NEW SUSTAINABLE
ALASKA
PLAN
Pulling Together to Build Our Future

Oil and Gas Tax Credit Reform
CS HB247(RES)

Department of Revenue

Presentation to the House Finance Committee

March 31, 2016

What We'll Be Discussing

1. History and Development of Credits
2. Credits- What Worked, What Didn't?
3. Credit Cost in Perspective
4. Overview of the Tax & Credit Calculations
5. Bill Summary- What is in the CS?
6. Changes from Governor's to Resources Version
7. Fiscal Impact of Changes
8. Summary of Scenario Analysis and Life Cycle Modeling: Economics of Changes
9. Implementation

History and Development of Credits

History of Oil and Gas Production Tax Credits

- First “modern” Oil and Gas credit was the Alternative Credit for Exploration (AS 43.55.025) passed in 2003 while Alaska still had the “Economic Limit Factor” (ELF) Gross Tax
- Several added in 2006 with passage of the “Petroleum Production Tax” (PPT) and switch to net profits taxation. Included Cook Inlet tax caps as well as the first “state repurchase” provisions
- Credits substantially modified with passage of “Alaska’s Clear and Equitable Share” (ACES) in 2007; state repurchase made more open-ended
- Cook Inlet Recovery Act and related legislation in 2010
- Frontier Basin credits added in 2012
- SB 21 passed in 2013, dramatically changed North Slope credits, replacing “spending” with “production” focus

History of Oil and Gas Production Tax Credits

- Credits initially added to encourage certain desired behaviors, tied to anxiety over declining production and a need for new investment
- Later credits were added as core components / offsets of the net profits system
- At times credits were layered on top of each other, creating unanticipated circumstances
- Credits can either be used against tax liability, sold / transferred to a taxpayer, or cashed out ("repurchased") by the state
- Per AS 43.55.028(e)(4), a company producing over 50,000 bbl / day can not have their credits repurchased by the state

History of Oil and Gas Production Tax Credits

Major Credits Available (current law):

- **.023(b) Net Operating Loss (25-45%)**
  This is the main refundable credit on the North Slope and the largest statewide credit. "Stackable"
- **.024(i&j) Per-Taxable Barrel ($0 to $8)**
  Only on North Slope
  Only can be used against tax liability
- **.023(a&l) Capital and Well Expend (20-40%)**
  Only outside North Slope, usually refunded
- **.025(var) Exploration Credit (30-40%)**
  Expires 7/16 in North Slope and Cook Inlet
  Extended in Interior / Frontier Areas until 2022
- **.024(c) Small Producer Credit (up to $12 mil)**
  Closed to new applicants in 5/16

Credits: What Worked, What Didn't?

Credits- What Worked, What Didn't?

Some Credits have Never Been Claimed

- Middle Earth "New Areas" $6 million Credit
  (AS 43.55.024(a); part of HB3001/PPT, 2006)
- Cook Inlet "Jack Up Rig" 100% Credit
  (AS 43.55.025(m); part of SB309, 2010)
- Frontier Basin 80% Drilling Credit
  (AS 43.55.025(n); part of SB23, 2012)

Companies did some of the activities incentivized by these, but were able to get better results from "stacking" other credits

All of these programs are sunsetting in 2016

Credits- What Worked, What Didn't?

To-date cost of Sunsetting Credits

Exploration Credits (various) 2007-sunset

- North Slope Refunded: $270 million
- North Slope Against Liability: $190 million
- Non-North Slope Refunded: $160 million
- Non-North Slope Against Liability: $0

Small Producer Credits 2007-2016

- North Slope Against Liability: $340 million
- Non-North Slope Against Liability: $60 million
- (these cannot be refunded)

Total: slightly over $1 billion

Credits- What Worked, What Didn't?

Credits Remaining if HB247 Passes

- **Carried-Forward Annual Loss Credit** (also called "net operating loss")
  - 35% on North Slope and 25% in Cook Inlet and elsewhere (non-NS reduced to 10% by H(RES))
- **Non-North Slope Drilling Credits**
  - "QCE" and "WLE" were repealed in governor's bill; maintained at 20% in H(RES) version
- **Exploration Credits outside North Slope and Cook Inlet** ("middle earth exploration")
  - 30-40% depending on location
  - Sunset January 1, 2022

Credits- What Worked, What Didn't?

Credits Remaining If HB247 Passes (contd.)

