SB 267

ALASKA STATE LEGISLATURE

SENATOR LESIL McGUIRE
SENATOR BILL WIELECHOWSKI
Co-Chairs, Senate Resources Committee

MEMORANDUM

Date: February 17, 2010

To: Kirsten Waid, Senate Secretary

From: Senator Lesil McGuire, Co-Chair
Senator Bill Wielechowski, Co-Chair
Senate Resources Committee

Re: Senate Resources Committee Schedule

Committee Schedule
Senate Resources
For the week of February 15-19

Unless otherwise noted, all meetings will be held in the Butrovich, Rm 205 @ 3:30 p.m.

Wednesday, February 17th

+ * SB 267 – Oil and Gas Production Tax
+ = *Bills Previously Heard/Scheduled*

Thursday, February 18th

+ * SB 220: Energy Efficiency/Alternative Energy
+ = *Bills Previously Heard/Scheduled*

* First Hearing in First Committee of Referral
\+ Teleconferenced
= Bill was previously Heard/Scheduled

Technical Aspects of SB 267 (Version A)

Dan E. Dickinson, CPA

Senate Resources Committee
Feb 17, 2010

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6 Changes in SB 267

1. Change progressivity from .4% to .2% per dollar
2. 30% credit for well work
3. Tax rate tied to Resident Hire
4. Interest not due on retroactive reg changes prior to implementation
5. Interest rate is lower of fed funds +2 or 11%
6. Restore 3 year statute of limitations

Structure of SB 267

Structure of SB 267 26-LS14521A Key Provision

		section:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	Need 2011 Eff Dt
5	Interest rate is lower of fed funds + 2 or 11%							6																			25	
4	Interest not due on retroactive regs changes prior to implementation								7							14											25	
1	Change progressivity from .4 % to .2 %												11													24		
	Housekeeping - reference to interest	1					5	6		8	9	10		12	13			16		**18**	19		21	22			25	
3	Tax rate tied to Resident hire			2	3	4											15			**18**					23		25	
2	30% credit for well work																		17							24		
6	Restore 3 year statute of limitations																					20					25	

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What is Progressivity?

- Base Production Tax rate is 25% (AS 43.55.011(e)(1)) of net value or "PTV"
- Combined Progressivity Tax (on same PTV base) can range from 0 to 50%
- Sum= Total tax rate can range from 25% to 75%
- Progressivity rate is calculated as net value of all the (oil and gas produced less royalty)/taxable barrels (boe)= PTV/per barrel
- No progressivity charge when PTV/bbl<$30,
- Current Law:
- For each dollar above $30, .4% added to tax rate
- At PTV/bbl of $92.5, rate drops to .1% for each dollar

SB 267 (Section 11): drop rate to .2%, increase bend-over point to $155

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Progressivity Effect (FY 2008)

- FY 2008 Estimate (year of high prices)
- 25% Base tax – $4.2 billion
- Progressivity – $3.2 billion
- (less credits of $.5 billion)

- Compare to FY 2008
- Royalties (2.4 to GF, .8 to PF) $3.2 billion
- Oil and Gas Income Taxes $.6 billion
- Oil and Gas Property Taxes (State and Local) $.4 billion

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Source: State of Alaska DOR Revenue Sources Book (Fall 2008)

Progressivity in AS 43.55.011(g) vs. Personal Income Tax

- Under AS 43.55.011(g) the progressivity rate generated at high net values (PTVs)/bbl is applied to all the net value.
- ((PTV/bbl-30)* .004)+ 25%* PTV= Tax
- Under federal personal income tax rules:

Schedule X—If your filing status is Single

If your taxable income is: Over—	But not over—	The tax is:	of the amount over—
$0	$8,350	..... 10%	$0
8,350	33,950	$835.00 + 15%	8,350
33,950	82,250	4,675.00 + 25%	33,950
82,250	171,550	16,750.00 + 28%	82,250
171,550	372,950	41,754.00 + 33%	171,550
372,950	.....	108,216.00 + 35%	372,950

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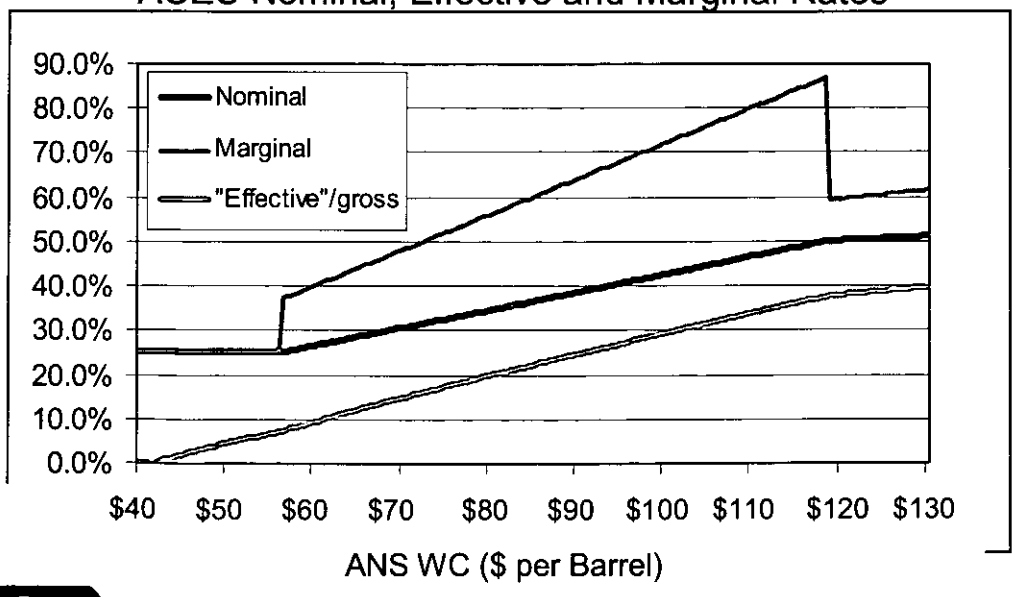
Production Tax: Progressivity + 25%

- Reproduction of Figure G from DOR January 14 Report
- "ACES Nominal, Effective and Marginal Rates"



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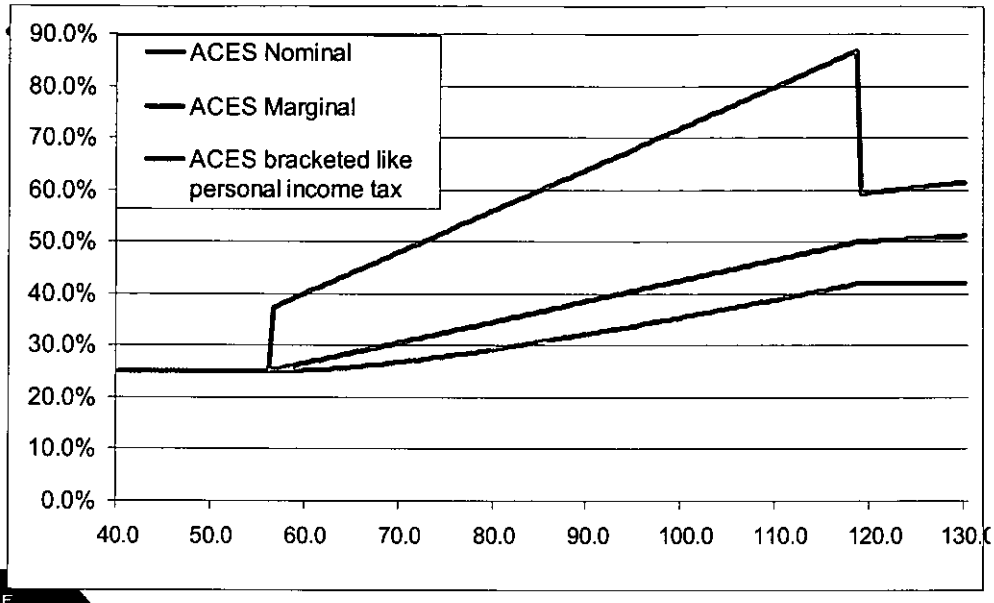
Production Tax: Progressivity + 25%

- What if the progressivity bracket was like personal federal income tax brackets.



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Crossing the Progressivity/Bracket Threshold

25.4% bigher bracket starts when net value (PTV) passes $30 a barrel

	30	31	Difference
Personal federal income tax progressivity			
PTV	$ 30.00	$30.00 + $ 1.00 = $31.00	$ 1.00
Tax Rate	25.0%	25.0% 25.4% 25.4%	
Tax	$ 7.500	$7.500 + $ 0.254 = $7.754	$ 0.254
Marginal Tax Rate:			25.4%
AS 43.55.011(g) Progressivity			
PTV	$ 30.00	$30.00 + $ 1.00 = $31.00	$ 1.00
Tax Rate	25.0%	25.4% 25.4% 25.4%	
Tax	$ 7.500	$7.620 + $ 0.254 = $7.874	$ 0.374
Marginal Tax Rate:			37%
Difference	$ -	$ 0.12 $ 0.12	$ 0.12

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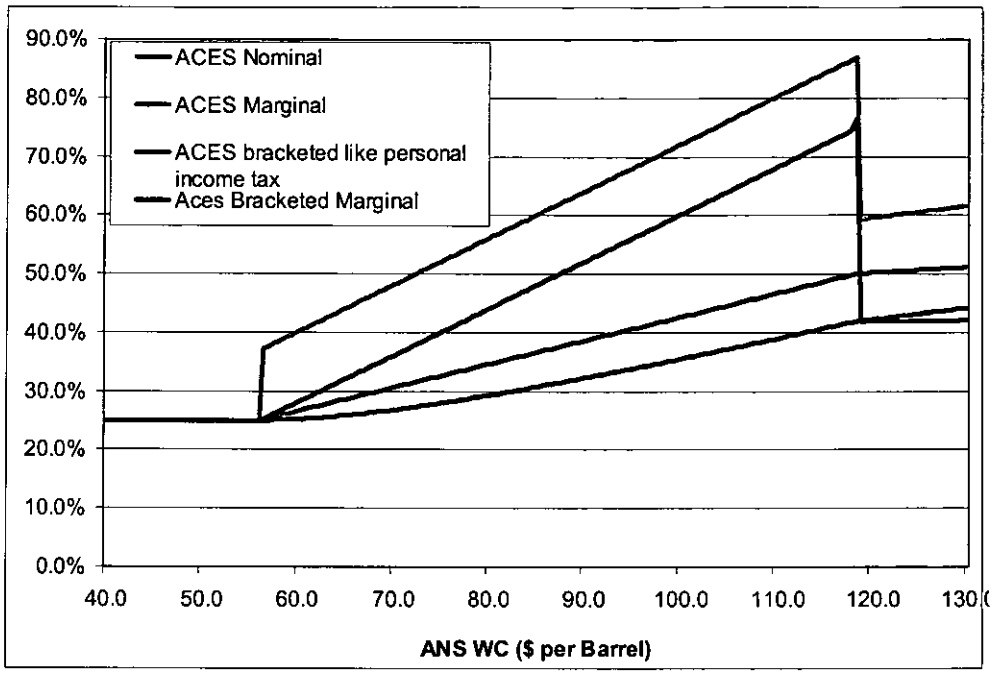
Production Tax: Progressivity + 25%



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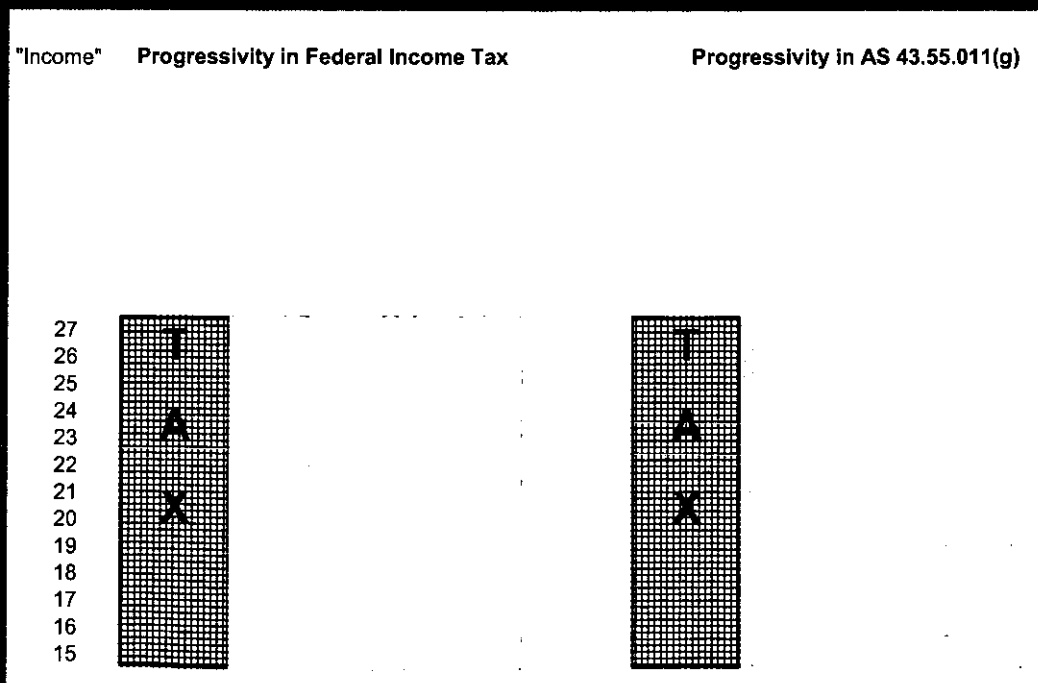
Progressivity in AS 43.55.011(g) vs. Personal Income Tax



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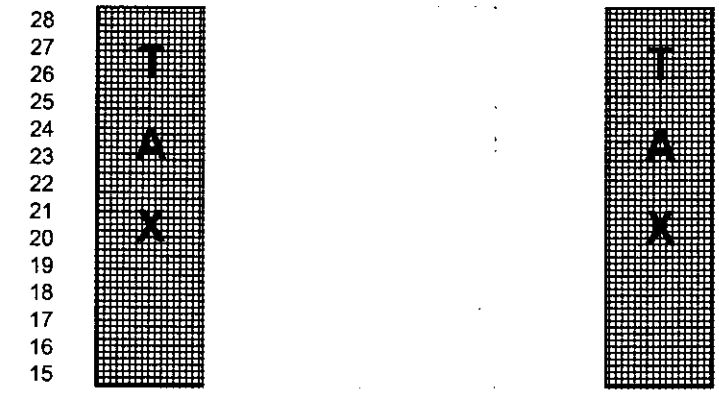
"Income" **Progressivity in Federal Income Tax** **Progressivity in AS 43.55.011(g)**



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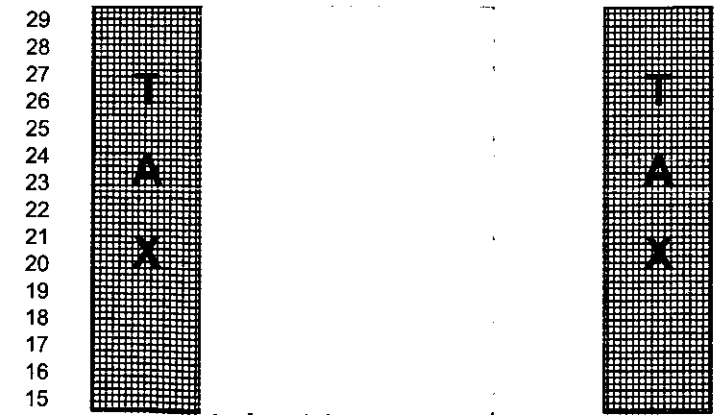

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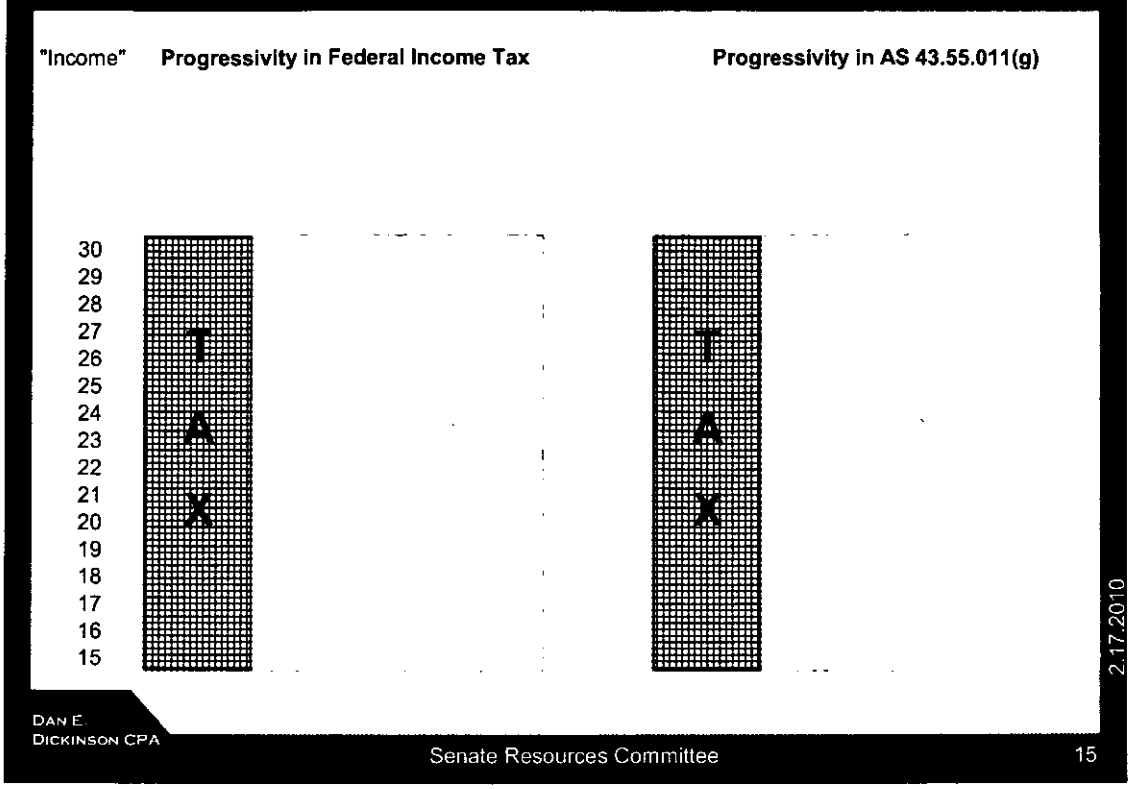

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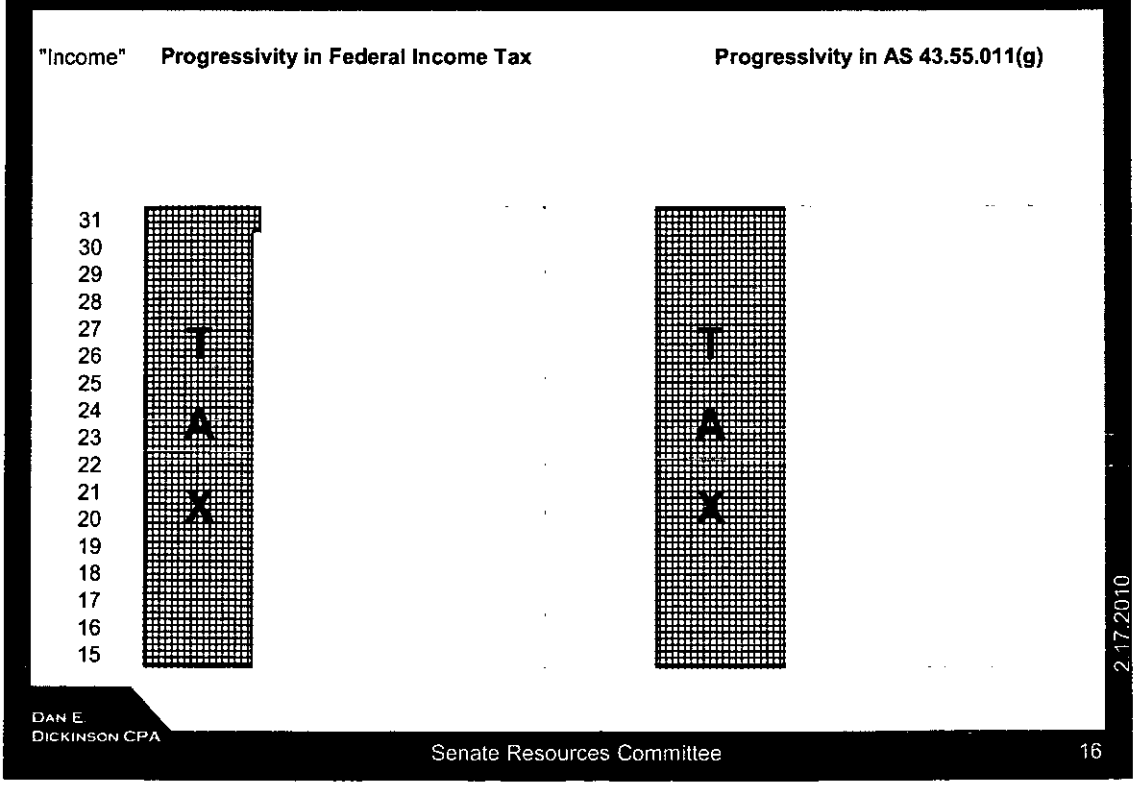

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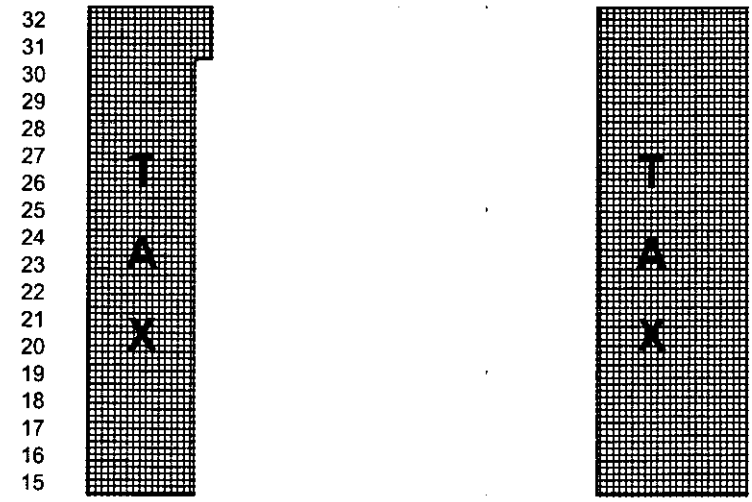

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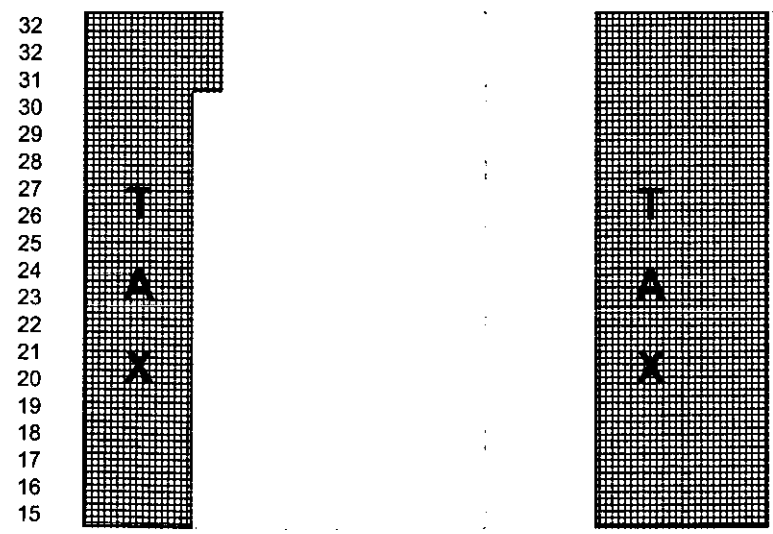

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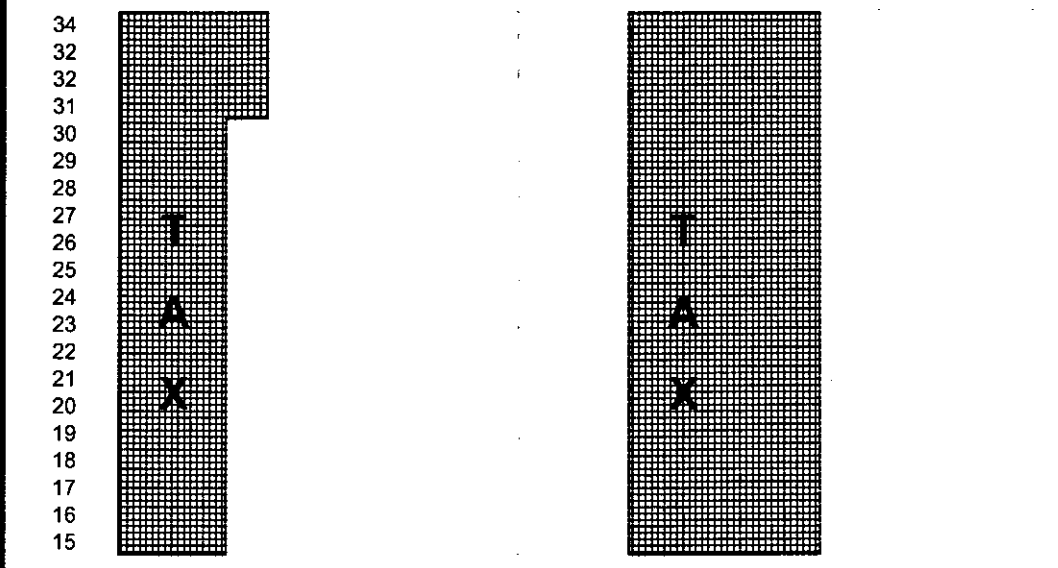

