NEW SUSTAINABLE
ALASKA
PLAN
Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform- SB130

Department of Revenue

Second Presentation: "Additional Modeling and Scenario Analysis"

Presentation to the Senate Resources Committee

April 4, 2016

What We'll Be Discussing

- Follow-ups from Prior Presentation
- Bill Details- Analysis and Modeling of Complex Sections
- Summary of Scenario Analysis and Life Cycle Modeling: Economics of Changes

Follow-Ups From Prior Presentation

Tax Credit Fund- Alternative History if Appropriation had Been at Statutory Level

Oil and Gas Tax Credit Fund: Budgeted vs. Actual vs. Statutory Tax Credit Fund Transfer Cap

(Beginning with the first budget cycle after the passage of ACES in November 2007)

Fiscal Year	Original Appropriation ($million)	Actual Claimed Credits ($million)	Actual Production Tax ($million)	Plus Credits Against Liab ($million)	AS 43.55.011 Revenue ($million)	Oil Price Per Spring 16 Forecast	Credit Cap per AS 43.55.028(c)	End Year Fund Balance	Non-Cashable Carried-Forward	Total Credit Oblig
Actual										
FY09	not to exceed $175	$193	$3,101	$334	$3,435	$85.73	$343	$150	$0.0	n/a
FY10	unspec **	$250	$2,861	$412	$3,273	$65.70	$327	$228	$0.0	n/a
FY11	est. $180	$450	$4,543	$361	$4,904	$73.32	$490	$268	$0.0	n/a
FY12	est. $400	$353	$6,137	$363	$6,500	$94.70	$650	$565	$0.0	n/a
FY13	est. $400	$369	$4,043	$550	$4,593	$110.44	$459	$655	$0.0	n/a
FY14	est. $400	$593	$2,589	$919	$3,508	$109.61	$351	$413	$0.0	n/a
FY15	est. $450	$628	$363	$664	$1,027	$95.24	$103	($112)	$0.0	$112
FY16	est. $700	$500	$133	$80	$213	$39.52	$32	($580)	$385	$965
Forecasted										
FY17	$73.4 (tent)	$775	$46	$80	$126	$38.89	$19	($1,336)	$632	$1,968
FY18	n/a	$500	$16	$150	$166	$43.79	$25	($1,811)	$766	$2,577
FY19	n/a	$375	$11	$205	$216	$48.89	$32	($2,154)	$747	$2,901
FY20	n/a	$270	$13	$250	$263	$54.48	$39	($2,384)	$600	$2,984
FY21	n/a	$250	$32	$305	$337	$60.29	$34	($2,601)	$284	$2,885
FY22	n/a	$250	$105	$325	$430	$61.64	$43	($2,808)	$151	$2,959
FY23	n/a	$250	$217	$280	$497	$63.05	$50	($3,008)	$74	$3,082
FY24	n/a	$250	$198	$205	$403	$64.45	$40	($3,218)	$1	$3,219
FY25	n/a	$250	$274	$185	$459	$65.90	$46	($3,422)	$0	$3,422

Detail on Current Tax Division Work Pool of Refundable Credit Applications (As Presented at 4/2 Hearing)

(All amounts in $millions)

Amount	**Description**	**North Slope**	**CI / ME**
$10	Older NOL Credits	$7	$3
$22	Older Exploration Credits	$0	$22
$552	2015 NOL, QCE, WLE	$335	$217
$60	2015 Exploration	$53	$7
$31	Additional 2015 Amended	$27	$4
$675		**$422**	**$253**

Bill Details & Calculations

Analysis of Complex Sections

Section 7: Interest Rate Compounding

Evolution of the interest rate language in SB21:

- Early Senate versions simply changed the rate in existing statute (kept compounding language)
- Final Senate version failed to pass an effective date clause vote (requires 14 senators)
- First House CS (Resources) added “applicability” language in many portions of the bill, to ensure that the old rates and conditions applied before 1/1/14 and the new rates and conditions after that date. Interest rate section kept compounding language

Section 7: Interest Rate Compounding

- Work Draft House CS (Finance) fixed technical error in Resources version, but inadvertently restored "higher of 11%" language for after 1/1/14. Kept compounding language.
- Technical committee amendment #15 (by co-chair Austerman) intended to delete the 11% language, but also deleted compounding. This was explained to the committee as simply restoring the floating rate language. The amendment passed unanimously.

Page 2, lines 23 - 25:

Delete "**, or at the annual rate of 11 percent, whichever is greater, compounded quarterly as of the last day of that quarter**"

Section 7: Interest Rate Increase

Middle ground tied to opportunity cost

- Seeking a point between the historic 11% and the current (effective) 4%
- **Currently, each dollar of tax not paid is another dollar out of savings**
- When this tax is eventually paid, it should compensate for what would have earned had it stayed in savings
- Current Permanent Fund estimate (Callan & Assoc.) is about 7%

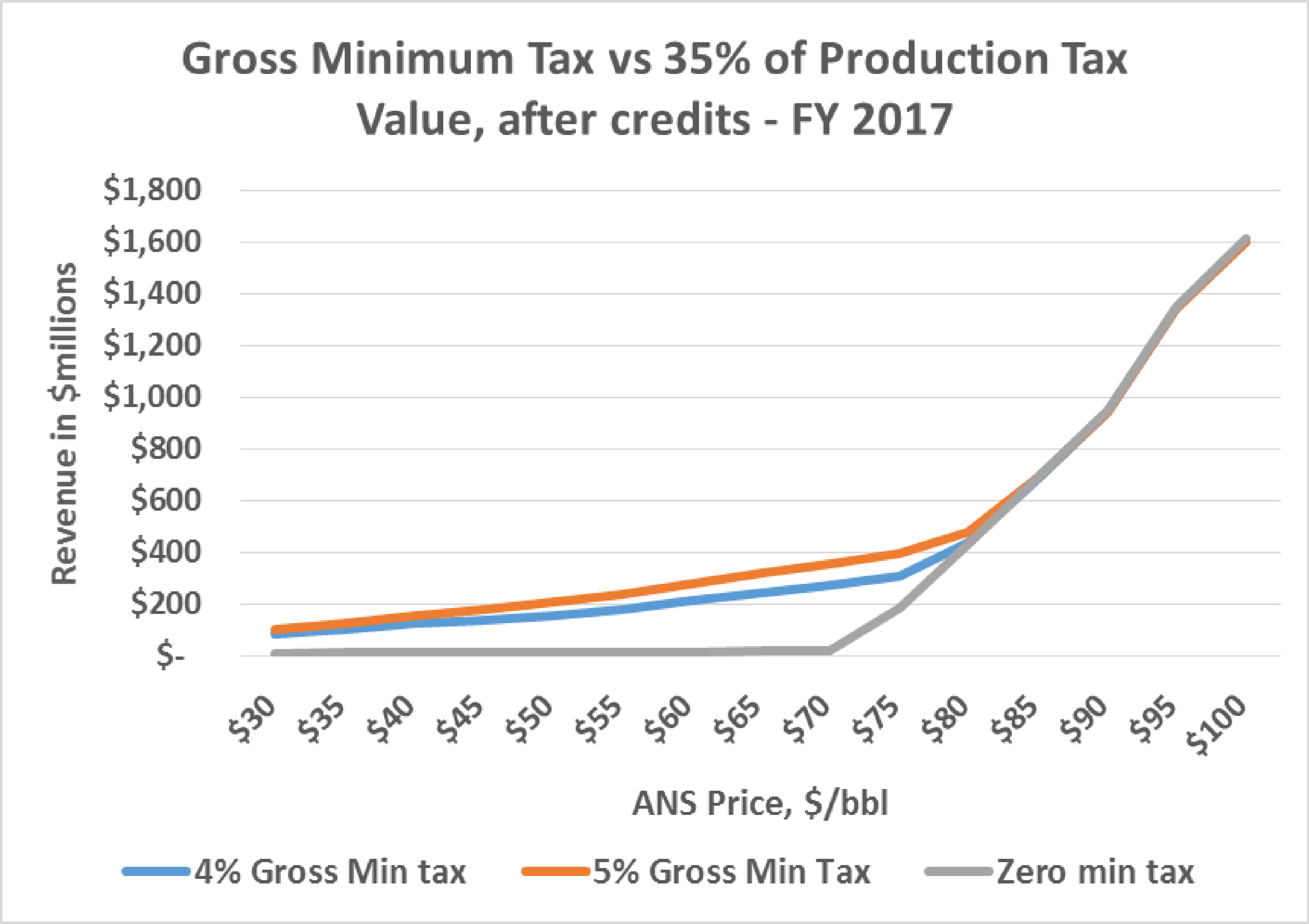
Section 7: Interest Rate Increase

Illustration: $1 million assessment to a tax due 12/31/15, and assessed 6/30/17						
Current Law						
	Q1 2016	**Q2 2016**	**Q3 2016**	**Q4 2016**	**Q1 2017**	**Q2 2017**
Pricipal	$ 1,000,000	$ 1,010,000	$ 1,020,000	$ 1,030,000	$ 1,040,000	$ 1,050,000
Subject to interest	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**
Rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Interest	**$ 10,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**
					Total Due 6/30/17	**$ 1,060,000**
HB 247						
	Q1 2016	**Q2 2016**	**Q3 2016**	**Q4 2016**	**Q1 2017**	**Q2 2017**
Principal	$ 1,000,000	$ 1,010,000	$ 1,020,000	$ 1,040,000	$ 1,060,400	$ 1,081,208
Subject to interest	**$ 1,000,000**	**$ 1,000,000**	**$ 1,000,000**	**$ 1,020,000**	**$ 1,040,400**	**$ 1,061,208**
Rate	4.00%	4.00%	8.00%	8.00%	8.00%	8.00%
Interest	**$ 10,000**	**$ 10,000**	**$ 20,000**	**$ 20,400**	**$ 20,808**	**$ 21,224**
					Total Due 6/30/17	**$ 1,102,432**
*Does not account for potential changes in Federal Reserve rate						
*This example would apply to either taxes due to state, or refunds payable						

