

SB 21

(FILE 2)

<TARGET><BILL>SB 21</BILL><SUBJECT>SB 21 (FILE
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4/5/13

Oil Tax Reform—Arresting TAPS Throughput Decline

House Finance Committee

Friday, April 5, 2013

Commissioner Daniel S. Sullivan, DNR

Commissioner Bryan Butcher, DOR



OUTLINE



PART I: Current Context—Opportunities & Challenges

PART II: Is the Current Tax System Working for Alaskans?

PART III: Production, Production, Production

PART I



Current Context—Opportunities & Challenges

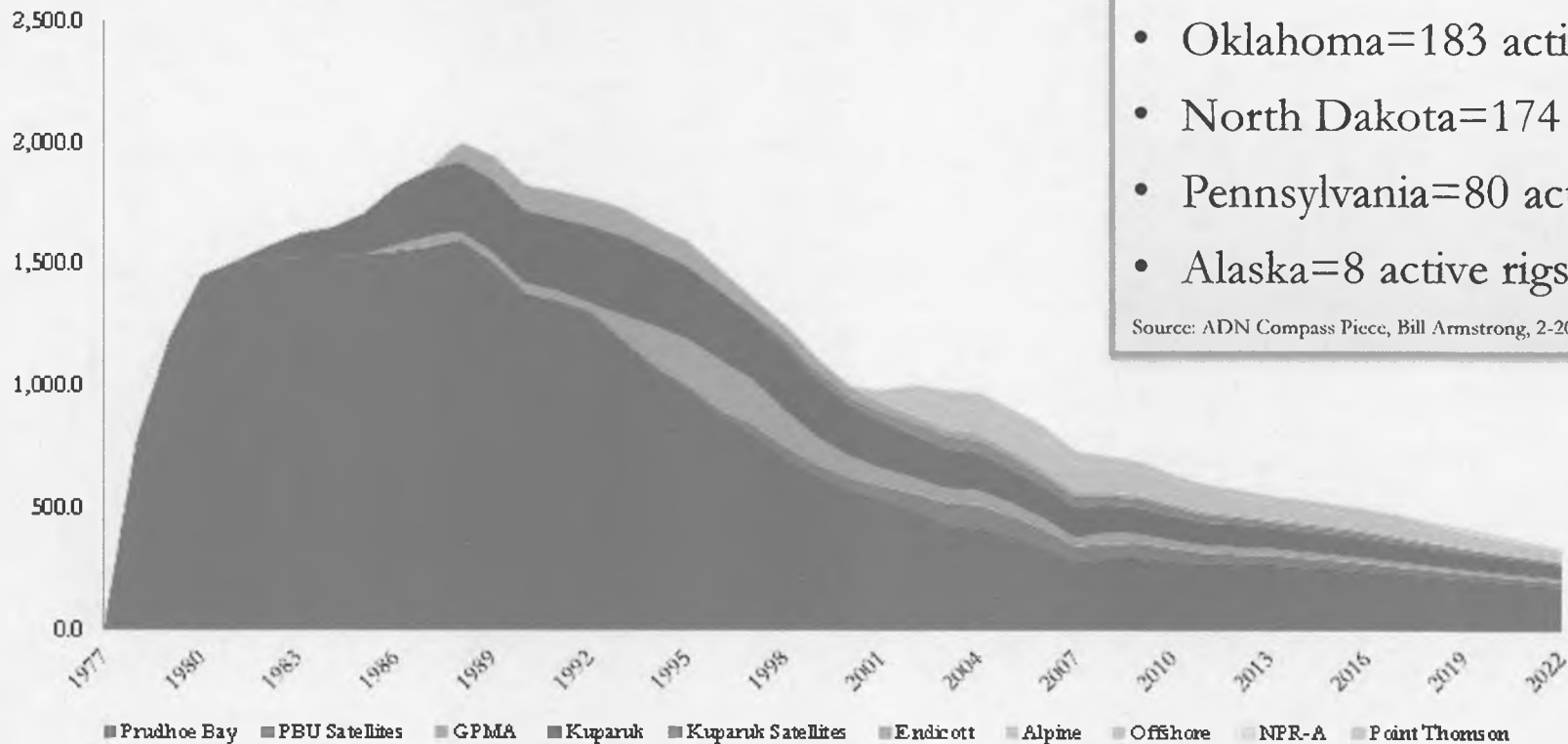
TAPS

- A CRITICAL STATE & NATIONAL ENERGY ASSET -

- TAPS has transported over 16.3 billion barrels of oil and natural gas liquids since June of 1977. Production peaked at 2.2 million barrels per day in the late 1980s, representing 25% of U.S. domestic production
- Since its peak, however, throughput has steadily declined; today, TAPS is 2/3 empty and declining at an average of 6% per year
- TAPS throughput decline threatens economic disruption and the very existence of our pipeline
- 90% of state revenues come from oil production
- We must encourage industry to invest in exploration and development of conventional and unconventional resources on state and federal land, onshore and offshore
- TAPS has plenty of capacity for increased throughput
- Most near-term critical economic issue facing the state
- Most urgent issue facing the state – two and half years of studies

PRODUCTION HISTORY

ANS Production



2013 Rig Count:

- Texas=830 active rigs
- Oklahoma=183 active rigs
- North Dakota=174 active rigs
- Pennsylvania=80 active rigs
- Alaska=8 active rigs

Source: ADN Compass Piece, Bill Armstrong, 2-20-13

Source: Alaska Department of Revenue Fall 2012 Revenue Sources Book: <http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2682f>

MASSIVE RESOURCE BASE

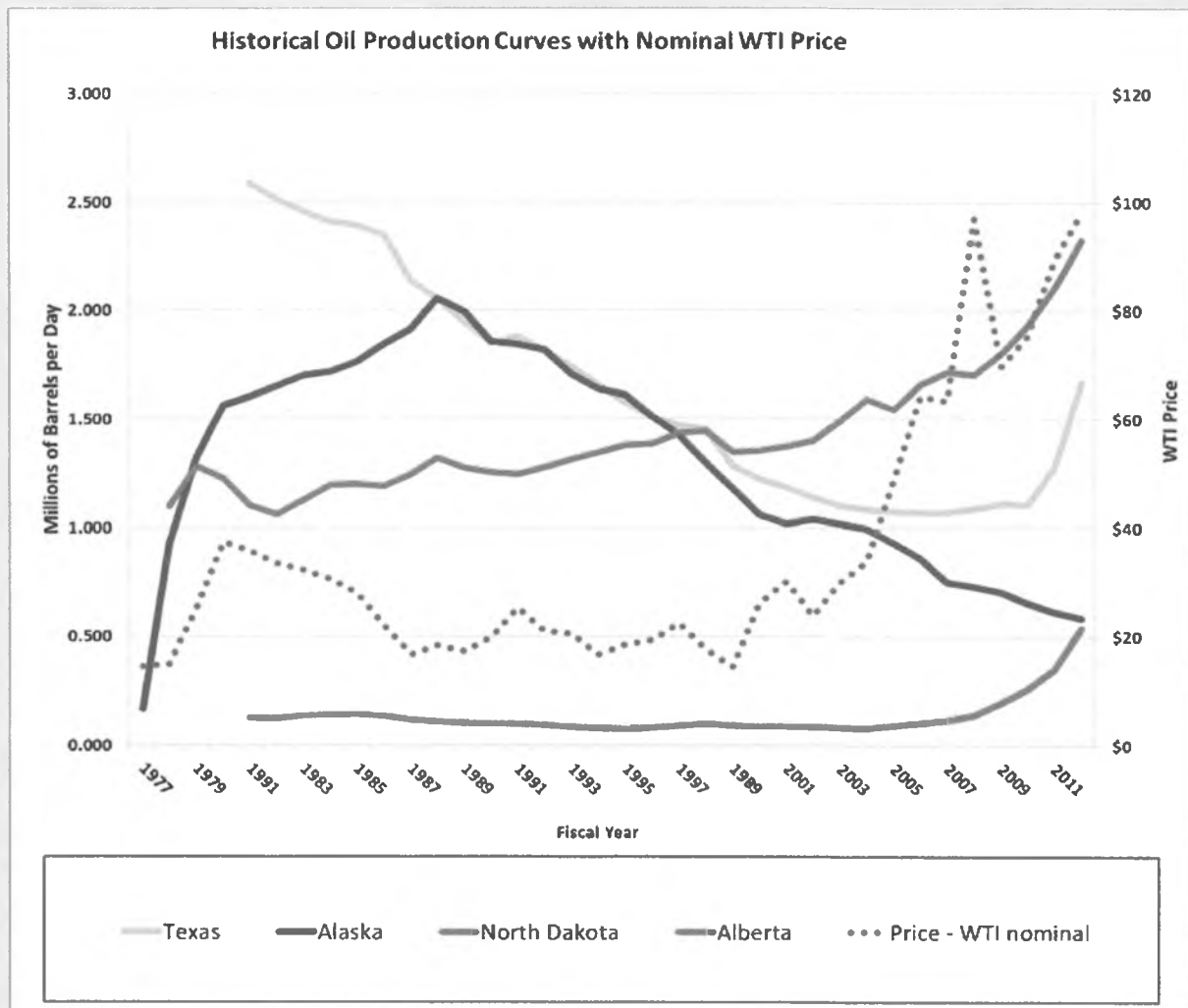
- USGS estimates that Alaska's North Slope has more oil than any other Arctic nation
 - **OIL:** Est. 40 billion barrels of conventional oil (*USGS & BOEMRE*)
 - **GAS:** Est. over 200 trillion cubic feet of conventional natural gas (*USGS*)
- Alaska has world-class unconventional resources, including tens of billions of barrels of heavy oil, shale oil, and viscous oil, and hundreds of trillions of cubic feet of shale gas, tight gas, and gas hydrates
- Alaska's North Slope has already produced more than 16 billion barrels of oil to date
- At year-end 2010, the Energy Information Agency (EIA)(federal Department of Energy) put remaining North Slope reserves at 3.7 billion barrels of oil
- Reforms now can create enormous future opportunities and benefits

Compared to most hydrocarbon basins, Alaska is relatively underexplored, with 500 exploration wells on the North Slope, compared to Wyoming's 19,000.

OTHER BASINS HAVE TURNED DECLINE AROUND

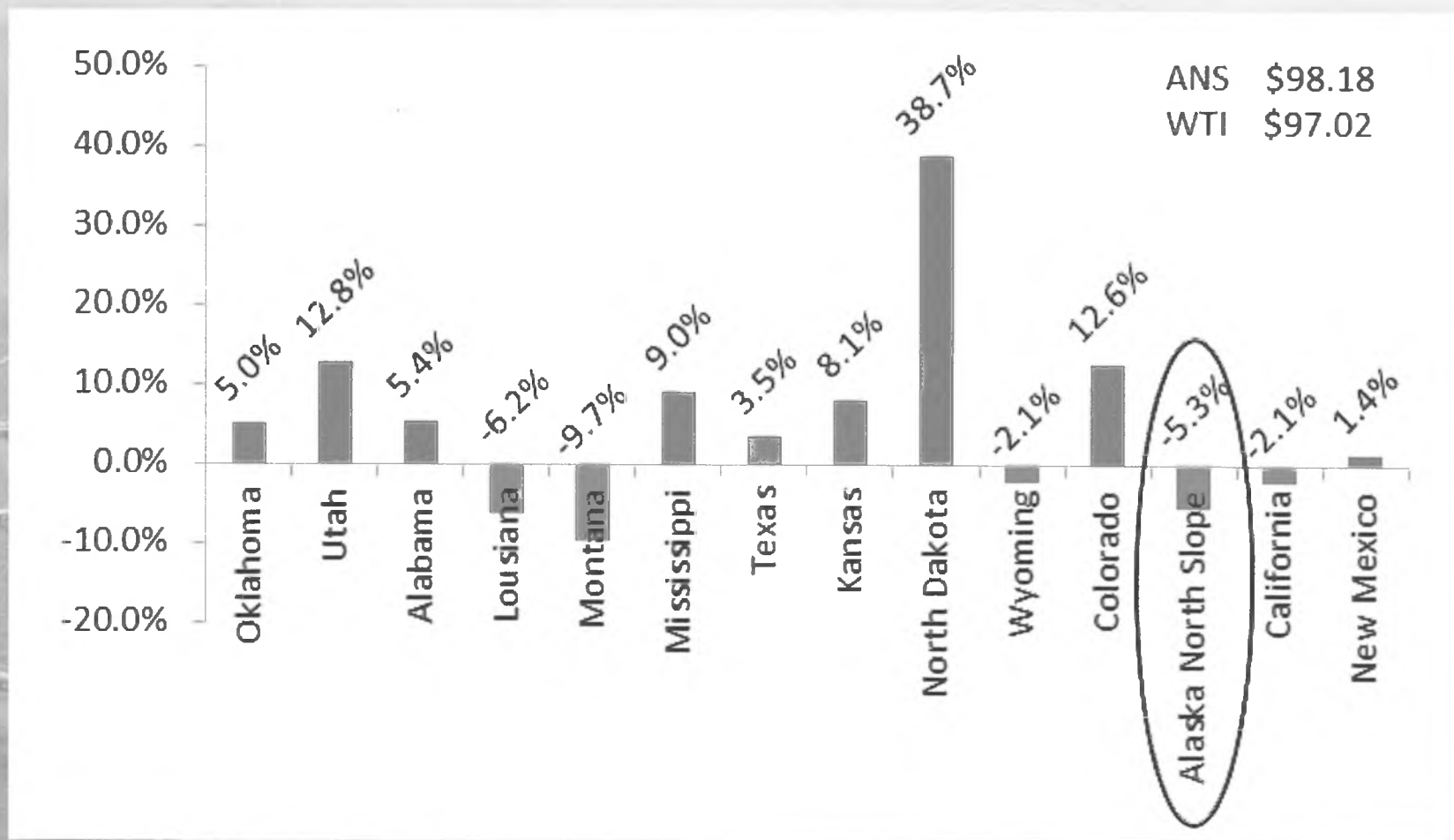
- HISTORICAL OIL PRODUCTION -

How Did Our Competition Fare When Prices Spiked?



CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2007-2008

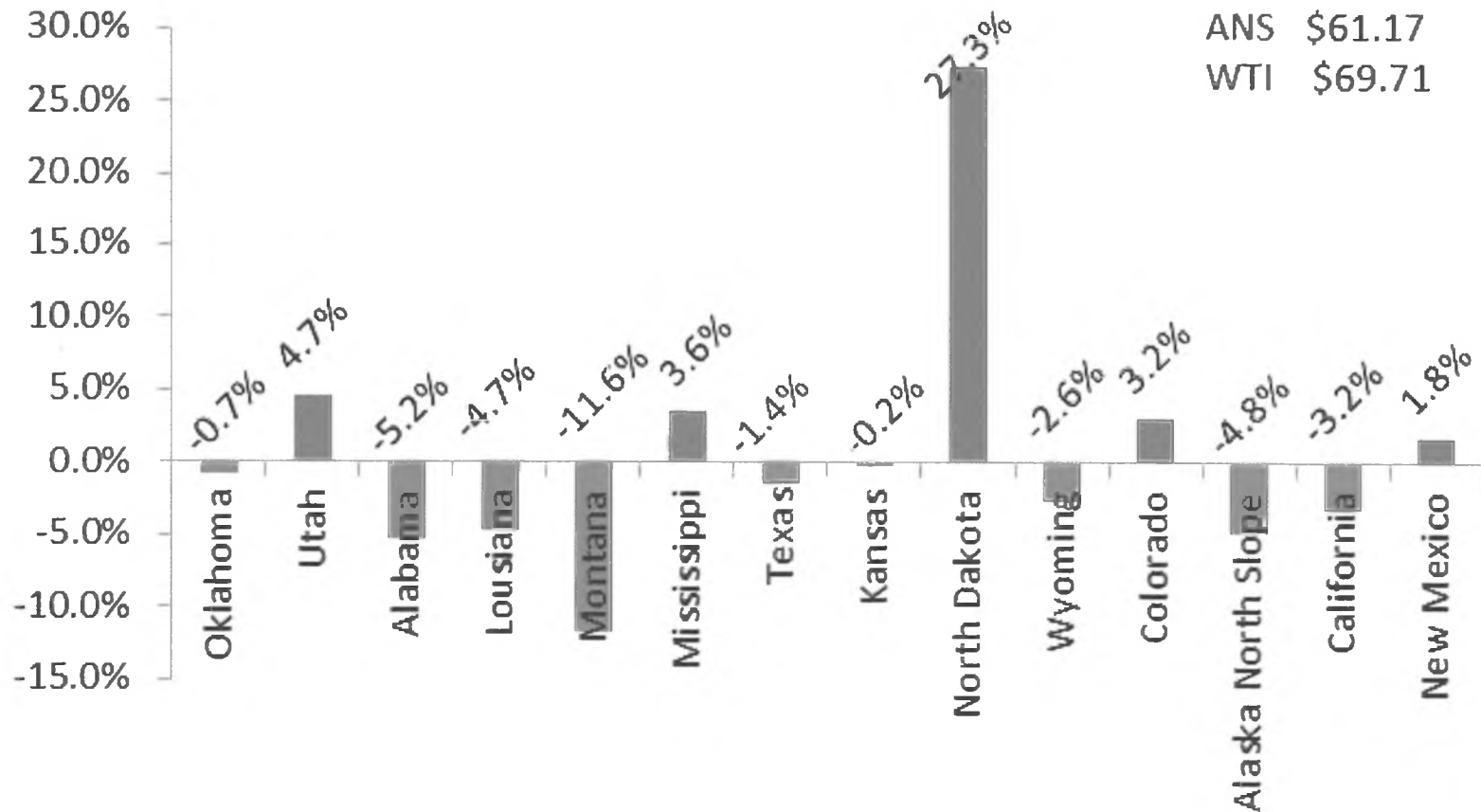
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2008-2009

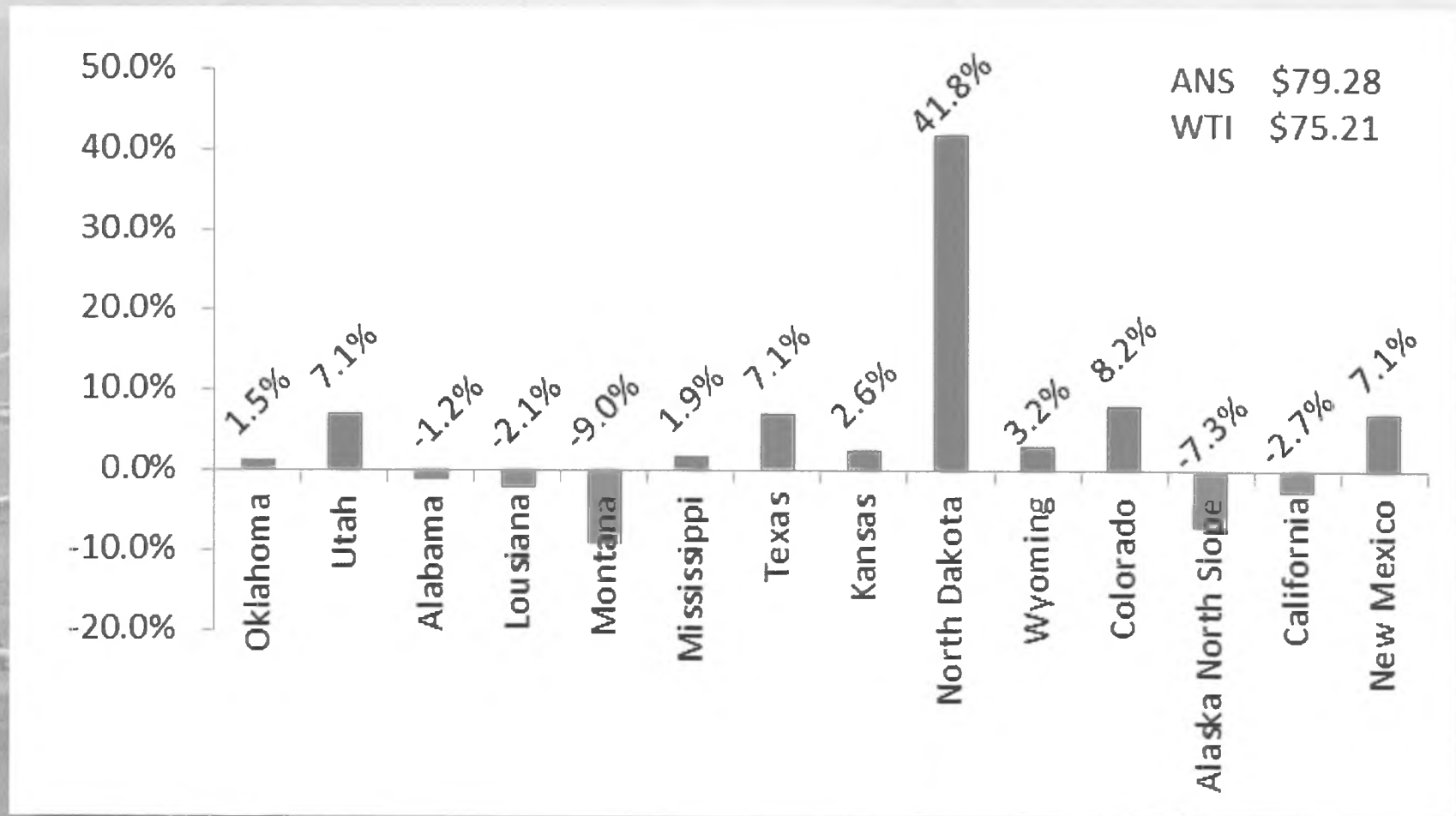
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2009-2010

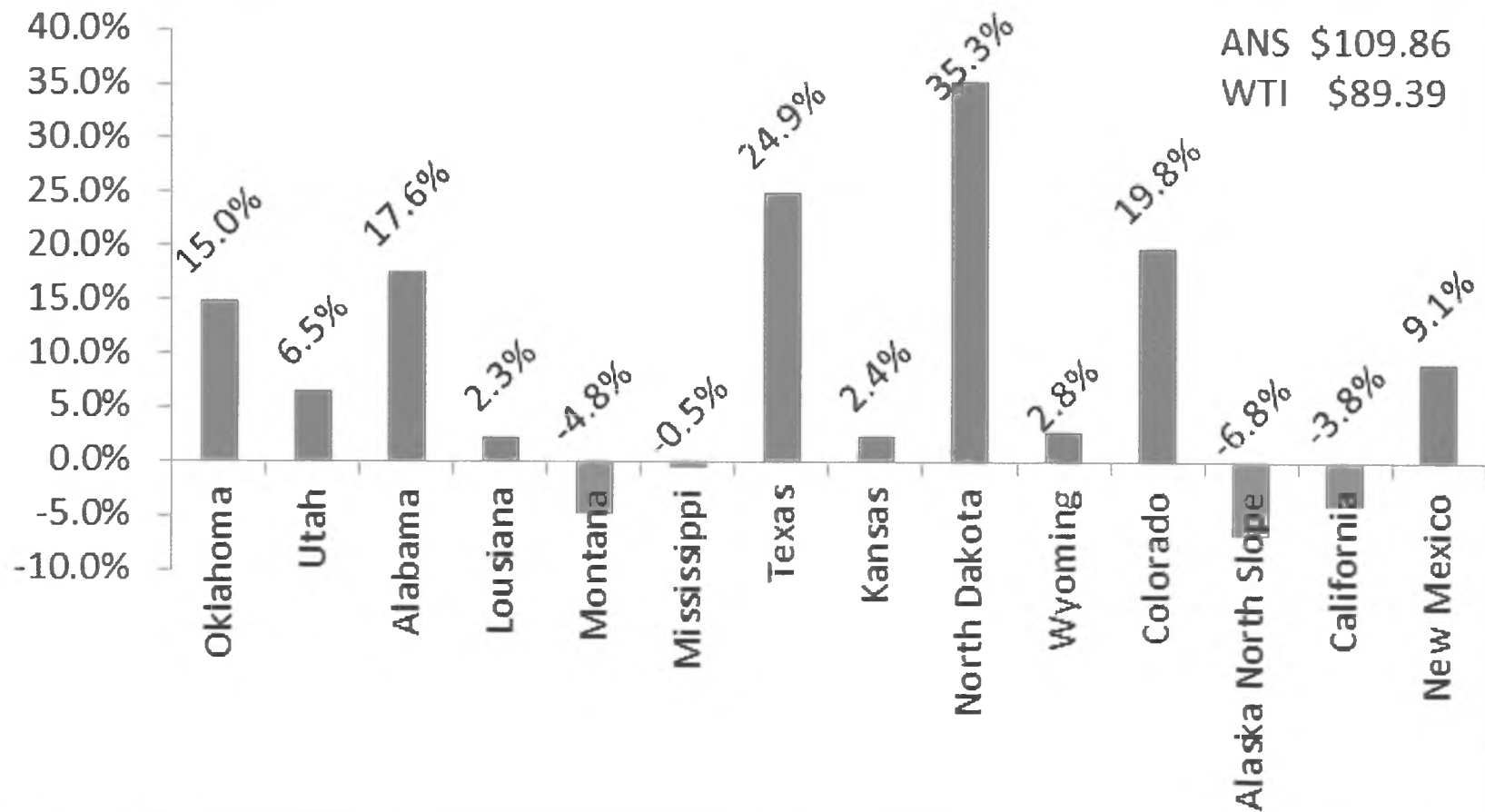
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2010-2011

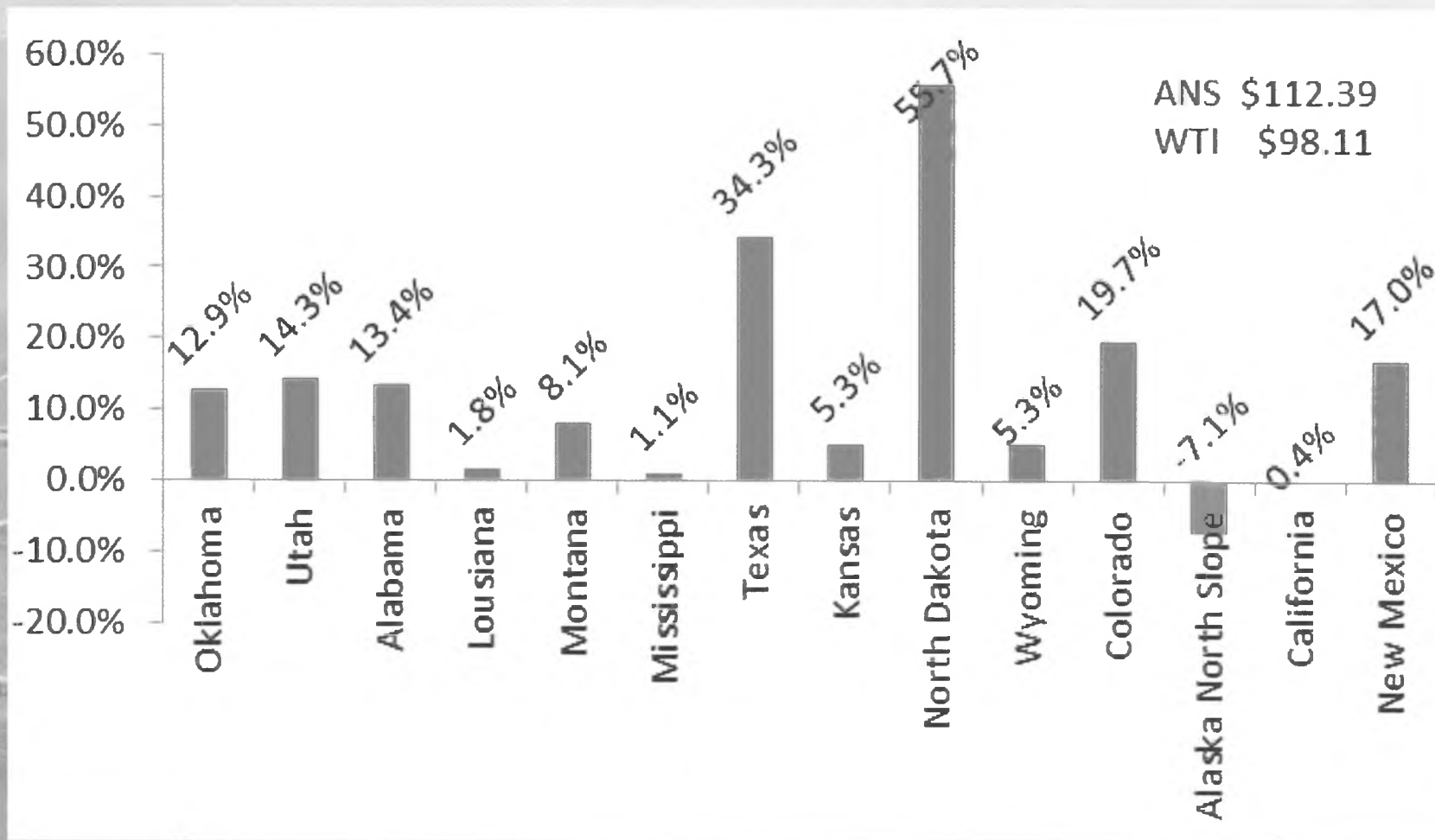
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