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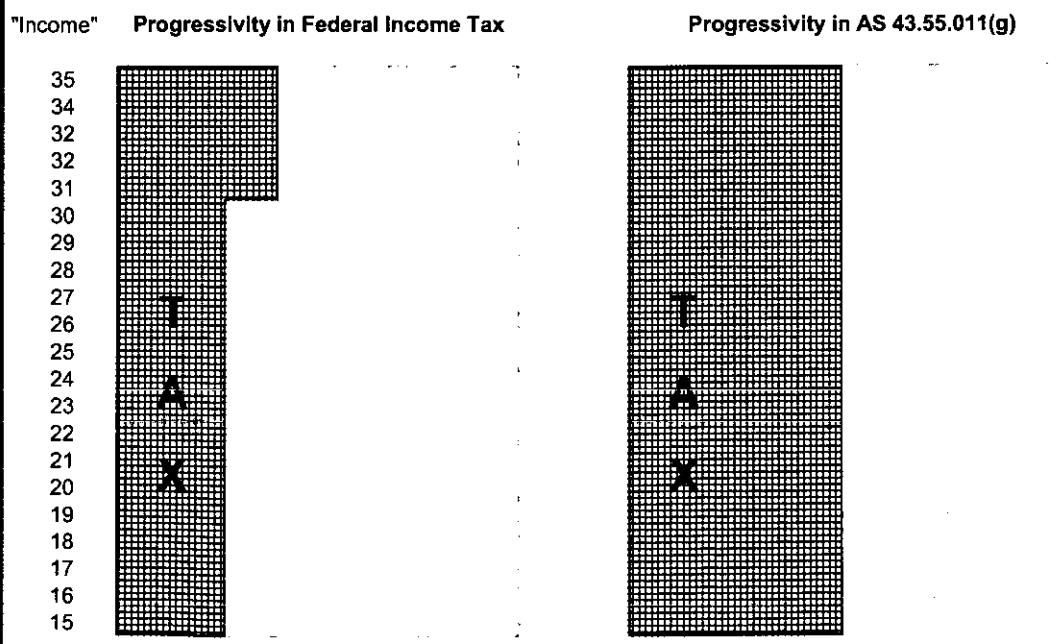

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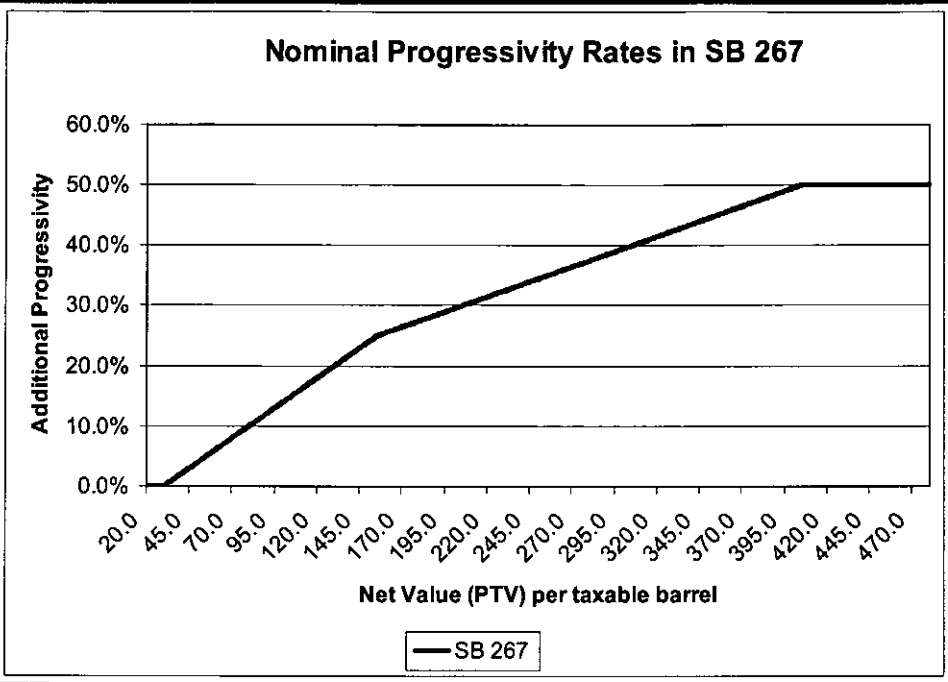
Progressivity Only



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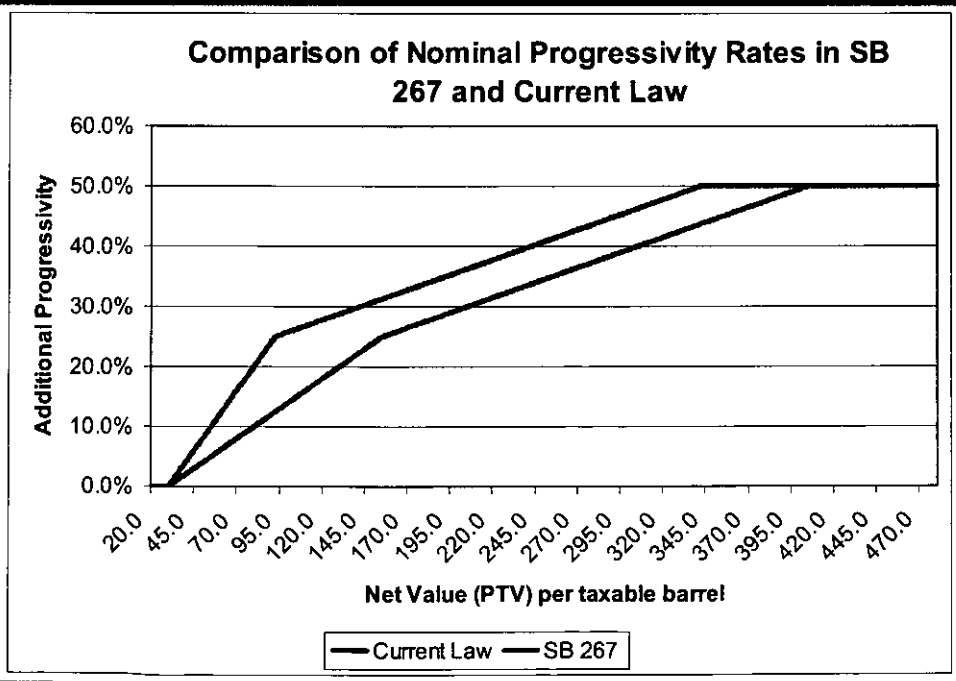

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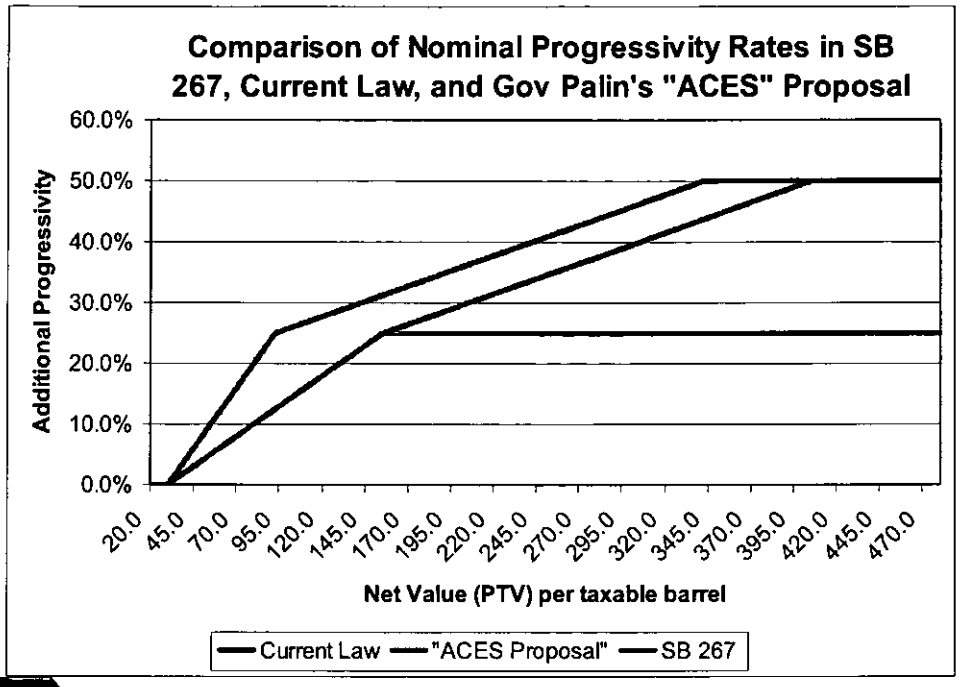

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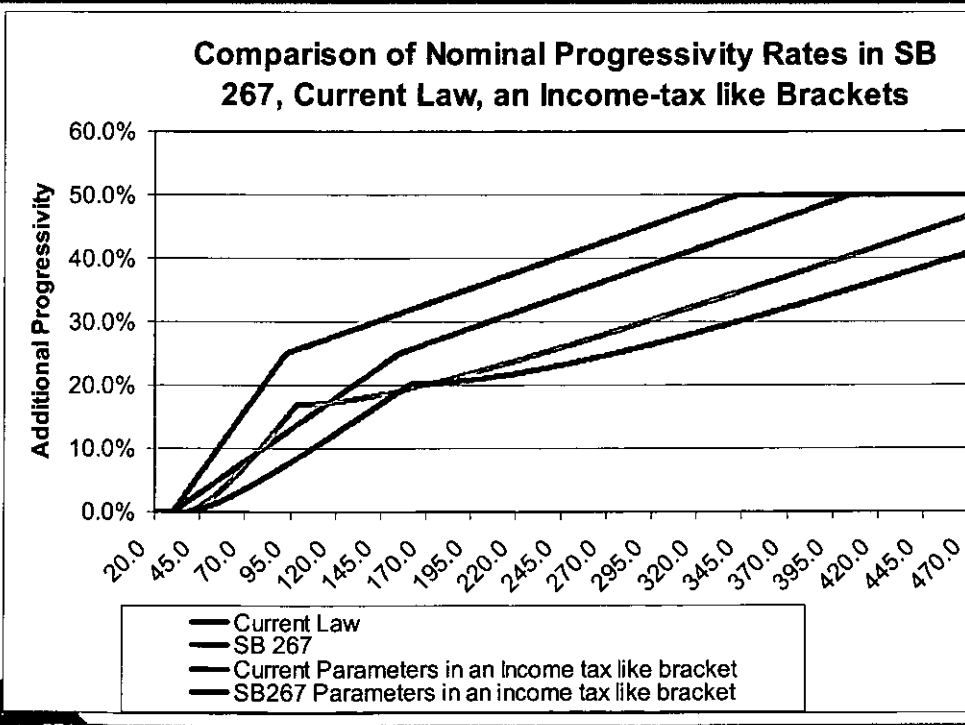

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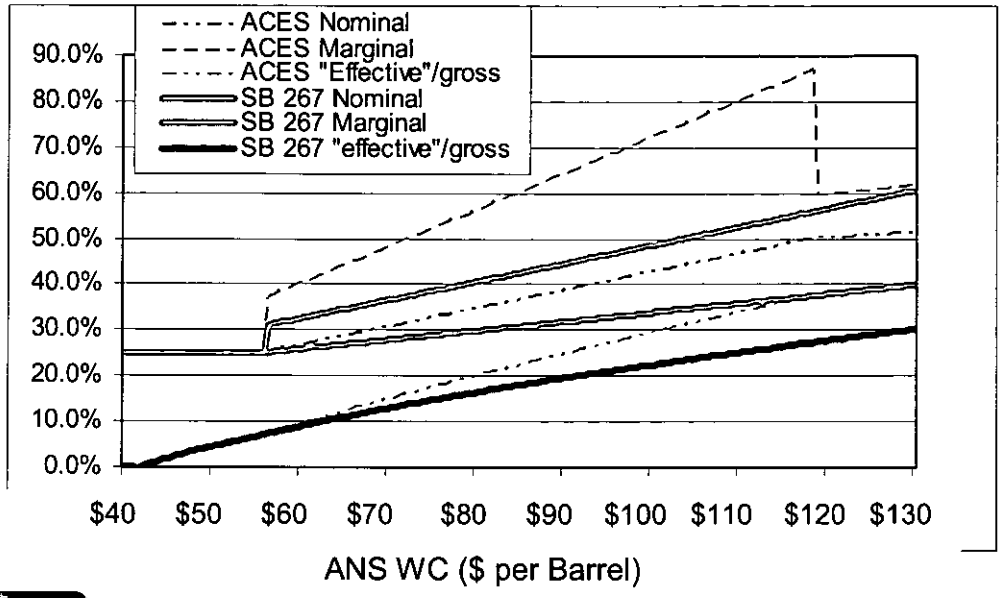
Production Tax: Progressivity + 25%

- Add SB 267 Nominal, Marginal and "effective"/gross"



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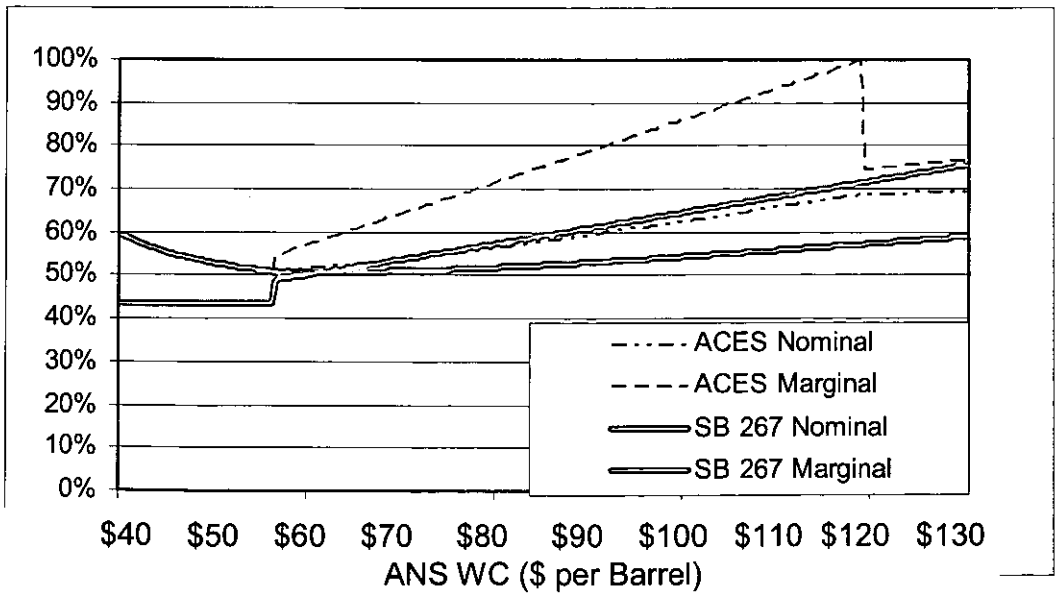
Total State of Alaska Take (Prod/Prop/Inc Tax + Royalty)



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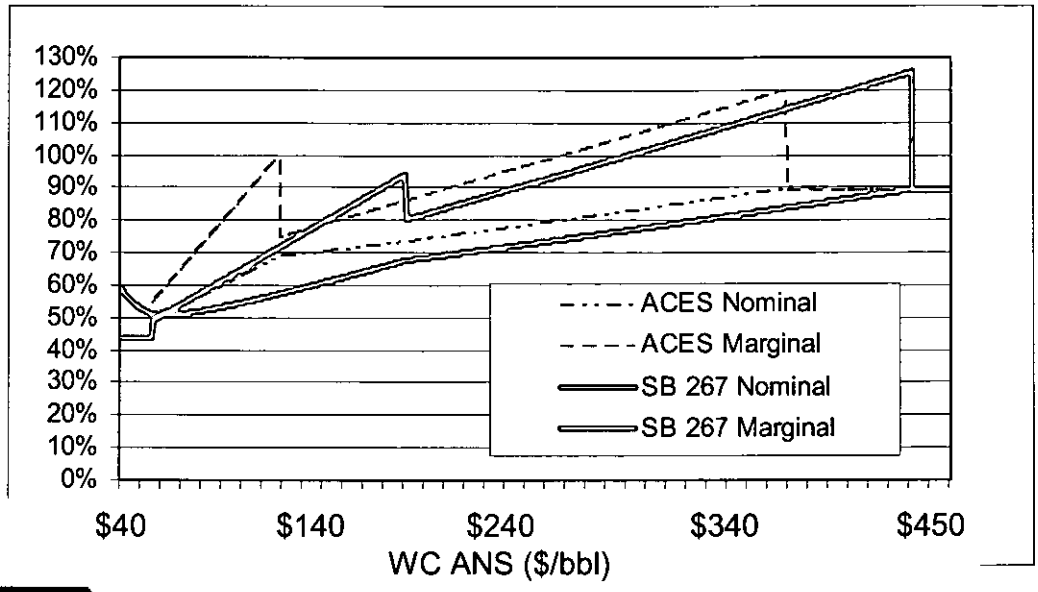

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Investment Credits

- Section 17 adds 30% well work credit to investment credits
- Under Current Law –
- 30% Credit for exploration wells (AS 43.55.025)
- 40% Credit for seismic work outside of existing unit,
  - or exploration wells 25 miles from existing unit, and
  - 3 miles from any prior well (or with certification from DNR that it is for a new target in the Cook Inlet) (AS 43.55.025)
- 20% Credit for any capital investment (AS 43.55.023(a))

- No change to Exploration Credits AS 43.55.025 under this bill

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Compare with Other Well Work Proposals

- How does this compare with Governor's "Well Credits" proposal

-Both create a 30% credit for well work

-Both include pertinent capex and opex

-CS should be effective on the first day of a month (Gov's bill is July 1, 2010) year.

- Differences:
- CS for HB 308 places the credit among the .023 "Tax Credits for certain losses and expenditures" Governor's bill changes name of .025 from "Exploration" to "Exploration and Development" and places it there.
- Different definition of well related expense.
- (Other changes to AS 43.55.025 in Gov's bill)

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Differences between AS .023 and .025

AS 43.55.023 – Tax credits for certain loses and expenditures	AS 43.55.025 – Alternative tax credit for oil and gas exploration
AS 43.55.023 deals with capital costs in (a), lease expenditures in (b), and both in sections (c), (d), (e), (g), (h) and (j). (note – (f) repealed and (i) and (k) deal only with capital).	AS 43.55.025 deals only with exploration costs –by explorers. Administration suggests totally re-writing and re-titling to cover this work by explorers and producers.
21 specific exclusions from lease expenditures listed in AS 43.55.165 (e) (1) – (21) including exclusion of 30 cents a barrel from any capital cost, and certain transactions with affiliates or related parties.	Prohibitions summed up in one paragraph (AS 43.55.025(b)(3)
Restrictions in AS 43.55.011(m) ("credits clawback") do not apply.	AS 43.55.011(m) ("credits clawback") does apply.

Question: Are we certain that the restructuring of AS 43.55.025 will not result in inadvertent changes to the rules?

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Definitions of well work compared

SB 267 proposed AS 43.55.023(m)(3)	Governor's Language proposed AS 43.55.025(b) (3) and (4)
"Well-related expenditures" means	Development well expenditures are for
A lease expenditure	Goods, services and rentals of personal property reasonable required for
related to a well	
and includes a lease expenditure for the purposes of sidetracking, well deepening, well recompletion, well workover,	Re-drilling, casing , cementing or logging, Completing, workover operations or other operations intended to increase or enhance well production
	From a known productive pool;
an injection well and well related seismic work and	And the well is not a service well [injector] or stratigraphic test well.
an intangible drilling and development cost authorized under 26 USC (IRC) as amended, and 26 CFR 1.612-4, regardless of the elections make under 26 USC 263(C0 as amended	
up to the flange connecting the well head to the well line.	

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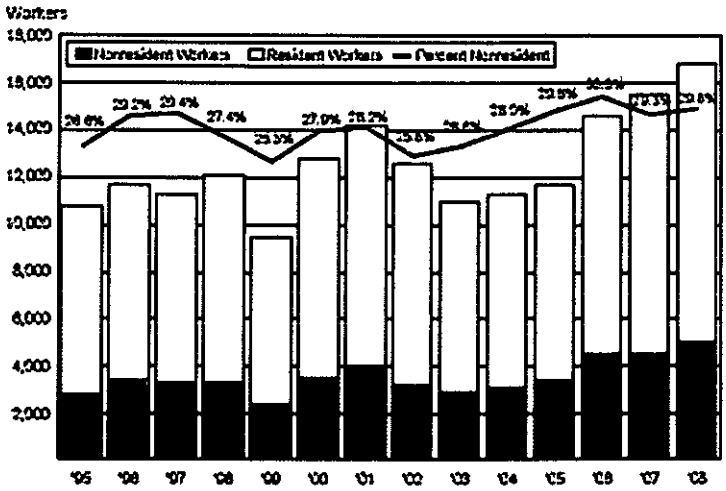
Non Resident Workers

6 Oil Industry
Number and Percent Nonresident Workers
Alaska 1995-2008



Note: Private Sector Only
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Source: Nonresidents Working in Alaska, 2008, State of Alaska, Dept of Labor and Workforce Development (Jan 2010) http://www.labor.state.ak.us/research/reshire/nonres.pdf

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Rate tied to Resident Hire

- General Approach – (section 15)
- Base Tax rate (in AS 43.55.011(e)) is 25%, and Taxpayers makes monthly payments at that rate
- Any direct labor that is a lease expenditure is accounted for as Resident or non-Resident.
- At the end of the year total hours of labor are used to calculate a ratio for the year: or resident hire %
- New effective rate is calculated:
  - 20% for a 100% Resident Hire ratio up to
  - 25% (current law) for an 80% Resident Hire ratio.
- Taxpayer can then apply for a rebate of the difference for the prior year.
- Note: effective date should be beginning of a year.

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Rates in CS HB 308 proposed 43.055.022 (b)

For Resident Hire Ratios		Rebate of amount under AS 43.55.011(e)(1)	Tax Rate in AS 43.55.011(e)(1)	Rebate as % of PTV	Effective Tax Rate
equal or above	but below				
70.0%	72.5%	0.0%	25.0%	0.0%	25.0%
72.5%	75.0%	0.0%	25.0%	0.0%	25.0%
75.0%	77.5%	0.0%	25.0%	0.0%	25.0%
80.0%	82.5%	2.0%	25.0%	0.5%	24.5%
82.5%	85.0%	4.0%	25.0%	1.0%	24.0%
85.0%	87.5%	6.0%	25.0%	1.5%	23.5%
87.5%	90.0%	8.0%	25.0%	2.0%	23.0%
90.0%	92.5%	10.0%	25.0%	2.5%	22.5%
92.5%	95.0%	12.0%	25.0%	3.0%	22.0%
95.0%	97.5%	14.0%	25.0%	3.5%	21.5%
97.5%	100.0%	16.0%	25.0%	4.0%	21.0%
100.0%		20.0%	25.0%	5.0%	20.0%

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Resident Hire -- What will it cost per job?

- "In an extreme example, [according to DOR] hiring just one Alaskan could mean $30 million in tax savings" (Anchorage Daily News 2/11/2010, backpage (A-14))

All figures in Millions of Dollars:	
FY2008 Estimated PTV ($millions)	$ 16,837.7
FY2009 Estimated PTV ($millions)	9,313.1
Average for CY 2009	13,075.4
Assumption: One company is responsible for half	6,537.7
AS 43.55.011(e)(1) taxes at 25%	1,634.4
If one incremental employee (hour) moves taxpayer by one bracket in between 80 - 97.5% then effect is (.5%)	**32.7**

Function of "brackets rate applied to base"
Opposite effect also occurs.

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Resident Hire – What will it cost per job?

Opposite effect also occurs.
Assumption: Company has 6,500 employees and contractors at the statewide average of 70% Residents
1. When Below 70%

	Total Workers	Resident Workers	Ratio	Tax rate
year one	6,500	4,550	70.00%	25.0%
add		649		
year two	6,500	5,199	79.98%	25.0%

	Total Worker Hours	Resident Worker Hours	Ratio	Tax rate
year one	13,000,000	9,100,000	70.00%	25.0%
add		1,298,000		
year two	13,000,000	10,398,000	79.98%	25.0%

"need to be at 80% to start the conversation"

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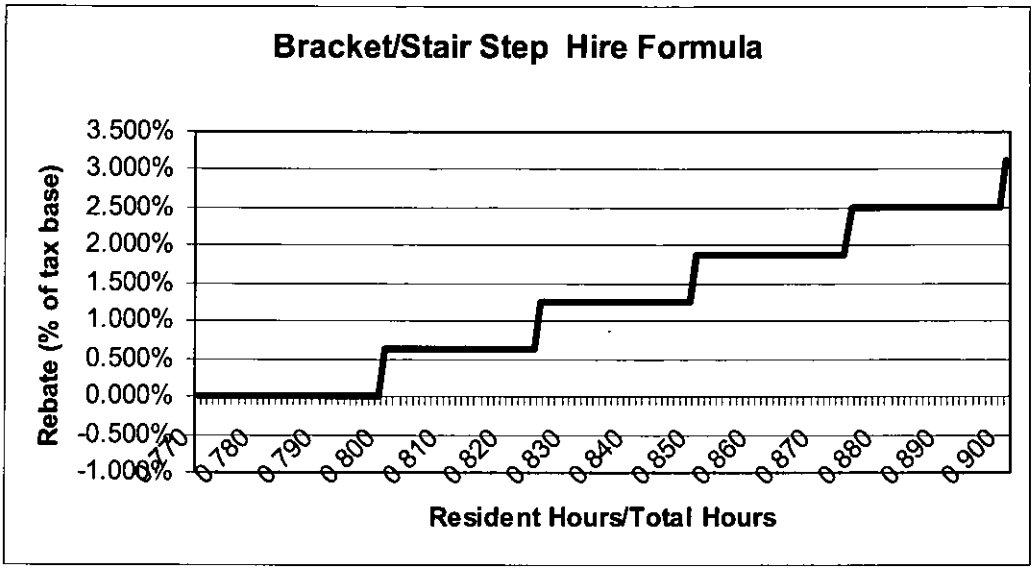
Resident Hire – What will it cost per job?



