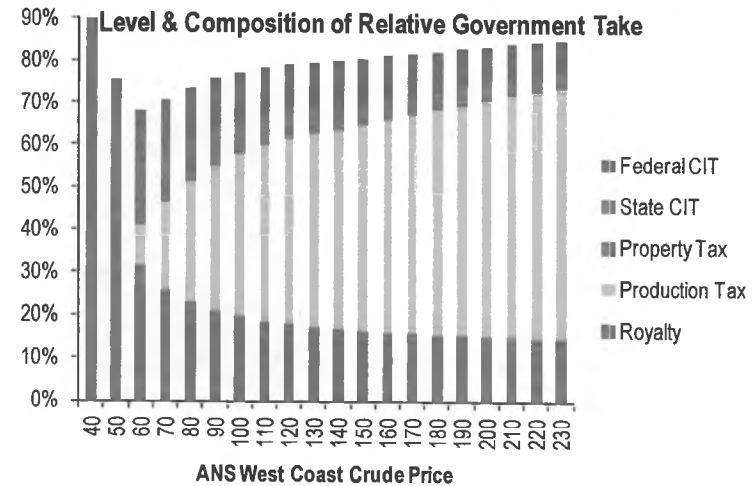
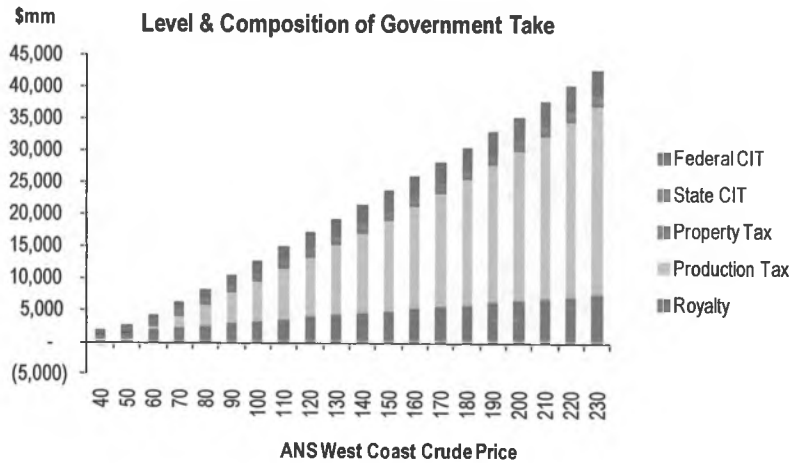
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total CIT
40	37%	1%	10%	4%	51%	15%	66%
50	26%	10%	6%	5%	47%	17%	64%
60	22%	15%	4%	5%	46%	18%	64%
70	20%	18%	3%	5%	47%	18%	65%
80	19%	22%	3%	5%	48%	18%	65%
90	18%	24%	2%	5%	49%	18%	66%
100	17%	27%	2%	5%	50%	17%	67%
110	16%	29%	2%	4%	51%	17%	68%
120	16%	30%	2%	4%	52%	16%	69%
130	16%	31%	1%	4%	53%	16%	69%
140	15%	33%	1%	4%	53%	16%	70%
150	15%	33%	1%	4%	54%	16%	70%
160	15%	34%	1%	4%	54%	16%	70%
170	15%	35%	1%	4%	55%	16%	71%
180	15%	35%	1%	4%	55%	16%	71%
190	15%	36%	1%	4%	55%	16%	71%
200	14%	36%	1%	4%	56%	15%	71%
210	14%	37%	1%	4%	56%	15%	71%
220	14%	37%	1%	4%	56%	15%	71%
230	14%	37%	1%	4%	56%	15%	71%



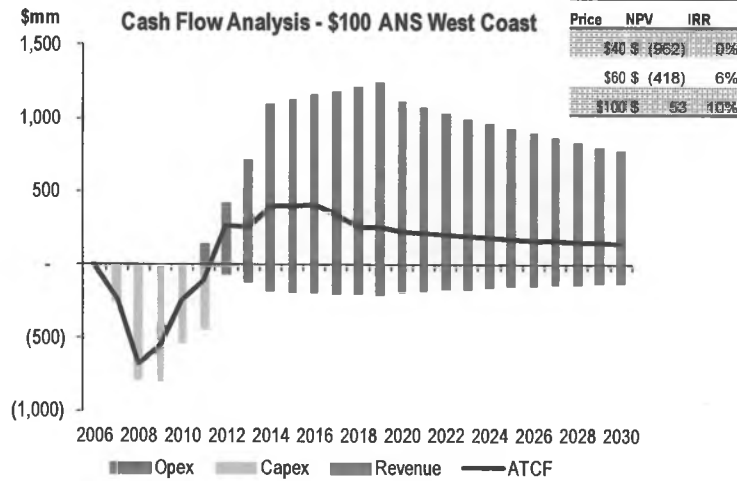
ACES (high cost development)



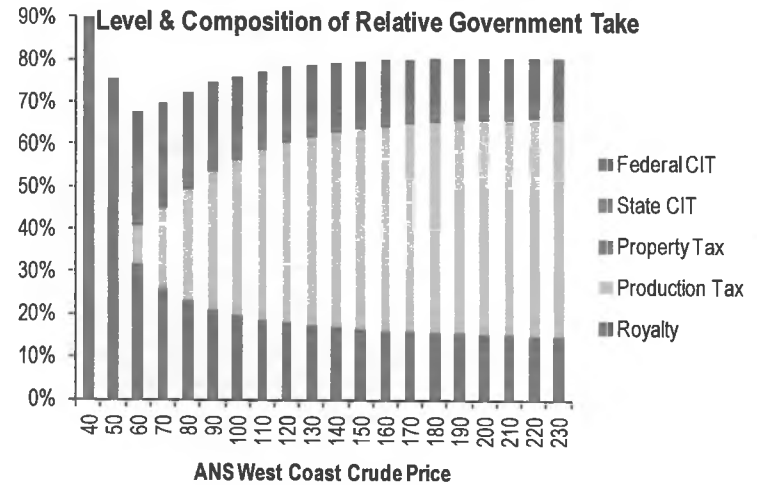
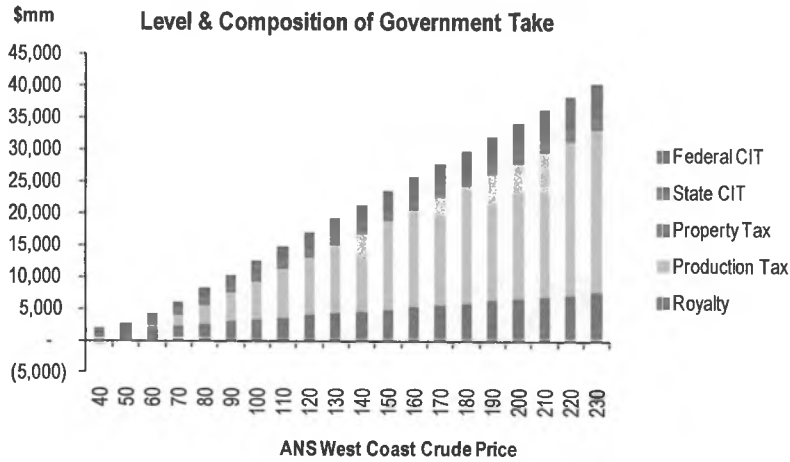
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total CIT
40	136%	-90%	73%	0%	119%	0%	119%
50	46%	-8%	20%	2%	60%	8%	68%
60	32%	10%	11%	3%	56%	12%	68%
70	26%	20%	8%	3%	58%	13%	71%
80	23%	28%	6%	3%	61%	13%	74%
90	21%	34%	5%	3%	63%	12%	76%
100	20%	38%	4%	3%	65%	12%	77%
110	19%	41%	4%	3%	67%	12%	78%
120	18%	44%	3%	3%	68%	11%	79%
130	17%	45%	3%	3%	68%	11%	80%
140	17%	47%	3%	3%	69%	11%	80%
150	16%	48%	2%	3%	70%	11%	81%
160	16%	50%	2%	3%	71%	10%	81%
170	16%	51%	2%	3%	72%	10%	82%
180	16%	53%	2%	2%	73%	9%	82%
190	15%	54%	2%	2%	74%	9%	83%
200	15%	55%	2%	2%	75%	9%	83%
210	15%	57%	2%	2%	76%	8%	84%
220	15%	58%	1%	2%	76%	8%	85%
230	15%	59%	1%	2%	77%	8%	85%



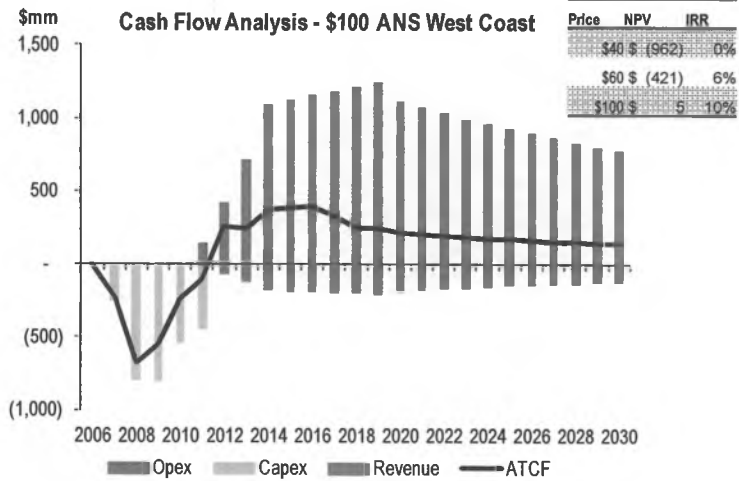
CSSB 192 (high cost development)



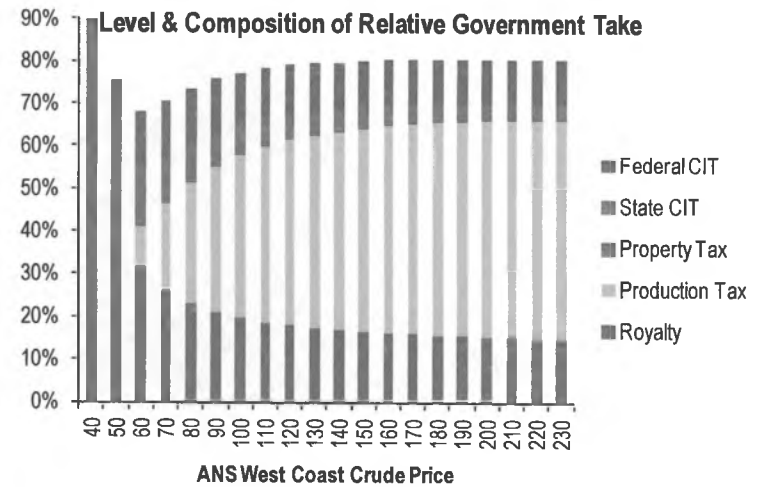
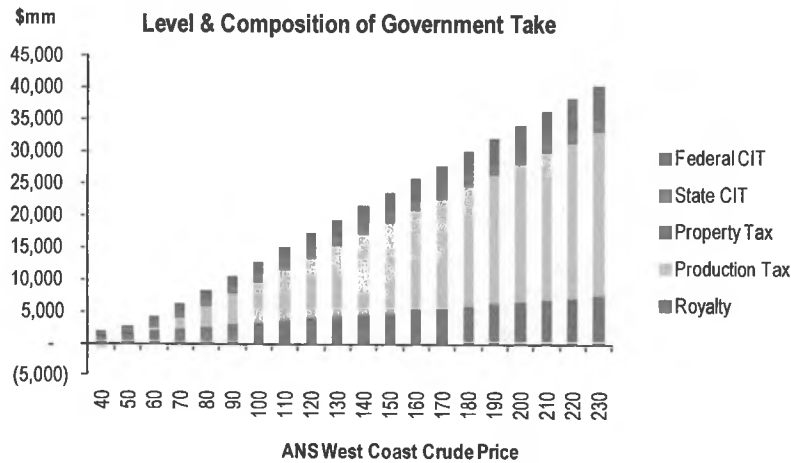
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	136%	-90%	73%	0%	119%	0%	119%
50	46%	-8%	20%	2%	60%	8%	68%
60	32%	9%	11%	3%	55%	12%	68%
70	26%	19%	8%	3%	56%	13%	70%
80	23%	26%	6%	4%	59%	13%	72%
90	21%	32%	5%	3%	62%	13%	75%
100	20%	37%	4%	3%	64%	12%	76%
110	19%	40%	4%	3%	66%	12%	77%
120	18%	43%	3%	3%	67%	12%	78%
130	17%	44%	3%	3%	68%	11%	79%
140	17%	46%	3%	3%	68%	11%	79%
150	16%	47%	2%	3%	69%	11%	80%
160	16%	48%	2%	3%	69%	11%	80%
170	16%	49%	2%	3%	70%	11%	80%
180	16%	50%	2%	3%	70%	10%	80%
190	15%	50%	2%	3%	70%	10%	80%
200	15%	51%	2%	3%	70%	10%	80%
210	15%	51%	2%	3%	70%	10%	80%
220	15%	51%	1%	3%	70%	10%	81%
230	15%	51%	1%	3%	70%	10%	81%



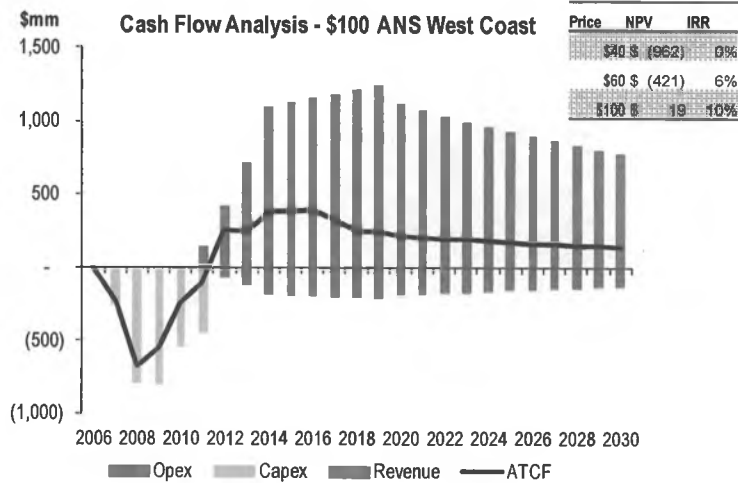
Amendment B8 (high cost development)



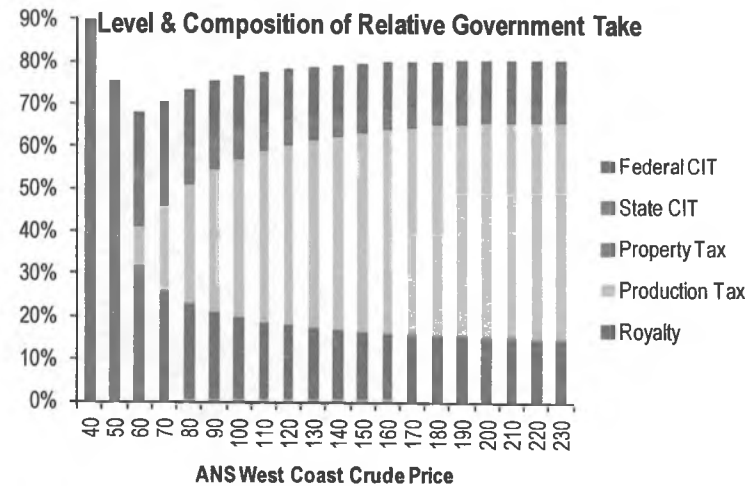
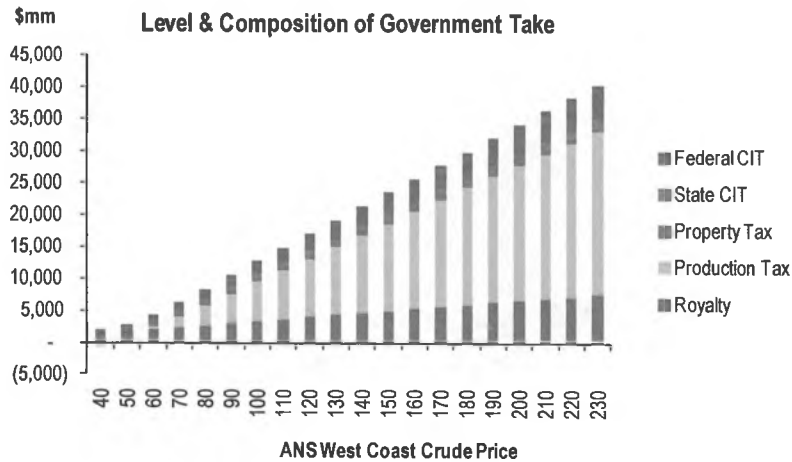
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total CIT
40	136%	-90%	73%	0%	119%	0%	119%
50	46%	-8%	20%	2%	60%	8%	68%
60	32%	10%	11%	3%	56%	12%	68%
70	26%	20%	8%	3%	58%	13%	71%
80	23%	28%	6%	3%	61%	13%	74%
90	21%	34%	5%	3%	63%	12%	76%
100	20%	38%	4%	3%	65%	12%	77%
110	19%	41%	4%	3%	67%	12%	78%
120	18%	44%	3%	3%	68%	11%	79%
130	17%	45%	3%	3%	68%	11%	80%
140	17%	47%	3%	3%	69%	11%	80%
150	16%	48%	2%	3%	69%	11%	80%
160	16%	49%	2%	3%	70%	11%	80%
170	16%	49%	2%	3%	70%	11%	81%
180	16%	50%	2%	3%	70%	10%	81%
190	15%	50%	2%	3%	70%	10%	81%
200	15%	51%	2%	3%	70%	10%	81%
210	15%	51%	2%	3%	70%	10%	81%
220	15%	51%	1%	3%	70%	10%	81%
230	15%	51%	1%	3%	70%	10%	81%



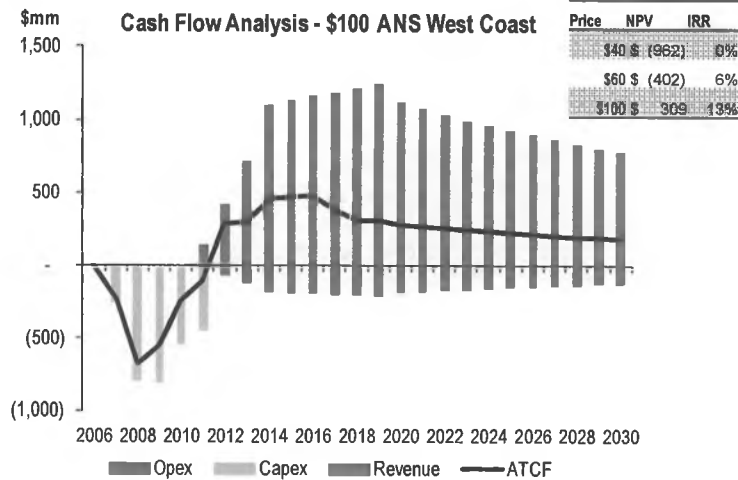
Amendment B18 (high cost development)



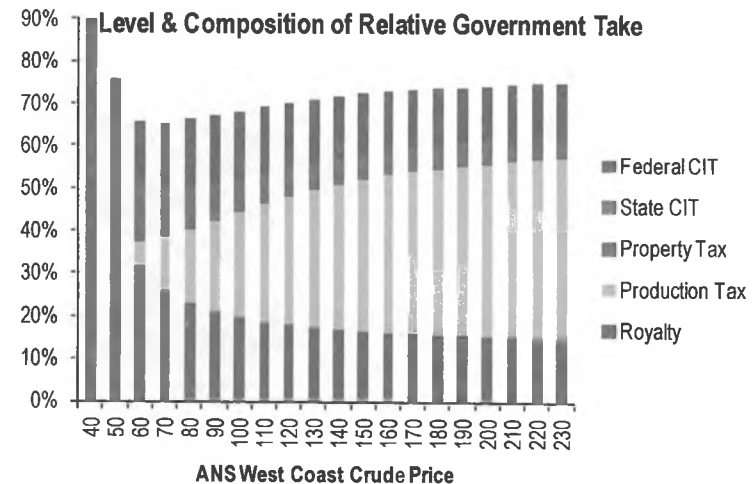
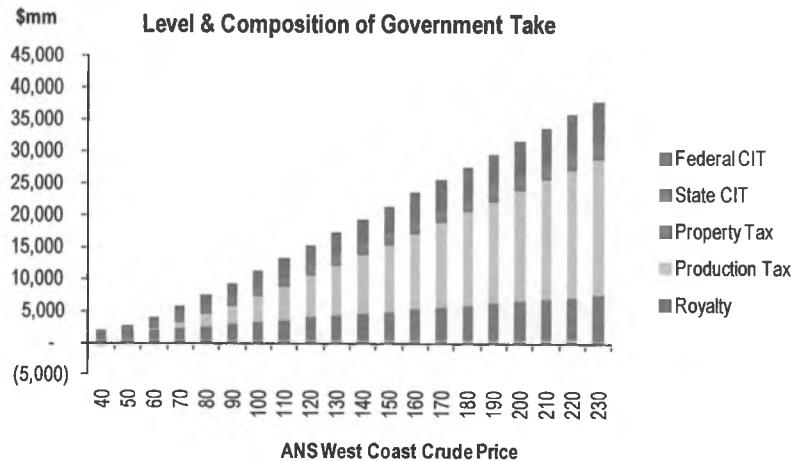
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	136%	-90%	73%	0%	119%	0%	119%
50	46%	-8%	20%	2%	60%	8%	68%
60	32%	10%	11%	3%	58%	12%	68%
70	26%	20%	8%	3%	58%	13%	71%
80	23%	28%	6%	3%	60%	13%	73%
90	21%	33%	5%	3%	63%	13%	75%
100	20%	37%	4%	3%	65%	12%	77%
110	19%	40%	4%	3%	66%	12%	78%
120	18%	42%	3%	3%	67%	12%	78%
130	17%	44%	3%	3%	67%	11%	79%
140	17%	46%	3%	3%	68%	11%	79%
150	16%	47%	2%	3%	69%	11%	80%
160	16%	48%	2%	3%	69%	11%	80%
170	16%	49%	2%	3%	69%	11%	80%
180	16%	49%	2%	3%	70%	11%	80%
190	15%	50%	2%	3%	70%	10%	80%
200	15%	50%	2%	3%	70%	10%	80%
210	15%	51%	2%	3%	70%	10%	80%
220	15%	51%	1%	3%	70%	10%	80%
230	15%	51%	1%	3%	70%	10%	81%



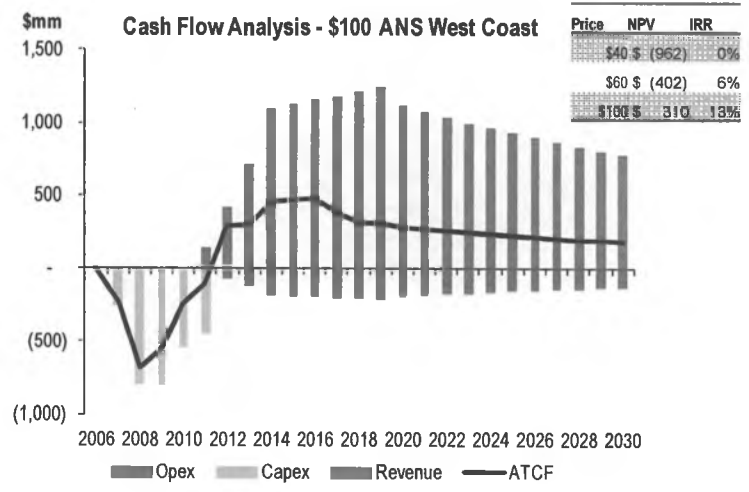
Amendment B4 (high cost development)



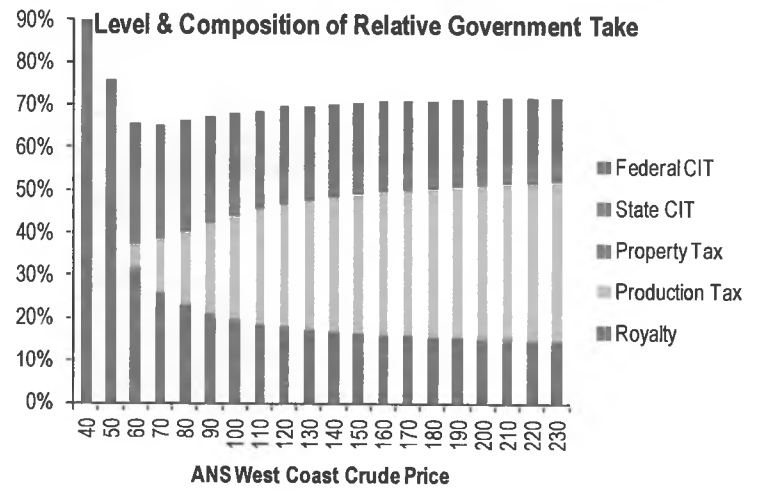
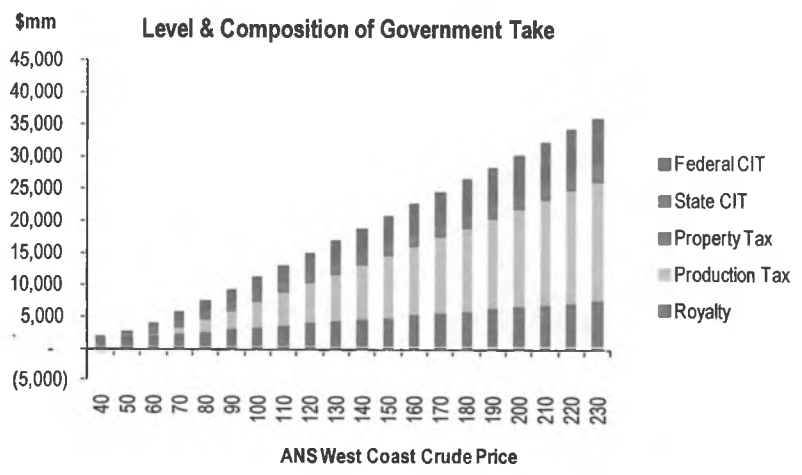
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	136%	-90%	73%	0%	119%	0%	119%
50	46%	-8%	20%	2%	59%	8%	68%
60	32%	6%	11%	4%	52%	13%	66%
70	26%	12%	8%	4%	50%	15%	65%
80	23%	17%	6%	4%	51%	16%	66%
90	21%	21%	5%	4%	51%	16%	67%
100	20%	25%	4%	4%	53%	16%	68%
110	19%	28%	4%	4%	54%	15%	69%
120	18%	30%	3%	4%	55%	15%	70%
130	17%	32%	3%	4%	56%	15%	71%
140	17%	34%	3%	4%	57%	14%	72%
150	16%	36%	2%	4%	58%	14%	73%
160	16%	37%	2%	4%	59%	14%	73%
170	16%	38%	2%	4%	60%	14%	73%
180	16%	39%	2%	4%	60%	14%	74%
190	15%	40%	2%	3%	61%	13%	74%
200	15%	41%	2%	3%	61%	13%	74%
210	15%	41%	2%	3%	62%	13%	75%
220	15%	42%	1%	3%	62%	13%	75%
230	15%	43%	1%	3%	62%	13%	75%



Amendment B5 (high cost development)



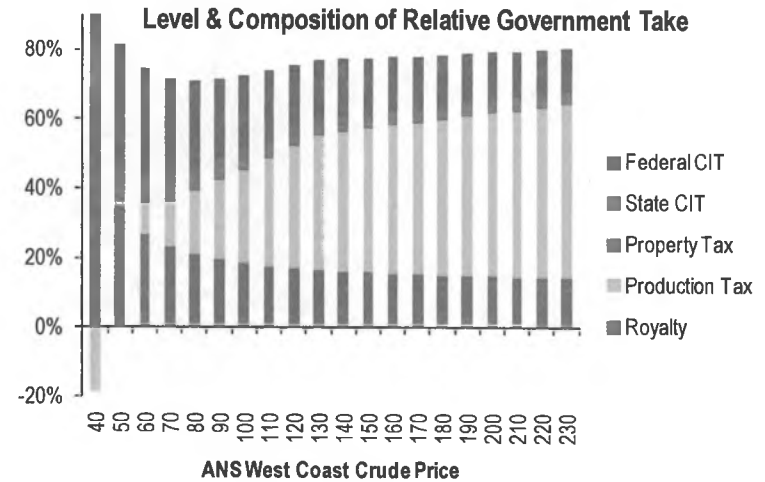
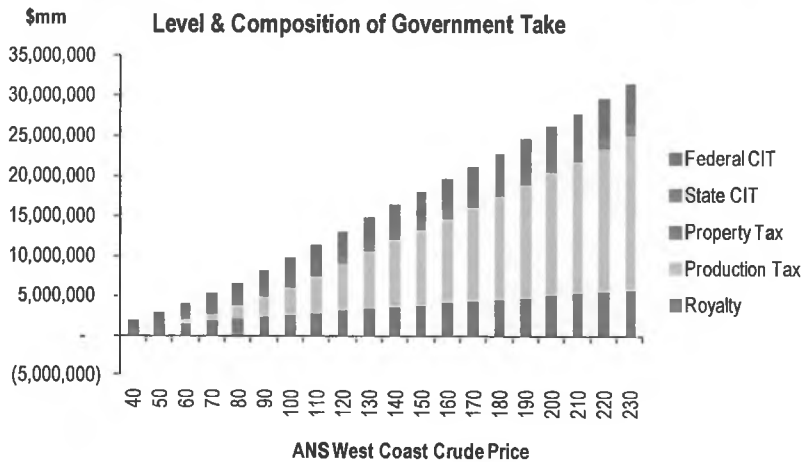
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total CIT
40	136%	-90%	73%	0%	119%	0%	119%
50	46%	-8%	20%	2%	59%	8%	68%
60	32%	6%	11%	4%	52%	13%	66%
70	26%	12%	8%	4%	50%	15%	65%
80	23%	17%	6%	4%	51%	16%	66%
90	21%	21%	5%	4%	51%	16%	67%
100	20%	24%	4%	4%	52%	16%	68%
110	19%	27%	4%	4%	53%	15%	68%
120	18%	29%	3%	4%	54%	16%	70%
130	17%	30%	3%	4%	55%	15%	70%
140	17%	32%	3%	4%	55%	15%	70%
150	16%	33%	2%	4%	56%	15%	71%
160	16%	34%	2%	4%	56%	15%	71%
170	16%	34%	2%	4%	56%	15%	71%
180	16%	35%	2%	4%	56%	15%	71%
190	15%	36%	2%	4%	57%	15%	71%
200	15%	36%	2%	4%	57%	15%	72%
210	15%	36%	2%	4%	57%	15%	72%
220	15%	37%	1%	4%	57%	15%	72%
230	15%	37%	1%	4%	57%	15%	72%



ACES (FY 2013 – DOR Estimate Inputs)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	\$ 985,712	\$ (290,533)	\$ 93,820	\$ 198,851	\$ 987,849	758,947	1,746,797
50	\$ 1,232,140	\$ 43,155	\$ 93,820	\$ 315,721	\$ 1,684,835	1,205,000	2,889,836
60	\$ 1,478,568	\$ 474,404	\$ 93,820	\$ 424,395	\$ 2,471,187	1,619,776	4,090,962
70	\$ 1,724,995	\$ 969,137	\$ 93,820	\$ 527,737	\$ 3,315,690	2,014,198	5,329,888
80	\$ 1,971,423	\$ 1,715,090	\$ 93,820	\$ 609,977	\$ 4,390,310	2,328,079	6,718,389
90	\$ 2,217,851	\$ 2,599,043	\$ 93,820	\$ 680,625	\$ 5,591,338	2,597,717	8,189,056
100	\$ 2,464,279	\$ 3,620,995	\$ 93,820	\$ 739,680	\$ 6,918,774	2,823,113	9,741,887
110	\$ 2,710,707	\$ 4,780,946	\$ 93,820	\$ 787,144	\$ 8,372,617	3,004,266	11,376,883
120	\$ 2,957,135	\$ 6,078,897	\$ 93,820	\$ 823,016	\$ 9,952,868	3,141,176	13,094,044
130	\$ 3,203,563	\$ 7,500,215	\$ 93,820	\$ 848,525	\$ 11,646,123	3,238,535	14,884,658
140	\$ 3,449,991	\$ 8,540,576	\$ 93,820	\$ 906,034	\$ 12,990,421	3,458,029	16,448,450
150	\$ 3,696,419	\$ 9,615,437	\$ 93,820	\$ 960,645	\$ 14,366,321	3,666,462	18,032,783
160	\$ 3,942,847	\$ 10,724,798	\$ 93,820	\$ 1,012,358	\$ 15,773,823	3,863,835	19,637,658
170	\$ 4,189,275	\$ 11,868,659	\$ 93,820	\$ 1,061,174	\$ 17,212,927	4,050,147	21,263,074
180	\$ 4,435,703	\$ 13,047,019	\$ 93,820	\$ 1,107,091	\$ 18,683,633	4,225,398	22,909,031
190	\$ 4,682,131	\$ 14,259,880	\$ 93,820	\$ 1,150,110	\$ 20,185,941	4,389,588	24,575,529
200	\$ 4,928,559	\$ 15,507,240	\$ 93,820	\$ 1,190,232	\$ 21,719,850	4,542,718	26,262,568
210	\$ 5,174,986	\$ 16,789,100	\$ 93,820	\$ 1,227,455	\$ 23,285,362	4,684,787	27,970,149
220	\$ 5,421,414	\$ 18,105,461	\$ 93,820	\$ 1,261,781	\$ 24,882,475	4,815,796	29,698,271
230	\$ 5,667,842	\$ 19,456,321	\$ 93,820	\$ 1,293,208	\$ 26,511,191	4,935,744	31,446,934

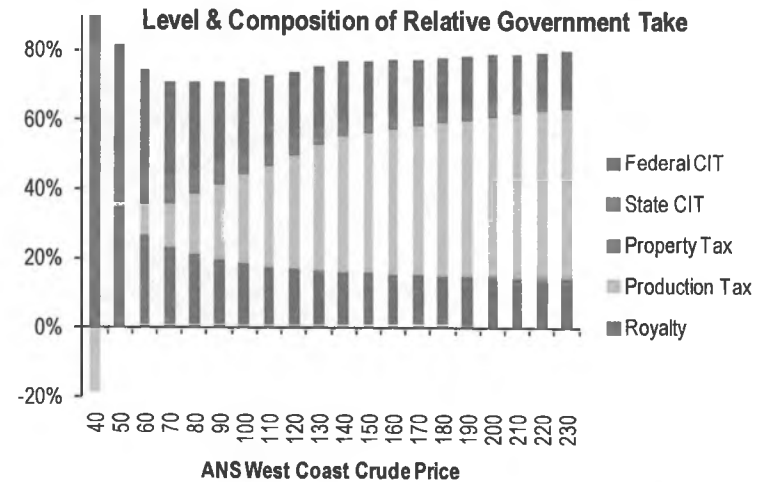
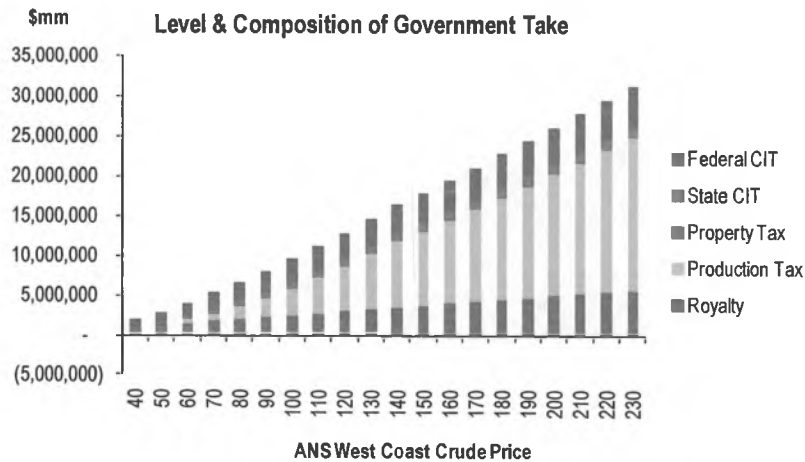
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	46%	0%	4%	65%	14%	79%
200	15%	47%	0%	4%	66%	14%	79%
210	15%	48%	0%	3%	66%	13%	80%
220	15%	49%	0%	3%	67%	13%	80%
230	15%	50%	0%	3%	68%	13%	81%



CSSB 192 (FY 2013 – DOR Estimate Inputs)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	\$ 985,712	\$ (290,533)	\$ 93,820	\$ 198,851	\$ 987,849	758,947	1,746,797
50	\$ 1,232,140	\$ 43,155	\$ 93,820	\$ 315,721	\$ 1,684,835	1,205,000	2,889,836
60	\$ 1,478,568	\$ 474,404	\$ 93,820	\$ 424,395	\$ 2,471,187	1,619,776	4,090,962
70	\$ 1,724,995	\$ 961,202	\$ 93,820	\$ 528,404	\$ 3,308,421	2,016,742	5,325,163
80	\$ 1,971,423	\$ 1,667,817	\$ 93,820	\$ 613,948	\$ 4,347,008	2,343,235	6,690,243
90	\$ 2,217,851	\$ 2,495,181	\$ 93,820	\$ 689,349	\$ 5,496,201	2,631,015	8,127,216
100	\$ 2,464,279	\$ 3,443,295	\$ 93,820	\$ 754,607	\$ 6,756,001	2,880,083	9,636,085
110	\$ 2,710,707	\$ 4,512,159	\$ 93,820	\$ 809,722	\$ 8,126,408	3,090,439	11,216,847
120	\$ 2,957,135	\$ 5,701,772	\$ 93,820	\$ 854,694	\$ 9,607,422	3,262,083	12,869,504
130	\$ 3,203,563	\$ 7,012,136	\$ 93,820	\$ 889,523	\$ 11,199,042	3,395,014	14,594,055
140	\$ 3,449,991	\$ 8,382,302	\$ 93,820	\$ 919,329	\$ 12,845,442	3,508,772	16,354,214
150	\$ 3,696,419	\$ 9,441,768	\$ 93,820	\$ 975,233	\$ 14,207,240	3,722,141	17,929,381
160	\$ 3,942,847	\$ 10,535,733	\$ 93,820	\$ 1,028,240	\$ 15,600,640	3,924,449	19,525,089
170	\$ 4,189,275	\$ 11,664,198	\$ 93,820	\$ 1,078,348	\$ 17,025,641	4,115,697	21,141,338
180	\$ 4,435,703	\$ 12,827,163	\$ 93,820	\$ 1,125,559	\$ 18,482,245	4,295,884	22,778,128
190	\$ 4,682,131	\$ 14,024,628	\$ 93,820	\$ 1,169,872	\$ 19,970,450	4,465,010	24,435,460
200	\$ 4,928,559	\$ 15,256,593	\$ 93,820	\$ 1,211,286	\$ 21,490,257	4,623,076	26,113,333
210	\$ 5,174,986	\$ 16,523,057	\$ 93,820	\$ 1,249,803	\$ 23,041,667	4,770,081	27,811,747
220	\$ 5,421,414	\$ 17,824,022	\$ 93,820	\$ 1,285,421	\$ 24,624,678	4,906,025	29,530,703
230	\$ 5,667,842	\$ 19,159,487	\$ 93,820	\$ 1,318,142	\$ 26,239,291	5,030,909	31,270,199

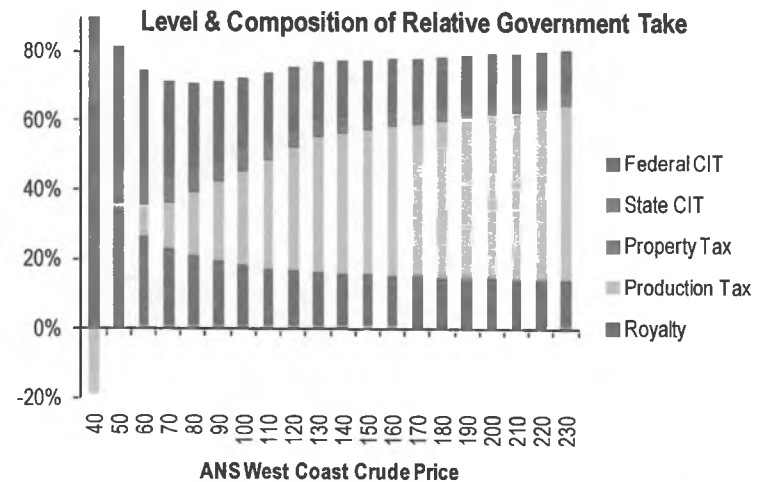
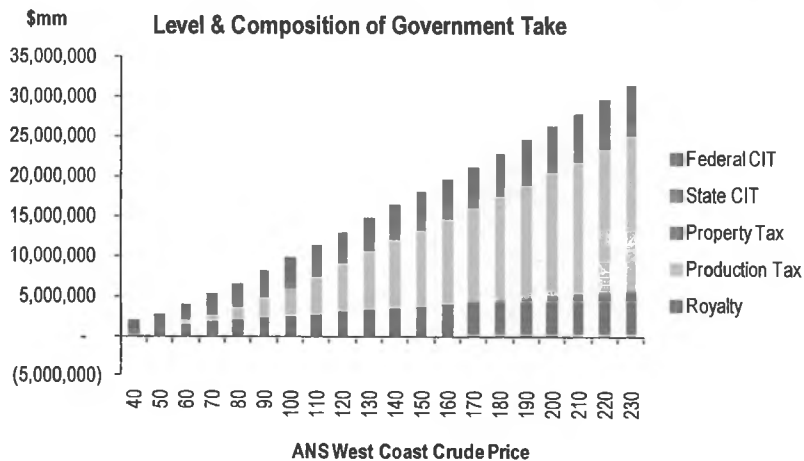
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	22%	1%	6%	48%	23%	71%
100	18%	26%	1%	6%	50%	22%	72%
110	18%	29%	1%	5%	53%	20%	73%
120	17%	33%	1%	5%	55%	19%	74%
130	17%	36%	0%	5%	58%	18%	76%
140	16%	39%	0%	4%	60%	16%	77%
150	16%	41%	0%	4%	61%	16%	77%
160	16%	42%	0%	4%	62%	16%	77%
170	15%	43%	0%	4%	63%	15%	78%
180	15%	44%	0%	4%	63%	15%	78%
190	15%	45%	0%	4%	64%	14%	78%
200	15%	46%	0%	4%	65%	14%	79%
210	15%	47%	0%	4%	66%	14%	79%
220	15%	48%	0%	3%	66%	13%	80%
230	15%	49%	0%	3%	67%	13%	80%



Amendment B8 (FY 2013 – DOR Estimate Inputs)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	\$ 985,712	\$ (290,533)	\$ 93,820	\$ 198,851	\$ 987,849	758,947	1,746,797
50	\$ 1,232,140	\$ 43,155	\$ 93,820	\$ 315,721	\$ 1,684,835	1,205,000	2,889,836
60	\$ 1,478,568	\$ 474,404	\$ 93,820	\$ 424,395	\$ 2,471,187	1,619,776	4,090,962
70	\$ 1,724,995	\$ 969,137	\$ 93,820	\$ 527,737	\$ 3,315,690	2,014,198	5,329,888
80	\$ 1,971,423	\$ 1,715,090	\$ 93,820	\$ 609,977	\$ 4,390,310	2,328,079	6,718,389
90	\$ 2,217,851	\$ 2,599,043	\$ 93,820	\$ 680,625	\$ 5,591,338	2,597,717	8,189,056
100	\$ 2,464,279	\$ 3,620,995	\$ 93,820	\$ 739,680	\$ 6,918,774	2,823,113	9,741,887
110	\$ 2,710,707	\$ 4,780,946	\$ 93,820	\$ 787,144	\$ 8,372,617	3,004,266	11,376,883
120	\$ 2,957,135	\$ 6,078,897	\$ 93,820	\$ 823,016	\$ 9,952,868	3,141,176	13,094,044
130	\$ 3,203,563	\$ 7,500,215	\$ 93,820	\$ 848,525	\$ 11,646,123	3,238,535	14,884,658
140	\$ 3,449,991	\$ 8,540,576	\$ 93,820	\$ 906,034	\$ 12,990,421	3,458,029	16,448,450
150	\$ 3,696,419	\$ 9,615,437	\$ 93,820	\$ 960,645	\$ 14,366,321	3,666,462	18,032,783
160	\$ 3,942,847	\$ 10,724,798	\$ 93,820	\$ 1,012,358	\$ 15,773,823	3,863,835	19,637,658
170	\$ 4,189,275	\$ 11,868,659	\$ 93,820	\$ 1,061,174	\$ 17,212,927	4,050,147	21,263,074
180	\$ 4,435,703	\$ 13,047,019	\$ 93,820	\$ 1,107,091	\$ 18,683,633	4,225,398	22,909,031
190	\$ 4,682,131	\$ 14,259,880	\$ 93,820	\$ 1,150,110	\$ 20,185,941	4,389,588	24,575,529
200	\$ 4,928,559	\$ 15,507,240	\$ 93,820	\$ 1,190,232	\$ 21,719,850	4,542,718	26,262,568
210	\$ 5,174,986	\$ 16,789,100	\$ 93,820	\$ 1,227,455	\$ 23,285,362	4,684,787	27,970,149
220	\$ 5,421,414	\$ 18,105,461	\$ 93,820	\$ 1,261,781	\$ 24,882,475	4,815,796	29,698,271
230	\$ 5,667,842	\$ 19,446,187	\$ 93,820	\$ 1,294,059	\$ 26,501,908	4,938,992	31,440,901

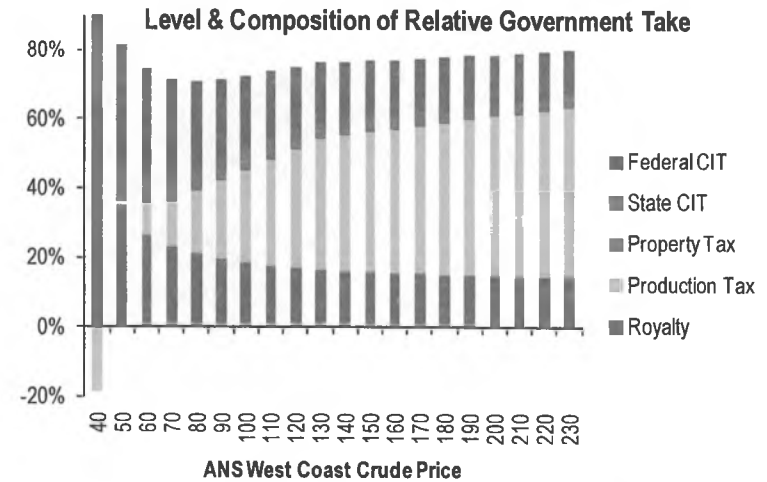
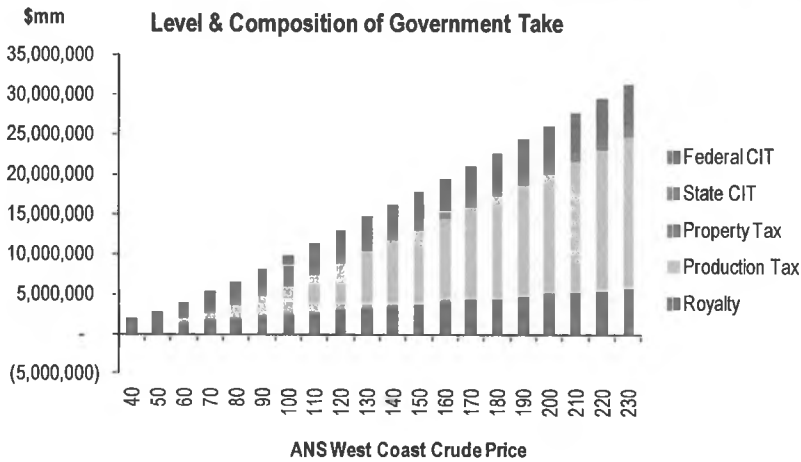
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	46%	0%	4%	65%	14%	79%
200	15%	47%	0%	4%	66%	14%	79%
210	15%	48%	0%	3%	66%	13%	80%
220	15%	49%	0%	3%	67%	13%	80%
230	15%	50%	0%	3%	68%	13%	81%