CHANGE IN AVERAGE DAILY OIL PRODUCTION BY STATE—2011-2012

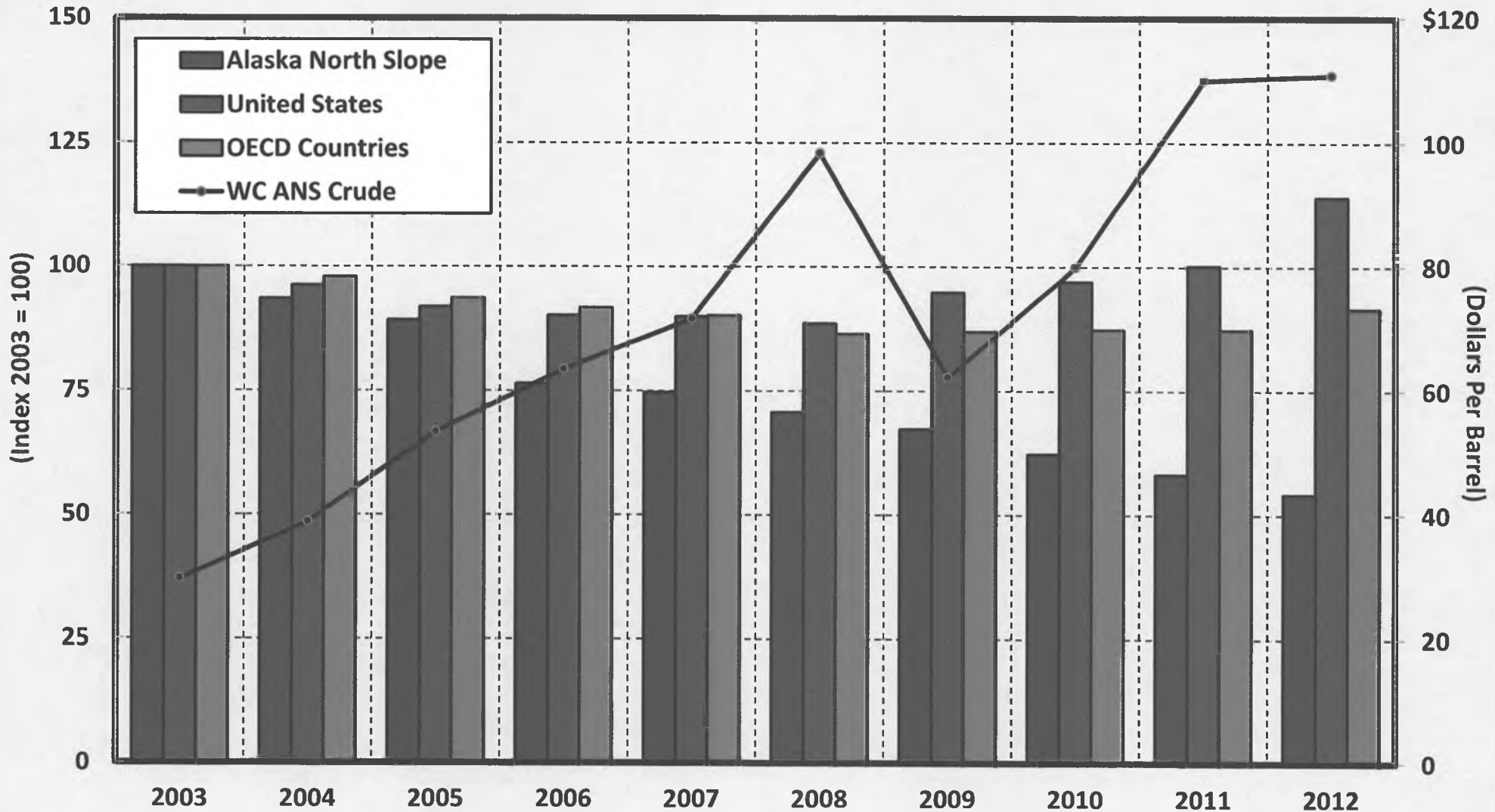
- PREPARED BY DOR, ECONOMIC RESEARCH GROUP (MARCH 18, 2013)-



Source: EIA Crude Oil Production By State. Link:
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_m.htm

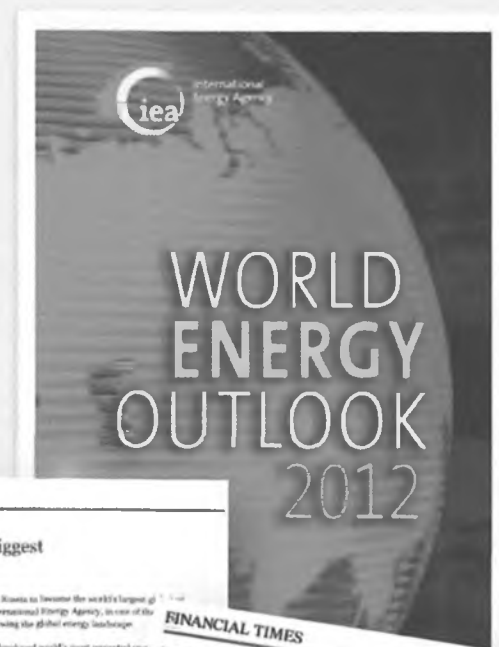
CRUDE OIL PRODUCTION:

AK NORTH SLOPE VS. U.S. & OECD COUNTRIES, 2003-2012



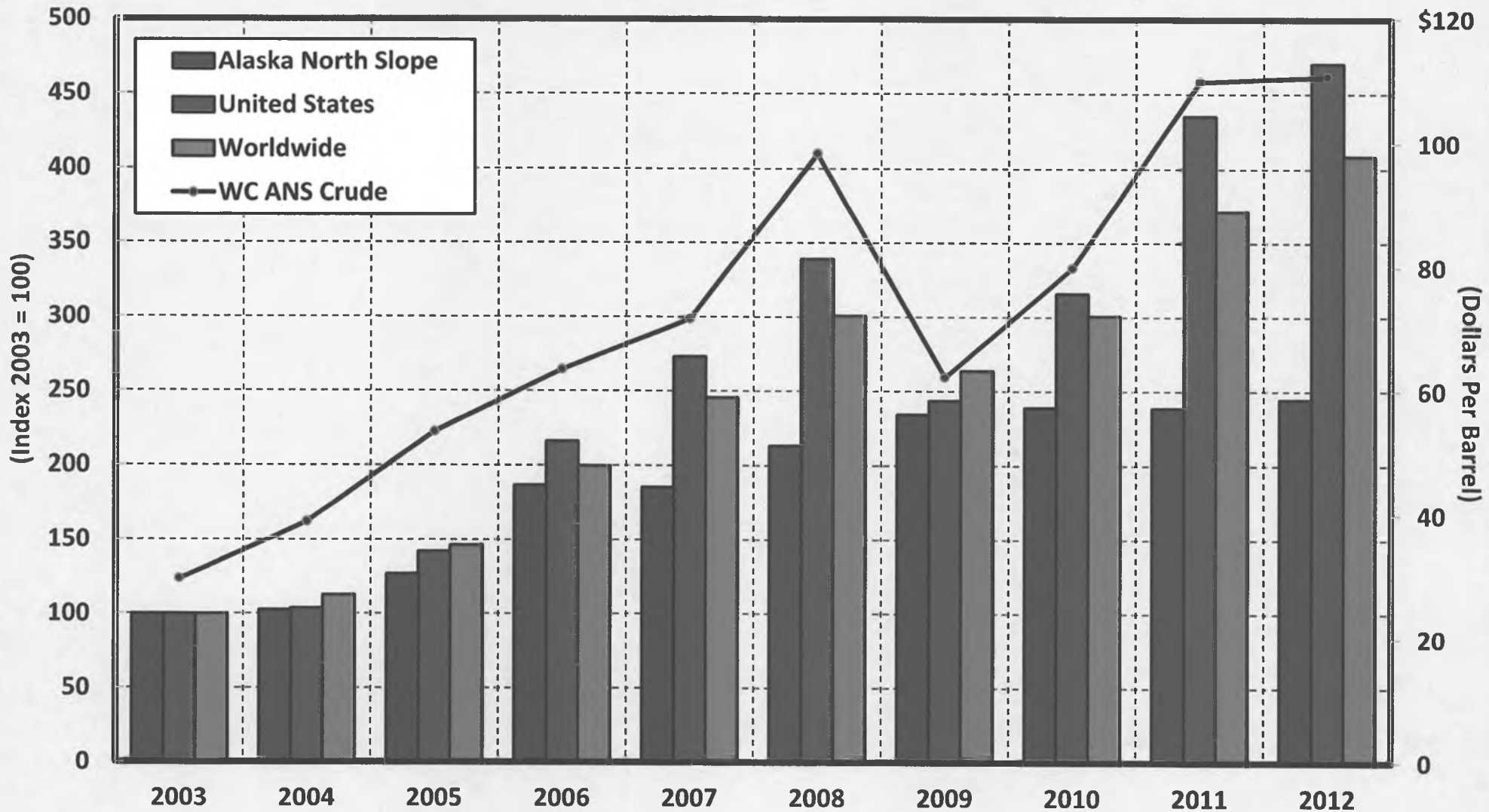
CAPITAL INVESTMENT & THE U.S. ENERGY RENAISSANCE

- Global and U.S. hydrocarbon boom
- IEA World Energy Outlook 2012 – U.S. to overtake Saudi Arabia and Russia to become the world's largest global oil producer by the second half of this decade
 - Congressional Research Service report found that since 2007, all increases in U.S. oil and gas production occurred outside federally controlled areas, with oil and gas production on federal lands decreasing by 7% and 33% respectively
- Financial Times, November 12, 2012 – *“U.S. set to become biggest oil producer”*
- Financial Times, December 27, 2012 – *“Oil and gas – hey big spenders”*
 - 2012 - \$600 billion on exploration and production in oil and gas industry
 - 2013 projected - \$650 billion on exploration and production in oil and gas industry
 - Alaska - one of the world's great hydrocarbon basins – accounted approximately half of 1% of these expenditures in 2012



EST. CAPITAL SPENDING FOR EXPLORATION & DEVELOPMENT:

AK NORTH SLOPE VS. U.S. & WORLD SPENDING*, 2003-2012



* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

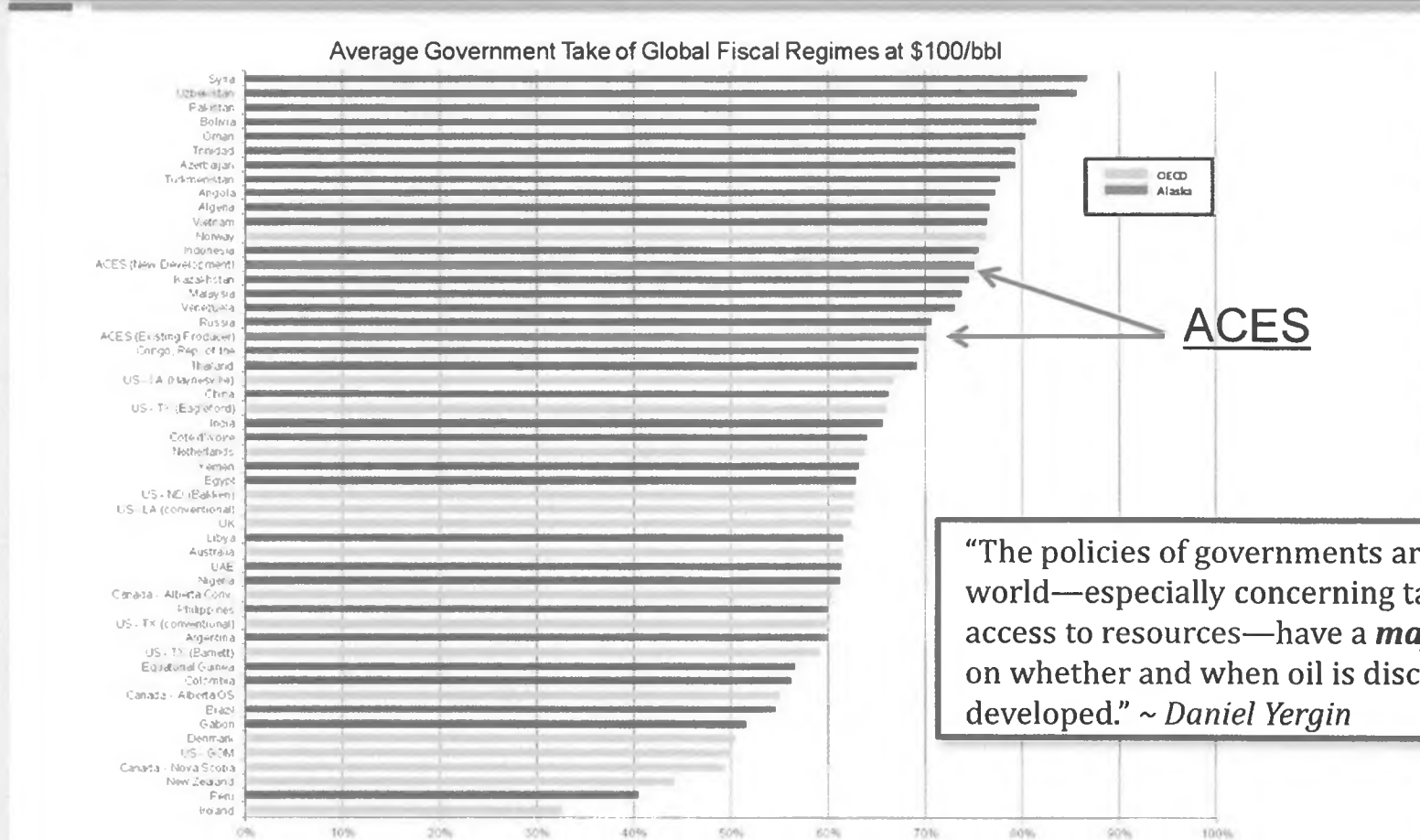
PART II



**Is the Current Tax System
Working for Alaskans?**

AVERAGE GOVERNMENT TAKE AT \$100/BBL

Regime Competitiveness: Average Government Take at \$100/bbl



“The policies of governments around the world—especially concerning taxes and access to resources—have a **major impact** on whether and when oil is discovered and developed.” ~ Daniel Yergin

CURRENT SYSTEM IS NOT WORKING FOR ALASKANS

Examples of the Real Giveaway

- ACES has taken away most of the incentive to produce more barrels and more profit at higher prices
 - In FY08, North Slope oil averaged \$96.51 per barrel and the total production tax collected was \$6.8 billion
 - By next fiscal year (FY14), prices are forecasted to be \$13 higher at \$109.61, but the total production tax collected is estimated to be \$3.8 billion – a decrease of more than \$3 billion in unrestricted general fund revenue
- The Ultimate Giveaway:
 - Comparing year-end 2011 and year-end 2012, there were ~40,000 fewer barrels of oil per day flowing through TAPS
 - Approximately 14.6 million barrels a year = \$1.46 billion in lost economic activity and value

NEW ENTRANTS IN ALASKA'S CURRENT TAX SYSTEM

- ***Secure Alaska's Future—Oil*** is the State's comprehensive strategy to increase TAPS throughput to one million barrels a day
 - I. Enhance Alaska's global competitiveness and investment climate
 - II. Ensure the permitting process is structured and efficient
 - III. Facilitate and incentivize the next phases of North Slope development
 - IV. Promote Alaska's resources and positive investment climate to world markets***

- **Governor Parnell's 2013 State of the State: "Our problem is not below the ground. Our problem is above the ground."**
 - The missing piece is meaningful tax reform
 - "Our state's prosperity has always rested on natural resources. Tonight, that foundation is at risk, not because we are running out of oil, but because we are running behind the competition."



NEW ENTRANTS IN ALASKA'S CURRENT TAX SYSTEM

- REPSOL EXAMPLE -



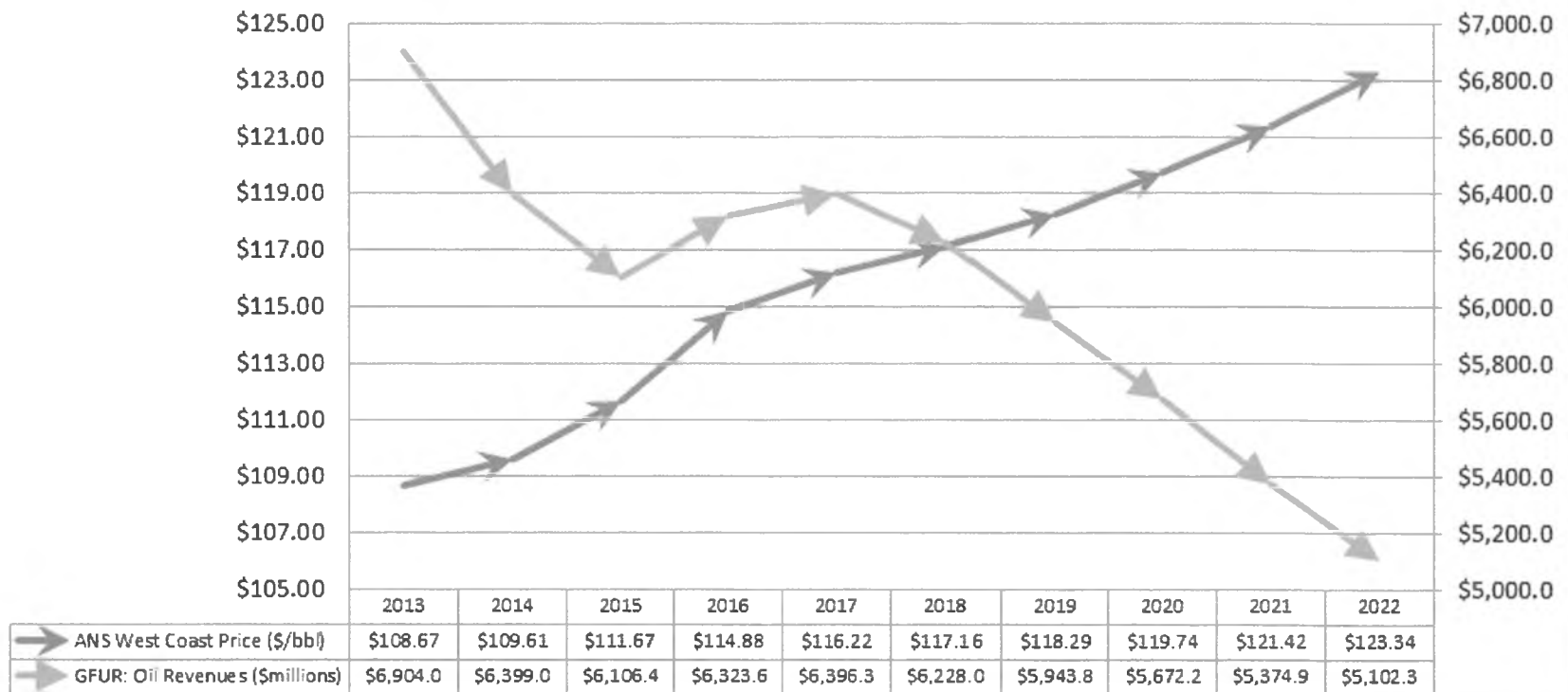
Excerpts from
March 6, 2013,
letter to the
Senate Finance
Committee



- We came to the North Slope in 2011, after many years of reviewing numerous opportunities and turning them down. We considered the North Slope to be an especially promising area that has been shown to be oil rich and with lower exploratory risk than other regions.
- Offsetting these positive aspects were the extreme climate, and a short exploration season in a remote, expensive and environmentally sensitive area with little established infrastructure. **The biggest negative factor, however, was a tax system that did not encourage long-term investment.**
- With regards to investment in onshore state lands, we found that in all but the best scenarios, **the progressive nature of the ACES petroleum tax structure did not allow for returns that were competitive with opportunities in the lower forty-eight states or other parts of the world.**
- This view changed in early 2011 when it appeared that serious reform of the ACES tax structure would be enacted... [Repsol was] convinced that the State of Alaska was serious about providing the necessary incentives for new investment. We were also convinced that if we waited for meaningful tax reform to be enacted, we would risk being lost in the rush of companies to Alaska to invest in North Slope exploration and development projects.


NORTH SLOPE OIL PRICES & UNRESTRICTED GF/UR REVENUES

Fall 2012 Forecast:
North Slope Oil Prices and Unrestricted GF Oil Revenues



- Under ACES – by 2022 oil prices will have to rise to \$123.44 per barrel for unrestricted general fund oil revenues to meet the forecast
- If oil prices do not rise further or if they fall, this revenue decline becomes much more severe

THE CHALLENGE

- 
- If we do not make the changes today to encourage the investment that will pay dividends tomorrow we are dooming our future to deficits and decline
 - If you are evaluating this challenge based simply on the range of the fiscal note, you are missing the scale of the obstacle we face in the future
 - \$1.3 billion less in revenues will require more than \$4,000 in new revenues per job in Alaska¹ – those revenues will have to come from somewhere

¹ \$1.3 billion divided by 320,600 (AK Department of Labor, February 2013 Total Non-Farm Wage and Salary)

PART III



**Production, Production,
Production**

OIL TAX REFORM

- PRINCIPLES -

- Tax reform must be fair to Alaskans
- Encourage new production
- Simple so that it restores balance to the system
- Durable for the long-term



CS SB21(FIN)'S MAJOR COMPONENTS ARE FOCUSED ON INCENTIVIZING PRODUCTION

ACES

- Qualified Capital Credit
 - Based on 20% of qualified capital expenditures
 - To generate an additional \$100 million in capital credits a company must spend \$500 million
 - $\$500 \text{ mm} \times 20\% = \100 mm

CS SB21(FIN)

- Per Barrel Credit
 - Based on taxable production
 - To generate an additional \$100 million in credits a company must produce an additional 20 million barrels
 - $20 \text{ mm} \times \$5 = \100 mm
- Gross Revenue Exclusion
 - Tax benefit for new production
 - Newer units (2003 and after)
 - New participating areas in legacy units
 - Expansions of participating areas in legacy units

STATUS QUO OF CONTINUED DECLINE IS UNACCEPTABLE

- This is about Alaskans' future— present citizens and future generations
- We clearly have the resource base to turn our oil production decline around
- The status quo of continued decline when there is a global investment boom and literally every other basin in the United States is increasing production is unacceptable
- ACES, although well-intentioned, is significantly contributing to our production decline as well as discouraging potential new entrants.
- As production continues to decline, the strain on the state will only grow
- Tax reform must focus on incentivizing production
- “The ANCSA Regional Association is calling on state leaders to continue moving on an oil tax reform bill. Tax reform for the oil and gas industry that results in increased production will give communities across the state access to important economic opportunities. Association members stress the importance of new and increased production with long-term benefits to Alaskans.” – March 28, 2013

4/6/13



ACES, SB21/HB72 and HCS CS SB21 (RES) for House Finance Committee

**Barry Pulliam
Managing Director
Econ One Research, Inc.**

April 6, 2013

Key Features of ACES, SB21/HB72 and HCS CS SB21 (RES)

	ACES	SB71/HB72	HCS CS SB21 (RES)
Base Tax Rate	25%	25%	33%
Progressive Tax	0.4% Per \$1 Above \$30 Net; 0.1% Per \$1 Above \$92.50 Net	None	None
Maximum Tax Rate	75%	25%	33%
Credits	20% of Qualified Capital Expenditure	None	Up to \$8/Bbl Produced
Gross Revenue Exclusion (GRE)			
Rate	N/A	20%	20%
Applicability		New Units/PAs	New Units/PAs PA Expansions
Monetization of Net Operating Losses (NOLs)	Yes	No Carried Forward With 15% Increase	Yes
Minimum Tax	4% of Gross @ WC ANS > \$25	4% of Gross @ WC ANS > \$25	4% of Gross @ WC ANS > \$25
Credits Reduce Minimum Tax	Yes	N/A	GRE Barrels Only
Small Producer Credit	\$12 Million (2016)	\$12 Million (2022)	\$12 Million (2022)

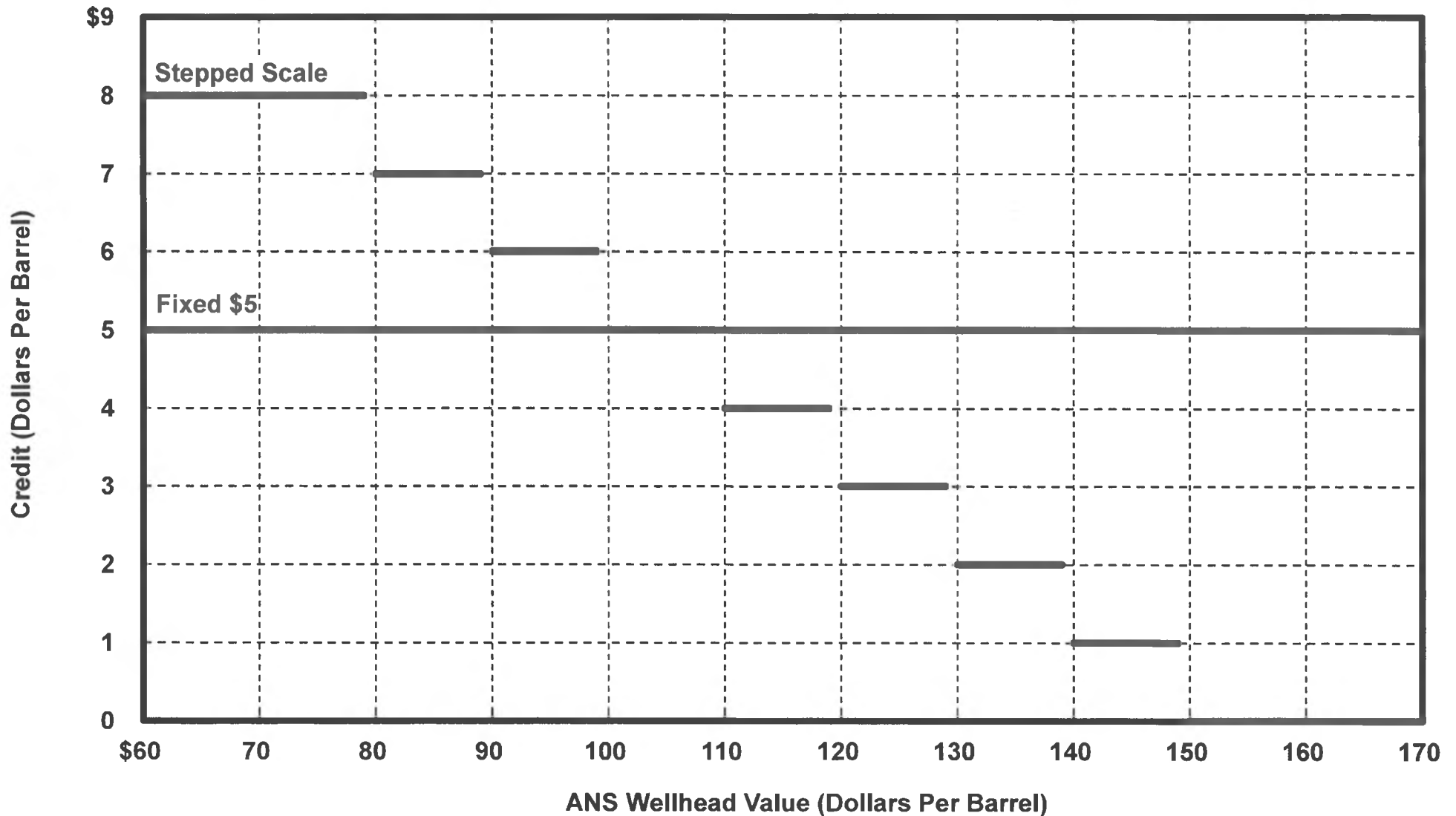
Tax Calculation Under ACES

(a) West Coast Price (\$/Bbl)			\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
(b) Transportation (\$/Bbl)	-		10.00	10.00	10.00	10.00	10.00
(c) Gross Value (\$/Bbl)	(a) - (b)	=	\$70.00	\$90.00	\$110.00	\$130.00	\$150.00
(d) Operating Costs (\$/Bbl)	-		15.00	15.00	15.00	15.00	15.00
(e) Capital Expenditures (\$/Bbl)	-		15.00	15.00	15.00	15.00	15.00
(f) Net Value (\$/Bbl)	(c) - (d) - (e)	=	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00
(g) ACES Base Tax Rate (Percent)			25%	25%	25%	25%	25%
(h) ACES Progressive Tax Rate (Percent)	+		4%	12%	20%	26%	28%
(i) Total Tax Rate (Percent)	(g) + (h)	=	29%	37%	45%	51%	53%
(j) Production Tax Before Credit (\$/Bbl)	(f) x (i)		\$11.60	\$22.20	\$36.00	\$50.75	\$63.30
(k) Qualified Capital Expenditure Credit (\$/Bbl)	(e) x 20%	-	3.00	3.00	3.00	3.00	3.00
(l) Production Tax After Credit (\$/Bbl)	(j) - (k)		\$8.60	\$19.20	\$33.00	\$47.75	\$60.30
(m) Taxable Barrels (Bbls)	x		1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
(n) Total Production Tax After Credit (\$000)	(l) x (m)	=	\$8,600	\$19,200	\$33,000	\$47,750	\$60,300
(o) Effective Tax Rate on Net Value (%)	(l) ÷ (f)		21.5%	32.0%	41.3%	47.8%	50.3%
(p) Effective Tax Rate on Gross Value (%)	(l) ÷ (c)		12.3%	21.3%	30.0%	36.7%	40.2%

Tax Calculation Under ACES: Varying Costs

(a) West Coast Price (\$/Bbl)			\$100.00	\$100.00	\$100.00
(b) Transportation (\$/Bbl)	-		10.00	10.00	10.00
(c) Gross Value (\$/Bbl)	(a) - (b)	=	\$90.00	\$90.00	\$90.00
(d) Operating Costs (\$/Bbl)	-		10.00	15.00	20.00
(e) Capital Expenditures (\$/Bbl)	-		10.00	15.00	20.00
(f) Net Value (\$/Bbl)	(c) - (d) - (e)	=	\$70.00	\$60.00	\$50.00
(g) ACES Base Tax Rate (Percent)			25%	25%	25%
(h) ACES Progressive Tax Rate (Percent)	+		16%	12%	8%
(i) Total Tax Rate (Percent)	(g) + (h)	=	41%	37%	33%
(j) Production Tax Before Credit (\$/Bbl)	(f) x (i)		\$28.70	\$22.20	\$16.50
(k) Qualified Capital Expenditure Credit (\$/Bbl)	(e) x 20%	-	2.00	3.00	4.00
(l) Production Tax After Credit (\$/Bbl)	(j) - (k)		\$26.70	\$19.20	\$12.50
(m) Taxable Barrels (Bbls)	x		1,000,000	1,000,000	1,000,000
(n) Total Production Tax After Credit (\$000)	(l) x (m)	=	\$26,700	\$19,200	\$12,500
(o) Effective Tax Rate on Net Value (%)	(l) ÷ (f)		38.1%	32.0%	25.0%
(p) Effective Tax Rate on Gross Value (%)	(l) ÷ (c)		29.7%	21.3%	13.9%

HCS CS SB21 (RES) Per-Barrel Credits Non-GRE Volumes (Stepped Scale) v. GRE Volumes (Fixed)

