

HB

20001

(FILE 2)

HFIN

FILE

Summary Comparison between Various House Approaches to Production Tax

Issue	Current Law	HB 2001 (ACES)	House O&G	House Resources	<u>Proposed House Finance</u>
Base Rate					
	AS 43.55.011 (e) & (g)	Bill Sections 15 & 17			
Base Tax Rate		25%		25%	25%
Progressivity					
	AS 43.55.011(g) & (h)	Bill Sections 17,18			
\$/bbl Starting point	\$40 net	\$30 net	\$50 gross	\$30,40,50,60 net	\$30 net
Tax/\$ of Price Index	0.25%	0.20%	0.225%	.2,.3,.4,.5%	0.20%
Average Value over	month	year	month	month	year
Applied to	net	net	gross	gross	net
Cap		25% of net	25% of gross	none	25% of net
Gross Value Floor					
	AS 43.55.011(f)	Bill Section 15, 16, 31-36, & 41-42			
Base		Prudhoe; Kuparuk			
Rate		10%			
Credits further reduce floor tax?		No			
Investment Credits					
	AS 43.55.023	Bill Section 26-28, 38-44 & 63			
Investment Credits		1/2 in each of two years			
Loss Carry Forward Credits		25%		rate in (e) (25%)	25%
Transitional Investment Credits	Yes	No	3 years of investment instead of 5	3 years of investment instead of 5	3 years of investment instead of 5

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>Proposed House Finance</u>
Exploration Credits	<i>AS 43.55.025</i>	<i>Bill Section 36 - 44</i>			
Rates		20; 40%		30;40%	30;40%
G&A Costs		bad acts I		bad acts I	bad acts II
DNR approval required?		Always		Always	Always
Confidentiality of well data		2 years		2 years	
Seismic on non state land		included		included	
Pre-existing well		Two consecutive drilling seasons		Two consecutive drilling seasons	Two consecutive drilling seasons
"DNR TIE" Credits for pre 2003 seismic work?		5%		5%	5%

State Purchase of Credits	<i>AS 43.55.023(f) & (g)</i>	<i>Bill Section 45 (AS 43.55.028)</i>			
Paid from:		oil and gas credit fund, funded from production taxes		oil and gas credit fund, funded from production taxes	
Annual dollar cap per taxpayer?	\$25 million	none	\$25 million	\$ 25 million (however ARM unlimited)	\$ 25 million (however ARM unlimited)
ARM Board Purchases?	n/a	n/a	n/a	yes	yes

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>Proposed House Finance</u>
Allowable Lease Expenditures	<i>AS 43.55.165</i>		<i>Bill Sections 52-64</i>		
Use producer audits of operators?	Explicit	Explicit repealed; Implicit	Explicit	Explicit repealed; Implicit	Explicit where other WIOs with ability to audit
Disallow bad acts II?	yes	add violation of law, lease or license	add violation of law, lease or license	add violation of law, [inc Clean Water Act] lease or license	Bad acts II, [inc Clean Water Act]
Dispute resolution				no, other disallowances	
DR&R Allowed?	Allocated	No	No	No	No
"Corrosion" Issue		\$0.30 + unscheduled events disallowed	\$0.30 + unscheduled events disallowed		
Field Topping Plants allowed?	Yes	No	No	No	No
Off Lease allowed			yes; other tests	No (also in state)	
Public Outreach costs	not explicit	not explicit	not explicit	no	no
Information	<i>AS 43.05.230 and royalty statutes</i>	<i>Bill Sections 2-9,11-13, 49 & 61</i>			
forward looking information required	none	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.	information "necessary to forecast ... revenues under AS 43.55".	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day if demanded information not forthcoming.
Disclosure of tax information		if aggregated w/2 other producers	if aggregated w/2 other producers	if aggregated w/2 other producers	
DNR sharing royalty information w/ DOR	limited ability	expanded ability	expanded ability	expanded ability	expanded ability
DOR sharing tax information with DNR	limited ability	expanded ability	expanded ability	expanded ability	expanded ability

Summary Comparison between Various House Approaches to Production Tax

Proposed House Finance

Issue Current Law HB 2001 (ACES) House O&G House Resources

Statute of Limitations	<i>AS 43.05.260</i>	<i>Bill Sections 1,14,50 now AS 43.55.075</i>			
State assessment must be issued within	3 yrs	6 yrs	6 yrs	6 yrs	4 yrs

DOR Auditors	<i>As 39.25.100</i>	<i>Bill Sections 10, 65, 67</i>			
DOR & DNR auditors exempt employees?	no	yes	yes	yes	yes

Effective Date		<i>Bill Section 64</i>			
Generally	n/a	Jan 1 2008	Jan 1 2008	Jan 1 2007	Jan 1 2008
Retroactive to April 1 2006	n/a	deferred maintenance issues	deferred maintenance issues	Loss carryforward, TIE limitations, most cost redefinitions	to 2003: not-for-profits selling credits

Downstream Costs	<i>As 43.55.150</i>				
Reasonable v actual				Downstream Tanker and Pipelines = FMV "or other reasonable method"	
<i>Prima facie</i> reasonable Taps Tariff				FMV (TSM not adjudicated just and reasonable)	

Gas Ceilings thru 2022		<i>As 43.55.011</i>			
Where	CI	CI	non North Slope	CI + gas used in the state	CI + gas used in the state

Additional Penalties	<i>new As 43.55.020</i>				
Penalty for under estimated payments	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	5% in addition to IRS Penalties (i.e. interest)	5% in addition to IRS Penalties (i.e. interest) if payment less than 90%

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>Proposed House Finance</u>
Intent Language					
overall intent of legislation	n/a	no	no	included	no
long standing interpretation of SOL	n/a	included	included	included	included
Half the money from certain retroactive applications to PERS and public education fund	n/a	no	no	included	no
tax savings from gas ceilings outside CI passed on to ultimate consumers	n/a	no	no	included	no
Admin					
	AS 43.55.020(a)				
Monthly Estimated payments		Ceilings applied monthly			Ceilings applied monthly

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: _____
Bill Version: CSHB2001(RES)
() Publish Date: _____

Identifier (file name): CSHB2001(RES)-DOR-TAX-11-9-07 Dept. Affected: Revenue 04
Title: An Act relating to the production tax on oil and gas.. RDU: Taxation and Treasury
Component: Tax Division
Sponsor: Governor
Requester: House Finance Component Number: 2476

Expenditures/Revenues (Thousands of Dollars)

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

	Appropriation Required	Information						
		FY 2009	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
OPERATING EXPENDITURES								
Personal Services	1,215.7		1,215.7	1,215.7	1,215.7	1,215.7	1,215.7	1,215.7
Travel								
Contractual	1,018.4		1,018.4	1,018.4	511.8	5.2	5.2	
Supplies								
Equipment								
Land & Structures								
Grants & Claims								
Miscellaneous								
TOTAL OPERATING	2,234.1		2,234.1	2,234.1	1,727.5	1,220.9	1,220.9	

CAPITAL EXPENDITURES							
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CHANGE IN REVENUES (654,000.0	494,000.0	497,000.0	689,000.0	703,000.0	492,000.0
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FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF	2,234.1		2,234.1	1,727.5	1,220.9	1,220.9	645.9
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	2,234.1		2,234.1	1,727.5	1,220.9	1,220.9	645.9

Estimate of any current year (FY2008) cost: 3,409.2

POSITIONS

Full-time	1	1	1	1	1	1	1
Part-time							
Temporary							

ANALYSIS: (Attach a separate page if necessary)

This bill makes economic and several administrative changes to the state's current petroleum profits tax. The bill retains the current tax system's structure, which taxes the net value of petroleum resources. The bill makes the following changes to the current system. It institutes a rate of 25% on net income. It calculates the progressivity surcharge as the difference between the per barrel net revenue and \$30 at 0.2%, 0.3% between \$40 and \$50, 0.4% between \$50 and \$60, and 0.5% over \$60. It eliminates the period by which past investments are recognized in the transition investment expenditure credits (AS 43 55 023(i)) from April 1, 2001 to April 1, 2003. Pipeline tariffs are based on reasonable rates. EIC credits are increased from 20% to 30%. The effective date of the bill is January 1, 2007.

Prepared by: Johanna Bales, Roge Marks, Cherie Nienhuis
Division: Tax Division
Approved by: Jerry Burnett
Department of Revenue

Phone: 269-6628
Date/Time: 11/9/07 1:00 PM
Date: 11/9/2007

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSHB2001(RES)

ANALYSIS CONTINUATION

Administrative changes to the current tax system include the following: excludes from qualified lease expenditures those expenses related to unscheduled production interruptions; excludes dismantlement, removal & restoration (DR&R) costs from allowable expenditures; requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; authorizes a short-term audit program; and designates an exempt class of oil and gas auditors.

Certain lease expenditure allowance provisions are retroactive to April 1, 2006; the other provisions of the tax proposal become effective January 1, 2007.

Personal Services: The department will reclassify the existing 5 vacant auditor positions, and create 4 to 5 senior level auditor positions with extensive industry oil and gas auditing experience. These positions will be classified as the Department's most senior level auditor positions and will have salaries that are consistent with market comparables and will be beyond the current salary levels allowed under the existing Oil and Gas Revenue Auditor (OGRA) pay classification system. In addition, the department expects that it will need one additional Programmer Analyst V position to maintain and manage the new oil and gas production tax database system at a cost of \$115,700 annually. The existing oil and gas specialist, oil and gas revenue auditors and their immediate supervisor will be offered the opportunity to opt into an exempt status with individual salaries established commensurate with experience and skill level, and consistent with market comparables.

The need for exempt status is based upon the difficulties the department has recruiting experienced auditors to administer the tax. The current pay range for an Oil and Gas Revenue Auditor is on the low range of the pay range for roughly similar jobs. The department estimates the new exempt positions and the potential salary increases associated with the change of existing staff to exempt status, will cost the state approximately \$1,100,000 annually.

Contractual: Contractual expenditures include \$1,013,200 annually to contract for audit assistance. This estimate is based on 3 auditors, working 40 hours per week each, for 4 years starting in January 2008 at an average rate of \$100 per hour, plus estimated transportation and lodging costs, and additional costs for training auditors. The need for such assistance is based upon the department's substantial difficulty in recruiting enough auditors to administer the oil and gas production tax. The department only anticipates the need for contract audit assistance for 4 years while the department recruits and trains auditors for positions that are currently vacant. The contract auditors would work in conjunction with department auditors during this time to maximize department resources and help train department auditors. The department will also need an additional \$5,200 each year in contractual costs associated with the new Analyst Programmer V position.

Current FY2008 costs: The department expects it will incur costs beginning January 2008 to immediately implement the new production tax structure. Those costs include: **Contractual** - \$2,620,800 capital funding to fund the scoping and development of an oil and gas production tax database system (including associated hardware) and \$506,600 to contract for audit assistance (as described above). The new database system will permit accurate and efficient management of information submitted by taxpayers to facilitate auditing and forecasting of revenues, and timely and accurate reports for internal and public uses. The proposed system will accommodate the migration of ELF-based data and continue to collect supplemental data from producers on volumes, wells and production. The system will include income-based data, including tracking credits, required under PPT and upon which the ACES tax structure is based. The system will also integrate into the division's accounting systems. **Personal Services** - \$218,000 from the period January 1, 2008 through June 30, 2008 due to creating an exempt class of oil and gas revenue auditors and increasing pay to more closely reflect what the market in Alaska pays for roughly similar positions. In addition, we will recruit for the Analyst Programmer V and bring that person on board to participate in the database scoping meetings. We estimate FY 2008 costs for this position to be approximately \$57,800. **Supplies** - \$6,000 for a computer and software for the new analyst programmer V position.

See page 3 for projected revenue estimates.

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. CSHB2001(RES)

ANALYSIS CONTINUATION

**Estimated Production Tax Revenues, PPT and ACES, at Various Prices
(in \$millions nominal)**

*For the months of January 2007 through May 2007, the proposal would have generated approximately \$244 million over the payments received for that period.

Fall 2007 DOR Official Forecast Prices

Fiscal Year	ANS WC \$ per barrel (in REAL dollars)	ANS WC \$ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	CSHB2001 (Res)	Increase or (Decrease) from PPT	Increase or (Decrease) from ACES
2008	71.65	71.65	1,947	2,368	2,984	1,037	616
2009	64.55	66.30	1,430	1,985	2,084	654	99
2010	60.05	63.40	1,217	1,767	1,711	494	-56
2011	59.70	64.75	1,250	1,766	1,748	497	-18
2012	59.55	66.35	1,174	1,701	1,863	689	162
2013	58.90	67.45	1,151	1,685	1,855	703	170
2014	58.25	68.55	1,217	1,558	1,709	492	150

DOR Forecast nominal prices rounded to the nearest \$0.05

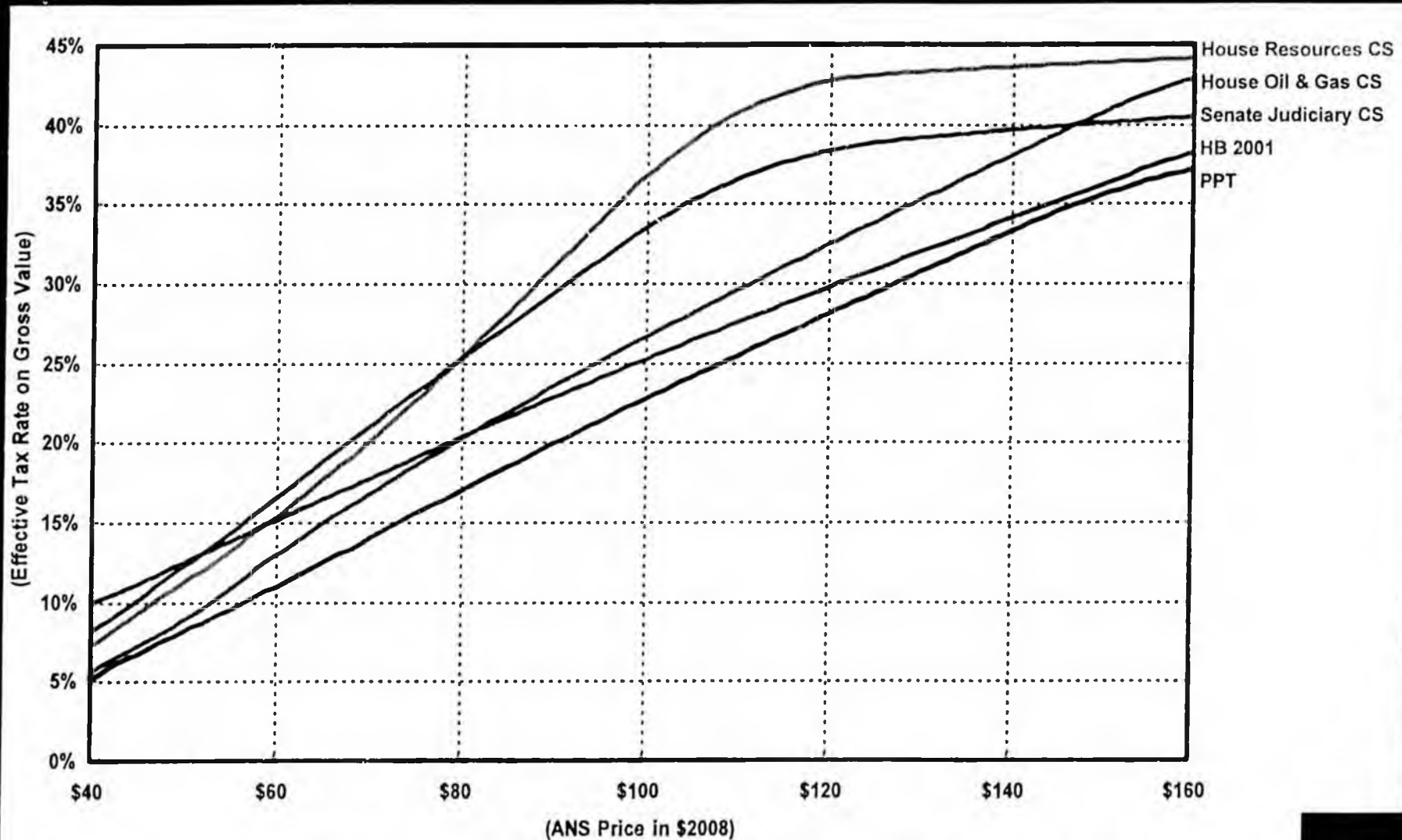
\$60 per barrel in REAL dollars

Fiscal Year	ANS WC \$ per barrel (in REAL dollars)	ANS WC \$ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	CSHB2001 (Res)	Increase or (Decrease) from PPT	Increase or (Decrease) from ACES
2008	60.00	60.00	1,073	1,452	1,691	618	240
2009	60.00	61.65	1,197	1,698	1,740	543	42
2010	60.00	63.35	1,247	1,802	1,747	500	-55
2011	60.00	65.09	1,272	1,795	1,779	507	-16
2012	60.00	66.88	1,204	1,737	1,906	702	169
2013	60.00	68.72	1,225	1,772	1,963	738	191
2014	60.00	70.61	1,334	1,696	1,881	548	185

\$80 per barrel in REAL dollars

Fiscal Year	ANS WC \$ per barrel (in REAL dollars)	ANS WC \$ per barrel (in NOMINAL dollars)	Status Quo - PPT	ACES	CSHB2001 (Res)	Increase or (Decrease) from PPT	Increase or (Decrease) from ACES
2008	80.00	80.00	2,693	3,137	4,157	1,465	1,020
2009	80.00	82.20	2,640	3,294	3,957	1,317	663
2010	80.00	84.46	2,751	3,431	4,059	1,308	628
2011	80.00	86.78	2,782	3,431	4,148	1,366	717
2012	80.00	89.17	2,698	3,360	4,321	1,623	961
2013	80.00	91.62	2,783	3,451	4,521	1,738	1,069
2014	80.00	94.14	2,950	3,407	4,538	1,588	1,131

Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels (FY 2008-2014)



Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Senate Judiciary: SB2001 using 0.4% progressivity rate, 60% overall cap, TIE credit 2Q06-2007 for new producers, does not include TAPS adjustment.
House Resources: Includes 60% cap on overall tax rate.



Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels (FY 2008-2014)

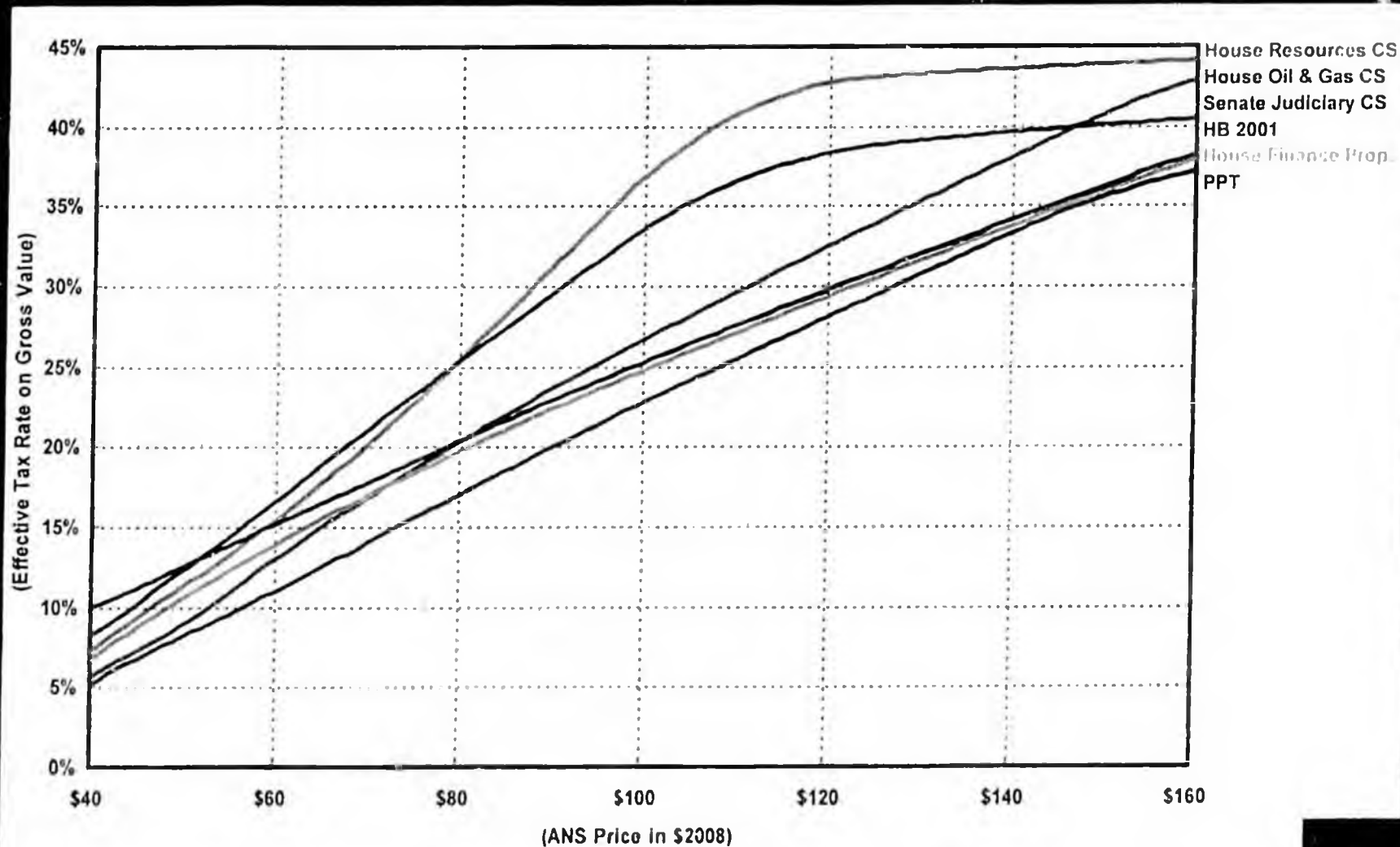
	Average ANS West Coast Price in Real 2008 Dollars:						
	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	5.1%	10.9%	17.0%	22.7%	28.1%	33.2%	37.2%
HB 2001	9.9%	15.1%	20.3%	25.2%	29.7%	34.1%	38.2%
House Oil & Gas CS	5.6%	13.0%	20.3%	26.7%	32.5%	38.1%	43.0%
House Resources CS	7.2%	15.4%	25.4%	36.8%	42.7%	43.6%	44.1%
Senate Judiciary CS	8.1%	16.5%	25.3%	33.5%	38.3%	39.6%	40.4%
Total Government Share of Net Cash (Percent)							
PPT	60.5%	60.6%	62.7%	65.3%	67.8%	70.4%	72.2%
HB 2001	64.5%	63.5%	64.9%	66.8%	68.8%	70.9%	72.9%
House Oil & Gas CS	60.9%	62.0%	64.9%	67.7%	70.5%	73.3%	75.7%
House Resources CS	61.9%	63.5%	68.2%	74.0%	76.7%	76.5%	76.3%
Senate Judiciary CS	63.0%	64.5%	68.1%	72.0%	74.1%	74.2%	74.2%
Marginal Government Share of Net Cash (Percent)							
PPT	58.9%	63.7%	70.7%	75.9%	81.0%	86.2%	78.9%
HB 2001	59.7%	65.4%	70.7%	75.1%	79.3%	83.5%	84.9%
House Oil & Gas CS	83.5%	68.5%	74.1%	79.5%	84.8%	90.2%	85.1%
House Resources CS	61.5%	71.1%	86.6%	94.9%	77.8%	75.1%	75.1%
Senate Judiciary CS	61.5%	71.9%	80.3%	86.4%	77.5%	74.2%	74.2%
Annual Average Tax Difference Above/(Below) PPT (Nominal \$M)							
HB 2001	\$423	\$587	\$635	\$608	\$493	\$287	\$423
House Oil & Gas CS	\$42	\$288	\$638	\$965	\$1,313	\$1,680	\$2,301
House Resources CS	\$201	\$656	\$1,668	\$3,500	\$4,395	\$3,661	\$2,854
Senate Judiciary CS	\$265	\$783	\$1,583	\$2,626	\$3,015	\$2,197	\$1,304

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Senate Judiciary: SB2001 using 0.4% progressivity rate, 60% overall cap, TIE credit 2006-2007 for new producers, does not include TAPS adjustment.
 House Resources: Includes 60% cap on overall tax rate.



Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels (FY 2008-2014)



Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Senate Judiciary: SB2001 using 0.4% progressivity rate, 80% overall cap, TIE credit 2008-2007 for new producers, does not include TAPS adjustment.
 House Resources: includes 80% cap on overall tax rate
 House Finance Proposed: HB2001 using 3-year TIE Credit and floor per current PPT

November 9, 2007;



Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels (FY 2008-2014)

Average ANS West Coast Price in Real 2008 Dollars:	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	5.1%	10.2%	17.0%	22.7%	28.1%	33.2%	37.2%
HB 2001	9.9%	15.1%	20.3%	25.2%	29.7%	34.1%	38.2%
House Oil & Gas CS	5.6%	13.0%	20.3%	26.7%	32.5%	38.1%	43.0%
House Resources CS	7.2%	15.4%	25.4%	36.8%	42.7%	43.6%	44.1%
Senate Judiciary CS	8.1%	16.5%	25.3%	33.5%	38.3%	39.6%	40.4%
House Finance Proposed	6.8%	13.0%	19.7%	24.7%	29.4%	33.0%	37.9%
Total Government Share of Net Cash (Percent)							
PPT	60.5%	60.6%	62.7%	65.3%	67.8%	70.4%	72.2%
HB 2001	64.5%	63.5%	64.9%	66.8%	68.8%	70.9%	72.9%
House Oil & Gas CS	60.9%	62.0%	64.9%	67.7%	70.5%	73.3%	75.7%
House Resources CS	61.9%	63.5%	66.2%	74.0%	76.7%	76.5%	76.3%
Senate Judiciary CS	63.0%	64.5%	68.1%	72.0%	74.1%	74.2%	74.2%
House Finance Proposed	61.9%	62.6%	64.5%	66.5%	68.6%	70.7%	72.7%
Marginal Government Share of Net Cash (Percent)							
PPT	58.9%	63.7%	70.7%	75.9%	81.0%	86.2%	78.9%
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HB 2001	\$423	\$587	\$635	\$608	\$493	\$287	\$423
House Oil & Gas CS	\$42	\$288	\$638	\$965	\$1,313	\$1,680	\$2,301
House Resources CS	\$201	\$656	\$1,668	\$3,500	\$4,395	\$3,661	\$2,854
Senate Judiciary CS	\$265	\$783	\$1,583	\$2,626	\$3,015	\$2,197	\$1,304
House Finance Proposed	\$148	\$312	\$520	\$485	\$380	\$174	\$310

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Senate Judiciary SB2001 using 0.4% progressivity rate, 50% overall cap, TIE credit 2006-2007 for new producers, does not include TAPS adjustment.
 House Resources: Includes 50% cap on overall tax rate.
 House Finance Proposed: HB2001 using 3-year TIE Credit and floor per current PPT

November 9, 2007



Adopted

11/9/07

25-GH0014\N
Finley/Bullock
11/9/07

CS FOR HOUSE BILL NO. 2001(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FIFTH LEGISLATURE - SECOND SPECIAL SESSION

BY THE HOUSE FINANCE COMMITTEE

Offered:

Referred:

Sponsor(s): HOUSE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Adopted 11/9/07

N/D

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to the production tax on oil and gas and to conservation surcharges on
 2 oil; providing a limit on the amount of tax that may be levied on the production of
 3 certain gas that is produced outside of the Cook Inlet sedimentary basin; providing a
 4 penalty for the underpayment of an installment payment of the production tax on oil
 5 and gas; relating to the sharing between agencies of certain information relating to the
 6 production tax and to oil and gas or gas only leases; expanding the period in which the
 7 Department of Revenue may assess the amount of oil and gas production tax and
 8 conservation surcharges; amending the State Personnel Act to place in the exempt
 9 service certain state oil and gas auditors and their immediate supervisors; providing for
 10 retroactive application of certain statutory provisions to the production tax on oil and
 11 gas; making conforming amendments; and providing for an effective date."

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

1 * Section 1. The uncodified law of the State of Alaska is amended by adding a new section
2 to read:

3 LEGISLATIVE INTENT. It is the intent of the legislature that AS 43.55.075(b),
4 enacted by sec. 42 of this Act, confirm by clarification the long-standing interpretation of
5 AS 43.05.260 by the Department of Revenue relating to limitation of assessments for the
6 production tax on oil and gas and conservation surcharges on oil.

7 * Sec. 2. AS 38.05.035(a) is amended to read:

8 (a) The director shall

9 (1) have general charge and supervision of the division and may
10 exercise the powers specifically delegated to the director; the director may employ
11 and fix the compensation of assistants and employees necessary for the operations of
12 the division; the director [AND] is the certifying officer of the division, with the
13 consent of the commissioner, and may approve vouchers for disbursements of money
14 appropriated to the division;

15 (2) manage, inspect, and control state land and improvements on it
16 belonging to the state and under the jurisdiction of the division;

17 (3) execute laws, rules, regulations, and orders adopted by the
18 commissioner;

19 (4) prescribe application procedures and practices for the sale, lease,
20 or other disposition of available land, resources, property, or interest in them;

21 (5) prescribe fees or service charges, with the consent of the
22 commissioner, for any public service rendered;

23 (6) under the conditions and limitations imposed by law and the
24 commissioner, issue deeds, leases, or other conveyances disposing of available land,
25 resources, property, or any interests in them;

26 (7) have jurisdiction over state land, except that land acquired by the
27 Alaska World War II Veterans Board and the Agricultural Loan Board or the
28 departments or agencies succeeding to their respective functions through foreclosure
29 or default; to this end, the director possesses the powers and, with the approval of the
30 commissioner, shall perform the duties necessary to protect the state's rights and
31 interest in state land, including the taking of all necessary action to protect and

1 enforce the state's contractual or other property rights;

2 (8) [REPEALED

3 (9) maintain the [SUCH] records [AS] the commissioner considers
4 necessary, administer oaths, and do all things incidental to the authority imposed; the
5 following records and files shall be kept confidential upon request of the person
6 supplying the information:

7 (A) the name of the person nominating or applying for the
8 sale, lease, or other disposal of land by competitive bidding;

9 (B) before the announced time of opening, the names of the
10 bidders and the amounts of the bids;

11 (C) all geological, geophysical, and engineering data supplied,
12 whether or not concerned with the extraction or development of natural
13 resources;

14 (D) except as provided in AS 38.05.036, cost data and
15 financial information submitted in support of applications, bonds, leases, and
16 similar items;

17 (E) applications for rights-of-way or easements;

18 (F) requests for information or applications by public agencies
19 for land that [WHICH] is being considered for use for a public purpose;

20 (9) [(10)] account for the fees, licenses, taxes, or other money
21 received in the administration of this chapter including the sale or leasing of land,
22 identify their source, and promptly transmit them to the proper fiscal department after
23 crediting them to the proper fund; receipts from land application filing fees and
24 charges for copies of maps and records shall be deposited immediately in the general
25 fund of the state by the director;

26 (10) [(11)] select and employ or obtain at reasonable compensation
27 cadastral, appraisal, or other professional personnel the director considers necessary
28 for the proper operation of the division;

29 (11) [(12)] be the certifying agent of the state to select, accept, and
30 secure by whatever action is necessary in the name of the state, by deed, sale, gift,
31 devise, judgment, operation of law, or other means any land, of whatever nature or

1 interest, available to the state; and be the certifying agent of the state, to select,
2 accept, or secure by whatever action is necessary in the name of the state any land, or
3 title or interest to land available, granted, or subject to being transferred to the state
4 for any purpose;

5 (12) on request, furnish records, files, and other information
6 related to the administration of AS 38.05.180 to the Department of Revenue for
7 use in forecasting state revenue under or administering AS 43.55, whether or not
8 those records, files, and other information are required to be kept confidential
9 under (8) of this subsection; in the case of records, files, or other information
10 required to be kept confidential under (8) of this subsection, the Department of
11 Revenue shall maintain the confidentiality that the Department of Natural
12 Resources is required to extend to records, files, and other information under (8)
13 of this subsection

14 [(13) REPEALED

15 (14) REPEALED].

16 * Sec. 3. AS 38.05.036(b) is amended to read:

17 (b) The Department of Revenue may obtain from the department information
18 relating to royalty and net profits payments and to exploration incentive credits under
19 this chapter or under AS 41.09, whether or not that information is confidential. The
20 Department of Revenue may use the information in carrying out its functions and
21 responsibilities under AS 43, and shall hold that information confidential to the extent
22 required by an agreement with the department or by AS 38.05.035(a)(8)
23 [AS 38.05.035(a)(9)], AS 41.09.010(d), or AS 43.05.230.

24 * Sec. 4. AS 38.05.036(f) is amended to read:

25 (f) Except as otherwise provided in this section or in connection with official
26 investigations or proceedings of the department, it is unlawful for a current or former
27 officer, employee, or agent of the state to divulge information obtained by the
28 department as a result of an audit under this section that is required by an agreement
29 with the department or by AS 38.05.035(a)(8) [AS 38.05.035(a)(9)] or
30 AS 41.09.010(d) to be kept confidential.

31 * Sec. 5. AS 38.05.036(g) is amended to read:

1 (g) Nothing in this section prohibits the publication of statistics in a manner
2 that maintains the confidentiality of information to the extent required by an
3 agreement with the department or by AS 38.05.035(a)(8) [AS 38.05.035(a)(9)] or
4 AS 41.09.010(d).

5 * Sec. 6. AS 38.05.123(f) is amended to read:

6 (f) As part of the timber sale negotiations authorized by this section, the
7 commissioner may require a prospective purchaser negotiating a timber sale contract
8 to submit financial and technical data that demonstrates that the requirements of this
9 section have been or will be met. Upon the prospective purchaser's request, the
10 commissioner shall keep data provided by the purchaser confidential in accordance
11 with the requirements of AS 38.05.035(a)(8) [AS 38.05.035(a)(9)].

12 * Sec. 7. AS 38.05.133(e) is amended to read:

13 (e) The commissioner may make a written request to a prospective licensee
14 for additional information on the prospective licensee's proposal. The commissioner
15 shall keep confidential information described in AS 38.05.035(a)(8)
16 [AS 38.05.035(a)(9)] that is voluntarily provided if the prospective licensee has made
17 a written request that the information remain confidential.

18 * Sec. 8. AS 38.05.180(j) is amended to read:

19 (j) The commissioner

20 (1) may provide for modification of royalty on individual leases,
21 leases unitized as described in (p) of this section, leases subject to an agreement
22 described in (s) or (t) of this section, or interests unitized under AS 31.05

23 (A) to allow for production from an oil or gas field or pool

24 (i) the oil or gas field or pool has been sufficiently
25 delineated to the satisfaction of the commissioner;

26 (ii) the field or pool has not previously produced oil or
27 gas for sale; and

28 (iii) oil or gas production from the field or pool would
29 not otherwise be economically feasible;

30 (B) to prolong the economic life of an oil or gas field or pool
31 as per barrel or barrel equivalent costs increase or as the price of oil or gas

1 decreases, and the increase or decrease is sufficient to make future production
2 no longer economically feasible; or

3 (C) to reestablish production of shut-in oil or gas that would
4 not otherwise be economically feasible;

5 (2) may not grant a royalty modification unless the lessee or lessees
6 requesting the change make a clear and convincing showing that a modification of
7 royalty meets the requirements of this subsection and is in the best interests of the
8 state;

9 (3) shall provide for an increase or decrease or other modification of
10 the state's royalty share by a sliding scale royalty or other mechanism that shall be
11 based on a change in the price of oil or gas and may also be based on other relevant
12 factors such as a change in production rate, projected ultimate recovery, development
13 costs, and operating costs;

14 (4) may not grant a royalty reduction for a field or pool

15 (A) under (1)(A) of this subsection if the royalty modification
16 for the field or pool would establish a royalty rate of less than five percent in
17 amount or value of the production removed or sold from a lease or leases
18 covering the field or pool;

19 (B) under (1)(B) or (1)(C) of this subsection if the royalty
20 modification for the field or pool would establish a royalty rate of less than
21 three percent in amount or value of the production removed or sold from a
22 lease or leases covering the field or pool;

23 (5) may not grant a royalty reduction under this subsection without
24 including an explicit condition that the royalty reduction is not assignable without the
25 prior written approval, which may not be unreasonably withheld, by the
26 commissioner; the commissioner shall, in the preliminary and final findings and
27 determinations, set out the conditions under which the royalty reduction may be
28 assigned;

29 (6) shall require the lessee or lessees to submit, with the application
30 for the royalty reduction, financial and technical data that demonstrate that the
31 requirements of this subsection are met; the commissioner

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(A) may require disclosure of only the financial and technical data related to development, production, and transportation of oil and gas or gas only from the field or pool that are reasonably available to the applicant; and

(B) shall keep the data confidential under AS 38.05.035(a)(8) [AS 38.05.035(a)(9)] at the request of the lessee or lessees making application for the royalty reduction; the confidential data may be disclosed by the commissioner to legislators and to the legislative auditor and as directed by the chair or vice-chair of the Legislative Budget and Audit Committee to the director of the division of legislative finance, the permanent employees of their respective divisions who are responsible for evaluating a royalty reduction, and to agents or contractors of the legislative auditor or the legislative finance director who are engaged under contract to evaluate the royalty reduction, if they sign an appropriate confidentiality agreement;

(7) may

(A) require the lessee or lessees making application for the royalty reduction under (1)(A) of this subsection to pay for the services of an independent contractor, selected by the lessee or lessees from a list of qualified consultants compiled by the commissioner, to evaluate hydrocarbon development, production, transportation, and economics and to assist the commissioner in evaluating the application and financial and technical data; if, under this subparagraph, the commissioner requires payment for the services of an independent contractor, the total cost of the services to be paid for by the lessee or lessees may not exceed \$150,000 for each application, and the commissioner shall determine the relevant scope of the work to be performed by the contractor; selection of an independent contractor under this subparagraph is not subject to AS 36.30;

(B) with the mutual consent of the lessee or lessees making application for the royalty reduction under (1)(B) or (1)(C) of this subsection, request payment for the services of an independent contractor, selected from a list of qualified consultants to evaluate hydrocarbon development, production,

1 transportation, and economics by the commissioner to assist the commissioner
2 in evaluating the application and financial and technical data; if, under this
3 subparagraph, the commissioner requires payment for the services of an
4 independent contractor, the total cost of the services that may be paid for by
5 the lessee or lessees may not exceed \$150,000 for each application, and the
6 commissioner shall determine the relevant scope of the work to be performed
7 by the contractor; selection of an independent contractor under this
8 subparagraph is not subject to AS 36.30;

9 (8) shall make and publish a preliminary findings and determination
10 on the royalty reduction application, give reasonable public notice of the preliminary
11 findings and determination, and invite public comment on the preliminary findings
12 and determination during a 30-day period for receipt of public comment;

13 (9) shall offer to appear before the Legislative Budget and Audit
14 Committee, on a day that is not earlier than 10 days and not later than 20 days after
15 giving public notice under (8) of this subsection, to provide the committee a review of
16 the commissioner's preliminary findings and determination on the royalty reduction
17 application and administrative process; if the Legislative Budget and Audit
18 Committee accepts the commissioner's offer, the committee shall give notice of the
19 committee's meeting to all members of the legislature;

20 (10) shall make copies of the preliminary findings and determination
21 available to

22 (A) the presiding officer of each house of the legislature;

23 (B) the chairs of the legislature's standing committees on
24 resources; and

25 (C) the chairs of the legislature's special committees on oil and
26 gas, if any;

27 (11) shall, within 30 days after the close of the public comment period
28 under (8) of this subsection,

29 (A) prepare a summary of the public response to the
30 commissioner's preliminary findings and determination;

31 (B) make a final findings and determination; the

1 commissioner's final findings and determination prepared under this
2 subparagraph regarding a royalty reduction is final and not appealable to the
3 court;

4 (C) transmit a copy of the final findings and determination to
5 the lessee;

6 (D) with the applicant's consent, amend the applicant's lease or
7 unitization agreement consistent with the commissioner's final decision; and

8 (E) make copies of the final findings and determination
9 available to each person who submitted comment under (8) of this subsection
10 and who has filed a request for the copies;

11 (12) is not limited by the provisions of AS 38.05.134(3) or (f) of this
12 section in the commissioner's determination under this subsection.

13 * Sec. 9. AS 38.05.275(c) is amended to read:

14 (c) Subsection (b) of this section may not be construed to limit the director in
15 the exercise of authority granted by AS 38.05.035(a)(11) [AS 38.05.035(a)(12)].

16 * Sec. 10. AS 39.25.110 is amended by adding a new paragraph to read:

17 (42) oil and gas auditors performing

18 (A) production tax audits, and their immediate supervisors, in
19 the Department of Revenue;

20 (B) royalty audits, including net profit share audits, and their
21 immediate supervisors, in the Department of Natural Resources.

22 * Sec. 11. AS 41.09.010(d) is amended to read:

23 (d) Data derived from drilling a stratigraphic test well or exploratory well that
24 is provided to the commissioner under (c)(3) of this section shall be kept confidential
25 for 24 months after receipt by the commissioner unless the owner of the well gives
26 written permission to the state to release the well data at an earlier date, and,
27 notwithstanding AS 31.05.035(c), confidentiality may not be extended beyond 24
28 months. The provisions of AS 38.05.035(a)(8)(C) [AS 38.05.035(a)(9)(C)] apply to
29 other data provided to the commissioner under (c)(3) of this section, except that the
30 commissioner, under appropriate confidentiality provisions and without preference or
31 discrimination, may display to all interested third parties, but may not distribute or

1 transfer in hard copy or electronic form, those data with respect to all land if the
2 commissioner determines that the limited disclosure is necessary to further the
3 interest of the state in evaluating or developing its land.

4 * Sec. 12. AS 43.05.230(h) is amended to read:

5 (h) The commissioner shall, upon request, furnish to the Department of
6 Natural Resources copies of tax returns, reports, and other documents filed under
7 AS 43.55 or AS 43.65, and the Department of Revenue's determinations and
8 workpapers under those chapters. The Department of Natural Resources shall
9 maintain the confidentiality that the Department of Revenue is required to extend to
10 the returns, reports, documents, determinations, and workpapers furnished to the
11 Department of Natural Resources under this subsection.

12 * Sec. 13. AS 43.05.260(a) is amended to read:

13 (a) Except as provided in (c) of this section, [AND] AS 43.20.200(b), and
14 AS 43.55.075, the amount of a tax imposed by this title must be assessed within three
15 years after the return was filed, whether or not a return was filed on or after the date
16 prescribed by law. If the tax is not assessed before the expiration of the applicable
17 [THREE-YEAR] period, proceedings may not be instituted in court for the collection
18 of the tax.

19 * Sec. 14. AS 43.55.011(e) is repealed and reenacted to read:

20 (e) There is levied on the producer of oil or gas a tax for all oil and gas
21 produced each calendar year from each lease or property in the state, less any oil and
22 gas the ownership or right to which is exempt from taxation or constitutes a
23 landowner's royalty interest. Except as otherwise provided under (f), (j), and (k) of
24 this section, the tax is equal to the production tax value of the taxable oil and gas as
25 calculated under AS 43.55.160 multiplied by the tax rate determined under (g) of this
26 section.

27 * Sec. 15. AS 43.55.011(g) is repealed and reenacted to read:

28 (g) The tax rate applied to the production tax value of oil and gas under (e) of
29 this section is 25 percent plus 0.20 percent times the price index for the calendar year
30 determined under (h) of this section. However, the tax rate calculated under this
31 subsection may not be more than 50 percent.

1 * Sec. 16. AS 43.55.011(h) is amended to read:

2 (h) For purposes of (g) of this section, the price index for a calendar year
3 [MONTH] is calculated by subtracting 30 [40] from the number that is equal to [THE
4 QUOTIENT OF] the total [MONTHLY] production tax value of the taxable oil and
5 gas produced by the producer from all leases or properties in the state during that
6 calendar year [DURING THAT MONTH], as calculated under AS 43.55.160,
7 divided by the total amount of that [THE TAXABLE] oil and gas [PRODUCED BY
8 THE PRODUCER DURING THAT MONTH], in BTU equivalent barrels. However,
9 a price index calculated under this subsection may not be less than zero.

10 * Sec. 17. AS 43.55.011(j) is amended to read:

11 (j) For a calendar year before 2022, the [TOTAL] tax levied by (e) [AND (g)]
12 of this section for [ON] gas produced from a lease or property in the Cook Inlet
13 sedimentary basin may not exceed

14 (1) for a lease or property that first commenced commercial
15 production of gas before April 1, 2006, the product obtained by multiplying (A) the
16 amount of taxable gas produced during the calendar year from the lease or property,
17 times (B) the average rate of tax that was imposed under this chapter for [ON]
18 taxable gas produced from the lease or property for the 12-month period ending on
19 March 31, 2006, times (C) the quotient obtained by dividing the total gross value at
20 the point of production of the taxable gas produced from the lease or property during
21 the 12-month period ending on March 31, 2006, by the total amount of that gas;

22 (2) for a lease or property that first commences commercial
23 production of gas after March 31, 2006, the product obtained by multiplying (A) the
24 amount of taxable gas produced during the calendar year from the lease or property,
25 times (B) the average rate of tax that was imposed under this chapter for [ON]
26 taxable gas produced from all leases or properties in the Cook Inlet sedimentary basin
27 for the 12-month period ending on March 31, 2006, times (C) the average prevailing
28 value for gas delivered in the Cook Inlet area for the 12-month period ending
29 March 31, 2006, as determined by the department under AS 43.55.020(i).

30 * Sec. 18. AS 43.55.011(k) is amended to read:

31 (k) For a calendar year before 2022, the [TOTAL] tax levied by (c) [AND

1 (g)] of this section for [ON] oil produced from a lease or property in the Cook Inlet
2 sedimentary basin may not exceed

3 (1) for a lease or property that first commenced commercial
4 production of oil before April 1, 2006, the product obtained by multiplying (A) the
5 amount of taxable oil produced during the calendar year from the lease or property,
6 times (B) the average rate of tax that was imposed under this chapter for [ON]
7 taxable oil produced from the lease or property for the 12-month period ending on
8 March 31, 2006, times (C) the quotient obtained by dividing the total gross value at
9 the point of production of the taxable oil produced from the lease or property during
10 the 12-month period ending on March 31, 2006, by the total amount of that oil;

11 (2) for a lease or property that first commences commercial
12 production of oil after March 31, 2006, the product obtained by multiplying (A) the
13 amount of taxable oil produced during the calendar year from the lease or property,
14 times (B) the average rate of tax that was imposed under this chapter for [ON]
15 taxable oil produced from all leases or properties in the Cook Inlet sedimentary basin
16 for the 12-month period ending on March 31, 2006, times (C) the average prevailing
17 value for oil produced and delivered in the Cook Inlet area for the 12-month period
18 ending on March 31, 2006, as determined by the department under AS 43.55.020(f).

19 * Sec. 19. AS 43.55.011(m) is amended to read:

20 (m) Notwithstanding any contrary provision of AS 38.05.180(i),
21 AS 41.09.010, AS 43.20.043, AS 43.55.024, or 43.55.025, tax credits under
22 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, AS 43.55.024, and 43.55.025 that are
23 allocated to gas produced from leases or properties in the Cook Inlet sedimentary
24 basin and that are available to be applied against a tax levied by (e) of this section for
25 [ON] gas produced from leases or properties in the Cook Inlet sedimentary basin
26 during a calendar year may be applied only against the tax levied by (e) of this section
27 for [ON] that gas. The amount by which the amount of tax credits that are allocated
28 to gas produced from leases or properties in the Cook Inlet sedimentary basin and that
29 the producer would otherwise be allowed to use for a later calendar year or transfer to
30 another person exceeds the amount of tax credits whose application would reduce the
31 tax levied by (e) of this section for [ON] that gas to zero, if any, is considered the

1 amount of excess tax credits, and the excess tax credits are subject to the following:

2 (1) for each lease or property for which a limitation under (j) or (k) of
3 this section on the tax levied by (e) and (g) of this section has the effect of reducing
4 the producer's tax below the amount of tax that would be levied in the absence of that
5 limitation, the producer shall calculate the amount of that reduction;

6 (2) the producer shall calculate the total of the reductions calculated
7 under (1) of this subsection for all affected leases or properties;

8 (3) the producer shall reduce the amount of excess tax credits by the
9 total calculated under (2) of this subsection, but not to less than zero;

10 (4) any amount of excess tax credits remaining after reduction under
11 (3) of this subsection may be used for a later calendar year, transferred to another
12 person, or applied against a tax levied for [ON] oil or gas produced from a lease or
13 property located anywhere in the state to the extent otherwise allowed under
14 applicable law governing the tax credits.

15 * Sec. 20. AS 43.55.011 is amended by adding a new subsection to read:

16 (o) Notwithstanding other provisions of this section, for a calendar year
17 before 2022, the tax levied under (e) of this section for each 1,000 cubic feet of gas
18 for gas produced from a lease or property outside the Cook Inlet sedimentary basin
19 and used in the state may not exceed the amount of tax for each 1,000 cubic feet of
20 gas that is determined under (j)(2) of this section.

21 * Sec. 21. AS 43.55.020(a) is repealed and reenacted to read:

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

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

31 (A) for oil and gas produced from leases or properties in the

1 state outside the Cook Inlet sedimentary basin or not subject to
2 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f),
3 the greater of

4 (i) zero; or

5 (ii) 25 percent of the remainder obtained by subtracting
6 1/12 of the producer's adjusted lease expenditures for the calendar year
7 of production under AS 43.55.165 and 43.55.170 that are deductible
8 for the leases or properties under AS 43.55.160 from the gross value at
9 the point of production of the oil and gas produced from the leases or
10 properties during the month for which the installment payment is
11 calculated;

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

14 (i) zero;

15 (ii) zero percent, one percent, two percent, three
16 percent, or four percent, as applicable, of the gross value at the point of
17 production of the oil and gas produced from all leases or properties in
18 the unit or nonunitized reservoir; or

19 (iii) 25 percent of the remainder obtained by
20 subtracting 1/12 of the producer's adjusted lease expenditures for the
21 calendar year of production under AS 43.55.165 and 43.55.170 that are
22 deductible for those leases or properties under AS 43.55.160 from the
23 gross value at the point of production of the oil and gas produced from
24 those leases or properties during the month for which the installment
25 payment is calculated;

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

28 (i) zero; or

29 (ii) 25 percent of the remainder obtained by subtracting
30 1/12 of the producer's adjusted lease expenditures for the calendar year
31 of production under AS 43.55.165 and 43.55.170 that are deductible

1 under AS 43.55.160 for oil or gas, respectively, produced from the
2 lease or property from the gross value at the point of production of the
3 oil or gas, respectively, produced from the lease or property during the
4 month for which the installment payment is calculated;

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

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

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

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

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

31 * Sec. 22. AS 43.55.020(g) is amended to read:

1 (g) Notwithstanding any contrary provision of AS 43.05.225, an unpaid
2 amount of an installment payment required under (a)(1) - (3) [(a)(1) - (4)] of this
3 section that is not paid when due bears interest (1) at the rate provided for an
4 underpayment under 26 U.S.C. 6621 (Internal Revenue Code), as amended,
5 compounded daily, from the date the installment payment is due until [THE]
6 March 31 following the calendar year of production [DESCRIBED IN
7 AS 43.55.030(a)], and (2) as provided for a delinquent tax under AS 43.05.225 after
8 that March 31. Interest accrued under (1) of this subsection that remains unpaid after
9 that March 31 is treated as an addition to tax that bears interest under (2) of this
10 subsection. An unpaid amount of tax due under (a)(4) [(a)(5)] of this section that is
11 not paid when due bears interest as provided for a delinquent tax under AS 43.05.225.

12 * Sec. 23. AS 43.55.020(h) is amended to read:

13 (h) Notwithstanding any contrary provision of AS 43.05.280,

14 (1) an overpayment of an installment payment required under (a)(1) -
15 (3) [(a)(1) - (4)] of this section bears interest at the rate provided for an overpayment
16 under 26 U.S.C. 6621 (Internal Revenue Code), as amended, compounded daily, from
17 the later of the date the installment payment is due or the date the overpayment is
18 made, until the earlier of

19 (A) the date it is refunded or is applied to an underpayment; [.]

20 or

21 (B) [THE] March 31 following the calendar year of
22 production [DESCRIBED IN AS 43.55.030(a)];

23 (2) except as provided under (1) of this subsection, interest with
24 respect to an overpayment is allowed only on any net overpayment of the payments
25 required under (a) of this section that remains after the later of [THE] March 31
26 following the calendar year of production [DESCRIBED IN AS 43.55.030(a)] or
27 the date that the statement required under AS 43.55.030(a) is filed;

28 (3) interest is allowed under (2) of this subsection only from a date
29 that is 90 days after the later of [THE] March 31 following the calendar year of
30 production [DESCRIBED IN AS 43.55.030(a)] or the date that the statement
31 required under AS 43.55.030(a) is filed; interest is not allowed if the overpayment

1 was refunded within the 90-day period;

2 (4) interest under (2) and (3) of this subsection is paid at the rate and
3 in the manner provided in AS 43.05.225(1).

4 * Sec. 24. AS 43.55.020 is amended by adding a new subsection to read:

5 (i) A civil penalty shall be added to the amount of an installment payment
6 required under (a)(1) - (3) of this section if at least 90 percent of the amount of the
7 payment is not paid by the date the payment is due. The penalty is equal to five
8 percent of the difference between the amount of the installment payment that was
9 made timely and the amount of the installment payment required under (a)(1) - (3) of
10 this section. If no part of the required installment payment was made timely, the
11 penalty is equal to five percent of the installment payment required under (a)(1) - (3)
12 of this section. The penalty is in addition to the interest imposed under (g) of this
13 section and a penalty added under AS 43.05.220, if any.

14 * Sec. 25. AS 43.55.023(b) is amended to read:

15 (b) A producer or explorer may elect to take a tax credit in the amount of 25
16 [20] percent of a carried-forward annual loss. A credit under this subsection may be
17 applied against a tax levied by [DUE UNDER] AS 43.55.011(e). For purposes of this
18 subsection, a carried-forward annual loss is the amount of a producer's or explorer's
19 adjusted lease expenditures under AS 43.55.165 and 43.55.170 for a previous
20 calendar year that was not deductible in calculating production tax values for that
21 calendar year under AS 43.55.160 [AS 43.55.160(b) AND (e)].

22 * Sec. 26. AS 43.55.023(i) is amended to read:

23 (i) For the purposes of this section,

24 (1) a producer's or explorer's transitional investment expenditures are
25 the sum of the expenditures the producer or explorer incurred after March 31, 2003
26 [2001], and before April 1, 2006, that would be qualified capital expenditures if they
27 were incurred after March 31, 2006, less the sum of the payments or credits the
28 producer or explorer received before April 1, 2006, for the sale or other transfer of
29 assets, including geological, geophysical, or well data or interpretations, acquired by
30 the producer or explorer as a result of expenditures the producer or explorer incurred
31 before April 1, 2006, that would be qualified capital expenditures, if they were

1 incurred after March 31, 2006;

2 (2) a producer or explorer may elect to take a tax credit against a tax
3 due under AS 43.55.011(e) in the amount of 20 percent of the producer's or explorer's
4 transitional investment expenditures, but only to the extent that the amount does not
5 exceed 1/10 of the producer's or explorer's qualified capital expenditures that are
6 incurred during the calendar year for which the credit is taken;

7 (3) a producer or explorer may not take a tax credit for a transitional
8 investment expenditure

9 (A) for any calendar year after the later of

10 (i) 2013; or

11 (ii) the sixth calendar year after the calendar year for
12 which the producer first applies a credit under this subsection against a
13 tax due under AS 43.55.011(e), if the producer did not have
14 commercial production of oil or gas from a lease or property in the
15 state before April 1, 2006;

16 (B) more than once; or

17 (C) if a credit for that expenditure was taken under
18 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025;

19 (4) notwithstanding (d), (e), and (g) of this section, a producer or
20 explorer may not transfer a tax credit or obtain a transferable tax credit certificate for
21 a transitional investment expenditure.

22 * Sec. 27. AS 43.55.023 is amended by adding a new subsection to read:

23 (l) A person that is exempt from taxation under this chapter may not apply for
24 a transferable tax credit certificate.

25 * Sec. 28. AS 43.55.023 is amended by adding a new subsection to read:

26 (m) Notwithstanding the limitation on the use of a transferable tax credit by a
27 transferee under (e) of this section and subject to appropriations made by law, if and
28 to the extent that purchase of transferable tax credits by the Alaska Retirement
29 Management Board is authorized by law, the department shall issue a cash refund to
30 the Alaska Retirement Management Board for a transferable tax credit originally
31 issued to a person under (d) of this section and purchased by the Alaska Retirement

1 Management Board.

2 * Sec. 29. AS 43.55.025(a) is amended to read:

3 (a) Subject to the terms and conditions of this section, a credit against the
4 production tax levied by [DUE UNDER] AS 43.55.011(e) or (f) is allowed for
5 exploration expenditures that qualify under (b) of this section in an amount equal to
6 one of the following:

7 (1) 30 [20] percent of the total exploration expenditures that qualify
8 only under (b) and (c) of this section;

9 (2) 30 [20] PERCENT of the total exploration expenditures [FOR
10 WORK PERFORMED BEFORE JULY 1, 2007, AND] that qualify only under (b)
11 and (d) of this section;

12 (3) 40 percent of the total exploration expenditures that qualify under
13 (b), (c), and (d) of this section; or

14 (4) 40 percent of the total exploration expenditures that qualify only
15 under (b) and (e) of this section.

16 * Sec. 30. AS 43.55.025(b) is amended to read:

17 (b) To qualify for the production tax credit under (a) of this section, an
18 exploration expenditure must be incurred for work performed [ON OR] after
19 December 31, 2006 [JULY 1, 2003], and before July 1, 2016, [EXCEPT THAT AN
20 EXPLORATION EXPENDITURE FOR A COOK INLET PROSPECT MUST BE
21 INCURRED FOR WORK PERFORMED ON OR AFTER JULY 1, 2005,] and

22 (1) may be for seismic or other geophysical exploration costs not
23 connected with a specific well;

24 (2) if for an exploration well,

25 (A) must be incurred by an explorer that holds an interest in
26 the exploration well for which the production tax credit is claimed;

27 (B) may be for either a [AN OIL OR GAS DISCOVERY]
28 well that encounters an oil or gas deposit or a dry hole; [AND]

29 (C) must be for a well that has been completed, suspended,
30 or abandoned under AS 31.05.030 at the time the explorer claims the tax
31 credit under (f) of this section; and

1 (D) must be for goods, services, or rentals of personal
2 property reasonably required for the surface preparation, drilling, casing,
3 cementing, and logging of an exploration well, and, in the case of a dry hole,
4 for the expenses required for abandonment if the well is abandoned within 18
5 months after the date the well was spudded;

6 (3) may not be for [TESTING, STIMULATION, OR COMPLETION
7 COSTS;] administration, supervision, engineering, or lease operating costs;
8 geological or management costs; community relations or environmental costs;
9 bonuses, taxes, or other payments to governments related to the well; costs arising
10 from fraud, wilful misconduct, gross negligence, criminal negligence, violation of
11 law, including a violation of 33 U.S.C. 1319(c)(1) or 1321(b)(3) (Clean Water
12 Act), or failure to comply with an obligation under a lease, permit, or license
13 issued by the state or federal government, or other costs that are generally
14 recognized as indirect costs or financing costs; and

15 (4) may not be incurred for an exploration well or seismic exploration
16 that is included in a plan of exploration or a plan of development for any unit on
17 May 13, 2003.

18 * Sec. 31. AS 43.55.025(e) is repealed and reenacted to read:

19 (e) To be eligible for the 30 percent production tax credit authorized by (a)(1)
20 of this section or the 40 percent production tax credit authorized by (a)(3) of this
21 section, exploration expenditures must

22 (1) qualify under (b) of this section; and

23 (2) be for an exploration well, subject to the following:

24 (A) before spudding the well, (i) the explorer shall submit to
25 the commissioner of natural resources the information necessary to determine
26 whether the geological objective of the well is a potential oil or gas trap that is
27 distinctly separate from any trap that has been tested by a preexisting well;
28 and (ii) the commissioner of natural resources must make an affirmative
29 determination on that question; the commissioner of natural resources shall
30 decide whether to make that determination within 60 days after receiving all
31 the necessary information from the explorer and based on the information

1 received and on other information the commissioner of natural resources may
2 consider relevant;

3 (B) for an exploration well other than a well to explore a Cook
4 Inlet prospect, the well must be located and drilled in such a manner that the
5 bottom hole is located not less than three miles away from the bottom hole of
6 a preexisting well drilled for oil or gas, irrespective of whether the preexisting
7 well has been completed, suspended, or abandoned;

8 (C) after completion, abandonment, or suspension under
9 AS 31.05.030 of the exploration well, the commissioner of natural resources
10 must determine that the well adequately achieved the explorer's stated
11 geological objective.

12 * Sec. 32. AS 43.55.025(f) is amended to read:

13 (f) For a production tax credit under this section,

14 (1) an explorer shall, in a form prescribed by the department and,
15 except for a credit under (f) of this section, within six months of the completion of
16 the exploration activity, claim the credit and submit information sufficient to
17 demonstrate to the department's satisfaction that the claimed exploration expenditures
18 qualify under this section;

19 (2) an explorer shall agree, in writing,

20 (A) to notify the Department of Natural Resources, within 30
21 days after completion of seismic or geophysical data processing, completion
22 of [A] well drilling, or filing of a claim for credit, whichever is the latest, for
23 which exploration costs are claimed, of the date of completion and submit a
24 report to that department describing the processing sequence and providing a
25 list of data sets available; [IF, UNDER (c)(2)(B) OF THIS SECTION, AN
26 EXPLORER SUBMITS A CLAIM FOR A CREDIT FOR EXPENDITURES
27 FOR AN EXPLORATION WELL THAT IS LOCATED WITHIN THREE
28 MILES OF A WELL ALREADY DRILLED FOR OIL AND GAS, IN
29 ADDITION TO THE SUBMISSIONS REQUIRED UNDER (1) OF THIS
30 SUBSECTION, THE EXPLORER SHALL SUBMIT THE INFORMATION
31 NECESSARY FOR THE COMMISSIONER OF NATURAL RESOURCES

1 TO EVALUATE THE VALIDITY OF THE EXPLORER'S CLAIM THAT
2 THE WELL IS DIRECTED AT A DISTINCTLY SEPARATE
3 EXPLORATION TARGET, AND THE COMMISSIONER OF NATURAL
4 RESOURCES SHALL, UPON RECEIPT OF ALL EVIDENCE
5 SUFFICIENT FOR THE COMMISSIONER TO EVALUATE THE
6 EXPLORER'S CLAIM, MAKE THAT DETERMINATION WITHIN 60
7 DAYS;]

8 (B) to provide to the Department of Natural Resources, within
9 30 days after the date of a request, unless a longer period is provided by the
10 Department of Natural Resources, specific data sets, ancillary data, and
11 reports identified in (A) of this paragraph; in this subparagraph, well data
12 include all derivative products, results, and copies of data collected and
13 data analyses for the well, including well logs; sample analyses;
14 geophysical and velocity data including vertical seismic profiles and
15 check shot surveys; and tangible material including, for each whole core
16 collected, a lengthwise cut slab that is at least 1/3 of the whole core
17 volume, and representative samples, as specified by the Department of
18 Natural Resources, of other gaseous, liquid, or solid material collected
19 from drilling or testing the well;

20 (C) that, notwithstanding any provision of AS 38, information
21 provided under this paragraph will be held confidential by the Department of
22 Natural Resources for 10 years following the completion date, at which time
23 that department will release the information after 30 days' public notice;

24 (3) if more than one explorer holds an interest in a well or seismic
25 exploration, each explorer may claim an amount of credit that is proportional to the
26 explorer's cost incurred;

27 (4) the department may exercise the full extent of its powers as though
28 the explorer were a taxpayer under this title, in order to verify that the claimed
29 expenditures are qualified exploration expenditures under this section; and

30 (5) if the department is satisfied that the explorer's claimed
31 expenditures are qualified under this section and that all data required to be

1 submitted under this section have been submitted, the department shall issue to the
2 explorer a production tax credit certificate for the amount of credit to be allowed
3 against production taxes levied by AS 43.55.011(e) or (f); the credit is available for
4 immediate use; notwithstanding any contrary provision of AS 38, AS 40.25.100,
5 or AS 43.05.230, the following information is not confidential:

6 (A) the explorer's name;

7 (B) the date of the application;

8 (C) the location of the well or seismic exploration;

9 (D) the date of the department's issuance of the certificate;

10 and

11 (E) the date on which the information required to be
12 submitted under this section will be released [DUE UNDER
13 AS 43.55.011(e) OR (f)].