Section 7: Interest Rate Increase

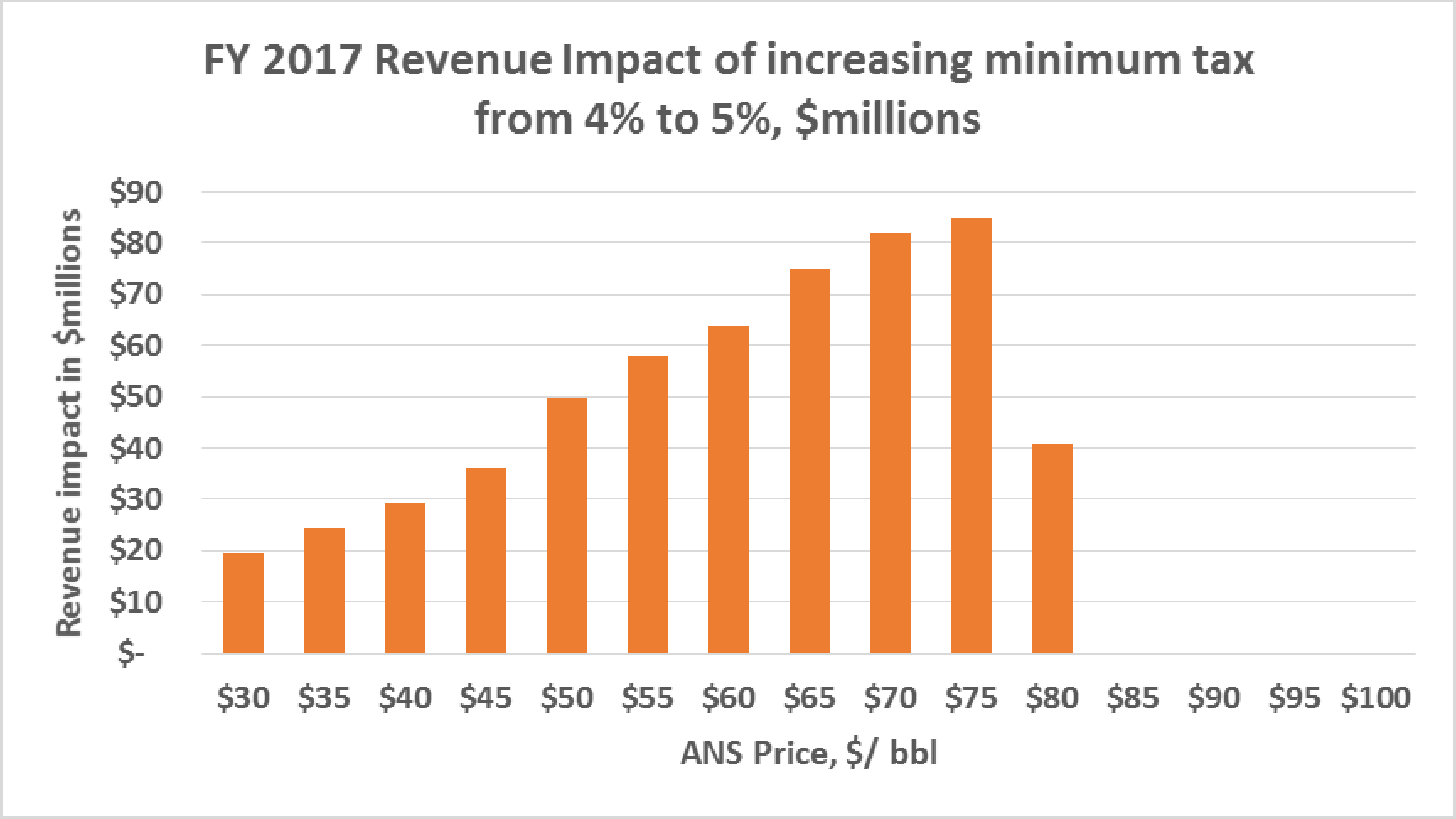
- **Future revenue impact difficult to quantify, since future tax assessments or refunds can't be predicted**
- **Little near-term impact, since change applies only to interest for quarters after 7/1/16**
- **For production tax, most impact will be on the Constitutional Budget Reserve Fund, since audit assessment revenues go to the CBR**

Section 12: Increase Minimum Tax



Source: DOR Fall 2015 forecast modeling

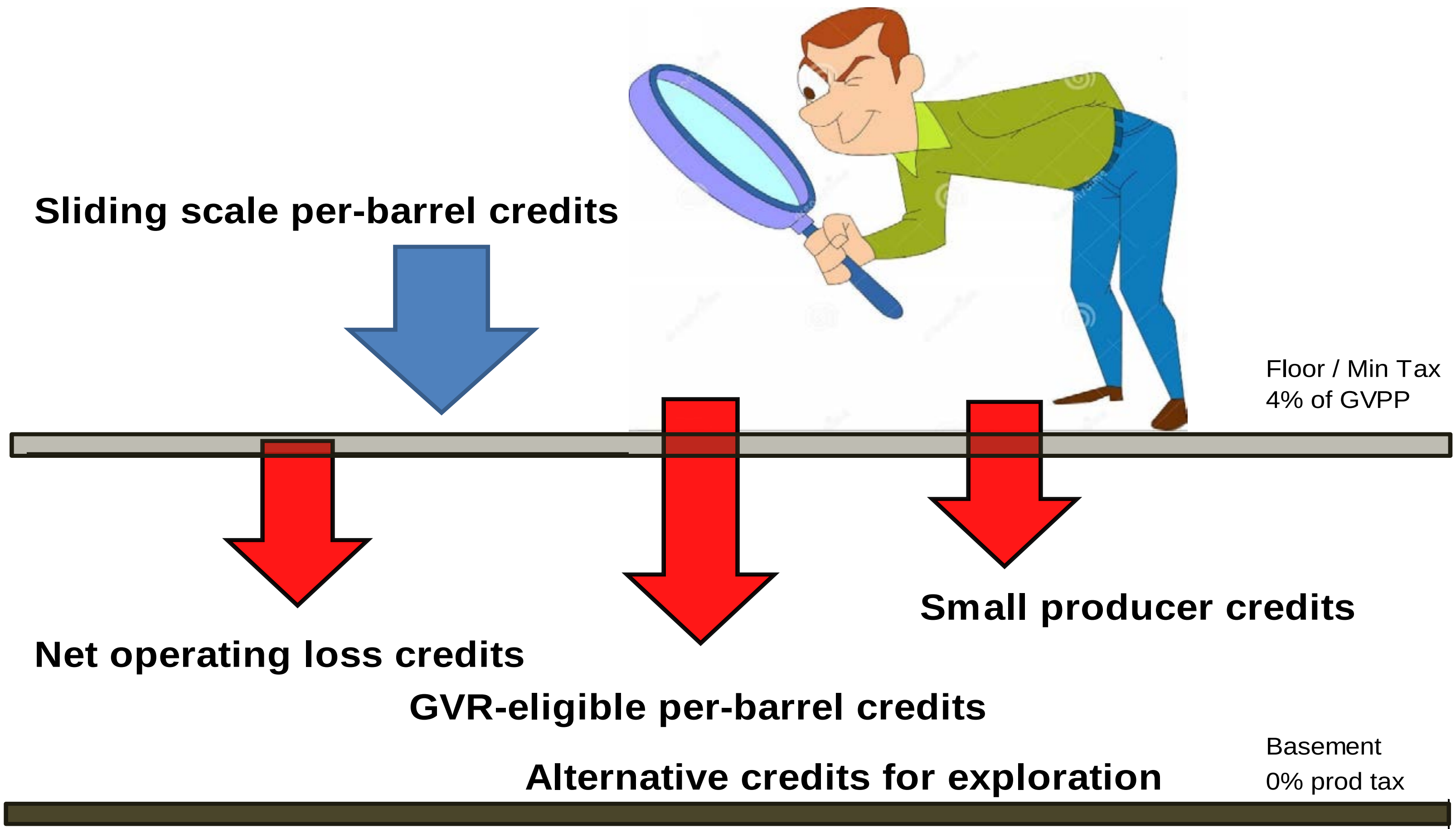
Section 12: Increase Minimum Tax



Source: DOR Fall 2015 forecast modeling

Section 17(b): Strengthen the Minimum Tax

Which credits can break through the floor under current law?



Section 17(b): Strengthen the Minimum Tax

- Current law allows all credits with the exception of the sliding scale per-barrel credits for legacy oil to reduce taxes below the minimum tax (also called the "floor")
- SB130 seeks to change law so that the following additional credits cannot reduce taxes below the minimum tax
  - Net operating loss credits
  - GVR-eligible per-barrel credits
  - Small producer credits
  - Alternative credits for exploration

Section 17(b): Strengthen the Minimum Tax

Preventing certain credits from being used against the minimum tax, or "floor"

This is really three different issues / policy questions
All of these only pertain to the North Slope:

1) **Net Operating Loss for producers not eligible for refundable credits**
(should the major producers ever be able to go below the floor? And should this be retroactive to Jan. 1?)

2) **Per-Barrel Credits for GVR "New" Oil**
(should the tax on production from new fields be allowed to go to zero?)

3) **Small Producer / Exploration Credits**
(should everyone, not just major producers, pay a minimum tax?)

Section 17(b): Strengthen the Minimum Tax

#1- Preventing companies from applying a net operating loss (NOL) credit against the minimum tax

- Net operating losses occur when a producer's total amount of lease expenditures for the year exceed the gross value at the point of production
- In plain English, this is when a producer has negative net income (based on Alaska production tax laws)
- NOL for Alaska production tax purposes is calculated on a calendar (tax) year basis, not a fiscal year basis

If this section is implemented, NOL's not used to reduce the minimum tax are still carried forward

Section 17(b): Strengthen the Minimum Tax

How the Production Tax Works at $100 oil

Tax on a single barrel of taxable North Slope oil.
We currently have about 160 million taxable barrels / year

Market Price	$100
Transport Cost	$10
Gross Value	$90
Lease Expenditures	$35
Production Tax Value	$55
Tax @ 35%	$19.25
Per-Barrel Credit	$6.00
Net Payment	$13.25
Minimum Tax Gross x 4%	$3.60
Higher Of (Actual Tax)	$13.25
Approx. Annual Revenue	$2.1 billion

Section 17(b): Strengthen the Minimum Tax

At $70 Oil, the “minimum tax” takes over

Market Price	$70
Transport Cost	$10
Gross Value	$60
Lease Expenditures	$35
Production Tax Value	$25
Tax @ 35%	$8.75
Per-Barrel Credit	$8.00
Net Payment	$0.75
Minimum Tax Gross x 4%	$2.40
Higher Of (Actual Tax)	$2.40
Approx. Annual Revenue	$380 million

Section 17(b): Strengthen the Minimum Tax

At $40 Oil, producers have operating losses

Market Price	$40
Transport Cost	$10
Gross Value	$30
Lease Expenditures	$35
Production Tax Value	($5)
Approx. Operating Loss	*$800 million*
Tax @ 35%	($1.75)
Per-Barrel Credit	$8.00
Net Payment	($9.75)
Minimum Tax Gross x 4%	$1.20
Higher Of (Actual Tax)	$1.20
Approx. Annual Revenue	$190 million
Carried Forward Loss Credit 35%	*$280 million*

Section 17(b): Strengthen the Minimum Tax

$40 for second year means Operating Loss credits can be used to reduce payments below the minimum tax

	Year 1	Year 2
Market Price	$40	$40
Transport Cost	$10	$10
Gross Value	$30	$30
Lease Expenditures	$35	$35
Production Tax Value	($5)	($5)
Approx. Operating Loss	*$800 million*	*$800 million*
Tax @ 35%	($1.75)	($1.75)
Per-Barrel Credit	$8.00	$8.00
Net Payment	($9.75)	($9.75)
Minimum Tax Gross x 4%	$1.20	$1.20
Higher Of (Actual Tax)	$1.20	$1.20
Approx. Annual Revenue	$190 million	$190 million
Less Carried-Forward Loss Credit		($190 million)
Actual Tax Payment	$190 million	$0
Carried-Forward Loss Credit 35%	*$280 million*	*$370 million*

Section 17(b): Strengthen the Minimum Tax

Using the scenario on the previous slide

- The net operating loss for Year 1 is estimated to be about $800 million. At a NOL credit rate of 35%, this loss will generate a credit of about $280 million
- Producers can apply their net operating loss credits against taxes due starting in January of Year 2
- $190 out of the $280 million in credits is used to reduce production tax payments to zero. The remaining $90 million is carried forward
- In Year 2, using same oil production and lease expenditure assumptions, the net operating loss would be another $800 million, resulting in another $280 million in NOL credits at 35%
- These are added to the $90 million carried forward from Year 1, resulting in $370 million to be carried to Year 3

Section 17(b): Strengthen the Minimum Tax

#2- How GVR-eligible per-barrel credits can reduce taxes below the minimum tax ($80 oil):

Minimum Tax and 20% and Legacy Production and GVR-Eligible Production*

	Legacy	GVR-Eligible
West Coast Price ($/tax bbl)	$80	$80
Transportation ($/tax bbl)	-$10	-$10
Wellhead Value ($/tax bbl)	$70	$70
Lease Expenditures ($/tax bbl)	-$36	-$36
Net Value ($/tax bbl)	$34	$34
Gross Value Reduction Rate (%)	x 0%	x 20%
Gross Value Reduction ($/tax bbl)	$0	$14
Net Value after GVR ($/tax bbl)	$34	$20
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits ($/tax bbl)	$11.90	$7.00
GVR Credit per-Tax-Barrel ($/tax bbl)	$8	$5
Base Production Tax after credits ($/tax bbl)	**$3.90**	**$2.00**
Minimum Tax Rate (%)	4%	4%
Wellhead Value ($/tax bbl)	x $70	x $70
Minimum Tax ($/tax bbl)	**$2.80**	**$2.80**

This credit can reduce tax below minimum tax; company pays $2 per barrel

*Current assumptions include transport costs of $10 per barrel and deductible lease expenditures of $36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160.

