

NEW SUSTAINABLE  
**ALASKA**  
PLAN



*Pulling Together to Build Our Future*

**CSHB 111(RES)\N by the House Resources Committee**

**Oil and Gas Production Tax and Credits:  
Background and Bill Analysis**

***Presentation to House Finance Committee***

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March 21, 2017



# *What I'm talking about today*

## **Background on Alaska's oil and gas taxes and analysis of CS HB111(RES)\N**

- **Money- how oil has funded the state in the past**
  - Transition- how we've adapted to falling prices
  - Credits- what we know, what has accrued
  - Last year's HB247 and remaining concerns
  - Overview of CSHB111(RES) with detail of selected tax sections
  - Fiscal note

# *History of Oil and Gas Taxes in Alaska*

## **Four Main Sources of State of Alaska Oil Revenue**

### **Property Tax (\$0.1 billion in FY12, \$0.1 billion in FY16)**

Pipeline, Equipment, Facilities

Numbers are state share; \$0.4 is shared with local governments

### **Royalty (\$2.9 billion in FY12, \$1.2 billion in FY16)**

Landowner's share, usually 12.5%. Most North Slope production is on State land. At least  $\frac{1}{4}$  of royalties go to the Permanent Fund

### **Production Tax (\$6.1 billion in FY12, \$0.2 billion in FY16)**

Based on net profits; most tax legislation in recent years is over this tax.

North Slope 35% less a variable "per taxable barrel" credit

### **Corp. Income Tax (\$0.6 billion in FY12, \$0.0 billion in FY16)**

Taxes remaining profit after production tax

Global asset apportionment; 9.4%, but effectively closer to 6.5%

**Total dropped from \$9.7 billion to \$1.5 billion in 4 years**

# *History of Oil and Gas Taxes in Alaska*

## **Six changes to the production tax since 2005:**

1. 2005: Gov. Murkowski aggregates Prudhoe Bay satellite fields for ELF calculation
2. 2006: Petroleum Production Tax “PPT” changed from taxing gross revenue to net profits (needed for Gov. Murkowski’s “stranded gas act” gasline)
3. 2007: Alaska’s Clear and Equitable Share “ACES” corrects revenue shortfalls due to bad cost estimates in PPT. Major tax increase
4. 2010: Cook Inlet Recovery Act “CIRA” provided additional credits outside the North Slope targeted at southcentral gas supply issues
5. 2013: SB21 was a tax cut at most prices (small tax increase at low prices) and provided “new oil” benefits
6. 2016: HB247 began tax credit reform, phasing out Cook Inlet credits and limiting “new oil” benefits

# *Government Take*

## **Oil as a percentage of government**

- In high price / high revenue years, oil has provided 90% or more of state UGF revenue
- FY2017 estimated at 67% of revenue
  - In FY2017 oil revenues are only covering 22% of the budget. About 2/3 is being paid out of savings

## **Since TAPS, in years 1978 - 2016, Alaska has received \$141 billion in petroleum revenue**

- Since the switch to Net, in years 2007 – 2016, Alaska has received \$64 billion
- Highest single year was 2008: \$11.3 billion

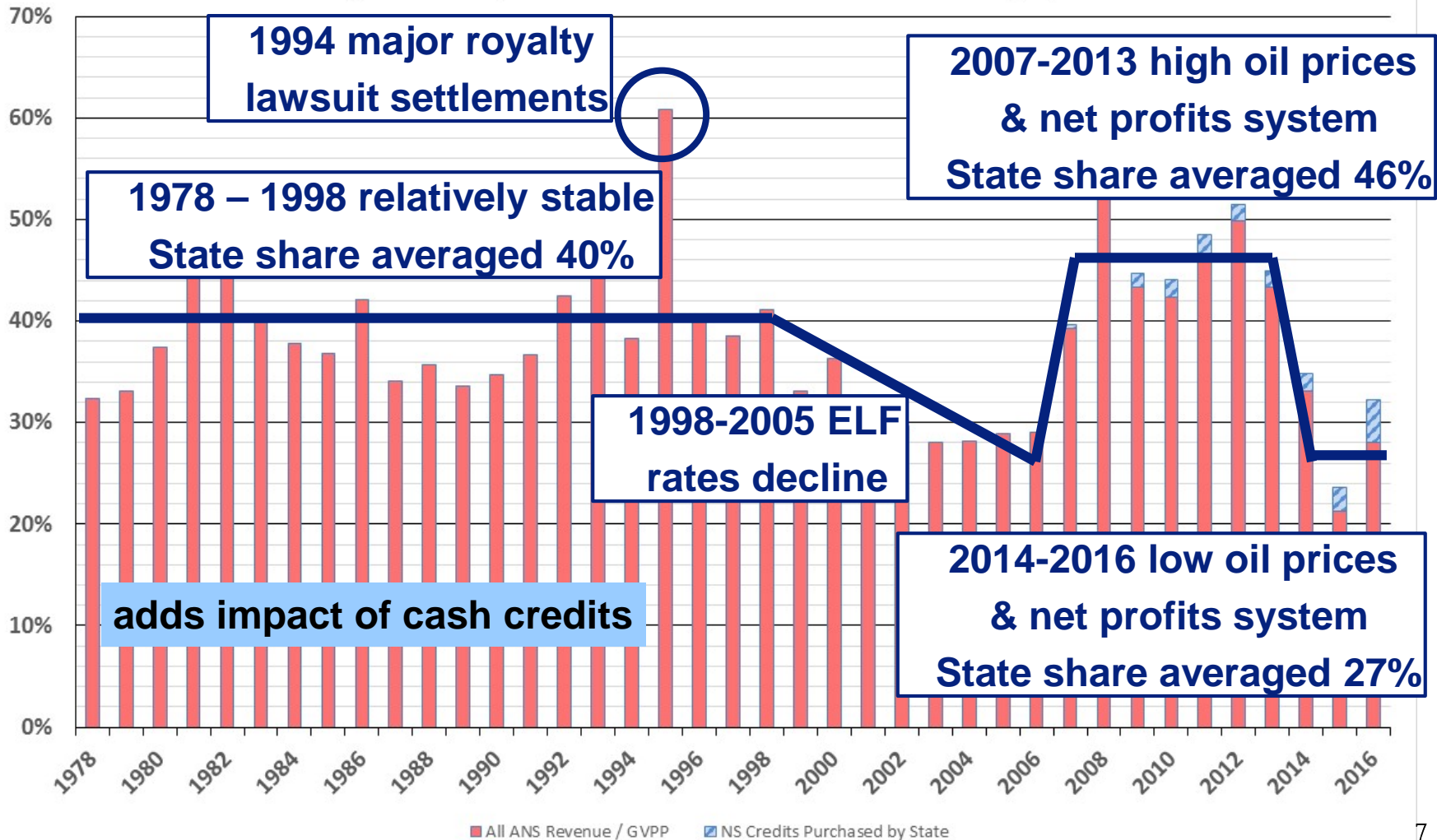
**Any discussion of the appropriate state “share” needs to clarify- “share of what?”**

# *Government Take*

- **Market Value?** (*sales price, or “ANS”*)
  - Market value of all Alaskan oil was \$527 billion
  - State averaged **27%** 1978 – 2016
- **Wellhead Value?** (*price after subtracting transportation, or “GVPP”*)
  - Wellhead value of all Alaska oil was \$347 billion
  - State averaged **41%** 1978 – 2016
- **Profits?** (*value less costs; “PTV” + royalty*)
  - Data only available since 2007 (switch to “net”)
  - Divisible profit of all Alaska oil was \$111 billion
  - State averaged **57%** 2007 – 2016
  - SB21 passed based on “total government take” estimates of about 65% at a wide range of prices, including federal revenue

# Government Take

Approximate ANS State Share of **GVPP Total Value:** (State Revenue from North Slope as a portion of wellhead value after subtracting transportation, offset by state repurchased credits from North Slope) 1978-2016



# *Government Take*

## What does “percent of value” translate to?

- 185 million NS barrels produced in a year
  - If oil is \$50 / bbl, that’s \$9.25 billion;  
**1% of total value is about \$90 million**
  - At \$50 oil, wellhead value is about \$40; that’s \$7.4 billion. **1% of wellhead value is about \$75 million**
- 160 million NS “taxable” (non royalty) barrels
  - **\$1/ bbl in added tax (or reduced credit) is \$160 million**
  - At \$50 oil, **1% increase to a “gross tax” is about \$65 million**
  - Each \$1 / bbl above “break even” is \$160 million in divisible profits. **State revenue is about \$25 million per dollar in price below \$75; \$80 million above**



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# *A Net Profits Tax is very Volatile to Price*

## **SB21 Tax Calculation (legacy / non-GVR oil)**

- Gross (“GVPP” or “wellhead”) value obtained by subtracting transportation costs
- State receives royalty share in kind or in value
- Lease expenditures subtracted from Gross value of taxable (non-royalty) barrels to get “Production Tax Value” (“PTV” or “Net”)
- Calculated Tax is 35% of PTV
- Subtract per barrel credit of between \$0 and \$8 depending on price (credit increases as prices decrease; \$8 at all prices below about \$90 / bbl)
- Minimum Tax “floor” is 4% of Gross (GVPP)
- Amount paid is the higher of these two calculations (35% of Net less per-bbl credit, or 4% of Gross)

# *A Net Profits Tax is very Volatile to Price*

## **SB21 Tax Calculation At Different Prices**

**per one barrel of taxable oil; FY17 costs per Fall 16 RSB**

<b>Price</b>	<b>\$40</b>	<b>\$60</b>	<b>\$80</b>	<b>\$100</b>	<b>\$120</b>	<b>\$140</b>
Transport	\$9.33	\$9.33	\$9.33	\$9.33	\$9.33	\$9.33
GVPP	\$30.67	\$50.67	\$70.67	\$90.67	\$110.67	\$130.67
Lease Expend	\$30.88	\$30.88	\$30.88	\$30.88	\$30.88	\$30.88
PTV (net)	-\$0.21	\$19.79	\$39.79	\$59.79	\$79.79	\$99.79
Tax at 35%	-\$0.07	\$6.93	\$13.93	\$20.93	\$27.93	\$34.93
Per-BBL Credit	\$8	\$8	\$8	\$6	\$4	\$2
Tax per Net	-\$8.07	-\$1.07	\$5.93	\$14.93	\$23.93	\$32.93
Minimum Tax	\$1.23	\$2.03	\$2.83	\$3.63	\$4.43	\$5.23
<b>Higher Of</b>	<b>\$1.23</b>	<b>\$2.03</b>	<b>\$5.93</b>	<b>\$14.93</b>	<b>\$23.93</b>	<b>\$32.93</b>
Tax as % of Price	3%	3%	7%	15%	20%	24%
Tax as % of GVPP	4%	4%	8%	16%	22%	25%
Tax as % of PTV	n/a	10%	15%	25%	30%	33%

# *A Net Profits Tax is very Volatile to Price*

## **Important take-aways from previous slide:**

When the price of oil falls by half from \$120 to \$60

- Wellhead value declines by 54%  
(\$110.67 to \$50.67)
- Taxable “net” declines by 75%  
(\$79.79 to \$19.79)
- Production taxes paid declines by 91%  
(\$23.93 to \$2.03; or for a full year  
over \$3.8 billion to \$325 million)

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# *History of Oil and Gas Production Tax Credits*