14 * Sec. 33. AS 43.55.025(g) is amended to read:

15 (g) An explorer, other than an entity that is exempt from taxation under
16 this chapter, may transfer, convey, or sell its production tax credit certificate to any
17 person, and any person who receives a production tax credit certificate may also
18 transfer, convey, or sell the certificate.

19 * Sec. 34. AS 43.55.025(i) is repealed and reenacted to read:

20 (i) For a production tax credit under this section,

21 (1) a credit may not be applied to reduce a taxpayer's tax liability
22 under AS 43.55.011(e) or (f) below zero for a calendar year; and

23 (2) an amount of the production tax credit in excess of the amount that
24 may be applied for a calendar year under this subsection may be carried forward and
25 applied against the taxpayer's tax liability under AS 43.55.011(e) or (f) in one or more
26 later calendar years.

27 * Sec. 35. AS 43.55.025(k) is amended by adding a new paragraph to read:

28 (4) "preexisting well" means a well that was spudded more than 540
29 days but less than 35 years before the date on which the exploration well to which it
30 is compared is spudded.

31 * Sec. 36. AS 43.55.025 is amended by adding a new subsection to read:

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(I) Subject to the terms and conditions of this section, if a claim is filed under (I)(1) of this section before January 1, 2016, a credit against the production tax levied by AS 43.55.011(e) or (I) is allowed in an amount equal to five percent of an eligible expenditure under this subsection incurred for seismic exploration performed before July 1, 2003. To be eligible under this subsection, an expenditure must

(1) have been for seismic exploration that

(A) obtained data that the commissioner of natural resources considers to be in the best interest of the state to acquire for public distribution; and

(B) was conducted outside the boundaries of a production unit; however, the amount of the expenditure that is otherwise eligible under this section is reduced proportionately by the portion of the seismic exploration activity that crossed into a production unit; and

(2) qualify under (b)(3) of this section.

* Sec. 37. AS 43.55.025 is amended by adding a new subsection to read:

(m) Subject to appropriations made by law, if and to the extent that purchase of transferable tax credits by the Alaska Retirement Management Board is authorized by law, the department shall issue a cash refund to the Alaska Retirement Management Board for a transferable tax credit originally issued to an explorer under (i) of this section and purchased by the Alaska Retirement Management Board.

* Sec. 38. AS 43.55.030(a) is amended to read:

(a) A producer that produces oil or gas from a lease or proper', in the state during a calendar year, whether or not any tax payment is due under AS 43.55.020(a) for that oil or gas, [THE PERSON PAYING THE TAX] shall file with the department on March 31 of the following year [FOLLOWING THE CALENDAR YEAR FOR WHICH THE TAX WAS LEVIED] a statement, under oath, in a form prescribed by the department, giving, with other information required, the following:

(1) a description, of each lease or property from which [THE] oil or [AND] gas was [WERE] produced, by name, legal description, lease number, or accounting codes assigned by the department;

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

3 (3) the gross amount of oil and the gross amount of gas produced from
4 each lease or property, and the percentage of the gross amount of oil and gas owned
5 by the [EACH] producer [FOR WHOM THE TAX IS PAID];

6 (4) the gross value at the point of production of the oil and of the gas
7 produced from each lease or property owned by the [EACH] producer and the costs
8 of transportation of the oil and gas [FOR WHOM THE TAX IS PAID];

9 (5) the name of the first purchaser and the price received for the oil
10 and for the gas, unless relieved from this requirement in whole or in part by the
11 department; [AND]

12 (6) the producer's qualified capital expenditures, as defined in
13 AS 43.55.023, other lease expenditures [AND ADJUSTMENTS AS
14 CALCULATED] under AS 43.55.165, and adjustments or other payments or
15 credits under AS 43.55.170;

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

18 (8) any claims for tax credits to be applied; and

19 (9) calculations showing the amounts, if any, that were or are due
20 under AS 43.55.020(a) and interest on any underpayment or overpayment
21 [AS 43.55.160 - 43.55.170].

22 * Sec. 39. AS 43.55.030(d) is amended to read:

23 (d) Reports required under this section [BY OR ON BEHALF OF THE
24 PRODUCER] are delinquent the first day following the day the report is due. The
25 person required to file the report is liable for a penalty, as determined by the
26 department under standards adopted in regulation by the department, of not
27 more than \$1,000 for each day the person fails to file the report at the time
28 required. The penalty is in addition to the penalties in AS 43.05.220 and
29 43.05.290 and is assessed, collected, and paid in the same manner as a tax
30 delinquency under this title. In this subsection, "report" includes a statement."

31 * Sec. 40. AS 43.55.030 is amended by adding new subsections to read:

1 (e) An explorer or producer that incurs a lease expenditure under
2 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar
3 year but does not produce oil or gas from a lease or property in the state during the
4 calendar year shall file with the department on March 31 of the following year a
5 statement, under oath, in a form prescribed by the department, giving, with other
6 information required, the following:

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

10 (2) if the explorer or producer receives a payment or credit under
11 AS 43.55.170, calculations showing whether the explorer or producer is liable for a
12 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount.

13 (f) The department may require a producer, an explorer, or an operator of a
14 lease or property to file monthly reports, as applicable, of

15 (1) the amounts and gross value at the point of production of oil and
16 gas produced;

17 (2) transportation costs of the oil and gas;

18 (3) any unscheduled interruption of, or reduction in the rate of, oil or
19 gas production;

20 (4) lease expenditures and adjustments under AS 43.55.165 and
21 43.55.170;

22 (5) joint interest billings;

23 (6) contracts for the sale or transportation of oil or gas;

24 (7) information and calculations used in determining monthly
25 installment payments of estimated tax under AS 43.55.020(a); and

26 (8) other records and information the department considers necessary
27 for the administration of this chapter.

28 * Sec. 41. AS 43.55.040 is amended to read:

29 **Sec. 43.55.040. Powers of Department of Revenue.** Except as provided in
30 AS 43.05.405 - 43.05.499, the department may

31 (1) require a person engaged in production and the agent or employee

1 of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil
2 or gas to furnish, whether by the filing of regular statements or reports or otherwise,
3 additional information that is considered by the department as necessary to compute
4 the amount of the tax; notwithstanding any contrary provision of law, the disclosure
5 of additional information under this paragraph to the producer obligated to pay the tax
6 does not violate AS 40.25.100(a) or AS 43.05.230(a); before disclosing information
7 under this paragraph that is otherwise required to be held confidential under
8 AS 40.25.100(a) or AS 43.05.230(a), the department shall

9 (A) provide the person that furnished the information a
10 reasonable opportunity to be heard regarding the proposed disclosure and the
11 conditions to be imposed under (B) of this paragraph; and

12 (B) impose appropriate conditions limiting

13 (i) access to the information to those legal counsel,
14 consultants, employees, officers, and agents of the producer who have
15 a need to know that information for the purpose of determining or
16 contesting the producer's tax obligation; and

17 (ii) the use of the information to use for that purpose;

18 (2) examine the books, records, and files of the [SUCH A] person;

19 (3) conduct hearings and compel the attendance of witnesses and the
20 production of books, records, and papers of any person; [AND]

21 (4) make an investigation or hold an inquiry that is considered
22 necessary to a disclosure of the facts as to

23 (A) the amount of production from any oil or gas location, or
24 of a company or other producer of oil or gas; and

25 (B) the rendition of the oil and gas for taxing purposes;

26 (5) require a producer, an explorer, or an operator of a lease or
27 property to file reports and copies of records that the department considers
28 necessary to forecast state revenue under this chapter; in the case of reports and
29 copies of records relating to proposed, expected, or approved unit expenditures
30 for a unit for which one or more working interest owners other than the
31 operator have authority to approve unit expenditures, the required reports and

1 copies of records are limited to those reports or copies of records that constitute
2 or disclose communications between the operator and the working interest
3 owners relating to unit budget matters; and

4 (6) assess against a person required under this section to file a
5 report, statement, or other document a penalty, as determined by the
6 department under standards adopted in regulation by the department, of not
7 more than \$1,000 for each day the person fails to file the report, statement, or
8 other document after notice by the department; the penalty is in addition to any
9 penalties under AS 43.05.220 and 43.05.290 and is assessed, collected, and paid
10 in the same manner as a tax deficiency under this title; the penalty shall bear
11 interest at the rate specified under AS 43.05.225(1).

12 * Sec. 42. AS 43.55 is amended by adding a new section to read:

13 Sec. 43.55.075. **Limitation on assessment and amended returns.** (a) Except
14 as provided in AS 43.05.260(c), the amount of a tax imposed by this chapter must be
15 assessed within four years after the latest return was filed.

16 (b) A decision of a regulatory agency, court, or other body with authority to
17 resolve disputes that results in a retroactive change to a lease expenditure, to an
18 adjustment to a lease expenditure, to costs of transportation, to sale price, to
19 prevailing value, or to consideration of quality differentials relating to the
20 commingling of oils has a corresponding effect, either an increase or decrease, as
21 applicable, on the production tax value of oil or gas or the amount or availability of a
22 tax credit as determined under this chapter. For purposes of this section, a change to a
23 lease expenditure includes a change in the categorization of a lease expenditure as a
24 qualified capital expenditure or as not a qualified capital expenditure. The producer
25 shall

26 (1) within 60 days after the change, notify the department in writing;
27 and

28 (2) within 120 days after the change, file amended returns covering all
29 periods affected by the change, unless the department agrees otherwise or a stay is in
30 place that affects the filing or payment, regardless of the pendency of appeals of the
31 decision.

1 (c) If an alteration in or modification of a producer's federal income tax return
2 or a recomputation of the producer's federal income tax or determination of
3 deficiency occurs that affects the amount of a tax imposed on the producer under this
4 chapter, the producer shall

5 (1) within 60 days after the final determination of the alteration,
6 modification, recomputation, or deficiency, notify the department in writing; and

7 (2) within 120 days after the final determination of the alteration,
8 modification, recomputation, or deficiency, file amended returns covering all affected
9 periods.

10 (d) In this section,

11 (1) "qualified capital expenditure" has the meaning given in
12 AS 43.55.023;

13 (2) "return" includes a report, a statement, and an amended return,
14 report, or statement.

15 * Sec. 43. AS 43.55.110 is amended by adding new subsections to read:

16 (e) The department may require that returns, statements, reports, notifications,
17 and applications filed under this chapter be filed electronically in a form and manner
18 approved or prescribed by the department.

19 (f) The department may require that payments required under this chapter be
20 made electronically in a form and manner approved or prescribed by the department.

21 (g) Notwithstanding AS 44.62, the department may issue, for the information
22 and guidance of producers, explorers, and other interested persons, advisory bulletins
23 stating the department's interpretation of provisions of this chapter and of regulations
24 adopted under this chapter. Unless otherwise provided by the department by
25 regulation, interpretations stated in the advisory bulletins are not binding on the
26 department or others.

27 * Sec. 44. AS 43.55.160(a) is amended to read:

28 (a) Except as provided in (b) of this section, for the purposes of

29 [(1)] AS 43.55.011(c), the annual production tax value of the taxable

30 (1) [(A)] oil and gas produced during a calendar year from leases or
31 properties in the state that include land north of 68 degrees North latitude is the gross

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

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

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

21 (4) [(D)] gas produced during a calendar year from a lease or property
22 in the Cook Inlet sedimentary basin is the gross value at the point of production of the
23 gas taxable under AS 43.55.011(e) and produced by the producer from that lease or
24 property, less the producer's lease expenditures under AS 43.55.165 for the calendar
25 year applicable to the gas produced by the producer from that lease or property, as
26 adjusted under AS 43.55.170;

27 (5) gas produced during a calendar year from a lease or property
28 outside the Cook Inlet sedimentary basin and used in the state is the gross value
29 at the point of production of that gas taxable under AS 43.55.011(e) and
30 produced by the producer from that lease or property, less the producer's lease
31 expenditures under AS 43.55.165 for the calendar year applicable to that gas

1 produced by the producer from that lease or property, as adjusted under
2 AS 43.55.170

3 [(2) AS 43.55.011(g), THE MONTHLY PRODUCTION TAX
4 VALUE OF THE TAXABLE

5 (A) OIL AND GAS PRODUCED DURING A MONTH
6 FROM LEASES OR PROPERTIES IN THE STATE THAT INCLUDE
7 LAND NORTH OF 68 DEGREES NORTH LATITUDE IS THE GROSS
8 VALUE AT THE POINT OF PRODUCTION OF THE OIL AND GAS
9 TAXABLE UNDER AS 43.55.011(g) AND PRODUCED BY THE
10 PRODUCER FROM THOSE LEASES OR PROPERTIES, LESS 1/12 OF
11 THE PRODUCER'S LEASE EXPENDITURES UNDER AS 43.55.165 FOR
12 THE CALENDAR YEAR APPLICABLE TO THE OIL AND GAS
13 PRODUCED BY THE PRODUCER FROM THOSE LEASES OR
14 PROPERTIES, AS ADJUSTED UNDER AS 43.55.170;

15 (B) OIL AND GAS PRODUCED DURING A MONTH
16 FROM LEASES OR PROPERTIES IN THE STATE OUTSIDE THE COOK
17 INLET SEDIMENTARY BASIN, NO PART OF WHICH IS NORTH OF 68
18 DEGREES NORTH LATITUDE, IS THE GROSS VALUE AT THE POINT
19 OF PRODUCTION OF THE OIL AND GAS TAXABLE UNDER
20 AS 43.55.011(g) AND PRODUCED BY THE PRODUCER FROM THOSE
21 LEASES OR PROPERTIES, LESS 1/12 OF THE PRODUCER'S LEASE
22 EXPENDITURES UNDER AS 43.55.165 FOR THE CALENDAR YEAR
23 APPLICABLE TO THE OIL AND GAS PRODUCED BY THE PRODUCER
24 FROM THOSE LEASES OR PROPERTIES, AS ADJUSTED UNDER
25 AS 43.55.170;

26 (C) OIL PRODUCED DURING A MONTH FROM A
27 LEASE OR PROPERTY IN THE COOK INLET SEDIMENTARY BASIN
28 IS THE GROSS VALUE AT THE POINT OF PRODUCTION OF THE OIL
29 TAXABLE UNDER AS 43.55.011(g) AND PRODUCED BY THE
30 PRODUCER FROM THAT LEASE OR PROPERTY, LESS 1/12 OF THE
31 PRODUCER'S LEASE EXPENDITURES UNDER AS 43.55.165 FOR THE

1 CALENDAR YEAR APPLICABLE TO THE OIL PRODUCED BY THE
2 PRODUCER FROM THAT LEASE OR PROPERTY, AS ADJUSTED
3 UNDER AS 43.55.170;

4 (D) GAS PRODUCED DURING A MONTH FROM A
5 LEASE OR PROPERTY IN THE COOK INLET SEDIMENTARY BASIN
6 IS THE GROSS VALUE AT THE POINT OF PRODUCTION OF THE GAS
7 TAXABLE UNDER AS 43.55.011(g) AND PRODUCED BY THE
8 PRODUCER FROM THAT LEASE OR PROPERTY, LESS 1/12 OF THE
9 PRODUCER'S LEASE EXPENDITURES UNDER AS 43.55.165 FOR THE
10 CALENDAR YEAR APPLICABLE TO THE GAS PRODUCED BY THE
11 PRODUCER FROM THAT LEASE OR PROPERTY, AS ADJUSTED
12 UNDER AS 43.55.170].

13 * Sec. 45. AS 43.55.160(e) is amended to read:

14 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that
15 would otherwise be deductible by a producer in a calendar year but whose deduction
16 would cause an annual production tax value calculated under (a) [(a)(1)] of this
17 section of taxable oil or gas produced during the calendar year to be less than zero
18 may be used to establish a carried-forward annual loss under AS 43.55.023(b). In this
19 subsection, "producer" includes "explorer."

20 * Sec. 46. AS 43.55.165(a) is amended to read:

21 (a) Except as provided under (c) and (e) [(c) - (e)] of this section, for the
22 purposes of AS 43.55.160, a producer's lease expenditures for a calendar year are the
23 ordinary and necessary costs upstream of the point of production of oil and gas that
24 are incurred during the calendar year by the producer after March 31, 2006, and that
25 are direct costs of exploring for, developing, or producing oil or gas deposits located
26 within the producer's leases or properties in the state or, in the case of land in which
27 the producer does not own a working interest, that are direct costs of exploring for oil
28 or gas deposits located within other land in the state. In determining whether costs are
29 lease expenditures, the department shall consider, among other factors,

30 (1) the typical industry practices and standards in the state that
31 determine the costs, other than items listed in (e) of this section, that an operator is

1 allowed to bill a working interest owner that is not the operator, under unit operating
2 agreements or similar operating agreements that were in effect before December 2,
3 2005, and were subject to negotiation with at least one working interest owner with
4 substantial bargaining power, other than the operator; and

5 (2) the standards adopted by the Department of Natural Resources that
6 determine the costs, other than items listed in (e) of this section, that a lessee is
7 allowed to deduct from revenue in calculating net profits under a lease issued under
8 AS 38.05.180(f)(3)(B), (D), or (E).

9 * Sec. 47. AS 43.55.165(c) is repealed and reenacted to read:

10 (c) Subject to (g) and (h) of this section, if the department finds that the
11 pertinent provisions of a unit operating agreement or similar operating agreement are
12 substantially consistent with the department's determinations and standards under (a)
13 of this section concerning whether costs are lease expenditures and, in addition, finds
14 that at least one working interest owner party to the agreement, other than the
15 operator, with substantial incentive and ability to effectively audit billings under the
16 agreement, in fact is effectively auditing billings under the agreement, the department
17 may authorize or require a producer, subject to conditions prescribed under
18 regulations adopted by the department, to treat as that portion of its lease expenditures
19 for a calendar year applicable to oil and gas produced from a lease or property in the
20 state only

21 (1) the costs, other than items listed in (e) of this section, that are
22 incurred by the operator during the calendar year and that

23 (A) are billed to the producer by the operator under the
24 agreement to which that lease or property is subject and are either not disputed
25 by a working interest owner party to the agreement or are finally determined
26 to be properly billable as a result of dispute resolution; or

27 (B) for a producer that is the operator, would be billable to the
28 producer by the operator in accordance with the terms of the agreement to
29 which that lease or property is subject if the producer were not the operator;
30 and

31 (2) a reasonable percentage, as determined under regulations adopted

1 by the department, of the costs that are billed under (1) of this subsection as an
2 allowance for overhead expenses directly related to exploring for, developing, and
3 producing oil or gas deposits located within the lease or property, to the extent those
4 expenses are not billable under the agreement.

5 * Sec. 48. AS 43.55.165(e) is amended to read:

6 (c) For purposes of this section, lease expenditures do not include

7 (1) depreciation, depletion, or amortization;

8 (2) oil or gas royalty payments, production payments, lease profit
9 shares, or other payments or distributions of a share of oil or gas production, profit, or
10 revenue;

11 (3) taxes based on or measured by net income;

12 (4) interest or other financing charges or costs of raising equity or
13 debt capital;

14 (5) acquisition costs for a lease or property or exploration license;

15 (6) costs arising from fraud, wilful misconduct, [OR] gross
16 negligence, criminal negligence, violation of law, including a violation of 33
17 U.S.C. 1319(e)(1) or 1321(b)(3) (Clean Water Act), or failure to comply with an
18 obligation under a lease, permit, or license issued by the state or federal
19 government;

20 (7) fines or penalties imposed by law;

21 (8) costs of arbitration, litigation, or other dispute resolution activities
22 that involve the state or concern the rights or obligations among owners of interests
23 in, or rights to production from, one or more leases or properties or a unit;

24 (9) costs incurred in organizing a partnership, joint venture, or other
25 business entity or arrangement;

26 (10) amounts paid to indemnify the state; the exclusion provided by
27 this paragraph does not apply to the costs of obtaining insurance or a surety bond
28 from a third-party insurer or surety;

29 (11) surcharges levied under AS 43.55.201 or 43.55.300;

30 (12) for a transaction that is an internal transfer or is otherwise not an
31 arm's length transaction, expenditures incurred that are in excess of fair market value;

1 (13) an expenditure incurred to purchase an interest in any
2 corporation, partnership, limited liability company, business trust, or any other
3 business entity, whether or not the transaction is treated as an asset sale for federal
4 income tax purposes;

5 (14) a tax levied under AS 43.55.011;

6 (15) [THE PORTION OF] costs incurred for dismantlement, removal,
7 surrender, or abandonment of a facility, pipeline, well pad, platform, or other
8 structure, or for the restoration of a lease, field, unit, area, tract of land, body of
9 water, or right-of-way in conjunction with dismantlement, removal, surrender, or
10 abandonment [, THAT IS ATTRIBUTABLE TO PRODUCTION OF OIL OR GAS
11 OCCURRING BEFORE APRIL 1, 2006; THE PORTION IS CALCULATED AS A
12 RATIO OF THE AMOUNT OF OIL AND GAS PRODUCTION, IN BARRELS OF
13 OIL EQUIVALENT, ASSOCIATED WITH THE FACILITY, PIPELINE, WELL
14 PAD, PLATFORM, OTHER STRUCTURE, LEASE, FIELD, UNIT, AREA, BODY
15 OF WATER, OR RIGHT-OF-WAY OCCURRING BEFORE APRIL 1, 2006, TO
16 THE TOTAL AMOUNT OF OIL AND GAS PRODUCTION, IN BARRELS OF
17 OIL EQUIVALENT, ASSOCIATED WITH THAT FACILITY, PIPELINE, WELL
18 PAD, PLATFORM, OTHER STRUCTURE, LEASE, FIELD, UNIT, AREA, BODY
19 OF WATER, OR RIGHT-OF-WAY THROUGH THE END OF THE CALENDAR
20 MONTH BEFORE COMMENCEMENT OF THE DISMANTLEMENT,
21 REMOVAL, SURRENDER, OR ABANDONMENT]; a cost is not excluded under
22 this paragraph if the dismantlement, removal, surrender, or abandonment for which
23 the cost is incurred is undertaken for the purpose of replacing, renovating, or
24 improving the facility, pipeline, well pad, platform, or other structure; [FOR THE
25 PURPOSES OF THIS PARAGRAPH, "BARREL OF OIL EQUIVALENT" MEANS

26 (A) IN THE CASE OF OIL, ONE BARREL;

27 (B) IN THE CASE OF GAS, 6,000 CUBIC FEET;]

28 (16) cost incurred for containment, control, cleanup, or removal in
29 connection with any unpermitted release of oil or a hazardous substance and any
30 liability for damages imposed on the producer or explorer for that unpermitted
31 release; this paragraph does not apply to the cost of developing and maintaining an oil

1 discharge prevention and contingency plan under AS 46.04.030;

2 (17) costs incurred to satisfy a work commitment under an exploration
3 license under AS 38.05.132;

4 (18) that portion of expenditures, that would otherwise be qualified
5 capital expenditures, as defined in AS 43.55.023 [AS 43.55.023(k)], incurred during a
6 calendar year that are less than the product of \$0.30 multiplied by the total taxable
7 production from each lease or property, in BTU equivalent barrels, during that
8 calendar year, except that, when a portion of a calendar year is subject to this
9 provision, the expenditures and volumes shall be prorated within that calendar year;

10 (19) costs incurred to construct, acquire, or operate a refinery or
11 crude oil topping plant, regardless of whether the products of the refinery or
12 topping plant are used in oil or gas exploration, development, or production
13 operations; however, if a producer owns a refinery or crude oil topping plant
14 that is located on or near the premises of the producer's lease or property in the
15 state and that processes the producer's oil produced from that lease or property
16 into a product that the producer uses in the operation of the lease or property in
17 drilling for or producing oil or gas, the producer's lease expenditures include the
18 amount calculated by subtracting from the fair market value of the product used
19 the prevailing value, as determined under AS 43.55.020(f), of the oil that is
20 processed;

21 (20) costs of lobbying, public relations advertising, or policy
22 advocacy.

23 * Sec. 49, AS 43.55.165(h) is amended to read:

24 (h) The department shall adopt regulations that provide for reasonable
25 methods of allocating costs between oil and gas, between gas subject to
26 AS 43.55.011(o) and other gas, and between leases or properties in those
27 circumstances where an allocation of costs is required to determine [THE
28 DETERMINATION OF THE] lease expenditures that are costs of exploring for,
29 developing, or producing oil deposits or costs of exploring for, developing, or
30 producing gas deposits [APPLICABLE TO OIL OR TO GAS], or that are costs of
31 exploring for, developing, or producing oil or gas deposits located within

1 [APPLICABLE TO OIL AND GAS PRODUCED FROM] different leases or
2 properties [, REQUIRES AN ALLOCATION OF COSTS].

3 * Sec. 50. AS 43.55.170(a) is amended to read:

4 (a) Unless the payment or credit has already been subtracted in calculating
5 billable or billed costs under AS 43.55.165(c) [OR (d)], a producer's lease
6 expenditures under AS 43.55.165 must be adjusted by subtracting payments or
7 credits, other than tax credits, received by the producer or by an operator acting for
8 the producer for

9 (1) the use by another person of a production facility in which the
10 producer has an ownership interest or the management by the producer of a
11 production facility under a management agreement providing for the producer to
12 receive a management fee;

13 (2) a reimbursement or similar payment that offsets the producer's
14 lease expenditures, including an insurance recovery from a third-party insurer and a
15 payment from the state or federal government for reimbursement of the producer's
16 upstream costs, including costs for gathering, separating, cleaning, dehydration,
17 compressing, or other field handling associated with the production of oil or gas
18 upstream of the point of production;

19 (3) the sale or other transfer of

20 (A) an asset, including geological, geophysical, or well data or
21 interpretations, acquired by the producer as a result of a lease expenditure or
22 an expenditure that would be a lease expenditure if it were incurred after
23 March 31, 2006; for purposes of this subparagraph,

24 (i) if a producer removes from the state, for use outside
25 the state, an asset described in this subparagraph, the value of the asset
26 at the time it is removed is considered a payment received by the
27 producer for sale or transfer of the asset;

28 (ii) for a transaction that is an internal transfer or is
29 otherwise not an arm's length transaction, if the sale or transfer of the
30 asset is made for less than fair market value, the amount subtracted
31 must be the fair market value; and

1 (B) oil or gas

2 (i) that is not considered produced from a lease or
3 property under AS 43.55.020(e); and

4 (ii) the cost of acquiring which is a lease expenditure
5 incurred by the person that acquires the oil or gas.

6 * Sec. 51. AS 43.55 is amended by adding a new section to article 4 to read:

7 **Sec. 43.55.890. Disclosure of tax information.** Subject to AS 40.25.100 and
8 AS 43.05.230(c), the department may publish the following information under this
9 chapter, if aggregated among three or more producers or explorers, showing by month
10 or calendar year and by lease or property, unit, or area of the state:

11 (1) the amount of oil or gas production;

12 (2) the amount of taxes levied under this chapter or paid under this
13 chapter;

14 (3) the effective tax rates under this chapter;

15 (4) the gross value of oil or gas at the point of production;

16 (5) the transportation costs for oil or gas;

17 (6) qualified capital expenditures under AS 43.55.023(k);

18 (7) exploration expenditures under AS 43.55.025;

19 (8) production tax values of oil or gas under AS 43.55.160;

20 (9) lease expenditures under AS 43.55.165;

21 (10) adjustments to lease expenditures under AS 43.55.170;

22 (11) tax credits applicable or potentially applicable against taxes
23 levied by this chapter.

24 * Sec. 52. AS 43.55.900 is amended by adding new paragraphs to read:

25 (22) "producer" means an owner of an operating right, operating
26 interest, or working interest in a mineral interest in oil or gas;

27 (23) "unit" means a group of tracts of land that is

28 (A) subject to a cooperative or a unit plan of development or
29 operation that has been certified by the commissioner of natural resources
30 under AS 38.05.180(p);

31 (B) subject to a cooperative or a unit plan of development or

1 operation that has been certified by the United States Secretary of the Interior
2 under 30 U.S.C. 226(m);

3 (C) subject to an agreement of the owners of interests in the
4 tracts of land to validly integrate their interests to provide for the unitized
5 management, development, and operation of the tracts of land as a unit, within
6 the meaning of AS 31.05.110(a); or

7 (D) within the unit area of a unit created by order of the
8 Alaska Oil and Gas Conservation Commission under AS 31.05.110(b);

9 (24) "used in the state" means delivered for consumption as fuel in the
10 state, including as fuel consumed to generate electricity.

11 * Sec. 53. AS 43.55.160(c) and 43.55.165(d) are repealed.

12 * Sec. 54. The uncodified law of the State of Alaska is amended by adding a new section to
13 read:

14 APPLICABILITY. (a) Sections 14 - 26, 28 - 32, 34 - 38, 40, 44 - 50, and 53 of this
15 Act apply to oil and gas produced after December 31, 2007.

16 (b) Sections 38 and 40 of this Act apply to statements and reports under
17 AS 43.55.030(a), as amended by sec. 38 of this Act, and AS 43.55.030(e) and (f), as added
18 by sec. 40 of this Act, required to be filed after December 31, 2007.

19 (c) Sections 29 - 32 and 35 of this Act apply to exploration expenditures incurred for
20 work performed after December 31, 2006, that are the basis of tax credits that may be
21 claimed against taxes levied for oil and gas produced after December 31, 2007.

22 (d) AS 43.55.075(a), enacted by sec. 42 of this Act, applies to any tax liability under
23 AS 43.55 with respect to which the period of limitations on assessment under AS 43.05.260
24 had not expired before the effective date of secs. 13 and 42 of this Act.

25 (e) AS 43.55.020(i), enacted by sec. 24 of this Act, applies to any installment
26 payment due after the effective date of sec. 24 of this Act that is not paid timely.

27 (f) The penalty in AS 43.55.030(d), enacted by the amendment to AS 43.55.030(d) in
28 sec. 39 of this Act, applies to any report required to be filed after the effective date of sec. 39
29 of this Act that is not filed timely.

30 (g) The penalty in AS 43.55.040(6), enacted by the amendment to AS 43.55.040 in
31 sec. 41 of this Act, applies to any report, statement, or other document required to be filed

1 after the effective date of sec. 41 of this Act.

2 * Sec. 55. The uncodified law of the State of Alaska is amended by adding a new section to
3 read:

4 TRANSITION: ASSIGNMENT OF OIL AND GAS AUDITORS IN THE
5 DEPARTMENT OF REVENUE AND DEPARTMENT OF NATURAL RESOURCES.
6 Notwithstanding any contrary provision of law, employees employed as oil and gas auditors
7 performing production tax audits or as their immediate supervisors in the Department of
8 Revenue and employees employed as oil and gas auditors performing royalty audits,
9 including net profit share audits, or as their immediate supervisors in the Department of
10 Natural Resources are assigned to the exempt service in accordance with AS 39.25.110(42),
11 added by sec. 10 of this Act, and may not be included in the general government or
12 supervisory collective bargaining units of state employees except as provided in this section.
13 All oil and gas auditors performing production tax audits or royalty audits and their
14 immediate supervisors hired before the effective date of sec. 10 of this Act have the option of
15 (1) continuing in the general government or supervisory collective bargaining units and being
16 subject to their respective collective bargaining agreements; or (2) being removed from those
17 bargaining units. Those employees have 90 days from the effective date of sec. 10 of this Act
18 to exercise the option to continue in the collective bargaining units. The option taken under
19 this section by the employee is irrevocable. The employees choosing to be removed from
20 those bargaining units are removed after any notice period required by a collective
21 bargaining agreement.

22 * Sec. 56. The uncodified law of the State of Alaska is amended by adding a new section to
23 read:

24 TRANSITION: REGULATIONS. The Department of Natural Resources and the
25 Department of Revenue may proceed to adopt regulations to implement this Act. The
26 regulations take effect under AS 44.62 (Administrative Procedure Act), but not before the
27 effective date of the law implemented by the regulation.

28 * Sec. 57. The uncodified law of the State of Alaska is amended by adding a new section to
29 read:

30 RETROACTIVITY OF CERTAIN PROVISIONS OF THIS ACT. Sections 27 and
31 33 of this Act are retroactive to July 1, 2003.

- 1 * Sec. 58. Sections 14 - 26, 28 - 32, 34 - 38, 40, 44 - 50, and 53 of this Act take effect
2 January 1, 2008.
- 3 * Sec. 59. Except as provided in sec. 58 of this Act, this Act takes effect immediately under
4 AS 01.10.070(c).

STAKEHOLDERS

Estimated Financial Impacts of Various Approaches to Current (PPT) Provisions

November 8, 2007

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Base Tax Rate

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

<u>WC ANS Price</u>	<u>Average FY2008-2014 Amount Above / (Below) PPT (\$M)</u>		
	<u>HB 2001</u>	<u>House Oil & Gas</u>	<u>House Resources</u>
	25%	22.5%	25%
\$40	\$101	\$0	\$101
\$60	\$231	\$0	\$231
\$80	\$351	\$0	\$351
\$100	\$470	\$0	\$470
\$120	\$589	\$0	\$589

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Progressivity

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

WC ANS Price	Average FY2008-2014 Amount Above / (Below) PPT (\$M)		
	HB 2001	House Oil & Gas	House Resources
	\$30 Net Trigger 0.2% Rate Apply to Net	\$50 Gross Trigger 0.225% Rate Apply to Gross	\$30, \$40, \$50, \$60 Net 0.2%, 0.3%, 0.4%, 0.5% Apply to Gross
\$40	\$0	\$0	\$0
\$60	\$135	\$227	\$248
\$80	\$132	\$596	\$1,038
\$100	(\$16)	\$932	\$2,619
\$120	(\$261)	\$1,285	\$4,766

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

TAPS Tariff

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

<u>WC ANS Price</u>	<u>Average FY2008-2014 Amount Above / (Below) PPT (\$M)</u>		
	<u>HB 2001</u>	<u>House Oil & Gas</u>	<u>House Resources</u>
	FERC	FERC	Reasonable
\$40	\$0	\$0	\$53
\$60	\$0	\$0	\$53
\$80	\$0	\$0	\$53
\$100	\$0	\$0	\$53
\$120	\$0	\$0	\$53

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).



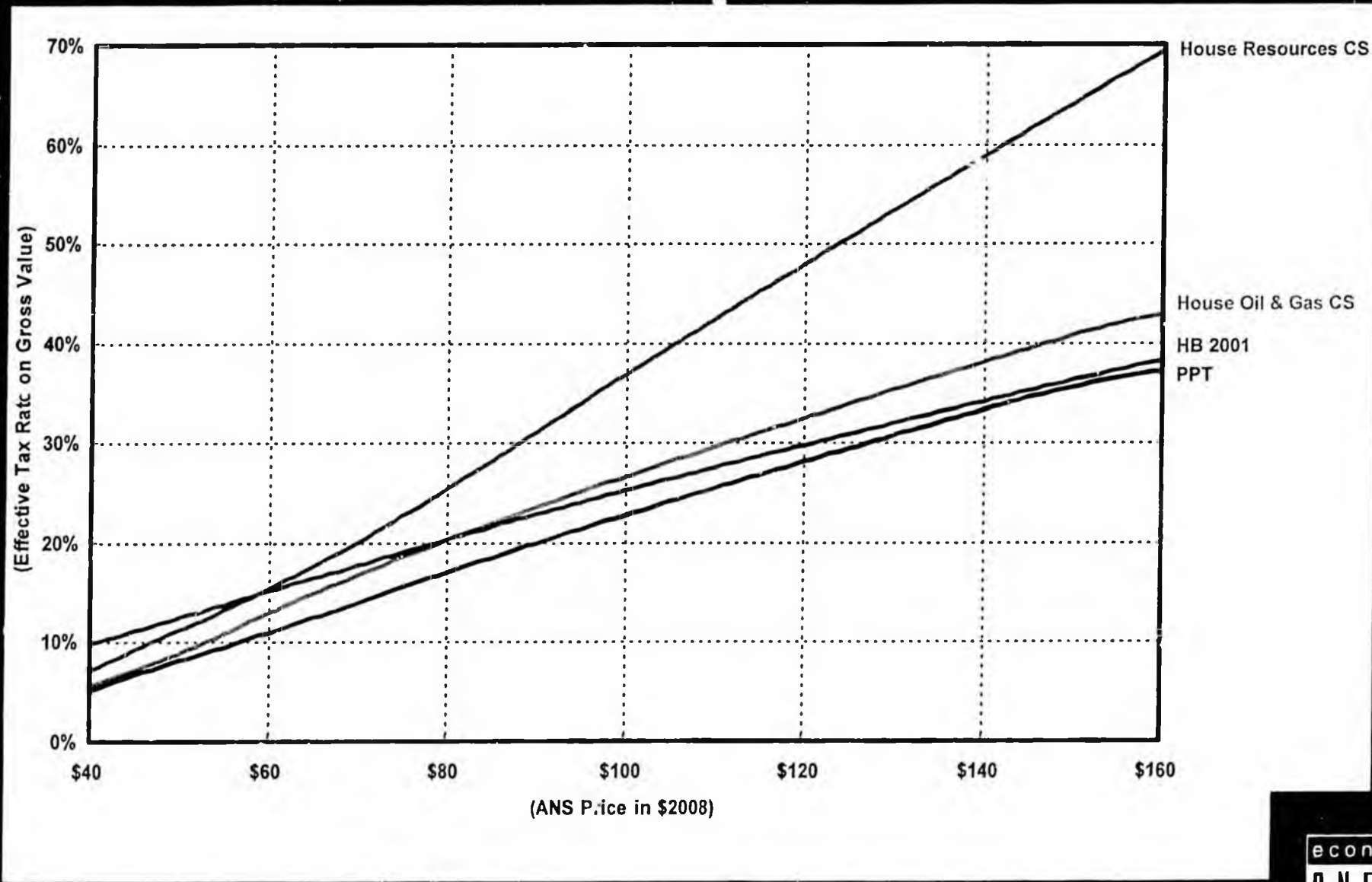
TIE Credits

Average FY2008-2014 Amount Above / (Below) PPT (\$M)

<u>WC ANS Price</u>	<u>Average FY2008-2014 Amount Above / (Below) PPT (\$M)</u>		
	<u>HB 2001</u>	<u>House Oil & Gas</u>	<u>House Resources</u>
	None	3 Years	3 Years
\$40	\$176	\$47	\$47
\$60	\$176	\$47	\$47
\$80	\$176	\$47	\$47
\$100	\$176	\$47	\$47
\$120	\$176	\$47	\$47

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Estimated Average Effective Tax Rate on Gross Taxable Value at Various West Coast ANS Price Levels (FY 2008-2014)



Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).



Estimated Average Effective Tax Rate, Government Shares and Revenue Impacts at Various West Coast ANS Price Levels (FY 2008-2014)

Average ANS West Coast Price in Real 2008 Dollars:	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
Effective Tax Rate on Gross Taxable Value (Percent)							
PPT	5.1%	10.9%	17.0%	22.7%	28.1%	33.2%	37.2%
HB 2001	9.9%	15.1%	20.3%	25.2%	29.7%	34.1%	38.2%
House Oil & Gas	5.6%	13.0%	20.3%	26.7%	32.5%	38.1%	43.0%
House Resources	7.2%	15.4%	25.4%	36.9%	48.0%	58.9%	69.6%
Total Government Share of Net Cash (Percent)							
PPT	60.5%	60.6%	62.7%	65.3%	67.8%	70.4%	72.2%
HB 2001	64.5%	63.5%	64.9%	66.8%	68.8%	70.9%	72.9%
House Oil & Gas	60.9%	62.0%	64.9%	67.7%	70.5%	73.3%	75.7%
House Resources	61.9%	63.5%	68.2%	74.1%	79.9%	85.7%	91.4%
Marginal Government Share of Net Cash (Percent)							
PPT	58.9%	63.7%	70.7%	75.9%	81.0%	86.2%	78.9%
HB 2001	59.7%	65.4%	70.7%	75.1%	79.3%	83.5%	84.9%
House Oil & Gas	83.5%	68.5%	74.1%	79.5%	84.8%	90.2%	85.1%
House Resources	61.5%	71.1%	86.6%	99.1%	110.2%	121.3%	132.4%
Annual Average Tax Difference Above/(Below) PPT (Nominal \$M)							
HB 2001	\$423	\$587	\$635	\$608	\$493	\$287	\$423
House Oil & Gas	\$42	\$288	\$638	\$965	\$1,313	\$1,680	\$2,301
House Resources	\$201	\$666	\$1,668	\$3,516	\$5,964	\$8,965	\$12,983

Note: Volumes per DOR's Fiscal Note to HB 2001 (as of November 7, 2007).

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>House Finance</u>
Base Rate	<i>AS 43.55.011 (e) & (g)</i>	<i>Bill Sections 15 & 17</i>			
Base Tax Rate		25%		25%	

Progressivity	<i>AS 43.55.011(g) & (h)</i>	<i>Bill Sections 17,18</i>		
\$/bbl Starting point	\$40 net	\$30 net	\$50 gross	\$30,40,50,60 net
Tax/\$ of Price Index	0.25%	0.20%	0.25%	.2,.3,.4,.5%
Average Value over	month	year	month	month
Applied to	net	net	gross	gross
Cap		25% of net	25% of gross	none

Gross Value Floor	<i>AS 43.55.011(f)</i>	<i>Bill Section 15, 16, 31-36, & 41-42</i>	
Base		Prudhoe; Kuparuk	
Rate		10%	
Credits further reduce floor tax?		No	

Investment Credits	<i>AS 43.55.023</i>	<i>Bill Section 26-28, 38-44 & 63</i>		
Investment Credits	Taken in year of investment	1/2 in each of two years	Taken in year of investment	Taken in year of investment
Loss Carry Forward Credits		25%		rate in (e) (25%)
Transitional Investment Credits	Yes	No	3 years of investment instead of 5	3 years of investment instead of 5

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>House Finance</u>
Exploration Credits	AS 43.55.025	Bill Section 36 - 44			
Rates		20; 40%		30;40%	
G&A Costs		bad acts I		bad acts I	
DNR approval required?		Always		Always	
Confidentiality of well data		2 years		2 years	
Pre-existing well		Two consecutive drilling seasons		Two consecutive drilling seasons	
"DNR TIE" Credits for pre 2003 seismic work?		5%		5%	

State Purchase of Credits	AS 43.55.023(f) & (g)	Bill Section 45 (AS 43.55.028)		
Paid from:	"appropriations made by law"	oil and gas credit fund, funded from production taxes	"appropriations made by law"	oil and gas credit fund, funded from production taxes
Annual dollar cap per taxpayer?	\$25 million	none	\$25 million	Yes (however ARM unlimited)
ARM Board Purchases?	n/a	n/a	n/a	yes

Allowable Lease Expenditures	AS 43.55.165	Bill Sections 52-64		
Use producer audits of operators?	Explicit	Explicit repealed; Implicit	Explicit	Explicit repealed; Implicit
Disallow bad acts II?	yes	add violation of law, lease or license	add violation of law, lease or license	add violation of law, [inc Clean Water Act] lease or license
Dispute resolution	except with state	except with state	except with state	no, other disallowances
DR&R Allowed?	Allocated	No	No	No
"Corrosion" Issue		\$0.30 + unscheduled events disallowed	\$0.30 + unscheduled events disallowed	
Field Topping Plants allowed?	Yes	No	No	No
Off Lease allowed	yes; other tests	yes; other tests	yes; other tests	No (also in-state)

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u> <i>AS 43.05.230 and royalty statutes</i>	<u>HB 2001 (ACES)</u> <i>Bill Sections 2-9,11-13, 49 & 61</i>	<u>House O&G</u>	<u>House Resources</u>	<u>House Finance</u>
Information					
forward looking information required	none	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.	information "necessary to forecast ... revenues under AS 43.55".	information "necessary to forecast ... revenues under AS 43.55". Penalty up to \$1000 a day.	
Disclosure of tax information	if aggregated to "prevent the identification of particular returns."	if aggregated other producers	if aggregated w/2 other producers	if aggregated w/2 other producers	
DNR sharing royalty information w/ DOR	limited ability	expanded ability	expanded ability	expanded ability	
DOR sharing tax information with DNR	limited ability	expanded ability	expanded ability	expanded ability	

Statute of Limitations *AS 43.05.260* *Bill Sections 1,14,50 new AS 43.55.075*

State assessment must be issued within	3 yrs	6 yrs	6 yrs	6 yrs
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DOR Auditors *As 39.25.100* *Bill Sections 10, 65, 67*

DOR & DNR auditors exempt employees?	no	yes	yes	yes
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Effective Date *Bill Section 64*

Generally	n/a	Jan 1 2008	Jan 1 2008	Jan 1 2007
Retroactive to April 1 2006	n/a	deferred maintenance issues	deferred maintenance issues	Loss carryforward, TIE limitations, most cost redefinitions

Summary Comparison between Various House Approaches to Production Tax

<u>Issue</u>	<u>Current Law</u>	<u>HB 2001 (ACES)</u>	<u>House O&G</u>	<u>House Resources</u>	<u>House Finance</u>
Downstream Costs <i>As 43.55.150</i>					
Reasonable v actual	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "and"	3 criteria linked by "or"	
<i>Prima facie</i> reasonable Taps Tariff	Filed TAPS tariff	Filed TAPS tariff	Filed TAPS tariff	FMV (TSM not adjudicated just and reasonable)	

TAPS
- interest
rates set at

Gas Ceilings thru 2022 <i>As 43.55.011</i>				
Where	CI	CI	non North Slope	CI + gas used in the state

Additional Penalties <i>new As 43.55.020</i>				
Penalty for under estimated payments	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	IRS Penalties (i.e. interest)	5% in addition to IRS Penalties (i.e. interest)

Intent Language				
overall intent of legislation	n/a	no	no	included
long standing interpretation of SOL	n/a	included	no	included
Half the money from certain retroactive applications to PERS and public education fund	n/a	no	no	included
tax savings from gas ceilings outside CI passed on to ultimate consumers	n/a	no	no	included

Alaska Oil and Gas Association



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TESTIMONY OF THE
ALASKA OIL AND GAS ASSOCIATION
TO THE HOUSE FINANCE COMMITTEE
REGARDING CSHB 2001(RES)

November 8, 2007

Mr. Chairman and Members of the Committee:

My name is Marilyn Crockett and I am the Executive Director of the Alaska Oil and Gas Association ("AOGA"). AOGA is the trade association for the oil and gas industry in Alaska. Our 17 members account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. Our membership includes Agrium, Alyeska Pipeline Service Co., and Alaska's instate refiners. It includes companies new to this state, hoping for the opportunity to explore. It includes companies that are active today and do not yet have production (but hope to in the future). And it includes companies that are producing today and have been producing here for years.

As one of its important functions, AOGA provides a forum for its members to consider regulatory and legislative proposals, and to reach agreement about industry positions on those proposals. Normally, to establish an AOGA position, a 5/6 vote is required. This ensures that, when AOGA voices a position, regulators and legislators can be assured that that position is the position of the overwhelming majority of Alaska's oil and gas industry.

But on tax issues, AOGA takes this approval process to the highest level. We take positions about taxes only if there is complete consensus in our Tax Committee about what is to be said. Every member receives a copy of each proposed statement on taxes while it is still only in draft form, and if any of them objects to something in a proposed statement, either that portion of the statement is rewritten to satisfy the objection, or else it is deleted. My testimony today has been developed and approved under this principle, with no dissent.

Throughout this special legislative session, individual companies have presented their views based on their operations and the impact of the proposed legislation to their individual companies. The role for AOGA is obviously different, and we have focused our testimony on two key areas.

First, we've strived to put into perspective the critical importance of continued and future industry investment needed to address the most significant issue facing Alaska's future—declining production to the State of Alaska.

Second, through AOGA's Tax Committee, we've provided very specific comments on the numerous technical components of the versions of the legislation before each committee. We've relied heavily on the expertise and experience of our Tax Committee members who have years of experience operating within the state's tax structure. Given the release of the House Resources Committee version of HB2001 just 1½ days ago, there simply hasn't been time for us to develop the quantitative assessment of the technical components in time for this morning's hearing. We are continuing our work in this area and will submit that analysis into the record as quickly as we can for your consideration.

We've heard it said repeatedly that our industry will "game the system" to take unfair advantage of the State — even to the point, some have asserted, of improperly claiming costs for lobbying, advertising or donations to Alaskan charities, despite assurances by the Administration that those costs are not allowed under the present law and will not be tolerated on audit. Accusations of "gaming the system" implies the companies will cheat on their taxes and cheat on the way they do business, if they think they can get away with it. Not only is that against the law, it is an insult to the integrity of the thousands of honest Alaskans who work in our industry.

Second, we all probably know, or know of, individuals who "game the system" a little bit when they report and pay their own income taxes to the IRS. They might pad a deduction, or fail to include cash income they got, or fudge their tax a little in some other way. To the extent someone might do this, it is because he or she feels the odds of being audited and caught by the IRS are small enough to make it worth taking that chance. But do you know anyone who would "game the system" if the chances of being audited by the IRS were 100 percent? Of course not. Well, oil companies are audited twice. First, by each other to ensure no unnecessary or inflated costs are charged to one another when they jointly operate a field. And these audits are every bit as aggressive as the IRS in making sure no costs are improperly included in the bills they have to pay. Second, oil company returns are audited for every state tax they report and pay to the State, for every tax period. The State's present oil and gas tax auditors are smart, experienced and professionally qualified, and we expect the new ones to be hired will be equally good.

Most recently, we hear it being said that the Gaffney Kline economic model shows Alaska can safely raise the production tax far beyond PPT's current levels without jeopardizing investments for the North Slope. I'm no expert, so I left their Capex Multiplier, Opex Multiplier and Production Multiplier at 100% so I wouldn't exaggerate the model's outputs. Then, when I plugged zero in as the value of the oil, the model came up with the totally unexpected result that the producer's internal rate of return is 156 percent. This was so incredible when I saw it, let me repeat it: the model shows an internal rate of return of 156% for the producer when you set oil prices at zero. Try it yourself. And, just as amazing, it shows the State's net present value to be \$1 billion at a price of zero. So this made me wonder what the model shows if I plugged zero in as the volume of oil being produced, instead of plugging it in as the price. The model still

calculated the same wonderful internal rate of return of 156% for the producer, and the State's net present value had actually increased to \$1.3 billion. If all activity on the North Slope were so spectacularly profitable even with no production or with oil prices of zero, then the whole world would be beating a path to Alaska's door to get a piece of that action. But the whole world is not on its way here, and this plain fact proves there must be something wrong.

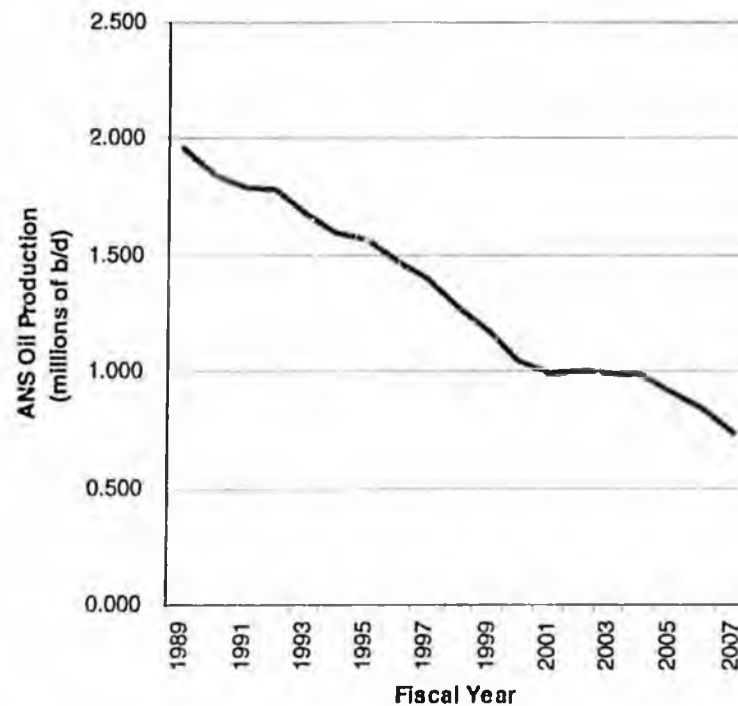
I'm not saying these surprising results prove the model is wrong. Instead, I'm saying that, if it is correct, then these results show there must be some very significant limitations as to the proper use of the model and the meaningfulness of its results. In the time since it was first demonstrated, we have repeatedly heard legislators and members of the public alike citing the model as proof that Alaska could raise its production tax rate to 50% or more of the "net value" without affecting investment. Such statements are not correct, and they reflect a serious misimpression about how the model can properly be used and about what it actually shows. In addition, the model appears to have inflated production volumes and has conveniently left out future operating and capital expenditures necessary to keep the well flowing, facility tie-in and operating costs from the rest of the infrastructure, future abandonment costs, etc. We find it very troubling that a model that is so narrow in its focus, and that considers only one type of investment opportunity in Alaska, is perpetuated to represent the total investment suite of opportunities available in Alaska.

If Alaska oil and gas opportunities are so profitable, according to the Gaffney Kline model, then why is production less than one third of its peak, and why have we only produced less than one quarter of the oil potential in Alaska? Even Pioneer and ENI have recently requested royalty relief for their developments. Doesn't that send a message on the challenges facing new explorers and future development of Alaska's resources? We believe that the focus needs to be on how to encourage the increasing investment needed to develop Alaska's resource potential. Increasing taxes will not help.

The realities that confront Alaska are these: First, nearly 90% of the discretionary money that the State is spending this fiscal year is coming from oil production, and the Department of Revenue ("DOR") predicts that oil revenues will account for over 80% of the State's unrestricted discretionary revenues through Fiscal Year 2013, and 70% or more of those revenues from FY 2014 to the end of its forecast period, FY 2017.¹ These percentages are before factoring in state revenues from a natural gas pipeline and from its associated natural gas production. Oil production has been, is today, and promises to remain the cornerstone of the finances of state government.

Second, production decline is eroding this cornerstone. On the next page is a graph showing how the average daily production rate for North Slope oil has become less and less since FY 1989. It is a historical fact that, on average from FY 1997 to FY 2007, North Slope production each year has been 6.2% less than the year before, while Cook Inlet oil production declined at an average of 8.0% a year.²

Third, it is going to cost billions and billions of dollars to slow this decline down. The North Slope's historical decline of 6% a year has occurred despite industry's investment of over

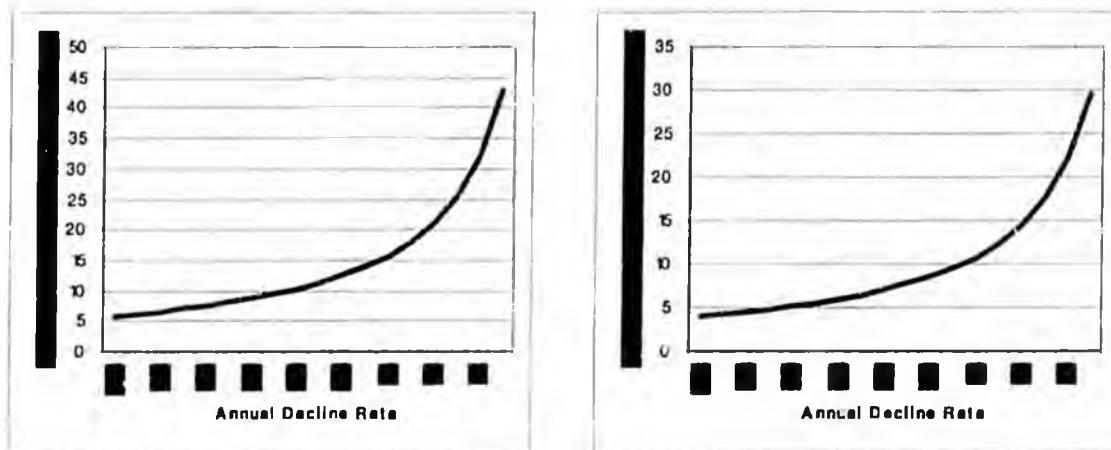


two billion dollars a year to produce more oil. Slowing the rate of decline below 6% will require each year massive increases beyond industry's already substantial, historic level of investment. We believe the investment level needs to increase to be over \$3 to \$4 billion to mitigate production decline. That is almost double the current level of investment being undertaken. Even the DOR's production forecast shows what increasing level of investment is needed. How do you attract the significant increase in investment needed? We don't believe increasing taxes will attract more investment, we believe it will slow down the investment levels needed. Increasing taxes will reduce the attractiveness of new projects and opportunities.

The difference between an ongoing decline of 6% a year and, for instance, 3% may not sound like much, but the difference for Alaska's future is profound. At present it seems the ultimate limit for North Slope oil production may be determined by the minimum capacity of TAPS to pump oil through the pipeline. The new pumps that Alyeska Pipeline Service Company is installing along the pipeline have a rated minimum capacity of 200,000 barrels a day, according to testimony cited during the House Resources Committee's hearings last week on HB 2001. However, the president of Alyeska earlier this year said publicly that the pipeline's minimum capacity with the new pumps will be about 300,000 barrels a day.*

* Whatever the mechanical threshold may actually prove to be for the new pumps being installed, it is generally expected that some new way will be found to operate TAPS at throughputs below that threshold.

Whether the new pumps' operating threshold is 200- or 300,000 barrels a day, the point is the same: There is a big difference between a 6% decline and 3% in terms of how long it would take to get to either threshold from this fiscal year's projected level of 740,000 barrels a day.³ Below are two graphs that show how big this difference is. I should emphasize that these charts are not predictions. They show only the purely mathematical results that flow from the decline rate one chooses.⁴



The chart of the left shows the time to decline from 740,000 barrels a day in FY 2007 to a 200,000-barrel-a-day threshold, the one on the right shows the time to get to 300,000 barrels a day. At a 6% rate of decline the 200,000-barrel threshold is hit in 21 years, but at a 3% decline it would take 43. If the threshold is 300,000 barrels a day, it would be hit after 15 years at 6% and 30 years at 3 percent. For either threshold, the difference between 3% decline and 6% decline gives enough additional time for almost an entire new generation of Alaskans to grow up. When AOGA says the choices facing this Legislature can affect the next generation, we mean it literally.

Fortunately for Alaska, the opportunities exist that should allow the rate of decline to be slowed below 6 percent. These opportunities are in oil and gas exploration, in the development of the huge resources of heavy and viscous oil that are already known to exist, and in the renewal and continued development of the existing fields. In our testimony before the committees previously considering this legislation, we have explained how all three kinds of investment in production will be needed if Alaska is to meet the challenge of production decline. The pattern and timing of the cash flows are different between one kind of investment and another, as is the amount of risk that each entails. But one thing is certain, they are all needed to maximize the resource recovery for Alaska.

One point that bears repeating is that the heavy and viscous oil resource lies within the areas of the so-called "legacy fields," as does the preponderance of the remaining opportunities for squeezing more "conventional" oil out of currently producing fields. The renewal of the existing fields will become increasingly important, as the existing production facilities need to be adapted, retrofitted or perhaps even replaced in order to be fit for service for the coming decades.

At the same time, in-fill drilling to drain the spaces between the existing wells, or develop new oil, offers the best promise of slowing decline in the short term. The pattern and timing of the cash flows are very different between in-fill drilling and renewal of major production facilities on the surface. So even within a classic "legacy field" without considering its resource of heavy and viscous oil, there is significant variation among the investments to be made, the economics for those investments, and the incentives for them. It would be a serious mistake to treat the "legacy fields" as economic monoliths, impervious to how they are taxed and unaffected by the incentives that may be granted them or withheld.

The last point I would like to make today is about destabilizing the investment climate here. In 2005 Governor Murkowski disregarded procedures established by regulation (15 AAC 55.027) and ordered DOR to aggregate certain fields within the Prudhoe Bay Unit, including fields with heavy oil in the West Sak formation, with the main field for ELF purposes. The result was an administratively created change in the tax law of over \$120 million a year. Last year the Legislature enacted the PPT, further increasing the production tax by over \$800 million during the last nine months of 2006 alone. And it did this retroactively back to April first of last year.

Now the Resources CS before you proposes to increase the production tax yet again, and even more massively — on the order of \$1.5 billion over even the PPT each year at \$80 real oil prices, according to DOR's fiscal note for the Resources CS. And, once again, it being proposed to make this change retroactive, this time to the first of this year.

As I have explained, you have been allowed to have serious misimpressions about what the Gaffney Kline model really shows and about how limited its proper use actually is. These misimpressions have, in turn, led to a serious underestimating of the effects of this newest change on future investment decisions about exploration, heavy and viscous oil development, and the renewal and ongoing development of existing "conventional" fields. The laws of economics say there will be adverse impacts on investment decisions here if the House CS becomes law.

It is unfortunate that so many in the public, and even in the halls here, do not believe the warnings being given by the explorers and producers here. Perhaps even this AOGA testimony will change no one's mind. But I have to hope it will. The future of Alaska is at stake, and we urge this Legislature to pull back to safer ground.

Thank you for giving AOGA this opportunity to testify.

ENDNOTES

¹ DOR, *Revenue Sources Book Spring 2007*, p. 17, Figure 2-13 ("Total Unrestricted General Purpose Revenue, FY 2006 and Forecasted FY 2007-2017"), column captioned "Percent From Oil".