- **Cook Inlet Tax Caps**
  - Oil tax of zero, gas tax averages 17 cents / mcf
  - Sunset January 1, 2022
- **Middle Earth Tax Caps**
  - 4% of gross value (first seven years of production that begins before 2027)
- **LNG Storage Facility Credit**
  - Lesser of 50% of cost or $15 million
- **Refinery Infrastructure Credit**
  - 40% of cost up to $10 million / year per refinery, before 2020

Credit Cost in Perspective

Credit Cost in Perspective

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 refunded 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 refunded credits (most since 2013)

Credit Cost in Perspective

Of the $3.0 billion in state-refunded credits through the end of FY15:

- $1.45 billion went to six North Slope projects that now have production
- $650 million went to 13 North Slope projects that do not have any production. Some of these are abandoned, and some are in process
- $450 million went to six non-North Slope projects that have production
- $450 million went to eight non-North Slope projects that do not have any production

Credit Cost in Perspective

North Slope Refundable Credits

Of the $1.45 billion that was spent between FY07-FY15 supporting six producing projects:

- Total production through end of FY15 is 38.5 million barrels
- Total credits = **$37.30** / barrel
  - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were $4.94 billion
  - Credit support was **29%** of lease expenditures

Credit Cost in Perspective

Cook Inlet Refundable Credits

Of the $450 million that was spent between FY07-FY15 supporting six producing projects:

- Total production through end of FY15 is 55.9 million BOE (much of this was gas)
- Total credits = **$7.80** / BOE or about **$1.30** / mcf
  - This number will decrease over time due to additional production from these fields
- Lease expenditures for these projects, through FY15, were $1.09 billion
  - Credit support was **40%** of lease expenditures

Credit Cost in Perspective

Cook Inlet Tax Caps

- Estimated value to industry $550-$850 over the years 2007-2013
- Total Production Estimate
  - Gas: ~ 250 million cubic feet / day for seven years = 640 BCF of gas or 106 million BOE
  - Oil: ~ 10,000 barrels / day for seven years = 26 million BOE
  - Total Production = 132 BOE
- Using midpoint $700 million estimate, value of caps = **$5.30** / barrel or **$0.88** / mcf

Overview of Tax and Credit Calculations

Overview of Tax and Credit Calculations

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**

Overview of Tax and Credit Calculations

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**

Overview of Tax and Credit Calculations

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*

Overview of Tax and Credit Calculations

$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*

Overview of Tax and Credit Calculations

- This is just the “baseline” scenario, for legacy oil from the North Slope.
- Does not account for the fact that roughly 9% of production qualifies for the “Gross Value Reduction” new oil tax break
- Can also provide example calculations for North Slope GVR Eligible Production as well as Cook Inlet scenarios

Bill Summary:
What is in the H(RES) CS?

Exploration Credits

HB247 Proposed / Kept in CS

- Allowing the .025(a) “alt. credit for exploration” to expire on 7/1/16, for North Slope and Cook Inlet
  - 025(a) credits remain for “Middle Earth” until 2022
- Also allowing the “Jack up Rig” and “Frontier Basin” credits to expire at the same time
- Preemptively repeal other exploration credit programs that are not currently being used, in AS 38.05.180(i) and AS 41.09.

Bill Summary- What is in the H(RES) CS?

Cook Inlet Credits, Current Conditions

New Field Developer

- Currently receives a 25% Net Operating Loss (NOL) credit stacked with either the 20% Capital (QCE) or 40% Well (WLE) credit. Generally a weighted average of the two "spending / drilling" credits
- State typically refunds 50-60% of costs

Existing Producer

- Currently pays low to zero taxes due to Cook Inlet tax caps, yet is eligible for 20% Capital or 40% Well Lease Expenditure credits
- State typically refunds 25%-35% of costs

Bill Summary- What is in the H(RES) CS?

Cook Inlet Credits, Changes in CS

New Field Developer

- NOL (Loss) credit reduced from 25% to 10% in 2017
- WLE (Well) credit reduced to 30% in 2017 and 20% in 2018 (effectively repealing it)
- QCE (Capital) credit remains until 2022 (anticipating sunset of Cook Inlet tax caps)
- State will typically refund 35% of costs in 2017 and 30% in 2018 and beyond

Existing Producer

- Tax caps remain until 2022. Continuation of 20% QCE credit means state will continue to refund 20% of capital spending

CS sets path for broader Cook Inlet tax reform by 2022

Repurchase Limits

Changes in Committee Substitute

- Adds an annual “cap” on per-company credit repurchases of $200 million
- Multiple partners in the same project can each claim $200 million. However, a single company cannot artificially split themselves to multiply the benefit
- Cash flow protection in the case of a large “outlier” project such as proposed by Armstrong
  - Modeling showed annual credits from a similar project of up to $800 million

Repurchase Limits (cont'd)

Historic 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

Remove Exceptions / Loopholes

CS retains two proposed changes to prevent artificially inflated net operating losses

- Can’t use GVR (new oil value reduction) to increase the size of a Net Operating Loss (has led to credits greater than 100% of loss)
- If a municipal entity owns production and sells only a portion of that production to an outside party, only the pro-rata share of expenses can be deducted against revenue

Bill Summary- What is in the H(RES) CS?