Amendment B18 (FY 2013 – DOR Estimate Inputs)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
\$ 40	\$ 985,712	\$ (290,533)	\$ 93,820	\$ 198,851	\$ 987,849	758,947	1,746,797
50	\$ 1,232,140	\$ 43,155	\$ 93,820	\$ 315,721	\$ 1,684,835	1,205,000	2,889,836
60	\$ 1,478,568	\$ 474,404	\$ 93,820	\$ 424,395	\$ 2,471,187	1,619,776	4,090,962
70	\$ 1,724,995	\$ 969,137	\$ 93,820	\$ 527,737	\$ 3,315,690	2,014,198	5,329,888
80	\$ 1,971,423	\$ 1,715,090	\$ 93,820	\$ 609,977	\$ 4,390,310	2,328,079	6,718,389
90	\$ 2,217,851	\$ 2,599,043	\$ 93,820	\$ 680,625	\$ 5,591,338	2,597,717	8,189,056
100	\$ 2,464,279	\$ 3,620,995	\$ 93,820	\$ 739,680	\$ 6,918,774	2,823,113	9,741,887
110	\$ 2,710,707	\$ 4,747,636	\$ 93,820	\$ 789,942	\$ 8,342,105	3,014,945	11,357,050
120	\$ 2,957,135	\$ 5,969,593	\$ 93,820	\$ 832,197	\$ 9,852,745	3,176,219	13,028,965
130	\$ 3,203,563	\$ 7,300,106	\$ 93,820	\$ 865,334	\$ 11,462,822	3,302,691	14,765,513
140	\$ 3,449,991	\$ 8,318,904	\$ 93,820	\$ 924,654	\$ 12,787,369	3,529,097	16,316,467
150	\$ 3,696,419	\$ 9,372,203	\$ 93,820	\$ 981,077	\$ 14,143,518	3,744,443	17,887,962
160	\$ 3,942,847	\$ 10,460,001	\$ 93,820	\$ 1,034,601	\$ 15,531,269	3,948,729	19,479,998
170	\$ 4,189,275	\$ 11,582,299	\$ 93,820	\$ 1,085,228	\$ 16,950,622	4,141,953	21,092,575
180	\$ 4,435,703	\$ 12,739,097	\$ 93,820	\$ 1,132,957	\$ 18,401,576	4,324,118	22,725,694
190	\$ 4,682,131	\$ 13,930,395	\$ 93,820	\$ 1,177,787	\$ 19,884,133	4,495,221	24,379,354
200	\$ 4,928,559	\$ 15,156,193	\$ 93,820	\$ 1,219,720	\$ 21,398,291	4,655,264	26,053,555
210	\$ 5,174,986	\$ 16,416,491	\$ 93,820	\$ 1,258,754	\$ 22,944,052	4,804,246	27,748,298
220	\$ 5,421,414	\$ 17,711,289	\$ 93,820	\$ 1,294,891	\$ 24,521,414	4,942,167	29,463,581
230	\$ 5,667,842	\$ 19,040,587	\$ 93,820	\$ 1,328,130	\$ 26,130,378	5,069,028	31,199,406

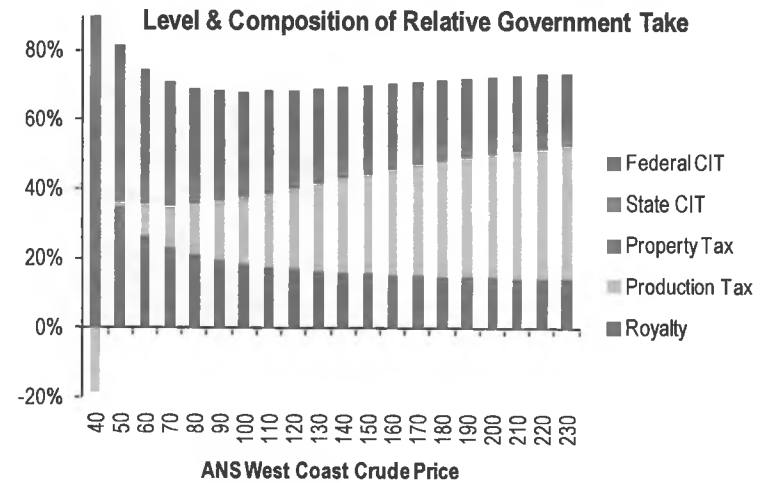
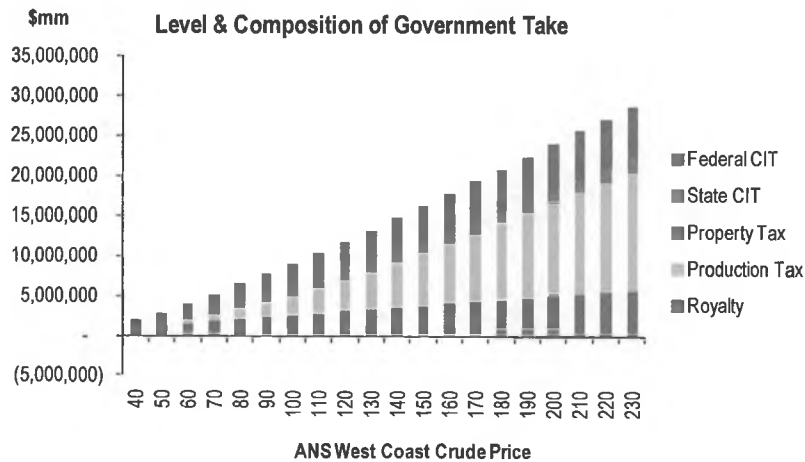
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	34%	1%	5%	57%	18%	75%
130	17%	38%	0%	4%	59%	17%	76%
140	16%	39%	0%	4%	60%	17%	77%
150	16%	40%	0%	4%	61%	16%	77%
160	16%	41%	0%	4%	62%	16%	77%
170	15%	43%	0%	4%	62%	15%	78%
180	15%	44%	0%	4%	63%	15%	78%
190	15%	45%	0%	4%	64%	14%	78%
200	15%	46%	0%	4%	65%	14%	79%
210	15%	47%	0%	4%	65%	14%	79%
220	15%	48%	0%	3%	66%	13%	80%
230	15%	49%	0%	3%	67%	13%	80%



Amendment B4 (FY 2013 – DOR Estimate Inputs)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	\$ 985,712	\$ (290,533)	\$ 93,820	\$ 198,851	\$ 987,849	758,947	1,746,797
50	\$ 1,232,140	\$ 43,155	\$ 93,820	\$ 315,721	\$ 1,684,835	1,205,000	2,889,836
60	\$ 1,478,568	\$ 474,404	\$ 93,820	\$ 424,395	\$ 2,471,187	1,619,778	4,090,962
70	\$ 1,724,995	\$ 917,748	\$ 93,820	\$ 532,054	\$ 3,268,618	2,030,673	5,299,291
80	\$ 1,971,423	\$ 1,394,750	\$ 93,820	\$ 636,886	\$ 4,096,879	2,430,780	6,527,659
90	\$ 2,217,851	\$ 1,955,373	\$ 93,820	\$ 734,693	\$ 5,001,737	2,804,078	7,805,815
100	\$ 2,464,279	\$ 2,583,312	\$ 93,820	\$ 826,846	\$ 5,968,257	3,155,794	9,124,051
110	\$ 2,710,707	\$ 3,275,938	\$ 93,820	\$ 913,565	\$ 6,994,030	3,486,772	10,480,801
120	\$ 2,957,135	\$ 4,033,252	\$ 93,820	\$ 994,850	\$ 8,079,056	3,797,010	11,876,067
130	\$ 3,203,563	\$ 4,853,938	\$ 93,820	\$ 1,070,812	\$ 9,222,133	4,086,932	13,309,065
140	\$ 3,449,991	\$ 5,716,436	\$ 93,820	\$ 1,143,262	\$ 10,403,509	4,363,449	14,766,957
150	\$ 3,696,419	\$ 6,646,249	\$ 93,820	\$ 1,210,057	\$ 11,646,545	4,618,384	16,264,929
160	\$ 3,942,847	\$ 7,640,749	\$ 93,820	\$ 1,271,419	\$ 12,948,835	4,852,581	17,801,415
170	\$ 4,189,275	\$ 8,675,747	\$ 93,820	\$ 1,329,378	\$ 14,288,220	5,073,794	19,362,014
180	\$ 4,435,703	\$ 9,710,744	\$ 93,820	\$ 1,387,338	\$ 15,627,605	5,295,008	20,922,612
190	\$ 4,682,131	\$ 10,745,741	\$ 93,820	\$ 1,445,298	\$ 16,966,990	5,516,221	22,483,211
200	\$ 4,928,559	\$ 11,780,739	\$ 93,820	\$ 1,503,258	\$ 18,306,375	5,737,434	24,043,809
210	\$ 5,174,986	\$ 12,815,736	\$ 93,820	\$ 1,561,218	\$ 19,645,760	5,958,648	25,604,408
220	\$ 5,421,414	\$ 13,850,733	\$ 93,820	\$ 1,619,178	\$ 20,985,145	6,179,861	27,165,006
230	\$ 5,667,842	\$ 14,885,730	\$ 93,820	\$ 1,677,137	\$ 22,324,530	6,401,075	28,725,605

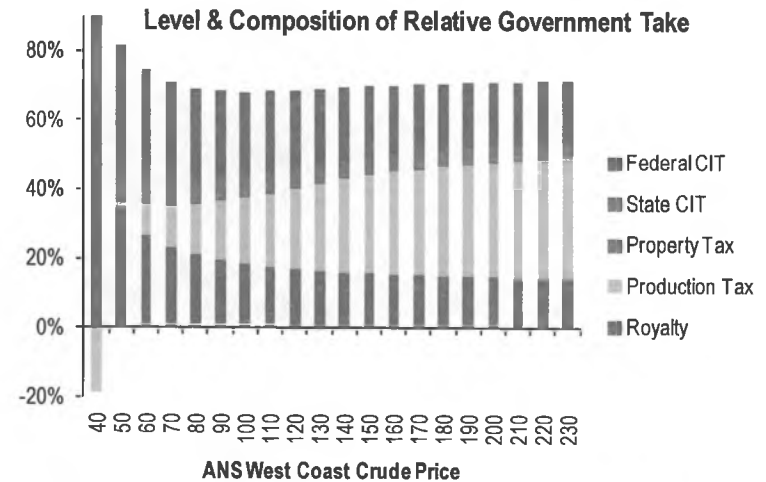
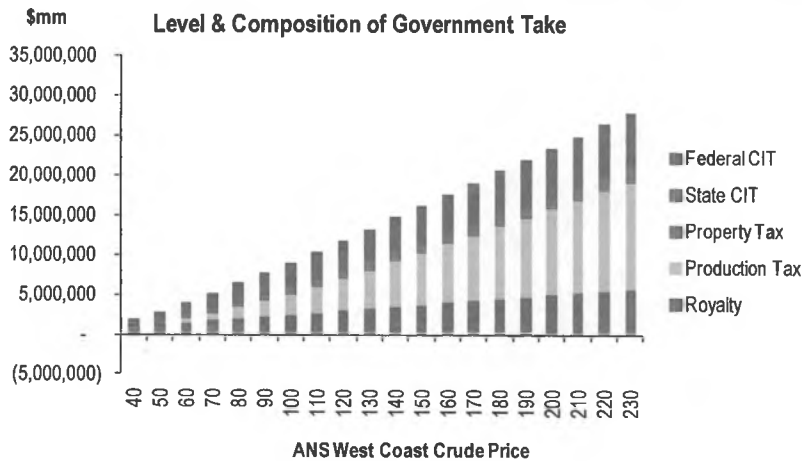
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	12%	1%	7%	44%	27%	71%
80	21%	15%	1%	7%	43%	26%	68%
90	19%	17%	1%	6%	44%	25%	68%
100	18%	19%	1%	6%	45%	24%	68%
110	18%	21%	1%	6%	46%	23%	68%
120	17%	23%	1%	6%	47%	22%	69%
130	17%	25%	0%	6%	48%	21%	69%
140	16%	27%	0%	5%	49%	21%	69%
150	16%	29%	0%	5%	50%	20%	70%
160	16%	30%	0%	5%	51%	19%	71%
170	15%	32%	0%	5%	53%	19%	71%
180	15%	33%	0%	5%	54%	18%	72%
190	15%	35%	0%	5%	54%	18%	72%
200	15%	36%	0%	5%	55%	17%	73%
210	15%	37%	0%	4%	56%	17%	73%
220	15%	37%	0%	4%	57%	17%	73%
230	15%	38%	0%	4%	57%	16%	74%



Amendment B5 (FY 2013 – DOR Estimate Inputs)

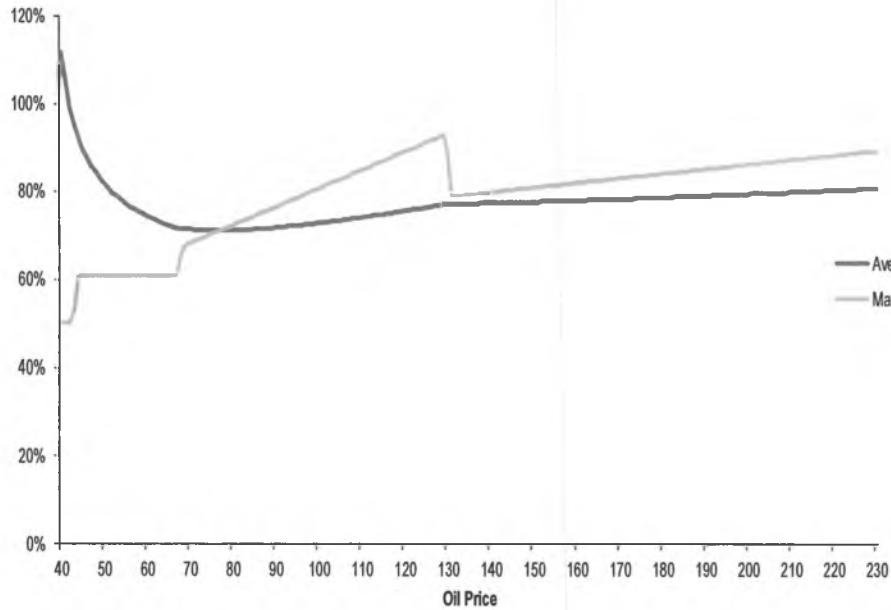
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	\$ 985,712	\$ (290,533)	\$ 93,820	\$ 198,851	\$ 987,849	758,947	1,746,797
50	\$ 1,232,140	\$ 43,155	\$ 93,820	\$ 315,721	\$ 1,684,835	1,205,000	2,889,836
60	\$ 1,478,568	\$ 474,404	\$ 93,820	\$ 424,395	\$ 2,471,187	1,619,776	4,090,962
70	\$ 1,724,995	\$ 917,748	\$ 93,820	\$ 532,054	\$ 3,268,618	2,030,673	5,299,291
80	\$ 1,971,423	\$ 1,394,750	\$ 93,820	\$ 636,886	\$ 4,096,879	2,430,780	6,527,659
90	\$ 2,217,851	\$ 1,955,373	\$ 93,820	\$ 734,693	\$ 5,001,737	2,804,078	7,805,815
100	\$ 2,464,279	\$ 2,583,312	\$ 93,820	\$ 826,846	\$ 5,968,257	3,155,794	9,124,051
110	\$ 2,710,707	\$ 3,275,938	\$ 93,820	\$ 913,565	\$ 6,994,030	3,486,772	10,480,801
120	\$ 2,957,135	\$ 4,033,252	\$ 93,820	\$ 994,850	\$ 8,079,056	3,797,010	11,876,067
130	\$ 3,203,563	\$ 4,853,938	\$ 93,820	\$ 1,070,812	\$ 9,222,133	4,086,932	13,309,065
140	\$ 3,449,991	\$ 5,716,436	\$ 93,820	\$ 1,143,262	\$ 10,403,509	4,363,449	14,766,957
150	\$ 3,696,419	\$ 6,578,934	\$ 93,820	\$ 1,215,711	\$ 11,584,884	4,639,965	16,224,849
160	\$ 3,942,847	\$ 7,441,432	\$ 93,820	\$ 1,288,161	\$ 12,766,260	4,916,482	17,682,742
170	\$ 4,189,275	\$ 8,303,929	\$ 93,820	\$ 1,360,611	\$ 13,947,635	5,192,999	19,140,634
180	\$ 4,435,703	\$ 9,166,427	\$ 93,820	\$ 1,433,061	\$ 15,129,010	5,469,516	20,598,526
190	\$ 4,682,131	\$ 10,028,925	\$ 93,820	\$ 1,505,511	\$ 16,310,386	5,746,032	22,056,418
200	\$ 4,928,559	\$ 10,891,423	\$ 93,820	\$ 1,577,960	\$ 17,491,761	6,022,549	23,514,311
210	\$ 5,174,986	\$ 11,753,920	\$ 93,820	\$ 1,650,410	\$ 18,673,137	6,299,066	24,972,203
220	\$ 5,421,414	\$ 12,616,418	\$ 93,820	\$ 1,722,860	\$ 19,854,512	6,575,583	26,430,095
230	\$ 5,667,842	\$ 13,478,916	\$ 93,820	\$ 1,795,310	\$ 21,035,888	6,852,100	27,887,987

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	12%	1%	7%	44%	27%	71%
80	21%	15%	1%	7%	43%	26%	69%
90	19%	17%	1%	6%	44%	25%	68%
100	18%	19%	1%	6%	45%	24%	68%
110	18%	21%	1%	6%	46%	23%	68%
120	17%	23%	1%	6%	47%	22%	69%
130	17%	25%	0%	6%	48%	21%	69%
140	16%	27%	0%	5%	49%	21%	69%
150	16%	28%	0%	5%	50%	20%	70%
160	16%	30%	0%	5%	51%	19%	70%
170	15%	31%	0%	5%	51%	19%	70%
180	15%	31%	0%	5%	52%	19%	71%
190	15%	32%	0%	5%	52%	18%	71%
200	15%	33%	0%	5%	53%	18%	71%
210	15%	34%	0%	5%	53%	18%	71%
220	15%	34%	0%	5%	54%	18%	71%
230	15%	35%	0%	5%	54%	18%	71%

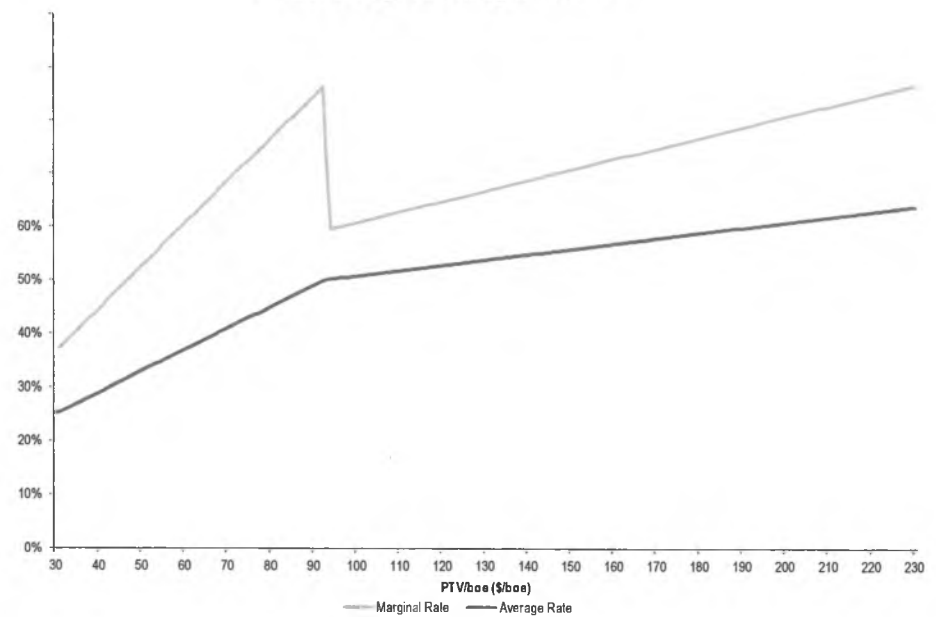


ACES (FY 2013 – DOR Estimate Inputs)

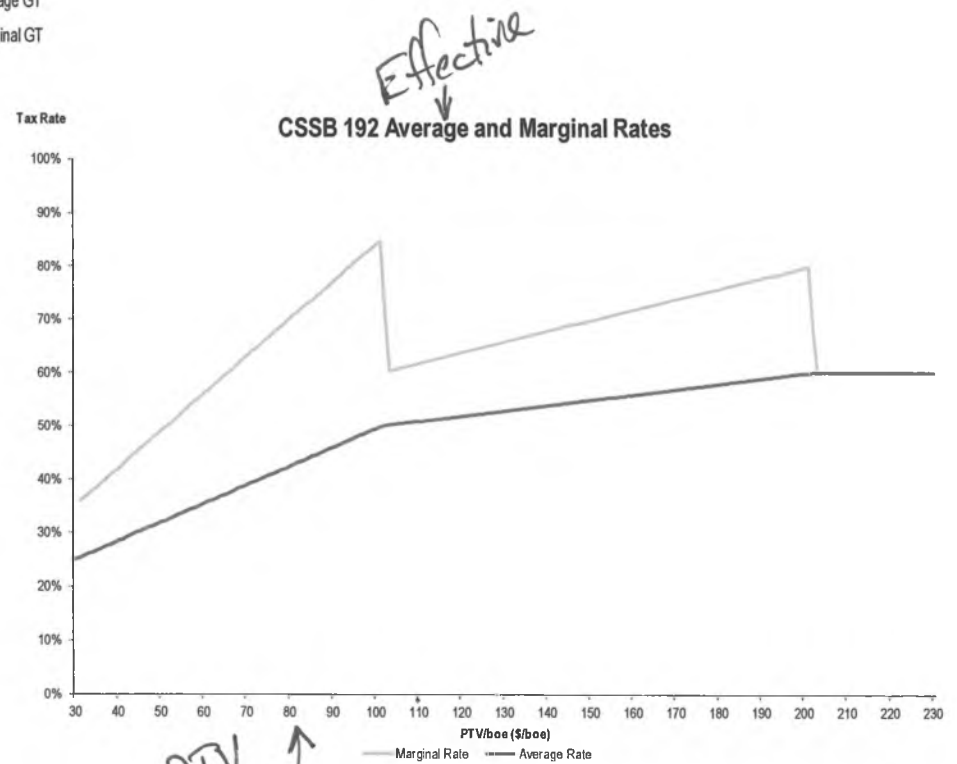
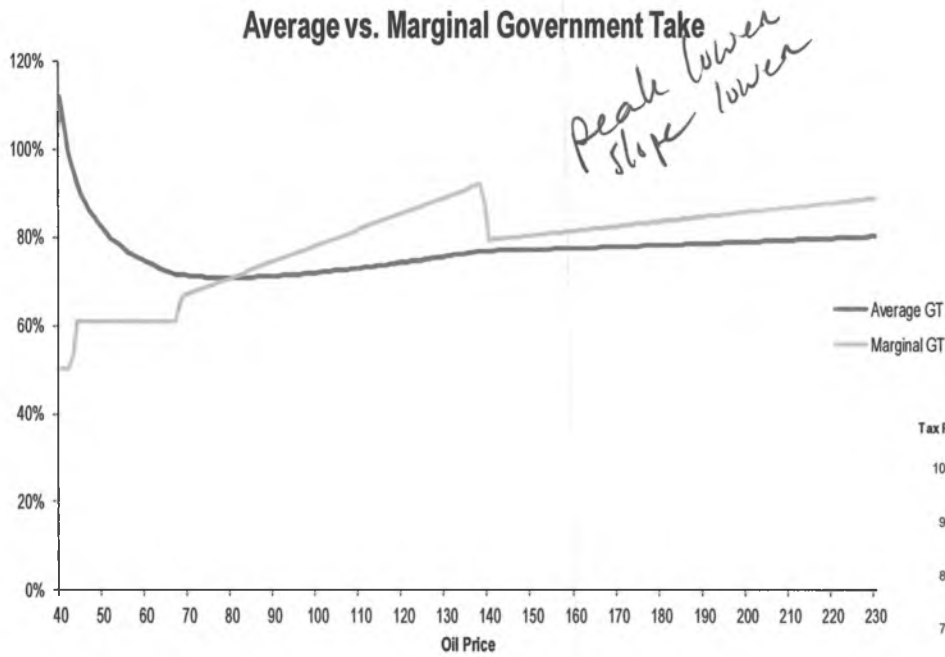
Average vs. Marginal Government Take



ACES Average and Marginal Rates

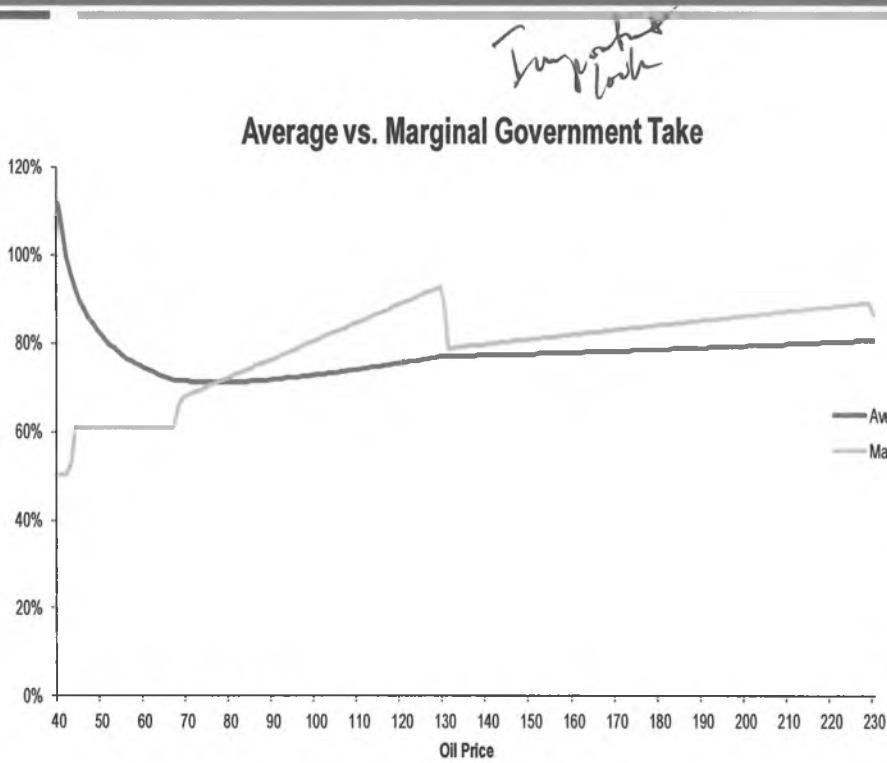


CSSB 192 (FY 2013 – DOR Estimate Inputs)



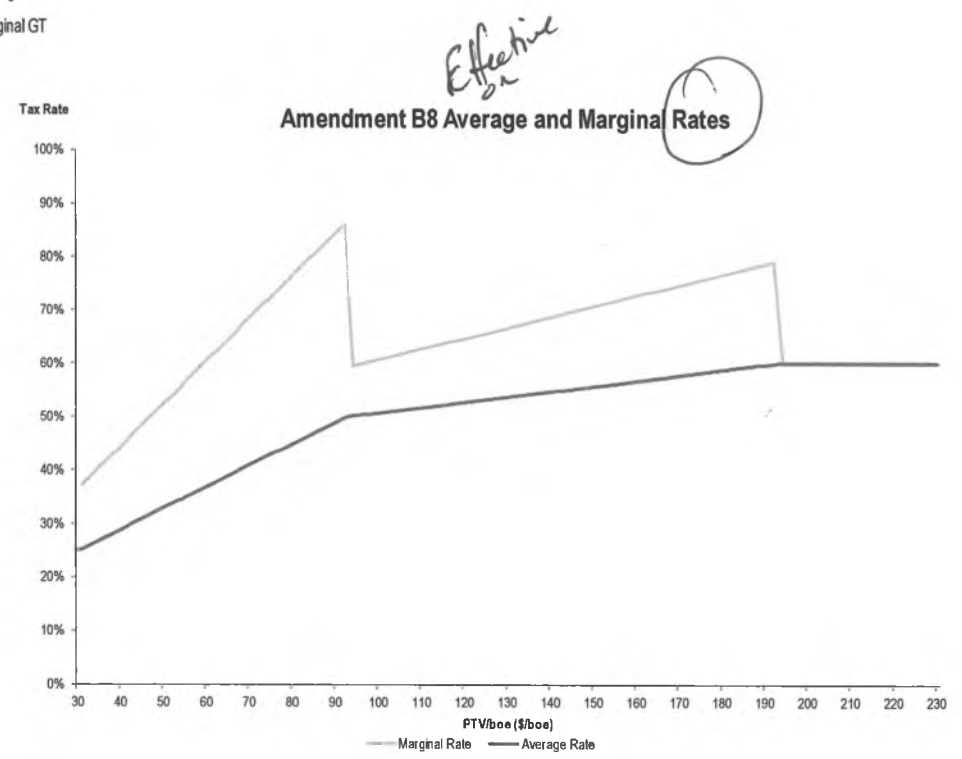
*PTV
Scale ↑*

Amendment B8 (FY 2013 – DOR Estimate Inputs)



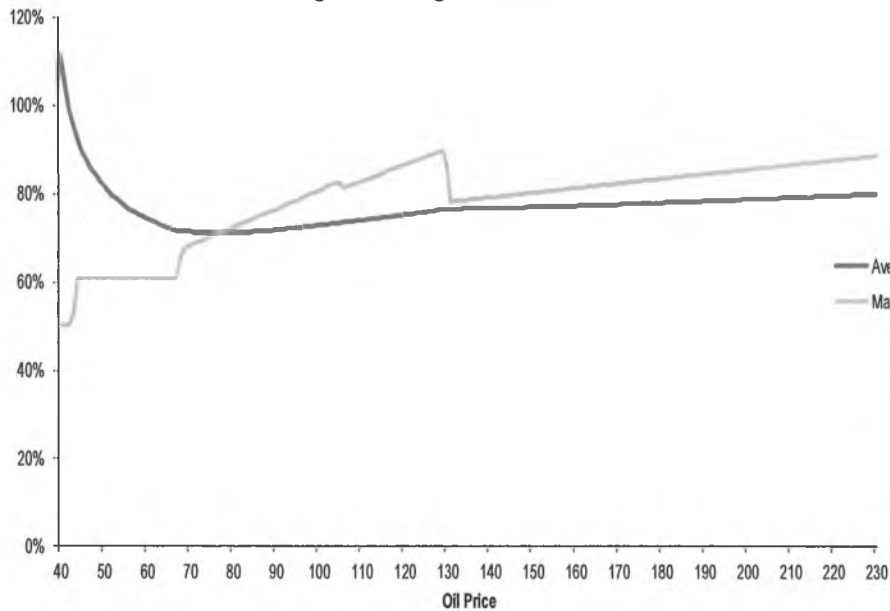
*NPV
10%
IRR*

*- low cost development
- high cost
actual*

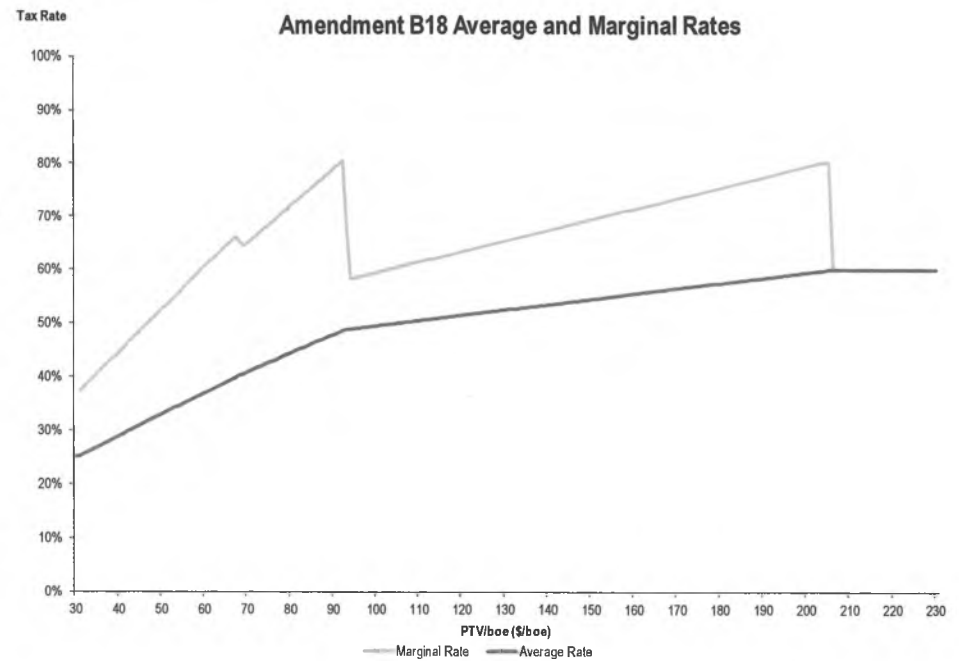


Amendment B18 (FY 2013 – DOR Estimate Inputs)

Average vs. Marginal Government Take

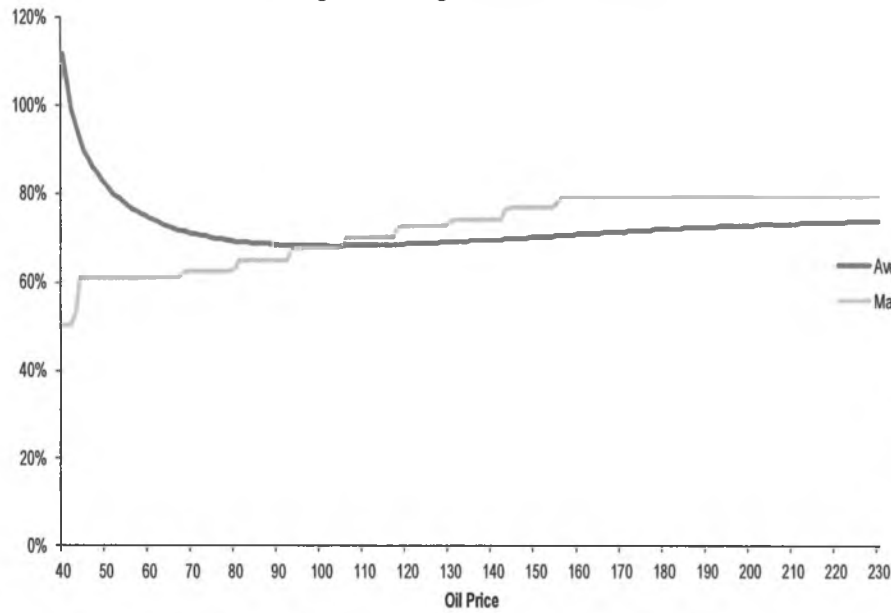


Amendment B18 Average and Marginal Rates

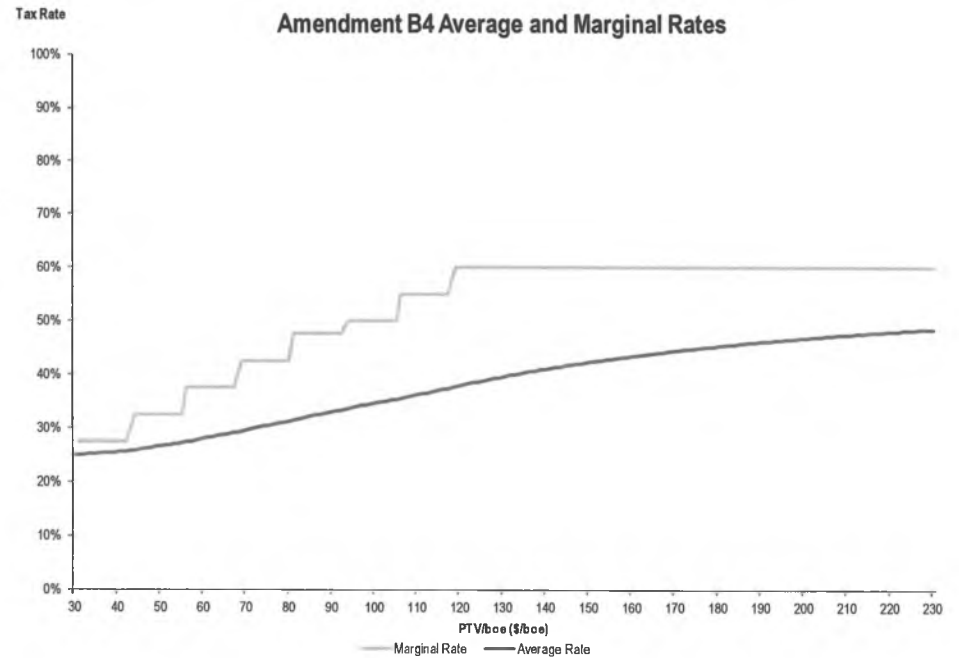


Amendment B4 (FY 2013 – DOR Estimate Inputs)

Average vs. Marginal Government Take

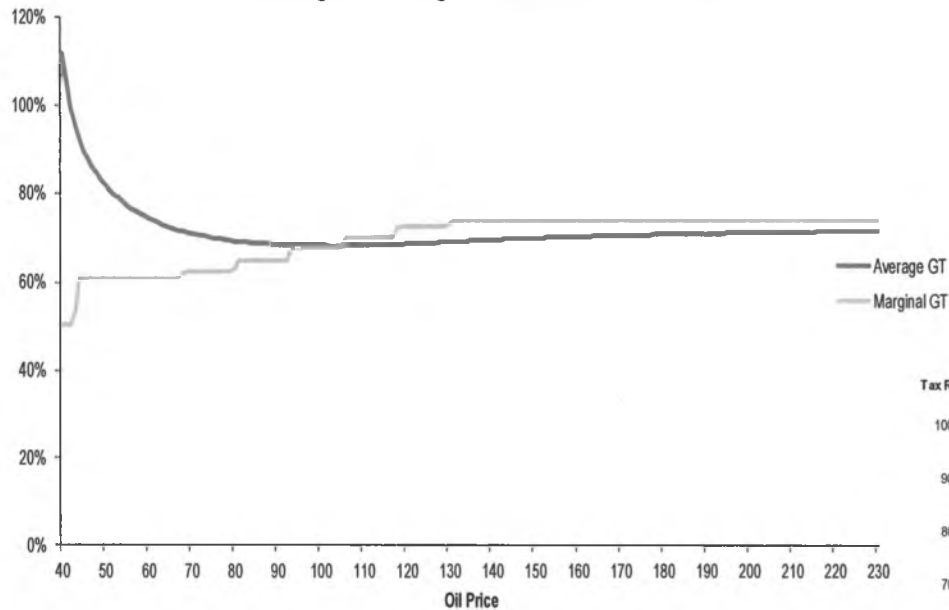


Amendment B4 Average and Marginal Rates

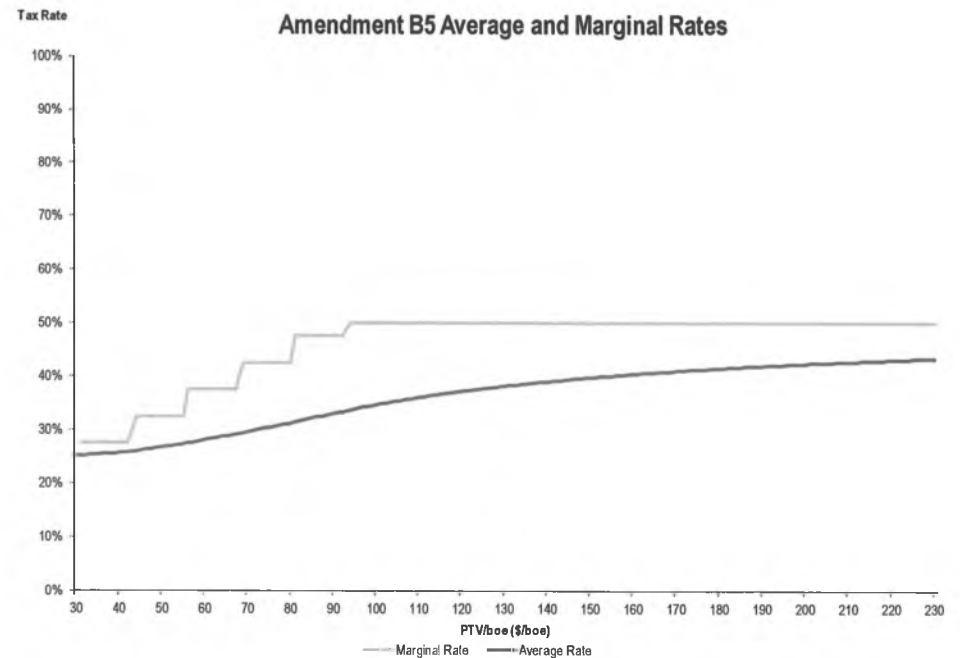


Amendment B5 (FY 2013 – DOR Estimate Inputs)

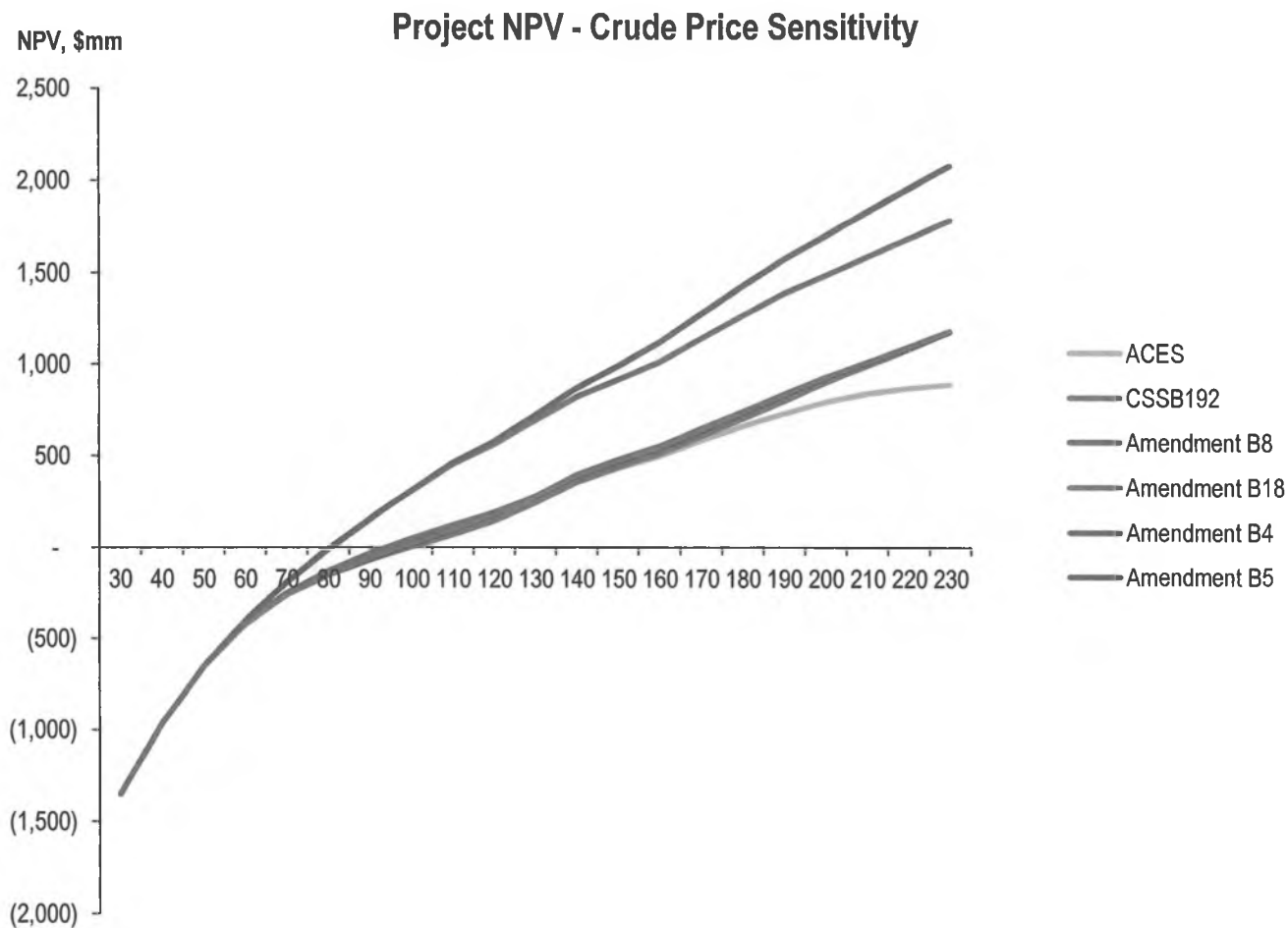
Average vs. Marginal Government Take



Amendment B5 Average and Marginal Rates



Impact of different amendment cases on high cost development economics



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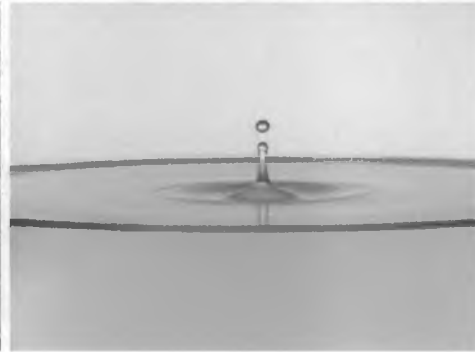
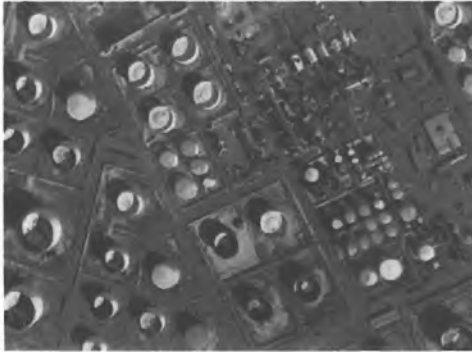
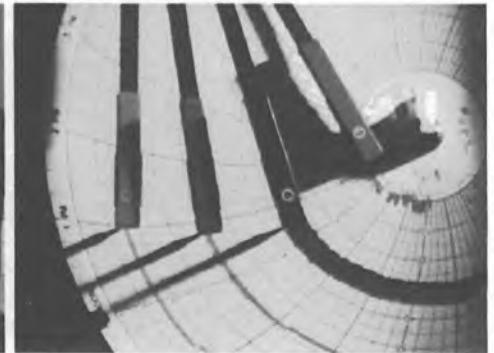
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable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