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Resident Hire – What will it cost per job?

Opposite effect also occurs.
Assumption: Company has 6,500 employees and contractors at the statewide average of 70% Residents
(2) When between brackets

	Total Workers	Resident Workers	Ratio	Tax rate
year one	6,500	5,200	80.00%	24.5%
add		162		
year two	6,500	5,362	82.49%	24.5%

	Total Worker Hours	Resident Worker Hours	Ratio	Tax rate
year one	13,000,000	10,400,000	80.00%	24.5%
add		324,000		
year two	13,000,000	10,724,000	82.49%	24.5%

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Stair Step versus Continuous Function

Solution – Continuous function (with rounding)

- Rebate equal to tax base (PTV) times
- Higher of ((Resident Hours/Total hours) or .8)
- Less .8

- That transforms Resident Hire rates between 80% and 100% into a series from 0% to 20%

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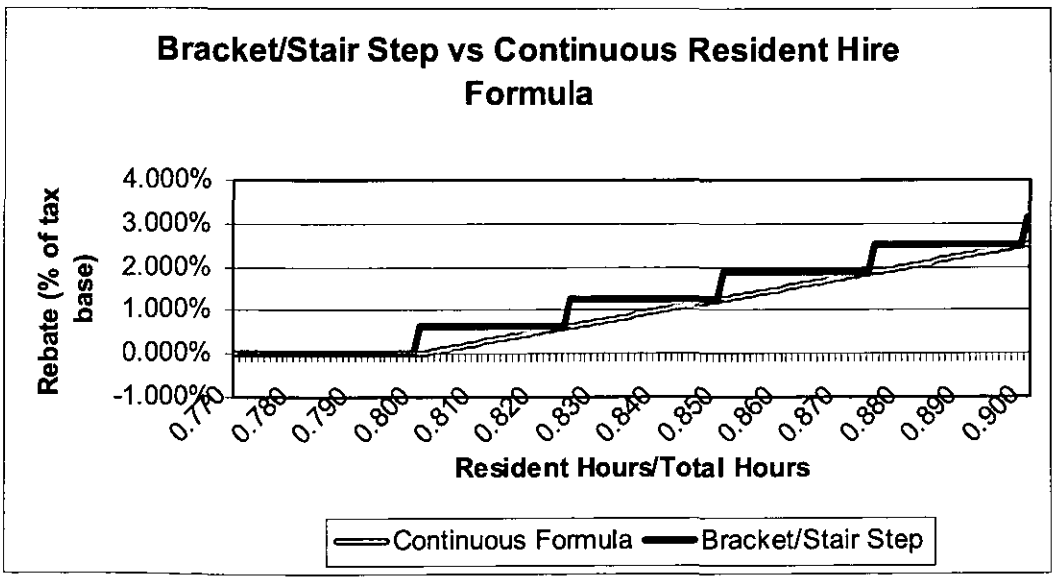
2. Stair Step versus Continuous Function



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Problem of "no reporting of nonresident wages"

		Actual	Rounded
FY2008 Estimated PTV ($millions)	$	16,837.7	
FY2009 Estimated PTV ($millions)		9,313.1	
Average for CY 2009		13,075.4	10,000
AS 43.55.011(e)(1) taxes at 25%		3,268.8	2,500
Maximum Rebate (20% of taxes, 5% of base)		653.8	500
Non Resident Workers in industry in 2008		5043	5,000
Average Wages (2008) per worker ($million)		0.083601	0.100000
Total Non- Resident Wages		422	500
Effect of not claiming Non resident wages as lease expense (25%) ($millions)		105.4	125
So by simply not reporting or deducting the 5043 non residents Decrease in taxes: ($millions)		548.4	375

Sources: State of Alaska, Dept. of Labor and Workforce Development, Nonresidents Working in Alaska, 2008 (Jan 2010), derivations from figures in Dept of Revenue, Revenue Sources Book (Fall 2009)

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Some solutions to "no reporting of nonresident wages"

1. Shift the scale so maximum tax savings are not $500 million by $100 million and tax rate could range from 24% to 25%.
2. Require that for any labor to be allowed as a lease expense, all the labor from that company must be calculated in Resident Hire calculation – (with additional rules for pass through).
3. Focus on new hires only, and specific dollar rebate for every new resident hire.
4. Given structure of industry, have the DOR determine a tax rate every year based on the Resident Hire Ratios of 10 (20?) largest employers in the industry or largest generators of lease expenditures.

2.17.2010

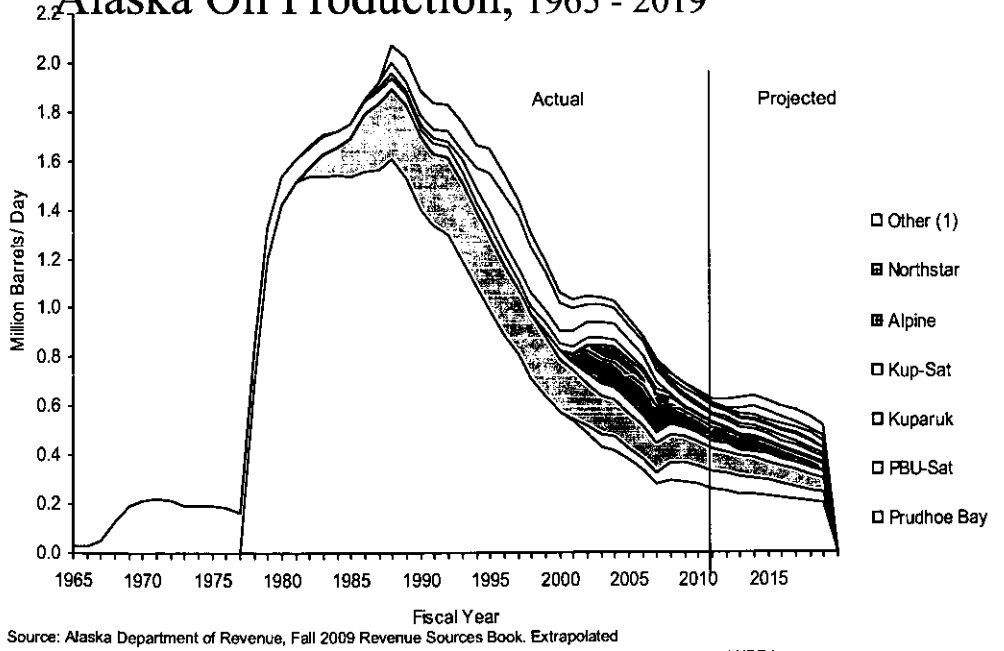
Structure of Industry in Alaska

- Producers (taxpayers) have employees & hire
  - Operator who has employees & hires
    - Contractors, and buys "stuff"
- According to the Dept of Labor & Workforce Development (2008) employment in
- Oil and gas (direct) 4,055
- Oilfield Services 12,875
- Total 16,930

2.17.2010

Sources: State of Alaska, Dept. of Labor and Workforce Development, Nonresidents Working in Alaska, 2008 (Jan 2010),

Alaska Oil Production, 1965 - 2019



Source: Alaska Department of Revenue, Fall 2009 Revenue Sources Book. Extrapolated
(1) Cook Inlet, Duck Island, Milne Point, Greater Point McIntyre, Liberty, Known On & Offshore, Fiord and NPRA.

2.17.2010

Who are the 15 Tax Production Tax Filers (2009)?

	1 CP	2 BP	3 EM	4 Anadarko	5 Chevron	6 Pioneer	7 -10 4 Others(1)	Total
Production in Millions of Bbls a day								
PBU & Sat	0.1317	0.0962	0.1328	-	0.0042	-	0.0001	0.365
KRU & Sat	0.0785	0.0558	0.0006	-	0.0071	-	-	0.142
North Star	-	0.0270	-	-	-	-	-	0.027
Alpine & Sat	0.0827	-	-	0.0233	-	-	-	0.106
Endicott	0.0004	0.0074	0.0045	-	0.0017	-	0.0001	0.014
Milne	-	0.0310	-	-	-	-	-	0.031
Oooguruk	-	-	-	-	-	0.0028	0.0012	0.004
Total bbl/day	0.2933	0.2174	0.1379	0.0233	0.0130	0.0028	0.0013	0.689
MM bbl/yr	**107.0**	**79.4**	**50.3**	**8.5**	**4.8**	**1.0**	**0.5**	**251.5**
% of NS	43%	32%	20%	3%	2%	0%	0%	100%

Cook Inlet 2009

10% of production

1/2 of 1% of tax due to AS 43.55.011(j) and (k) limitations

Cook Inlet Production	
oil	4.0
gas (boe)	24.9
Total CI	28.9
Total AK	**280.43**

Cook Inlet:

11 Aurora
*Chevron (heritage Unocal & Chevron)
*CP (heritage Arco and Phillips)
12 Pacific Energy (acquired Forest interests)
13 Marathon
14 ML&P
*EM (heritage Mobil & XTO)
15 Pioneer (Lawrenceville, Ill)

(1) Others
7 Nana
8 Doyen
9 Forest &
10 ENI

Source: DNR Division of Oil and Gas 2006 & 2009 Annual Reports, DOR, Fall 2009 Revenue Sources Book

2.17.2010

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DED estimate covered by AS 43.55.024 credit

Source: DNR Division of Oil and Gas 2006 & 2009 Annual Reports, DOR, Fall 2009 Revenue Sources Book

2.17.2010

Who are the Employers in the Oil and Gas Industry

- Recall EM, BP and CP are largest taxpayers – they would put pressure on employers to qualify for lower rate

Ranking in Top 100	Total Employees			Non Resident %
5 ASRC	2250	2499	Oil Field Services	24.1%
8 CH2MHill	1750	1999	Oil Field Services	35.5%
9 BP Exploration			Oil & Gas Extraction	27.7%
17 Conoco Phillips	1000	1249	Oil & Gas Extraction	20.7%
36 Nabors Alaska Drilling	500	749	Oil Field Services	
43 Schlumberger Technologies			Oil Field Services	30.5%
49 Udelhoven Oilfied System Services			Oil Field Services	30.5%
52 Peak Oilfield Service Company	250	499	Oil Field Services	26.8%
69 Norcon			Oil Field Services	23.2%
73 Chevron			Oil & Gas Extraction	
78 Hallibturon			Oil Field Services	32.3%
95 Doyon Drilling			Oil Field Services	
Veritas Dgc Land Inc				47.9%
Baker Hughes Oilfield Operations Inc.				54.1%

NOTE: Does Not Include "Catering/Security", Engineering, Transportion, Communications, Construction

2.17.2010

Sources: State of Alaska, Dept. of Labor and Workforce Development, 100 Largest Private Employers, 2008 (Alaska Economic Trends, July 2009),Nonresidents Working in Alaska, 2008 (Jan 2010)

To be addressed by Statute (or Regulations)

- Is the "overhead labor" that is replaced by a formula in 15 AAC 55.270 part of the resident labor calculation?
- If a contractor has a fixed price contract, or charges a fee that includes labor (such as for transportation, turnkey modules, any manufactured good) who determines, or how is it determined whether and how to analyze the labor in that transaction for resident labor?
- Are billed professional services (say by an engineer) "labor" for the resident hire calculation.

2.17.2010

To be addressed by Statute

- If tax was not paid due to limitations in AS 43.55.011(j), (k) and (o) – CI or instate gas, can it be rebated?
- If tax was not paid due to applications of .023 Capitol and Loss Carry Forward Credits, .024 "Low Production" Credits and/or .025 Exploration Credits, can it be rebated?
- If times are tough and taxpayers have to pay the "alternative minimum tax" under AS 43.55.011(f), can that be rebated? It is a tax based on gross – but will still require the calculation of labor costs.
- If there is lots of investment activity and so that generates a loss – No resident hire issues if no tax base? Or should the rebate effect the loss carryforward. (Perverse incentive)

2.17.2010

6 Changes in SB 267

1. Change progressivity from .4% to .2% per dollar
2. 30% credit for well work
3. Tax rate tied to Resident Hire
4. Interest not due on retroactive reg changes prior to implementation
5. Interest rate is lower of fed funds +2 or 11%
6. Restore 3 year statute of limitations

2.17.2010

How is interest calculated?

Current Law

- Production Tax is due on last day of the month following the month of production (AS 43.55.020 (a)).
- Amount of tax due changes because of audit, revised reporting by taxpayer, retroactive revision of tariff due to a regulatory order in a rate case, retroactive change in regulations.
- Interest is charged back to when original tax is due.
- In a settlement Department can compromise amount of tax and amount of Penalty. (AS 43.55.070) – No mention of interest.

SB 267 (section 7) For all taxes, when retroactive regulation is passed, interest only goes back to effective date of regulation.

2.17.2010

Regulations required retroactive to July 2007*

- In 2007 reforms ("ACES") Department charged with a number of specific responsibilities for regulations, as well as general implementation.
  - AS 43.55.150 "the department shall determine the reasonable cost of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available modes of transportation or other reasonable methods.
  - AS 43.55.165(a) "...a producer's lease expenditures for a calendar year are ... costs ...allowed by the department by regulation..."
  - Production tax is a yearly tax – however, effective dates of most of 2007 reform was July 1, 2007, so ways of combining two half years had to be implemented.
  - New reporting requirements (AS 43.55.030 & .040)
  - *New rules for exploration credits (AS 43.55.025)

2.17.2010

Status of Regulations Affecting Returns after July 2007

	Discussion Draft				Public Comment Draft		Adopted
	1	2	3	4	1	2	
Project One - Reporting Requirement							
15 AAC 55. 520 Reporting					Feb-08		May '08 effective as of June '08
Project Two - NS PV, Civil Penalties, Mid Year Statutory Changes, CI reporting							
35 sections	Feb-08	*Oct-08*	*Nov-08*		Apr-08	Sep-08	Sep '09 effective as of Oct '09
Project Three - Exploration Credits							
6 sections					Aug-08	Jun-09	Nov '09 effective as of Dec '09
Project Four - Lease Expenditures							
10 Sections	Jan-08	Mar-08	Sep-08				Jan '10 effective as of Feb '10
Project Five - Reasonable Transportation							
5 sections	Mar-08	May-08	Jan-09		Feb-10		
6. Other Projects							
15 AAC 55. 173 NS Gas PV	Feb-08				Apr-08		Aug '08 effective as of Oct 1 '08
Facility Sharing	Oct-08	Nov-08	Feb-09	Jul-09			
Credit Safeguards	Nov-08						
"Affiliated" definition	Jan-09						
PV of oil					Jan-10		

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Interest on Retroactive Regulatory Changes

- Governor Parnell's suggested approach:
  - More thorough – explicitly recognizes that the absence of regulations is not the absence of any rules
  - Explicitly retroactive – deals with the 2007 -2010 regulatory delay
  - Does not require restructuring AS 43.05.225 (thus eliminates half the provisions in the SB 267) – however only applies to production tax.
  - (although in current version A, section 6, page 3 line 5 requires in the insertion of an "a" in any case.)

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Interest on Retroactive Regulatory Changes

- Possible upgrades to Governor's Language:
- Instead of requiring a departmental determination of good faith by the producer in each case. Assume it, and allow the department to prove otherwise if it finds egregious behavior.
- Possible upgrades to either approach
- AS 43.55.020 (a)(1)-(3) are monthly "installment payments of estimated tax" using 1/12th of estimated credits and 1/12th estimated lease expenditures - so
  - No true up caused by retroactive regs except for annual true up already required under AS 43.55.020 (a) (4) and
  - First first day of month more than 90 days after effective date of regs.

2.17.2010

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2.17.2010

Interest rate in AS 43.05.225

- Lower tax rate for all tax types (section 6)
- The interest rate applies to all 20 Alaska Tax Types*
- Current law – higher of fed funds + 5 or 11%
- Also applies to late royalty payments.
- **Compounded** Quarterly
- Implemented in 1991 amidst settlement of major production tax and royalty litigation going back to 1977 and era of simple interest.
- Effective date should be end of year, or at the very least, quarter.

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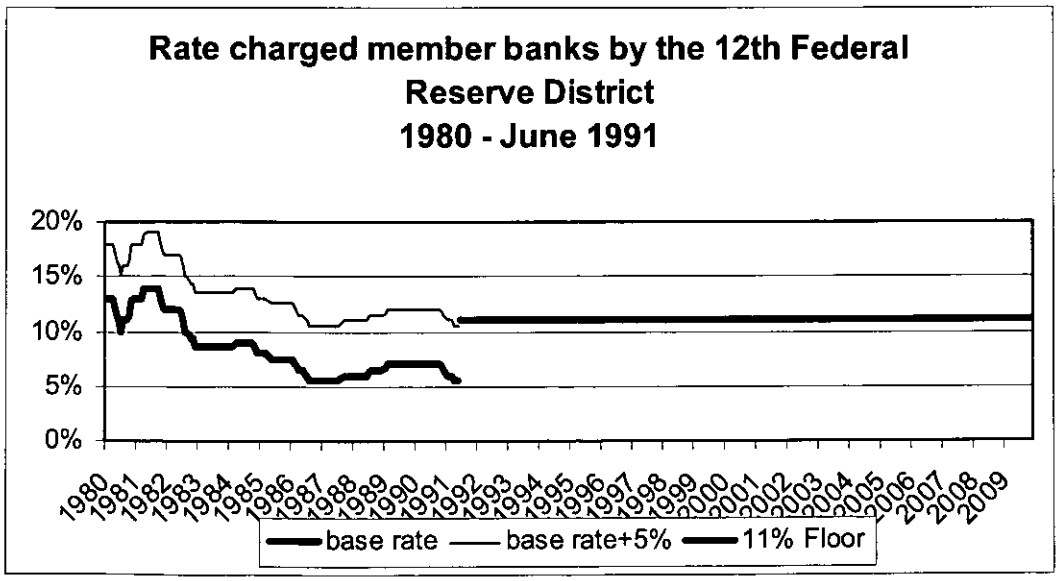
Interest Rates: The view from June 1991



Source: Federal Reserve Bank of San Francisco (frbsf.org)

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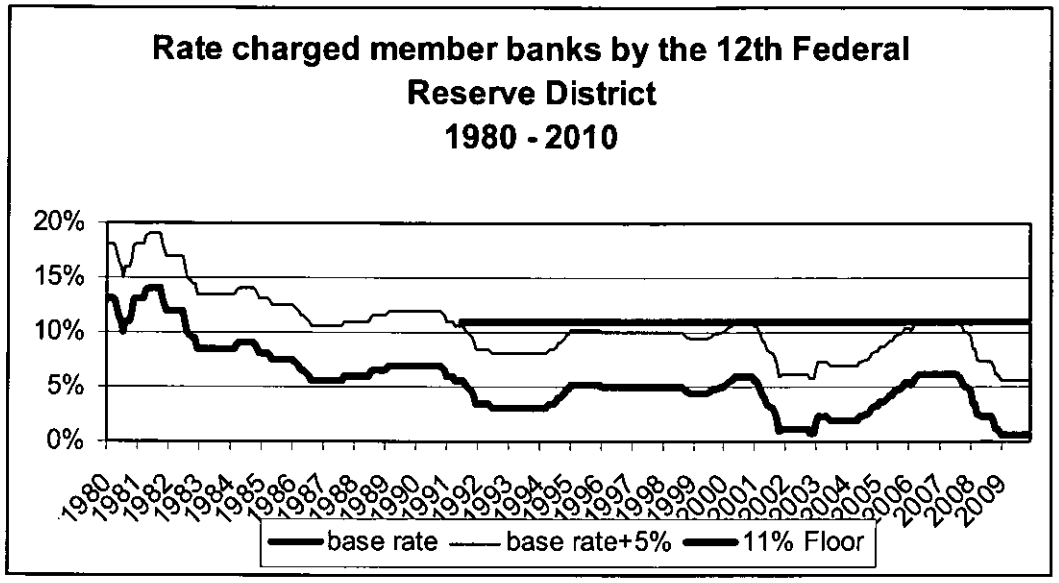
Interest Rates – The 11% floor since 1991



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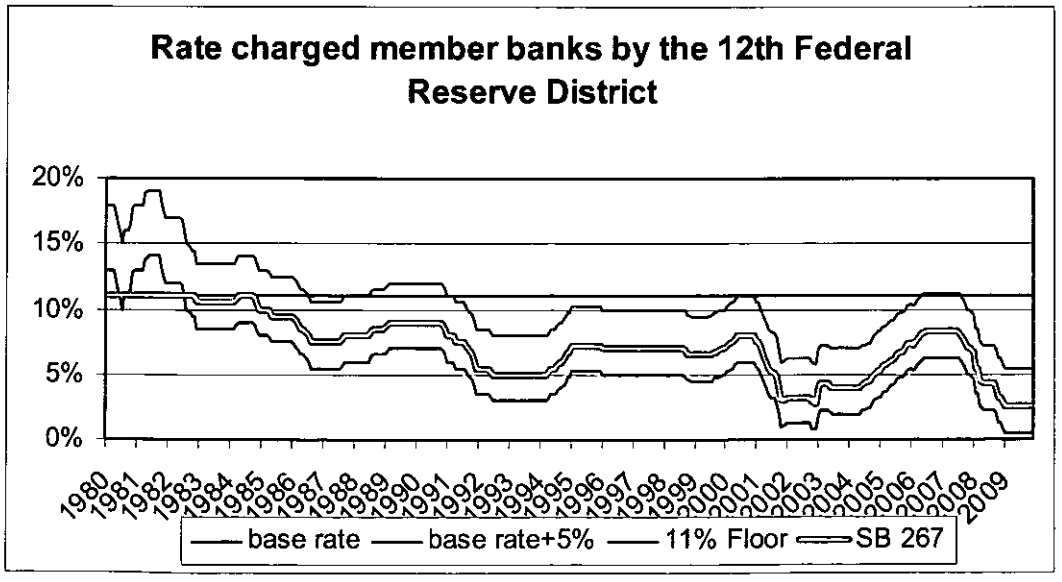
DAN E. DICKINSON CPA

Looking back: What would the rate have been under SB 267



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DAN E. DICKINSON CPA

Alaska compared with federal rate

- How are federal interest rates computed under IRC:

	Over Payments of Tax	Under Payments of Tax
Non- Corporate	Fed Funds + 3%	Fed Funds + 3%
Corporate	Fed Funds + 2%	Fed Funds + 3%
Corporate - Large	Fed Funds + ½%	Fed Funds + 5%

2.17.2010

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Restore 3 year State of Limitations

- Section 20 Restores statute of limitations to three years for production tax - time for the state to complete a production tax audit (or, agree to an extension with taxpayer or issue a blue sky assessment)
- Three year rule would begin with 2011 tax year
- Note: in the case of False or Fraudulent returns, or failure to file a return, may proceed "at any time"

- Prior to 2007, SOL was three years for all tax types under AS 43.05.260 –
- In 2007 production tax pulled out and extended to 6 years in AS 43.55.075

2.17.2010

Thank You

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2.17.2010

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Senate Committee on World Trade, Technology and Innovations

Co-Chair
Senate Resources Committee

Member
Senate Judiciary Committee

SENATOR LESIL MCGUIRE

Sponsor Statement for Senate Bill 267

Anchorage economist Scott Goldsmith characterizes Alaska's economy prior to the discovery of the immense oil deposits on the North Slope as "small, thin and seasonal." With the federal government providing roughly half of Alaska's ninety thousand jobs at the time, the economy was dominated by outside residents and the State's revenue base was small. In 1960 for example, the State of Alaska collected roughly $154 million (2009 dollars) in taxes. This year, the State of Alaska will collect more than $5 billion. In 2009, 89% of the State of Alaska's general fund revenues will come from oil.

Alaska taxes oil based on the value of each barrel of oil produced. Although high oil prices certainly affect the State's treasury, oil must be produced in order for it to be taxed. Currently, Alaska's oil production is declining at between four and five percent per year. Simply maintaining this steady decline rate will require billions of dollars of investment in Alaska's oil patch. Reducing it will require billions more. While this challenge may sound daunting, it is actually an opportunity. For dollars invested in Alaska's oil patch aren't simply large numbers or entries in an accounting ledger; ultimately, dollars invested in Alaska are jobs.

Senate Bill 267 offers a simple exchange to the companies that operate, explore and invest in Alaska: If you invest in the type of activities that lead to increased oil production in Alaska, you will receive the capital investment credits already available to other investments. If you are willing to risk your capital in Alaska, you will be able to reap a reasonable reward for your investment. And most importantly, if you employ Alaskans, you will receive an additional credit against your taxes.