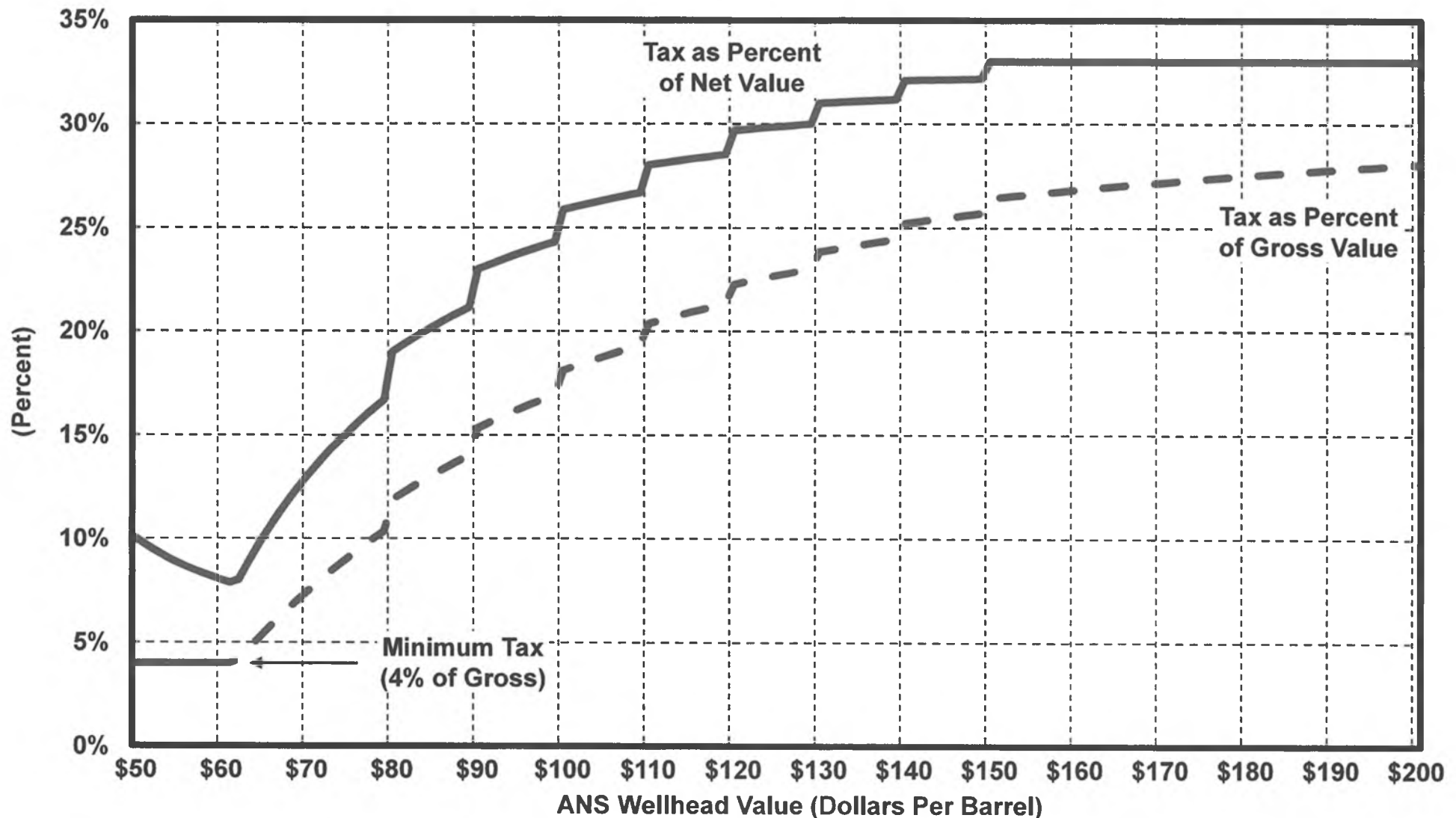


Tax Calculation Using Stepped Scale Production Credit (Volumes Not Subject to Gross Revenue Exclusion)

(a) West Coast Price (\$/Bbl)			\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
(b) Transportation (\$/Bbl)	-		10.00	10.00	10.00	10.00	10.00
(c) Gross Value (\$/Bbl)	(a) - (b)	=	\$70.00	\$90.00	\$110.00	\$130.00	\$150.00
(d) Lease Expenditures (\$/Bbl)	-		30.00	30.00	30.00	30.00	30.00
(e) Net Value (\$/Bbl)	(c) - (d)	=	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00
(f) Tax Rate (Percent)	x		33%	33%	33%	33%	33%
(g) Production Tax Before Credit (\$/Bbl)	(e) x (f)		\$13.20	\$19.80	\$26.40	\$33.00	\$39.60
(h) Production Credit (\$/Bbl)	-		8.00	6.00	4.00	2.00	0.00
(i) Production Tax After Credit (\$/Bbl)	(g) - (h)		\$5.20	\$13.80	\$22.40	\$31.00	\$39.60
(j) Taxable Barrels (Bbls)	x		1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
(k) Total Production Tax After Credit (\$000)	(i) x (j)	=	\$5,200	\$13,800	\$22,400	\$31,000	\$39,600
(l) Effective Tax Rate on Net Value (%)	(i) ÷ (e)		13.0%	23.0%	28.0%	31.0%	33.0%
(m) Effective Tax Rate on Gross Value (%)	(i) ÷ (c)		7.4%	15.3%	20.4%	23.8%	26.4%

Note: Per barrel credit is equal to \$8/Bbl at wellhead prices below \$80/bbl, diminishing to \$0/Bbl at a wellhead price of \$150/bbl. The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above \$25/Bbl.

Effective Tax Rates Under HCS CS SB21 (RES) (Volumes Not Subject to Gross Revenue Exclusion)

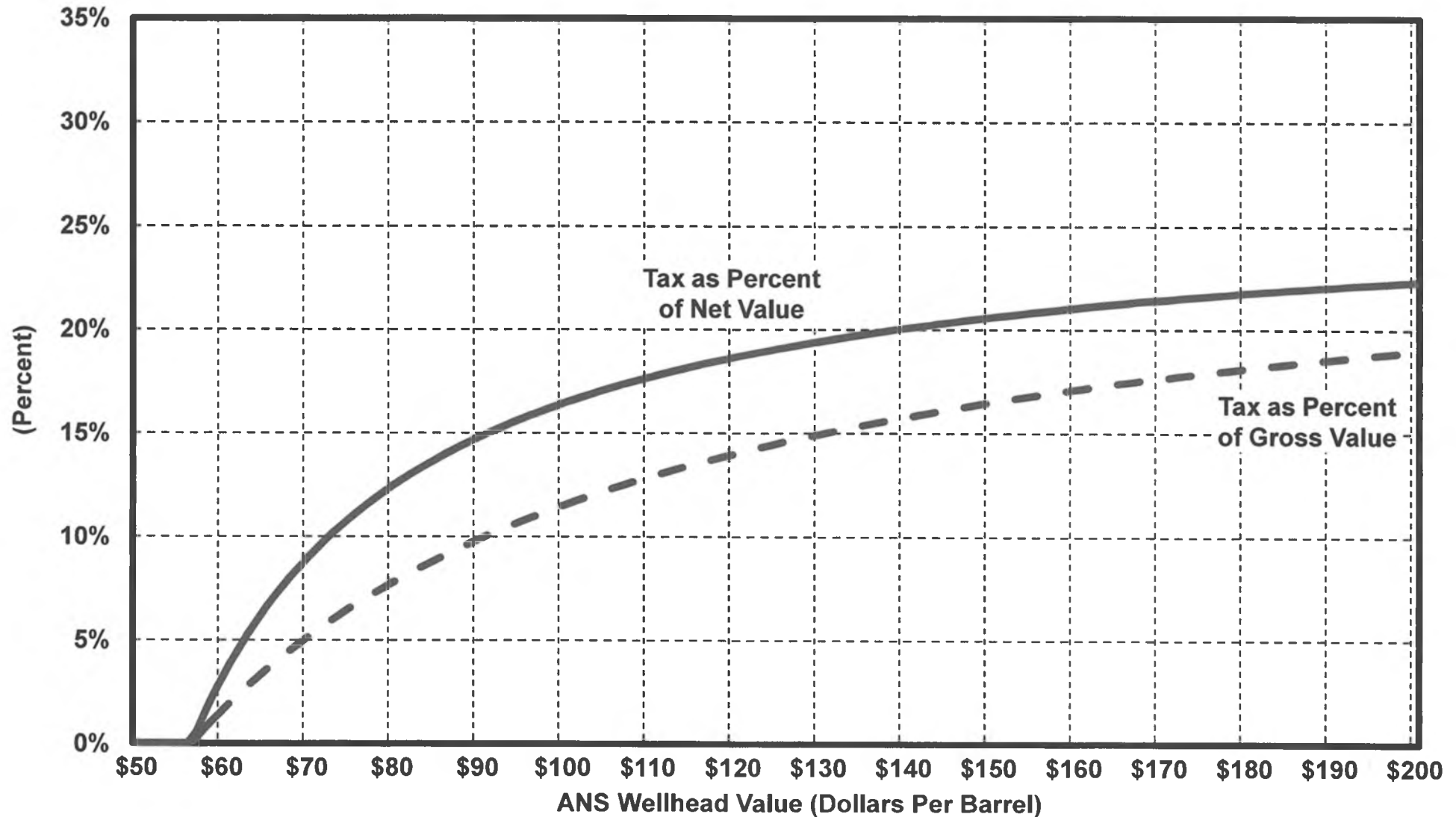


Note: Per barrel credit is equal to \$8/Bbl at wellhead prices below \$80/bbl, diminishing to \$0/Bbl at a wellhead price of \$150/bbl.
The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above \$25/Bbl.

Tax Calculation Using Fixed \$5 Production Credit (Volumes Subject to Gross Revenue Exclusion)

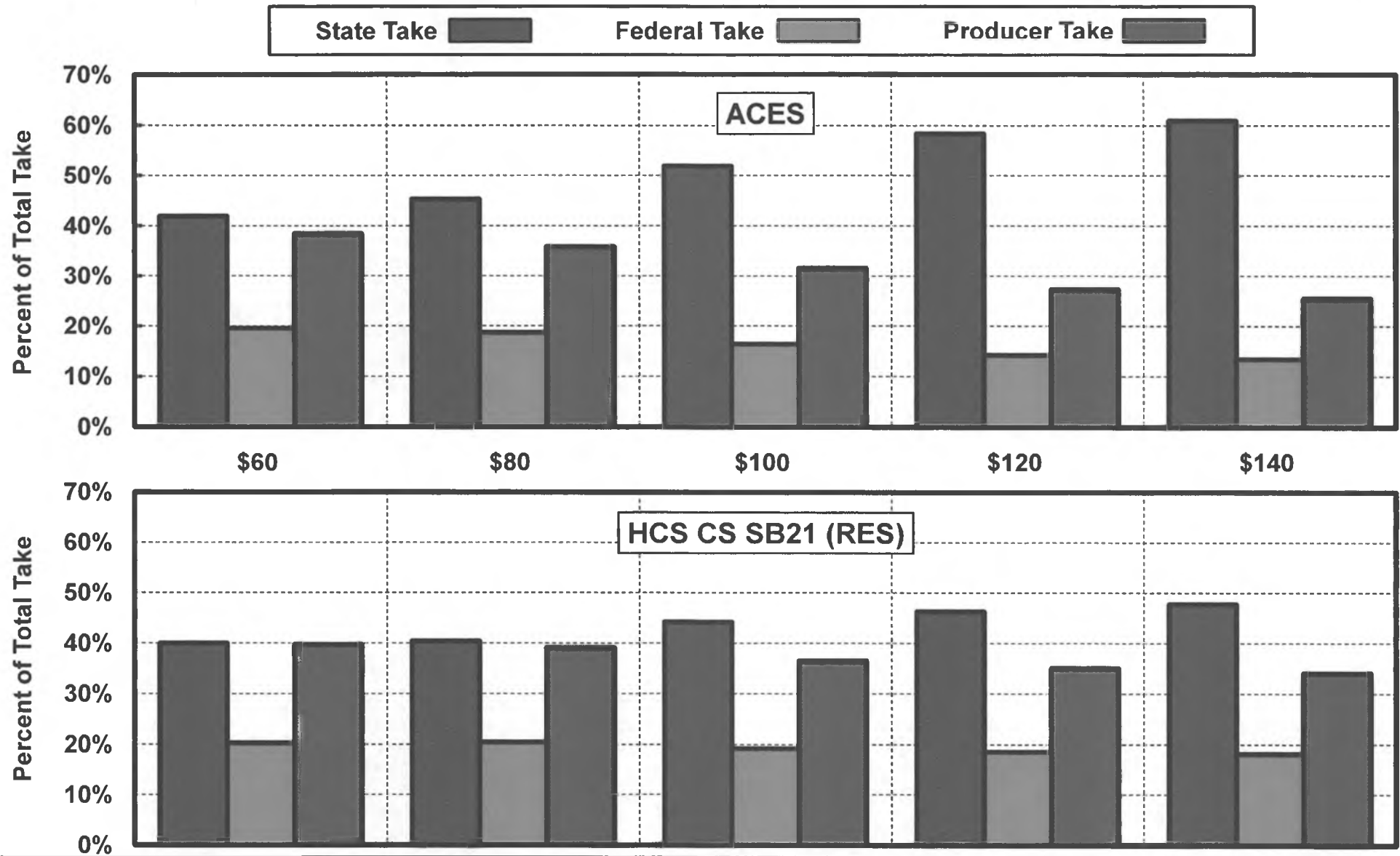
(a) West Coast Price (\$/Bbl)			\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
(b) Transportation (\$/Bbl)	-		10.00	10.00	10.00	10.00	10.00
(c) Gross Value (\$/Bbl)	(a) - (b)	=	\$70.00	\$90.00	\$110.00	\$130.00	\$150.00
(d) Lease Expenditures (\$/Bbl)	-		30.00	30.00	30.00	30.00	30.00
(e) Net Value (\$/Bbl)	(c) - (d)	=	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00
(f) Gross Revenue Exclusion (%)			20%	20%	20%	20%	20%
(g) Gross Value After GRE (\$/Bbl)	(c) x [100%-(h)]		\$56.00	\$72.00	\$88.00	\$104.00	\$120.00
(h) Net Value After GRE (\$/Bbl)	(g) - (d)		\$26.00	\$42.00	\$58.00	\$74.00	\$90.00
(i) Tax Rate (Percent)	x		33%	33%	33%	33%	33%
(j) Production Tax Before Credit (\$/Bbl)	(h) x (i)	=	\$8.58	\$13.86	\$19.14	\$24.42	\$29.70
(k) Production Credit (\$/Bbl)	-		5.00	5.00	5.00	5.00	5.00
(l) Production Tax After Credit (\$/Bbl)	(j) - (k)	=	\$3.58	\$8.86	\$14.14	\$19.42	\$24.70
(m) Taxable Barrels (Bbls)	x		1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
(n) Total Production Tax After Credit (\$000)	(l) x (m)	=	\$3,580	\$8,860	\$14,140	\$19,420	\$24,700
(o) Effective Tax Rate on Net Value (%)	(l) ÷ (e)		9.0%	14.8%	17.7%	19.4%	20.6%
(p) Effective Tax Rate on Gross Value (%)	(l) ÷ (c)		5.1%	9.8%	12.9%	14.9%	16.5%

Effective Tax Rates Under HCS CS SB21 (RES) (Volumes Subject to Gross Revenue Exclusion)



State, Federal and Producer Take at Various \$2012 WC ANS Prices for All Producers (FY 2015 - FY 2019)

ACES and HCS CS SB21 (RES)

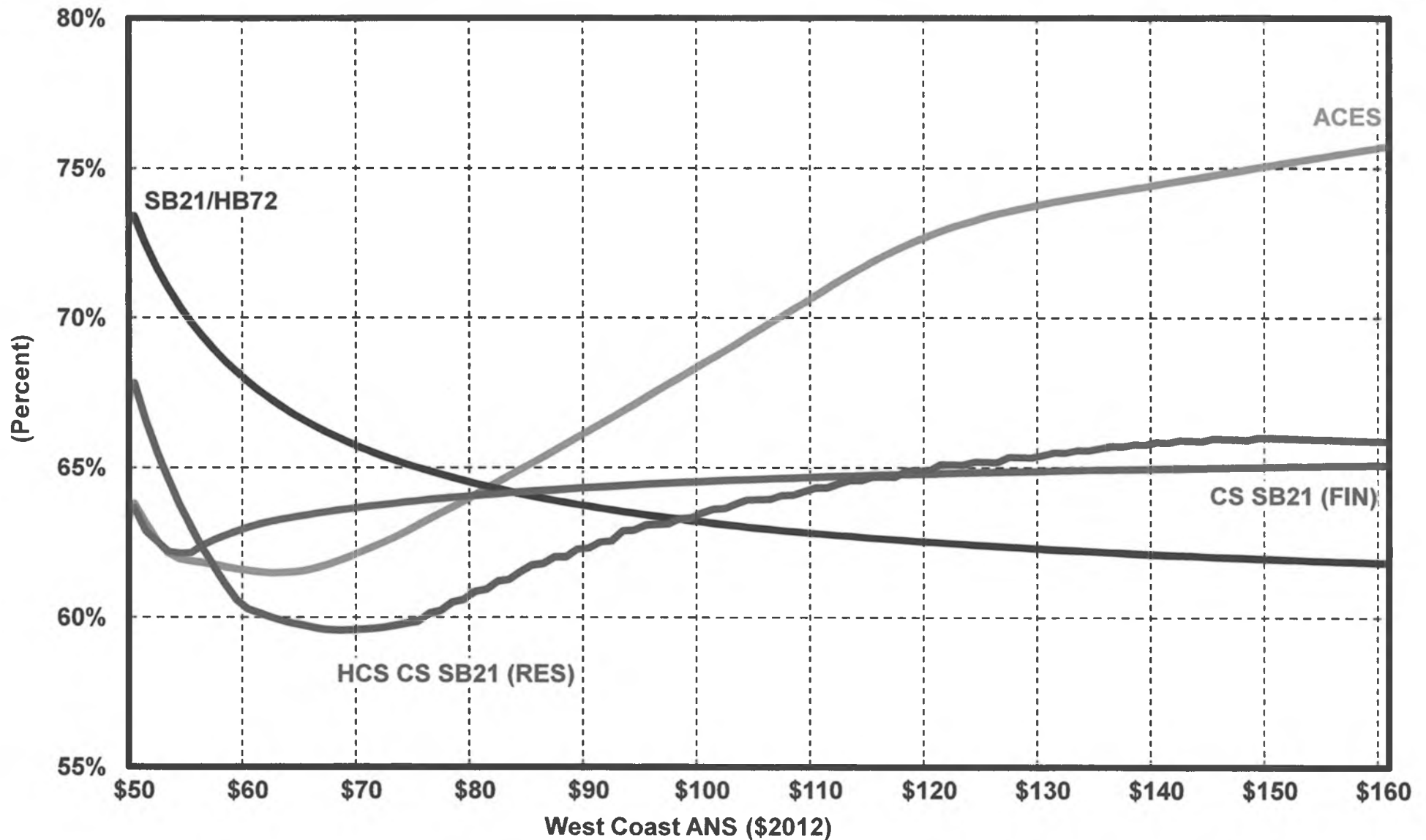


Average Government Take for All Existing Producers (FY2015-FY2019)

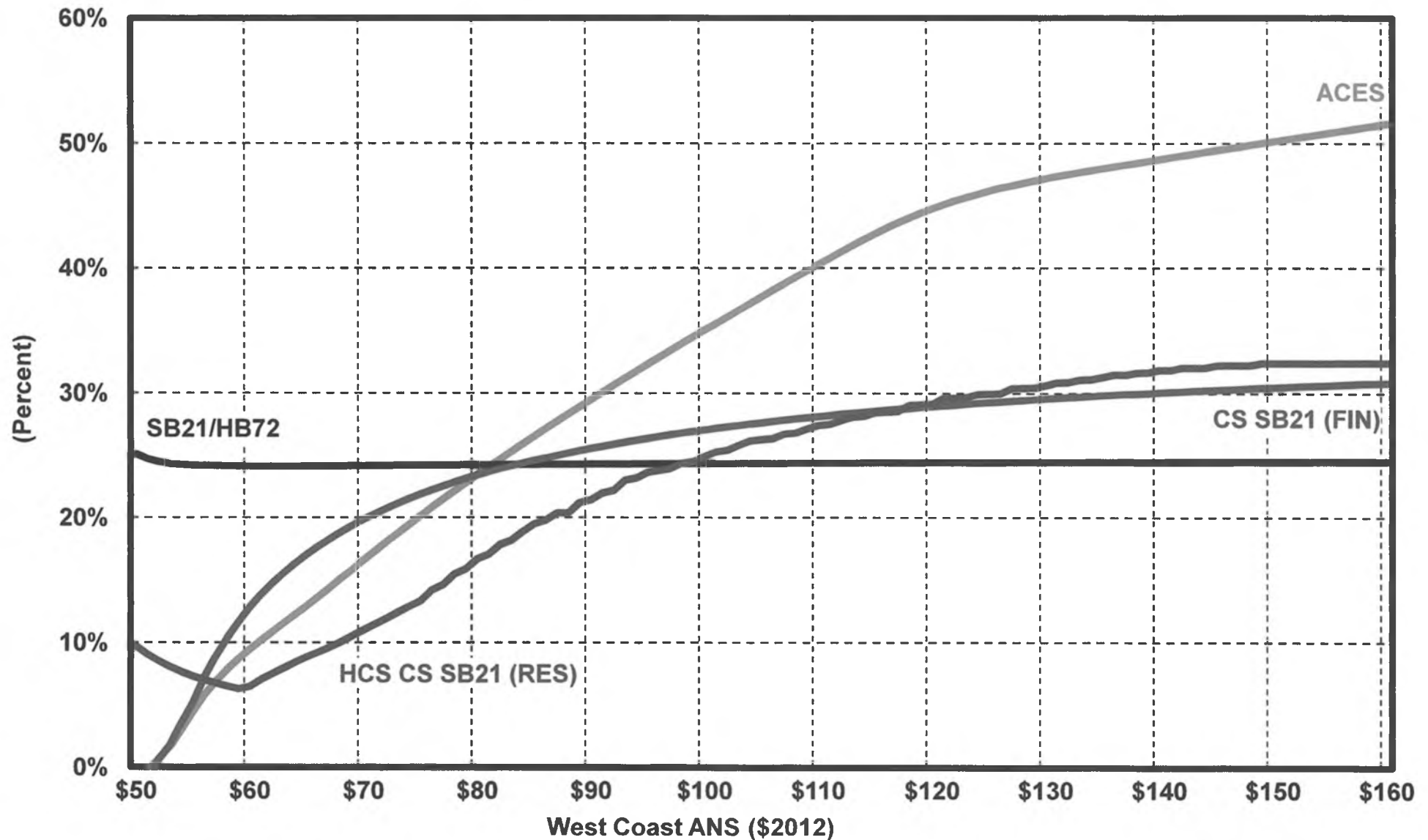
2012 West Coast ANS Price (\$2012 \$/Bbl)	Government Take			
	HB72/SB21	CS SB21 (FIN)	HCS CS SB21 (RES)	ACES
	(Percent)			
(1)	(2)	(3)	(4)	(5)
\$60	67.9%	63.0%	60.3%	61.6%
\$70	65.7%	63.7%	59.6%	62.2%
\$80	64.5%	64.1%	60.9%	64.1%
\$90	63.7%	64.3%	62.3%	66.2%
\$100	63.2%	64.5%	63.5%	68.5%
\$110	62.8%	64.7%	64.3%	70.7%
\$120	62.5%	64.8%	64.9%	72.8%
\$130	62.3%	64.9%	65.4%	73.8%
\$140	62.1%	65.0%	65.9%	74.5%
\$150	62.0%	65.0%	66.0%	75.1%
\$160	61.8%	65.1%	65.9%	75.7%

Note: Under HCS CS SB21 (RES), per barrel credit is equal to \$8/Bbl at wellhead prices below \$80/bbl, diminishing to \$0/Bbl at a wellhead price of \$150/bbl. The minimum tax is 4% of the wellhead value of the oil whenever West Coast ANS is above \$25/Bbl for non-GRE barrels.

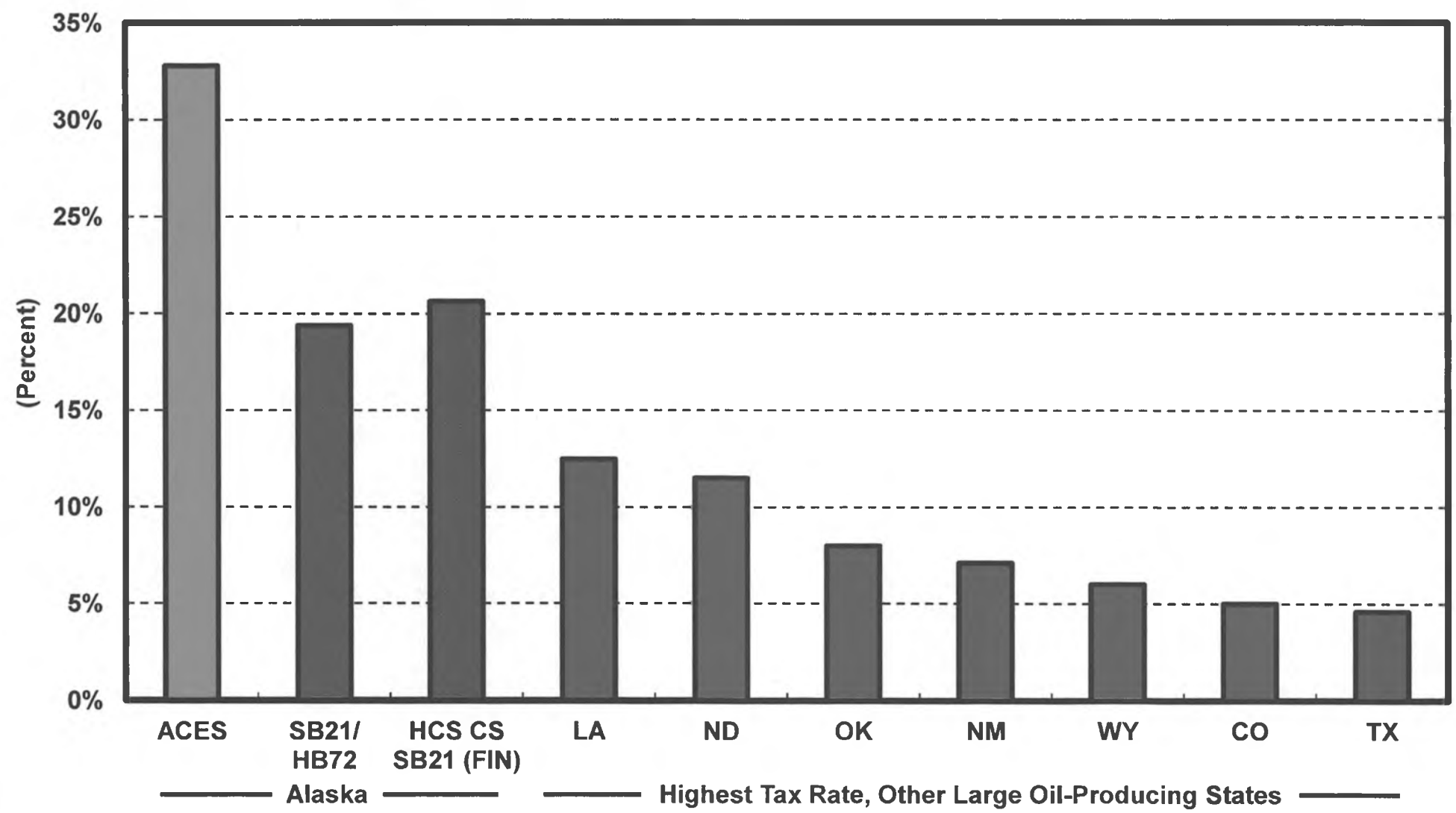
Average Government Take for All Existing Producers (FY2015-FY2019) ACES v. SB21/HB72, CS SB21 (FIN) and HCS CS SB21 (RES)



Effective Tax Rate for All Existing Producers (FY2015-FY2019) ACES v. SB21/HB72, CS SB21 (FIN) and HCS CS SB21 (RES)



Effective Tax Rates on Gross Value for Legacy Production ACES vs. SB21/HB72, HCS CS SB21 (RES) and Other Large Oil-Producing States With Production Taxes at \$100 Wellhead Value*



Note: California and Federal Offshore properties are not subject to a severance tax.
* FY2012 Combined PBU/KPU Costs and Volumes

Summary of Investment Measures for New Participant 50 MMBO Alaska Oil Development ACES and HCS CS SB21 (RES) v. Benchmark Areas



Real \$2012 West Coast ANS Price	ACES		HCS CS SB21 (RES)							United Kingdom	
	16.67% Royalty	12.50% Royalty	16.67% Royalty	12.50% Royalty	Unconventional Lower-48		Offshore	Canada	Norway	Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
	(1)	(2)	(3)	(4)	Eagle Ford	Bakken	GOM	Oil Sands SAGD	(9)	(10)	(11)
Producer NPV-12 / BOE (Dollars Per BOE)											
\$80	\$2.28	\$2.76	\$3.24	\$2.95	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$4.17	\$4.68	\$6.35	\$6.39	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$5.79	\$6.35	\$9.21	\$9.80	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
Profitability Index-12											
\$80	1.18	1.22	1.26	1.24	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.33	1.37	1.51	1.51	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.46	1.51	1.74	1.78	1.78	1.60	1.85	1.26	1.27	1.42	1.55
IRR (Percent)											
\$80	18.4%	19.6%	19.5%	18.8%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	23.3%	24.5%	25.6%	25.4%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	26.9%	28.1%	30.5%	31.1%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
5-Year (2017-2021) Cash Margins (Dollars Per BOE)											
\$80	\$20.82	\$22.25	\$23.62	\$22.41	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$26.78	\$28.26	\$33.03	\$32.55	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$30.79	\$32.26	\$40.98	\$42.16	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
Government Take (Percent)											
\$80	70.4%	67.8%	60.2%	61.4%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	73.9%	72.0%	62.1%	61.3%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	76.0%	74.4%	63.5%	61.3%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
State/Municipal NPV-12/BOE (Dollars Per BOE)											
\$80	\$6.06	\$5.33	\$4.58	\$5.03	-	-	-	-	-	-	-
\$100	\$11.80	\$11.02	\$8.45	\$8.39	-	-	-	-	-	-	-
\$120	\$17.96	\$17.10	\$12.70	\$11.78	-	-	-	-	-	-	-

* Brownfield Allowance applied to 100 MMBOE development.

Alaska Oil Development : New development profile and costs are based on Pioneer's presentation dated February 18, 2013 -- \$18/Bbl. Development Capex.

