

**SB 21**

**(FILE 3)**

<TARGET><BILL>SB 21</BILL><SUBJECT>SB 21 (FILE  
3)</SUBJECT><COMM>SRES28</COMM></TARGET>



# Progressivity

*Presentation to the  
Senate Resources Committee*

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*February 15, 2013*



# Introduction



1. Calculating the Production Tax Liability.
2. How Does the Basic Progressivity Calculation Work?
3. What are Some of the Problems with Progressivity?



# ACES Tax Liability =

[Production Tax Value \* Tax Rate] – Credits

- Production Tax Value = (Value - Costs)
  - ❑ Value = Volume of Taxable Oil & Gas Produced \* Wellhead Value
  - ❑ Costs = Operating Expenditures + Capital Expenditures
- Tax Rate = 25% + 0.4% for every \$1 per barrel that this “net income” exceeds \$30, up to \$92.50, then 0.1%
- Credits = (20% \* Capital Expenditures)<sup>(1)</sup> + (20% \* Eligible Transition Expenditures)<sup>(2)</sup> + Small Producer Credit <sup>(3)</sup>

(1) Spread over two years

(2) Limited to those credits earned while the PPT was in effect and could not be used

(3) Credit is for companies producing less than 100,000 bbls/day. Available up to \$12 million for North Slope and/or Cook Inlet Producers, and \$6 million for production outside of North Slope and Cook Inlet annually. Small producer credits cannot be redeemed for cash certificates or carried forward.



# The Progressivity Function



- Found in AS 43.55.011 (g)
- Based on the *Production Tax Value* (PTV)
- When the PTV exceeds \$30 per barrel of oil equivalent (BOE) the tax is levied at:
  - .4% per dollar until the PTV/bbl = \$92.50
  - .1% per dollar that the PTV/bbl is greater than \$92.50
  - Maximum rate of 50% (in addition to 25% base tax)
- Calculated monthly
- A single statewide calculation on all oil and gas



## Progressivity: How it is Calculated.



- Based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Production: 170,262,000
- *GVPP = Gross Value at the Point of Production.*
- *PTV = Production Tax Value.*

ANS West Coast Price:	\$109.61
Transportation Costs:	-\$8.81
<b>GVPP:</b>	<b>\$100.80</b>
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$19.61
<b>Production Tax Value (PTV):</b>	<b>\$64.87</b>
Base Tax (25%):	\$16.22



# Progressivity: How it is Calculated.



Calculating the Progressivity with a PTV/bbl = \$64.87

- $\$64.87 - \$30 = \$34.87$
- Because the PTV/bbl < \$92.50
- $\$34.87 \times .004 \approx 13.95\%$

The 13.95% progressive tax is then applied to the PTV/bbl of \$64.87 not to the \$34.87

$\$64.87 \times 13.95\% = \$9.05$  per barrel

Therefore: the \$9.05 progressive tax + \$16.22 (25%) base tax = \$25.27 production tax per barrel **before credits**.

Multiplied by the taxable production (170,262,000 bbls) = \$4,302 million



## Observations



- Progressivity increases the overall tax rate as the overall profitability (before state and federal income taxes) rises.
- Remember, progressivity is company specific and each company will have a different exposure because progressivity is sensitive to:
  - The oil price.
  - Spending.
  - Production.
- Progressivity is only one part of what makes the overall system progressive; it is not a factor at low oil prices.



# Example 1: New Capital Spending in Fiscal Year 2014



- Based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Production: 170,262,000.
- Increased capital spending by \$500 million from \$3,338.6 million to \$3,836.6 million.
- CAPEX per barrel goes from \$19.61 to \$22.55 per barrel.

ANS West Coast Price:	\$109.61
Transportation Costs:	-\$8.81
<b>GVPP:</b>	<b>\$100.80</b>
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$22.55
<b>Production Tax Value (PTV):</b>	<b>\$61.93</b>
Base Tax (25%):	\$15.48



## Example 1: New Capital Spending in Fiscal Year 2014



Calculating the Progressivity with a PTV/bbl = \$61.93

- $\$61.93 - \$30 = \$31.93$
- Because the PTV/bbl  $< \$92.50$
- $\$31.93 \times .004 \approx 12.77\%$

The 12.77% progressive tax is then applied to the PTV/bbl of \$61.93 not to the \$31.93

$\$61.93 \times 12.77\% = \$7.91$  per barrel

Therefore: the \$7.91 progressive tax + \$15.48 (25%) base tax = \$23.39 production tax per barrel **before credits**.

Multiplied by the taxable production (170,262,000) = \$3,983 million

Therefore – capital spending went up \$500 million and state revenues went down \$319 million before considering the credits.



## Observations



- Progressivity based on the net production tax incentivizes spending.
- The level of the incentive depends on the price of oil and the cost structure of the investor not the project's economics.
- The value of the deduction often exceeds the value of the tax credits.
- This benefit is only available to incumbent producers and doesn't create a level playing field with new entrants.



## Example 2: New Capital Spending in Fiscal Year 2014 with lower oil price



- Based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Production: 170,262,000.
- Oil Prices decline \$10 to \$99.61
- Increased capital spending by \$500 million from \$3,338.6 million to \$3,836.6 million
- CAPEX per barrel goes from \$19.61 to \$22.55 per barrel.

ANS West Coast Price:	\$99.61
Transportation Costs:	-\$8.81
<b>GVPP:</b>	<b>\$90.80</b>
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$22.55
<b>Production Tax Value (PTV):</b>	<b>\$51.93</b>
Base Tax (25%):	\$12.98



## Example 2: New Capital Spending in Fiscal Year 2014 with lower oil price



Calculating the Progressivity with a PTV/bbl = \$51.95

- $\$51.93 - \$30 = \$21.93$
- Because the PTV/bbl < \$92.50
- $\$21.93 \times .004 \approx 8.77\%$

$\$51.93 \times 8.77\% = \$4.56$  per barrel

Therefore: the \$4.56 progressive tax + \$12.98 (25%) base tax = \$17.54 production tax per barrel **before credits.**

Multiplied by the taxable production (170,262,000) = \$2,986 million

The same equation run **without** the additional capital spending (Capital at \$19.61 / bbl) derives \$3,265 million.

Therefore the benefit of the deduction of an additional \$500 million in capital spending at an oil price of \$109.61 was **\$319 million** but at an oil price of \$99.61 was **\$279 million.**



# Observations



- Since the value of a deduction is dependent on the price of oil it is very difficult for a company to predict the value of the deduction especially with long lead time projects.
- The reduction in taxes is temporary, since as soon as the spending is done the tax rate rises back to the higher rate.
- This effect can potentially create misalignments amongst working interest owners in the same field.
  - If one working interest owner is spending and another isn't, then the value of the incremental spending to the company that is already spending will be less than to the one that isn't.
- Greater incentive to spend at higher prices than at lower prices – the opposite of what is needed to make projects economic.



## Example 3: Cutting Costs



- Again, based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Oil Production: 170,262,000
- Reduce the capital cost per barrel by \$5.

ANS West Coast Price:	\$109.61
Transportation Costs:	-\$8.81
<b>GVPP:</b>	<b>\$100.80</b>
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$14.61
<b>Production Tax Value (PTV):</b>	<b>\$69.87</b>
Base Tax (25%):	\$17.47



## Example 3: Cutting Costs



Calculating the Progressivity with a PTV/bbl = \$69.87

- $\$69.87 - \$30 = \$39.87$
- Because the PTV/bbl  $< \$92.50$
- $\$39.87 \times .004 \approx 15.95\%$

$\$69.87 \times 15.95\% = \$11.14$  per barrel

Therefore: the \$11.14 progressive tax + \$17.47 (25%) base tax = \$28.61 production tax per barrel **before credits.**

Before the cost savings, taxes per barrel were \$25.27

Therefore a reduction in capital cost per barrel of \$5 **leads to a tax increase of \$3.34 per barrel.**

With progressivity, producer keeps \$1.66 of the \$5 in cost savings ( $\$5 - \$3.34$ ); without progressivity, producer keeps \$3.75 of the \$5 in cost savings ( $\$5 - \$1.25$ )



## Observations



- When cutting costs increases taxes it creates distortions in decision making and behavior.
- Technology that improves economic value will create the same effect as cutting costs because it increases the production tax value and therefore, the progressive tax rate.
- Similarly, things that reduce the production tax value reduce the tax rate.
- Much stronger incentive to keep costs under control without progressivity – good for both producer and state.



## Example 4: Gas sales (the decoupling dilemma)



- Based on page 108 of the 2012 Fall Revenue Sources Book.
- Taxable Production: 170,262,000.
- Plus gas sale of 1 BCF/day (60,833,333 BOE for year)
- Gas price of \$8 / mmboe and transportation of \$4.50 / mmboe
- Costs per BOE same as for oil – for illustration purposes

ANS West Coast Price:	\$93.39
Transportation Costs:	-\$13.60
<b>GVPP:</b>	<b>\$79.79</b>
Deductible Lease Expend:	
Operating:	-\$16.32
Capital:	-\$19.61
<b>Production Tax Value (PTV):</b>	<b>\$43.86</b>
Base Tax (25%):	\$10.97



# Gas sales: The Decoupling Dilemma



- The “Decoupling” problem was identified and thoroughly discussed during the 26<sup>th</sup> Alaska Legislature.
- Fundamentally, it is a problem exacerbated by the net based progressive function when a high value product (light oil) is blended with a low value product (gas).
- For the purposes of this example, we assumed 1 BCF/ day of gas sales in addition to FY 14 oil production.
- Gas price for the purpose of the example will be \$8 per mmbtu (6 mmbtu = 1 barrel of oil equivalent). With transportation costs of \$4.50 per mmbtu.
- 170,262,000 barrels of taxable oil are sold at \$109.61 per barrel.
- 60,833,333 “barrels” of gas are sold at \$48 per BOE.
- This gives us a blended price of \$93.39 per BOE and lower overall revenues.
  - GVPP / BOE falls from \$100.80 to \$79.79
    - due to both lower value and higher transport costs for gas
  - Progressive tax rate falls from 13.95% to 5.55%
  - Revenue **before credits** falls from \$4,302 billion to \$3,096 billion
- This is an illustration only to demonstrate the decoupling dilemma.



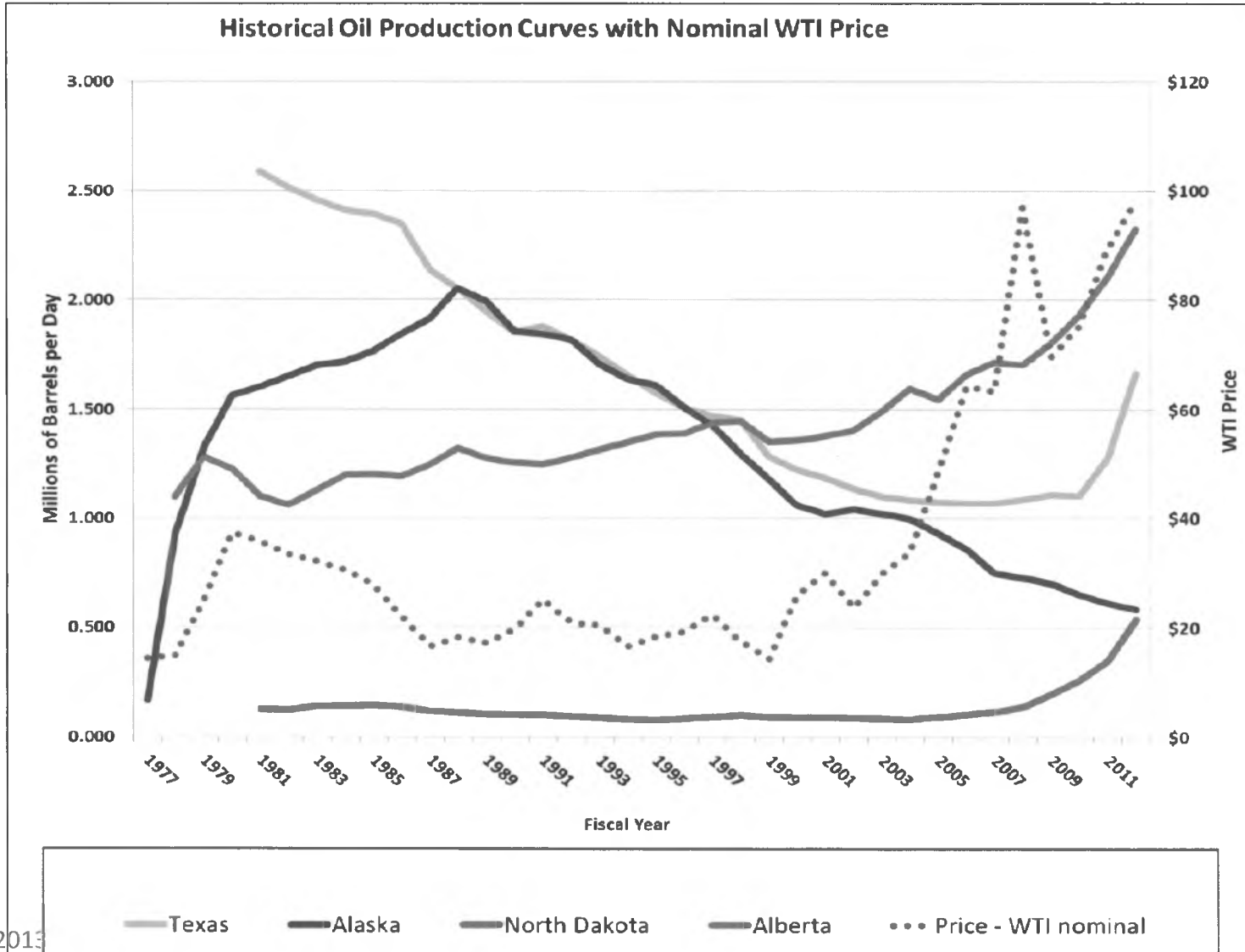
# Summary



- Progressivity is not simple:
  - It reduces the cash margin per barrel in ways that leaves Alaska uncompetitive.
  - It is highly sensitive—making it difficult to predict for the State of Alaska and taxpayers.
  - It creates misalignments between working interest owners based on individual spending programs.
  - It incentivizes spending—but not necessarily investments that lead to production.
  - It mutes the incentive to save costs or utilize technology.
  - It creates the decoupling dilemma.