Section 17(b): Strengthen the Minimum Tax

#2- How GVR-eligible per-barrel credits can reduce taxes below the minimum tax ($60 oil):

Minimum Tax and 20% and Legacy Production and GVR-Eligible Production*

	Legacy	**GVR-Eligible**
West Coast Price ($/tax bbl)	$60	$60
Transportation ($/tax bbl)	-$10	-$10
Wellhead Value ($/tax bbl)	$50	$50
Lease Expenditures ($/tax bbl)	-$36	-$36
Net Value ($/tax bbl)	$14	$14
Gross Value Reduction Rate (%)	x 0%	x 20%
Gross Value Reduction ($/tax bbl)	$0	$10
Net Value after GVR ($/tax bbl)	$14	$4
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits ($/tax bbl)	$4.90	$1.40
GVR Credit per-Tax-Barrel ($/tax bbl)	$8	$5
Base Production Tax after credits ($/tax bbl)	**$0.00**	**$0.00**
Minimum Tax Rate (%)	4%	4%
Wellhead Value ($/tax bbl)	x $50	x $50
Minimum Tax ($/tax bbl)	**$2.00**	**$2.00**

*Current assumptions include transport costs of $10 per barrel and deductible lease expenditures of $36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160.

This is the amount paid. Legacy fields pay minimum tax of $2 while GVR-eligible fields pay zero.

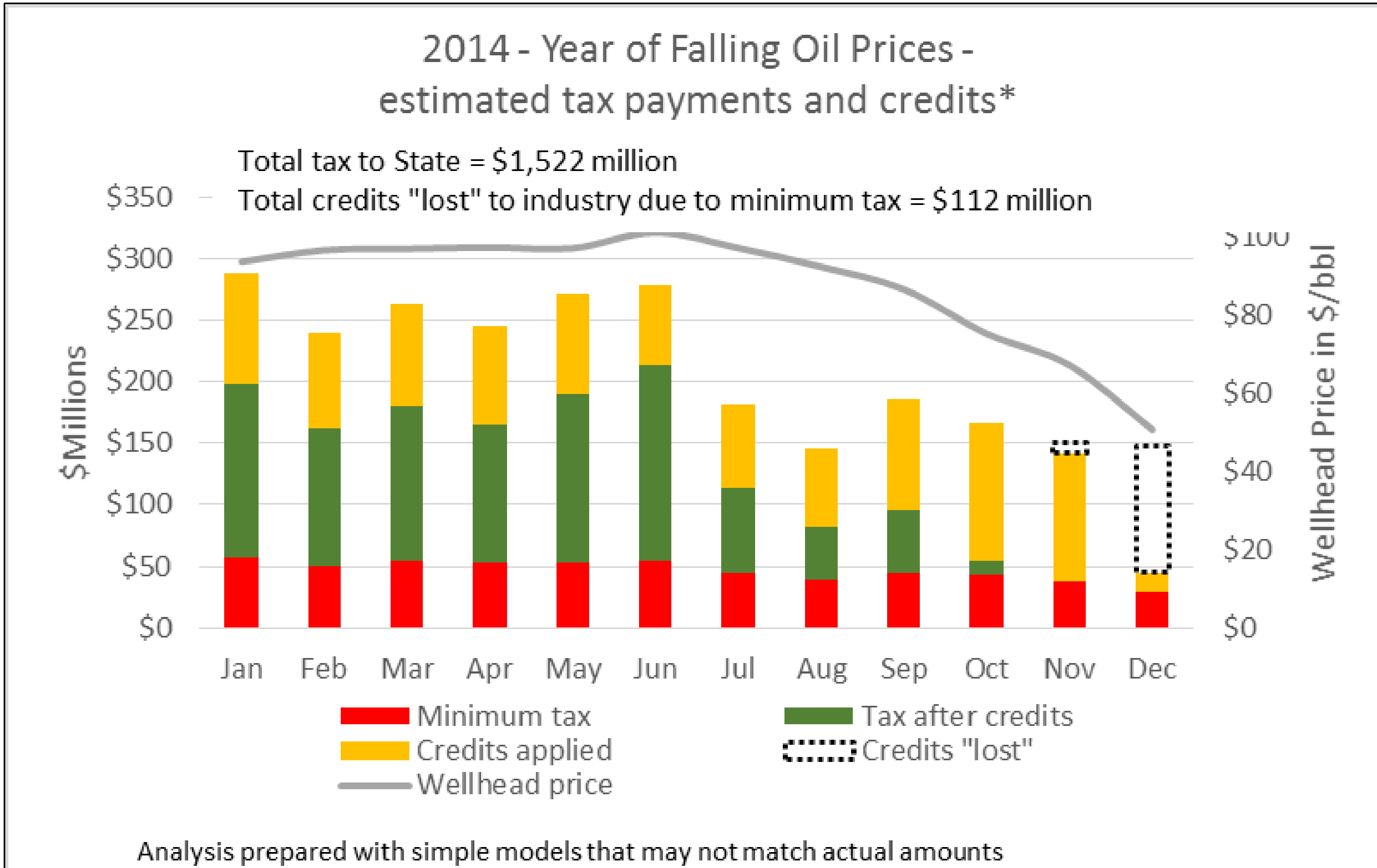
Section 17(c): Strengthen the Minimum Tax

Preventing per-taxable barrel credits from being used in another month other than the month earned

- Current law allows sliding scale credits “lost” to the minimum tax to be recovered at annual true-up under certain conditions
- This reduces the “upside” potential for the State in a year with moderate oil price volatility
- ACES progressivity was a <u>monthly</u> calculation with no annual true-up
- If sliding scale credits were intended to be a form of “reverse progressivity,” then the calculation should be monthly with no annual true-up

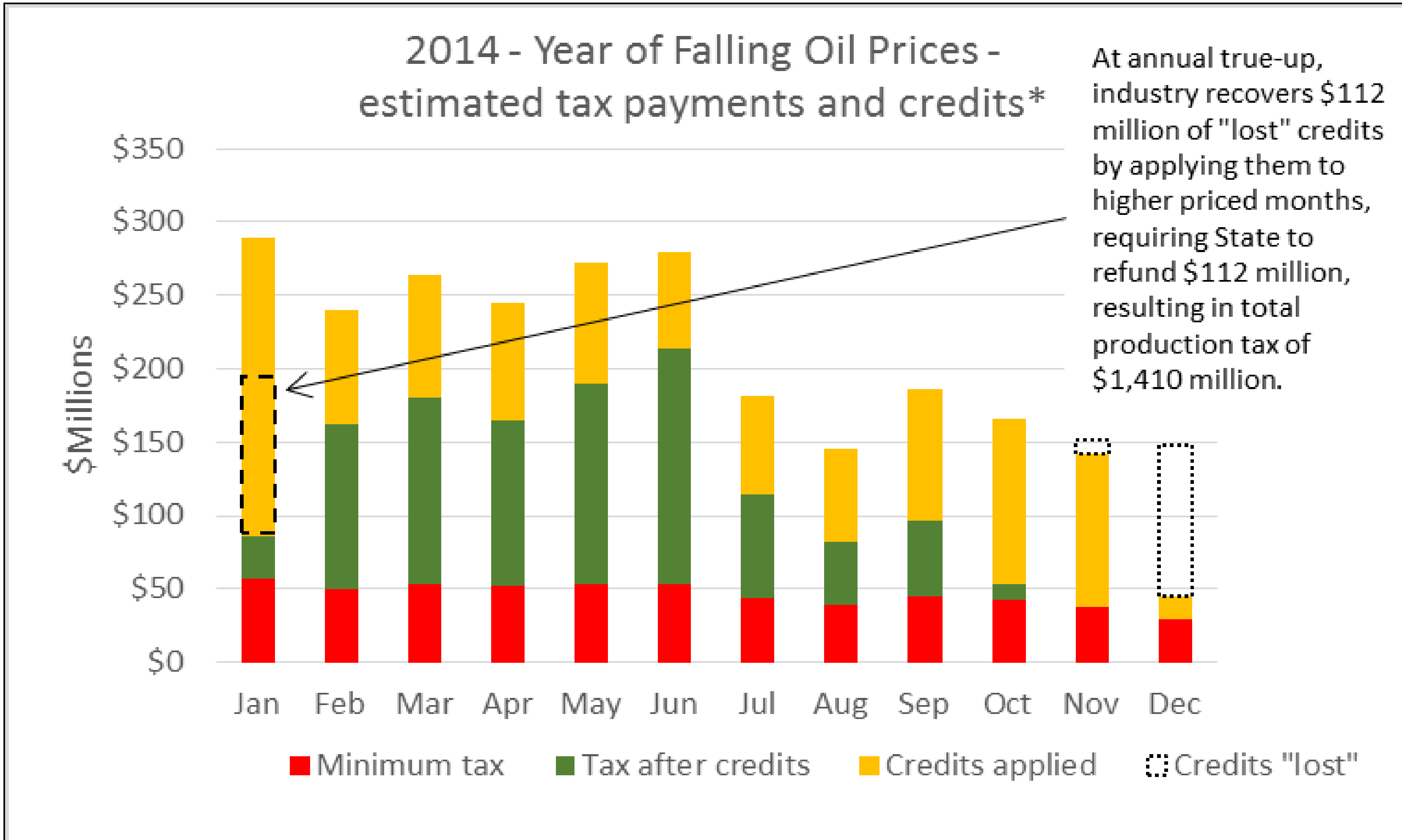
Section 17(c): Strengthen the Minimum Tax