Brief explanation of GVR / NOL Problem
(Sec. 12; AS 43.55.23(b)(2))

- CSHB 247 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

Bill Summary- What is in the H(RES) CS?

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.

Bill Summary- What is in the H(RES) CS?

Brief explanation of Municipal Utility Problem
(Sec. 26; AS 43.55.895(b))

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.

<u>Current law allows all lease expenditures to be used to offset the comparably small amount of sales, potentially generating large credits.</u> HB247 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**

Other Provisions

Interest Rate Reform

- Fixes a technical error in SB21 that prevents compound interest on underpayments and assessments.
  Since 2014 we have collected only simple interest
- Interest rate remains 3% above federal discount rate

Bankruptcy & Debt Protection

- Credit certificates can be used to satisfy obligations to the state for the company's oil and gas business before repurchase
- Surety bond of $250,000 for developers, to protect unsecured creditors in event of default

Changes from Governor's to Resources Version

Changes made in House Resources

- Kept and improved many of the technical fixes, including inadvertent “double dip” credit for new oil on the North Slope
- Reduced Cook Inlet credits, with different emphasis and delayed phase-out
- Increased repurchase “cap,” limiting its impact to just very large ‘outlier’ projects
- Removed all changes to minimum tax “floor,” transparency provisions, interest rate increase, and several smaller provisions
- New legislative working group to review tax regimes outside the North Slope

Cook Inlet Credits

Original proposal was to repeal 20% Capital (QCE) and 40% Well (WLE) credits on 7/1/16, while maintaining the 25% Operating Loss (NOL)

- Effectively, three substantial changes:
  1. Timing: CS phased in the changes over 18 months, taking full effect on 1/1/18
  2. Total: CS retained a 30% level of development support vs. 25% in original bill
  3. Applicability: CS maintained 20% credit support for producers who earn a profit, vs. no support in original version. Means additional companies will still qualify for cash credits

Repurchase Limits

Original proposal added four limits to repurchase:

- Per-company / per-year cap of $25 million
- Large companies, with annual revenue over $10 billion, are ineligible for credit repurchase
- Percentage of repurchase tied to percentage of Alaska resident hire
- 10-year carry forward sunset

Impact of Changes

- A large percentage of projected savings were in these provisions, although tighter repurchase limits would increase the total amount of “carried forward” credits that could offset future production

Strengthen Minimum Tax

CS eliminated- items that impact legacy producers:

- Can't use an operating loss credit, to reduce payments below the 4% floor
  <u>This was the largest "added revenue" component</u>
- Prevent per-taxable-barrel credits earned in one month from being used against another month's taxes at true-up
- Increase in minimum tax from 4% to 5%

CS eliminated- items that impact new oil producers:

- Extend minimum tax to GVR-eligible "new" oil
- Not allow small producer credit to reduce tax payments below the floor

Fiscal Impact

Fiscal Impact

Summary of Fiscal Note with Bill Changes

(updated for Prelim. Spring 2016 Revenue Forecast)

	FY17		FY18		FY19	
	HB247	CS HB247(RES)	HB247	CS HB247(RES)	HB247	CS HB247(RES)
Reduced Spending						
Credits Eliminated or Reduced						
North Slope	$15	$10	$25	$25	$20	$20
Cook Inlet / Mid Earth	$35	$10	$65	$45	$45	$30
Credits Deferred						
North Slope	$275	$0	$50	$0	$25	$0
Cook Inlet / Mid Earth	$275	$0	$50	$0	$25	$0
Budget Subtotal	**$600**	**$20**	**$190**	**$70**	**$115**	**$50**
Increased Revenue						
Floor "Hardening"	$125	$0	$180	$0	$215	$0
Floor Increase to 5%	$50	$0	$55	$0	$50	$0
CI Credit Repeal	$10	$0	$10	$0	$10	$0
Revenue Subtotal	**$185**	**$0**	**$245**	**$0**	**$275**	**$0**
Total Bill Impact	**$785**	**$20**	**$435**	**$70**	**$390**	**$50**