# Progressivity Inhibits a North Slope decline turnaround at high prices





# Thank You

# Senate Resources Committee

Testimony re: SB 21/HB72

Feb. 18, 2013

J. Patrick Foley

Land and External Affairs Manager

Incoming President, Pioneer Natural Resources, Alaska



NYSE: PXD  
[www.pxd.com](http://www.pxd.com)

## Pioneer Natural Resources, Alaska

# Forward Looking Statements

*Except for historical information contained herein, the statements, charts and graphs in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, international operations and associated international political and economic instability, litigation, the costs and results of drilling and operations, availability of equipment, services and personnel required to complete the Company's operating activities, access to and availability of transportation, processing and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility and derivative contracts and the purchasers of Pioneer's oil, NGL and gas production, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, and acts of war or terrorism. These and other risks are described in Pioneer's 10-K and 10-Q Reports and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Pioneer undertakes no duty to publicly update these statements except as required by law.*

# Presentation Overview

- Pioneer overview
- Importance of a healthy industry
- Competition for capital
- SB 21/HB 72
- Incentives for Alaskan investments
- Closing thoughts



## Corporate overview:

- \$19 Billion enterprise value
- ~3,500 employees
- \$3 Billion capital budget
- \$2 Billion cash flow from operations
- Leading performer in peer group



## Alaska Operations Overview:

- 1<sup>st</sup> independent operator on North Slope
- 70+ full-time Alaska employees
- \$14+ million in annual wages (employees)
- 150 - 300 Alaska contract workers
- ~\$180 million 2013 capital budget
- ~ 6,000 BOPD gross production
- ~ 40% production growth anticipated for 2014

# Pioneer Alaska Profile: Oooguruk

## Exploration:

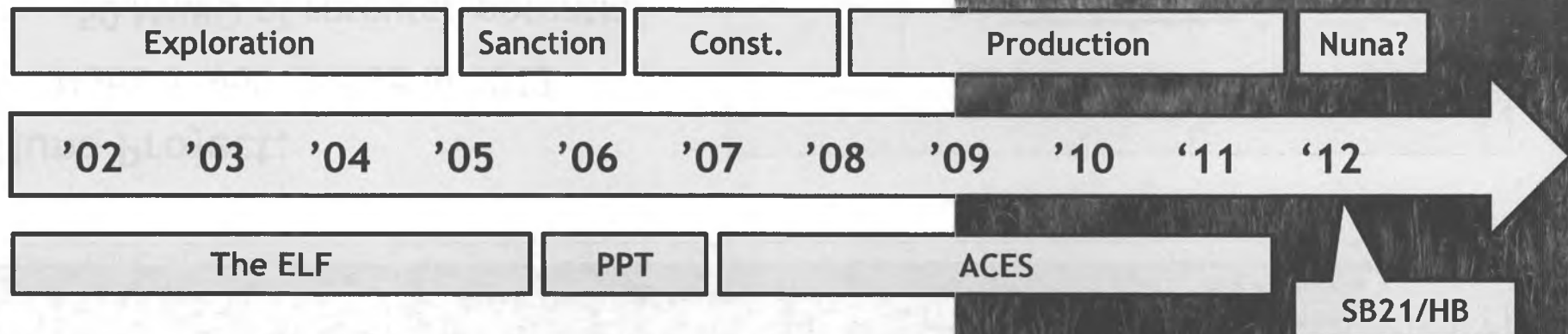
- 11 exploration wells '02 -'05
- 1 commercial project

## Oooguruk Quick Facts:

- 70% Pioneer (operator) : 30% Eni
- ~\$1 billion capital invested
- 12+ million barrels produced
- ~\$270 million in credits received  
(~7 % of total credits issued by the state)



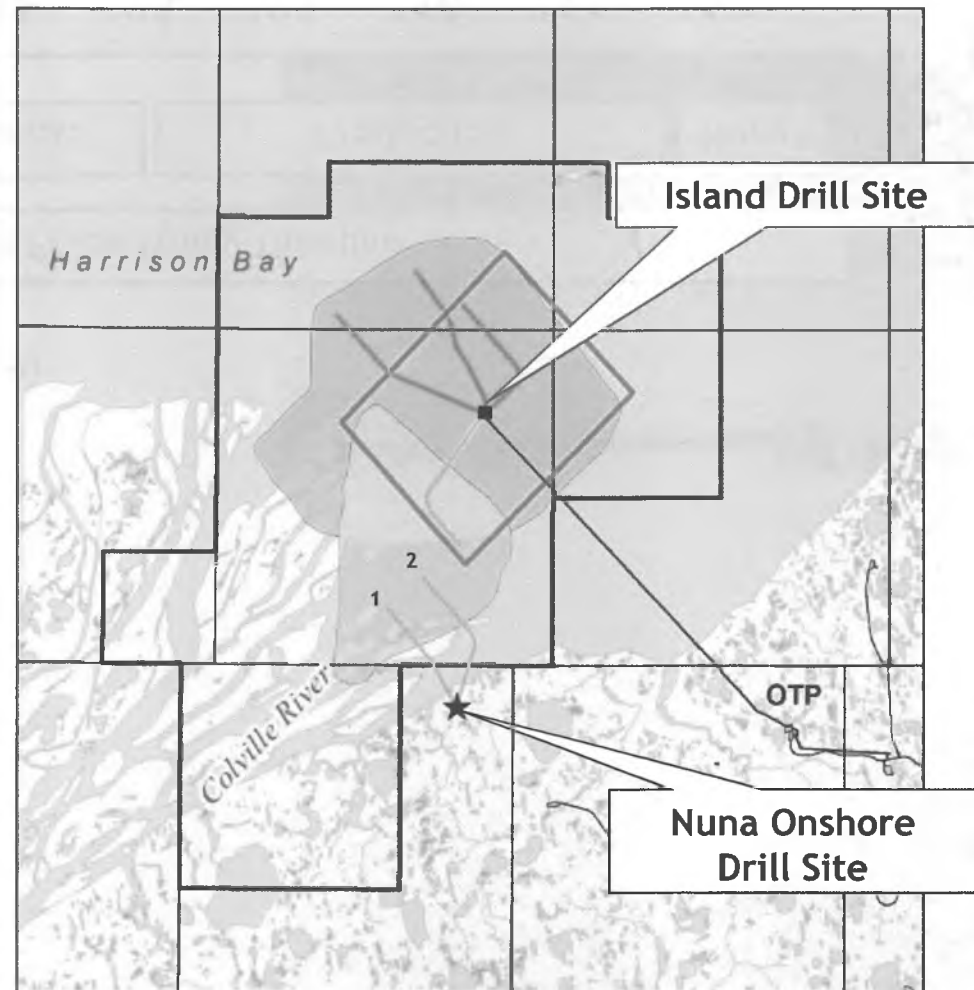
## Oooguruk Project and Fiscal Policy Timeline



# What's Next?

## Nuna Project:

- Nuna-1 well drilled in 2012
- ~50 MMBO of resource potential
- Nuna-2 drilling underway
- Phase I development overview
  - Q3 2013 sanction decision
  - ~\$1 Billion capital required
  - 2015 first oil
  - 14 MBOPD peak production
  - Jobs and economic impact
- Potential for 2<sup>nd</sup> drill site
- **Must compete for limited capital against low-risk, fast-cycle projects in Lower 48**



## Alaska Relative to Lower 48 Resource Plays:

### Resource

	Alaska	Lower 48
<b>Resource Report Card</b>		
Resource Potential	✓	✓
Resource Competition	✓	
Geologic Risk		✓
Oil Bias	✓	✓
Regulatory Process Ease		✓
Land Acquisition	✓	✓

### Profitability

	Alaska	Lower 48
<b>Profitability Report Card</b>		
Cycle Times / Payback		✓
Execution Risk		✓
Operational Flexibility		✓
Operating Margins		✓

# Pioneer Competitive Resource Opportunities

## WOLFCAMP / SPRABERRY

\$1,650 MM Drilling Program  
627 MMBOE Proven

### Vertical Program

20 Wells ('13)

+1.5 BBOE Net Potential

### Wolfcamp / Spraberry

30-40 Wells ('13)

+3.0 BBOE Net Potential

### Wolfcamp Joint Interest Area

#### Drilling Program(2)

120 wells ('14)

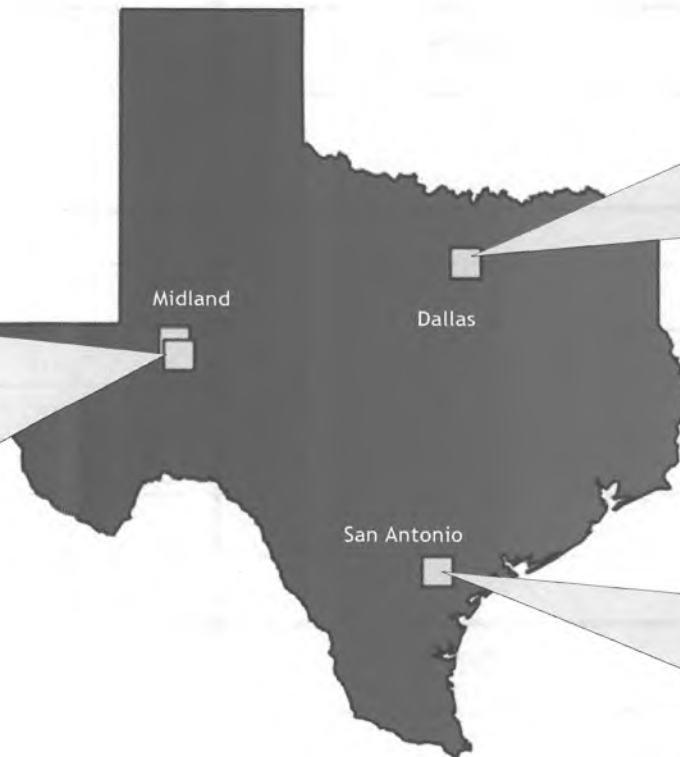
+1.6B BBOE Net Potential

### 2013 Production (Growth):

75-80 MBOEPD (+14 - 21%)

> 40 rigs running

> 2000 drilling locations



## Barnett Shale Combo

\$185 MM Drilling Program

33 MMBOE Proved

+300 MMBOE Net Potential

### 2013 Production (Growth):

9-12 MBOEPD (+22 - 41%)

## Eagle Ford Shale

\$575 MM Drilling Program

116 MMBOE Proved

86 Wells ('13)

+340 MMBOE Net Potential

### 2013 Production (Growth):

38-42 MBOEPD (+36% - 50%)

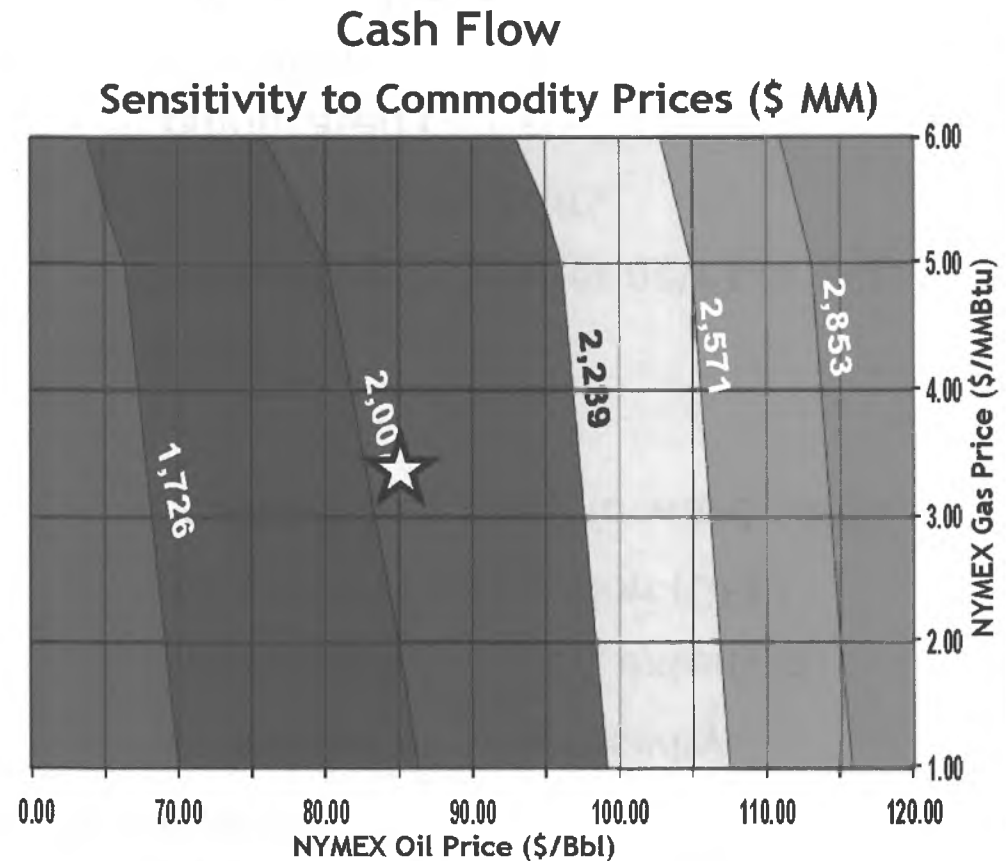
# 2013E Capital Spending and Cash Flow<sup>1</sup>

## Capital Program of \$3.0 B includes:

- Drilling capital: 2.75 B total
  - \$190 MM Alaska  
(7% of pioneer drilling capital)

## Capital program funded from:

- \$2.0 B operating cash flow
- \$0.6 B joint interest cash flow (2)
- \$0.4 B capital markets