Summary of Investment Measures for Incumbent 50 MMBO Alaska Oil Development ACES and HCS CS SB21 (RES) v. Benchmark Areas

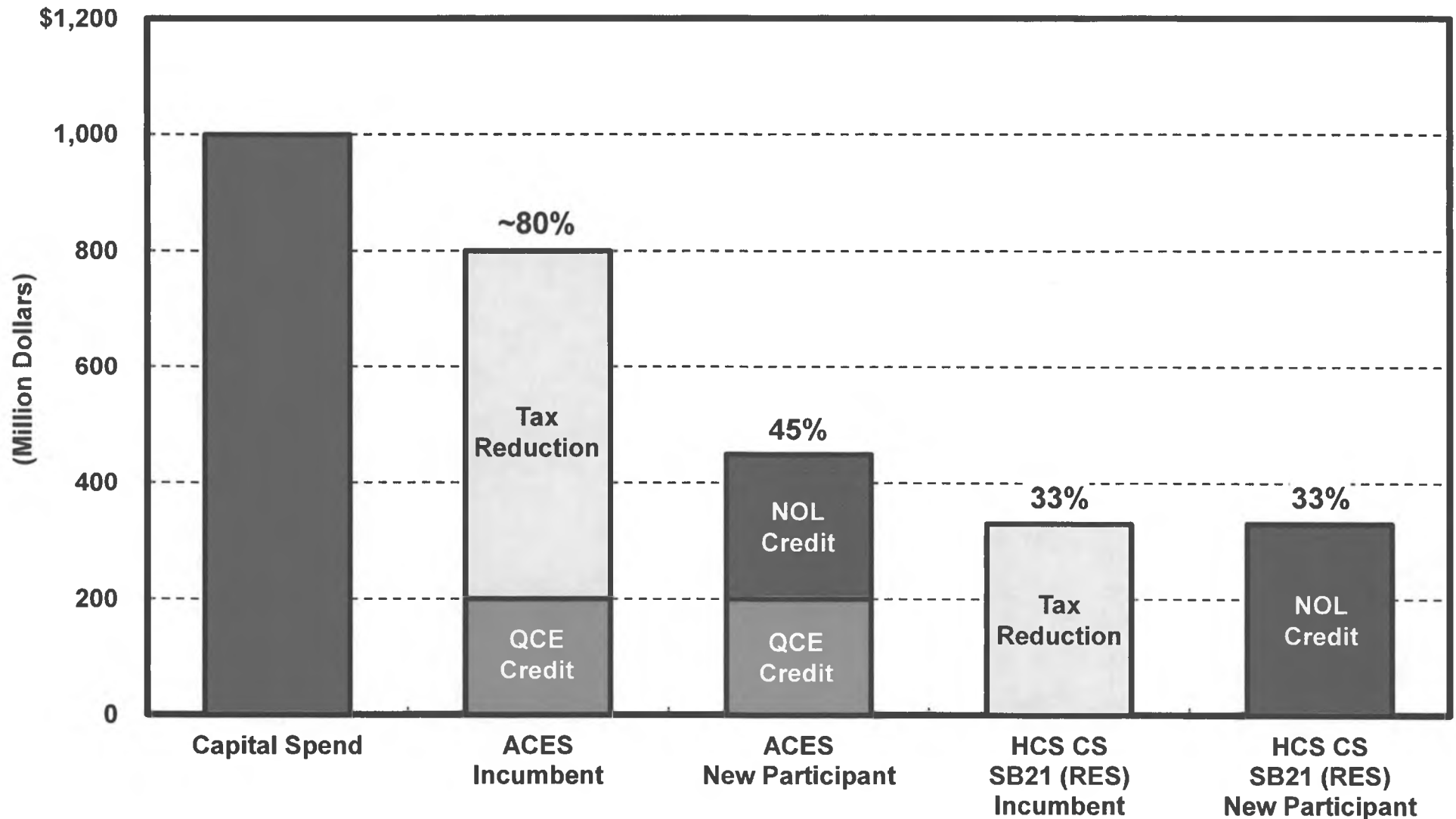
Real \$2012 West Coast ANS Price	ACES		HCS CS SB21 (RES)		Unconventional Lower-48		Offshore GOM	Canada Oil Sands SAGD	Norway	United Kingdom	
	16.67%	12.50%	GRE	Non-GRE	Eagle Ford	Bakken				Pre-1993 w/ Brownfield Allowance*	Post-1993 w/ Brownfield Allowance*
	Royalty	Royalty	Royalty	Royalty	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	(1)	(2)	(3)	(4)							
					Producer NPV-12 / BOE (Dollars Per BOE)						
\$80	\$3.44	\$3.88	\$3.23	\$3.04	\$3.61	\$0.67	\$2.80	(\$0.93)	\$0.24	\$4.81	\$4.62
\$100	\$5.94	\$6.39	\$6.14	\$6.24	\$6.75	\$4.29	\$6.22	\$0.46	\$2.34	\$7.09	\$8.25
\$120	\$8.28	\$8.82	\$8.92	\$9.54	\$11.17	\$9.16	\$9.64	\$2.01	\$4.44	\$9.09	\$11.88
					Profitability Index-12						
\$80	1.27	1.31	1.26	1.24	1.25	1.04	1.25	0.88	1.01	1.22	1.21
\$100	1.47	1.51	1.49	1.50	1.47	1.28	1.55	1.06	1.14	1.33	1.38
\$120	1.66	1.70	1.71	1.76	1.78	1.60	1.85	1.26	1.27	1.42	1.55
					IRR (Percent)						
\$80	23.7%	24.9%	19.6%	19.2%	29.9%	13.6%	18.3%	9.7%	12.4%	34.5%	24.7%
\$100	34.8%	36.1%	25.4%	25.3%	46.3%	22.7%	24.3%	13.1%	16.0%	45.2%	32.9%
\$120	47.8%	49.3%	30.2%	30.9%	73.6%	37.0%	29.3%	16.3%	19.3%	53.5%	40.2%
					5-Year (2017-2021) Cash Margins (Dollars Per BOE)						
\$80	\$20.26	\$21.48	\$23.10	\$22.72	\$23.39	\$28.39	\$26.31	\$26.07	\$34.51	\$22.94	\$29.35
\$100	\$25.51	\$26.81	\$31.36	\$31.58	\$29.99	\$36.48	\$37.34	\$29.14	\$39.42	\$28.85	\$37.82
\$120	\$28.68	\$30.18	\$39.20	\$40.45	\$36.87	\$44.91	\$48.37	\$33.37	\$44.32	\$31.29	\$46.30
					Government Take (Percent)						
\$80	67.5%	65.0%	60.9%	61.6%	71.7%	77.1%	55.7%	63.4%	67.8%	61.0%	52.0%
\$100	71.9%	70.2%	63.0%	62.0%	67.9%	72.1%	52.6%	63.5%	71.7%	68.6%	55.8%
\$120	73.3%	71.7%	64.4%	62.1%	65.1%	68.7%	50.9%	63.0%	73.4%	72.0%	57.5%
					State/Municipal NPV-12/BOE (Dollars Per BOE)						
\$80	\$4.27	\$3.60	\$4.61	\$4.89	-	-	-	-	-	-	-
\$100	\$9.08	\$8.38	\$8.77	\$8.62	-	-	-	-	-	-	-
\$120	\$14.13	\$13.30	\$13.15	\$12.19	-	-	-	-	-	-	-

Note: Analysis of incumbent production includes "buy-down" impact for reduced taxes on existing production.

* Brownfield Allowance applied to 100 MMBOE development.

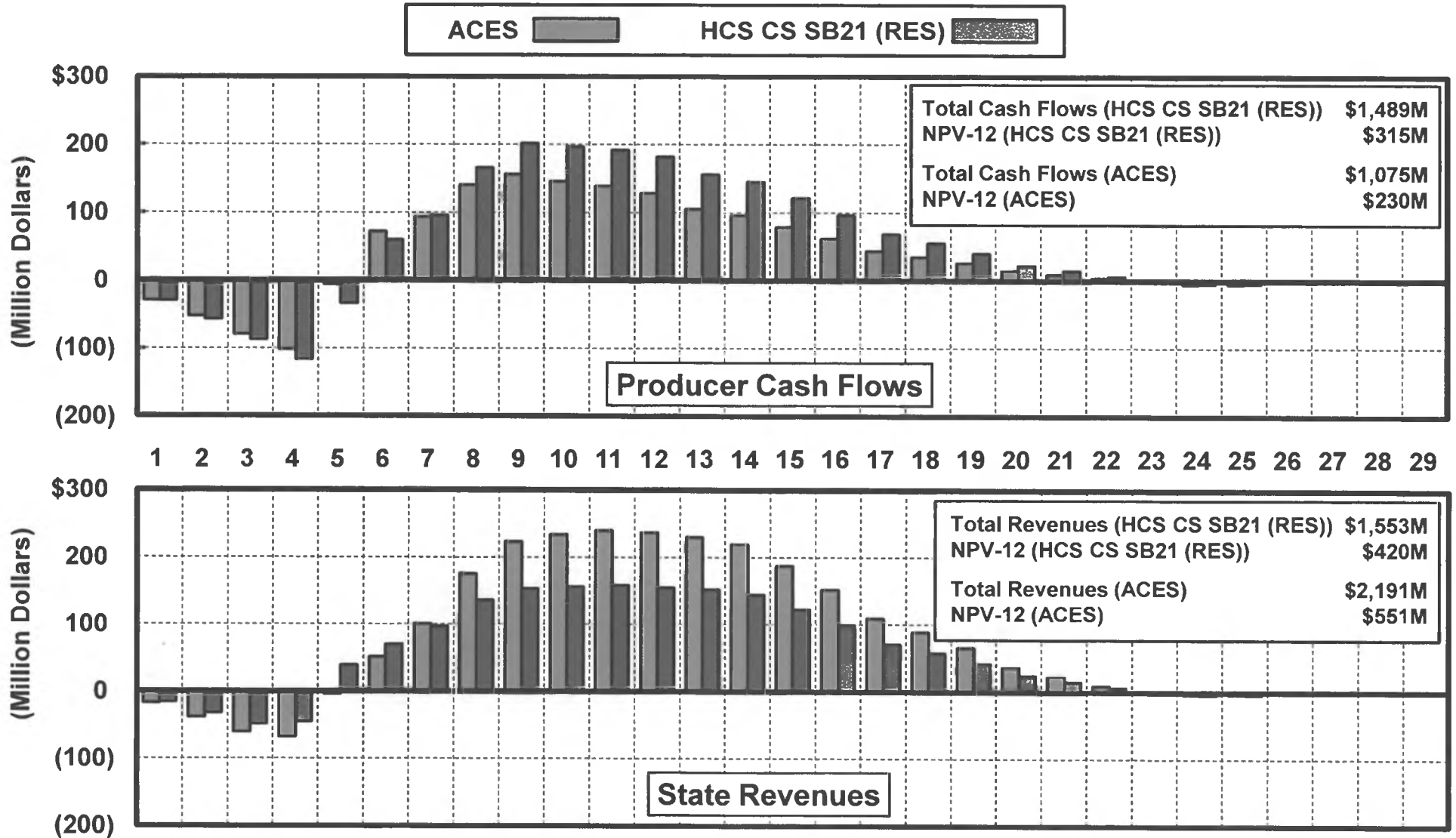
Alaska Oil Development : New development profile and costs are based on Pioneer's presentation dated February 18, 2013 -- \$18/Bbl. Development Capex.

State Support for Capital Spending Under ACES and HCS CS SB21 (RES) at \$100 West Coast ANS (\$2012)



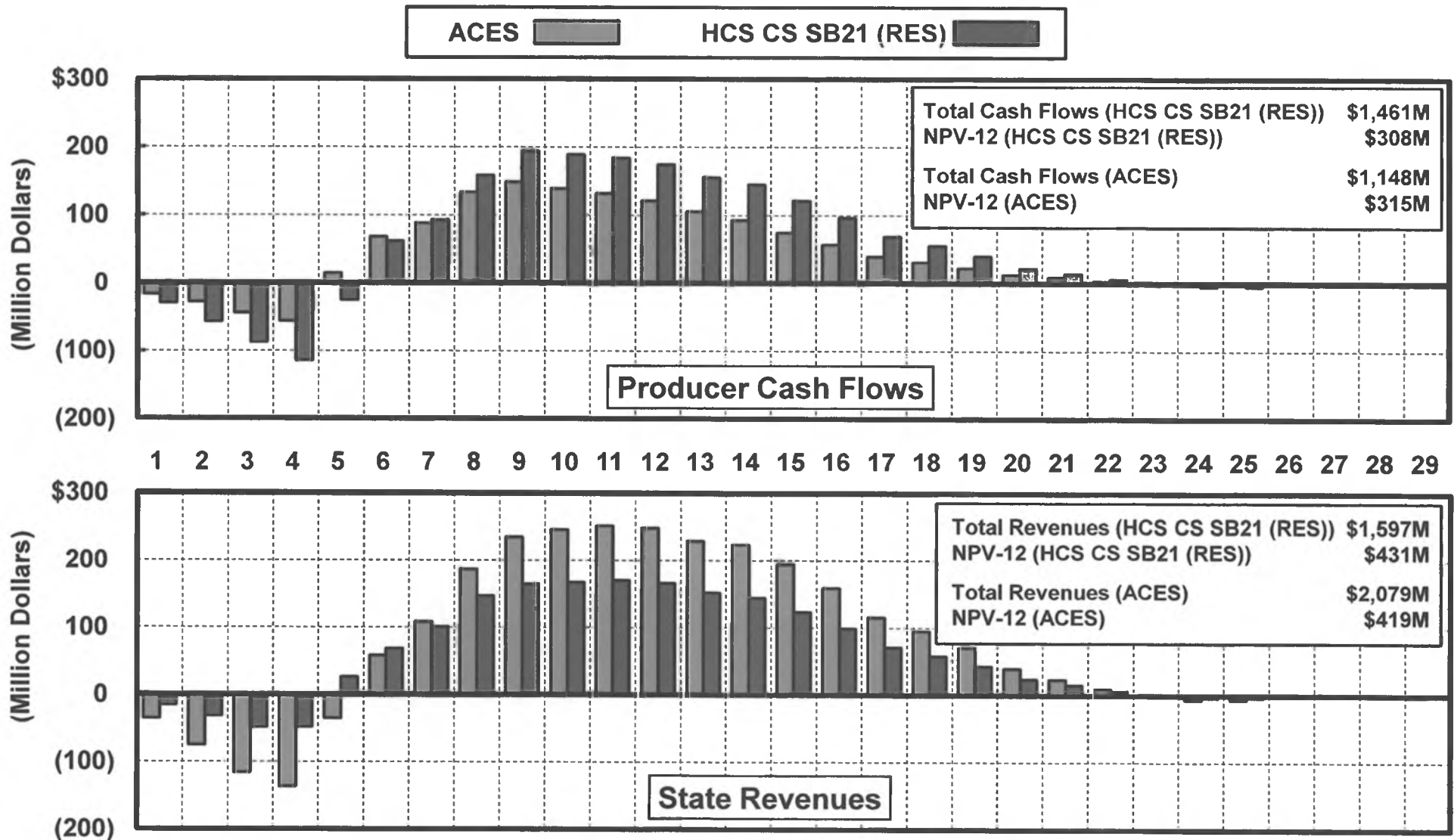
Assumes \$1 billion of development spending prior to new production

Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012) 50 MMBO Alaska Oil Development New Participant in Alaska



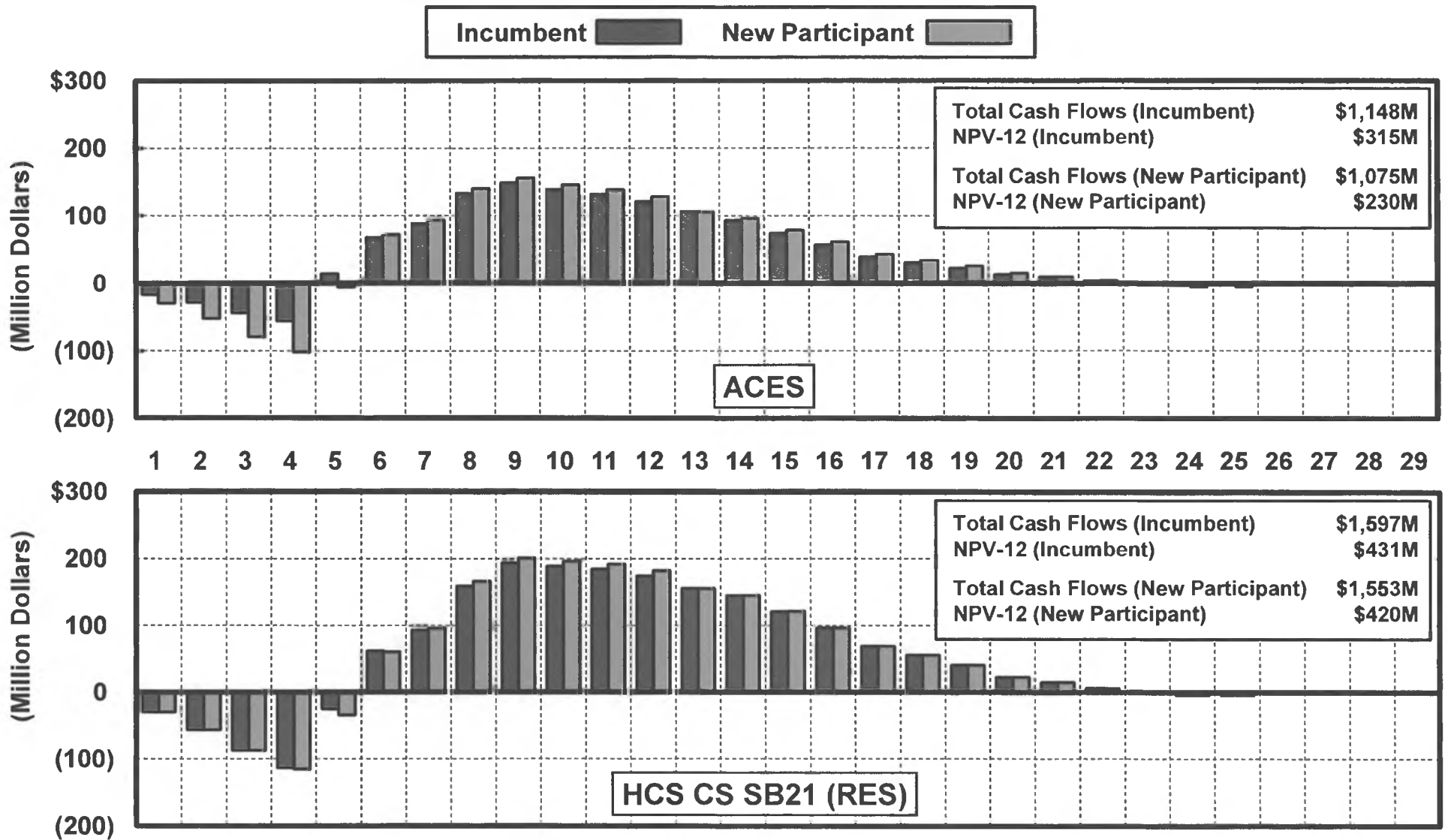
New development profile and costs are based on Pioneer's presentation dated February 18, 2013 -- \$18/Bbl. Development Capex.

Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS (\$2012) 50 MMBO Alaska Oil Development Incumbent Participant in Alaska



New development profile and costs are based on Pioneer's presentation dated February 18, 2013 -- \$18/Bbl. Development Capex.

Annual Producer Cash Flows at \$100 West Coast ANS (\$2012) 50 MMBO Alaska Oil Development



New development profile and costs are based on Pioneer's presentation dated February 18, 2013 -- \$18/Bbl. Development Capex.

Additional Volumes Need to Offset Projected Fiscal Impact of HCS CS SB21 (RES) (FY2014 - FY2043)

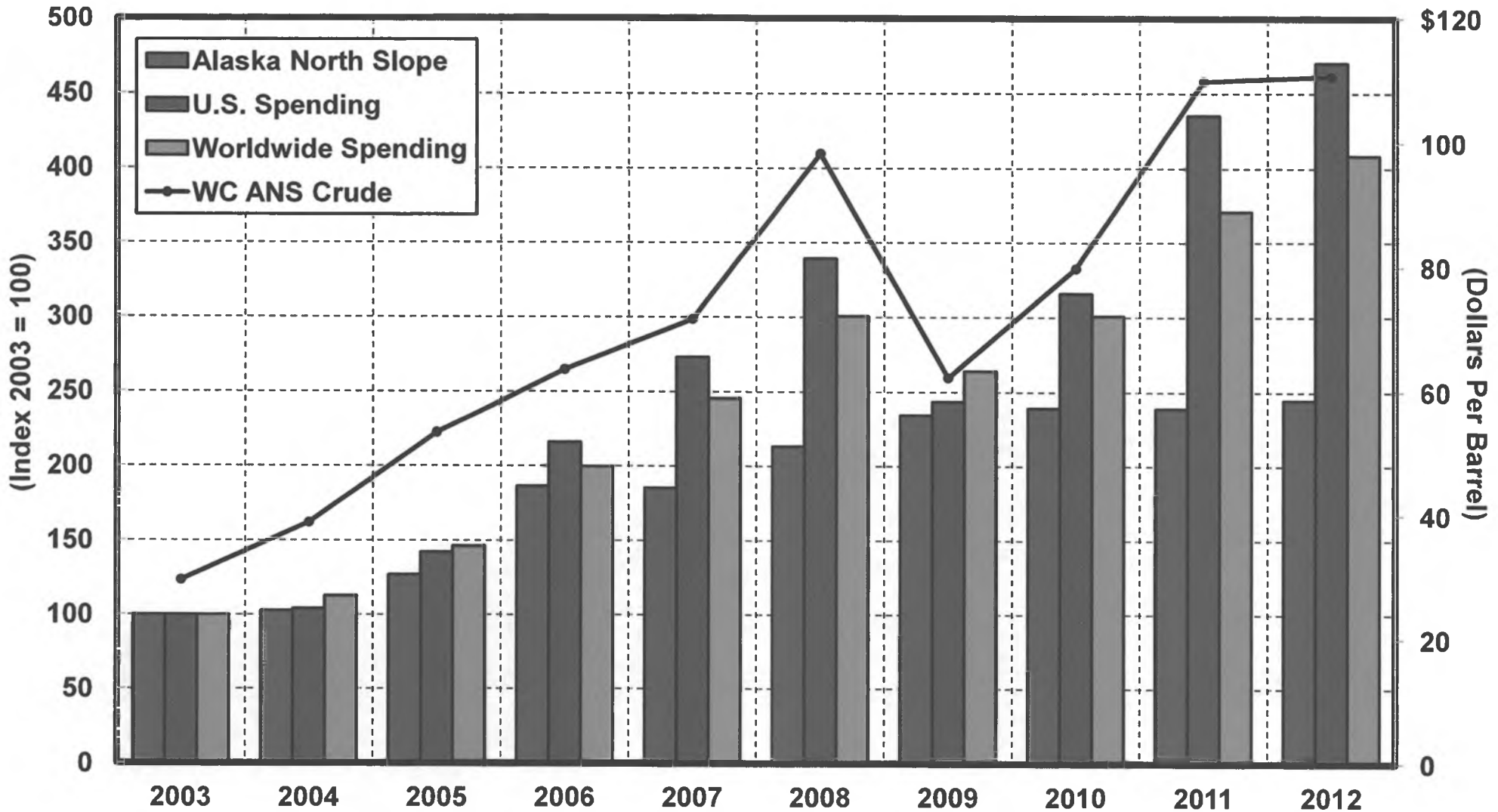
Assumptions: \$18/Bbl Development Cost
Price = \$105/Bbl West Coast ANS Price (\$2012)
Taxes Per HCS CS SB21 (RES): 33% Base Rate, \$5/Bbl Credit (GRE Volumes), 20% GRE

	<u>16.67% Royalty</u>	<u>12.5% Royalty</u>
State Revenue From New Development (\$2012/Bbl)		
Excluding Impact on Tariff	\$25.25	\$22.25
Tariff Impact	\$3.50	\$3.50
Total	\$28.75	\$25.75
Annual Average Revenue Loss Assuming No New Development 2014 - 2043 (\$2012 Million)	\$475	\$475
Total Barrels Needed to Develop (MMBO)	496	553
Annual Barrels Needed (MMBO)	17	18
Central North Slope Undiscovered Conventional Economically Recoverable Resources (MMBO)	3,000	3,000
% of Resources Required Annually	0.6%	0.6%
Additional Needed on Daily Basis (BPD)	45,000	51,000

Testing Reasonableness of Achieving Breakeven Development Capital Required (\$2012)

Annual Development Required (Barrels)		17,500,000
\$/Bbl Development Costs	x	\$18
Annual Capital Required (Dollars)	=	<u>\$315,000,000</u>
2012 Capital Spending (Dollars)		\$2,400,000,000
Additional Capital Required as Percent of 2012 Spending Level		13.1%

Estimated Capital Spending for Exploration and Development Alaska North Slope vs. U.S. and Worldwide Spending* 2003 - 2012



* North Slope based on tax return information; U.S. based on top 50 public companies; worldwide based on top 75 public companies

Testing Reasonableness of Achieving Breakeven Development Capital Spending Increase at Worldwide Pace

Worldwide Capital Spending Growth 2003-2012 (Percent)		400%
Alaska Capital Spending in 2003 (Dollars)		\$1,000,000,000
Alaska Capital Spending in 2012 with Growth at Worldwide Pace (Dollars)		\$4,000,000,000
Actual 2012 Capital Spending (Dollars)	-	2,400,000,000
Worldwide Pace vs Actual (Dollars)	=	\$1,600,000,000
Percentage Over Actual 2012 Spending (Percent)		67%
Potential Development @ \$18/Bbl (Barrels)		88,900,000
Breakeven Volume (Barrels)		17,500,000
Difference (Barrels)		71,400,000

Testing Reasonableness of Achieving Breakeven Development

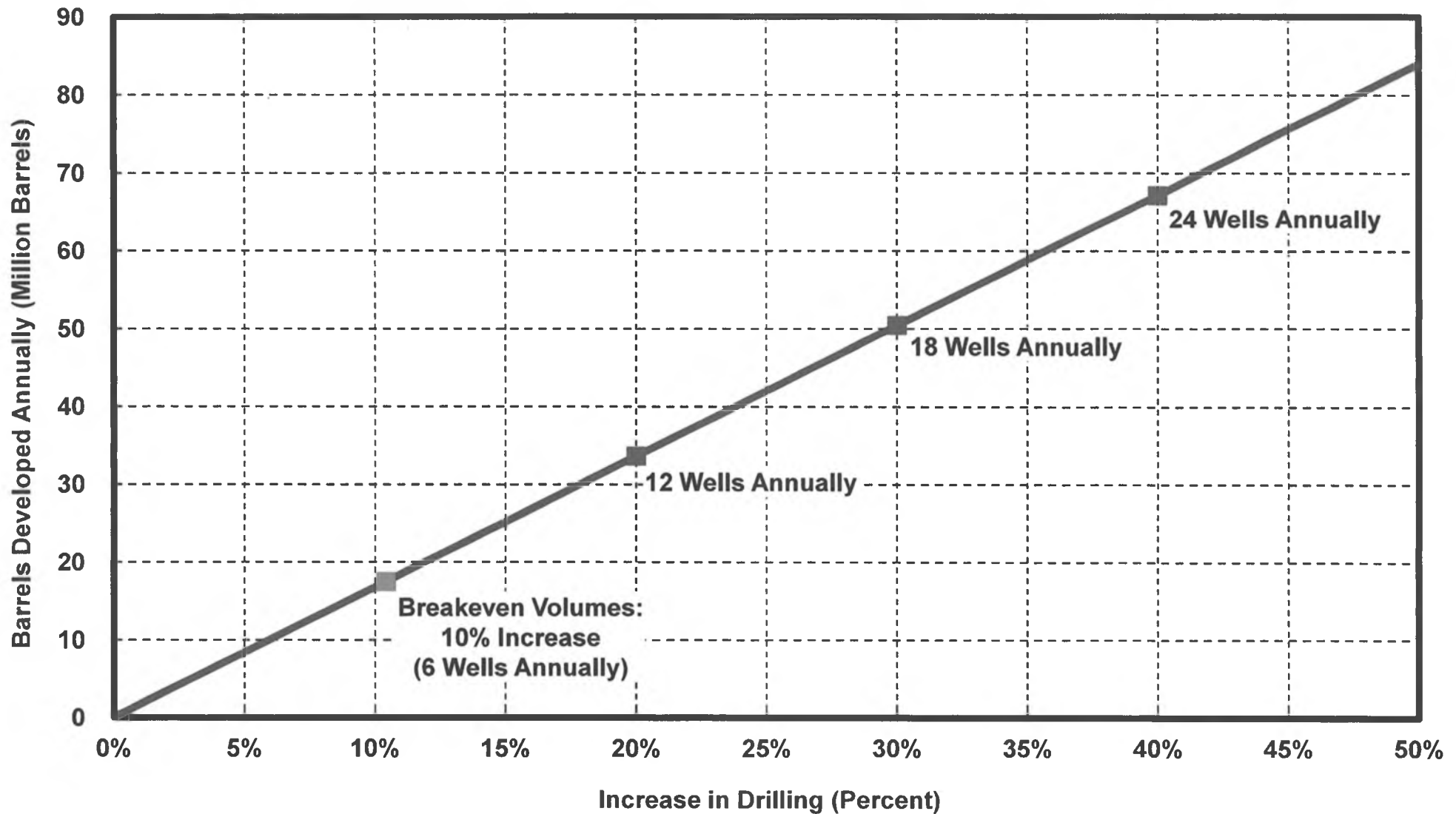
Gerking, et al. Study of Sensitivity of Drilling to Tax Rates

Drilling Change Due to Reduction in Gross Severance Tax By 5.3 Percentage Points (From 10.6% to 5.3%) *		23.0%
Change Per 1% Change in Severance Tax Rate		4.0%
Change in Alaska Tax Rate (Gross Equivalent) (10 Percentage Points)	x	10%
Implied Impact on Drilling Starts (Percent)	=	40.0%
2012 Well Starts in Alaska with Production	x	60
Implied Increase in Drilling Starts	=	24
Expected First Year Recovery (Barrels) (Assumes 80% in-field wells with initial production of 1,000 b/d; 20% new field drilling with initial production of 2,000 b/d)		10,512,000
Total Expected Recovery (Barrels) (Assumes 15% Annual Decline)		67,200,000

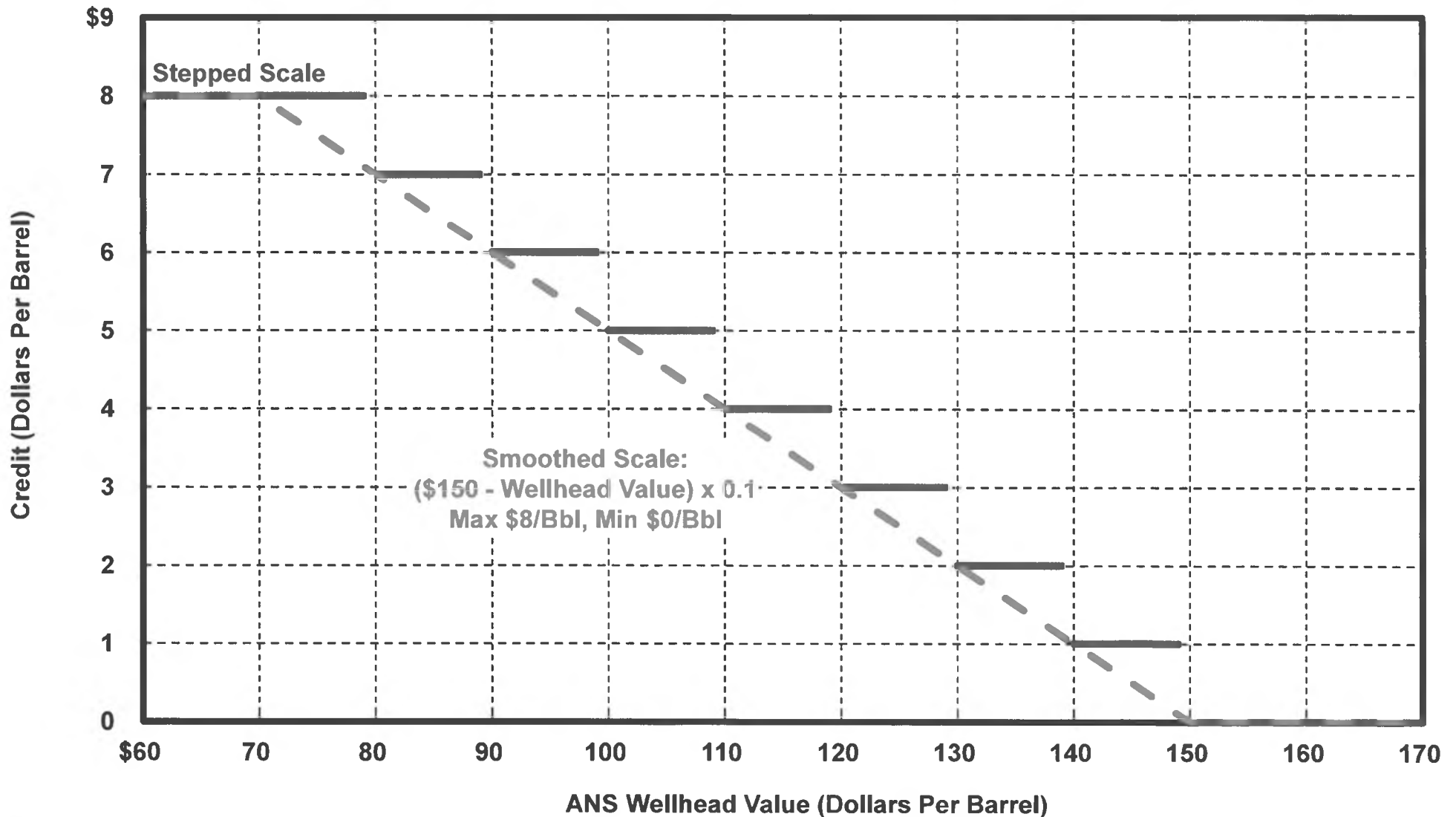
* "Kunce, Gerking and Morgan, 2001." Study found that a hypothetical doubling of the severance tax rate in Wyoming from 5.3% to 10.6% would result in a 19.4% decrease in drilling rates (from 211 new wells to 170 new wells annually). Reversing the direction of the tax change (i.e., a reduction from 10.6% to 5.3%), therefore, would be expected to increase drilling by 23% (from 170 to 211 wells). The study also found that while the impact of a tax increase on new drilling (i.e., new investment) was relatively large, the impact on overall production was relatively small, as new wells bring on an average of approximately 75 barrels per day of initial production in Wyoming and production from existing wells (i.e., prior investments) would not be significantly reduced. Average well productivity in Alaska is significantly higher than in Wyoming (1,000 barrels per day v. 75 barrels per day). Accordingly, a similar impact on drilling rates in Alaska would carry with it a much greater impact on total State production.