Fiscal Impact

Impact of Changes from Fall 15 to Preliminary Spring 16 Forecast

- Much lower prices for longer period means:
  - Larger company operating losses
  - Status quo, production tax goes to near zero as all of it is offset by NOL credits
  - Large carried-forward NOL's, $630 million after FY17
- Refundable credit estimate for FY17 increases by $200 mil
  - Larger company operating losses
  - Higher than expected work on exploration projects, before expected sunset this year (up to 85% on NS)

Fiscal Impact

In future years, our "status quo" credit forecast appears to decrease.

This can't really be built into future budgets.

- Our credit forecast only includes "known" projects
- Most "new" projects would add to the amount of projected credits
- Credit projections use the same conservative methodology as DOR's production forecast

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
- Status quo modeled vs. Governor's original bill
- Two full presentations on BASIS from previous committee

Introduction to Scenario Analysis

Fields Analyzed:

North Slope Scenarios:

- 50 million barrel North Slope Oil
- 750 million barrel North Slope Oil (20% GVR)

Cook Inlet Scenarios

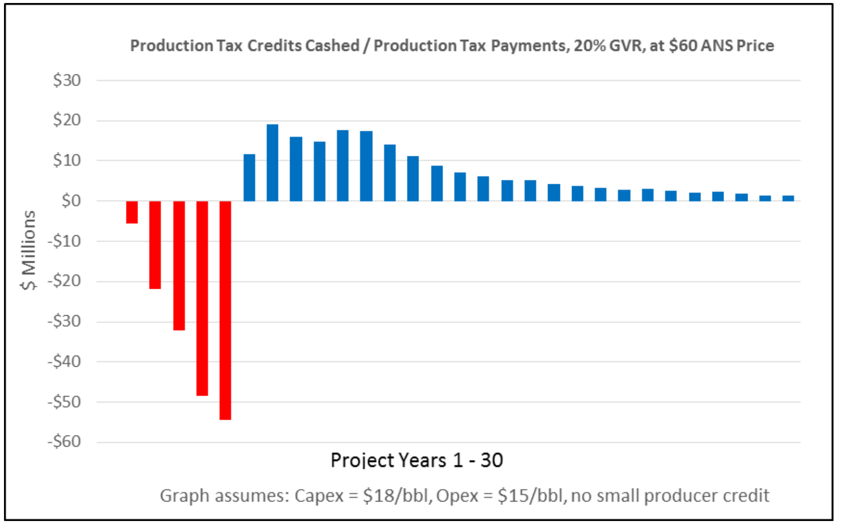
- 50 million barrel Cook Inlet Oil (with and without tax caps)