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PFC Energy



Alaska Senate Resources Committee:

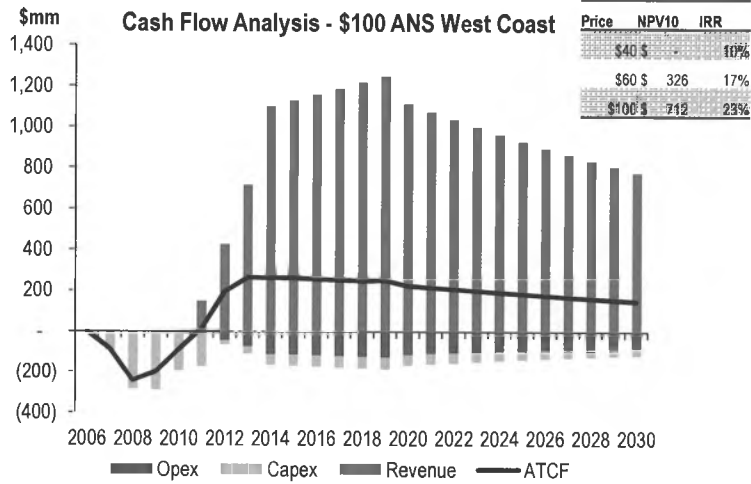
Requested Analysis of Possible ACES
Progressivity Caps Under Different Cost
Assumptions

February 27, 2012

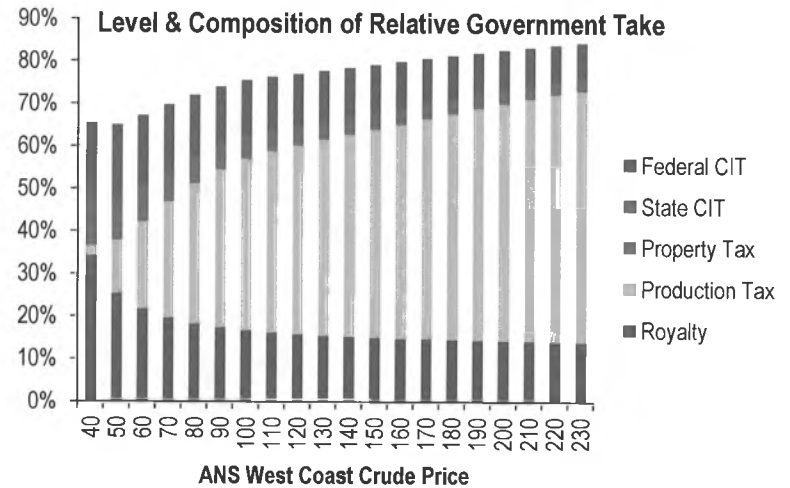
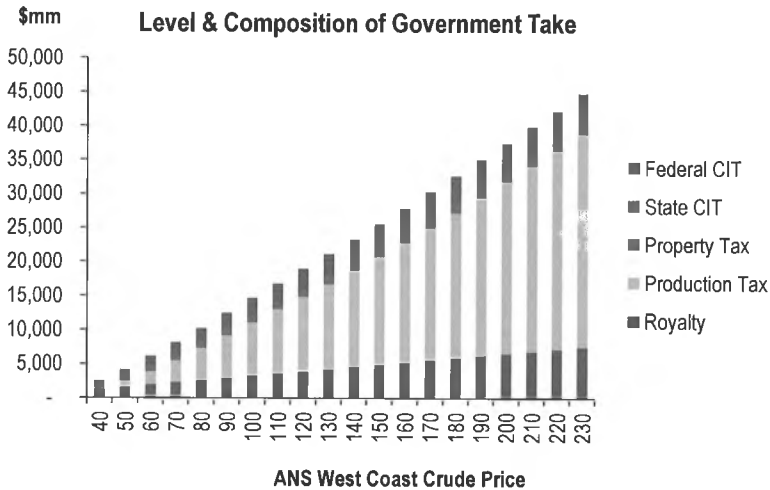
Janak Mayer
Manager, Upstream & Gas
PFC Energy

Cost Assumptions Underlying Development-Forward Analysis

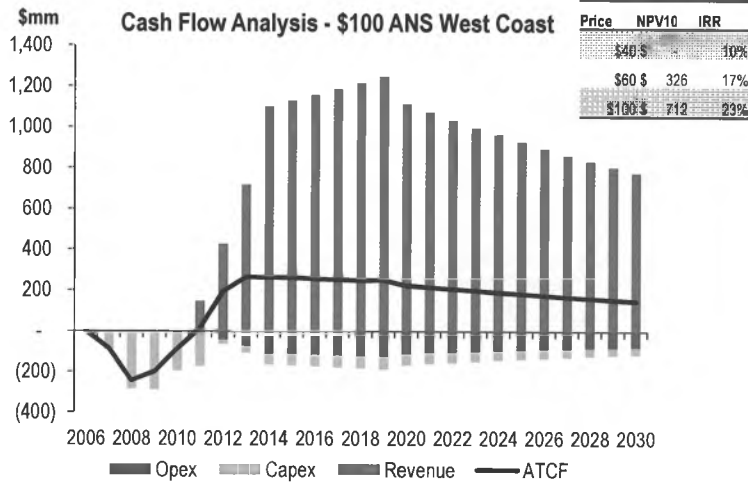
- Development-forward analysis has been undertaken by looking economics for a generic example low-cost field development. Cost examples underpinning the modeled scenarios are:
 - \$10 per flowing bbl operating expenditures
 - \$5 per bbl reserves initial development capital expenditures
 - \$5 per flowing bbl ongoing capital expenditures
 - \$7.40 per flowing bbl transportation costs
- These assumptions are broadly in keeping with actual reported costs for lower-cost production from the North Slope. They are in total higher than the calendar year 2010 costs reported by DOR for the Prudhoe Bay Unit, which are:
 - 1,314mm operating expenditures (~\$11.89 per flowing bbl)
 - \$561mm capital expenditures (includes both maintenance and additional new development ~\$5.08 per flowing bbl)
- On the following slides, the original analyses from the February 17 presentation to Senate Resources Committee have been reproduced, with some minor revisions, and with the addition analysis of production tax caps at 55% and 65%



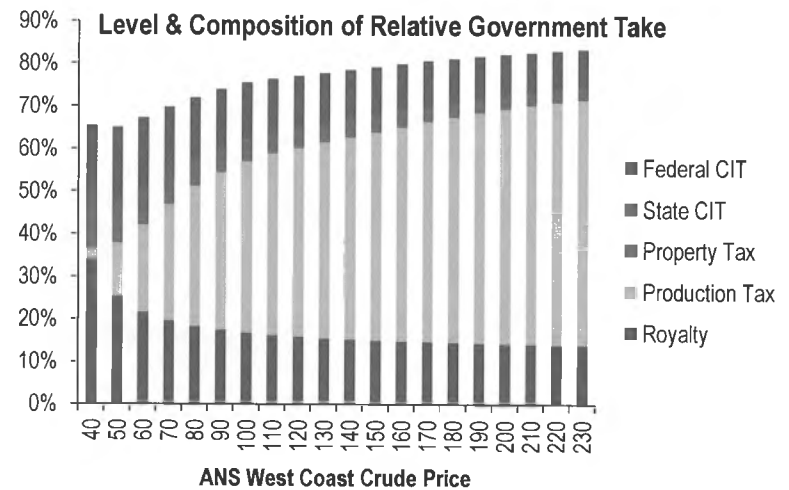
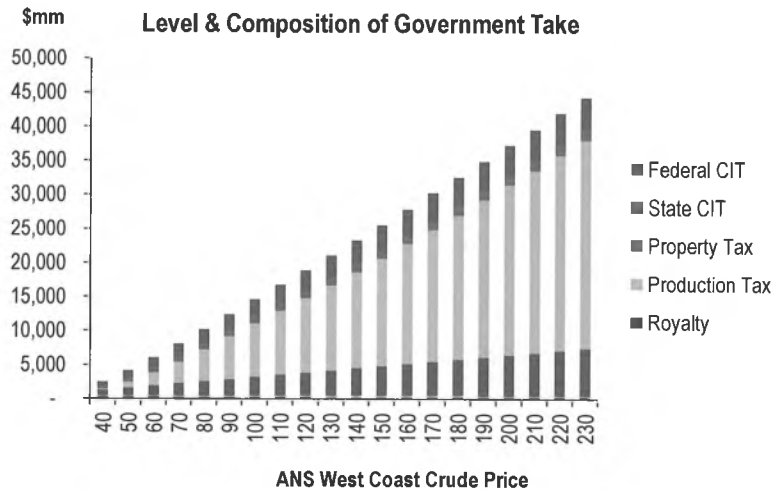
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	25%	12%	6%	4%	48%	17%	65%
60	22%	21%	4%	4%	51%	17%	67%
70	20%	27%	3%	4%	54%	16%	70%
80	18%	33%	3%	4%	58%	14%	72%
90	17%	37%	2%	4%	60%	14%	74%
100	17%	40%	2%	3%	62%	13%	75%
110	16%	43%	2%	3%	64%	13%	76%
120	16%	44%	2%	3%	65%	12%	77%
130	16%	46%	1%	3%	66%	12%	78%
140	15%	47%	1%	3%	67%	12%	78%
150	15%	49%	1%	3%	68%	11%	79%
160	15%	50%	1%	3%	69%	11%	80%
170	15%	52%	1%	3%	70%	10%	81%
180	15%	53%	1%	3%	71%	10%	81%
190	14%	54%	1%	3%	72%	10%	82%
200	14%	56%	1%	2%	73%	9%	83%
210	14%	57%	1%	2%	74%	9%	83%
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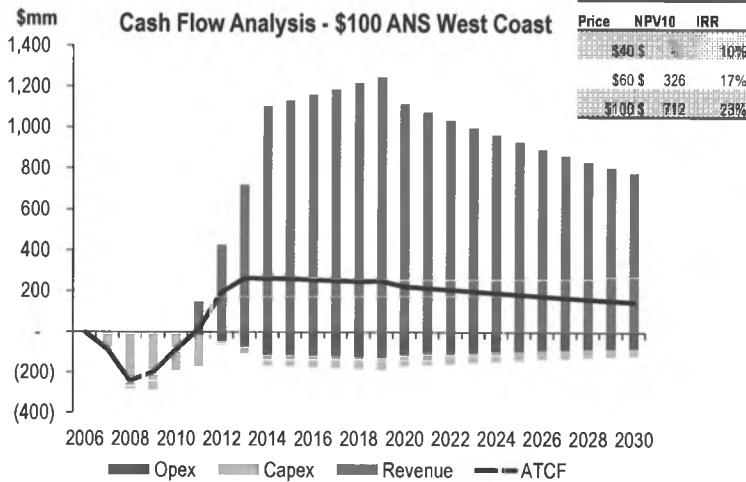
ACES – Capped at Maximum of 70%



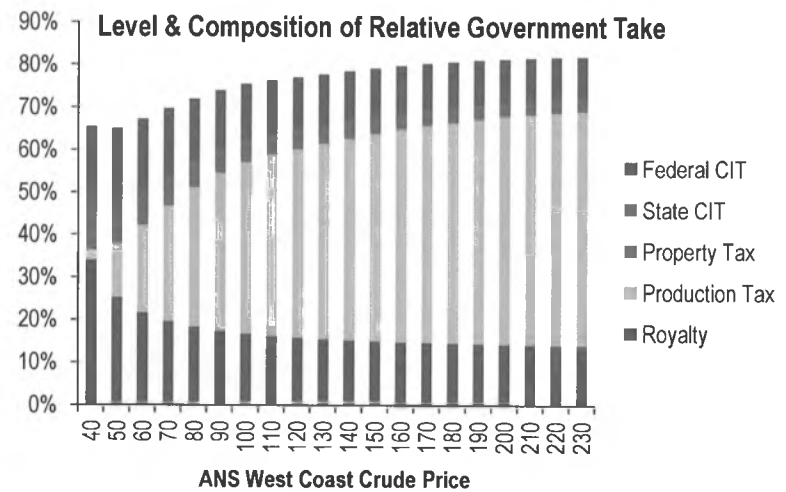
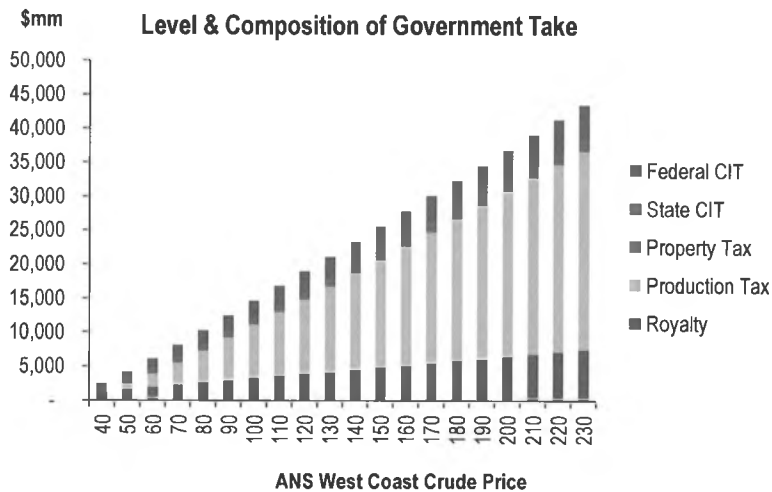
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	25%	12%	6%	4%	48%	17%	65%
60	22%	21%	4%	4%	51%	17%	67%
70	20%	27%	3%	4%	54%	16%	70%
80	18%	33%	3%	4%	58%	14%	72%
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100	17%	40%	2%	3%	62%	13%	75%
110	16%	43%	2%	3%	64%	13%	76%
120	16%	44%	2%	3%	65%	12%	77%
130	16%	46%	1%	3%	66%	12%	78%
140	15%	47%	1%	3%	67%	12%	78%
150	15%	49%	1%	3%	68%	11%	79%
160	15%	50%	1%	3%	69%	11%	80%
170	15%	52%	1%	3%	70%	11%	81%
180	15%	53%	1%	3%	71%	10%	81%
190	14%	54%	1%	3%	72%	10%	82%
200	14%	55%	1%	3%	73%	10%	82%
210	14%	56%	1%	2%	73%	9%	83%
220	14%	57%	1%	2%	74%	9%	83%
230	14%	57%	1%	2%	75%	9%	83%



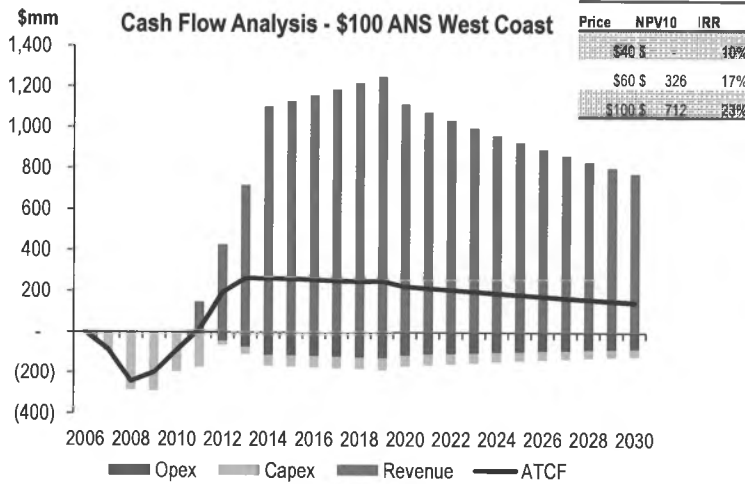
ACES – Capped at Maximum of 65%



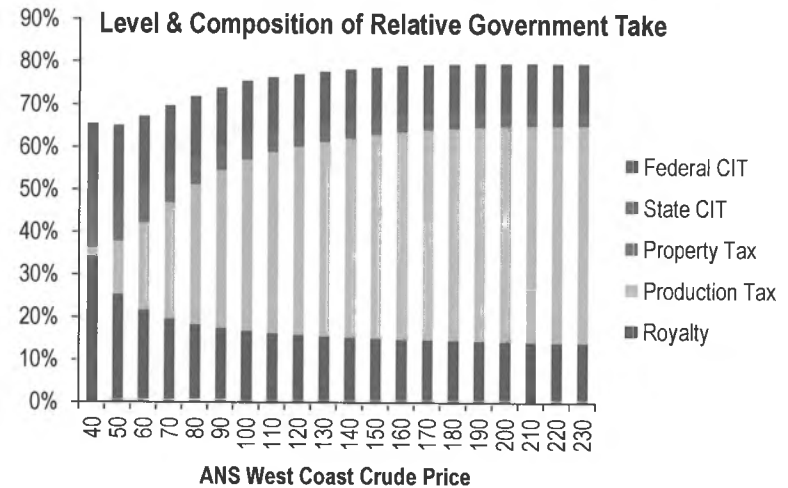
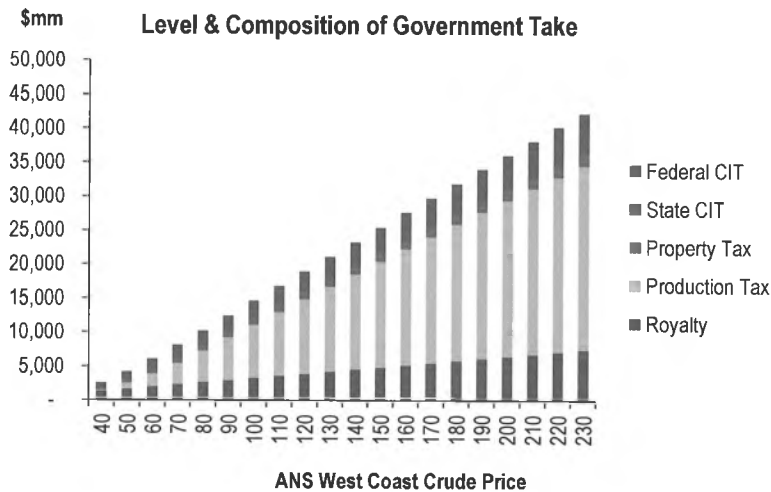
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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60	22%	21%	4%	4%	51%	17%	67%
70	20%	27%	3%	4%	54%	16%	70%
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100	17%	40%	2%	3%	62%	13%	75%
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120	16%	44%	2%	3%	65%	12%	77%
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190	14%	53%	1%	3%	71%	10%	81%
200	14%	53%	1%	3%	71%	10%	81%
210	14%	54%	1%	3%	72%	10%	82%
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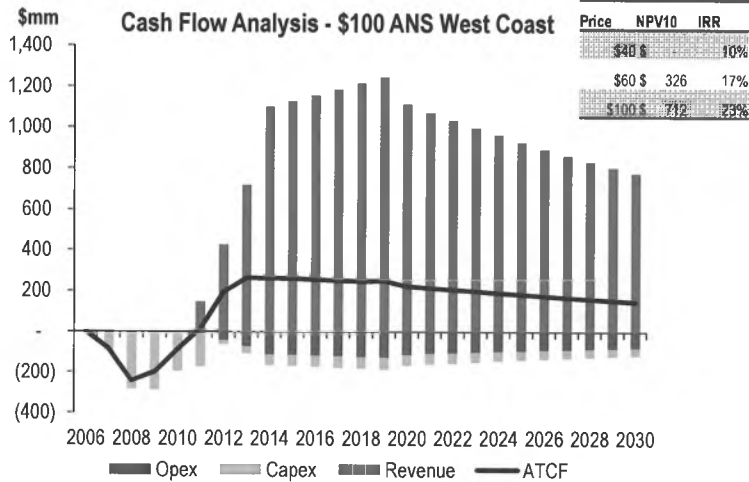
ACES – Capped at Maximum of 60%



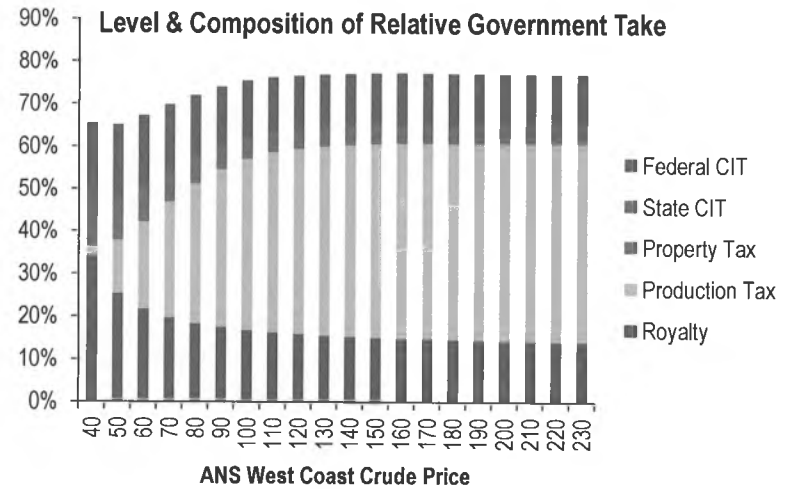
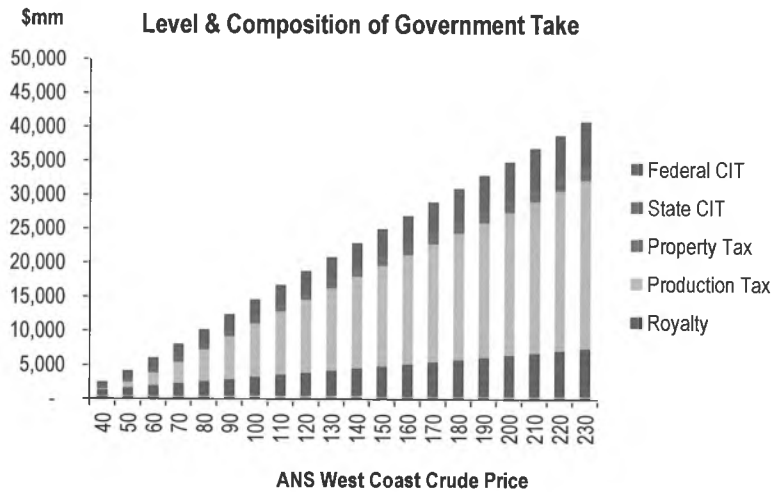
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total CIT
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60	22%	21%	4%	4%	51%	17%	67%
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80	18%	33%	3%	4%	58%	14%	72%
90	17%	37%	2%	4%	60%	14%	74%
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110	16%	43%	2%	3%	64%	13%	76%
120	16%	44%	2%	3%	65%	12%	77%
130	16%	46%	1%	3%	66%	12%	78%
140	15%	47%	1%	3%	66%	12%	78%
150	15%	48%	1%	3%	67%	11%	79%
160	15%	49%	1%	3%	68%	11%	79%
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200	14%	51%	1%	3%	69%	11%	80%
210	14%	51%	1%	3%	69%	11%	80%
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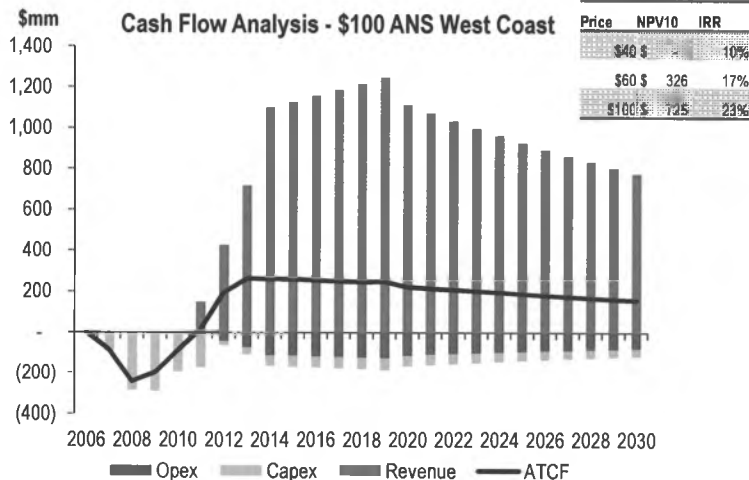
ACES – Capped at Maximum of 55%



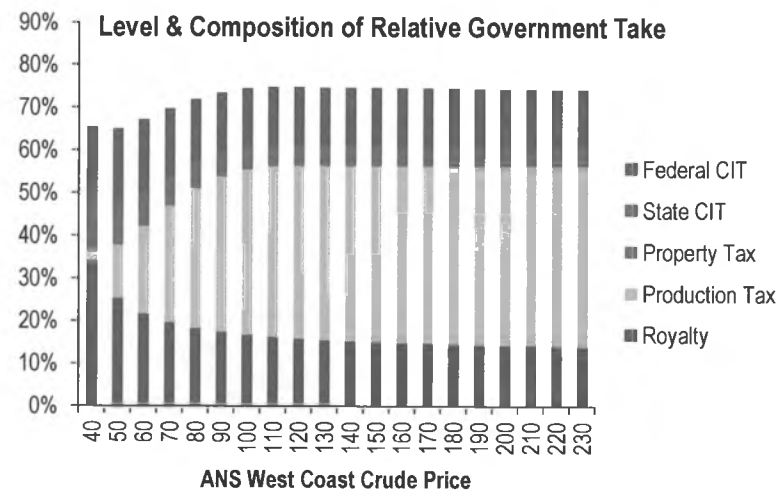
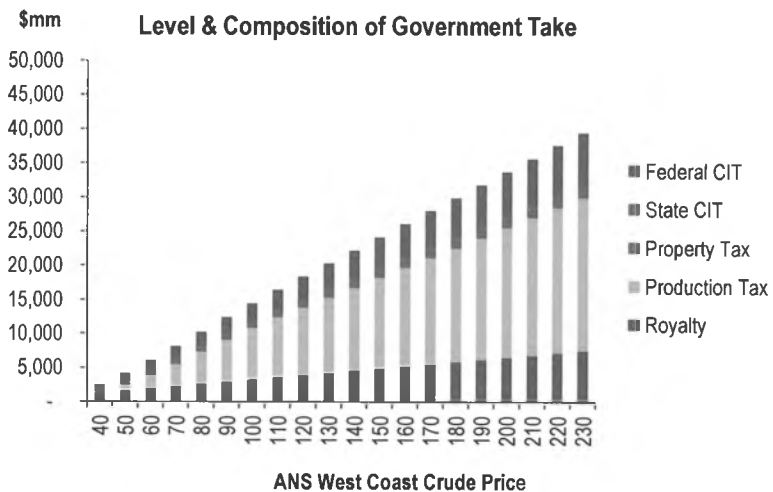
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	25%	12%	6%	4%	48%	17%	65%
60	22%	21%	4%	4%	51%	16%	67%
70	20%	27%	3%	4%	54%	16%	70%
80	18%	33%	3%	4%	58%	14%	72%
90	17%	37%	2%	4%	60%	14%	74%
100	17%	40%	2%	3%	62%	13%	75%
110	16%	42%	2%	3%	63%	13%	76%
120	16%	43%	2%	3%	64%	12%	76%
130	16%	44%	1%	3%	64%	12%	77%
140	15%	45%	1%	3%	65%	12%	77%
150	15%	45%	1%	3%	65%	12%	77%
160	15%	46%	1%	3%	65%	12%	77%
170	15%	46%	1%	3%	65%	12%	77%
180	15%	46%	1%	3%	65%	12%	77%
190	14%	46%	1%	3%	65%	12%	77%
200	14%	46%	1%	3%	65%	12%	77%
210	14%	46%	1%	3%	65%	12%	77%
220	14%	46%	1%	3%	65%	12%	77%
230	14%	47%	1%	3%	65%	12%	77%



ACES – Capped at Maximum of 50%



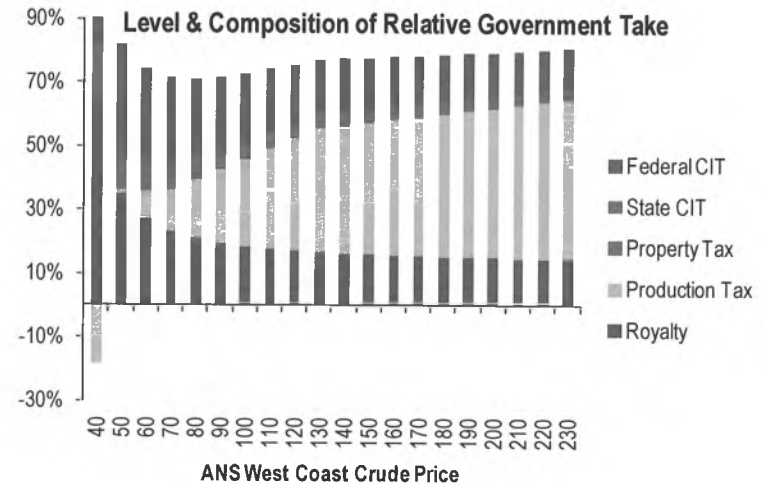
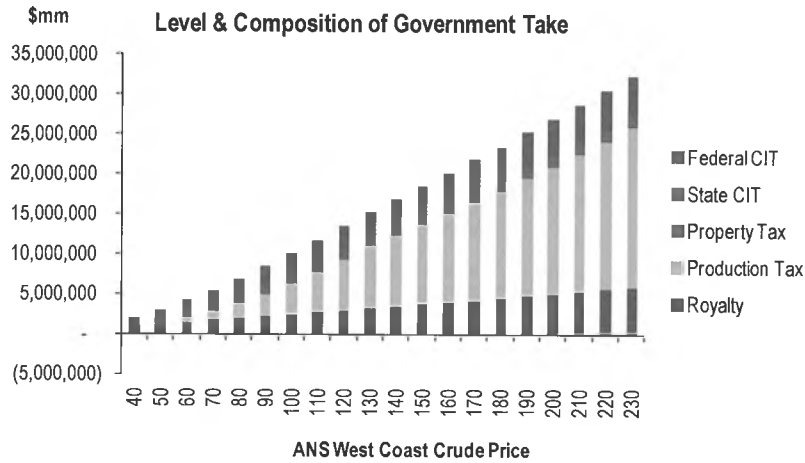
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	34%	2%	10%	4%	50%	15%	65%
50	25%	12%	6%	4%	48%	17%	65%
60	22%	21%	4%	4%	51%	17%	67%
70	20%	27%	3%	4%	54%	16%	70%
80	18%	33%	3%	4%	57%	14%	72%
90	17%	36%	2%	4%	60%	14%	73%
100	17%	39%	2%	4%	61%	14%	74%
110	16%	40%	2%	4%	61%	13%	75%
120	16%	41%	2%	4%	61%	13%	75%
130	16%	41%	1%	4%	61%	13%	75%
140	15%	41%	1%	4%	61%	14%	75%
150	15%	41%	1%	4%	61%	14%	75%
160	15%	41%	1%	4%	61%	14%	75%
170	15%	42%	1%	4%	61%	14%	75%
180	15%	42%	1%	4%	61%	14%	74%
190	14%	42%	1%	4%	61%	14%	74%
200	14%	42%	1%	4%	61%	14%	74%
210	14%	42%	1%	4%	61%	14%	74%
220	14%	42%	1%	4%	61%	14%	74%
230	14%	42%	1%	4%	61%	14%	74%



Analysis Using DOR FY2013 Estimated Average Costs

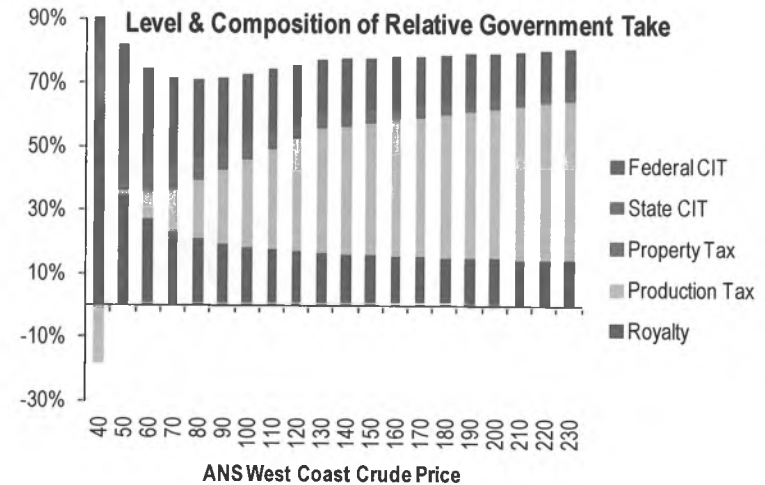
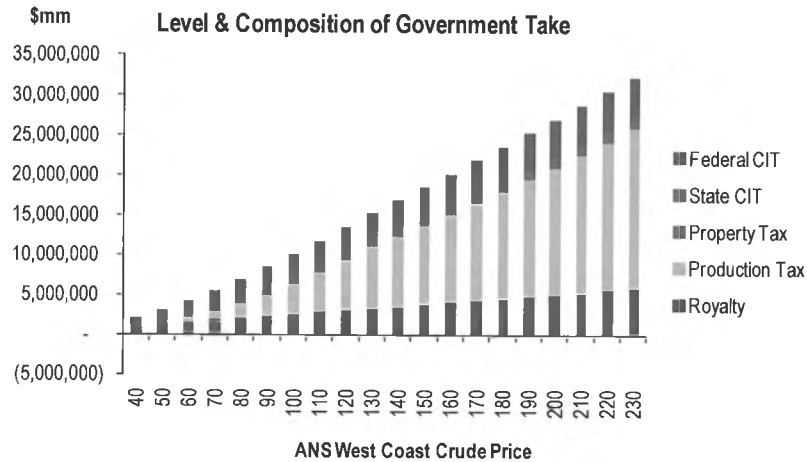
- As requested, an alternate analysis of ACES and the various potential maximum production tax rates has also been performed using DOR FY2013 forecast North Slope cost and production figures
 - By using a 'snapshot' of costs and production for a given year, the analysis inherently no longer presents a development-forward lifecycle analysis, since it combines initial development capex for some projects with ongoing spending on others
 - As a result, such an analysis should be performed only as a snapshot of a single year
 - As such, such an analysis represents a high-level approximation of Government Take in that particular year, not over the actual lifecycle of a particular asset type
 - Such an analysis also does not account for the 'bracket-creep' or 'stealth-tax' effect of inflation over time
- DOR FY2013 cost forecasts are:
 - \$13.75 per taxable barrel operating expenditures
 - \$15.36 per taxable barrel capital expenditures
 - \$8.56 per taxable barrel transportation costs
- On a per-flowing-barrel basis, these equate to:
 - \$11.71 /bbl operating expenditures
 - \$13.07 /bbl capital expenditures
 - \$7.29 /bbl transportation costs
- On the following slides, the ACES system, along with ACES with maximum production tax levels set at 50%, 55%, 60%, 65% and 70% has been analyzed, using these cost figures

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	46%	0%	4%	65%	14%	79%
200	15%	47%	0%	4%	66%	14%	79%
210	15%	48%	0%	3%	66%	13%	80%
220	15%	49%	0%	3%	67%	13%	80%
230	15%	50%	0%	3%	68%	13%	81%



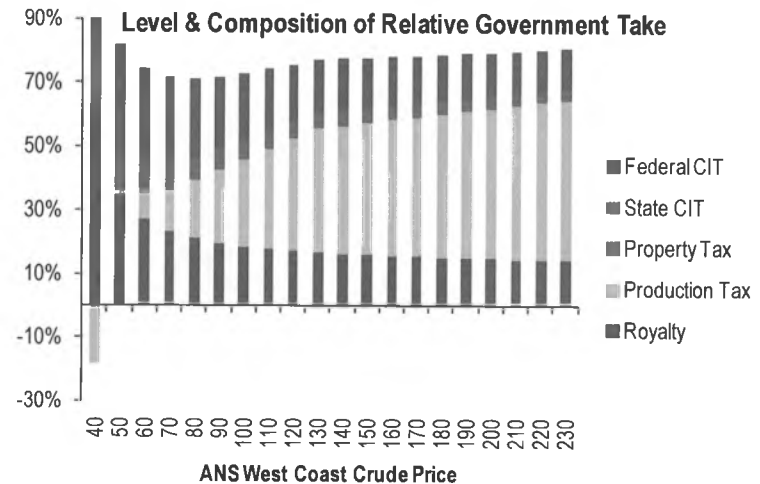
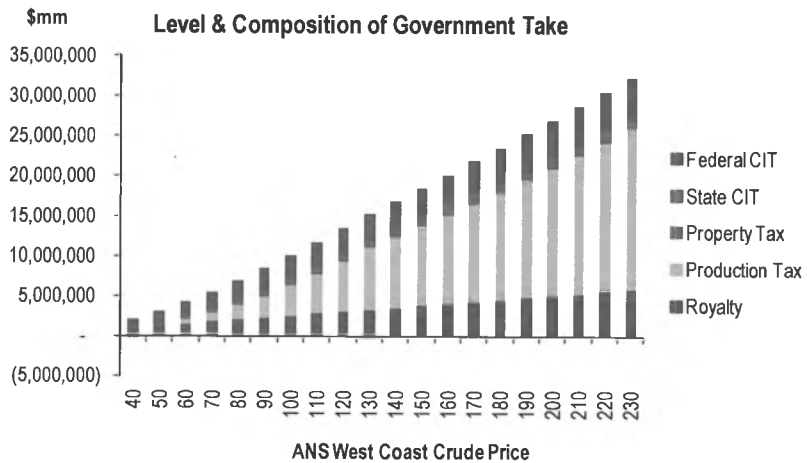
ACES – Capped at Maximum of 70%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	46%	0%	4%	65%	14%	79%
200	15%	47%	0%	4%	66%	14%	79%
210	15%	48%	0%	3%	66%	13%	80%
220	15%	49%	0%	3%	67%	13%	80%
230	15%	50%	0%	3%	68%	13%	81%



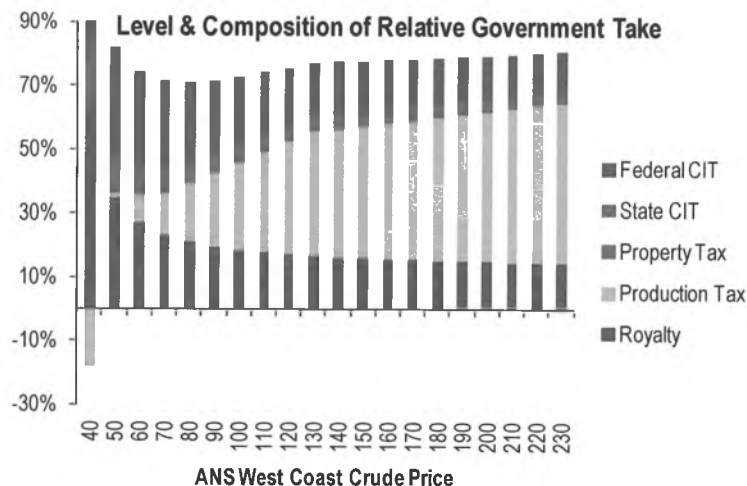
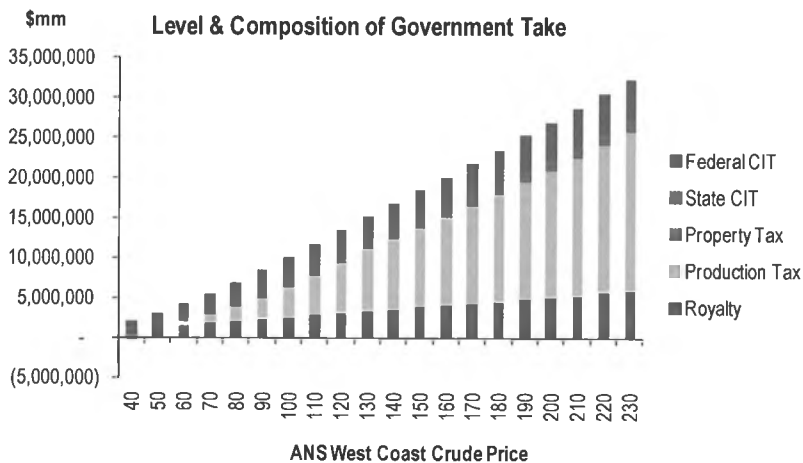
ACES – Capped at Maximum of 65%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	46%	0%	4%	65%	14%	79%
200	15%	47%	0%	4%	66%	14%	79%
210	15%	48%	0%	3%	66%	13%	80%
220	15%	49%	0%	3%	67%	13%	80%
230	15%	50%	0%	3%	68%	13%	81%



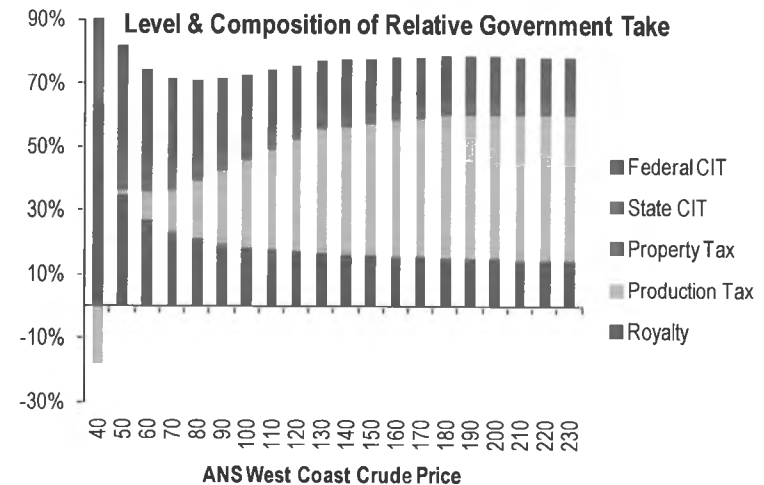
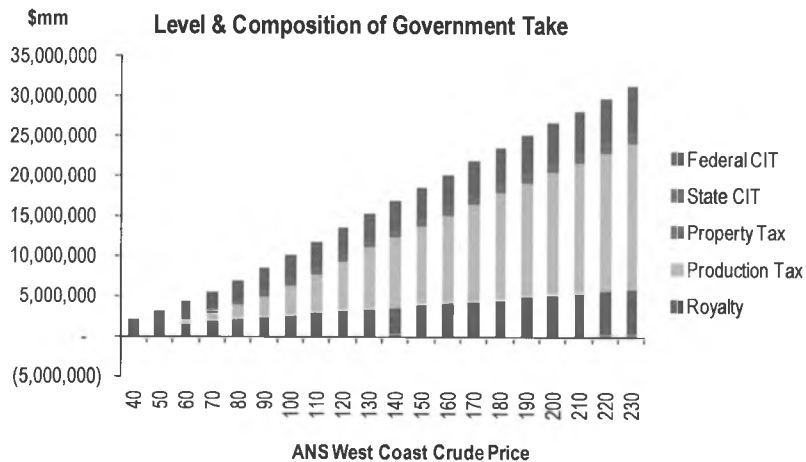
ACES – Capped at Maximum of 60%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	46%	0%	4%	65%	14%	79%
200	15%	47%	0%	4%	66%	14%	79%
210	15%	48%	0%	3%	66%	13%	80%
220	15%	49%	0%	3%	67%	13%	80%
230	15%	50%	0%	3%	68%	13%	81%



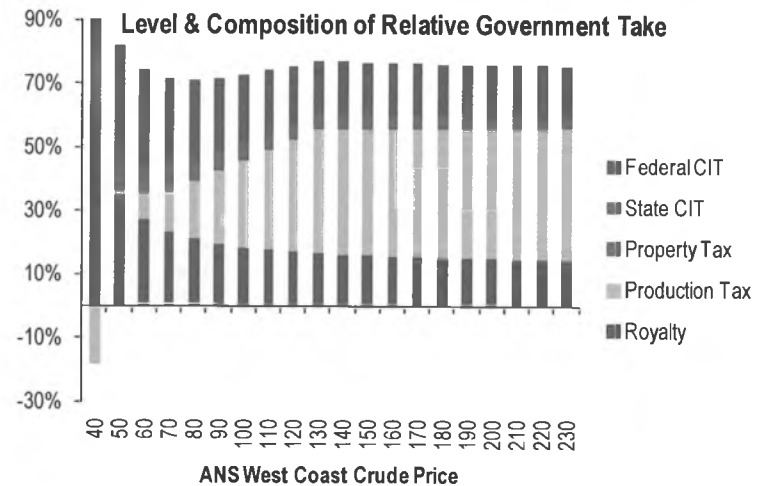
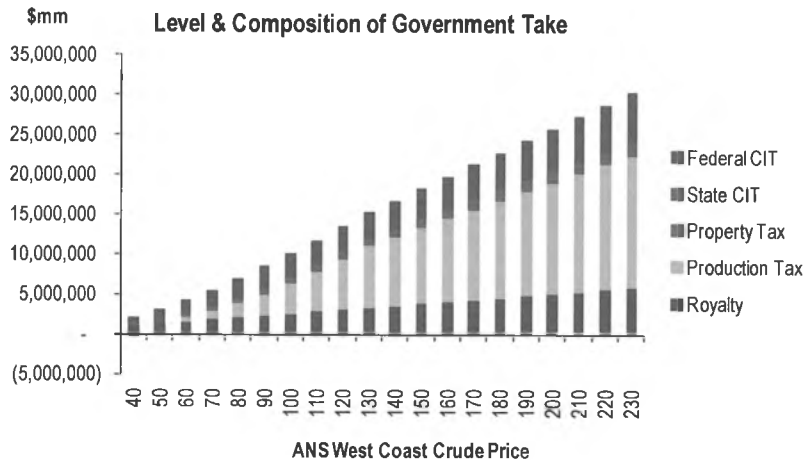
ACES – Capped at Maximum of 55%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	40%	0%	4%	61%	16%	77%
150	16%	41%	0%	4%	62%	16%	78%
160	16%	43%	0%	4%	63%	15%	78%
170	15%	44%	0%	4%	63%	15%	78%
180	15%	45%	0%	4%	64%	14%	79%
190	15%	45%	0%	4%	64%	14%	78%
200	15%	45%	0%	4%	64%	14%	78%
210	15%	45%	0%	4%	64%	14%	78%
220	15%	45%	0%	4%	64%	14%	78%
230	15%	46%	0%	4%	64%	14%	78%



ACES – Capped at Maximum of 50%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total CIT
40	63%	-19%	6%	13%	63%	49%	112%
50	35%	1%	3%	9%	48%	34%	82%
60	27%	9%	2%	8%	45%	29%	74%
70	23%	13%	1%	7%	44%	27%	71%
80	21%	18%	1%	6%	46%	25%	71%
90	19%	23%	1%	6%	49%	23%	72%
100	18%	27%	1%	6%	52%	21%	73%
110	18%	31%	1%	5%	54%	20%	74%
120	17%	35%	1%	5%	57%	18%	76%
130	17%	39%	0%	4%	60%	17%	77%
140	16%	39%	0%	4%	60%	17%	77%
150	16%	40%	0%	4%	60%	16%	77%
160	16%	40%	0%	4%	60%	16%	76%
170	15%	40%	0%	4%	60%	16%	76%
180	15%	40%	0%	4%	60%	16%	76%
190	15%	41%	0%	4%	60%	16%	76%
200	15%	41%	0%	4%	60%	16%	76%
210	15%	41%	0%	4%	60%	16%	76%
220	15%	41%	0%	4%	60%	15%	76%
230	15%	41%	0%	4%	60%	15%	76%



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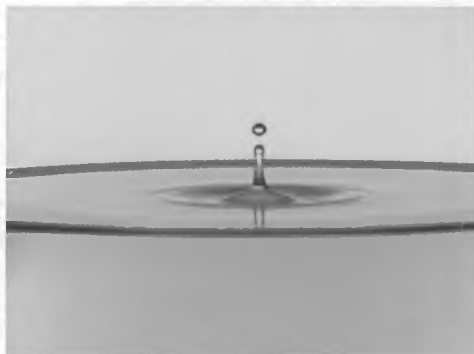
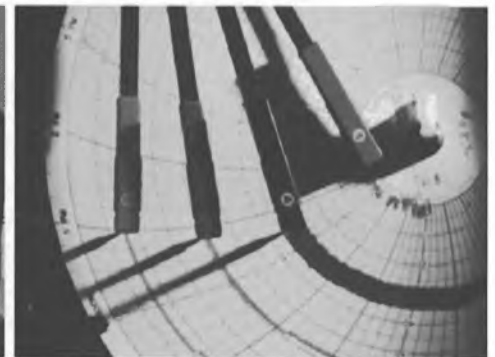
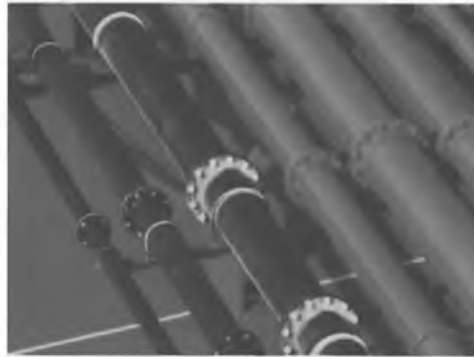
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable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

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PFC Energy



Discussion Slides: Alaska Senate Resources Committee

REVISED

February 16-17, 2012

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The Art of Taxation

“The art of taxation consists in so plucking the goose as to get the most feathers with the least hissing.”