Testing Reasonableness of Achieving Breakeven Development

Relationship Between Drilling Increases and Expected Barrels Developed Annually

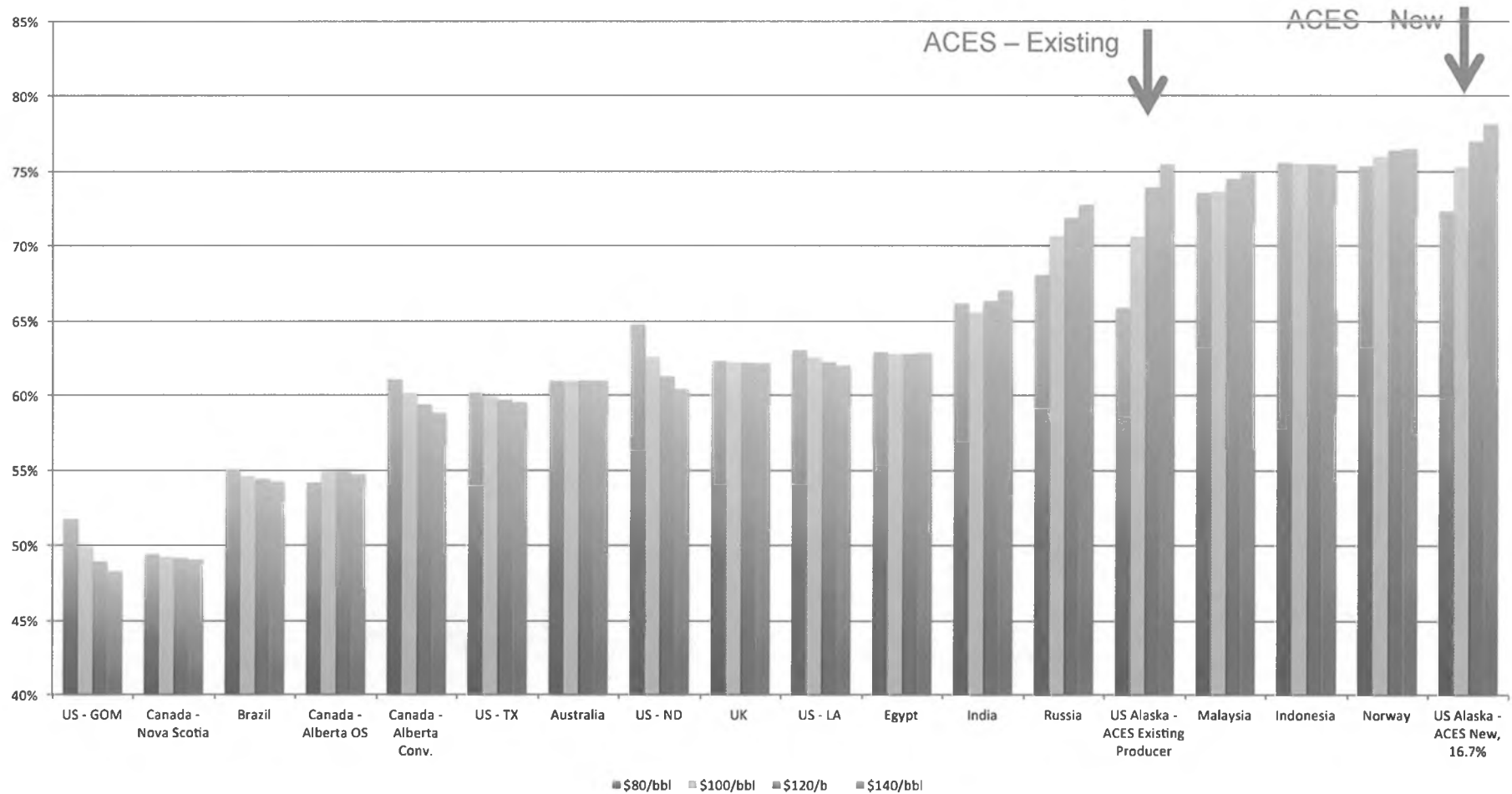


HCS CS SB21 (RES) Per-Barrel Credits for Non-GRE Volumes Stepped Scale v. Smoothed Scale



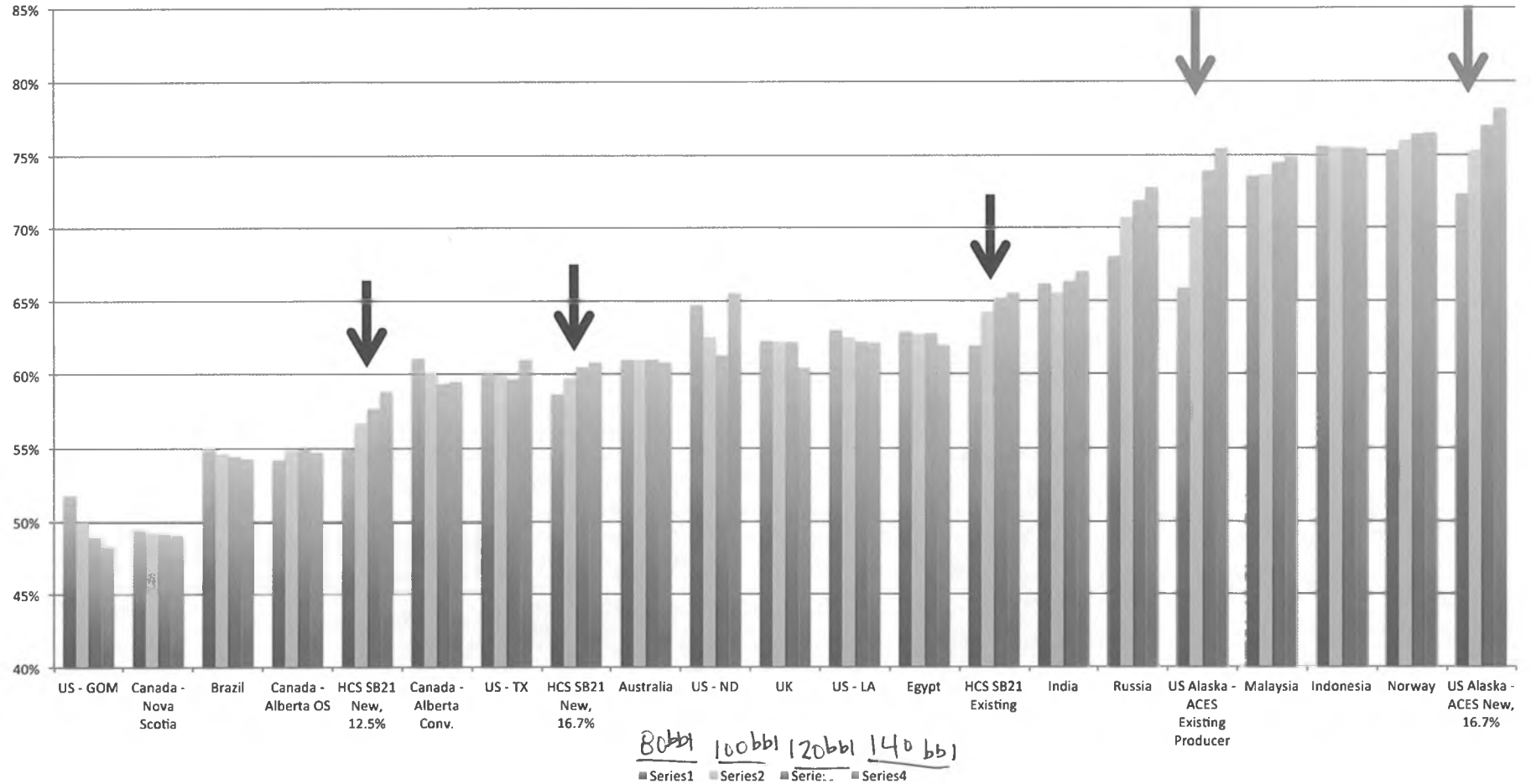
Government Take Competitiveness – Most Relevant Competitor Regimes

Alaska Government Take Competitiveness - Comparable Regimes



Government Take Competitiveness

Alaska Government Take Competitiveness - Comparable Regimes





Fiscal Impact HCS CSSB21(RES)

*For Presentation to the
House Finance Committee*

April 6, 2013



Introduction



1. Key provisions analyzed
2. Total fiscal impact under Fall 2012 forecast
3. Hypothetical additional production scenarios
4. FY 2015 revenue sensitivity

Note: presentation assumes an effective date of January 1, 2014 for most major provisions.



1. Repeals progressive surcharge



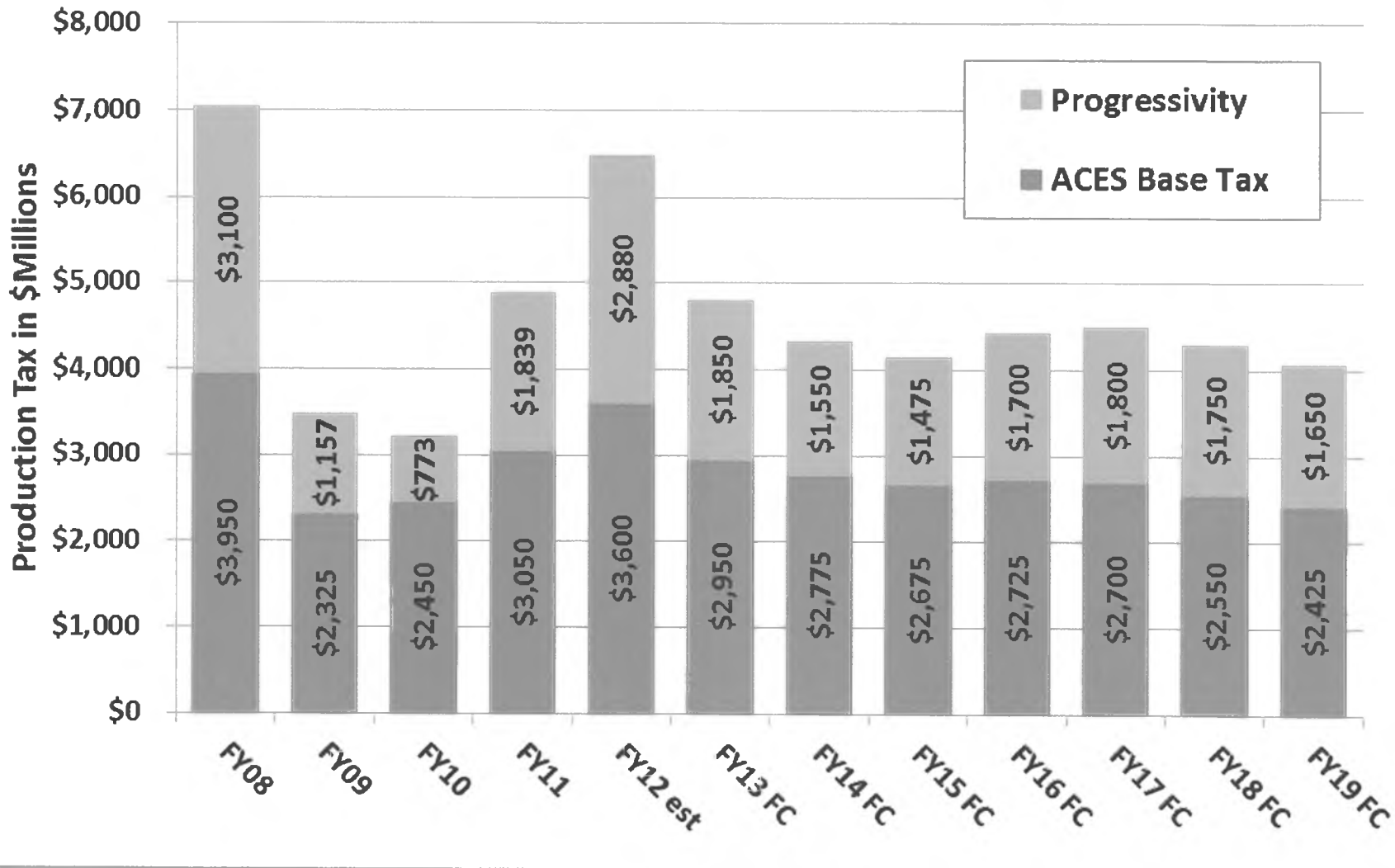
- Progressive surcharge at AS 43.55.011(g) repealed
- Progressive surcharge is an additional tax that is added to base tax
- Progressive surcharge increases tax rate at production tax values of greater than \$30 / barrel
- Progressive surcharge may add up to 50% to the total tax rate at very high prices for a maximum total tax rate of 75%
- Fiscal Impact = varies by fiscal year, up to \$1.8 billion per year under our Fall 2012 forecast



Impact of Progressive Surcharge



Production Tax Revenue before Credits under ACES





2. Increases base production tax rate



- Base tax rate increased to 33% from 25% under ACES; decreased from 35% from CS SB21
- Base tax rate of 33% applied to production tax value
- The higher base tax rate increases revenue from the base tax
- The higher base tax rate provides greater protection to the state at low oil prices
- Fiscal Impact = varies by fiscal year, up to \$875 million per year under our Fall 2012 forecast



3. Limitations on capital credits



- Production tax credits under AS 43.55.023(a) for qualified capital expenditures are limited to expenditures incurred before January 1, 2014 for the North Slope
- 20% capital credit eliminated for North Slope after 1/1/2014 (replaced with new mechanisms that incentivize production, not spending).
- ACES provisions are unchanged for Cook Inlet and Middle Earth and they retain 20% capital credit
- Since capital credits are taken against liability or refunded, fiscal impact is on both revenue and budget
- Likely fiscal impact is summarized on following slide



Estimated Fiscal Impact for limitations on credits as compared to Fall 2012 Forecast (\$millions)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
NS capital credits against tax liability	\$300	\$700	\$650	\$550	\$475	\$400
NS credits for refund	\$0	\$150	\$150	\$150	\$150	\$150
Total Fiscal Impact	\$300	\$850	\$800	\$700	\$625	\$550

Note: these are positive fiscal impacts. NS credits for refund includes both capital and NOL credits refunded.



4. Changes to Net Operating Loss credit



- Companies that incur net losses from leases or properties on the North Slope will earn a credit of 33% of those losses, an 8% increase over the 25% credit provided in ACES.
 - Transferable credit.
 - Eligible for refund by the state.
- The revenue impact of this provision is -\$30 million per year over the amount forecasted under ACES



5. Establishes Gross Revenue Exclusion



- Excludes 20% of gross value by reducing the gross value of the qualifying production in the determination of the production tax value.
- Qualifying production is any of the following:
 - **New Units** - Land was not in a unit on 1/1/2003
 - **New Participating Areas** - Produced within a PA established after 12/31/2011, in a unit formed before 1/1/2003, if participating area does not contain a reservoir that had been in a PA established before 12/31/2011
 - **Expansions of Participating Areas** - Produced from acreage that was added to an existing participating area by the Department of Natural Resources on or after 1/1/2014, and the producer demonstrates that the volume of oil or gas produced is from acreage added to an existing participating area.
- Fiscal Impact = Indeterminate, under \$50 million / year under Fall 2012 forecast
- GRE benefit would apply almost entirely to “New Production” not currently included in our forecast. The fiscal impact that we are including in the analysis refers to production in our forecast that is likely to qualify.



6. Eliminates requirement that credits be taken over two years



- Capital credits and Net Operating Loss credits earned had to be split across two years under ACES
- This provision allows credits to be used in the year they were earned
- This provision aligns credit treatment on the North Slope with credit treatment in all other parts of the state
- Fiscal impact is neutral – simply shifts a future obligation to FY14.
- \$400 million total obligation shifted to FY14: \$250 million revenue impact; \$150 million operating budget impact.



7. Changes funding source for community revenue sharing



- The community revenue sharing fund is amended to allow the legislature to make appropriations from the tax revenue collected under AS 43.20, as opposed to revenue collected under the provision that is proposed to be repealed - AS 43.55.011(g).
- Corporate income tax revenue under AS 43.20 is adequate to provide the maximum annual appropriation of \$60 million or the amount to bring the fund up to \$180 million.
 - Corporate income tax has exceeded \$500 million every year for the last 8 years.
- Zero fiscal impact.



8. Establishes per oil barrel tax credit



- \$5 credit per taxable barrel for oil production subject to GRE.
 - Must be applied against tax liability and cannot cause tax liability to be less than zero
- Sliding scale for Non-GRE eligible oil production.
 - Scale is progressive on GVPP (wellhead) value per barrel of oil starting at \$8/barrel at wellhead prices up to \$80/barrel down to \$0/barrel at wellhead prices over \$150/barrel
 - Sliding scale is at rate of \$1 credit per \$10 wellhead price
 - Adds a slightly progressive feature to the system
- Both credits tie incentives to production, not spending
- Credits can not be transferred, carried forward, or used to reduce the producer's tax liability to less than zero.
 - The credit for areas not eligible for a GRE may not reduce the producer's tax liability to less than the minimum tax established under AS 43.55.011(f).
- Likely fiscal impact is summarized on next slide



Estimated Fiscal Impact for \$5 per taxable oil barrel and sliding scale credit* as compared to Fall 2012 Forecast (\$millions)

FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
-\$425	-\$825	-\$775	-\$750	-\$700	-\$675

* At forecast prices the per taxable barrel credit is \$5 on the sliding scale.



9. Creates service industry expenditures credit



- New Corporate Income Tax Credit for oil and gas service companies
- Credit is 10% of qualifying in-state expenditures:
 - Manufacturing of oil and gas equipment
 - Modification of oil and gas equipment
 - For in-state spending only
- Maximum \$10 million per taxpayer per year
- Non-transferable; Any amount of the credit that exceeds the taxpayer's liability under AS 43.20 may be carried forward for 5 years.
- Fiscal Impact = Indeterminate, less than \$25 million / year
- Difficult to estimate due to lack of data



10. Interest rate on delinquent taxes changed



- Currently the higher of 5 percentage points above the annual rate of interest charged by the 12th Federal Reserve District or 11 percent.
- Changed to 3 percentage points above the annual rate of interest charged by the 12th Federal Reserve District.
- Change applied to interest charged on delinquent taxes and refunds and assessments for most taxes administered by DOR.
- Fiscal impacts include \$100,000 for DOR accounting system changes.
- Fiscal impact is estimated to be up to -\$25 million per year, increasing over time as more delinquent taxes are calculated under the new interest rates established with this provision.
- Our fiscal impact estimates do not take into account changes in taxpayer behavior as a result of this reduction in interest rate.



11. Removes 3-mile requirement for “Middle Earth” frontier basin credit



- Explanation:
 - Removes requirement that well be 3 miles from existing well to qualify for credit
 - Applies to frontier basin credit in AS 43.55.025(a)(6)
 - Credit is 80% of eligible drilling expenditures, up to \$25 million, for first four eligible wells
 - Drilled before July 1, 2016 in qualifying frontier basin
 - Must be a new target pre-approved by DNR
 - Well data shared with DNR
 - Credit is transferable
 - Cannot take this credit along with NOL credit
- Fiscal Impact already accounted for in Fall 2012 forecast



12. The small producer credit



- **The small producer credit at AS 43.55.024 is extended to the later of 2022 or the ninth calendar year after the calendar year that the producer first has commercial production.**
- Fiscal impact:
 - Zero in FY 2014-2016
 - -\$25 million in FY 2017-2018
 - -\$50 million in FY 2019



13. DOR Production Tax Report to Legislature



- The Department of Revenue is required to provide a report to the legislature on or before the first day of the 2016 regular session.
 - This report will study various elements of the production tax system and recommend changes to the system.
- This report will be completed with existing professional staff and has no revenue impact.



14. Joint Interest Billings Consideration



- The Department of Revenue is required to consider Joint Interest Billings in the audit process for production tax and may rely on audits performed by joint interest owners in performing state audits of taxpayers.
- This provision may lead to slight changes in the department's audit process and has an indeterminate fiscal impact.
- Fiscal impacts include \$50,000 for regulations review for this and other provisions.



15. AIDEA Bonding Authority



- AIDEA is given bonding authority to finance construction of oil and gas processing facilities.
- This provision does not have any fiscal impact on the Department of Revenue.

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Fall 2012 Forecast (\$millions)¹

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-\$800	-\$1,500	-\$1,700	-\$1,800	-\$1,750	-\$1,650
2. Base tax rate changed to 33% of production tax value	\$450	\$850	\$875	\$850	\$800	\$775
3. Limitation of credits for qualified capital expenditures for North Slope	\$300	\$700	\$650	\$550	\$475	\$400
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	\$0	-\$25	-\$25	-\$50	-\$25	-\$50
6. Provision requiring credits be taken over 2 years eliminated ²	-\$250					
7. Amendment to the community revenue sharing fund	\$0	\$0	\$0	\$0	\$0	\$0
8. Credit of \$5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-\$425	-\$825	-\$775	-\$750	-\$700	-\$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -\$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -\$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	\$0	\$0	\$0	\$0	\$0	\$0
12. Small producer credit extended to 2022	\$0	\$0	\$0	-\$25	-\$25	-\$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	-\$725 to -\$775	-\$800 to -\$850	-\$975 to -\$1025	-\$1200 to -\$1250	-\$1200 to -\$1250	-\$1200 to -\$1250
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-\$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		\$150	\$150	\$150	\$150	\$150
Impact on Operating Budget of increase in Net Operating Loss credits		-\$30	-\$30	-\$30	-\$30	-\$30
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production³	-\$875 to -\$925	-\$680 to -\$730	-\$855 to -\$905	-\$1080 to -\$1130	-\$1080 to -\$1130	-\$1080 to -\$1130

¹The impacts listed are based on production and prices as forecasted in our Fall 2012 revenue forecast. The forecasted oil prices are between \$109.61 and \$118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is \$400 million, with \$250 million taken against tax liability as a revenue impact and \$150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

³NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.



Production Scenarios



Scenario A:

- New 50 Million barrel field developed by small producer without tax liability
- Peak production = 10,000 bbls/day
- Development costs = \$500,000,000
- Qualifies for GRE and NOL



Production Scenarios



Scenario B:

- Operators of existing units add 4 drill rigs to current plans
- Each rig adds 4,000 bbls/day in new production each year
 - Which each then decline at 15% per year
- Does not qualify for GRE



Production Scenarios

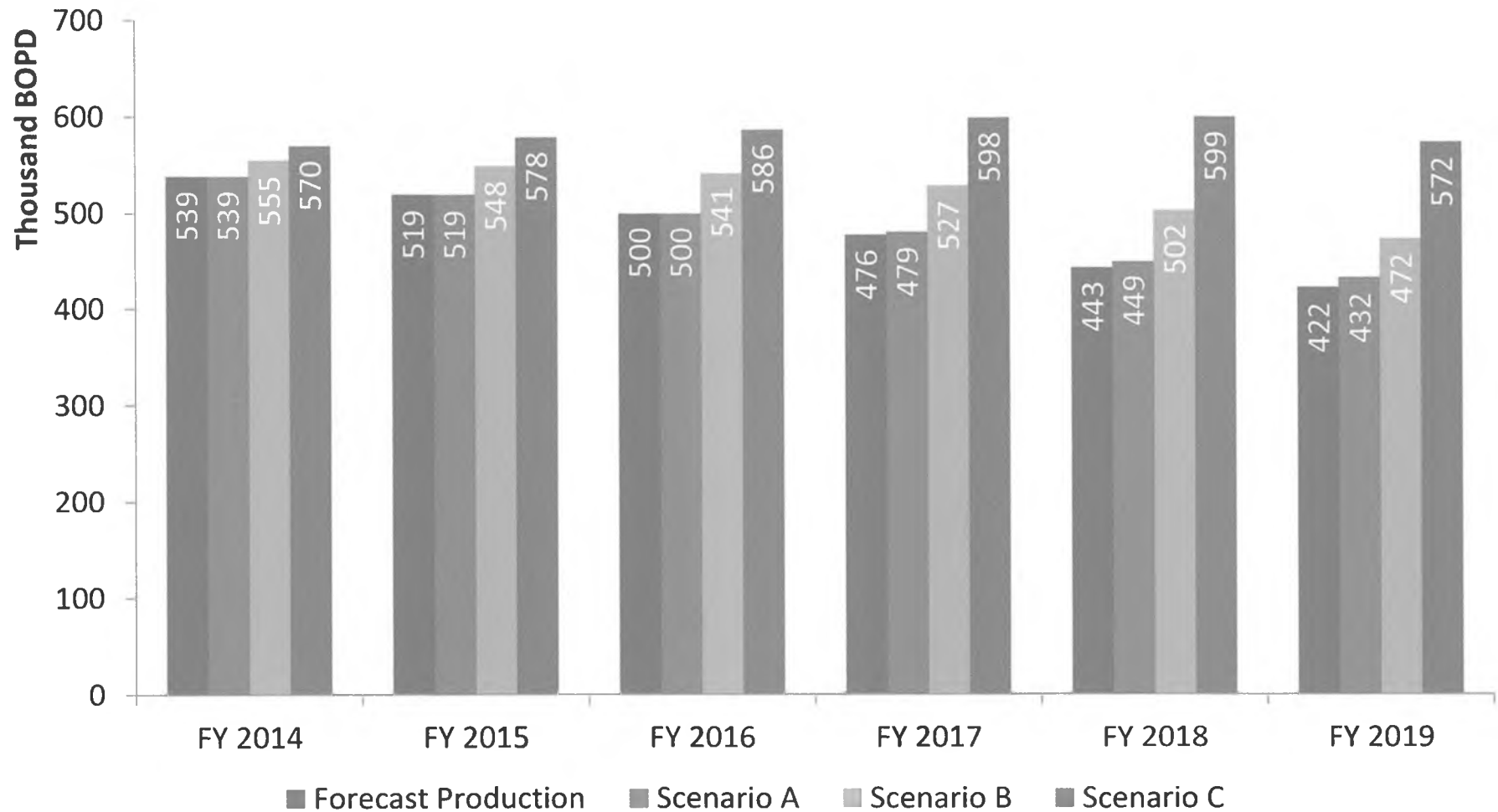


Scenario C:

- Operator of existing legacy unit builds new drill pad
- Development cost = \$5 billion
- Adds 15,000 bbls/day in 2014 increasing to peak rate of 90,000 bbls/day in 2018
- Does not qualify for GRE



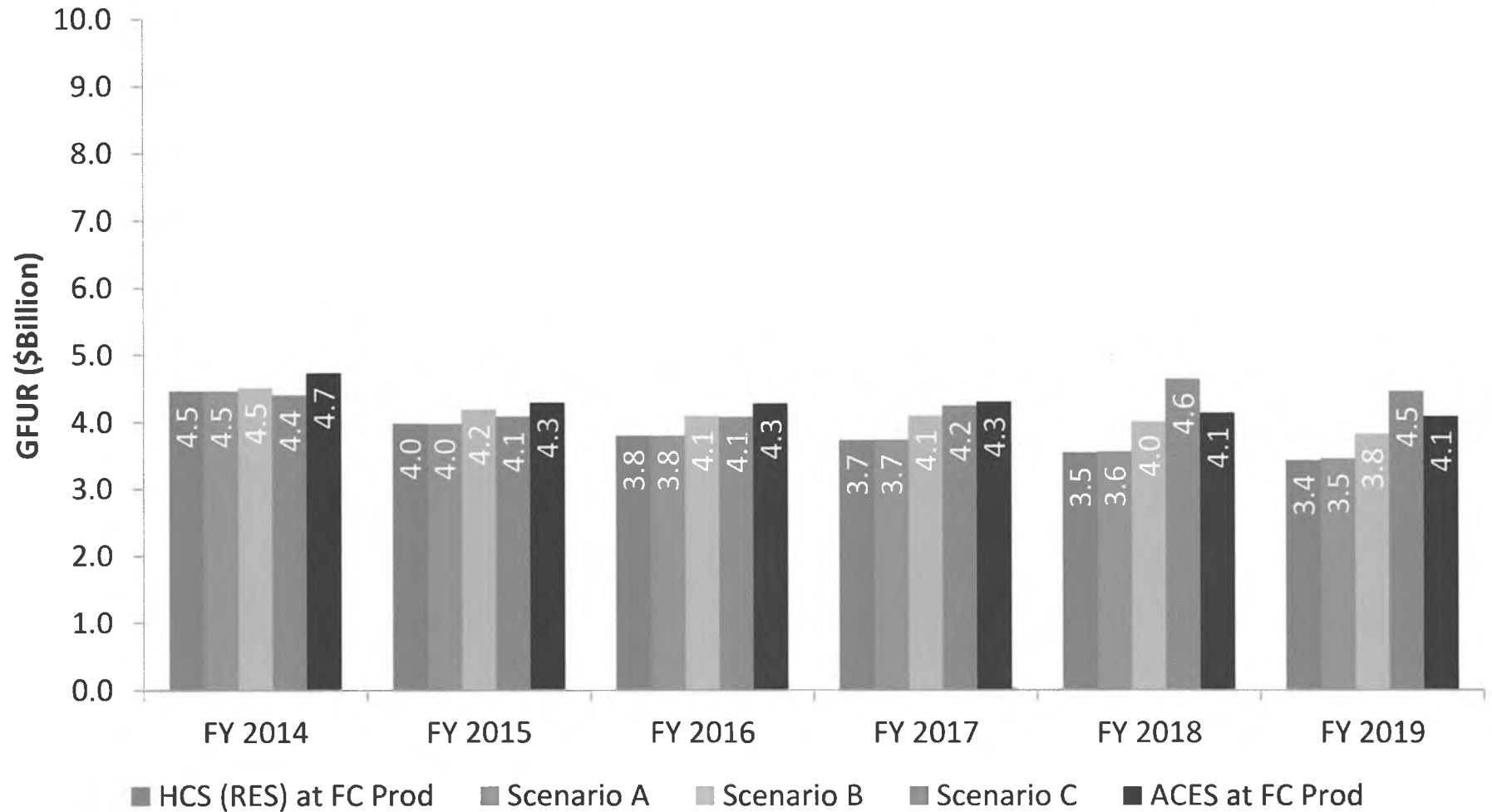
Production Profiles of Production Scenarios



Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.