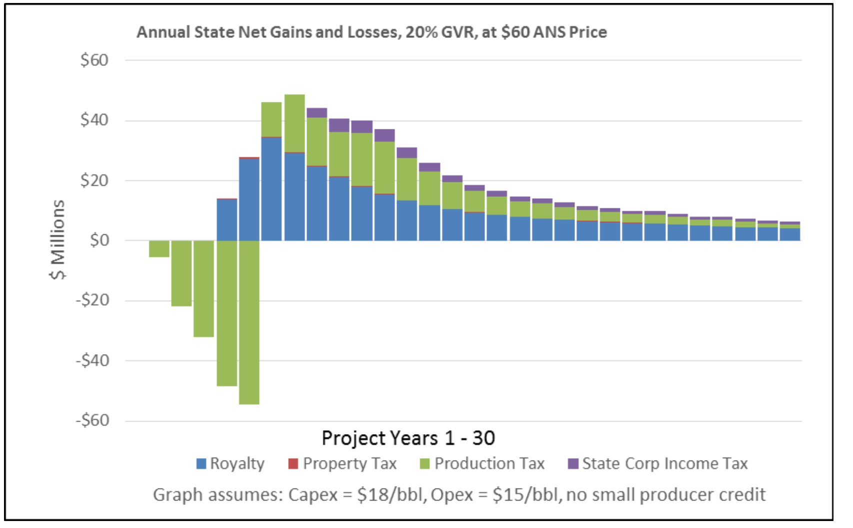
Supplemental Scenarios

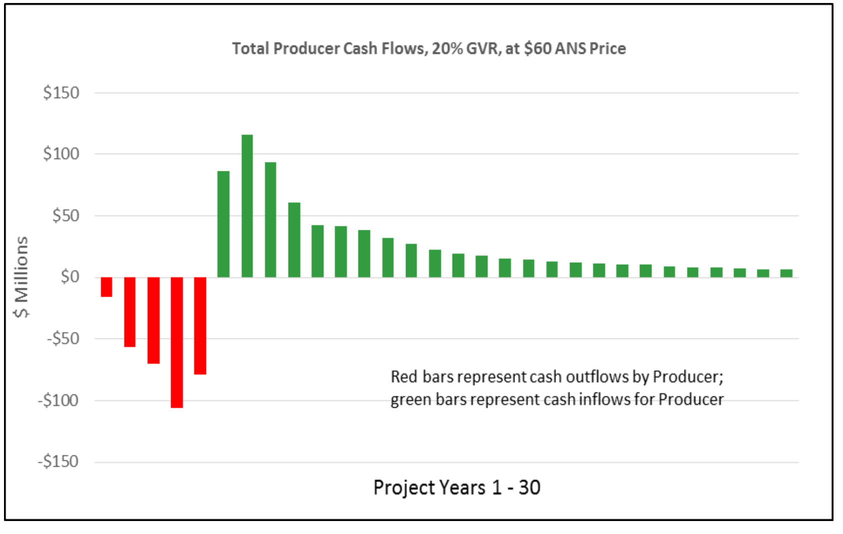
- 750 million barrel North Slope Oil (30% GVR)
- 750 million barrel North Slope Oil (50% Private Royalty)
- 670 bcf Cook Inlet Gas
- 670 bcf Middle Earth Gas