## **Types of Credits**

- Exploration Credits- AS 43.55.025; 2003-2016
  - Added as a new incentive during ELF era
  - 20-40% of seismic work and exploration drilling
- Capital Expenditure Credit- AS 43.55.023(a) and (l)
  - 20% credit added 2006 as part of “PPT” bill
  - Expanded outside North Slope to include 40% “well lease expenditure” credit in 2010
  - Repealed on North Slope with passage of SB21 in 2013
  - HB247 cut in half 2017, repealed in Cook Inlet 2018
- Carried Forward Annual Loss Credit- AS 43.55.023(b)
  - “NOL” pays for a percentage of a company’s losses
  - Currently 35% on North Slope- main remaining credit
  - Was 25% in Cook Inlet, now 15%, phased out 2018
  - “Stackable” with Exploration and Capital credits

# *History of Oil and Gas Production Tax Credits*

## **Types of Credits (cont'd.)**

- Small Producer Credit- AS 43.55.024(c)
  - Tax reduction of up to \$12 million for first nine years
  - Qualification ended in 2016; gradually phasing out
- Per-Taxable Barrel Credit- AS 43.55.024(i) and (j)
  - Subtracted from taxes as part of SB21 calculation
- Credits against corporate income taxes- AS 43.20
  - Gas storage, LNG storage, Refinery investment

## **In 2007, state began “repurchasing” certain credits**

To qualify for credit “repurchase” a producer must produce less than 50,000 bbl / day. Larger companies must carry forward to use against future year’s taxes

## **Cashable tax credits are unique to Alaska**

# *History of Oil and Gas Production Tax Credits*

## **FY 2007 thru 2016, \$8.0 Billion in Credits**

### **North Slope**

- \$4.4 billion credits against tax liability
  - Major producers; mostly 20% capital credit in ACES and per-taxable-barrel credit in SB21
- \$2.3 billion repurchased credits
  - New producers and explorers developing new fields

### **Non-North Slope (Cook Inlet & Middle Earth)**

- \$0.1 billion credits against tax liability
  - Another \$500 to \$800 million Cook Inlet tax reductions (through 2013) due to the tax cap still tied to ELF
- \$1.2 billion repurchased credits (most since 2013)



# *History of Oil and Gas Production Tax Credits*

**Providing some detail out of confidential data:**

**Of the nearly \$3.5 billion in state-repurchased credits through the end of FY16:**

- \$1.5 billion went to eight North Slope projects that now have production
- \$0.8 billion went to 11 North Slope projects that do not yet have any production. Some of these are abandoned, and some are in process
- \$0.9 million went to eight non-North Slope projects that have production
- \$0.3 million went to eight non-North Slope projects that do not yet have any production

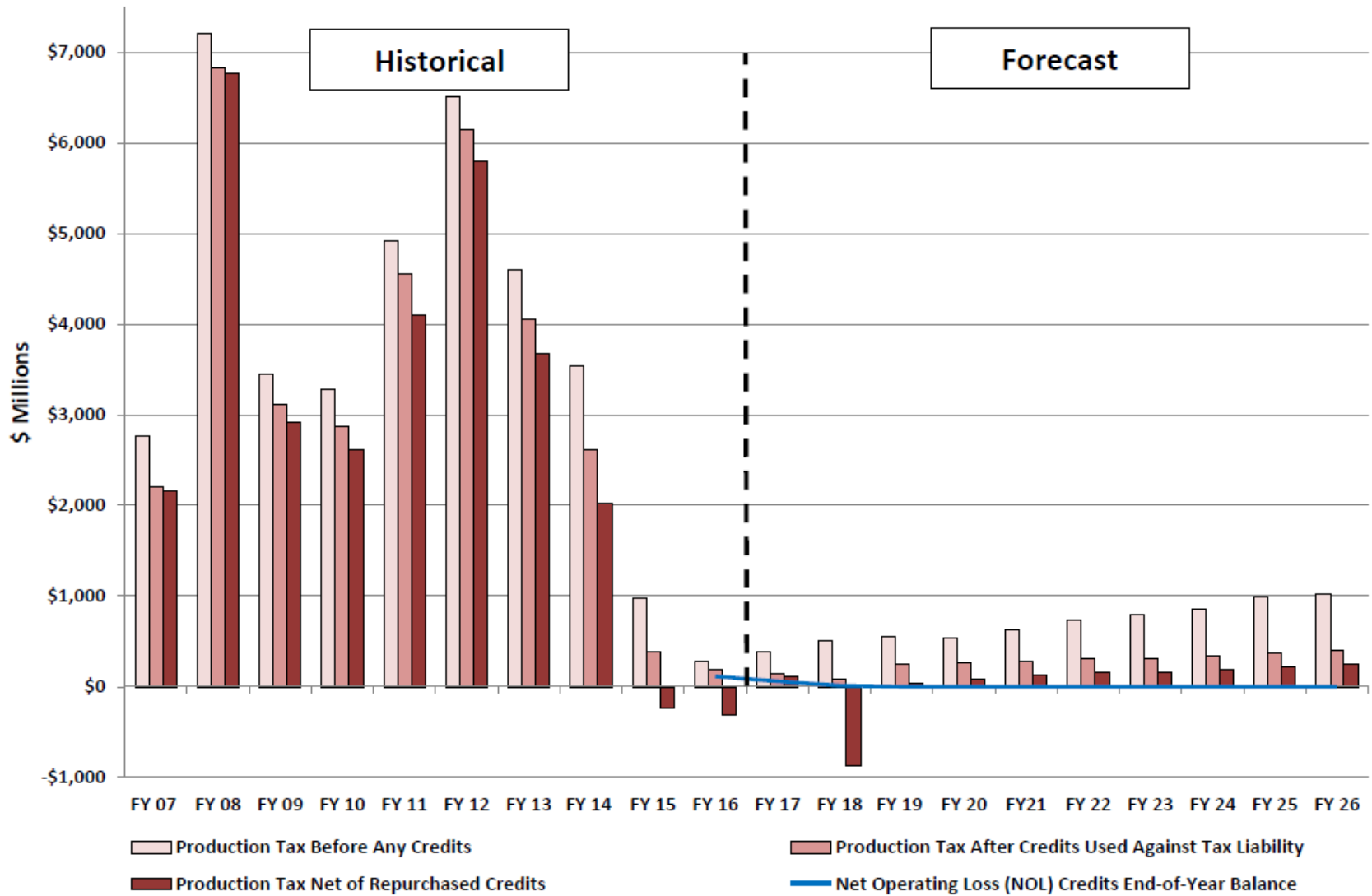
## *Credit Cost in Perspective*

### **North Slope Repurchased Credits**

- Between FY07-FY16 spent \$1.5 billion supporting eight producing projects
- Total production from these producers through end of 2015 is 63 million barrels
- Total credits = **\$24** / barrel
  - Doesn't include payments to non-producing projects
  - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were \$6.0 billion
  - Credit support was **25%** of lease expenditures

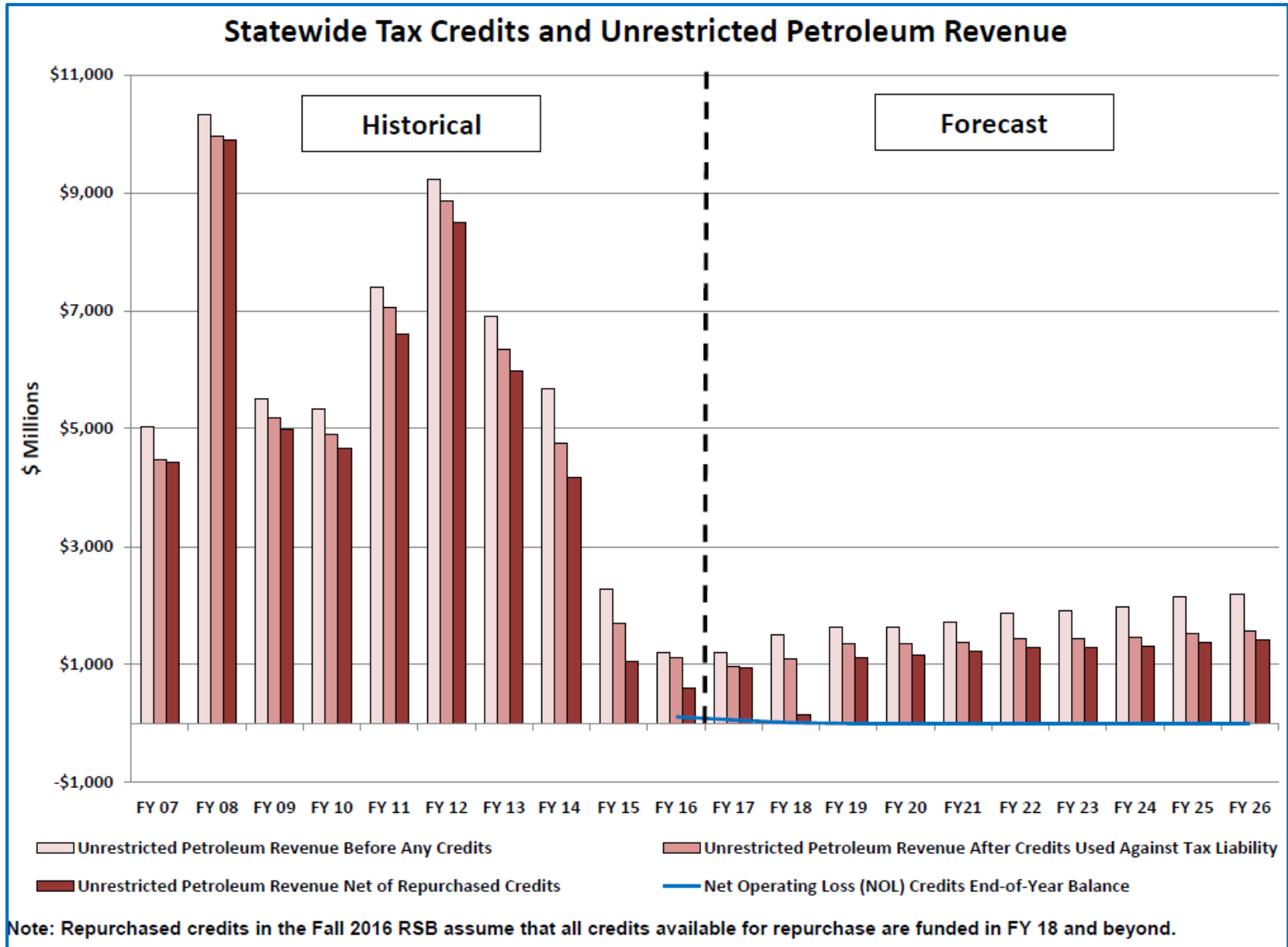
# Why the Need for Reform?

## Statewide Tax Credits and Production Tax Revenue



Note: Repurchased credits in the Fall 2016 RSB assume that all credits available for repurchase are funded in FY 18 and beyond.