★ 2013 capital program based on  
\$85/Bbl oil and \$3.25/MMBtu gas

1) Capital spending excludes acquisitions, asset retirement obligations, capitalized interest and G&G G&A  
 2) Pioneer incurs 100% of capital costs from January 1<sup>st</sup> through estimated closing date of June 1<sup>st</sup>; Pioneer will be reimbursed by Sinochem for 40% of this amount as an adjustment at closing (not credited to cost incurred); Sinochem pays 40% of capital costs and carries Pioneer for 75% of Pioneer's 60% of capital costs post closing

## Governor's Guiding Principles

- Tax policy must be **fair** to Alaskans
- Any changes to oil taxes should, when taken together, be geared to foster **new production**
- Changes should result in a more **simple** tax system and restore **balance** to our fiscal system
- Tax policy must make Alaska **competitive** for the long-term

## ■ **Positives:**

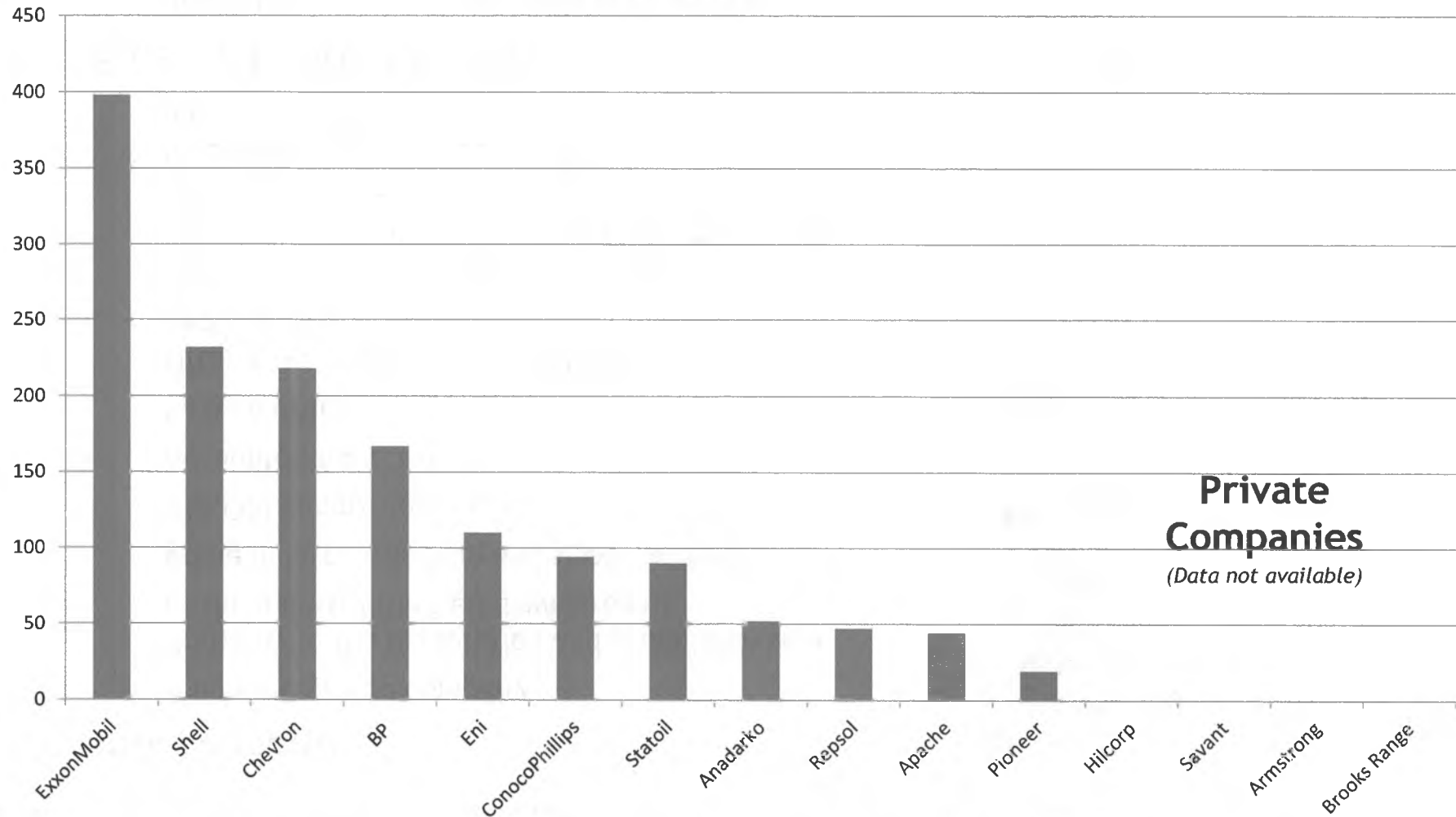
- Elimination of progressivity
- Small producer credit extension
- Gross revenue exclusion (GRE)
- Escalating loss carry forward credit

## ■ **Negatives:**

- Disadvantages smaller new projects
- Loss of capital credits
- Complicated carried-forward loss calculation
- No GRE for legacy fields
- Advantage to legacy producers may motivate consolidation of assets

# Relative Rankings

### Enterprise Value (Bn\$)



**Private  
Companies**

*(Data not available)*

## ■ Independents <sup>1</sup>

- A non-integrated company
- Primarily in the exploration and production side of the industry (limited downstream)
- Come in large, medium and small varieties
- ~18,000 companies in U.S.
- Accounted for 2.1 million U.S. jobs in 2010
- First to drill in the offshore
- Often first to adopt and develop new technologies
- Independents account for 65% of total natural gas production and 45% of total oil production in the United States
- Independents drill close to 94% of America's oil and natural gas wells

## ■ Financial Market Drivers

- Independents are rewarded for **production growth and debt management**

<sup>1</sup> Source: The Economic Contribution of the Onshore Independent Oil and Natural Gas Producers to the US Economy, IHS Global insight(USA), Inc, April 2011

**“While their [smaller Independents] production may not seem significant, their economic impact is. Some companies would have had to move their work to North Dakota if it wasn't for them.”**

-Doug Smith, president, Little Red Services,  
Testimony before TAPS Throughput  
Committee Jan 13, 2013

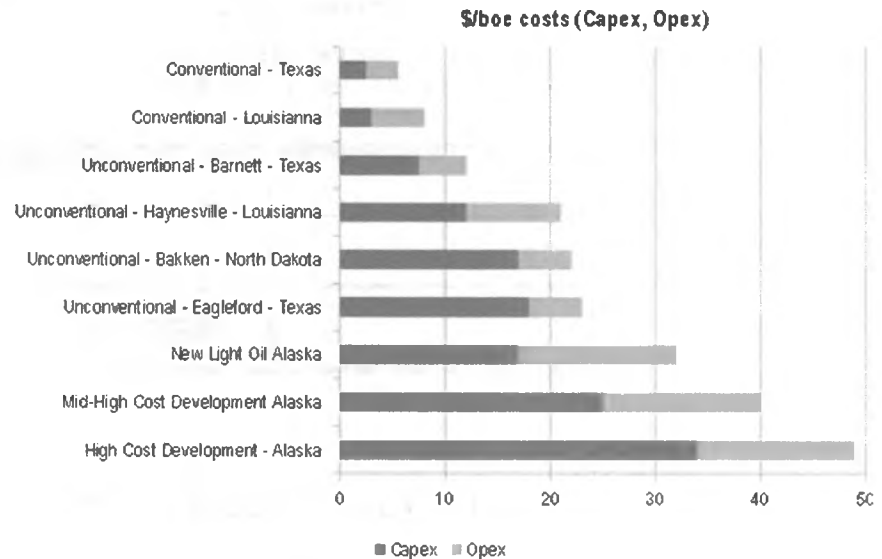
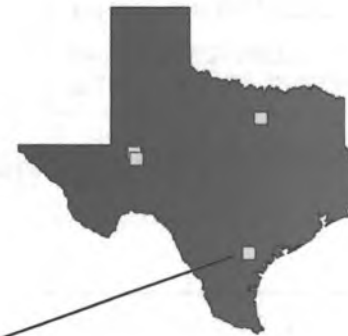
**“Independents compete on growth”**

-Tony Reinsch, PFC Energy  
TAPS Throughput Decline Committee  
1/31/13

# Eagle Ford Operators and Companies

**PIONEER**  
NATURAL RESOURCES

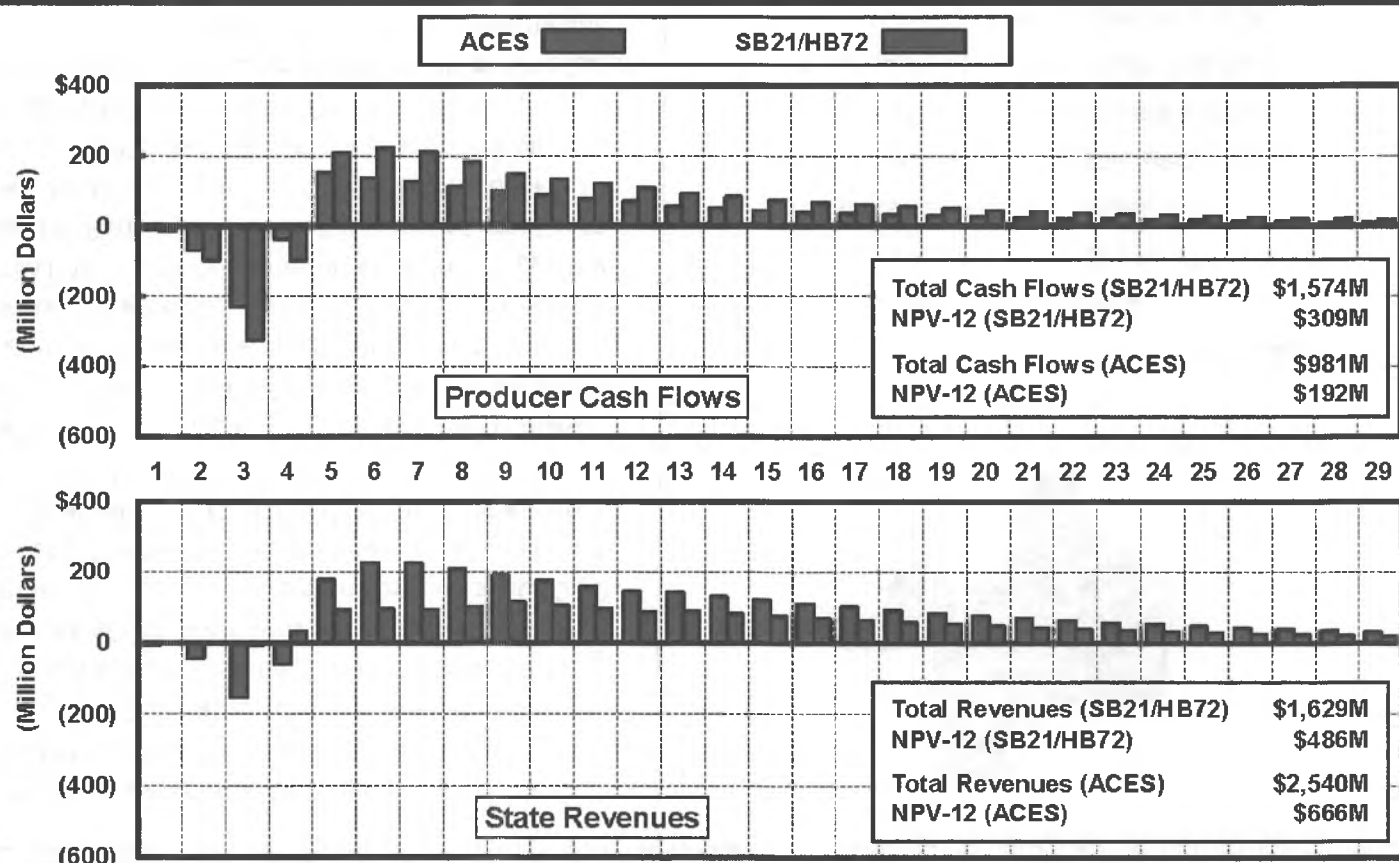
■ Abraxas Petroleum ■ Alta Mesa Holdings ■ Anadarko ■ Apache Corp. ■ Aruba Petroleum ■ Aurora resources ■ Austin Exploration (Aus-Tex Expl.) ■ BHP Billiton ■ BP ■ Cabot Oil & Gas ■ Carrizo Oil & Gas ■ Chaparral Energy ■ Chesapeake Energy ■ Cinco Resources ■ Clayton Williams Energy ■ Comstock Resources ■ ConocoPhillips – (Burlington Resources) ■ CNOOC (China National Offshore Oil Corporation) ■ Crimson Exploration ■ Devon Energy ■ Eagle Ford Oil & Gas Corp. ■ El Paso ■ Enduring Resources ■ Enerjex Resources ■ EOG Resources ■ Escondido Resources ■ Espada Operating ■ Exxon-XTO ■ Forest Oil ■ GAIL (Gas Authority of India Limited) ■ GeoResources Inc. ■ Goodrich Petroleum ■ Global Petroleum ■ Hess Corporation ■ Hilcorp Resources ■ Hunt Oil ■ Jadela Oil ■ Japan Petroleum Exploration ■ KNOC (Korea National Oil Corporation) ■ Laredo Energy ■ Lewis Energy Group (BP Partner) ■ Lonestar Resources ■ Lucas Energy ■ Magnum Hunter Resources ■ Marathon Oil ■ Marubeni Corporation (Hunt Oil Partner) ■ Matador Resources ■ Mitsui ■ Murphy Oil ■ Newfield Exploration ■ NFR Energy ■ Penn Virginia Corp ■ Peregrine Petroleum ■ PetroHawk ■ PetroQuest ■ Pioneer Natural Resources ■ Plains Exploration & Production ■ Redemption Oil & Gas ■ Reliance Industries ■ Riley Exploration ■ Rock Oil Company ■ Rosetta Resources ■ San Isidro Development (Acquired by Chesapeake) ■ Sanchez Energy ■ Sandstone Energy, LLC ■ Saxon Oil Company ■ Shell ■ SM Energy (St. Mary Land & Exploration) ■ Statoil ■ Strand Energy ■ Strike Energy ■ Swift Energy ■ Talisman Energy ■ Texon Petroleum ■ Tidal Petroleum ■ TXCO Resources (Now, Newfield & Anadarko) ■ Unit Corporation ■ U.S. Energy Corp. ■ Weber Energy ■ WEJCO E&P ■ ZaZa Energy