Sample of Scenario Analysis

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



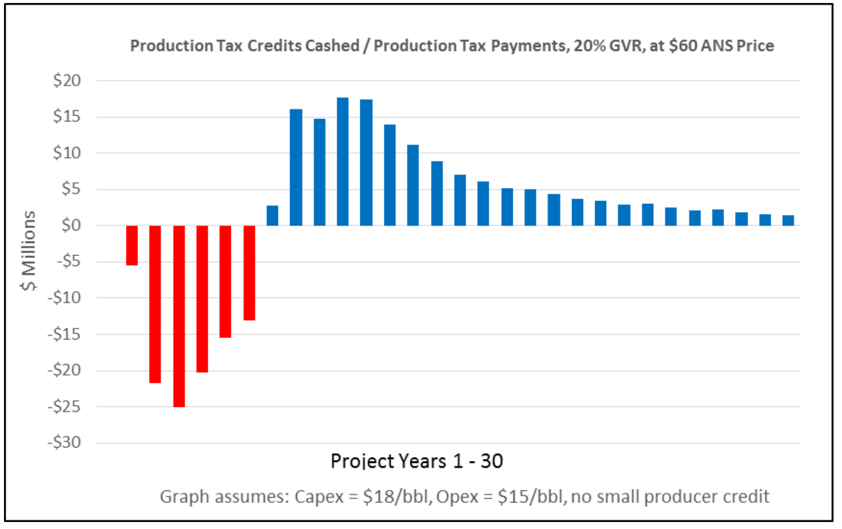


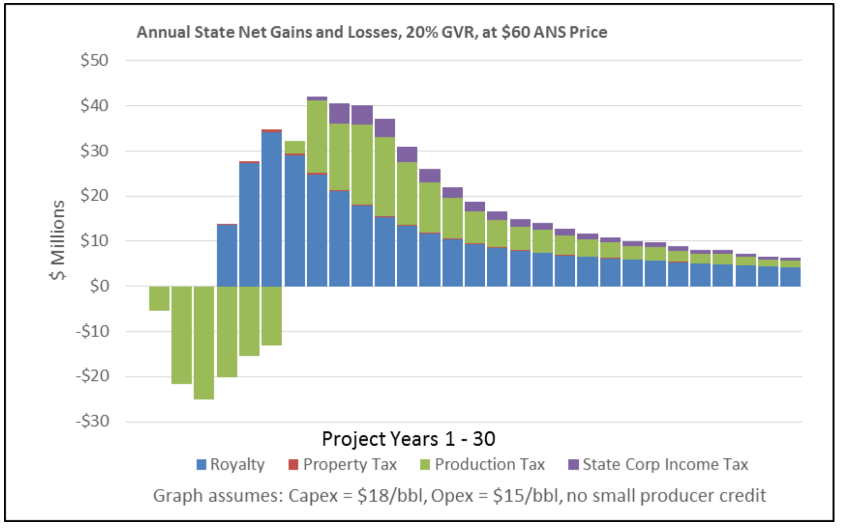


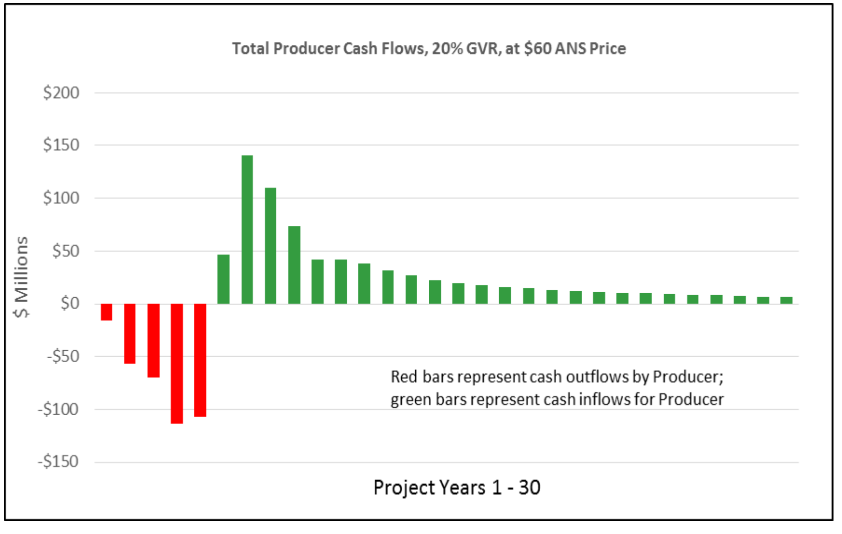
Life Cycle Totals	$Millions
Production Tax Credits Cashed	162
Production Tax Paid	183
Net Production Tax	21
Production Tax NPV 6.15%	-37
Total Annual State Losses	121
Total Annual State Gains	501
Net State Gain (Loss)	380
State NPV 6.15%	136
Total Producer Cash Out	327
Total Producer Cash In	731
Net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