# Why the Need for Reform?



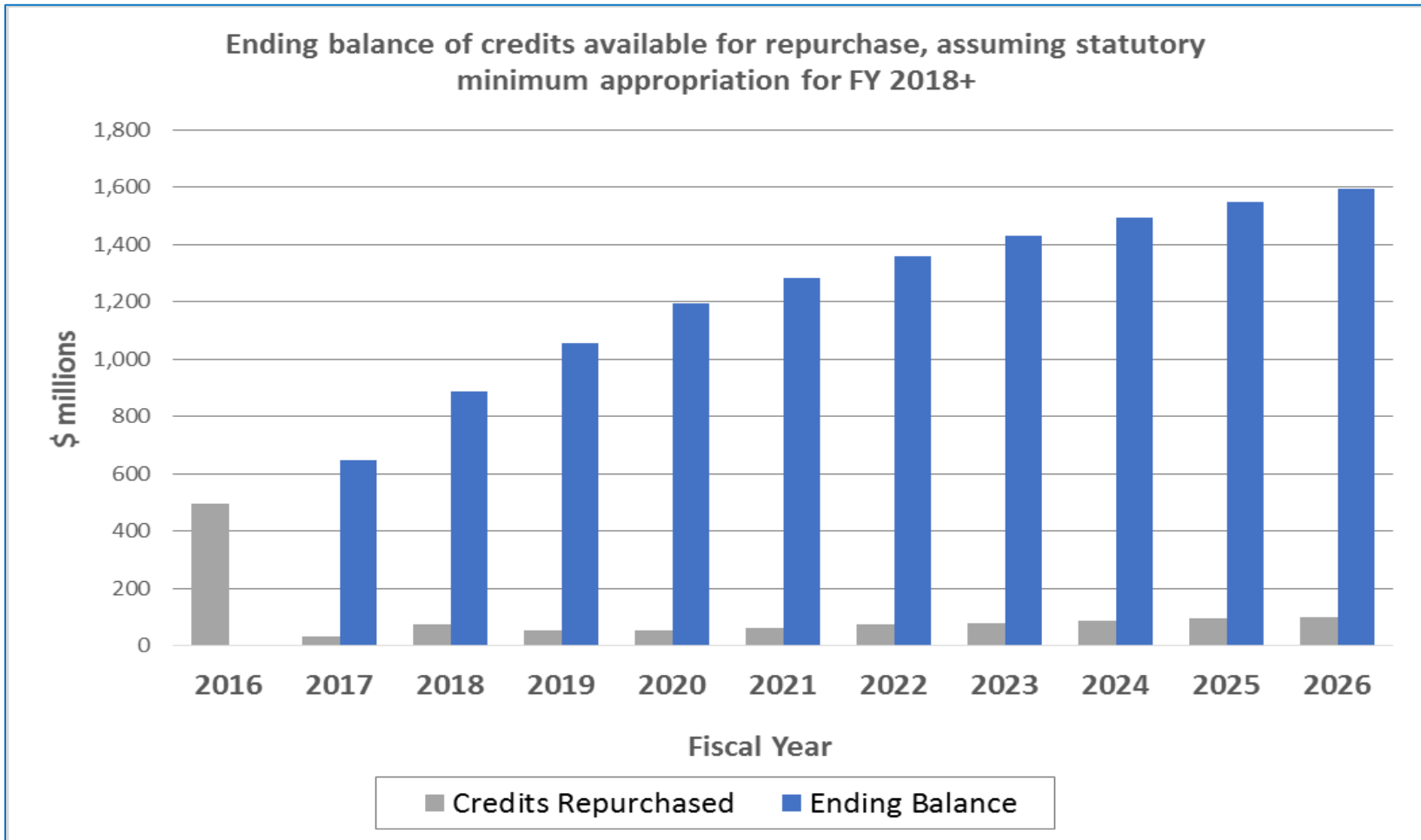
# *Credits Outstanding, Impact of Partial Payment*

- FY2009-2015 Legislature used “open ended” appropriation language. All credit certificates presented were purchased
- FY16 Appropriation Capped at **\$500 million**
  - \$498 million paid out by end of June
  - About \$211 million North Slope, \$287 million non-NS
- FY17 Governor proposes **\$1 billion** to clear credit liability as part of reform package and full fiscal plan
  - Legislature appropriated **\$460 million** towards expected demand of \$775 million
  - Governor vetoed all but **\$30 million (formula calc.)**
  - Funds were paid first in-first out; most went to Cook Inlet capital and well lease expenditure claims

## *Credits Outstanding, Impact of Partial Payment*

- \$600 million in certificates have been issued in FY17  
Of these, about \$100 million have either been:
  - Paid (from the roughly \$30 million available funds);
  - Transferred (to be used against another company's tax liability); or
  - Are ineligible for repurchase
- Total remaining awaiting repurchase ~\$500 million
- Applications in-hand about \$200 million
  - \$50 million “023” credits (NOL and Cook Inlet drilling)
  - \$150 million “025” credits (Exploration; have sunset)
- **So total known demand is roughly \$700 million**
- Additional ~\$400 million forecasted for FY18

# Credits Outstanding, Impact of Partial Payment



Per AS 43.55.028, formula-generated appropriation is 10% of production tax levied, before credits, when ANS price forecast is \$60 or higher. Formula appropriation is 15% of production tax levied, before credits, when ANS price forecast is below \$60.

Does not include changes in company behavior or credit transfers beyond FY 2018 as a result of only making minimum appropriation.

Source: Department of Revenue - Revenue Sources Book Fall 2016

# *Credits Outstanding, Impact of Partial Payment*

## **Credit appropriation formula AS 43.55.028(b) and (c)**

- Based on a percentage of production tax revenue (before subtracting credits that are taken against liability)
  - *Forecast price below \$60: 15%*
  - *Forecast price above \$60: 10%*
- Was never used in previous years' budgets before FY17
- Earlier years would have generated large appropriations that would have exceeded the demand for credits, “endowing” the fund
- Recent years would have spent down any past surpluses; reducing the fund to zero by FY2016
- We'd be in the same place now- only there wouldn't be the expectation that we'd provide unlimited funding



# Tax Credit Fund Appropriations

## Oil and Gas Tax Credit Fund:

### Budgeted vs. Actual vs. Statutory Tax Credit Fund Formula

(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
<b>Actual</b>								
FY09	not to exceed \$175	\$193	\$3,101	\$334	\$3,435	\$85.73	\$343	\$150
FY10	unspec **	\$250	\$2,861	\$412	\$3,273	\$65.70	\$327	\$228
FY11	est. \$180	\$450	\$4,543	\$361	\$4,904	\$73.32	\$490	\$268
FY12	est. \$400	\$353	\$6,137	\$363	\$6,500	\$94.70	\$650	\$565
FY13	est. \$400	\$369	\$4,043	\$550	\$4,593	\$110.44	\$459	\$655
FY14	est. \$400	\$593	\$2,589	\$919	\$3,508	\$109.61	\$351	\$413
FY15	est. \$450	\$628	\$363	\$664	\$1,027	\$95.24	\$103	(\$112)
FY16	est. \$700	\$500	\$144	\$70	\$214	\$39.99	\$32	(\$580)

# *Credits Outstanding, Impact of Partial Payment*

## **Options for companies holding credit certificates**

1. Wait for production (use against own taxes)
2. Wait for additional funding (tax credit obligations are not state “debt” and do not incur interest)
3. Sell to a company with a tax liability
  - Limited demand with low oil prices- the major producers are forecasted to have relatively low liability
  - .023 credits can only offset up to 20% of a company’s tax liability
  - No restriction on use of .025 credits to offset taxes other than the minimum tax. The bulk of large .025 credits will be issued later this year

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# *HB247: Major Provisions & Regional Impacts*

## **Cook Inlet**

- Complete phase-out of NOL, QCE, and WLE by 2018
- Extends “tax caps” on gas indefinitely, adds \$1 / bbl oil tax
- Municipal utility pro-ration of costs

## **Middle Earth**

- Reduces the NOL, QCE, and WLE credit rates
- Extends “Frontier Basin” exploration credit to July 2017

## **North Slope**

- GVR “Graduation” provision after three to seven years
- GVR can’t be used to increase the amount of an NOL

## **Statewide**

- \$70 million per company per year cap (\$61 with “haircut”)
- Interest rates increased for 3 years, then drops to zero
- Transparency, local hire, state obligation offsets, surety bond

## *Remaining concerns with tax and credit system*

- Hybrid system with a net tax above \$75, a gross tax between \$45 and \$75, and a net tax (via the NOL credit) below \$45
- Possible multi-billion dollar future liability for large new discoveries
- Possible ability to use carried forward operating loss credits to zero out all taxes (“hardening the floor”)
- Equity between major producers and new explorers if major changes made to operating loss credits
- High per barrel credit keeps us in the 4% “minimum tax” at up to nearly \$80 oil

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## *Bill Analysis: Section 2 (interest rates)*

### **Interest rates were amended in HB247**

- DOR expressed concern when Senate Finance CS introduced the “zero interest after 3-year” provision
- Makes it very hard to settle tax disputes
- Sought to get it removed in Conference Committee
- Proposed removing it in HB 5005 (July session)
- Currently, doesn't impact any actual interest calculation until 2020 so can be retroactive to 1/1/17

**Concern with language:** *HB247 separated the Oil and Gas Production Tax interest rate from all other taxes for the first time. HB111 does not fix this. We would prefer all taxes to use the same interest.*

# *Bill Analysis: Section 3-4, 20-22 (transparency)*

## **Information about credits made public**

- These sections were originally introduced as HB99
- Expands provision from HB247 requiring annual DOR report of who received tax credits and the amount
- Adds to the report how much in tax credit certificates is issued, as well as
  - A description of each company's expenditures;
  - The purpose of the expenditure; and
  - The lease or property on which it's located

**Concern with language:** *As this bill mostly eliminates “credits,” to meet the intent of the original bill it may be necessary to redraft Sec. 4 to report “lease expenditures. Also, Sec. 22 is redundant with the other report requirement in Sec. 4*



## *Bill Analysis: Section 5, (executive sessions)*

### **Provides authority for DOR to share certain confidential taxpayer information with legislators**

- As written, legislators would have access to the same information as our audit employees
- Section requires developing a substantial confidentiality agreement to be signed by legislators
- Some administrative costs and possible taxpayer concerns
- Would likely engage IRS rules including background checks, chain of custody, information retention, etc.

**Concern with language:** *Also may need to change reference from “credits” to “lease expenditures”*

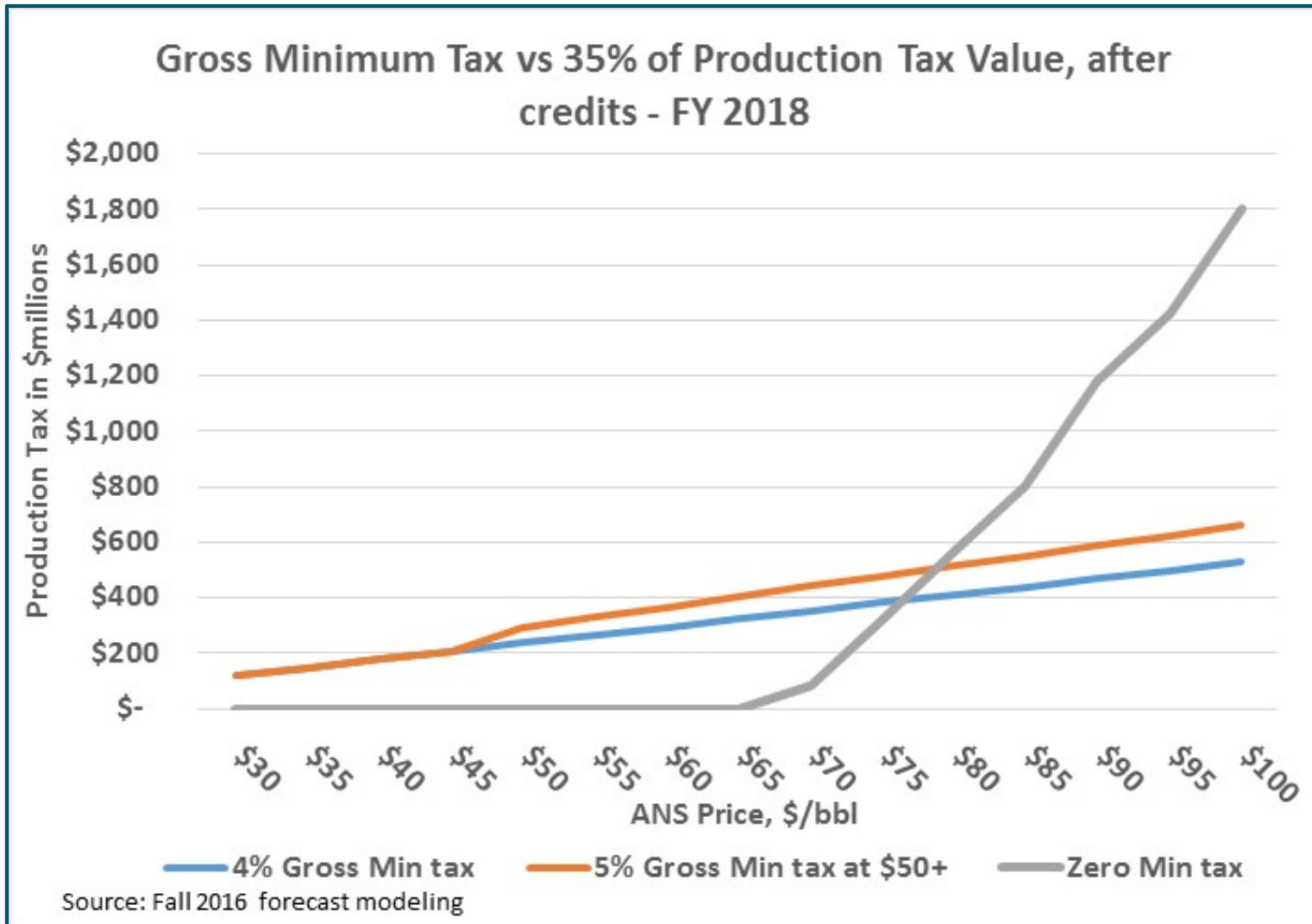
## *Bill Analysis: Section 6 (minimum tax)*