Through the resident worker rebate in Senate Bill 267, a company maintaining an Alaska resident workforce of at least 80% will see immediate reductions in their tax bill. The rebate increases as the level of the resident workforce increases. Estimates show that this provision could generate roughly 5,000 high-paying jobs for Alaskans and $1.2 billion in economic impact for $500 million in foregone State revenues. To put these numbers in perspective, if the credit was just 50% effective (2,500) new jobs it would be like adding the third largest private sector employer in Alaska. More plainly put, 2,500 jobs is roughly the equivalent of the total jobs available in Wasilla according to the last census or another military base. That is millions in new paychecks for Alaskans, who then spend their money in the local economy and generate work for other Alaskans. This multiplier effect will help shore up the economic foundation of our communities and subsequently, strengthen the social fabric of our State.

The battle for Statehood was largely fought over outside control and non-resident employment in Alaska's fishing industry. SB 267 builds on the promise of Statehood by aligning the interest of the oil industry with Alaskans so that together, we can develop our resources as required by our Constitution: for the maximum benefit of Alaskans.

Backup Contents for SB 267

1. Dan Dickinson Presentation on SB 267
2. Department of Revenue: ACES Status Report
3. Frasier Institute: Global Petroleum Survey 2009, Executive Summary
4. ConocoPhillips: Presentation to Meet Alaska
5. BP: John Minge speech to Meet Alaska

State of Alaska

Department of Revenue

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January 14, 2010

Honorable Governor Parnell,

Recently you requested a review of Alaska's oil and gas production tax, and recommendations for how the production tax could be improved. Enclosed for your review is analysis of Alaska's oil and gas production tax (otherwise referred to as "ACES"), which was compiled at my request by the Department of Revenue's technical staff. The ACES Status Report evaluates whether ACES is meeting its intended goals of providing a fair share of revenue to the state while encouraging investment in new oil and gas exploration and development activities.

Based on the report, I am recommending a collection of potential amendments to ACES and its associated Exploration Incentive Credit (EIC) program. The amendments are primarily intended to accomplish two things: 1. Further incentivize drilling and other production enhancing activities; and 2. Address a number of provisions of ACES that may keep explorers from enjoying the full intended value of the capital credit program.

The status report shows that ACES successfully allowed the state to share in the benefits of high oil prices while accommodating fluctuations in production costs and oil prices. ACES adjusted when oil prices tumbled and kept oil operations in Alaska highly profitable relative to other oil provinces. With respect to the impact that the new production tax has had on investment activity, the report is positive, but ultimately inconclusive. While the overall level of taxation increased with ACES, it distributed the impact of that tax burden in a way designed to incentivize investment in new exploration and development. Since ACES passed the legislature, overall spending on oil and gas activities on the North Slope has increased. However, given only two and a half years of experience, during which time oil prices climbed to $140 per barrel then plunged to under $30 per barrel, it would be premature to attribute the increased level of oil company investment to the success of ACES.

Oil taxes are clearly an important factor in industry investment decisions. However, it is misleading to isolate their influence from other key factors, such as world oil prices, geologic potential, access to land, resources and markets, costs of infrastructure and support services, and the legal and regulatory framework. As noted in the report, the true merit of Alaska's current fiscal system can only be determined when it is evaluated in conjunction with these other variables. The scope of the status report, and the limited timeframe since ACES passed, do not allow for such a comprehensive analysis and definitive conclusions.

In addition to documenting several promising trends in industry spending activity, the report notes a number of discrete policy issues associated with the production tax where improvement can be made. These warrant your consideration as potential amendments to the ACES framework.

1. **Increase Credits for All Well-Related Activity to 30%:** The Capital Credit and Exploration Incentive Credit (EIC) programs have been identified as influential in spurring exploration activities. However, the EIC program's 30% credits are only available to wells located more than 3 miles from all existing wells. The state has a significant interest in also incentivizing infill drilling and other well work that will increase oil production, particularly for heavy oil. I therefore recommend expanding the EIC program so that all expenditures related to drilling and well work that add new production or increase the efficiency of existing production will qualify for the 30% EIC credit under AS 43.55.025 regardless of a well's location relative to existing wells.

2. **Increase Access to Capital Credits for New Explorers:** Small producers are currently required to invest in new activities during subsequent years in order to obtain direct payment from the state for previously earned tax credits. This is not an issue for existing producers because they simply deduct credits from their current tax bill and do not need to seek direct payment from the state. Deleting this provision would make the tax credits more accessible to smaller explorers, level the playing field between new and existing operators, and eliminate an unfair double standard.

3. **Accelerate Capital Credit Usage**: Companies currently can only use half of their capital credits in the year they are earned, and the other half the following year. This is true whether the credits are applied against a tax liability or purchased by the state. Taxpayers would see increased value in the credits if they could apply the entire credit in the first year. In addition, this would ease the cost of administering these credits.

4. **Waive Interest on Late Tax Payments Due to Drafting of Regulations**: The ACES regulations, including those defining 'allowable lease expenditures' are being finalized this month. Under the statutes, these regulations are to be applied retroactively to various dates in 2007. To the extent additional taxes are due as a result of the application of the new regulations, such payments would be subject to interest and possibly penalties. While the department can waive penalties, it cannot waive interest charges. A statutory change is required in order to permit the waiver of interest.

I am confident you will find the ACES Status Report informative and interesting. Please consider my recommendations to improve the effectiveness and fair administration of ACES and the EIC program. I look forward to continuing to work with you to encourage additional oil and gas development while preserving Alaska's equitable share of oil and gas profits.

Sincerely,

Patrick S. Galvin
Commissioner

Alaska's Clear and Equitable Share (ACES)
Status Report
Alaska Department of Revenue
January 14, 2010

Introduction

In November 2007, the Alaska Legislature passed House Bill 2001, known as Alaska's Clear and Equitable Share (ACES). ACES made modifications to the prior production tax called the Petroleum Profits Tax (PPT), enacted in 2006. The changes made first with PPT and later with ACES represented substantial production tax reform in that the basis of the tax shifted from the *gross value* to the *net value* of oil and gas production. The gross tax which had been in place prior to the PPT is generally referred to as the Economic Limit Factor (ELF).

This report was prepared at the request of the Commissioner of Revenue in order to evaluate whether ACES is meeting its intended goals of providing a fair share of oil and gas revenue to the state, and encouraging investment in the exploration and development of new oil and gas resources in Alaska.

Following are the key findings of this report:

1) State revenues under ACES in FY 2009 exceeded amounts which would have been generated under either the PPT or ELF systems. The crossover point at which ACES is projected to provide more revenue than ELF is $51 per barrel west coast price in FY 2010.

2) Activation of the progressive surcharge is estimated to occur when west coast sales prices reach $56 per barrel.

3) Capital spending on the North Slope totaled over $2.2 billion in FY 2009 an increase over FY 2008. This is nearly the highest level of capital spending in nominal dollars since oil production began in the state.

4) The impact of the production tax modifications on industry investment cannot be clearly determined due to the influence of other factors and given the limited timeframe during which ACES has been in place.

5) Operating costs have risen since the enactment of PPT and ACES, but the impact of these cost increases to state tax revenues was moderated by the "standard deduction" provision of ACES, which expired December 31, 2009.

6) Increased reporting requirements, particularly of forward looking expenditure information, has greatly enhanced the accuracy of the Department's revenue forecasting efforts.

7) The Department has made significant progress in implementing ACES regulations, but there will be challenges to both the department and taxpayers as the regulations are implemented. Preliminary audits of taxpayers under the new profits-based system (formerly PPT) have begun, consistent with the normal audit timeframe.

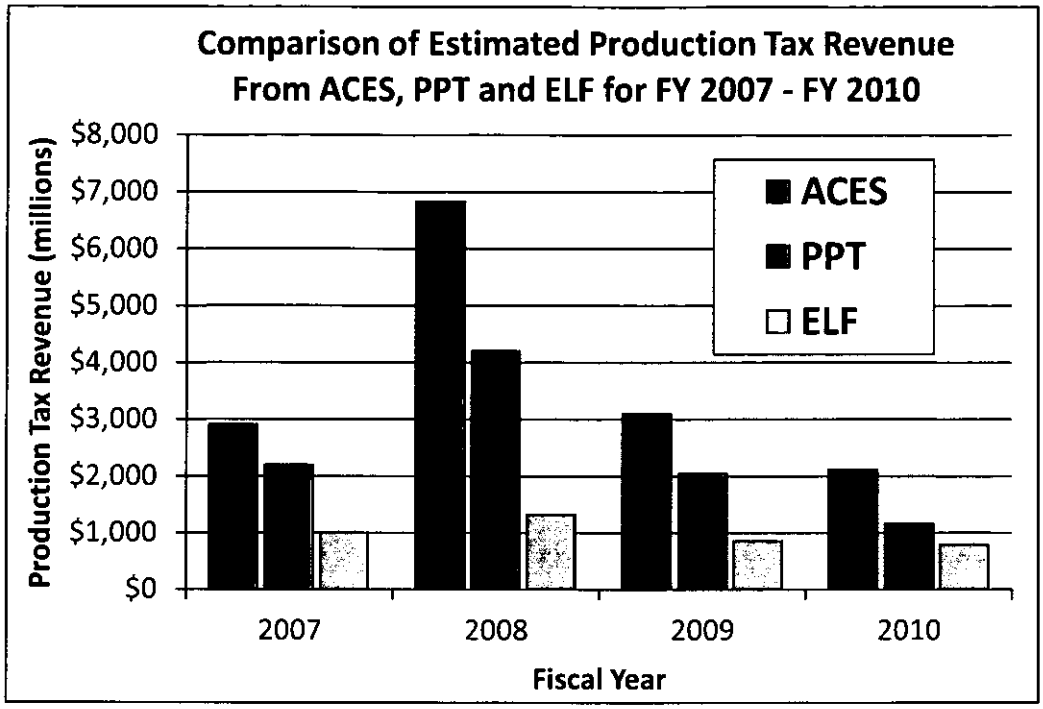
Comparison of Revenues under ACES, PPT and ELF

The net tax structure – first enacted under PPT (2006) and later with ACES (2007) – represents a significant change from the oil and gas tax structure used for much of Alaska's history. Under the earlier tax, known as the Economic Limit Factor (ELF), production tax was levied on oil and gas producing properties, regardless of whether operations were profitable. The current production tax structure requires companies to pay tax only when they are making profits from oil and gas production in the state. In addition, tax credits are provided for capital expenditures, with higher credits available for certain oil and gas exploration investments.

Since its enactment in 2007, ACES has generated more state revenue than would have been generated under either PPT or ELF. In FY 2008, a period of very high oil prices and profits, ACES generated $6.8 billion in production tax revenue, compared with $4.2 billion which would have been received under PPT and $1.3 billion which would have been received under ELF. In fiscal year 2009, during which west coast oil prices average $68.34, ACES generated just over $3.1 billion. This compares with roughly $2 billion that would have been generated under PPT and $858 million under the earlier ELF system.

Figure A compares revenue from ACES, PPT and ELF for FY 2007-2010. The FY 2009 revenues are preliminary. Estimates for FY 2010 are based on the Department's fall 2009 forecast of an average west coast oil price of $66.93 per barrel.

Figure A[1]



The progressive feature in ACES means that the state receives more production tax revenue when oil prices are high relative to underlying costs. Similarly, it significantly lessens the state's share of revenues when per-barrel margins decline. This effect was illustrated in 2008, when oil prices reached a high of $140 per barrel in July, bringing in $900 million in production tax for the month, and later plunged to below $30 per barrel in December, producing a total of $50 million in production tax for the month. Over the course of the full year, ANS crude oil averaged over $92 per barrel, resulting in five times more revenue than would have been realized under the ELF system.

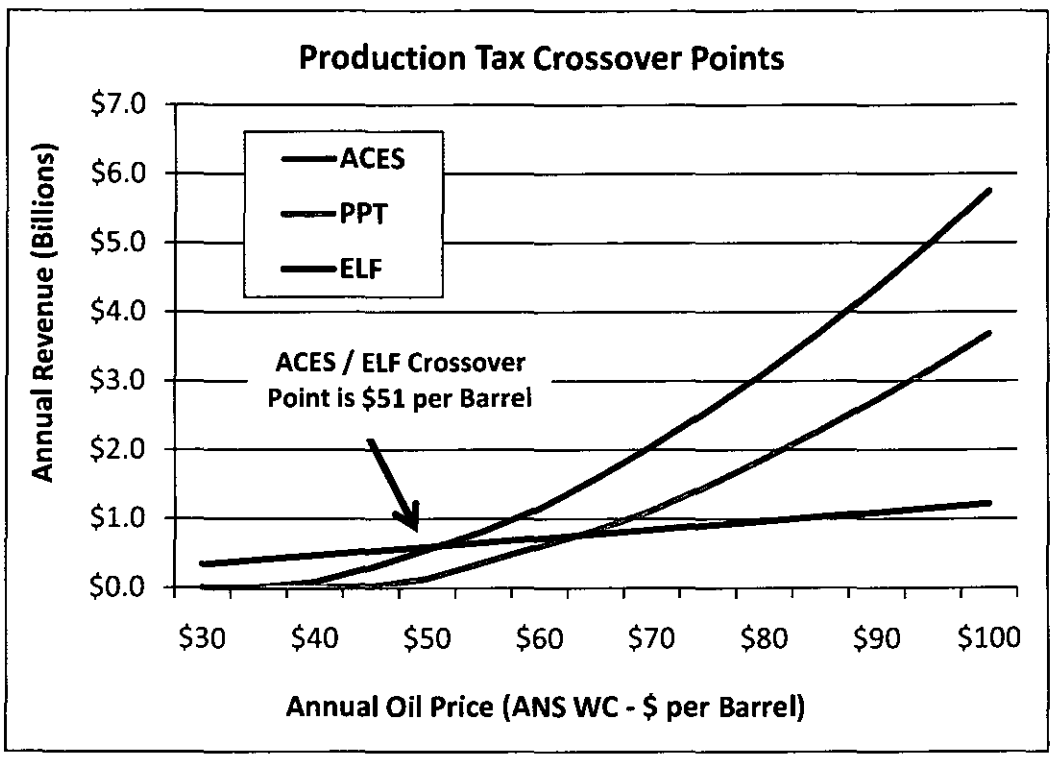
Figure B shows estimated revenues that would be received under ACES, ELF and PPT at various oil prices.[2] The oil price crossover point at which the state receives more revenue under ACES than the ELF system is roughly $51 per barrel. The crossover point has increased over prior

[1] Production tax revenue includes surcharges but does not include any settlements which go to the Constitutional Budget Reserve Fund. FY 2007 PPT revenue includes true-up payments for the period of April 2006 through December 2006. FY 2007 ACES revenue assumes similar true-up payments for comparison purposes. For FY 2007 - FY 2009, assumes actual data for oil price, production, costs and other variables. For FY 2010, assumes oil price, production, costs and other variables as of the fall 2009 forecast. Costs under PPT for FY 2010 for Prudhoe Bay and Kuparuk are based on aggregated company forecasts. For ACES only, assumes that standard deduction would apply for all of FY 2007-FY 2009 and first half of FY 2010. Actual tax revenue, as opposed to modeled revenue, is used for PPT in FY 2007 and ACES in FY 2008-FY 2009.

[2] This analysis assumes a constant oil price for the entire year, production of 655,000 barrels per day, deductible lease expenditures of $20 per barrel and transit costs of $6 per barrel.

years because lease expenditures, which are deductible under ACES, have increased since ACES was passed. It is expected that lease expenditures will decrease as costs decline in delayed response to the decline in oil prices from their 2008 levels.

Figure B[3]



Lease Expenditures

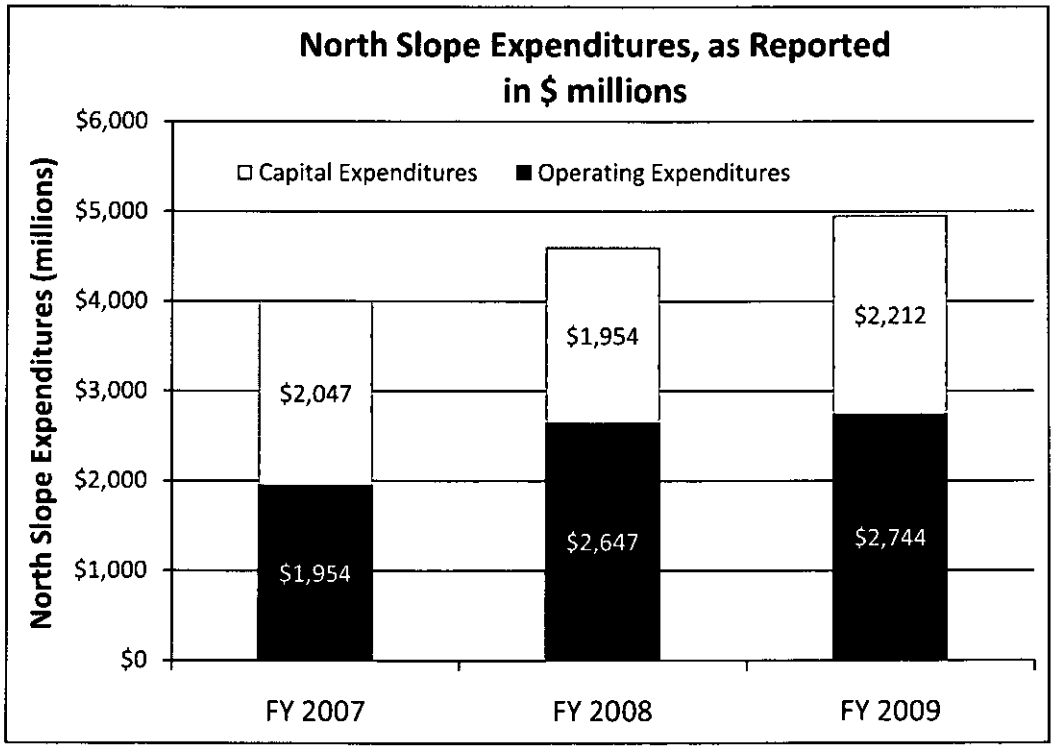
With the introduction of the net tax, it became necessary for the state to identify and forecast allowable lease expenditures for purposes of the tax calculation. Prior to the passage of PPT, the department had not been required to track or audit oil and gas production costs in Alaska. Some early cost data had been acquired directly from producing companies and through preliminary examination of federal tax returns. However, even during the debate over PPT, the state did not have access to comprehensive, Alaska-specific data that would enable policymakers to analyze the effects of the proposed tax over the life of a project. With much more information now being provided under the new tax structure, the department is developing a better understanding of oil and gas costs in Alaska, which will significantly benefit future policy deliberations.

[3] Assumes fixed operating and capital cost of $20 per barrel.

Lease expenditures fall into two general categories that constitute the major deductions under the ACES tax system. Operating expenditures are the costs to operate an oil or gas production facility on a day-to-day basis. These include labor, heat and light for the facilities, and some well work and minor equipment repairs. Capital expenditures are costs incurred to enhance or improve the reserve base, level of production, or facilities. Drilling is one of the most common forms of capital costs, as is facility construction or expansion.

Figure C shows the operating and capital expenditures, as reported on company tax returns and monthly reports, for their North Slope operations, from FY 2007 through FY 2009. Note that the graph represents all reported expenditures for all North Slope properties, regardless of whether or not they are subject to the "standard deduction" provisions of AS 43.55.165(j).

Figure C[4]



Operating Expenditures

Operating costs have risen significantly in recent years for the oil and gas industry worldwide. This has often been linked to the corresponding rise in oil prices beginning around 2002. Projects around the world that were once marginally economic have become viable, increasing the demand for limited supplies of engineering, procurement and construction services, as well

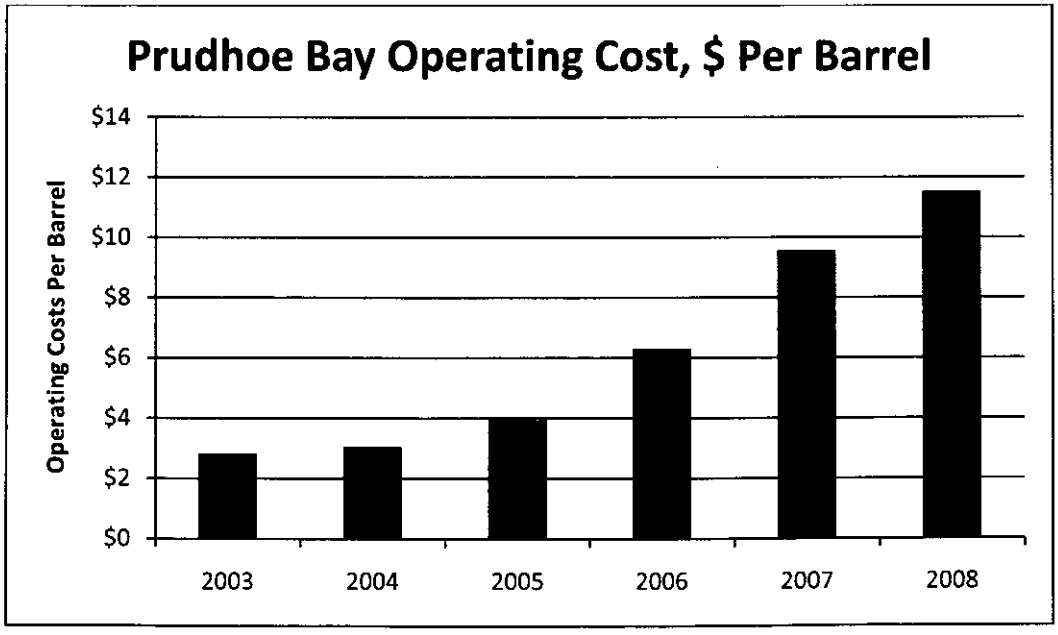
[4] Operating expenditures includes total reported costs, not standard deduction; FY 2007 estimated based on incomplete reporting

as raw materials. Cambridge Energy Research Associates (CERA) reports the upstream operating cost index rose for oil and gas field operations roughly 67% between 2002 and the end of 2008.[5] Meanwhile, the global capital cost index rose over 100% during the same period.[6]

Alaska-specific information obtained through public sources and shared in confidence during the Stranded Gas Development Act negotiations and through ACES reporting shows similar trends on the North Slope. Estimates of operating costs prior to PPT ranged from $3 to $5 per barrel. More recent information indicates that operating costs on the North Slope have doubled, and in some cases nearly tripled. Following the Prudhoe Bay corrosion incidents in 2006, operating expenditures on major repairs increased. However, since that time, the proportion of total operating expenditures directed to major repairs does not appear to have been a key driver in the growth of total operating expenditures.

Figure D shows the upward trend in per-barrel operating costs at Prudhoe Bay from 2003 to 2008. The chart shows a dramatic increase over the six-year period, consistent with cost increases seen in the oil and gas sector worldwide.

Figure D



The recent downturn of the global economy has started to push operating costs back down again. In June of 2009, CERA reported that worldwide, operating costs had declined 8 percent

[5] IHS CERA Upstream Operating Cost Index (UOCI), http://www.ihsindexes.com (Accessed December 11, 2009)
[6] IHS CERA Upstream Capital Cost Index (UOCI), http://www.ihsindexes.com (Accessed December 11, 2009)

over the previous 6 months.[7] The most recent information reported to the department under the new ACES requirements shows this trend to also be developing on the North Slope.

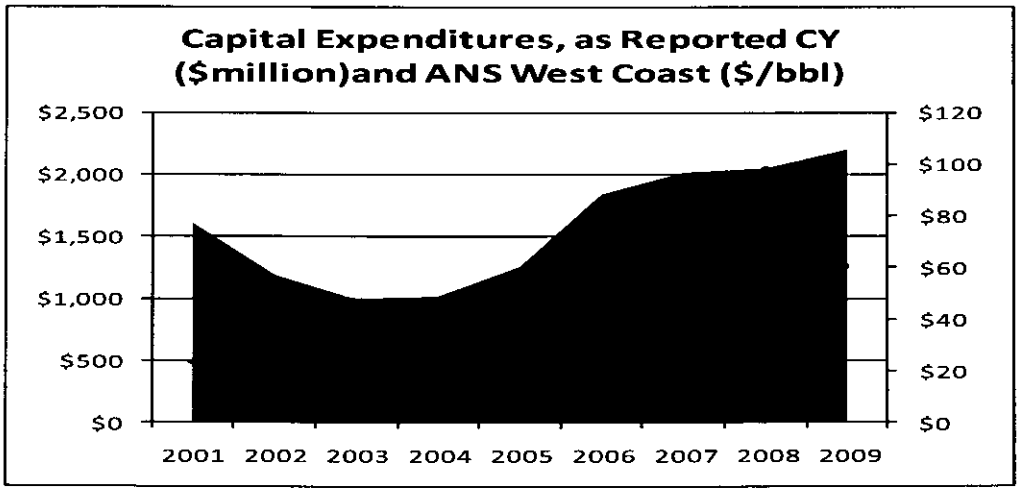
Much of this change can once again be linked to recent trends in oil prices. Lower oil prices led to a slackening of worldwide project activity, driving down the costs of transportation and various consumables. Despite this correlation, however, operating costs have not fallen at the same rate as oil prices. While the department anticipates that per-barrel operating costs will continue to decline under the lower oil price forecast for FY 2009 and FY 2010, they are expected to remain relatively high compared with those from five or more years ago.