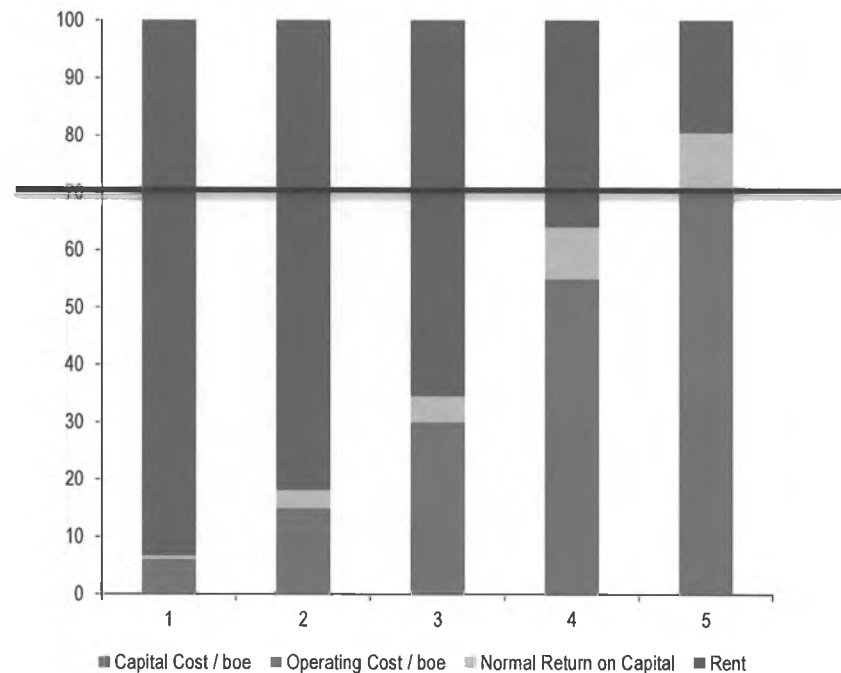
Jean Baptiste Colbert - Economist and Minister of Finance under King Louis XIV of France, 1619

...or, in more contemporary terms

- The art of taxation consists in maximizing revenues, subject to two important constraints
 - **Efficiency:** Not distorting investment choices, or preventing marginal investments that would otherwise have been made from occurring
 - **Competitiveness:** Ensuring that in the real world, which is characterized by limited capital with competing uses

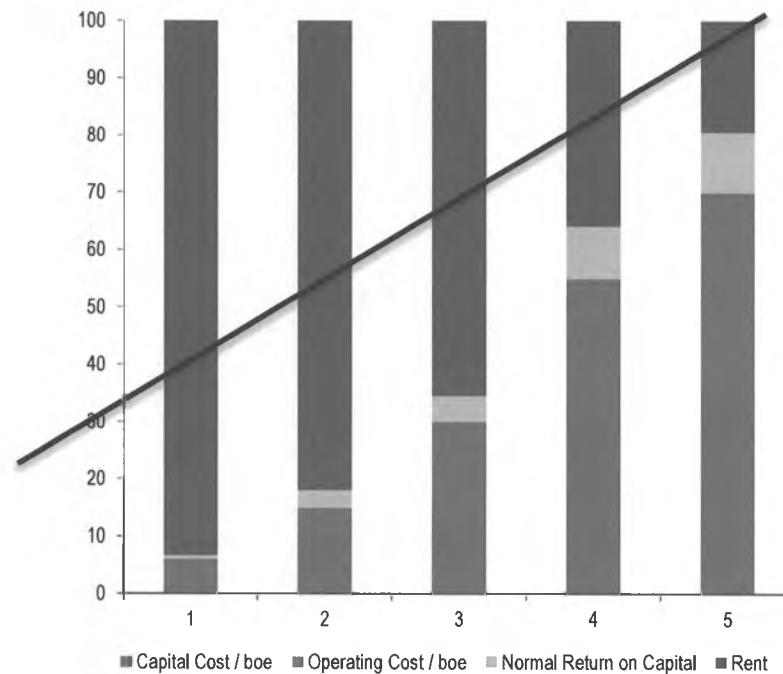
Efficiency: Conclusions on a Fixed Percentage Royalty

- The fixed royalty is **inefficient** because it distorts investment, making previously marginal projects uneconomic at a given price
- It is highly **regressive** with regard to both price and cost, because Relative Government Take falls as prices rise, and as costs fall
- This also increases **sovereign risk** – since when prices rise, governments will be tempted to set a new rate, even though investments have been made on the basis of the current one
- It has only one major strength – it is very **simple to administer**, requiring knowledge of only 2 variables - production and price



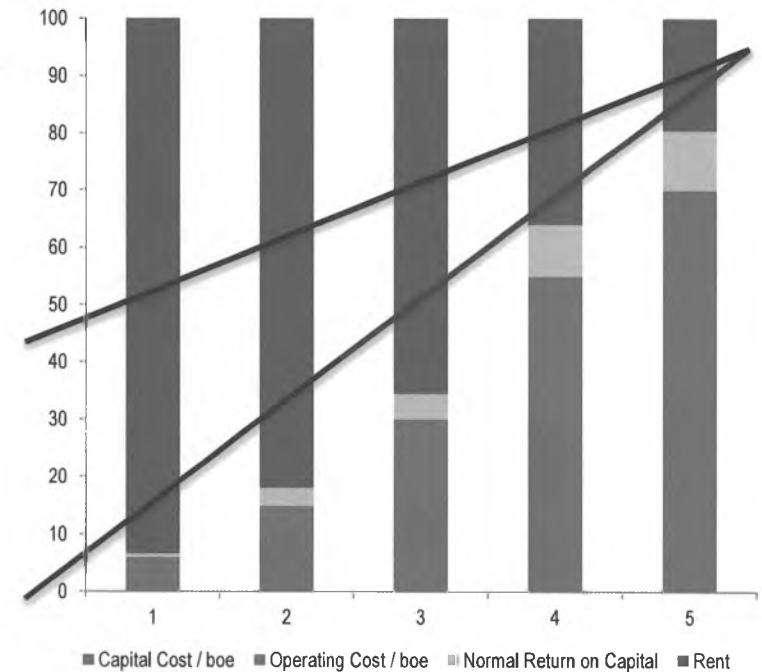
Efficiency: Targeting Economic Rent

- What we would like to do instead is to tax the red bars – the Economic Rent – directly
- That way, we could *pluck more feathers, with less hissing*
- What are the different ways, over time, that governments have attempted to do this?



Progressivity

- Progressivity may be used for a range of different purposes in a fiscal regime
 - In some cases, used to counterbalance the inherent regressivity of other elements of the regime
 - In other cases, a deliberate policy to gain not only a steady share of the rents, but to capture ever more as economics improve
- Implemented properly (ie taxing only economic rents), both of these approaches can be efficient – ie non-distorting of relative investment opportunities at the margin
- Regimes that use both high levels of relative government take, in addition to high progressivity to capture most or all of the upside of high price environments will not necessarily be competitive



Different Implementations of Progressivity: Production Levels

- One of the earliest and still commonest metrics used to progressively increase rates of government take for projects that produce more economic rent has been the use of sliding scales for the split of profit oil or the setting of a royalty, based on levels of production, as is the case in Vietnam’s PSC fiscal system
- Brazil similarly applies a production-level-based windfall profits tax in its tax-royalty system
- Such systems are almost always bracketed, so the higher rate applies only to production above a given threshold
- Production-based progressivity uses production levels as a proxy for profitability – and it is an imperfect proxy at best
 - The Vietnam example here attempts to improve here by setting different tiers, based on project cost
 - British Columbia, Canada uses a combination of Price and Production Quantity in its progressive Royalty rate

Vietnam Fiscal Terms			Pre-2010	Post-2010 with Incentives	Post-2010 without Incentives	Deepwater/ Frontier
Oil Royalty		mb/d				
	<=	20.00	8%	7%	10%	6%
	>20 <=	50.00	10%	9%	12%	8%
	>50 <=	75.00	10%	11%	14%	8%
	>75 <=	100.00	15%	13%	19%	10%
	>100 <=	150.00	20%	18%	24%	15%
	>150		25%	23%	29%	20%
Gas Royalty		mmcf/d				
	<=	176.55	0%	1%	2%	0%
	>176.55 <=	350.00	5%	3%	5%	3%
	>350		25%	6%	10%	6%
Cost Oil Limit			35%	35%	35%	50%
Cost Gas Limit			60%	60%	60%	70%
Profit Oil Split to Gov.		mb/d				
	<=	75.00	50%	50%	50%	50%
	>75 <=	100.00	55%	55%	55%	55%
	>100 <=	150.00	60%	60%	60%	60%
	>150		70%	70%	70%	70%
Profit Gas Split			50%	50%	50%	50%
Corporate Tax Rate			32%			

Different Implementations of Progressivity: Price

- A number of regimes are progressive explicitly on price
- This approach is particularly common in setting “windfall profits” taxes
- China and Venezuela both use a price-progressive windfall profits tax to capture progressive shares of economic rent in high price environments
- Such systems are almost always bracketed, taxing only profits resulting from the higher price bracket at the higher rate
- Alaska’s ACES system is an exception to this rule

Thresholds for Venezuela’s Windfall Profits Tax

Oil Price	Rate
< \$40	0%
\$ 40 - \$70	20%
\$ 70 - \$90	80%
\$ 90 - \$100	90%
> \$100	95%

Different Implementations of Progressivity: Cost Recovery

- A more sophisticated approach to targeting economic rent more directly is for a regime to be progressive using the extent to which a project has recovered its costs as a metric by which to set the tax or profit sharing rate
- Malaysia's current PSC model, introduced in 1997, uses "R-Factor", the ratio of cumulative revenues to cumulative costs, to set its profit split and its cost limit
- Once a project has recovered its costs, profit share to the IOC is progressively reduced

Malaysia Fiscal Terms						
Oil Royalty	10%					
	R Factor					
1997 PSC Parameters	R<=1.0	R<=1.4	R<=2.0	R<=2.5	R<=3.0	R>3
Cost Oil/Gas Limit	70%	60%	50%	30%	30%	30%
Unutilized Cost Oil/Gas Split (below THV)	0%	80%	70%	60%	50%	40%
Unutilized Cost Oil/Gas Split (above THV)	0%	40%	40%	40%	40%	20%
Profit Oil/Gas Split (below THV)	80%	70%	60%	50%	40%	30%
Profit Oil/Gas Split (above THV)	40%	30%	30%	30%	30%	10%
Threshold Value (THV) - Oil	30	mmbbls				
Threshold Value (THV) - Gas	0.75	tcf				

Different Implementations of Progressivity: Rates of Return

- Similarly, some regimes seek to target “super-profits” more directly by linking progressivity to the Internal Rate of Return (IRR) that a project has accomplished by any point in time
 - Angola’s PSC regime uses IRR to set the profit oil split

- Onshore and Shallow Water

IRR	Contractor's Share
< 20%	60%
20 – 25%	50%
25 – 30%	40%
> 30%	30%

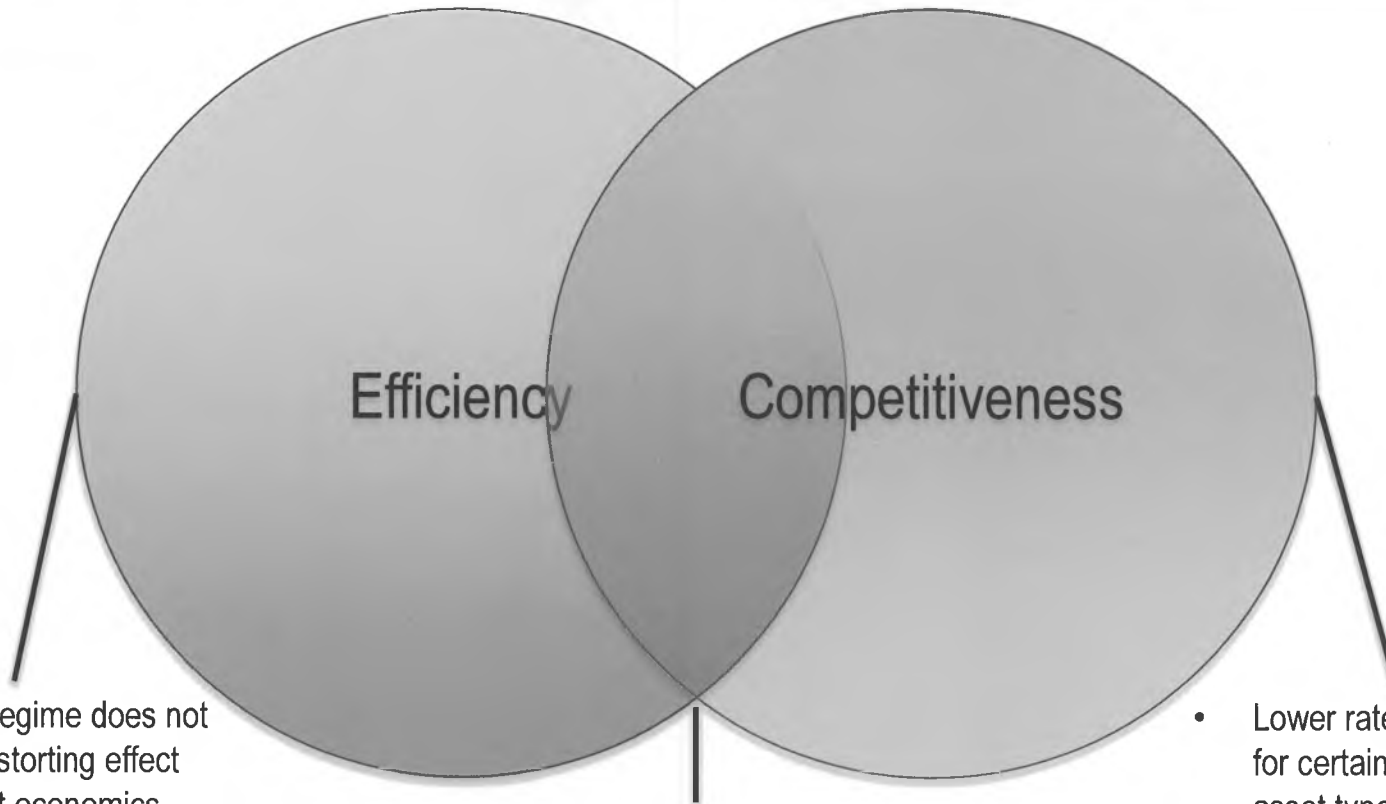
- Deepwater

IRR	Contractor's Share
< 15%	80%
15 – 25%	60%
25 – 30%	40%
> 30%	20%

Different Implementations of Progressivity: Taxing Rent Directly

- Many of these regimes are highly complex, and use highly imperfect proxies for targeting economic rent
- Australia's Petroleum Resource Rent Tax, by contrast, is unusual in being both very simple in design, and in seeking to tax economic rent directly
- The tax seeks to replicate the economics of a 40% direct participation by the state, by taxing net cashflow at a rate of 40%
- All losses, however, are carried forward indefinitely, and maintain present value since they are inflated each year by a rate similar to the corporate cost of capital
- The ultimate economics are as if government is paying a 40% share of the cost of development, and taking a 40% share of the resulting cashflow
- With no royalty, and no other taxes in the system other than Corporate Income Tax, this is one of the simplest fiscal designs anywhere, but also one of the most efficient – because it taxes rent directly

Finding the Intersection

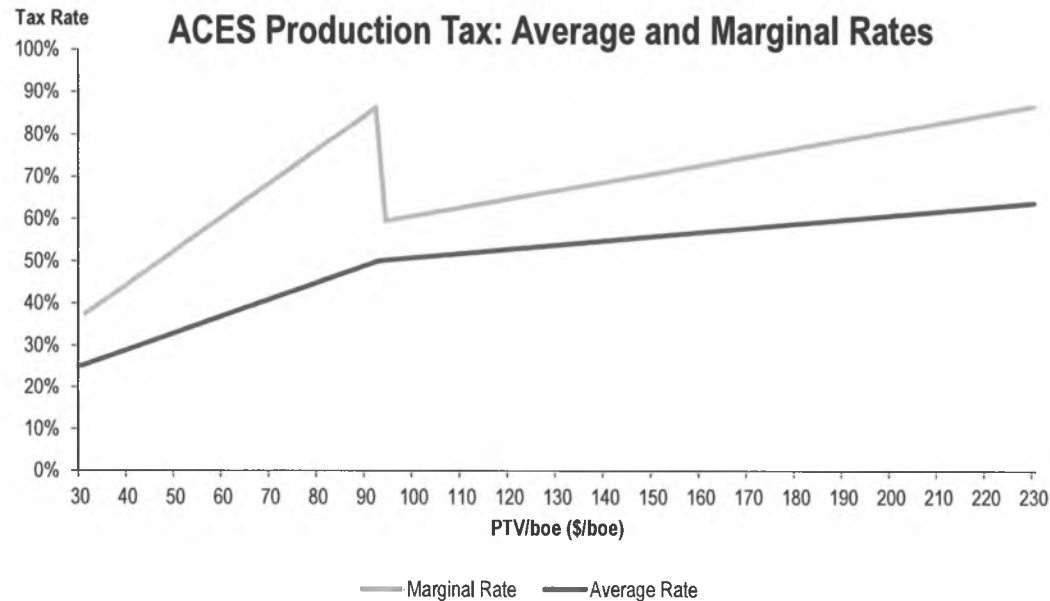


- Efficient regime does not have a distorting effect on project economics
- But rates are too high, and other jurisdictions are more successful in attracting capital as a result

- Regime does not distort investment
- Rates are internationally competitive, given fundamental attractiveness of the opportunity

- Lower rates may mean for certain projects or asset types, the regime is highly internationally competitive
- But distorting structure means certain otherwise marginal projects are unviable

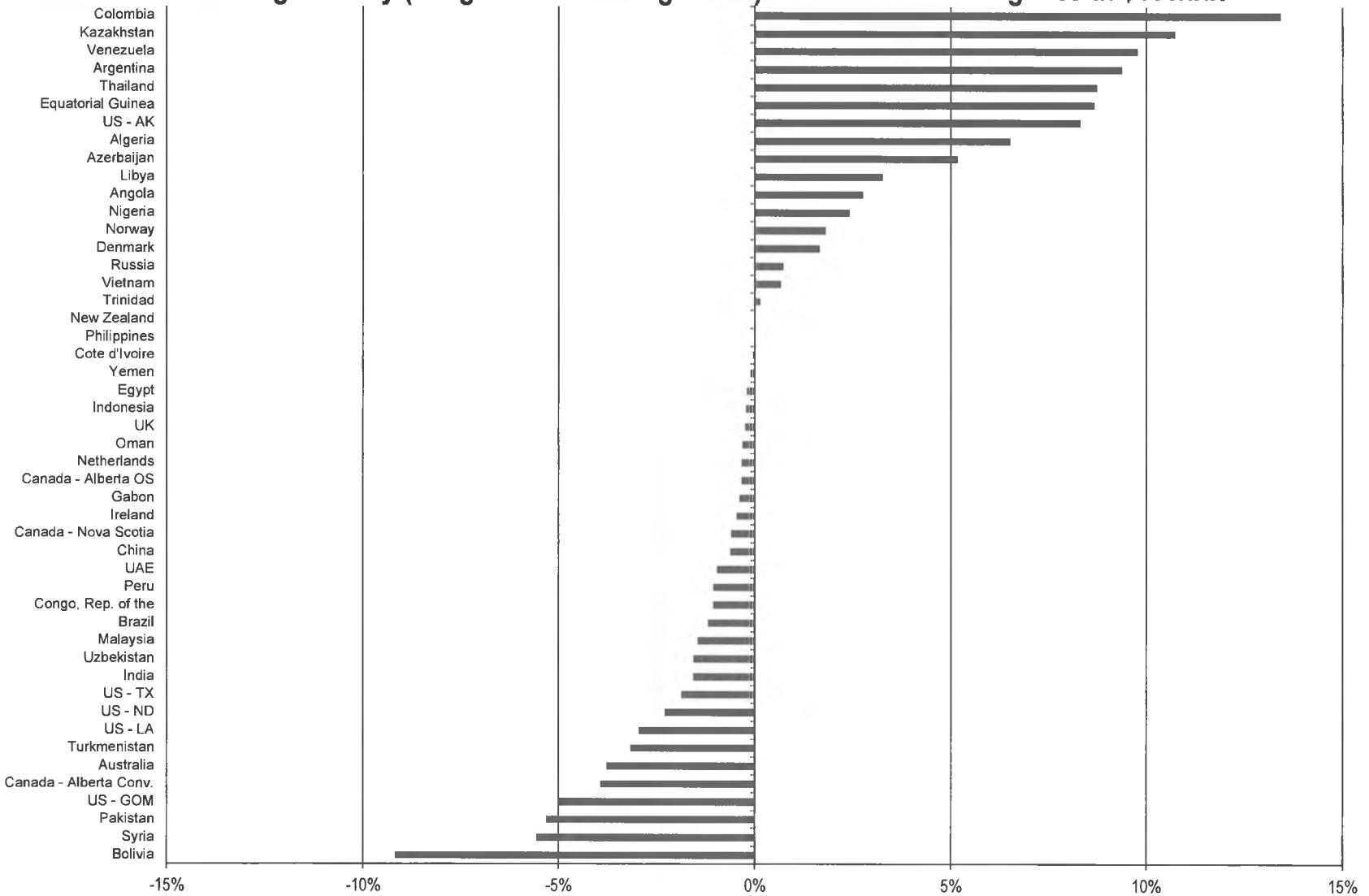
Average vs Marginal Rates



- It is average or effective rates, not marginal rates that drive project economics at a given price level
- Marginal rates remain, however, a useful metric for understanding key aspects of a regime
- The **difference between marginal and average** rates enable us to understand **how progressive a regime** is on a comparative basis
- Marginal rates represent the combination of high average rates with high progressivity
- In a profit-based system, high marginal rates may create perverse incentives with regard to cost control, encouraging “gold-plating”

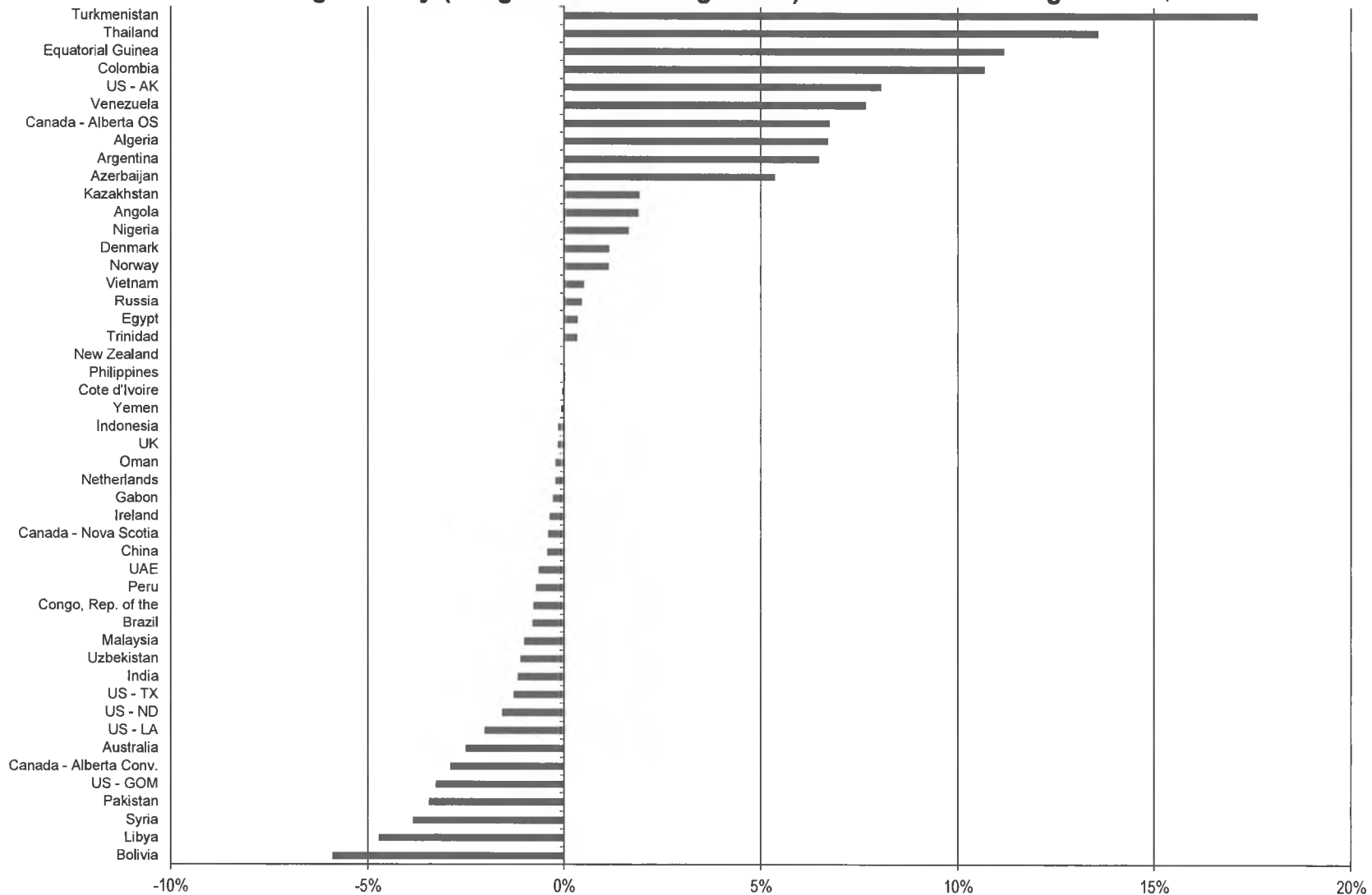
Benchmarking Progressivity for a Range of Global Regimes

Progressivity (Marginal less Average Take) of Global Fiscal Regimes at \$100/bbl



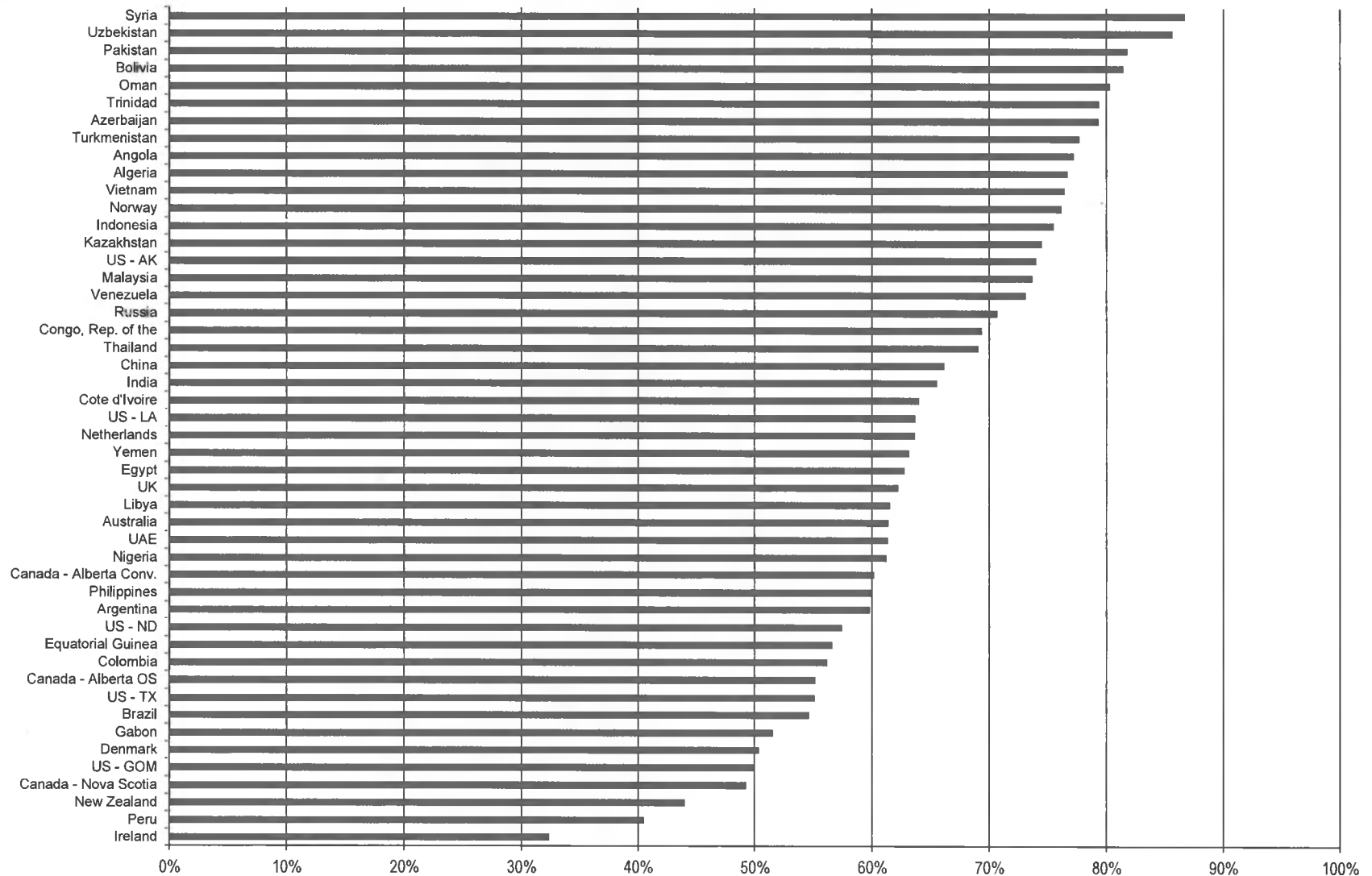
Benchmarking Progressivity for a Range of Global Regimes

Progressivity (Marginal less Average Take) of Global Fiscal Regimes at \$140/bbl



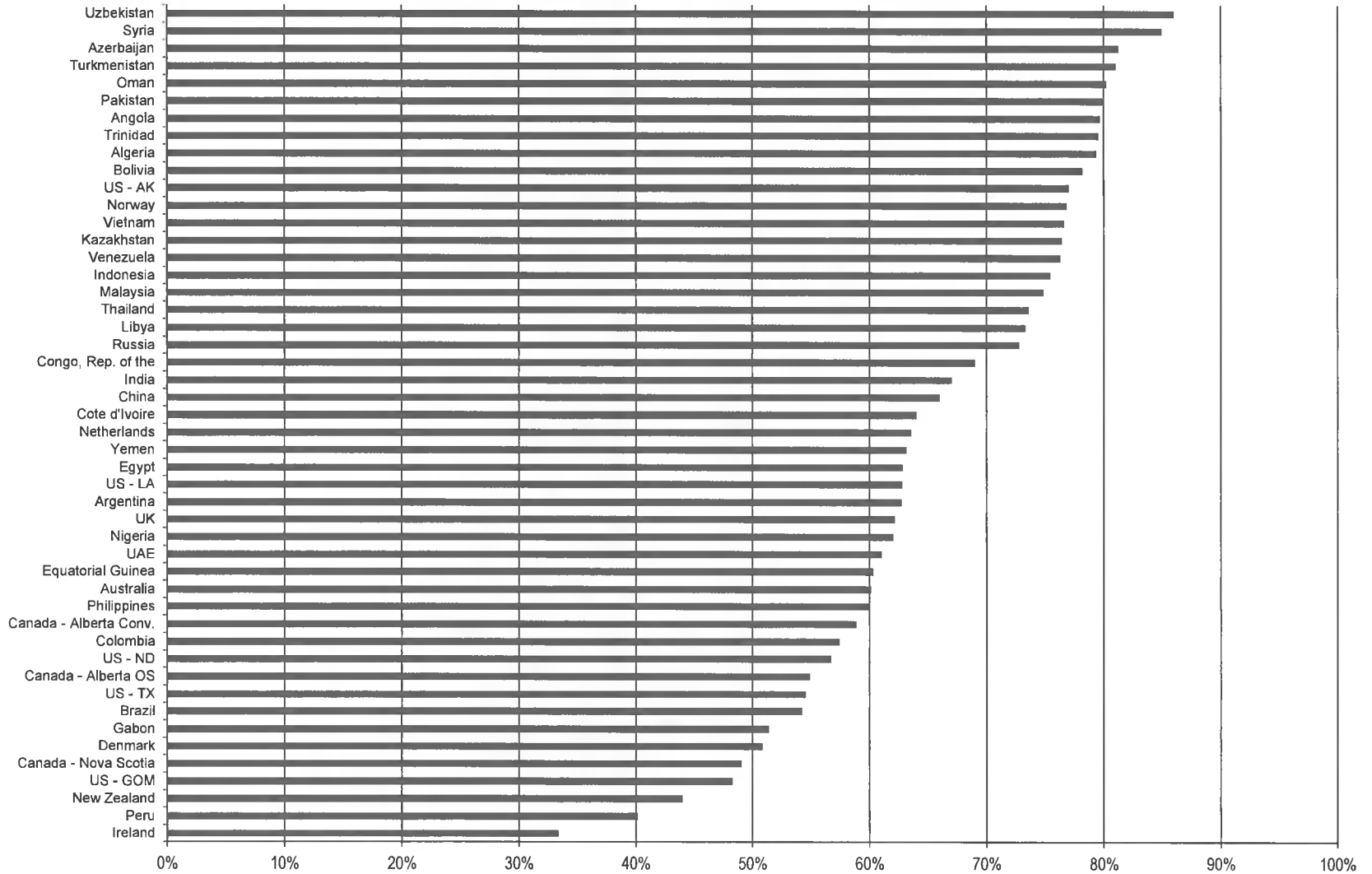
Regime Competitiveness: Relative Government Take

Relative (Average) Government Take at \$100/bbl

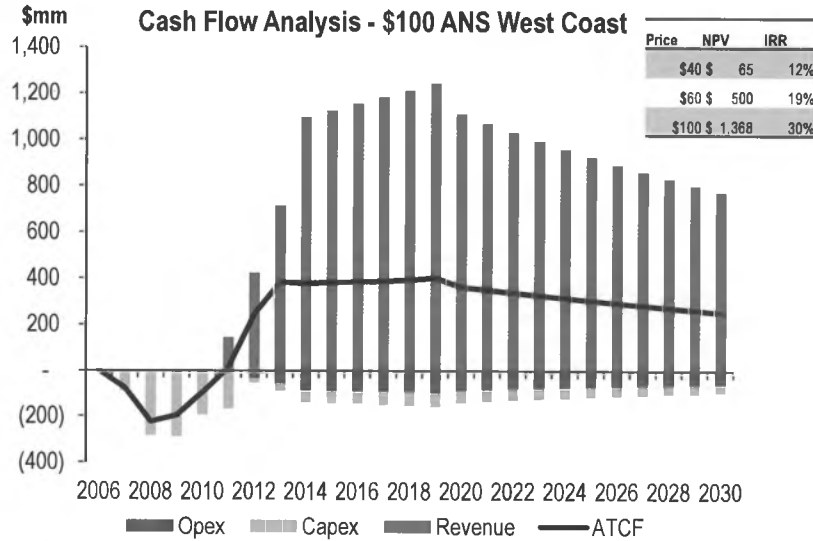


Regime Competitiveness: Relative Government Take

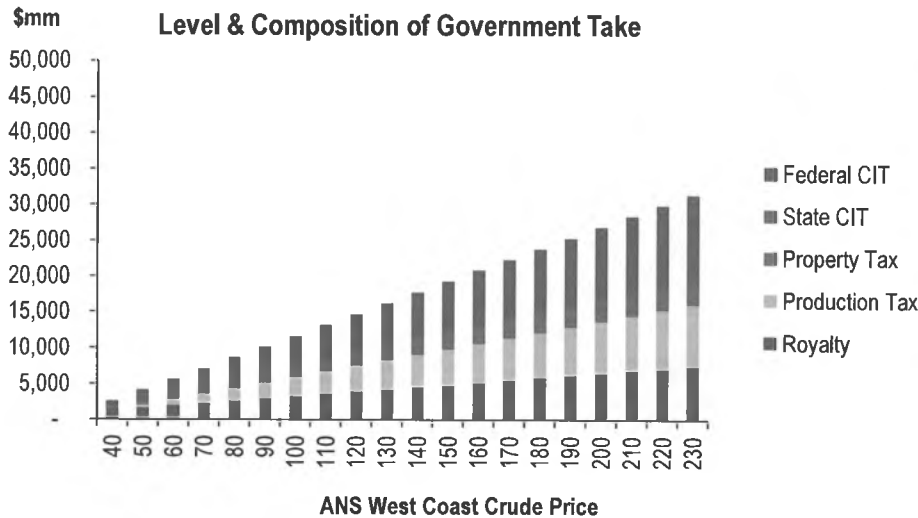
Relative (Average) Government Take at \$140/bbl



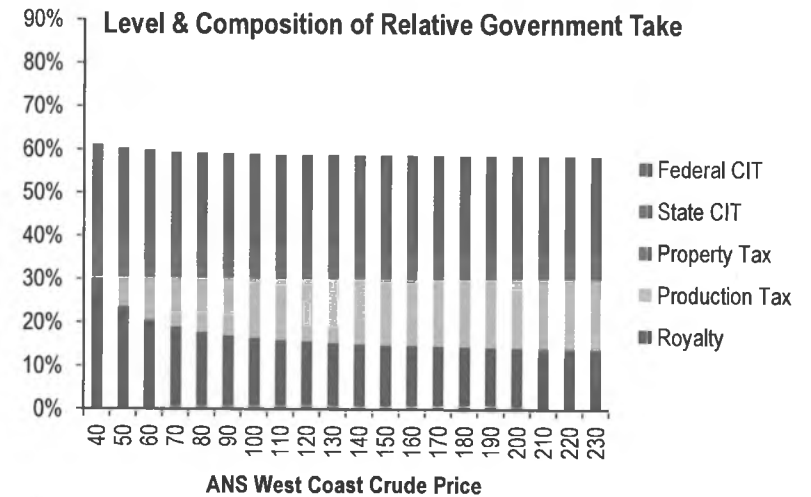
PPT As Originally Proposed



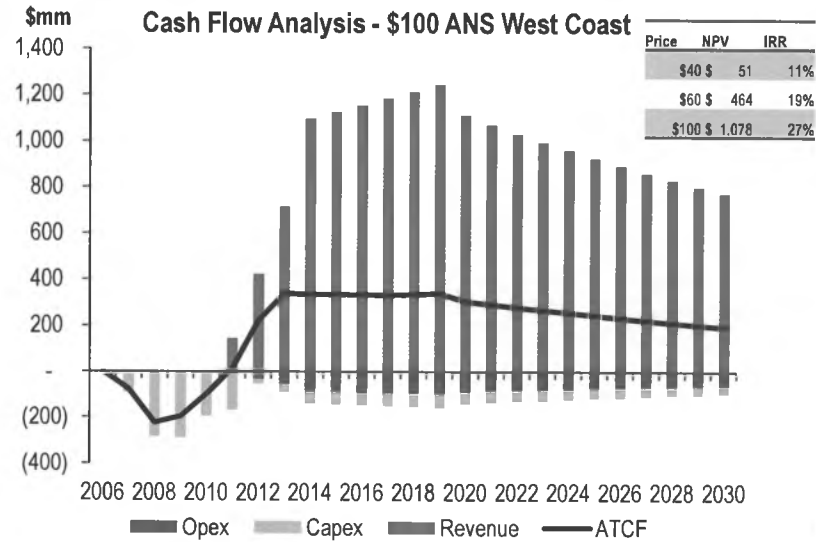
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	30%	1%	9%	5%	44%	17%	61%
50	23%	7%	5%	5%	41%	19%	60%
60	20%	10%	4%	5%	40%	20%	60%
70	19%	12%	3%	5%	39%	21%	59%
80	18%	13%	3%	5%	38%	21%	59%
90	17%	13%	2%	6%	38%	21%	59%
100	16%	14%	2%	6%	38%	21%	59%
110	16%	14%	2%	6%	37%	21%	59%
120	16%	15%	1%	6%	37%	22%	59%
130	15%	15%	1%	6%	37%	22%	59%
140	15%	15%	1%	6%	37%	22%	59%
150	15%	15%	1%	6%	37%	22%	59%
160	15%	15%	1%	6%	37%	22%	59%
170	14%	16%	1%	6%	37%	22%	59%
180	14%	16%	1%	6%	37%	22%	59%
190	14%	16%	1%	6%	37%	22%	59%
200	14%	16%	1%	6%	37%	22%	59%
210	14%	16%	1%	6%	37%	22%	59%
220	14%	16%	1%	6%	37%	22%	59%
230	14%	16%	1%	6%	37%	22%	59%



* Percentage figures are percentages of divisible income, summing to Total Government Take

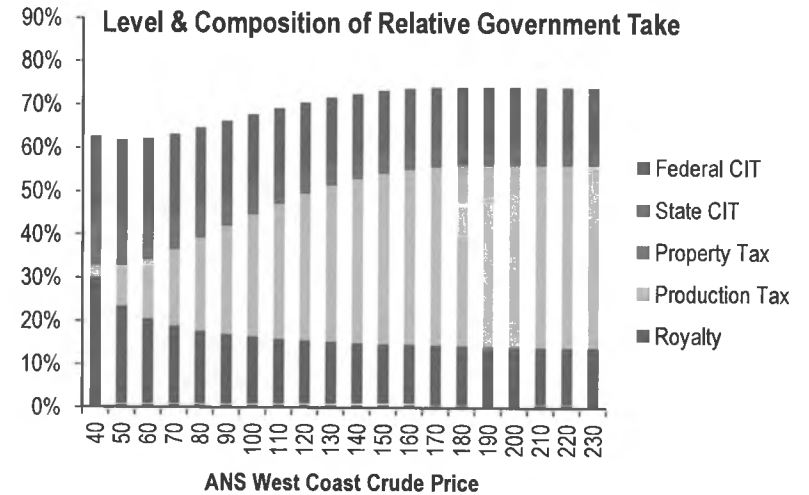
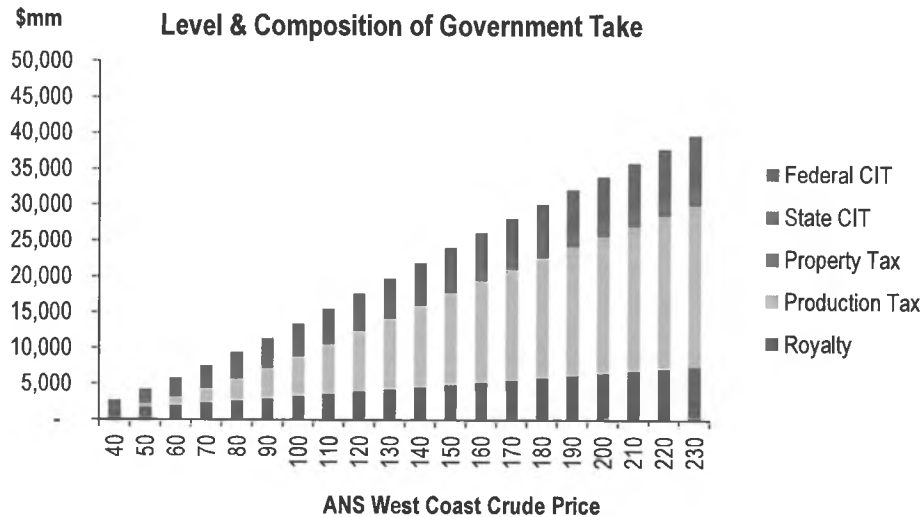


PPT As Enacted

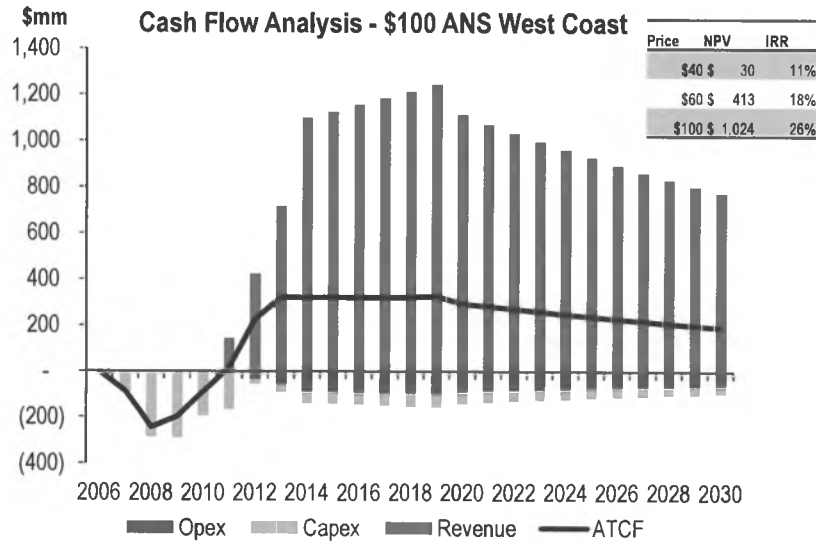


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	30%	3%	9%	4%	46%	17%	63%
50	23%	9%	5%	5%	43%	19%	62%
60	20%	14%	4%	5%	43%	19%	62%
70	19%	18%	3%	5%	45%	19%	63%
80	18%	22%	3%	5%	47%	18%	65%
90	17%	25%	2%	5%	49%	18%	66%
100	16%	28%	2%	4%	51%	17%	68%
110	16%	32%	2%	4%	53%	16%	69%
120	16%	34%	1%	4%	55%	15%	71%
130	15%	36%	1%	4%	57%	15%	72%
140	15%	38%	1%	4%	58%	15%	73%
150	15%	39%	1%	4%	59%	14%	73%
160	15%	40%	1%	4%	60%	14%	74%
170	14%	41%	1%	4%	60%	14%	74%
180	14%	42%	1%	4%	61%	14%	74%
190	14%	42%	1%	4%	61%	14%	74%
200	14%	42%	1%	4%	61%	14%	74%
210	14%	42%	1%	4%	61%	14%	74%
220	14%	42%	1%	4%	60%	14%	74%
230	14%	42%	1%	4%	60%	14%	74%