### **The minimum tax is an “alternative” calculation**

- The taxpayer calculates their net-profits tax, which is 35% of “production tax value” less the sliding scale per-barrel credit
- In parallel, they calculate the “gross minimum tax”, which is 4% of gross (wellhead) value when oil prices are above \$25 / bbl
- Actual tax due is the ‘higher of’ the two calculations
- Typical “crossover” occurs at about \$70-\$75 oil
- Amendment raises this minimum tax from 4% to 5% when the oil price is above \$50

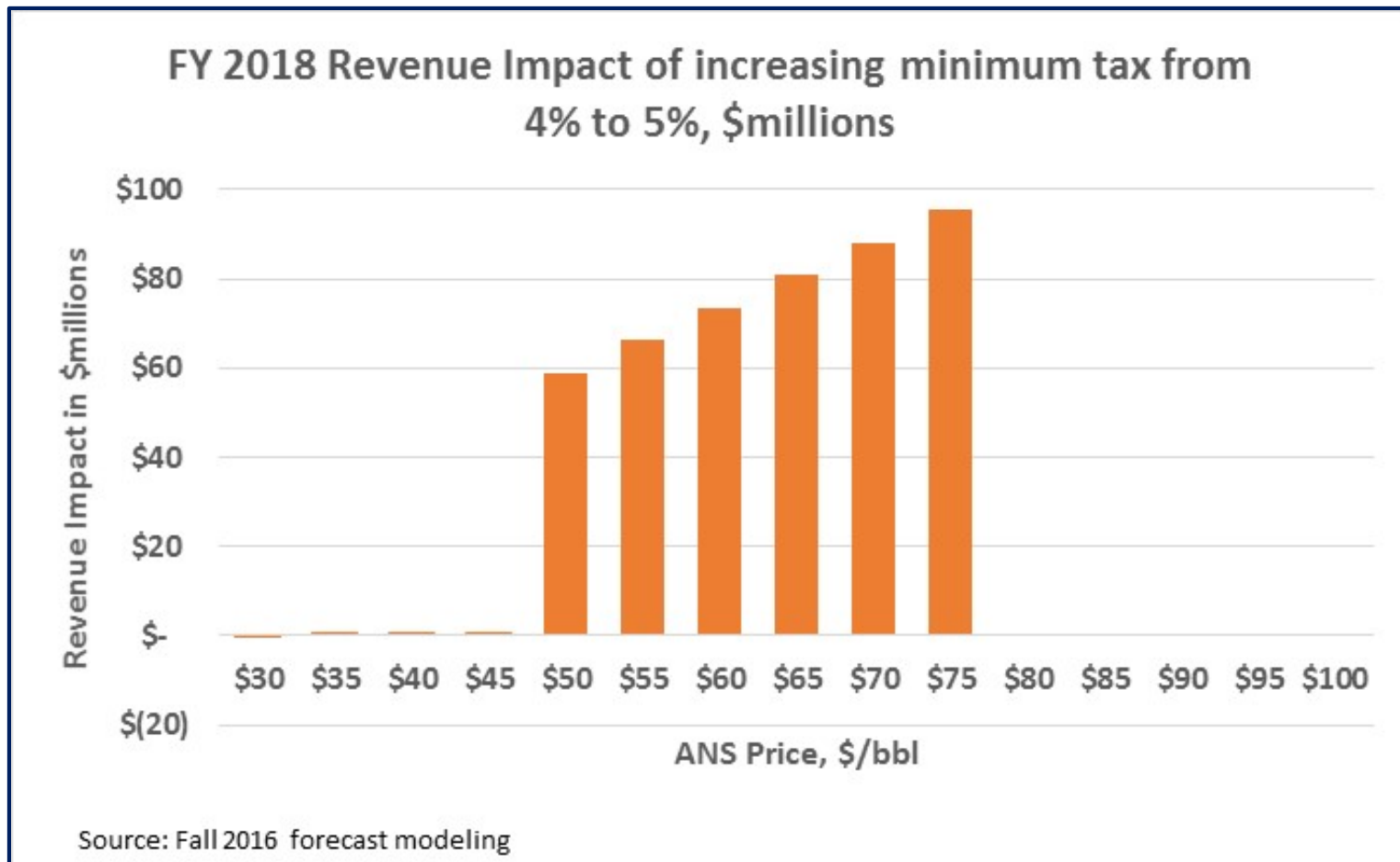
# Bill Analysis: Section 6 (minimum tax)

Increasing the rate moves the “crossover” to a slightly higher oil price



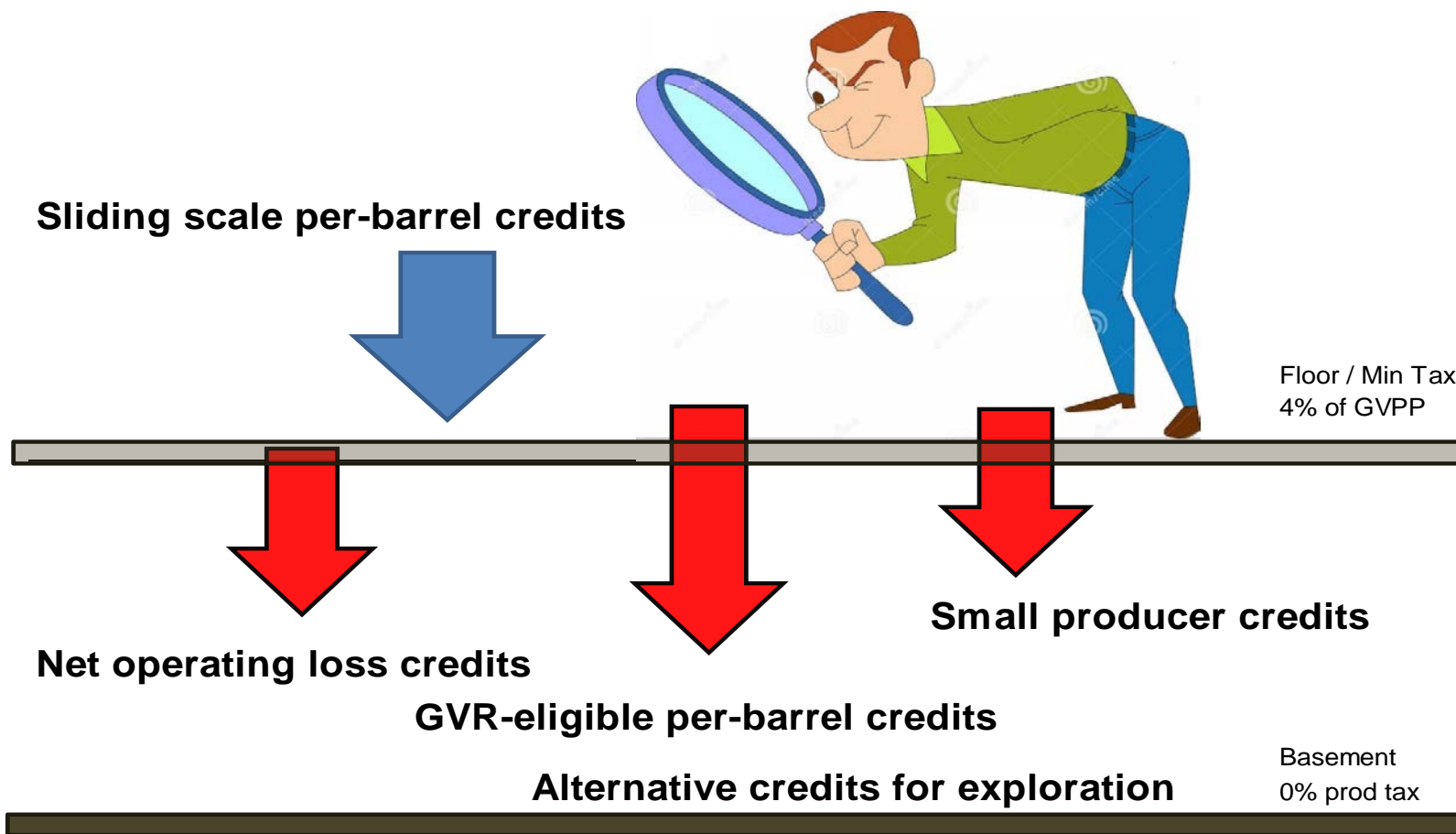
## *Bill Analysis: Section 6 (minimum tax)*

**Impact of the 1% tax increase is limited to prices between \$50 and \$75**



# *Bill Analysis: Sections 7, 8, 10, 12, 13, & 16* *(harden floor)*

**Which credits can break through the floor under current law?**



## *Bill Analysis: Sections 7, etc. (harden floor)*

- Current law allows credits other than the sliding scale per-barrel credits for legacy oil to potentially reduce taxes below the minimum tax (“floor”)
- If a company is using any sliding scale credits, no other credits can be used below the floor
- HB 111 seeks to prevent all other credits in AS 43.55 from reducing taxes below the minimum tax
  - Small producer credits
  - GVR-eligible per-barrel credits
  - Net operating loss credits
  - Alternative credits for exploration
- Near term impact at low prices ~\$20 million

## *Bill Analysis: Sections 7, etc. (harden floor)*

**This is really three different issues / policy questions**

All of these only pertain to the North Slope:

**1) Losses incurred by producers not eligible for refundable credits**

Producers of more than 50,000 bbl / day are ineligible for cash credits and must carry them forward

**2) Small Producer Credits**

Impacts independents plus junior partners within legacy fields

**3) Per-Barrel Credits for GVR “New” Oil**

Currently the \$5 per-barrel credit earned during the 3-7 years of eligibility for GVR is not limited by the floor. In CSHB111, floor is 4% of GVPP as reduced by GVR