² When production declines at $X\%$ a year, this means the production rate after one year (P_1) is $(1 - X\%)$ of the initial production rate (P_0), or $P_1 = P_0 \times (1 - X\%)$. After the second year the production rate (P_2) is $(1 - X\%)$ of the rate after one year of production, or $P_2 = P_1 \times (1 - X\%) = [P_0 \times (1 - X\%)] \times (1 - X\%)$, which can be simplified as $P_2 = P_0 \times (1 - X\%)^2$. After 10 years of decline, the rate P_{10} is $P_0 \times (1 - X\%)^{10}$. North Slope production was 1.404 million barrels a day in FY 1997 and 740 thousand barrels a day in FY 2007, while Cook Inlet produced 37 thousand barrels a day in '97 and 16 thousand barrels a day in '07. See DOR, *Revenue Sources Book Spring 2007*, pp. 97-98. So for the last 10 years of North Slope production decline,

$$1,404,000 \times (1 - X\%)^{10} = 740,000.$$

Dividing both sides of this equation by 1,404,000 gives:

$$(1 - X\%)^{10} = 740,000/1,404,000 = 0.5271.$$

One can solve for $(1 - X\%)$ by taking the 10th root of both sides of this latter equation:

$$\sqrt[10]{(1 - X\%)^{10}} = \sqrt[10]{0.5271}, \text{ or}$$

$$(1 - X\%) = 0.9380.$$

Since $(1 - X\%)$ is the same as $1 - X\%$, one can subtract 1 from each side of the equation to get:

$$-X\% = -0.0620,$$

and then dividing both sides by -1 yields:

$$X\% = 6.20.$$

In other words, the rate of decline averaged 6.20% a year for the North Slope. The same calculations for Cook Inlet, using beginning and ending production of 37,000 and 16,000 barrels a day respectively instead of 1,404,000 and 740,000, yields an average annual decline rate of 8.0 percent.

³ DOR, *Revenue Sources Book Spring 2007*, p.

⁴ Here is the math for the 300,000-barrel-a-day threshold shown in the right-hand graph: From the analysis in Endnote 1 above, we know that for a given decline rate R , the volume of production after N years of decline is $P \times (1 - R)^N$. So for each decline rate in the table, you use that as the value of R in the formula, and then you solve for X as the value of N that gives 300,000 barrels a day as the rate. The equation for this is:

$$740,000 \times (1 - R)^X = 300,000.$$

When you take the logarithm of both sides of this equation, you get the following equation:

$$\log[740,000 \times (1 - R)^X] = \log[300,000].$$

The reason for using logarithms is that they have the property that the logarithm of two numbers being multiplied together equals the sum of the logarithms for each of them, while the logarithm of a number raised to an exponent X equals X times the logarithm of that number. Using this gives the following restatement of the prior equation:

$$\log[740,000] + X \times \log[1 - R] = \log[300,000].$$

Subtracting $\log[740,000]$ from both sides of the last equation yields the following:

[continued on next page]

$$X \times \log[(1 - R)] = \log[300,000] - \log[740,000].$$

Now you can solve for X by dividing both sides of the last equation by $\log[(1 - R)]$, which yields:

$$X = \frac{\log[300,000] - \log[740,000]}{\log[(1 - R)]}.$$

By plugging the decline rate of your choice into this last equation as the value of R , the value of X can be calculated by simple arithmetic and a set of logarithm tables, or with a calculator or computer that can compute logarithms. This straightforward calculation has been done for each of the decline rates shown in the right-hand graph. The equations and arithmetic are the same for the left-hand graph, except that 200,000 replaces 300,000 in the equations.

Comments On ACES Petroleum Tax Proposal, October, 2007
By Ken Thompson, Managing Director, AVCG/Brooks Range Petroleum

Personal Background

For the record, my name is Ken Thompson. I reside at 12031 Lilac Drive, Anchorage, Alaska. I am the Managing Director for Alaska Venture Capital Group, or AVCG LLC, an independent oil exploration company formed with a sole focus on the North Slope of Alaska. AVCG is a privately held member LLC comprised of private equity investors made up of 15 independent oil and gas companies and individuals from Kansas and me as an owner/member partner from Alaska. AVCG has a technical and operational services' subsidiary company called Brooks Range Petroleum, with offices and staff in Anchorage. In Alaska and on the North Slope, we operate under the name Brooks Range Petroleum.

AVCG has lease holdings and explores currently only in Alaska...and nowhere else. AVCG/Brooks Range Petroleum likes to think of our company as "Alaska's *Independent Oil and Gas Company.*"

AVCG LLC has been very active in the past seven North Slope areawide lease sales and active in acquiring acreage held by other companies where we see potential. We and our partners currently hold over 300,000 acres of exploration leases in five exploration prospect areas on the Slope. Our exploration strategy is to explore in the central part of the North Slope for fields in the 10-100+ million barrels range, fields that may be too small for the giant producers but satisfy as niche fields that can be "company makers" for a small independent. We believe there are hundreds of millions if not billions of barrels of oil left on the central North Slope in smaller fields of this size for small independents like ours that want to take this type of exploration risk.

Last year, AVCG LLC announced joint venture agreements with two Canadian independents, TG World Energy and Bow Valley Energy, and with a private exploration company from Houston, Ramshorn Exploration. Together, as working interest co-owners we are exploring the central part of the North Slope.

In the winter of 2006, AVCG participated with an ownership interest in the Cronus exploration well about 10 miles southwest of the Kuparuk Field, operated by Pioneer Natural Resources. Unfortunately, that well was a dry hole.

This past winter for the first time, our operations subsidiary, Brooks Range Petroleum operated the drilling of two exploration wells for our working interest partners in the Gwydyr Bay area of the North Slope, just northwest of Prudhoe Bay. One well, the Sak River #1, was a dry hole, but we were excited to announce earlier this year that our Northshore #1 well northwest of the Prudhoe Bay Field did strike oil. We plan to complete and test this well this winter. In addition, we ran a 130-square mile 3D

seismic survey over our acreage and surrounding area in the Gwydyr Bay area on the North Slope. In total this past drilling season, our JV Group invested over \$44 million on land, seismic and drilling activities.

This winter our Joint Venture Group will be among the most active of explorers as we plan to shoot over 200 square miles of new seismic data on the extreme western and eastern sides of the Central North Slope and to drill up to four exploration wells. We plan to test the Northshore #1 well and also drill one or two other exploration wells nearby to see if we can discover a sufficient volume of oil to warrant a commercial development at Gywdyr Bay. We will drill our Tofkat #1 well south of the Alpine Field and also drill a fourth exploration well on a prospect to be named. In total, our group will spend over \$40 million in seismic and exploratory drilling in winter 2008. If our Northshore oil completion test is as suspected and one of the wells strikes oil close by, we may proceed with Northshore development with more substantial capital investment in the second half of 2008.

My comments today represent the perspectives of a small, independent exploration company that is actively exploring on the North Slope with a good level of activity, generally on prospects that because of smaller size no longer interests the major companies. At the end of next drilling season, AVCG since 1999 and our partners since last year will have jointly invested over \$100 million in Alaska even though none in our group have generated any revenues yet from Alaska oil, so we sincerely appreciate being listened to. We think in the long run we can bring substantial, incremental value to the State of Alaska. Please wish us good luck.

Many of you also know me as the past President of ARCO Alaska, Inc. from 1994-1998. I also served as Executive Vice-President for ARCO and head of global oil and gas exploration for ARCO. I do have exploration and production experience in 10 U.S. states and in over 20 countries throughout the world, so I'll also share my perspective in how I see the ACES bill in the context of competitiveness in the United States and in the world.

General Comments On ACES Legislation

At this point, I would like to address various key points in the ACES legislation.

First, our company prefers that the PPT be allowed to run its course in the next few years, and that ACES not be approved with its current provisions. I agree with Dr. Pedro van Meurs that in the light of declining oil production in the state of Alaska and prospectivity trending to smaller field sizes, the State should not once again increase its taxes after having done so last year. I will tell you that when recruiting companies to join in our Alaska ventures in 2005 and 2006, many were concerned about the threat of tax increases in Alaska. PPT proved tax increases were not a threat but a reality. Adding yet another tax increase via the ACES bill this year shows instability

in Alaska's tax policy which results in uncertainty and risk when making investment decisions.

I heard that consultant Daniel Johnston differed strongly from Dr. van Meurs and urged the oil industry to understand the "cloud of corruption" over the existing Petroleum Profits Tax, or PPT, and that this alone provides a good reason to change PPT. I challenge Daniel Johnston that the bushel should not be thrown out because of a few bad apples.

In fact, last year during the PPT debates, I recall those who are guilty of paying bribes and some who are accused of taking bribes actually supported a 20% base tax rate, not the 22.5% base rate that was finally adopted. In fact, I'd like to think that the almost all in the Legislature and in Industry were honest, that they could be trusted in their deliberations last year, and that the final answer of PPT was a good answer and an honorable answer.

It is also very important to keep in mind that the progressivity tax was added at high oil prices to drive the real tax rate to even higher levels than 22.5%, with a range exceeding 30% now possible at certain prices. And let's not forget to tack on the royalty, the corporate tax, the ad valorem property tax, and environmental and permitting fees. It appeared to me that the checks and balances in the system worked in the Legislature last year, and I applaud the honesty of the legislators who in the end made a positive difference.

But I sit here feeling as if the honest and trustworthy investors in this industry are being punished alongside the guilty. I personally think this will have negative consequences for Alaska in the long haul in relationships and even in sustainable increased value.

But I am politically astute enough to know that the ACES train is moving fast down the track, so I can stand out of the way or jump on board and try to make the ACES bill better before we reach derailment in the long-term relationships between this industry I love and this State I love.

So, I have some suggestions of things not to change and things to change in the ACES proposal.

Five Things *Not* To Change In ACES

- 1) **Keep the exploration and development investment tax credits.** For a small explorer startup company like AVCG LLC, the exploration economics with the exploration tax credits ranging from 20-40% as provided by PPT and with ACES are more favorable with an improvement in the investor's rate of return as compared with Alaska's old severance tax system. Near-term cash flow because of the investment tax credits is higher which improves the return

on investment. Plus refund of cash to companies like AVCG and our working interest partners via the credits mean that we can apply that cash to our capital budget the next year to run adequate seismic and do additional drilling that increases the chance of more oil production and reserves for us and for the State.

Likewise, the credits for losses for a startup company like ours while we establish production and also the development investment credit can take substantial risk out of development of smaller fields that our company is focusing on. May of these smaller fields can add up over time and provide significant incremental revenue to the State.

- 2) **Keep the "standard tax deduction/exemption" for smaller companies.** The "Small Producer Tax Credit" that exempts up to the first \$12,000,000 in production taxes for smaller companies can allow us to return a larger share of our annual cash flow for exploration and investment while we build the company to a critical mass of reserves and production necessary to expand staffing and have a routine level of major capital spending each year.
- 3) **Keep the new ACES tax credit allowance for qualified delineation wells.** A new proposal in the ACES bill that was not in the PPT law is the possible tax credit allowance for the investment in up to two delineation wells following a discovery. This would be very helpful to small explorers as well as for large companies on the North Slope where often one well is not enough to determine if field size is large enough to warrant development.

A real case in point is that should we have a discovery this coming winter at our Tofkat exploration well on the western side of the Slope, we will have to drill one or two delineation wells to confirm if field size is sufficient to develop the resource at this remote location. Often, due to the nature of these complex stratigraphic traps where sands unpredictably come and go, the delineation wells can be almost as risky as the initial exploration well. Having a credit where the State, in a real sense, is sharing in the risk will – I think – expedite delineation of new fields and advance development for revenues.

- 4) **Keep the revised progressivity tax rate at 0.2% per dollar increase in oil price.** The PPT tax law had an incremental tax rate of 0.25% per each dollar increase in oil price above a trigger price while the new ACES reduces this incremental tax rate to 0.2% per dollar increase in oil price at a trigger price. While we can debate all day long the competitiveness of Alaska's tax rate with other countries' fiscal systems, giving some reduction in this surcharge keeps the government take at more reasonable levels. However, as I'll outline below, I would change the ACES trigger price back to \$40 per barrel net and not the proposed \$30 per barrel net if Alaska wants to better balance revenues with industry capital investment at low prices as I'll more fully discuss.

- 5) Do establish the Oil and Gas Tax Credit Fund for the purposes of purchasing certain tax credits from explorers and producers. This ACES provision would establish a procedure and standard for appropriation into this fund and management of this fund. Having a clear and transparent way for small explorers to receive their credits at full value is extremely important for AVCG to then be able to plow those credits back into seismic and exploration on the North Slope.

Four Things To Change In ACES

- 1) Change the recovery of tax credits from two years as proposed in ACES back to the recovery of credits in one year currently provided for in the PPT law. In the PPT law, a company could file for the various credits, and if approved, would receive those full capital credits not to exceed credits of \$25 million per company. In the new ACES law, while the cap has been removed which is very positive, the credits are refunded over two years instead of over one year, e.g., 50% of qualified credits can be applied for in the first year once a well is completed or abandoned and 50% in the following year.

For a small company like ours, this will definitely affect our capital spending in a given winter as we plow all the credit refunds back into seismic or exploration drilling. As a very real example, AVCG and our working interest owners are projecting to spend \$41 million in seismic and exploration drilling this coming winter and likely around the same in 2009. We calculate that we could receive \$16 million cash in qualified credits in mid-year 2008. So essentially, our working interest owners are planning to provide cash out of pocket of \$25 million for the 2009 drilling season; this is a fixed number based on cash availability in these small companies to spend toward the Alaska portfolio. If the State refunds only one-half of this credit in the first year, or only \$8 million instead of \$16 million, AVCG and our partners will still provide \$25 million out of our pockets as now planned and budgeted...meaning our overall spending in 2009 will be \$33 million, not \$41 million, i.e. \$25 million from our available funds and only \$8MM from the State. This would mean one less well that will be drilled by our group in 2009. And one less chance for another discovery that eventually could provide revenues to us all. With small companies, this is just the way our cash flow situation works. And for some of our AVCG investors like me, when I say "out of pocket," I mean "out of pocket."

So, we hope the full credit can be applied for and refunded in a given year. We hope this happens for all of industry. As an innovative compromise, however, the Legislature may consider a "Small Company Refund" provision that allows for companies that meet the no production or low production measures in the "Small Company Tax Credit" provision of the PPT law - that remains in ACES - to receive tax credit refunds that are fully refunded in the

first year for qualified costs. Once a company grows in production beyond this "small company" measure with more substantial cash flow, perhaps refunds of 50% each year would apply as outlined in ACES.

- 2) **Change the base tax rate in ACES from 25% back to the PPT tax rate of 22.5%, and re-review again in 2011 after some time has passed as allowed for in current law.** As I mentioned in my introduction, I felt the 22.5% base tax rate was reasonable. And the real tax rate is much higher with the tax progressivity factor. But what is fair, and how exactly is "fair" determined?

I saw a copy of a presentation entitled "Guiding Principles For A New Production Tax System" by the Department of Revenue urging the changes in ACES, arguing that the average government take in various international countries averaged 67% for all types of fiscal regimes internationally, averaged 74% for production sharing agreements, but only 55% for tax and royalty regimes internationally. Somehow, the Department of Revenue representatives concluded an average of 68% as provided for in ACES would be close to the average of 67% for all types of regimes internationally.

First, the average recommended to Alaska is the average of all regimes, i.e. the averaging of government take from tax and royalty regimes with the government take from production sharing agreement (PSA) regimes. In some countries that I worked in that had production sharing regimes, the risk profile for capital development was often much different than in regimes that use a tax and royalty regime such as Alaska. In PSA countries, it was not unusual for a producer on capital projects to have a very low initial tax burden until the capital investment was fully recovered plus a negotiated rate-of-return was achieved. Then and only then was the government take increased substantially...thus giving the average take for such countries as 74%. But the risk profile was often much better than Alaska, i.e. there was up front recovery of capital and a preferred investor rate-of-return. That is not the risk profile of Alaska when a company first has production...the ACES high tax rate and the added progressivity tax will start immediately along with royalties, corporate taxes, property tax and other charges rather than allowing for recovery of capital and a contractual rate-of-return.

As another distinction, most of the individual people and company investors specifically in AVCG, LLC, do not consider international regimes as areas to consider as competition for our investment dollars with Alaska. Rather, the main competition for most AVCG Owners' cash is in other states in the U.S. I found it astounding and concerning that the average of 67% for all international regimes did not consider weight-averaging in the major American producing states. As examples, the current government takes in the Gulf of Mexico offshore – one of the main competing areas for Alaska investment

dollars – averages 45%. This is under consideration by the U.S. government for increase, but it is highly doubtful with the boom going on in deep water exploration and development that the U.S. government would increase the government take from 45% to 68%.

In other producing states that compete for investment by our AVCG investors, the state and federal combined government takes in 2006 were as follows and averaged 45-57%:

U.S. Gulf of Mexico	45%
Colorado	51%
Wyoming	52%
Kansas	53%
Texas	53%
New Mexico	53%
Oklahoma	53%
California	53%
Louisiana	57%

To my knowledge, these states do not have the added progressivity surcharge tax which further separates Alaska in government take from these competing states. I would argue that Alaska should have a government take of 55% if we were to maintain long-term competitiveness with these other states for investment dollars. Having said that, some of these states do not have the prospectivity of Alaska, so Alaska could command some premium in take, but certainly not as high as being proposed in ACES.

If Alaska set a government take at 60% to the government and 40% to the investor, the ACES legislation should be amended to allow for a base tax rate of 22.5% not 25%, should be amended to allow for a trigger price of \$40 per barrel and not \$30 per barrel, and the incremental progressivity tax rate increase should be 0.2% per dollar.

- 3) Change the trigger price to \$40 per barrel net and not \$30 per barrel.** If the government take is to be the fair and equitable 60% and not the unfair 68%, the trigger price should stay the same as in the PPT law, i.e. \$40 per barrel net. If Alaska is to share in high prices with the progressivity surcharge tax, then Alaska should share in the pain of low prices. To amend the trigger price lower when and if prices collapse will be a false economy measure for the State of Alaska. When prices fall and a company's cash flow is sharply reduced, capital spending will fall. A "double whammy" to be taxed more with a progressivity tax at lower prices further reduces the amount of capital for re-investment.

- 4) Consider some type of "Transitional Investment Expenditure (TIE)" tax credit. This provision allowed for in PPT was repealed in ACES. While this provision does not greatly benefit our company, AVCG, because we did not have large seismic or exploration drilling costs between March 31, 2001, and April 1, 2006, it is important to other major investors in Alaska

As an example, the largest explorer and developer in Alaska, ConocoPhillips, now with the ARCO heritage assets was hardest hit in tax exposure with the change from the old severance tax law to the PPT and now to ACES. I simply think allowing a good steward who is the largest explorer in Alaska some transition allowance to ease the pain of greatly increased taxes is the right thing to do and can only build better, more trusting relationships.

Again, this provision does not greatly benefit our company, however.

Concluding Remarks

This concludes my remarks. I tried to share the perspective of an independent exploration company that only invests in Alaska. My ultimate wish would be for the State to leave PPT alone and re-review it under the law as planned in 2011 or perhaps even in 2010. But if the ACES train has left the station and cannot be stopped, I urge you to at least consider the five things our company would not change in this bill and the four things we would change.

The above comments are offered with a hope that there can be an eventual win-win solution to this complex subject of the State realizing more revenues at higher prices while attracting exploration and development investors who can also realize upside at higher prices for the substantial risk they have taken in the remote and harsh environment of the North Slope. In the end, I hope both sides get a fair and equitable share at all price levels.

And my comments are offered with the highest sincerity that the State and Industry can someday restore a mutual trust at all levels.

I sincerely thank you for the opportunity to present my comments, and I would be happy to take any questions.

Respectfully submitted,

Ken Thompson

TESTIMONY OF CRAIG HAYMES

ON PROPOSED CS HB 2001 (RES)

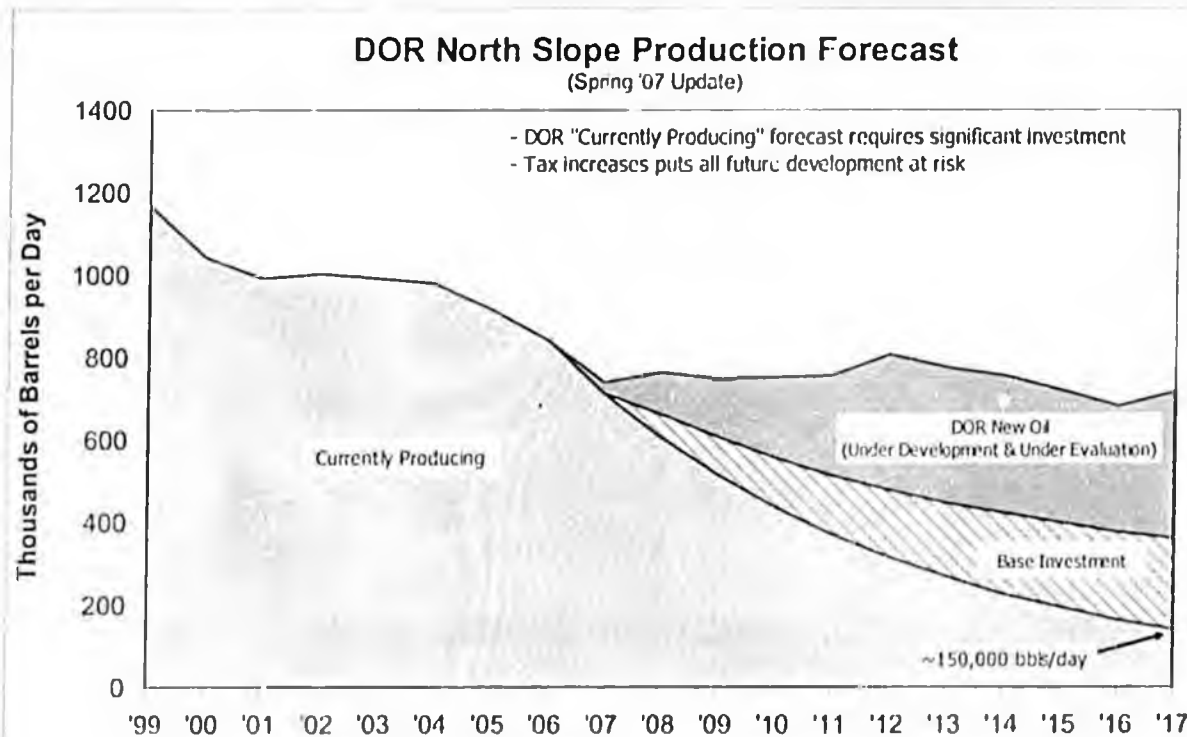
TO THE ALASKA HOUSE FINANCE COMMITTEE

NOVEMBER 8, 2007

EXECUTIVE SUMMARY

Alaska's Future

- **Alaska has significant resource potential**
 - Produced 17 billion barrels of oil, world class result, production today 1/3 of peak
 - Undiscovered technically recoverable resources – 53 BB oil; 259 TCF gas
 - Alaska's world ranking of proved reserves is declining - 14th in 1977, 30th today
 - Prudhoe Bay/Kuparuk > 70% of North Slope production – hubs for future opportunities
- **Alaska's high cost environment challenges pace of exploration & development**
 - Severe arctic conditions, remote, sensitive environment, exploration restrictions
 - Effective application of technology critical
- **Alaska & industry collaboratively need to create a resource development policy**

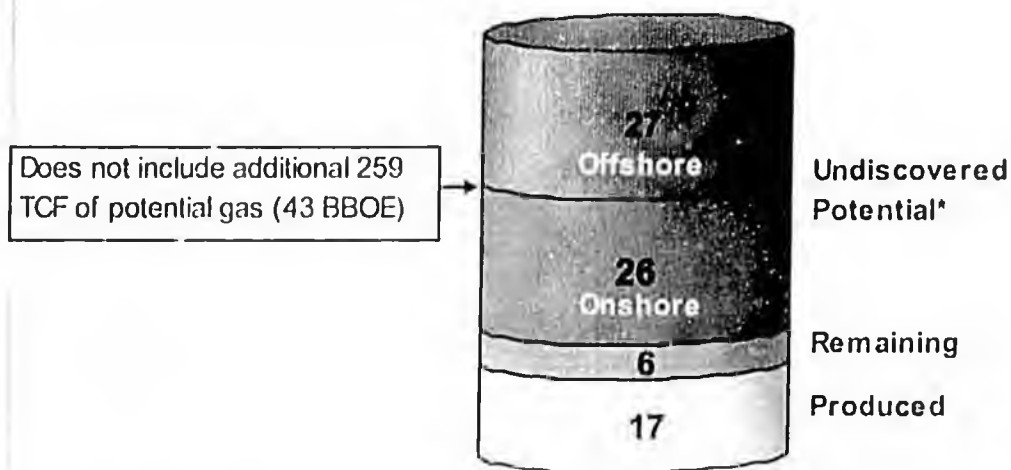


In 10 years, 75% of oil production will come from new investments. Such production will need > \$30-40 Billion of new investments

Alaska Needs a Long-Term Resource Development Policy

- We propose a collaborative approach to develop a sustainable long-term resource policy:
 - Characterization of state-wide resource potential
 - Identification of key issues challenging exploration and development
 - Determination of key factors that impact resource value
 - Establishment of goals and measurement of progress
 - A fiscal policy that will encourage development of remaining resources
 - Regular meetings with industry and agency representatives

Alaska Resource Assessment 76 Billion Barrels of Oil



How do we commercialize Alaska's full resource potential?

SOURCE: USGS, MMS, DNR

* mean undiscovered technically recoverable resource

ExxonMobil

Fiscal Predictability Is Important

- **Industry needs a predictable fiscal environment**
 - Investments are capital intensive and typically evaluated over decades
- **Changing fiscal environment for capital projects reduces attractiveness of investments**
 - For every well or project not progressed, production and State revenues are forgone
- **Support the concept of a net based tax**
- **PPT has only been in existence for slightly more than one year**
 - Department of Revenue has not completed regulations or started an audit
 - Willing to work with DOR and its auditors to improve understanding of joint interest billings

**Policies established today will
impact attractiveness of
potential future projects**

Proposed Tax Increase More Complicated

- **Proposed CS HB 2001 creates greater uncertainty**
 - Additional reporting requirements for exploration tax credits - credit qualification linked to release of proprietary information
 - Exploration confidentiality protection diminished
 - Additional information requests ambiguous – “other records and information the department considers necessary....”
 - Actual transportation costs versus “reasonableness” standard
 - Qualified lease expenditures restricted to those incurred on the lease producing oil or gas
 - Disallowance/Limitation of costs associated with refineries/crude oil topping plants

Proposed changes increase complexity and costs

Proposed Tax Increase Significant

- **Proposed CS HB 2001 increases administrative burden for Department and Industry**
 - Increasing statute of limitations from 3 to 6 years
 - Elimination of requirement for JI Billings as starting point for audits
- **Proposed CS HB 2001 unreasonably excessive**
 - Reduction of transitional tax credits
 - Excessive late filing and document submission penalties
 - Publication of proprietary tax information

At today's prices

- **ACES would increase production taxes by 350% since 2005**
- **CS HB 2001 would increase production taxes by 470% since 2005**

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TESTIMONY OF CRAIG HAYMES
ON PROPOSED CS HB 2001(RES)
TO THE ALASKA HOUSE FINANCE COMMITTEE
NOVEMBER 8, 2007

INTRODUCTION

Mr. Chairman, members of the committee:

Good morning. For the record, my name is Craig Haymes. I am the Alaska Production Manager for ExxonMobil, a position I commenced in January of this year. I reside in Anchorage with my family. I want to thank the committee for the opportunity to express ExxonMobil's views regarding the Administration's proposed tax increase.

I would like to state at the outset that ExxonMobil believes the current PPT tax rate and the increase proposed by the Administration will not result in the additional investment needed to maximize the development of Alaska's resources. When you consider Alaska's resource potential and the current production decline we do not support the tax increase proposed by the Administration.

ExxonMobil has had a presence in Alaska for over 50 years and has been a key player in Alaska's oil industry development, spending and investing over \$20 billion dollars. We are currently active with our co-owners at Prudhoe Bay, Kuparuk, Duck Island, Granite Point and Point Thomson. Our current working interest share of oil production in the State is approximately 150,000 barrels per day and we are the largest owner of

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discovered Alaska gas resources. We look forward to working with Alaska for many years to come.

Alaska has significant undiscovered resource potential in both oil and gas; but oil production is declining - today it is one third of the peak of over 2 million barrels per day in 1988. Increasing investment in Alaska is needed to mitigate oil production decline - Government and industry have a common goal - to maximize economic resource development, both oil and gas. Challenging this significant resource potential, and the pace of exploration and development, is Alaska's high cost environment. For any investor, higher costs reduce attractiveness of opportunities.

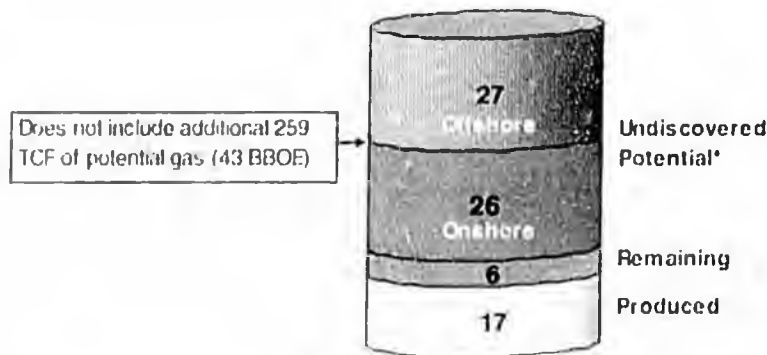
ExxonMobil believes technology is the lifeblood of the industry and the key to unlocking Alaska's future resources. Historically, the effective application of technology by ExxonMobil and other companies has proven to be successful in reducing costs for the exploration and development of Alaska's resources. Significant long term research and development of technology will be required to realize Alaska's resource potential.

The full development of Alaska's resource potential will require Government, the industry, and the people of Alaska to work together to enhance the development of Alaska's resources. We believe that Alaska needs to create a long-term resource development policy, a policy that will encourage increasing investment needed to mitigate production decline, a policy that recognizes Alaska's high cost and challenging environment, a policy that will encourage the full development of Alaska's oil and gas resources.

ALASKA RESOURCE POTENTIAL IS SIGNIFICANT

According to the US Geological Survey and the US Minerals Management Service, Alaska still has undiscovered technically recoverable resources of over 53 billion barrels of oil. This is in addition to the Department of Natural Resources estimate for known remaining oil resources of 6 billion barrels. When you consider this resource potential, Alaska has only produced one quarter of its oil potential. Alaska still has the potential to produce another 59 billion barrels of oil. Expanding the resource assessment to include gas almost doubles this undiscovered potential on an oil equivalent basis. Alaska has significant oil and gas resources.

**Alaska Resource Assessment
76 Billion Barrels of Oil**



SOURCE: USGS, MMS, DNR

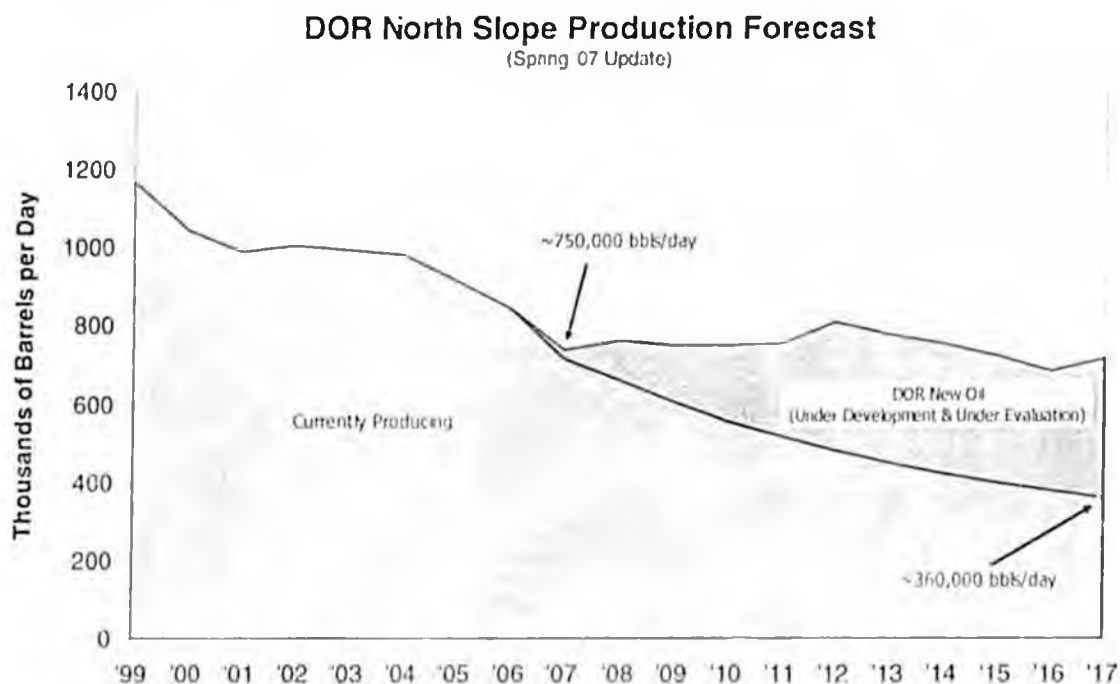
* means undiscovered technically recoverable resource

Whilst Alaska's resource potential is high, the Oil and Gas Journal and Energy Information Administration report that its world ranking of proved reserves has declined from 14th in 1977 to a position closer to 30th today. How can Alaska increase proved reserves: how can we commercialize Alaska's resource potential?

ALASKA'S FUTURE OIL PRODUCTION

Alaska is currently producing approximately 750,000 barrels of oil per day from the North Slope, one third of its peak production. The Department of Revenue released a production forecast in their Spring Revenue Sources Book. The forecast consists of two main components, as shown in the chart below.

- Current base production (shown as green)
- Future "Under Development and Under Evaluation" production (shown as blue)



As the Department's forecast shows, the current base production is estimated to decline at 9% annually to approximately 360,000 barrels per day by 2017 with continued investment. That is a production level of less than half of today's. The Department's forecast also shows that this production decline will be partially mitigated by the "Under Development and Under Evaluation" production – which includes future investments in areas such as development drilling in non core areas, satellite developments, and enhanced oil recovery from existing fields. Based on this forecast, 50% of future oil

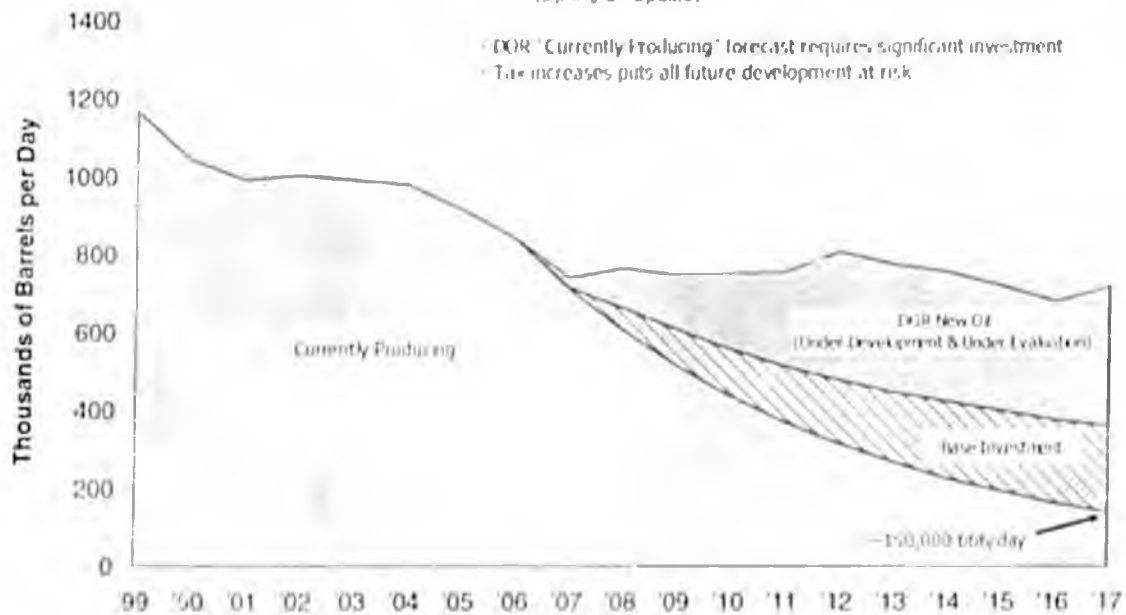
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production in 10 years is not even developed or producing today. Considering that most North Slope projects take at least 5-7 years to bring discovered resources to production, near term investment for these activities will be critical to underpin the future of Alaska's oil production.

As I mentioned earlier, the Department of Revenue's forecast is based on a 9% annual decline in Alaska's current base production. However, this decline includes current production enhancement investments at the core Prudhoe Bay, Kuparuk and Alpine areas. The Department's forecast does not highlight that this activity requires investment decisions that are no different from the "Under Development and Under Evaluation" categories. As such, a more accurate representation of the future investment levels required to achieve the Department's forecast is show in the chart below.

DOR North Slope Production Forecast

(Spring 07 Update)



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As this chart shows, Alaska's oil production from the North Slope could be as low as 150,000 barrels per day within 10 years without ongoing and increasing investment (assuming 15% decline, which is typical for large oil fields such as Prudhoe Bay). Based on this forecast, within 10 years, 75% of production will come from new investments.

Conservatively, we estimate that at least \$30-40 billion of new investment is required within the next 10 years to achieve the Department of Revenue forecast. This does not include the billions of dollars of additional operating expenditures that would be required to support the developments once they are producing. This is a significant level of future investment and spending.

ALASKA'S TWO LARGEST OIL FIELDS

The two largest oil fields in Alaska - Prudhoe Bay and Kuparuk account for over 70% of the State's North Slope oil production. With continued investment these fields could remain at this portion of production for the next decade. But like any oil field in the world, in order to keep the oil flowing, additional investments are required; such as the historical significant investments at Prudhoe Bay resulting in the installation of water and gas injection, and gas compression facilities.

Currently, the owners spend over \$2 billion dollars annually to optimize and enhance production from Prudhoe Bay and Kuparuk. These spending levels are in addition to the capital investments pursuing new wells, projects, and enhanced oil recovery opportunities. These operating expenditures are essential to mitigate production decline at these significant fields.

Many of today's exploration and development activities are occurring in and around Prudhoe Bay and Kuparuk. As an example, since the year 2000 there have been multiple Prudhoe Bay satellite fields developed (Aurora, Borealis, Midnight Sun, Polaris, and Orion) which are currently contributing over 40,000 B/D of oil production. By leveraging existing Prudhoe Bay and Kuparuk infrastructure, satellite development costs have been significantly reduced. If the major Prudhoe Bay and Kuparuk developments did not exist these satellite fields would not have been economic to develop. As infrastructure on the North Slope expands the economic viability of future satellite developments increases.

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Development drilling in and around Prudhoe Bay and Kuparuk is another example of their critical contribution to Alaska's oil production. For the past seven years over 900 new wells have been drilled in Prudhoe Bay and Kuparuk. The drilling of these new wells has slowed the overall production decline from 12-15% to an estimated 6-9%. Almost 40% of Prudhoe Bay's production today is from these new wells. For the past two years, development drilling at Prudhoe Bay alone has achieved the equivalent development of resources as the important Oooguruk development.

Prudhoe Bay and Kuparuk have the potential to remain key hubs and enablers for the pursuit of new heavy or viscous oil, light oil and gas projects. Encouraging increasing investment at these key fields is as important as encouraging investment in exploration and development of new fields.

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EXXONMOBIL'S POSITION ON THE ENACTED PPT

I believe it is important that i clarify ExxonMobil's position on the current PPT.

ExxonMobil did not support the PPT that was enacted last year. As we testified last year, we supported the concept of a net based tax but stated that the proposed 20% tax rate, in the original PPT bill, would not encourage the full development of Alaska's resources. We agreed with the 20% tax rate in order to support the progression of a gas pipeline project.

The PPT that was ultimately enacted increased the high 20% base tax rate to 22.5% with progressivity - more than doubling industry's taxation. When combined with the gross royalties and the high cost environment, it reduces the attractiveness of Alaska's resource developments

There has been a lot of discussion recently on PPT revenues and forecasts, which has been used in part to support the Administration's proposal to increase taxes. PPT has only been in existence for slightly more than one year. The Department of Revenue has not completed its PPT regulations or started any PPT audit. ExxonMobil, like a number of the other producers, met with the Department of Revenue several months ago to discuss ways to help the State better forecast its expected PPT revenues and we are willing to continue those efforts. We are also willing to work with Department of Revenue auditors and our partners to improve the understanding of joint interest billings.

EXXONMOBIL'S POSITION ON THE COMMITTEE SUBSTITUTE

I would now like to offer ExxonMobil's view on major provisions of the Committee Substitute for House Bill 2001 (RES). In analyzing the Committee Substitute, we found that virtually all of the provisions are simply tax increases or further increases in complexity. In a number of instances, existing statutory provisions of general applicability are being replaced or supplemented to apply only to the PPT. Our comments are presented in the following section-by-section analysis.

Base Tax Rate & Progressivity:

The first sections I would like to comment on are Sections 15 and 20, commencing on page 11 and 14 respectively. I have combined these two sections together for discussion purposes because they really are the core of the major issues with the proposed Committee Substitute. Section 15 proposes to raise the base PPT tax rate from 22.5% up to 25%. Section 20 proposes to replace the current progressivity surcharge with a higher one based on gross revenues. As I mentioned earlier, ExxonMobil believes the current PPT tax rate will not result in the additional investment needed to maximize the development of Alaska's resources. When you increase the already high base tax rate you reduce the attractiveness of investments. When you then add an additional level of tax as prices increase, the attractiveness of future investments is substantially reduced, which will impact resource recovery and long-term state revenues. This is especially true under a gross tax element which ignores the true economics of a project. We urge this Committee to not adopt either Section 15 or 20 and to reconsider the current base tax and progressivity element.

Penalties:

Section 25, commencing on line 19 of page 18 would establish a 5% penalty for an underpayment of a monthly estimated tax payment. Section 43, commencing on line 13 of page 31 proposes to allow the Department of Revenue to assess a penalty of up to \$1,000 per day for each day a "tax return" is not filed when required. Paragraph (6) of Section 45 commencing on line 26 of page 33, proposes to allow the Department of Revenue to assess a \$1,000 penalty per day for each "report, statement or other document" the Department "considers necessary" to forecast state revenue that a producer, explorer or operator fails to provide when the Department deems necessary. Each of these amendments is unnecessary.

Under current law, there are already significant penalties to ensure taxpayer compliance with filing tax returns, paying the appropriate amount of tax when due and for providing other information to the Department. Such penalties include a 5% penalty per month (25% maximum) for failure to file a tax return and a similar penalty for failure to pay the full amount of tax when due, among others. The Department also has significant powers to compel production of information, including holding investigations, issuing subpoenas and taking depositions. For these reasons, ExxonMobil believes the proposed penalties are excessive and unnecessary.

In addition, the proposed penalties are unreasonably excessive. A \$1,000 per day penalty for each "report, statement or other document" that is not produced "at the time required" by the Department can quickly result in amounts disproportionate to the nature or severity of the offense. For example, a single one page document that a

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taxpayer did not provide six months earlier because the taxpayer reasonably believed it was already addressed in another submission, would subject the taxpayer to a penalty close to \$200,000. Each of these penalties should be removed.

Transition Tax Credits:

Section 29, commencing on line 13 of page 20, proposes to reduce the amount of tax credits for capital expenditures incurred during the five years immediately preceding the enactment of the PPT to those capital expenditures incurred during the prior three years. ExxonMobil believes the current transition provision allowing 100% cost recovery of the prior five years of capital investment is an important feature of the PPT since it recognizes the long time-frame required for a return on an oil and gas investment to occur.

Conversion to the PPT resulted in a 250% tax increase on the entire industry under today's prices. The Legislature recognized this dramatic change to Alaska's production tax regime by including a five-year transition allowance. The transition allowance was put in place to address the impacts on historical investments made under a significantly lower tax rate.

The transition recovery period is also consistent with the State's objective to encourage future capital investment since the producer has to spend \$2 of additional new capital for every \$1 dollar of prior year investment recovered.

We recommend that the Committee reinstate the transition credits originally intended by the Legislature to mitigate the impacts of the conversion to the higher PPT tax and not adopt the proposed changes in Section 29.

Additional reporting requirements for exploration tax credits:

Paragraphs (B) and (C) of Section 34, beginning on line 27 on page 24 would require that in order to qualify for an exploration tax credit an explorer has to agree in writing to release highly proprietary information; such as seismic, well geophysical surveys and core samples.

Providing this type of proprietary information is not the norm throughout North America. Releasing key competitive and high value information would be a concern to any explorer. It often takes decades to progress from exploration to production phase. The release of proprietary and competitive information before an asset is producing is not appropriate so early in the phase of a future development. This would decrease the value of the exploration credit and may discourage an explorer from applying for the credit.

In addition, providing this type of information to the State would increase the amount of investment required of an explorer. Core samples, for example, are very costly.

Providing one-third of the core material to the State would not only add to the costs of exploring, but would be physically challenging and potentially damaging to the integrity of the entire core. The same constraints also apply to other very limited gas, fluid, and solid samples collected by downhole devices like sidewall core guns or formation samplers. Cores can always be made available for state review upon request and analyses of downhole-collected samples are already routinely provided to the state.

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The confidentiality provisions are also of serious concern. The proposal provides confidentiality protection for only ten years for most of the seismic data required to be produced, and for only two years on the rest. Seismic data typically has a shelf life in exploration areas (especially frontier areas) much longer than 10 years. More troubling is that under the proposal, an operator is required to provide a copy of check shot surveys or vertical seismic profiles. These geophysical surveys are expensive and are intended solely for seismic interpretation. They are key pieces of proprietary data. They have an indefinite shelf life and can be used to tie seismic of any vintage, new or old, to wells. Yet under the administration's proposal, such information would be classified as "well data", and afforded only a 2-year period of confidentiality.

These requirements go against the basic principle that if a party is willing to spend money and take risks to collect information critical to the success of a project, that party should be entitled to maintain the confidentiality, value and integrity of that information for the life of the project. Exploration is a long-term effort, requiring the allocation of finite resources across a spectrum of competing opportunities over a number of years to successfully identify those opportunities that will bring financial returns to the explorer. Alaska's exploration tax credits will improve the attractiveness of future programs, but the value of these credits will be undermined by tying them to complying with onerous requirements. ExxonMobil urges this Committee to remove the onerous requirements outlined in Section 34.

Information Requests:

The Administration is proposing that they require additional information to assist in the administration of the PPT and improve their ability to forecast future revenues for PPT. We recognize conversion to the net based PPT structure has increased the information needs for the Department of Revenue, and ExxonMobil is willing to help the Department meet its needs. We believe that additional information requirements beyond that currently submitted with our tax filings needs to be carefully considered. There must be some limitations and reasonableness standards established.

For example, subsection (f) of Section 44 of the Committee Substitute, commencing on line 4 of page 32, lists items a producer, explorer or an operator would be required to provide the Department on a monthly basis. Items (1)-(7) are clear, however item (8) on line 17 would obligate the producer, explorer or operator to provide any "other records and information the department considers necessary. . ." - every month. This language is ambiguous on what standards would be applied and how a taxpayer would comply. Taxpayers would be required to provide whatever the Department's auditors consider "necessary". We believe item (8) is too open-ended and should be deleted.

Paragraph (5) of Section 45, commencing on line 17 of page 33, would require a producer, explorer or operator to file whatever reports and copies of records the Department considers "necessary" to forecast PPT revenues. We believe this language in paragraph (5) is too vague. While recognizing the Department's need for forward looking data we believe the tax statutes should specify the required information.

Statute Of Limitations

In lines 7-9 on page 34, Section 46 of the Committee Substitute proposes a new six-year statute of limitations for the PPT only. Currently, the statute of limitations for the PPT, as well as all other taxes under Title 43, is three years. The Department has not started a single PPT audit and increasing the statute of limitations can only delay audits and increase administrative costs. We fail to understand why this amendment is needed. Historically, most companies generally extend the audit deadlines as appropriate when requested by the Department of Revenue.

The purpose of a tax statute of limitations is to establish a reasonable time within which an audit must be brought so that the records, documents, and recollections of witnesses are not lost by the time the claims are finally raised. It also provides some limitation on the amount of interest that could accrue on any underpayment claimed in an audit. Extending the statute of limitations to six years could result in audits not being completed for six years, when they may have otherwise been done more quickly, increasing the interest risk to taxpayers.

The present three-year statute of limitations has worked well for all the taxes, including the production tax. We believe lines 7-9 on page 34 should be deleted.

Actual Pipeline/Marine Transportation Costs:

Sections 48 and 49, commencing on line 21 of page 35 and continuing through line 9 on page 36, is proposing that the Department of Revenue can substitute, at anytime, its determination of "reasonable" costs of transportation for the taxpayer's actual pipeline tariffs or marine transportation costs.

Currently, a taxpayer's actual transportation costs are used to determine the taxable value of the taxpayer's oil unless the Department establishes all three conditions set forth in AS 43.55.150(a). The proposed amendment would ease that standard to allow actual costs to be disregarded by an auditor by simply asserting the actual costs do not meet the auditor's view of "reasonableness", despite the existence of valid third party contracts or federally regulated tariffs.

The proposed amendment represents another instance where the Department of Revenue is asking the Legislature to allow it to selectively determine what costs it deems reasonable versus allowing the deduction of valid costs properly incurred. The proposed changes to AS.43.55.150(a) in Section 48 of the Committee Substitute should not be adopted.

In the Committee Substitute, Section 150(b) would be amended, commencing on line 2 of page 36, to provide that only tariff rates that "have been adjudicated as just and reasonable" by the RCA or other regulatory agency are considered prima facia reasonable. This could unduly restrict rates that will be considered as reasonable costs. In certain instances, tariff rates may be properly filed, as currently allowed, and

November 8, 2007

not challenged by any party or allowed to go into effect on an interim basis. In such case there may not be a final "adjudication" of the reasonableness of the rates when they go into effect. If challenged, a period of time may pass before the rates are finally determined to be just and reasonable. Any such final determination by the relevant regulatory agency will address any revision in the rate that may be required, including for prior periods. These matters should be left to the determination of the regulatory agencies with responsibility for such matters. There is no need to further condition how these rates will be used to determine allowable transportation costs. Subsection 150(b) should not be revised as proposed.

Location of Lease Expenditures:

Paragraph (2) of Section 52, commencing on line 31 of page 39, and further modified by Paragraph (2) of Section 53, commencing on line 19 of page 40, would limit qualified lease expenditures to only those associated with activities physically located on the premises of the lease or property from which oil or gas is recovered.

Limiting lease expenditures to those incurred physically within the producer's or explorer's lease or property where oil or gas is recovered would reduce the attractiveness of development and exploration activities. Given the extreme arctic conditions and limited construction capabilities on the North Slope, necessary equipment and production modules are often fabricated elsewhere for delivery to the Slope. Drilling rigs, unavailable in Alaska but needed for exploration and well work, are imported from the Lower 48. These are ordinary and necessary costs required for the operation of the North Slope production facilities and exploration activities, both essential for the future development of Alaska's resources.

The proposed amendment would also allow an auditor to disallow valid upstream costs if no oil or gas is recovered on the property, regardless if the costs are ordinary and necessary for the prudent and safe operation of the upstream facilities. For example, this proposal would disallow costs associated with a warehouse storing emergency response equipment or a facility housing North Slope workers located on a property that has no production, exploration and development occurring at the time, despite such costs being essential for oil production on the North Slope.

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Disallowing such costs would reduce the attractiveness of future development and exploration projects and diminish the likelihood of those projects being funded. The proposed amendment to Paragraph (2) should not be adopted.

Costs Arising From Noncompliance With Lease/Permit/License Terms:

Paragraph (6) of Section 54, commencing on line 2 of page 41, is proposing to disallow expenditures that result from failure to comply with lease obligations or permit requirements. Such a limitation raises a number of concerns. In certain instances, a lease term is a matter of contract between the lease holder and the state as a contracting party. The contract typically will spell out the means for redress by the parties and the consequence of a "breach" of the contract. This should provide adequate remedies for the state to ensure contract obligations are met. In the case of a federal permit, there likely will be specific provisions that address the consequence of any permit non-compliance and what the permit holder must do to remedy the problem. These provisions are adequate to address any concerns for the state.

There is no recognition in the proposed language of the severity of the non-compliance, or the efforts by the leaseholder or permit holder to comply. This is different from an act of "fraud" or "willful misconduct" contained in the current law. This is complicated by the uncertainty in the proposed language on how such a determination will be made. Particularly if the state is a party to a lease, there should be a separate determination whether there has been non-compliance with the lease term or permit and the remedy should be as spelled out in the contract (or as allowed by existing law). The language "...or failure to comply with an obligation under a lease, permit, or license issued by the state or federal government" is unnecessary.

Disallowance/Limitation Of Costs Associated With Refineries/Crude Oil Topping Plants:

Paragraph (19) starting on line 30 of page 42 proposes to disallow and limit costs associated with refineries and crude oil topping plants, essential components of producing oil from the North Slope.

Currently, the State of Alaska and the federal government require North Slope operators to convert to ultra low sulfur diesel to operate all North Slope motor vehicles and off road equipment. The North Slope producers are considering a modification to the existing Kuparuk crude oil topping plant to produce the required ultra low sulfur diesel. The proposed amendment reduces the economic viability of a potential crude oil topping plant modification. Without a modification to the existing crude oil topping plant, it will be necessary to haul low sulfur diesel up to the slope, requiring up to 50 trucks per day. This could potentially increase environmental impacts, including increased exhaust emissions and potential spill risks from truck accidents. Costs associated with the topping plant should therefore be recoverable just as the costs to truck diesel to the Slope would be.

The Administration's proposed amendment encourages a less optimum solution for the oil industry and the State. Paragraph (19) would increase operating costs while complicating business operations and should not be adopted.

Disclosure Of Tax Information:

Section 57 of the Committee Substitute, commencing on line 24 of page 44, proposes the publication of certain proprietary tax information when such information is aggregated among three or more producers or explorers. We understand the Administration's and Legislature's desire to obtain information necessary for the development of the PPT net tax framework to provide the State of Alaska with a fair return on the development of its energy resources. We also support the Administration's goal of transparency. Aggregation of information from three companies dramatically increases the likelihood that competitors, including competitors whose information is being aggregated, will be able to determine individual company proprietary information.

Such information could be used by competitors to discern information regarding operating costs, investments, contract terms, or other competitive information. This risk of individual company proprietary information being ascertained by competitors could also create conflicts between the proposed amendment and federal protections provided in the Federal Trade Secrets Act and federal Anti Trust laws. The proposed amendment may also violate the Alaska Constitution's right of privacy, equal protection and unlawful takings of commercially sensitive data protections.

The Legislature should ensure taxpayer information remains confidential.

November 8, 2007

Elimination Of Requirement For Joint Interest Billings As Starting Point For Audits:

Section 59 of the Committee Substitute, appearing on line 30 of page 45, proposes to repeal AS 43.55.165(c) and (d). The effect of repealing those sections would be to remove the joint interest billings as the starting point for audits. As a non-operator at Prudhoe Bay, Kuparuk, Duck Island and Granite Point we fail to see how not using this information is to anyone's advantage.

In a field's joint operating agreement the working interest owners have specified what costs an operator can bill to the co-owners. All of a producer's deductible lease expenditures are in accordance with the monthly cost data charged by the field operator to its co-owners. Each year the operator is subjected to very detailed audits by the other owners to ensure compliance with the limitations in those agreements. ExxonMobil currently spends over 100 staff weeks each year auditing operator joint billings to ensure we are not charged any inappropriate costs.

The use of these joint interest billings as the foundation of allowable business expenses would provide greater predictability and eliminate the need for the State to re-audit the same materials. Using joint interest billings will reduce disputes over appropriate deductions as well as the State's and the producers' administrative and audit costs. AS 43.55.165(c) and (d) should not be repealed.

FISCAL PREDICTABILITY IS IMPORTANT

I would now like to address another important element of the business environment for any investor - fiscal predictability. Our investments are capital intensive and typically evaluated over timeframes of decades. A change in the fiscal regime has a direct impact on how we view predictability of the Alaskan fiscal environment. This directly impacts how we evaluate on a risked basis future investment decisions.

The Administration's proposed tax increase would represent the third significant change to Alaska's fiscal terms in the past three years. As a result of these changes, the industry tax burden has increased by approximately 350% at today's prices. With the current Committee Substitute proposal the tax increase would be approximately 470% under today's prices. Changing the fiscal environment for capital intensive projects, that take many years to generate a return, can only reduce the attractiveness of future investments. For every well or project not progressed, additional production and State revenues are forgone. Alaska needs to double its current investment levels in the near term to achieve the Department of Revenues production forecast. Increasing taxes will not encourage the increasing investment needed.

ExxonMobil expects to be involved in Alaska for many years to come. The policies established today, and in the future, will impact the attractiveness of potential projects and the future of Alaska.

November 8, 2007

ALASKA NEEDS A LONG-TERM RESOURCE DEVELOPMENT POLICY

ExxonMobil believes a long-term sustainable resource development policy is required to enable Alaska to maximize its oil and gas resource. We believe there are many factors that need to be considered. I hope that key points addressed in my testimony are considered:

- Alaska has significant resource potential, but it is in a high cost environment
- Oil production is one third of its peak, yet we have only produced one fourth of the oil resource potential. The gas resource potential is equal to oil.
- In 10 years, 75% of Alaska's future oil production needs over \$30-40 billion of new investments - investments that are needed sooner than 10 years.
- Prudhoe Bay and Kuparuk are the "hub" of the North Slope, they
 - Represent 70% of North Slope oil production for the next 10+ years
 - Can provide significant new production in the near term
 - Can be the backbone for future exploration and economic developments, whether it is existing production, future light oil, heavy oil, or gas
 - Need increasing investments to achieve their potential

November 8, 2007

We propose a collaborative approach to develop a sustainable long term resource policy that will encourage the needed increasing investments and build the future of Alaska for many generations to come. We believe that a long term resource policy should consider:

- Characterization of state-wide resource potential
- Identification of key issues challenging exploration and development
- Key factors that impact resource value, such as research and technology, exploration and development costs, regulatory and environmental considerations, land access
- Establishment of goals and measurement of progress
- Fiscal policy that will encourage development of remaining resources
- Regular meetings with industry and agency representatives

ExxonMobil looks forward to working with the Administration, the legislators, industry and the people of Alaska in the future pursuit and development of its oil and gas resources.

Thank you again Mister Chairman for the opportunity to testify today.

Chevron



Testimony on SB2001/ HB2001

**John P. Zager
General Manager, Alaska**

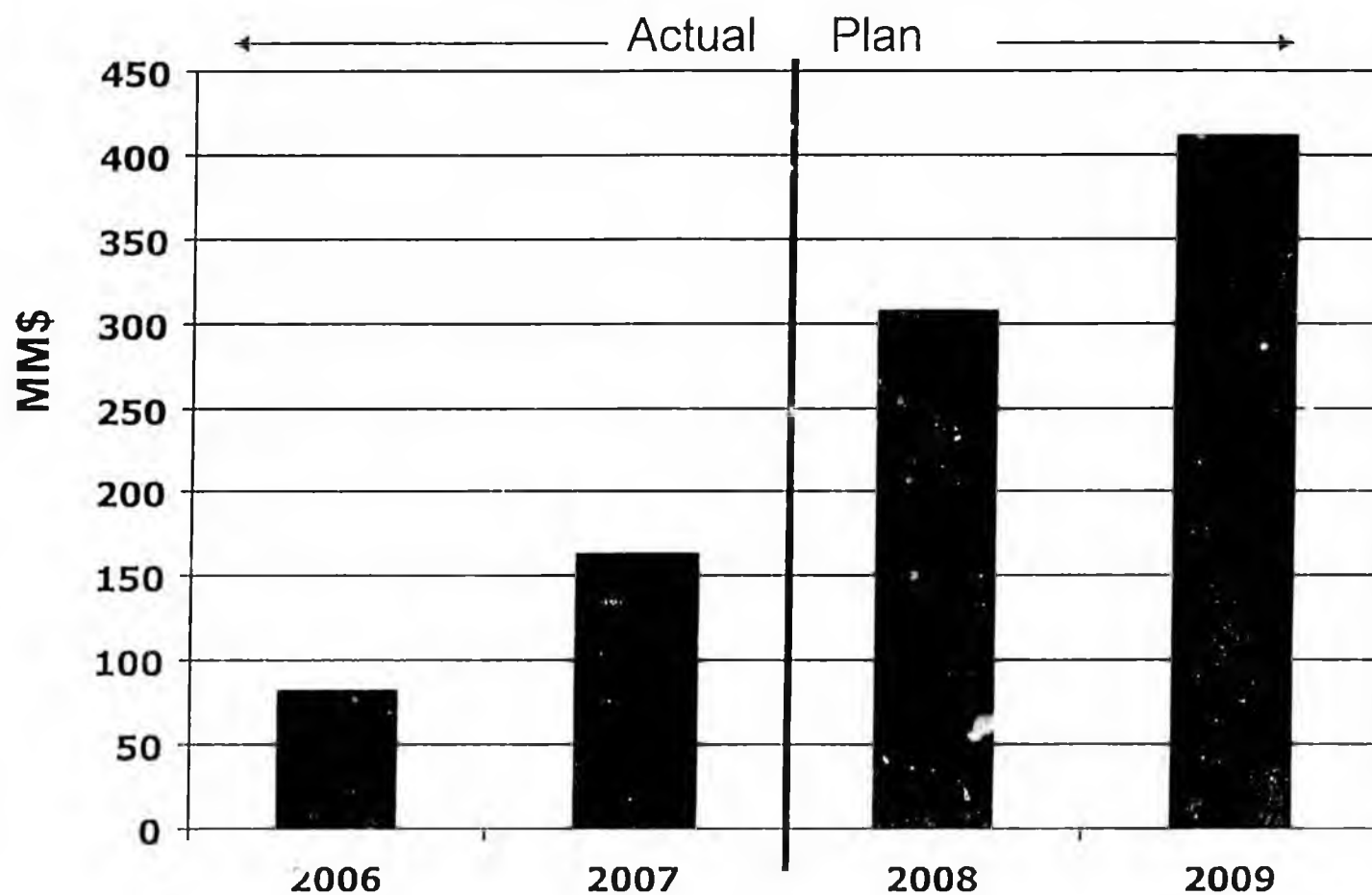


**Juneau, Alaska
November 8, 2007**



Chevron is increasing investment in the Cook Inlet and North Slope exploration under PPT

Capital Investment



Taxing the upside will deter investment

ACES EXAMPLE RISKED ECONOMIC ANALYSIS, 4 pt Economic Model

Example A – decision is to drill the well

MEAN EXPECTED VALUE
3.6

DRILL WELL ?
YES

POS
15.0%
Value
20.625



P90
P50
P10

POF
85.0%
Value
-17



FAILURE

NPV

300
100
25

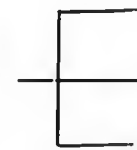
Heavily taxing the upside, can change the investment decision today

Example B – decision is to not drill the well

MEAN EXPECTED VALUE
-0.9

DRILL WELL ?
NO

POS
15.0%
Value
16.125



P90
P50
P10

POF
85.0%
Value
-17



FAILURE

NPV

200
100
25



Look at this bill as it morphs from the original version – is there any balance remaining?