Credits "lost" to the minimum tax before annual true-up



Section 17(c): Strengthen the Minimum Tax

“Lost” credits recovered at annual true-up



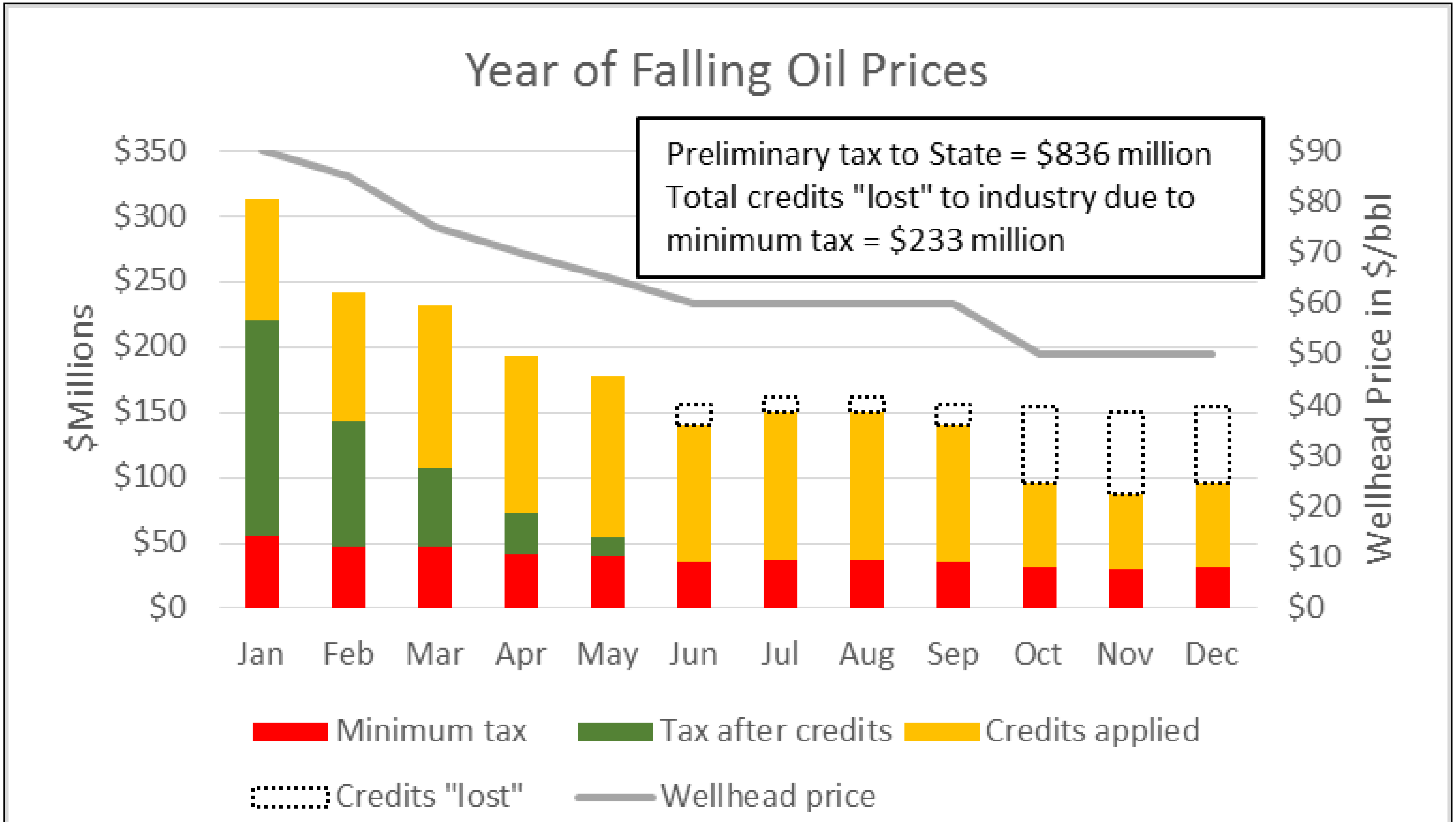
Analysis prepared with simple models that may not match actual amounts

Section 17(c): Strengthen the Minimum Tax

- In years of greater oil price volatility, credit recovery can take a greater share and could reduce State production tax collection to the minimum tax.
- This occurs because the minimum tax is an annual tax, and credits that cannot be used within the year can be recovered at year’s end.
- Next two slides show a hypothetical year with greater oil price volatility

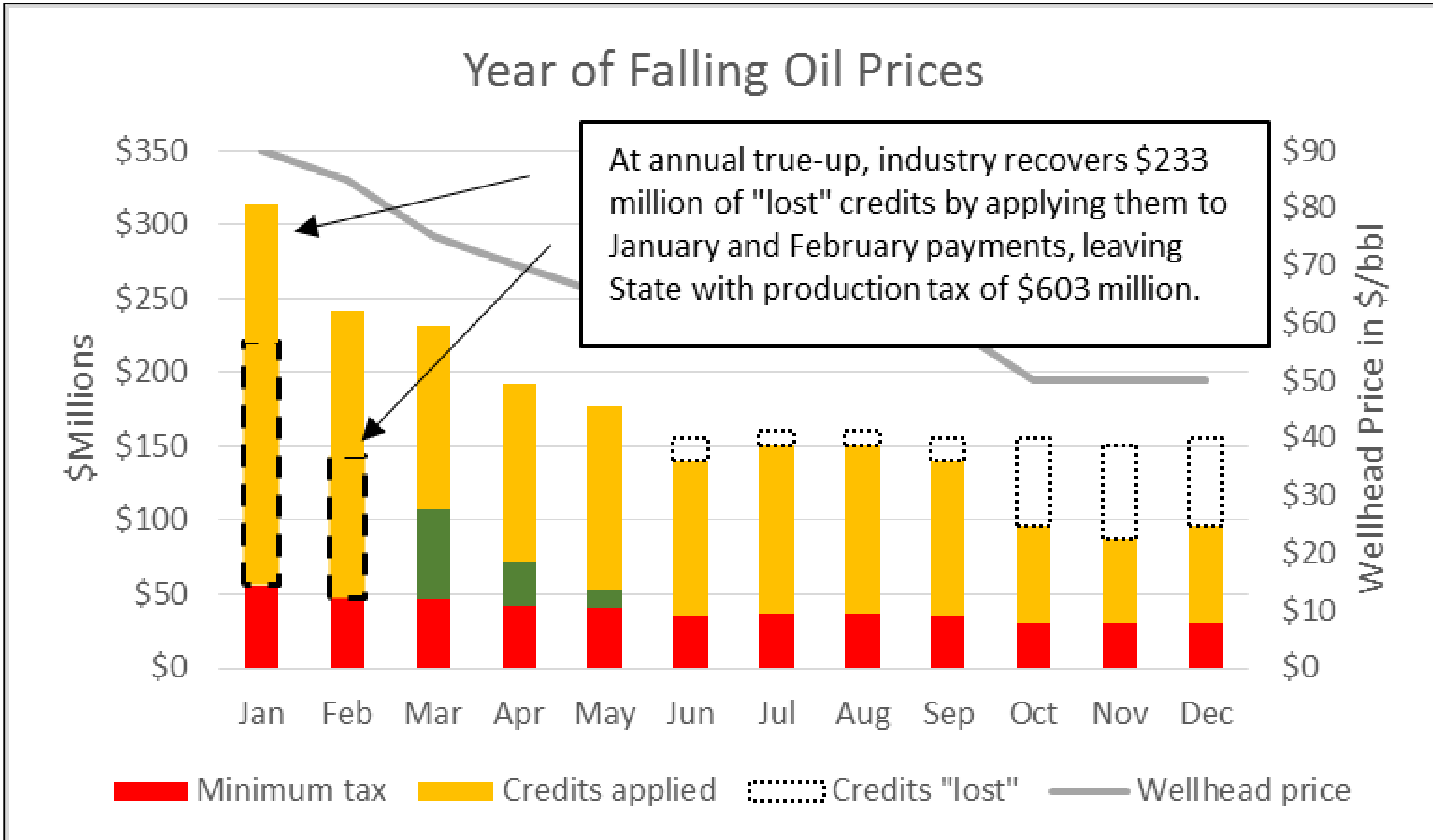
Section 17(c): Strengthen the Minimum Tax

Credits “lost” to the minimum tax before annual true-up



Section 17(c): Strengthen the Minimum Tax

"Lost" credits recovered at annual true-up



Section 17(c): Strengthen the Minimum Tax

- Only an issue in years of oil price volatility, where <u>some but not all months trigger the minimum tax</u>
- Example on previous two slides showing moderate oil price volatility
  - Reduces State tax payments by close to 30%
  - Reduces effective tax rate on net from 14.5% to 10.5%
  - Results in State forfeiting some of the “upside” in years where monthly oil prices could reach $100 per barrel or more

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

- SB 130 would prohibit the gross value reduction (GVR) from being used to increase size of net operating loss and by extension, the NOL credit
- In the low oil price / low cost example shown on the next page, the net operating loss would be limited to the net value before GVR, which is $6 per barrel instead of $12 per barrel
- The resulting credit is 35% of the actual net operating loss, reducing the credit liability to the State by 50%. For a GVR-field producing 10,000 taxable barrels per day, the difference is $7.6 million

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

Current law allows GVR to increase an NOL credit

Example showing NOL due to low prices

20% GVR-Eligible Production increasing Size of Net Operating Loss and Proposed Change*

	Current Law	Proposed Change
West Coast Price ($/tax bbl)	$40	$40
Transportation ($/tax bbl)	-$10	-$10
Wellhead Value ($/tax bbl)	$30	$30
Lease Expenditures ($/tax bbl)	-$36	-$36
Net Value before GVR ($/tax bbl)	-$6	-$6
Wellhead Value from above ($/tax bbl)	$30	$30
Gross Value Reduction Rate (%)	x 20%	x 20%
Gross Value Reduction ($/tax bbl)	$6	$6
GVR-Adjusted Net Value ($/tax bbl)	-$12	-$12
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits ($/tax bbl)	$0.00	$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value ($/tax bbl)	$30	$30
Minimum Tax ($/tax bbl)	**$1.20**	**$1.20**
GVR Credit per-Tax-Barrel ($/tax bbl)	$5	$5
Production Tax after credits ($/tax bbl)	**$0.00**	**$0.00**
Net Operating Loss for Credit ($/tax bbl)	-$12	-$6
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit ($/tax bbl)	$4.20	$2.10
NOL per barrel times 10,000 taxable b/d	$15,330,000	$7,665,000
Difference		$7,665,000

*Current assumptions include transport costs of $10 per barrel and deductible lease expenditures of $36 per taxable barrel, that are typical but will not match exactly Fall 2015 assumptions. For this table, net value is the same as "production tax value," defined in AS 43.55.160.

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

- In the high oil price / high cost example shown on the next page, the net operating loss would be limited to the net value before GVR, which is $10 per barrel instead of $24 per barrel
- The resulting credit is 35% of the actual net operating loss, reducing the credit liability to the State by 50%. For a GVR-field producing 10,000 taxable barrels per day, the difference is close to $18 million

Section 18: GVR Can't Increase Net Operating Loss (NOL) Credit

Current law allows GVR to increase an NOL credit

Example showing NOL due to higher prices with high continued investment

20% GVR-Eligible Production increasing Size of Net Operating Loss and Proposed Change*

	Current Law	**Proposed Change**
West Coast Price ($/tax bbl)	$80	$80
Transportation ($/tax bbl)	-$10	-$10
Wellhead Value ($/tax bbl)	$70	$70
Lease Expenditures ($/tax bbl)	$80	$80
Net Value before GVR ($/tax bbl)	-$10	-$10
Wellhead Value from above ($/tax bbl)	$70	$70
Gross Value Reduction Rate (%)	x 20%	x 20%
Gross Value Reduction ($/tax bbl)	$14	$14
GVR-Adjusted Net Value ($/tax bbl)	-$24	-$24
Base Tax Rate (%)	x 35%	x 35%
Base Production Tax before Credits ($/tax bbl)	$0.00	$0.00
Minimum Tax Rate (%)	4%	4%
Wellhead Value ($/tax bbl)	$70	$70
Minimum Tax ($/tax bbl)	**$2.80**	**$2.80**
GVR Credit per-Tax-Barrel ($/tax bbl)	$5	$5
Production Tax after credits ($/tax bbl)	**$0.00**	**$0.00**
Net Operating Loss for Credit ($/tax bbl)	-$24	-$10
Net Operating Loss Credit Rate (%)	x 35%	x 35%
Net Operating Loss Credit ($/tax bbl)	$8.40	$3.50
NOL per barrel times 10,000 taxable b/d	$30,660,000	$12,775,000
Difference		$17,885,000

*Assumes early development of new field, producing small amounts of oil while still drilling and building out infrastructure.