## *Bill Analysis: Sections 7, etc. (harden floor)*

### **NOLs and Major Producers**

- Currently, companies producing over 50,000 bbl / day are not eligible to receive cash for tax credits. They must carry them forward to use in a future year
- NOLs for explorers and developer are simply their allowable expenditures. They don't have revenue
- NOLs for producers occur when their spending exceeds their revenue. This can be due to low prices, new investment, or a combination of both
- At least one major producer had an operating loss in 2015 and others possibly in 2016
  - This can be seen in the RSB, table 8-4 on page 80: \$107 million worth of North Slope NOL credits are estimated to be used against liability in FY2017-2019



# Bill Analysis: Sections 7, etc. (harden floor)

How the CS attempts to preserve a tax benefit for GVR-eligible production while still hardening the floor (\$49 oil)

Minimum Tax, Legacy Production, and GVR-Eligible Production*			
	Legacy	GVR-Eligible	GVR-Elig CSHB111(RES)
West Coast Price (\$/tax bbl)	\$49.00	\$49.00	\$49.00
Transportation (\$/tax bbl)	<u>-\$9.77</u>	<u>-\$9.77</u>	<u>-\$9.77</u>
Wellhead Value (\$/tax bbl)	\$39.23	\$39.23	\$39.23
Gross Value Reduction Rate (%)	x 0%	x 20%	x 20%
Gross Value Reduction (\$/tax bbl)	\$0.00	\$7.85	\$7.85
Adjusted Wellhead Value (\$/tax bbl)	\$39.23	\$31.38	\$31.38
Lease Expenditures (\$/tax bbl)	<u>-\$33.64</u>	<u>-\$33.64</u>	<u>-\$33.64</u>
Net Value after GVR (\$/tax bbl)	\$5.59	-\$2.26	-\$2.26
Base Tax Rate (%)	x 35%	x 35%	x 35%
Base Production Tax before Credits (\$/tax bbl)	\$1.96	-\$0.79	-\$0.79
Per-Taxable-Barrel Credit (\$/tax bbl)	\$8	\$5	\$5
<b>Base Production Tax after credits (\$/tax bbl)</b>	<b>\$0.00</b>	<b>\$0.00</b>	<b>\$0.00</b>
Minimum Tax Rate (%)	4%	4%	4%
Wellhead Value (\$/tax bbl)	x \$39.23	x \$39.23	x \$39.23
Adjusted Wellhead Value	<u>n/a</u>	<u>n/a</u>	x \$31.38
<b>Minimum Tax (\$/tax bbl)</b>	<b>\$1.57</b>	<b>\$1.57</b>	<b>\$1.26</b>

\*Current assumptions include transport costs of \$9.77 per barrel and deductible lease expenditures of \$33.64 per taxable barrel, based on the North Slope average for FY 2018 as estimated in the Fall 2016 forecast. For this table, net value is the same as "production tax value," defined in AS 43.55.160.

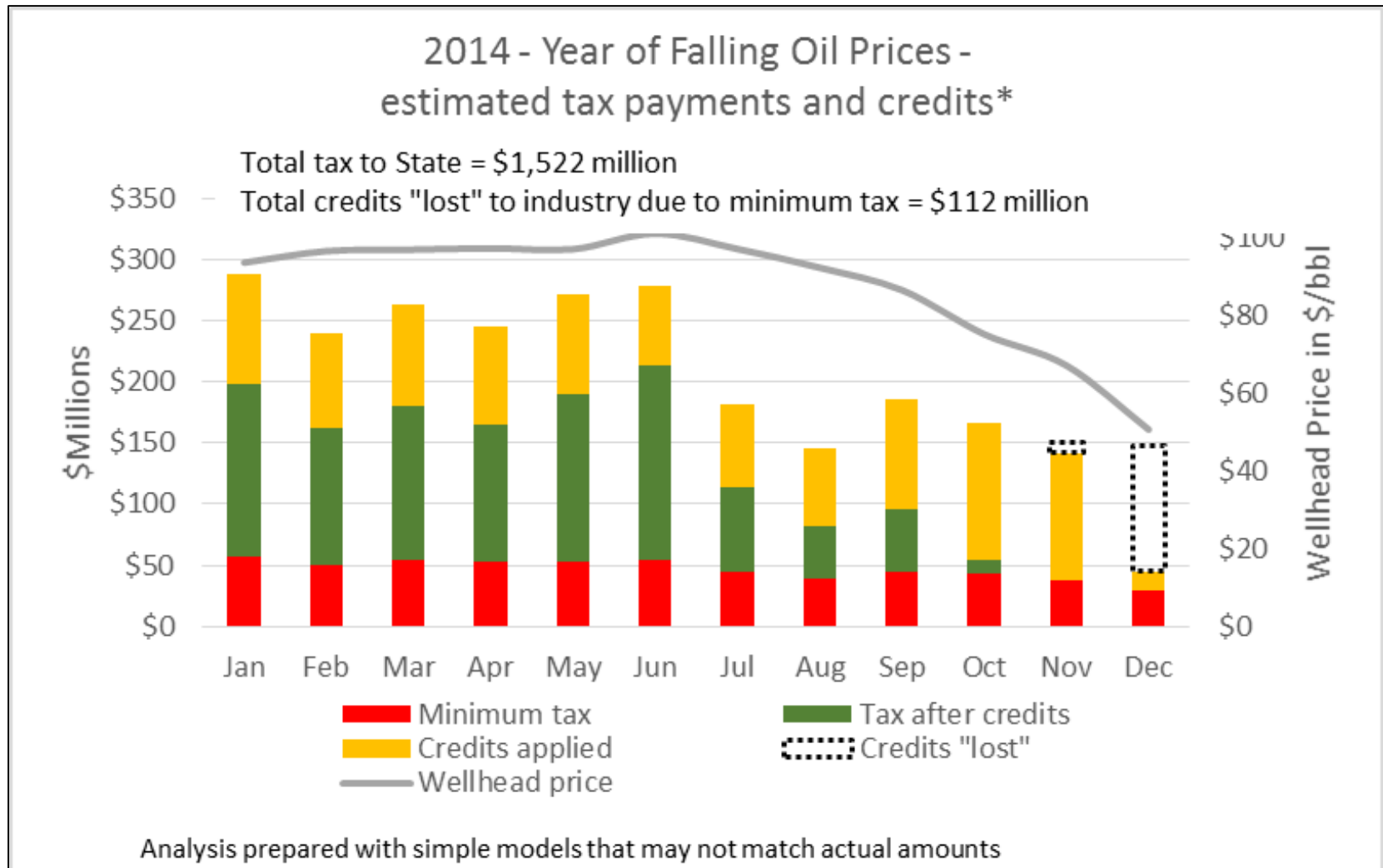
## *Bill Analysis: Section 7-8 (migrating credits)*

### **Preventing per-taxable barrel credits from being used in a month other than the month earned**

- In a low price month, the per-barrel credits are only used until the tax liability reaches the 4% minimum tax. Any additional per-barrel credits are “lost”
- 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
- Sliding scale credits are earned based on monthly price, and vary from month to month. Language in bill would mean the use of the credit would similarly be monthly with no annual true-up

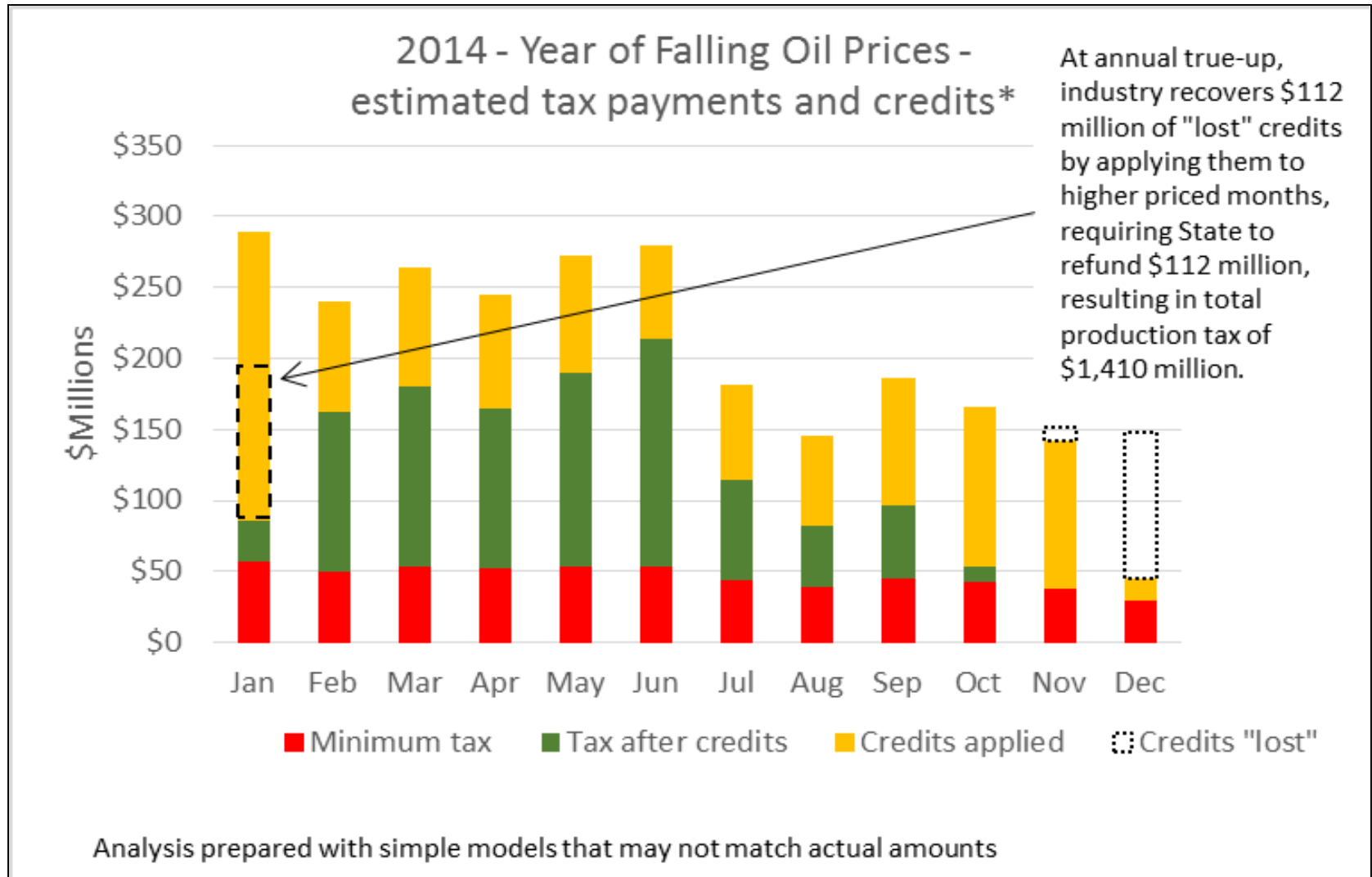
# Bill Analysis: Section 7-8 (migrating credits)

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



# Bill Analysis: Section 7-8 (migrating credits)

## “Lost” credits recovered at annual true-up



## *Bill Analysis: Section 7-8 (migrating credits)*

- This occurs because the minimum tax is an annual tax, and credits that cannot be used within a particular month can be recovered at year's end
- This is only relevant in calendar years where some months result in a tax collection above the minimum tax, and other months are below- for example 2014
- In years with greater oil price volatility, credit recovery can take a larger share and could reduce State production tax collection to the minimum tax
- At extreme: in a year with otherwise low prices, several months of a major price spike due to a global event, and the state only gets the 4% minimum tax on production from those months