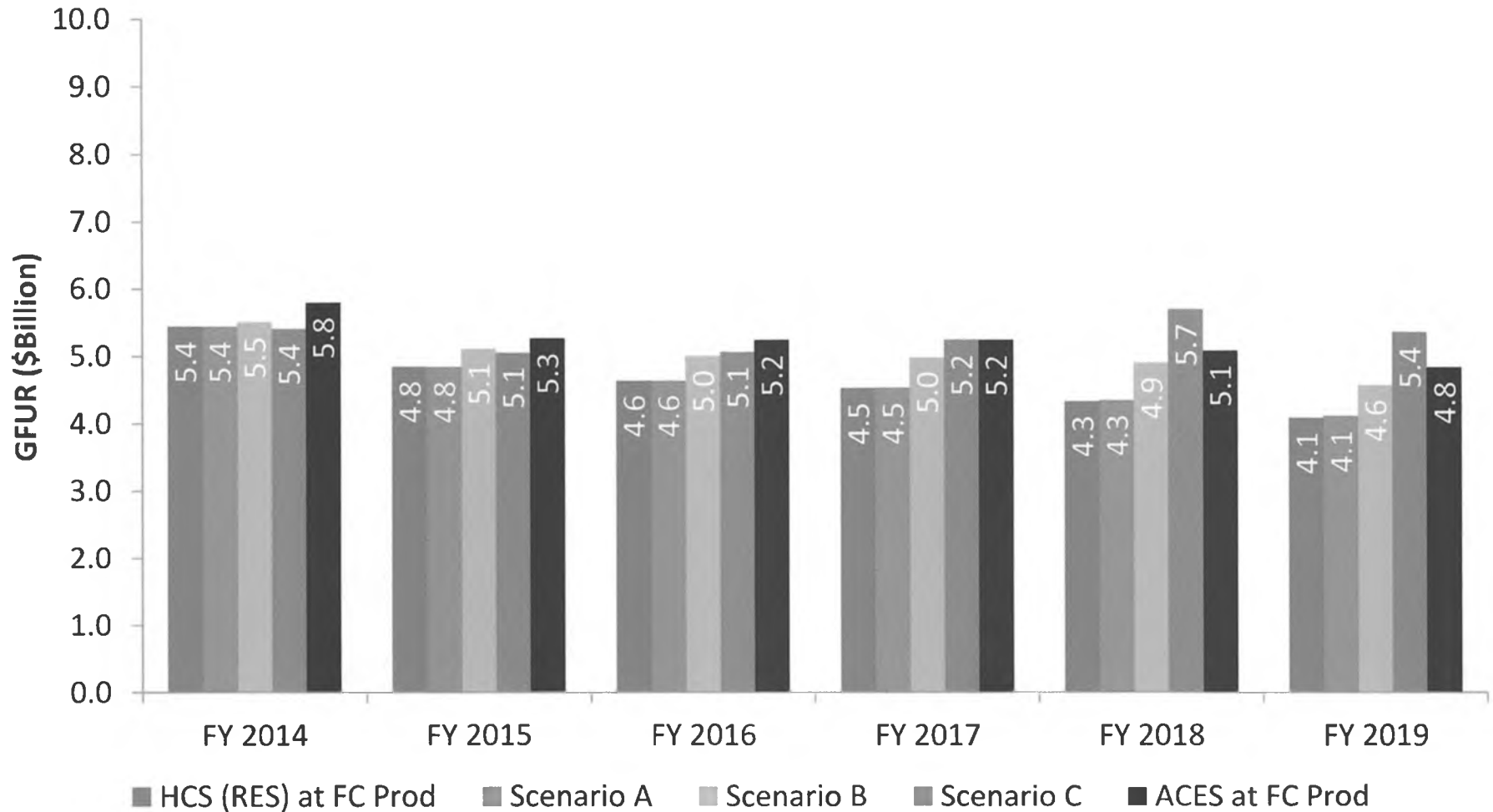
Projected revenues under production scenarios – at \$90 / barrel ANS



Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.



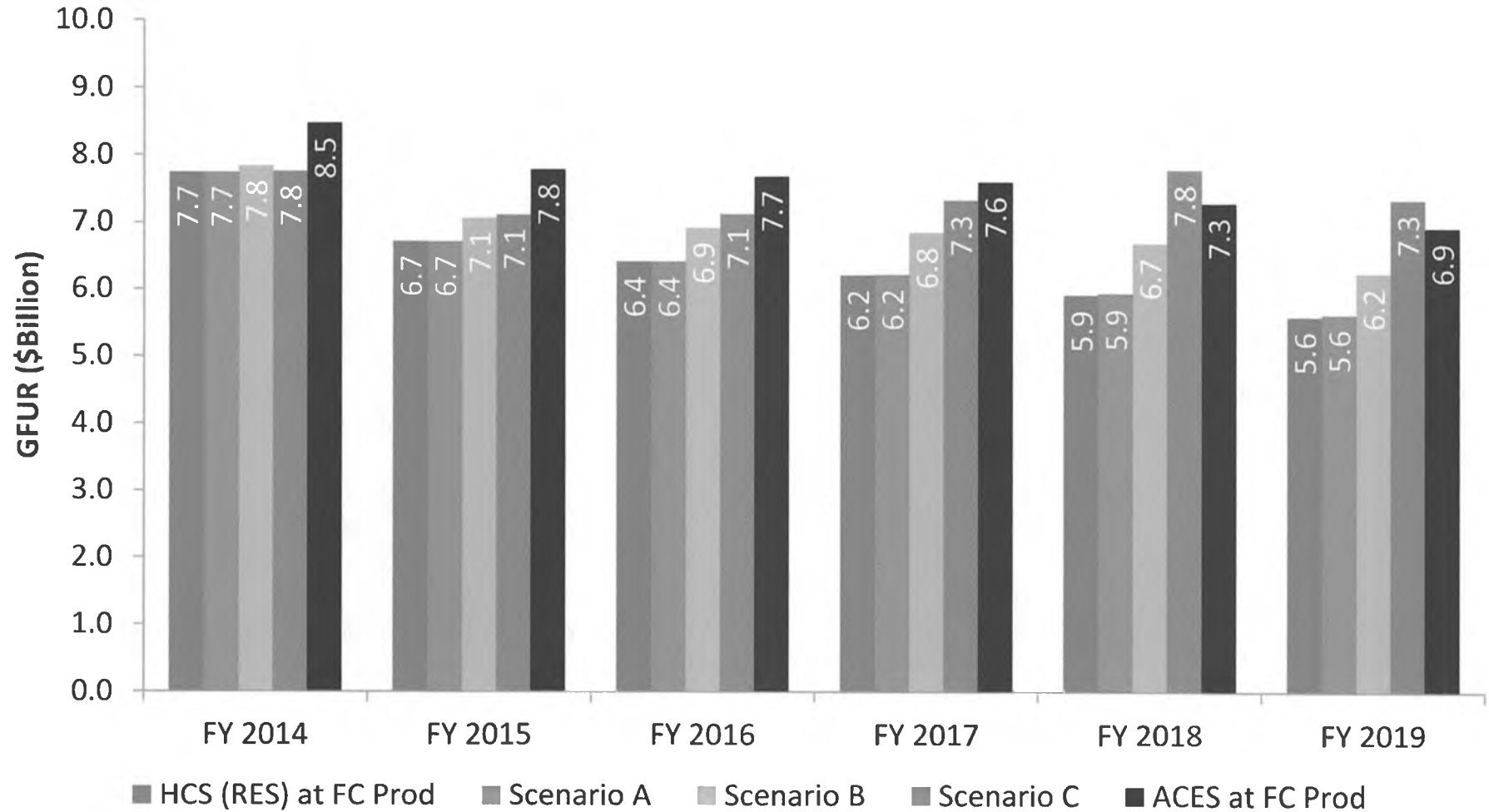
Projected revenues under production scenarios – at \$100 / barrel ANS



Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.



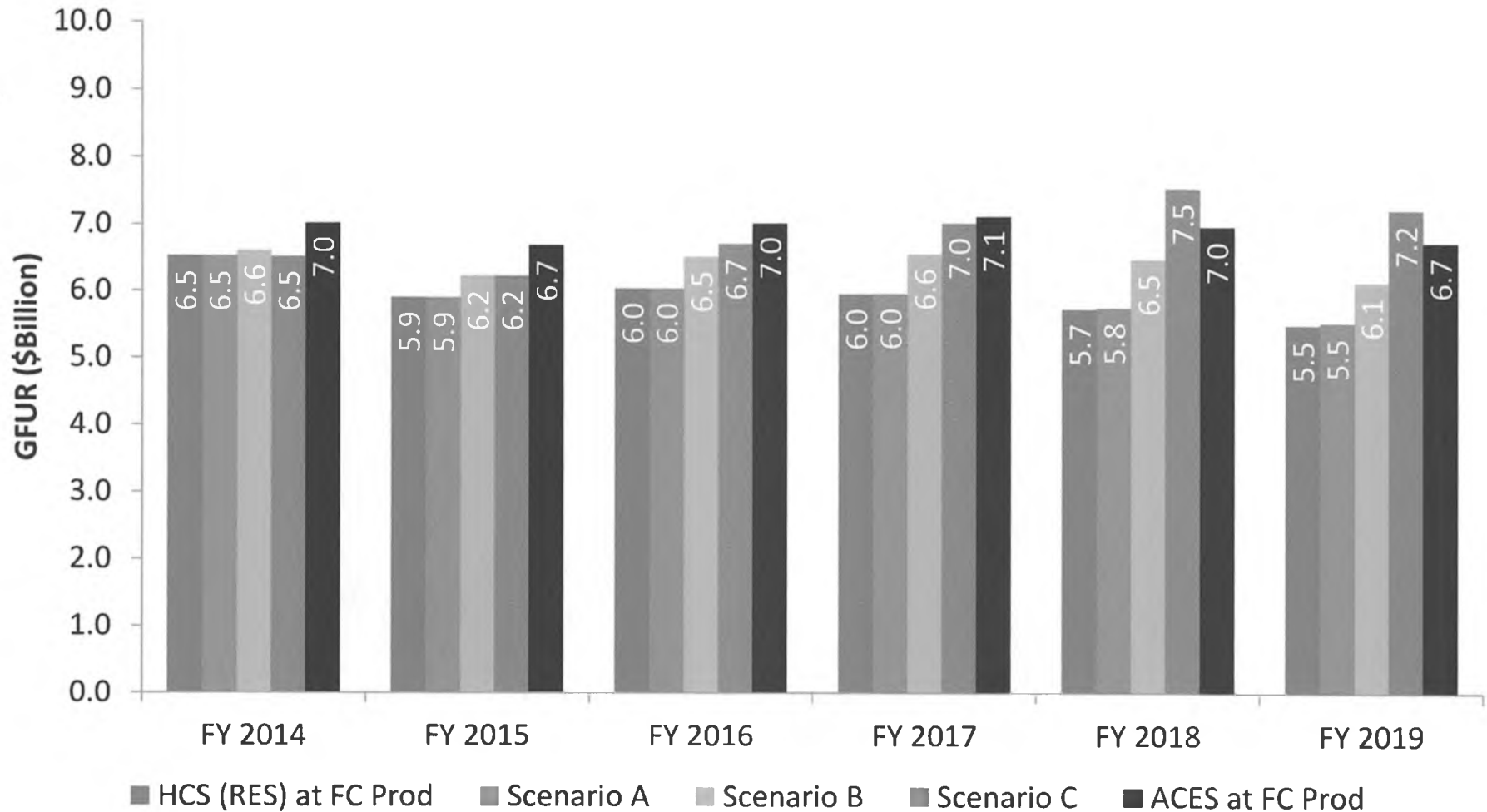
Projected revenues under production scenarios – at \$120 / barrel ANS



Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.



Projected revenues under production scenarios – at forecast ANS price



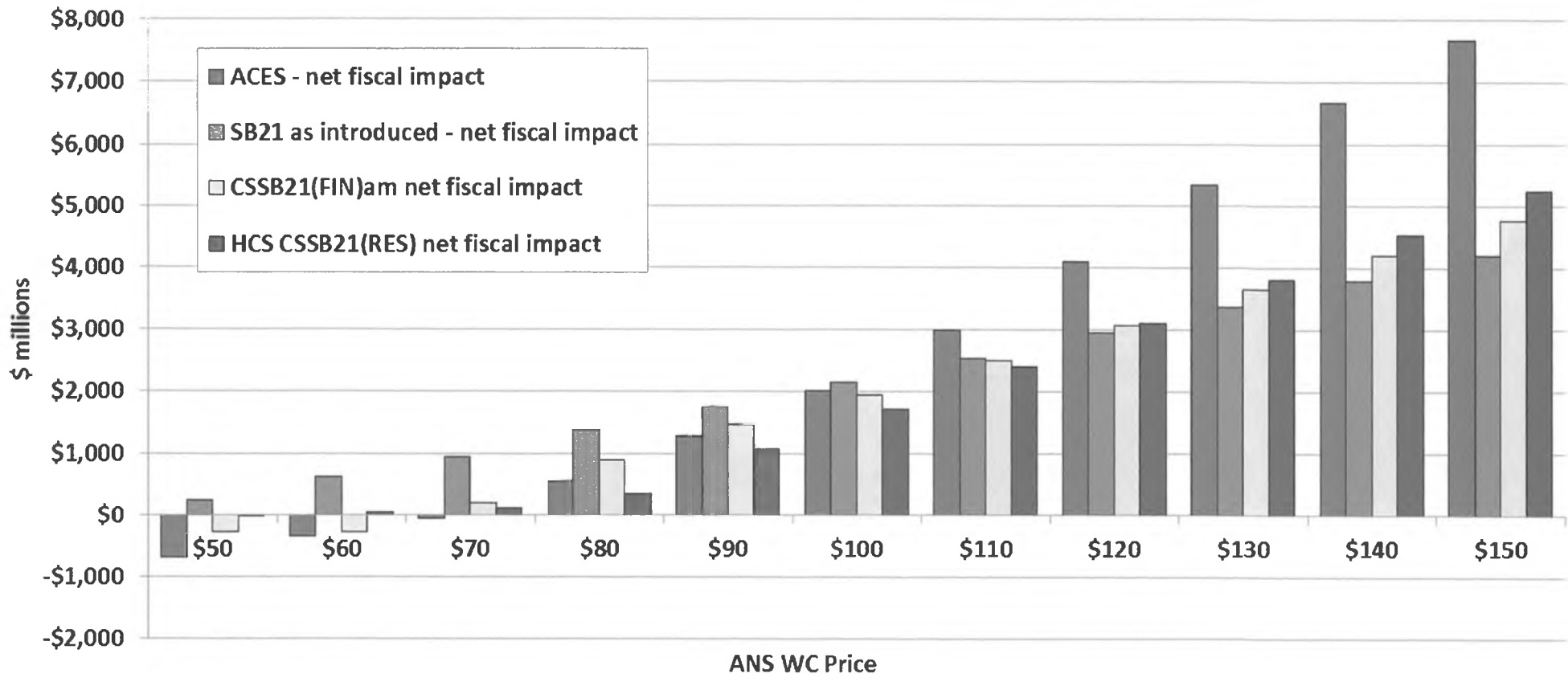
Note: Compares CSSB21(RES) under several production scenarios, to ACES under forecast production.



Production Tax Revenue, less North Slope refunded and carried-forward credits



**FY15 ACES, SB21, CSSB21(FIN) am, and HCS CSSB21 (RES) -
Production Tax Revenue with certain adjustments**



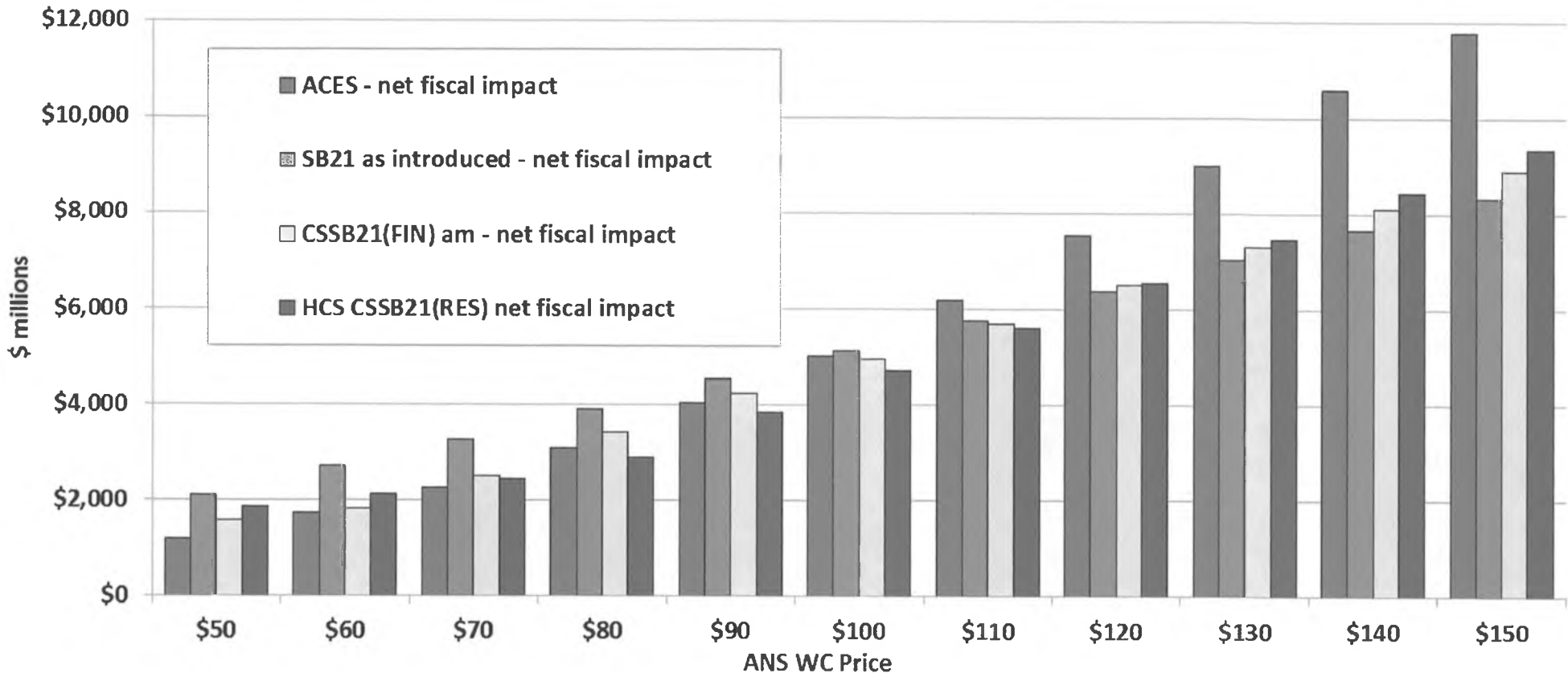
Source: Fall 2012 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. For \$50, also includes expected liability for carried forward credits in excess tax liability for major producers. CSSB21(FIN) and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.



General Fund Unrestricted Revenue, less North Slope refunded and carried-forward credits



FY15 ACES, SB21, CSSB21(FIN) am, and HCS CSSB21 (RES) - GF Unrestricted Revenue with certain adjustments



Source: Fall 2012 forecast model modified for SB21 and CSSB21. Note, "Net fiscal impact" includes forecast revenue, less expected North Slope credit payments. For \$50, also includes expected liability for carried forward credits in excess tax liability for major producers. CSSB21(FIN) and HCS CSSB21 (RES) do not include impact of new service industry CIT credit or reduced interest rate for late payments and assessments on most taxes.



Thank You

4/6/13

OIL TAX REFORM: GROSS REVENUE EXCLUSION

House Finance Committee

April 6, 2013

Department of Natural Resources

- Joe Balash, Deputy Commissioner
- Bill Barron, Director, Division of Oil & Gas



HOW DOES PRODUCTION QUALIFY *for the GRE?*

There are three ways to qualify:

1. Production from a Unit formed after 2003
 - Nikaitchuq Unit, Oooguruk Unit
2. Production from a PA formed after 2012 which is in a unit formed prior to 2003
 - New PA at Prudhoe Bay
3. Production from acreage that was added to an existing participating area by DNR on and after January 1, 2014, and the producer demonstrates to DNR that the volume of oil or gas produced is from acreage added to an existing participating area

LEASING & UNITIZATION

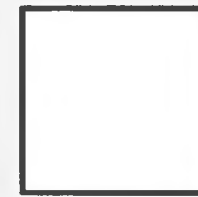
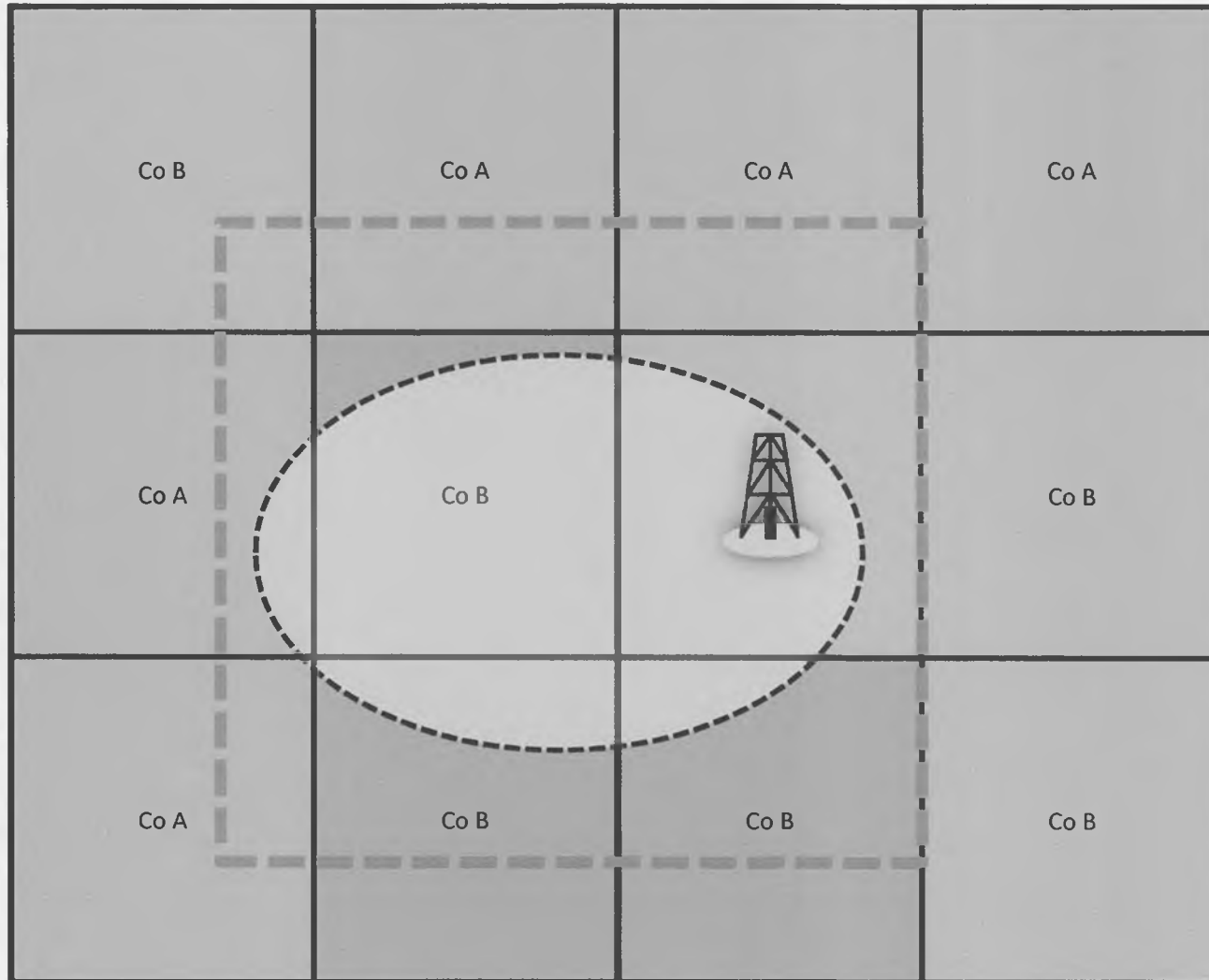
Leasing is the primary mechanism by which the State grants exclusive rights to explore and develop the oil and gas mineral rights of the State to private parties

- Competitive bidding
- Terms and conditions have varied over time
- Tracts are generally 3x3 miles, except in prime shale areas

Unitization is the mechanism to join contiguous leased tracts together into a unit in order to

- Protect the interests of all parties, including the state
- Ensure proper reservoir management, and
- Enhance recovery of reserves

UNITIZATION



Tract Boundaries



Delineated Reservoir



Proposed Unit Boundary

WHAT is a PARTICIPATING AREA (PA)?