Sections 26-27: Credit Refund Limitations

Four New Limitations on Cash Refunds:

- Refunds limited to companies with gross revenues less than $10 billion in previous year
- Limit State credit refunds to $25 million / company / year (same limitation as in PPT, from 2006)
- Percentage of refund limited to percentage of Alaska resident hire in previous year
- Any unused net operating loss credits expire 10 years from the date they were issued

This section has one of the largest fiscal impacts of any in the bill. Several hundred million in the first year; future years will depend on actual projects

These credits are deferred rather than saved; companies will use them to offset future years' taxes

Section 31: Gross Value can't go below Zero

- SB130 would prohibit the Gross Value at the Point of Production from being less than zero
- At current market oil prices of around $30 per barrel, this means that transport costs must be $30 or less
- At current prices, there are few properties that have transport costs approaching $30 per barrel
- If prices were to go lower than $20 per barrel, more properties could be affected

Section 31: Gross Value can't go below Zero

Jan. 2016 TAPS and feeder pipeline tariffs

(these are before adding the $3.37 marine transport cost)

TAPS Tariff	**$6.13**	Weighted Average

Badami Unit Tariffs	$1.41	Badami Connection
	$1.78	Badami Pipeline
	$6.13	TAPS
Badami Unit Tariffs	**$9.32**	**Total**
Colville River Unit Tariffs	$0.32	Kuparuk Pipeline
	$0.94	Alpine Tariff
	$6.13	TAPS
Colville River Unit Tariffs	**$7.39**	**Total**
Duck Island Unit Tariffs	$2.22	Endicott Pipeline
	$6.13	TAPS
Duck Island Unit Tariffs	**$8.35**	**Total**
Kuparuk River Unit Tariffs	$0.32	Kuparuk Pipeline
	$6.13	TAPS
Kuparuk River Unit Tariffs	**$6.45**	**Total**

Milne Point Unit Tariffs	$0.24	Kup - Milne Connection
	$1.44	Milne Pt Pipeline
	$6.13	TAPS
Milne Point Unit Tariffs	**$7.81**	**Total**
Pt Thomson Unit Tariffs	$1.41	Badami Connection
	$1.78	Badami Pipeline
	$19.17	Pt Thomson Pipeline
	$6.13	TAPS
Pt Thomson Unit Tariffs	**$28.49**	**Total**
Northstar Unit Tariffs	$1.09	Northstar Pipeline
	$6.13	TAPS
Northstar Unit Tariffs	**$7.22**	**Total**

Source: Alaska Department of Natural Resources

Section 31: Gross Value can't go below Zero

Example of gross value potentially going below zero

West Coast Price ($/bbl)	$30.00
Point Thomson Unit Tariffs ($/bbl)	$28.49
Marine Transportation ($/bbl)	$3.37
Wellhead Price ($/bbl)	-$1.86
Annual Oil Production (bbls)	3,650,000
Royalty Oil Production (bbls)*	456,250
Taxable Oil Production (bbls)	3,193,750
Wellhead Price from above ($/bbl)	-$1.86
Taxable Oil Production from above (bbls)	3,193,750
Gross Value at Point of Production	-$5,940,375

*Royalty rate of 12.5% assumed; actual royalty rates may differ from those shown in this analysis.

This negative GVPP could be used to offset positive values from elsewhere on the North Slope, resulting in a tax reduction of 35% of the difference (about $2 million)

Section 37: Municipal Utility Limitation

- If a municipal utility owns a portion of a gas field and uses all of the gas to generate its own power, this is not taxable

However, if a portion of that gas is sold to a third party, those sales are taxable.

Current law allows all lease expenditures to be used to offset the comparably small amount of sales, potentially generating large credits. SB130 proposes to limit the lease expenditure calculation to just the pro-rata share of the expenditures equal to the proportion of the gas that was sold

	Current Law	**HB247 Proposal**
Daily Volume Produced (mmcf)	20	20
Volume Used By Utility (untaxable)	18	18
Volume Sold to 3rd Parties (taxable)	2	2
Sales Price / mcf	$8	$8
Annual Revenue Subject to Tax ($000)	$5,840	$5,840
Lease Expenditures per mcf produced	$3	$3
Annual Lease Expenditures ($000)	$21,900	$21,900
Allowable Lease Expenditures	$21,900	$2,190
Operating Profit (Loss)	**($16,060)**	**$3,650**
Operating Loss Credit @ 25%	**$4,015**	**n/a**

Intro, Samples, and Summary of Scenario Analysis Model

Introduction to Scenario Analysis

- The Tax Division has developed a new model, looking at project life cycles
- Cash flow over the 30-40 year life of a project, for the state's production tax and credits, all state revenue, the producer's cash flow, and discounted (NPV)
- Scenarios Analyzed at $40, $60, $80, and Fall Forecast oil price
  - Been asked by House Finance for $20, $100, and $120
  - Will provide these runs to this committee when done
- Status quo modeled vs. Governor's original bill
- Full modeling runs will be provided as a separate document

Introduction to Scenario Analysis

Fields Analyzed:

North Slope Oil Scenarios

- 50 million barrel
- 750 million barrel (12.5% Royalty / 20% GVR)
- 750 million barrel (16.67% Royalty / 30% GVR)
- 750 million barrel (50% Private Royalty)

Cook Inlet Oil Scenarios

- 50 million barrel (tax caps sunset)
- 50 million barrel (tax caps extended)

Gas Scenarios

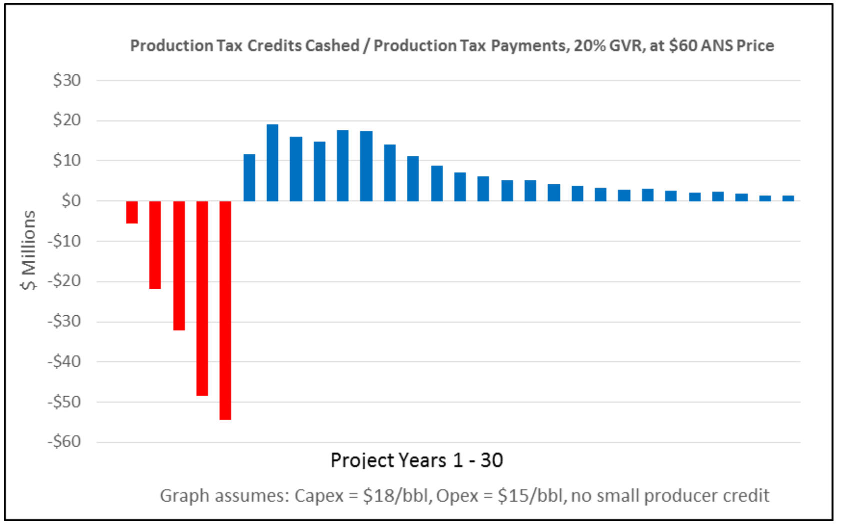
- 670 bcf Cook Inlet Gas (tax cap sunset and extended)
- 670 bcf Middle Earth Gas

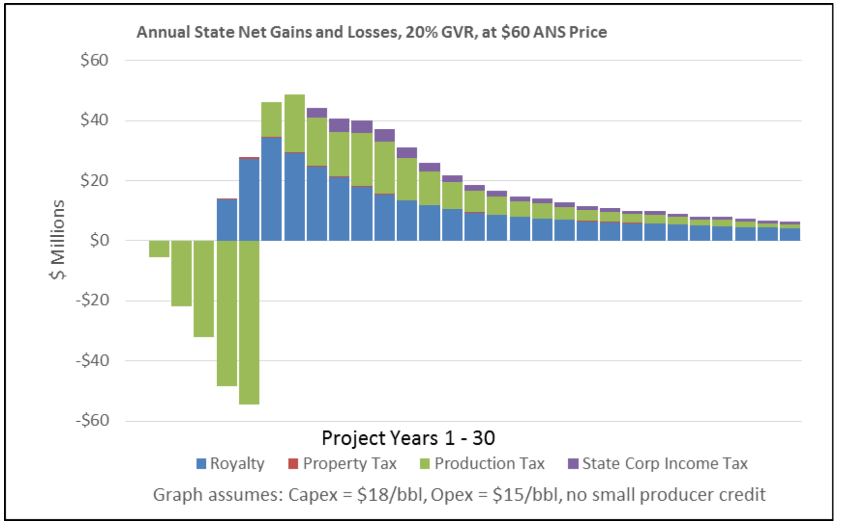
Each analyzed at $40 oil, $60, $80, and Fall Forecast

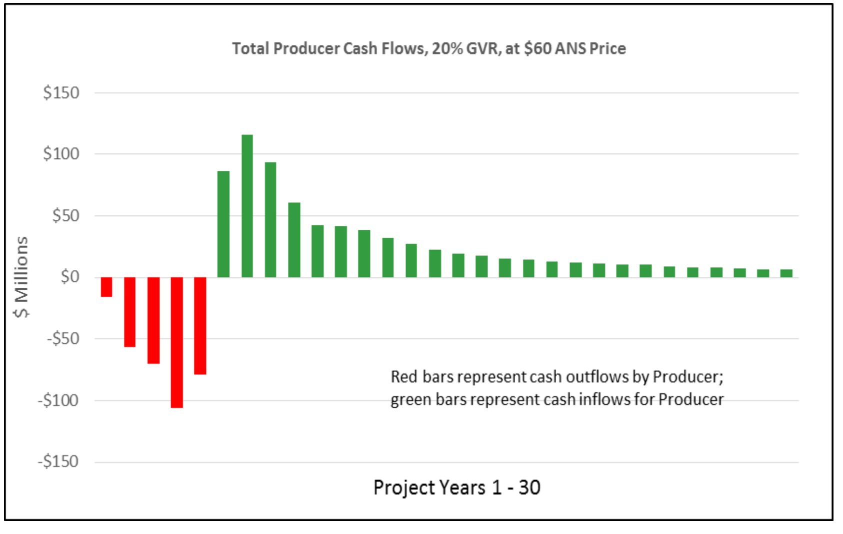
Been asked by House Finance to do $20, $100, and $120