Source: Alaska Discussion Slides, PFC Energy 2012, February 11, 2013

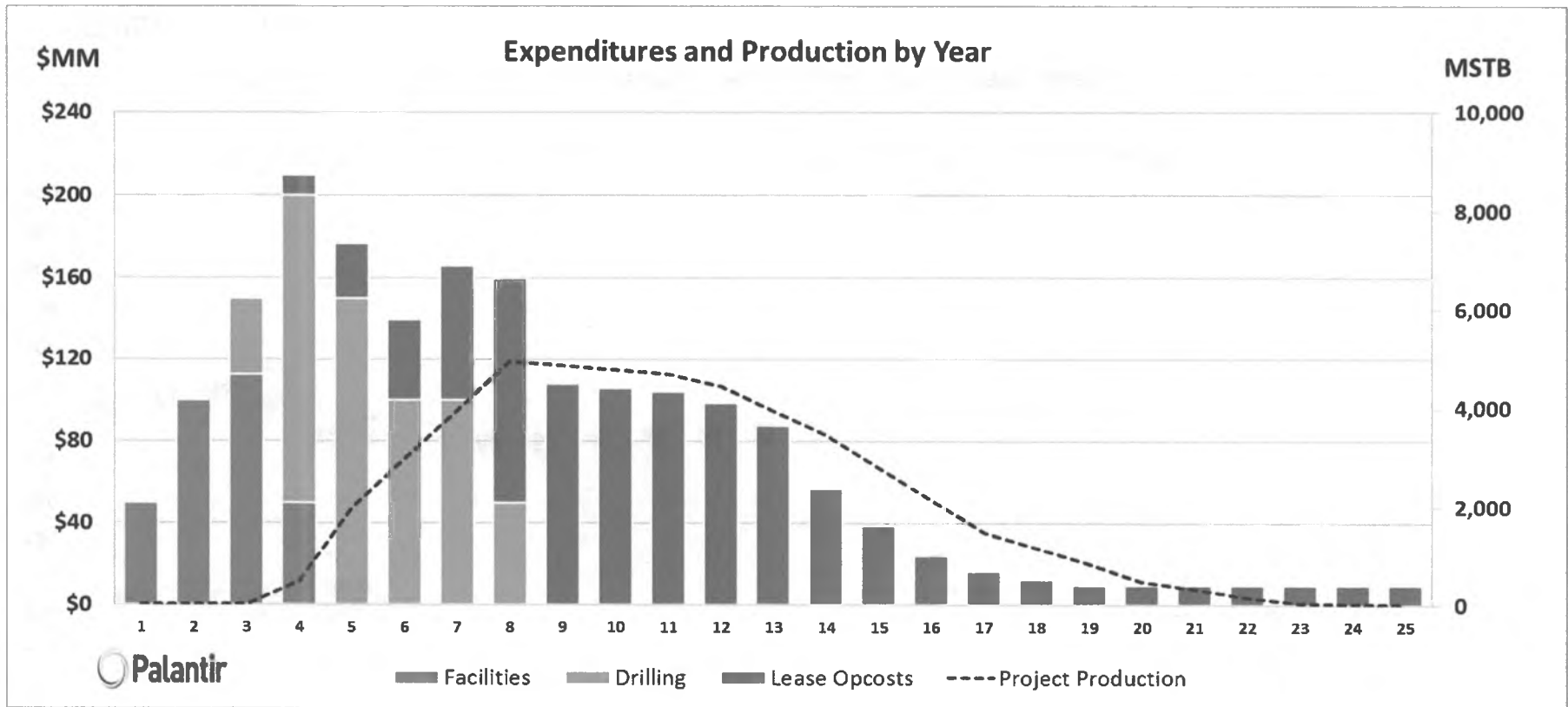
# SB21/HB72: Econ One Initial Project Evaluation

Annual State Revenues and Producer Cash Flows at \$100 West Coast ANS  
Light Conventional Oil Alaska Development  
New Participant in Alaska



+\$115MM

# Typical New Project Spend Profile



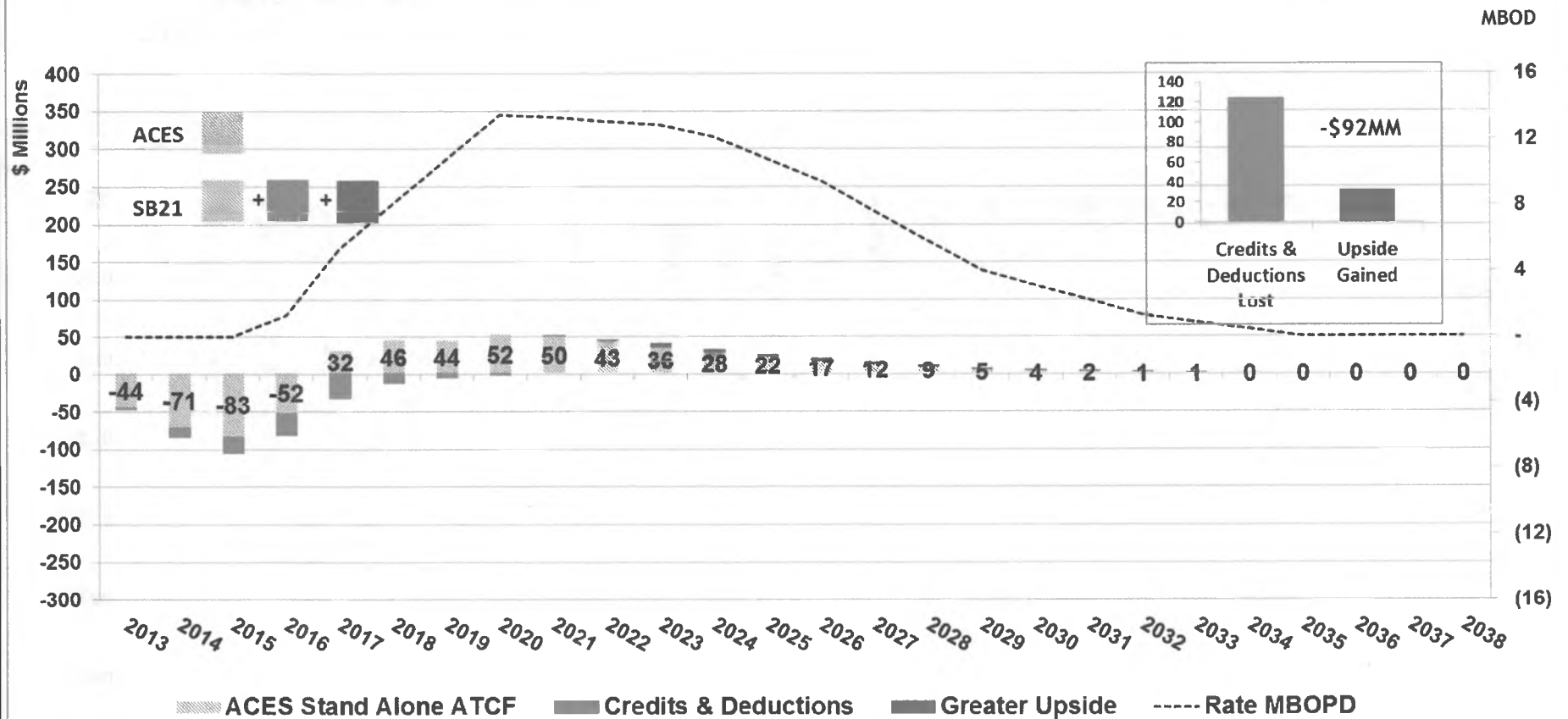
## Typical Project (after discovery):

- 1st year: front end engineering work
- 2nd year: 100% of capital spent on facilities
- 3rd year: 75% capital is for facility work
- Drilling begins late in 3<sup>rd</sup> year, no production until 4th year
- 4th year: production begins
- Peak production rate occurs during 5<sup>th</sup> year after start of production

# New Entrant - Stand Alone Project

## DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

Under SB21 a standalone producer has to source more upfront capital in exchange for greater upside later



### Field assumptions:

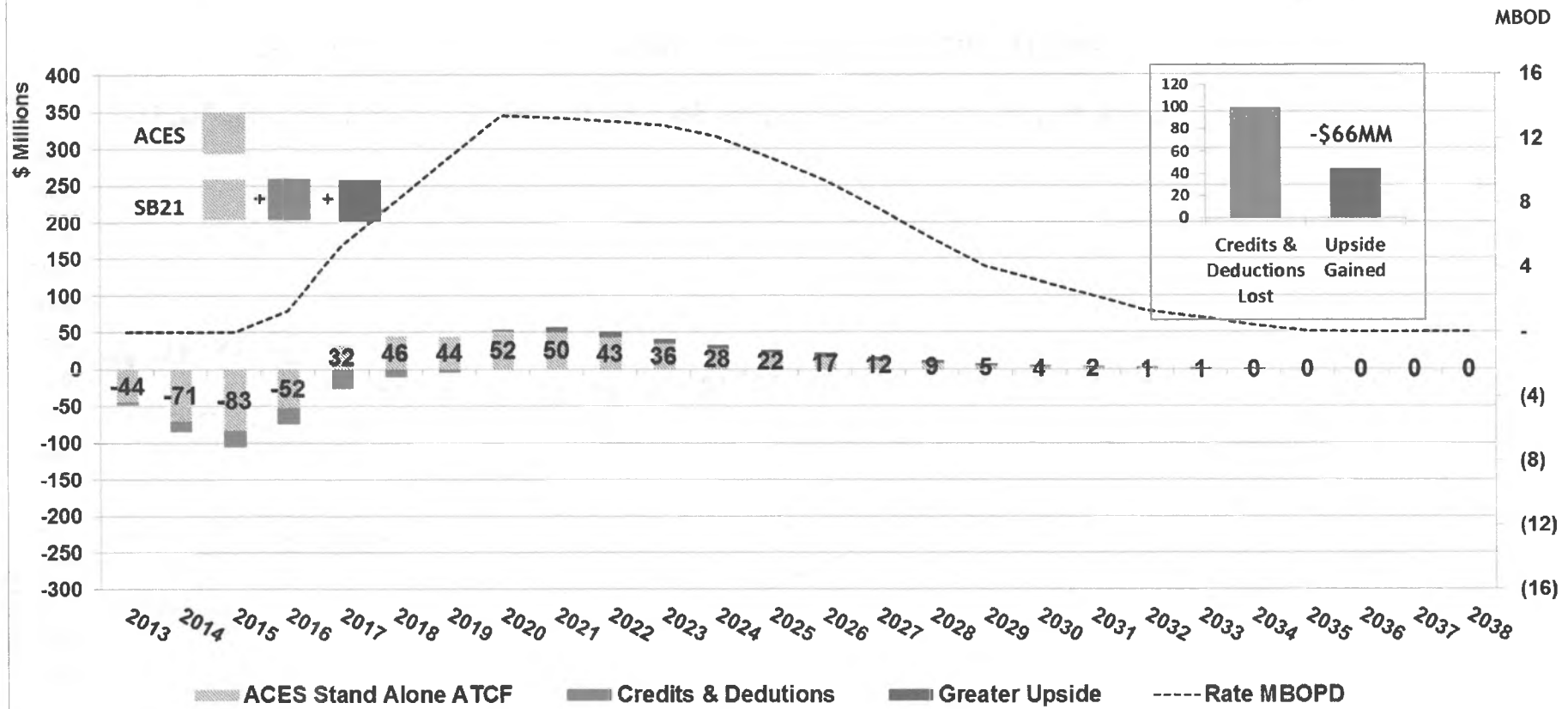
- 50 MMBO field
- \$1 billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast
- NPV-12
- Gross revenue exclusion
- Small producer credit

# Current Small Producer



## DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

Under SB21 a midsize producer has to source more upfront capital in exchange for greater upside later



### Field assumptions:

- 50 MMBO field
- \$1 billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast
- NPV-12
- Gross revenue exclusion
- Small producer credit