**A set of tracts within a Unit, overlying a reservoir
which is on sustained production**

- North Slope: 18 State Units, 38 PAs
- A unit may have multiple reservoirs at different depths – each PA is defined vertically as well as horizontally
- Leases approved for inclusion into a PA may not be severed
- PA provides mechanism to allocate costs and revenues

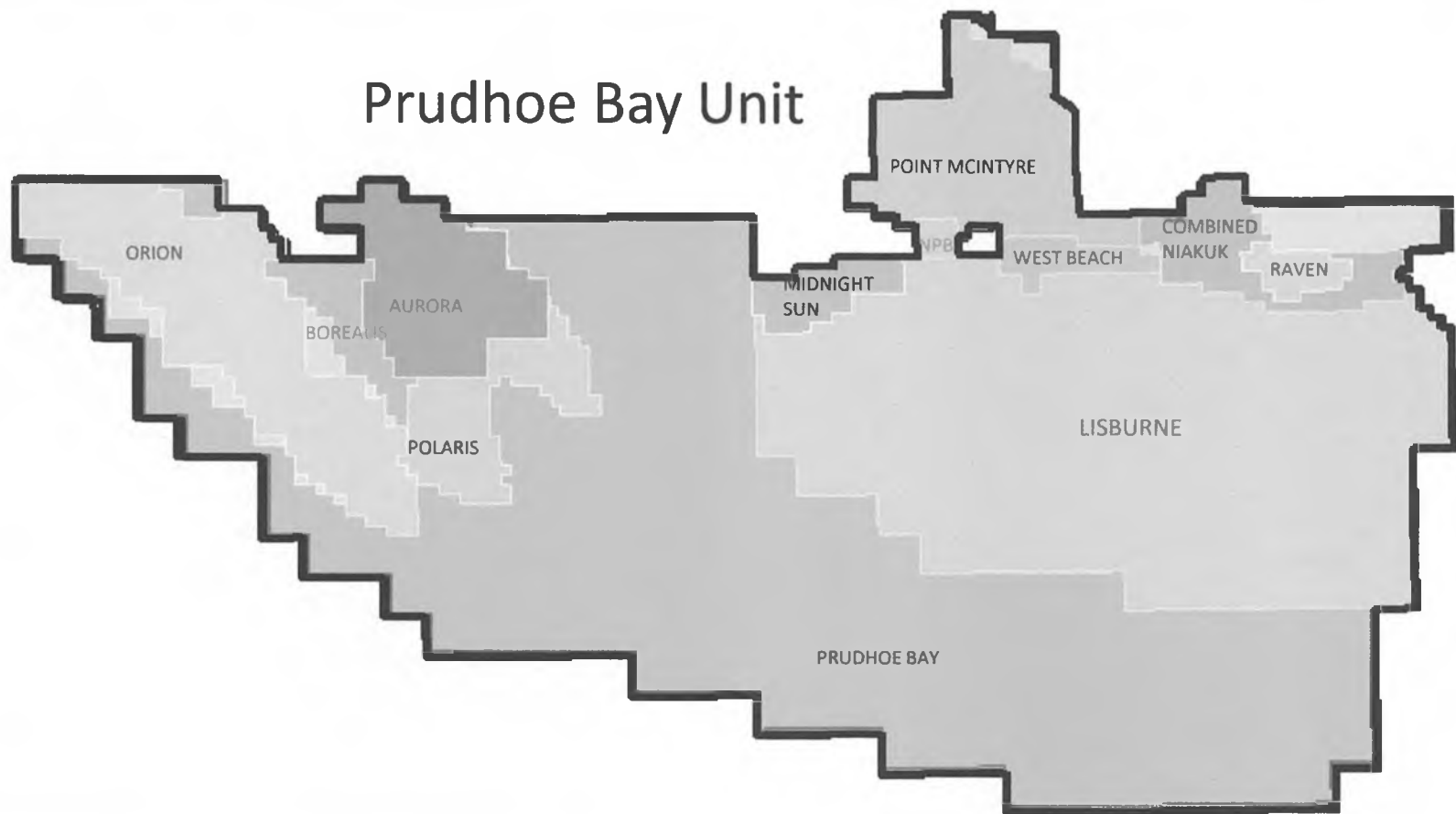
Regulations

- 11 AAC 83.351 PA Formation, Expansion, Contraction
- 11 AAC 83.343 Plans of Development
- 11 AAC 83.371 Allocation of Production and Costs
- 11 AAC 83.303 Protect all parties

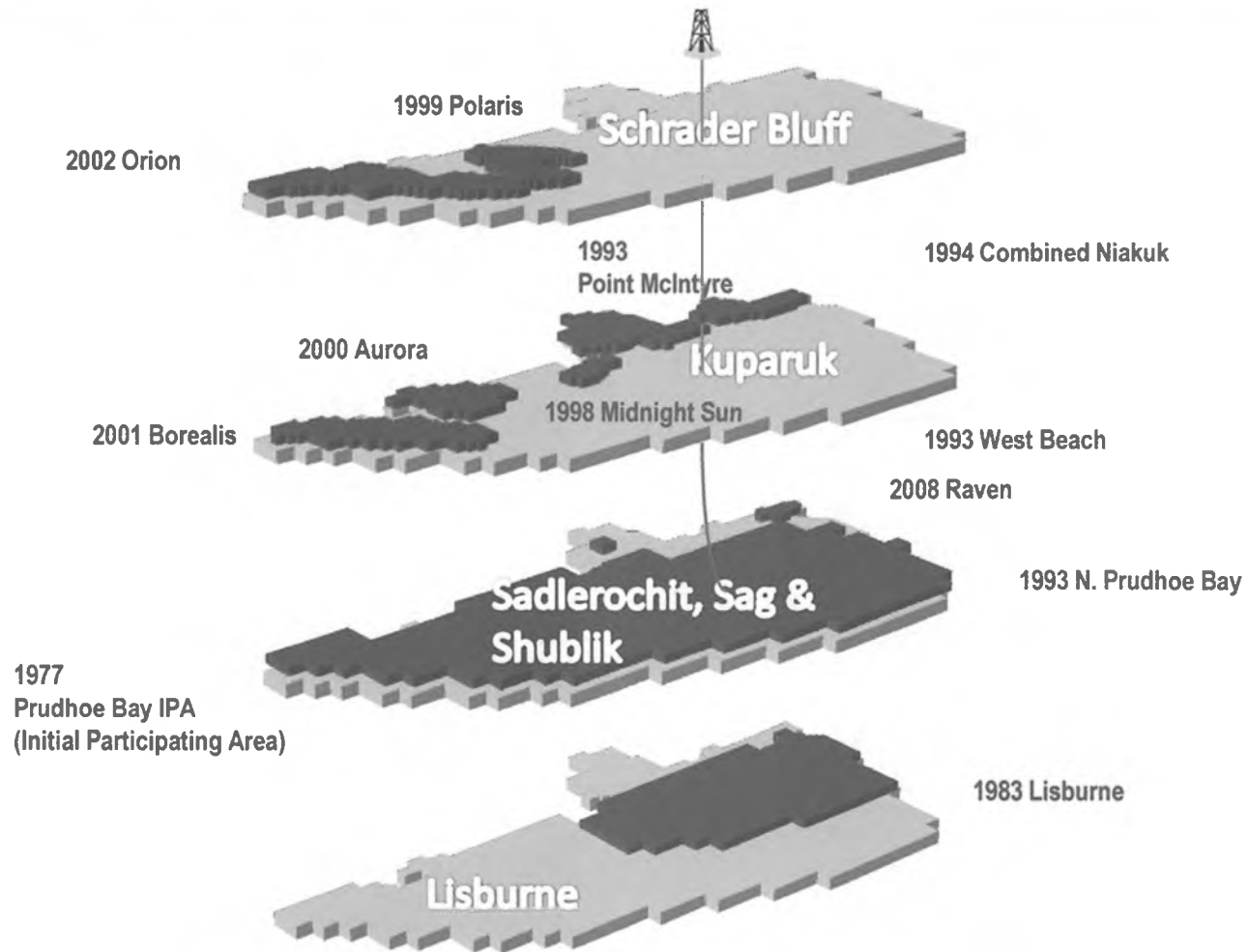
NORTH SLOPE PAs

	1977	1980	1985	1990	1995	2000	2005	2010
Nikaitchuq								2011 Nikaitchuq Schrader Bluff
Ooguruk								2008 Ooguruk Kuparuk 2008 Ooguruk Nuiqsut 2010 Ooguruk Torok
Northstar						2001 Northstar		2012 Northstar Fido 2013 Hooligan (pending)
Colville						2000 Alpine		2006 F Kuparuk 2006 Nanuq Kuparuk 2006 F Nechelik 2006 Nanuq Nanuq 2008 Quannik
Badami						1998 Badami Sands		
Duck Island				1987 Endicott 1989 Sag Delta North		1998 Eider		
Milne Point			1985 Kuparuk	1991 Schrader Bluff			2005 Sag River	
KRU			1981 Kuparuk			2000 Aurora 1998 Tarn 1998 Tabasco 1997 West Sak 2001 Meltwater		2008 KRU News
Prudhoe	1977 IPA Oil Rim/Gas Cap		1983 Lisburne			1998 Midnight Sun 1999 Polaris		2008 Raven
				1993 Pt McIntyre 1993 West Beach 1993 N Prudhoe Bay 1994 Combined Niakuk		2001 Borealis 2002 Orion		

PRUDHOE BAY UNIT



PRUDHOE BAY UNIT



EVALUATION *and* APPROVAL *of* PAs

11 AAC 83.351: PA Formation, Expansion, Contraction

- PA may include only the land capable of producing or contributing to production of hydrocarbons in paying quantities
- PA must be contracted to exclude acreage incapable of contributing to production of hydrocarbons in paying quantities

11 AAC 83.303 Criteria

- Promote conservation
- Prevent waste
- Protect all parties

EVALUATION *and* APPROVAL *of* PAs

PA application has no regulatory deadline as with unit applications

- Operator submits application no later than 90 days prior to sustained production
- Submittal includes Exhibits C and D, legal description with allocation factors, and map
 - Allocation factors allocate production to each tract
- Must include Exhibits E and F if Net Profit Share (NPS) leases included
 - NPS leases require accounting of costs and revenues to determine “pay out”. Exhibits E and F provides methodology and basis for cost allocation, used by Royalty Accounting and Audit

PA EXHIBITS C and D

NIKAITCHUQ UNIT AGREEMENT: Exhibit C SCHRADER BLUFF PARTICIPATING AREA Nikaitchuq Unit Area

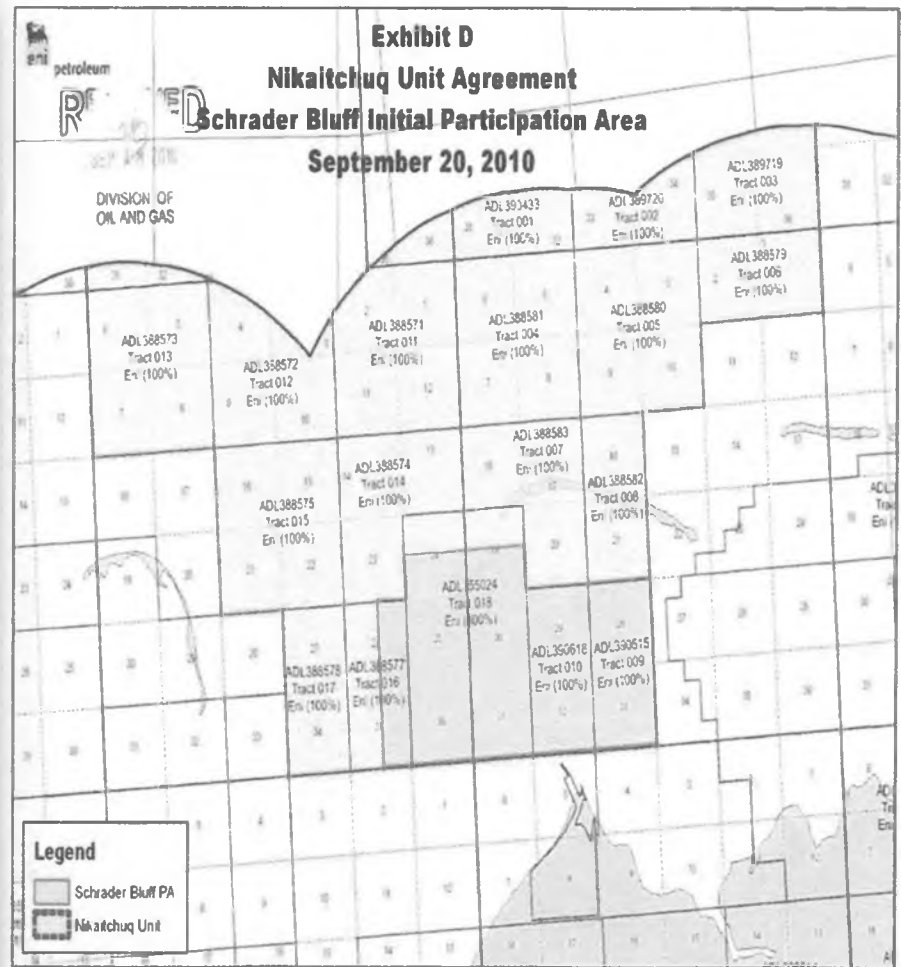
Tract No.	Section	County	Area (Acres)	Participating Interest (%)	Operator	Duration (Years)	Percentage of Net Proceeds	Percentage of Operating Expenses	Unit Participation Basis or Surface Area
1	550615	Twp. 6 S., R. 1 E., 10th N. MERIDIAN	Sec. 24	360.000	100%	DHF Exploration North Saskatchewan, LLC	10/01/00	10%	20%
			Sec. 25	360.000	100%				
			Sec. 26	360.000	100%				
			Sec. 27	360.000	100%				
			Sec. 28	360.000	100%				
			Sec. 29	360.000	100%				
			Sec. 30	360.000	100%				
			Sec. 31	360.000	100%				
			Sec. 32	360.000	100%				
			Sec. 33	360.000	100%				
2	550616	Twp. 6 S., R. 1 E., 10th N. MERIDIAN	Sec. 24	360.000	100%	DHF Exploration North Saskatchewan, LLC	10/01/00	10%	20%
			Sec. 25	360.000	100%				
			Sec. 26	360.000	100%				
			Sec. 27	360.000	100%				
			Sec. 28	360.000	100%				
			Sec. 29	360.000	100%				
			Sec. 30	360.000	100%				
			Sec. 31	360.000	100%				
			Sec. 32	360.000	100%				
			Sec. 33	360.000	100%				
3	550617	Twp. 6 S., R. 1 E., 10th N. MERIDIAN	Sec. 24	360.000	100%	DHF Exploration North Saskatchewan, LLC	10/01/00	10%	20%
			Sec. 25	360.000	100%				
			Sec. 26	360.000	100%				
			Sec. 27	360.000	100%				
			Sec. 28	360.000	100%				
			Sec. 29	360.000	100%				
			Sec. 30	360.000	100%				
			Sec. 31	360.000	100%				
			Sec. 32	360.000	100%				
			Sec. 33	360.000	100%				
4	550618	Twp. 6 S., R. 1 E., 10th N. MERIDIAN	Sec. 24	360.000	100%	DHF Exploration North Saskatchewan, LLC	10/01/00	10%	20%
			Sec. 25	360.000	100%				
			Sec. 26	360.000	100%				
			Sec. 27	360.000	100%				
			Sec. 28	360.000	100%				
			Sec. 29	360.000	100%				
			Sec. 30	360.000	100%				
			Sec. 31	360.000	100%				
			Sec. 32	360.000	100%				
			Sec. 33	360.000	100%				

Total Unitized Land Area: 14400.000

Unitized Land Area: 14400.000

Total Unitized Land: 6,351.58

RECEIVED
SEP 28 2010
DIVISION OF OIL AND GAS



PA PLAN *of* DEVELOPMENT

Once development activities commence and/or a PA is formed, a Plan of Development (POD) is required under 11 AAC 83.343

- Describes plans to develop the reservoir
 - Development activities: facilities, pipelines, offshore production islands, gathering lines, and permanent drill sites
- POD is submitted annually for review and approval
- If POD deemed insufficient for approval, DNR may propose modifications. If Operator agrees to modification, POD approved
 - If modifications not accepted by Operator and reviewed POD not approved, current POD may expire

TRACT ALLOCATION FACTORS

11 AAC 83.371

- Approval of PA includes approval of Allocation Factors (Tract Factors or TF) to protect all parties
 - Exhibit C designates each PA tract a TF
 - Bases for calculating TF proscribed in Operating Agreement sometimes Unit Agreement or approval decision
 - Acreage
 - Original Oil in Place (OOIP)
 - Recoverable
 - Value Based
- Working Interest Owners receive revenue based on TF
 - Equity negotiations
- State of Alaska receives royalties based on TF
 - Commercial interest evaluation

REVISIONS *to* DIVISION of INTEREST: REALLOCATIONS

- **Production is reallocated**

- As PA expands of contracts

- Development wells identified and committed to in Plan of Development
- Expansion of Milne Point Unit Sag River PA
- Contraction of Milne Point Unit Sag River PA

- As basis for allocation changes

- Field matures, more technical information gathered and evaluated, production is reallocated
- Revised Exhibit C designates each PA tract a TF
- Bases for calculating TF proscribed in Operating Agreement sometimes Unit Agreement or approval decision
 - Acreage, OOIP, Recoverable, Value Based

- Resource Evaluation, Commercial, Royalty Accounting, Audit Sections

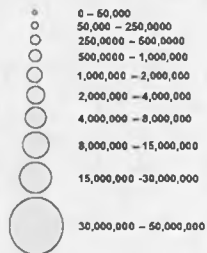
- Evaluation of protection of State's Interest
- Protection of all parties

KUPARUK RIVER UNIT (KRU)

KRU Boundary

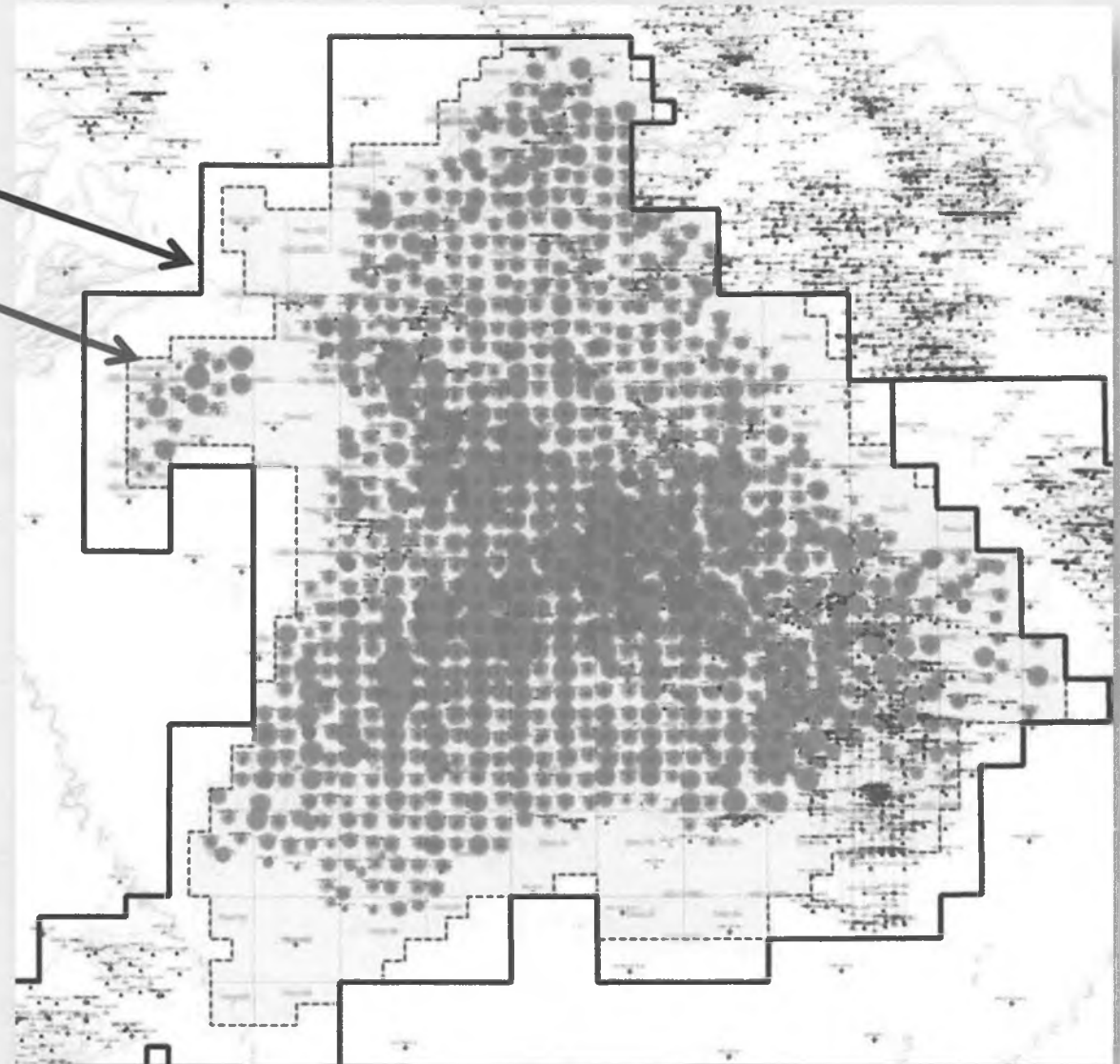
Kuparuk PA Boundary

Cumulative Barrels (KPA)



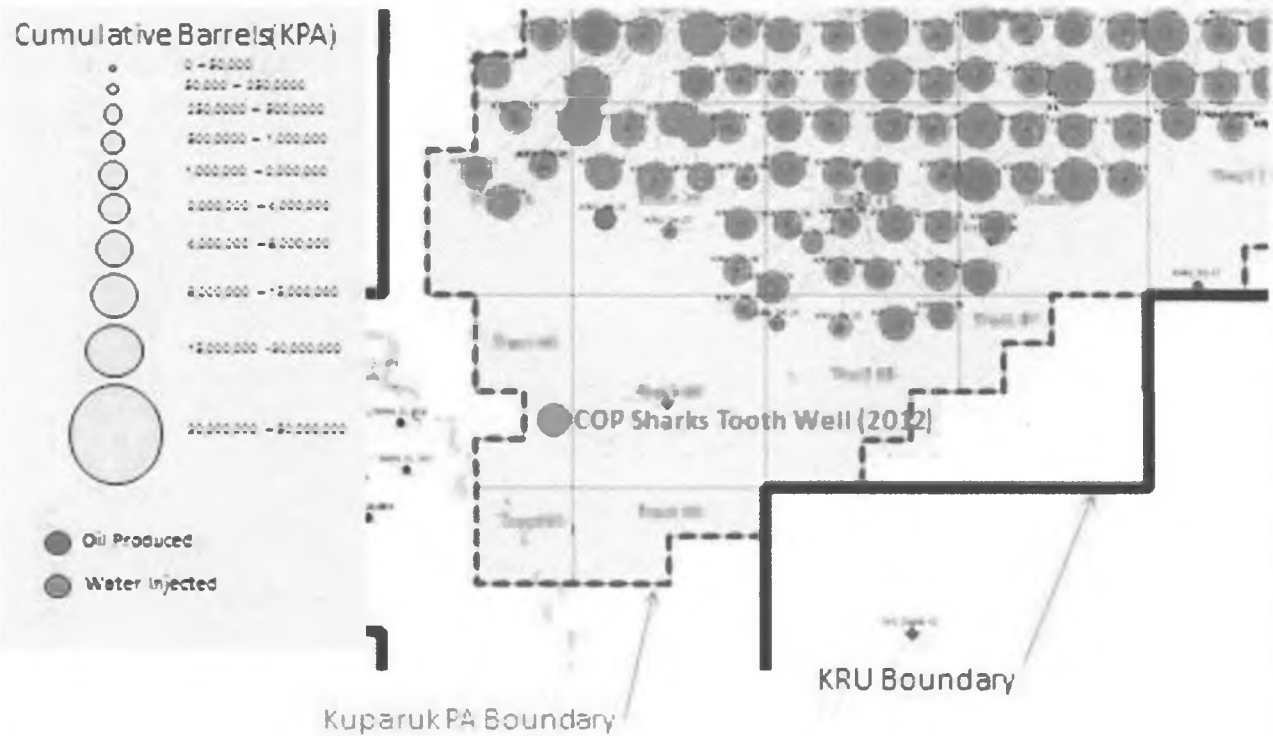
● Oil Produced

● Water Injected



KUPARUK RIVER UNIT (KRU)

Southwest Portion Kuparuk River Unit (KRU)



QUESTIONS?



THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

COMMISSIONER'S OFFICE
Bryan Butcher, Commissioner

333 Willoughby Avenue, 11th Floor
PO Box 110400
Juneau, Alaska 99811-0400
Main: 907.465.2300
Fax: 907.465.2389

April 6, 2013

The Honorable Representatives Bill Stoltze and Alan Austerman
Alaska State Representatives
Co-Chairs, House Finance Committee
State Capitol Rooms 515 and 505
Juneau, AK 99801

Dear Representative Stoltze and Representative Austerman,

The purpose of this letter is to provide you with a response to some of the questions that came up during the House Finance Committee meeting earlier this morning. This includes follow-up questions from the presentation by the Department of Revenue.

1. *Provide side-by-side comparison of bill versions.*

See attached chart comparing major provisions of ACES, and three versions of SB21. These include SB21 as introduced, SB21 as it passed the Senate, and SB21 as it passed House Resources.

2. *Provide information about the number of taxpayers for production tax.*

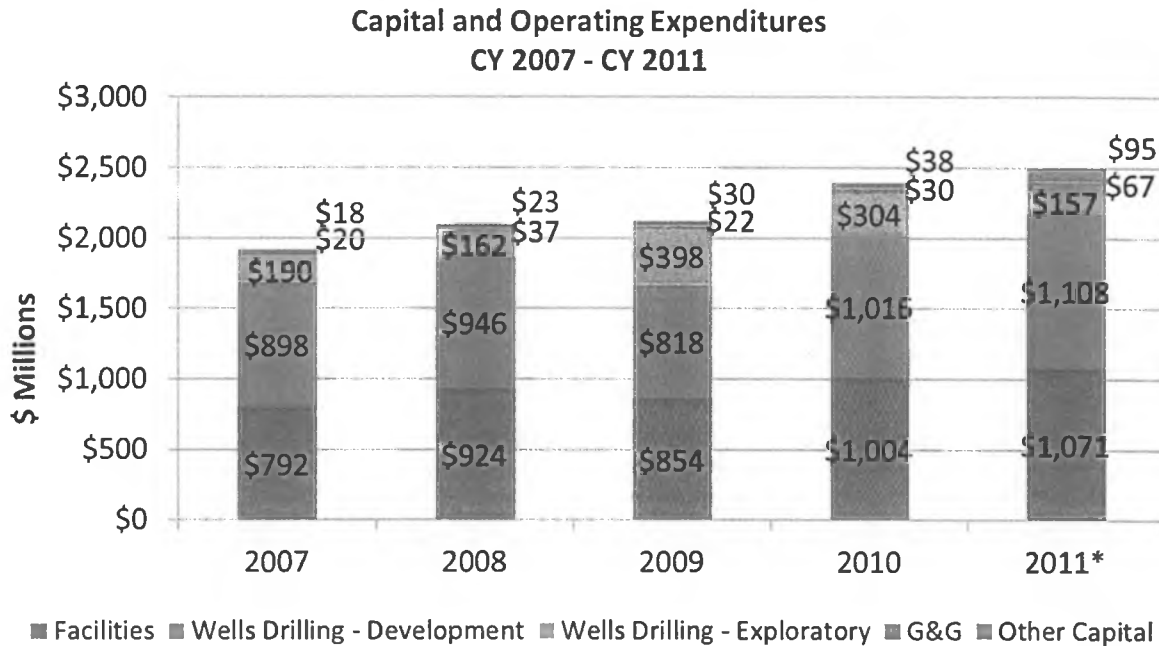
Our production audit group reported the following statistics for production tax: There were 19 producers, 6 of which had a net tax liability after application of credits. Additionally, there were 33 explorers filing for credit refunds for a total of 52 companies making production tax filings with the Department. This information is prior to receipt of the 2012 annual returns.

3. *Provide information about effectiveness of tax credits.*

The Department does not have the ability to determine what investment and / or production took place specifically as a result of tax credits. However, we do have some information about what types of investments were made as a result of company spending, which may qualify for tax credits. The following figure is a summary of the "5-year look-back" information that has been collected by the Department. It shows the capital expenditures by major category: facilities, wells drilling for development and for exploration, geological and geophysical work, and other capital expenditure. Note that the historical information includes most but not all companies that were doing business in the state,

and may not exactly match expenditure amounts reported elsewhere. However, at a high level, it is instructive as to the question of what types of projects companies have spent money on.

Historical Expenditures



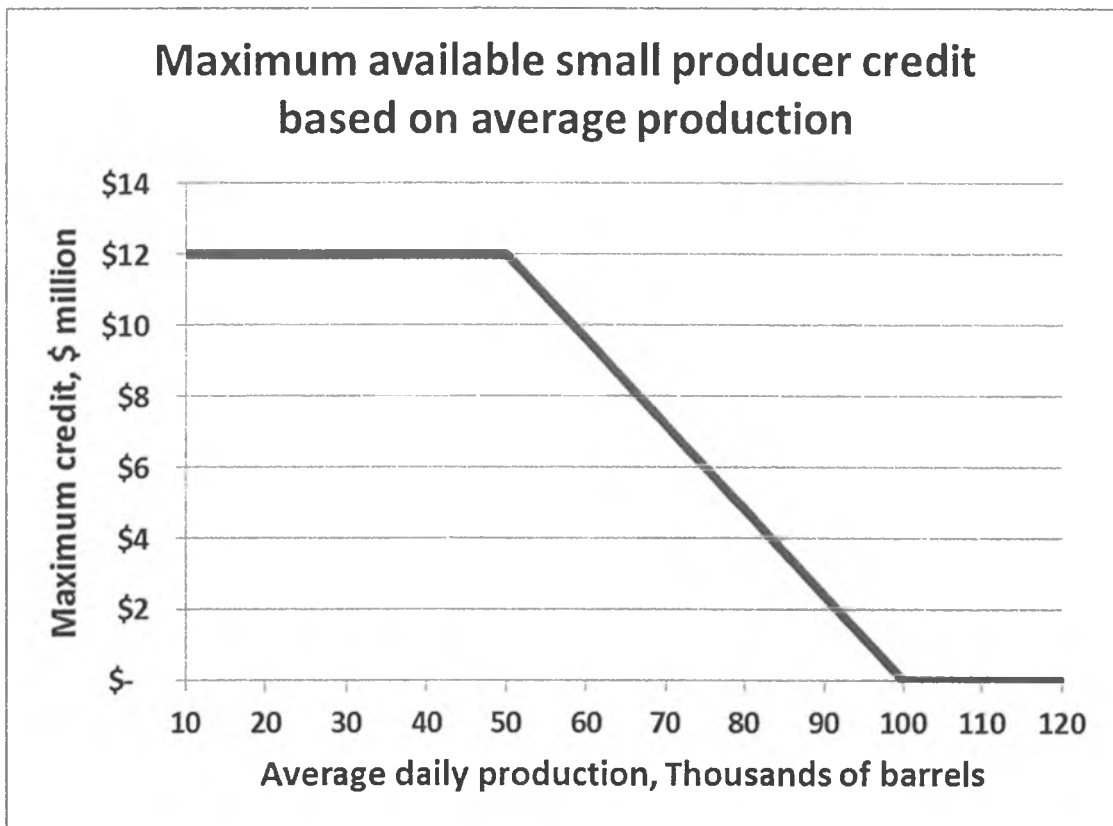
*Includes all exploring or producing petroleum companies in Alaska.

Alaska Department of Revenue

1

4. *Explain the phase-out provision of the small producer credit.*

The small producer credit under AS 43.55.024(c) is available for taxpayers with Alaska oil and gas production that is less than 100,000 BTU equivalent barrels per day. When average oil and gas production is no more than 50,000 barrels per day, the credit is \$12 million per taxpayer, per year. When production exceeds 50,000 barrels per day, but is less than 100,000 barrels per day, the credit is allocated based on production volumes as illustrated in the following chart. The credit is only available against tax liability and cannot be transferred, refunded, or carried forward. Under ACES, this credit sunsets the later of 2016, or the ninth calendar year after the first year of production. Under SB21 as it passed House Resources, the credit is extended to sunset the later of 2022 or the ninth calendar year after the first year of production.