Sample of Scenario Analysis

North Slope- 50 mmbo Status Quo, $60/bbl



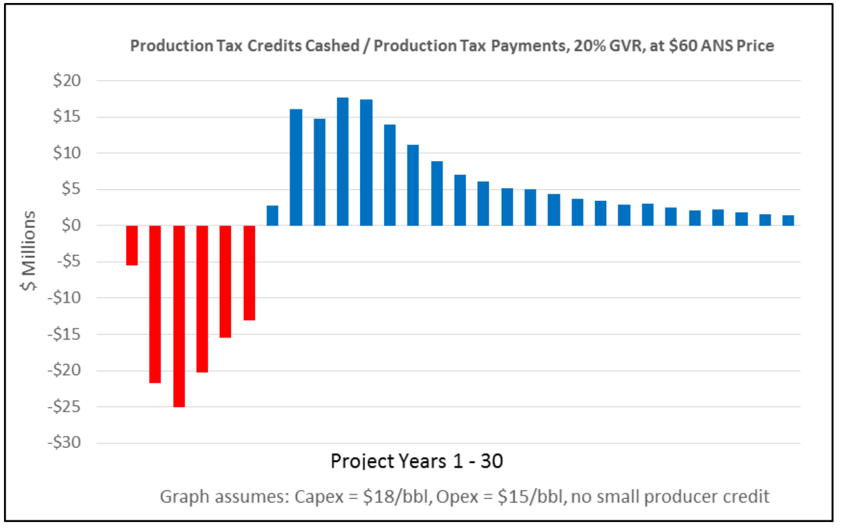


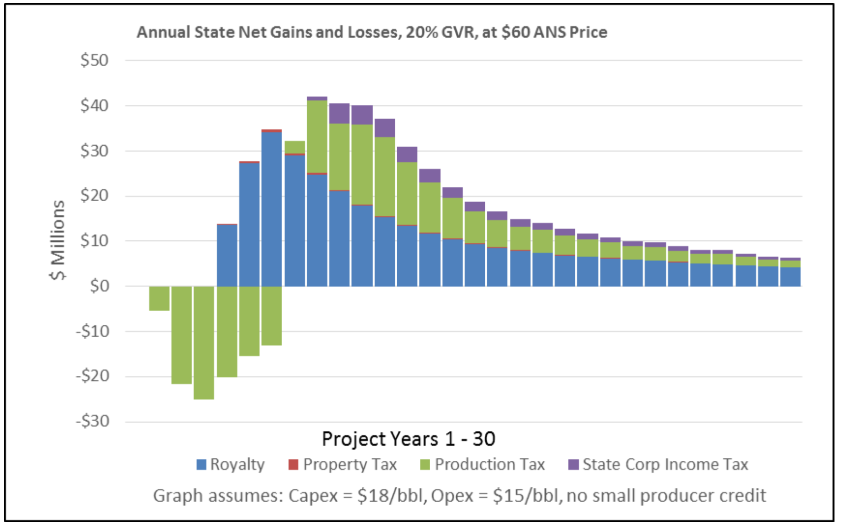


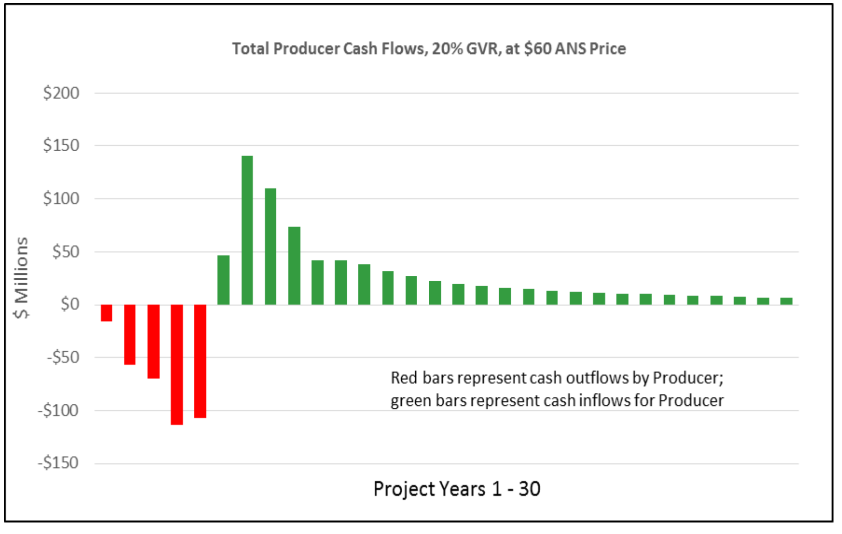
Life Cycle Totals	$Millions
Production Tax Credits Cashed	162
Production Tax Paid	183
Net Production Tax	21
Production Tax NPV 6.15%	-37
Total Annual State Losses	121
Total Annual State Gains	501
Net State Gain (Loss)	380
State NPV 6.15%	136
Total Producer Cash Out	327
Total Producer Cash In	731
Net Producer Cash Flow	404
Producer Cash NPV 6.15%	112

Sample of Scenario Analysis

North Slope- 50 mmbo HB 247, $60 / bbl



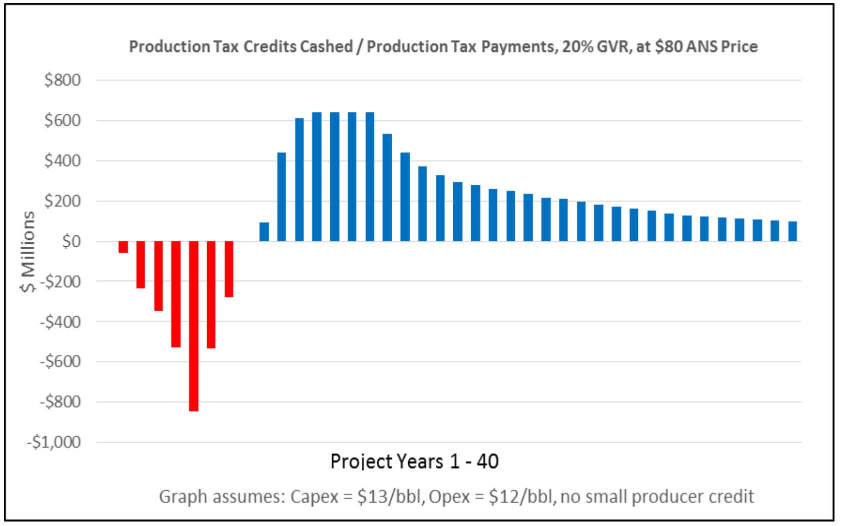


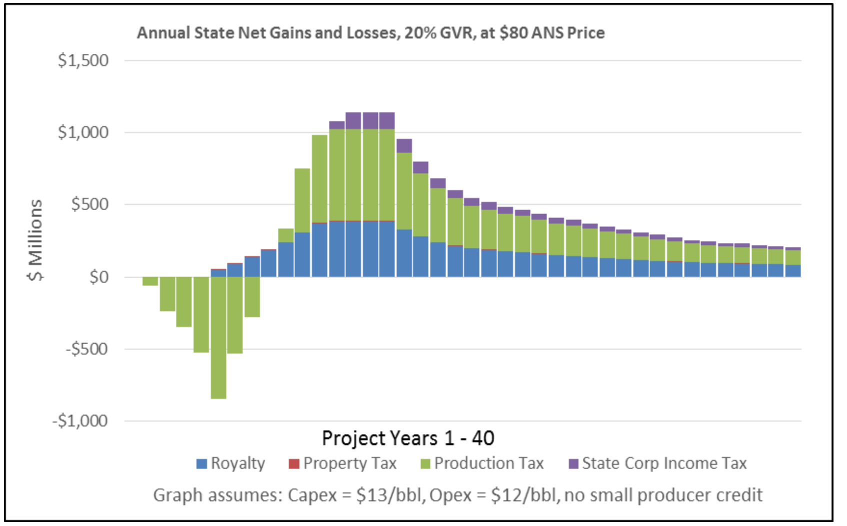


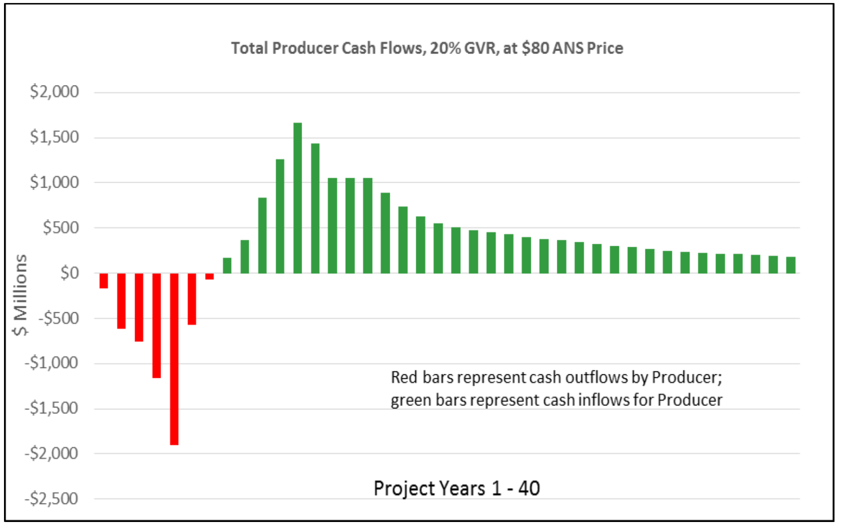
Life Cycle Totals	$Millions
Production Tax Credits Cashed	101
Production Tax Paid	155
Net Production Tax	54
Production Tax NPV 6.15%	-10
Total Annual State Losses	59
Total Annual State Gains	470
Net State Gain (Loss)	412
State NPV 6.15%	163
Total Producer Cash Out	362
Total Producer Cash In	746
Net Producer Cash Flow	384
Producer Cash NPV 6.15%	93