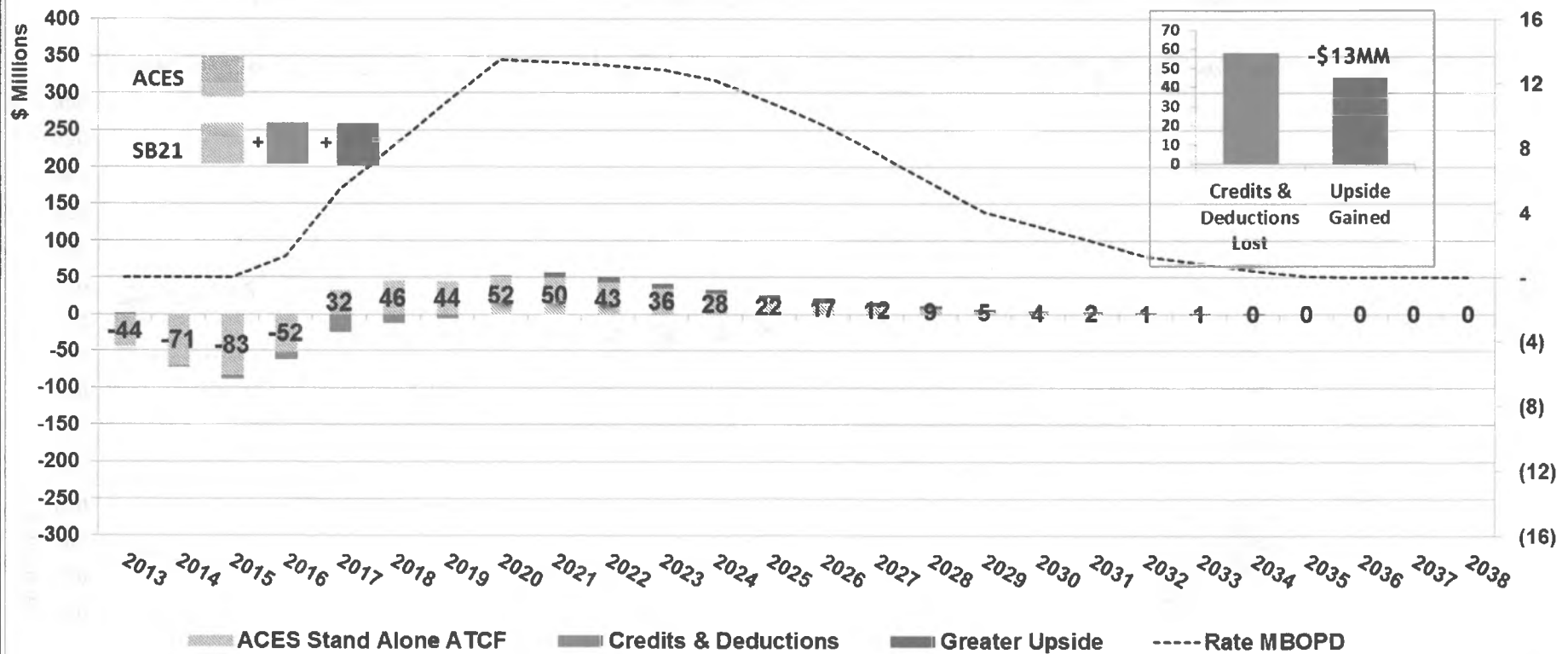
# Current Large Producer with GRE



## DISCOUNTED AFTER TAX CASH FLOW (\$100/bbl ANS)

Under SB21 a large producer with gross value exemption

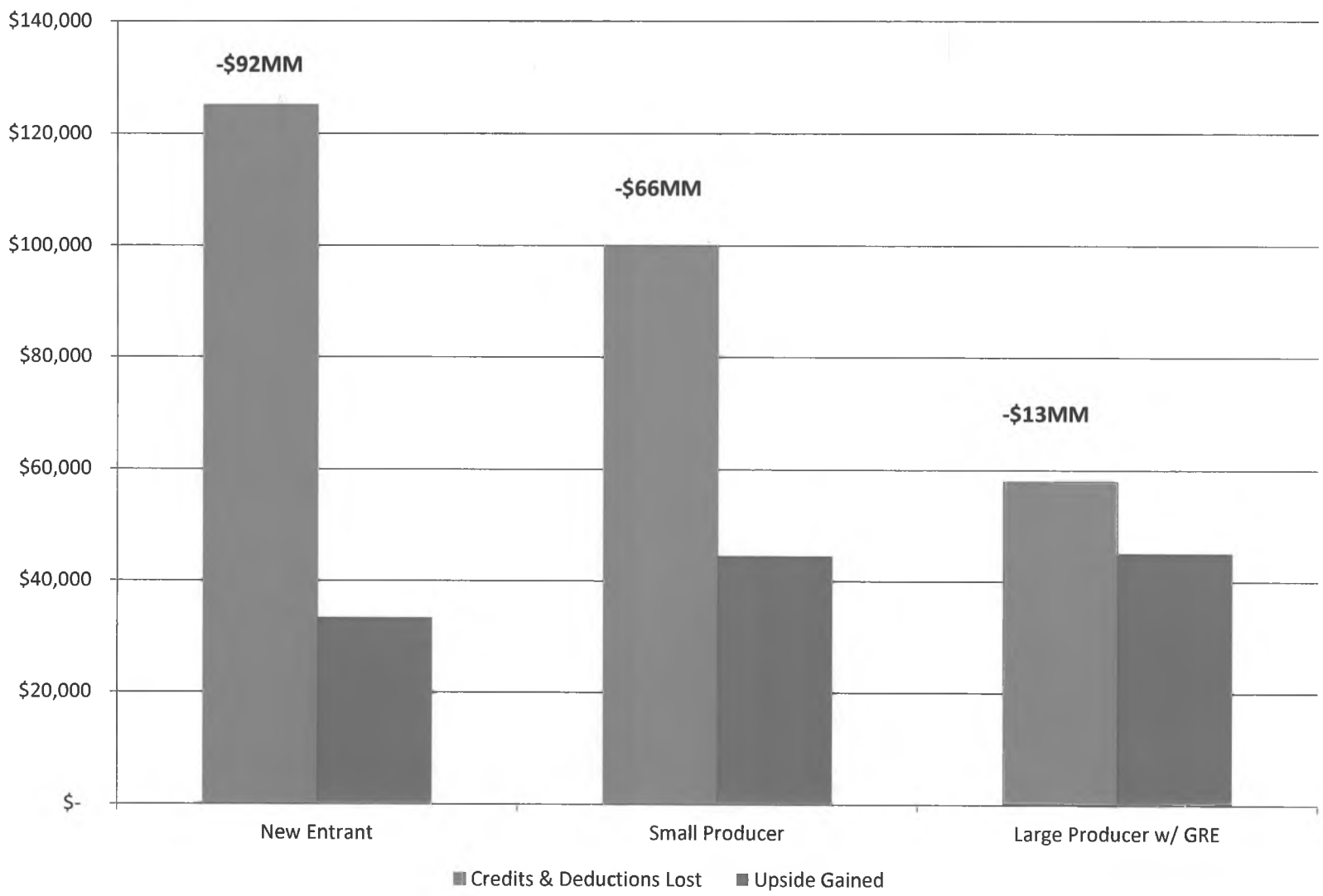
has to source more upfront capital in exchange for greater upside later



### Field assumptions:

- 50 MMBO field
- \$1 billion Capex
- \$10-\$20/bbl variable Opex
- \$100 ANS West Coast
- NPV-12
- Gross revenue exclusion
- Small producer credit

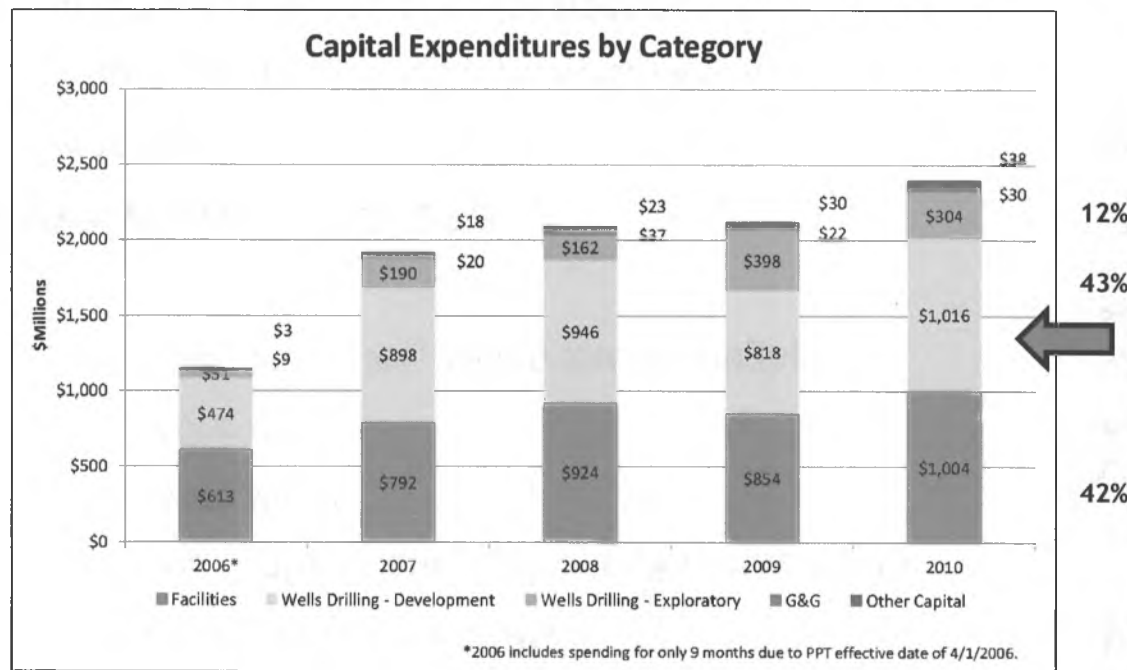
# New Field: ACES vs. SB21/HB 72 Summary



# Industry Spending on North Slope



## Historical CAPEX by Category (CY)



### Alaska Department of Revenue: 5 year look back

- Goal: to answer capital expenditure questions relating to credits
- Oil industry capital expenditures by category
- Categorized capital expenditure data represents 90% of costs related to credit applications

Source: Dept. of Revenue presentation to the Senate Resources Committee, Feb. 13, 2012

## ■ Benefits to State

- Credits encourage activity
  - Jobs, direct and indirect (9X multiplier)
  - More wells
  - More oil
  - More royalties, taxes and throughput

## ■ Benefits to Developer

- Reduces investor risk
- Improves small project economics
- Improves financial performance
  - Doesn't increase debt
- Builds healthy industry
- Strengthens competitiveness

## Purpose of Tax Credit Provisions:

*“The fiscal impact of the tax credits was an investment incentive that state must offer to secure a ‘long-term stream of oil.’”*

- Senate Finance Committee 5/13/2003

Source: DOR Presentation to Senate Resources Committee 2/13/2012

# SB 21 Closing Thoughts:

## ▪ Pros

- Eliminates progressivity
  - Shares upside potential
  - Improves competitiveness
- GRE reduces tax for new oil
- Extends small producer credit

## ▪ Cons

- Elimination of credits increases investor risk
  - Requires more upfront capital
- Does not simplify tax calculations
  - Complex carried-forward loss calculations
- Does not strongly motivate additional investment
- Does not create balance/equities among investors

## ▪ SB 21 / HB 72 Suggestions

- Targeted incentives for well related costs
- Targeted incentives for new facilities (time limited)
- Redeemable / transferable credits for new projects
- Expand use of the gross revenue exclusion (legacy fields)
- Simplify carry-forward loss calculation





**AOGA**

**OIL & GAS:  
FUELING  
ALASKA'S  
ECONOMY**

# Senate Resources Committee – SB 21

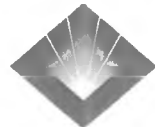
February 18, 2013  
Kara Moriarty, Executive Director

# AOGA Member Companies

**PIONEER**  
NATURAL RESOURCES ALASKA



Hilcorp Alaska, LLC



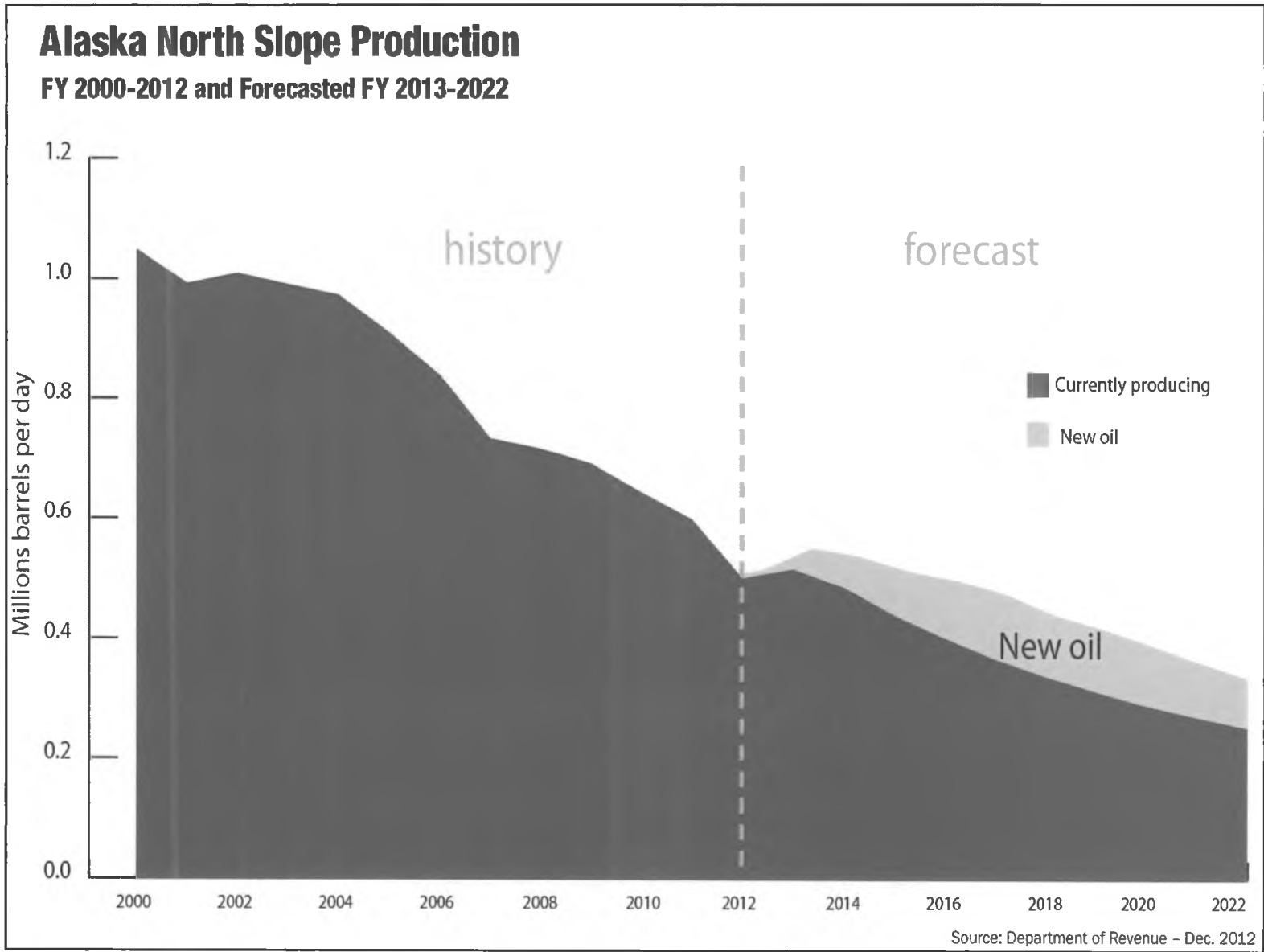
TESORO



petroleum



**AOGA** | Work Together. WIN Together.



## Governor Lays out Principles for Oil Tax Reform

*Anchorage Daily News*, Jan. 6, 2013:

Reform must:

- Be fair to Alaskans
- Encourage new oil production
- Be simple and restore balance
- Be durable and long-term in nature

## Governor Lays out Principles for Oil Tax Reform

*Anchorage Daily News*, Jan. 6, 2013:

Reform must:

- Be fair to Alaskans
- Encourage new oil production
- Be simple and restore balance
- Be durable and long-term in nature
- *AOGA Recommendation: Avoid changes that artificially create “winners & losers”*

## ***SB 21 Component: Progressivity***

- *AOGA supports the elimination of progressivity*
  - 1) Progressivity attacks and destroys one of the few strategic advantages that Alaska has, which lies in its economic remoteness.
  - 2) Progressivity bring extraordinary complexity to the tax.