- Base tax rate increase
- Aggressive progressivity
- Transitional Investment Credits reduced or gone
- Retroactive effective date
- Disallowance of certain costs & SB80 language
- Weakening of taxpayer confidentiality
- Multiple layers of penalties for mispayments and errant reporting

Please consider this bill as a whole and find places to restore some balance

Why should we be concerned about costs?



**Cambridge Energy Research Associates
Report issued 4/24/2006**

"RISING CAPITAL COSTS BEAR DOWN ON E&P PROFITABILITY"

"Higher oil and gas prices have encouraged a wave of new investments for discovering and developing resources. However, the soaring costs of exploration and production (E&P) programs and the volatility of energy prices have left many producers uneasy about future profit margins."

"* E&P capital costs are accelerating and have increased approximately 42 percent from 2000 to 2005 (third quarter) compared with a 15 percent rise in the Consumer Price Index."

"* Increasing costs and energy price volatility are having an impact on investments. Oil and gas projects that were profitable at \$22 per barrel in 2002 now require \$35 per barrel to achieve similar returns."

Actual Slides from Testimony to House Finance Committee on April 28, 2006



Parting Questions

- To what degree are you willing to risk future oil and gas investments in Alaska?
- To what degree are you willing to risk the Alaskan economy?
- Is Alaska "open for business"?
- Will Alaska have more or less opportunity for our children after this bill passes?



PIONEER

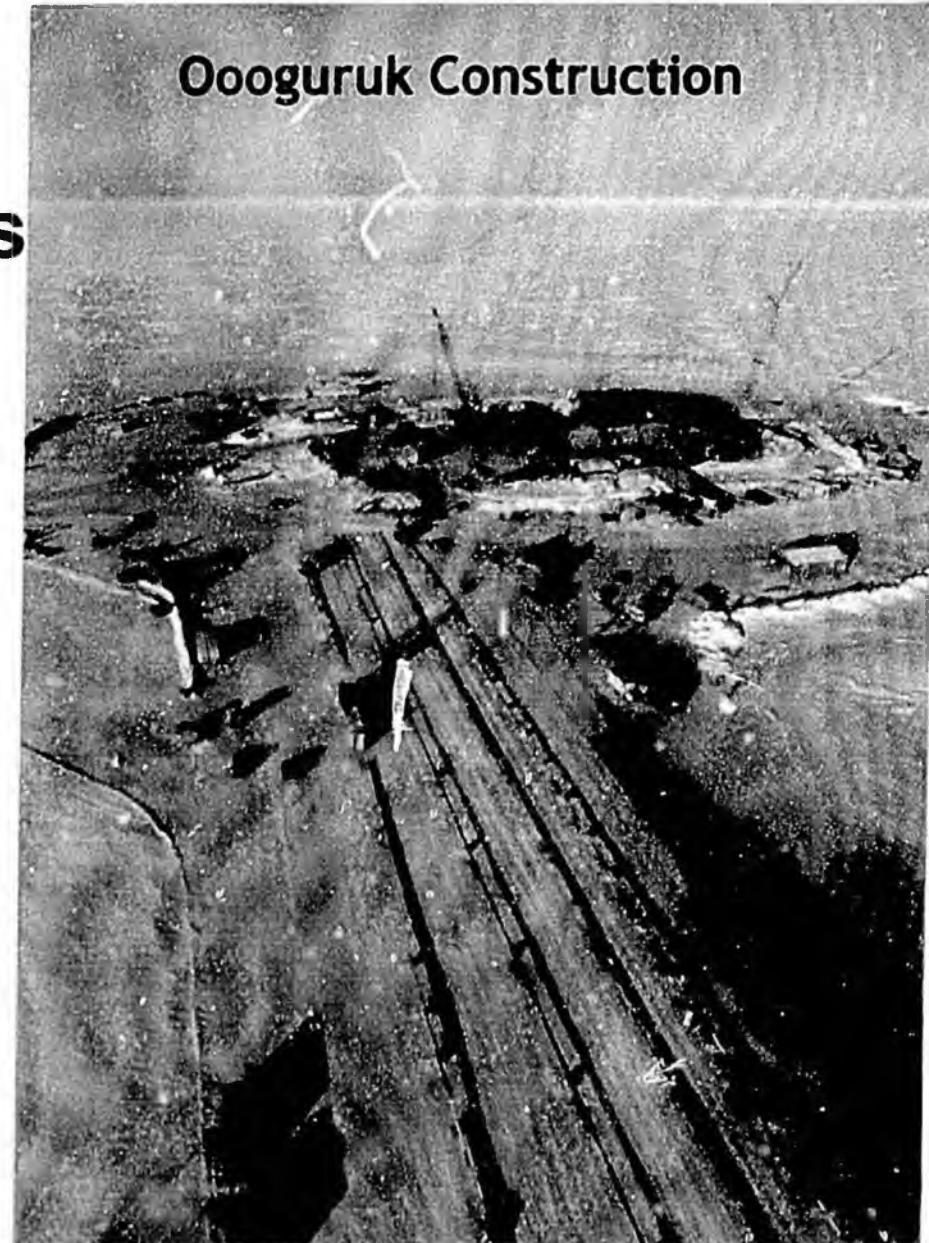
Pioneer's View of ESG

House Finance Committee
November 8, 2007

NYSE: PXD
www.pxd.com



- **Pioneer Profile**
- **Oooguruk Project Benefits**
- **General Policy Concerns**
- **NPSL “Fair Share”**
- **Exploration Incentives**
- **Conclusion**



- **Entered Alaska in late 2002**
- **Oooguruk Unit Operator**
- **Cosmopolitan Unit Operator**
- **~1.5 million acre leasehold**
- **11 NS exploration wells**
- **35 local Alaska staff**

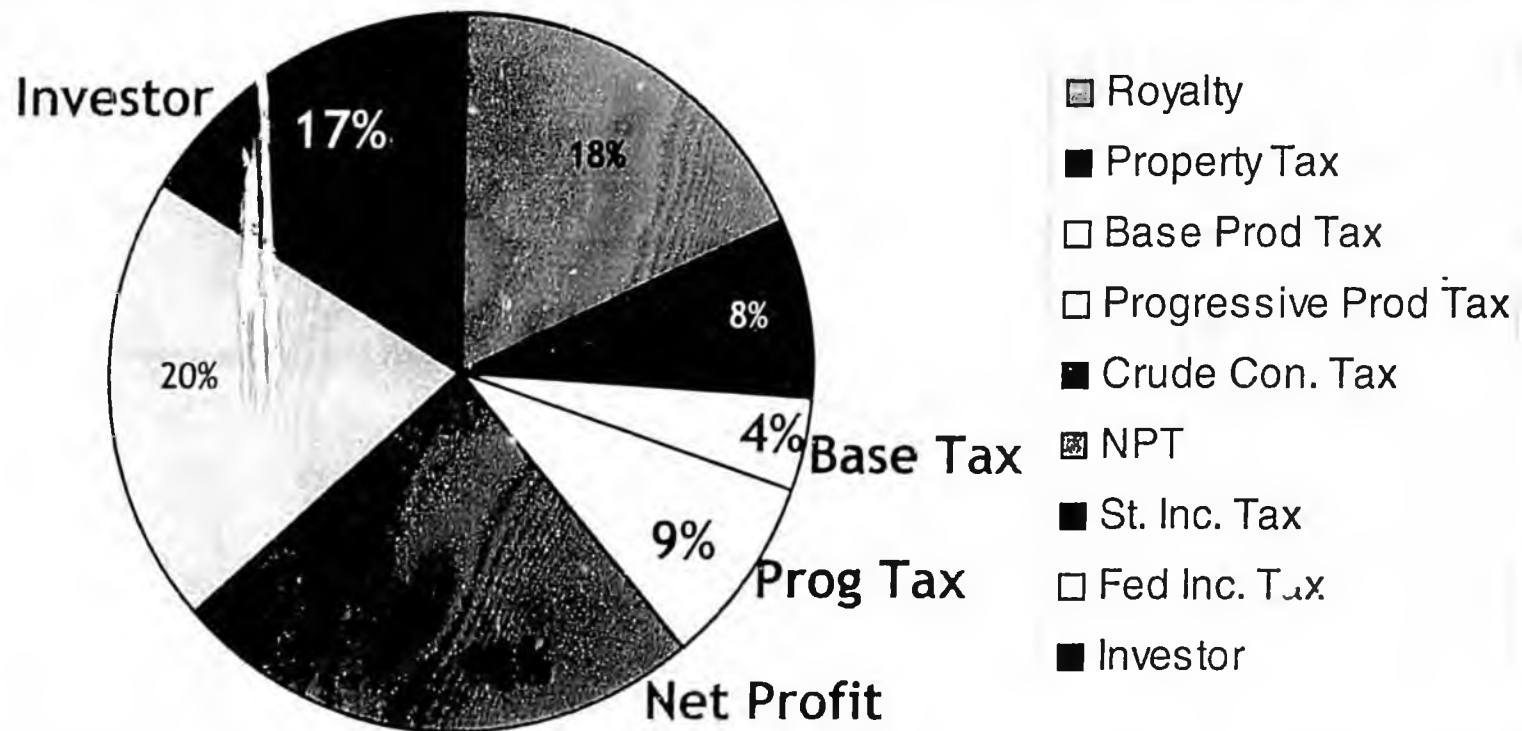
- **First independent NS oil producer**
- **First third party facility access**
- **Trailblazer for other investors**
- **Royalty + 30% net profits to SOA**
- **State income tax**
- **Property taxes to NSB**
- **Construction & Operating jobs**
- **Contractor profits**

Future Operating Statistics	
Gross Reserve Potential	70 - 90 MMBO
First Production	2008
Gross Peak Flow Rates	15 - 20 MBOPD
Productive Life	25+ Years

- **Satisfaction with the state of the local Industry?**
 - Legacy fields 6% annual production decline
 - Limited activity from new players
- **Is AK attractive to independents for investment?**
 - Investment competition for Independents is L-48 resource plays:
 - Lower cost - Shorter cycle time - Greater flexibility
 - Lower take - No progressivity – Price upside retained by investor
- **Will current bill improve this situation?**

- **Progressivity is an attempt to capture price windfall**
- **NPSL obligation is over and above Production Tax**

Ooquruk Estimated Lifecycle Take Split (mm\$ - Discounted - @\$70)



- **Net Profit Payments already capture 30+% of all profits**

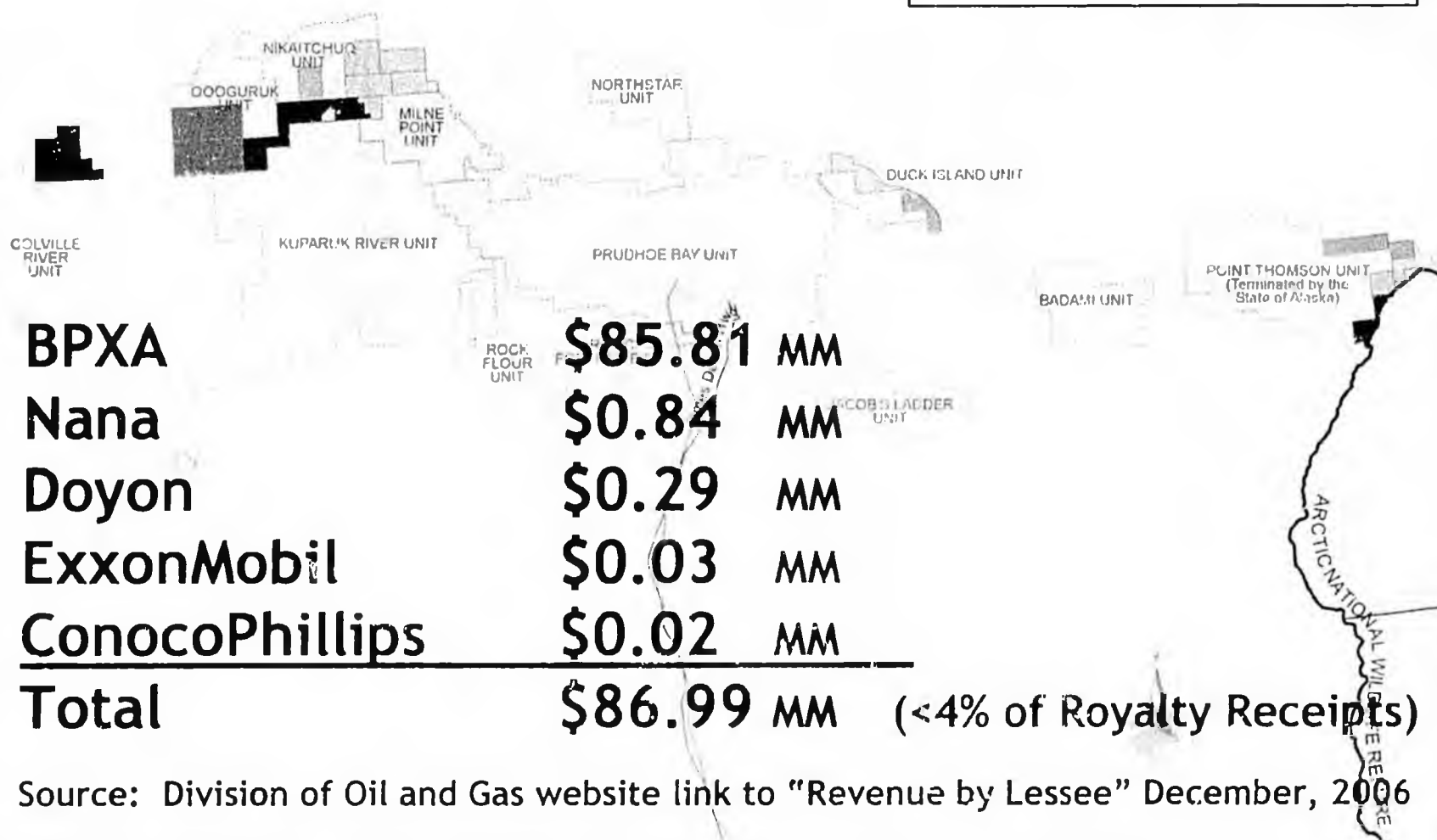
Equitable Solution: Credit NPSL payments against Progressivity

CURRENT NET PROFIT LEASES ARCTIC SLOPE & BEAUFORT SEA, ALASKA



CURRENT NET PROFIT LEASES BY OPERATOR

-  BPXA
-  CHEVRON
-  CPAI
-  ENI US
-  EXXON MOBIL
-  PIONEER NR
-  CURRENT LEASES



Source: Division of Oil and Gas website link to "Revenue by Lessee" December, 2006

- **Current Program Incentives Exploration**

- **Proposed Program Cumbersome & Reduces Incentives**
 1. Explorers must prove well tests separate new trap
 2. Wells must be pre-approved by the DNR Commissioner
 3. DNR must determine geologic objective was achieved
 4. Well data now includes All derivative work products
 5. Well data goes public 24 months after delivery, no extensions

- **A Program without certainty does not affect investment**

- **Pioneer has been an aggressive investor to date**
- **Proposed changes makes all N S projects less competitive**
 - Vast majority of Pioneer's investment opportunities are not burdened by Progressivity – Price upside is retained
 - At higher prices AK Opportunities are even less competitive
- **Raising taxes will push marginal projects off the table**
- **Unfunded projects create zero royalty, tax or jobs**
- **State already captures price upside on NPSL Leases**
 - Credit of NPSL payments against progressive tax is fair & equitable
- **Full protection of TIE credits remains important to Pioneer**

- **Does current bill motivate the desired behavior?**

bp



BP Presentation on HB 2001CS
House Finance Committee

Claire Fitzpatrick and Bernard Hajny
November 7, 2007

Is the bill true to the stated Guiding Principles for the New Production Tax System?



- Fair Revenue to the State (Higher)
 - Share upside benefit and downside risk
- Attractive Investment Climate – new exploration and reinvestment in existing fields (including heavy oil)
- Transparency – reduce the risk to the state
 - Clear to both state and taxpayer

Does the current bill accomplish these objectives relative to PPT?



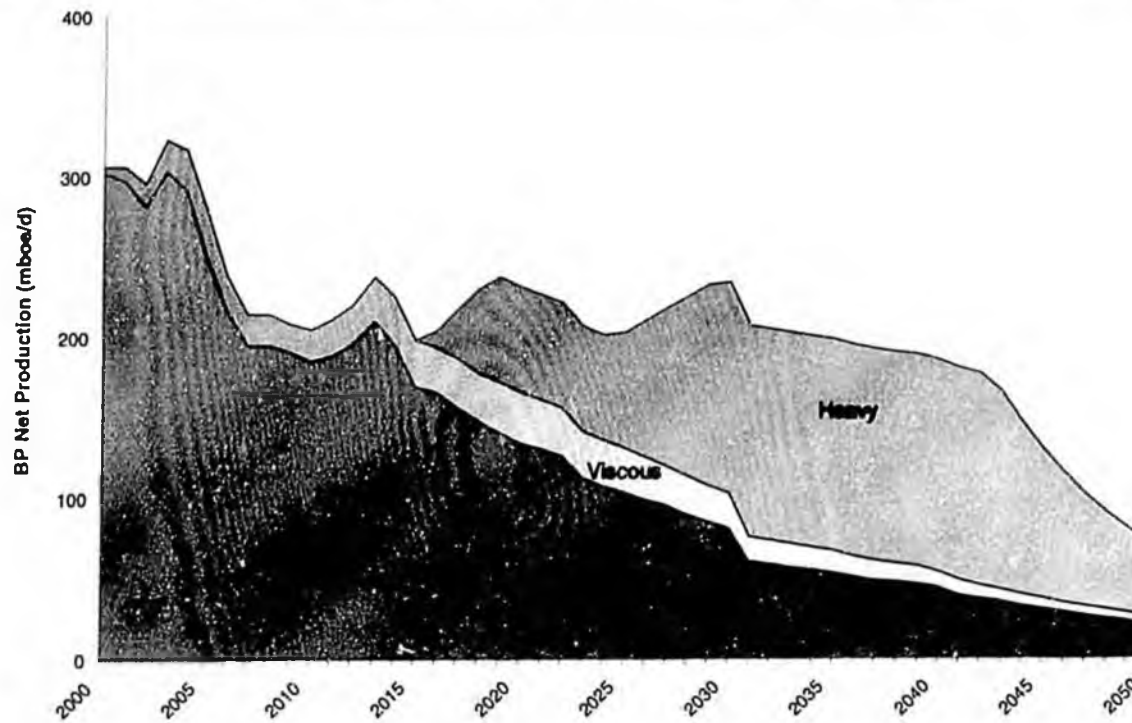
Proposed Measures	Fair? (HIGHER) Revenue	Attractive Investment Climate	Clear and Transparent
Tax Rate of 25% vs. 22.5%	✓	✗	NA
Gross Progressivity	✓	✗	✗
Capital Credits	Neutral	Neutral	Neutral
TIE Credits 3 years vs 5	✓	✗	NA
Takes away JIB use as basis for deductible costs	?	✗	✗
DR&R Non Deductible	?	NA	NA
Excludes ULSD Plant	?	✗	✗

Does the current bill accomplish these objectives relative to PPT?



Proposed Measures	Fair? (HIGHER) Revenue	Attractive Investment Climate	Clear and Transparent
Costs must be physically on lease	✓	✗	✗
Transportation deductions limited to those ruled by RCA	✓	✗	✗
\$1000 per day penalty to provide information	?	Neutral	?
Retroactivity	✗	✗	✗
6 year statute of limitations for Audits	?	✗	✓
Publication of aggregated tax information for 3 or more taxpayers	NA	?	?

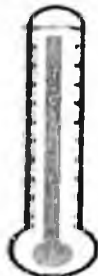
Impact of Investment Climate to Heavy Oil



Heavy Oil Benefits for Alaska

- ❖ Multi-billion spend in the market
- ❖ 50 years of production
- ❖ 2+ Billion new barrels of oil
- ❖ Many new jobs
- ❖ Alaska becomes recognized among industry leader in "Arctic Heavy Oil"
- ❖ Huge ripple effect on the Alaska economy

PPT or Better



Economic prize is big enough to try to unlock HO.

ACES



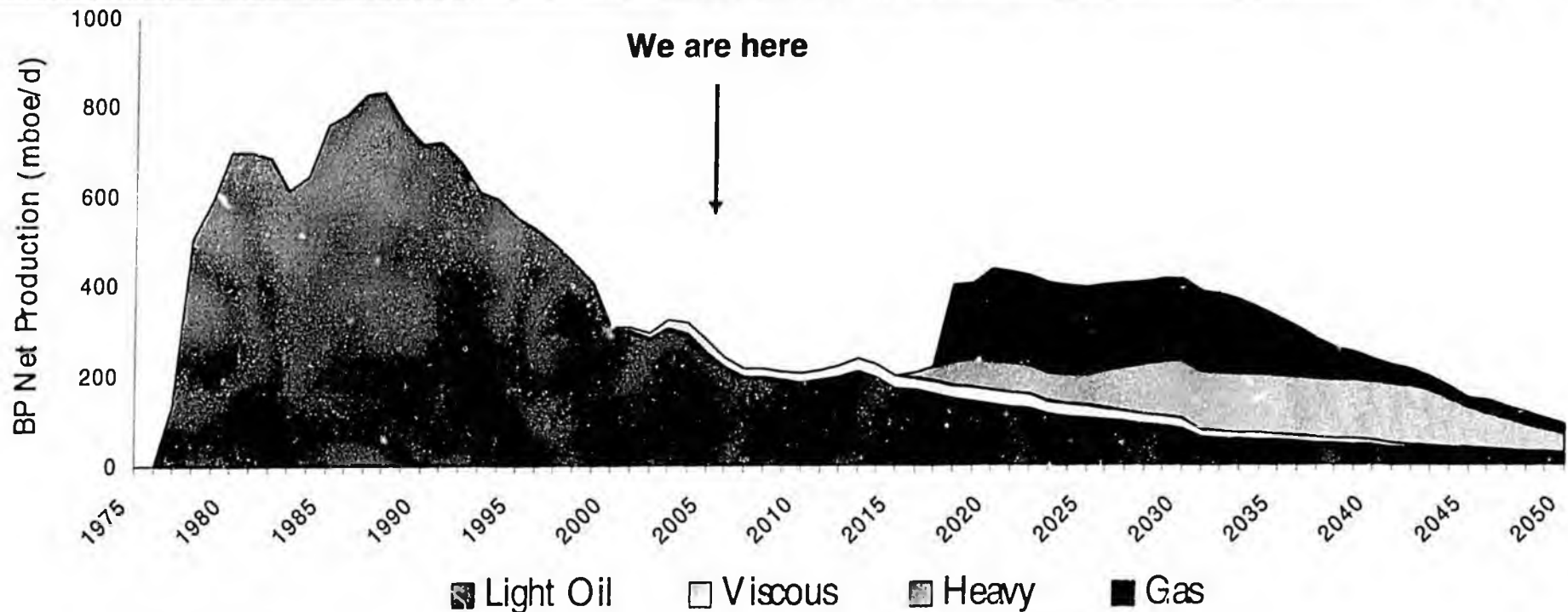
Economic prize is more marginal – may not be adequate to balance the risk.

Latest CS's



Unfavorable relationship between risk and reward.

BP Alaska – Building for the Future



Strategy

- **FOCUS** on the known Resource Base
 - Manage decline for Light Oil
 - Unlock Heavy Oil
- **ACCELERATE RENEWAL** of facilities, infrastructure and people
- **BRIDGE** to Gas

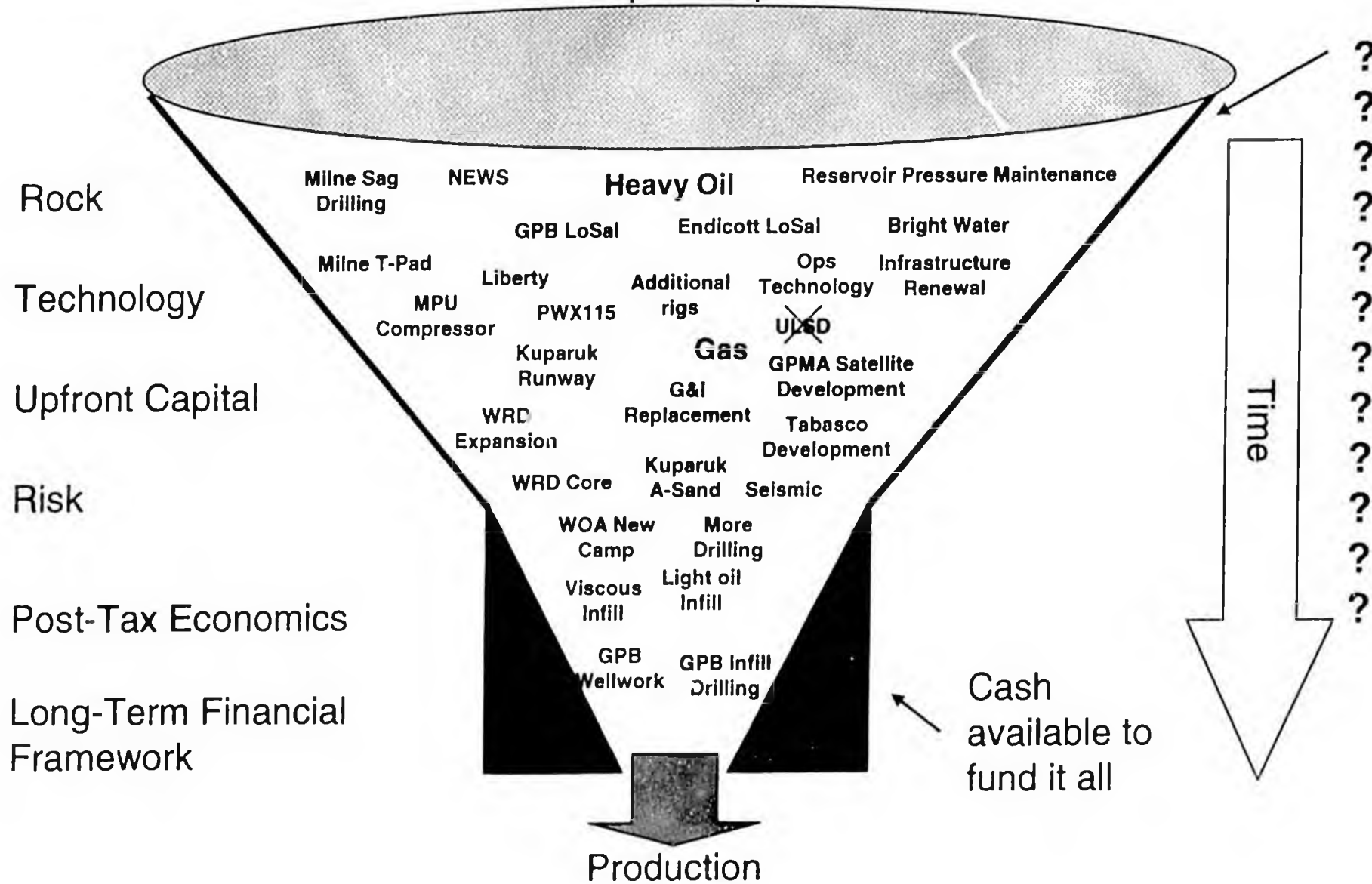
Enabling Themes

- Fiscal stability
- Facility & Infrastructure Renewal
- Organizational Renewal
- Technology Pull-through
- Reserves Progression
- Government & Regulatory Relationships

The Investment Hopper Squeeze



Development Options



Rep. Les Gara

From: Tremaine, Richard (DOR) [richard.tremaine@alaska.gov]
Sent: Wednesday, October 31, 2007 4:21 PM
To: Rep. Les Gara
Cc: Williams, Michael D (DOR)
Subject: Review of estimates of BP and ConocoPhillips profit margins for 2006

Rep. Gara,

You provided estimated profit margins for 2006 ConocoPhillips and BP in the range of 36% to 37%.

I have preliminarily reviewed unaudited PPT filings for these two companies for 2006. I have had to estimate federal and state corporate income tax. My preliminary review suggests that your profit margins underestimate actual profit margins these two companies enjoyed for ANS operations in 2006 after PPT and income tax calculations.

I hope this answers your question.

Dick Tremaine
Economist
Alaska Department of Revenue

*Distributed by
Rep. Gara*



Alaska State Legislature

Senator Bill Wielechowski

Representative Les Gara

716 W. 4th Avenue, Anchorage, Alaska 99501

October 22, 2007

James Bowles
President of ConocoPhillips Alaska
700 G St.
Anchorage, AK 99501

Doug Suttles
President of BP Exploration (Alaska) Inc.
900 E. Benson Blvd.
Anchorage, AK 99508

Dear Sirs:

We are writing to ask that you confirm your companies' Alaska profit margins which, by our calculations from your 2006 annual reports, seem much higher than your companies earn elsewhere around the world. While your companies are presenting the public with selective information stating that costs in Alaska are high, we have not heard your companies mention to the public that under the current Alaska tax system, your companies are left with higher profit margins in Alaska than almost anywhere else in the world. We would appreciate confirmation that we are not missing any information when looking at your annual reports.

According to Conoco's 2006 Annual Report, that company earned \$2.3 billion in clear Alaska profit on 6.5 billion in total Alaska revenues. That leaves Conoco with a profit margin (profits earned as a percent of total revenue) of roughly 36%. That is the second highest profit margin Conoco reports of any other region where it does business around the world, and is a far higher margin than Conoco earns on average worldwide. According to Conoco's 2006 report, it's world profit margins are as follows:

<i>Region</i>	<i>Profit Margin</i>
Alaska	36%
Middle East/Africa	7%
Russia	Negative
Europe	22%
Lower 48	27%

Canada	30%
Pacific/Asia	42% (but \$1.5 billion in profit compared to \$2.3 billion in Alaska)
Worldwide Average	28%

According to BP's 2006 Annual Report, it earned \$2.2 billion in profits on \$6 billion in revenue in Alaska in 2006. That is more than triple the profit margin BP earns worldwide. While BP does not appear to report its profits in other areas by region, its Annual Report shows a roughly 36.5% profit margin in Alaska. According to BP's 2006 Annual Report, worldwide BP earned less than a 10% profit margin (\$22 billion in profit on \$274 billion in revenue).

In April, 2007, both companies completed their 2006 tax payments, and it is not clear whether those final payments are reflected in your 2006 annual reports, and we ask that you confirm whether or not that is the case.

Assuming the 2007 payments need to be subtracted from your companies' 2006 profit numbers, those numbers change very little. In April all Alaska oil producers paid, in total, supplemental "true up" tax payments of roughly \$1 billion. Companies only pay 65% of this amount (\$677 million), since 35% of this amount gets deducted from your Federal tax payments. Roughly 42% of Alaska's North Slope oil is produced by Conoco, and 35% by BP. The Department of Revenue will be asked to confirm these numbers, but our best estimate is that Conoco's profit would be reduced by \$285 million (42% of \$677 million), and that BP's profit would be reduced by \$237 million (35% of \$677 million).

Using these estimates, even assuming the true up payments were not reflected in your companies' 2006 profit reports, those profit numbers would be adjusted as follows: Conoco's profit margins and profits would be reduced from 36% to 31.4%, and \$2.3 billion to \$2.05 billion respectively. That would still leave Alaska as Conoco's second highest profit margin region in the world. BP's margins and profits would be reduced from 36.5% to 32.6%, and \$2.2 billion to \$1.96 billion respectively.

We would appreciate it if you would advise us whether your companies' 2006 annual reports reflected the 2006 true up payments made in 2007, and, if not, how much your companies paid in 2006 taxes, after the 35% federal tax deduction you receive.

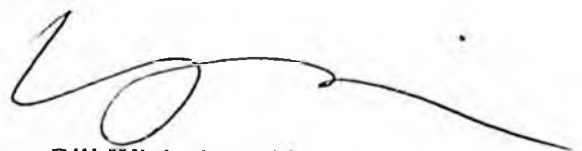
As we proceed with discussions on an appropriate oil tax, the public is entitled to know the profits your companies are making from holdings on the highly profitable Prudhoe Bay, Kuparuk and Alpine fields (Conoco has shares in all three).

Thank you.

Sincerely,



Rep. Les Gara



Sen. Bill Wielechowski

ConocoPhillips 2006 Alaska Profits

• Results of Operations

Year Ended	Millions of Dollars										
December 31	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2006											
Sales	\$ 6,304	3,408	9,712	2,951	5,950	3,755	1,965	—	140	24,473	5,161
Transfers	210	4,023	4,233	—	2,954	9	542	—	—	7,738	2,821
Other revenues	2	56	58	145	14	(8)	127	—	4	340	108
Total revenues	6,516	7,487	14,003	3,096	8,918	3,756	2,634	—	144	32,551	8,090
Production costs excluding taxes	708	893	1,601	706	814	324	215	—	27	3,687	739
Taxes other than income taxes	914	554	1,468	52	37	91	10	1	30	1,689	3,444
Exploration expenses	105	222	327	246	73	121	44	32	17	860	46
Depreciation, depletion and amortization	460	2,272	2,732	1,155	1,200	512	220	1	21	5,841	461
Property impairment	—	15	15	131	—	10	—	—	19	175	—
Transportation costs	610	555	1,165	104	316	89	18	—	10	1,702	420
Other related expenses	11	44	55	15	87	18	38	43	28	284	52
Accretion	34	36	70	39	97	8	2	—	—	216	6
Provision for income taxes	3,674	2,896	6,570	648	6,294	2,583	2,087	(77)	(8)	18,097	2,922
	1,409	1,064	2,473	(193)	4,578	1,061	1,931	(13)	(7)	9,830	891
Results of operations for producing activities	2,265	1,832	4,097	841	1,716	1,522	156	(64)	(1)	8,267	2,031
Other earnings	68	183	251	191	335	62	32	(4)	(25)	842	133
Net income (loss)	2,333	2,015	4,348	1,032	2,051	1,584	188	(68)	(26)	9,109	2,164
Results of operations for producing activities of equity affiliates	—	—	—	—	—	—	(6)	1,229	808	—	2,031

BP (Alaska) Inc. 2006 Profits

Income statement

\$ million

For the year
ended 31
December

2006

	Issued	Guarantor	Other subsidiaries	Eliminations and reclassifications	BP group
	BP Exploration (Alaska) Inc.	BP p.l.c.			
Sales and other operating revenues	4,812	-	265,906	(4,812)	265,906
Earnings from jointly controlled entities - after interest and tax	-	-	3,553	-	3,553
Earnings from associates - after interest and tax	-	-	442	-	442
Equity accounted income of subsidiaries after interest and tax	570	23,119	-	(23,689)	-
Interest and other revenues	627	187	881	(994)	701
Total revenues	6,009	23,306	270,782	(29,495)	270,602
Gains on sale of businesses and fixed assets	-	105	3,714	(105)	3,714
Total revenues and other income	6,009	23,411	274,496	(29,600)	274,316

Purchases	506	-	191,429	(4,812)	187,183
Production and manufacturing expenses	814	-	22,479	-	23,293
Production and similar taxes	605	-	2,956	-	3,621
Depreciation, depletion and amortization	374	-	8,754	-	9,128
Impairment and losses on sale of businesses and fixed assets	109	-	440	-	549
Exploration expense	14	-	1,031	-	1,045
Distribution and administration expenses	20	278	14,264	(115)	14,447
Fair value (gain) loss on embedded derivatives	-	-	(608)	-	(608)
<hr/>					
Profit before interest and taxation from continuing operations	3,447	23,133	33,751	(24,673)	35,658
Finance costs	--	702	895	(879)	718
Other finance expense (income)	11	(675)	462	-	(202)
<hr/>					
Profit before taxation from continuing operations	3,436	23,106	32,394	(23,794)	35,142
Taxation	1,243	686	10,587	-	12,516
<hr/>					
Profit from continuing	2,193	22,420	21,807	(23,794)	22,626

operations Profit (loss) from Innovene operations	-	-	(25)	-	(25)
Profit for the year	2,193	22,420	21,782	(23,794)	22,601
Attributable to BP shareholders	2,193	22,420	21,496	(23,794)	22,315
Minority interest	-	-	286	-	286
	2,193	22,420	21,782	(23,794)	22,601

The following is a summary of the adjustments to the profit for the year attributable to BP shareholders which would be required if US GAAP had been applied instead of IFRS.

		\$ million			
		2006			
	Issuer	Guarantor		Eliminations and reclassifications	BP group
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries		
Profit as reported	2,193	22,420	21,496	(23,794)	22,315

Source: Figures from BP PLC SEC Filings for 2006; pg.185

Available at: <http://www.sec.gov/Archives/edgar/data/313807/000115697307000346/b848881-20f.htm>

**CS HB 2001 Testimony
November 8, 2007**

ConocoPhillips Alaska

Kevin Mitchell

Vice President, Finance & Administration

Jim Taylor

Vice President, Commercial Assets

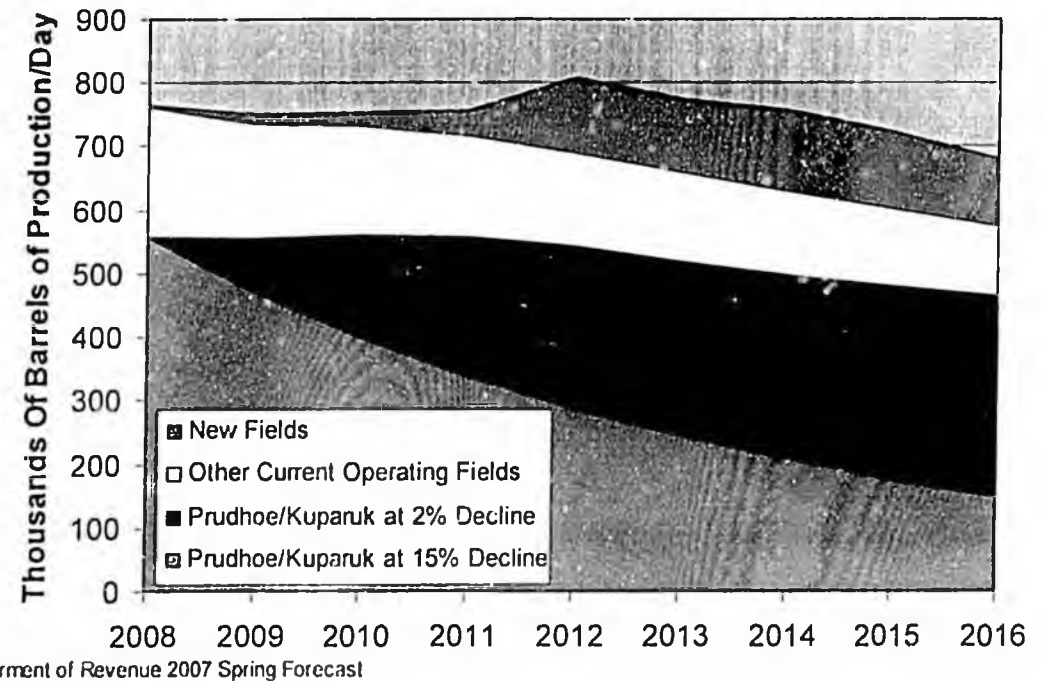
ConocoPhillips

Summary of CS Bill

- Less attractive climate for investors:
 - Increased base rate
 - Increased progressivity
 - Multiple changes to deductions and other provisions
- Will have an impact on decisions
- Will result in less investment

Tax System and Investments

- Base rate increase
- Progressivity increase
- Gross elements
- Reduced TIE credits



A tax system formulated on the most economic projects will deter investment on more marginal projects, including Heavy Oil

Other Provisions

- Out of state exclusion
- Topping plant exclusion
- DR&R exclusion
- “Reasonable” transportation costs
- Exploration confidentiality
- 6 year statute of limitations
- Retroactive implementation

Impact on Investment Climate

- Enhanced EICs – Positive
- Base rate increase to 25% – Negative
- Increased progressivity – Negative
- Progressivity on gross – Negative
- Reduce TIE credits – Negative
- Exclude out of state costs – Negative
- Exclude topping plant – Negative
- “Reasonable” transportation costs – Negative
- Exclude DR&R – Negative
- Exploration data confidentiality – Negative
- Retroactive implementation – Negative

ADMINISTRATION

State of Alaska
Department of Revenue
Commissioner's Office



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

November 7, 2007

The Honorable Mike Chenault
Co-Chair, House Finance Committee
State Capitol, Room 505
Juneau, AK 99801-3100

Cc: All Members, House Resources Committee

Re: Request for Outline of Department of Revenue Penalty Provisions

Dear Representative Chenault:

Attached is a short description of the penalty provisions applicable to taxpayers under Alaska's current oil and gas production tax laws and proposed changes, as requested today by Representative Hawker.

Sincerely,

Marcia Davis, Deputy Commissioner
Department of Revenue

Tax Penalties Under Current Law and Proposed under CSHB2001(RES) and CSSB 2001(JUD)

Distributed by the Department of Revenue

November 6, 2007

I. CURENT LAW

1. Penalties applicable to all state tax types.

Under AS 43.05.220, the state may levy three types of civil penalties for failure to file a return or report or pay the full amount of tax:

- basic penalty for underpayment or failure to file
- penalty for negligence
- penalty for fraud

All three are general provisions applying to all state taxes, including the oil and gas production tax. Penalties are calculated as a percentage of the tax deficiency and are cumulative, so that a fraudulent taxpayer, for example, could be assessed the fraud penalty, in addition to the negligence penalty and the basic failure to file or pay penalty.

2. Federal IRS Penalties Incorporated into State Law

Additional penalties are levied under the Internal Revenue Service code, for which the state has no equivalent. The state has incorporated these penalties in its corporate income tax structure by reference in AS 43.20.021. These include penalties for deficient estimated taxes, substantial understatement, Gross Value Misstatement, and others that are less significant for state purposes.

3. Penalties unique to oil and gas production taxes (AS 43.55).

HB 2001 did not propose any change to the applicability of the general penalties and their application to the oil and gas production tax. Currently, there are no penalties specific to the failure to file or the underpayment of taxes due under AS 43.55.

II. PROPOSED CHANGES TO LAW

1. Penalties Associated with Reporting Requirements.

SB/HB 2001, CSHB2001(RES) and CSHB2001(JUD) propose to add penalties for failure to comply with the proposed information reporting

requirements. (See Sec. 43 and Sec. 45 of CS House Bill 2001(Res)). The penalty provisions allow the department to assess not more than \$1000 per day for each day a taxpayer fails to make the required report. These additional penalty provisions are necessary because the existing penalties are structured as a percentage of a tax deficiency and the reporting requirements do not have associated tax deficiencies. These penalties will ensure that the Department receives timely and complete reporting of costs, potential tax credits, etc., from explorers and producers to enable it to fulfill its revenue forecasting duties for the Governor and the Legislature.

2. House Penalty for Improper Monthly Installment Payments.

Section 25 of CSHB2001 (RES) also proposes a 5% civil penalty for failure to file timely the monthly installment payments due under AS43.55.020(a)(1)-(4). This provision is necessary because under the House bill, production tax is owed annually, and the monthly estimated payments would not give rise to tax deficiencies. Therefore current penalties structures would not function with this monthly reporting structure.

3. Senate Penalty for substantial and gross understatement of tax.

Section 49 of CSSB 2001 (JUD) provides for a 20% and 40% penalty for substantial and gross understatement of tax, in a manner similar to the federal IRS rules. A substantial understatement is greater than 10% of the tax requirement or at least \$10 million. A gross understatement is greater than 20% of the tax requirement or at least \$20 million.

The following is more detailed information about the penalties identified above:

Failure to File (Basic) Penalty

State of Alaska / Federal, IRS

The basic failure to file penalty arises when the taxpayer fails to file a return or report when required or pay the full amount due. The penalty levied by the state in this case, is generally the same as would be issued by the Internal Revenue Service (IRS). Five percent of the unpaid balance of the tax liability is added to a tax for each 30 day period, or fraction of the period of noncompliance. This penalty may not exceed a total of 25% of the unpaid

balance. The penalty may be forgiven if the taxpayer shows that the failure to file or pay is due to reasonable cause and not willful neglect.¹

Reasonable cause is not easy to show and the burden of proof lies with the taxpayer. The taxpayer must demonstrate in writing, and under penalty of perjury, that they acted in good faith to take all reasonable steps to ensure timeliness of the filing or payment. In determining whether the taxpayer has shown that the failure was due to reasonable cause and not willful neglect, the department considers the standards imposed by the Internal Revenue Code. Circumstances that may constitute reasonable cause include acts of God, war, other disaster that made filing or delay unavoidable, or acts by another person beyond the control of the person required to file.²

Fraudulent Failure to File

Federal, IRS

Fifteen percent of the unpaid balance of the tax liability is added to a tax for each 30 day period, or fraction of the period of noncompliance. This penalty may not exceed a total of 75% of the unpaid balance.

Negligence Penalty

State of Alaska

In addition to the basic penalty, if a deficiency is due to negligence or intentional disregard of a law or regulation, the department will, in its discretion, assess a penalty of 5% of the total amount of the deficiency. The penalty is calculated based on the total deficiency, even if only a part of the deficiency is due to negligence or intentional disregard. Negligence or intentional disregard may be shown by any relevant evidence including that the taxpayer has substantially deviated from the statutes or regulations, failed to keep adequate records, exaggerated deductions, or understated income without justification.³

Federal, IRS

Federal accuracy-related penalties are generally set at 20% of the portion of the underpayment. This applies to:

¹ AS 43.05.220(a). For more detail on failure to file and failure to pay penalties, see 15 AAC 05.210.

² 15 AAC 05.200.

³ AS 43.05.220(b); 15 AAC 05.210(g). For more detail on the additional penalty for negligence or intentional disregard, see 15 AAC 05.220.

- Negligence
- Substantial Understatements: An understatement of the greater of \$5000 or 10% of the due tax
- Substantial Valuation Misstatements: Valuation is off by 200% or more

Gross Valuation Misstatement

This penalty is similar to other negligence penalties under the IRS code, for Substantial Valuation Misstatement, but applies when valuation is off by more than 400%. Under this circumstance, the penalty is increased from 20% to 40% of the portion of the underpayment.

Fraud Penalty

State of Alaska

If a deficiency is due to fraud, the department shall add a penalty equal to 50% of the tax due or \$500, whichever is greater. The penalty is calculated based on the total deficiency, even if only a part of the deficiency is due to fraud. To establish fraud, the department must show by clear and convincing evidence that the taxpayer understated a tax liability with the intent to evade tax. The intent to evade the tax may be shown by any relevant evidence including evidence of false explanations regarding income, false source documents, unjustified omissions or significant understatements of income, or substantial overstatement of a deduction.⁴

In addition to the three civil penalties discussed above, AS 43.05.290 provides for a number of criminal penalties for tax evasion and willful failure to comply with payment, filing, truthful accounting and information requirements, and for perjury. Along with several misdemeanors, penalties include felonies for willfully attempting to evade a tax, willfully failing to truthfully account for and pay a tax, and willfully and knowingly assisting in preparing or presenting a false return.

Federal, IRS

The IRS generally levies a penalty of 75% of the underpayment amount attributable to fraud.

⁴ AS 43.05.220(c); 15 AAC 05.230.

Proposed Changes to Current Law

1. Penalties Associated with Reporting Requirements.
SB/HB 2001, CSHB2001(RES) and CSHB2001(JUD)

AS.43.55.030(d)—Failure to file annual and monthly reports

(d) Reports **required under this section** [BY OR ON BEHALF OF THE PRODUCER] are delinquent the first day following the day the report is due. **The person required to file the report is liable for a penalty, as determined by the department under standards adopted in regulation by the department, of not more than \$1,000 for each day the person fails to file the report at the time required. The penalty is in addition to the penalties in AS 43.05.220 and 43.05.290 and is assessed, collected, and paid in the same manner as a tax deficiency under this title. In this subsection, "report" includes a statement.**

AS.43.55.040(6)—Failure to provide reports needed for state revenue forecasts

(6) assess against a person required under this section to file a report, statement, or other document a penalty, as determined by the department under standards adopted in regulation by the department, of not more than \$1,000 for each day the person fails to file the report, statement, or other document at the time required; the penalty is in addition to the penalties in AS 43.05.220 and 43.05.290 and is assessed, collected, and paid in the same manner as a tax deficiency under this title.

2. House Penalty for Improper Monthly Installment Payments.
Section 25 of CSHB2001 (RES)

Sec. 25. AS 43.55.020 is amended by adding a new subsection to read:

(i) A civil penalty shall be added to the amount of an installment payment required under (a)(1) - (4) of this section if the full amount of the payment is not paid by the date the payment is due. The penalty is equal to five percent of the difference between the amount of the installment payment that was made timely and the amount of the installment payment required under (a)(1) - (4) of this section. If no part of the required installment payment was made timely, the penalty is equal to five percent of the installment payment

required under (a)(1) - (4) of this section. The penalty is in addition to the interest imposed under (g) of this section and a penalty added under AS 43.05.220, if any.

3. Senate Penalty for substantial and gross understatement of tax.
Section 49 of CSSB 2001 (JUD)

Sec. 49. AS 43.55. is amended by adding a new section to read:

Sec. 43.55.055. Penalty for understatement of tax. (a) In addition to other penalties prescribed by law, if there is a substantial understatement of tax required to be shown on a return under this chapter, there shall be added to the tax an amount equal to 20 percent of the substantial understatement of tax.

(b) In addition to other penalties prescribed by law, if there is a gross understatement of tax required to be shown on a return under this chapter, there shall be added to the tax an amount equal to 40 percent of the gross understatement of tax.

(c) In addition to the penalties imposed under (a) or (b) of this section, a person who has made a substantial or gross underpayment of tax is liable to the state for the reasonable costs of the state's enforcement action, including auditing costs.

(d) For purposes of this section,

(1) a substantial understatement of tax for any taxable year exists if the amount of the understatement for the taxable year exceeds the lesser of 10 percent of the tax required to be shown on the return for the taxable year or \$10,000,000;

(2) a gross understatement of tax for any taxable year exists if the amount of the understatement for the taxable year exceeds the lesser of 20 percent of the tax required to be shown on the return for the taxable year or \$20,000,000;

(3) "understatement" means the amount by which the tax required to be shown on the return for the taxable year exceeds the amount of the tax reported as due by the taxpayer as shown on the return.

Alaska's Equitable Share

House Finance Committee

07 November 2007



Topics

- GCA's understanding of the goals or drivers for Alaska's Petroleum Fiscal System?
- Description and comparison of the four fiscal structures under consideration
- Working from a portfolio of projects representative of the opportunities described by industry, show the impacts of each fiscal system
- Analysis of industry returns from the Prudhoe Bay drilling program

Goals

Goals 1, 2 & 4

The Fiscal Design Challenge



- **At the same time the State must address “The Take”**
 - (1) Capture the State’s equitable share when margins are very high (as they are today)
 - (4) Include a form of progressive structure to adapt to the inevitable changes in the three main variables of the business:
 - Price
 - Production
 - Cost
- **...as well as “The Give Back”**
 - (2) Encouragement to reinvest profits for more development inside legacy units



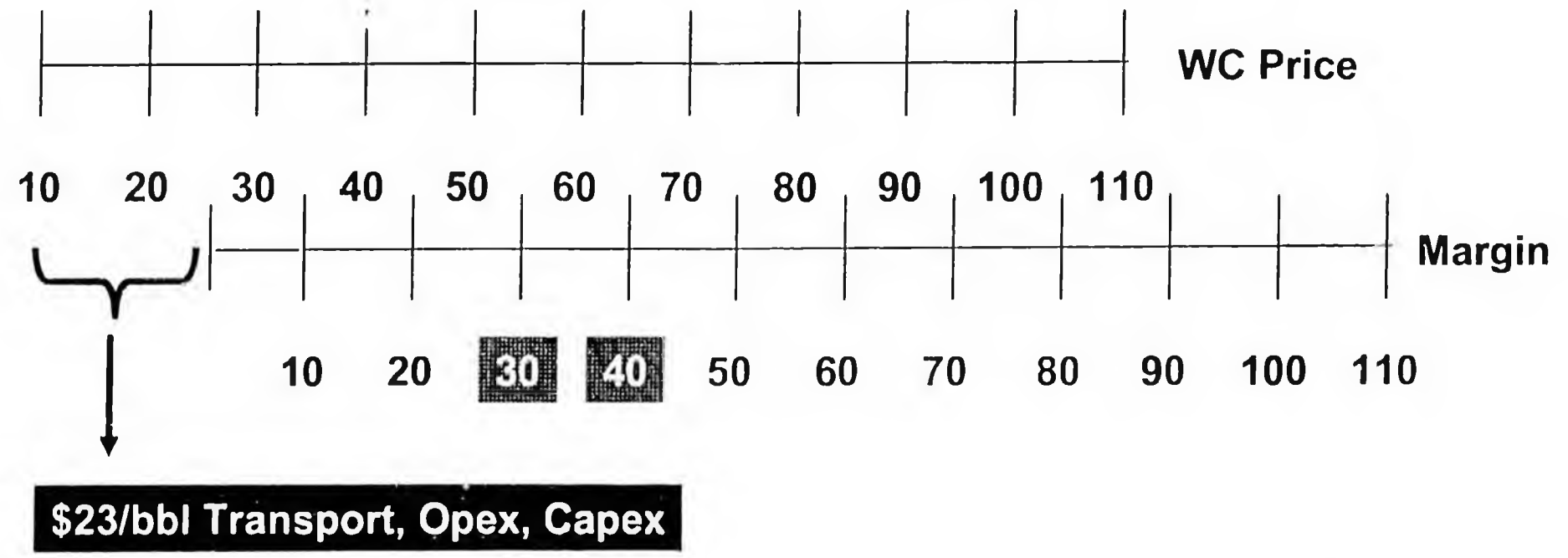
Goal 3: Encourage New Investment

- **The proposed legislation appears to provide the right incentives to encourage investment in new fields**
 - Investment credits
 - Net Operating Loss credits
 - Aid to new entrants with no existing tax base
 - The net based systems by design lower the applicable production tax rate for fields with higher cost structure
 - More distant from infrastructure
 - Heavy Oil
 - Gas
- **Beyond the individual project, the State and industry benefit from new developments as they provide additional barrels down TAPS thus extending the productive life of existing reservoirs**

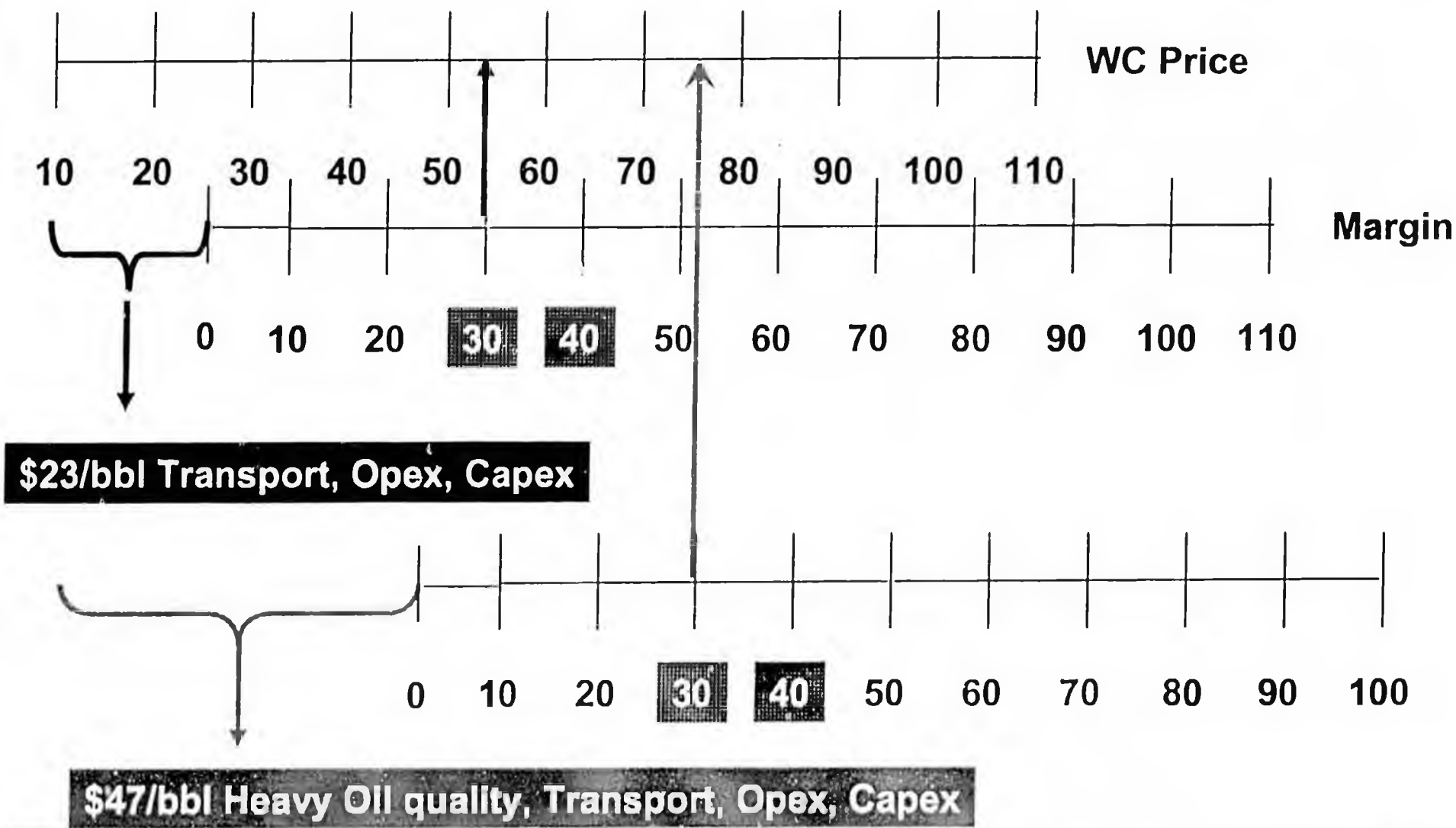


Key Point Easily Misunderstood

Price \neq Margin



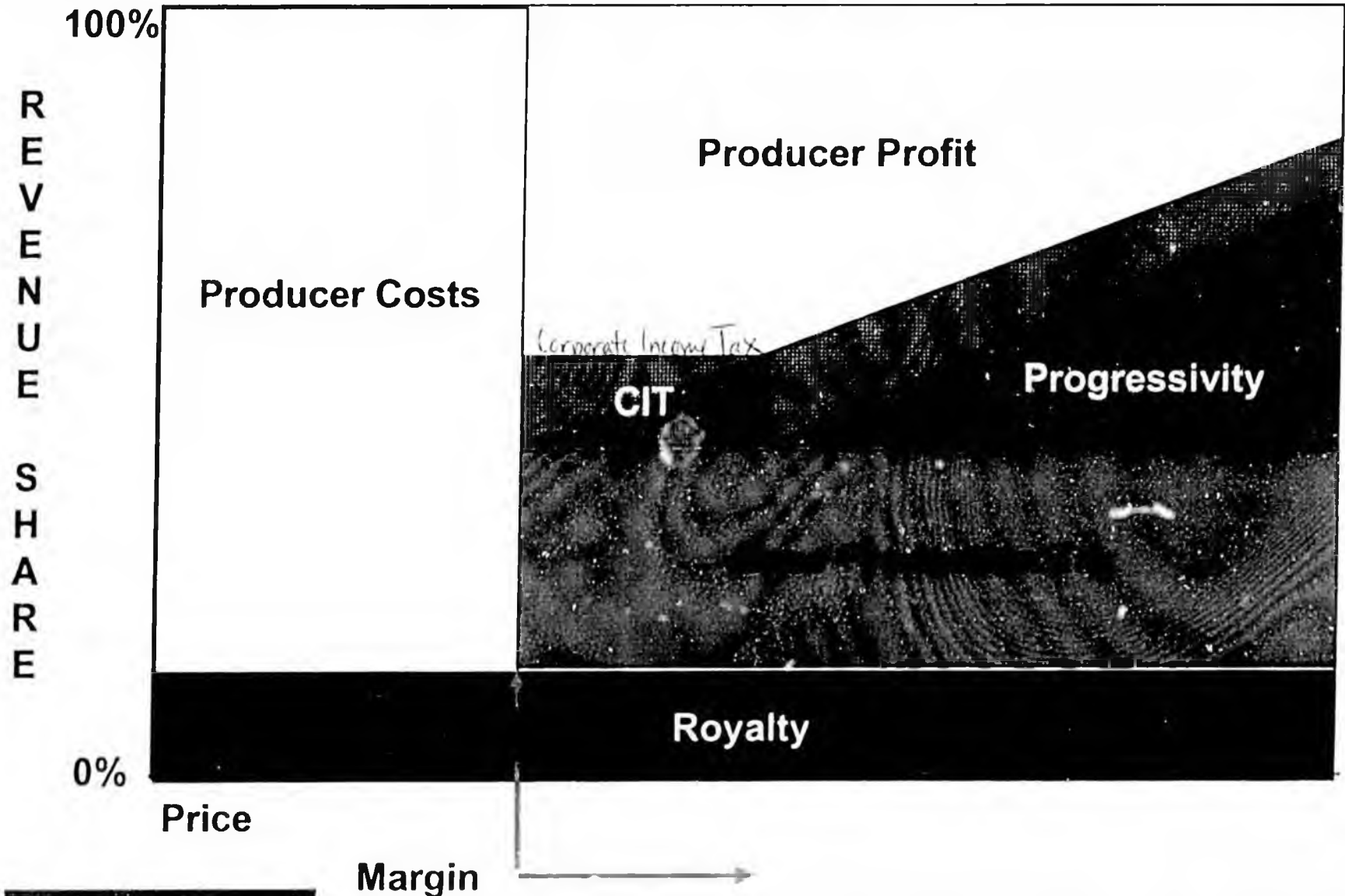
Margin/Price relationship changes with time and with project addition