5. *Explain logic and advantages and disadvantages of current structure of credits in HCS CSSB21(RES).*

The current bill has been refined and adjusted throughout the committee process, and new credits have been added beyond the governor's original proposal. These include the per-barrel credits, and the refundable carry-forward loss credits. That being said, the suite of credits in the current bill is in large part consistent with the original policy goal of directly incentivizing production. The current bill still eliminates the North Slope 20% capital credits which are tied to spending, not production. The current bill adds the per-barrel credits which are directly tied to production, as are the small producer credits (only available against a tax liability).

The bill also retains exploration credits, and allows refund of net operating loss credits.

Advantages of the proposed system include that it reduces the state's exposure to refunded credits at low oil prices, and it more closely aligns credits with the policy goal of oil production. Disadvantages of the current bill are that credits are slightly more complex than the governor's original proposal.

6. *Can production tax liability go below zero based on credits remaining in the bill?*

The production tax liability can only go below zero using credits that can be monetized. The non-monetizable credits under AS 43.55.024 (per-barrel and small producer) credits can only take liability

to zero. A producer with monetizable net operating loss credits, exploration credits, or capital credits for areas outside the North Slope, could receive a net refund under the current version of SB21. According to the fiscal note, the total amount of credits refunded by the state is expected to be reduced by \$120 million per year, compared to ACES. This is due to elimination of the 20% capital credit, partially offset by an increase in the rate of the net operating loss credit.

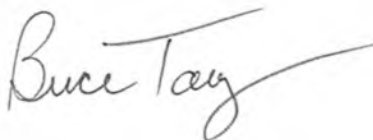
7. *Has the state ever collected less than 25% effective tax rate under ACES?*

The production tax rate is determined on a monthly basis, by company. Some companies have and currently do have an effective tax rate (after credits) of less than 25% under ACES. This occurs when a company's total credits exceed their total progressive surcharge. In the aggregate, however, the current effective tax rate exceeds 25% and is expected to continue to exceed 25%.

Historically, the effective ACES tax rate has been below 25% in some months when oil prices were low. For example, in late 2008 and early 2009 ANS oil prices were in the \$30's and \$40's for several months. During these months, no progressivity was triggered, and credits applied against the tax liability took effective tax rate below the nominal 25% rate.

We hope that the answers set forth above have addressed your questions. Please do not hesitate to contact me if you have further questions.

Sincerely,



Bruce Tangeman
Deputy Commissioner

Attachment: Comparison chart of SB21 provisions in different bill versions

Sending AK tech abroad

ConocoPhillips is using technology to increase production in Alaska, Outside

Eric Lidji

For Petroleum News

ConocoPhillips plans to spend some \$2.5 billion in Alaska over the next five years using a collection of drilling technologies to mitigate declining production on the North Slope.

The largest producer in Alaska believes it can get some 35,000 barrels per day of incremental production from its three legacy North Slope oil fields by using 4-D seismic, coiled-tubing drilling and casing drilling to lower development costs and access additional resources, but as with any discussion of investments, the company insists it could do more if Alaska policymakers would make the fiscal regime more "competitive." *

The 35,000 barrels per day would stem production declines in Alaska to some 3 percent per year by 2017, ConocoPhillips' Executive Vice President of Exploration and Production Matthew Fox said during the company's annual analyst day on Feb. 28. And, Fox noted, if ConocoPhillips brings the Alpine West/CD-5 satellite into production as scheduled in the 2015-16 timeframe, the annual decline could drop to some 2 percent. *

The goal of the \$2.5 billion program is to use newly perfected techniques to suck additional oil out of Prudhoe Bay, Kuparuk River and Alpine, but with tax changes "we can see additional opportunities that we could take advantage of to grow production in Alaska and to grow production through the Trans-Alaska Pipeline System," Fox said.

A pair of techniques

The program involves two techniques "honed" in Alaska.

Distributed by Rep. Gara

**SECTIONAL ANALYSIS
HCS CSSB 21 (RES)
28-GS1647S**

Section 1: Conforming amendments to AS 05.15.095(c) (delinquent gaming fees) required by amendment to AS 43.05.225, interest rates due on delinquent taxes.

Section 2: AS 29.60.850(b), relating to certain appropriations to the general fund is amended to remove the reference to AS 43.55.011(g) and to reference instead AS 43.20.030(c), relating to payments under the Alaska Net Income Tax Act. The legislature may appropriate revenues from AS 43.20.030 or an amount to the community revenue sharing fund not to exceed \$60,000,000 or the amount that, when added to the fund balance on June 30 of the previous fiscal year, equals \$180,000,000.

Section 3: Conforming amendments to AS 34.45.470(a) (unclaimed property) required by amendment to AS 43.05.225, interest rates due on delinquent taxes.

Section 4: AS 43.05.225, interest, is amended to allow that interest rates under current law apply to delinquent taxes and fees before January 1 2014.

Section 5: Amends AS 43.05.225, for interest on delinquent taxes after January 1, 2014; to add subsection (b)(1) providing that interest accrues at the rate of three percentage points above the applicable annual federal rate and subsection (b)(2) to refer to the interest rate for delinquent fees (AS 05.15.095(c)) and unclaimed property (AS 34.45.470(a)).

Sections 6-7: Conforming amendments to AS 43.20.046(i) (gas storage credit) and 43.20.047(i) (LNG storage credit) required by amendment to AS 43.05.225, interest rates due on delinquent taxes.

Section 8: Amends AS 43.20, the Alaska Net Income Tax Act, by adding a new section, AS 43.20.049, to establish a credit for qualified oil and gas service industry expenditures to be effective for a tax year beginning after the date of this act. A taxpayer may apply a tax credit for 10 percent of the taxpayer's qualified oil and gas service industry expenditures incurred in the state, limited to not more than \$10,000,000 in a tax year. The credit or unused portion of the credit may be carried forward for five years. An expenditure that is the basis for the credit may not be used as a deduction under Chapter 20, a credit or deduction under another provision in Title 43, or for any federal credit under Title 43.

Subsection (d) provides that the Department of Revenue may publish the total amount of tax credits claimed under this section along with a description of the expenditures that were the basis of the tax credits in a year that three or more taxpayers claim a tax credit under this section.

Subsection (e) provides definitions of “manufacture”, “modification” and “qualified oil and gas service industry expenditure.”

Section 9: Conforming amendment to AS 43.50.570 (cigarette stamps) required by amendment to AS 43.05.225, interest rates due on delinquent taxes before January 1, 2014.

Section 10: Conforming amendment to AS 43.50.570 (cigarette stamps) required by new subsection (b) to AS 43.05.225, interest rates due on delinquent taxes after January 1, 2014.

Section 11: Amends AS 43.55.011(e), relating to the levy of the oil and gas production tax. For oil and gas produced before January 1, 2014, the levy of tax remains at the current base rate of 25 percent and the monthly progressivity tax. For oil and gas produced after December 31, 2013 new subsection AS 43.55.011(e)(2) would levy on producers of oil and gas produced each calendar year a flat rate tax of 33 percent (instead of the current 25 percent plus progressivity) of the production tax value of taxable oil and gas produced from each lease or property in the state

Section 12: A conforming amendment is made to AS 43.55.011(i), payment of production tax on private landowner royalties.

Section 13: Amends AS 43.55.011(o), relating to gas used in the state, to clarify that the tax ceiling applicable to gas used in the state does not apply to gas subject to AS 43.55.011(p) (the seven year tax limitation of four percent of gross value at the point of production for oil and gas first produced commercially outside of the Cook Inlet basin and south of 68 degrees North latitude after December 31, 2012, and before January 1, 2022).

Section 14: Amends AS 43.55.020(a), monthly installment payments of estimated tax, for oil and gas produced after January 1, 2014 to apply the new base rate of 33 percent, remove reference to the monthly progressivity tax for oil and gas produced after December 31, 2013, and to account for the reduction in gross value at the point of production for new oil and gas that meets the criteria in new subsection (f), AS 43.55.160 of the bill.

Section 15: A conforming amendment to AS 43.55.020(d), related to payment by a producer to a private royalty owner before January 1, 2014.

Section 16: Conforming amendments to AS 43.55.020(g) (unpaid installment payments) required by new subsection (b) to AS 43.05.225, the interest rates due on delinquent taxes that will apply on or after January 1, 2014.

Section 17: Adds a new section, AS 43.55.020(*l*), related to payment by a producer to a private royalty owner, to apply for settlements with a private royalty owner after January 1, 2014.

Section 18: Amends AS 43.55.023(a) to eliminate the current restrictions on use of a tax credit for qualified capital expenditures and allow the full amount of a tax credit to be applied in a single calendar for expenditures incurred on or after January 1, 2013. A new subsection is added to limit the 20 percent tax credit for qualified capital expenditures incurred north of 68 degrees North latitude (North Slope) to expenditures incurred before January 1, 2014.

Section 19: Amends AS 43.55.023(b) to provide that the carried-forward annual loss credit will continue to be in the amount of 25 percent for lease expenditures incurred south of 68 degrees North latitude, but the credit will be in the amount of 33 percent based on expenditures incurred after December 31, 2013, to explore for, develop, or produce oil and gas deposits located on the North Slope.

Section 20: Amends AS 43.55.023(d), issuance of transferable and redeemable tax credit certificates for qualified capital expenditures, to conform to the amendments to AS 43.55.023(a) authorizing the Department of Revenue to issue one tax credit certificate for the full amount of a transferable tax credit.

Section 21: Amends AS 43.55.023(g), issuance of tax credit certificates, to conform to amendments to AS 43.55.020(d) related to issuance of tax credit certificates.

Section 22: Amends AS 43.55.023(n), issuance of tax credit certificates, to conform to amendments to AS 43.55.020(d).

Section 23: Adds a new section, AS 43.55.023(p), to account for limitations based on AS 43.55.023(i), the transitional investment expenditure credit, before January 1, 2014.

Section 24: Amends AS 43.55.024, the small producer credit, by extending the sunset date from 2016 to 2022.

Section 25: Amends AS 43.55.024(e) to reference only subsections (a) (the new area credit) and (c) (the small producer credit) to conform to the new per barrel credits in AS 43.55.024 (i) and (j).

Section 26: Amends AS 43.55.024 to add two new non-transferable tax credits. Subsection (i) provides for a credit of \$5 for each barrel of oil taxable under AS 43.55.011(e) produced in a calendar year after December 31, 2013 that meets the criteria of AS 43.55.160(f), the gross revenue reduction for certain North Slope production.

Subsection (j) provides a sliding scale credit based on the monthly gross value at the point of production of each barrel of taxable oil produced on the North Slope after December 31, 2013 that does not meet the criteria in AS 43.55.160(f). The sliding scale credit may not be applied to reduce a producer's tax liability under AS 43.55.011(e) to below the amount calculated under AS 43.55.011(f), the alternate minimum tax on North Slope oil and gas.

Sections 27 -28: Amends AS 43.55.025 (a) the alternative tax credit for oil and gas exploration so that the three mile well limitation in AS 43.55.025(c)(2)(B) does not apply to subsection (m), the basin tax credit for up to four exploration wells drilled after June 1, 2012 and before July 1, 2016 outside of the Cook Inlet sedimentary basin and south of the North Slope.

Sections 29 -30: Amends AS 43.55.028(e) and (g) (oil and gas tax credit fund) to conform to changes in the issuance of tax credit certificates in AS 43.55.020(d).

Section 31: Amends AS 43.55.030(e)(1), "Filing of statements", to clarify current practice that both explorers and producers must file statements reporting qualified capital expenditures and other information required under AS 43.55.030(e) even if they do not produce oil or gas.

Section 32: Amends AS 43.55.160, relating to calculation of annual and monthly production tax values, to account for new subsection (f), and makes clarifying and conforming amendments.

Section 33: Amends AS 43.55.160 by adding new subsection (f) which provides that in calculating the annual production tax value for oil and gas produced from the North Slope on or after January 1, 2014, the gross value at the point of production of the oil or gas meeting one or more of the following criteria is reduced by 20 percent 1) oil or gas produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003; (2) oil or gas produced from a participating area, established after December 31, 2011, within a unit formed by the Department of Natural Resources before January 1, 2003 if the participating area does not contain a reservoir that was previously in a participating area; (3) oil or gas produced from acreage that was added to an existing participating area by the Department of Natural Resources on or after January 1, 2014, and the producer demonstrates to the Department of Revenue the volume of oil or gas from the added acreage.

Adds a new subsection (g) for calculation of annual production tax value for oil and gas produced on or after January 1, 2014.

Section 34: Repeals and reenacts AS 43.55.165(a) related to deductible lease expenditures, which are ordinary and necessary costs upstream of the point of production

of oil and gas incurred during a calendar year. In determining whether a cost is a lease expenditure, the Department of Revenue is directed to consider typical industry practices that determine the costs a field operator is allowed to bill a working interest owner, and the standards developed by the Department of Natural Resources that a lessee may deduct under a lease issued under AS 38.05.180(b)(3)(B), (D), or (E), the net profit share lease provisions.

Section 35: Repeals and reenacts AS 43.55.165(b), related to qualifications for lease expenditures, for direct costs, a reasonable allowance for overhead (to be determined by regulations) and to provide that an activity need not be physically located on the lease or property in order for the cost to be considered upstream of the point of production of the oil or gas.

Section 36: AS 43.55.165 is amended to add a new section (m) to allow the Department of Revenue to consider whether a unit operating agreement or similar agreement is consistent with the Department's determinations and standards under subsection (a) concerning whether costs are lease expenditures, and to allow the Department to authorize or require a producer to treat as lease expenditures costs, other than statutorily excluded costs, that are billed or billable to the producer by the operator under the operating agreement, including a reasonable percentage for overhead expenses related to oil and gas exploration, development and production. The Department is given the discretion, in subsection (n), to authorize or require costs under a unit operating agreement or similar agreement to be treated as lease expenditures if certain conditions related to audit billings by the parties to the unit operating agreement or similar agreement are met.

Section 37: Amends AS 43.55.180 to require a report by the Department of Revenue to the legislature on the first day of the 2016 legislative session. The report must consider the effects of AS 43.55 on oil and gas exploration, development, and production, on investment for the same, on the entry of new producers of oil and gas, on state revenue, on tax administration and compliance under AS 43.55011, AS 43.55.023 – 43.55.025, and 43.55.160 – 170 and the effect of tax rates for private landowner royalties on state revenues and oil and gas exploration, development, and production on private land.

Section 38: Amends AS 43.56.160, relating to interest on the oil and gas exploration, production, and pipeline transportation property tax, to conform to amendments to AS 43.05.225, interest rate for delinquent taxes.

Section 39: Amends AS 43.77.020(d), relating to payments of the fishery resource landing tax, to conform to amendments to AS 43.05.225 relating to interest rates for delinquent taxes.

Section 40: Amends AS 43.90.430, relating to interest to payments due the state under the Alaska Gasline Inducement Act, to conform to the changes in bill section 4, amendments to AS 43.05.225.

Section 41: Amends AS 44.88.140(a), related to property exempt from taxation of the Alaska Industrial Development and Export Authority (AIDEA), to include reference to new AS 44.88.168 in the bill

Section 42: Adds new section AS 44.88.168 to allow AIDEA to issue bonds for an oil processing facility and to establish an oil and gas infrastructure fund. The fund will consist of appropriated funds, and is not an account in the revolving loan fund. Money in the fund will be used to finance the construction or improvement of an oil and gas processing facility on the North Slope, including flow lines and other surface infrastructure.

Section 43: Repeals AS 43.55.023(m) related to tax credit certificates to conform to changes made so that tax credit certificates statewide will be issued as one certificate.

Section 44: Repeals AS 43.05.225(a), AS 43.50.570(a), AS 43.55.011(e)(1), AS 43.55.011(g), AS 43.55.020(d), 43.55.023(i), AS 43.55.023(p). AS 43.55.160(a)(2) and AS 43.55.160(c) as of January 1, 2014.

Section 45 : Applicability sections for sections that apply to oil and gas produced after a certain date and for expenditures incurred after a certain date.

Section 46 : Transitional provision providing the Department of Revenue's authority to adopt regulations, to be effective not before the date of the effective date of the provisions of this bill.

Section 47: Provisions related to legislative approval of AIDEA bonding issuance.

Section 48: Provisions related to retroactive application of certain sections.

Department of Revenue
Sectional Review
HCS CSSB 21(RES)
April 5, 2013
House Finance Committee

Main Provisions

- **Interest Rate for Delinquent Tax Payments and Refunds of Overpayments of Taxes**
- **Income Tax Credit for Qualified Oil and Gas Service Industry Expenditures**
- **Production Tax Rate - 33%**
- **Repeal of Progressivity**
- **Gross Value Reduction**
 - Establishes 20 % reduction from the gross value at the point of production for North Slope oil and gas produced from
 - 1) new units,
 - 2) new participating areas in existing units and,
 - 3) expanded acreage.
- **Tax Credits**
 - Eliminates current 20% capital expenditure tax credit for North Slope after December 31, 2013.
 - Increases tax credit for carried-forward annual losses to 33% for the North Slope after December 31, 2013.
 - Establishes a \$5 per barrel of oil tax credit for some production.
 - Establishes a sliding scale credit for production not qualified for the \$5 credit.
 - Extends small producer credit.
 - **Revenue report to legislature in 2016**
 - **Lease expenditures and joint interest billings**
 - **Oil and gas infrastructure fund in AIDEA**

Interest Rate for Delinquent Taxes

- **Amends AS 43.05.225(1)** to set the interest rate at 3% points above the annual rate charged member banks for advances by the 12th Federal Reserve District compounded quarterly.
 - Currently, the interest rate is the greater of either 5% points above the annual rate charged member banks for advances by the 12th Federal Reserve District OR the annual rate of 11% compounded quarterly.
- **Eliminates the 11% alternate annual rate.**
- **Applies to many tax types.**
- **Applies against the State for refunds of overpayments of taxes.**
- **Interest rate change as of January 1, 2014.**

Qualified Oil and Gas Industry Service Expenditure Tax Credit

- Amends the Alaska Net Income Tax Act by adding a new section, AS 43.20.049.
- Provides a tax credit for the lesser of 10 % of qualified oil and gas industry service expenditures incurred in the state or \$10,000,000.
- Applies against tax liability, may be carried-forward for no more than 5 tax years after the expenditures were incurred.
- Qualified oil and gas service industry expenditure must be directly attributable to the in-state manufacture or modification of tangible personal property that has a useful life of 3 years or more used in the exploration, development, or production of oil or gas.

AS 43.55 Tax Rate

- AS 43.55.011(e) is amended to levy an annual flat tax rate of 33%. Applies to oil and gas produced after December 31, 2013.
- AS 43.55.011(g), the monthly progressivity tax, is repealed as of January 1, 2014.
- Producers of oil and gas still make estimated monthly installment payments.

Community Revenue Sharing Fund

- Amends AS 29.60.850(b) to eliminate the reference to AS 43.55.011(g) and substitutes the corporate income tax.
 - Statute directs appropriation not to exceed \$60,000,000 or amount when added to fund balance, equals \$180,000,000.
- **No change** is made to the eligibility determinations for community revenue sharing payments or **to authority of legislature to appropriate any amount.**

Qualified Capital Expenditure Tax Credit

- The 20% qualified capital expenditure tax credit is limited to expenditures incurred before January 1, 2014 to explore for, develop, or produce oil and gas deposits on the North Slope.
- Tax credits for expenditures incurred to explore for, develop, or produce oil and gas deposits south of the North Slope are not impacted.
- The full amount of a tax credit certificate may be issued in a single year.

Carried-Forward Tax Credit

AS 43.55.023(b)

- Based on the amount of a producer's or explorer's adjusted lease expenditures that were not deductible in calculating the annual production tax values for that year.
- Retains 25% credit for a carried-forward annual loss for adjusted lease expenditures incurred outside of the North Slope.
- Provides a tax credit of 33% for a carried-forward annual loss for adjusted lease expenditures incurred after December 31, 2013 on the North Slope.

AS 43.55.024 Credit

- Extends the small producer credit to 2022 (from 2016) for producers of less than 100,000 BTU equivalent barrels of daily production.
- Non-transferable, only applies against AS 43.55.011(e) tax.
- Establishes a \$5 per barrel credit for each barrel of taxable oil that qualifies for a gross revenue exclusion.
- Establishes a sliding scale credit from \$8 to zero based on monthly gross value of oil produced on the North Slope that does not qualify for the gross revenue exclusion. Not applicable against the minimum tax.

Gross Revenue Exclusion for North Slope Oil and Gas (*Gross Value Reduction*)

- For oil and gas produced **north of 68 degrees North latitude**, the gross value at the point of production is reduced by **20 percent** for the oil or gas produced from:
 - 1) Leases in a unit established after January 1, 2003;
 - 2) New reservoirs in an **expanded participating area** within a unit formed before January 1, 2003; or
 - 3) **Acreage added to an existing participating area** with approval by the Department of Natural Resources.

Lease Expenditures

- Lease expenditures are ordinary and necessary costs of upstream operations for exploration, development, and production deducted to determine production tax value. Currently lease expenditures are allowed by regulation as required by AS 43.55.165(a)(1)(B).
- The bill restores 2006 language that allows Revenue to consider JIBs that are substantially similar to Revenue's definition of lease expenditure and rely on audits performed by joint interest owners in performing state audits. Field operators bill other working interest owners via Joint Interest Billings (JIBs) which are invoices for operating agreements.

Other Key Provisions

- Allows the Alaska Industrial Development and Export authority to issue bonds for an oil processing facility and to establish an oil and gas infrastructure fund. AS 44.88.168. The fund consists of appropriated funds and is not in the revolving loan fund, AS 44.88.060.
- Requires DOR to issue a report in 2016 under AS 43.55.180 on the effects of AS 43.55 on oil and gas exploration, development, and production; new entrants, and other development matters.

Summary

- Four principles:
 - Tax reform that is fair to Alaskans.
 - To encourage new production.
 - Simple and balanced system.
 - Competitive for the long term.



THE STATE
of ALASKA
GOVERNOR SEAN PARNELL

Department of Revenue

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April 7, 2013

The Honorable Representatives Bill Stoltze and Alan Austerman
Alaska State Representatives
Co-Chairs, House Finance Committee
State Capitol Rooms 515 and 505
Juneau, AK 99801

Dear Representative Stoltze and Representative Austerman,

The purpose of this letter is to provide you with a response to some of the questions that came up during the House Finance Committee meeting earlier today. This includes follow-up questions from the fiscal impact presentation by the Department of Revenue. Additionally, we will continue to work with members of the committee regarding requests for additional modeling and analysis as you consider the current version of SB21.

1. *Provide fiscal impact using Spring 2013 forecast.*

Figure 1 shows the summary fiscal table from slide 21 of our presentation, updated based on the Spring 2013 forecast.

2. *Did Alberta's tax reduction lead to increased production?*

See attached slides from EconOne, showing how production, capital spending, employment, and drilling / development activity have increased in Alberta.

3. *Provide transcript of Conoco analysis presentation regarding 2-3% expected decline rates.*

See attached.

4. *Recreate slide 21 with 35% base rate, and with the two different per-barrel credits broken out.*

Figure 2 shows the summary fiscal table from slide 21 of our presentation, with a 35% base rate. We assume that the Net Operating Loss credit is also increased to 35% to match the base rate. Additionally, the table separates the impact of the \$5 per taxable barrel credit for GRE-eligible oil and the sliding-scale credit for non-GRE oil.

6. *Show impact of various levels of per-barrel credits.*

The following chart shows the estimated revenue impact of per-barrel credits at different levels per the Fall 2012 revenue forecast.

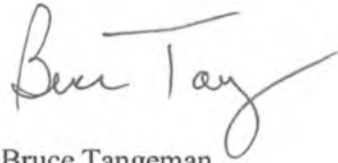
Estimated Fiscal Impact of different per-barrel credit levels under Fall 2012 Forecast (\$millions)

Amount of credit	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
\$1 per taxable barrel credit	-\$75	-\$175	-\$150	-\$150	-\$150	-\$125
\$2 per taxable barrel credit	-\$175	-\$325	-\$325	-\$300	-\$275	-\$275
\$3 per taxable barrel credit	-\$250	-\$500	-\$475	-\$450	-\$425	-\$400
\$4 per taxable barrel credit	-\$350	-\$650	-\$625	-\$600	-\$550	-\$525
\$5 per taxable barrel credit	-\$425	-\$825	-\$775	-\$750	-\$700	-\$675
\$6 per taxable barrel credit	-\$525	-\$1,000	-\$950	-\$900	-\$825	-\$800
\$7 per taxable barrel credit	-\$600	-\$1,150	-\$1,100	-\$1,050	-\$975	-\$925
\$8 per taxable barrel credit	-\$700	-\$1,325	-\$1,250	-\$1,200	-\$1,100	-\$1,075
\$9 per taxable barrel credit	-\$775	-\$1,475	-\$1,425	-\$1,350	-\$1,250	-\$1,200
\$10 per taxable barrel credit	-\$850	-\$1,650	-\$1,575	-\$1,500	-\$1,400	-\$1,325

The Honorable Bill Stoltze and Alan Austerman
Page 3 of 5

We hope that the answers set forth above have addressed your questions. Please do not hesitate to contact me if you have further questions.

Sincerely,

A handwritten signature in black ink that reads "Bruce Tangeman". The signature is written in a cursive style with a long horizontal stroke extending from the top of the "B".

Bruce Tangeman
Deputy Commissioner

Attachments:

Alberta Benchmark slides from EconOne

ConocoPhillips February 28, 2013 analyst meeting transcript

Figure 1: Fiscal Impact Summary table, updated to reflect Spring 2013 Forecast Assumptions

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Spring 2013 Forecast (\$millions)¹

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-\$725	-\$1,400	-\$1,725	-\$1,875	-\$1,650	-\$1,525
2. Base tax rate changed to 33% of production tax value	\$425	\$825	\$875	\$875	\$800	\$750
3. Limitation of credits for qualified capital expenditures for North Slope	\$300	\$675	\$650	\$525	\$475	\$450
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	\$0	-\$25	-\$25	-\$50	-\$25	-\$50
6. Provision requiring credits be taken over 2 years eliminated ²	-\$225					
7. Amendment to the community revenue sharing fund	\$0	\$0	\$0	\$0	\$0	\$0
8. Credit of \$5 per taxable barrel / Sliding scale credit per taxable barrel based on oil price	-\$425	-\$825	-\$775	-\$750	-\$700	-\$675
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -\$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -\$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	\$0	\$0	\$0	\$0	\$0	\$0
12. Small producer credit extended to 2022	\$0	\$0	\$0	-\$25	-\$25	-\$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	-\$650 to -\$700	-\$750 to -\$800	-\$1000 to -\$1050	-\$1275 to -\$1325	-\$1100 to -\$1150	-\$1050 to -\$1100
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-\$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		\$150	\$150	\$150	\$150	\$150
Impact on Operating Budget of increase in Net Operating Loss credits		-\$30	-\$30	-\$30	-\$30	-\$30
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production³	-\$800 to -\$850	-\$630 to -\$680	-\$880 to -\$930	-\$1155 to -\$1205	-\$980 to -\$1030	-\$930 to -\$980

¹The impacts listed are based on production and prices as forecasted in our Spring 2013 revenue forecast. The forecasted oil prices are between \$109.61 and \$118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is \$400 million, with \$250 million taken against tax liability as a revenue impact and \$150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

³NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.

Figure 2: Fiscal Impact Summary table, with 35% base rate and separate impacts of per-barrel credits

Provisions in HCS CSSB21(RES) and their Estimated Fiscal Impact as compared to Fall 2012 Forecast (\$millions)¹

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-\$800	-\$1,500	-\$1,700	-\$1,800	-\$1,750	-\$1,650
2. Base tax rate changed to 35% of production tax value	\$550	\$1,075	\$1,100	\$1,075	\$1,025	\$975
3. Limitation of credits for qualified capital expenditures for North Slope	\$300	\$700	\$650	\$550	\$475	\$400
4. Net operating loss credit rate increased to 33%; are transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	\$0	-\$25	-\$25	-\$50	-\$25	-\$50
6. Provision requiring credits be taken over 2 years eliminated ²	-\$250					
7. Amendment to the community revenue sharing fund	\$0	\$0	\$0	\$0	\$0	\$0
8a. Credit of \$5 per taxable barrel for GRE-eligible production	-\$5	-\$10	-\$25	-\$25	-\$25	-\$25
8b. Sliding scale credit per taxable barrel based on oil price for non GRE-eligible production	-\$420	-\$815	-\$750	-\$725	-\$675	-\$650
9. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -\$25 million annually)					
10. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -\$25 million annually, increasing over time)					
11. Removal of 3-mile requirement for frontier basin tax credit	\$0	\$0	\$0	\$0	\$0	\$0
12. Small producer credit extended to 2022	\$0	\$0	\$0	-\$25	-\$25	-\$50
13. 2016 required report to legislature	No fiscal impact					
14. Requirement to consider Joint Interest Billings in audit process	Indeterminate					
15. AIDEA bonding authority to finance oil and gas processing facilities	No Department of Revenue fiscal impact					
Total Revenue Impact	-\$625 to	-\$575 to	-\$750 to	-\$975 to	-\$975 to	-\$1000 to
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-\$675	-\$625	-\$800	-\$1025	-\$1025	-\$1050
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		\$150	\$150	\$150	\$150	\$150
Impact on Operating Budget of increase in Net Operating Loss credits to 35%		-\$40	-\$40	-\$40	-\$40	-\$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production³	-\$775 to	-\$465 to	-\$640 to	-\$865 to	-\$865 to	-\$890 to
	-\$825	-\$515	-\$690	-\$915	-\$915	-\$940

¹The impacts listed are based on production and prices as forecasted in our Fall 2012 revenue forecast. The forecasted oil prices are between \$109.61 and \$118.29. All data here are estimates; all figures have been rounded to reflect the uncertainty in the estimates.

²Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is \$400 million, with \$250 million taken against tax liability as a revenue impact and \$150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

³NOTE: "Total Fiscal Impact" includes best estimates of both revenue and operating budget impacts. Operating budget impact for FY 2014 represents additional refunded credits due to elimination of the provision requiring that credits be taken over 2 years. Operating budget impact for FY 2015 and beyond represents reduction in refunded credits due to limitation of credits for qualified capital expenditures for North Slope. This amount also includes increases in credit refunds paid through the operating budget for the increase in NOL credit rates.