## ***Bill Analysis: Section 9, 11, 18 (NOL certificate)***

### **These sections eliminate direct cash support for North Slope activities**

- Sec. 9 eliminates the 35% North Slope NOL
- Sec. 11 and 18 amend existing statute that speaks to transferability and cashability of credits, and the use of the tax credit fund to pay for credits
  - Since the North Slope benefit is no longer a “credit”, it is no longer transferrable and must be held by the company
- Remaining credits eligible for repurchase:
  1. Qualified Capital Expenditure and Well Lease Expenditure credits (only in Middle Earth after 2017)
  2. Exploration credits (only in Middle Earth after 2016)
  3. LNG Storage and Refinery Infrastructure credits (corporate income tax credits that aren't earned by oil producers)
  4. (new dry hole credit added in Sec. 17)

## *Bill Analysis: Section 14 (per barrel credit)*

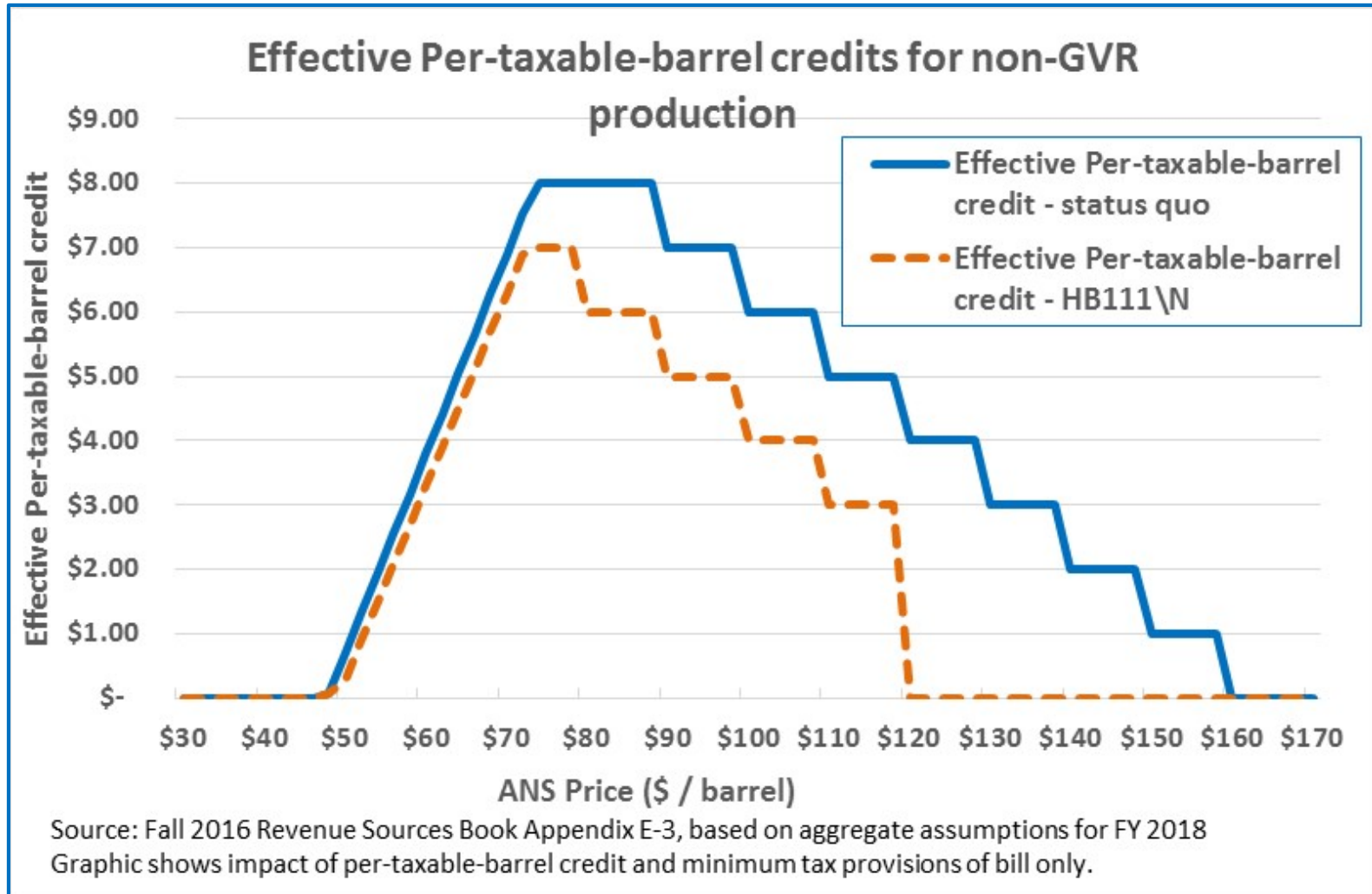
**Current credit is \$8 at wellhead value <\$80; \$7 below \$90, etc.; going to zero at wellhead value >\$150**

- This is “subtracted” from the 35% tax on production tax value (profits)
- HB111 retains the \$8 credit at wellhead value <\$60; generally shifts all the tax tiers down by \$20
- Although the \$8 credit applies in theory at oil prices below about \$90, in practice the minimum tax limits the amount of this credit that can be used at prices below about \$70.
- HB111 reduces most of the break points by \$20. This results in a \$2 / taxable barrel reduction in tax benefit at a wide range of prices- about \$320 million tax impact at oil prices of \$80+

**Concern with language:** Existing per-barrel credit creates an unusual “marginal tax” where a 1c change in price can result in a \$1 change in credit benefit. HB111 exaggerates this with the \$3 decrease in credit when GVPP increases from \$109.99 to \$110 <sup>47</sup>

# Bill Analysis: Section 14 (per barrel credit)

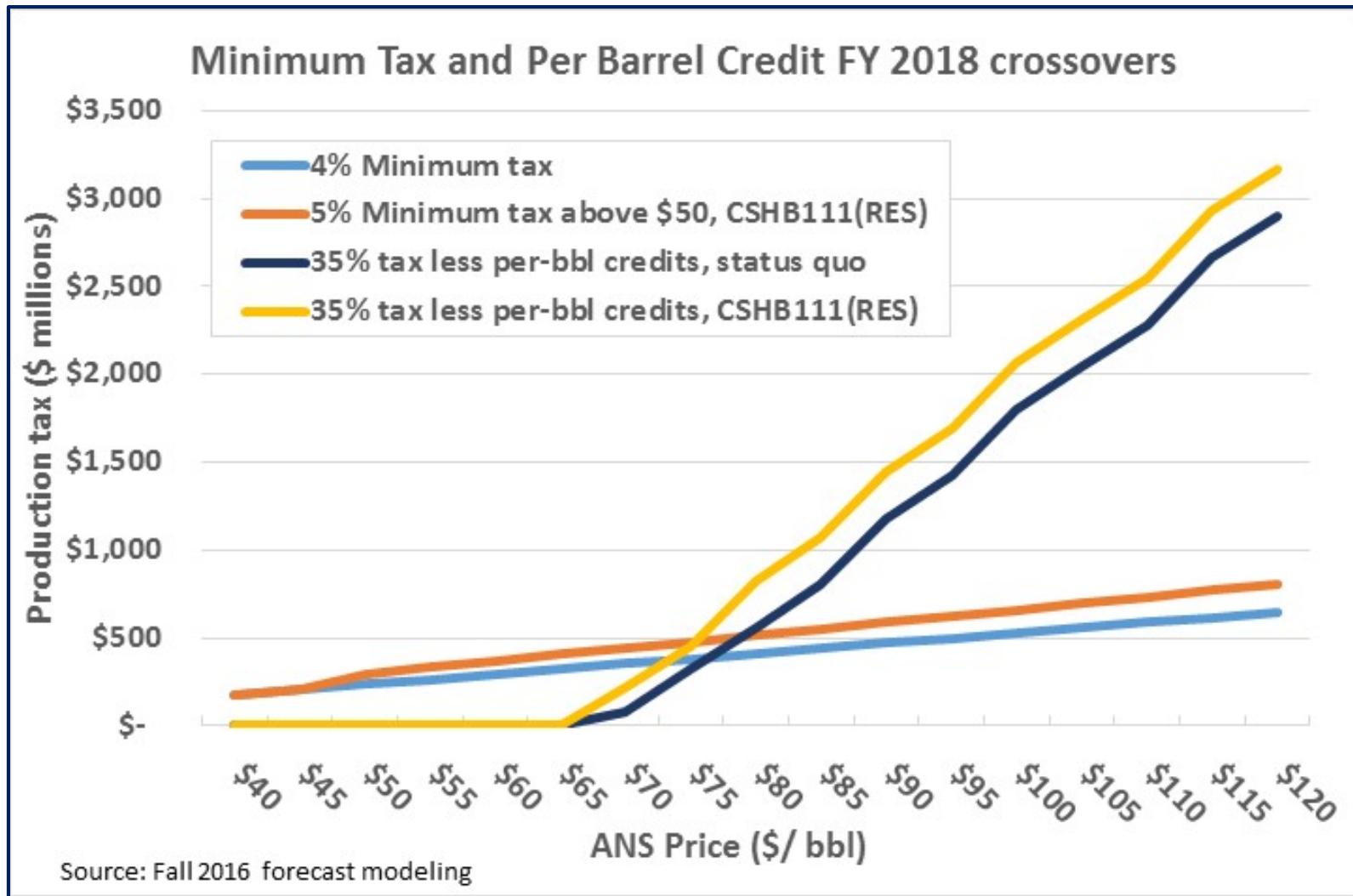
## Effective (usable) rate of “per-taxable barrel” credit at different prices





# Bill Analysis: Section 14 (per barrel credit)

Revenue changes from the “light blue to dark blue” line to the “orange to yellow” line



## *Bill Analysis: Section 15, 17 (dry hole credit)*

**Creates a new exploration credit that is eligible for cash at 15% once conditions are met:**

- No production
- Vendors paid
- Leases returned
- Expenditure not used for another credit

**Concerns with language:** *As written, this would also apply in Cook Inlet. Unsure if this is intentional, as all credits have been eliminated there effective 2018.*

*Also, it's unsure whether this intended to be linked to all lease expenditures or just qualified exploration expenses that have specific criteria defined in AS 43.55.025.*

*Also, is there a possible "double dip" with carry forwards that could be used elsewhere?*

## *Bill Analysis: Section 19 (cash limits)*

### **Amends the statute that describes limits on cash for credits**

- Reduces per-company, per-year limit from \$70 million to \$35 million
  - Sec. 29 also repeals the 25% “haircut” on the second \$35 million in credit cash
- Reduces eligibility for cash to producers below 15,000 bbl / day, from the current 50,000

**Concern with language:** *Much of this section may be superfluous due to Sec. 9, 11, and 18. If North Slope NOLs are eliminated, or are made no longer eligible for cash, only Middle Earth credits remain so. Explorers in Middle Earth are not likely to approach the \$35 million limit, and none have any current production.*

## *Bill Analysis: Section 19 (cash limits)*

### **Notes on large annual credits**

Over the 2007-2016 history of the tax credit program:

- There has only been **one** instance of a company who ever received > **\$200** million in a single year
- **Five** times ever when one company received between **\$100 - \$200** million in one year
- **11** times ever when one company received between **\$50 - \$100** million in one year

Of the \$500 million existing unpurchased certificates:

- **Three** different companies are holding **\$100 million+**

## *Bill Analysis: Section 23 (GVPP below zero)*

- HB 111 would prohibit the Gross Value at the Point of Production from being less than zero
- GVPP is the market price less transportation
- This was possible in early 2016 when oil prices dropped to \$30 per barrel and below
- Only relevant in unusual circumstances; 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