## ***SB 21 Component: Tax Credits***

*There is no tax credit liability for the State until the investor invests here*

- 1) *AOGA does not support repeal of Qualified Capital Expenditure Credits (QCE)*
  - a) Elimination of QCE would undo significant part of competitive environment
  - b) Repeal likely creates “winners & losers”

## ***SB 21 Component: Tax Credits***

### ***2) AOGA supports extension of Small-producer tax credit***

- Attracts new players to Alaska
- From testimony...has made a material difference for some companies

### ***3) AOGA Recommendation: Extend exploration credits as well***

- Support for the same reason as small-producer credit
- Exploration credits bring about exploration in a timely fashion

## ***SB 21 Component: Tax Credits***

*4) AOGA opposes the current proposal to bar almost completely the transferability of “Loss Carry Forward” credit*

- 10 year shelf life is unrealistically short
- *AOGA Recommendation:*  
*Increase the shelf life to 15 years*

## ***SB 21 Component: Gross Revenue Exclusion (GRE)***

*AOGA supports concept, but concerned it will not apply to majority of current production*

- Misses 80-90 percent of potential production
- Fields likely to lose out from GRE: Prudhoe Bay, Kuparuk, Lisburne, Milne Point, Endicott, Niakuk, Point McIntyre, Alpine, PBU Satellite fields (Aurora, Borealis, Midnight Sun, North Prudhoe Bay, Orion, and Polaris) and Kuparuk satellites (Meltwater, NEWS, Tabasco, Tarn and West Sak)

*AOGA Recommendation:*

*More needs to be done for these fields*



## Estimated Undiscovered Conventional Oil Resources on Alaska North Slope

	Technically Recoverable Resources			Economically Recoverable @ \$90/bbl	Expected Typical Field Size
	P95	Mean	P5		
	(Million Barrels)				
	(1)	(2)	(3)	(4)	(5)
Central North Slope	2,800	3,400	3,900	3,000	32 - 64
Beaufort Sea	400	8,200	23,200	5,800	-
Chukchi Sea	2,300	15,400	40,100	9,900	-
NPRA	400	900	1,700	500	32 - 64
<u>ANWR</u>	<u>5,900</u>	<u>10,400</u>	<u>15,200</u>	<u>9,900</u>	<u>64 - 128</u>
<b><u>Total</u></b>		<b><u>38,300</u></b>		<b><u>29,100</u></b>	

Source:  
 USGS Reports 2011-1103 and 2009-1112;  
 BOEM, Assessment of undiscovered technically recoverable oil and gas resources of the nation's outer continental shelf.

Econ One Research

6

## Components Not Addressed in SB 21

### 1) Minimum Tax

- AOGA Recommendation: Minimum Tax should be repealed.

### 2) Statute of Limitations & Statutory Interest

**At 3 years: \$0.38**

$$\begin{aligned} & \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 3 \text{ years})} - 1] \\ & = \$1.00 \times [1.38478 - 1] = \$0.38. \end{aligned}$$

**At 6 years: \$0.92**

$$\begin{aligned} & \$1.00 \times [(1 + 0.11/4)^{(4 \text{ compoundings per year times } 6 \text{ years})} - 1] \\ & = \$1.00 \times [1.91763 - 1] = \$0.92. \end{aligned}$$

## ***Components Not Addressed in SB 21***

### ***2) Statute of Limitations & Statutory Interest***

- It is the combination of a 6-year statute of limitation plus the minimum 11% interest rate that is harmful.

- 6-year statute of limitations also creates uncertainty and complicated audit assessments due to inconsistent terms in regulation and inability to predict DOR's calculations

- *AOGA Recommendation: Either shorten the period for DOR determinations from 6 years back to 3 years, or eliminate the 11% minimum interest rate, or both*

## ***Components Not Addressed in SB 21***

### ***3) Joint-interest Billings:***

- Instead of one audit of the expenses by a joint venture (found in a joint-interest billing) for any given period, DOR audits each participant separately for its respective share of the same pool of expenses

- *AOGA Recommendation: Restore language specifically authorizing DOR to rely on joint-interest billings if it chooses to do so.*

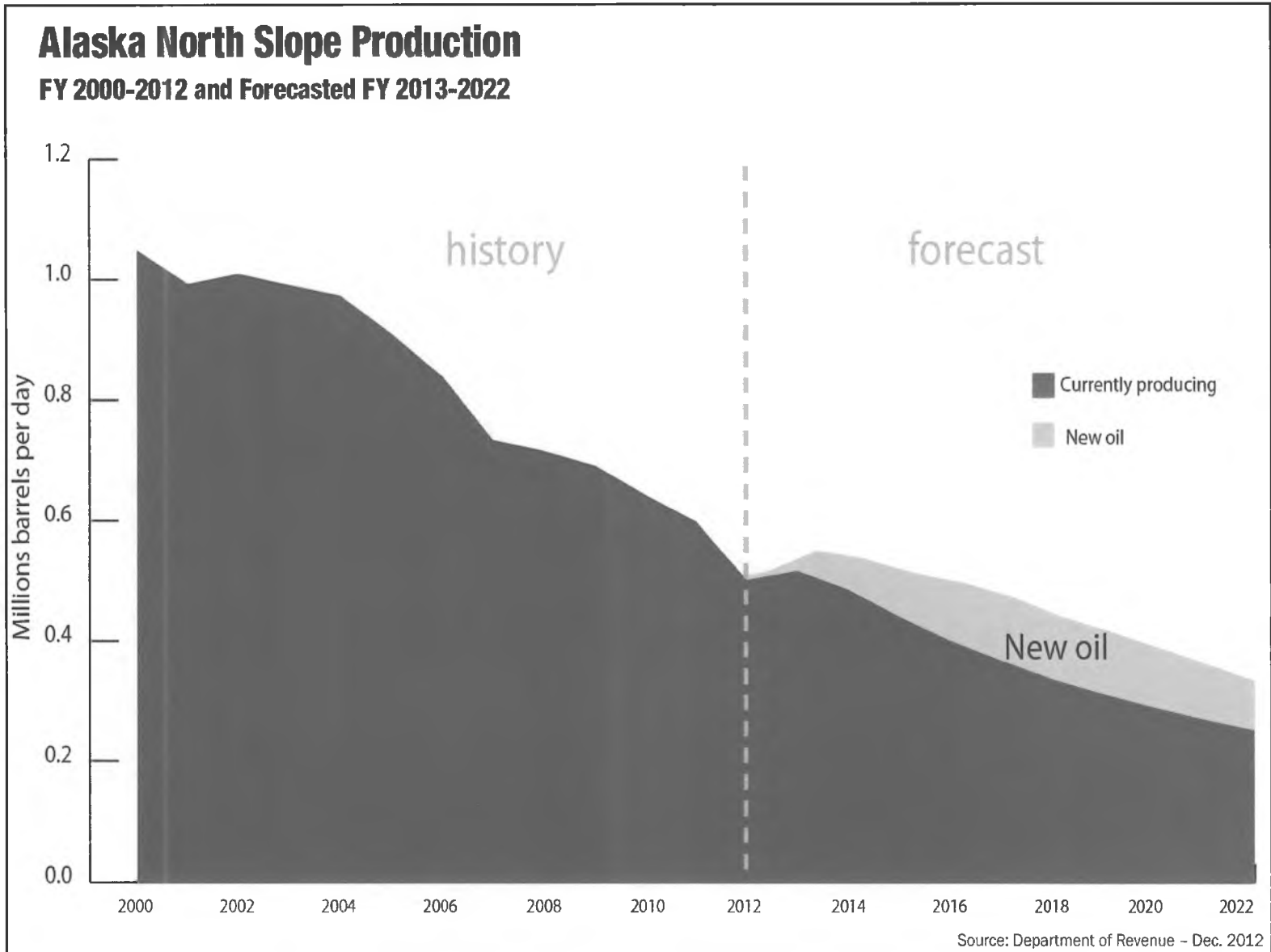
## ***AOGA Supports Components of SB 21***

### **Cornerstone for significant and crucial tax reform**

- Support the elimination of progressivity
- Support the concept of gross revenue exclusions
- Support the extension of the small producer tax credit

## ***AOGA Concerns with SB 21***

- Serious concerns with how the bill addresses tax credits (QCE elimination, no extension of exploration credit, and changing the loss carry forward credit)
- Gross Revenue Exclusions should be expanded to fit the majority of projects in legacy fields
- Identified other ways to improve policy (repeal minimum tax, change statute of limitations/interest rate, and allow DOR to use joint-interest billings)



# Senate Resources Committee Presentation on SB 21

## AVCG

(Alaska Venture Capital Group, LLC)

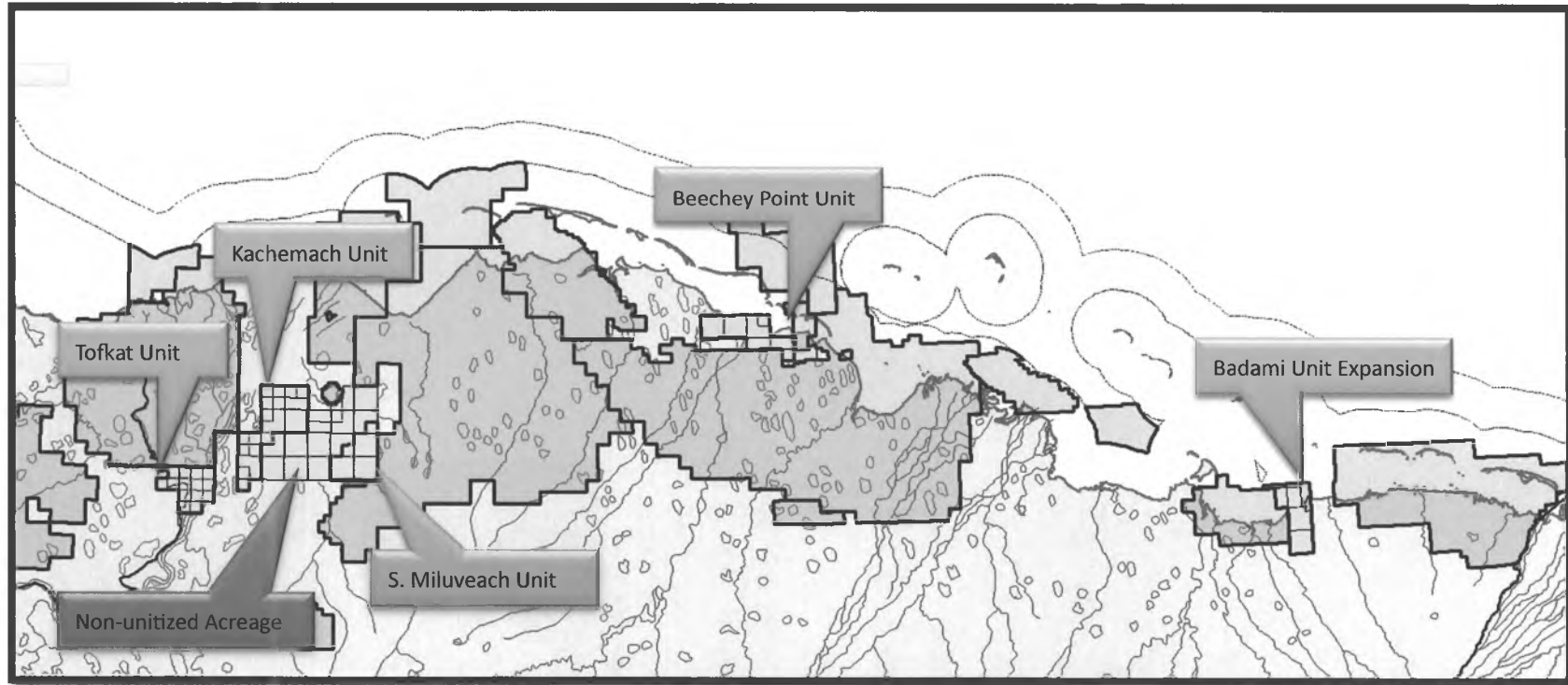
Ken Thompson, AVCG Co-Owner/Investor

February 18, 2013

### AGENDA

- “Top 10” Facts About AVCG
- Land Position And Drilling Successes
- Capital Needs And Capital Fundraising
  - Production Growth Possible
- What Can Most Help Us To Grow Production?