Regime Comparison

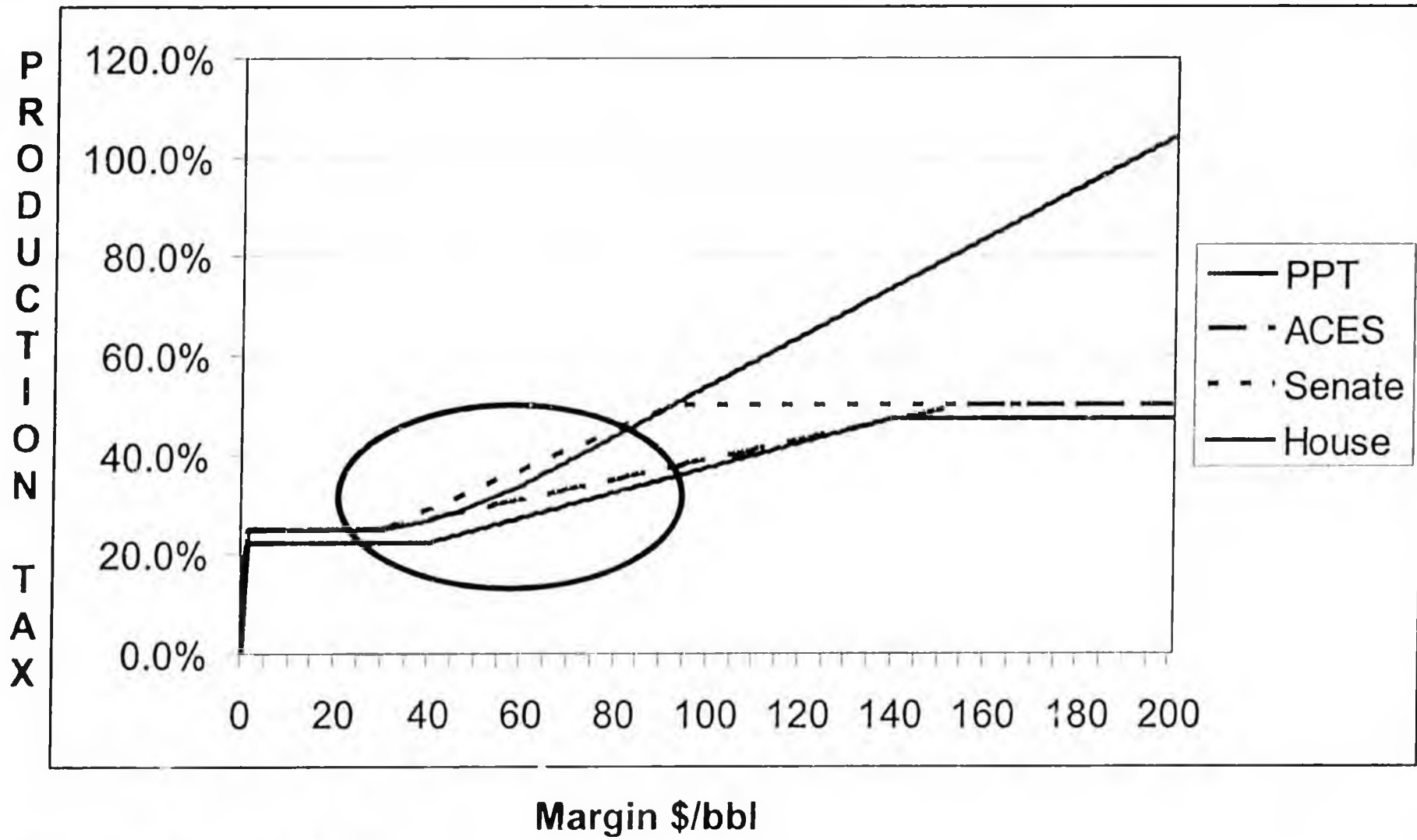


For PPT, ACES and Senate CS



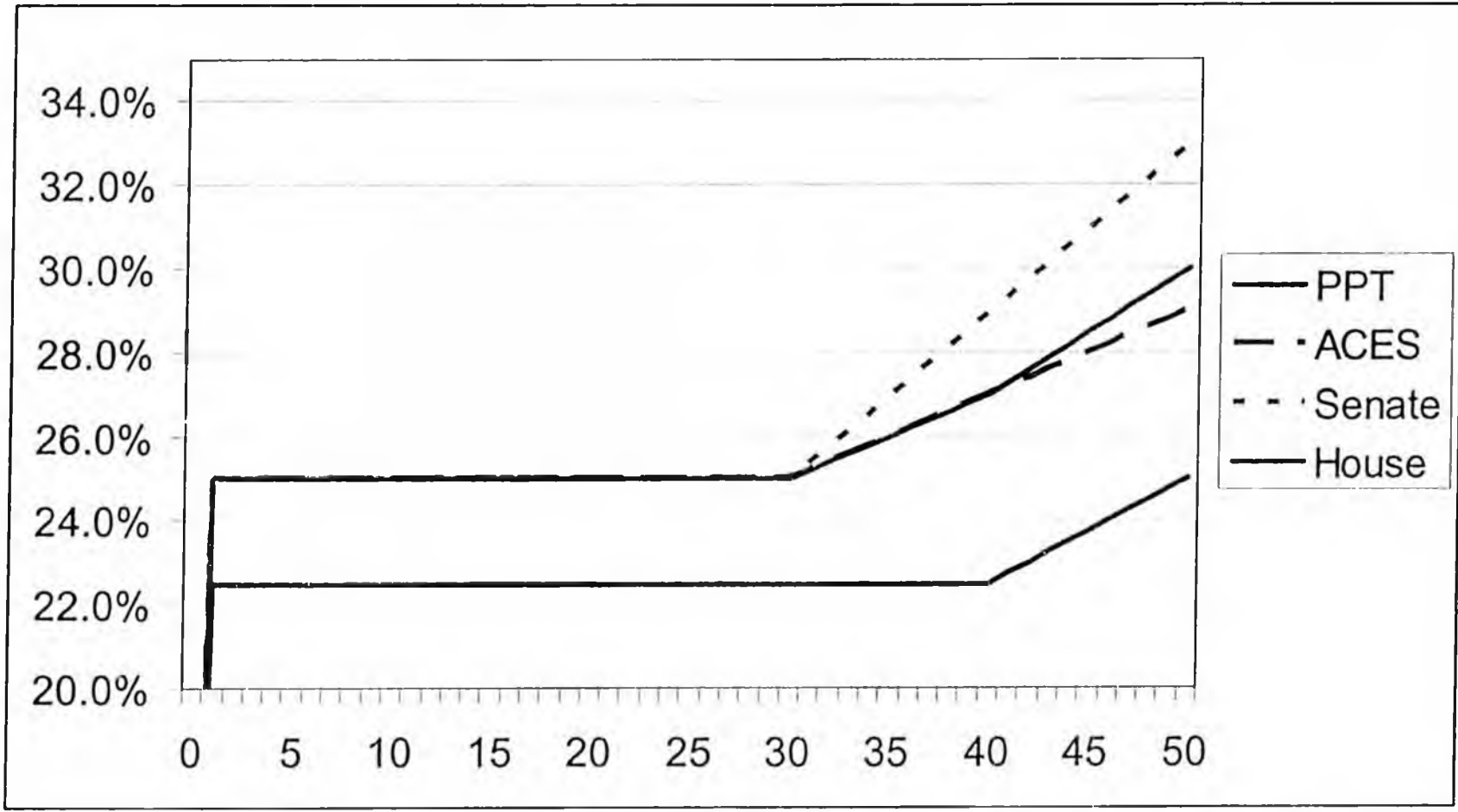


Four fiscal systems





Likely zone of operation



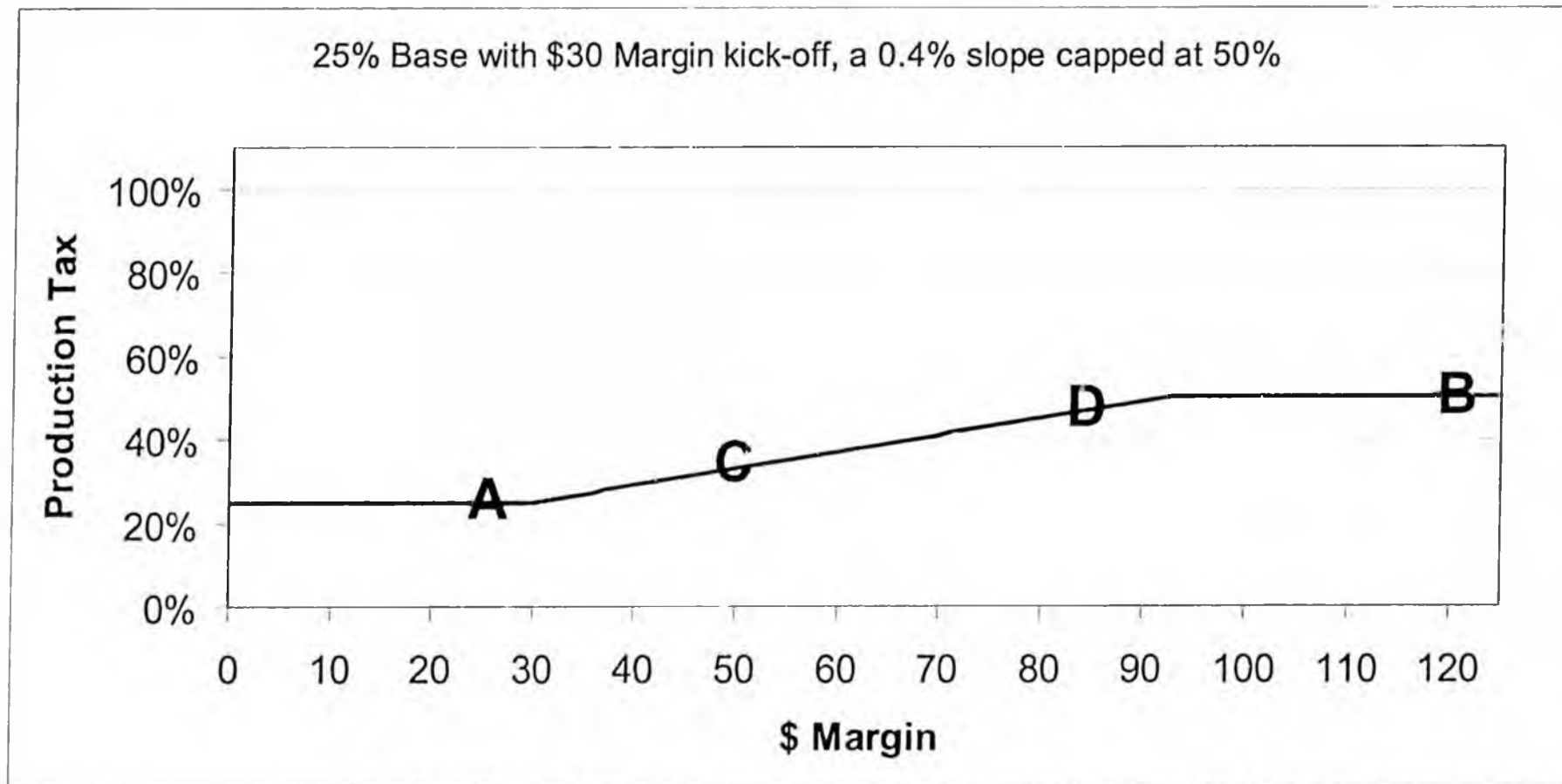


Progressivity Impacts

- **The use of progressivity creates a sizeable difference between the effective rate and the marginal rate of tax in relation to investment decisions**
 - This is present with the existing PPT language
 - The impact provides either:
 - A good sized “carrot” to invest; or
 - A good sized “stick” to not export after tax cash flow from Alaska



Margin Cases



Federal and State Income tax impacts excluded



An Example of Progressivity Impacts

- **Let's assume a company has \$1000 before tax cash flow and is deciding whether or not to make a \$100 investment (or roughly reinvest 10%)**
 - If the net margin before investment is under \$30/bbl
 - Production tax savings associated with the \$100 investment is 25%
 - If the net margin is greater than \$92.5/bbl
 - Production tax savings associated with the \$100 investment is 50%
 - If the net margin is between \$31/bbl and \$92.5/bbl
 - Production tax savings associated with the \$100 investment ranges from 25% to over 100%



Taxpayer 'A' - Low Margin

- **\$1000 net revenue @ a margin of \$25/bbl**
 - Tax = \$1000 x 25%
 - Tax = \$250
- **Now we invest \$100- reduces net revenue to \$900 and our margin to \$22/bbl**
 - Tax = \$900 x 25%
 - Tax = \$225
- **Production Tax savings due to the investment**
 - Tax Savings = $(\$250 - \$225)/\$100$
 - Tax Savings = 25/100
 - New Marginal Tax Rate = 25%



Taxpayer 'B' - High Margin

- **\$1000 net revenue @ a margin of \$125/bbl**
 - Tax = \$1000 x 50%
 - Tax = \$500
- **Now we invest \$100 that takes our net revenue to \$900 and our margin to \$110/bbl**
 - Tax = \$900 x 50%
 - Tax = \$450
- **Production Tax savings due to the investment**
 - Tax Savings = $(\$500 - \$450)/\$100$
 - Tax Savings = 50/100
 - New Marginal Tax Rate = 50%



Taxpayer 'C' – Low on the slope

- **\$1000 net revenue @ a margin of \$50/bbl**
 - Tax = \$1000 x 33%
 - Tax = \$330
- **Now we invest \$100 that takes our net revenue to \$900 and our margin to \$45/bbl**
 - Tax = \$900 x 31%
 - Tax = \$279
- **Production Tax savings due to the investment**
 - Tax Savings = $(\$330 - \$279)/\$100$
 - Tax Savings = 51/100
 - New Marginal Tax Rate = 51%

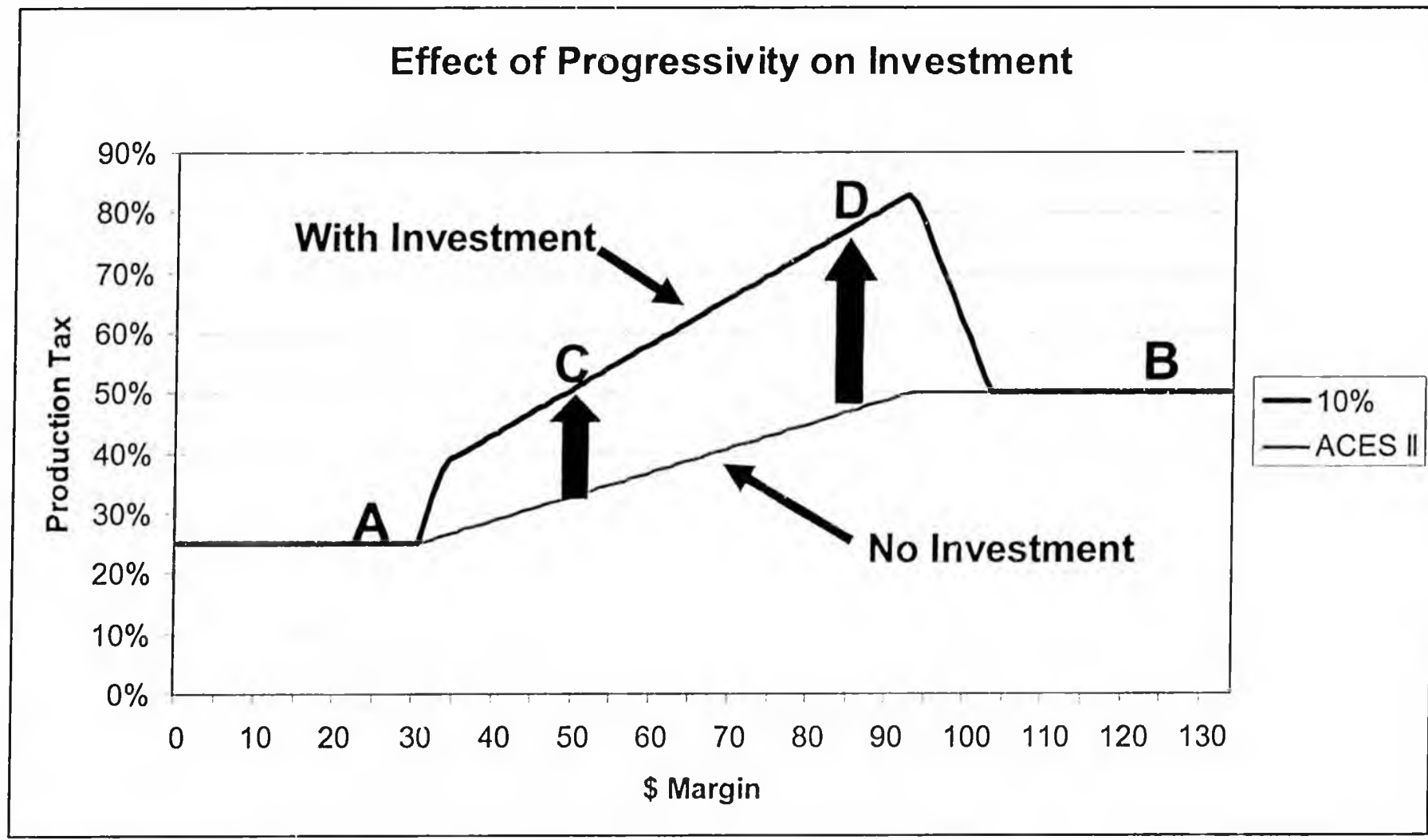


Taxpayer 'D' – High on the slope

- **\$1000 net revenue @ a margin of \$85/bbl**
 - Tax = \$1000 x 47%
 - Tax = \$470
- **Now we invest \$100 that takes our net revenue to \$900 and our margin to \$72/bbl**
 - Tax = \$900 x 43.6%
 - Tax = \$392
- **Production Tax savings due to the investment**
 - Tax Savings = $(\$470 - \$392)/\$100$
 - Tax Savings = 78/100
 - New Marginal Tax Rate = 78%



'C' & 'D' New Marginal tax rate higher



The Net Tax Structure



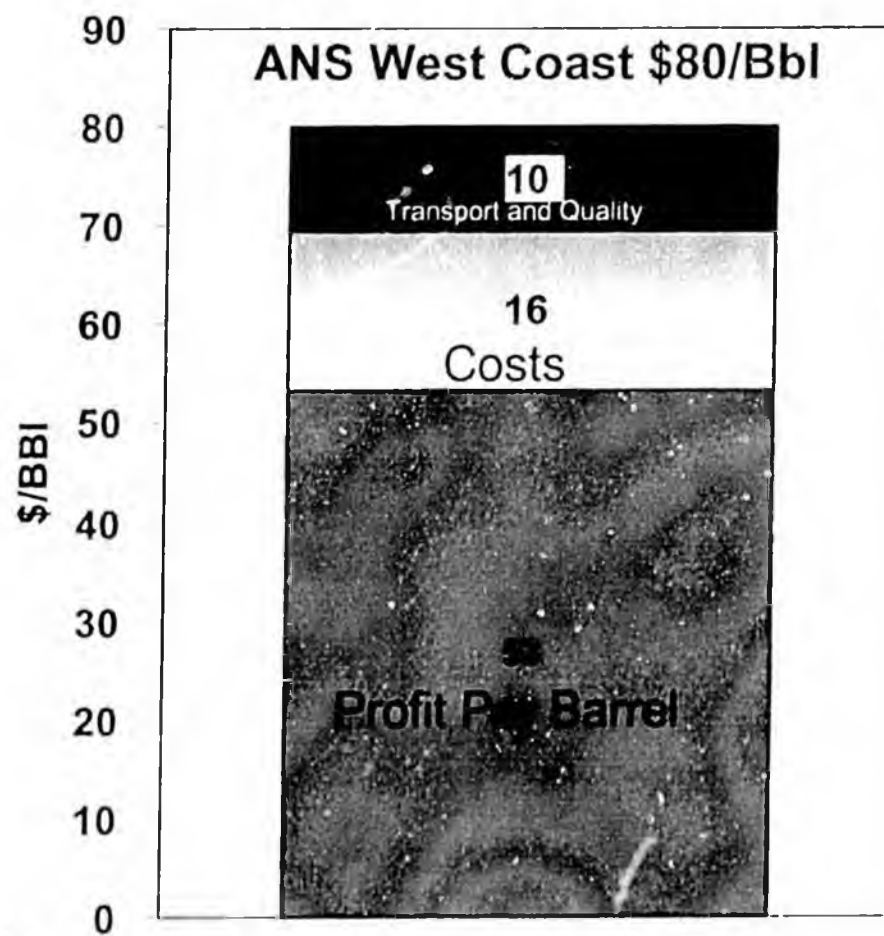
Net Tax Structure – “Headlines”

- Tax on net profits
- Contains progressivity feature that increases tax rate with increasing profitability per barrel
- Ringfenced so that profit per barrel reflects a company’s entire portfolio



Profitability As Typically Described

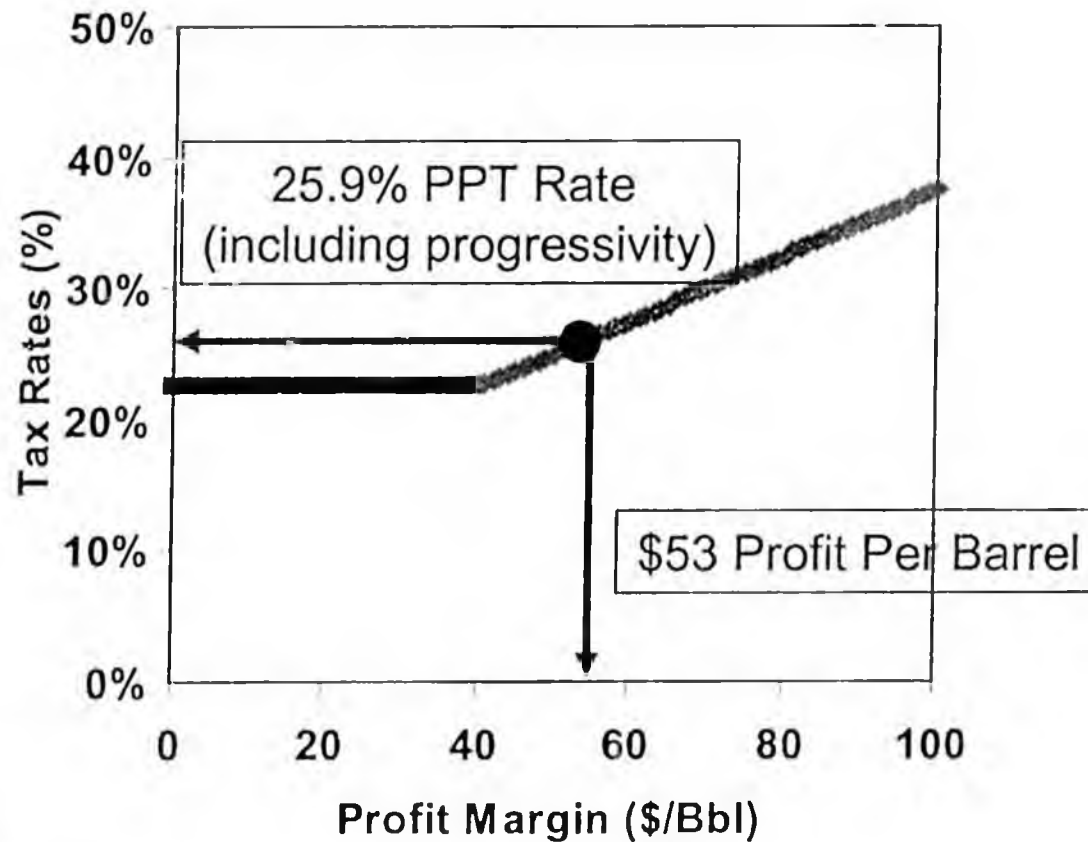
Portfolio Profitability





PPT - Based On \$53/Bbl Profit ...

Tax Rate Structure
(Incorporating Progressivity)





Misconception – Net Progressivity

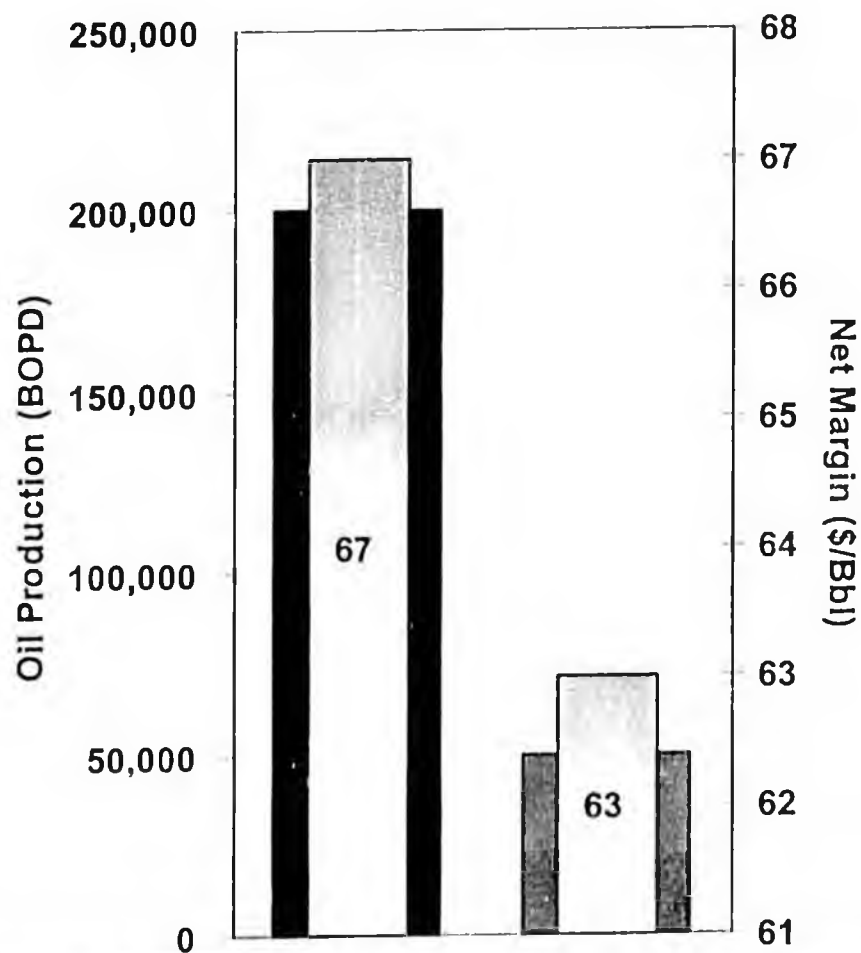
- **“Net” taxes all fields at a single rate**
 - If only looking at the “headline” net tax rate, this would be the perception
 - In reality, when looking at the marginal impact of different parts of the portfolio, it taxes different fields or reservoirs at different rates
 - Based upon their individual profitability

Understanding How “Net” Works



Now, Add Another Field

Expanded Portfolio



Average Net Margin on the expanded portfolio is \$66.20

PPT Rate on these fields Combined would be 29.1%

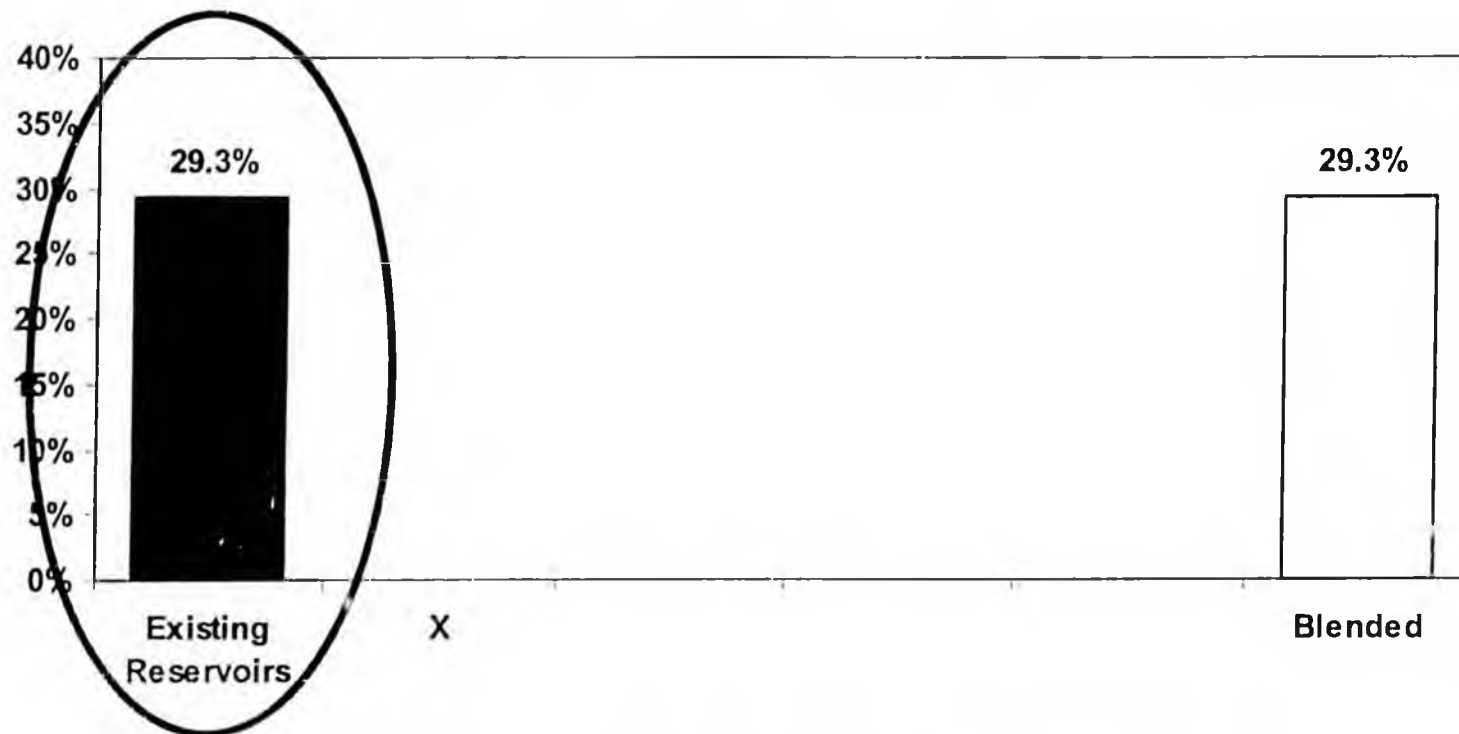
**So, does this mean that I am
paying 29.1% on each field ?**

No

So, Does That Mean I Am Paying 29.1% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

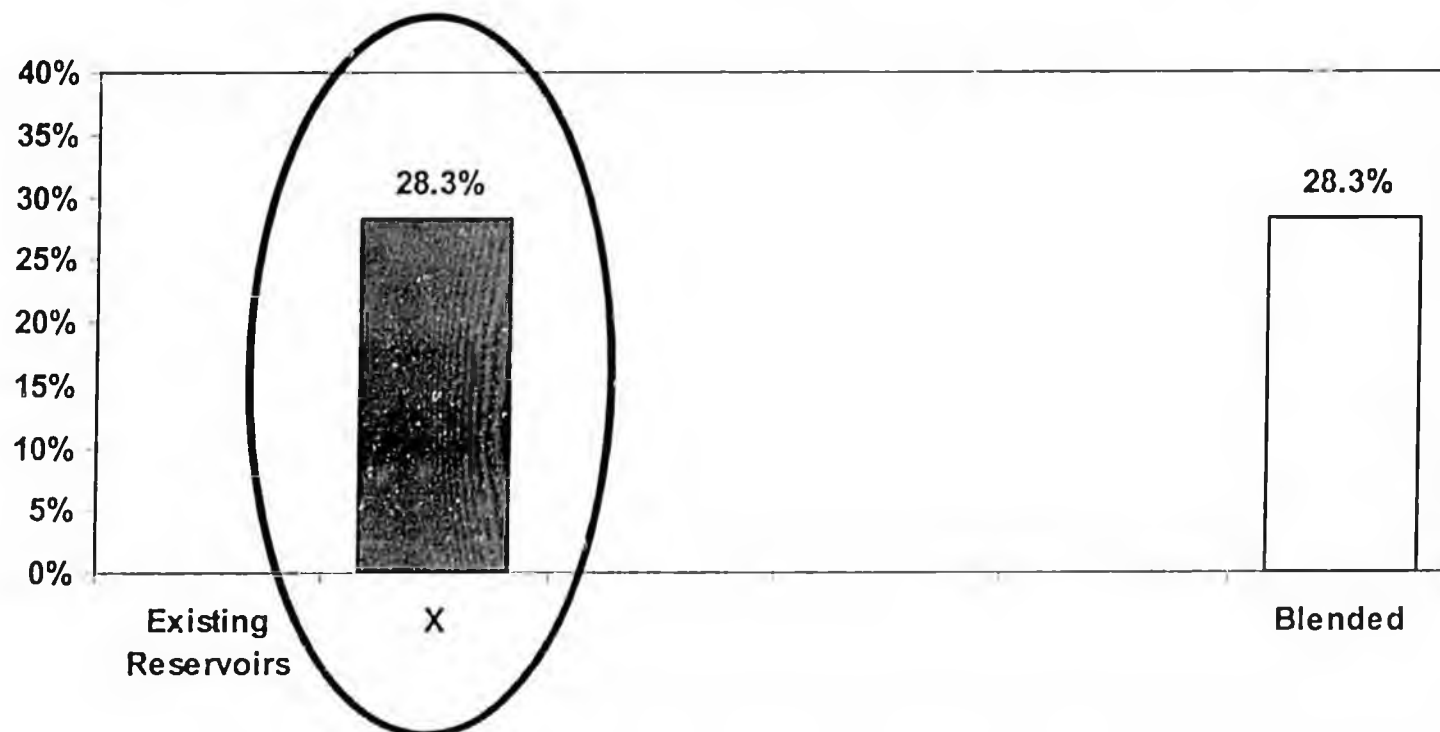


If I had just Existing Reservoirs, and did not develop anything new, I would pay tax on my profits at 29.3%

So, Does That Mean I Am Paying 29.1% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending

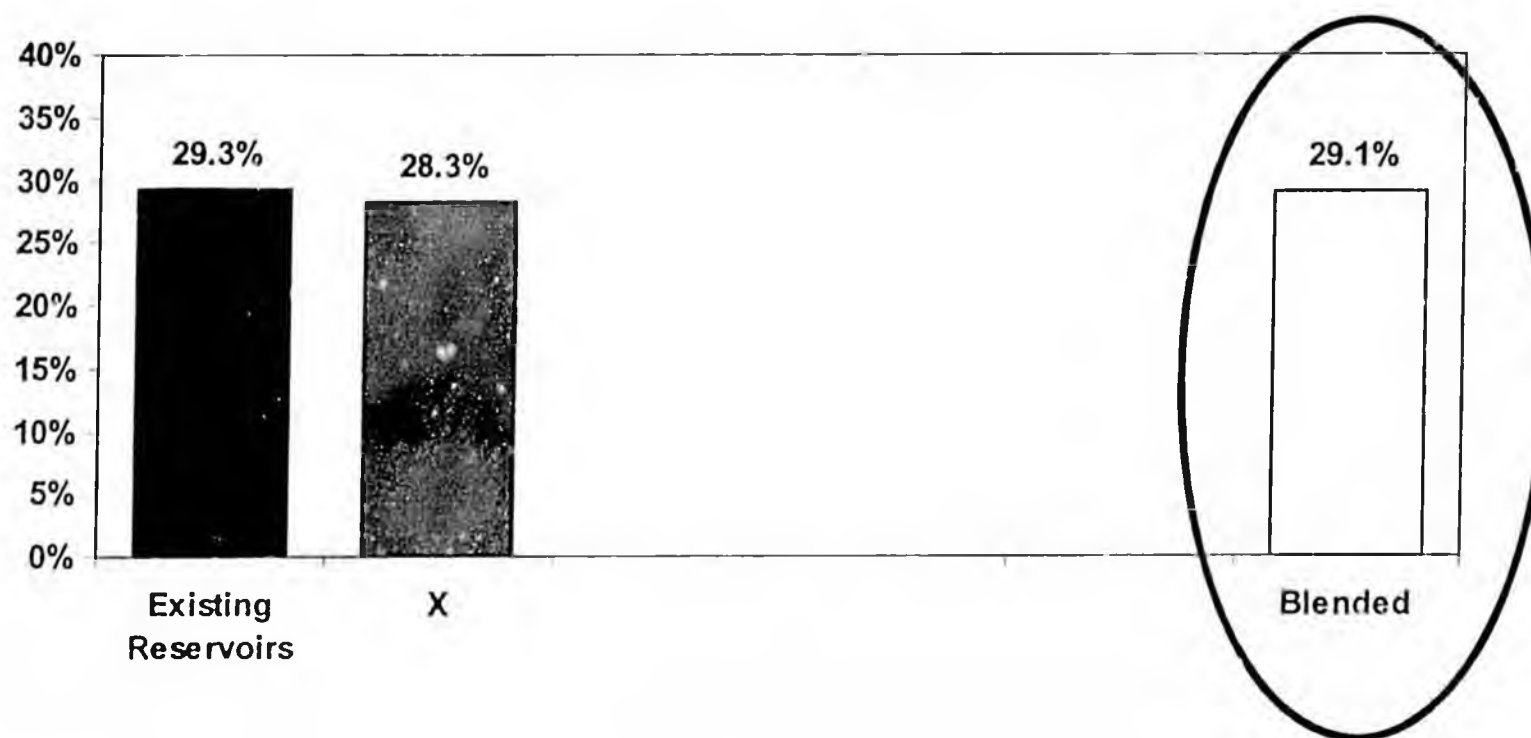


If I had just Field X, I would pay tax on my profits at 28.3% - its margin is slightly lower

So, Does That Mean I Am Paying 29.1% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



Both fields together, the rate is 29.1%

**However, this does not tell
the whole story . . .**

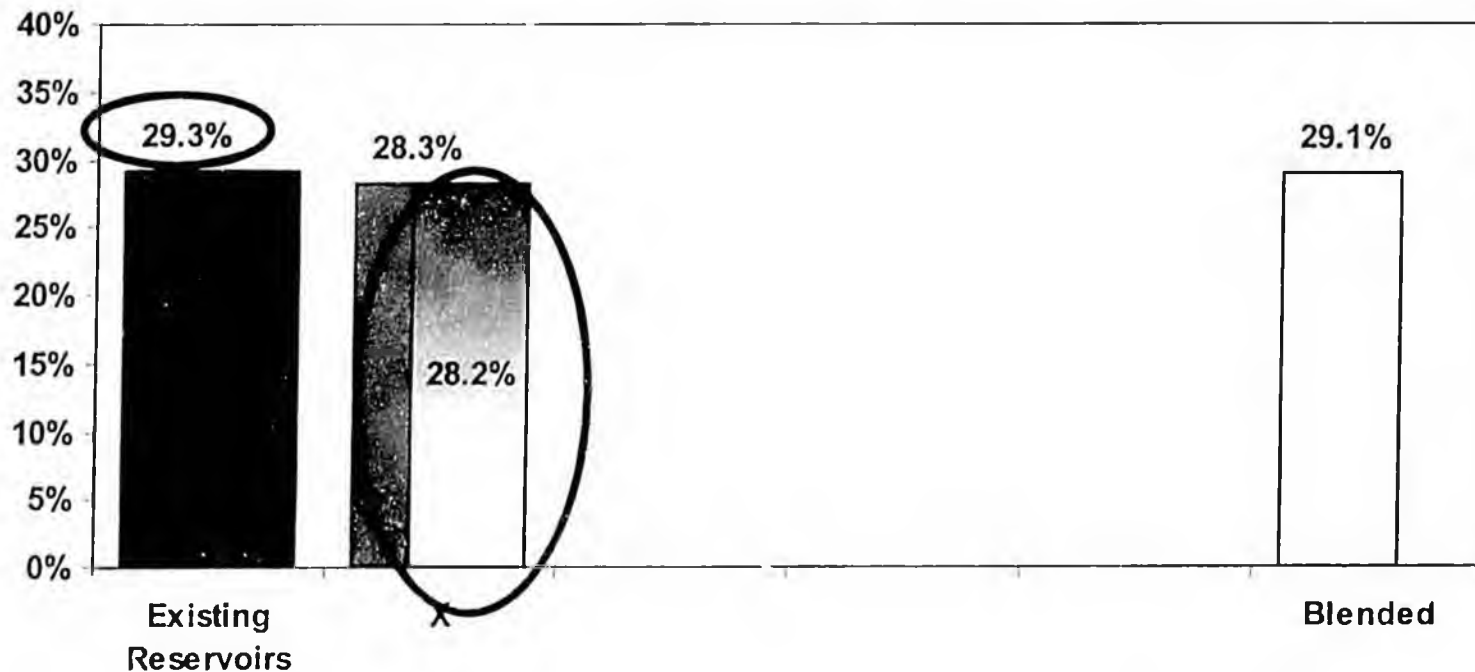
**The lower profitability field benefits from
the progressivity structure**

AK LEGISLATURE FINANCE COMMITTEES FILES 2007-2008 3286 168

So, Does That Mean I Am Paying 29.1% On Each Field ?



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



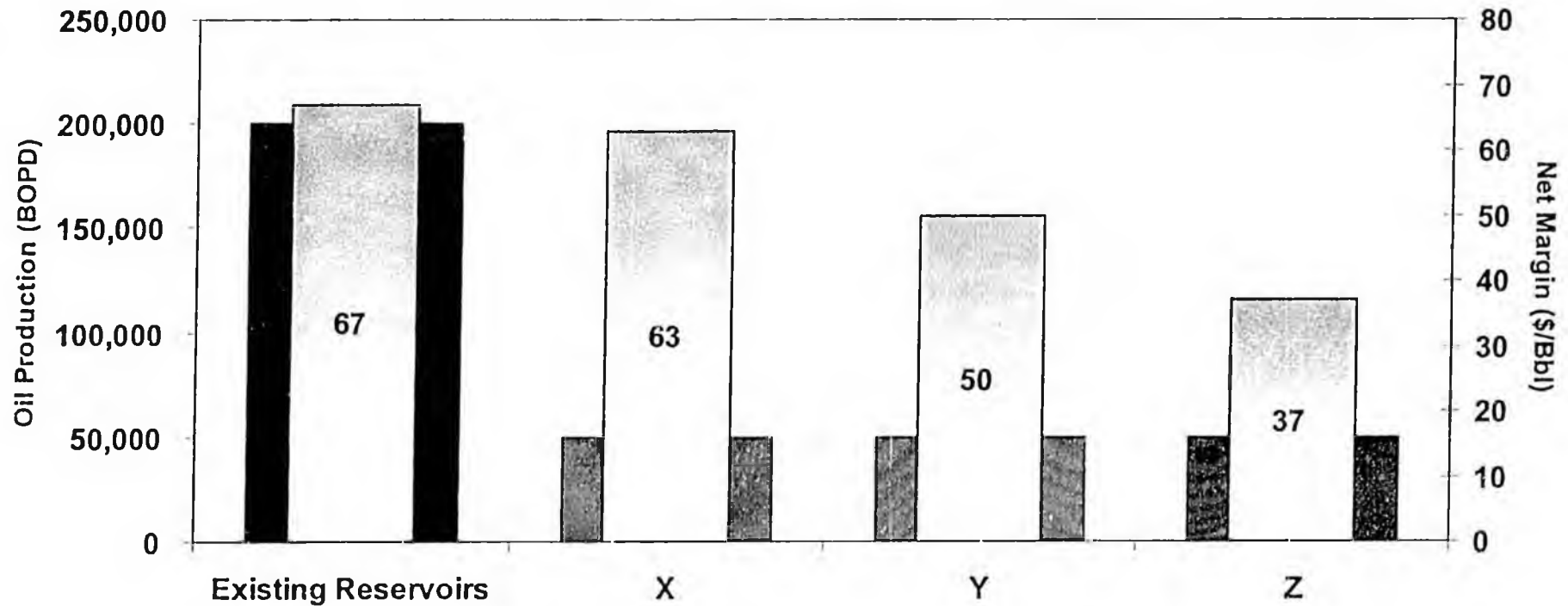
The mathematics of this reduction means that actually while Existing Reservoirs continue to pay tax at a rate of 29.3%,
The effective rate on Field X is actually 28.2%
... less than it would be if it were developed stand-alone

**This Impact Can Be
Seen Further
In A Broader Portfolio**



Consider A Portfolio Of 4 Fields

Portfolio Production Rate and Net Margin

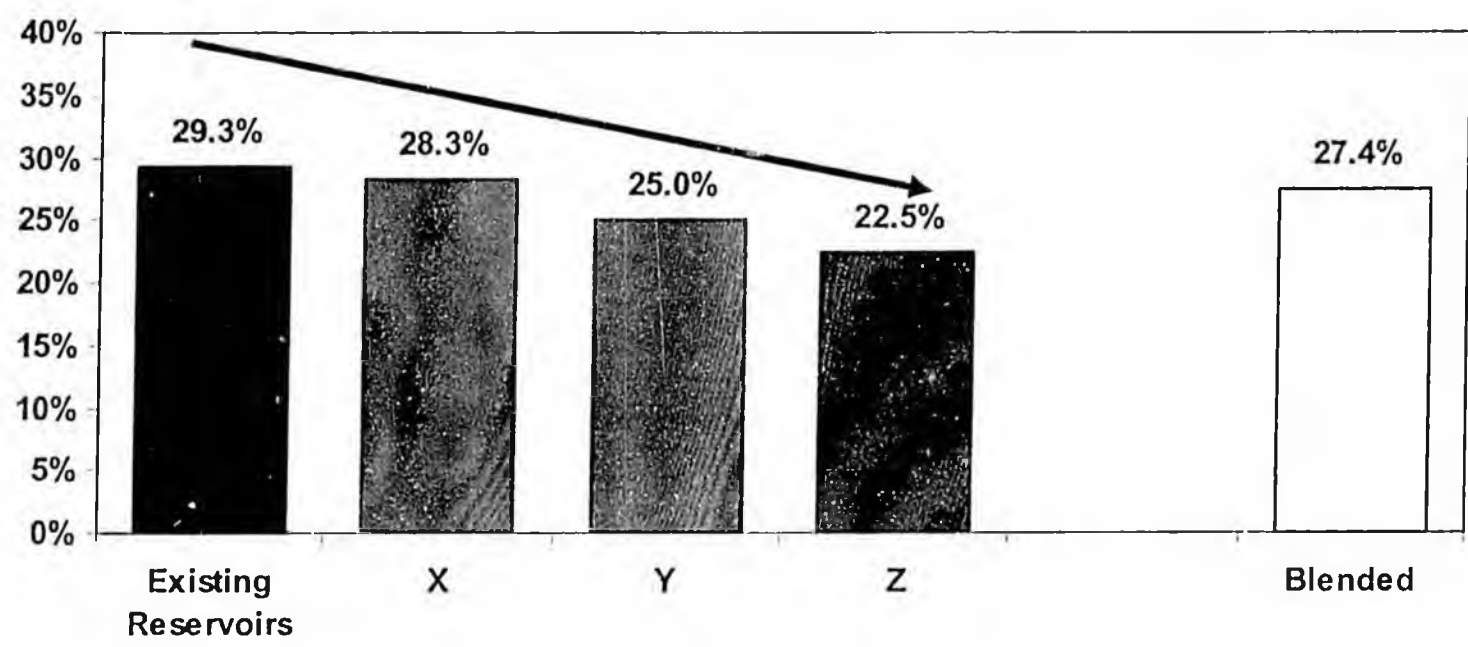


.. One producing 200,000 bopd and three others, each producing 50,000 bopd, and each of decreasing profitability



Tax rates if stand alone development

Tax Rate By Field Within A Company - As Affected By Portfolio Blending



The progressivity can be seen through the lower tax rate on lower margin fields

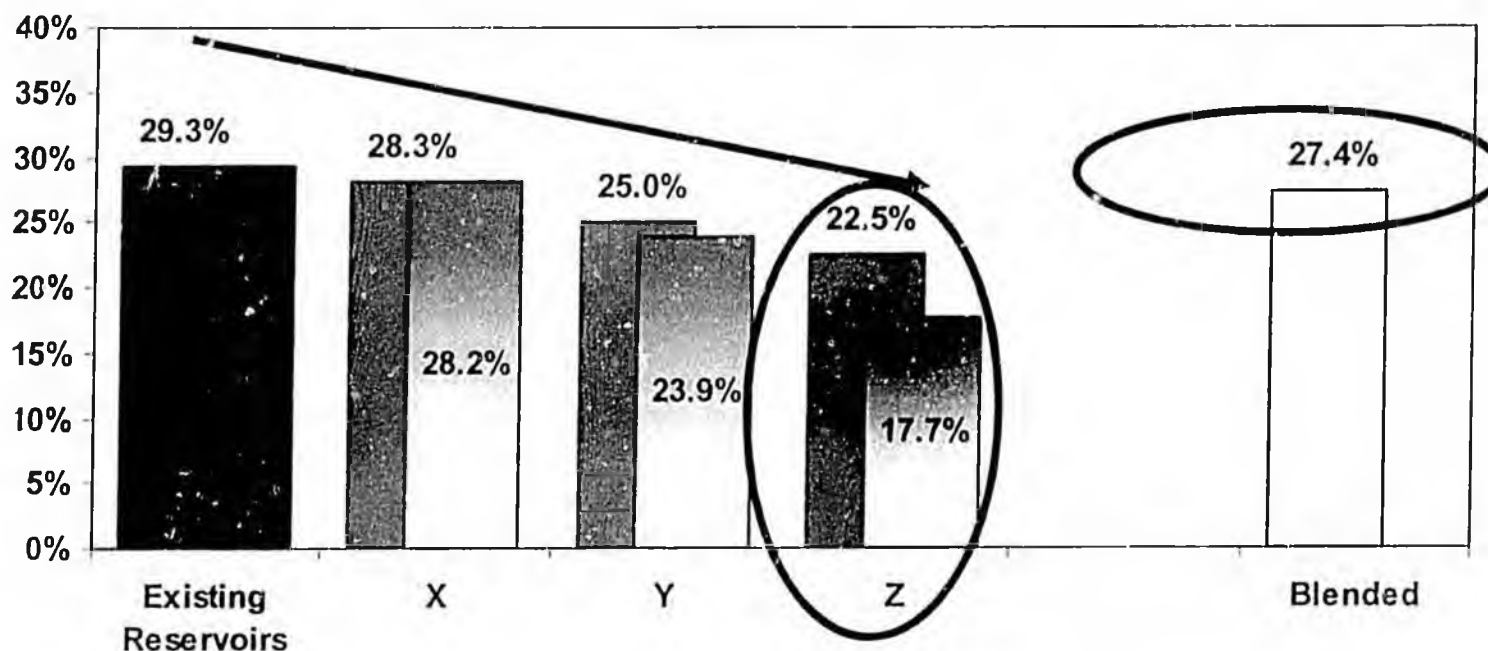
The Least Profitable Field ..

**... can actually have an effective rate
below the basic rate**

The Impact On The Lower Margin Fields Is More Noticeable



Tax Rate By Field Within A Company - As Affected By Portfolio Blending



The effective rate on some lower-margin fields may even be lower than the basic rate (22.5% in PPT)

This is manifested in the blended rate being lower than the weighted average rate

The Impact Of Capital Investment



How The Net Tax System Operates

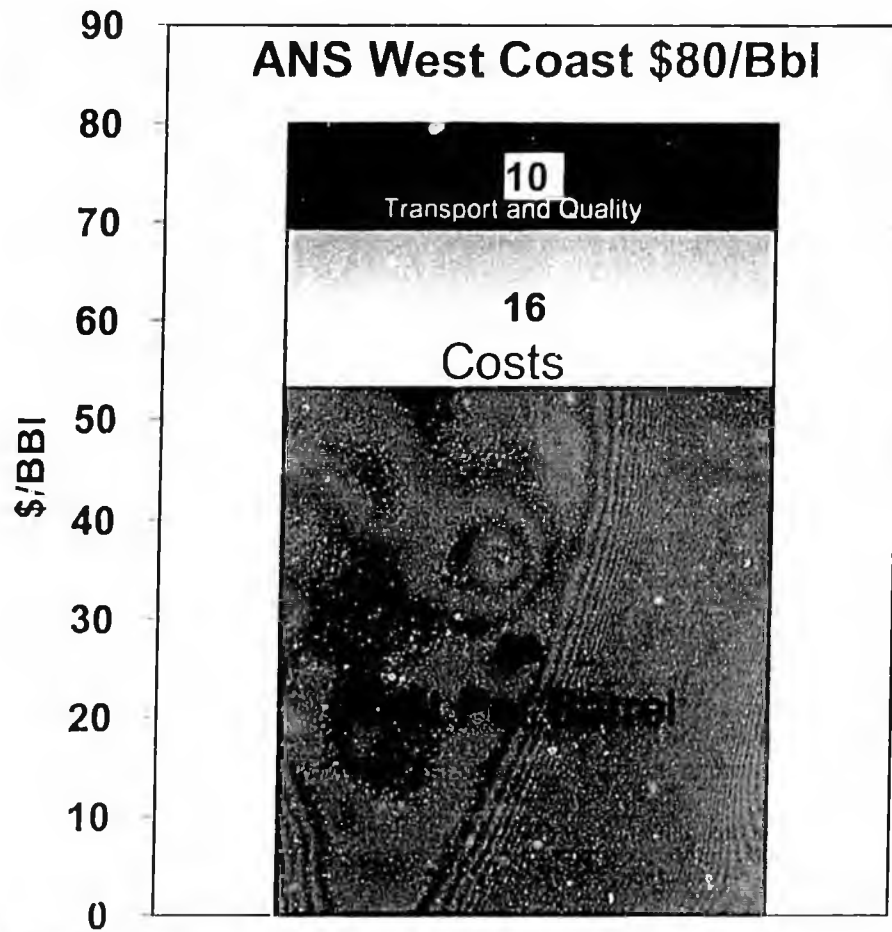
- “Net” taxes all fields at a single rate
 - If only looking at the “headline” net tax rate, this would be the perception
 - In reality, when looking at the marginal impact of different parts of the portfolio, it taxes different fields or reservoirs at different rates
 - Based upon their individual profitability
- **Further, it doesn’t tax operating profits, but retained cash flow after reinvestment**



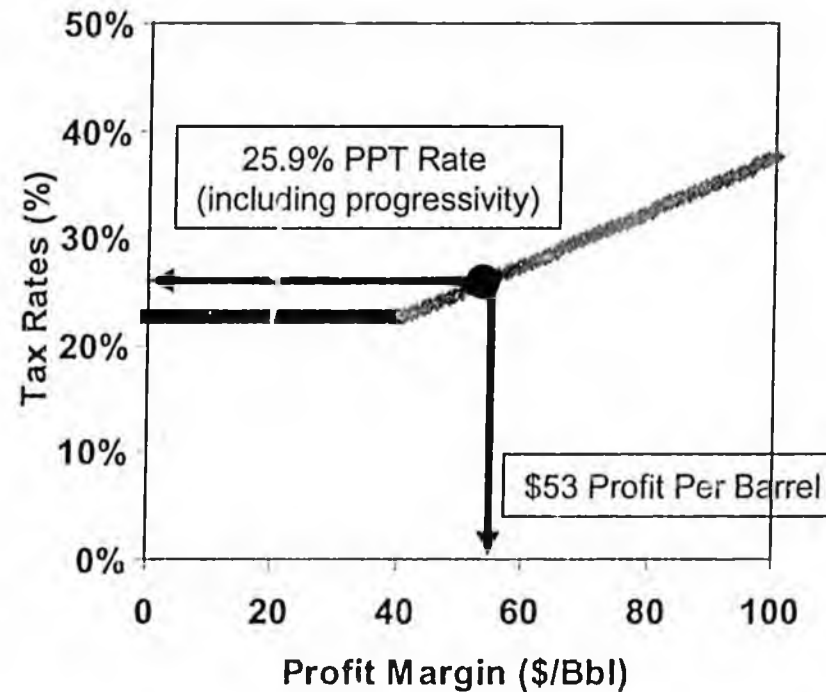
Remember These Slides ?

Portfolio Profitability

The portfolio in the previous slides had a blended rate of 27.4%, not 25.9%



Tax Rate Structure (Incorporating Progressivity)



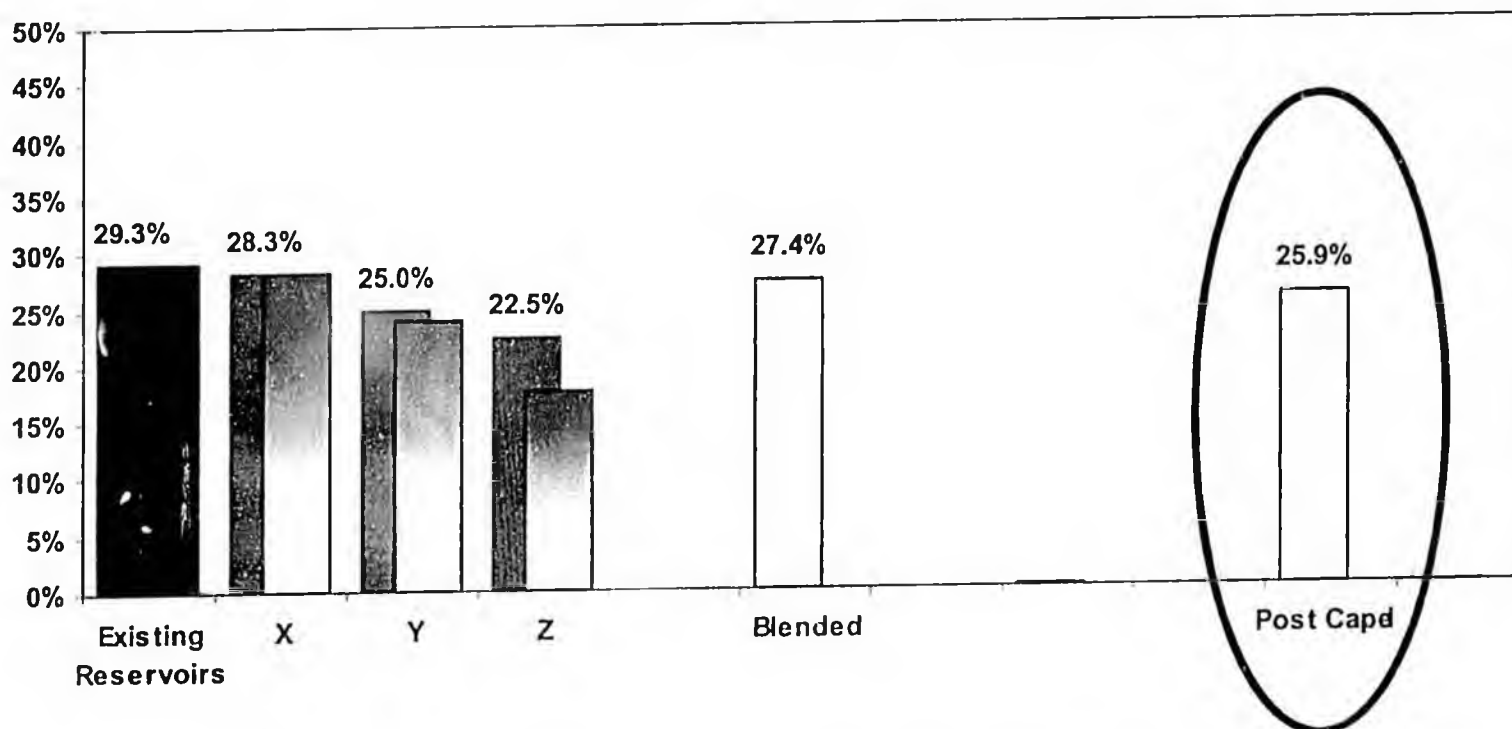
**Assume that 27.4% is the rate that will
be payable before further capital
investment decisions are made ...**

... in this example \$800 million

Capital Spending Has An Impact On Rate, Too



Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



This reduces the rate payable from 27.4% to 25.9%

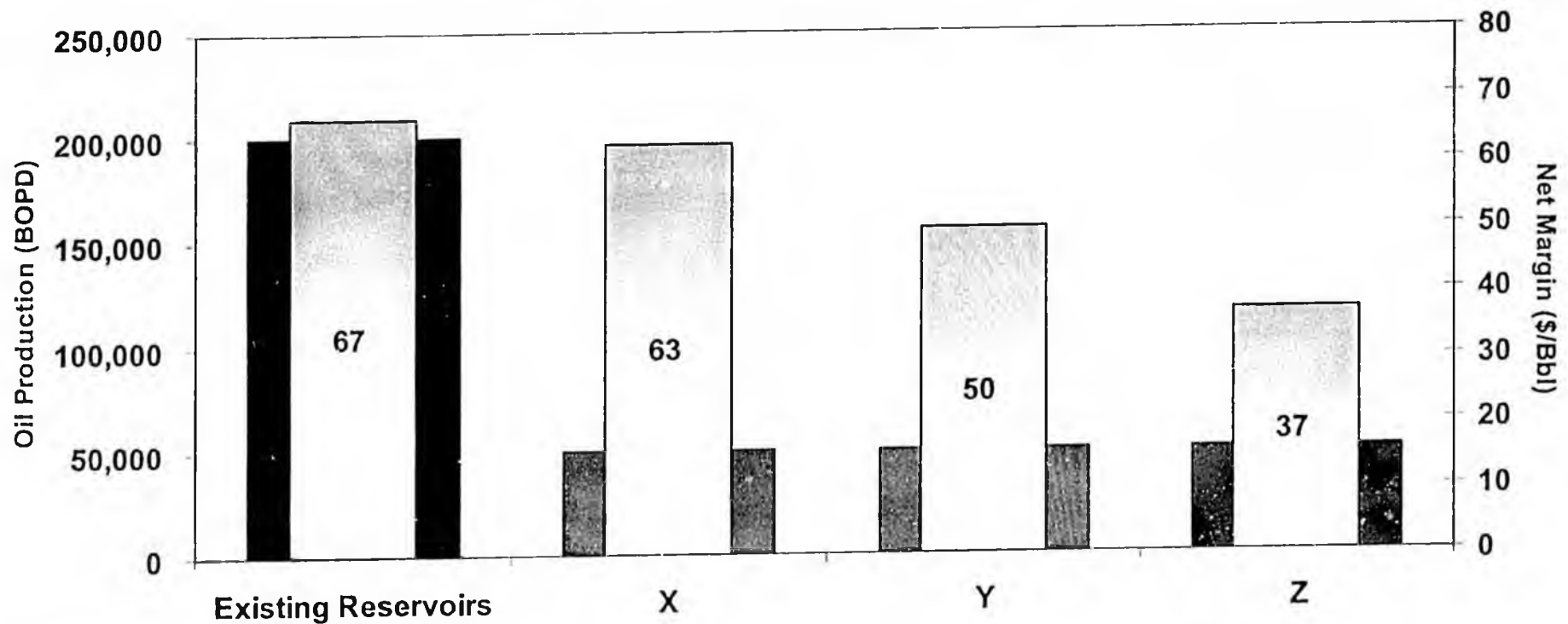
How ?