Capital Expenditures

Capital expenditures have also increased since PPT and ACES were enacted. While capital expenditures on pipeline repairs at Prudhoe Bay increased after the Prudhoe Bay corrosion incidents in 2006, the majority of growth in capital expenditures is attributable to drilling, seismic and other projects. As shown below, capital spending on the North Slope in CY 2009 was roughly twice the level in either 2003 or 2004. At least some of this increase is due to new development activities. Two major developments – Oooguruk and Nikaitchuq – have gone forward despite recent oil price setbacks. Development of the Point Thomson field is also underway.

Figure E shows historical capital expenditures from CY 2001 to 2009 as reported by oil and gas producing companies operating on the North Slope.

Figure E



[7] IHS CERA: *"Period of Sustained Cost Escalation for Upstream Oil and Gas Facilities Comes to an End,"* June 5, 2009. http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10388 (Accessed December 11, 2009)

In order to forecast North Slope lease expenditures, the department receives forward looking spending projections from taxpayers, and also consults a variety of information sources, including unit forecasts, plans of development, and federal partnership returns. These data give the department significantly better insight into future development plans, as well as trends in operating and capital expenditures.

This information shows a variety of changes on the North Slope in the years ahead. There is continuing development of newer fields like Oooguruk, Nikaitchuq, and Point Thomson. Growth in capital expenditures at many major North Slope units (i.e. Prudhoe Bay, Kuparuk, Colville River and others) appear to slow slightly or decline in the next year or two and re-surge thereafter to the level of the recent past or higher. This trend is consistent with indicators of worldwide industry activity which show a dramatic drop in capital expenditures from the high levels experienced in 2008. This suggests that recent economic contraction may have caused some North Slope development projects to be delayed as producers hope to form a better idea of where the economy and oil prices may be headed.

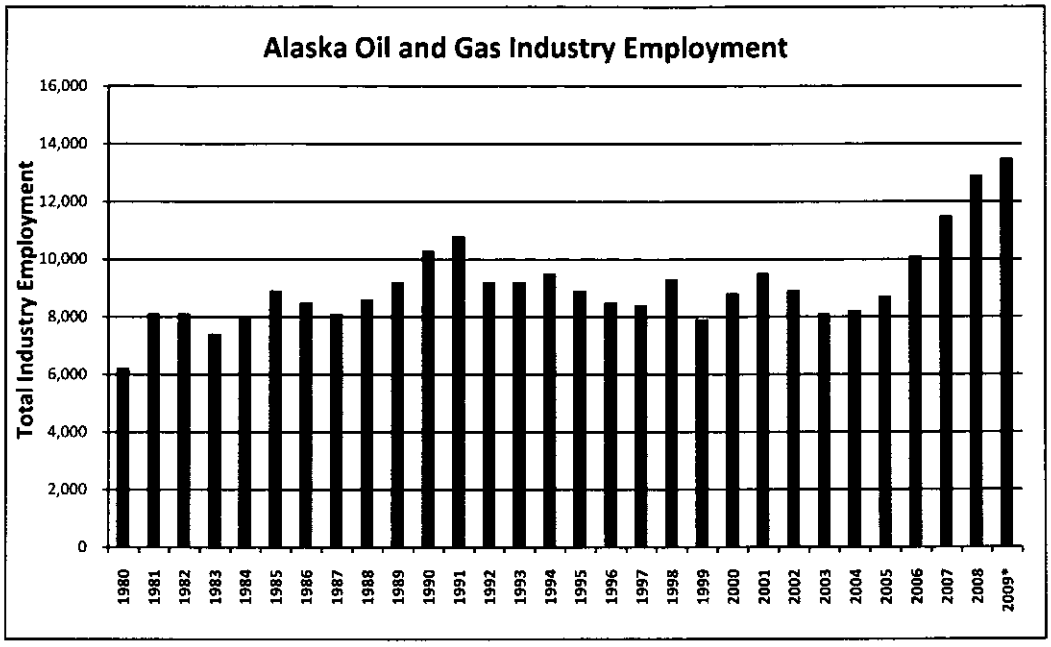
It would be presumptuous to solely attribute the rise in expenditures to the success of the investment incentives found in ACES. Many factors beyond tax policy drive oil and gas investment decisions. However, one of Alaska's new explorers, Savant Alaska, stated in a recent Petroleum News article that ACES had assisted in their development efforts at Badami. "ACES was an important component for Savant in considering investment in Alaska. It definitely had its intended consequence with us." [8]

Industry Employment

Employment in the industry has also increased steadily since the implementation of PPT and ACES, with 2009 forecast to be the highest in state history. It is important to note that this occurred concurrent with a steady rise in the oil prices, which has generally shown a strong correlation with industry activity.

[8] Kay Cashman quoting Savant's Chief Operating Officer Greg Vigil, "Savant Accelerates Badami Drilling Plan," *Petroleum News*, Volume 14, No. 3, January 18, 2009.

Figure F[9]



Flexibility of Tax Burden Evidenced

The increased revenues generated under ACES represent an increased tax burden on Alaska's oil and gas industry. However, there is evidence that ACES effectively adjusts that burden when oil prices drop and profit margins are squeezed. In 2009, a period of relatively low oil prices in comparison to recent years, 35 percent of ConocoPhillips total reported exploration and production profit in the first quarter of the year (Q1), 55 percent in Q2, and 36 percent in Q3, came from its Alaska operations, which only account for 12 percent of the company's worldwide production.[10]

ACES Structure and Tax Rate

The ACES tax consists of a base rate of 25% plus a progressive surcharge, which is triggered when a company's net profits — also known as "production tax value"— exceed $30 per barrel. Beyond this point, the base tax rate is increased by 0.4% for each additional $1 increase in per-barrel production tax value. Using current estimated transportation and production costs of roughly $26 per barrel, the surcharge would begin to be applied when west coast oil prices reach $56 per barrel. When the combined base rate and progressive surcharge reach 50%

[9] Data from Alaska Department of Labor and Workforce Development, Research and Analysis Section (January 11, 2010). Includes nonagricultural wage and salary data and excludes the self-employed. *Estimates for 2009 are preliminary.

[10] ConocoPhillips, Form 10-Q Quarterly Reports Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, March 31, 2009, June 30, 2009 and September 30, 2009.

(approximately $92.50 per-barrel profit or $118.50 West Coast price) the progressive surcharge is lessened to 0.1% for each additional $1 increase in per-barrel production tax value. The maximum nominal tax rate is 75%, which would apply at a profit rate of $342.50 per barrel or $368.50 West Coast price.

As with any tax, ACES may be evaluated using a variety of different metrics, including "effective," "nominal" and "marginal" tax rate comparisons. While each of these can be helpful under the appropriate circumstances, each is also subject to certain limitations. It is important when using these metrics to understand their relative value and how they reflect upon the objectives of the tax system.

The "effective tax rate" is the share of the total gross taxable value at the point of production that is paid in production taxes after credits are applied. It is a good universal measure of the sharing of total petroleum value that can be compared to gross value-based tax systems.

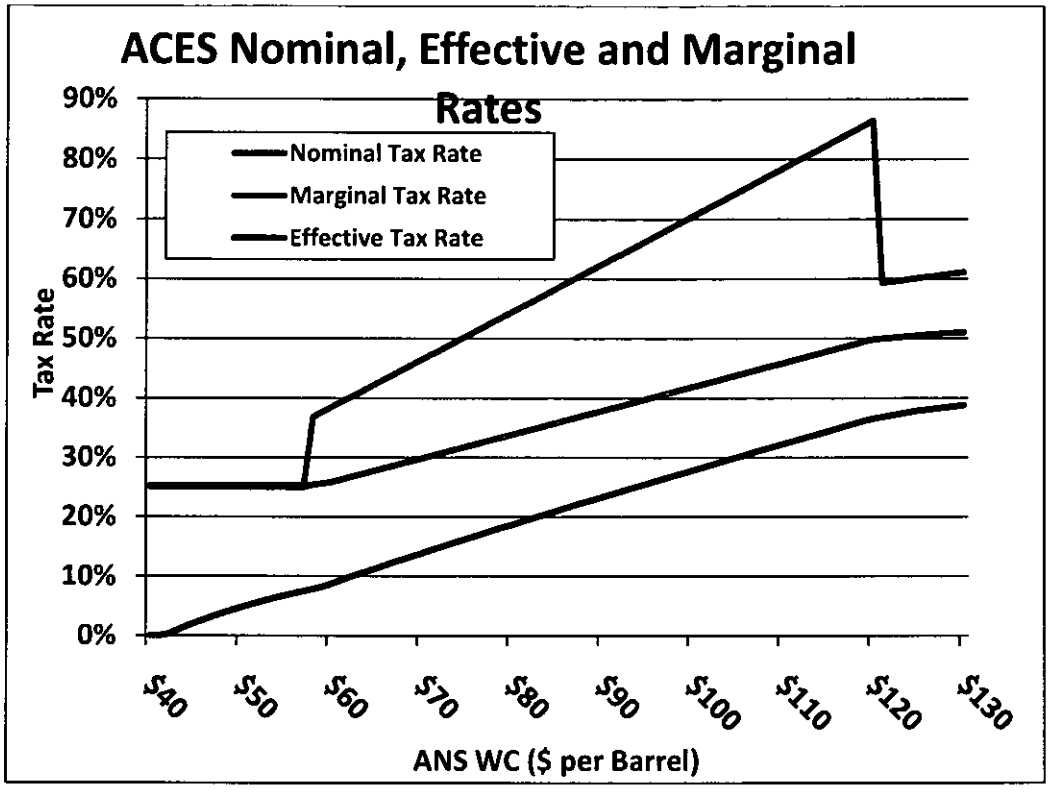
The "nominal tax rate" is the statutory tax rate as applied to the net value of oil and gas production. It does not account for credits or other tax benefits which ultimately impact a company's bottom line. Under ACES, the nominal tax rate varies with the per-barrel profitability. In addition to a base tax rate of 25%, ACES levies a progressive surcharge that can raise the combined nominal tax rate to 75% at extreme price levels.

The "marginal tax rate" is the rate theoretically applied to each dollar increase in oil price. In the case of ACES, the marginal tax rate is 25% until per barrel profit reaches $30 per barrel (about $56 per barrel in west coast spot price under the current cost structure), at which point it increases for every additional dollar up to a marginal tax rate of 87% when the profit reaches $92.50 per barrel (about $118.50 per barrel on the west coast). Following this peak, the marginal tax rate drops off significantly as the profit level continue to rise. With a net based tax system, this metric shows a company the impact of making additional investment, because each dollar they invest is "subsidized" by the government based on the amount of marginal tax they have avoided paying on that dollar.

Each of these metrics has their limitations when considered in isolation from other metrics, or when only one data point on the curve is presented. For example, a marginal tax rate of up to 87% initially sounds excessive. However, at that same price level, the effective tax rate (the tax burden) is less than 40%. The marginal rate of 87% actually represents the state's "portion" of any new investment made at such high prices.

Figure G shows the nominal, effective and marginal tax rates under ACES using a wide range of west coast spot prices.

Figure G



Production Tax Administration and Implementation

The passage of ACES presented significant challenges for tax administration and implementation because it involved comprehensive structural changes to the tax on the heels of the prior year's legislative changes through PPT. These challenges are experienced both on the taxpayer and on the state side.

Tax Credit Successes and Difficulties

The increased spending levels reported earlier in this document, may be due in part to the expansion of capital and exploration credits provided under ACES for reinvestment in the state. Credits can be applied against tax liabilities, sold to other companies or, for companies producing less than 50,000 boe/day, can be purchased by the state. Nearly $550 million in credits were claimed in FY 2009. Approximately $193 million was paid to oil and gas companies

to purchase oil and gas tax credits, while an additional $350 million in tax credits were used to offset tax liabilities.

Some administrative difficulties have arisen due to the requirement that the 20% capital credit be spread out over two years. It has taken a substantial amount of time and resources to develop a database with which the division can track the issuance and staged application of these credits for each taxpayer. This detailed tracking was made necessary by the transferability and use of the credits, and some confusion by taxpayers and their transferees regarding how the credits could be applied. In addition, the two-year spread in the application of the capital credits diminishes their value to taxpayers who look for quick return of their investment dollars. Finally, one of the reasons for the two-year spread in credits was to assist the department in forecasting future revenues. However, the department has found that the information provisions in ACES have been extremely valuable and successful in improving the volume and quality of spending projection data provided to the department by operators. This forward looking spending information has been much more valuable to the revenue forecasting process than the two-year spread in credits.

The Department has also received feedback regarding the reinvestment requirements for new explorers. Under current law, companies generally receive a financial benefit of over 45 percent of exploration expenditures incurred in the state. However, a new entrant to Alaska (with no production to immediately apply the credit against) can only get full value for their expenditures by applying to the state for cash payment for their credits earned. In order to receive such a payment, the company must continue to make expenditures in future years. Although this provision was originally created to support new explorers, it appears to be a limiting factor for companies that have fewer financial resources and are only considering a single exploration investment. In application, this requirement creates a "double standard" where new entrants to Alaska are provided less value for their credits compared to incumbent companies.

"Standard Deduction" provision at AS 43.55.165(j)

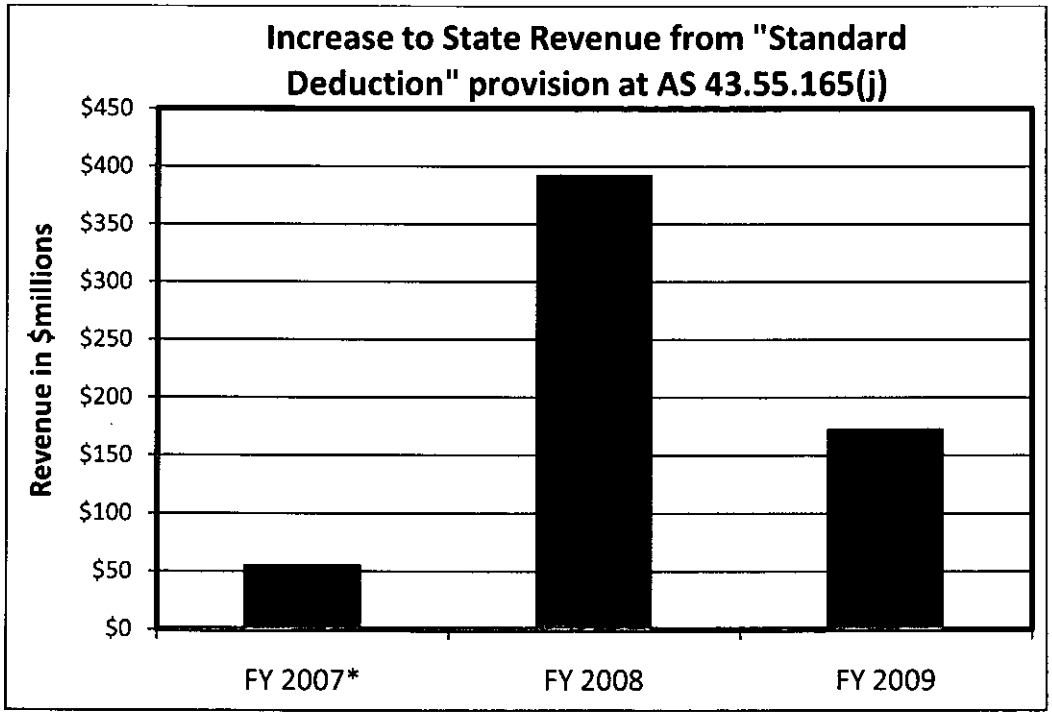
The ACES tax reform made modifications to the deductibility of operating expenditures for certain fields on the North Slope. Alaska Statute 43.55.165(j) limited the deduction of operating expenditures at leases or properties that have produced a cumulative 1 billion barrels of oil and NGLs since the lease or property began oil production. The Prudhoe Bay Unit and the Kuparuk River Unit are subject to these provisions based on their cumulative production. The provision, coined the "standard deduction," limits the deduction of operating expenditures to the amount deducted on the first PPT returns, filed April 1, 2007, for calendar year 2006 expenditures, adjusted annually. This provision, which was effective through December 31,

2009, was intended to moderate the risk associated with adopting a profits based tax without substantial historical data on which to rely for future cost estimates.

Based on company-reported expenditure data, the provision has resulted in a substantially greater tax liability to the state during the time it has been in place. The total liability in FY 2008 was substantially larger than the liability for FY 2009 due to the higher tax rate in FY2008 because of higher net profits realized due to high oil prices.

Figure H shows the increased revenue to the state from the standard deduction from FY 2007 through FY 2009.

Figure H[11]



Regulations

The ACES tax included new restrictions and guidance on allowable lease expenditures, requiring complex regulations. The department has actively sought industry input on the structure of the regulations to ensure they continue to achieve their intended purposes, while avoiding undue burdens for either side. The process has included numerous public workshops pertaining to credit regulation, conforming regulatory changes required by ACES, lease expenditures, facility sharing costs and transportation costs. As a result, the regulation drafting process has been

[11] *Standard Deduction was only in place for half of FY 2007.

lengthy and complex. However, the regulations to define allowable lease expenditures are expected to be finalized this month.

Under the statute the regulations are retroactive to various 2007 dates. To the extent additional taxes are due, taxpayers would be required to pay interest on what would now be late tax payments. The department has discretion to waive any penalties for late payments. However, a statutory change would be needed in order for the department to provide a waiver from interest payments.

Reporting and Revenue Forecasting

ACES requires that companies exploring for or producing oil and gas in the state submit a monthly information report to the department. This report includes estimated data on production volumes, the value of the production, and the operating and capital expenditures related to production. The monthly report is used primarily by state economists to monitor company production and spending. Included with the monthly report is an estimate of taxes owed and credits earned. Twice annually, companies are asked to provide the department with forward-looking expenditure information, along with future production plans to aid the department in providing the legislature with state revenue forecasts.

These reports, in combination with the monthly information reports and the annual tax returns, have significantly enhanced the quality of the department's revenue forecasts.

Audit Compliance

The ACES legislation extended from three to six years, the period in which the department is required to assess production taxes owed. The extension was seen as necessary to assure proper tax assessments, particularly given the complexity of overlapping ELF, PPT and ACES tax laws. The new tax law also included funding for four new "Audit Masters" within the department. The department is still experiencing significant difficulties recruiting and filling audit positions. The department has successfully recruited three Audit Masters, and these individuals have been placed within sections of the Tax Division to assist with implementation and administration of the tax. The recruitment of the fourth Audit Master, and Oil and Gas Revenue Auditors is ongoing.

During 2008, the department's auditors began auditing tax returns that were submitted for calendar year 2006 under the PPT program.

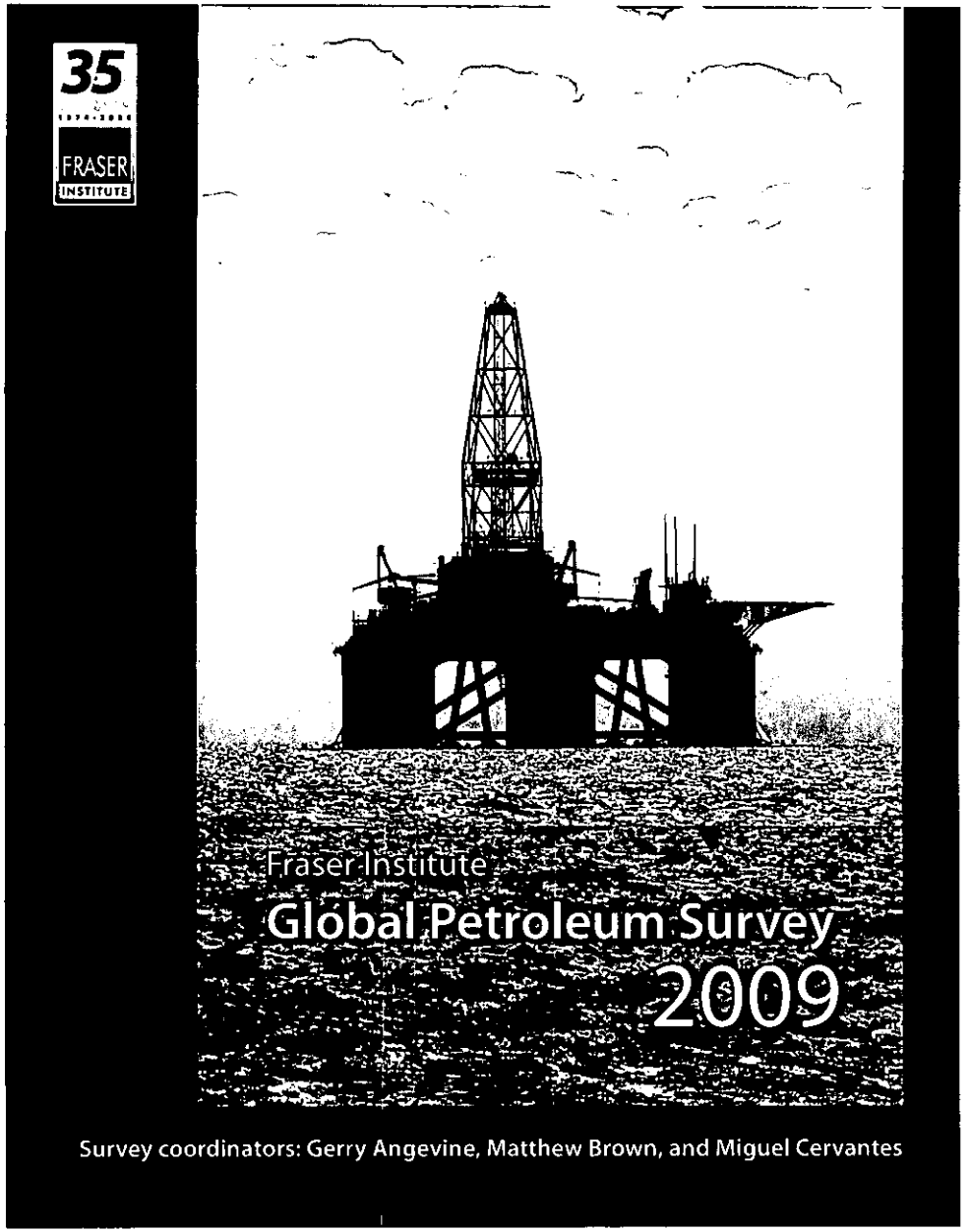
Conclusion

The ACES production tax has been effective in allowing the state to share in the benefits of high oil profitability. It has also responded well to lower oil prices by reducing state tax burden on Alaska's oil and gas producers. Over $2 billion in new capital investment was reported in fiscal year 2009 reaching near-record levels. While these and other indicators suggest that the profits-based tax system has supported North Slope exploration and development, it would be misleading to suggest that ACES alone influences the level of investment. While tax is recognized as being an important factor in investment decisions, it is not the primary determinant. Long-term price forecasts, as well as the resources themselves, have proven to be much more significant drivers of industry activity.

The department is continuing to analyze ACES to identify opportunities to improve the tax framework in order to support additional exploration and development in the state, while not harming the state's revenue base.

The new reporting requirements under ACES are helping the department develop a better understanding of industry expenditures and activity, and have assisted in the state's revenue forecasting efforts. Development of new tax regulations is progressing, though several challenges remain for both the state and taxpayers. Numerous workshops have been held to solicit industry input and these will continue as the department continues to work through outstanding issues. In 2008, the production tax audit group began auditing taxpayers who submitted annual returns for CY 2006 under PPT.

Overall, the information reviewed by the department indicates that ACES is performing as expected when it was passed by the Legislature in 2007. The economic provisions are resulting in the revenue levels anticipated, and the investment incentives appear to distribute the increased tax burden in a fashion that continues to encourage reinvestment, though the experience with the credit program could be improved for new explorers. Challenges remain in the implementation by the department, but they are manageable and the department is positioned to meet those challenges.



Acknowledgements

First and foremost, we wish to thank the many managers and senior officers of petroleum exploration companies and associated firms who submitted survey responses, thereby providing the data for the analyses in this report. We also appreciate the assistance of numerous Canadian trade commissioners overseas who identified petroleum industry contacts in their host countries.

Thanks also are due to the Australian Petroleum Producers and Explorers Association for identifying key companies and providing contact information to ensure ample representation from "down under." We are very grateful to the following groups, among others, for bringing the survey to the attention of their members: the South Australian Chamber of Mines and Energy; the Instituto Argentina del Petroleo y del Gas; the Canadian Association of Petroleum Producers; the Colorado Oil and Gas Association; the Independent Petroleum Association of America; and the Small Explorers and Producers Association of Canada.

Special thanks are due to Diane Katz, the Fraser Institute's Director of Risk, Environment, and Energy Policy, for her insightful editing of this report; to Kristin McCahon for managing its publication; and to Bill Ray for developing the world and regional maps.

Any errors or omissions are the sole responsibility of the authors. As they worked independently, opinions expressed by the authors are their own and do not necessarily reflect the opinions of supporters, trustees, or other staff of the Fraser Institute.

Date of issue

June 2009

Editing, design, and production

Kristin McCahon

Cover artwork

Design by Bill Ray. Image copyright © Elnur, Fotolia

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Survey Information

The 2009 Fraser Institute Global Petroleum Survey was distributed to managers and executives of petroleum exploration and production companies around the world and to firms that provide support services to such companies.