- 1) Startup company (1999), restricted only to Alaska North Slope E&P...no current oil production
- 2) 105,000 acres in 3 core areas on North Slope in JV Partnership with Ramshorn Exploration
- 3) ~ \$ 190 MM invested to date in Alaska North Slope projects
- 4) Formed Anchorage technical/operations subsidiary, Brooks Range Petroleum Corporation (2004)
- 5) 6 discovery wells – 3 by AVCG/Ramshorn operated by BRPC – 3 drilled by other companies  
(N Shore #1, Tofkat & N Tarn/Mustang - acquired Pete’s Wicked, Pt Storkerson & E Mickelson)
- 6) 4 development projects in permitting/conceptual engineering stage  
(44 MMBO Mustang Field anchor development...construction currently underway)
- 7) 4 State approved unitized blocks (45,000 unitized – 60,000 non-unitized)
- 8) 570 square miles of modern 3D seismic  
(330 square miles of proprietary 3D shot by BRPC - 240 square miles purchased from others and re-processed)
- 9) AVCG/Ramshorn wells operated by BRPC account for 28% of all exploration activity on State land over last 6 years (10 of 36 wells drilled from 2007-12)
- 10) First production and oil cash flow predicted on startup of Mustang in 3Q 2014



# North Slope Drilling Results And Success

AVCG LLC

## Tofkat Unit

- ~ 40 MMBO Kup C, ~ 20 MMBO Jurassic
- Offset Alpine & Nanuq fields
- Ran 3D after drilling indicates Kup C may extend into Nanuq field
- 3 delineation wells drilled
- Returning to delineate in Q1 2014
- COP drilled 4 wells into Jurassic at Nanuq
- Less than 1 mile to Alpine CC pipeline
- Upside defined in Brookian, new leases Nov 2012
- **FIRST OIL 2015 or 2016**

## Beechey Point Unit

- ~ 26 MMBO Kup C & Ivishak
- Adjacent to Prudhoe Bay and Midnight Sun
- 3-D definition on traps
- 3 discovery wells
- Substantial commercial opportunities within drilling reach
- East Shore prospect analog is Midnight Sun
- Lease block win Nov 2011 increases resource expectations
- **FIRST OIL 2016**

## Kachemach Unit

3-D seismic evaluation  
Exploration drilling planning

## S. Miluveach Unit – Mustang / Appaloosa

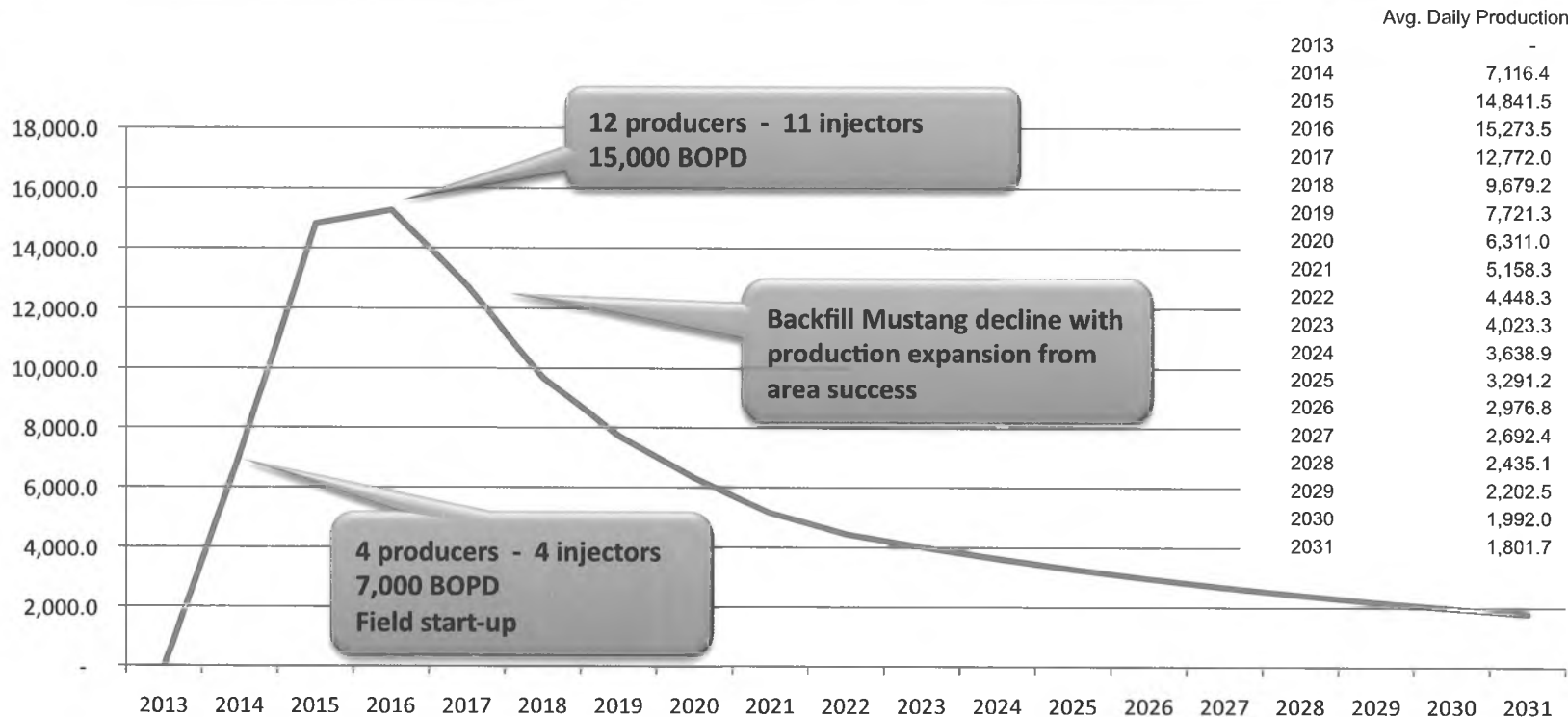
- 44 MMBO Kup C Mustang, ~ 37 MMBO Appaloosa
- Extension to KRU field
- N Tarn well penetrated reservoir 2011, re-entered & tested 2012 (20+ Kup C discovery)
- N Tarn #1A confirmed quality C sand 10+ ft. oil test
- Drilled confirmation Mustang #1 2012 20+ ft.
- Confirmed communication with KRU 2M
- Common carrier pipeline 700' from production pad
- 200 sq. miles proprietary 3D + 240 WBA license 3D
- **FIRST OIL 2014**

## Badami Unit Expansion

- ~ 16 MMBO Flaxman Sst
- Project area located between Badami & Pt. Thomson
- E Mikkelson #1 tested 250 BOPD un-stimulated
- Improved reservoir setting to Badami
- Horizontal development strategy
- Facilities and pipeline capacity in close proximity- no need to build facilities
- Pt. Thomson sand upside
- **FIRST OIL 2015 or 2016**

- 1) JV partners have spent \$190+ MM to date, seeking additional third party capital to spread capital risk, particularly for AVCG which is a small company
  - a) AVCG seeking additional \$100 MM for Mustang development project (AVCG 38.6% working interest)
  - b) AVCG seeking an additional \$150 MM commitment spread over 5 years for a continuous North Slope exploration drilling program of 3-4 wildcats per year (AVCG 50% working interest)
  
- 2) Have been working on the fundraising effort since September 2011
  - a) Hired world-class energy advisory firm, Tudor Pickering & Holt, to assist
  - b) Mailed materials, followed up with phone calls to 210 producers and private equity firms
  - c) Only 19 (9%) of the 210 firms showed an interest in investing in Alaska, asking for management presentations
  - d) Of the 19, only two companies and their investment partners remain interested
  - e) Discussions with these **two contenders continue** but are uncertain...both have asked to follow AK Legislative process and the outcome on taxation certainty
  
- 3) Results have been eye opening about how other producers and private equity funds look at capital investing in Alaska...*“three 800-pound gorillas blocking the door to entry to most”*
  - a) Pursuing Lower 48 source rock plays as perceive higher reserve stakes, lower capital spending risk, easier and faster permitting, and less time from drilling to production startup (e.g., NY PE firms)
  - b) Source rocks plays, for many companies, allow sufficient reserve additions for them to stop conventional exploration
  - c) State taxation seen by most interviewed as “most complex and unfair” of any state. Progressivity likened to 80s’ Federal Windfall Profits Taxes that sent activity and jobs to foreign countries...ACES’ bad PR cannot be overcome
  
- 4) But on the positive side...two companies remain interested and in discussions
  - a) Feel “sweet spots” of Lower 48 source rocks have been leased...re-interested in conventional exploration and Alaska is seen as the “last frontier” for onshore, U.S. exploration
  - b) AVCG/Ramshorn portfolio seen as a good mix of near-term development projects with positive cash flow by 3Q 2014 and mid- to long-term exploration upside
  - c) The current development tax credits show the state has a stake in the game, lowers producer’s eventual capital needs and exposure...but state’s investment returned via royalties and production taxes after startup
  - d) Belief in our confidence that the AK Legislature will make positive change to the oil tax structure in 2013

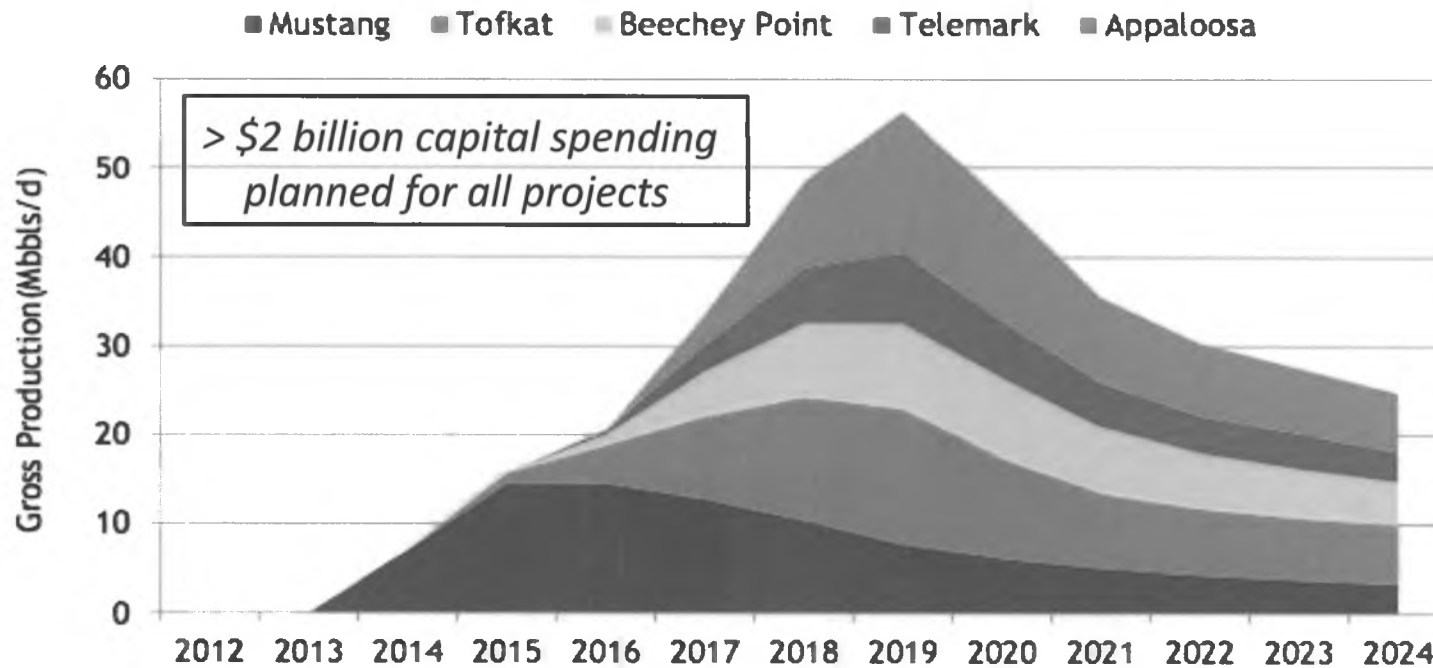
# Mustang Development Production Curve



	Wells	Gross Cost
Exploration Drilling	0	Already made
Development Drilling	23	\$ (345,000,000)
Production Facility	1	\$ (232,000,000)
<b>TOTAL COST</b>		<b>\$ (577,000,000)</b>

**THIS CAPITAL OF ~ \$225 MM/YR COMPARES TO CONOCOPHILLIPS' OF ~ \$750 MM/YR**

## Production Profile (Mbbls/d)



Between 2012 and 2011, North Slope oil production declined 50,768 BOPD. Developments such as these, if repeated, could potentially help replace production fall off...**AND ACHIEVE "NO DECLINE!"** And these results represent those of only one small independent startup!

Note: Mustang delineated and development underway. Tokfat, Beechey Point, Telemark, Appaloosa require delineation before sanctioning...not risked.

### **Qualified Capital Expenditures (QCE)**

- 20% QCE tax credit for capital expenditures
- 50% of credit year 1 other 50% in year 2
- Credits do not expire and can be held, sold to third parties or sold back to the state.

### **Carry Forward Loss (CFL) Credits**

- 25% credit based on calendar year losses
- 50% of credit in year 1 other 50% in year 2
- Credits do not expire and can be sold to third parties or sold back to the state

### **Small Producer Credit**

- Small producers (less than 50,000 BOPD)
- Entitled to a \$12MM per year production tax credit
- Credit is in effect for 10 years after start of production(need to start production by 2016 to qualify).