Sample of Scenario Analysis

North Slope- 750 mmbo Status Quo, $80/bbl



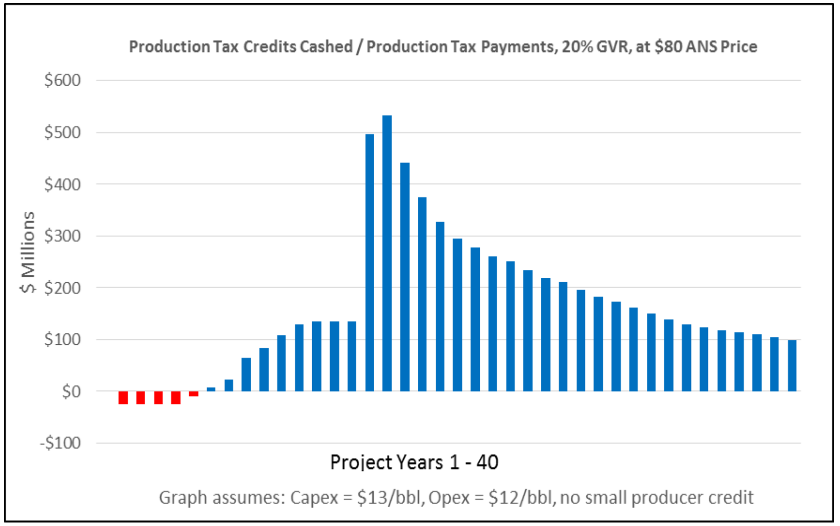


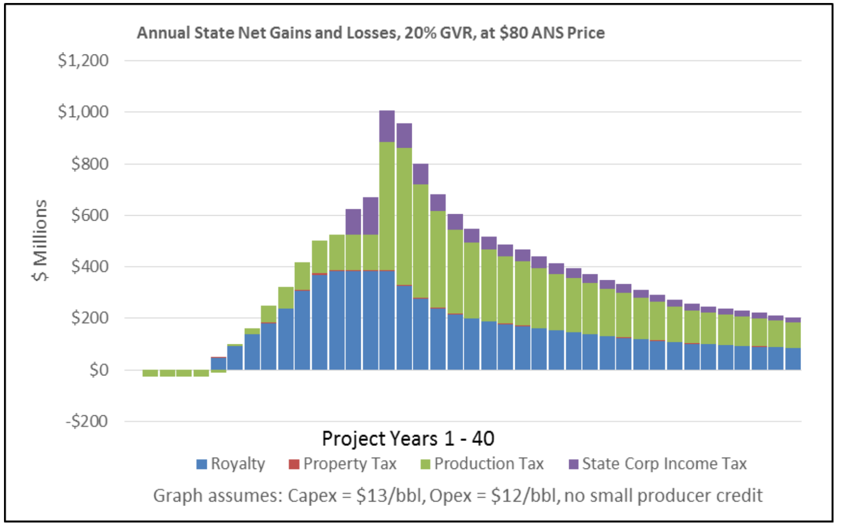


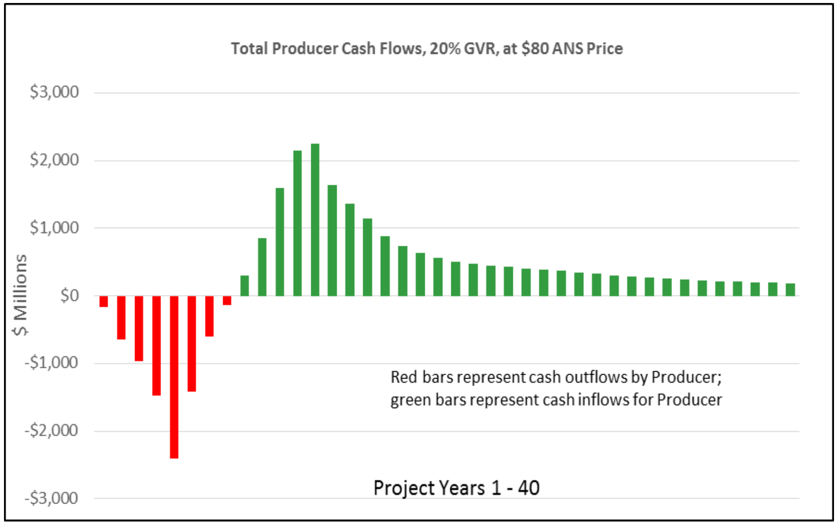
Life Cycle Totals	$Millions
Production Tax Credits Cashed	2,830
Production Tax Paid	8,923
Net Production Tax	6,093
Production Tax NPV 6.15%	869
Total Annual State Losses	2,553
Total Annual State Gains	16,623
Net State Gain (Loss)	14,069
State NPV 6.15%	3,527
Total Producer Cash Out	5,247
Total Producer Cash In	17,933
Net Producer Cash Flow	12,686
Producer Cash NPV 6.15%	2,216

Sample of Scenario Analysis

North Slope- 750 mmbo HB 247, $80 / bbl



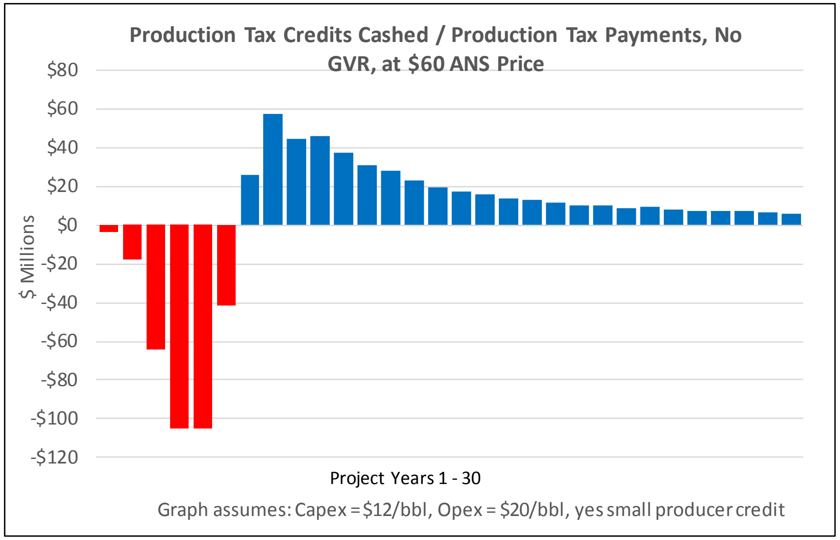


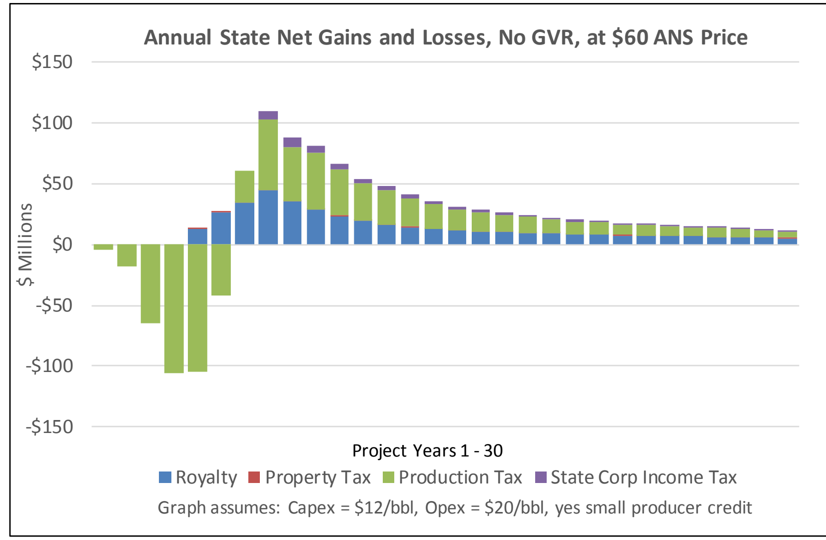


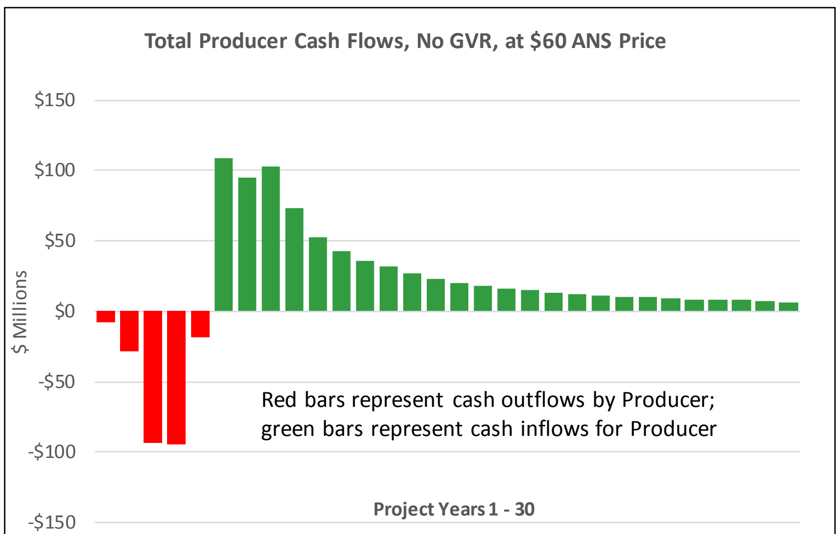
Life Cycle Totals	$Millions
Production Tax Credits Cashed	109
Production Tax Paid	6,533
Net Production Tax	6,424
Production Tax NPV 6.15%	1,743
Total Annual State Losses	100
Total Annual State Gains	14,479
Net State Gain (Loss)	14,379
State NPV 6.15%	4,388
Total Producer Cash Out	7,832
Total Producer Cash In	20,317
Net Producer Cash Flow	12,485
Producer Cash NPV 6.15%	1,415

Sample of Scenario Analysis

Cook Inlet 50 mmbo Status Quo, 2022 Tax Caps expire, $60/bbl



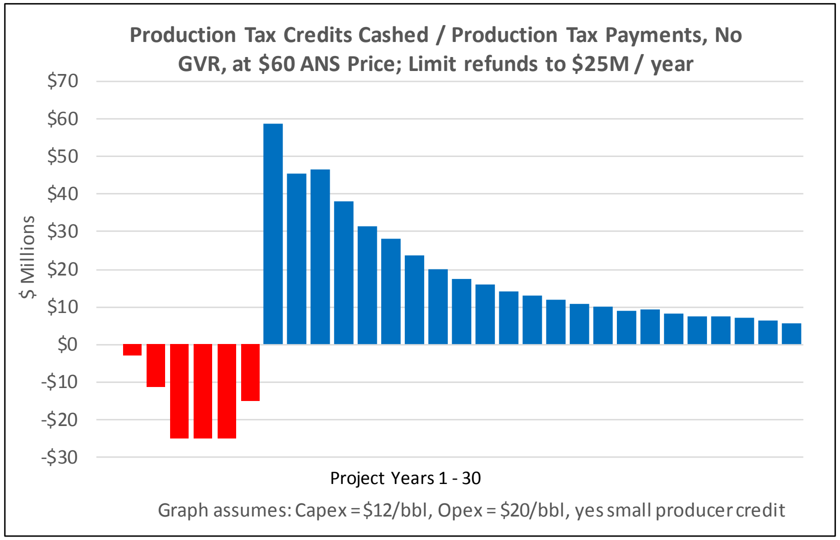


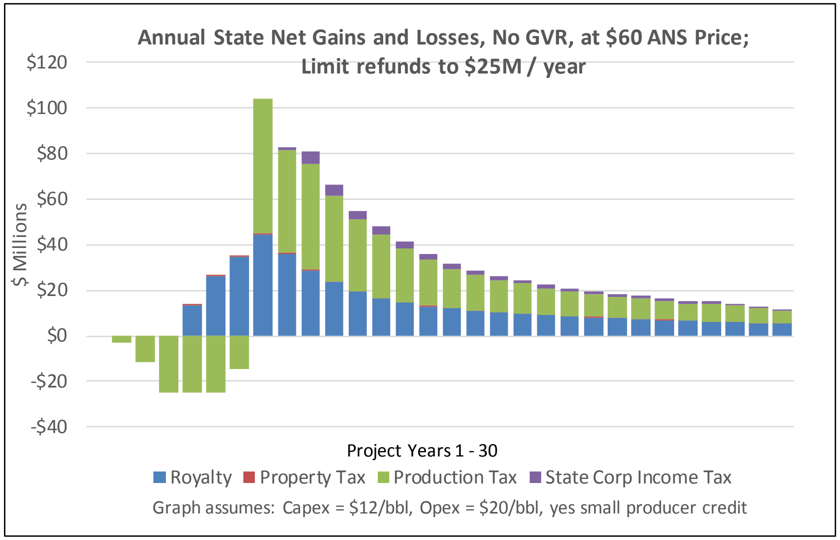


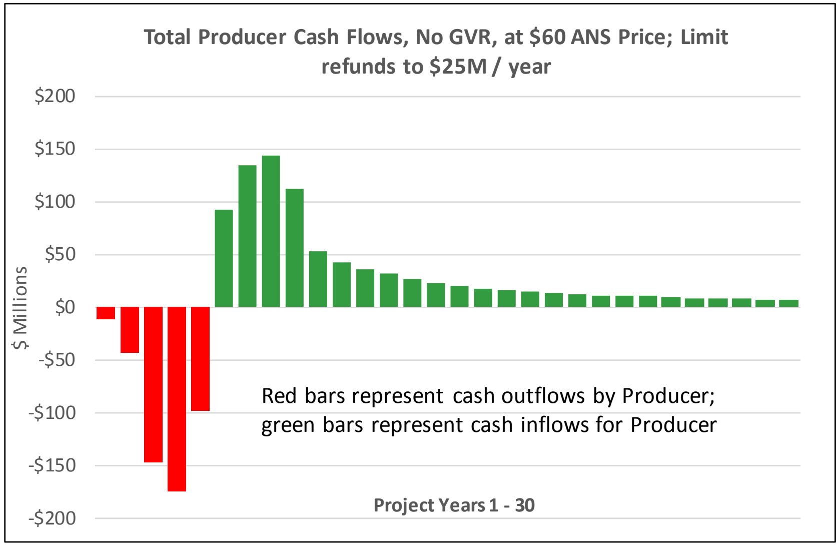
Life Cycle Totals	$Millions
Production Tax Credits Cashed	337
Production Tax Paid	465
Net Production Tax	128
Production Tax NPV 6.15%	-50
Total Annual State Losses	297
Total Annual State Gains	877
Net State Gain (Loss)	579
State NPV 6.15%	167
Total Producer Cash Out	241
Total Producer Cash In	768
Net Producer Cash Flow	527
Producer Cash NPV 6.15%	202