Sample of Scenario Analysis

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



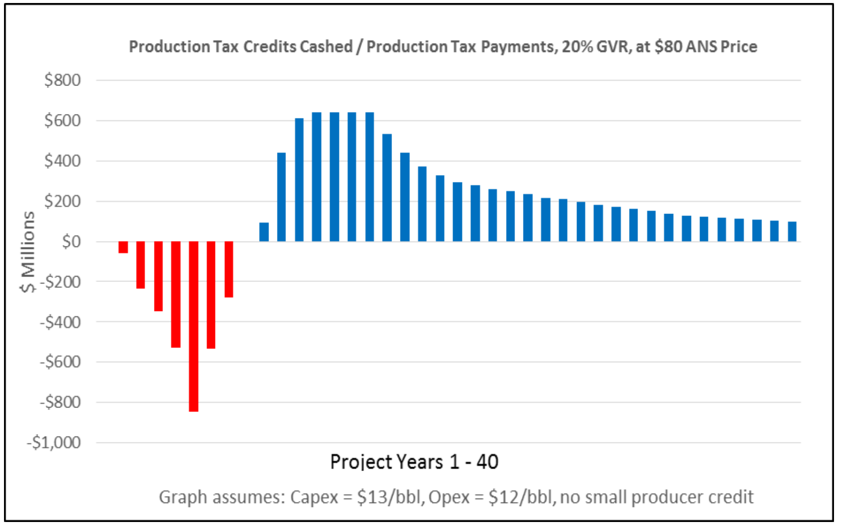


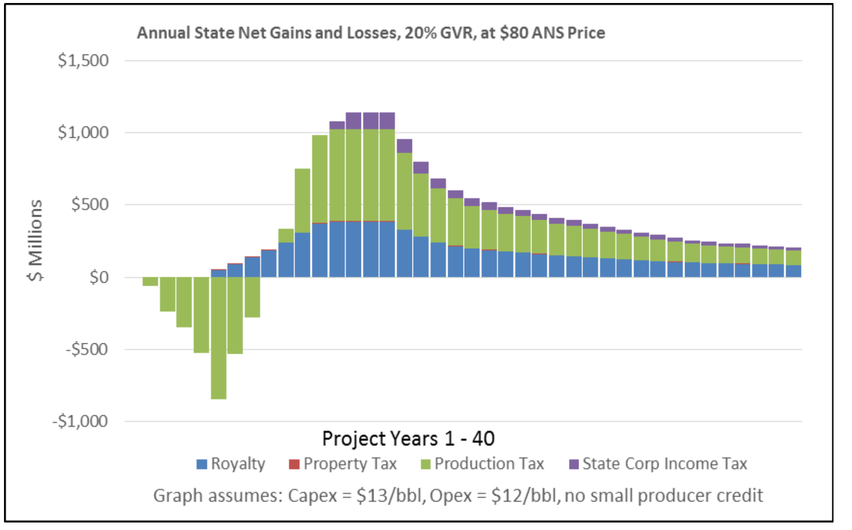


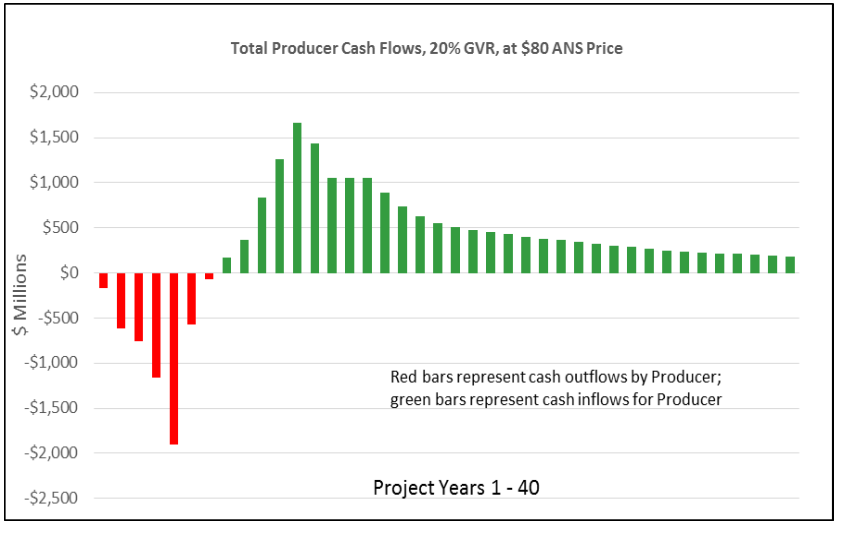
Life Cycle Totals	$Millions
Production Tax Credits Cashed	101
Production Tax Paid	155
Net Production Tax	54
Production Tax NPV 6.15%	-10
Total Annual State Losses	59
Total Annual State Gains	470
Net State Gain (Loss)	412
State NPV 6.15%	163
Total Producer Cash Out	362
Total Producer Cash In	746
Net Producer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