* Percentage figures are percentages of divisible income, summing to Total Government Take

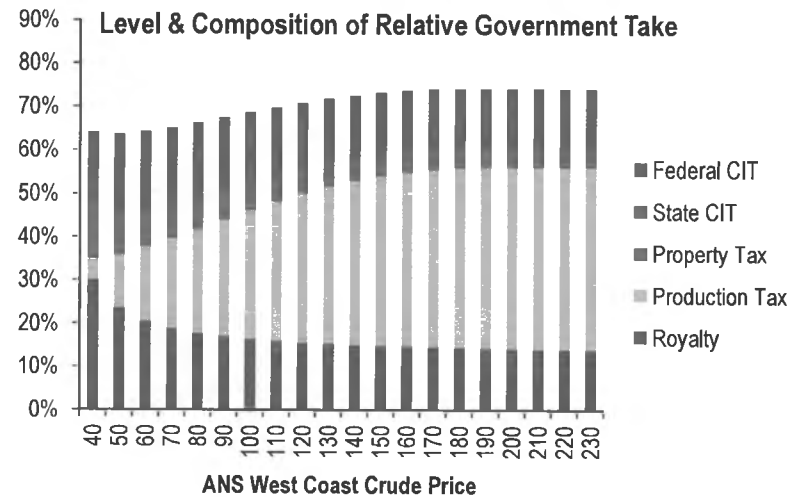
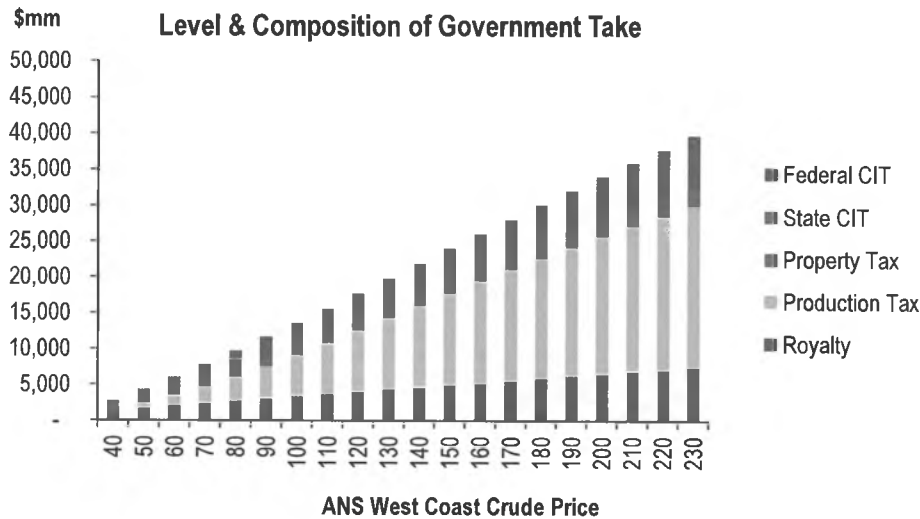


ACES As Proposed

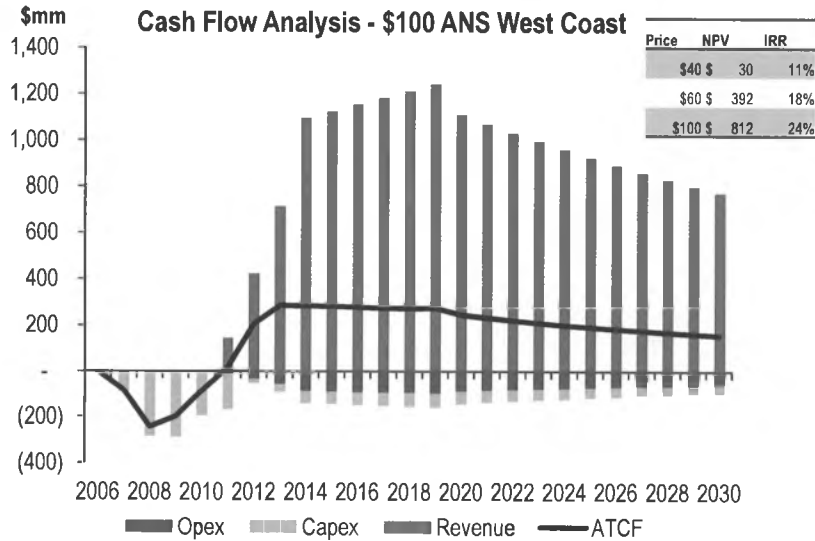


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	30%	5%	9%	4%	48%	16%	64%
50	23%	12%	5%	5%	46%	18%	64%
60	20%	17%	4%	5%	46%	18%	64%
70	19%	21%	3%	5%	47%	18%	65%
80	18%	24%	3%	5%	49%	17%	66%
90	17%	27%	2%	4%	51%	17%	68%
100	16%	30%	2%	4%	52%	16%	69%
110	15%	32%	2%	4%	54%	16%	70%
120	16%	35%	1%	4%	56%	15%	71%
130	15%	37%	1%	4%	57%	15%	72%
140	15%	38%	1%	4%	58%	15%	73%
150	15%	39%	1%	4%	59%	14%	73%
160	15%	40%	1%	4%	60%	14%	74%
170	14%	41%	1%	4%	60%	14%	74%
180	14%	42%	1%	4%	60%	14%	74%
190	14%	42%	1%	4%	61%	14%	74%
200	14%	42%	1%	4%	61%	14%	74%
210	14%	42%	1%	4%	61%	14%	74%
220	14%	42%	1%	4%	61%	14%	74%
230	14%	42%	1%	4%	60%	14%	74%

* Percentage figures are percentages of divisible income, summing to Total Government Take

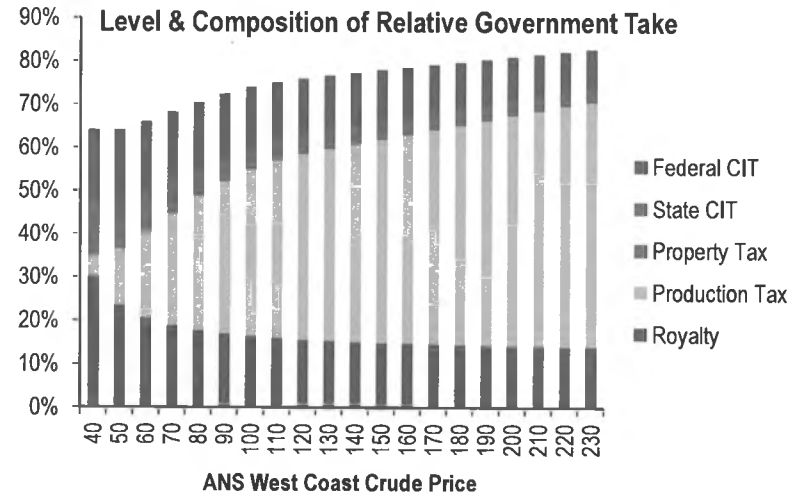
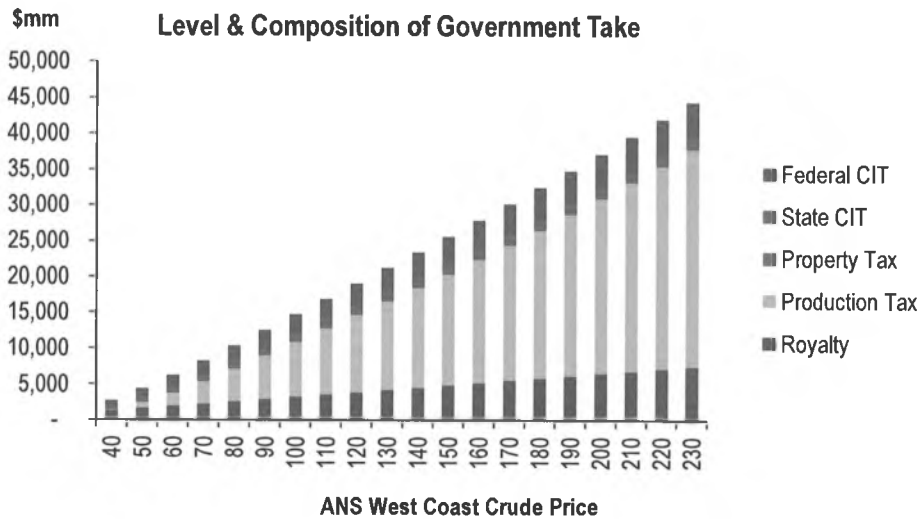


ACES As Enacted

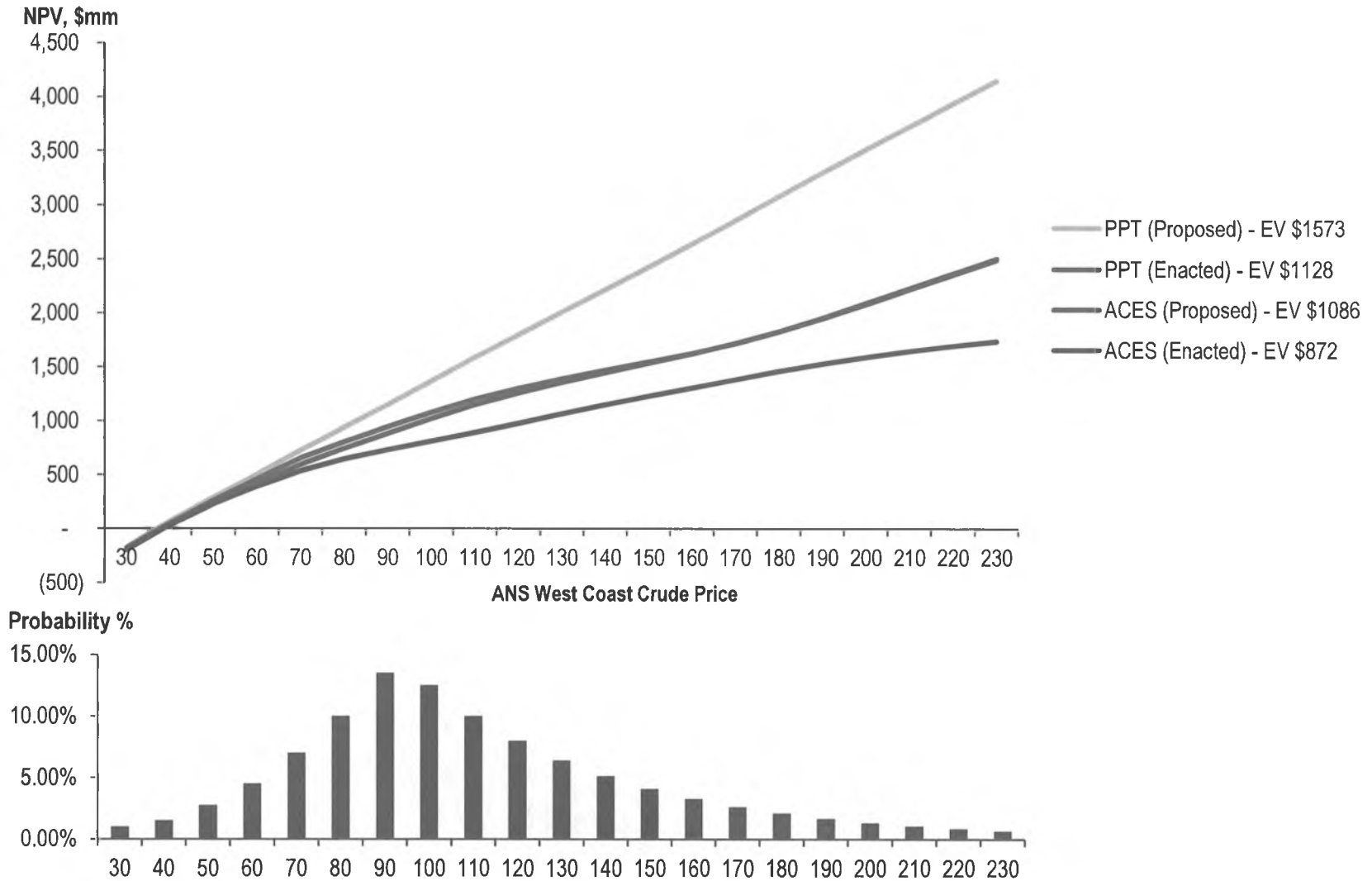


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	23%	13%	5%	5%	47%	18%	64%
60	20%	20%	4%	5%	49%	17%	66%
70	19%	26%	3%	4%	52%	16%	68%
80	18%	31%	3%	4%	55%	15%	71%
90	17%	35%	2%	4%	58%	14%	73%
100	16%	39%	2%	4%	60%	14%	74%
110	16%	41%	2%	3%	62%	13%	75%
120	16%	43%	1%	3%	63%	13%	76%
130	15%	45%	1%	3%	64%	12%	77%
140	15%	46%	1%	3%	65%	12%	77%
150	15%	47%	1%	3%	66%	12%	78%
160	15%	49%	1%	3%	67%	11%	79%
170	14%	50%	1%	3%	68%	11%	79%
180	14%	51%	1%	3%	69%	11%	80%
190	14%	52%	1%	3%	70%	10%	80%
200	14%	53%	1%	3%	71%	10%	81%
210	14%	55%	1%	3%	72%	10%	82%
220	14%	56%	1%	2%	73%	9%	82%
230	14%	57%	1%	2%	74%	9%	83%

* Percentage figures are percentages of divisible income, summing to Total Government Take

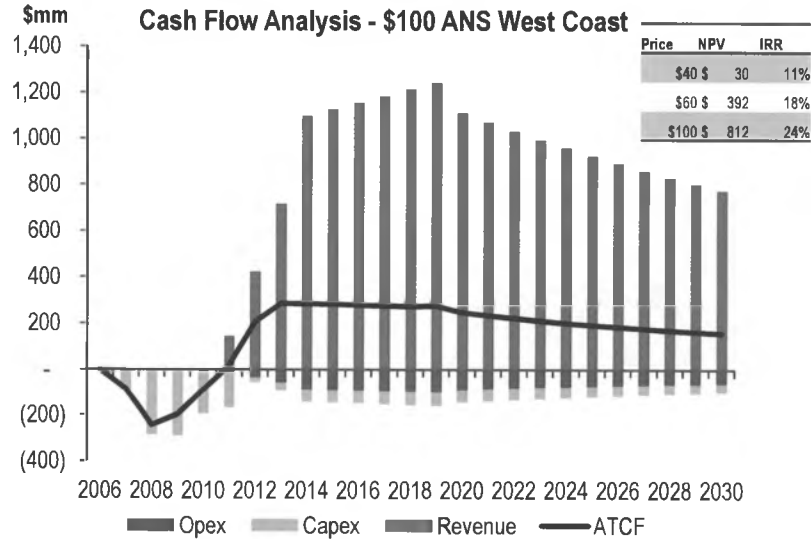


Limitations on Price Upside: A Probabilistic Approach

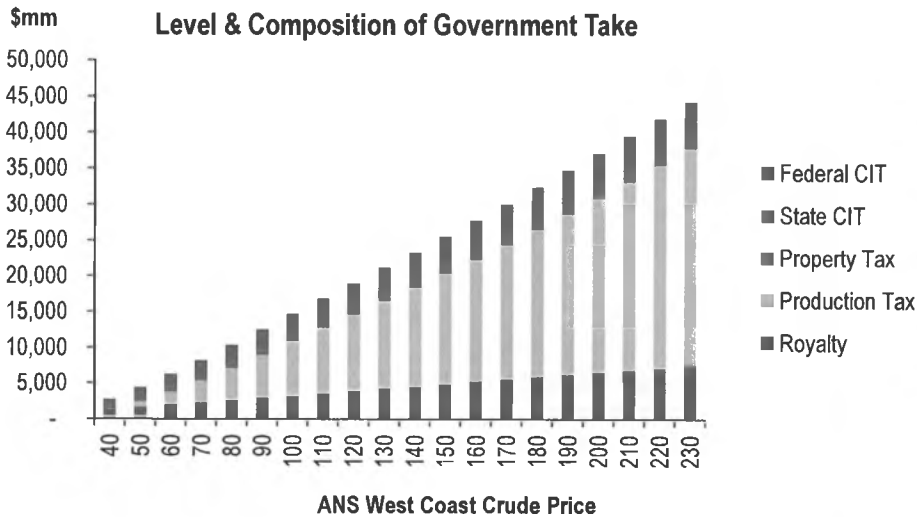


*Probability distribution is for illustrative purposes only

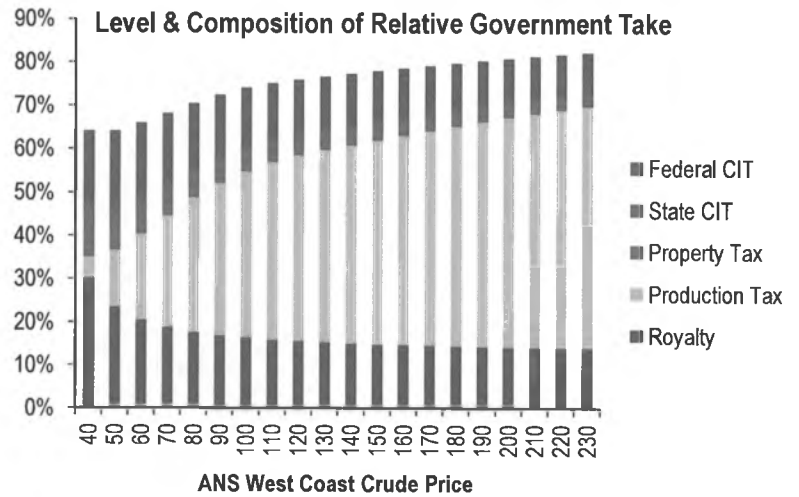
ACES – Capped at Maximum of 70%



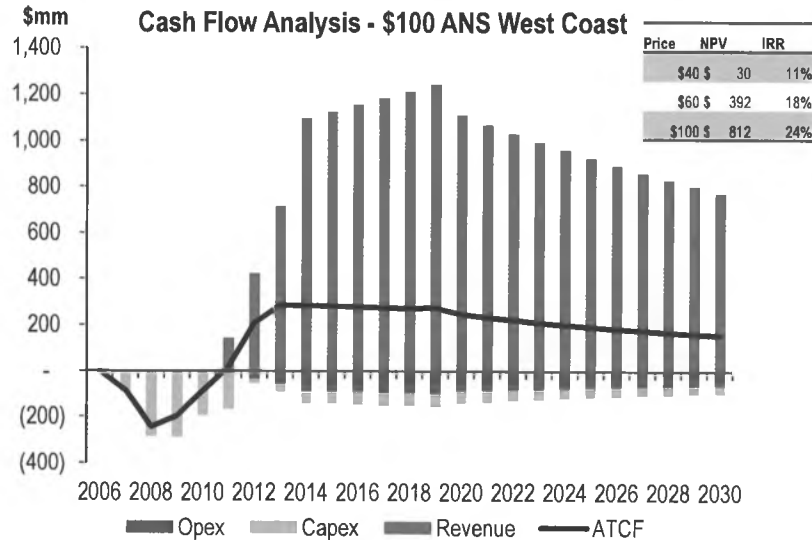
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	30%	5%	9%	4%	48%	16%	64%
50	23%	13%	5%	5%	47%	18%	64%
60	20%	20%	4%	5%	49%	17%	66%
70	19%	26%	3%	4%	52%	16%	68%
80	18%	31%	3%	4%	55%	15%	71%
90	17%	35%	2%	4%	58%	14%	73%
100	16%	39%	2%	4%	60%	14%	74%
110	16%	41%	2%	3%	62%	13%	75%
120	16%	43%	1%	3%	63%	13%	76%
130	15%	45%	1%	3%	64%	12%	77%
140	15%	46%	1%	3%	65%	12%	77%
150	15%	47%	1%	3%	66%	12%	78%
160	15%	49%	1%	3%	67%	11%	79%
170	14%	50%	1%	3%	68%	11%	79%
180	14%	51%	1%	3%	69%	11%	80%
190	14%	52%	1%	3%	70%	10%	80%
200	14%	53%	1%	3%	71%	10%	81%
210	14%	54%	1%	3%	72%	10%	81%
220	14%	55%	1%	3%	72%	10%	82%
230	14%	56%	1%	2%	73%	9%	82%



* Percentage figures are percentages of divisible income, summing to Total Government Take

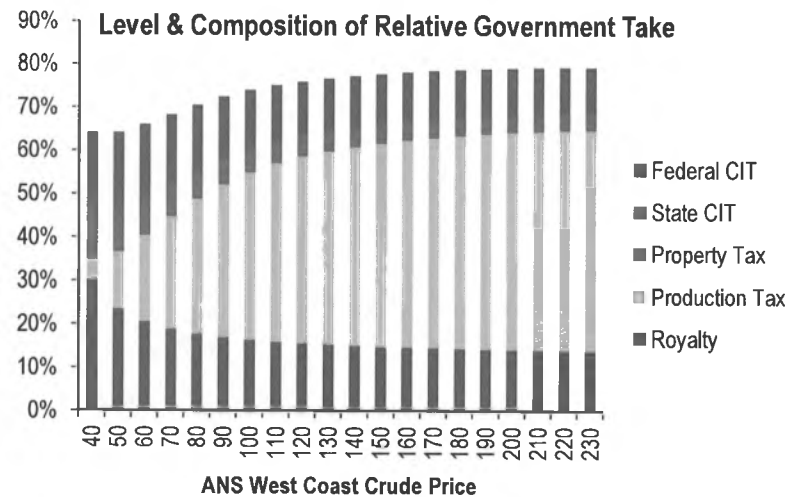
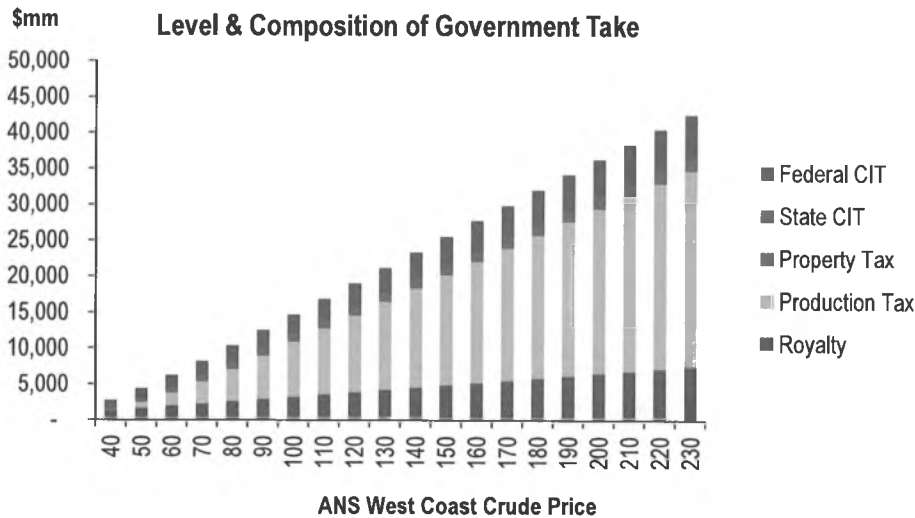


ACES – Capped at Maximum of 60%

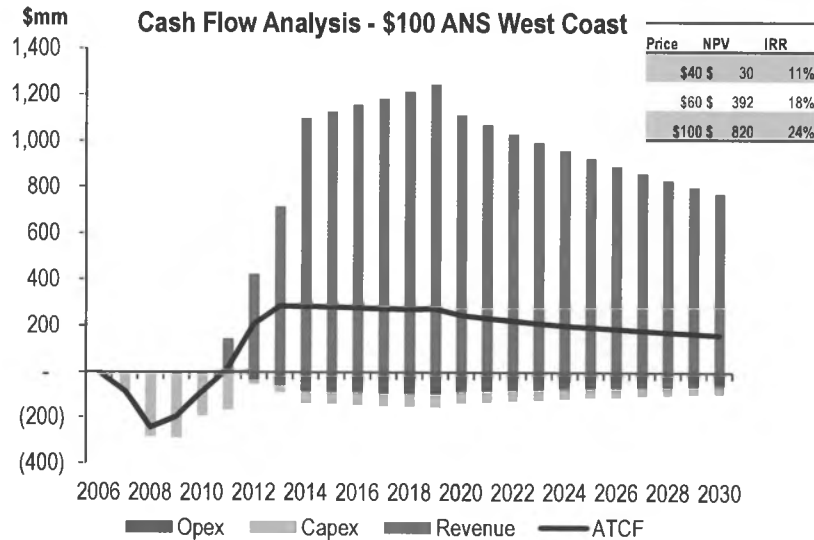


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	30%	5%	9%	4%	48%	16%	64%
50	23%	13%	5%	5%	47%	18%	64%
60	20%	20%	4%	5%	49%	17%	66%
70	19%	26%	3%	4%	52%	16%	68%
80	18%	31%	3%	4%	55%	15%	71%
90	17%	35%	2%	4%	58%	14%	73%
100	16%	39%	2%	4%	60%	14%	74%
110	16%	41%	2%	3%	62%	13%	75%
120	16%	43%	1%	3%	63%	13%	76%
130	15%	45%	1%	3%	64%	12%	77%
140	15%	46%	1%	3%	65%	12%	77%
150	15%	47%	1%	3%	66%	12%	78%
160	15%	48%	1%	3%	67%	12%	78%
170	14%	49%	1%	3%	67%	12%	79%
180	14%	49%	1%	3%	67%	11%	79%
190	14%	50%	1%	3%	68%	11%	79%
200	14%	50%	1%	3%	68%	11%	79%
210	14%	51%	1%	3%	68%	11%	79%
220	14%	51%	1%	3%	68%	11%	79%
230	14%	51%	1%	3%	68%	11%	79%

* Percentage figures are percentages of divisible income, summing to Total Government Take

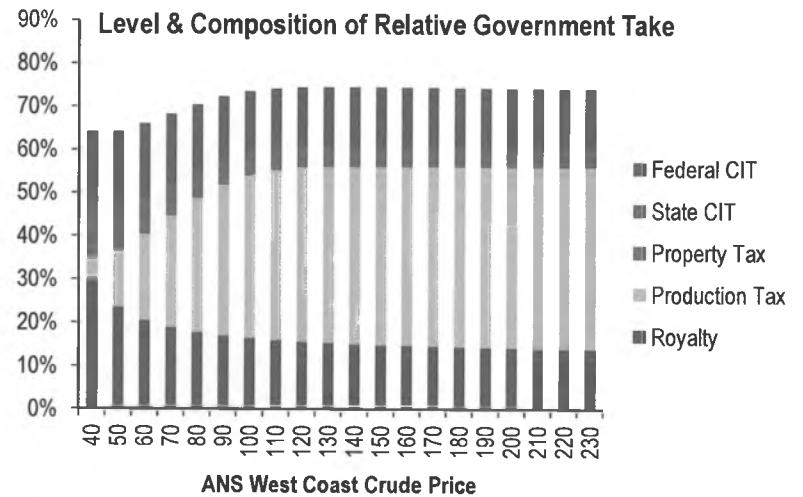
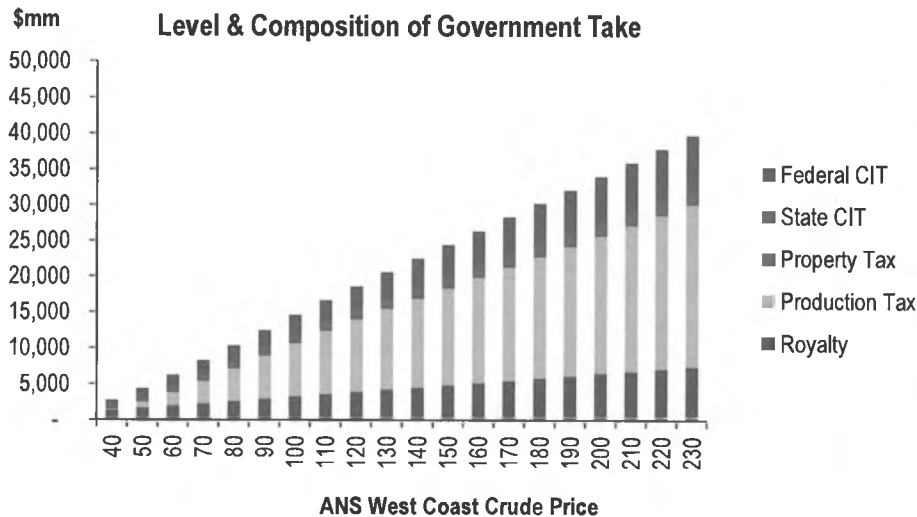


ACES – Capped at Maximum of 50%

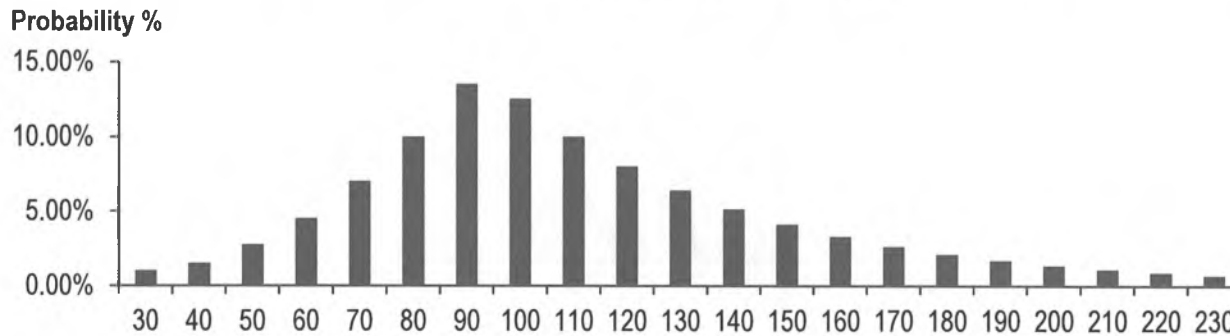
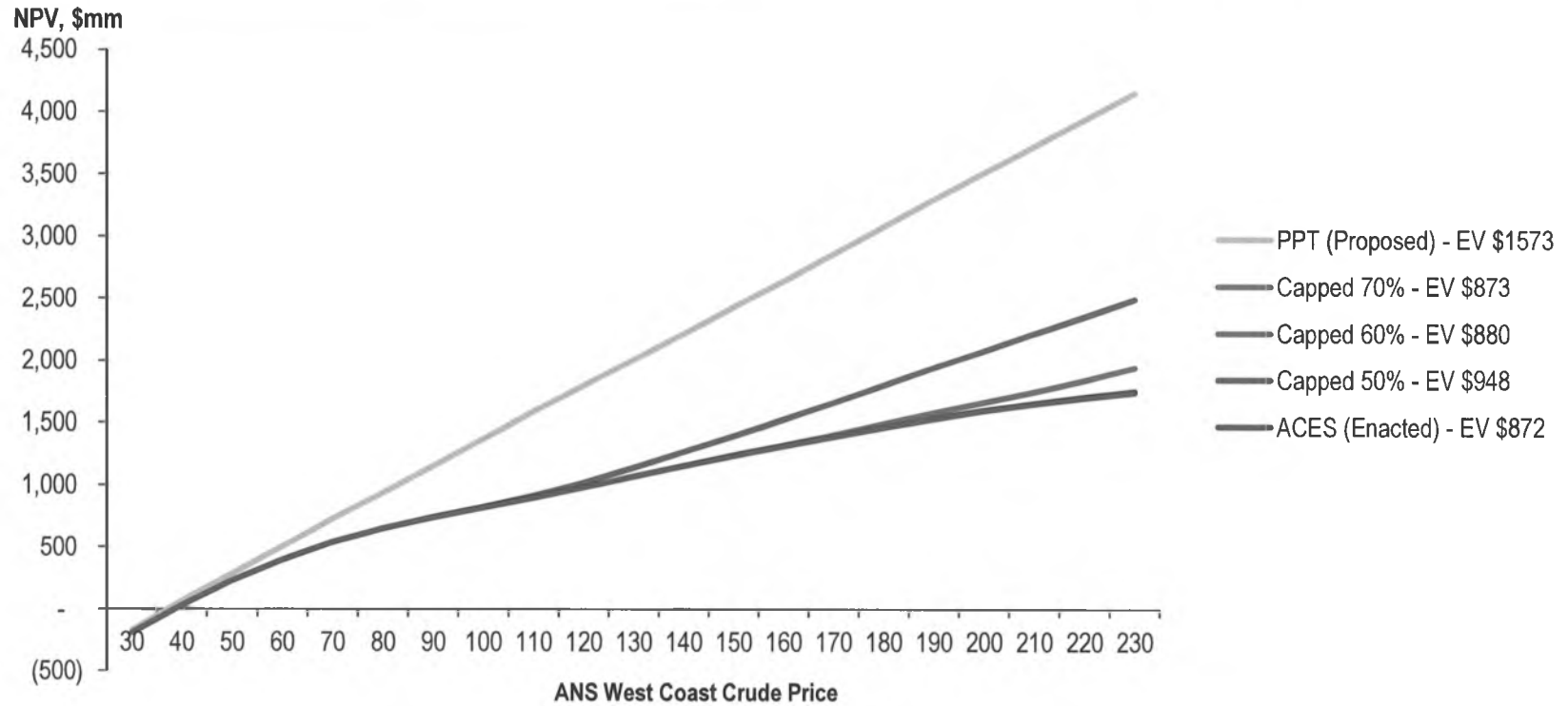


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	30%	5%	9%	4%	48%	16%	64%
50	23%	13%	5%	5%	47%	18%	64%
60	20%	20%	4%	5%	49%	17%	66%
70	19%	26%	3%	4%	52%	16%	68%
80	18%	31%	3%	4%	55%	15%	71%
90	17%	35%	2%	4%	58%	15%	72%
100	16%	38%	2%	4%	60%	14%	74%
110	16%	40%	2%	4%	61%	14%	74%
120	16%	41%	1%	4%	61%	13%	74%
130	15%	41%	1%	4%	61%	13%	75%
140	15%	41%	1%	4%	61%	14%	75%
150	15%	41%	1%	4%	61%	14%	75%
160	15%	42%	1%	4%	61%	14%	75%
170	14%	42%	1%	4%	61%	14%	74%
180	14%	42%	1%	4%	61%	14%	74%
190	14%	42%	1%	4%	61%	14%	74%
200	14%	42%	1%	4%	61%	14%	74%
210	14%	42%	1%	4%	61%	14%	74%
220	14%	42%	1%	4%	61%	14%	74%
230	14%	42%	1%	4%	61%	14%	74%

* Percentage figures are percentages of divisible income, summing to Total Government Take



Limitations on Price Upside: A Probabilistic Approach



* Probability distribution is for illustrative purposes only

Conclusions

- There are a wide range of forms of progressivity, and metrics on which it may be based
- Sometimes progressivity may be used to counterbalance regressive elements of a regime, and at other times, it may simply be about taking as large a share of the economic rent as possible
- A well-designed highly progressive regime may be efficient, but it will not necessarily be competitive
- Alaska is one of the more progressive regimes in the world, and has a relatively high level of Government Take (GT)
 - In the OECD, only Norway has a higher level of GT, and Alaska GT is equal to Norway's at \$140 oil
 - Higher GT regimes tend to be PSC regimes in some of the highest take regimes in the world
- PPT as it was proposed was a progressive component that counterbalanced other regressive elements, to create a fairly neutral regime
- PPT as enacted was highly progressive, and ACES is even more so.

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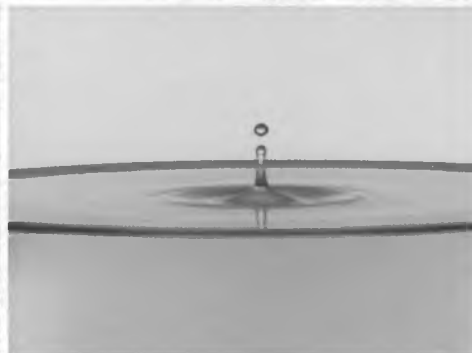
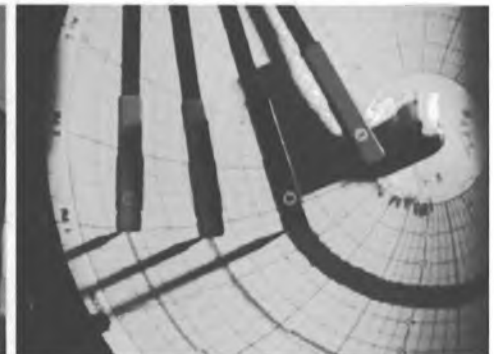
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Final Findings and Determination

For

**Nikaitchuq Development
Royalty Modification
Application**

Commissioner of the Department of Natural Resources

**APPROVAL
OF MODIFICATION OF ROYALTY
FOR LEASES:**

**ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583,
390615, 390616 and 391283**

January 11, 2008

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I. INTRODUCTION AND BACKGROUND

A. Introduction

On October 16, 2007, Eni US Operating Co. Inc. (Eni), as operator of the Nikaitchuq Unit (NU), on behalf of its affiliate Eni Petroleum US LLC, 100 percent working interest owner of the subject leases, submitted an application to the commissioner of the State of Alaska Department of Natural Resources (ADNR) for modification of royalty under AS 38.05.180(j)(1)(A) (Attachment 1). On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for 30 days ending January 7, 2008. ADNR hereby issues its Final Findings and Determination as required under AS 38.05.

Eni has applied for royalty modification on 12 leases which overlie the Schrader Bluff and the Sag River reservoirs. However, the Sag River reservoir was withdrawn from the application at the request of Eni. Eni requests that the fixed royalty rates of

- 12.5 percent on the Net Profit Share (NPS) lease, ADL 391283, and
- 16.66667 percent on the 11 leases (ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616)

be reduced to the minimum rate allowed, 5.0 percent, with an annual sliding-scale royalty percentage adjustment based on the level of Alaska North Slope West Coast (ANSWC) crude oil price. The 30 percent net profit share rate on ADL 391283 is to remain unchanged. Attachment 2 depicts the Nikaitchuq Unit boundaries and leases subject to this royalty modification application.

This Final Findings and Determination responds to the royalty modification application as required under AS 38.05.180(j)(8). Part I summarizes the royalty modification application and process. Part II reviews the history of the Nikaitchuq Unit formation and development, and Eni's royalty modification application. Part III reviews the state's authority to carry out royalty modification. Part IV reviews the requirements and terms of royalty modification pursuant to this application. Part V contains ADNR's analysis of the application under the royalty modification criteria. Part VI is the Final Findings and Determination.

B. Royalty Modification Procedure

This Final Findings and Determination is the first step in a process contemplated in AS 38.05.180(j) that could result in an authorization to modify the royalty terms for certain leases. The commissioner published the Preliminary Findings and Determination, gave public notice of a 30-day public comment period (Attachments 3 and 4), and offered to appear before the Legislative Budget and Audit Committee to provide a review of the

Findings and Determination and the administrative process. The commissioner will keep the submitted data confidential under AS 38.05.035(a)(9) at the request of the lessee or lessees making application for the royalty reduction. This Final Findings and Determination by ADNR regarding royalty modification is final and not appealable. With the Applicant's concurrence, ADNR will amend the subject leases to conform to the terms of this royalty modification Final Findings and Determination.

II. SUMMARY OF ENI'S APPLICATION FOR ROYALTY MODIFICATION

A. Unit and Lease Summary

ADNR approved the formation of the Nikaitchuq Unit effective April 29, 2004. At that time, Kerr-McGee Oil & Gas Corp. (KMG) held 70 percent of the working interest and Armstrong Oil & Gas Inc. (Armstrong) held 30 percent. The unit originally consisted of eight leases covering 12,968 offshore acres in the shallow waters of Harrison Bay in the Beaufort Sea, approximately three miles north of Oliktok Point. The Kuparuk River Unit (KRU) lies to the south, and the Milne Point Unit (MPU) lies to the east of the Nikaitchuq Unit. The Tuvaq Unit, formed in August 2004, was adjacent to the western boundary of the original Nikaitchuq Unit. Effective October 5, 2007, ADNR approved the first expansion of the Nikaitchuq Unit, termination of the Tuvaq Unit and the contraction of the Kuparuk River Unit. The Nikaitchuq Unit expanded to include all of the Tuvaq Unit leases, the Kigun lease, formerly committed to the KRU, and two additional leases acquired by ENI at the 2004 Beaufort Sea Sale.

All 12 leases in the Eni royalty modification application are committed to the expanded Nikaitchuq Unit. (See lease map in Attachment 2.)

The ownership of the Nikaitchuq Unit has changed significantly since formation. Eni acquired Armstrong's 30 percent WIO of Nikaitchuq Unit in August 2005. In August 2006, Anadarko Petroleum Co. (Anadarko) acquired KMG, including KMG's 70 percent WIO in Nikaitchuq Unit, and became Nikaitchuq Unit operator. Eni subsequently acquired the remaining 70 percent Nikaitchuq Unit ownership from the operator, Anadarko, in March 2007, and became the 100 percent WIO and operator of Nikaitchuq Unit.

On January 11, 2006, KMG submitted an application for royalty modification under AS 38.05.180(j)(1)(A) for 14 leases of which 12 are the subject of this application.¹ KMG's application requested that the royalty rate for the 14 leases be modified from their respective existing fixed royalty rates of 16.67 percent and 12.5 percent to a fixed royalty rate of 5 percent. Effective October 31, 2006, the ADNR issued the Final Findings and Determination of the Commissioner of the Department of Natural Resources for the Nikaitchuq Development Royalty Modification Application denying KMG's application for royalty modification.

¹ The KMG application included ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, 388583, 390615, and 390616.

B. Project Development History

In the 2003-2004 and 2004-2005 exploration/appraisal drilling programs KMG/Armstrong encountered accumulations of hydrocarbons in the area of the then-proposed Nikaitchuq Unit. A total of six wells were drilled in the Nikaitchuq area in the 2004 and 2005 winter drilling seasons; two additional wells were drilled in 2006.

The planned development includes:

- Construction of a gravel pad with drilling, gathering and production facilities on Oliktok Point near the existing ConocoPhillips Alaska Inc. seawater treatment facility.
- Construction of a gravel drilling island near Spy Island tied back via a 3.8-mile subsea flow line and utility bundle to Oliktok Point for fluid processing.
- Construction of a +/-14-mile pipeline from Oliktok Point to a tie-in near KRU DS-1Y pad for connection to the Kuparuk Transportation common carrier pipeline.
- Consideration of future modifications required to adjust facility configuration to accommodate actual results of well performance.
- A total of 73 wells drilled between 2008 and 2011, of which 31 are expected to be producers.
- First oil expected in 2010.

Development studies indicate that extended reach horizontal producing and injection wells required for pressure maintenance are needed to economically recover the hydrocarbons in place. The planned development would permit a relatively small "footprint" for centralized facilities and minimal well pads, thereby reducing environmental impacts to the region. Initial drilling will be from a 313,000-square-foot pad to be constructed at Oliktok Point. Existing roads will be utilized for access. The production facilities will be located on the same pad. Later, a small gravel island is to be constructed within the barrier islands for future drilling. A subsea bundle containing a three-phase production line and multiple utility lines will be constructed to connect the gravel island to Oliktok Point to transport production and provide fuel, secondary recovery fluid, and power to the gravel island.

C. Eni Royalty Modification Request

On October 16, 2007, Eni submitted an application (Attachment 3) to the ADNR commissioner for modification of royalty on 12 leases, ADLs: 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616 and ADL 391283 under AS 38.05.180(j)(1)(A). In accordance with 11 AAC 88.105, 11 AAC 83.185, and 11 AAC 05.010(a)(10)(H) Eni submitted a complete application with the required \$250.00 filing fee.

The Eni application for royalty modification submitted on October 16, 2007, requests a 5.0 percent fixed royalty if the Alaska North Slope West Coast (ANSWC) crude oil price falls below an ANSWC price equivalent to the U.S. Department of Interior, Minerals Management Service (MMS) NYMEX West Texas Intermediate (WTI) oil price threshold for royalty modification for OCS August 2004-2006 deepwater oil leases in the Gulf of Mexico (GOM).² Eni proposes a sliding-scale royalty rate in any month after production start-up (expected in 2010) that would range between 5.0 and 16.6667 percent, depending on the average monthly price of ANSWC crude oil. An ANSWC monthly (nominal) price below the Alaska Department of Revenue (ADOR) *Spring 2007 Revenue Sources* forecast between 2010 (the year of first production) and 2017 shown in Figure II.1 (below) would trigger a reduced royalty rate from original fixed lease rates of 12.5 percent and 16.6667 percent, respectively. The amount of the reduction in royalty percentage would depend on (a) the original lease rate (either 12.5 percent or 16.6667 percent) and (b) the extent to which the actual future oil price falls below the ADOR forecast threshold.³

The original fixed royalty rate of 16.6667 percent for ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583, 390615, and 390616 and 12.5 percent with 30 percent net profit for ADL 391283 would be subject to the sliding scale modification in a low commodity price environment to a level at or above a floor of 5 percent. The 30 percent net profit share to the State attached to ADL 391283 would be unchanged under the Eni royalty modification proposal.

The Eni application also would provide full royalty relief at a reduced rate of 5 percent for all leases regardless of oil price if monthly production is below 4,000 barrels of oil per day for the first 10 years following the effective date of the royalty modification decision.

² ADNR estimates threshold to be \$42.53 per barrel in 2010 based on a 2007 NYMEX WTI price of \$42.64 assuming a 94 percent basis adjustment to ANSWC and 2 percent price escalation pursuant to the ENI proposal. See: MMS, *Price Thresholds and Annual Market Prices for MMS Deepwater and Deep Depth Oil and Gas Royalty Relief Programs*, Deep Water Oil, Economics Division at www.mms.gov/econ/DWRRAPrice1.htm.

³ Under the Eni proposal, the royalty percentage rate adjustment would be approximately $\frac{3}{4}$ percentage point per \$1 change in ANSWC price for leases with a 16.6667 percent base royalty rate and $\frac{1}{2}$ percentage point per \$1 change in ANSWC price for leases with a 12.5 percent base royalty rate. After 2017, the ADOR ANSWC price forecast is inflated by the monthly change in the Producer Price Index (PPI).