The analyses contained in this report are based on information obtained from 577 respondents representing 276 companies. The exploration and development budgets of these participating companies totaled about $200 billion in 2008. That represents more than 50 percent of global upstream expenditures last year, according to the *World Energy Outlook* 2008 (International Energy Agency, 2008).

Executive Summary

This report presents the results of the Fraser Institute's 3rd annual survey of petroleum industry executives and managers regarding barriers to investment in oil and gas exploration and production in various jurisdictions around the world. The survey responses have been tallied to rank provinces, states, and countries by the severity of investment barriers such as high tax rates, costly regulatory schemes, and security threats, among other factors.

A total of 577 respondents completed the survey questionnaire this year, providing sufficient data to evaluate 143 jurisdictions. This is a substantial increase from the 2008 survey, in which 81 jurisdictions were rated, and the 2007 survey, in which 54 jurisdictions were rated.

The jurisdictions have been assigned scores for each of 16 factors that affect investment decisions. The scores are based on the proportion of negative responses a jurisdiction received; the greater the proportion of negative responses, the greater the perceived investment barriers and, therefore, the lower the jurisdiction's ranking.

This year for the first time, the six Australian states, Australia's Northern Territory, and the Timor Gap were each evaluated as individual jurisdictions.

An All-Inclusive Composite Index derived from the scores of all 16 factors provides an overall assessment of each jurisdiction. On this basis, the 10 least attractive jurisdictions for investment are Bolivia, Niger, Venezuela, Ecuador, Sudan, Russia, Bangladesh, Nigeria, Kazakhstan, and Ethiopia.

Jurisdictions within North America, Europe, Australia, and New Zealand generally received the best rankings overall. The 10 most attractive jurisdictions for investment, based on the All-Inclusive Composite Index, are Arkansas, Alabama, Kansas, Austria, Mississippi, Nebraska, South Dakota, Texas, Oklahoma, and Indiana.

Nine of the top 10 jurisdictions on this year's All Inclusive Composite Index are US states. Of these, top-ranked Arkansas and second-ranked Alabama were also among the top three jurisdictions in 2008. Saskatchewan, the only Canadian jurisdiction among the top 10 last year, fell to 38th (of 143) this year.

Among jurisdictions experiencing the greatest drops on the All Inclusive Composite Index are Bangladesh, Cote d'Ivoire, Myanmar, and Libya. In Europe, both Spain and Italy lost considerable ground in the rankings, as did the Ukraine, which continues to be regarded as among the least attractive jurisdictions for investment. Canada's Yukon and Northwest Territories also slipped in the rankings and, along with the third territory, Nunavut, which was rated for the first time this year, stand out as the least attractive regions in North America for investment in exploration and development.

Comments received from respondents highlight why some jurisdictions are considered attractive for investment and others not. Investors say they turn to different jurisdictions when confronted with high royalty fees and tax rates, inadequate infrastructure, price controls, and labor shortages. Similarly, investors prefer to avoid jurisdictions with costly and time-consuming regulations. Other factors being equal, competitive tax and regulatory regimes can attract investment and thus generate substantial economic benefits.

Survey Methodology

Sample design

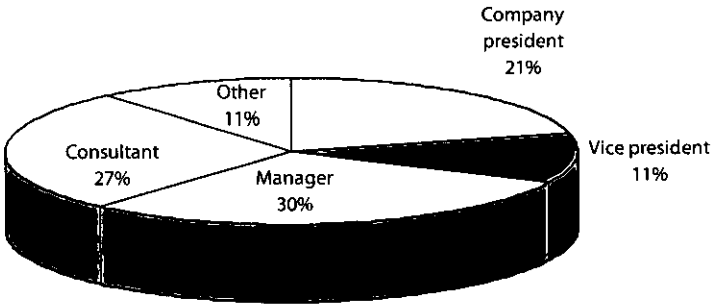
This survey was designed to identify the provinces, states, and countries with the highest barriers to investment in oil and gas exploration and production. This allows jurisdictions ranked poorly by investors to consider reforms that would improve the investment environment. Petroleum companies use the information to corroborate their own assessments and to identify jurisdictions where new investment may be attractive.

The survey was distributed to managers and executives in the "upstream" petroleum industry. This includes exploration for oil and gas reserves, and the production of crude oil, bitumen, and both conventional and non-conventional forms of natural gas. It does not include the refining and processing of crude oil and raw natural gas, or the transportation and marketing of petroleum products.

The names of potential respondents were chosen from publicly available membership lists of trade associations. Canadian trade commissioners abroad also provided the names of some companies and individuals in their host countries. In addition, some industry associations provided contact information for individuals with member companies.

The survey was administered from February 2, 2009 to April 17, 2009. A total of 577 responses were received from individuals representing 276 companies. About two-thirds of the respondents identified themselves as either a manager or holding a higher-level position. The companies represented in the survey account for more than 50% of the industry's annual spending on petroleum exploration and production (International Energy Agency, 2008).

Figure 1: The Position Survey Respondents Hold in Their Company, 2009



Survey questionnaire

The survey was designed to capture the opinions of managers and executives regarding the level of investment barriers in jurisdictions with which their companies were familiar. Respondents were asked to rate how the 16 factors listed below influence company decisions to invest in various jurisdictions.

1. Fiscal Terms—government requirements pertaining to royalty payments, production shares, and licensing fees.
2. Taxation Regime—the tax burden (other than for oil production, which is reflected under Fiscal Terms), including personal, corporate, payroll, and capital taxes.
3. Local Natural Gas Prices—whether regulated rates for natural gas are set too low to recoup exploration and production costs.
4. Cost of Regulatory Compliance—the costs of processing permit applications, participating in hearings, etc.
5. Regulatory Uncertainty—the extent to which the regulatory environment is unstable, i.e., whether there are frequent, unexpected, or unjustified changes in rules and requirements.
6. Environmental Regulations—the costs of complying with regulatory requirements on exploration and production processes and facilities.
7. Local Processing Requirements—the extent to which a jurisdiction requires oil and gas that is extracted locally also to be processed locally.
8. Trade Regulations—the ability of producers to gain access to markets through the export of crude oil, natural gas, and refined petroleum products.
9. Labour Regulations and Employment Agreements—the degree of flexibility employers may exercise in hiring and firing, compensation, and work rules.
10. Local Public Infrastructure—the availability and quality of schools and colleges, hospitals, and recreation facilities.
11. Business Infrastructure—the adequacy of roads, railways, and airports.
12. Geological Database—the availability of credible and complete data on area geology.
13. Labor Availability—the supply and quality of labor, and the willingness of foreign workers to relocate to the region.
14. Aboriginal Land Claims—the uncertainty of unresolved claims by native groups, which can interfere with land access and transportation rights-of-way.
15. Political Stability—the frequency of changes in policies, regulations, and elected officials.
16. Security—the safety of assets and personnel, and the risk of expropriation.

For each of the 16 factors, respondents were asked to select one of the following five responses that best described each jurisdiction they were familiar with:

1. Encourages investment
2. Is not a deterrent to investment
3. Is a mild deterrent to investment
4. Is a strong deterrent to investment
5. Would not invest due to this criterion

The survey included a list of 162 jurisdictions that respondents could evaluate, including most Canadian provinces and territories, many US states (and the Atlantic, Pacific, Alaska, and Gulf Coast offshore regions), all 6 Australian states and 1 territory, the Timor Gap, and countries with current or potential petroleum production capacity. Mexico and other countries where investment in upstream petroleum exploration and development is mostly confined to government-owned facilities were excluded.

Scoring the survey responses

For each jurisdiction, we calculated the percentage of negative scores for each of the 16 factors.[1] We then developed an index for each factor by assigning the jurisdiction with the highest percentage of negative responses a score of 100, and correspondingly lower scores to the other jurisdictions according to their ratings. The jurisdictions with the lowest scores are considered the most attractive by the upstream investors and thus rank better than jurisdictions with higher, more negative scores.

Only jurisdictions evaluated on all 16 factors by an average of five respondents are included in the rankings, and no jurisdictions are included for which fewer than three responses were received for any of the 16 factors. This resulted in the ranking of 143 jurisdictions with a median of 19 responses each.

In addition to rankings for each of the 16 factors, jurisdictions are ranked on four composite indices, as follows.

All-Inclusive Composite Index

The All-Inclusive Composite Index is derived equally from the scores earned by jurisdictions on all 16 factors. This index is the most comprehensive measure of the investment barriers within each jurisdiction. A large index value indicates that investors consider a jurisdiction relatively unattractive for investment.

1 The negative scores were determined by the number of times respondents graded a factor as "a mild deterrent to investment" or as a "strong deterrent to investment," or indicated that they "would not invest" in the jurisdiction because of issues summarized under that factor heading. This year, the scoring methodology was changed to include the "mild deterrent to investment" response in order to differentiate among jurisdictions for which the number of stronger negative responses was negligible or constituted only a small portion of the total number of responses received.

Commercial Environment Index

The Commercial Environment Index ranks jurisdictions on five factors affecting the costs of conducting business and the net revenue potential:

- Fiscal terms
- Taxation regime
- Local price of natural gas
- Local business infrastructure
- Labor availability

The index ranking was calculated by averaging the negative scores for each of these five factors. A large index value indicates that industry managers and executives consider that commercial conditions constitute significant barriers to investment.

Regulatory Climate Index

The Regulatory Climate Index reflects the scores assigned to jurisdictions for the following six factors:

- The cost of regulatory compliance
- Regulatory uncertainty
- Environmental regulations
- Local processing requirements
- Trade regulations
- Labor regulations and employment agreements

A relatively high Regulatory Climate Index value indicates that regulations, requirements, and agreements in a jurisdiction constitute a considerable barrier to investment, resulting in a relatively poor ranking.

Geopolitical Risk Index

The Geopolitical Risk Index represents the scores earned by jurisdictions for political stability and security. These two factors are considered to be more difficult to overcome than either regulatory or commercial barriers because political change typically is necessary before significant progress can be made. A high score on the Geopolitical Risk Index indicates that investment is relatively unattractive in that jurisdiction because of political instability and/or security problems such as crime, confiscation and use of company equipment and vehicles, and the threat of expropriation.

Global Results

All-Inclusive Composite Index

Table 1 compares the 2009 and 2008 scores and rankings of the All-Inclusive Composite Index. The first and second columns present the 2009 and 2008 rankings respectively. The third and fourth columns present the absolute scores for each jurisdiction in 2009 and 2008, based on the percentage of negative responses for each of the 16 factors in the survey. Those at the top of the list are regarded as having relatively few investment barriers and, therefore, as being attractive for investment.

The marked increase in the number of jurisdictions ranked this year represents greater survey participation by upstream investors with knowledge about overseas jurisdictions, especially in the Pacific Rim, Africa, and Europe, as well as a number of US states, and federally administered offshore regions.

The 10 jurisdictions with the largest percentage of negative responses, indicating the greatest barriers to investment, are:

1. Bolivia
2. Niger
3. Venezuela
4. Ecuador
5. Sudan
6. Russia
7. Bangladesh
8. Nigeria
9. Kazakhstan
10. Ethiopia

Apart from Ethiopia and Niger, which were not ranked in 2008, and Bangladesh, which fell from 45th (of 81) in 2008 to 137th (of 143) this year, the jurisdictions in this group were also among the 10 worst in last year's survey.

Bangladesh appears to have fallen from investors' favor largely as a result of fiscal terms, taxation, and the local price of natural gas. The security of production facilities and equipment has also become more problematic there.

In 2008, we noted some deterioration in the relative attractiveness for investment of Colorado, Alaska, and Alberta compared with 2007. The unfavorable ratings for Alberta and Alaska stemmed from increasingly costly fiscal terms and tax rates. Colorado's ranking suffered because of the stringency of its proposed environmental regulations for oil and gas explorers. As table 1 indicates, these factors have continued to affect the jurisdictional rankings.

Table 1: Jurisdictional Rankings According to the Extent of Investment Barriers (based on All-Inclusive Composite Index values)

Jurisdiction	2009 Rank in Group of 143	2008 Rank in Group of 81	2009 Score	2008 Score
US—Arkansas	1	3	6.73	10.08
US—Alabama	2	1	8.88	8.17
US—Kansas	3	16	8.93	20.48
Austria	4	NA	9.81	NA
US—Mississippi	5	27	9.88	26.77
US—Nebraska	6	NA	10.62	NA
US—South Dakota	7	NA	10.90	NA
US—Texas	8	8	10.97	16.24
US—Oklahoma	9	7	11.30	15.18
US—Indiana	10	NA	12.46	NA
US—Nevada	11	NA	13.70	NA
US—Illinois	12	NA	15.26	NA
US—Utah	13	49	15.45	36.35
US Offshore—Gulf of Mexico	14	NA	15.96	NA
US—Louisiana	15	35	16.18	31.34
US—Wyoming	16	24	17.35	23.82
AU—South Australia	17	NA	18.73	NA
Netherlands—North Sea	18	NA	19.16	NA
Namibia	19	NA	19.80	NA
Tunisia	20	66	20.42	48.29
CA—Manitoba	21	17	20.98	20.49
US—Michigan	22	32	21.00	29.52
Chile	23	25	21.46	24.68
Bahrain	24	NA	21.62	NA
Netherlands	25	29	21.63	26.89
US—Kentucky	26	NA	21.66	NA
Ireland	27	NA	21.88	NA
US—North Dakota	28	19	22.37	21.23
US—New York	29	6	22.73	13.37
New Zealand	30	51	23.19	37.79
US—Virginia	31	NA	23.25	NA
AU—Northern Territory	32	NA	23.46	NA
US Offshore—Pacific	33	NA	23.55	NA
Croatia	34	NA	23.59	NA
Qatar	35	9	23.90	17.46
US—Ohio	36	18	24.06	20.69
Norway—North Sea	37	11	24.81	19.28

Table 1: Jurisdictional Rankings According to the Extent of Investment Barriers (based on All-Inclusive Composite Index values)

Jurisdiction	2009 Rank in Group of 143	2008 Rank in Group of 81	2009 Score	2008 Score
CA—Saskatchewan	38	10	25.02	18.89
United Kingdom—North Sea	39	12	25.02	19.66
Denmark	40	4	25.53	10.89
US—Montana	41	59	25.74	41.75
Taiwan	42	NA	26.16	NA
US—New Mexico	43	23	26.75	23.72
AU—Tasmania	44	NA	27.13	NA
United Kingdom	45	22	27.87	23.52
Norway	46	20	28.28	21.59
United Arab Emirates	47	5	28.29	12.84
France	48	38	28.61	32.68
AU—Queensland	49	NA	28.80	NA
Germany	50	28	28.90	26.78
US—Pennsylvania	51	55	29.56	40.46
Oman	52	NA	29.78	NA
US Offshore—Atlantic	53	NA	29.78	NA
CA—Nova Scotia	54	40	30.37	34.23
Brunei	55	NA	31.15	NA
AU—Western Australia	56	NA	31.25	NA
AU—Victoria	57	NA	31.52	NA
US—West Virginia	58	57	32.34	40.86
Trinidad and Tobago	59	58	32.81	41.06
CA—Ontario	60	30	33.30	29.12
Morocco	61	NA	33.49	NA
AU—New South Wales	62	NA	33.77	NA
Timor Gap	63	NA	34.82	NA
Thailand	64	48	35.77	36.34
Romania	65	43	36.09	35.70
Colombia	66	52	36.16	37.82
Uruguay	67	NA	36.26	NA
CA—Quebec	68	NA	36.89	NA
Egypt	69	26	37.15	25.06
Serbia	70	NA	37.57	NA
CA—British Columbia	71	33	37.66	29.86
US Offshore—Alaska	72	NA	37.92	NA
Ghana	73	NA	37.95	NA
Japan	74	NA	38.53	NA

Table 1: Jurisdictional Rankings According to the Extent of Investment Barriers (based on All-Inclusive Composite Index values)

Jurisdiction	2009 Rank in Group of 143	2008 Rank in Group of 81	2009 Score	2008 Score
Malaysia	75	44	39.06	35.84
Costa Rica	76	NA	39.12	NA
Kuwait	77	42	39.71	35.48
US—Alaska	78	46	39.75	36.31
US—California	79	74	40.13	58.39
Mozambique	80	NA	40.32	NA
US—Colorado	81	61	40.42	42.35
CA—Newfoundland and Labrador	82	63	40.87	46.04
Greenland	83	NA	41.44	NA
Bulgaria	84	NA	41.54	NA
Albania	85	NA	42.90	NA
Azerbaijan	86	37	43.91	32.44
Jordan	87	NA	44.56	NA
China	88	36	44.86	32.42
Brazil	89	64	45.43	46.51
Philippines	90	NA	45.65	NA
Hungary	91	NA	46.62	NA
CA—Alberta	92	54	47.46	38.78
Poland	93	NA	47.53	NA
Papua New Guinea	94	NA	48.29	NA
Gabon	95	NA	48.74	NA
Tanzania	96	NA	49.09	NA
Guatemala	97	NA	49.69	NA
Spain	98	15	50.04	20.30
South Africa	99	NA	50.36	NA
Yemen	100	69	51.46	51.74
Turkey	101	NA	51.57	NA
Peru	102	77	51.60	60.83
Italy	103	34	52.83	30.72
Vietnam	104	NA	53.95	NA
CA—Yukon	105	31	54.05	29.12
Greece	106	NA	54.26	NA
India	107	NA	54.71	NA
Cameroon	108	NA	55.27	NA
Syria	109	NA	56.27	NA
Uzbekistan	110	56	56.91	40.52
Suriname	111	NA	57.52	NA

Table 1: Jurisdictional Rankings According to the Extent of Investment Barriers (based on All-Inclusive Composite Index values)

Jurisdiction	2009 Rank in Group of 143	2008 Rank in Group of 81	2009 Score	2008 Score
Angola	112	39	58.72	33.38
Libya	113	14	58.95	20.30
Indonesia	114	67	59.66	48.98
Turkmenistan	115	60	60.57	41.82
Republic of Congo (Brazzaville)	116	NA	61.04	NA
Kyrgyzstan	117	NA	61.04	NA
Algeria	118	62	61.83	42.98
Pakistan	119	53	62.77	38.21
CA—Northwest Territories	120	65	62.84	47.18
CA—Nunavut	121	NA	63.51	NA
Paraguay	122	NA	63.95	NA
Cambodia	123	NA	64.08	NA
Equatorial Guinea	124	NA	65.15	NA
Guyana	125	NA	65.99	NA
Ukraine	126	50	69.16	37.67
Iran	127	NA	69.29	NA
Cote d'Ivoire	128	41	69.76	35.29
Iraq	129	68	70.09	49.09
Democratic Rep. of Congo (Kinshasa)	130	NA	70.68	NA
Argentina	131	76	71.51	59.35
Chad	132	70	73.46	54.51
Myanmar	133	NA	73.60	NA
Ethiopia	134	NA	74.24	NA
Kazakhstan	135	72	74.43	57.42
Nigeria	136	73	74.85	57.43
Bangladesh	137	45	74.99	36.09
Russia	138	78	78.69	62.33
Sudan	139	75	82.64	58.60
Ecuador	140	81	87.80	100.00
Venezuela	141	79	91.86	88.58
Niger	142	NA	99.03	NA
Bolivia	143	80	100.00	97.28
US—Arizona	NA	2	NA	8.66
US—Offshore*	NA	13	NA	20.09
Australia*	NA	21	NA	22.20
Afghanistan	NA	47	NA	36.34
US—Florida	NA	71	NA	56.91

*Not available in 2009 because the jurisdictions were broken down into more detailed states, territories, and districts.

FINAL

Thank you,

This is my first opportunity to speak at the Meet Alaska, it's a real honor. I'm going to talk about things close to home, to build on the global views we've heard today.

Continuous improvement is very important to BP. It's not a catch phrase or a slogan, but an attitude about how we do our business. It means that we want to be better today than we were yesterday. And better tomorrow than we are today.

In town hall meetings with our Alaska employees, I talk about **BP's 50-year Alaska strategy as a dream – not a promise.**

We've go a lot to do, but there is a lot to play for. The BP resource base in Alaska is greater than 5 billion BOE– but it is challenged.

The barrels are challenged: challenged by markets, challenged by technology and challenged by the cost of doing business.

Our strategy is focused on:

- Safe, Reliable and Efficient Operations
- Building a stable and viable base business at $50/bbl oil price
- And growing the business through unlocking the vast heavy oil and natural gas resources in our portfolio.

Nothing has changed in our strategy – but the business environment has changed, so our tactics have changed.

Factors like our medium term and long term outlook on oil price, costs and productivity, technology, technical risk, and the federal and state fiscal and policy regimes.

To achieve our 50-year dream we need to:

- continuously improve our performance in safety,
- protect the environment,
- deliver a business that is viable today, fit for tomorrow.

And delivers competitive investment options that sustain the business well into the future.

And when I say we, I don't simply mean BP. "We" includes: the industry, our contractors, the state and all Alaskans.

Together, we are facing more challenges than we did a few years ago. I want to touch on safety first. We have made progress – but we are not finished.

BP can't do it without you – safety starts with the people in this room. Our contractors, employees, and everyone who does business in the Alaska oil patch.

Of the 20 million man-hours worked last year, 80 percent were contractor man-hours. I need your help to ensure all the work on the Slope is conducted safely.

We all need to learn from companies like Little Red Services that had zero recordable incidents last year.

Or, facilities like Endicott that earned a three-year re-certification of its VPP Star status under the US OSHA Voluntary Protection Program. It was the first facility in Alaska to be certified by the OSHA program.

We need to learn from the people who made these success stories happen. That's what continuous improvement is all about.

For the contractors in the room, I think it's clear that the way to earn business with BP is to demonstrate you can work safely and efficiently.

The foundation of our strategy rests on a healthy light oil business. And a healthy light oil business is critical to a sustainable oil business in Alaska.

The light oil business has suffered the last few years due to declining production and rising costs.

Costs have risen through significant inflation and increased government take. Our cash break-even point is significantly higher today than it was 5 years ago – and is a threat to our future.

This is hard for people to understand, we remember when the price of oil was very low – $10, so what's changed?

Over the last 5 years, oil and gas industry costs have increased at a rate of four times the price of oil. [1] Meanwhile, North Slope oil production has declined about 29 percent.

Rising cost, reduced outputs and a lower commodity price; this is not a model for a sustainable business.

Economics and policies will continue to drive our business choices, because investment capital is limited.

The best opportunities attract the investment dollars.

BP is in action to improve the quality of the business and the risk-reward balance. We're focusing on three things.

1. Prioritizing the activity set or scope of work
2. Tackling inflation through competition to drive down costs
3. Improving the efficiency and productivity of every $ invested

[1] CERA Capital Cost Index Increased 200% since 2004, 3Q 2009 202%

Regarding the activity set – we are being selective and we are choosing what - and how much - we do.

- risk reduction activities focusing on infrastructure have the first priority
- Growth projects in execution like Liberty are next
- And finally, the base business

Activities that we've slowed or stopped for sustainability are:

- Western Region Development Expansion (WRDX) project as it is not competitive
- Heavy oil project continues, but has slowed by 50%
- Reduced our rig count from 10 to 7 from January last year.[1]

In terms of tackling inflation, many of you are aware of the steps we have taken in our "fit for the future" program.

The industry suffered significant inflation with the increased oil prices … and when the oil prices collapsed, the inflation remained.

[1] 1Q 2009 10 rigs, 1Q 2010 7 rigs, verified by Robinson

As I've said to contractors and to my team, we need to do what's right and fair with the contractor community. We live here too, and I want to ensure that the way we interact with you as contractors has been fair and reasonable.

We want to do business with Alaska contractors -- we just need you to be competitive.

The problem is that a dollar of cost to us is a dollar of revenue to you. No one likes to give up a dollar of revenue. It really hits close to home when you realize 80 percent of BP's spend is with Alaskan companies.

But to be sustainable, we need to ensure we pay market prices for goods and services. Competition is good and we have taken steps to award work to the most competitive suppliers.

For some activities, we've reduced costs by more than 50 percent from a few years ago.

Finally, we are looking to do things more efficiently. We are driving our business to continuously improve – so the next

well we drill will be better than the last ... so that tomorrow's activity is completed more efficiently than today.

We have some stunning examples of great teams making a real difference - teams that are changing the game in terms of safety, productivity and efficiency.

Accuren under the leadership of Dennis Lee, has more than doubled the number of corrosion inspections, improved efficiency and reduced injuries by 90%.

The CH2M Hill Weld Shop under the supervision of Chuck Shaumann and Jay Fillingham increased efficiency by 65%, with less than 1% rejection rate in more than 11,000 welds.

And, the BP Drilling & Wells Workover team and Nabors Rig 4ES, under the leadership of Dave Hebert, improved efficiencies in the installation of electric submersible pumps (ESP) by 33% in less than a year, saving more than $1MM.

These are just a few examples. What we find is that the most efficient teams are also becoming the safest teams. Our

focus is to have this kind of performance everywhere we work.

I have touched on how we are improving the performance and economics of our business – and now I would like to touch on government policy.

Last week's announcement by Governor Parnell on oil tax credits was a positive signal to the industry that he and his administration recognize that the ACES tax needs change to stimulate activity.

The opportunity for dialog is encouraging and we will participate openly. We believe the proposal is a good start, but it's not enough for sustainability of Alaska's oil and gas industry.

In Alaska, policy decisions around taxes made over the past few years have slowed the pace and scale of some of our North Slope developments.

We put projects on the shelf that didn't make sense in this environment and I mentioned three examples earlier.