The Portfolio Produces 350,000 Bopd

this is 127.75 Million Barrels Per Year

Portfolio Production Rate and Net Margin

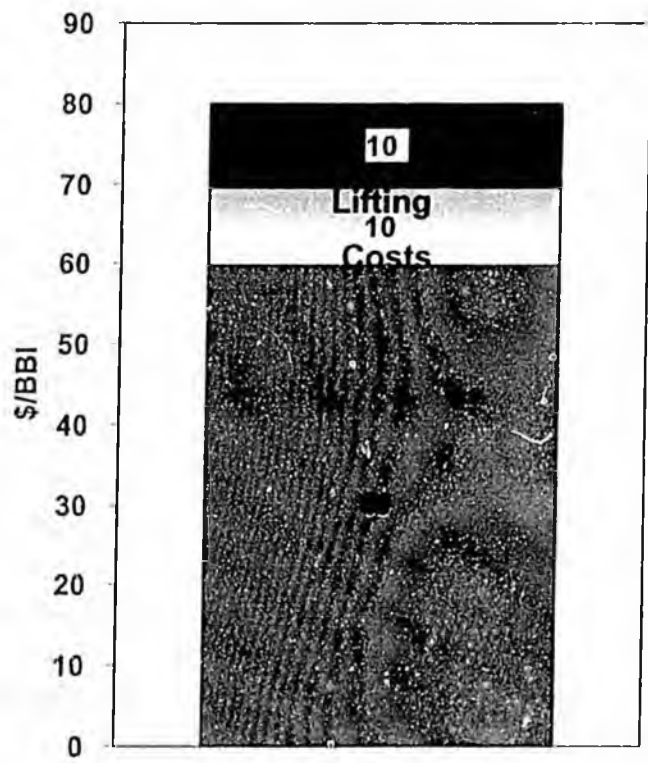


The \$6.26 Per Barrel Capital Increases "Costs" And Lowers The Tax Rate

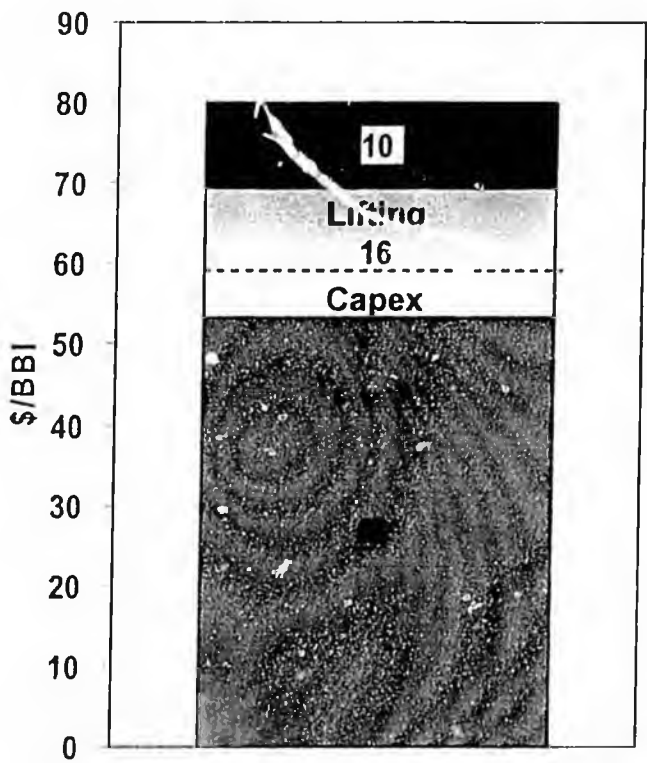


Portfolio Profitability

Pre-Capex Margin



Tax Rate
27.4%



Tax Rate
25.9%

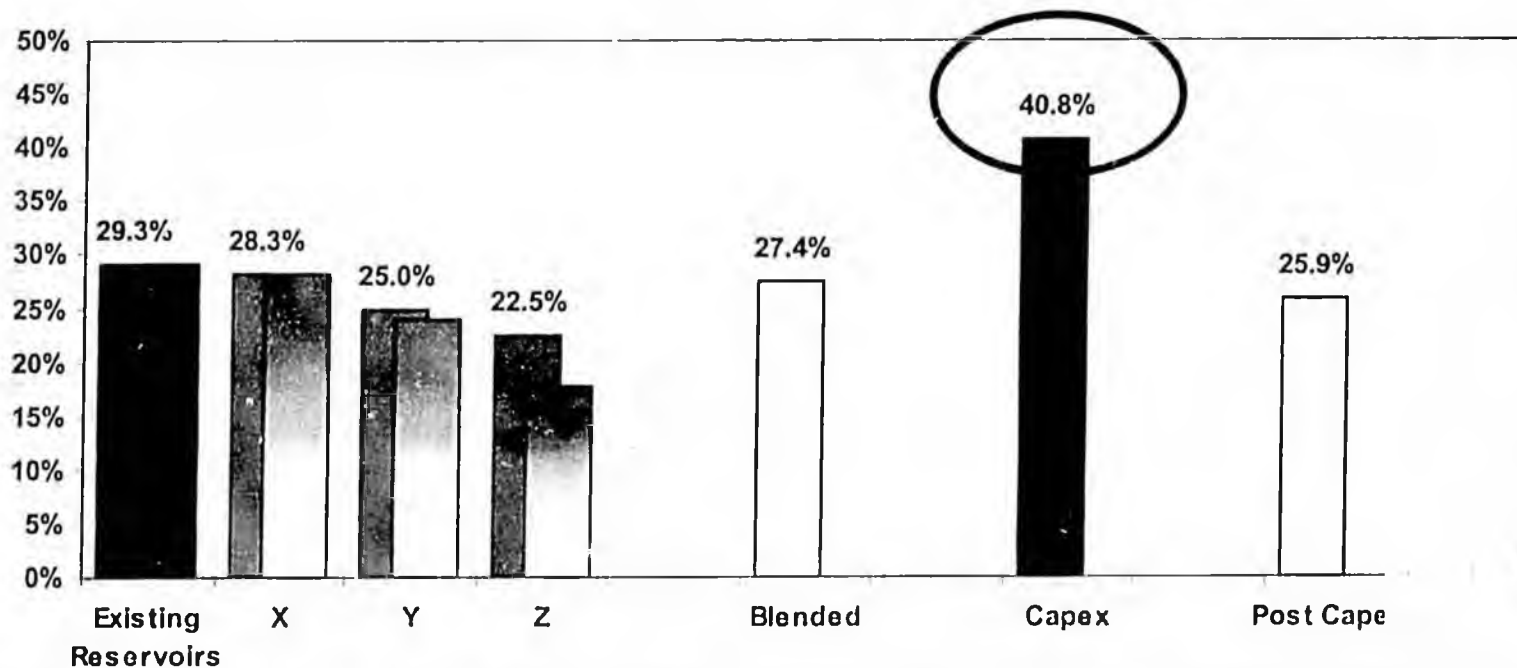
This Can Be looked At Differently Though ...

... as a tax rebate on the capex

The Reduction In Tax Rate Lowers The Net Investment Cost To Companies



Tax Rate By Field Within A Company - As Affected By Portfolio Blending, Capex And Tax Credit



It is the same as still paying the blended rate of 27.4% on the portfolio production (or having an effective rate of 29.3% on Existing Reservoirs .. down to 17.7% on Field Z) and Alaska paying* 40.8% of that \$800 million capital

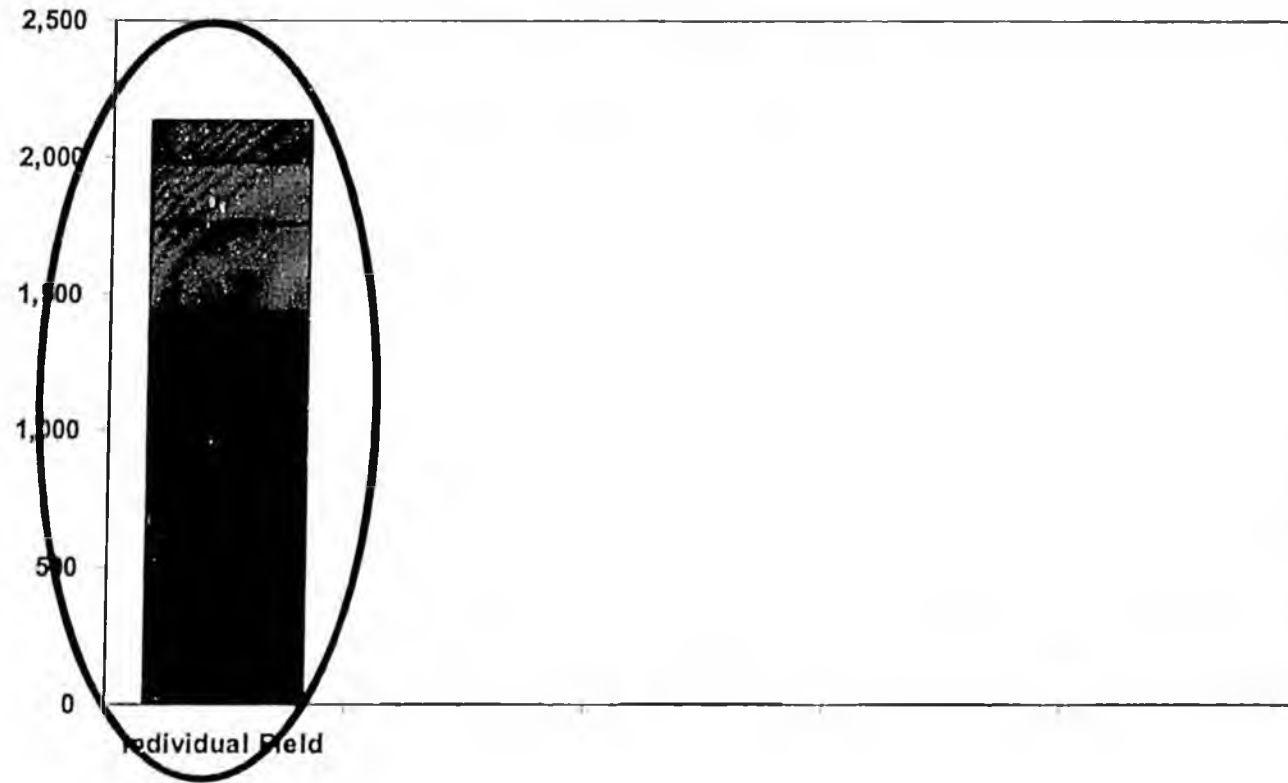
This 40.8% is higher than the Blended tax rate ... and is a function of the capex per barrel and the overall portfolio cost and margin structure

* from PPT only - does not include State and Federal tax effects

Look At The Tax System Through The Amount Of Tax Payable ...



Tax Allocable By Field Within Portfolio



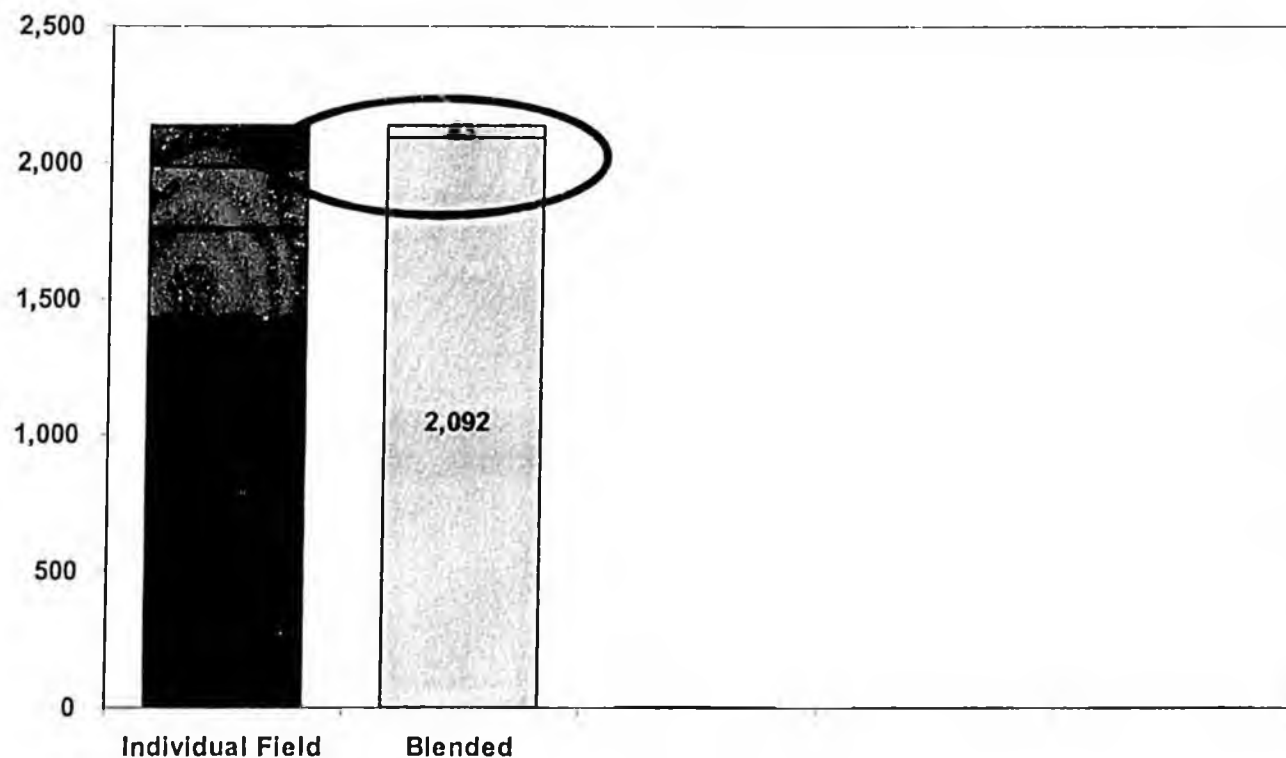
As individual fields, and at these assumed oil prices and costs, this portfolio would pay \$2,135 million in PPT

* from PPT only – does not include State and Federal tax effects



Portfolio Effects Lower Total Tax

Tax Allocable By Field Within Portfolio

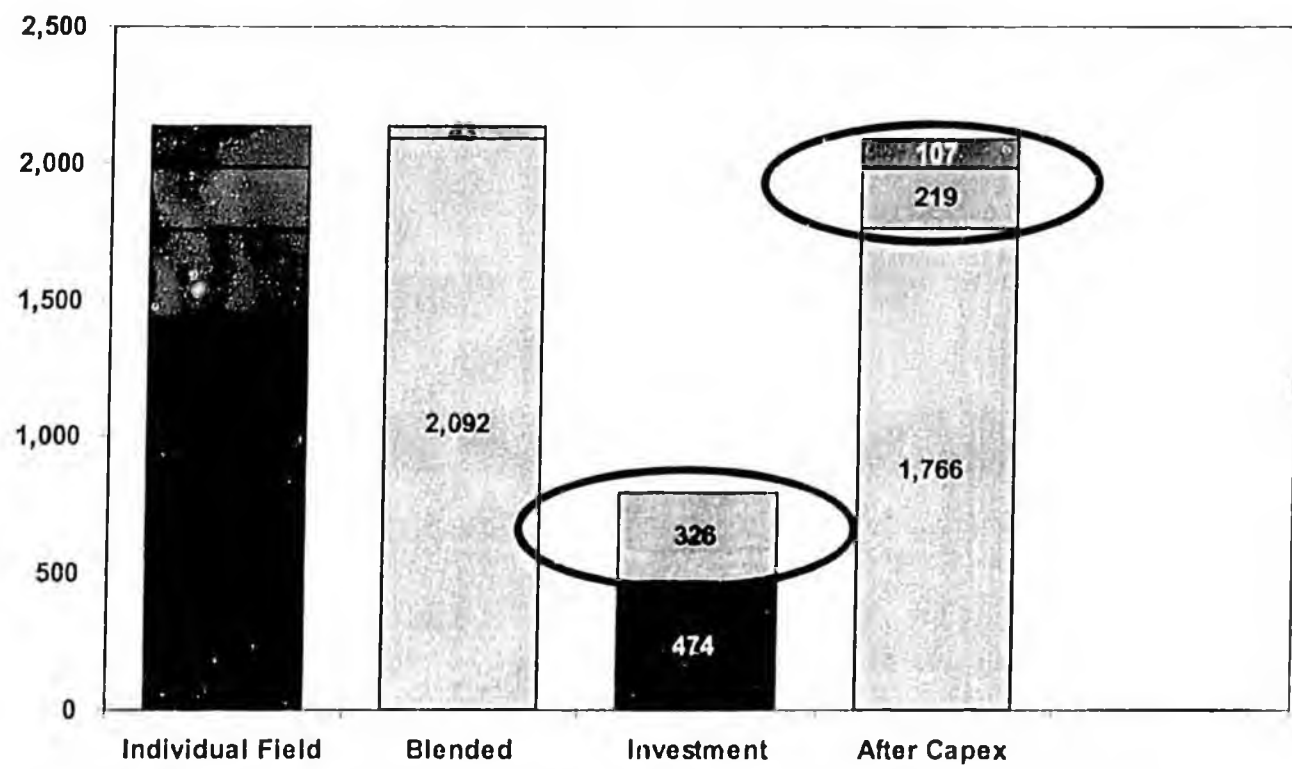


Putting all fields in one portfolio (company) lowers this to \$2,092 million
... a saving of \$ 43 million



The Big Winner Though Is Capex

Tax Allocable By Field Within Portfolio



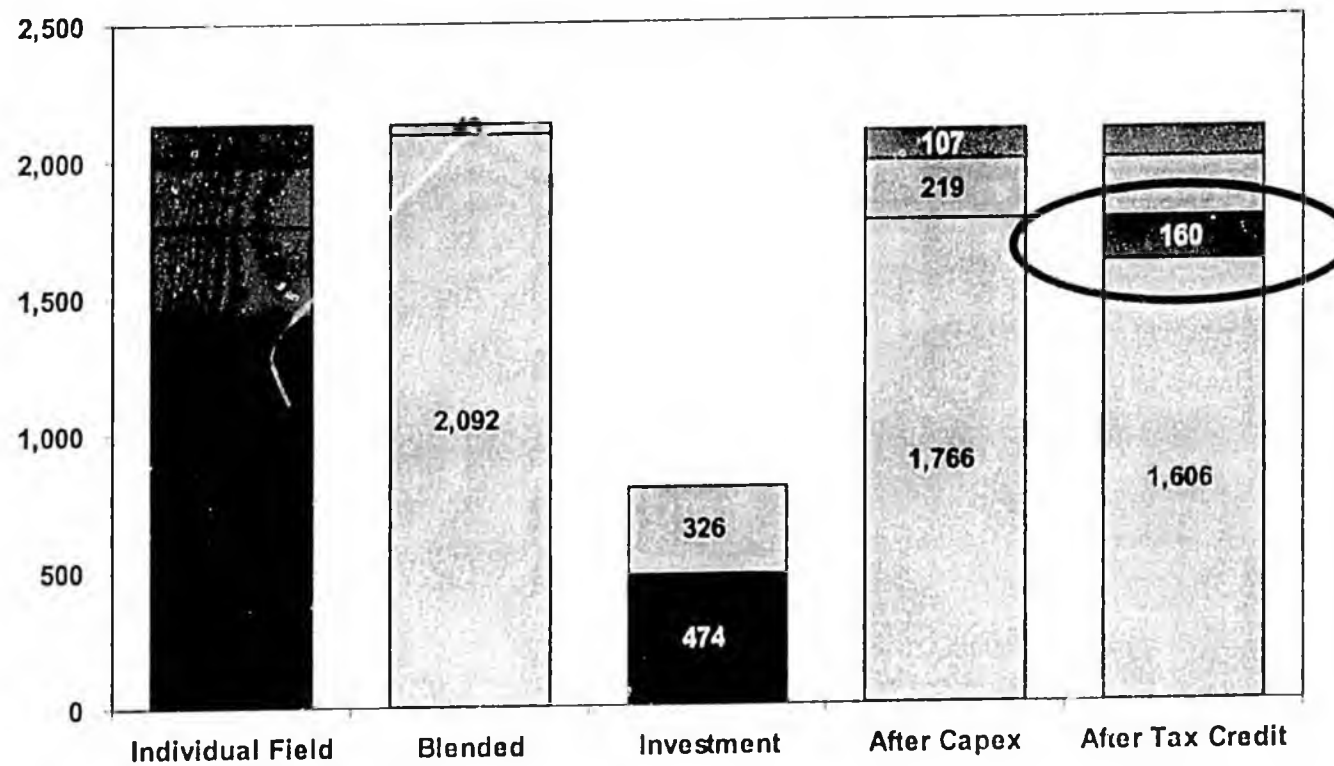
In this example the State pays \$326 million (40.8%) of the capital (the percentage will vary based on overall portfolio net margin per barrel)
The \$326 million can be allocated as \$219 million from reducing taxable income at 27.4% and \$107 million from lowering the rate from 27.4% to 25.9%

But Wait ! That Is Not All



Investment Credits Also Apply ..

Tax Allocable By Field Within Portfolio

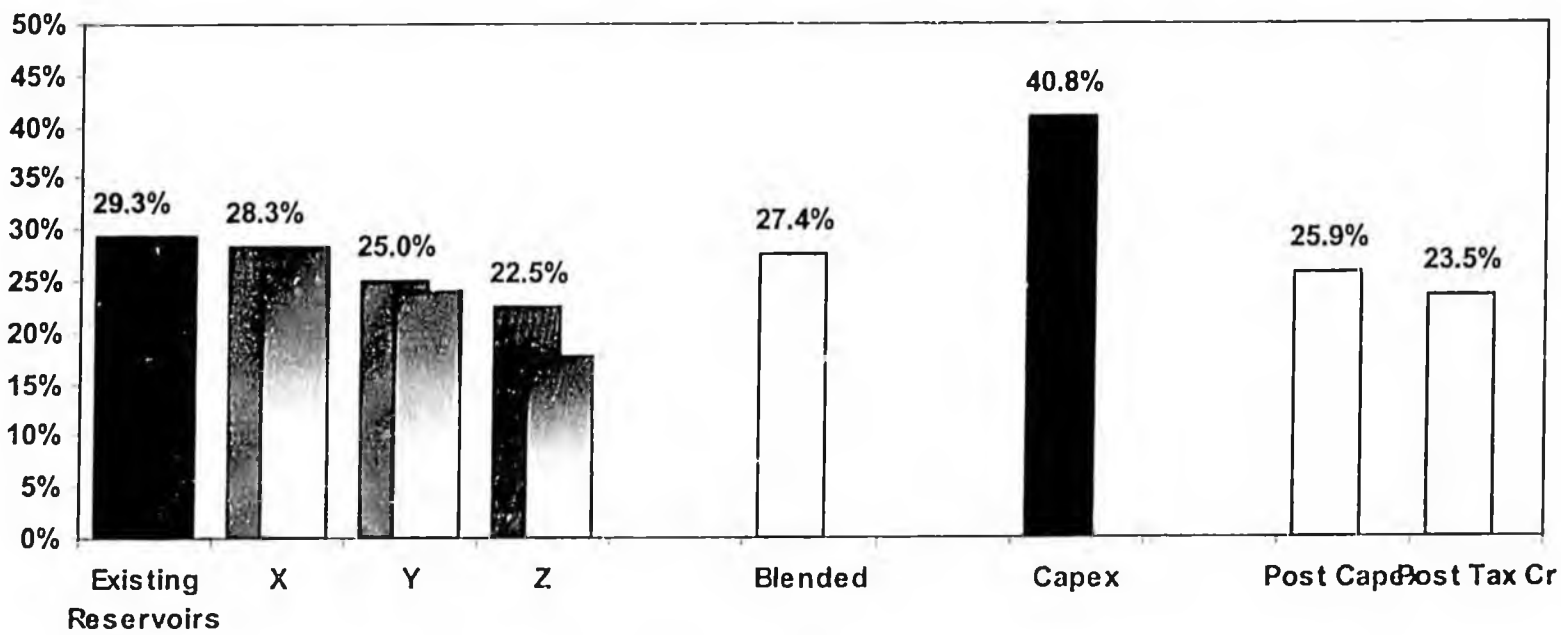


Investment Credits Take a further \$160 million (20% of \$800 million) from the tax payable



After Investment Credits ...

Tax Rate By Field Within A Company - As Affected By Portfolio Blending,
Capex And Tax Credit



... has the effect of lowering the tax rate further, to 23.5%*

(note: the tax rate is not actually lowered, but this is the mathematical effect)

* In this example

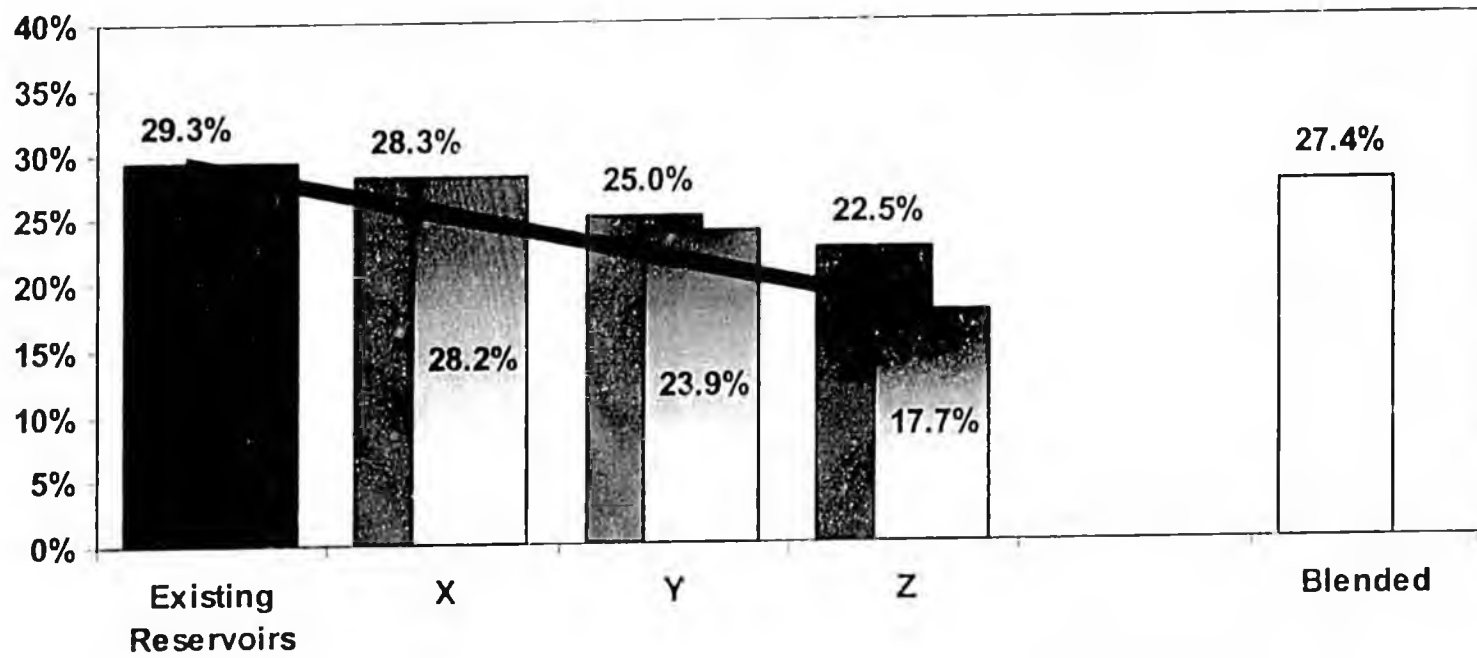
Tax Structure As Applied Under Various Structures

PPT
ACES
Senate Judiciary
House Resources



PPT Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

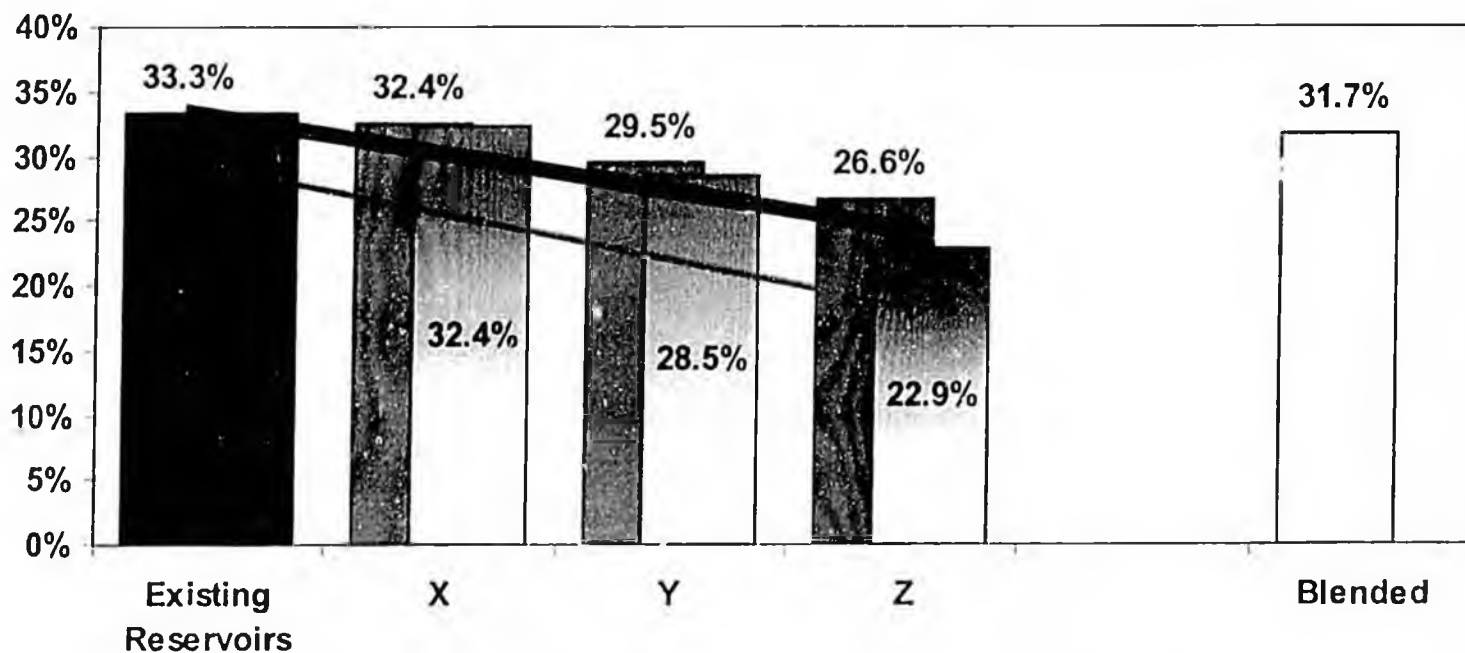


The progressivity can be seen through the lower effective tax rate on lower margin fields



ACES Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

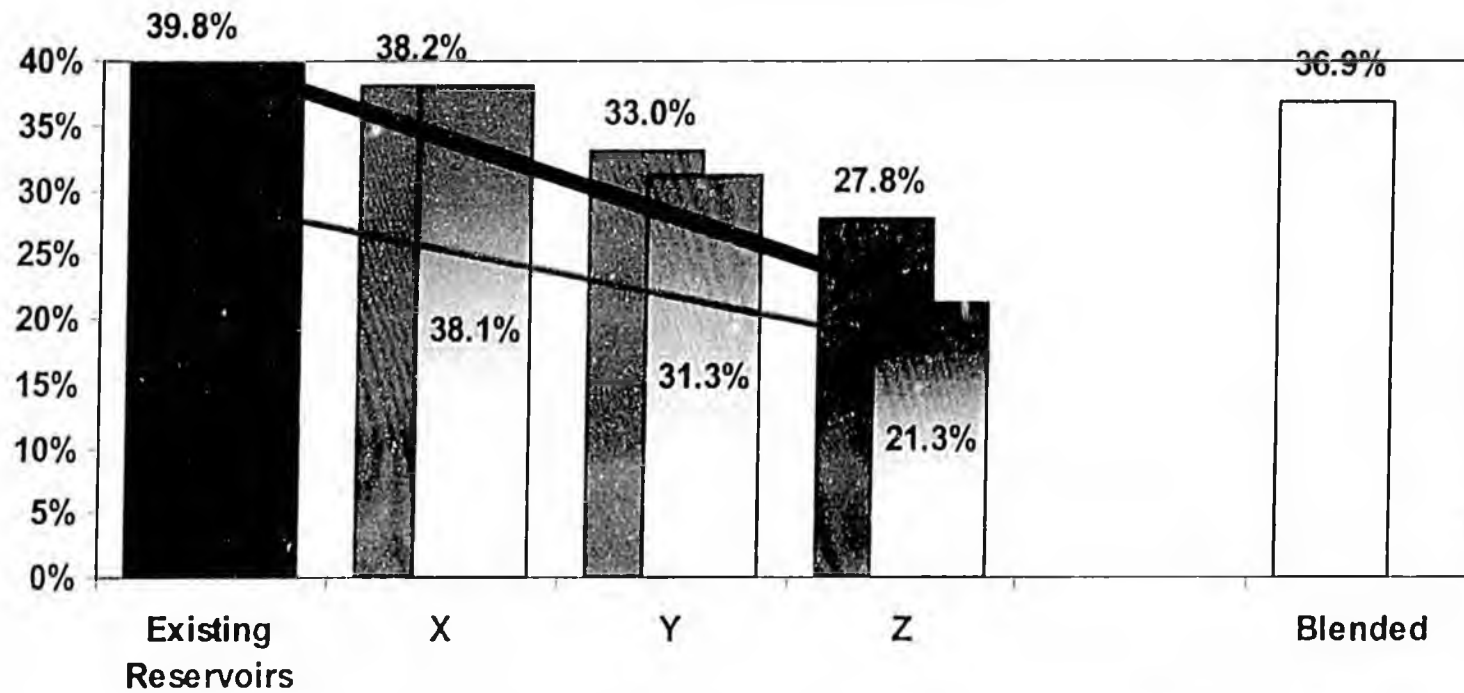


The progressivity feature is maintained, although ACES has a higher base rate (25% compared to PPT 22.5%) and a shallower progressivity (0.2% compared to 0.25%), starting \$10 earlier (\$30 rather than \$40 net cash flow per barrel)



Senate Judiciary Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending



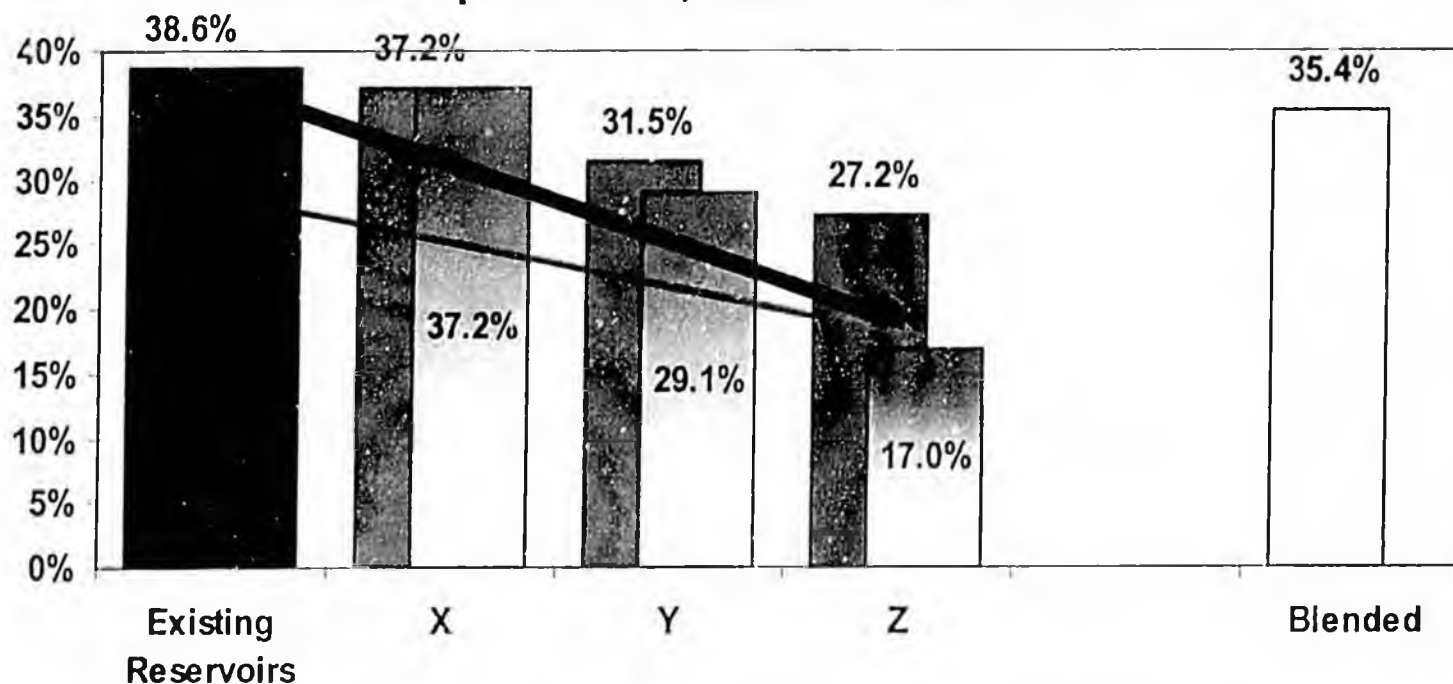
The Senate Judiciary CS starts at the same point as ACES, but has a progressivity of 0.4%, rather than 0.2%
As a result, while this results in an overall larger take, the less profitable field in this example actually benefits from a lower rate



House Resources Progressivity

Tax Rate By Field Within A Company - As Affected By Portfolio Blending

The progressivity in the House Resources CS sets its rate from the net cash flow per barrel, but taxes the Gross Value



As such its effective rate becomes higher than a “pure net” system with the same progressivity feature, but the progressive taxation of different profitability fields is maintained



Conclusions

- A net tax on the “profit margin” is actually a tax on a company’s retained cash flow and not just a tax on simple profitability
- The progressive feature in PPT, in ACES, and in the Senate Judiciary CS and House Resources CS allows fields of different profitability within the same company to have different effective tax rates
- More aggressive net progressivity provides a greater differentiation on the effective rate

Actual Prudhoe Results



Where is the tipping point?

- **Quite legitimately several legislators have asked how far (increasing taxes) is just right and how far is too far?**
 - The companies, for obvious reasons, have passed on the opportunity to describe in numerical terms what impact a change in Alaska taxes will have
 - Decision making process has many factors
 - Worldwide better rock trumps fiscal systems
 - Appears the majority of capital spending of the major Alaskan oil companies is in regimes with higher government take
 - All consultants acknowledged that taxes are but one of many factors that control decision making, and cannot say with certainty what tax rate is just right



Testing the Tipping Point

- **Industry testimony to previous committees paints a fairly clear picture of one very important aspect of North Slope operations**
 - AOGA letter which reflects “the full consensus of the members of the AOGA Tax Committee, with no dissent”
 - BP’s very detailed presentation on Prudhoe Bay area
 - Conoco’s useful insight on project economics
 - And other information supplied by Anadarko, Chevron, Exxon and Pioneer.
- **Details presented were then double checked against annual reports, SEC filings, analyst presentations and other company press releases where available**



Overall Observations

- **Based on the testimony and presentations from industry GCA believes:**
 - There is significant upside in terms of barrels of oil to be produced by investing to reduce the natural field decline rate in the major North Slope fields
 - The economics of reinvestment in existing producing assets on the North Slope are extremely profitable
 - Evaluated with actual costs, production and prices as reported by BP
 - Profitable even when tested against various stress points



AOGA Testimony to the House

In discussing the merits of HB 2001 versus PPT and the Administration's concerns, we must always keep in mind the real-world situation that Alaska faces. The greatest challenge that confronts this generation of Alaskans and the next is the ongoing decline of oil production, which has been, is today, and promises to remain the cornerstone of the finances of state government.

- **The fiscal system chosen must recognize the current and near-term importance of improving production from existing assets.**



AOGA Testimony – Recent Success

This gets us to investment in currently producing fields. Fortunately, there are investments that can be made, and are being made, in these fields to slow their decline. In the short term, this is in-fill drilling — that is, drilling new wells into the portions of a reservoir that are between the wells that have already been drilled. This accelerates the drainage of oil from the rock that currently lies in between existing wells. In-fill drilling last year contributed some 70,000 barrels a day to production from the Prudhoe Bay field. To put this into perspective, a 70,000 barrel per day field would be the 4th largest stand-alone field on the North Slope today.

- **AOGA, with the 100% backing of their member organization touted the importance of infill drilling along with its success**
- **Additional production of 70,000 bopd was achieved with the 2006 infill drilling program.**

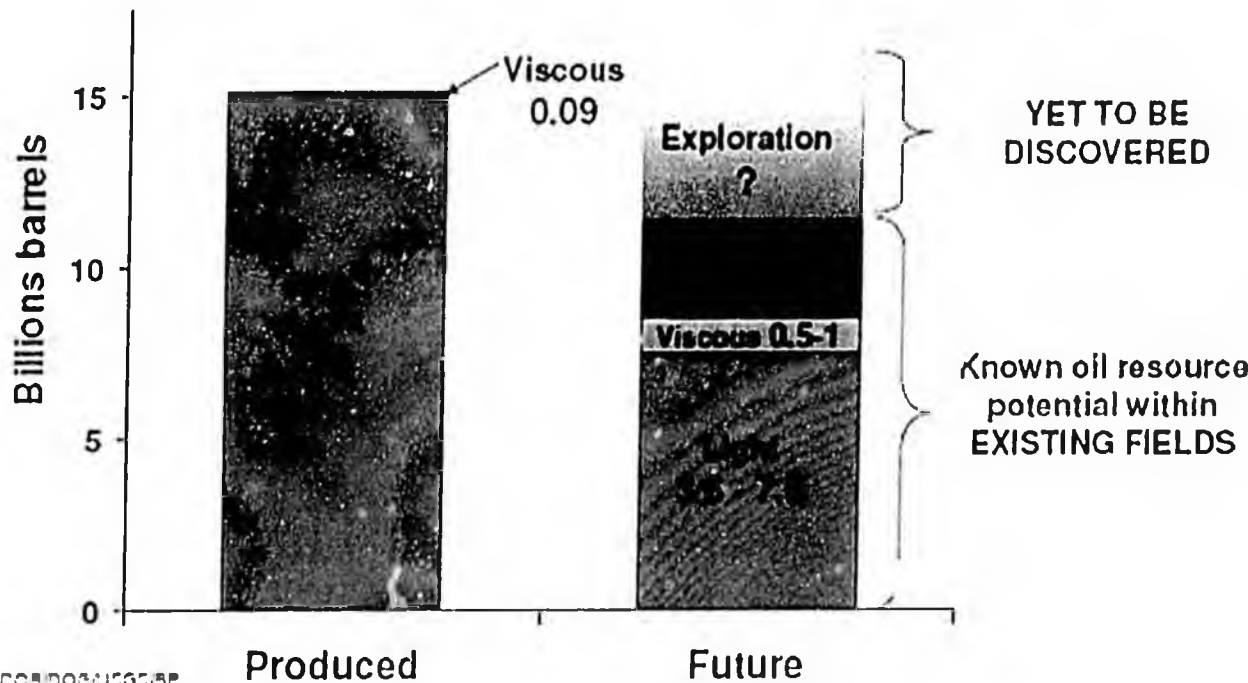


Potential infill upside

The future of North Slope oil still tied to existing fields



Sustained investment in light oil development is critical to developing heavy oil and new fields



Source: DOR, DDC, USGS, BP

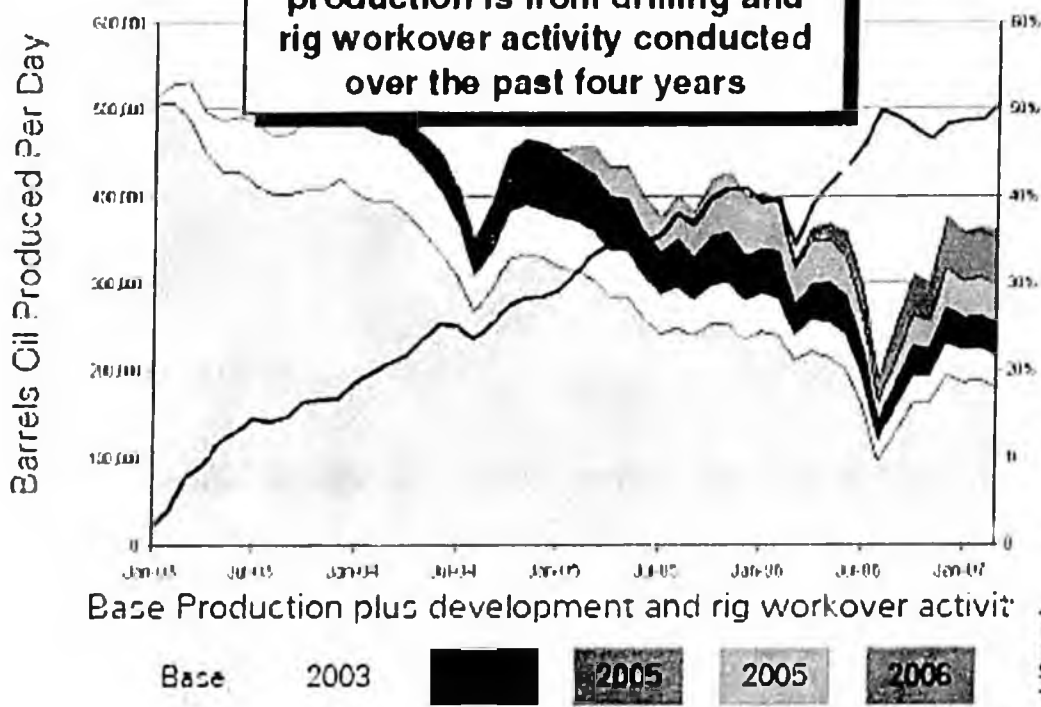
BP noted that light oil represented as much as 7.5 Bn bbls out of a total of 11.5 Bn bbls

Light oil ~ 70% of the identified potential

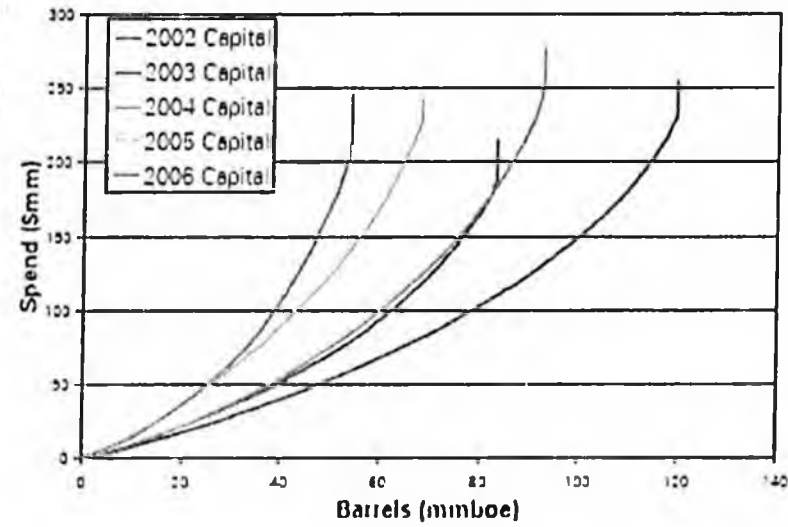


Prudhoe Bay infill drilling results

50% Of GPB's current oil production is from drilling and rig workover activity conducted over the past four years



GPB Well Investments: 2002-2006



BP House testimony page 12



Costlier Development

- It is getting more expensive to develop a barrel of reserves (BP Infill program)

	2002	2003	2004	2005	2006
Capex	255	220	275	240	245
MMbbls	120	90	80	60	50
\$/bbl	2.13	2.44	3.44	4.00	4.90

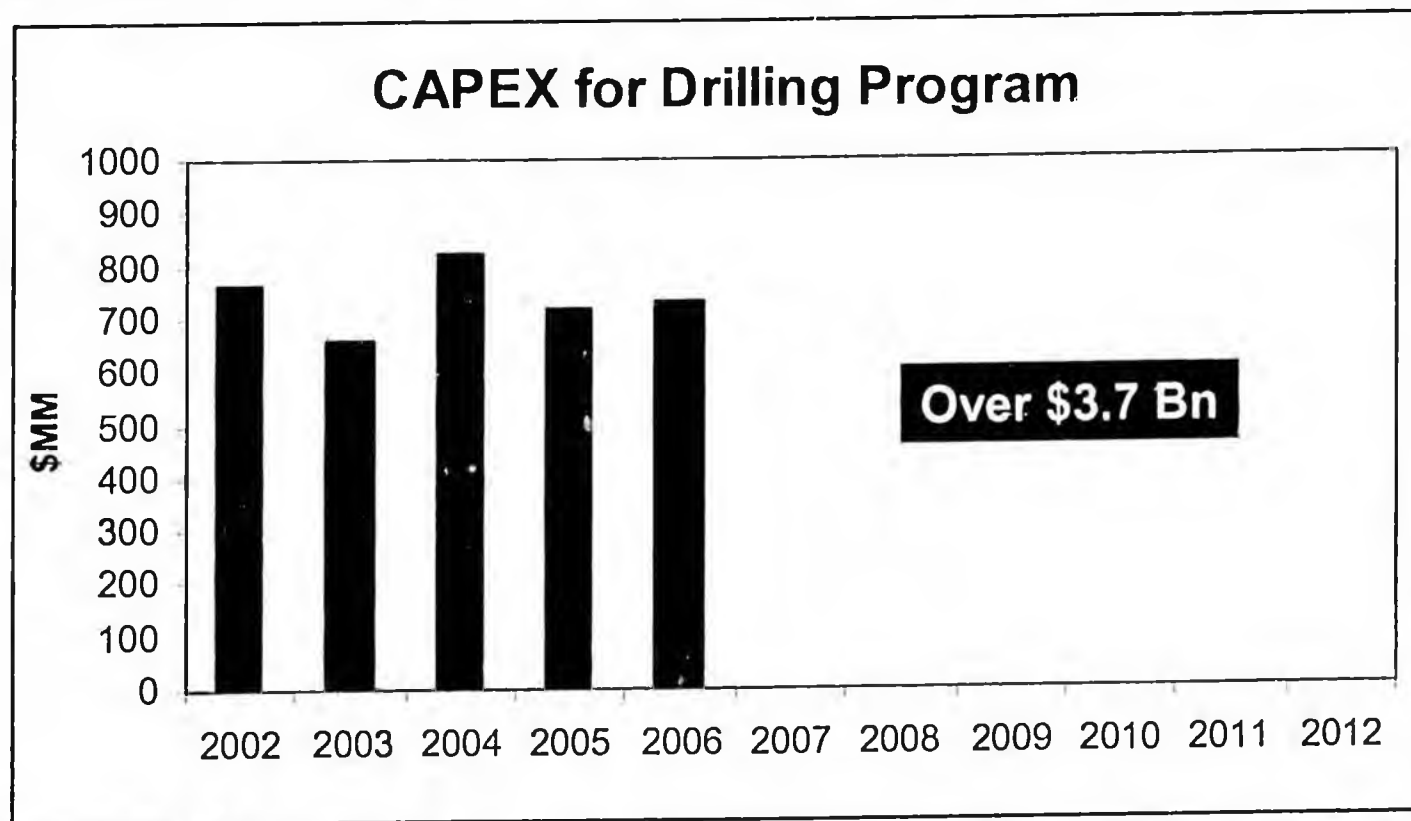
- Contrast the above per barrel F&D costs with:
 - \$2 or less CAPEX for Prudhoe and Kuparuk to date
 - \$19bn to produce 9.5 bn bbls
 - The P/K upside at \$3.5(15%), \$7.7 (6%), \$12 (3%)
 - Pioneer's view of average F&D for Lower-48 of \$14

*Findlay
Indonug*



5 Year Prudhoe Drilling Program

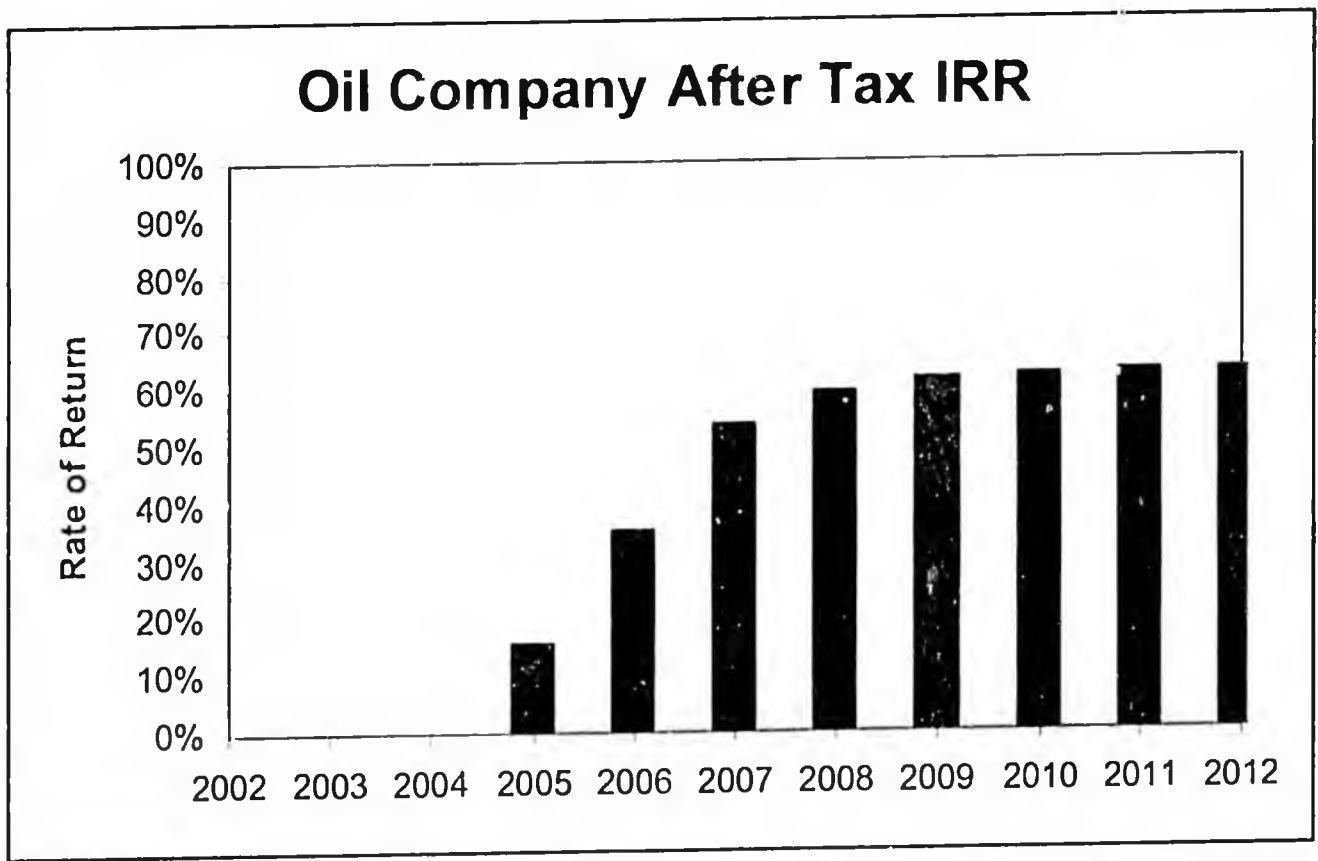
- BP noted that for every dollar spent on an infill well another two dollars were spent on injection and surface facilities – base case is 300% Capex





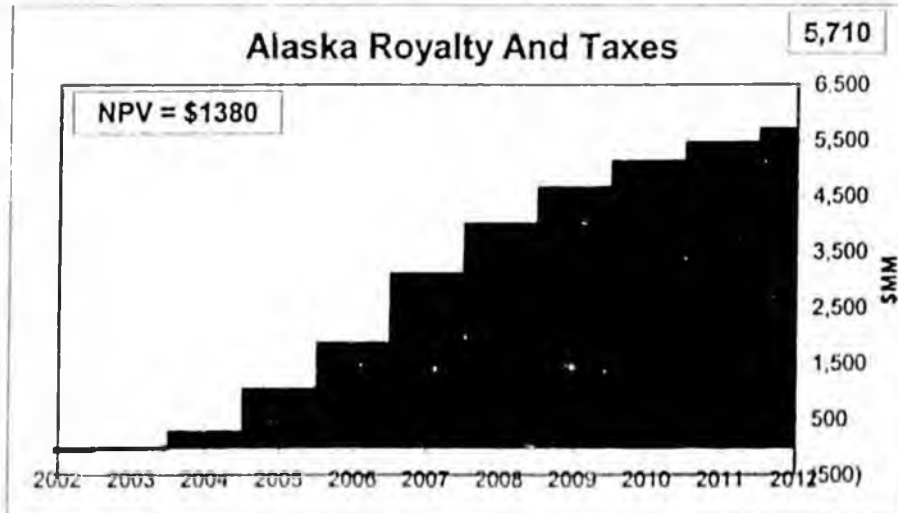
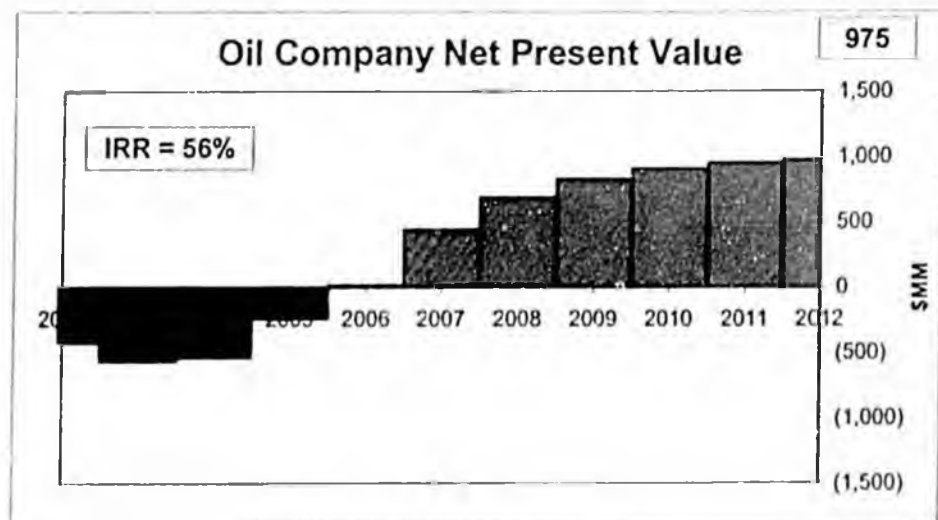
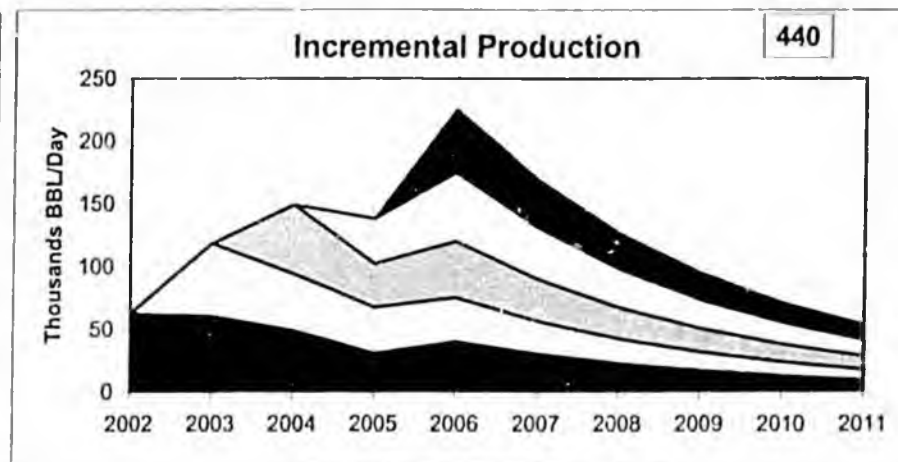
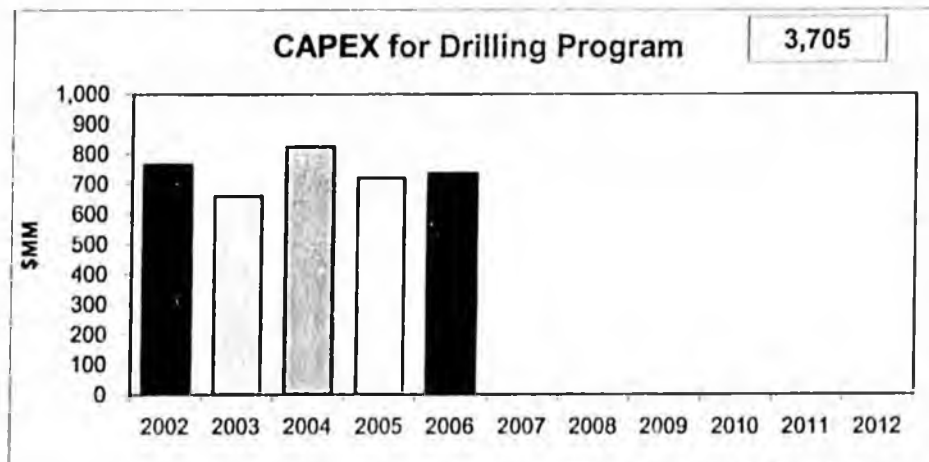
BP Prudhoe Bay

- This is the after tax return on (300%) investment realized by the Prudhoe Bay owners





Overly Stressed Case



Model Demonstration





North Slope Potential

Production Drives Revenue



Decline Rate	15%	6%	3%
Produced Barrels	1.3 bn	3.9 bn	7.5 bn
Industry Investment	\$5 bn	\$25 bn	\$70 bn
		Status quo	

- **Built a generic model based on the above barrels and investments**
 - Used indicated decline rates
 - 250,000 bpd abandonment rate
(Based on the oil companies' and AOGA presentation of the mechanical limit of 300,000 bpd for TAPS and the above decline rates and produced barrels)

Backup

Actual drilling program assuming PPT applies throughout



- Without investment credits pre 2006
- Oil Company IRR = 53%, NPV10 = \$4 billion

Modeling the Prudhoe Success contained in AOGA/BP Testimony

Drilling Program Year

2002

2003

2004

2005

2006

Capex Multiplier 300%

Opex Multiplier 100%

Production Multiplier 100%

Discount Rate 10%

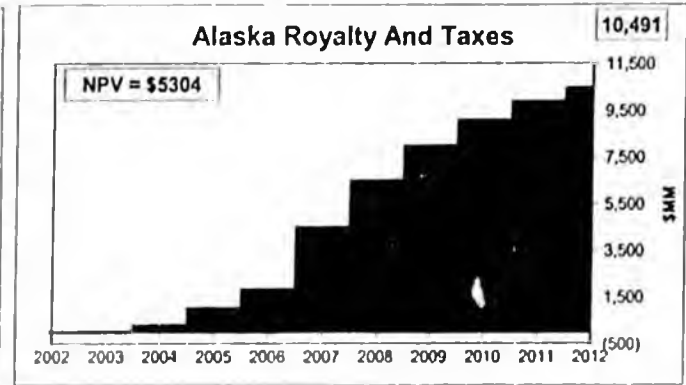
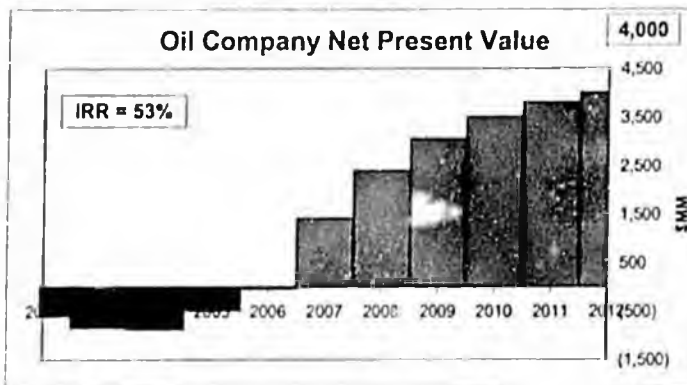
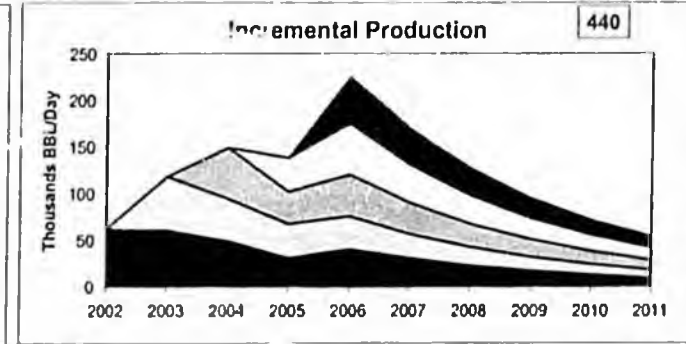
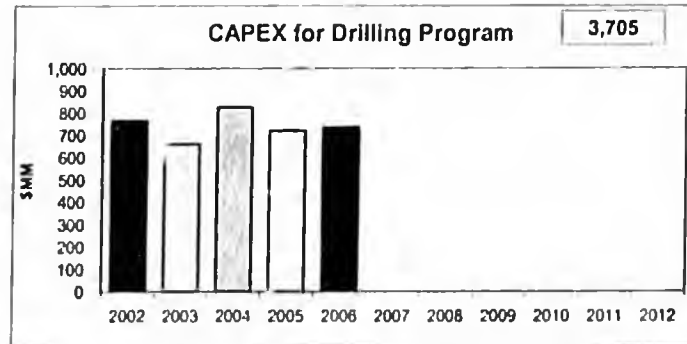
Royalty 12.5%