**III. SUMMARY OF ROYALTY MODIFICATION AUTHORITY
AS 38.05.180(j)(1)(A), (2), (3), (4)(A), (5)**

A. General Royalty Modification Requirements

AS 38.05.180(j)(1)(A) authorizes the DNR commissioner to provide for royalty modification on individual leases, leases unitized as described in (p) of this section (AS 38.05.180), leases subject to an agreement described in (s) or (t) of this section (AS 38.05.180), or interests unitized under AS 31.05 to allow for production from an oil or gas field or pool if:

1. the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;
2. the field or pool has not previously produced oil or gas for sale; and
3. oil or gas production from the field or pool would not otherwise be economically feasible.
4. Under AS 38.05.180(j)(2), the commissioner may not grant a royalty modification unless the lessee or lessees requesting the royalty modification make a clear and convincing showing that a royalty modification meets the three requirements set out above and is in the best interests of the state.

B. General Royalty Modification Terms

1. Under AS 38.05.180(j)(3) the royalty modification terms must provide for an increase or decrease or other modification of the state's royalty share by a sliding-scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs.
2. Under AS 38.05.180(j)(4)(A) a modification to royalty may not be granted for the field or pool if the royalty modification would result in a royalty rate of less than 5 percent in amount or value of the production removed or sold from a lease or leases covering the field or pool.
3. Under AS 38.05.180(j)(5) a royalty reduction must include an explicit condition that the royalty reduction is not assignable without the prior written approval, which may not be unreasonably withheld, by the commissioner. The commissioner shall, in the preliminary and final findings and determinations, set out the conditions under which the royalty reduction may be assigned and may not grant a royalty reduction without an explicit condition that the royalty reduction is not transferable.

IV. DISCUSSION OF ROYALTY MODIFICATION CRITERIA

A. Leases Are Eligible For Consideration

The leases meet the requirements for consideration and all eleven subject leases proposed for royalty modification are committed in entirety to the Nikaitchuq Unit. AS 38.05.180(j)(1) allows modification of royalty for individual leases and unitized leases.

B. Reservoir Delineation: Discussion of Reservoir Geology and Engineering

1. Introduction to reservoir delineation.

The commissioner may grant royalty modification to allow for production from an oil or gas field or pool if the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner.

The area within the Nikaitchuq Unit for which royalty relief is sought lies offshore in the Beaufort Sea in the vicinity of Spy Island, approximately three miles north of Oliktok Point. The Nikaitchuq Unit is north of and contiguous with the northern edge of the KRU and the Milne Point Unit (MPU). The KRU is operated by ConocoPhillips and produces from the Cretaceous Kuparuk River Formation and shallower Schrader Bluff Formation. The BP-operated MPU field lies to the south-southeast of the Nikaitchuq Unit and produces oil from the Schrader Bluff, Kuparuk, and Triassic Sag River formations. The western edge of the proposed Nikaitchuq Unit is adjacent to the recently expanded Ooguruk Unit (OU) operated by Pioneer. Production from the OU is expected from the Kuparuk and Jurassic Nuiqsut sandstones.

Within the Nikaitchuq Unit, potential commercially recoverable reserves have been tested in both the Cretaceous Schrader Bluff and the Triassic Sag River formations.

Based upon the submitted application and the planned initial development, the request for royalty modification at Nikaitchuq is limited to the OA sand of the Schrader Bluff Formation. For the purpose of this application, the OA sand is defined in Kerr McGee Nikaitchuq #1 (API No. 50629231930000), completed in 2004, as the interval between 5034 feet measured depth (4127 feet subsea true vertical depth) and 5090 feet measured depth (4170 feet subsea true vertical depth).

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Although upside potential may also exist within the shallower Schrader Bluff N sand interval, the current lack of core, well test, or fluid data from this interval increases the risk and precludes it from being deemed delineated and included as part of this application. ENI plans to gather more data to thoroughly evaluate the N sand during the course of developing the deeper OA sand.

The Sag River Formation contains lighter oil than the Schrader; however, it is plagued with poor quality reservoir rock. The development potential is marginal at best unless there are significant advances in stimulation or enhanced oil recovery technology. Delineation of the Sag River Formation at Nikaitchuq to date has revealed limited reserves and similar test results to the analog at MPU where wells within the Sag River Formation consistently show initial flush production followed by steep decline within the first year. ENI is still evaluating the development potential of this interval and, as such, it has been excluded from this application.

2. Exploration History of the Area

Two key early exploration wells lie within several miles of the Nikaitchuq development area. The Unocal East Harrison Bay State #1 well lies near the northwest corner of the KRU, to the southwest of the Nikaitchuq Unit. The well was drilled in February 1977 to a measured depth of 9,809 feet, bottoming in argillite basement. The East Harrison Bay State #1 well logs appear to contain about 15 feet of oil-bearing Kuparuk Formation that appears cemented in the upper half. The Jurassic section looks silty on logs. The ARCO Kalubik #3 well, drilled in February 1998, lies to the south-southwest of the Nikaitchuq area. The well bottomed in the Jurassic at a measured depth of 7,000 feet. The well encountered a 40-foot-thick measured depth (MD) interval of Kuparuk C sandstone that appears on electric logs as oil-bearing, but siderite cemented in the upper 10 feet of the interval. On well logs the Jurassic interval contains silt with a 12-foot silty sand developed around 6,565 feet MD. The well was plugged and abandoned on March 6, 1998.

3. Drilling History

The first major exploration activity in the area in the early 1970s targeted the Ivishak Formation following the discovery of the prolific Ivishak Formation in Prudhoe Bay State #1 in 1967. The Hamilton Brothers Milne Point #18-1 was one of the early wells drilled on the Milne Point structure in 1970 in search of Ivishak and Lisburne objectives. This well encountered about 50 feet of tight oil-saturated sandstone that was not tested and a section of Kuparuk sandstone that tested at a rate of 875 BOPD. This discovery led to increased industry interest in the Milne Point area and led to exploration and delineation drilling for Kuparuk reserves. In the early 1980s the Sag River was cored in the Conoco Milne Point Unit #C-1 well and contained bleeding oil and gas. The Sag River Sandstone was also cored in the MPU #L-1 well and contained no visible porosity or staining and appeared tight on wire line logs.

In the early 1990s about a dozen wells were drilled to the west-southwest of the Nikaitchuq area with Jurassic sandstones and Kuparuk C sandstones as targets. The ARCO Kalubik #1 well encountered approximately 160 feet of productive Nuiqsut and Nechelik sandstone that tested approximately 336 BOPD (un-stimulated). In addition, the well penetrated an 85-foot section of Sag River Sandstone with calculated log porosities in the range of 15 to 22 percent. The Thetis Island #1 well also encountered an 80-foot section of porous Sag River sandstone with log-calculated porosities in the range of 16-24 percent. A pay section of Nuiqsut sandstone was also encountered that tested at an average rate of 120 BOPD with a high rate of 650 BOPD. Both the Kalubik #1 well and Thetis Island #1 well drilled through Brookian sandstones that contained mud log hydrocarbon shows.

In the late 1990s BP drilled several dedicated Sag River Sandstone test wells, including MPU #C-23, #K-33, #E-13A, 3F-33, #F-33A, and #F-73A. Alaska Oil and Gas Conservation Commission (AOGCC) production data indicate that several Milne Point wells have produced oil out of the Sag River Sandstone and two oil producing wells MPU F-33A and K-33, are currently shut-in. MPU #C-23 produced 378,012 barrels of oil between 1996 and 2001. MPU #F-33 produced 314,276 barrels of oil between September 1996 and May 1999 and was subsequently plugged and abandoned. MPU #K-33 has produced approximately 93,241 barrels of oil since 1997. MPU #E-13A produced 366,665 barrels of oil between 1995 and April 2001. MPU #F-33A produced approximately 661,099 barrels of oil since April of 2001. MPU #F-73A produced 13,430 and is now a water-alternating-gas injection (WAGIN) well. BP estimated the original oil-in-place (OOIP) at 62 MM STB oil and the reservoir area about 8500 acres based upon seismic and log data during an AOGCC Conservation Order hearing in May 1998. AOGCC reservoir data indicate that the oil commonly recovered from the Sag River sandstone has an API oil gravity of about 37 degrees. Total production from the MPU Sag River Sandstone has been 1,834,131 barrels of oil and 1,875,668 MSCF gas through October 2007. MPU Sag River recovery is less than 3 percent to date based on OOIP. The original GOR ranged from 784 – 974 SCF/STB. Production from the Sag River pool at MPU has been intermittent with extended shut-in periods since June 1999.

Between 2004 and 2005, Kerr McGee (KMG) drilled six wells in the Nikaitchuq and Tuvaq Units. Initially, the primary exploration target was the Sag River Formation; the Kuparuk Formation was a secondary target. Although the wells did not encounter reservoir quality sand in the Kuparuk, the well logs indicated that sands in the shallower Schrader Bluff Formation were prospective. KMG then adjusted the exploration program to thoroughly evaluate the Schrader Bluff Formation. Three of the six wells tested oil from the viscous Schrader Bluff or Sag River formations. In 2006/2007 KMG drilled two additional pre-development wells from Oliktok Point to further delineate and test the Schrader Bluff sandstone. The two wells are currently suspended.

4. Schrader Bluff Formation Tests

KMG Nikaitchuq #4

Approximately 3,000 feet of gross horizontal Schrader Bluff OA sand was drilled in this well, with approximately 2,270 feet of horizontal or lateral net pay, from a 30-foot true-vertical-depth net pay thickness. A two-week production test was performed on the well using an electric submersible pump (ESP) to aid in producing the 16–17 API crude. The well tested at rates up to 1,200 barrels of oil per day during periods of the initial test. Permeability estimated from the test was greater than 350 millidarcies and was confirmed from the analysis of the flow tests conducted on a whole core obtained from the well.

KMG Tuvaaq #1

The well was not tested. It penetrated 30 feet net pay Schrader Bluff OA Sand and 12 feet net Schrader Bluff N sand. There were no cores taken at Tuvaaq. Schrader Bluff N sand was interpreted to be oil-filled here and at Kigun #1 appeared unconsolidated with permeability estimated from 100-1000 millidarcies and porosity 25-35 percent.

KMG Kigun #1

The well was not tested. It penetrated 29 feet net pay Schrader Bluff OA sand and 30 feet net N sand. An MDT tool run sampled the Schrader Bluff OA fluids which were 18 degree API, GOR 59 SCF/STB and viscosity of 82 cp at 87 degree reservoir temperature. (Contamination of the samples with oil-based mud caused concern about the reliability of the sample estimates and properties.) Schrader Bluff OA sand core data indicated 25 percent to 38 percent porosity and up to 1,000 millidarcies permeability in the sandstone intervals.

KMG Oliktok Point I-1 KMG Oliktok Point I-2

These two wells were drilled by KMG during the 2006/2007 drilling season as pre-development wells to further test and delineate the Schrader Bluff reservoir. These wells have been suspended. Results from these wells are currently held confidential under AS 38.05.035(a)(9).

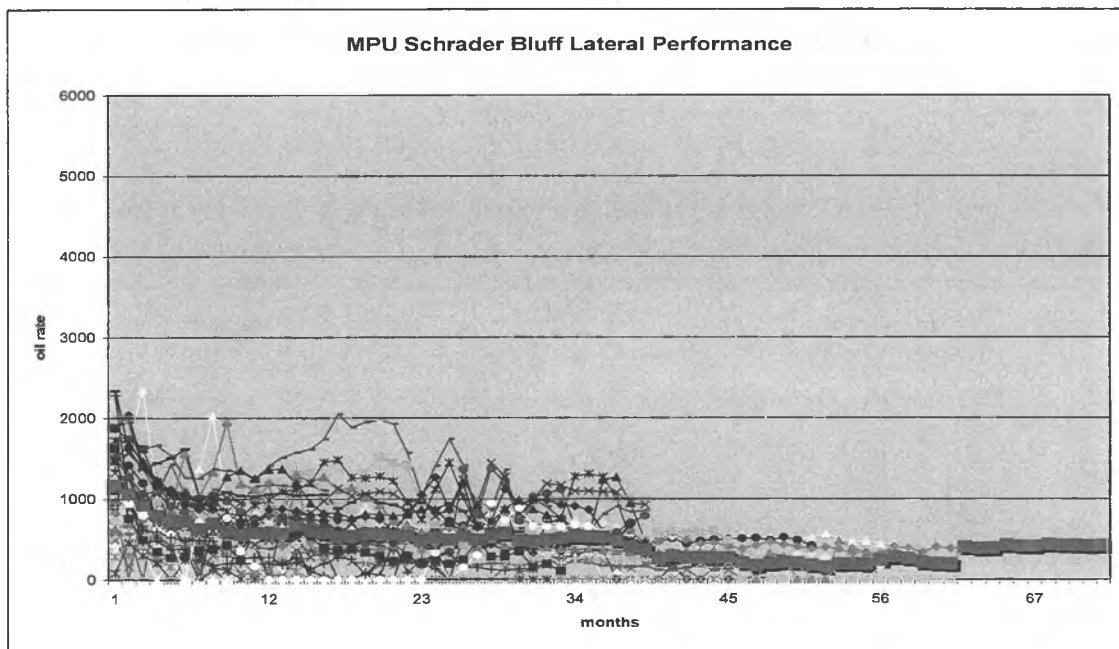
5. Analog Schrader Bluff Formation Performance

Milne Point Unit (MPU) Schrader Bluff Pool (Figure 1), Kuparuk River Unit (KRU) West Sak Pool (Figure 2) and Prudhoe Bay Unit (PBU) Polaris and Orion pools – Figure 3, represent analog Schrader Bluff Formation horizontal well performance. Each of the pools was developed initially with vertical or slanted completions. More recently a number of horizontal lateral and multi-lateral wells have been completed in each of these pools. MPU and KRU Schrader Bluff wells show a distinct, lower rate performance than the newer developed Polaris and Orion Pool wells. A significant portion of the performance difference is likely due to differences in fluid quality. Within the Schrader Bluff Formation / West Sak, developments oil gravities can vary between 15-24 degrees API and viscosity can vary between 5-130 centipoise. To date, development has been limited to those areas with higher API Gravity and lower viscosity. Later Schrader Bluff Formation developments are building on earlier techniques by going from vertical to

horizontal and multilaterals wells. The horizontal and multilaterals should consistently outperform the older wells because more formation is exposed and the completions are more efficient.

The wells in each Schrader Bluff Formation pool exhibit early flush production for six to 12 months. The PBU Schrader Bluff completions show slightly higher initial rate profiles followed by relatively steep decline. The average MPU Schrader Bluff completion (heavy bright green points and line) declined from 1200 bopd to 500 bopd at 12 to 40 months. KRU West Sak lateral completions have performed similar to MPU Schrader Bluff.

Figure 1. MPU Schrader Bluff Formation lateral performance and average performance (heavy green).



6. Reservoir delineation determination.

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Figure 2. KRU West Sak sands lateral performance and average performance (heavy orange).

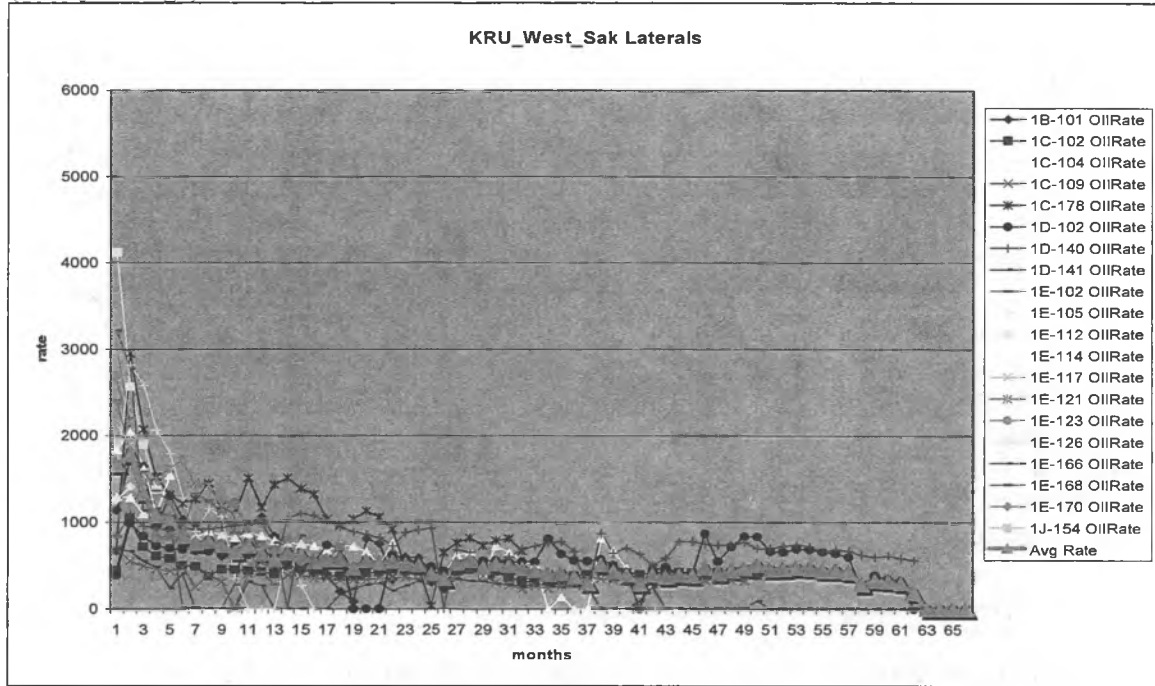
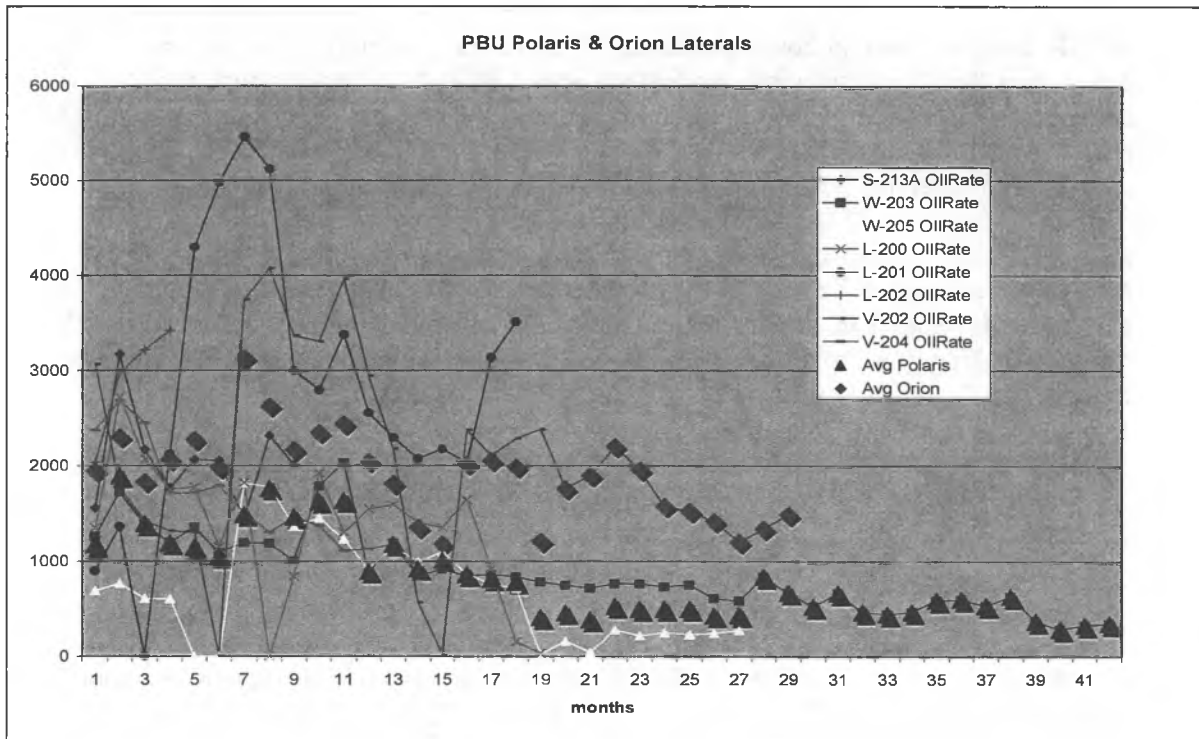


Figure 3. PBU Polaris and Orion Schrader Bluff Formation initial performance.



ENI stated that their plan is to develop Nikaitchuq Schrader Bluff Formation with horizontal wells. Their prognosis of performance can be compared to the analogs by evaluating average Schrader Bluff well performance from initial completion to date. There are up to seven years of production history for the various Schrader Bluff Formation horizontal and lateral wells. Orion appears to be more productive so far but the long term performance has yet to be defined. ENI appears to estimate their development will improve on the previous KRU and MPU Schrader Bluff completions by using the latest technology, namely very long horizontal and or multi-lateral completions. ENI's cases align reasonably with the MPU Schrader Bluff and KRU West Sak and PBU Polaris average performance. PBU Orion performance is notably better than ENI's high case average rates. Analyses of oil samples taken within the OA sand in the Nikaitchuq area demonstrate measured oil viscosities of 95–188 centipoise. This is heavier than the average viscosity of production from existing KRU, MPU and PBU Schrader Bluff developments. In addition, the Nikaitchuq development will include construction of a new standalone facility. The KRU, MPU, and PBU Schrader Bluff pools had existing infrastructure and production from other formations to support the additional development. Both of these factors increase the risk and make this project more economically challenged compared to existing heavy oil developments.

C. No Previous Sale of Produced Oil or Gas

The pools underlying the leases have not previously produced oil or gas for sale.

D. Economic Analysis

ADNR used its own in-house probabilistic economic model (ADNR Model) for the Nikaitchuq development to independently assess the financial performance and ultimate economic effects of a royalty modification for both Eni and for the State of Alaska. Eni shared with the state portions of its proprietary economic model, but the state chose to use its own model that incorporated many input assumptions provided by Eni.⁴

ADNR closely examined the assumptions and methods currently in use by the U.S. Minerals Management Service (MMS) for the Deep Water Royalty Relief Program. The MMS has developed an in-house proprietary probabilistic economic model for Royalty Suspension Viability Program. ADNR adopted an approach similar to that of the MMS by applying the quantitative results from the ADNR model to a prudent-investor decision framework. The ADNR decision framework is confidential. It is designed to replicate the kind of analytical framework used by industry for making prudent oil and gas investment decisions under uncertain conditions involving significant capital outlays and lengthy project life cycles.

⁴ Eni has submitted financial and technical data and analyses and requested that they be held confidential in accordance with AS 38.05.035(a)(9). Thus this section does not discuss any confidential information concerning Eni's geologic, engineering and cost data. These documents are included and discussed in detail in the confidential *Economic Analysis and Internal Decision Process*, (Attachment 6).

The prudent investor standard is maintained throughout the project evaluation process. Under this standard, ADNR incorporates a collection of project performance benchmarks that are consistent with industry norms.

To obtain royalty relief the applicant must show by clear and convincing evidence that without royalty modification the project is not economically feasible. Nikaitchuq is an offshore, heavy oil prospect with relatively high expected exploration and development costs and low expected production possibilities. The final analysis of Nikaitchuq project development conducted by ADNR pursuant to the Eni royalty modification application suggests that, under reasonable assumptions about future oil prices and without some form of royalty relief, this project would not be sanctioned for funding and development.

In its simplest form, the ADNR Model describes project cash-flows for the Nikaitchuq development over a 50-year time horizon. The ADNR Model incorporates expected investment, production, price, revenue, and cost. It incorporates fiscal system attributes, including state and federal tax, state production tax (including the recent ACES legislation)⁵, and royalty obligations, as well as other important commercial relationships, such as facility sharing and pipeline transportation charges.

The ADNR in-house model is flexible enough to allow ADNR to evaluate the effects of changes to the fiscal system. The model provides a platform for systematic evaluation of the effect of a change to the royalty rate. The model calculates the changes to the various financial metrics that result from a change in the royalty rate. These metrics include annual and cumulative discounted and undiscounted cash flow, years to payout, net present value (NPV), expected monetary value (EMV), and internal rate of return (IRR) on investment, as well as state revenues. Also, ADNR used its model to carry out sensitivity analysis of key driver assumptions and to characterize certain price, production, and cost variables in terms of probability distributions to evaluate how uncertainty among these drivers affects key project metrics and state revenues.

Eni furnished ADNR with 200 realizations of project production that depict the range of values and probabilities for the many reservoir factors that determine ultimate reservoir recovery (e.g., aerial and vertical extent, rock characteristics, fluid composition and properties). These 200 Eni realizations represent the universe of possible resource recovery outcomes for ADNR's Monte Carlo analysis that fit the well-test data. The ADNR model samples repeatedly from this universe of production realizations, as well as from volatility inherent in price formation, as characterized in the mean reversion price model (see below), to generate a distribution of net present value (NPV) outcomes for the Nikaitchuq project. The central tendency (mean and median) and dispersion (variance) of the NPV outcomes depict project performance uncertainty and speak to the dimensions of ADNR's prudent-investor decision framework mentioned above.

ADNR incorporated the applicant's input data into its model along with its own assumptions about the path of uncertain future prices to derive independent results for the

⁵ See HB2001 (11/15/2007).

economic feasibility of the Nikaitchuq project. The ADNR Model examines a range of possible inputs to derive a P50, or median, outcome from a Monte Carlo simulation. The P50 result is the value where 50 percent of the outcomes lay below this point and 50 percent of the outcomes lay above the P50 outcome. The ADNR Model uses Palisades Software's "@Risk" Monte Carlo software application to run the simulations and determine risk-weighted outcomes reported in the confidential supplement to this *Final Findings and Determination* (Attachment 7).

Calculating risk weighted outcomes is critical to a full analysis of a project. The probabilistic rate profile, determined based on the applicant's reservoir simulation results, is combined with pricing to determine the project revenue stream. Annual Alaska North Slope West Coast (ANSWC) crude oil prices were generated from an Ornstein-Uhlenbeck type Mean-Reversion price model⁶ with parameters estimated as described by Schwartz, (1997)⁷ using annual price data for ANSWC crude as reported by Platt's. The starting ANSWC delivered price used in the model is \$67 per barrel, the average price for 2007. The risk weighted cost profiles are then matched to the revenue stream generated by the probabilistic price and production models. This yields an NPV distribution. The mean of the NPV distribution is the EMV for the entire project that incorporates uncertainty and can be compared "apples-to-apples" with other versions of the project.

ADNR analyzed various scenarios to explore Nikaitchuq project performance with and without royalty modification. DNR approves royalty modification only when it believes a project will not go forward without it. This means that the impact to royalty revenues to the state is the difference between the royalty revenues with royalty modification as was prescribed in the DNR decision and zero. Even under low price scenarios, ADNR determined that the state can expect to receive an additional \$100 million over the life of the project.

If it is assumed that the project could have gone forward without royalty modification (again, not what ADNR assumes) the impact would be as indicated in Table 1. This table presents several possible price scenarios and the indicated change to the state royalty cash flow stream.

In Table 1 the scenarios labeled "\$43 and Above (Sustained)" and "\$40 Sustained" simply use a flat price deck for "Alaska North Slope West Coast" (ANSWC) crude oil (before inflation) for the life of the project, the price does not vary from year-to-year. An oil price of \$40 is always just below the \$42.64 royalty modification threshold and thus results in 5 percent royalty rates for every barrel of oil produced from the reservoir for the life of the project and the greatest negative impact to overall state royalty revenues.

⁶ Dixit & Pindyck, 1994, http://www.puc-rio.br/marco.ind/sim_stoc_proc.html#mc-mrd.

⁷ The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging", Schwartz, E., *Journal of Finance*, 1997, Volume 52, issue 3, 923-973

Table 1. Change in Alaska royalty revenues if royalty modification were not necessary and project produced oil without royalty modification.

Price Scenario	Impact on State of Alaska Royalty Revenue ("With Royalty Modification Per Decision" Minus "Without Royalty Modification", 5% discount rate)
\$43 and Above (Sustained)	\$0 million
DNR Price Model	(\$39 million)
\$40 Sustained	(\$160 million)

The "DNR Price Model" scenario does not use a constant or "sustained" price for the life of the project (i.e. flat price deck) as is the case with the other two scenarios in Table 1. We use a forward-looking, Monte Carlo-based "mean-reversion" model, as discussed above. This price model creates a price forecast where oil price fluctuates over time, simulating real-life price variability similar to what history has shown. The price for 2007, \$67 per barrel ANSWC, was taken from U.S. Energy Information Agency's most recent price projection for West Texas Intermediate (WTI) crude, and adjusted for ANS-WTI basis by taking the previous 12-month average difference between these two prices. The model reverts to DNR's expected mean value of \$53 per barrel, over time.

The ADNR has determined that under ADNR's price and discounting assumptions, the project attributes furnished by Eni, and the existing lease royalty rates in effect prior to this *Final Finding and Determination* (16.6667 percent fixed royalty rate and the 12.5 percent fixed royalty with 30 percent NPS for ADL 391283), the Nikaitchuq project does not meet prudent-investor standards for economic feasibility. ADNR concludes further that the royalty modification terms and conditions stipulated in Section IV.B would improve project economics. Eni represents that royalty modification would make project sanction more likely.

V. PUBLIC COMMENTS

On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for thirty days, ending January 7, 2008 (Attachments 3 and 4).

No comments were received from the public.

VI. STATE'S PROPOSED ROYALTY MODIFICATION

A. Royalty Modification Requirements for the Nikaitchuq Project

1. Eni's application for royalty modification on ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616, and ADL 391283 meets the requirements for consideration under AS 38.05.180(j)(1). Eni has paid the filing fee and submitted a complete application for the royalty modification including financial and technical data that meet the requirements of 11 AAC 88.105, 11 AAC 83.185, 11 AAC 05.010(a)(10)(H), and AS 38.05.180(j)(6).
2. The Schrader Bluff pool has been sufficiently delineated to the satisfaction of the commissioner for the purpose of considering royalty modification; this pool has not previously produced oil or gas for sale.
3. Eni has shown that oil or gas production from the Schrader Bluff pool would not otherwise be economically feasible.
4. Eni has made a clear and convincing showing that a modification of royalty meets the requirements of 38.05.180(j)(1)(A), and is in the best interests of the state.

B. Royalty Modification Terms for the Nikaitchuq Project

1. Royalty modification pursuant to the terms herein is granted to Eni US Operating Co. Inc. (Eni), as operator and 100 percent working interest owner of the Nikaitchuq project (Project), on ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, 390616, and 391283. Royalty modification is denied for ADL 388580 because there was no apparent resource allocated to this lease.
2. Only production from Nikaitchuq Unit's Schrader Bluff OA reservoir, as delineated under this Findings and Determination, shall be eligible for royalty modification. To receive royalty modification on production, the lease must be committed to an approved participating area within six years of the date of Project sanction. After six years, any subject lease or portion of a subject lease not committed to an approved participating area for the Nikaitchuq Schrader Bluff OA reservoir shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

3. If the Project, not materially changed from that set out in the October 16, 2007, royalty modification application, is not sanctioned by all working interest owners by February 28, 2008, this royalty modification decision is rescinded.
4. Within 30 days following the date of Project sanction, the working interest owners shall provide ADNR with the Project sanction documents, approvals for expenditure, and other documents supporting the technical and financial data submitted with Project sanction documents excluding any proprietary data. ADNR agrees to keep all such data confidential.
5. If six years following the date of Project sanction total actual Project spending starting December 1, 2007, does not meet \$822 million in nominal dollars, then this royalty modification is rescinded. If 11 years following the date of Project sanction total actual Project spending does not meet \$1.398 billion in nominal dollars, then this royalty modification is rescinded. The ADNR may audit the working interest owners' spending on this Project to determine compliance any time between the sixth and the 13th year following Project sanction. If at either cost threshold juncture this royalty modification is rescinded, then Eni will refund to the State of Alaska the difference between the royalty which would have been due at the royalty rates that were in effect immediately prior to the effective date of this Findings and Determination and the royalty due at the modified royalty rate, with interest as set forth in AS 38.05.135(d).
6. The NPS lease regulations set out in 11 AAC 83.201 – 11 AAC 83.295 remain in full force and effect for ADL 391283, except that the cost to the applicant for the application for royalty modification will not be included in any NPS lease Development Account balance.
7. (a) Nikaitchuq royalty modification mechanism implemented as follows:
 - i. Original lease rates are 12.5 percent for ADL 391283 and 16.67 percent for ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, and 390616.
 - ii. For the first 25 years following the date of first sustained production, when Alaska North Slope West Coast ("ANS WC") delivered crude prices are below the threshold price per barrel as adjusted by inflation, then production from the Nikaitchuq Schrader Bluff OA reservoir on the subject lease will pay a 5 percent royalty. The ANS WC crude price for the month of production is the average assessment by Platt's Oilgram Price Report and Reuters online data providing service, of the spot price for ANS delivered on the West Coast. The average assessment of the spot price for ANS by each reporting service is the average of the midpoints of the high and low closing assessments for the spot price for ANS for all days during the month of production for which closing assessments are

reported. The threshold price shall start at \$42.64 per barrel. This threshold price will be adjusted annually for inflation starting on May 1, 2008, and shall be adjusted on each May 1 thereafter. The inflation adjustment shall be $(1 + \text{inflation rate})$ multiplied by the previous year's inflation-adjusted threshold price. The inflation rate shall be determined by taking the previous year's annual implicit price deflator for GDP (initially, for the year 2007) as reported by the end of April of each year, dividing that deflator by the two-years-previous annual implicit price deflator (initially, for the year 2006), and then subtracting 1. The source of the inflation data shall be the Department of Commerce Bureau of Analysis (BEA) U.S. Economic Accounts-GDP. National Income and Productions Account (NIPA) Table 1.1.9. When the monthly ANS WC oil price is above the threshold, royalty rates for production attributable to such month(s) shall return to the original lease royalty rates.

iii. This royalty modification shall be terminated 25 years following the date of first sustained production and at that time royalty rates shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

(b) For the 18th through the 120th months after first commercial production from the Nikaitchuq Schrader Bluff OA reservoir, if production from all of the subject leases averages below 4,000 barrels of oil per day for any previous twelve month period, full royalty modification rates of 5 percent shall be in effect for all production from the Nikaitchuq Schrader Bluff OA reservoir, regardless of oil price. Provided, however, nothing in this provision shall prevent Eni from applying for royalty modification under AS 38.05.180 (j)(1)(B) or (C).

8. In the determination of royalty value of oil or gas from any of its properties, Eni shall waive any rights to a transportation deduction for the pipeline constructed pursuant to the Easement granted on ADL 417493. This waiver shall remain in effect even if such pipeline is converted to a common carrier.
9. If any working interest owner should contract to use any processing facilities at any time for production from the reservoirs delineated and leases covered in this Findings and Determination, that working interest owner shall furnish ADNR the facilities contract, including information regarding the fee structure and volumes processed unless such contract prevents disclosure of such information. This information will be kept confidential by ADNR. The working interest owner shall also furnish produced oil, water, and gas volumes on a monthly basis broken down by individual working interest owner.
10. Should any third party petition the Nikaitchuq Unit facility owners to contract for use of any unit facilities, the cost of use shall be based on market rates. Any

resulting contract covering facilities access or use shall be shared with the ADNR. ADNR agrees to keep all such information confidential.

11. This royalty modification is not assignable without prior written approval of the ADNR commissioner, which shall not be unreasonably withheld. The assignee must be fit, willing, and able to satisfy all of the duties and obligations attached to this royalty modification and all other lease terms.

12. If at any time royalty modification is rescinded, the terms and conditions of this Findings and Determination shall terminate, with two exceptions. First, the provisions of Term 8 shall survive the termination of royalty modification. Second, all obligations to keep information confidential that was submitted pursuant to this Findings and Determination shall survive the termination of royalty modification.

VI. PROPOSED FINDINGS AND DETERMINATION

After detailed consideration where all the materials presented by the applicant were reviewed and incorporated into our analysis, the ADNR has determined that Eni meets the necessary requirements and that royalty modification for the Nikaitchuq development project is warranted under the terms established in Section IV of this finding and determination.



Thomas E. Irwin
Commissioner

1/11/08
Date

cc: Kevin Banks, Director, Division of Oil and Gas
Antony Scott, Senior Commercial Analyst, Division of Oil and Gas
Jeff Landry, Department of Law

Senate Resources Committee
Joe Paskvan, Co-Chair / March 1, 2012

Let's call the meeting to order.

Let the record reflect that it is _____ p.m. on Thursday, March 1.

Let the record reflect that there is a quorum. Present are

- Co-Chair Wagoner
- Senator Stedman
- Senator Stevens
- Senator Wielechowski
- Senator French
- Senator McGuire
- And myself, Senator Paskvan

During this hearing, we are joined by BP and ConocoPhillips, who will offer comments on the Committee Substitute for Senate Bill 192, relating to Oil and Gas Production Tax Rates.

ExxonMobile, Pioneer Natural Resources, and the Arctic Slope Regional Corporation have also submitted letters in the past couple of days. Those were subsequently distributed to Committee members and posted on BASIS.

For the record, approximately 140 Alaskans offered public testimony to the Resources Committee on Tuesday and Wednesday evenings. We very much appreciate the input of each and every Alaskan in the public process.

Additionally, each of us has also been receiving dozens of emails from around the State; in fact, we have been communicating with Alaskans about the oil tax issue almost daily for the past year. Today, I gathered all of the email messages that I have received this week and distributed those to each Committee member. They will be submitted as part of the public record. Again, the Committee welcomes and appreciates the thoughts of all Alaskans.

CS SB 192: Summary

- Preserves Deductions of Capital Expenditures, Operating Expenditures, and Transportation Costs (i.e., net profits tax)
- Preserves Tax Credits
- Preserves Royalty Rate
- Preserves Royalty Modification
- Reduces Progressivity
 - Reduces the Slope of Progressivity
 - Lowers the Cap on Progressivity

CS SB 192: Preserves Tax Credits

- Credits which may be taken against oil and gas production taxes include:
 - Capital Expenditure Credits
 - Alternative Tax Credits for Oil and Gas Exploration
 - Net Operating Loss (“NOL”) Carry Forward Credits
 - Transitional Investment Expenditure (“TIE”) Credits
 - Well Lease Expenditure Credit
 - Cook Inlet Jack-Up Rig Credit

(Source: “Production Tax Credits,” DOR Presentation to the Sen Res Committee; March 16, 2011)
(See also: “Tax Credit Update,” DOR Presentation to the Senate Resources Committee; January 27, 2012)

CS SB 192: Preserves Low Royalty

- Alaska: Owner of a World Class Resource
 - 12.5% to 16.67%
- Comparison States
 - Texas: Private Lands
 - “Average assumed to be 25%”
 - North Dakota: The majority of production is from private lands
 - “Most production pays at 18.75%”

(Source: *Alaska's Oil and Gas Fiscal Regime: A Closer Look From A Global Perspective*, DOR, Jan 2012)

CS SB 192:

Preserves Royalty Modification

- Allows commissioner to modify royalty to allow for production from a field or pool under three conditions/scenarios:
 - Not in production
 - Field or pool must be sufficiently delineated
 - Field that would not otherwise be economically feasible
 - Royalty shall never be lower than 5%
 - Prolong economic life
 - As costs increase or price decreases... to make future production uneconomic
 - Royalty shall never be lower than 3%
 - Re-establish production
 - Royalty shall never be lower than 3%

(Source: Presentation to Senate Resources Committee by Bill Barron, Director, DNR Division of Oil and Gas; Feb 21, 2012)

CS SB 192: Lowers Progressivity

- The Committee Substitute retains the original trigger of \$30 in Production Tax Value (PTV); at which point the progressive tax rate is calculated at .35% per dollar increase in PTV up to 50% (\$101.43);
- At 50% (\$101.43), the CS adds a second trigger on the progressive tax rate calculation that lowers the progressive tax rate to .1% on PTV up to 60% (\$201.43);
- Adds a statutory maximum tax rate of 60% under the production tax statutes.

TAXABLE BBS
AFTER WY/27

TRANS
OPEX
C&A EX

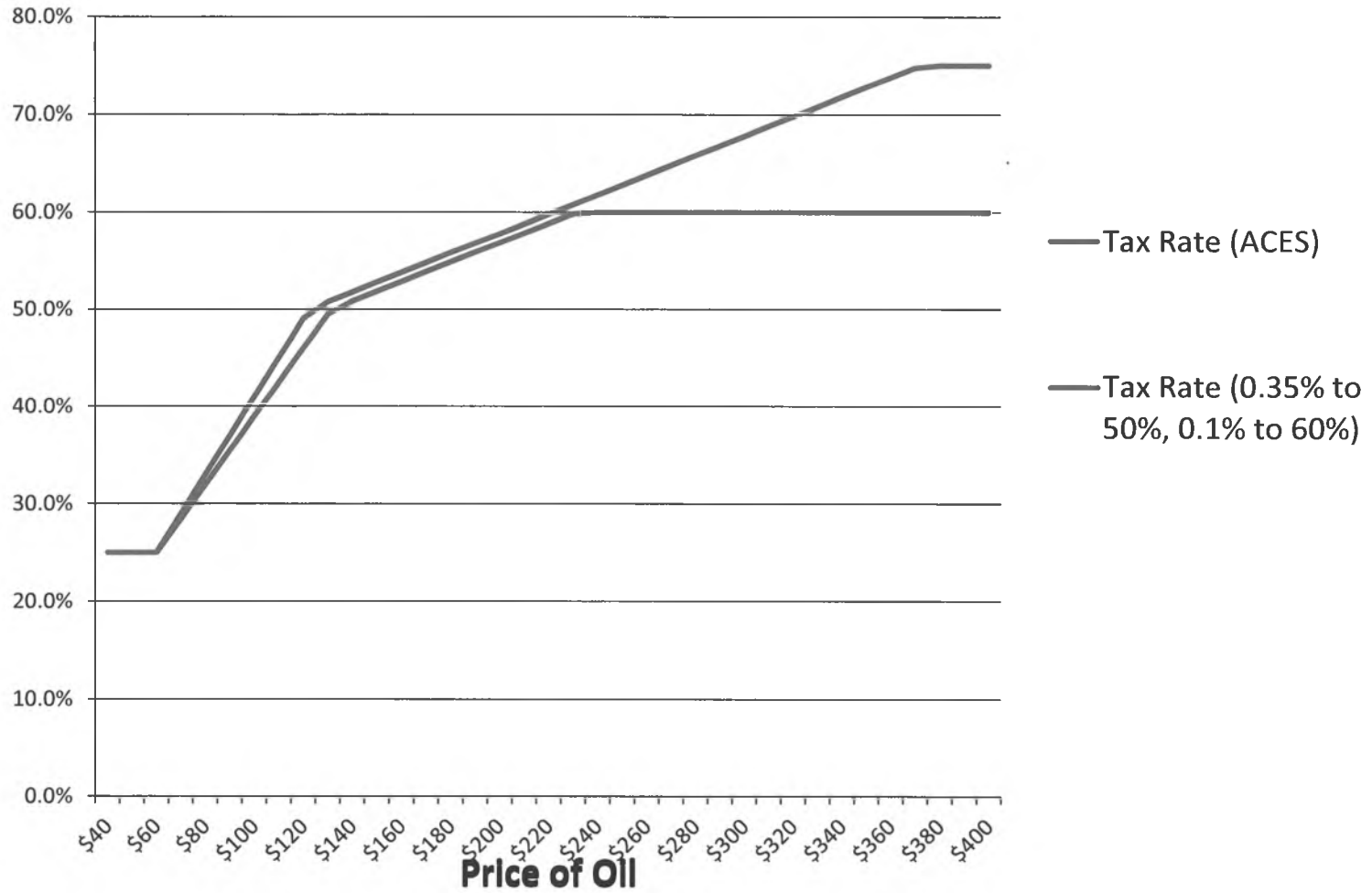
Before we get started with the testimony, I want to summarize – briefly – the CS for SB 192 for those who might be tuning in for the first time. I think that it's important for the public to understand what we are discussing today.

[SEE SUMMARY ATTACHED]

Now, we welcome Damian Bilboa from BP, to be followed by ConocoPhillips.