It wouldn't be fair for me to assert that our investment decisions are solely based on the tax structure – in reality, there are a host of market factors. However, the tax structure plays a significant part in the decision process.

For a tax and royalty regime, Alaska has the least competitive tax structure of anywhere BP works in the world.

In the USA, the tax and royalty structures in the L48 and GOM are more competitive. The tax and royalty regimes in Australia, the North Sea, and Trinidad are also more competitive.

That means Alaska projects have to be more efficient to compete. This means our projects need to produce more barrels per dollar of investment and lower unit costs.

It's a tough challenge against the backdrop of decline and the Arctic environment where construction costs are significantly higher than the L48.

The two biggest issues with the Alaska tax structure are the overall tax rate, and the progressivity portion of ACES.

Here is a simple example:
In a Gulf of Mexico investment, the government take (taxes & royalties) from an incremental $1 at a $90 oil price is about 40 cents. That means the company has the upside potential of nearly 60 cents out of every incremental dollar.

So what is the government take on state lands in Alaska at $90 oil price? Because of the progressivity of the ACES severance tax, the government keeps between 70-80 cents of that one dollar, and the industry's share ranges from 20-30 cents.

If you had opportunities for new growth – where would you put your money? In a place where you can earn 60 cents on an incremental dollar, or 20-30 cents?

It should come as no surprise that we will need to reduce our capital spending about 15% this year. This year's actual capital spending will be about $850 million, compared to over $1 billion in 2009.

However, this 15% top line reduction actually masks the real impact that ACES has had on our base business.

Our 2010 investment consists of roughly one-third infrastructure renewal, one-third for growth and one-third drilling.

The infrastructure investment is not adding production, and the growth projects for BP are primarily our investment in Denali and Liberty.

The investment in our base business is focused on offsetting decline and delivering increased production from in field drilling. This is the activity that delivers more production in the short term.

That activity has been reduced since ACES passed at the end of 2007.

Here is some data that supports that statement:

Our total drilled footage will be more than 50% lower in 2010 vs. 2007. It was nearly 1 million feet in 2007.

Also, our capital investment in the base business has been reduced by 30% when comparing 2007 and 2010 investment.

It was encouraging that the Governor's announcement recognizes that this is an issue. That's a step in the right direction.

The bottom line is it's more difficult to attract capital to Alaska because the risk/reward balance is disadvantaged against investment opportunities in other parts of the world. Alaska has become more of a margin play as there is very little reward for price upside. Alaska needs to do better if it wants to attract investment.

So why then are we investing in Liberty?

Liberty will be the first full federal offshore development in Alaska, and the competitiveness of the project is helped because the high technical risk is balanced with higher

reward under the **federal tax structure – the project is not subject to ACES severance tax**. This is a good example of how policy drives investment.

This year, the first of up to six Liberty ultra-extended reach wells will reach 6-8 miles to a new 100-million barrel field.

First oil production is expected in 2011, peak of 40,000 barrels/day and a capital investment more than $1 billion.

That said, the state still benefits from Liberty:

- In state income and property taxes;
- a share of the federal royalty;
- 40,000 barrels/day down TAPS;
- and a lot of jobs -- about 40 Alaska companies worked on Liberty's construction.

There are other growth opportunities too. But like everything else, economics and policy will drive investment decisions.

The remaining resources in Alaska are significant – there is a lot to play for … but they are technically and commercially challenged – and they are harder to reach.

Being more technically challenged means it's harder for projects to be profitable – it takes more investment for less barrels compared with the past.

But the size of the resource base gives us great hope. There are significant opportunities in heavy oil and Alaska gas. But there are equally significant challenges.

You all know the heavy oil story. In a nutshell, it's an exciting opportunity that requires a technological solution. We have a strong belief we will find that solution.

However, our current estimates indicate that even with technological success, heavy oil is not economic under the current tax structure at today's oil prices.

Gas development is also an important part of our Alaska strategy, and it's certainly on the mind of every person in Alaska.

We all read the papers. Producers in the lower 48 have been aggressively looking at ways to access abundant shale gas resources. And they are succeeding. There has been a significant change in the Lower 48 gas market due to a technological breakthrough.

A recent study estimates that by 2020, unconventional gas, such as shale, is forecast to account for over 50% of total US production … with estimated shale gas supplies that will meet today's US market for 50 to 100 years.[3]

At the same time, Natural gas demand is forecast to remain relatively flat for the next 30 years.[2]

The market in the lower 48 is working … supply is up, demand is flat and Henry Hub prices have reacted.

I believe that demand will have to increase to make Alaska gas commercially viable in the Lower 48.

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[3] Source: EIA Annual Energy Outlook 2009 & Brian Frank Presentation 1/09

[2] DOE 09 Forecast flat demand 23TCF/yr through 2020.

So gas is challenged. More challenged than it was just a few short years ago. But my team and I are absolutely focused on finding a way to bring Alaska North Slope gas to market. I don't know exactly how the future will play out, but I can promise that we are looking at all options for Alaska gas development.

That takes me back to where I began – our future is about continuous improvement of our business and playing the ball where it lies.

BP's employees are passionate about building a sustainable business in Alaska.

Over 81 percent of our two thousand person workforce call Alaska home. Together BP and our employees support more than 700 education, community organizations and youth teams in 49 different towns and villages across Alaska. Our employees are also the largest contributors to United Way.

Their commitment to Alaska is personal, and so is mine.

For decades BP has been the responsible steward of Alaska resources, delivering revenues to our state.

Our commitment has *not changed*, but our business reality has.

I believe the future will require all the "We" to work together differently – and better, than we have in the past.

I believe by working together with Alaskans, we can make our 50 year dream a promise … and that's what get's me excited about working in Alaska.

Thank you

Alliance Breakfast

Stimulating Production and Jobs

February 11, 2010

Investments → **Jobs + Production + Revenues for State and Industry**

Brian Wenzel
Vice President – Finance
ConocoPhillips Alaska

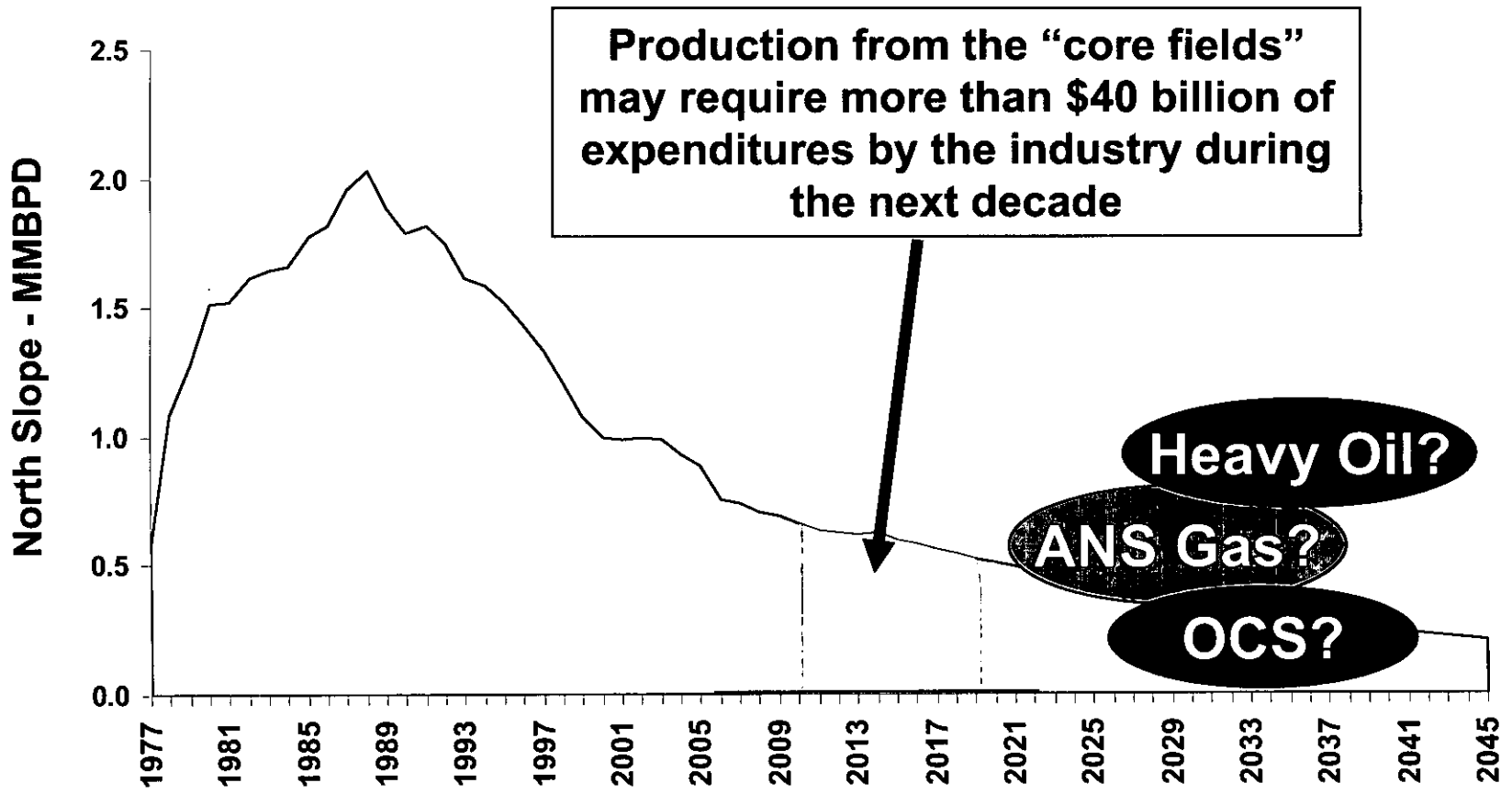
ConocoPhillips

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

The following presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbors created thereby. You can identify our forward-looking statements by words such as "anticipates," "expects," "intends," "plans," "projects," "believes," "estimates," and similar expressions. Forward-looking statements relating to ConocoPhillips' operations are based on management's expectations, estimates and projections about ConocoPhillips and the petroleum industry in general on the date these presentations were given. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict. Further, certain forward-looking statements are based upon assumptions as to future events that may not prove to be accurate. Therefore, actual outcomes and results may differ materially from what is expressed or forecast in such forward-looking statements.

Factors that could cause actual results or events to differ materially include, but are not limited to, crude oil and natural gas prices; refining and marketing margins; potential failure to achieve, and potential delays in achieving, expected reserves or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks, and the inherent uncertainties in interpreting engineering data relating to underground accumulations of oil and gas; unsuccessful exploratory drilling activities; lack of exploration success; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying company manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; international monetary conditions and exchange controls; potential liability for remedial actions under existing or future environmental regulations; potential liability resulting from pending or future litigation; general domestic and international economic and political conditions, as well as changes in tax and other laws applicable to ConocoPhillips' business; and limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets. Other factors that could cause actual results to differ materially from those described in the forward-looking statements include other economic, business, competitive and/or regulatory factors affecting ConocoPhillips' business generally as set forth in ConocoPhillips' filings with the Securities and Exchange Commission (SEC), including our Form 10-K for the year ending December 31, 2008, as updated by our quarterly and current reports on Forms 10-Q and 8-K, respectively. ConocoPhillips is under no obligation (and expressly disclaims any such obligation) to update or alter its forward-looking statements, whether as a result of new information, future events or otherwise.

Investment in Core Fields

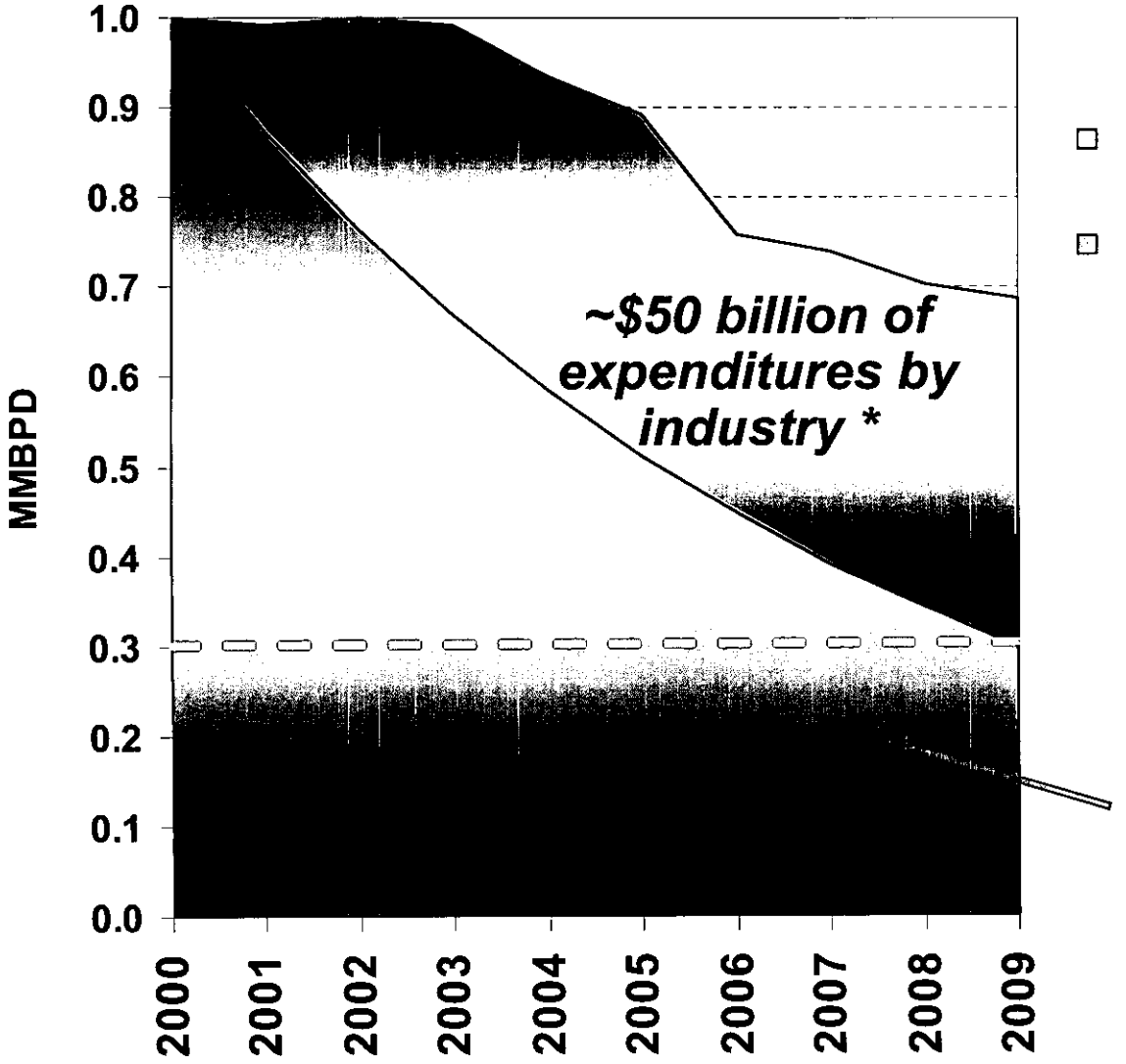


Core fields are the bridge to the future

Sources: DNR production forecast and extrapolation of DOR expenditures forecast

ConocoPhillips

2000-2009 North Slope Production
with and without $50 Billion Invested by Industry



- Peak production in 1988
- $50 billion of expenditures by industry from 2000 - 09
  - Mitigated decline of nearly 400,000 bbl/day

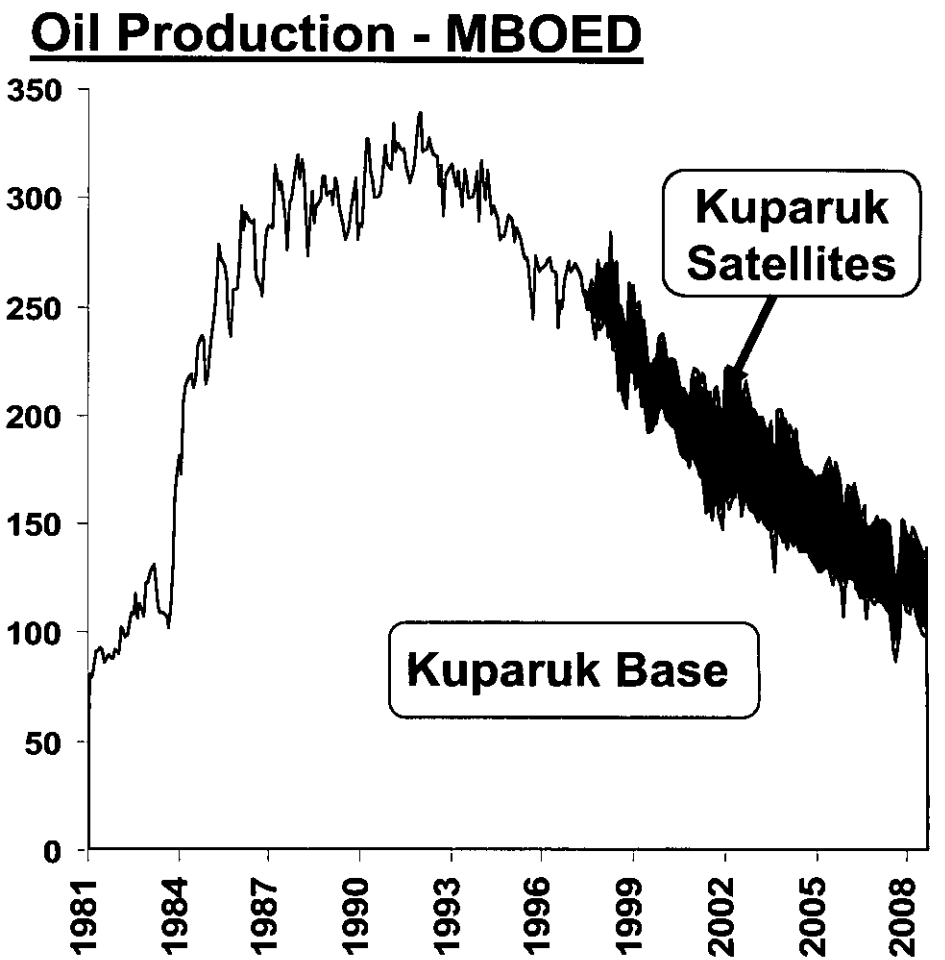
Assumes 12.5% decline
<u>without investment:</u>
Production could have fallen to ~300,000 bbl per day

Sources: $50 billion per Wood Mackenzie Global Economic Model, DNR data for total volume, COP estimates for base decline rate

ConocoPhillips

Nearing 30 Years at Kuparuk

- 1st Production in 1981
  - Over 6 Billion barrels OOIP[1]
    - *1% recovery = 60 million barrels*
  - Waterflood / Miscible gas EOR
- Recent activity
  - Pipeline and well maintenance
  - Coiled tubing drilling rig



1 – Original oil in place including satellites; Source – DNR website

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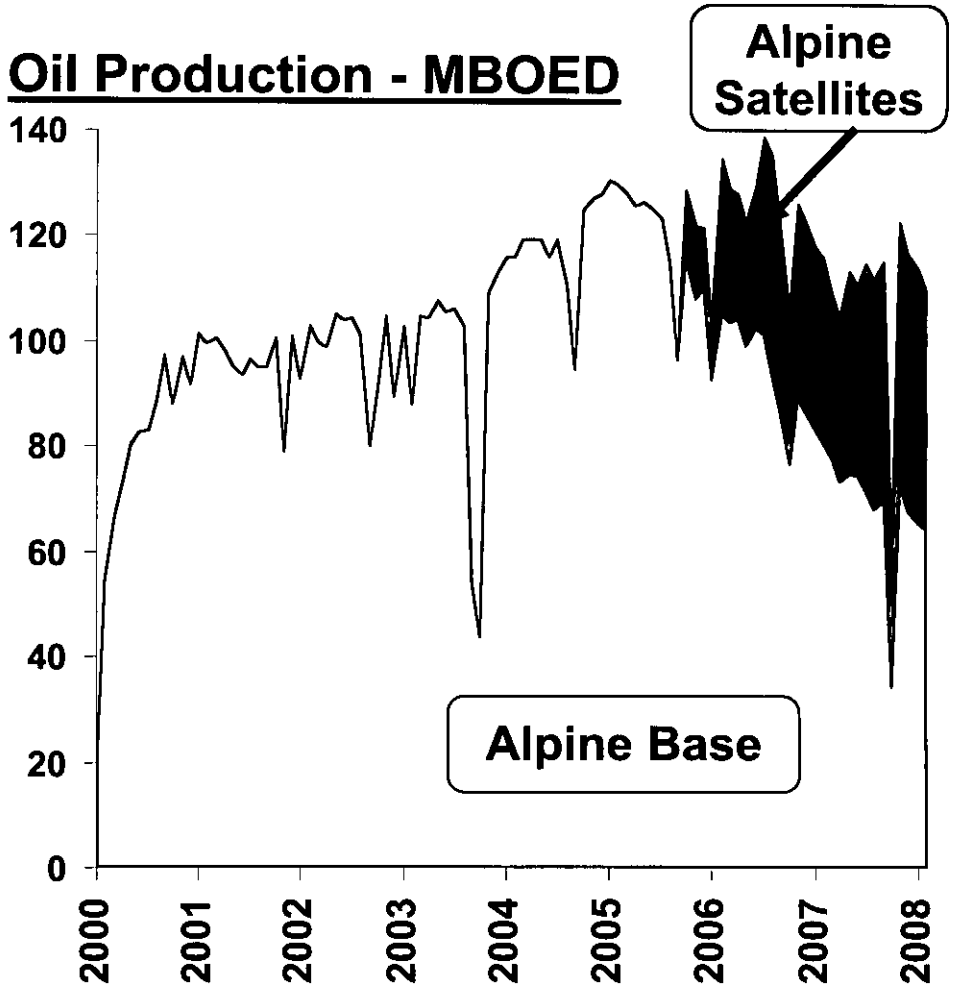
10 Years at Alpine

- 1st Production in 2000
  - Over 1 billion barrels OOIP[1]
  - Waterflood / Miscible gas EOR
  - Extended reach drilling
- Current opportunities
  - 3-D seismic
  - Satellite development is key



1 – Original oil in place including satellites; Source – DNR website

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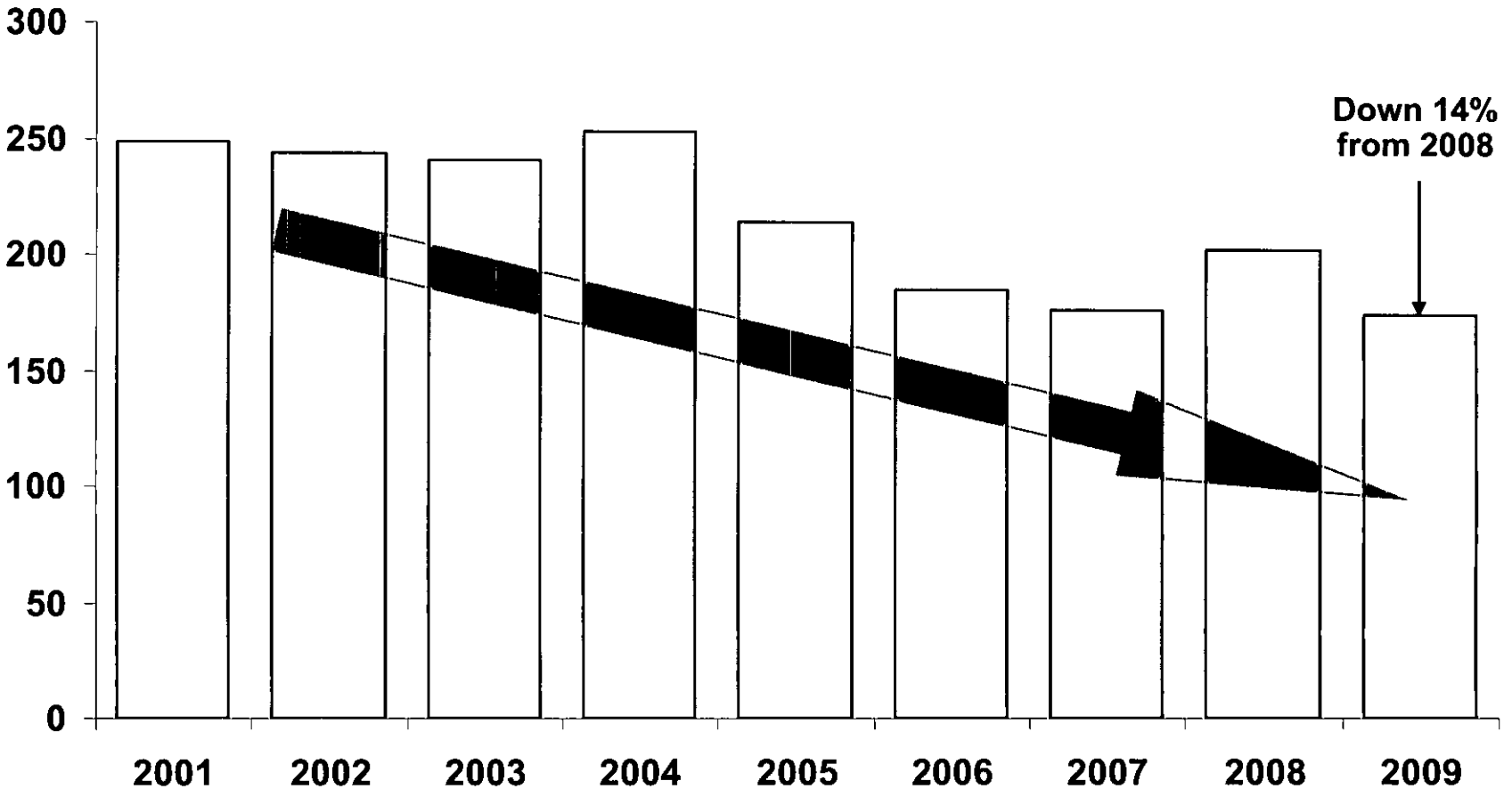
Alaska Drilling Permits