Sample of Scenario Analysis

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



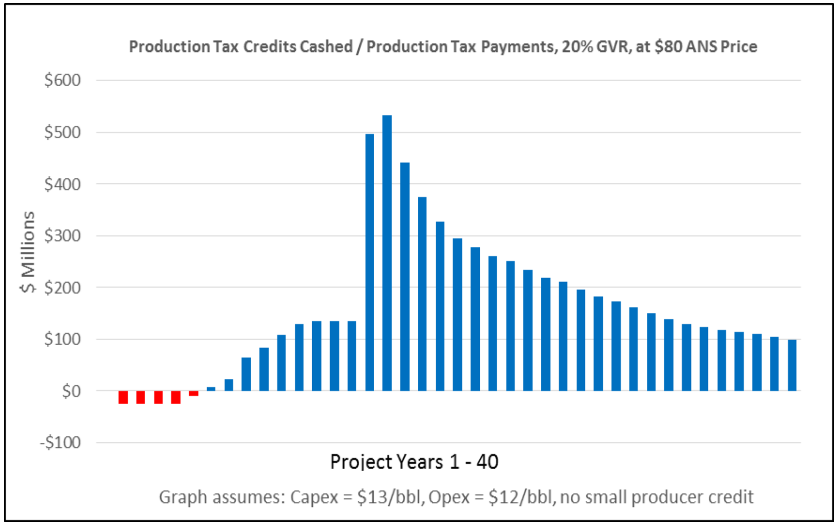


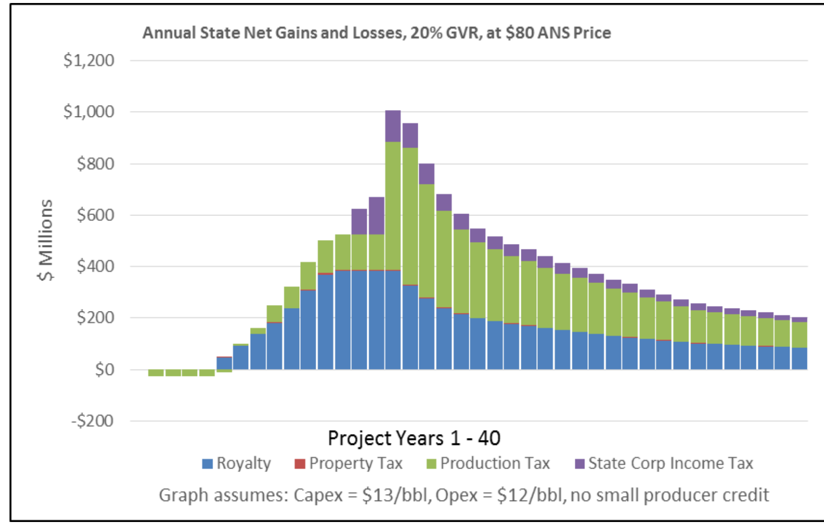


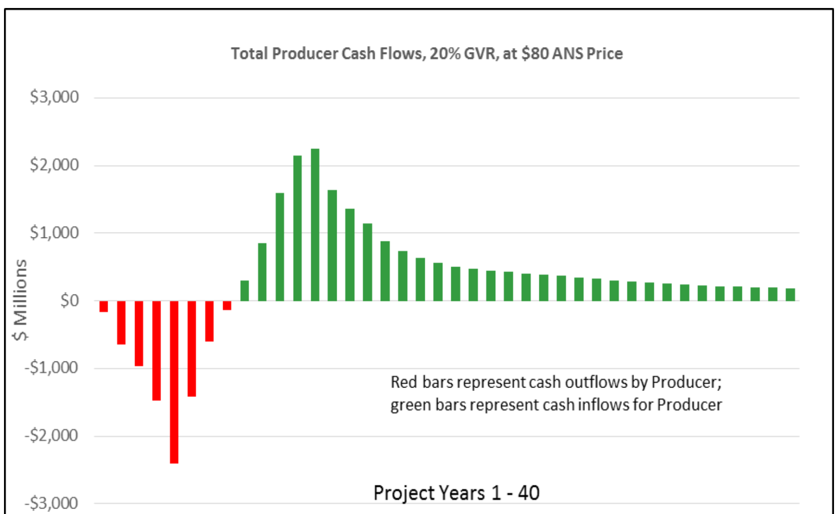
Life Cycle Totals	$Millions
Production Tax Credits Cashed	2,830
Production Tax Paid	8,923
Net Production Tax	6,093
Production Tax NPV 6.15%	869
Total Annual State Losses	2,553
Total Annual State Gains	16,623
Net State Gain (Loss)	14,069
State NPV 6.15%	3,527
Total Producer Cash Out	5,247
Total Producer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

Summary of Scenario Analysis

North Slope 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

Cook Inlet 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

Supplemental North Slope 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

Supplemental Cook Inlet and Middle Earth 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

Implementation

Transition

- Original bill was written with an effective date of 7/1/16 for nearly all changes
- CS moves most changes to 1/1/17, with the full repeal of the Well Lease Expenditure credit on 1/1/18
- The bill's original fiscal note included a fund capitalization for $926,575.0 to the .028 fund. This is the difference between what is in the operating budget and $1 billion.
- This would have covered all expected credit liability before the effective date.
- With the changes made in the CS, additional appropriation will be needed

Connection to Fiscal Plan

- HB247 was introduced as one of 10 bills that comprised the governor’s fiscal plan.
- All the bills taken together, with anticipated budget cuts, proposed a balanced budget by FY19
- The broader fiscal package, and the specific tax credit bill, are intended to add certainty to industry regarding what support the state can provide and how we’re going to continue to pay for government
- Original bill also assumed companion “AIDEA Loan” bill to help with projects that lost funding with credit changes
    - HB246 would create a new “fourth fund” at AIDEA to concentrate on oil and gas development loans, for proven reserves
    - Envisioned $200 million initial fund capitalization

Administration

- The changes anticipated in this bill still require somewhat substantial reprogramming of the Tax Revenue Management System (TRMS) and Revenue Online (ROL) which allows a taxpayer to file a return online and update the current tax return forms
- We have received a preliminary estimate from the software developer, and currently assume a one-time cost of about $1.2 million to accomplish this
- We do not anticipate any additional costs to administer the tax program
- There will also be a need for substantial amendments to existing regulations to fully implement the changes

NEW SUSTAINABLE ALASKA PLAN

Pulling Together to Build Our Future

Thank You!

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