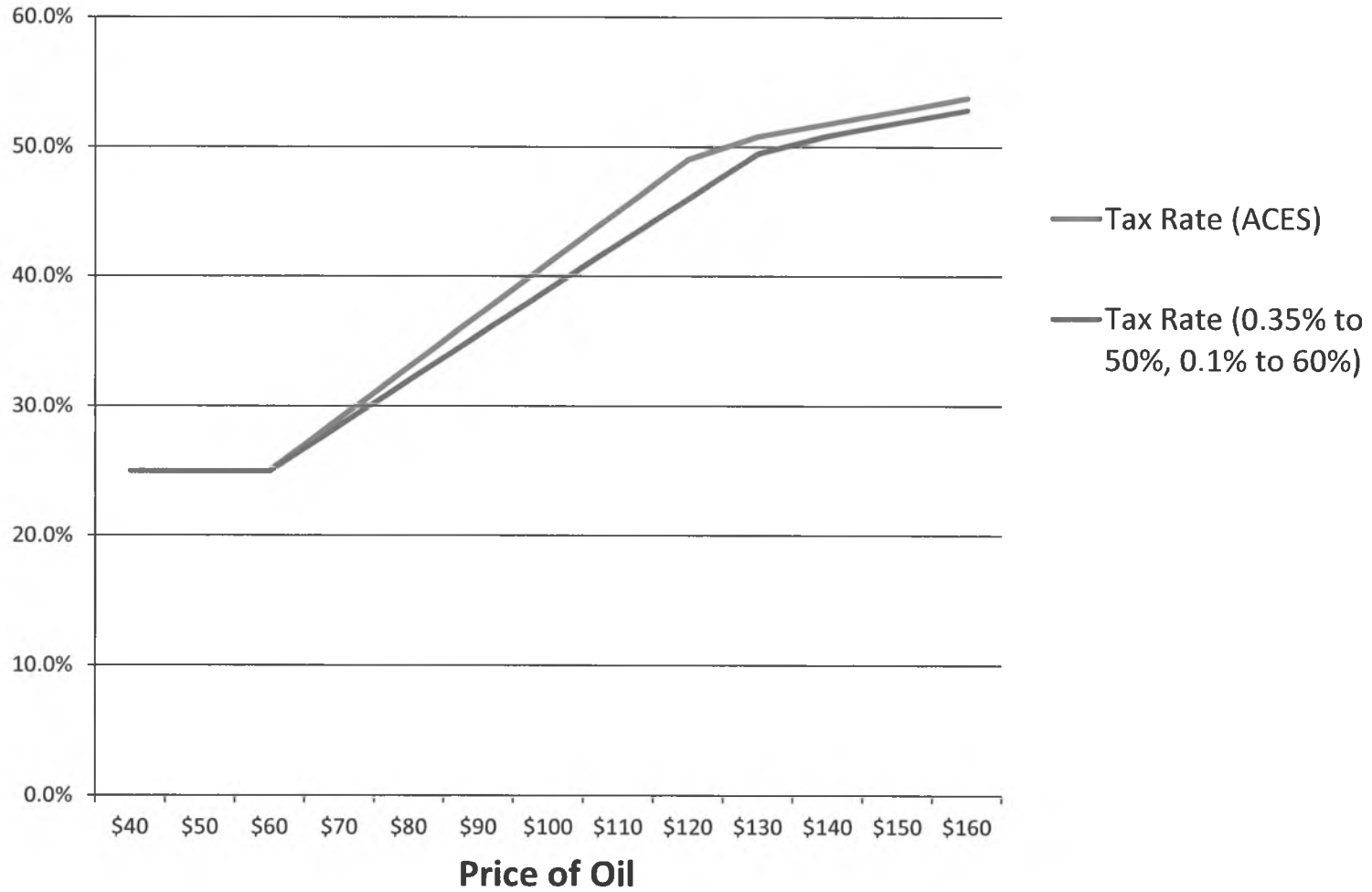
Tax Rate: ACES vs Proposed CS \$40 to \$400

Assume costs \$38 / barrel



Tax Rate: ACES vs Proposed CS \$40 to \$160

Assume costs \$38 / barrel



Library

bp



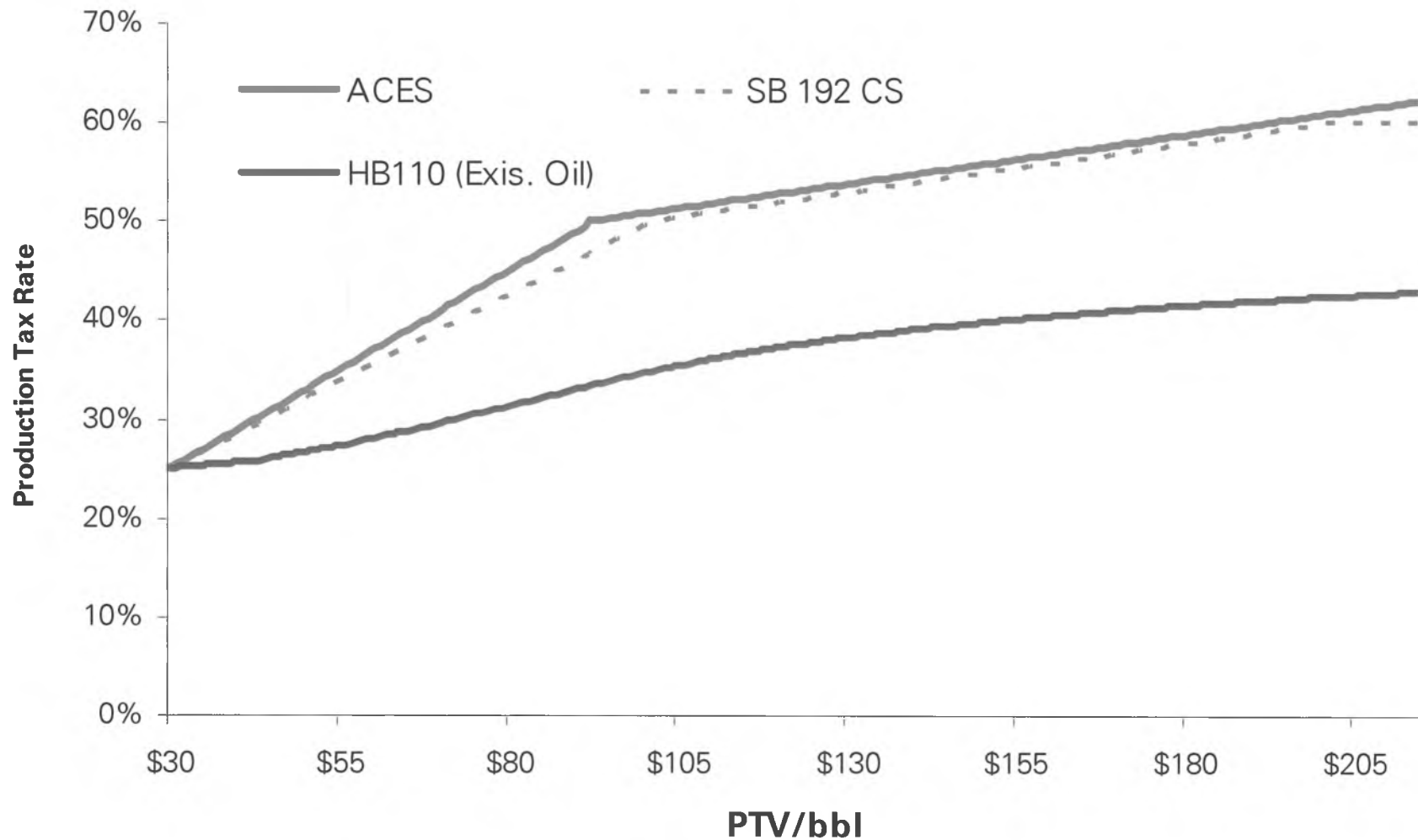
BP Testimony to Senate Resources

Damian Bilbao, Head of Finance: Developments and Resources

March 1, 2012

Meaningful Change Drives Investment

Technology+Efficiency+Tax Change=Production



Proposed Master Expenditures Categories List

CAPEX Expenditure Categories	Category Definition
G&G	Includes work and or costs associated with the performance or acquisition of seismic and/or geological and geophysical data.
Exploration Drilling	Includes drilling an exploration well, drilling an appraisal well that is post discovery and prior to development and including side tracks on a discovery well, appraisal costs including coring and testing discovery wells.
Development Drilling	Includes costs associated with well drilling, completions, planned multilaterals of development wells, including costs upstream of the christmas tree.
Well Workovers	The process of performing major maintenance or remedial treatments on an oil or gas well to increase production. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location.
Production Facilities – Rate Increasing	Includes well tie-in costs, increases to choke capacity, expansions of existing facilities such as increasing oil, gas or water handling, debottlenecking, or processing facilities.
Production Facilities – Non-rate Increasing	Includes improvements to reliability or reduced operational costs, costs that do not contribute to the choke capacity of a production facility, and production control system upgrades.
Support Facilities	Includes costs for IT, communications equipment, non-production control systems, camp sites or accommodation facilities, medical facility, laboratories, warehouses, and maintenance buildings.
Transit and gathering/flow lines	Includes transit lines, gathering lines, and flow lines, or the addition of new production lines and/or pumps to trunk or downstream lines.
Transit and gathering/flow lines – Replacement	Includes replacement of transit lines, gathering lines, and flow lines to trunk or downstream lines. Does not include repairs to such lines.

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CAPEX Expenditure Categories	Category Definition
Other Capital	Includes significant capital equipment, health, safety, environment, and other non-drilling related costs not captured in other categories.
Exclusions (AS 43.55.165(e))	Include total amount of exclusions as described under AS 43.55.165(e).

OPEX Expenditure Categories	Category Definition
G&G (Geological & Geophysical Work)	Includes work and or costs associated with the performance or acquisition of seismic and/or geological and geophysical data that is not included in CAPEX "G&G" expenditures.
Wellwork	The process of performing major maintenance or remedial treatments on an oil or gas well to restore or maintain production. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location.
Platforms Operations	Includes operation, maintenance and repair expenditures for platforms and platform facilities for oil and gas production from marine platform operations. This should include lifting, gathering, treating, field processing, on site staff and support facilities, and other services.
Facility - Production – Operations & Maintenance	Includes operation, maintenance and repair expenditures for on-shore facilities for oil and gas production. This should include lifting, gathering, treating, field processing, on-site staff and support facilities, and other services.
Facility - Production – Major Repairs	Includes major repairs of facilities associated with oil and gas production operations. This should include major repair of lifting, gathering, treating, and field processing activities.

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OPEX Expenditure Categories	Category Definition
Facility - Support – Operations	Includes on-site housing, medical facilities, testing facilities, warehouse and workshop facilities, emergency services, and equipment fueling facilities, and their maintenance and repairs.
Transit Lines - Operation	Includes all in-field and connecting lines receiving oil or gas from gathering lines and transporting such to trunk and or sales points beyond gathering lines and centers.
Transit Lines - Major Repairs	Includes major repairs of transit and flow lines not covered by CAPEX pipeline expenditures.
Gathering Lines - Operation	Includes all in-field connecting, gathering, and flow lines delivering oil and/or gas to transit/flow lines, trunk lines or sales points.
Gathering Lines – Major Repairs	Includes major repairs of gathering lines and systems delivering oil and/or gas to transit/flow lines, trunk lines or sales points.
Fuel	The volume of gas purchased and used on the producing leases injected for reservoir maintenance or used as gas lift.
Roads, Pads & Runway Maintenance	Includes maintenance and repairs to access roads, pads used in those operations, and heliport or aircraft runway and facility maintenance within the area of oil and gas exploration, development and production activities.
Health, Safety & Environmental	Includes staff, facilities, and activities associated with personnel health, operations safety preservation and support, and maintaining environmental integrity.
Other Operating Expenses	Total other costs incurred in operations that are not included in any of the other categories defined in this list of OPEX expenditures, not to exceed 155 of the total OPEX expenditures.
Taxes - Property	Total ad valorem taxes paid to state and local government entities for facilities and property assessments.

DRAFT

OPEX Expenditure Categories	Category Definition
Taxes - PILT - Payments in Lieu of Taxes	Total payments to a government that are not production or income taxes.
Net-Profit-Share Lease Payments	Total of all net-profit-share lease payments made during the calendar year.
Adjustments - Payments Under 43.55.170 (a)(1) Reimbursed Facility Charges & (a)(2) Reimbursed Lease Expenditures	List a total amount of all payments that were received during the calendar year for the calendar year being report that would be included as described in AS 43.55.170 (a)(1) & (a)(2).
Adjustments - Payments Under 43.55.170 (a)(3) Sale or Transfer of Asset or Oil or Gas	List a total amount of all payments were received during the calendar year for the calendar year being reported that would be included as described in AS 43.55.170(a)(3).
Exclusions - Under 15 AAC 55.520(f)(4)(G) which are the Exclusions under AS 43.44.165 (e)(19)	List a total amount of all expenditures made during the calendar year for the calendar year being reported that would be excluded as described under 15 AAC 55.520(f)(4)(G) that are the Exclusions under AS 43.44.165 (e)(19).

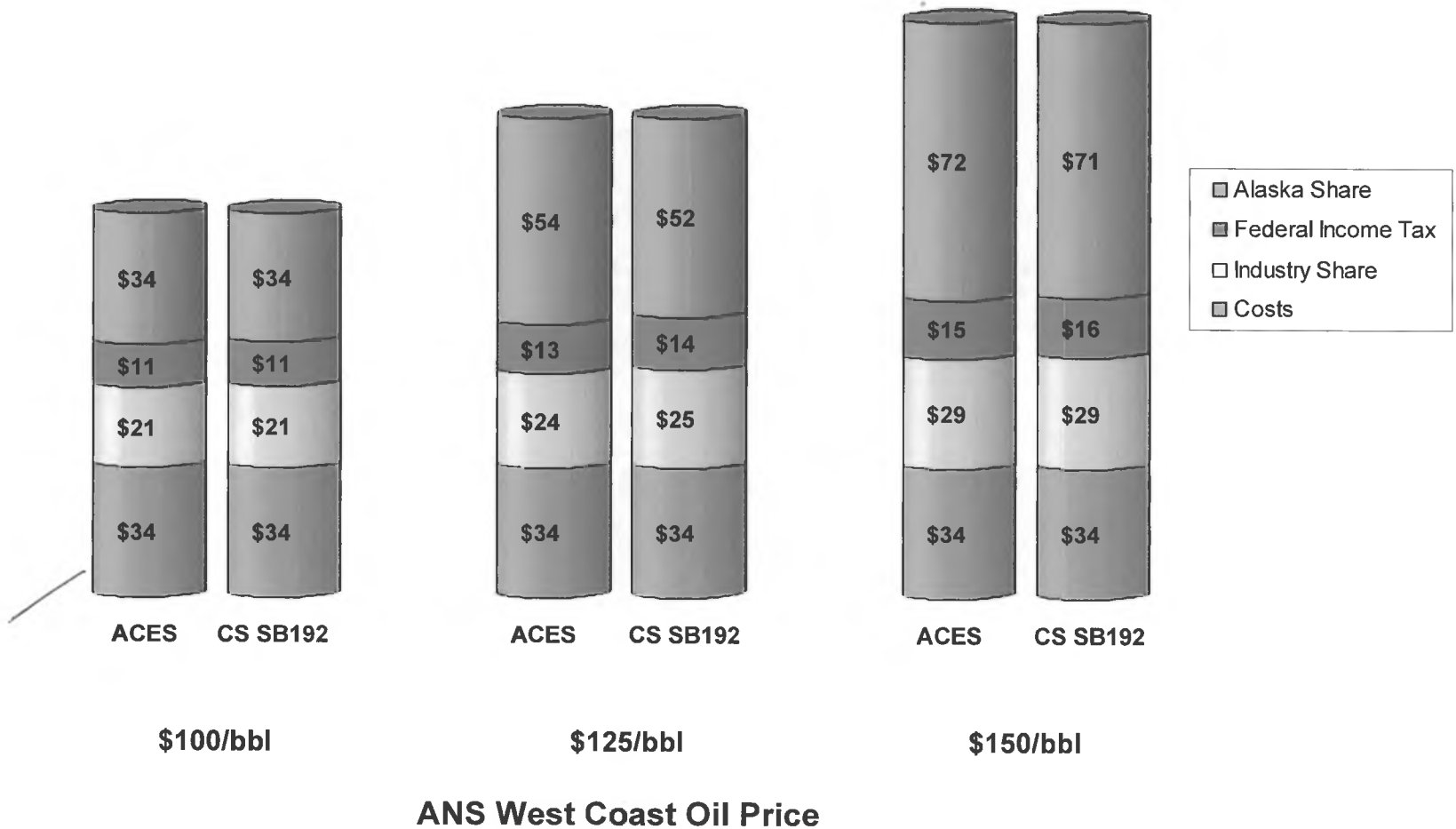
Senate Resources

CS SB192 and Potential Amendments

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

March 1, 2012

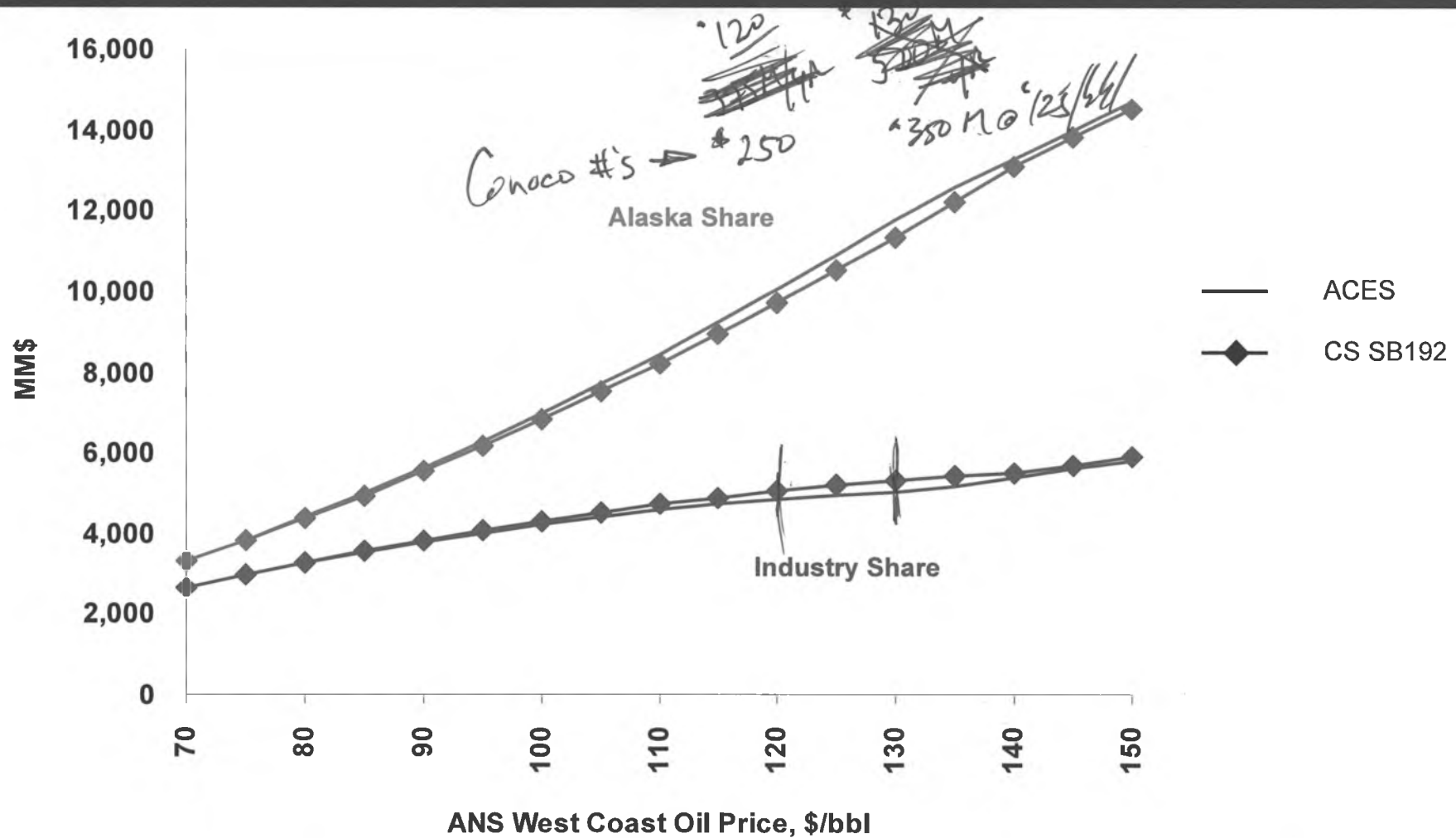
CS SB192 has Minimal Impact



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

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

Alaska / Industry Share



CS SB192 has minimal impact

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

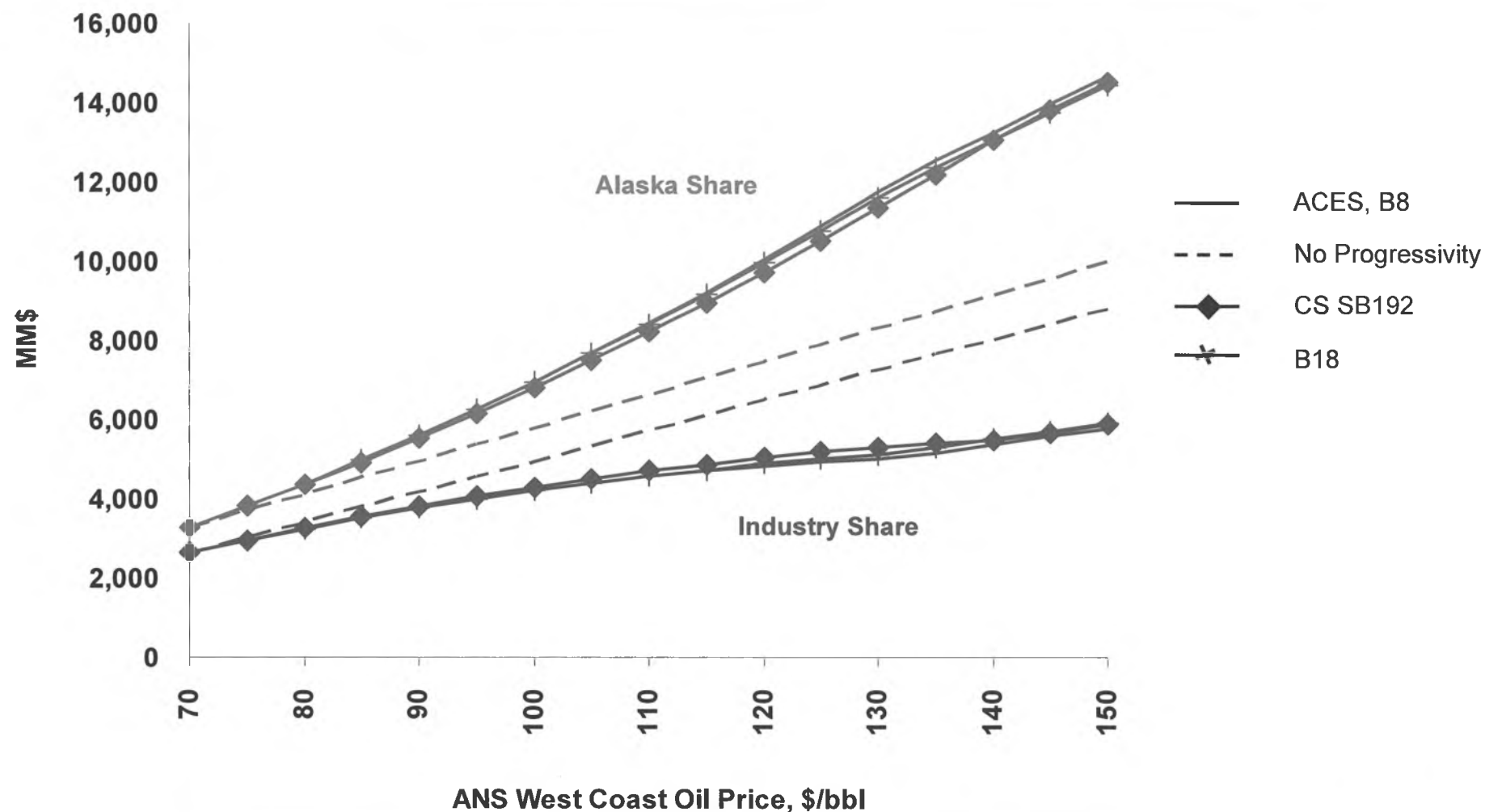
Alaska Share includes royalty, severance tax, income tax, and property tax

Alaska / Industry Share



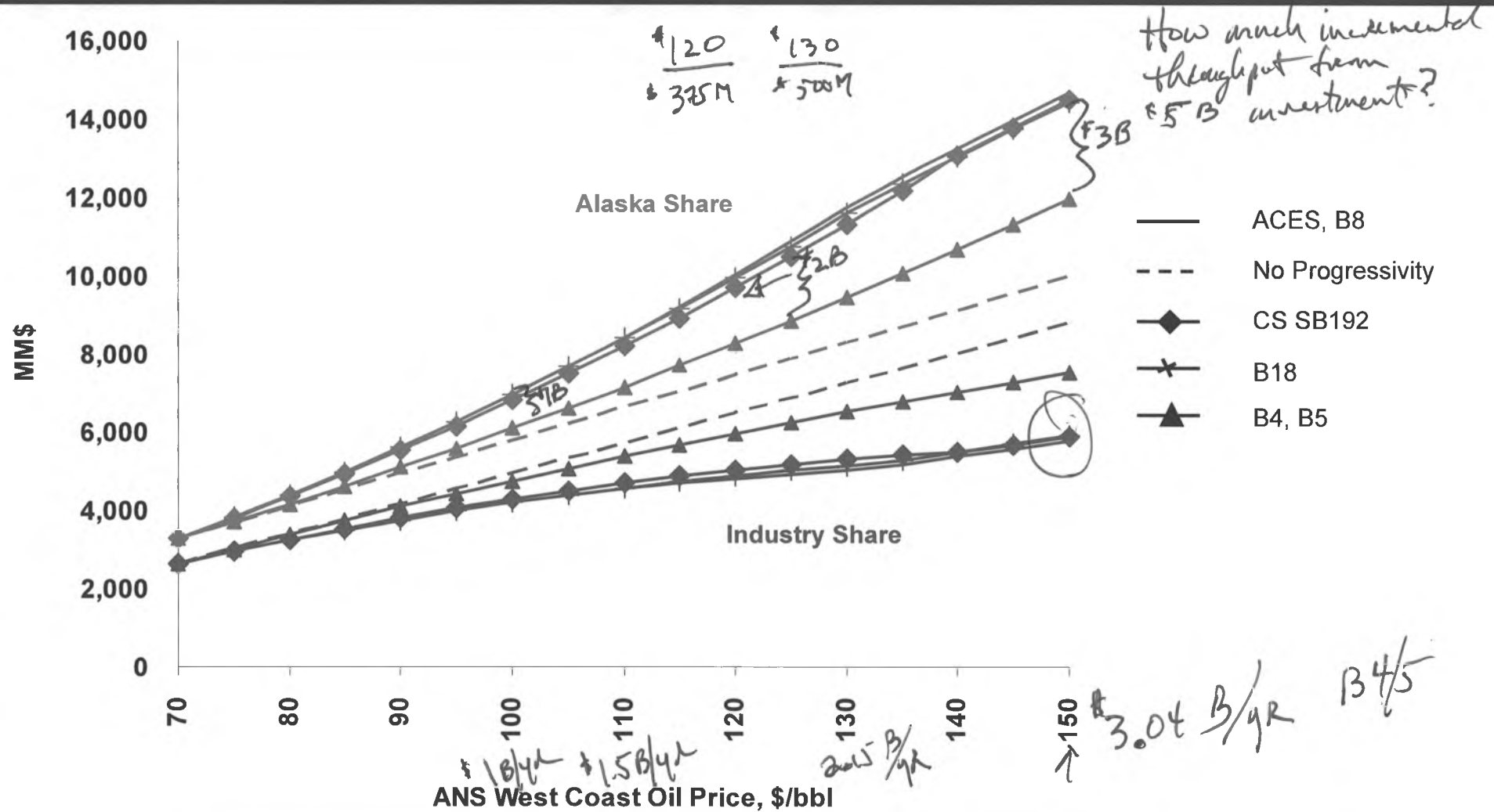
Both Alaska and industry share in the upside with no progressivity

Alaska / Industry Share



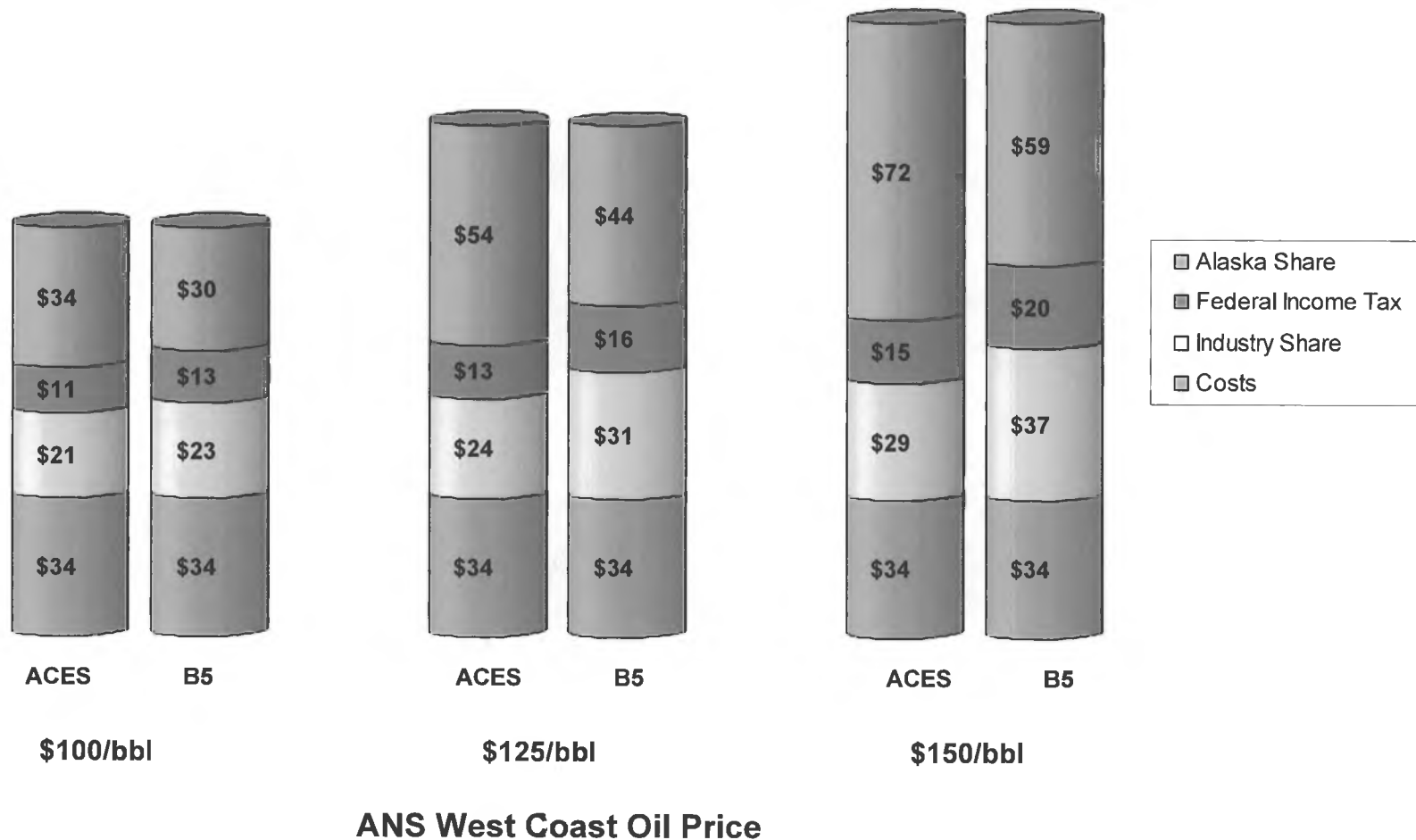
B8 and B18 amendments have negligible impact

Alaska / Industry Share



Bracketed progressivity makes a meaningful impact

Bracketed Progressivity is Meaningful



- Bracketed progressivity has the potential to have a positive, material impact on severance tax
- Inflation indexing progressivity trigger points makes sense
- Progressivity is the problem - the other proposed amendments do not fix the problem
- CS SB192 as currently proposed will not change investment climate

ExxonMobil Production Company

P. O. Box 196601
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Dale Pittman

Alaska Production Manager
Joint Interest U.S.



March 1, 2012

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

Dear Senator Paskvan:

ExxonMobil continues to follow the progress of the tax reform debate with great interest. While some discussions in the Committee have been encouraging, we are concerned with the proposed Committee Substitute to Senate Bill 192 and the apparent lack of urgency in the Committee in making meaningful tax reform necessary to attract new investments. The proposed Committee Substitute, while a small step in the right direction, will not significantly improve Alaska's overall uncompetitive fiscal regime or attract the necessary investments to enable the state to reach its goal of increased oil production.

Oil and gas investors depend on economic upside potential in order to accept the inherent downside risks of long-term, capital-intensive investments. As experts have testified before your Committee and during other hearings throughout this deliberative process, with Alaska's Clear and Equitable Share (ACES) production tax, the State has one of the highest progressive tax structures in the world. Simply put, Alaska's total government take is too high to fully develop its vast resources.

Without meaningful tax reform Alaska should expect to continue at or likely below the Department of Revenue production forecasts.

It was also disappointing to review many of the amendments discussed in the Committee for consideration. While a few of the proposed amendments, like those offering needed brackets to the progressivity tax and incentives to new production, would have meaningful impacts on investment decisions, others were actually tax increases. We fail to understand how proposals to increase industry's tax burden would serve to improve Alaska's already uncompetitive fiscal regime.

ExxonMobil remains hopeful that the dialogue in your Committee and with the entire Legislature for needed meaningful tax reform will continue and will ultimately lead to the development of a competitive, stable fiscal regime to attract the unprecedented investments that Alaska's North Slope requires. It is ExxonMobil's firm belief that passage of meaningful changes to ACES this year, aligned with those proposed by the Governor's office, will support additional investments in Alaska that will lead to greater development and production.

Thank you again for the opportunity to provide input on the Committee Substitute to Senate Bill 192 and the need for meaningful tax reform.

Sincerely,

A handwritten signature in cursive script, appearing to read "DDP:jpc".

DDP:jpc

xc: Governor Sean Parnell
Senator Thomas Wagoner, Co-Chairman, Senate Resources Committee

J. Scott Jepsen
Vice President, External Affairs

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RECEIVED
FEB 29 2012

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

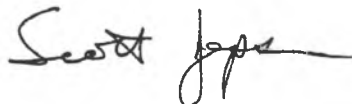
governments. Using the RSB, the industry paid \$542 million in state income taxes and \$476 million in property taxes (state share \$110 million, local share \$366 million). The total of these additional burdens is over \$1 billion more in taxes to the industry than in your analysis.

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,

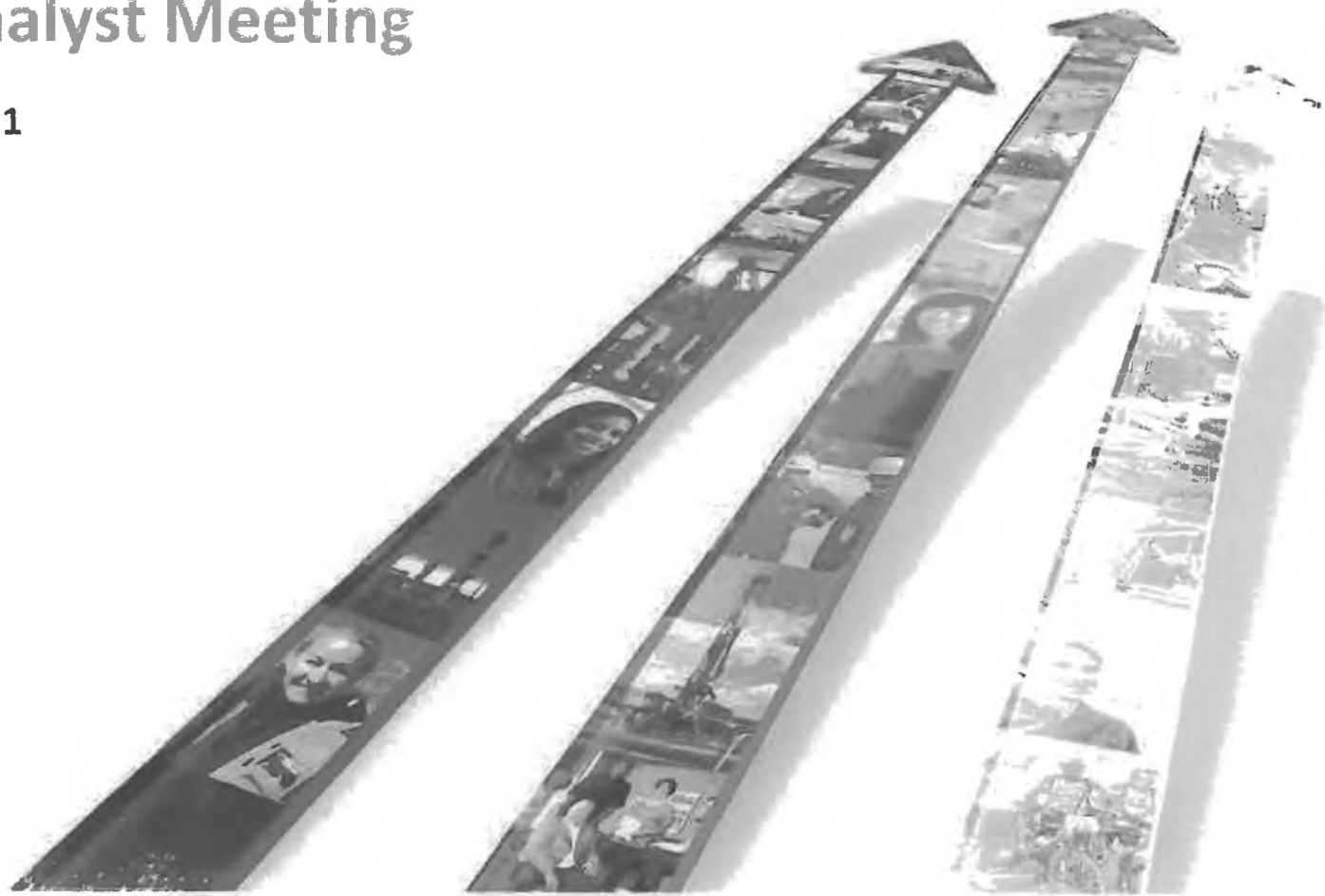


J. Scott Jepsen



2011 Analyst Meeting

March 23, 2011
New York, NY



Major Project Startups

Alaska

Alpine West (CD5)
 Lookout (CD6)
 ANS gas
 Ugnu

Canada Arctic

Parsons Lake
 Amaluigak
 Umiak

Canada SAGD

Christina Lake C
 Christina Lake D
 Christina Lake E
 Foster Creek F
 Surmont 2
 Surmont 3+
 Foster Creek G/H
 Christina Lake F/G
 Narrows Lake A/B
 Thornbury / Clyden
 Saleski

North Sea

Jasmine
 Britannia LTCP¹
 Ekofisk South
 Eldfisk II
 Clair Ridge
 Rivers Phase II
 Tor Redevelopment
 Tommeliten Alpha

Caspian

Kashagan 1²
 Kashagan 2+

China

Bohai Phase II
 Panyu growth
 Bohai Phase III

Lower 48

Eagle Ford
 Golden Pass
 Tiber

Algeria

El Merk

Libya

Faregh 2
 North Gialo
 NC-98

Malaysia

Gumusut
 KBB / Malikai
 Petai
 Pisagan
 Ubah
 Kamunsu East

Indonesia

Bawal
 S Belut
 Caltex 3
 Suban 3

Vietnam

Su Tu Nau
 Su Tu Trang

Nigeria

NLNG T4-5
 NLNG T6
 Uge

Australia

APLNG
 Sunrise
 Poseidon

~500
 MBOED

2015E

- 2011-2012 startups
- 2013-2015 startups
- 2016+ startups

30 startups over next 5 years

¹ Long-Term Compression Project

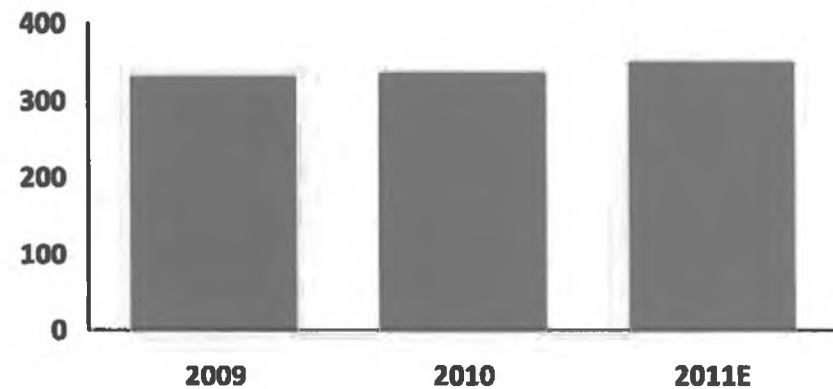
² Projected startup of 2012/13

2015 production from 2011 to 2015 major project startups.

- **Largest producer & reserves holder**
- **Strong cash margins**
- **Future growth driven by**
 - **In-field drilling opportunities**
 - **Western North Slope satellites**
 - **Unlocking heavy oil potential**
 - **ANS gas commercialization**



Drilling Program Capital - \$MM



Major Projects



Startup	Region	Significant Project	WI%	Gross Peak Production MBOED	Current Project Phase
2013+	Alaska	Alpine West (CD5)	78	10 – 15	Define
		Lookout (CD6)	78	15 - 20	Optimize
		ANS Gas	36	600 – 700	Appraise
		Ugnu	56	20 – 30	Appraise
	United Kingdom	Clair Ridge	24	80 – 100	Define
		Britannia LTCP ¹	59	15 – 20	Define
		Rivers Phase II	100	15 - 20	Appraise
	Norway	Ekofisk South	35	70 – 80	Execute
		Eldfisk II	35	70 - 80	Execute
		Tor Redevelopment	31	40 – 60	Appraise
Tommeliten Alpha		28	30 – 40	Appraise	

 COP operated

¹ Long-Term Compression Project.

Just a thought piece



FisH

Selected data from ConocoPhillips 2010 10-K

	Alaska	Lower 48	Canada	Europe	Asia Pacific/M iddle East	Africa	Other Areas	Total
Reserves (crude oil and NGL)	1285	649	80	469	300	270	108	3161
Reserves (BOE)	1762	1918	920	779	735	424	117	6655
Average Sales Price per BBL (Crude Oil and NGL 2010)	\$78.61	\$57.69	\$55.70	\$77.35	\$75.50	\$76.80	-	\$72.63
Average Production Cost per BOE (2010)	\$9.55	\$7.62	\$10.68	\$7.93	\$5.70	\$7.81	-	\$8.10
Taxes Other than Income per Barrel of Oil Equivalent (2010)	\$17.65	\$3.08	\$0.91	\$0.05	\$3.76	\$0.47	-	\$4.27
Future Cash Inflows	102,743	68,949	38,083	49,270	37,673	24,487	8,466	329,671
Less:								
Future production and transportation costs	57,899	29,749	16,753	12,899	10,480	4,142	3,007	134,929
Future development costs	8,792	12,700	11,161	10,295	2,226	1,133	3,050	49,357
Future income tax provisions	13,383	9,024	2,416	16,765	9,211	16,217	384	67,400
Future net cash flows	22,669	17,476	7,753	9,311	15,756	2,995	2,025	77,985
10 percent annual discount	10,723	7,551	3,890	2,597	4,889	1,025	2,368	33,043
discounted future net cash flows	11,946	9,925	3,863	6,714	10,867	1,970	(343)	44,942

Data taken from COP 2010 form 10-K pages 140,146,155, 161. Does not include numbers from equity affiliates.

Source: <http://www.sec.gov/Archives/edgar/data/1163165/000095012311016957/h76276e10vk.htm#H76276308>

Analysis (not from 10-K)

Future Cash Inflow per bbl (BOE)	\$58.31	\$35.95	\$41.39	\$63.25	\$51.26	\$57.75	\$72.36	\$49.54
Future production and transportation costs per bbl (BOE)	\$32.86	\$15.51	\$18.21	\$16.56	\$14.26	\$9.77	\$25.70	\$20.27
Future development costs per bbl (BOE)	\$4.99	\$6.62	\$12.13	\$13.22	\$3.03	\$2.67	\$26.07	\$7.42
Future income tax provisions per bbl (BOE)	\$7.60	\$4.70	\$2.63	\$21.52	\$12.53	\$38.25	\$3.28	\$10.13
Discounted Future Net Cash Flow per bbl (BOE)	\$6.78	\$5.17	\$4.20	\$8.62	\$14.79	\$4.65	-\$2.93	\$6.75
Future Cash Inflows (as % of company total)	31.17%	20.91%	11.55%	14.95%	11.43%	7.43%	2.57%	100.00%
Discounted Future Net Cash Flows (as % of company total)	26.58%	22.08%	8.60%	14.94%	24.18%	4.38%	-0.76%	100.00%



Effectiveness of Severance Tax Incentives in the U.S. Oil Industry

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Abstract

This paper develops a dynamic empirical framework that can be used to test the effectiveness of state-level severance tax incentives in the U.S. oil industry. The framework embeds U.S. state-level panel data estimates into Pindyck's (1978) widely received theoretical model of exhaustible resource supply and can be applied to any of 20 states that produce significant quantities of oil. The model allows for interactions between taxes levied by different levels of government and for the first time addresses potential interstate differences in exploration costs, extraction costs, and reserve additions. In general, results show that severance tax incentives (in the form of tax rate reductions) substantially reduce state tax revenue collected, but yield moderate to little change in oil drilling and production activity. This outcome suggests that states should be wary of arguments asserting that large swings in oil field activity can be obtained from changes in severance tax rates.

Keywords: state taxation, nonrenewable resources

JEL Code: H71, Q32

1. Introduction

For roughly twenty years, major oil and gas producing states have granted severance tax exemptions, reductions, incentives, and credits to oil and gas producers for the purpose of stimulating exploration, field development, production, and job creation.¹ For example, to date 2000, Alaska, Kansas, and Louisiana have offered 13 such incentive programs, Texas has granted 12, Oklahoma 10, New Mexico 8, and Wyoming 8 (Interstate Oil and Gas Compact Commission, 2001). Incentive programs, generally, involve across the board cuts in nominal severance tax rates levied or discounts against existing severance tax liabilities for special situations faced by producers. The inherent tradeoff state governments must consider when offering incentives involves the potential loss of tax revenue for purported gains in exploration and production activity. A key question then arises: Are severance tax incentives effective in this regard? Surprisingly, very little empirical evidence exists regarding this question despite the heavy reliance on taxation of oil, gas, and/or coal production in many states to fund public goods.

This paper develops a dynamic empirical framework that can be used to test the effectiveness of state-level severance tax incentives in the U.S. oil industry. The framework embeds U.S. state-level panel data estimates into Pindyck's (1978) widely received theoretical model of exhaustible resource supply and can be applied to any of 20 states that produce significant

quantities of oil. The model allows for interactions between taxes levied by different levels of government and for the first time addresses potential interstate differences in exploration costs, extraction costs, and reserve additions. As shown, costs, reserve additions, and tax structures vary considerably across states. Thus, this adapted model is arguably superior to and more comprehensive than previous efforts to develop general econometric and/or simulation models of taxation and natural resource exploration and production. Specifically, Deacon et al. (1990) and Moroney (1997) focus only on one state (California and Texas, respectively), and estimate econometric equations that may not be entirely consistent with a dynamic profit-maximizing framework. Pesaran (1990) estimates an econometric model of offshore oil production in the UK that can be better justified theoretically, but does not consider the role of taxes and estimates of the shadow price of oil in the ground are not always positive. Favero (1992) adds taxes to Pesaran's analysis, but again, estimates of the shadow price of oil in the ground are sometimes negative, suggesting that the model overstates the impact of taxation on profit. The Pindyck based simulation studies conducted by Yücel (1989) and Deacon (1993) examine effects of various types of tax changes on exploration and production but do not consider interactions between tax bases claimed by different levels of government, as well as possible interstate differences in exploration costs, extraction costs, and reserve additions. Also, these studies are aimed mainly at assessing the generality of theoretical results obtained in more limited settings rather than analyzing possible outcomes of changes in state tax policies.

Use of the modeling framework developed here is illustrated by simulating effects of reductions in *existing* state severance tax rates. Thus, results presented have the advantage of showing potential effects of specific state tax policy changes. Examining optimal tax regimes is beyond the scope of this analysis. In general, results show that severance tax rate cuts substantially reduce state tax revenue collected, but yield moderate to little change in oil drilling and production activity. This outcome suggests that states should be wary of arguments asserting that large swings in oil field activity can be obtained from changes in severance tax rates.

The remainder of the paper is divided into four sections. Section 2 presents the theoretical model used in the study. Section 3 presents empirical estimates of the model's parameters. Key estimates are obtained using panel data from the 20 most important oil-producing states over the period 1970–2000. Section 4 presents simulation results showing how oil exploration, reserves and production in Wyoming vary in response to severance tax reductions. Although the model developed can be applied to any of 20 states that produce significant quantities of oil, Wyoming is singled out because the estimates developed are likely to be at least broadly representative of what would be obtained for other states. Moreover, focusing on Wyoming highlights the state's heavy reliance on energy production taxes to fund public services. Implications and conclusions of this analysis are drawn out in Section 5.

2. Conceptual Framework and Model

The analysis presented in this paper extends Pindyck's (1978) model of nonrenewable resource development to incorporate key aspects of federal, state and local taxes facing the U.S. oil industry. Because the theoretical model is familiar, discussion later in this

section is kept to a minimum. Perfectly competitive producers are assumed to maximize the discounted present value of future operating profits from the sale of resources. The firm's problem is to take known future output prices and taxes as given and then choose optimal time paths for exploration and production. This assumption parallels the basic tax competition models, reviewed by Wilson (1999), where governments commit to a tax regime and then perfectly competitive firms react treating the structure as exogenous.² Whereas the studies reviewed by Wilson model firms that are to some extent geographically mobile, firms extracting nonrenewable resources are tied to an immobile reserve base that represents the key component of their capital stock. In consequence, extractive firms view time, rather than space, as the most important dimension over which to substitute in response to changes in tax policy. Substitutions over time, of course, alter relative rates of exploration and production occurring at different locations. Yet, timing of activities is the most important aspect of the extractive firm's problem and information about location choice can be recovered as a by-product simply by comparing rates of development for particular reserves. A single firm is used to represent the industry, so the common pool problem and well spacing regulations are ignored (McDonald, 1994). For simplicity and because of data constraints discussed in the next section, exploration is defined to include resource development, although the two activities clearly are not the same (Adelman, 1990). The aim of exploration is to add to the reserve base, which in the model represents a form of immobile capital.