Net Tax Rate 22.5%

Progressivity 0.25%

Progressivity Start 40

Price 80



No tax credits 2002-2005

Actual oil price (but based on PPT) thru 2006, then Fcst

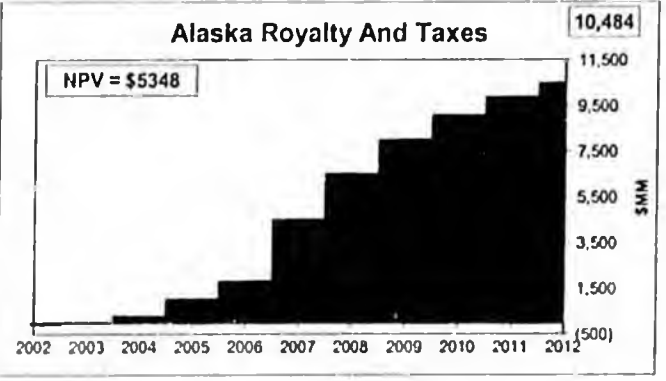
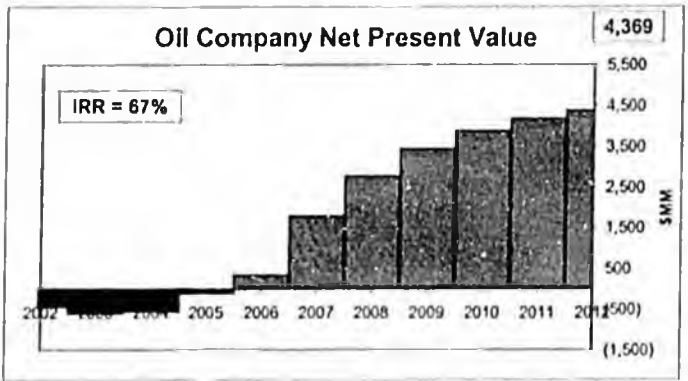
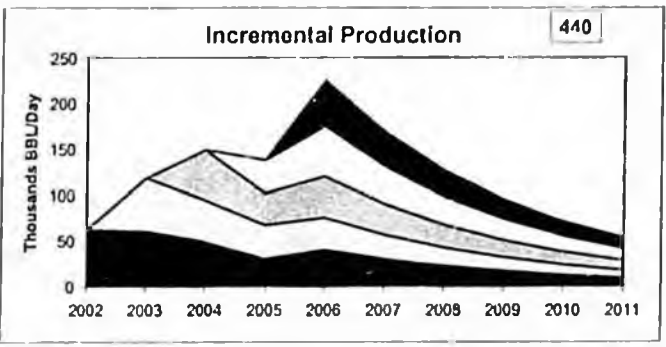
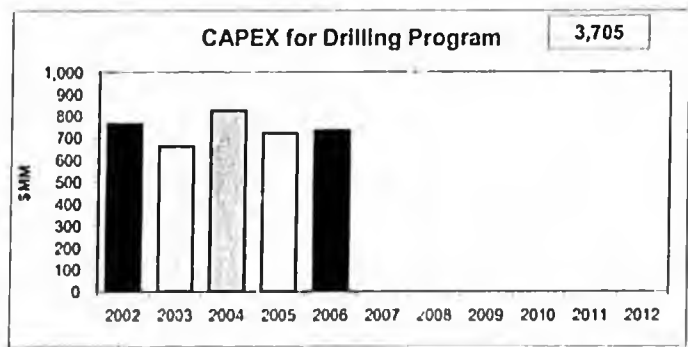


Assuming PPT from 2002 with credits

- With investment credits pre 2006
- Oil Company IRR = 67%, NPV10 = \$4.4 billion

Modeling the Prudhoe Success contained in AOGA/BP Testimony

- Drilling Program Year
 - 2002
 - 2003
 - 2004
 - 2005
 - 2006
- Capex Multiplier 300%
- Opex Multiplier 100%
- Production Multiplier 100%
- Discount Rate 10%
- Royalty 12.5%
- Net Tax Rate 22.5%
- Progressivity 0.25%
- Progressivity Start 40
- Price 80



Tax Credits from outset
 Actual oil price (but based on PPT) thru 2006, then Fcst

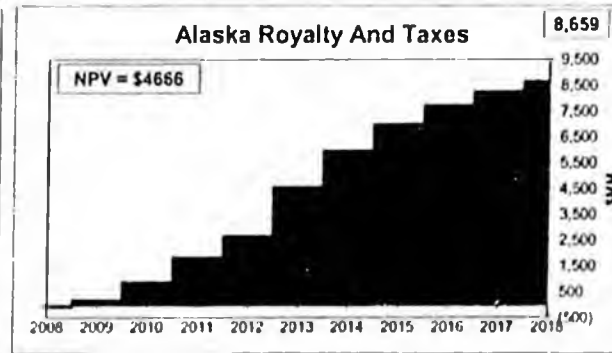
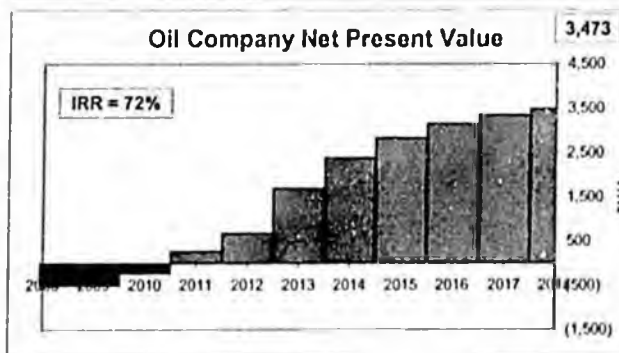
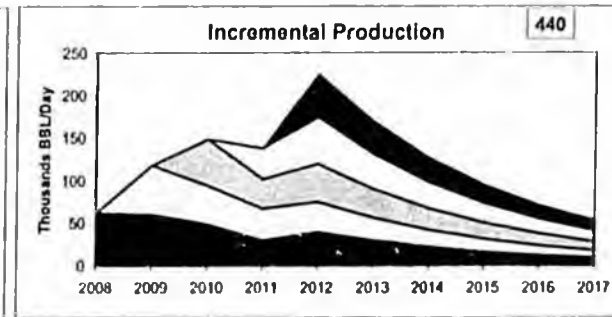
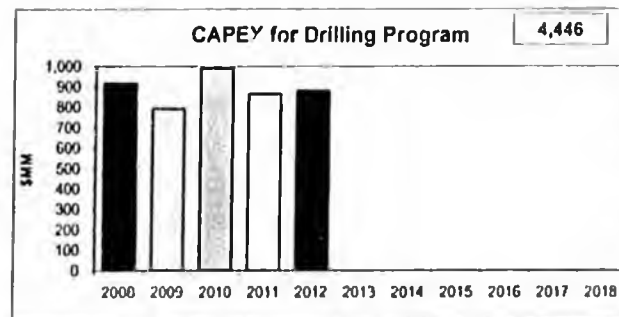
Duplicate 2002 – 2006 Program Starting in 2008



- Capex to 360%, \$60 oil, Senate CS, Forecast mode
- Oil Company IRR = 72% and NPV10 = \$3473 MM

Modeling the Prudhoe Success contained in AOGA/BP Testimony

- Drilling Program Year
- 2002
 - 2003
 - 2004
 - 2005
 - 2006
- Capex Multiplier 360%
- Opex Multiplier 100%
- Production Multiplier 100%
- Discount Rate 10%
- Royalty 12.5%
- Net Tax Rate 25.0%
- Progressivity 0.40%
- Progressivity Start 30
- Price 60



- Tax Credits from outset
- Forecast Only Mode

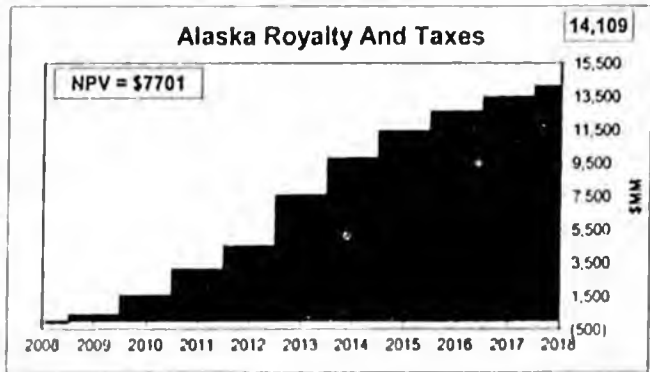
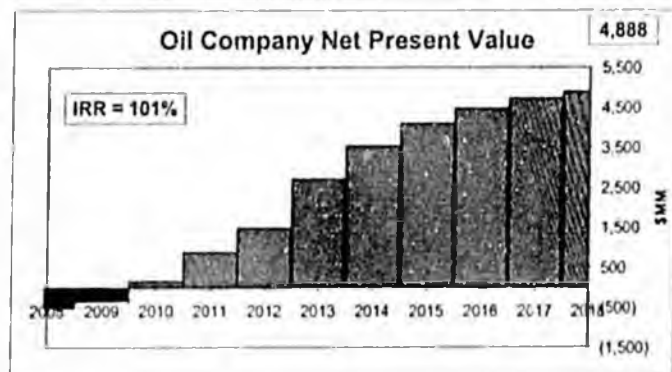
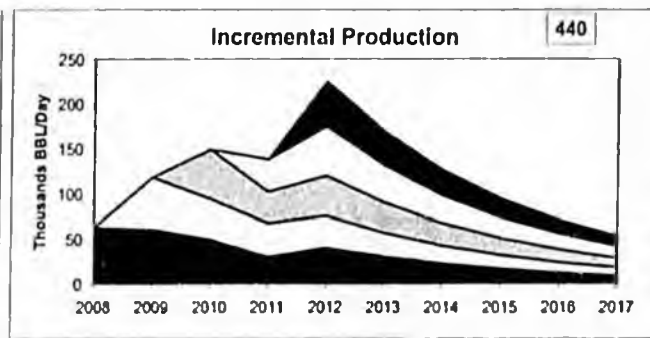
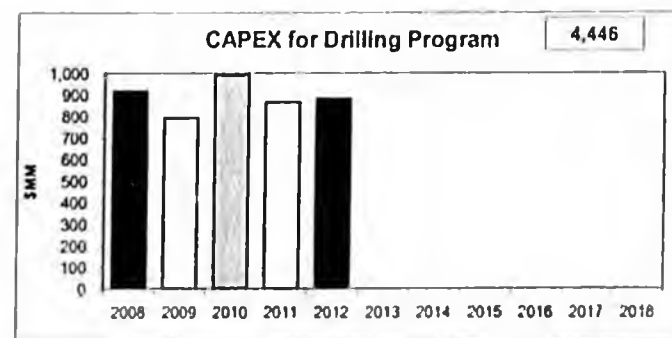


Forecast at the NYMEX strip price

- All things the same, but oil at \$80 per barrel
- Oil Company IRR = 101%, NPV10 = \$4,888 MM

Modeling the Prudhoe Success contained in AOGA/BP Testimony

- Drilling Program Year
 - 2002
 - 2003
 - 2004
 - 2005
 - 2006
- Capex Multiplier 360%
- Opex Multiplier 100%
- Production Multiplier 100%
- Discount Rate 10%
- Royalty 12.5%
- Net Tax Rate 25.0%
- Progressivity 0.40%
- Progressivity Start 30
- Price 80



- Tax Credits from outset
- Forecast Only Mode

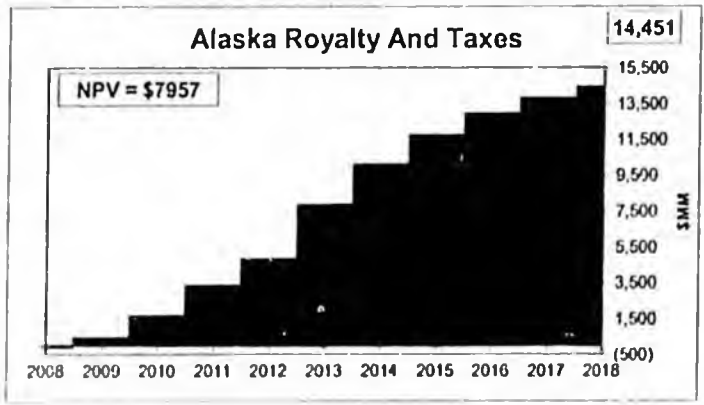
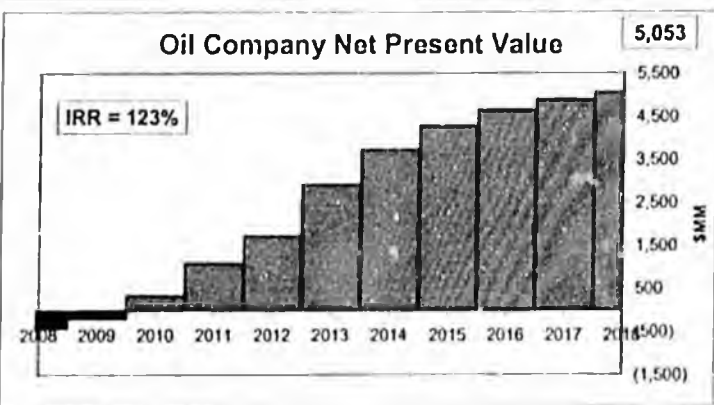
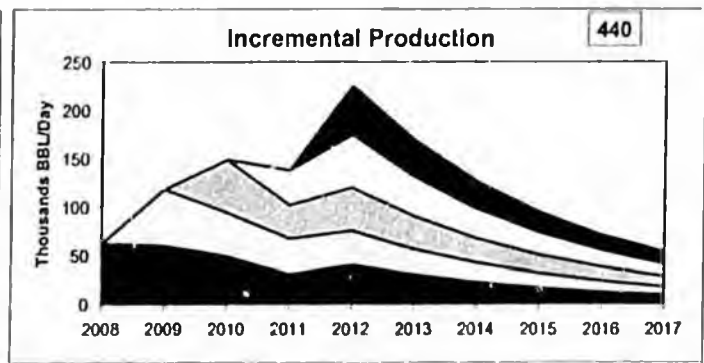
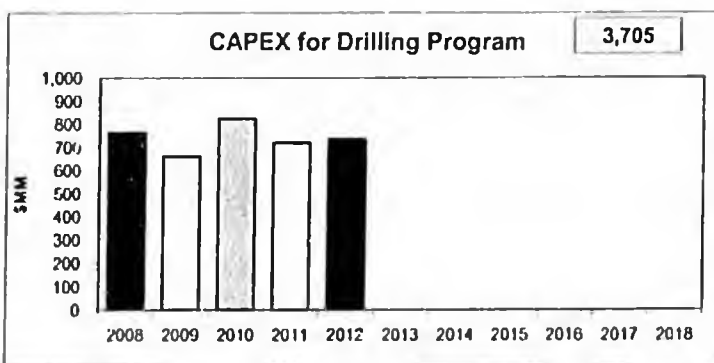


Senate CS – Forecast Mode, \$80 oil

- IRR = 123%, NPV10 = \$5.375 billion

Modeling the Prudhoe Success contained in AOGA/BP Testimony

- Drilling Program Year
 - 2002
 - 2003
 - 2004
 - 2005
 - 2006
- Capex Multiplier 300%
- Opex Multiplier 100%
- Production Multiplier 100%
- Discount Rate 10%
- Royalty 12.5%
- Net Tax Rate 25.0%
- Progressivity 0.40%
- Progressivity Start 30
- Price 80



Tax Credits from outset
 Forecast Only Mode

Report to the Alaska Legislature on Production Cost Increases

November 7, 2007

Barry Pulliam
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Suite 2825
Three Allen Center
333 Clay Street
Houston, Texas 77002
713 228 2700

Suite 230
106 E 6th Street
Austin, Texas 78701
512 476 3711

econ
ONE

Summary of Costs

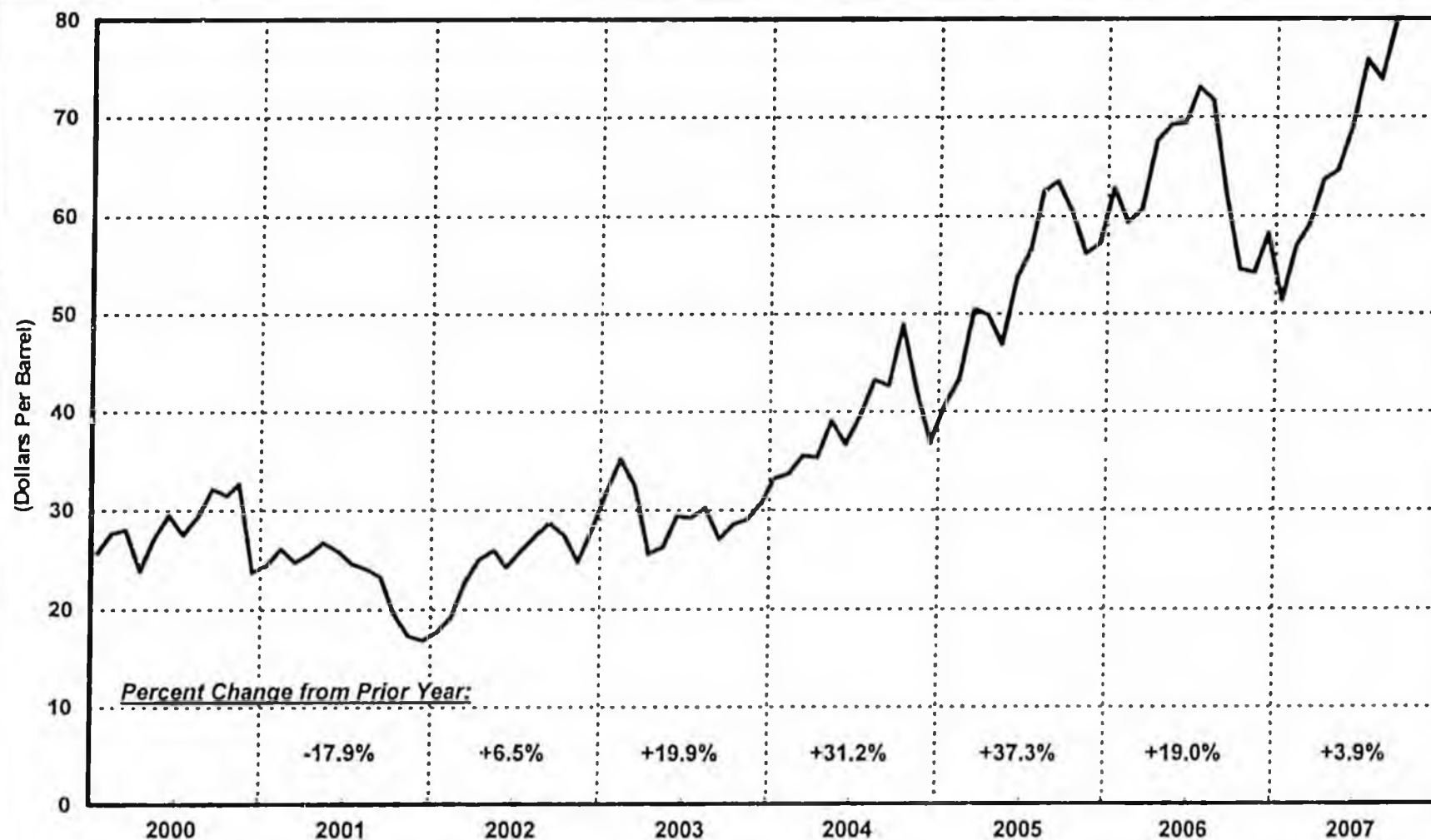
Fiscal Note HB 3001:

	FY 2008		
	<u>Capex</u>	<u>Opex</u>	<u>Total</u>
Total (\$M)	\$1,052	\$1,076	\$2,128
Per Taxable Barrel (\$/Bbl.)	\$4.58	\$4.68	\$9.26

Fiscal Note HB 2001 (Current):

	FY 2008		
	<u>Capex</u>	<u>Opex</u>	<u>Total</u>
Total (\$M)	\$2,146	\$2,187	\$4,333
Per Taxable Barrel (\$/Bbl.)	\$9.33	\$9.51	\$18.85

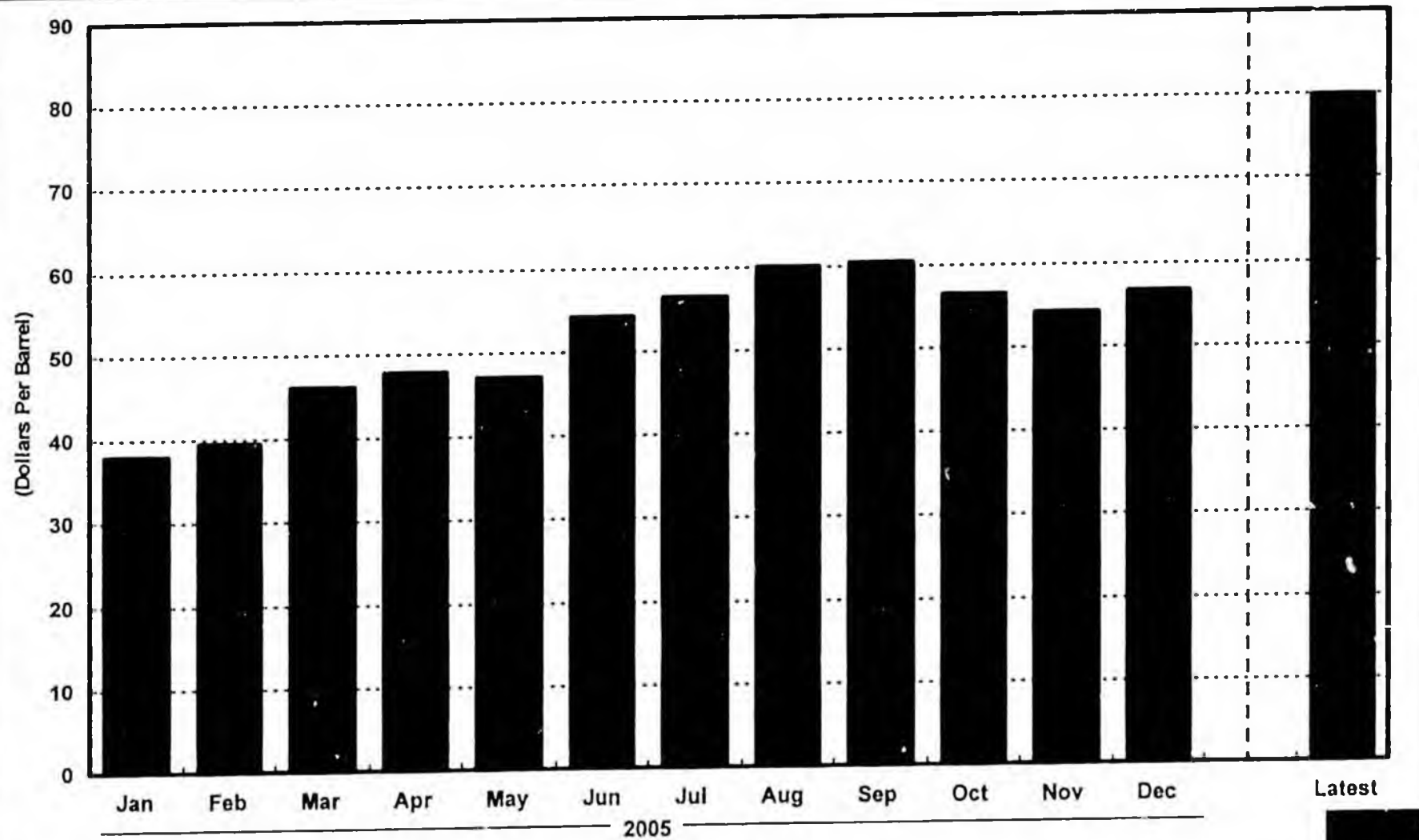
Platt's ANS Crude Oil Price January 2000 - September 2007



Source: Platt's.

econ
ONE

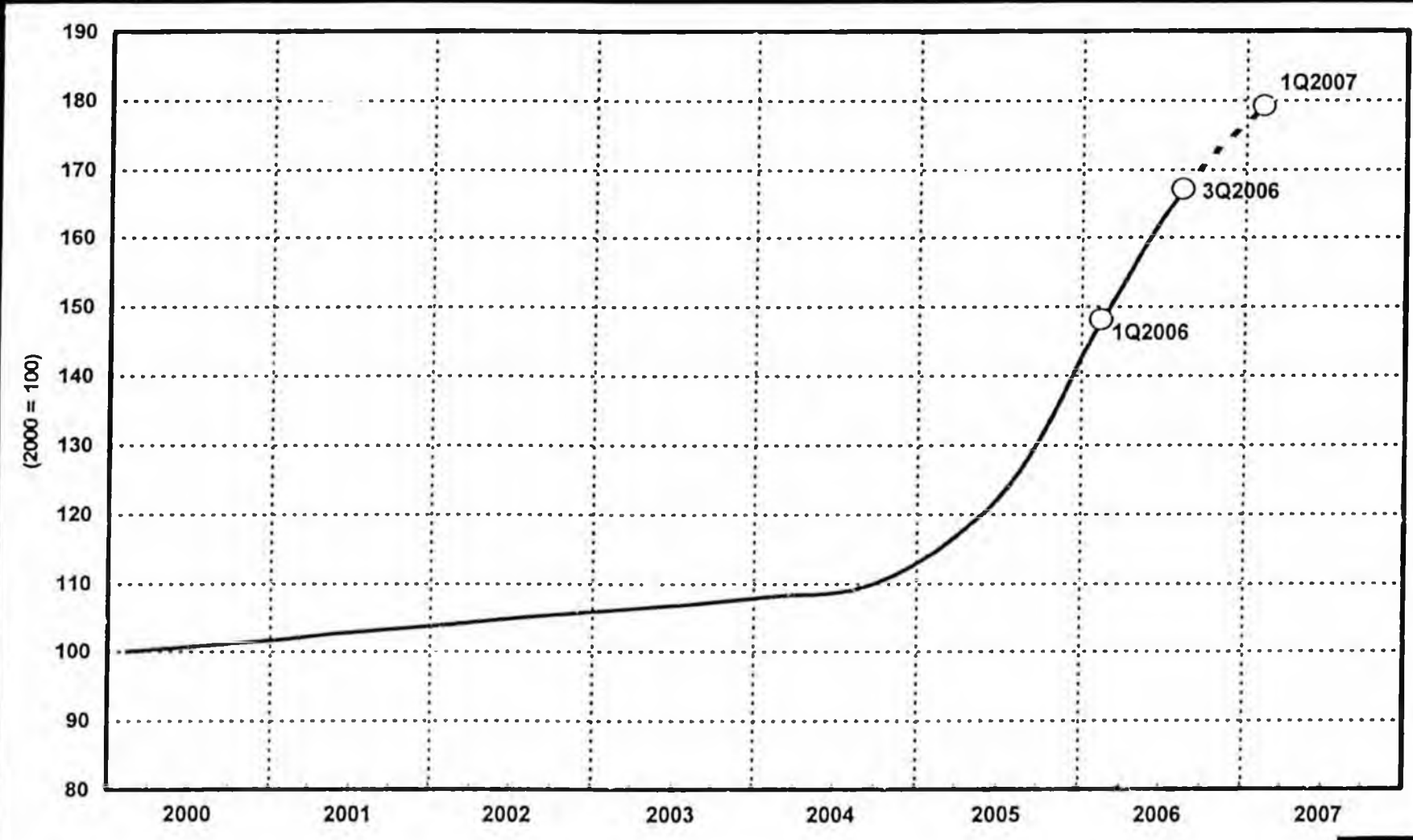
NYMEX Futures Price for December 2011 Delivery January - December 2005, Latest Quotes



Source: NYMEX.



IHS/CERA Upstream Capital Cost Index 1Q2000 - 1Q2007



Source: Based on Cambridge Energy Research Associates May 8, 2007 Press Release.

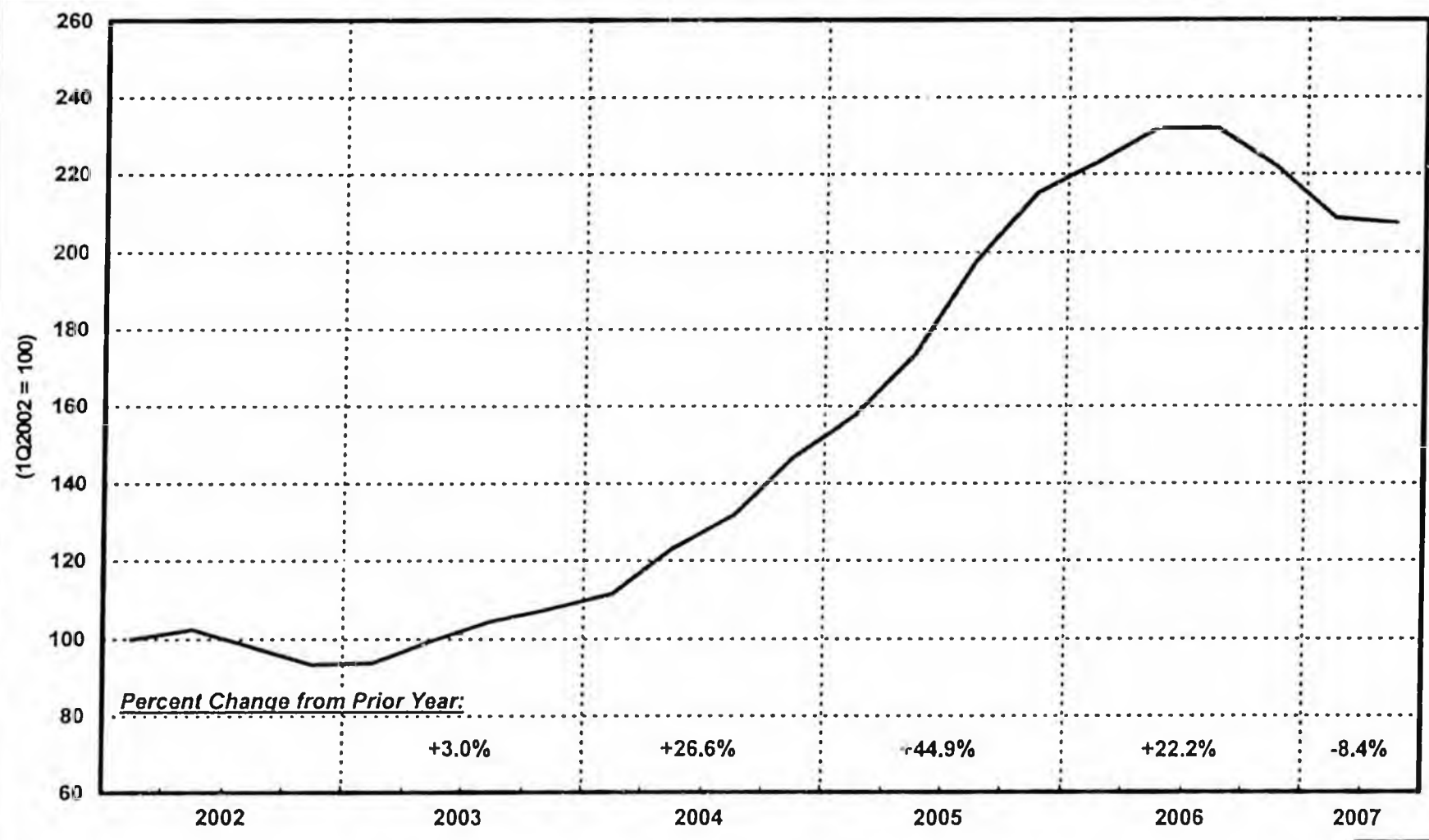


IHS/CERA Upstream Capital Cost Index vs. West Coast ANS Price 2000 - 2007



Source: Index Based on Cambridge Energy Research Associates May 8, 2007 Press Release; Prices from Platt's.

Average* Oil Drilling Rig Daily Rates Index 1Q2002 - 2Q2007

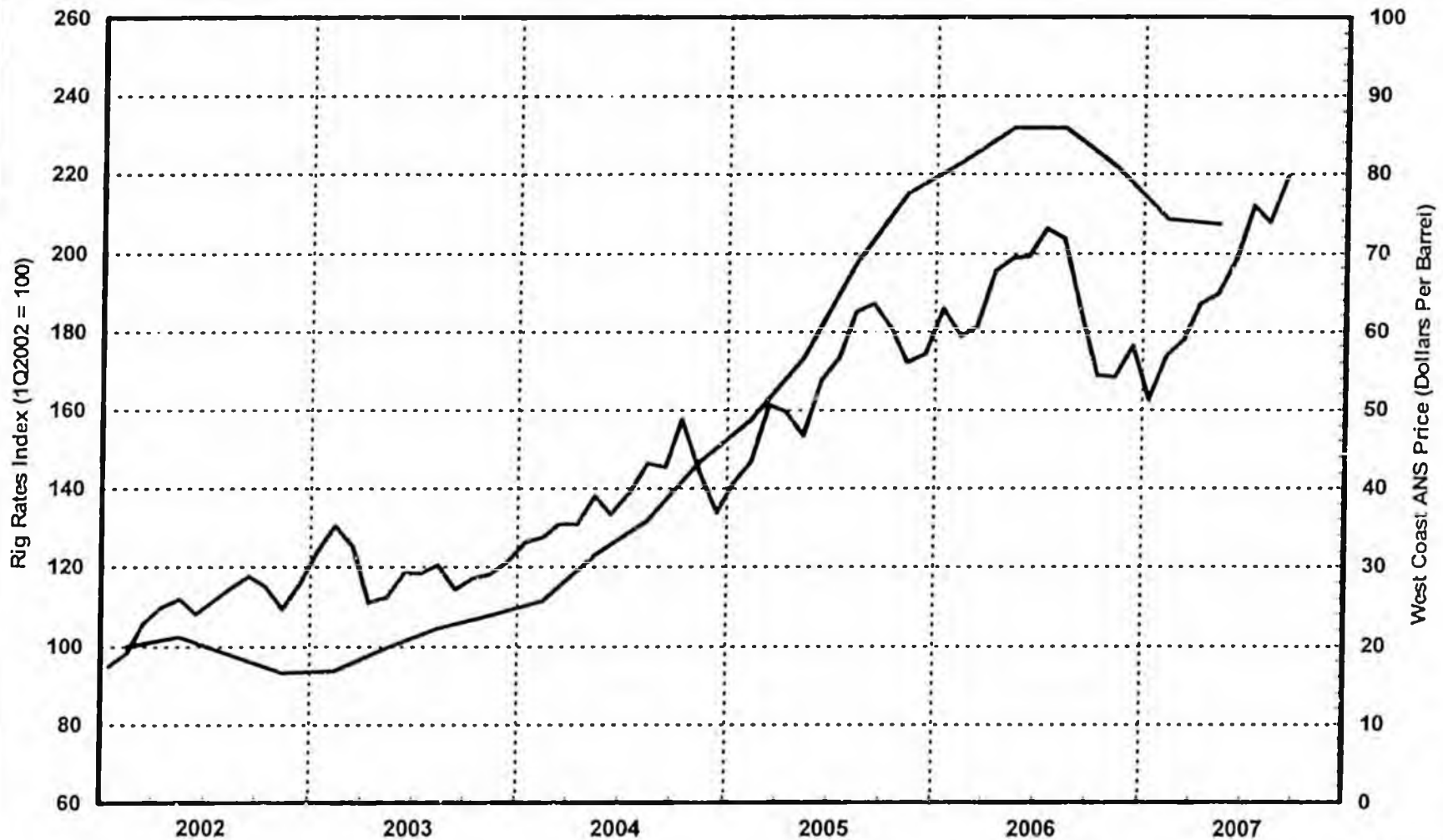


* Average of Mid-Continent, ArkLaTex, Gulf Coast, Permian Basin, Rocky Mountains, and South Texas.

Source: Land Rig Newsletter.



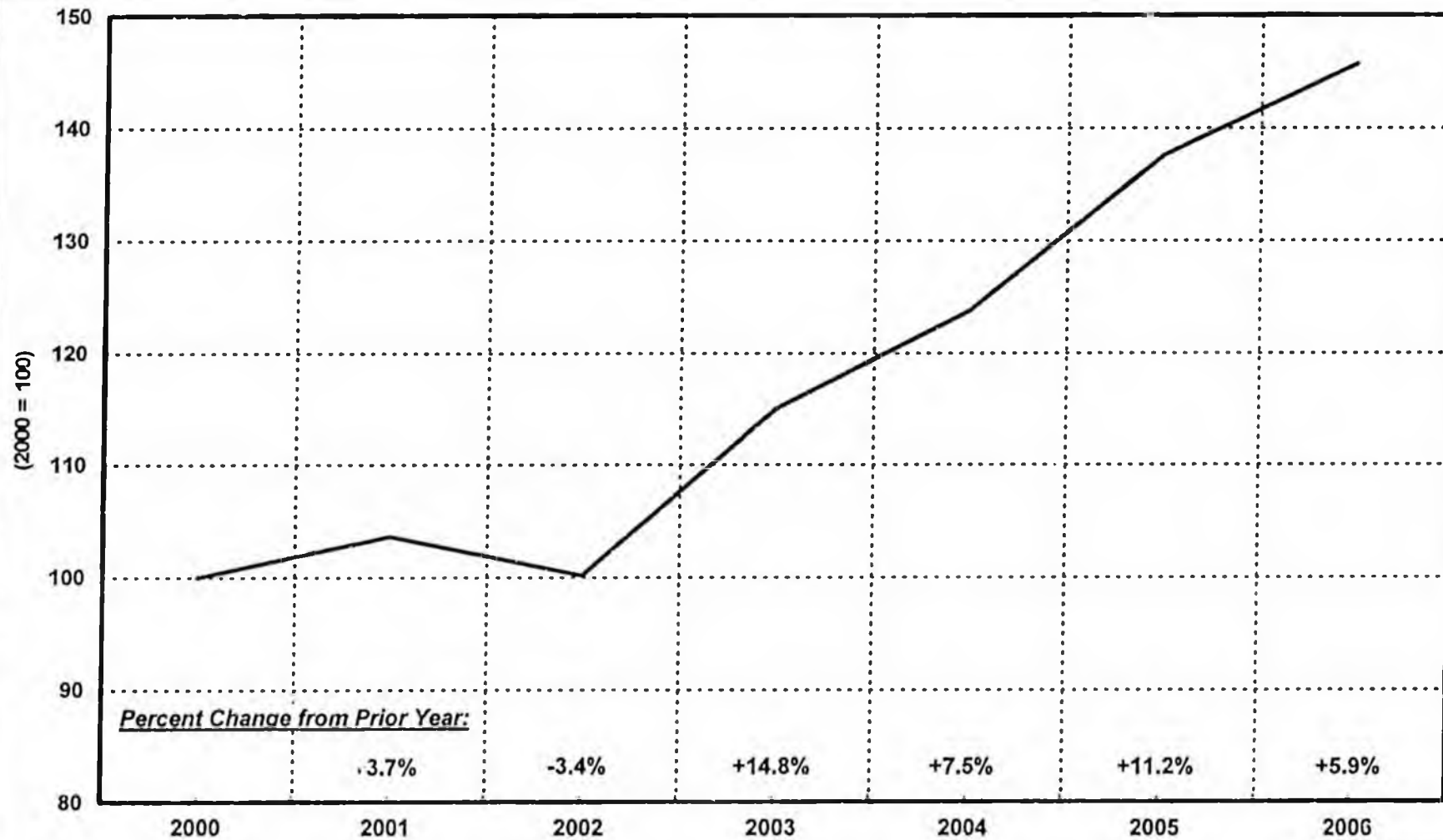
Average* Oil Drilling Rig Daily Rates Index vs. West Coast ANS Price 2002 - 2007



* Average of Mid-Continent, ArkLaTex, Gulf Coast, Permian Basin, Rocky Mountains, and South Texas.

Source: Rig Rate from Land Rig Newsletter; Prices from Platt's.

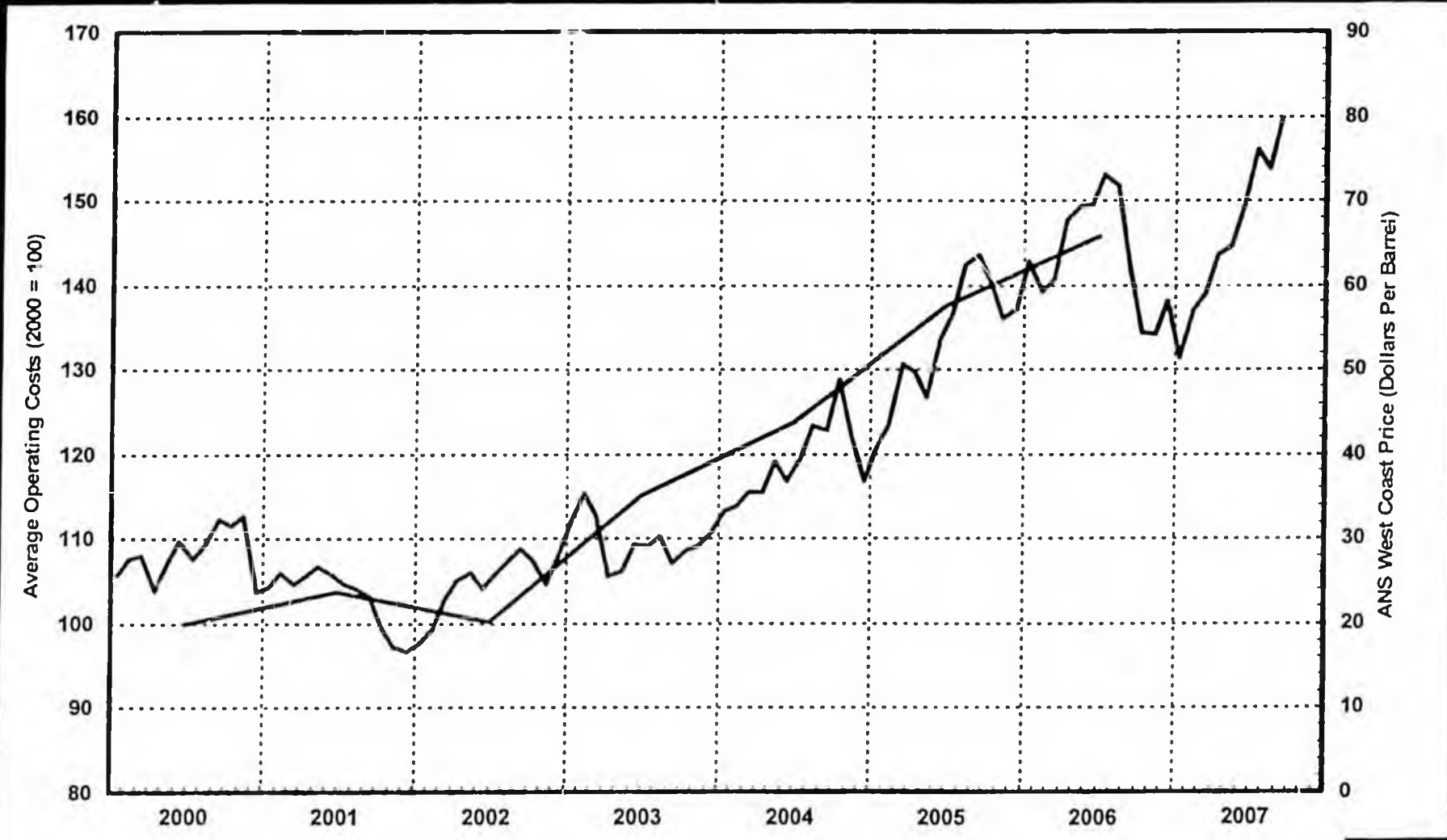
Average* Operating Costs for 10-Well Oil Lease Index 2000 - 2006



* Average of California, Oklahoma, South Louisiana, South Texas, West Texas, and Rocky Moutains.

Source: EIA.

Average* Operating Costs for 10-Well Oil Lease Index vs. West Coast ANS Price 2000 - 2007

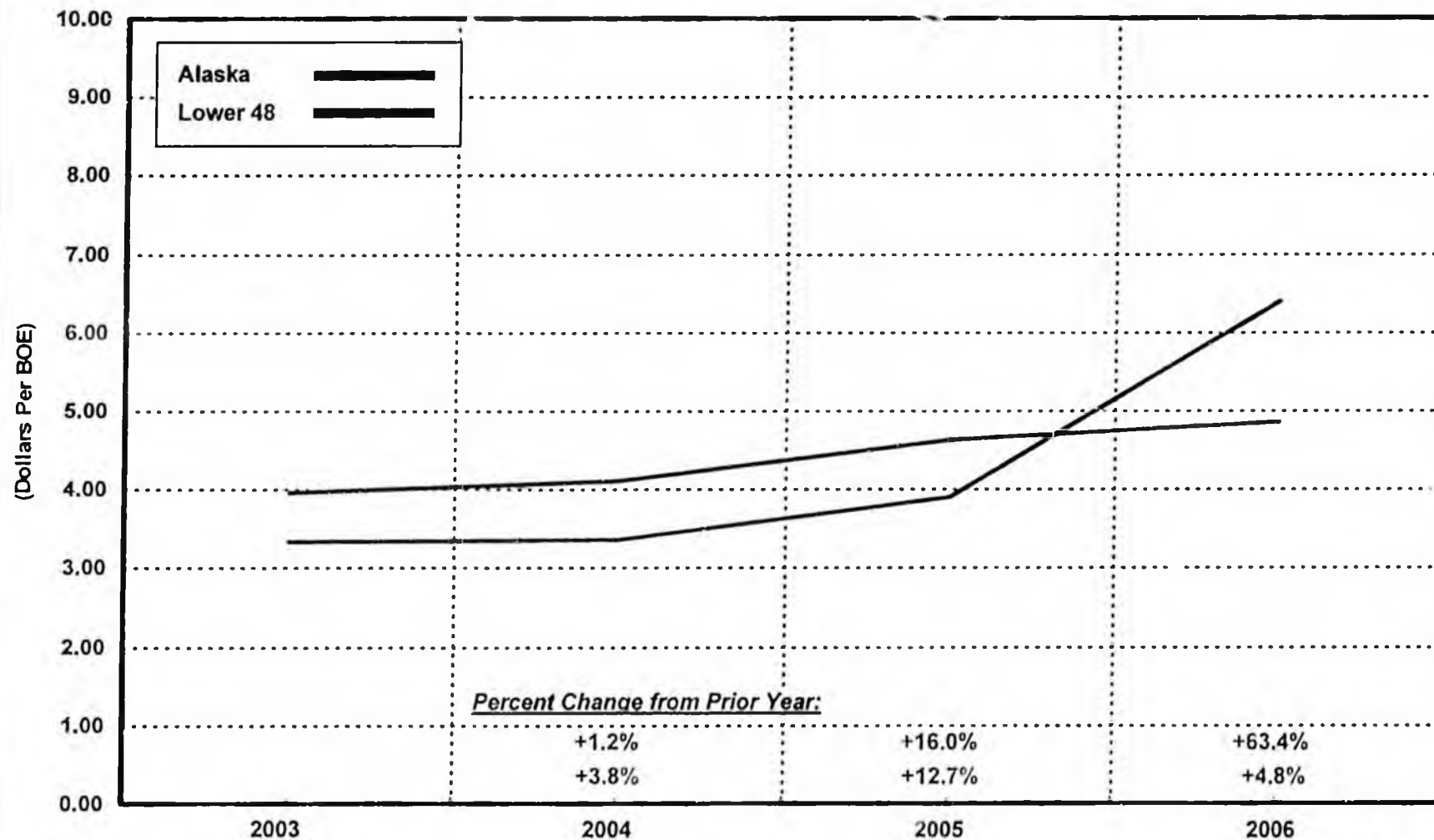


* Average of California, Oklahoma, South Louisiana, South Texas, West Texas, and Rocky Moutains.

Source: Costs from EIA; Prices from Platt's.

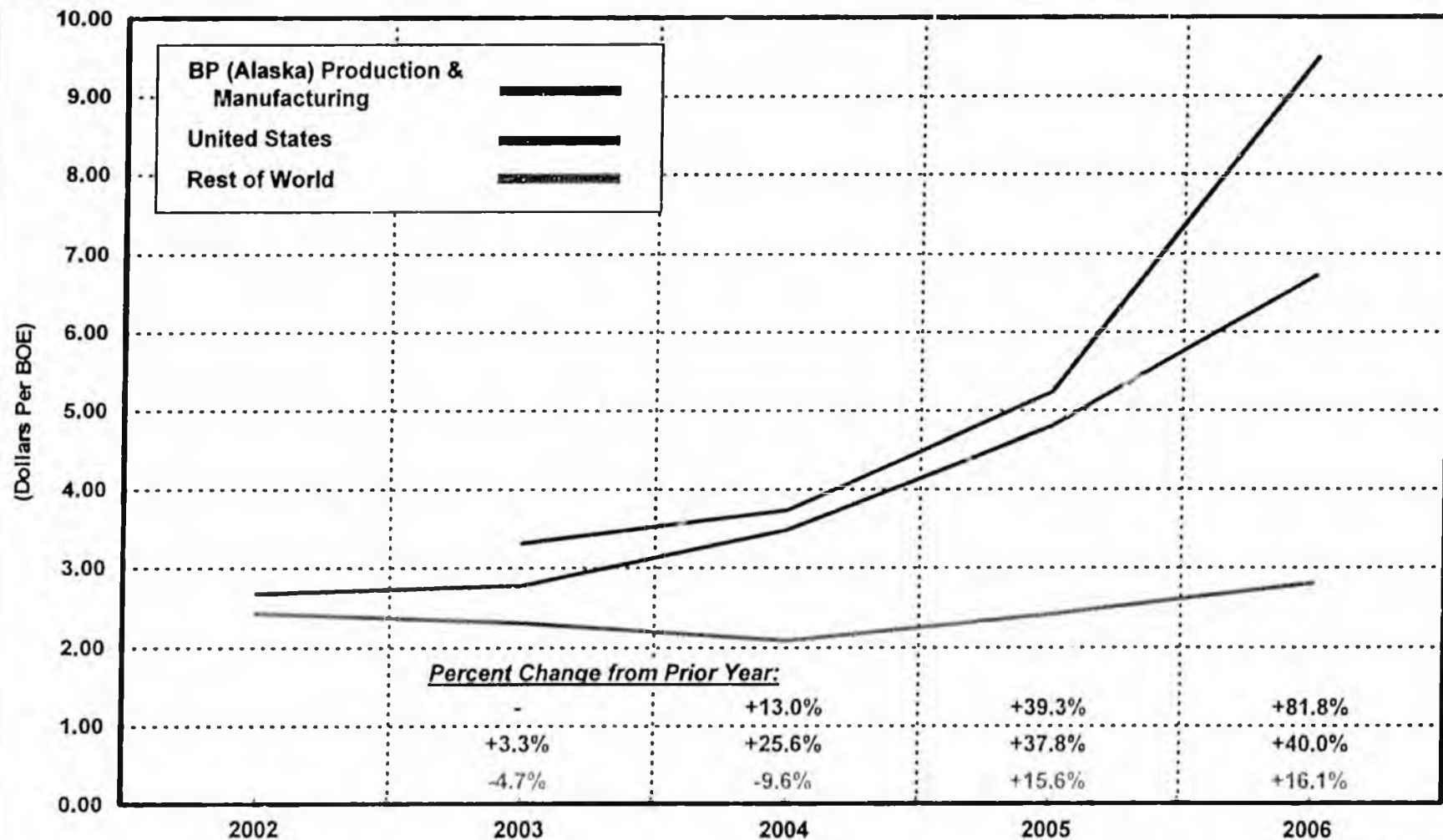


ConocoPhillips Reported Production Costs Per BOE 2003 - 2006



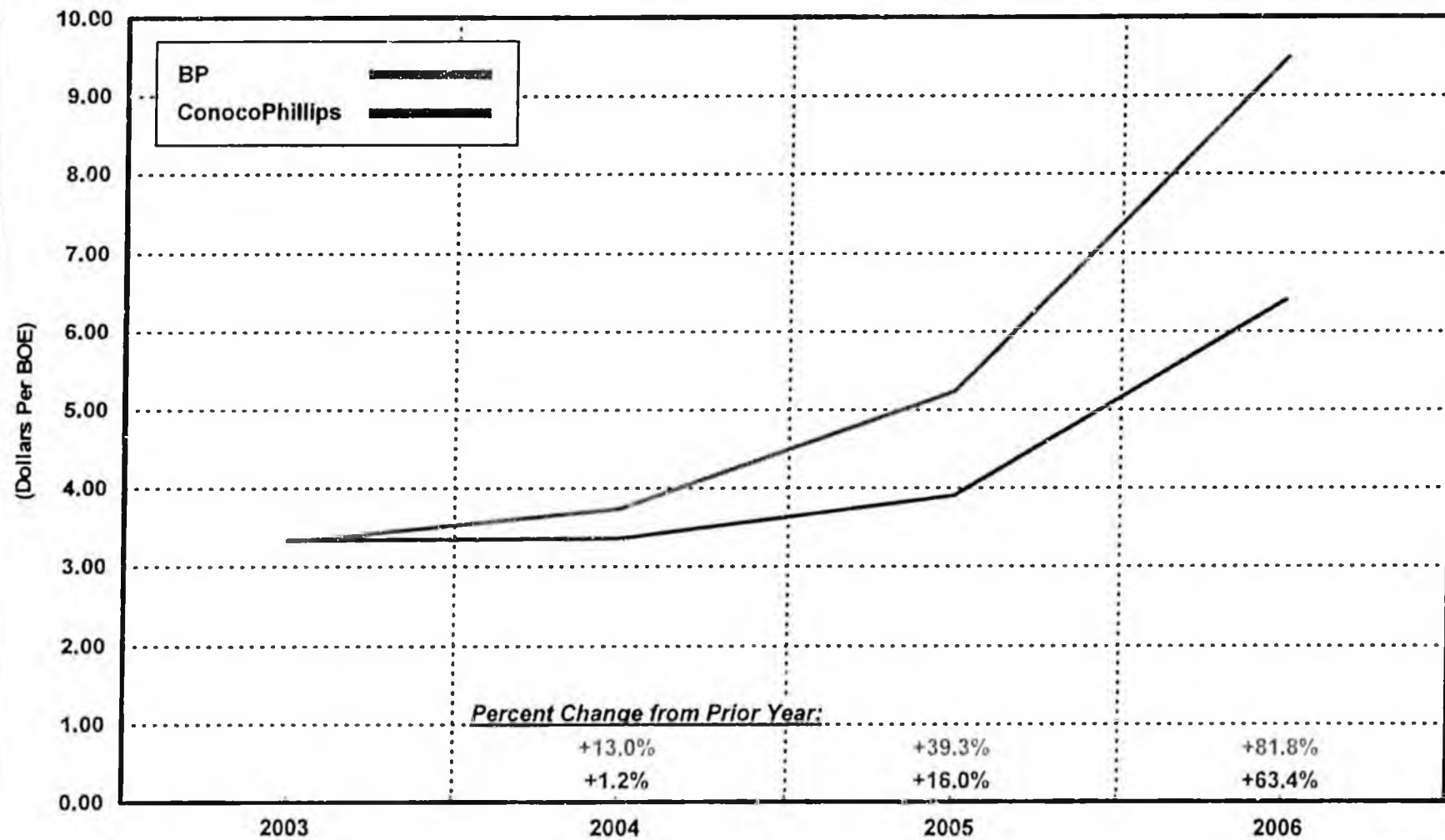
Source: ConocoPhillips 10-K filings.

BP Reported Production Costs Per BOE 2002 - 2006



Source: BP Financial and Operating Information, 2002-2006.

BP and ConocoPhillips Reported Alaska Production Costs Per BOE 2003 - 2006



Source: ConocoPhillips 10-K filings, BP Financial and Operating Information, 2002-2006.

Corrosion / Integrity Management Costs

- **\$260M for OTL Replacement**
- **\$550M Net for Integrity Management 2007-2008**
(BP Form 20-F, pg. 18)
- **Likely Increase in Costs for Other Production-Related Activities**
- **Probably Reflected in DOR Cost Forecasts**

Conclusions

- **DOR Current Forecasts are Based on Unaudited Taxpayer Returns Under the PPT. These Costs May be Reduced After Review and Audit.**
- **Forecast Costs Used in DOR's Fiscal Note to HB 3001 are in Line with Publicly Reported Information Specific to Alaska During the 2002-2005 Period.**
- **Costs Have Increased in Recent Years with Increases in Expectations of Future Crude Oil Prices. The Level of Increase is Likely to be Mitigated Over the Long Run.**
- **The Increases in Costs Filed with the SEC for Alaska Relative to the Lower 48 and Elsewhere Reflect in Part, Expenses Associated with Corrosion Repair and "Integrity Management" Efforts in Alaska.**

Conclusions

- **Corrosion Repair and “Integrity Management” Efforts Likely to Increase Costs Reported for Alaska, Even for Non-Corrosion Repair Services.**
- **SEC Filings Suggest that Corrosion Repair and “Integrity Management” Costs are Likely Included in Alaska Figures.**
- **DOR Forecasts Likely Include Costs Related to These Efforts.**
- **DOR Cost Estimates Now Include Cost / Price Sensitivity. This is Appropriate.**
- **A Proper Determination of the Actual Costs will Require Examination of Supporting Materials. Examination Should Include a Review of Unit-by-Unit Information Both During the PPT Period and Several Years Prior to the Implementation of PPT.**



REPORT TO THE ALASKA LEGISLATURE ON PRODUCTION COST INCREASES

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November 2, 2007

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Report to the Alaska Legislature on Production Cost Increases

Barry Pulliam
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November 2, 2007

I. Introduction

This report addresses issues raised in Senator Therriault's August 30, 2007 letter on PPT lease costs. In preparing this report we have,

- reviewed the modeling used for the Alaska Department of Revenue's (DOR) Fiscal Note accompanying HB 3001;
- reviewed DOR's August 3, 2007 PPT Status Report;
- interviewed DOR personnel familiar with the DOR models, cost assumptions and PPT filings by the producers;
- reviewed various presentations made during PPT hearings last year;
- reviewed SEC filings made by producers;
- reviewed data compiled by the Energy Information Agency regarding production costs;
- reviewed reports prepared by market analysts regarding production costs; and
- reviewed cost information regarding drilling rig rates in the Lower 48 states.

II. DOR Forecast Lease Cost Increases Generally

The Alaska Department of Revenue (DOR) issued a "PPT Status Report" on August 3, 2007. In that report, the DOR stated that for FY 2008, revenues were expected to be \$800 million lower than earlier forecasts, as reflected in the Fiscal Note accompanying HB 3001. The DOR Status Report is included here as Attachment 1.

The DOR identified higher than forecast costs as the primary reason for the decrease in projected revenues. Relative to the HB 3001 Fiscal Note, the DOR forecast lease cost increases for FY 2008 of nearly \$2 billion. This represents an approximate 100% increase in costs. Capital cost forecasts increased by \$1.1 billion, while operating costs increased by \$0.9 billion. The impact of increased costs forecasts would account for the reduction in forecast revenues of approximately \$800 million as set forth in the Status Report.

In the Fiscal Note accompanying HB 2001 (ACES), the DOR has increased its cost increases further. The DOR currently projects total operating and capital costs for FY 2008 of \$4.33 billion, an increase of approximately 7% over the figures set forth in the August 2007 Status Report. DOR expects these higher cost levels to continue for the

near future. Attachment 2 sets forth the DOR's current lease cost forecasts through Fiscal 2014.

III. Basis for the Costs Used in DOR's HB 3001 Fiscal Note

The cost projections included in DOR's HB 3001 Fiscal Note were developed in late 2005 and were based on information available at that time. This included confidential income tax returns and public SEC filings for the years through 2004 -- the most recent years available in 2005 -- and published consultant reports covering the period through 2003. DOR reviewed this information with the producers. In addition, we (Econ One) reviewed the DOR's cost projections.

The cost projections used in DOR's HB 3001 Fiscal Note totaled approximately \$2.1 billion for the FY 2008. On a (gross) per-barrel basis, those cost projections averaged \$7.27/bbl.¹ DOR's current volume projections for FY 2008 are approximately 70,000 (79 mbd) lower (725 mbd vs 804 mbd) than they were at the time the Fiscal Note was prepared. Holding total costs constant, this projected drop in volumes would increase the average cost to \$8.04/bbl, an increase of just over 10%.²

The DOR cost projections were used throughout the PPT debate in the spring and summer of 2006 in the analyses it presented to the legislature. In addition, industry presented revenue estimates during the debate that incorporated cost projections in line with the DOR projections.³

We also prepared various revenue projections during the PPT hearings. Those projections fell into two categories: (1) the economics of exploration and development and (2) revenues arising from production in fields included in production forecasts used in DOR's Fiscal Note. Our base cost estimates used in these later estimates were somewhat, though not significantly, higher than the cost estimates used by the DOR.⁴

IV. The Basis for DOR's Current Cost Forecasts

DOR has based its current cost forecasts primarily on the filings submitted by the producer/taxpayers. As has been stated by DOR personnel in testimony, these costs are

¹ The \$7.27/bbl figure represents the average cost per barrel produced. Spread across taxable barrels (assuming an average royalty of approximately 12.9%), it would be \$8.35/bbl.

² The increase in average \$/bbl costs resulting from volume declines may be somewhat smaller than noted above, as a small portion of the total operating costs would be variable with production.

³ See ConocoPhillips presentation on February 27, 2006. While the cost assumptions are not stated in the chart, the revenues for the PPT are in line with the DOR projections, indicating that similar costs were used in the analysis.

⁴ In addition, we presented revenue sensitivities showing varying cost increases over base forecasts. These included a 20% cost increase, an assumption of a tripling of cost inflation (i.e., 7.5% rather than 2.5%) and an increase in capital expenditures by approximately 100% to an annual rate of \$2.5 billion.

not audited, nor have they been adjusted by DOR for potential misstatements or reporting errors.