# Bill Analysis: Section 23 (GVPP below zero)

## Jan. 2017 TAPS and feeder pipeline tariffs (these are before adding the \$3.13 marine transport cost)

TAPS Weighted Average Tariff \$5.80

<b>Badami Unit Tariffs</b>	\$ 5.80	TAPS
	\$ 2.08	Badami Connection
	\$ 1.10	Badami Pipeline
<b>Badami Unit</b>	<b>\$ 8.98</b>	<b>Total</b>

<b>Milne Point Unit Tariffs</b>	\$ 5.80	TAPS
	\$ 0.17	Kuparuk - Milne Point Conn
	\$ 0.63	Milne Point Pipeline
<b>Milne Point Unit</b>	<b>\$ 6.60</b>	<b>Total</b>

<b>Colville River Unit Tariffs</b>	\$ 5.80	TAPS
	\$ 0.23	Kuparuk Pipeline
	\$ 0.72	Alpine Tariff
<b>Colville River Unit</b>	<b>\$ 6.75</b>	<b>Total</b>

<b>PT Thomson Unit Tariffs</b>	\$ 5.80	TAPS
	\$ 2.08	Badami Connection
	\$ 1.10	Badami Pipeline
	\$ 17.56	Pt. Thomson Pipeline
<b>PT Thomson Unit</b>	<b>\$ 26.54</b>	<b>Total</b>

<b>Duck Island Unit Tariffs</b>	\$ 5.80	TAPS
	\$ 3.27	Endicott Pipeline
<b>Duck Island Unit</b>	<b>\$ 9.07</b>	<b>Total</b>

<b>Northstar Unit Tariff</b>	\$ 5.80	TAPS
	\$ 1.14	Northstar Pipeline
<b>Northstar Unit</b>	<b>\$ 6.94</b>	<b>Total</b>

<b>Kuparuk River Unit Tariffs</b>	\$ 5.80	TAPS
	\$ 0.23	Kuparuk Pipeline
<b>Kuparuk River Unit</b>	<b>\$ 6.03</b>	<b>Total</b>

## *Bill Analysis: Section 25 (carry forwards)*

**This is the major change to how losses are treated on the North Slope, and incorporates advice from LB&A consultant Ruggiero**

- Current law- company earns a credit based on a percentage of a loss
  - Losses become a 35% credit, eligible for cash
- HB111, 50% of lease expenditures carry forward to a future year to offset taxes
  - Since carry-forward balances can offset taxes, this is equivalent to a 17.5% NOL rate (50% of 35%)
  - Adds an “uplift” (Sec. 26) where carry-forward balances can earn interest for seven years

# *Bill Analysis: Section 25 (carry forwards)*

## **How the Calculation works**

- Company loses \$100 million in year 1
  - Carries forward \$50 million to year 2
  - \$50 million is subtracted from year 2 profits which are subject to the 35% tax calculation
  - Taxpayer saves \$17.5 million in year 2 (does not impact per-barrel credits)
  - 17.5% is much closer to, although still higher than, the effective tax rate at forecasted oil prices
  - If carried for multiple years, the balance earns the uplift, increasing it's value



## *Bill Analysis: Section 25 (carry forwards)*

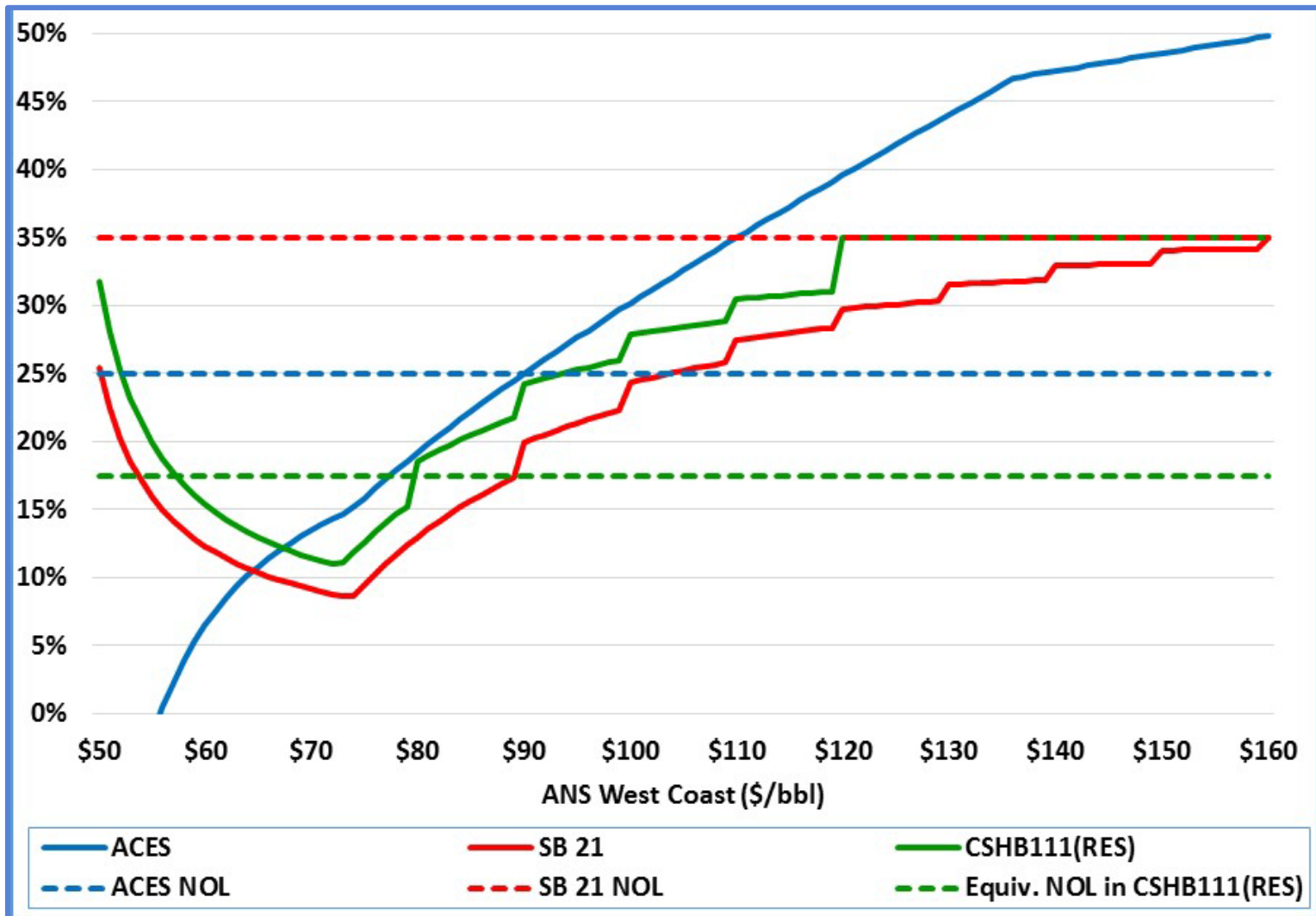
- The 35% NOL rate from SB21 was a distortion that occurred when the legislature added the “per barrel credit”
- The switch from a 25% tax with no credit (as introduced) to a 35% tax with the per barrel credit was believed to be revenue neutral at then-expected oil prices around \$100

	Original SB21	Final
<b>Taxable value at \$100 oil with \$40 costs</b>	\$60	\$60
<b>Tax Rate</b>	25%	35%
<b>Tax</b>	\$15	\$21
<b>Less Per-bbl Credit</b>	\$0	\$6
<b>Effective Tax</b>	<b>\$15</b>	<b>\$15</b>
<b>NOL Rate</b>	<b>25%</b>	<b>35%</b>

- Yet the NOL rate was simultaneously increased to 35%, increasing the benefit for companies that have losses

# Bill Analysis: Section 25 (carry forwards)

Comparison of effective tax rates with NOL (or equivalent) credit rate at different prices



## *Bill Analysis: Section 25 (carry forwards)*

**Is there any real difference, whether it's an NOL credit or a carry forward?**

1. Taxpayer can't earn the value until they actually have a tax liability (not cashable)
2. The benefit is not transferrable, meaning the holder can't sell it to another taxpayer to use against that company's tax liability
3. Indirectly hardens the floor, since there is no longer a "credit" that can be used to offset taxes

**However, each of these could be accomplished by simply adding restrictions to the credit and how it can be used**

## *Bill Analysis: Section 25 (carry forwards)*

**Concerns with language:** *50% language could be interpreted as reducing all carry forwards by 50% each year. So an unused expenditure from year 1 could be worth 25% in year 3, etc. Technical correction.*

*Carry forwards appear to be available statewide. Given the very different Cook Inlet tax regime, it may be appropriate to limit this to North Slope only.*

*Given the hard floor, it is unclear whether the carried-forward lease expenditures would be used to reduce PTV to zero (while still paying the floor), or to only the amount that would result in the minimum tax payment.*

*May need conforming language in AS 43.55.160(a) that limits deduction of lease expenditures “for the calendar year”*

## *Bill Analysis: Section 25 (carry forwards)*

**Another Possible Concern:** *Intent of carry forward structure appears to be to defer the tax benefit until a field comes into production. This could potentially be circumvented if the developer simply sold their company to a major producer. This would enable the uplifted lease expenditures to offset tax liability from legacy fields.*

*Possible solution would be to require taxpayers, when filing annual taxes and claiming the NOL, to identify the lease or property to which they are attached, and to limit the applicability of the carry-forwards to production from that field.*

## *Bill Analysis: Section 26 (uplift)*

### **How the carry-forward and uplift works:**

- Taxpayer has a \$100 million loss in 2018; carries forward \$50 million in lease expenditures
  - If company is profitable in 2019, they reduce their taxable PTV by \$50 million and pay taxes on the remaining amount (equivalent to a 17.5% NOL rate)
  - If company first comes into production in 2026 (seven years later), their balance is “uplifted” by 7% plus the federal discount rate (currently 8.25%) per year
  - Compounded value of \$50 million x 8.25% x 7 yrs is \$87 million (equivalent to a 30% NOL when used)
- Substantial impact if these numbers change

**Concerns with language:** *Section references actual interest rate. May be better to directly tie it to the delinquent tax interest in AS 43.05.225- so both would change together.*

*Unclear whether each year's lease expenditures earn uplift for 7 years, versus each company once losses begin (technical).*

## *Bill Analysis: Section 26 (DNR pre-approval)*

### **New section requires DNR to adopt regulations to pre approve lease expenditures and carry forwards**

- Unclear what criteria should be used for this approval:
  - Legal eligibility of the lease expenditure?  
(currently done by DOR as part of normal tax examination process)
  - Best interest of the state, or cost / benefit?  
(could be a substantial additional workload)
  - How often / what spending levels trigger review?
  - Other possible solution is to tie the carryforward to the actual lease so it only has value after production
- DNR will have more to add

## *What I'm talking about today*

### **Background on Alaska's oil and gas taxes and analysis of CS HB111(RES)\N**

- Money- how oil has funded the state in the past
- Transition- how we've adapted to falling prices
- Credits- what we know, what has accrued
- Last year's HB247 and remaining concerns
- Overview of CSHB111(RES) with detail of selected tax sections

#### ➤ **Fiscal note**



## *Summary of fiscal impact*

- Near term dollar impact \$140-\$200 million once the various sections become effective
  - Less than half of impact is due to increased taxes
  - The majority of the impact of this bill is due to reduced spending (no more cash credits)
  - Does not include what “would be” the liability for possible future large projects
- Longer term impact about \$250 million
  - In later years due to a higher forecasted oil price, the per-barrel credit change shows additional revenue
- Increase in the value of carried-forward lease expenditures that will reduce future taxes
  - The associated projects don't come into production during the fiscal note period