Institutional features of taxation facing oil producers are complex, however, incorporating these aspects into the model is not difficult conceptually and distinctly separates it from previous efforts mentioned in the introduction. Tax structures vary considerably among states and tax bases interact, particularly between the state and federal level. For example, among the eight states responsible for about 89% of 2000 U.S. oil production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming), all states except California levy severance taxes against the value of output. Severance taxes dominate other forms of local taxation in Alaska, Wyoming, and Louisiana. Most states do not levy property taxes on the value of reserves in the ground (Texas and California do). Most states treat royalty payments (computed as a percentage of gross value of production) for production on public land as deductible items in computing severance tax liabilities (Louisiana does not). Public land royalties are prominent in Alaska, New Mexico, and Wyoming due to the large shares of publicly owned land. Most states levy a corporate income tax that applies to oil operators (Wyoming and Texas do not). Also, states have granted innumerable exemptions and credits (which differ by state) against various tax liabilities for special situations that may be encountered by operators. Hence, effective rather than nominal rates are incorporated in the model developed below. Within states, counties apply their own mill levies to compute property taxes on above-ground and down-hole equipment at different rates. However, taxation of structures and equipment are usually less important than other sources of revenue and are not treated in the model below.

Regarding federal taxes, all incorporated producers file federal corporate income tax returns that allow deductions for various types of operating costs and for state and local tax payments. Independent producers (those without downstream refining or retail interests) are permitted to take a percentage depletion allowance, while major producers are allowed only cost depletion, which is significantly less generous. Both major and independent

incorporated producers can expense intangible drilling costs incurred on their federal corporate income tax returns. The fact that some smaller producers are not incorporated and may therefore face alternative state and federal tax treatment is not treated here.

The firm's maximization problem now becomes

$$\max_{q,w} \Omega = \int_0^{\infty} [qp - C(q, R) - D(w) - \gamma R]e^{-rt} dt \quad (1)$$

subject to

$$\dot{R} = \dot{x} - q \quad (2)$$

$$\dot{x} = f(w, x) \quad (3)$$

$$q \geq 0, \quad w \geq 0, \quad R \geq 0, \quad x \geq 0 \quad (4)$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil extracted measured in barrels, p denotes the exogenous market price per barrel net of all taxes, $C(q, R)$ denotes the total cost net of taxes of extracting the resource, which is assumed to depend on production (q) and reserve levels (R), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes the net of all tax constant effective property tax rate on reserves, r denotes the discount rate which represents the risk-free real rate of long-term borrowing, x denotes cumulative reserve additions (discoveries), $f(w, x)$ denotes the production function for gross reserve additions (\dot{x}) which is assumed to depend on current exploratory effort (w) and cumulative discoveries (x), and \dot{R} denotes reserve additions net of production (q).³ In this formulation, the net-of-tax price per barrel is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a constant comprised of federal, state, and local effective tax rates such that $0 < \alpha_p < 1$. Correspondingly, $C(q, R) = \alpha_c C^*(q, R)$ and $D(w) = \alpha_D D^*(w)$, where α_c and α_D also are constants generated from effective tax rates and lie on the unit interval. A more complete discussion of the tax policy parameters follows below in Section 3.3.

The Hamiltonian for this problem is

$$H = qpe^{-rt} - C(q, R)e^{-rt} - D(w)e^{-rt} - \gamma Re^{-rt} + \lambda_1[f(w, x) - q] + \lambda_2[f(w, x)]. \quad (5)$$

Differentiating H with respect to R , q , x , and w yields the maximum principle conditions

$$\dot{\lambda}_1 = (C_R + \gamma)e^{-rt} \quad (6)$$

$$pe^{-rt} - C_q e^{-rt} - \lambda_1 = 0 \quad (7)$$

$$\dot{\lambda}_2 = -f_x(\lambda_1 + \lambda_2) \quad (8)$$

$$-D_w e^{-rt} + f_w(\lambda_1 + \lambda_2) = 0. \quad (9)$$

From equation (7), operators will produce if the discounted net-of-tax price exceeds discounted extraction costs. A severance tax decrease will increase the net-of-tax price which could affect the production decision. In equations (6)–(9), λ_1 is the discounted shadow price of the reserve state, λ_2 is the discounted shadow price of cumulative reserve additions, and letter subscripts represent partial derivatives. The shadow price of cumulative reserve additions, λ_2 , is expected to be negative (and small relative to λ_1) for oil because current reserve

discoveries will increase the amount of exploration needed in the future. From equations (8) and (9), the term $(\lambda_1 + \lambda_2)$ equals the discounted value of the marginal cost of adding another unit of reserves by exploration $[D_w/f_w]e^{-rt}$. Because $0 < \alpha_D < 1$, this net marginal cost is lower than in the pretax case.

The evolution of q is obtained by differentiating equation (7) with respect to time and setting the result equal to equation (6) to eliminate λ_1 . This yields

$$\dot{q} = \frac{-r(p - C_q) + \dot{p} - C_{qR}\dot{R} - (C_R + \gamma)}{C_{qq}} \quad (10)$$

The optimal time path of w can be determined using equation (7) and equation (9) to solve for λ_2 , differentiating with respect to time to obtain an expression for $\dot{\lambda}_2$, equating the result to equation (8) and rearranging terms:⁴

$$\dot{w} = \frac{D_w[(f_{wx}/f_w) \cdot \dot{f} - f_x + r] + (C_R + \gamma)f_w}{[-D_w(f_{ww}/f_w)]} \quad (11)$$

Equation (11) shows that the trajectory of exploratory effort is determined by a tradeoff between the cost of finding new reserves and the extraction cost savings this new level of reserves yields. As specified in this model, a severance tax incentive (rate decrease) could increase incentives to explore and enhance reserves due to the subsequent increase in the net-of-tax price. This effect is discussed in more detail in Section 4. The numerator of equation (10) emphasizes the role reserves play in the optimal extraction path. If reserves rise, marginal extraction costs fall, thus increasing production. While general suppositions such as these can be drawn analytically, the complexity of the dynamic process just described may be best examined with simulation as developed below.

Boundary conditions can be established by first assuming that $D_w/f_w = 0$ when $w = 0$ (see Pindyck, 1978, pp. 846–847). In this situation, when production ceases at some terminal time T , exploration ceases at the same time because it is of no further value. Also, $\lambda_2(T) = 0$ as long as there are no terminal costs associated with cumulative discoveries. In consequence, from equation (9), $\lambda_1(T) = 0$ implies that operating profit on the last unit of reserves extracted is zero, $p = C_q$. An alternative terminal state centers on the case where $D_w/f_w = \Phi > 0$, when $w = 0$. In this situation, production will continue after exploratory effort ceases. Let $T_1 < T$ denote the time when $w = 0$. If exploratory effort is zero, $f_x = 0$, hence $\dot{\lambda}_2(T_1) = 0$ and $\lambda_2(T_1) = 0$. From (7) and (9), $p - C_q = \lambda_1(T_1)e^{rt} = \Phi = D_w/f_w$, which indicates that exploration will stop just as $p - C_q$ approaches marginal discovery cost, Φ . These two alternative terminal conditions are discussed in the next section as well as in connection with the simulations presented in Section 4.

3. Estimation

As shown in equations (10) and (11), the evolutions of w and q are nonlinear functions of both the levels of these variables and the previously defined tax parameters. Estimating these equations directly poses certain econometric issues (see Pesaran, 1990) and it is unclear how information from the transversality conditions would be incorporated. In consequence, rather than attempt to obtain econometric estimates of these two equations directly, equations

for exploration costs (D^*), production of reserve additions (f), and extraction costs (C^*) are estimated and then substituted into the model along with estimates of the tax policy parameters α_p , α_c , α_D , and γ (see Yücel, 1989; Deacon, 1993 for similar treatments). Effects of severance tax changes then are obtained by simulation. State-specific estimates of equations for D^* and f are treated together in Section 3.1 because they are used to compute the marginal cost of reserve additions (D_w^*/f_w) which is a crucial function of the model described above. The equation for C^* is treated in Section 3.2 and the tax parameters are derived in Section 3.3. Key interstate differences regarding all estimates are highlighted throughout the discussion below.

3.1. Marginal Cost of Reserve Additions

The before-tax marginal cost of reserve additions (D_w^*/f_w) is computed from estimates of equations for drilling costs and for the production of reserve additions. Drilling costs are modeled in equation (12) as proportional to drilling effort.

$$D^*(w) = \phi w e^u \quad (12)$$

This approach ensures that the objective function (see equation (1)) represents a perfectly competitive firm ($D_{ww} = 0$). In equation (12), ϕ is the parameter to be estimated, and the disturbance term e^u is lognormally distributed with mean of unity and variance σ_u^2 . Data by state and over time on labor, capital, and other primary inputs to drilling are unavailable, so the annual number of wells drilled in a state is used as a measure of drilling effort (w). Data on footage drilled also could be used as a measure of w (see Deacon, 1993). However, in the data set applied (see below) the number of wells drilled is positively correlated with total footage drilled (Pearson correlation = .98). Also, total drilling cost is approximately proportional to both footage and the number of wells, so to some extent the two variables measure the same thing. As discussed in Section 2, cumulative reserve discovery (x) appears as an argument in the production function for new reserves (see equation (13) below). A proxy for x can be constructed from available data (American Petroleum Institute, 1971) on the total number of wells drilled by state since 1859 (when the first oil well was drilled in Pennsylvania), whereas corresponding data on total footage drilled since that date are not available. Thus, use of number of wells as a measure of drilling effort simplifies the simulations presented in Section 4 and eliminates the need for arbitrary assumptions about historical average depth per well.

The production function for reserve additions is specified as

$$f(w, x) = A w^\rho e^{-\beta x} e^v \quad (13)$$

where A , ρ , and β are parameters to be estimated and the multiplicative disturbance e^v is assumed lognormally distributed with mean of unity and variance σ_v^2 . The functional form selected for f is similar to the equation describing the discovery process proposed by Uhler (1976) and later adopted and estimated by Pindyck (1978) and Pesaran (1990). The idea behind this equation is that the marginal product of exploration declines as reserve discoveries cumulate. As previously discussed, data on cumulative reserve discoveries of oil are unavailable, so the cumulative number of wells drilled by state was used as a proxy.

As in the drilling cost function, the annual number of wells drilled is used as a measure of w .

Drilling cost and reserve production functions are estimated using annual data from 20 U.S. states for which complete information on wells drilled, drilling costs, reserve additions, and cumulative drilling could be assembled for the period 1970–2000.⁵ Regarding costs, operators report the total cost (both tangible and intangible) of each well completed (including dry holes) via the Joint Association Survey on Drilling Costs.⁶ Oil reserve additions are comprised of extensions, new field discoveries and new reservoir discoveries in old fields as defined by the U.S. Department of Energy, Energy Information Administration (DOE/EIA). The 20 states included in the data set accounted for 98.5% of the total U.S. oil production over 1970–2000.

Data sources, definitions, and sample means of variables used in the analysis are presented in Table 1. All nominal costs are converted to year 2000 dollars using the GDP deflator. Equations (12) and (13) were estimated in natural logarithms. An instrument for the natural logarithm of *WELLS* was used in equation (13) because w is an endogenous variable in the model presented in Section 2 and a Durbin-Wu-Hausman test (see Davidson and MacKinnon, 1993, pp. 389–393) rejected the exogeneity of w at the 5% level. An instrument for w was obtained by predicting the natural logarithm of the number of wells drilled from the one-way fixed-effects regression reported in Table 2. Time-specific effects tested insignificant at conventional levels. *PRICE* and *CWELLS* were included as explanatory variables because they are exogenous variables in the model. *PRICE2*, *CWELLS2*, and *PRICE*CWELLS* were included to account for non-linearities expected in light of relationships in the model. All estimated coefficients are significantly different from zero at conventional levels. The marginal effect of *WELLS* with respect to *PRICE* increases at a decreasing rate. The Pearson correlation between the actual values of $LN(WELLS)$ and the corresponding predicted values, $LN(PREDWELLS)$, is 0.96.

Estimates of the drilling cost equation (12) are obtained by regressing the natural log of drilling costs minus the natural log of wells on dummy variables for states and years. This two-way fixed effects approach is a simple way to control for heterogeneity across states and over time. Examples of state-specific effects include geologic conditions, geographic remoteness of on-shore oil and gas resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time varying factors common to all states may include technological advancement and macroeconomic cycles. For this equation, each state-specific effect for a given year, conveniently, becomes the state-specific estimate of ϕ .

Estimates of equation (13) are obtained in a one-way fixed effects framework that yields common estimates of the slope coefficients across states and corrects for first-order serial correlation.⁷ The one-way fixed effects estimation with correction for serial correlation is used for four interrelated reasons. First, this approach is a simple way to control for, yet avoid enumerating, unique aspects of states that affect reserve additions, but do not change over time. Second, time-specific effects are not jointly significant at conventional levels, making estimation in a two-way fixed effects framework unnecessary. Third, the random-effects specification, in which state-specific effects are treated as error components, is rejected by a Hausman (1978) test at the 5% level of significance. Moreover, conditional estimates of

Table 1. Variable definitions, data sources, and sample means.

Variable	Definition	Source	Sample mean
<i>TRCOST</i>	Total drilling costs in millions of 2000 dollars, for oil wells by state and year.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	332
<i>WELLS</i>	Total oil wells drilled in a state by year.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	741
<i>CWELLS</i>	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute. <i>Petroleum Facts & Figures</i> (1971 ed.)	95492
<i>TRCWELL</i>	Total drilling cost per well drilled, by state and year, in millions of 2000 dollars.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	0.723
<i>FTWELL</i>	Total footage per well drilled, by state and year.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	5666
<i>PRICE</i>	Average wellhead price of oil per barrel, by state and year, in 2000 dollars.	American Petroleum Institute. <i>Basic Petroleum Data Book</i> . Feb. and Aug. Annually.	24.56
<i>ADDED RESERVES</i>	Oil reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrels.	U.S. Energy Administration. <i>U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves</i> . Annual.	31.4
<i>RESERVES</i>	Proved reserves by state and year in millions of barrels.	American Petroleum Institute. <i>Basic Petroleum Data Book</i> . Feb. and Aug. Annually.	1320.5
<i>PROD</i>	Production by state and year in millions of barrels.	American Petroleum Institute. <i>Basic Petroleum Data Book</i> . Feb. and Aug. Annually.	126.4
<i>PRICE2</i>	Average real price squared.	-	757
<i>CWELLS2</i>	Cumulative total wells squared.	-	3.4E+10
<i>PRICE* CWELLS</i>	Interaction of real price and cumulative total wells.	-	2.4E+6

the effects on reserve additions obtained from fixed-effects are thought to be of greater interest than corresponding unconditional estimates obtained using random effects. Fourth, the null hypothesis of no serial correlation is rejected at the 5% level, hence, the equation was re-estimated with correction for first-order serial correlation.

Table 3 reports estimates of the drilling cost equation for 8 major producing states. The 2000 state-specific estimates of ϕ have been corrected for the fact that the equation was estimated in logarithmic form (see Greene, 1997, p. 279). As shown, R^2 is 0.93 with state- and time-specific effects jointly significant under the appropriate F-test. State-specific estimates of ϕ test different from each other, except for Texas and Oklahoma, at the 5% level. Results suggest that total drilling costs increase with w and that constant marginal drilling

Table 2. One-way fixed effects construction of instrument for $LN(WELLS)$.

Explanatory variable	Coefficient (<i>t</i> -statistic)
<i>PRICE</i>	0.062 (6.58)
<i>PRICE2</i>	-0.32E-3 (-2.34)
<i>CWELLS</i>	-0.33E-4 (-6.76)
<i>CWELLS2</i>	0.22E-10 (5.46)
<i>PRICE * CWELLS</i>	0.72E-8 (1.82)
Summary statistics	
NT	620
R ²	0.86
F(19,596) ^a	49.55
F(30,565) ^b	1.18
Hausman ^c	45.20

^aTest statistic for joint significance of state-specific effects.

^bTest statistic for joint significance of time-effects after removing state-specific effects.

^cStatistic for testing consistency of corresponding random effects estimates.

costs (D_w^*) differ substantially across the 8 states shown. Estimates of the reserve addition equation are shown in Tables 4 and 5. The coefficient of $LN(PREDWELLS)$ is 0.56 and this estimate is significantly different from one and zero at conventional levels. The value of R^2 is 0.63 and the state-specific effects are jointly significant under the appropriate F-test. Also, the negative coefficient of $CWELLS$, though insignificant at conventional levels, suggests that reserve additions decline with the passage of time as new reserves become more difficult to identify. Table 5 shows the corrected state-specific intercept terms (A) for 8 major producing states. Results suggest that the marginal product of drilling (f_w) decreases with wells drilled and this marginal product would vary between states even if the number of wells drilled were the same in each.

Estimates of the two equations combined suggest that marginal cost of reserve additions (D_w^*/f_w) increases with drilling activity. As w increases, the marginal cost of drilling is constant, but the marginal product of drilling in finding new reserves (f_w) falls. Table 6 shows how pre-tax values of D_w^* , f_w , and D_w^*/f_w differ by state for 8 of the major producing states, assuming that the 2000 level of wells are drilled in each. Estimates of drilling cost per well (D_w^*) range from \$132,907 in Kansas, where wells tend to be shallow, to \$3,881,600 in Alaska, where the drilling experience is very different as compared to the lower 48 states. Marginal reserve additions from drilling (f_w) range from 11,051 barrels per well

Table 3. Two-way fixed effects, instrumental variable estimates of the drilling cost function (Corrected 2000 estimates of ϕ for 8 major producing states^a).

State	Corrected fixed effect (<i>t</i> -statistic)
Alaska	3.881 (16.25)
California	0.277 (15.28)
Kansas	0.133 (24.05)
Louisiana	1.323 (3.38)
New Mexico	0.493 (8.41)
Oklahoma	0.357 (12.26)
Texas	0.352 (12.44)
Wyoming	0.601 (6.04)
Summary statistics	
NT	620
R ²	0.93
F(49,570) ^b	149.5

^aSee Greene (1997, p. 279) for specific details on intercept bias adjustment. 2000 time-effect added.

^bTest of joint significance of state- and time-specific effects.

in Kansas to 177,067 barrels per well in Alaska. Thus, while drilling a well in Alaska is markedly more expensive than in Kansas, Alaska experiences a greater payoff from these more costly exploration and development efforts. In fact, estimates of the marginal cost of reserve additions, D_w^*/f_w , reflect somewhat less variation across states than do estimates of either D_w^* or f_w , ranging from a low of \$11.24 per barrel in Louisiana to a high of \$21.92 in Alaska. Although relatively little variation in D_w^*/f_w would be expected when operators are familiar with costs and payoffs from drilling in alternative locations, values of the marginal cost of reserve additions are not expected to be equal across states. For example, aside from random factors introduced in estimation, variation in D_w^*/f_w between states could be due to differences in oil quality, transportation costs, as well as other factors that can cause wellhead prices of oil to differ across states

3.2. Extraction Costs

Direct operating (lifting) cost for oil by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual cost index studies published by the DOE/EIA for the period

Table 4. One-way fixed effects, instrumental variable estimates of the reserve additions function.

Explanatory variable	Coefficient (<i>t</i> -statistic)
<i>LN(PREDWELLS)</i>	0.56 (11.09)
<i>CWELLS</i>	-0.3E-5 (-1.26)
Summary statistics	
NT	620
R ²	0.63
F(19,579) ^a	22.2
F(30,568) ^b	1.12
RHO	0.394
Hausman ^c	15.1

^aStatistic for testing joint significance of state-specific effects.

^bStatistic for testing joint significance of time-specific effects after removing state effects.

^cStatistic for testing consistency of corresponding random effects estimates.

Table 5. One-way fixed effects, instrumental variable estimates of the reserve additions function (Corrected estimates of *A* for 8 major producing states^a).

State	Corrected fixed effect (<i>t</i> -statistic)
Alaska	1.57 (1.64)
California	0.78 (2.01)
Kansas	0.31 (1.17)
Louisiana	2.49 (1.82)
New Mexico	0.57 (1.68)
Oklahoma	0.62 (1.94)
Texas	0.52 (2.11)
Wyoming	0.78 (2.03)

^aSee Greene (1997, p. 279) for specific details on intercept bias adjustment.

Table 6. Pre-tax marginal drilling cost, marginal product of drilling, marginal cost of reserve additions for 8 major producing states^a.

State	D_w^* (in \$)	f_w (in bbls)	D_w^*/f_w
Alaska	3,881,600	177,067	21.92
California	277,119	14,717	18.83
Kansas	132,907	11,051	12.03
Louisiana	1,323,014	117,753	11.24
New Mexico	492,620	27,123	18.16
Oklahoma	356,754	23,477	15.20
Texas	351,654	24,219	14.52
Wyoming	600,911	39,238	15.31

^aEvaluated at each state's actual 2000 wells drilled. State-specific cumulative wells total is set to actual 2000 values.

1970–2000. However, these data are of limited value for two reasons. First, cost estimates are not always disaggregated to the state level and cost estimates for other states may not be representative of all production. Second, through the mid-1980s, price controls on oil and/or gas distorted production incentives, making historical extraction costs difficult to compare with extraction costs in more recent years. As a compromise, following Deacon (1993), values of extraction cost parameters are calibrated for the following Cobb–Douglas function,

$$C(q, R) = \kappa q^\varepsilon R^{1-\varepsilon}, \quad (14)$$

where $\varepsilon = 1/\mu$, μ is the production share of non-reserve inputs, and κ is a constant that drives the production cost modeled to an average level of *lifting costs* representative of the 2000 DOA/EIA surveyed estimates described above. State-specific estimates for μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above (see Deacon, 1993 for specific calibration methods). Table 7

Table 7. Non-reserve production input share μ , and pre-tax marginal extraction cost for major producing states.

State	μ	C_q^a
California	0.27	7.12
Kansas	0.17	4.99
Louisiana	0.21	9.11
New Mexico	0.31	6.87
Oklahoma	0.26	6.89
Texas	0.32	7.01
Wyoming	0.34	6.93

^aCalculated at 2000 levels for production and reserves, in year 2000 dollars. The EIA does not provide data for Alaska.

shows the pre-tax marginal extraction costs (C_q^*) and the non-reserve input shares (μ) for 7 major producing states. The DOE/EIA does not estimate lifting costs for Alaska. As shown, real marginal extraction costs range from a low of \$4.99 per barrel in Kansas to a high of \$9.11 per barrel in Louisiana. The Cobb-Douglas form for extraction costs insures that these costs will rise without limit as reserves approach zero. This condition implies that a positive level of reserves will remain at any terminal time, denoted T_1 . Likewise, the functional form invokes a strictly positive level of production given any positive level of reserves. Thus, simulations reported in Section 4 are based on the second of the two alternative boundary conditions discussed in Section 2. This condition implies that production continues after incentives for further exploration vanish and that the terminal date for maximizing discounted operating profits must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

3.3. Tax Policy Parameters

For most states in most years, γ and α_j ($j = p, C, D$) can be specified by noting whether reserves are subject to a property tax (see text equation (1)) and then evaluating the following equations:

$$\gamma = \{(1 - \tau_{us})(1 - \tau_r)\tau_R\} \quad (15)$$

$$\alpha_p = \{(1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\delta\} \quad (16)$$

$$\alpha_c = \{(1 - \tau_{us})(1 - \tau_s)\} \quad (17)$$

$$\alpha_D = \{(1 - \tau_{us})(1 - \tau_s)\eta\} \quad (18)$$

The derivation of equations (15)–(18) can be found in Appendix A. In (15)–(18), τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, τ_R denotes the property tax rate on reserves weighted by the per unit assessed value, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p denotes the production (severance) tax rate, δ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and η denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. The parameter η is made up of two components: (1) the percentage of current period drilling costs expensed and (2) the estimated present value of cost depletion deductions for the capitalized portion of current and past drilling expenditures. Producers are allowed to expense costs associated with drilling dry holes along with certain intangible costs (e.g., labor and fuel) for completed wells as they are incurred. All direct (tangible) expenditures for completed wells must be capitalized then depleted over the life of the producing well.

This formulation captures several aspects of the U.S. tax structure as it applies to the oil industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes on reserves, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities. (3) State corporate income taxes are deductible against federal corporate income tax liabilities. As noted in

Section 2, state tax treatment of the oil industry is not uniform and there are a number of situations in which these equations would have to be modified. Notice that this treatment of taxes in the model highlights the interaction between tax bases and is more detailed than the corresponding treatment given by Moroney (1997) and Deacon et al. (1990). Also, the entire tax structure is incorporated into the model, rather than simply analyzing one tax at a time as in Deacon (1993).

All tax parameters in equations (15)–(18) are effective rather than nominal rates. States grant numerous credits and exemptions against taxes levied, so nominal rates generally overstate amounts actually paid. State and local data required for these effective rate calculations are neither available from a central source nor compiled in a common format, so they were obtained directly from tax officials in each state. Royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production. Production tax rates are computed as total production tax collections divided by the gross value of production net of public land royalties. At the federal level, data from Statistics of Income (U.S. Department of Treasury, 1999–2000) for the oil and gas sector show that federal corporate taxes paid averaged about 11% of *net operating* income in 2000. The ratio of the federal effective to marginal rate was also applied to each state's top marginal corporate income tax rate to obtain an effective estimate. The current nominal percentage depletion rate is 15% and it applies to each state's percentage of non-integrated producers. Also, the expensed portion of current period drilling costs is approximately 42% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that the ratio of production to reserves is constant (see U.S. Department of Commerce, Bureau of the Census, 2000; Deacon, 1993). The ratio of production to reserves (q/R) varies across states but the industry expense share (42%) applies to all states.

4. Simulation Results

The model presented in Section 2 can be simulated for any of the 20 oil-producing states to obtain responses of exploration and production to reductions in severance taxes. The discussion below focuses mainly on severance tax rate reductions in just one state, Wyoming, for four reasons. First, this approach substantially reduces the amount of institutional detail that must be presented. Second, despite the large interstate differences in costs, reserve additions, and tax structures shown above, changes in severance taxes turn out to have quite similar comparative effects in each of the major oil producing states. Therefore, estimates for Wyoming are likely to be broadly representative of what would be obtained for other states. Third, simulation results reported are based on the assumption that severance tax reductions in one state do not affect the wellhead price of oil seen by operators in other states. This assumption is warranted in view of the fact that oil prices are determined in a world market. Also, as shown below, tax rate cuts considered appear to lead to comparatively small changes in output, so cross border effects are unlikely to be important in any case. Finally, taxation of oil extraction is a long-standing, contentious public policy issue in Wyoming partly because of heavy reliance on energy production taxes to fund public services.

Simulations for Wyoming were performed using the estimates of equations (12) and (13), the calibrated production cost parameters ($\varepsilon = 2.93$, $\kappa = 150$) of equation (14), and the tax parameters ($\alpha_p = 0.72$, $\alpha_c = 0.89$, $\alpha_D = 0.75$, $\gamma = 0$) as derived in Appendix A. As shown, severance tax changes will affect the price tax parameter, α_p . The discount rate, r , was set at 4% to reflect the risk-free real rate of long-term borrowing and the future price path was fixed at \$25.00 per barrel each year reflecting the real sample mean for all 20 states. Other price trajectories (rising or falling) were simulated, but the alternative paths have little or no effect on the comparative results presented below. The initial value of reserves and cumulative wells drilled are fixed to year-end 2000 levels at 561 million barrels and 39,993 wells, respectively. To obtain numerical solutions for the time paths of drilling, production, and reserves, difference equation approximations are derived for the time rates of change in production and exploratory effort (equations (10) and (11) and for the state variable evolution equations (2) and (3)). For example, the evolution of reserves, equation (2), is approximated by the difference, $R_{t+1} - R_t = f_t - q_t$. The model is solved recursively by iterating over the initial values of the control variables, q and w , until transversality conditions are satisfied. Under these base case conditions, exploratory effort approaches zero after approximately 40 years, thus the terminal time (T_1) is set to 40 periods. The Solver algorithm in Microsoft Excel was used to generate numerical solutions.

Before the simulation results are discussed, a historical analysis of Wyoming's oil experience is warranted. Figure 1 depicts the actual time paths of real price, wells drilled, production, and reserves for Wyoming from 1970–2000. In this figure, the vertical axis shows wellhead price (dotted line) in year 2000 dollars $\times 10$, wells drilled (dashed line) in



Figure 1. Wyoming oil 1970–2000.

total wells, production (solid line) in $\text{bbls} \times 10^5$, and reserves (bold line) in millions of barrels (MMbbls). In reviewing these data, several observations are noteworthy. Historical drilling appears sensitive to price. Oil wells drilled increased markedly during the high price period of the early 1980s. Extraction activity, however, appears to map the declining proved reserve level in the state. In fact, oil production continued to decline during the late 1970s and early 1980s even though real prices increased roughly 3 fold. As shown, the increased drilling effort of the early to mid 1980s failed to replenish the depleting oil reserves in the state.

As depicted in Figure 1, the low real prices for oil in the 1990's provided the oil industry incentive to lobby state legislatures for tax breaks intended to stimulate exploration and production. In 1999, both Wyoming and Oklahoma enacted oil producer recovery acts which lowered state level nominal severance taxes by approximately 25–35% on all oil production, provided that oil prices remain below a certain level.⁸ Using this scenario as a back-drop, the comparative simulation below shows the results of a once-and-for-all reduction in Wyoming's effective severance tax on oil production by 2 percentage-points. Results presented have the advantage of showing how exploration and production might be expected to change over time in response to an *actual* constant policy change.

The solid lines in Figures 2–4 show the evolution of drilling, reserves, and production under the base case assumptions outlined above. Wells drilled fall steadily over time from

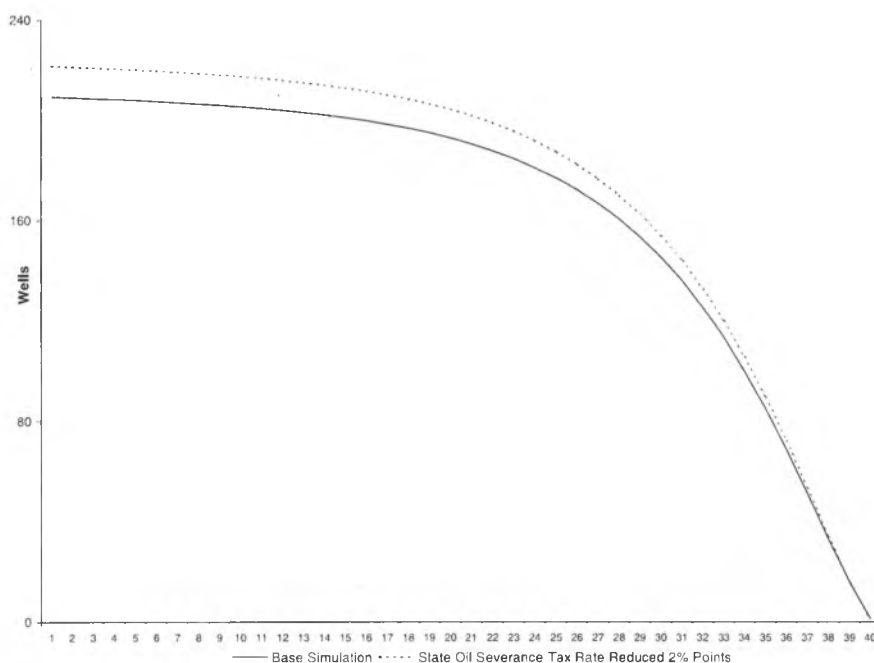


Figure 2. Wyoming oil (drilling).

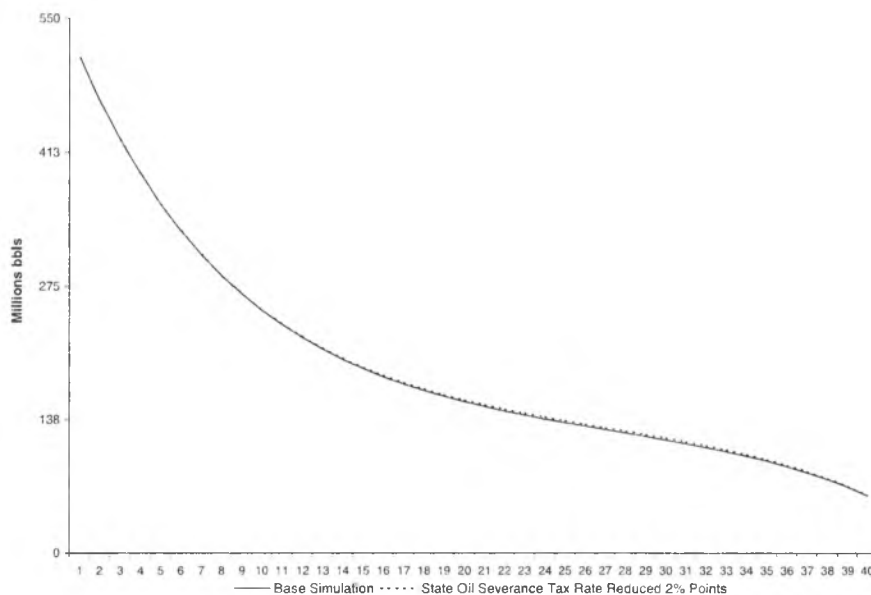


Figure 3. Wyoming oil (reserves).

209 in year 1 (2001) to 1 in year 40 (2040). Reserves also decline over this period from 510 MMbbls to 59 MMbbls with production declining from 59 MMbbls to 11 MMbbls. The dotted lines in these figures show the effects of a once-and-for-all reduction in the state oil severance tax by 2 percentage-points, which reduces the state effective rate from 5.8 to 3.8% and increases net-of-tax price by 40 cents (α_p increases by 0.016). As shown in Figure 2, the tax decrease increases drilling in the early years of the program when compared to the base simulation. Overall, drilling increases by 378 wells or 5.8% above the 40-year program base. With increased drilling in the early years, additional reserves are identified (15 million barrels more) and, as shown in Figure 3, proved reserves slightly rise in the out years.

Through the life of the program, the tax decrease results in increased production by about 14.9 million barrels, about 1.6% above the base solution. As Figure 4 depicts, this difference is roughly equal to the 15 million barrel increase in reserve additions that comes about because of the tax decrease. Also, the increase in output reflects a relatively low elasticity of production with respect to severance tax rate changes. Over the life of the program, this elasticity is approximately 0.05. Intuitively, while a decrease in the severance tax stimulates drilling activity, the additional drilling has a comparatively small effect on reserve levels. Given that over 63,000 wells (oil and gas) have been drilled in Wyoming to date 2000, prospects of a significant oil discovery are unlikely and the marginal product of drilling in finding new reserves is lower than in the past. As a consequence, reserve additions also respond inelastically to the severance tax decrease. Moreover, such small increases in

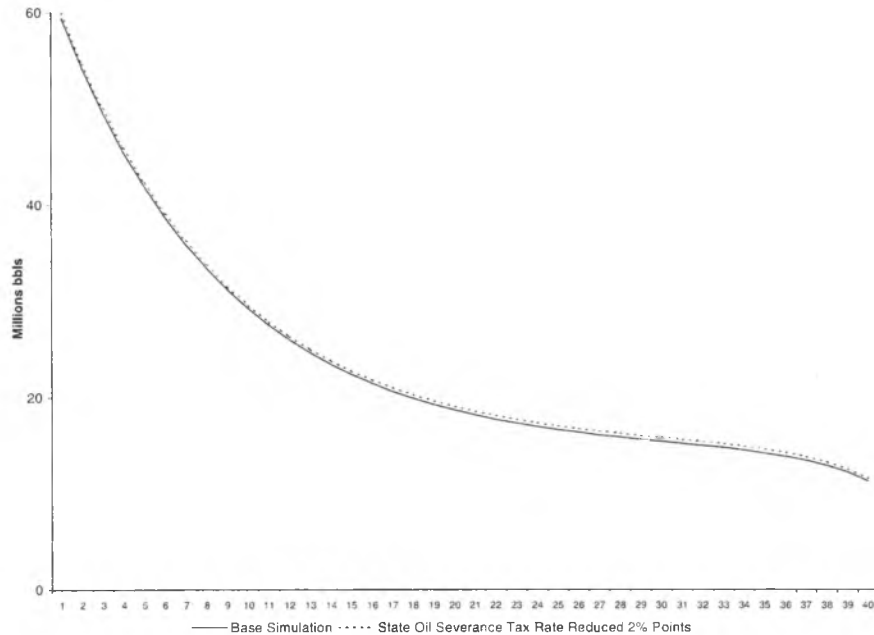


Figure 4. Wyoming oil (production).

net price (e.g., 40 cents per barrel) will unlikely affect production from existing wells and provides little incentive to reopen 'shut-in' wells.

The largest change associated with the 2 percentage-point reduction in state oil severance taxes is found in state production tax collections. Applying the discount rate of 4%, the tax change results in a decline in the present value of Wyoming *state* severance tax collections from \$751 million to \$498 million, a decline of over 33%. Alternatively stated, Wyoming would forego \$669,312 in present value of severance tax revenue for each of the additional 378 wells drilled. Certainly, the incentive enhanced drilling effort may provide the state other forms of benefits (i.e., short-term rig employment and sales tax collections) but these additional benefits would have to be considerable in order to offset what appears to be an insurmountable loss of state tax revenue.

Because severance taxes are deductible in computing federal corporate income tax liabilities, tax payments to the federal government increase by \$27 million (3.6% above the base case). Also, the 2 percentage-point severance tax decrease transfers state revenue to local governments because of the production stimulus. Discounted local production taxes increase by \$12 million or 2% above the base case. The same can be said for discounted public land royalties which increase by 1.9% (\$18 million) because of the increase in production. These results highlight the importance of the tax interactions described in Section 2 above.

XXXXXXXXX

The key result of this analysis is that oil reserve additions and production respond quite inelastically to reductions in severance tax rates. In the case at hand, a constant 2 percentage-point rate reduction increases overall simulated production by 1.6%—but decreases state severance tax revenue substantially in present value terms, by over 33%. This general outcome also applies to the other major oil producing states that levy a severance tax. In any case, oil-producing states should be wary of arguments promising large increases in oil exploration and production in response to cuts in severance tax rates.

5. Conclusions

This paper has adapted Pindyck's (1978) model of nonrenewable natural resource production to allow for an empirical test of the effectiveness of state oil severance tax incentives. Equations of the model are estimated econometrically from panel data on production, exploration and reserve additions for 20 states over the period 1970–00. The model is designed so that effects of changes in existing state severance tax rates on the evolution of exploration, reserves and production can be simulated into the mid-21st century. In general, results show that severance tax rate reductions result in a substantial loss of tax revenue, moderate increases in drilling, but little change in reserve additions and production. A key question regarding this general result is: Why does output of oil respond so grudgingly to changes in severance taxes? There appears to be four reasons why this is so. First, a reduction in severance taxes offers no *direct* stimulus for reserve exploration. A cut in the severance tax, as modeled, does nothing to directly stimulate reserve additions—operators get the future benefits of this tax incentive only if they drill *and only if they are successful*. In general, “upstream” incentives given at the beginning of the exploration-development-production process may provide a greater stimulus to production than “downstream” incentives given at the end of the process—e.g., cuts in severance taxes.

Second, operators do not see the full effect of state severance tax changes because of the many tax base and rate interactions at all levels. For example, severance taxes are deductible against federal corporate income tax liabilities. Therefore, when severance tax rates fall, federal corporate income tax liabilities rise and vice-versa. In fact, results herein suggest taxes should not be analyzed independently without reference to the entire tax structure applied by all levels of government; for example, a tax discount granted at one level may be partially offset by increased liabilities at another level. Therefore, operators do not receive the full value of tax reductions that may be granted by Wyoming and other states. Third, and in a related vein, a reduction in severance tax rates by 2 percentage-points has only a small impact on the net-of-tax price received by operators. The tax reduction *it* receive above increases the constant net-of-tax price by only 40 cents per barrel. This small *it* Third, cannot be expected to generate much in the way of *new* oil production.

Fourth, and most importantly, production of (as contrasted with exploration for) oil is driven mainly by reserves, not by prices, severance tax rates, or tax discounts. This is a basic fact of geology and is easily illustrated by reexamining Wyoming's own history of oil production. Since 1970, Wyoming oil reserves steadily declined from 1 billion barrels to 561 million barrels in 2000 (see Figure 1). In other words, despite much exploration over the past 31 years (over 12,300 wells drilled), production has drawn down reserves faster

than new discoveries have added to them. This implies that for states like Texas, Oklahoma, and Wyoming the prospect of major exploratory success is not particularly promising (see Moroney, 1997 for a similar analysis of Texas). Moreover, during the past 31 years, oil production declined from 160 million barrels in 1970 to 61 million barrels in 2000. In fact, oil production continued to decline during the late 1970s and early 1980s even though real (year 2000 dollars) oil prices rose by a factor of more than 3, from about \$18/bbl. to more than \$55/bbl. Thus, even comparatively large price increases are not expected to call forth much additional output.

The general conclusion that severance tax changes appear to be unimportant may be problematic to public officials in oil producing states hoping to stimulate local economic activity by lowering such rates. The prospect of modest increases in exploration and production comes at a considerable cost, the loss of substantial state tax revenue that must be offset. Rather, state officials may have the incentive to raise severance tax rates risking little in the way of loss to future oil field activity.

Appendix A

This appendix derives the (generalized) constant tax parameters numbered (15)–(18) in the text. Restating the producer's problem (bracketed terms in text equation (1)) accounting for all tax effects yields

$$\begin{aligned} qp^* - qp^* \tau_r - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R - \tau_s [qp^* - qp^* \tau_r \\ - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R] - \tau_{us} \{qp^* - qp^* \tau_r - qp^*(1-\tau_r)\tau_p \\ - qp^*(1-\tau_r)\delta - C^* - \eta D^* - \tau_R R - \tau_s [qp^* - qp^* \tau_r \\ - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R]\}. \end{aligned} \quad (\text{A.1})$$

Collecting terms from (A.1) gives

$$(1 - \tau_{us})(1 - \tau_s)[qp^* - qp^* \tau_r - qp^*(1 - \tau_r)\tau_p - C^* - \eta D^* - \tau_R R] + \tau_{us} qp^*(1 - \tau_r)\delta \quad (\text{A.2})$$

which reduces to

$$\begin{aligned} qp^* \{(1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\delta\} - C^* \{(1 - \tau_{us})(1 - \tau_s)\} \\ - \eta D^* \{(1 - \tau_{us})(1 - \tau_s)\} - \tau_R R \{(1 - \tau_{us})(1 - \tau_s)\}. \end{aligned} \quad (\text{A.3})$$

For a single barrel of q and R , (A.3) becomes

$$\alpha_p p^* - \alpha_c C^* - \alpha_D D^* - \gamma. \quad (\text{A.4})$$

where

$$\gamma = \{(1 - \tau_{us})(1 - \tau_s)\tau_R\} \quad (\text{A.5})$$

$$\alpha_p = \{(1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\delta\} \quad (\text{A.6})$$

$$\alpha_c = \{(1 - \tau_{us})(1 - \tau_s)\} \quad (\text{A.7})$$

$$\alpha_D = \{(1 - \tau_{us})(1 - \tau_s)\eta\} \quad (\text{A.8})$$

equate to equations (15)–(18) in the text.

Wyoming Tax Parameters

In developing a base simulation solution, equations (A.5)–(A.8) can be simplified because Wyoming does not have a state corporate income tax ($\tau_c = 0$) and does not levy a property tax against reserves in the ground ($\tau_R = 0$). For Wyoming, royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production and averaged 9.1% for oil in 2000. This percentage is higher than for other oil producing states because of the comparatively large share of Wyoming's production on public lands. Production tax rates are computed as total production tax collections divided by the gross value of production net of public land royalties. In Wyoming, there are both local and state levies against this net value of production. Local ad valorem taxes are based on the prior year's production value. The sum of the two average effective rates in 2000 totaled approximately 12.3% (local 6.5% and state 5.8%). Also, the current nominal percentage depletion rate of 15% applied to about 52% of Wyoming oil producers in 2000, thus $\delta = 7.8\%$. Also, the expensed portion of current period drilling costs is approximately 42% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that the ratio of production to reserves is constant (see Deacon, 1993). Wyoming's mean value of q/R was approximately 11% for the sample period, therefore $\eta = 0.42 + (1 - 0.42) * (0.11/(0.04 + 0.11)) = 0.84$. The base tax policy parameters for Wyoming are $\alpha_p = 0.72$, $\alpha_c = 0.89$, $\alpha_D = 0.75$, $\gamma = 0$.

Acknowledgments

This research is supported by an appropriation from the Wyoming Legislature (1999 Wyoming Session Laws, Chapter 168, Section 3). However, this paper may or may not reflect the views of public officials in the state. Thanks to John Livernois, editor John Wilson, and two anonymous referees for a number of constructive suggestions that improved this paper.

Notes

1. Severance or production taxes are typically ad valorem taxes levied on the net production value (or volume) of a resource as it is extracted from the ground or at the final point of sale.
2. Making tax rates endogenous to the problem considered here would be a logical and important extension of this research.
3. Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the logical inconsistencies discussed by Livernois and Uhler (1987), Livernois (1987, 1988) and Swierzbinski and Mendelsohn (1989). These authors argue that Pindyck's extraction cost function is defensible when reserves are of uniform quality but in the presence of exploration, reserves must be treated as heterogeneous because the most accessible deposits are added to the reserve base first. They show that aggregation of extraction costs across heterogeneous deposits is not valid except under special circumstances. Another problem with this function is that extraction costs should be a function of γ . The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have γ as an argument because the reserve base is an input to oil and gas production. These complications are not treated in the analysis below because of severe data constraints on estimating the extraction cost function (see Section 3.2).

4. Equation (11) can be simplified by choosing a functional form for reserve additions such as the one used in Section 3 (see equation (13)). In this case, $(f_{\tau w}/f_w) \cdot f - f_{\tau} = 0$.
5. The Energy Information Administration and the American Petroleum Institute (2000) report annual production data for 31 states over this period, but data on reserve additions, cumulative drilling, and drilling costs are not available in all years for the 11 smallest producing states. The 20 states included are AK, AL, AR, CA, CO, IL, IN, KS, KY, LA, MI, MS, MT, ND, NE, NM, OK, TX, UT, and WY.
6. Major cost items are for labor, materials, supplies, machinery and tools, water, transportation, fuels, power, and direct overhead for operations such as permitting and preparation, road building, drilling pit construction, erecting and dismantling derricks/drilling rigs, drilling hole, casing, hauling and disposal of waste materials and site restoration. For additional details, see Joint Association Survey on Drilling Costs, Appendix A (1998).
7. Equation (13) was also estimated allowing for both state-specific intercepts and state-specific coefficients for ρ and β . This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.
8. Wyoming rescinded this legislation in 2000.

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