To our knowledge, DOR has not reviewed any of the supporting information behind the tax filings. Moreover, DOR has not reviewed any of the other information that would regularly be prepared by the field operators detailing their actual and anticipated costs. These would include items such as annual operating budgets, production and drilling plans, regular (e.g., quarterly and annual) expense statements and capital expenditure authorizations (AFEs). This is information that would be shared regularly between working interest owners in each unit.⁵

Without a review of the information underlying the tax filings, or a review of the types of budget and expense reports prepared by the operator of each unit, it is not possible at this time to determine whether the cost increases (relative to the earlier Fiscal Note assumptions) that are reflected in the tax filings to date and the DOR's current cost forecasts will prove to be accurate, or whether they may be adjusted after review.

V. Rising Costs Over the Past Several Years

There is broad consensus among industry analysts that per-barrel operating and capital costs in the U.S. have increased sharply over the past several years. The increase in costs has been higher than general inflation and is driven in large part by higher sustained oil and gas prices relative to expectations of several years ago.

Attachment 3 shows actual ANS West Coast prices over the period January 2000 through September 2007. During this period, ANS prices have increased by approximately \$57/bbl. Moreover, expectations as to long-term crude oil prices have increased considerably just since January 2005. Attachment 4 shows expected price levels as reflected in NYMEX futures trading for oil delivered at the end of 2011. In January 2005 the forward price on the NYMEX was close to \$40/bbl. The forward price rose sharply over the course of the year, ending at close to \$60/bbl. Today, the forward price for delivery at the end of 2011 is about \$80/bbl, which is an increase of \$40/bbl since January 2005.

Expectations for sharply increased, long-term crude oil prices have led companies to spend more money looking for and evaluating prospective properties. In addition, it has led them to spend more money developing costlier reserves from existing properties. This additional demand, which results in large part from an increase in price expectations, has led to increased costs.

VI. Publicly Available Data Regarding Production Cost Increases

Publicly available data reflecting operating and capital costs show increases generally over the past several years, with sharp increases occurring in 2005 and 2006. The timing

⁵ It is our understanding that DOR does not have access to this information at this time.

of these increases is consistent with rapid increases in actual and expected long-term crude oil prices that began in 2005.

Attachment 5 shows an index of upstream capital costs since 2000 presented in a May 8, 2007 release by the consulting firm IHS/CERA. The index is designed to track capital costs associated with oil and gas production world-wide. The IHS/CERA figures show moderate cost inflation (consistent with the general economy) through 2004, then rising quickly, particularly in the 2nd half of 2005 and throughout 2006.

Attachment 6 shows an index of operating costs prepared from lease cost data reported by the Energy Information Administration (EIA) for Lower 48 states.⁶ The EIA operating data shows a cumulative cost increase of 29% in 2006 relative to average cost levels over the 2002 - 2004 period that formed the basis of the earlier DOR forecast.

Attachment 7 shows an index of equipment costs prepared from the same EIA data. This chart shows a relative large increase in costs occurring in 2004, moderating somewhat in 2005 and 2006. On average, 2006 equipment costs reflected in the EIA data were 32% greater than average costs over the 2002 - 2004 period.

Attachment 8 shows an index of daily rental rates for oil drilling rigs in the Lower 48 states prepared using data from the Land Rig Newsletter. Rental rates for oil drilling rigs in the Lower 48 began rising in 2004 and increased sharply in 2005. The rate of increase slowed somewhat in 2006 and has actually declined since 1Q2006. Overall, the index shows an approximate doubling of 2006 daily rig rental rates relative to the 2002 - 2004 period.

None of the data presented in these attachments reflect actual costs in Alaska. Rather, they reflect generalized world-wide costs or costs in the Lower-48 states. These data indicate that the cost of production has risen generally over the course of the past several years. We would expect that the same pressures on production costs outside of Alaska would lead to increased costs in Alaska. And given some of the unique aspects of Alaska's production (isolation, shorter drilling season, number of suppliers available to industry in Alaska during the short-term), combined with the impact of the corrosion repair and "integrity management" work in Alaska, these general cost pressures may impact the State greater than they have elsewhere, at least in the near term.

VII. Production Costs Reported to the SEC and Alaska Specific Costs

Publicly traded oil companies report production costs to the SEC in their annual filings. US companies' data is contained in their form 10-K. Foreign companies, such as BP, report the information in form 20-F. In some cases the costs are broken out separately for Alaska and other areas. Attachments 9 - 12 set forth reported production costs per barrel for ConocoPhillips, BP, ExxonMobil and Chevron. The reported production costs reflect operating expenses and do not include capital investments.

⁶ The EIA does not publish data for Alaska.

ConocoPhillips and BP report their production costs in Alaska separately from production costs elsewhere. These reported figures show generally increasing production costs worldwide over the past 4 years, with higher increases in the U.S. and in Alaska in particular. Alaska cost increases reported by BP were much greater than those reported by ConocoPhillips over the last 2 years.

ConocoPhillips' publicly reported production costs over the period 2003 - 2006 for equity production in Alaska and the Lower 48 states are set forth in Attachment 9. The ConocoPhillips' data shows Alaska production costs of approximately \$3.50 per barrel between 2003 and 2005. These are similar to the operating costs used by the DOR in their earlier forecasting.

Consistent with the cost and price data presented above, the ConocoPhillips' reported costs began to rise in 2005, with a sharp (63%) increase in 2006 to approximately \$6.40/bbl. ConocoPhillips' production costs for the Lower 48 states shows a much more moderate rate of increase over the past 4 years than do their Alaska costs.

BP's publicly reported production costs over the same period for equity production in Alaska, the United States and the rest of the world are set forth in Attachment 10. BP's reported figures for Alaska are in the same general range as ConocoPhillips' costs for 2003 and 2004 (approximately \$3.50 per barrel), then rise in 2005 by 38%, with a further sharp (81%) increase to over \$9.00/bbl in 2006.

ExxonMobil's reported costs are shown in Attachment 11. Unlike the other 2 large producers, ExxonMobil does not break out Alaska in its public filings. ExxonMobil's reported figures show increasing production costs over the 2002 - 2006 period higher worldwide, with a greater increase in the US, particularly in 2006.

Attachment 12 shows production costs reported by Chevron for the 2002 - 2006 period. Chevron's costs show increases generally over the period, with larger increases in the US beginning in 2005.

VIII. Information on Corrosion-Related Costs

DOR personnel stated that they did not know the amount that has been claimed for costs related to corrosion repair work on the North Slope. The level of cost reporting contained in the PPT filings does not provide detail regarding the nature of underlying costs. And as discussed above, these tax filings largely form the basis for DOR's cost projections going forward.

One way to attempt to determine the extent of corrosion related costs claimed and included in the tax filings would be to examine and compare the tax data across taxpayers and units, comparing costs claimed for Prudhoe Bay and by BP with costs claimed by other taxpayers and for other areas. While DOR has certainly done this, they stated that they could not share any data or analysis with us due to stated tax-payer confidentiality issues.

BP has stated publicly that it will spend \$260 million to replace the oil transit lines (OTLs) at Prudhoe Bay. Assuming these costs are all spent during 2006 and 2007, they would represent a little more than a \$1/bbl cost spread across taxable barrels at Prudhoe Bay for those two years.

In addition to the \$260 million OTL replacement cost figure, BP reported in its 2006 form 20-F that it planned to spend over \$550 million during 2007 and 2008 "net" on "integrity management" in Alaska.⁷

There are several questions with respect to this figure and how it relates to the corrosion issues. First, BP's filings do not define what is included in "integrity management." However, the statement would appear to be directed to efforts to insure the "integrity" of facilities at Alaska in an effort to prevent future spills or shutdowns. Second, BP's reports do not specify whether these would be operating or capital expenses. Third, it is unclear whether the \$550 million figure is all that is anticipated with respect to the integrity management issues, or whether BP has just reported anticipated costs for a two-year period. Fourth, it is unclear whether the \$550 million refers to expenses born solely by BP in its capacity as working interest owner, or whether these reflect the gross amount that BP as operator will pay on behalf of itself and the other working interest owners at Prudhoe Bay. If these expenses reflect BP's net working interest share, then the total integrity management expenditures over the 2007 - 2008 period could be far greater than \$550 million. Finally, aside from this statement, BP's filings do not separately list expenditure amounts related to "integrity management" issues prior to 2007. Accordingly, the publicly available data do not allow us to determine exactly how much of the \$550 million spending represents an increase in spending levels for this expense category relative to prior years.

Whether and to what extent corrosion-related costs are reported as a part of taxpayers' PPT deductions, the impact of these events likely has had some effect on increasing overall production costs on the North Slope for non-corrosion-related production services. As discussed above, increasing oil prices overall have put pressure on costs. The added pressure to deal with the corrosion repair and integrity management issues, particularly in a short time period, adds to the general cost pressure brought about by rising crude oil price expectations.

IX. Some Final Thoughts on Cost Increases and the PPT

⁷ BP's 2006 form 20-F, page 19 states, "In response to the recent corrosion discoveries, BP has decided to replace the main oil transit lines (16 miles) in both the Eastern and Western Operating Areas of Prudhoe Bay. In addition, BP plans to spend over \$550 million (net) over the next two years on integrity management in Alaska."

The PPT system, through the deduction of costs and capital credits, was designed to encourage capital investment and increased production in Alaska over the long run. Accordingly, the fact that costs have risen relative to expectations, particularly capital-related costs, should not be viewed in and of itself as a problem. Indeed, increased capital spending is one of the policy objectives of the PPT system.

However, it would seem doubtful that the entirety, or even the majority, of the cost increases reflected in the producers' tax filings to date relative to the projections used in the earlier Fiscal Note are the result of potential stimulative effects of the PPT system.

At the outset of this project we had sought to obtain data from the DOR as to costs filed by category (i.e., capital and operating) at different fields. Examination of that data might provide an indication as to where (geographically) the cost increases relative to forecast were coming from. In addition, such an examination, along with information regarding drilling activity, might provide insight into the question of whether some of the increased costs could be explained by increased exploration activity and/or development activity in certain areas, which are policy objectives of the tax system.

As discussed above, DOR personnel have maintained that cost information by taxpayer and even aggregated cost across taxpayers by field or unit, is considered as taxpayer confidential and could not be made available. Accordingly, we were not able to undertake this analysis as initially hoped.

Based on our discussions with DOR personnel and the data reviewed we can draw the following conclusions with respect to the cost increases in DOR's model at this time.

- The DOR's forecasts are based largely on unaudited taxpayer returns under the PPT tax. Those costs may be reduced after review and audit.
- An increase in costs for Alaska production is consistent with the cost patterns observed generally in the industry during the past several years. Costs began to increase sharply beginning generally in 2005.
- Forecast costs used in DOR's Fiscal Note to HB 3001 appear to be in line with publicly (SEC) reported information specific to Alaska during the period 2002 through 2005.
- Capital cost forecasts used by the DOR in the HB 3001 Fiscal Note are in line with historical capital spending levels on the North Slope between 2002 and 2005.
- Repair costs for corrosion related work and integrity management on the North Slope likely add costs for non-corrosion related costs in Alaska generally.

- The increases in costs filed with the SEC for Alaska relative to the Lower 48 and elsewhere reflect in part, expenses associated with corrosion repair and “integrity management” efforts in Alaska.
- The size of the cost increases, as reflected in the DOR’s forecasts, suggests that corrosion-related expenses and/or higher anticipated “integrity management” expenses are likely included in the tax filings, and as a result, included as a part of the cost forecasts.
- A proper determination of the reasons (appropriate or inappropriate) underlying the cost increases will require examination of the data underlying producer/taxpayer returns and claims under the PPT period. The examination should include review of unit-by-unit cost information both during the PPT period (i.e., from April 2006 forward) and during the several years prior to the implementation of the PPT.
- Costs have increased in recent years with unexpected increases in expectations of future crude oil prices. In the event that price expectations increase further costs may further increase. The level of increase is likely to be mitigated over the longer run with new entry (i.e., increased supply) for production-related services.
- Likewise, to the extent that long-run price expectations fall significantly (say down to \$40/bbl), we can expect to see downward pressure on costs over the long term.
- DOR did not include a cost/price sensitivity in its HP 3001 Fiscal Note or in its PPT Status Report. Its current forecast adjusts costs up or down when expected price levels rise above or fall below \$60/bbl, respectively. While these relationships are difficult to estimate with precision given the information available, in our view, this type of sensitivity is a good addition to the forecasting process.

Attachment 1

Petroleum Profits Tax (PPT)
Implementation Status Report

Alaska Department of Revenue
August 3, 2007

PPT IMPLEMENTATION STATUS REPORT

I. Purpose of the Report and Conclusions:

In August 2006, the Alaska Legislature passed HB 3001 containing a new oil and gas production tax system called the Petroleum Profits Tax (PPT). The new profits-based tax replaced the previous production tax based on gross value, generally referred to as the "Economic Limit Factor" (ELF) tax system. Debate and passage of HB 3001 was contentious, with questions raised on the propriety of a profits-based tax and on the appropriate tax rate. The controversy escalated earlier this year with the handing down of federal indictments against several legislators that centered on potential corruption involving the PPT deliberations and votes.

The Governor tasked the Commissioner of Revenue with evaluating whether the PPT was meeting expectations with respect to state revenues and industry's reinvestment in Alaska. The Commissioner of Revenue formed a Production Tax Team, staffed with members from the Department of Revenue, Division of Tax and the Department of Natural Resources, Division of Oil and Gas to review various aspects of PPT implementation. Based on the information provided by the Production Tax Team, the initial conclusions of the Department of Revenue are:

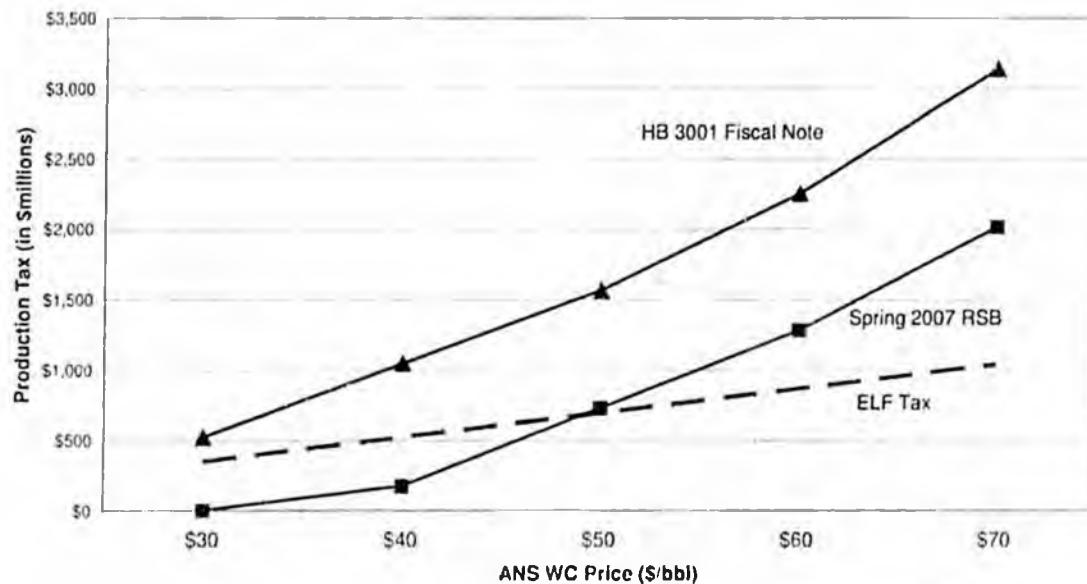
- 1) At current prices, the state is collecting more production tax revenues under PPT than it would have under the ELF system. However, those revenues are falling far short of what was expected when PPT was passed.
- 2) Operating and capital costs are substantially higher than were forecasted in the PPT fiscal note provided to the legislature.
- 3) The value of PPT credits may not be fully realized for exploration companies new to Alaska, given the small market for resale among "producers."
- 4) The crossover oil price point where the state receives more revenue under the PPT than under the ELF system has moved from the \$26/barrel predicted in the PPT fiscal note to \$48/barrel.
- 5) The activation of the progressive surcharge has shifted from a market price of \$55 to over \$60 a barrel.
- 6) DOR faces significant challenges in implementing the PPT as currently structured.

II. Discussion:

1) Production tax revenues are falling far short of expectations. The following graph shows the differences in modeling results for FY 2008 production tax revenues; this graph compares initial modeling for FY 2008¹, as prepared for the House Bill 3001 (PPT) fiscal note [SCS HB3001(NGD)], with current modeling, as prepared for the *Spring 2007 Revenue Sources Book*, and with the tax revenue that would have been generated under the ELF system. The tax revenue expectations for FY 2008 are significantly lower than the revenue forecasted when the fiscal note was drafted. This is primarily due to the significantly higher costs being reported as compared to what was estimated in the fiscal note, as noted below.

In FY 2008, based on forecasted price and production levels, the PPT is expected to generate about \$250 million over that which would have been generated under the ELF system. However, this is more than \$800 million less than what was predicted in the PPT fiscal note.

FY 2008 Production Tax Estimates: HB 3001 (24th Legislature) Fiscal Note and Spring 2007 Revenue Sources Book PPT Forecasts; and ELF Tax



Note: All revenue estimates are based on most current taxpayer submitted expenditure forecasts and do not reflect any changes in spending due to increases or decreases in oil price.

¹ Because of the unexpected disruptions to revenues and costs caused by the gathering line failures in the Prudhoe Bay Unit in FY 2007, the Department is using FY 2008 as the comparison year to eliminate one-time aberrations. In addition, the HB 3001 Fiscal Note and ELF Tax models have been adjusted to reflect current production estimates.

2) Operating and capital costs are substantially higher than were forecasted in the PPT fiscal note. The substantial and unanticipated increase in costs is the primary reason revenues are falling short of expectations. Throughout the latter half of 2004 and 2005, DOR officials gathered information from confidential tax documents, annual reports, private consultant analyses, and the industry about the costs of producing petroleum on the North Slope. DOR modeled the PPT revenue forecasts using these cost data and the results of this modeling were provided to the legislature to aid their consideration of the PPT.

Based on the cost data received by the Department for 2006 and 2007 since passage of PPT, the Department has increased by almost 100% taxpayer operating and capital cost estimates for FY 2008 in its Spring 2007 Revenue Source Book revenue projections. In discussions with taxpayers, DOR has been told that these higher costs levels for 2006 and 2007 are not aberrations caused by unique events, such as the Prudhoe Bay shutdown, and that we should anticipate costs remaining at these levels for the foreseeable future.

**North Slope Production and Costs FY 2008,
per HB 3001 Fiscal Note and Spring 2007 Forecast**

	HB 3001 Fiscal Note	Spring 2007 Forecast
FY 2008		
Production (barrels per day)	802,000	764,000
Costs		
Operating costs (\$millions)	\$1,076	\$2,160
Capital costs (\$millions)	\$1,052	\$1,900
Total Costs	<u>\$2,128</u>	<u>\$4,060</u>
Total Costs per Barrel	\$7.27	\$14.56
Operating costs per barrel	\$3.68	\$7.75
Capital costs per barrel	\$3.59	\$6.81

High oil and gas prices since 2005 are frequently cited as the cause of these cost increases. Projects around the world that were once only marginally economic, are now considered very viable, and are now placing increased demands on limited supplies of engineering, procurement and construction services and on raw construction materials. The Upstream Capital Costs Index, developed by Cambridge Energy Research Associates (CERA), shows that costs for oil and gas production equipment, facilities, construction materials and personnel have increased 53% since 2005. CERA expects cost escalation to continue through 2007, although at a slower pace. Fluor Corporation estimates that prices for fabricated structural steel have increased 60-70% from 2003 to 2006, and that delivery times for these materials increased by 18-20 weeks from their previous levels. The same company reports that prices for seamless and welded pipe used in petroleum production have increased 80-160% from 2003 to 2006, and expects increases of another 15-50% by 2009.

It is too early to tell whether all of the costs reported under PPT thus far are properly deductible. Also, it is too early to know whether the increase in reported industry spending in the state will result in increased future production, or whether the increase in spending can be attributed to changed behavior as a result of the incentives included in PPT. What we do know is that the costs used in the modeling for the PPT fiscal note have proven inaccurate.

3) The value of PPT credits may not be fully realized for exploration companies new to Alaska given the small market for resale among "producers."

Under PPT, tax credits earned by investors and explorers may be transferred and sold to other taxpayers who have a production tax liability. Companies that have been issued credit certificates above and beyond the \$25 million that can be refunded by the state would presumably sell their certificates to the highest bidder. In the first year that the PPT has been in place, however, companies holding credit certificates report that there have been few buyers for the certificates, and that those offering to buy them are doing so at large discounts.

4) The oil price crossover point where the state receives more revenue under the PPT than under the prior ELF system has moved from \$26/barrel to \$48/barrel.

The ELF system "crossover point"—that is, the Alaska North Slope - West Coast (ANS WC) oil price whereby the PPT generates more revenue than the ELF system—was the focus of some attention during the 2006 legislative session. Primarily due to the increase in the cost estimate, the currently estimated crossover point is substantially higher than was projected in 2006.

5) The activation of the progressive surcharge has shifted from a market price of \$55 to \$60-63 a barrel. Because the surcharge is not activated until the taxpayer's net income per barrel exceeds \$40, higher costs have depressed taxpayer net income, thus delaying the price at which the surcharge kicks in. In addition, as production declines, the price at which the progressive surcharge is activated will move higher as costs are spread over fewer barrels. Although the level differs for each individual taxpayer, the North Slope average progressivity trigger is now estimated to be somewhere between \$60 and \$63 per barrel.

6) DOR faces significant challenges in administering the PPT as currently structured.

a) Regulations- The second phase of PPT regulations has been delayed as a result of the challenge of accurately describing the allowed and disallowed lease expenditure deductions.

b) Revenue Forecasts- The Department has been severely hampered in its ability to provide the administration and the legislature with accurate revenue forecasts because the department lacks future capital and operating expenditure information. The Department is in the process of rectifying this problem by requiring operators to provide forward-looking cost data, when and as provided to the unit working interest owners.

Statutory changes may be required to fortify and focus these requests for unit cost information.

c) Audits- With the passage of PPT, the department was authorized to hire eight auditors and one tax technician to assist with the additional audit requirements of the new tax structure. To date, the department has successfully filled the three most senior auditor positions, and has reduced the skills requirements for the remaining junior level auditor positions in light of the challenges of matching competitive pay with the more senior level skill sets.

The complexity of auditing production tax has increased several fold under the PPT, and the PPT increased the number of determinations an auditor must make. The provisions in the PPT which are intended to simplify and streamline these determinations through reliance upon unit owners' auditing of unit operators may assist this process, but we have not yet been through an audit cycle to assess the efficacy of this approach.

III. Conclusion

The state's experience with PPT puts a spotlight on the risks associated with a net profit-based tax system. The new system introduced the added variable of costs into the oil revenue equation. While it is a risk that is inherent in the decision to approve a net profit-based tax, the question is whether the magnitude of the risk was fully understood by the legislature given the information provided to them. While costs would be expected to increase, the dramatic difference between what was predicted and what has actually been experienced brings into question whether the legislature made its decisions based upon appropriate information.

Another aspect of PPT, the tax credits given for capital expenditures, has been significantly reduced in value due to the lack of an efficient market for those new exploration companies looking to sell their credits to those who have current production. This deficiency is particularly troubling because these new exploration companies are the ones that provide the state with the greatest opportunity to encourage new production that might not otherwise occur.

Clearly, there are aspects to PPT that should be re-examined by the legislature. In particular, the legislature should reassess whether the state is getting its fair share of oil and gas revenues, and whether the credits are designed optimally to provide the maximum impact on the state's goal of encouraging investment that leads to more oil and gas production.

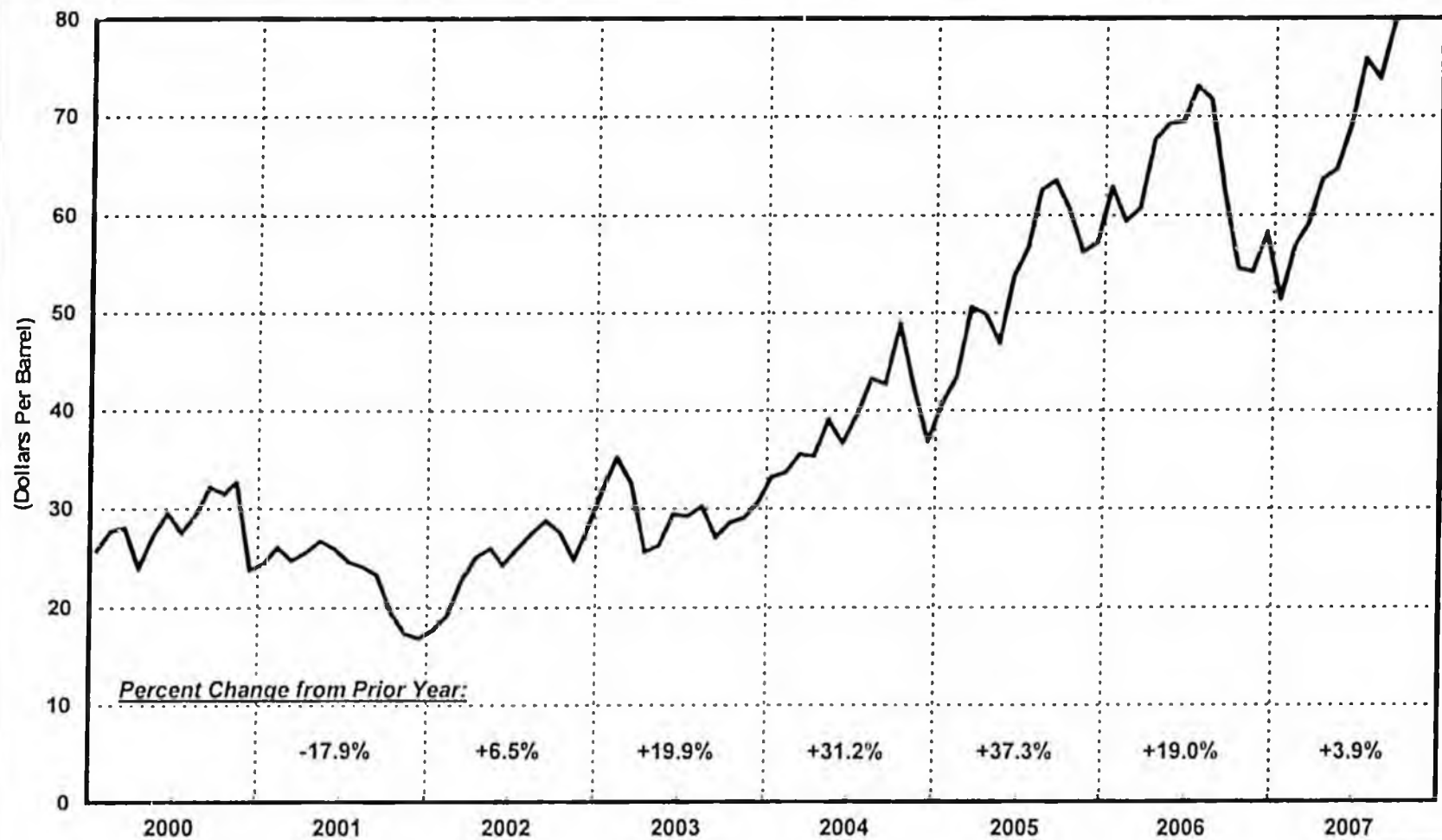
Attachment 2

**Summary of Cost Assumptions in
Fiscal Note to HB 2001 (ACES)
FY 2008 - FY 2014**

<u>FY</u>	<u>Operating Costs</u>	<u>Capital Costs</u>	<u>Operating and Capital Costs</u>
	(Million Dollars)		
	(1)	(2)	(1) + (2) (3)
2008	\$2,146	\$2,187	\$4,333
2009	2,286	1,932	4,218
2010	2,375	2,024	4,399
2011	2,464	1,950	4,414
2012	2,572	2,028	4,599
2013	2,638	2,021	4,660
2014	2,712	2,360	5,072

Attachment 3

Platt's ANS Crude Oil Price January 2000 – September 2007

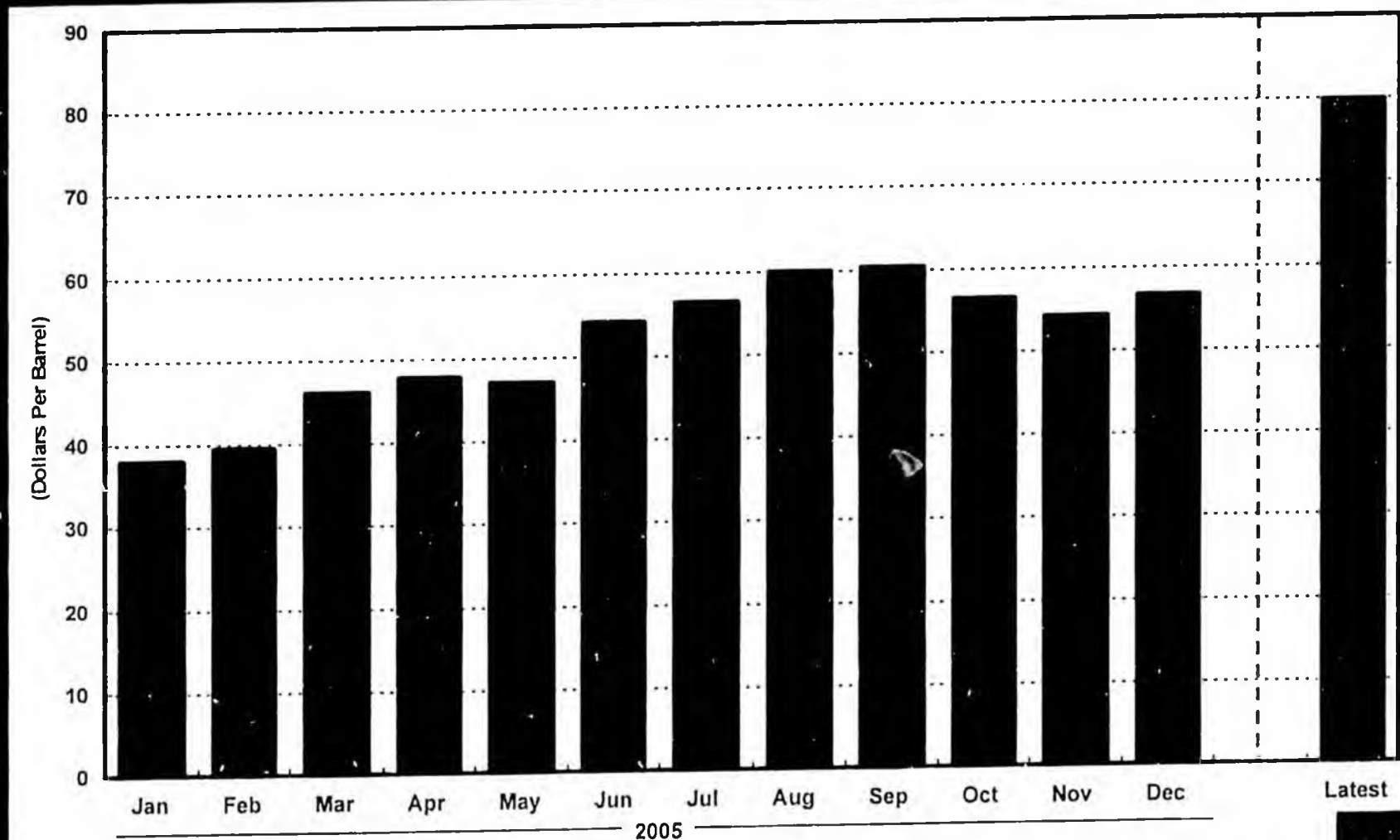


Source: Platt's.

econ
ONE

Attachment 4

NYMEX Futures Price for December 2011 Delivery January - December 2005, Latest Quotes

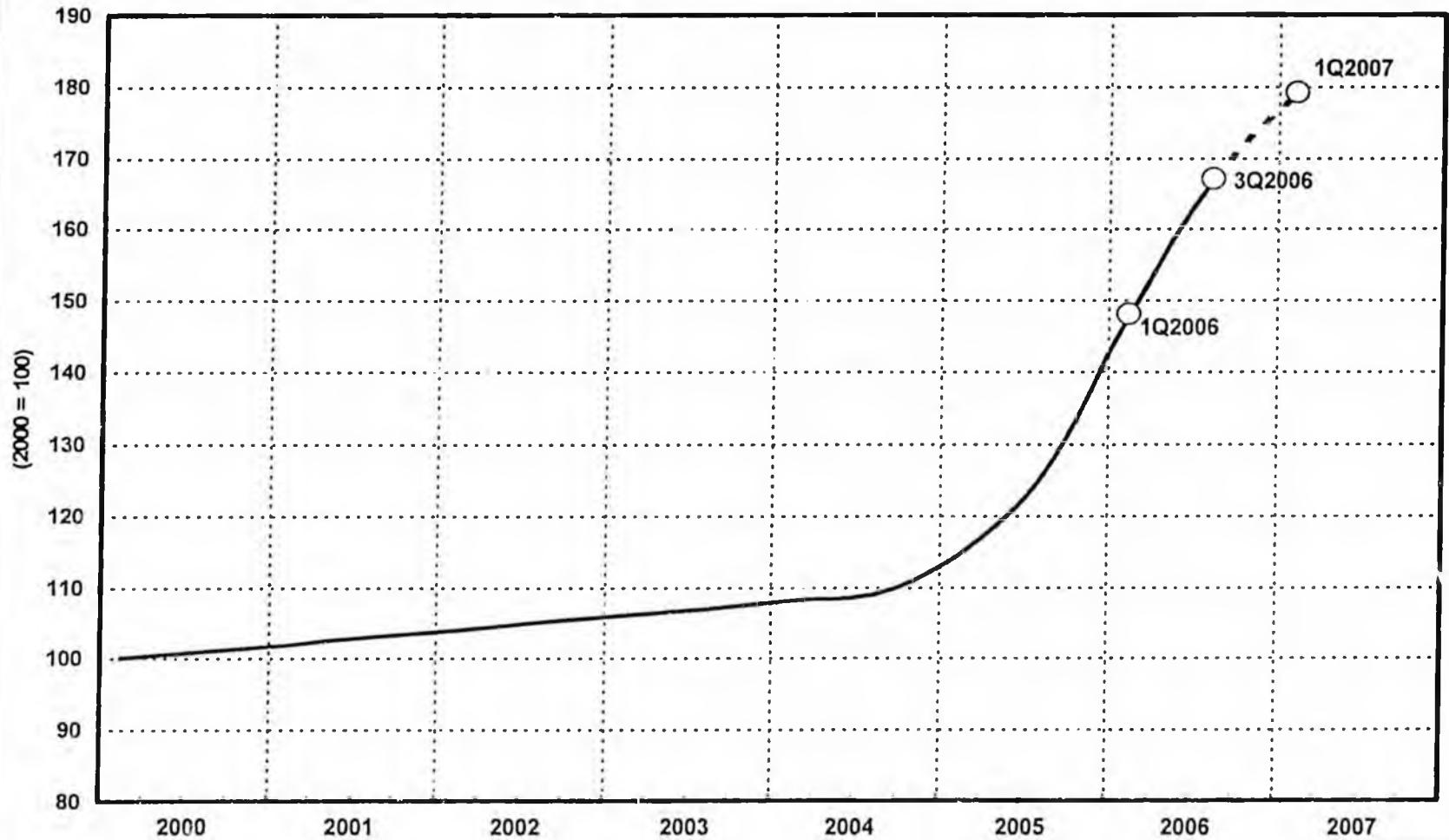


Source: NYMEX.

econ
DNE

Attachment 5

IHS/CERA Upstream Capital Cost Index 1Q2000 - 1Q2007

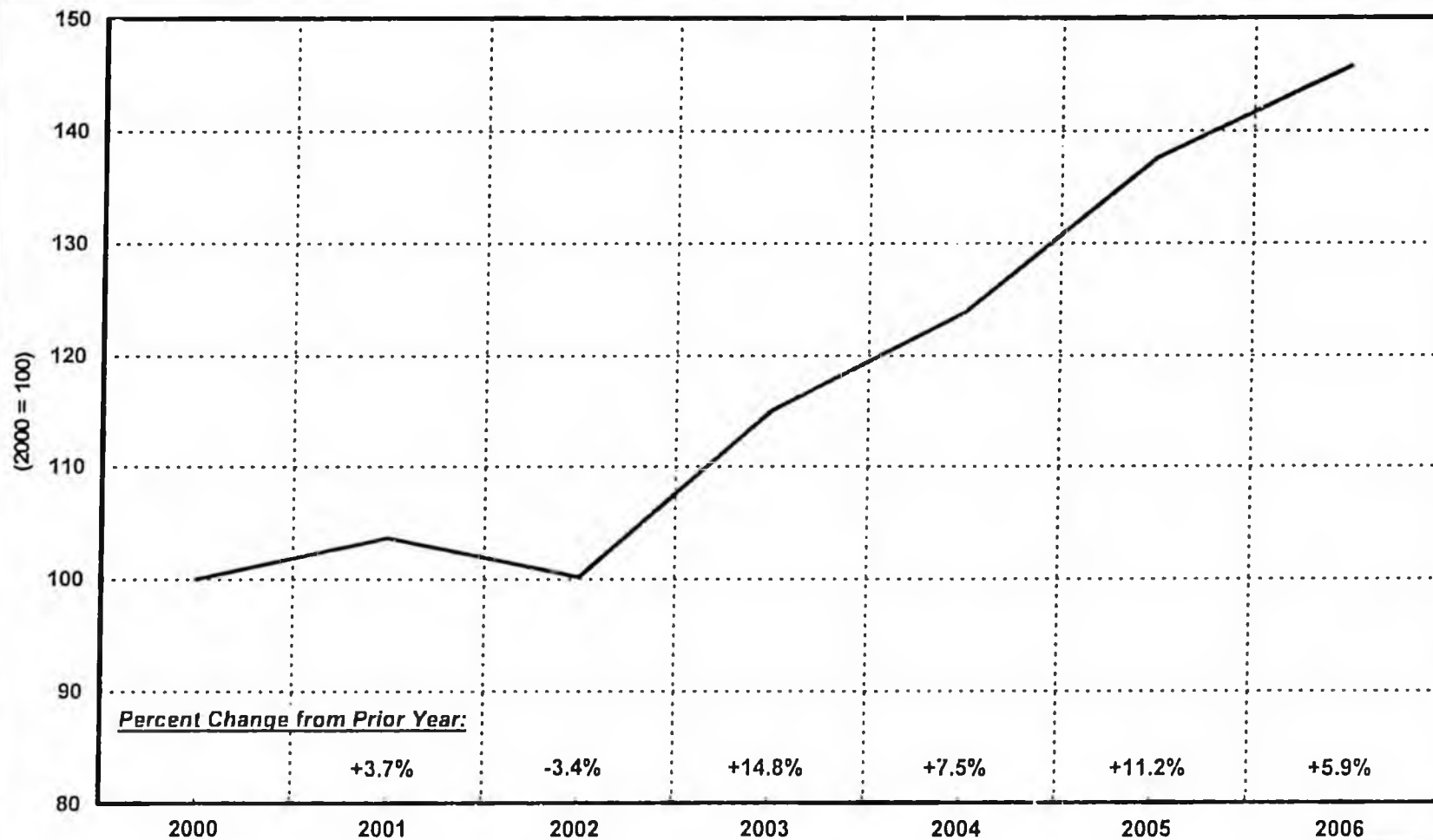


Source: Based on Cambridge Energy Research Associates May 8, 2007 Press Release.



Attachment 6

Average* Operating Costs for 10-Well Oil Lease Index 2000 - 2006

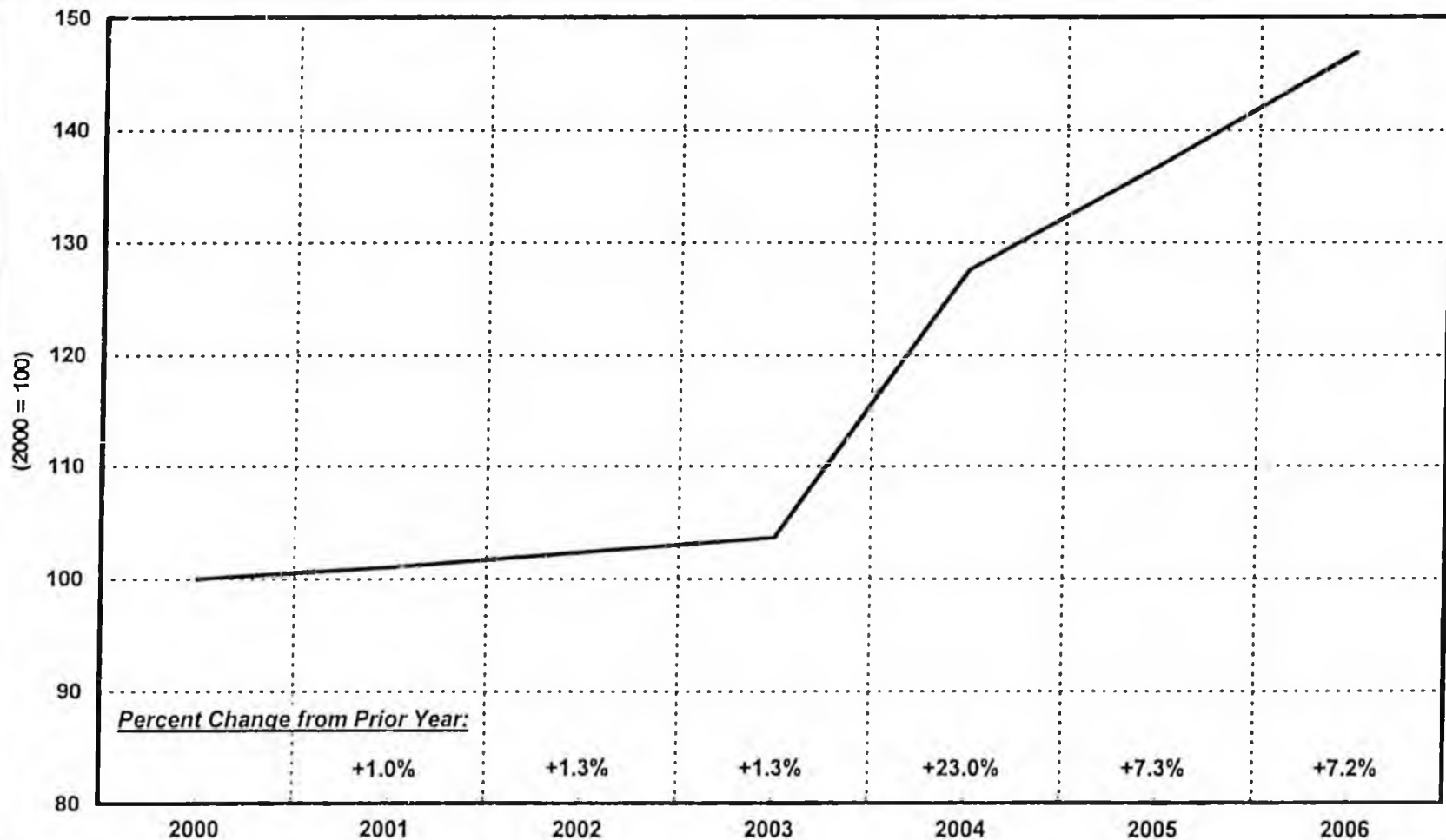


* Average of California, Oklahoma, South Louisiana, South Texas, West Texas, and Rocky Mountains.

Source: EIA.

Attachment 7

Average* Equipment Costs for 10-Well Oil Lease Index 2000 - 2006



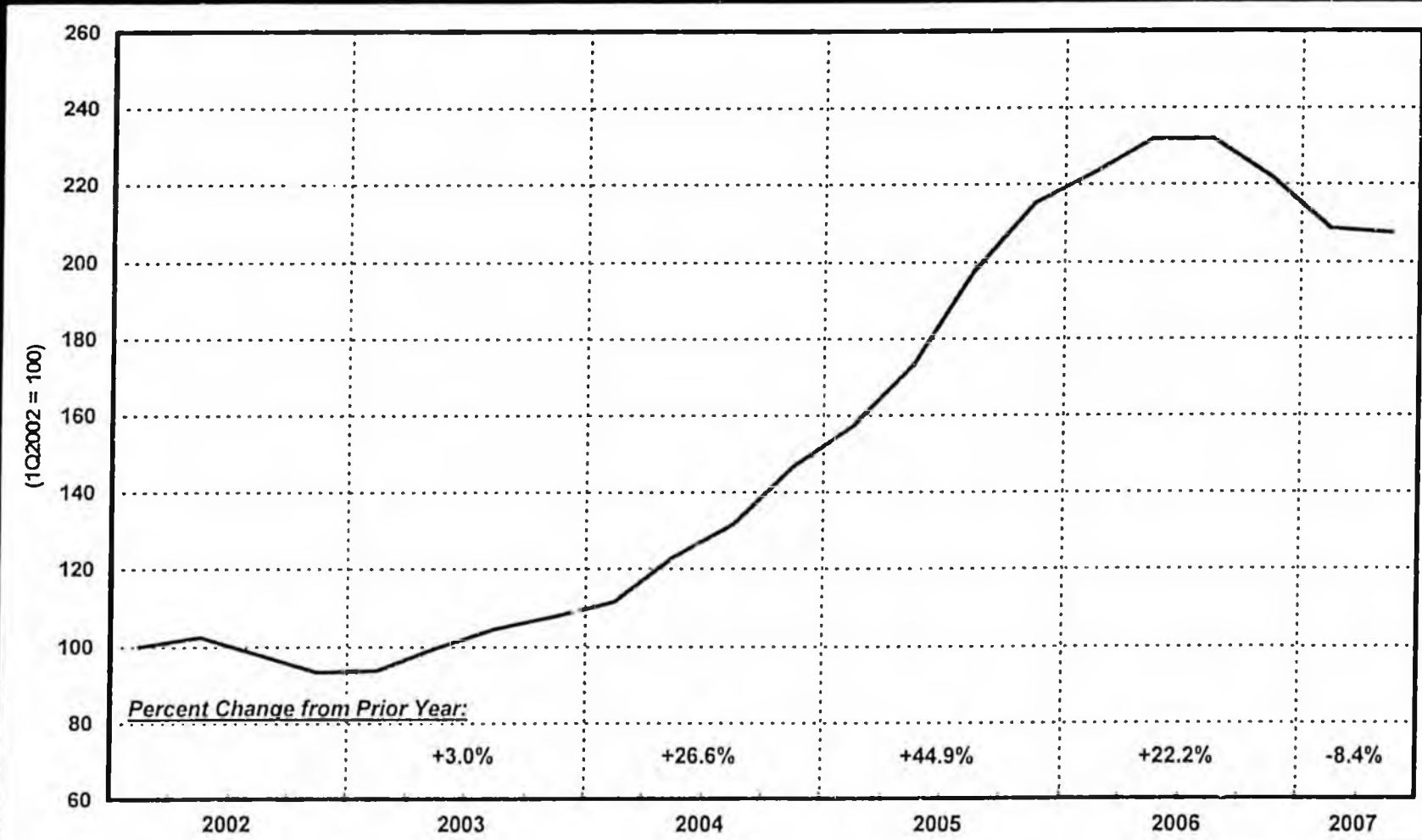
* Average of California, Oklahoma, North Louisiana, South Texas, West Texas, and Rocky Mountains.

Source: EIA.



Attachment 8

Average* Oil Drilling Rig Daily Rates Index 1Q2002 - 2Q2007



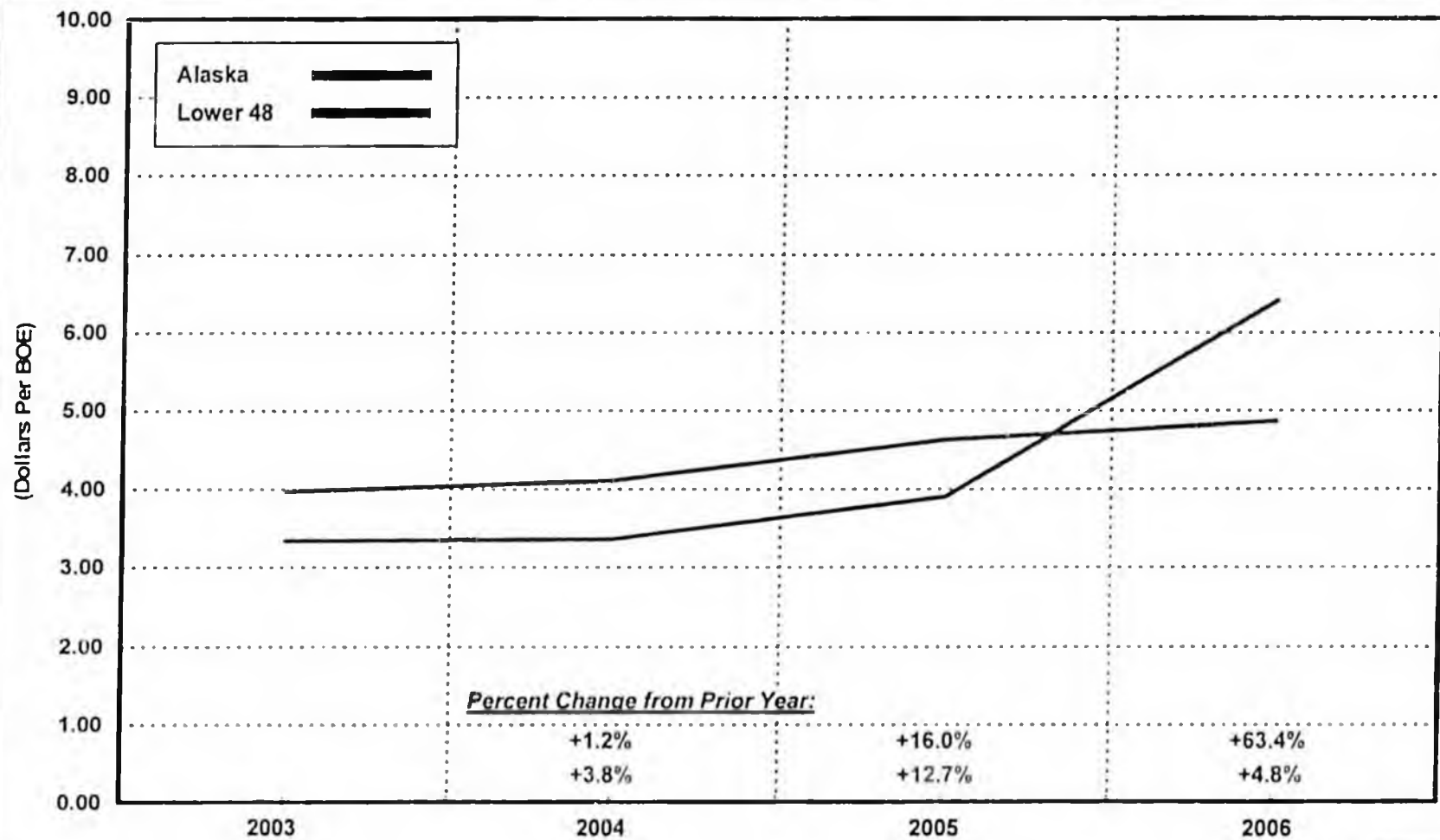
* Average of Mid-Continent, ArkLaTox, Gulf Coast, Permian Basin, Rocky Mountains, and South Texas.

Source: Land Rig Newsletter.



Attachment 9

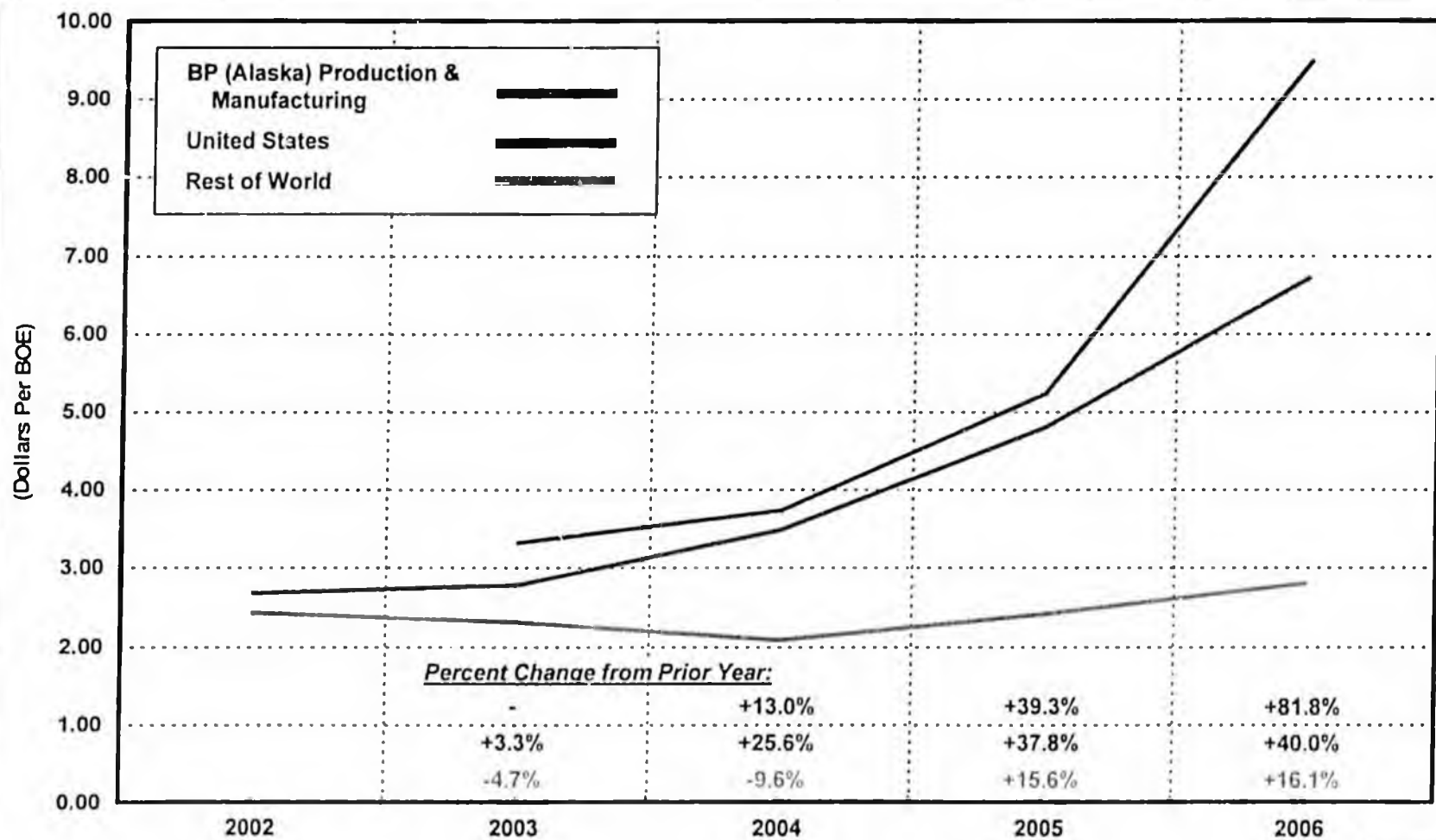
ConocoPhillips Reported Production Costs Per BOE 2003 - 2006



Source: ConocoPhillips 10-K filings.

Attachment 10

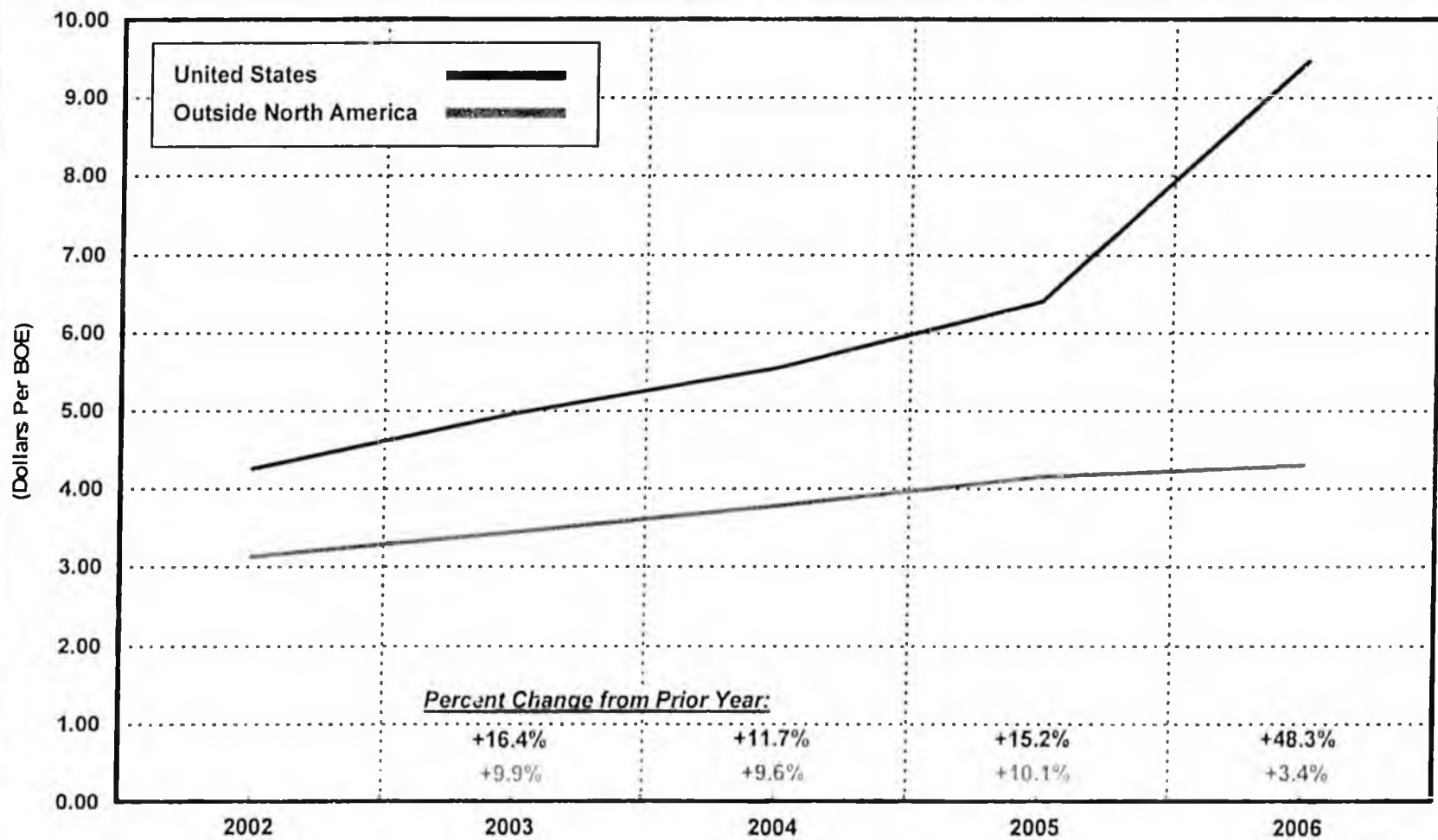
BP Reported Production Costs Per BOE 2002 - 2006



Source: BP Financial and Operating Information, 2002-2006.

Attachment 11

ExxonMobil Reported Production Costs Per BOE 2002 - 2006

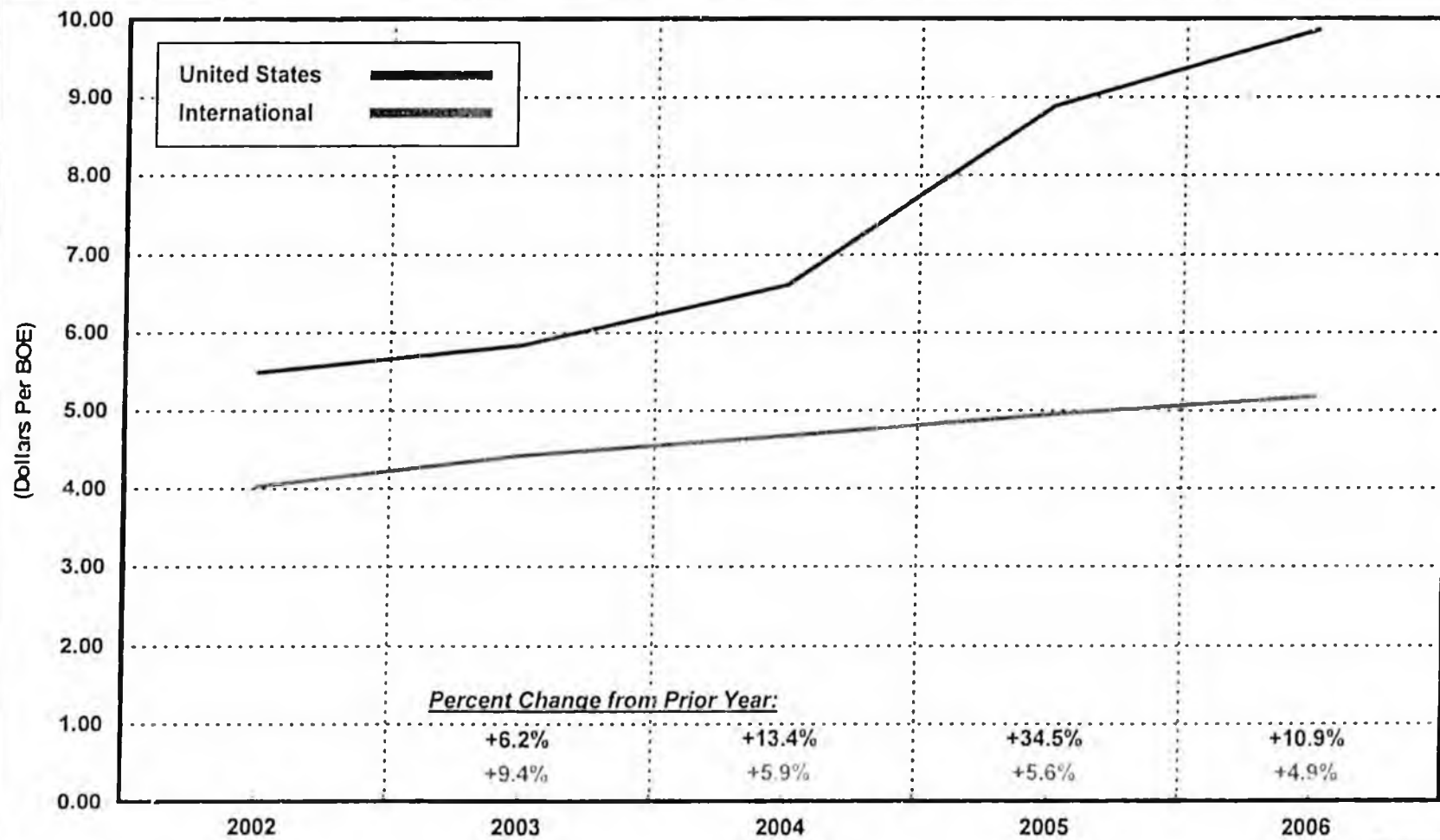


Source: ExxonMobil Financial and Operating Review, 2006.



Attachment 12

Chevron Reported Production Costs Per BOE 2002 - 2006



Source: Chevron 10-K filings.