# *Fiscal Note – change in revenue (taxes)*

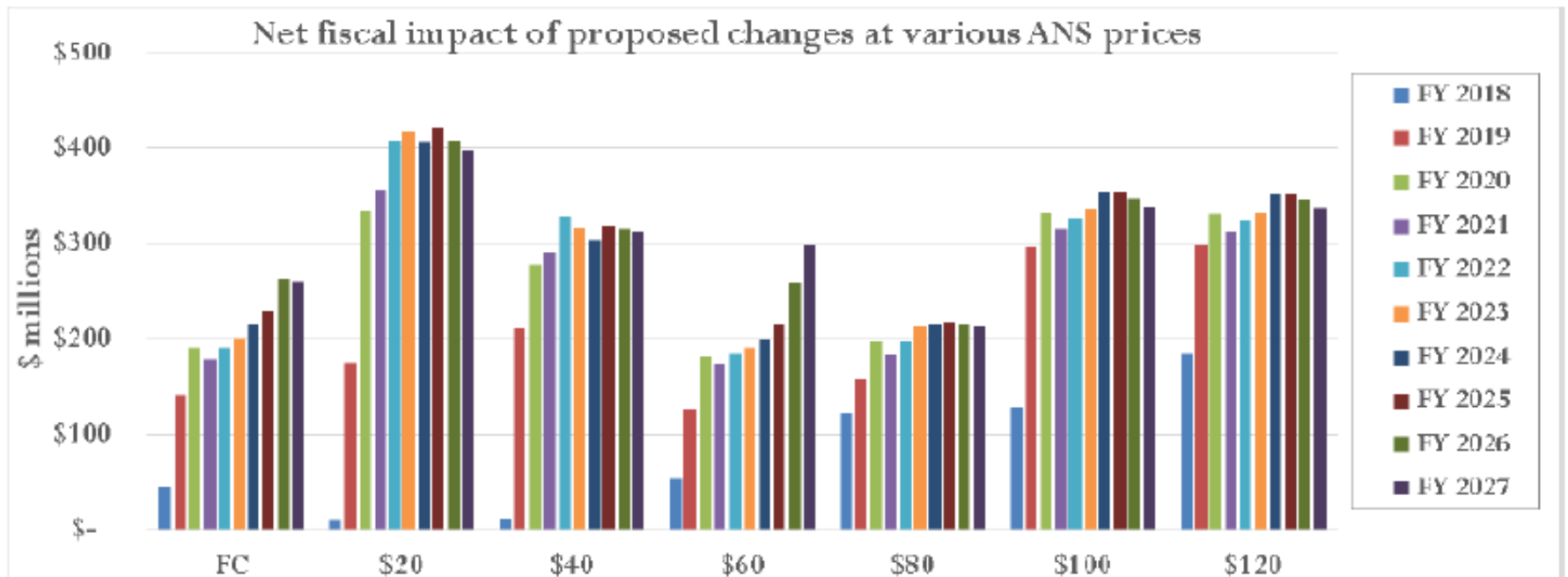
Description of Provision	FY 2018	FY 2019	FY 2020
1. Effective 1/1/18, Operating loss credit eliminated for North Slope and replaced with carry-forward lease expenditures provision. A company may carry forward 50% of DNR-approved North Slope lease expenditures not deducted against tax. Carry-forward earns interest for up to 7 years.	\$0	\$0	\$0
2. No credits can reduce tax below the minimum tax effective 1/1/18.	\$20	\$15	\$0
3. Minimum tax increased to 5% of GVPP at prices of \$50 and above, and GVR reduces basis for minimum tax, effective 1/1/18.	\$20	\$65	\$60
4. No cash repurchase available for net operating loss credits based on expenses incurred after 1/1/18 (for purposes of this fiscal note, assumes all outstanding credits are funded in FY 2018).	\$0	\$0	\$0
5. State purchase of credits limited to \$35 million per company per year, and only companies with less than 15,000 BTU-equivalent barrels of production, effective 1/1/18.	\$0	\$0	\$0
6. Sliding scale per-taxable-barrel credits changed to \$8 when GVPP per barrel is less than \$60, with brackets ranging to zero when GVPP per barrel is \$110 and above, effective 1/1/18.	\$0	\$0	\$0
7. Gross value at point of production (GVPP) cannot go below zero effective 1/1/18.	\$0	\$0	\$0
8. Interest on delinquent taxes continues to accrue after 3 years, retroactive to 1/1/17.			
9. No true-up of excess per-taxable-barrel credits effective 1/1/18.			No impact
10. New "dry hole" credit of 15% of qualifying expenditures, effective 1/1/18.			
Additional impact of implementing above provisions together vs standalone.	\$5	-\$5	\$0
<b>Total Revenue Impact</b>	<b>\$45</b>	<b>\$75</b>	<b>\$60</b>

# *Fiscal Note – budget impact (buying credits) plus carry-forwards*

Description of Provision	FY 2018	FY 2019	FY 2020
A. Budget impact of operating loss and carry-forward lease expenditures changes effective 1/1/18.	\$0	\$45	\$105
B. Budget impact of no credits can reduce tax below the minimum tax effective 1/1/18.	\$0	\$0	\$0
C. Budget impact of minimum tax changes effective 1/1/18.	\$0	\$0	\$0
D. Budget impact of no cash repurchase for net NOL credits earned after 1/1/18.	\$0	\$45	\$110
E. Budget impact of new limits to credit repurchase eligibility, effective 1/1/18.	\$0	\$0	\$0
F. Budget impact of adjustments to sliding scale per-taxable-barrel credits, effective 1/1/18.	\$0	\$0	\$0
G. Budget impact of GVPP cannot go below zero effective 1/1/18.	\$0	\$0	\$0
H. Budget impact of interest accrual changes, retroactive to 1/1/17.	\$0	\$0	\$0
I. Budget impact of no true-up of excess per-taxable-barrel credits effective 1/1/18.	\$0	\$0	\$0
J. Budget impact of new "dry hole" credit effective 1/1/18.			
Additional impact of implementing above provisions together vs standalone	\$0	-\$25	-\$85
<b>Total Budget Impact</b>	<b>\$0</b>	<b>\$65</b>	<b>\$130</b>
<b>Total Fiscal Impact - (does not include potential changes in investment)</b>	<b>\$45</b>	<b>\$140</b>	<b>\$190</b>
Tax impact of carry-forward lease expenditure balances - current law	\$14	\$0	\$0
Tax impact of carry-forward lease expenditure balances - proposed	\$75	\$140	\$195
<b>Change in year-end balance due to proposal</b>	<b>\$61</b>	<b>\$140</b>	<b>\$195</b>

# *Fiscal Note – impact at different oil prices*

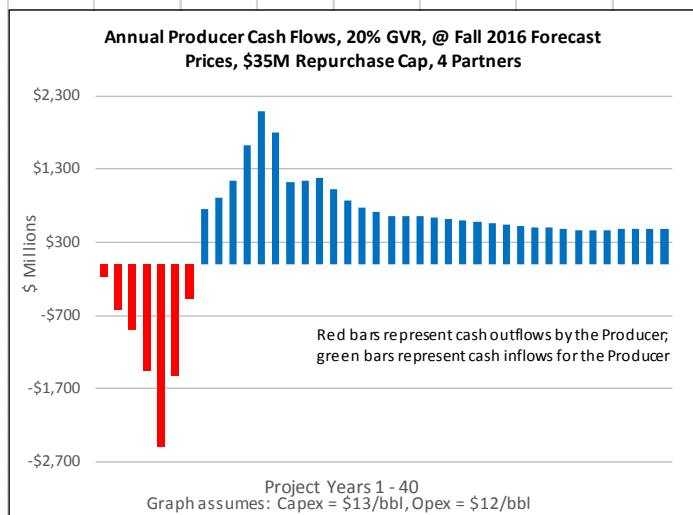
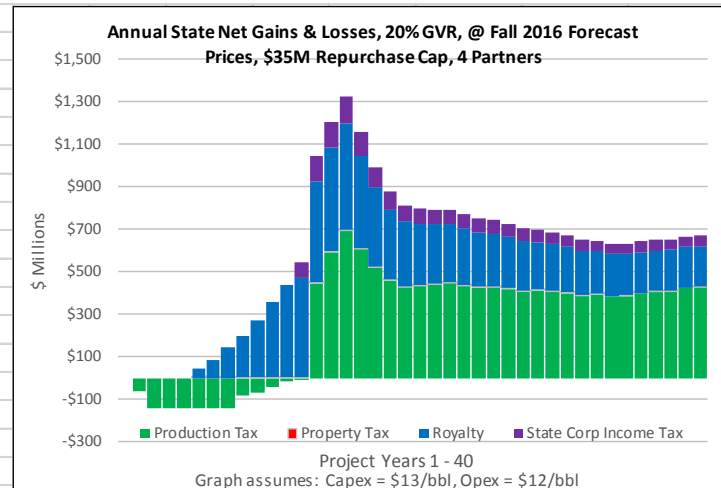
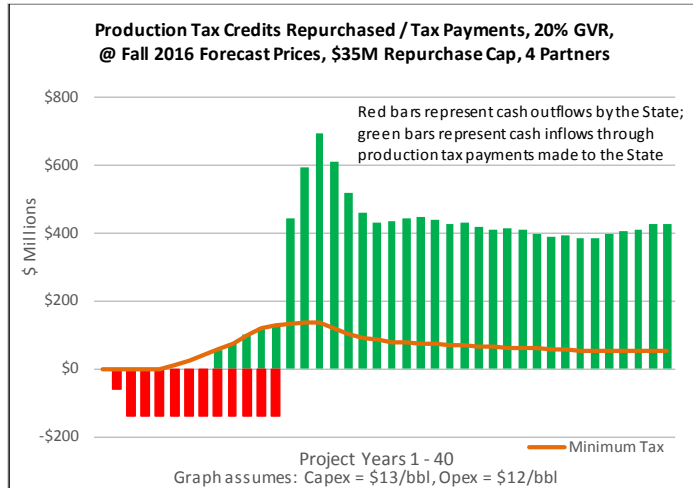
## Net Fiscal Impact of CSHB111(RES)\N at Various Prices



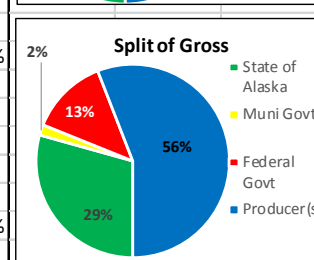
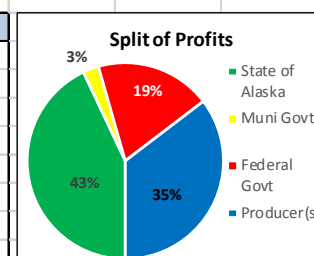
# Fiscal Note – scenario modeling

Additional “life cycle” modeling will be presented on Friday

## 750 mmbo, Status Quo, Fall 2016 Forecast Prices, 4 Partners



Lifecycle Totals	
Tax Credits Repurchased = \$M	1,600
Production Tax Paid = \$M	12,549
Net Production Tax = \$M	10,950
Production Tax NPV @ 6.95% = \$M	1,638
Total Annual State Losses = \$M	629
Total Annual State Gains = \$M	23,014
Net State Gain (Loss) = \$M	22,385
State NPV @ 6.95% = \$M	4,683
Internal Rate of Return (IRR)	29%
Total Producer Cash Out = \$M	7,620
Total Producer Cash In = \$M	26,037
Net Producer Cash Flow = \$M	18,417
Producer Cash NPV @ 10.0% = \$M	112
Internal Rate of Return (IRR)	10%



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*Pulling Together to Build Our Future*

**Thank You!**

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