Decline in Alaska drilling permits

Source: AOGCC

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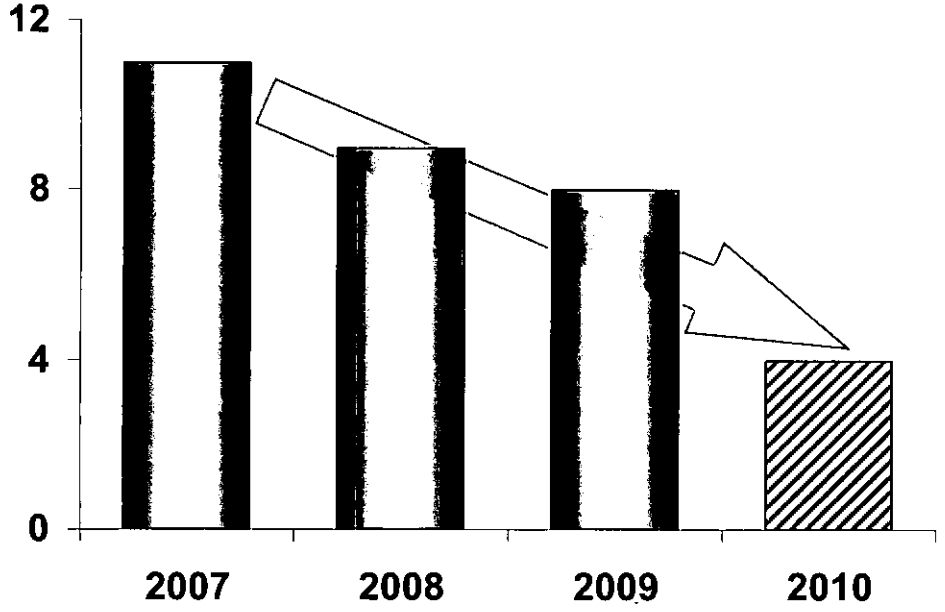
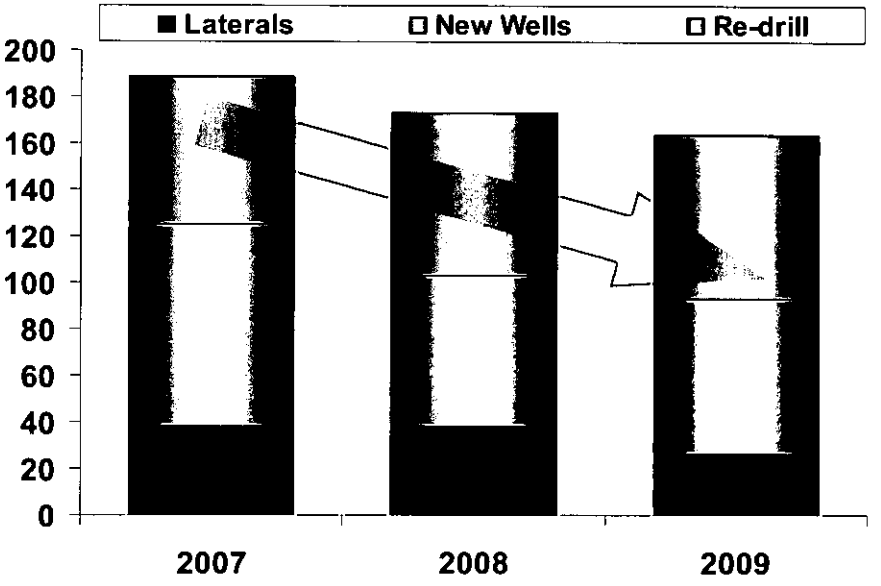
Investments and Jobs at Risk

Industry Exploration Wells *Down*



Industry Drilling *Down*



- **Decline in drilling means:**
  - **Fewer jobs; TAPS production decline; Less new reserves; Less State royalties, taxes**

All drilling indicators are down

Source: AOGCC data for drilling and exploration wells (exploration wells are North Slope only)

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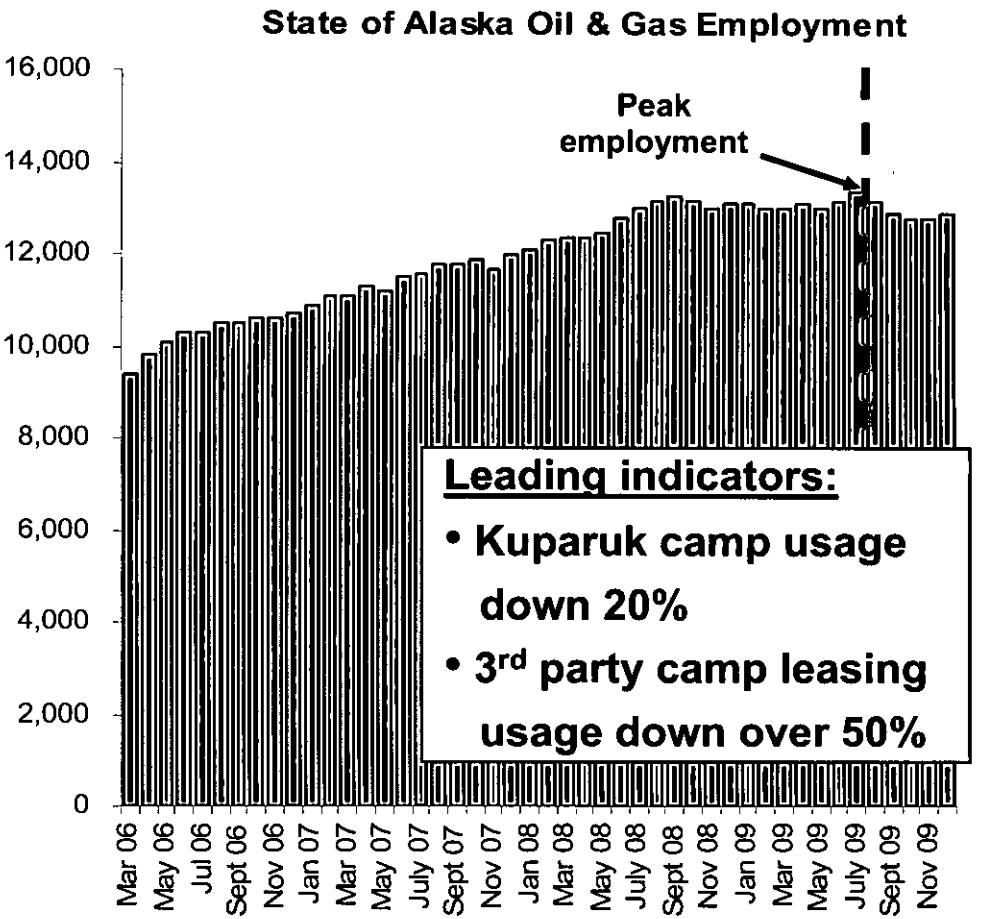
Oil & Gas Employment

Department of Revenue:

- ***"Employment in the industry has also increased steadily since the implementation of PPT and ACES, with 2009 forecast to be the highest in state history"***

Response:

- **Data since July-09 indicate downward trend in Oil & Gas jobs**
- **Prior to July-09 - employment levels driven primarily by maintenance and inspection activity, rather than PPT and ACES**
- **Alaska state unemployment rising**



Source: Alaska Dept of Labor

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Investments

Department of Revenue:

- **Investments are up since 2007**
- ***"majority of growth in capital expenditures is attributable to drilling, seismic and other projects"***

Response:

- **Cost levels impacted by hyper-inflation**
- **Maintenance spending is primary driver of recent activity increases on the slope**
- **Investment in new oil production has declined**
  - **Industry drilling / well count down**
  - **$2 billion in projects deferred**

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ACES Impacting Projects

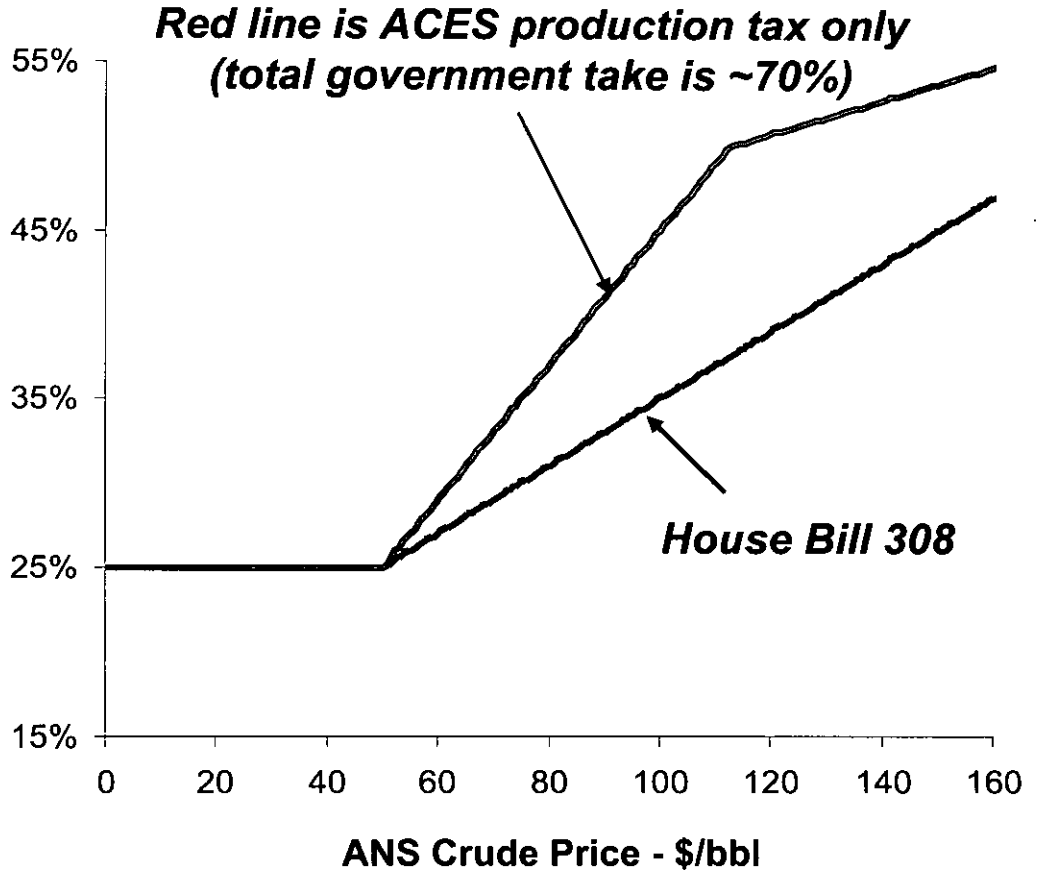
- Project activity since ACES passed
  - Oooguruk – pre-ACES, royalty relief
  - Nikaitchuq – royalty relief
  - Liberty – not subject to ACES
- Over $2 Billion in projects deferred since ACES
  - Approx. 40,000 barrels per day, plus impact on jobs
    - Prudhoe I-Pad and Gas Partial Processing (GPP)
    - West Sak slower pace
    - ULSD topping plant *(opportunity foregone)*

Larger, long-term projects impacted by progressivity

ACES – Progressively Increasing Tax

- **Rapidly increasing tax**
  - Net cash flow tax
  - Higher base tax rate
  - Retroactive
  - Restricted cost deductions
- **Incentives**
  - 20% tax credit for capital
  - 30-40% credit for exploration
- **Uncertainty increased**
  - Dept of Revenue discretion
  - Additional reporting / admin.
  - 6-year audit period
  - Punitive interest rates

ACES Production Tax *(does not incl. royalty, federal, other taxes)*



Significant increase in tax burden and administrative costs

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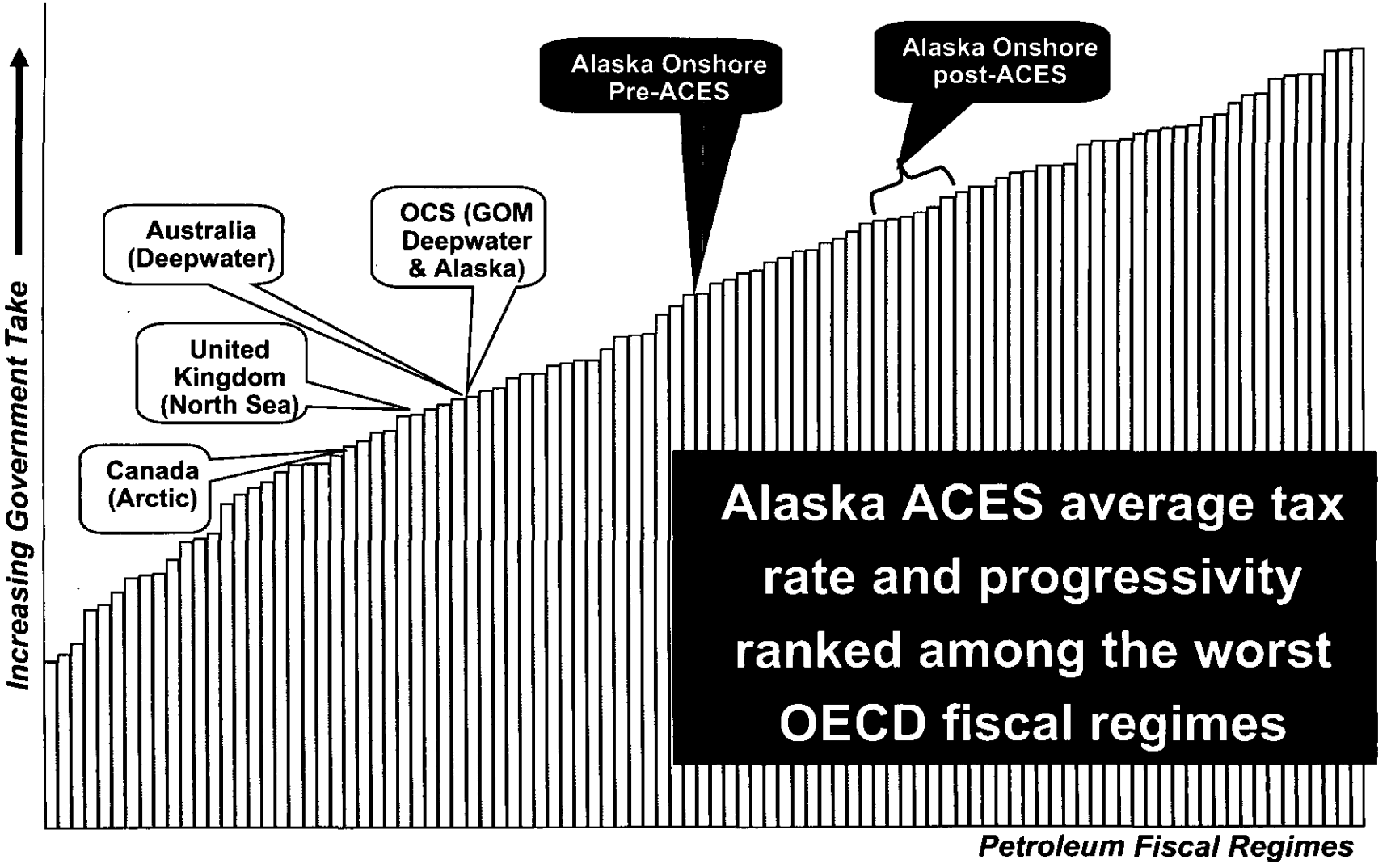
Global Perspective on Government Take



Source: Wood Mackenzie Government Take Analysis Dec 2009 and internal COP – high price case

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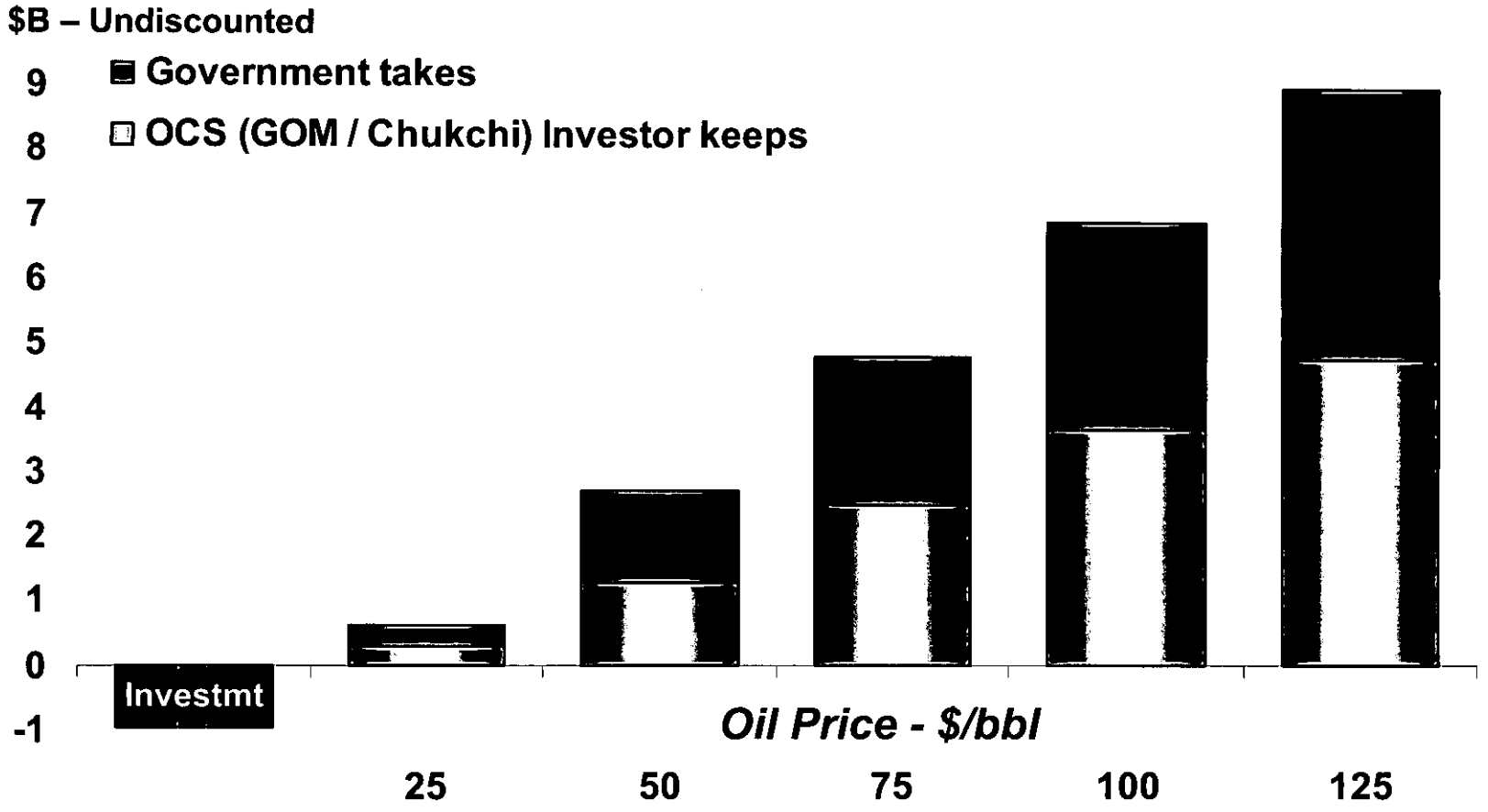
OCS Fiscal – Risk/Reward is Balanced

Example - $1 Billion Investment (success case)



Adequate success case returns justify taking up front risks

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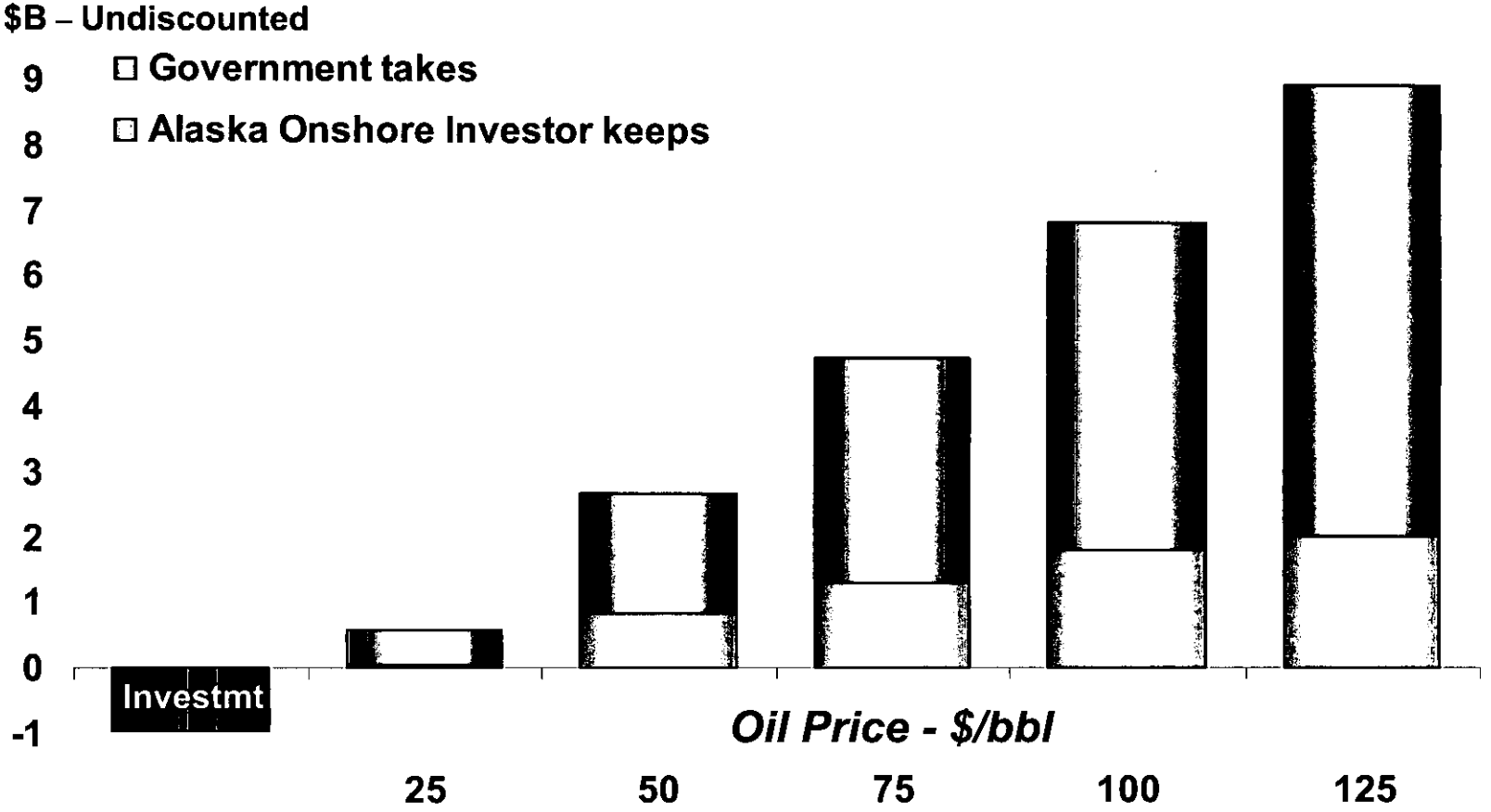
Alaska Fiscal – Risk/Reward is Broken

Example - $1 Billion Investment (success case)



Alaska onshore fiscal terms not competitive

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Oil Tax Legislation

	Current Law	Governor Bill (SB271/HB337)	House Bill 308CS / Senate Bill 267	House Bill 321
Base Tax Rate	25%	*No change*	*No change*	**20%**
Progressivity	0.4% per $1 price	*No change*	**Reduced from 0.4 to 0.2%**	*No change*
Tax credits	20% for capital; 30%, 40% for exploration	**Extended to all wellwork activities a 30% credit**	**Extended to all wellwork activities a 30% credit**	*No change*
Audit period	6 years	*No change*	**Return to 3 years**	*No change*
Interest due to delayed regulations	Charge punitive interest with regulations not fully defined	**Grants DOR authority to waive interest**	**Grants DOR authority to waive interest**	*No change*
Capital tax credit utilization	Credits spread over two years	**Full use of credits in the year incurred vs. one half currently**	*No change*	*No change*

Other areas of concern not addressed:

DOR discretion, incomplete regulations, facility sharing treatment, administrative burden, other hidden costs

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Summary

- **Industry has over $40 billion in opportunities over the next decade**
  - **Existing fields have upside potential**
- **Future investments are challenged**
  - **Deferred over $2 billion in projects**
  - **Drilling activity has declined**
  - **Increased maintenance activity**
- **Expected legislative focus**
  - **30% well-related activity is a step in the right direction**
  - **Reduced progressivity required for more balanced risk / reward**

Improvements to ACES needed to increase investment and jobs