Sample of Scenario Analysis

Cook Inlet 50 mmbo HB247, 2022 Tax Caps expire, $60/bbl







Life Cycle Totals	$Millions
Production Tax Credits Cashed	104
Production Tax Paid	447
Net Production Tax	343
Production Tax NPV 6.15%	121
Total Annual State Losses	51
Total Annual State Gains	831
Net State Gain (Loss)	780
State NPV 6.15%	331
Total Producer Cash Out	473
Total Producer Cash In	869
Net Producer Cash Flow	397
Producer Cash NPV 6.15%	80

Summary of Scenario Analysis

North Slope Oil Scenarios

Field Size (million bbl)	Tax Regime	Producer Size (>$10 billion revenue)	Oil Price	Credits Paid ($millions)	Net Production Tax Paid ($millions)	Production Tax NPV 6.15% ($millions)	Net State Gain (Loss) ($millions)	State NPV 6.15% ($millions)	Producer Cash Flow ($millions)	Producer NPV 6.15% ($millions)
50	Status Quo	n/a	$40	$221	($217)	($153)	($24)	($58)	$19	($99)
50	Status Quo	n/a	$60	$162	$21	($37)	$380	$136	$404	$112
50	Status Quo	n/a	$80	$134	$323	$110	$844	$364	$751	$289
50	Status Quo	n/a	Fall 15 FC	$155	$183	$40	$629	$255	$588	$203
50	HB 247	small	$40	$150	($116)	($95)	$71	($1)	($71)	($155)
50	HB 247	small	$60	$101	$54	($10)	$412	$163	$384	$93
50	HB 247	small	$80	$82	$344	$128	$863	$380	$738	$277
50	HB 247	small	Fall 15 FC	$95	$207	$60	$651	$274	$574	$189
750	Status Quo	n/a	$40	$2,967	($2,738)	($2,047)	$367	($1,016)	$2,131	($1,768)
750	Status Quo	n/a	$60	$2,897	$1,568	($642)	$7,115	$1,197	$7,475	$312
750	Status Quo	n/a	$80	$2,830	$6,093	$869	$14,069	$3,527	$12,686	$2,216
750	Status Quo	n/a	Fall 15 FC	$2,864	$4,135	$206	$11,069	$2,509	$10,458	$1,401
750	HB 247	small	$40	$134	$807	$206	$3,685	$1,192	($39)	($3,744)
750	HB 247	small	$60	$116	$2,867	$749	$8,331	$2,553	$6,686	($870)
750	HB 247	small	$80	$109	$6,424	$1,743	$14,379	$4,388	$12,485	$1,415
750	HB 247	small	Fall 15 FC	$111	$4,523	$1,172	$11,433	$3,461	$10,222	$520
750	HB 247	large	$40	$0	$982	$337	$3,860	$1,322	($214)	($3,875)
750	HB 247	large	$60	$0	$3,084	$879	$8,494	$2,679	$6,579	($974)
750	HB 247	large	$80	$0	$6,424	$1,806	$14,379	$4,451	$12,485	$1,355
750	HB 247	large	Fall 15 FC	$0	$4,683	$1,303	$11,596	$3,587	$10,116	$417

Summary of Scenario Analysis

North Slope Oil (nonstandard royalty) Scenarios

Tax Regime	Oil Price	Producer Size (>$10 billion revenue)	Credits Paid ($millions)	Net Production Tax Paid ($millions)	Production Tax NPV 6.15% ($millions)	Net State Gain (Loss) ($millions)	State NPV 6.15% ($millions)	Producer Cash Flow ($millions)	Producer NPV 6.15% ($millions)
750 MM Barrel Field, 16.67% Royalty, 30% GVR; Assumes all Royalty paid to State									
Status Quo	$40	n/a	$2,982	($2,893)	($2,096)	$1,097	($756)	$1,656	($1,965)
Status Quo	$60	n/a	$2,905	$1,178	($772)	$8,210	$1,578	$6,764	$48
Status Quo	$80	n/a	$2,841	$5,472	$656	$15,532	$4,030	$11,735	$1,879
Status Quo	Fall 2015 FC	n/a	$2,874	$3,623	$35	$12,383	$2,964	$9,604	$1,092
Status Quo	$80	Large	$2,841	$5,472	$656	$15,532	$4,030	$11,735	$1,879
HB 247	$40	n/a	$136	$761	$190	$4,574	$1,496	($928)	($4,049)
HB 247	$60	n/a	$117	$2,605	$679	$9,544	$2,992	$5,897	($1,179)
HB 247	$80	n/a	$110	$5,818	$1,557	$15,855	$4,918	$11,525	$1,052
HB 247	Fall 2015 FC	n/a	$112	$4,171	$1,078	$12,896	$3,991	$9,271	$154
HB 247	$80	Large	$0	$5,818	$1,621	$15,855	$4,982	$11,525	$991
750 MM Barrel Field, 50% Private Royalty (at 12.5%), 20% GVR; Assumes non-Private Royalty paid to State									
Status Quo	$40	n/a	$2,963	($2,668)	($2,023)	($971)	($1,474)	$2,089	($1,785)
Status Quo	$60	n/a	$2,892	$1,685	($602)	$4,886	$433	$7,404	$286
Status Quo	$80	n/a	$2,823	$6,256	$925	$10,947	$2,458	$12,587	$2,181
Status Quo	Fall 2015 FC	n/a	$2,858	$4,278	$255	$8,331	$1,572	$10,371	$1,370
Status Quo	$80	Large	$2,823	$6,256	$925	$10,947	$2,458	$12,587	$2,181
HB 247	$40	n/a	$131	$878	$230	$2,351	$735	($109)	($3,768)
HB 247	$60	n/a	$113	$2,984	$789	$6,101	$1,789	$6,614	($896)
HB 247	$80	n/a	$108	$6,588	$1,799	$11,257	$3,319	$12,385	$1,379
HB 247	Fall 2015 FC	n/a	$110	$4,667	$1,222	$8,694	$2,524	$10,135	$488
HB 247	$80	Large	$0	$6,588	$1,862	$11,257	$3,382	$12,385	$1,319

Summary of Scenario Analysis

Cook Inlet Oil Scenarios

Field Size (million bbl)	Tax Regime	Tax Caps Sunset?	Oil Price	Credits Paid ($millions)	Net Production Tax Paid ($millions)	Production Tax NPV 6.15% ($millions)	Net State Gain (Loss) ($millions)	State NPV 6.15% ($millions)	Producer Cash Flow ($millions)	Producer NPV 6.15% ($millions)
50	Status Quo	yes	$40	$349	($177)	($192)	$99	($59)	$139	$3
50	Status Quo	yes	$60	$337	$128	($50)	$579	$167	$527	$202
50	Status Quo	yes	$80	$329	$432	$92	$1,060	$395	$915	$396
50	Status Quo	yes	Fall 15 FC	$335	$294	$26	$840	$288	$735	$303
50	Status Quo	no	$40	$357	($357)	($275)	($70)	($137)	$249	$54
50	Status Quo	no	$60	$349	($349)	($269)	$134	($37)	$817	$335
50	Status Quo	no	$80	$341	($341)	($263)	$337	$63	$1,385	$612
50	Status Quo	no	Fall 15 FC	$347	($347)	($268)	$241	$14	$1,124	$481
50	HB 247	yes	$40	$120	$38	($19)	$300	$108	$9	($135)
50	HB 247	yes	$60	$104	$343	$121	$780	$331	$397	$80
50	HB 247	yes	$80	$89	$647	$263	$1,261	$557	$784	$278
50	HB 247	yes	Fall 15 FC	$89	$509	$197	$1,041	$451	$604	$183
50	HB 247	no	$40	$142	($142)	($101)	$131	$29	$118	($76)
50	HB 247	no	$60	$134	($134)	($97)	$335	$126	$686	$214
50	HB 247	no	$80	$126	($126)	($92)	$538	$225	$1,254	$494
50	HB 247	no	Fall 15 FC	$132	($132)	($95)	$442	$177	$994	$362

Summary of Scenario Analysis

Cook Inlet and Middle Earth Gas Scenarios

Geography	Tax Regime	Tax Caps Sunset?	Gas Price	Credits Paid ($millions)	Net Production Tax Paid ($millions)	Production Tax NPV 6.15% ($millions)	Net State Gain (Loss) ($millions)	State NPV 6.15% ($millions)	Producer Cash Flow ($millions)	Producer NPV 6.15% ($millions)
Cook Inlet	Status Quo	yes	$4.00	$365	($262)	($264)	$124	($67)	$177	$30
Cook Inlet	Status Quo	yes	$6.00	$360	$105	($84)	$709	$226	$663	$292
Cook Inlet	Status Quo	yes	$8.00	$351	$462	$89	$1,285	$512	$1,154	$554
Cook Inlet	Status Quo	no	$4.00	$404	($367)	($315)	$26	($114)	$241	$60
Cook Inlet	Status Quo	no	$6.00	$383	($336)	($297)	$297	$27	$931	$421
Cook Inlet	Status Quo	no	$8.00	$373	($326)	($290)	$548	$158	$1,633	$784
Cook Inlet	HB 247	yes	$4.00	$136	$16	($35)	$384	$154	$8	($148)
Cook Inlet	HB 247	yes	$6.00	$122	$383	$143	$696	$442	$494	$132
Cook Inlet	HB 247	yes	$8.00	$113	$740	$316	$1,545	$727	$985	$400
Cook Inlet	HB 247	no	$4.00	$144	($88)	($86)	$286	$106	$72	($114)
Cook Inlet	HB 247	no	$6.00	$122	($58)	($69)	$557	$243	$762	$263
Cook Inlet	HB 247	no	$8.00	$113	($48)	($63)	$809	$373	$1,464	$630
Mid Earth	Status Quo	N/A	$4.00	$404	($281)	($277)	$73	($95)	$189	$37
Mid Earth	Status Quo	N/A	$6.00	$383	($6)	($154)	$573	$144	$731	$334
Mid Earth	Status Quo	N/A	$8.00	$373	$259	($37)	$1,063	$377	$1,278	$630
Mid Earth	HB 247	N/A	$4.00	$144	($3)	($47)	$333	$126	$20	($139)
Mid Earth	HB 247	N/A	$6.00	$122	$272	$74	$833	$361	$562	$175
Mid Earth	HB 247	N/A	$8.00	$113	$537	$190	$1,323	$592	$1,109	$476

NEW SUSTAINABLE ALASKA PLAN

Pulling Together to Build Our Future

Thank You!

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