- ❖ AVCG/Ramshorn JV has invested \$190+ MM to date
- ❖ For this investment, JV has received refunded state credits totaling \$69 MM
- ❖ ALL CREDITS HAVE BEEN RE-DEPLOYED ON THE NORTH SLOPE FOR NEW SEISMIC AND DRILLING...NONE HAS BEEN DIVIDENDED TO OWNERS
- ❖ Credits re-deployed has allowed in some years the drilling of 3 wells instead of 2...or 2 wells instead of 1...and has expedited development, PV of Mustang
- ❖ State will receive all credits back plus some within the first year of production from Mustang...not only credits received on Mustang but all the \$69 MM of credits received on all AVCG/Ramshorn projects for the past few years
- ❖ State will ultimately receive \$1.2 billion in revenues from Mustang in terms of royalties, production taxes, etc. vs. their investment of \$69 MM credits
- ❖ Presence of credits have allowed a new company to share the capital burden with the state of Alaska...and is helping in attracting new funding...in return for the state receiving future new revenues of \$1.2 billion

- 1) Do not eliminate 20% development tax credits on 12/31/13 but extend (43.55.023(a))
  - a) Option 1: extend through end of 2014 or 2015 for all of industry
  - b) Option 2: grandfather new approved development projects for credits until production start date
  - c) Option 3: or for “small producers” extend to 2022...similar to the “Small Producer Credits” extension to 2022 being considered (43.55.024(c))
  - d) Option 4: certainly keep for those companies without current production until their first production start date
- 2) Allow for tax credit certificate payment in single year (43.55.023(a))
- 3) SB 21 contemplates eliminating Keep Carry Forward Loss Credit payments in cash...but keep CFL’s payable in cash for “small producers” or certainly those without current production (43.55.023(b))
- 4) Extend “Small Producer Credits” to 2022 (43.55.024(c))
- 5) Eliminate progressivity, maintain 25% base tax rate but resolve low oil price take scenario (43.55.011(e))
  - a) Progressivity single biggest “Fear Factor” externally about Alaska oil and gas production taxes...negative PR Outside
- 6) Allow 40% capital credit for all intangible well work not only for Cook Inlet but also for NS (43.55.023)
  - a) Will increase well workovers and recompletions to stimulate more production, and potentially increase exploration
- 7) For new oil tax calculation, approve “20% Gross Revenue Exclusion” but amend HB 21 to not limit to non-unit lands post-2003...consider granting to new oil on all lands with 1/6 royalty (43.55.160)
- 8) *New idea not in SB 21:* To increase pace of exploration drilling on North Slope, allow same exploration well tax credits as now allowed for the Cook Inlet...a “conditional” 30-40% credit
  - a) AVCG/Ramshorn has never received any exploration well tax credits under AS 43.55.025...we drilled risky exploration wells but none outside the 25-mile unit buffer (last of these credits last granted in 1994? And only for 22 wells in 1983-94?)
  - b) Adopt the same exploration well tax credit rules for the North Slope as currently exist for Cook Inlet
    - 30% of the cost of an exploratory well if well target is pre-approved as an exploration well (use SEC definition?)...OR
    - Credit increased from 30% to 40% if pre-approved as an exploration well AND well is at least 10 miles from any unit boundary

# Brooks Range Petroleum Corporation

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*Presentation for:*

## **Senate Resources Committee**

**SB 21**

**Bart Armfield, Chief Operating Officer**

**February 18, 2013**

# SB 21 Support / Considerations

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## AS 43.55.023(a)

- ✓ Allows for certificate payment in single year
- Eliminates 023 credits after 12/31/13 ( consider extension or .023 (I) redefinition of .025 to include exploration projects )

## AS 43.55.023 (I) (suggest adoption for North Slope )

- ✓ Allows 40% capital credit for all intangible well work (consider adoption )

## AS 43.55.011 (e)

- ✓ Eliminates progressivity maintains 25% base tax

## AS 43.55.023(b)

- After 12/31/13, CFL credits no longer redeemed for cash must apply to tax burden
- ✓ 15 % interest on unused credits

## AS 43.55.024(c)

- ✓ Extends Small Producer Credits to 2022

## AS 43.55.160

- ✓ Gross Revenue Exclusion
- “Does not contain land that was in a unit on January 1, 2003” ( consider adjustment )

✓ Support

2

● Consider Adjustment

# Reasons for Entering Alaska

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- L48 oil price, reduced cash flows, lack of quality prospect inventory
  - In 2000, oil price had dipped to very low levels
  - Lower 48 average wells struggled to generate breakeven cash flow
  - Prospect reserve base was not very attractive
  - Deals were few and those that were being shopped didn't impact CF for risk
- Drivers to Increase Cash Flow
  - Big reserves with high production rates increases cash flow
  - Acceptable cost of doing business
  - Tax policy was not an impact consideration - ELF
  - Expected eventual cycle change in focus with some majors lessening activity and independents entering as occurred in;

Mid-continent, Rocky Mountains, Gulf of Mexico, North Sea

# What does Alaska have to offer ??

---

	ALASKA	LOWER 48
World class reserve base	X →	
Accessible infrastructure		X
Cost environment		X
Relative Oil Price	X ←	
Meaningful SOA credit structure	X	
Impacts of tax policy	?	?
Perception of tax consequences		X
Confidence in a 5 to 10 year business plan		X

# Why more players are not in Alaska

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## 3 Key Elements

- Aggressive desire to be in Alaska
- Knowledge base to understand
- Financial capacity to fully execute

## What is the Reality

- Most are content with core areas
- High oil price provides superior cash flows
- Established relationships with knowledgeable investors and traditional capital sources
- Insufficient cause to compel a change in their operational focus
- Many would prefer to control own destiny
- Question internal geologic expertise for Alaska
- Deficiencies of staff operational competence
- Lack of fiscal comprehension
- Unable to model minimum 5 year business plan that is consistent
- Current capital commitments on other projects
- Alaska requires **VERY** patient capital
- Perception that majors control and inability or reluctance to compete

**“Alaska is an educational process”**

# Credits have helped keep us in the game

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QCE - .023 (a)

## Qualified Capital Expenditures

20% QCE tax credit for capital expenditures

50% of credit year 1 other 50% in year 2

Credits do not expire and can be held, sold to third parties or sold back to the state.

CFL - .023 (b)

## Carry Forward Loss Credits

25% credit based on calendar year losses

50% of credit in year 1 other 50% in year 2

Credits do not expire and can be sold to third parties or sold back to the state.

SPC - .024 (d)

## Small Producer Credit

Small producers (less than 50,000 BOPD)  
Entitled to a \$12MM per year production tax credit.

Credit is in effect for 10 years after start of production

(need to start production by 2016 to qualify).

EIC - .025

## Exploration Incentive Credits

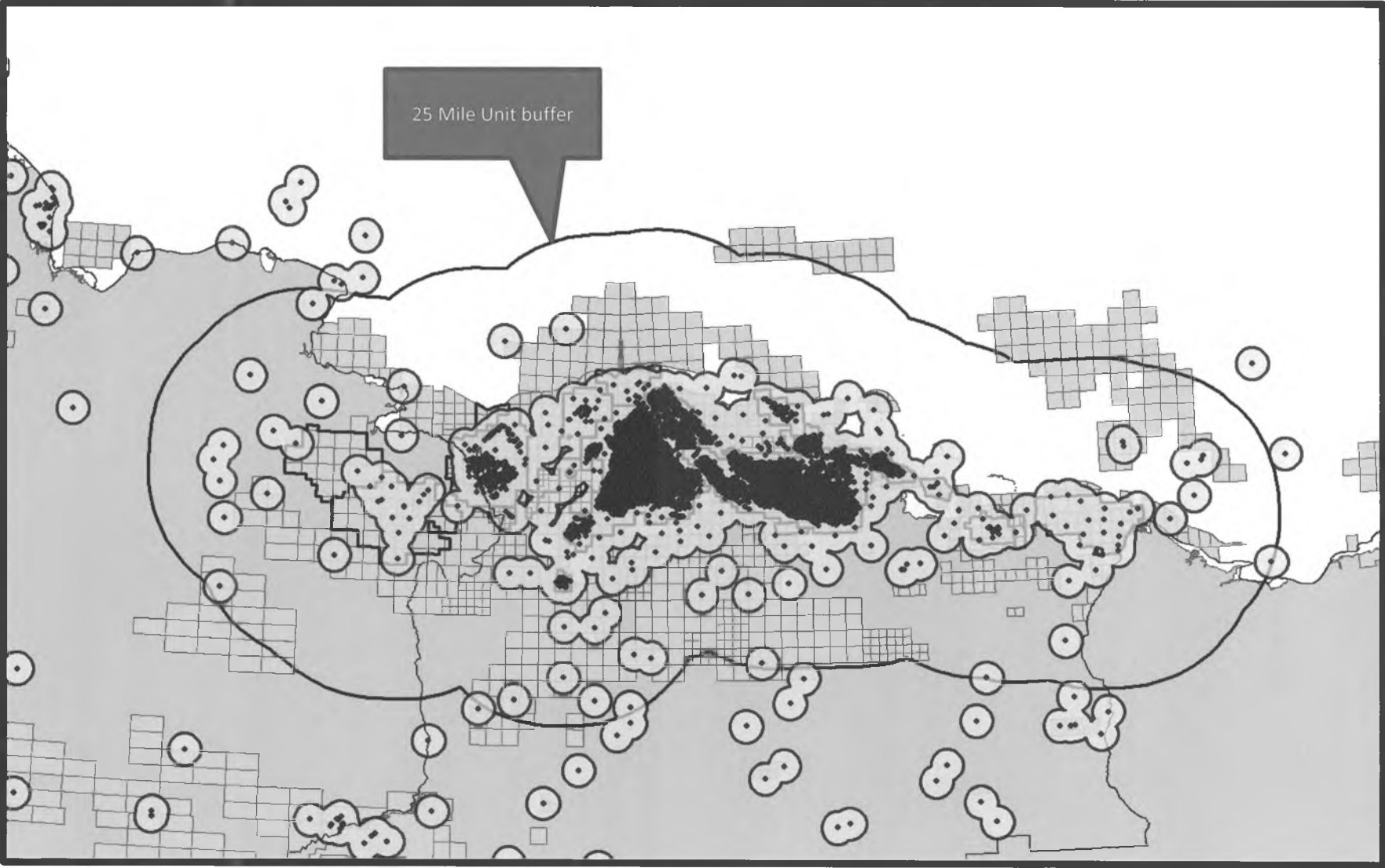
40% credit depending on well location and the prospect traits.

Can take EIC credit or the QCE credits, but not both.

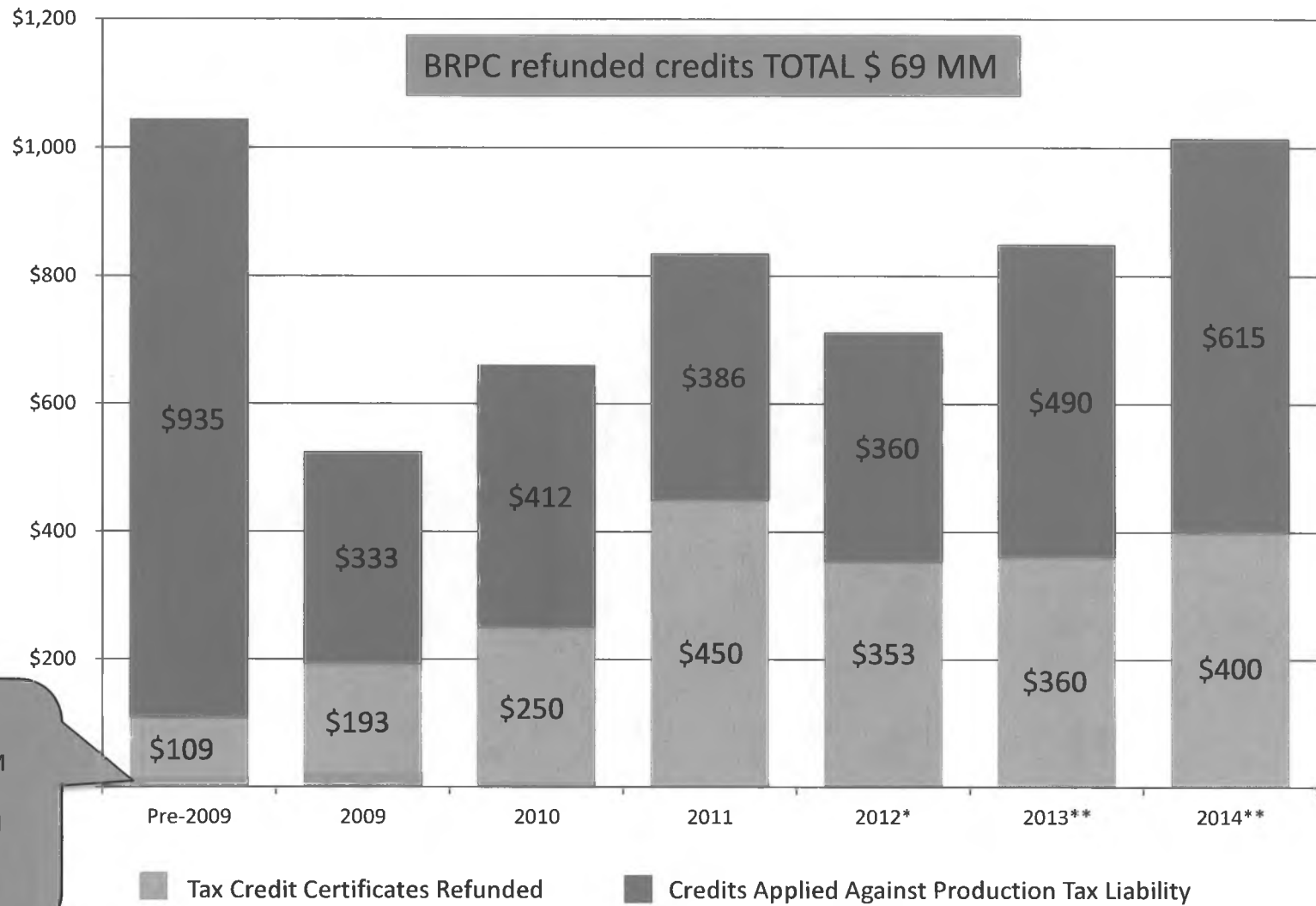
Work needs to be complete by July 1, 2016 to qualify.

BRPC has never received this for exploration wells

# AS 43.55.025 Limitations - 25 Mile Unit Buffer With 3 Mile Well Buffer



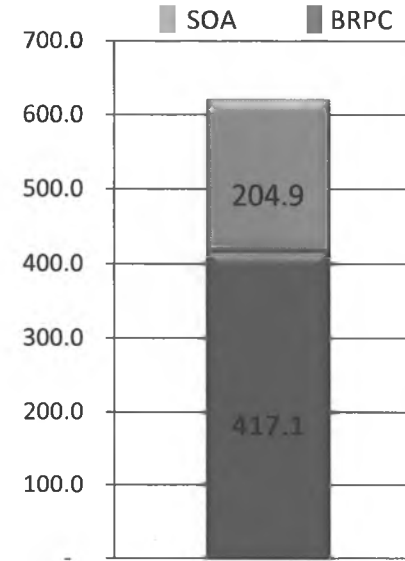
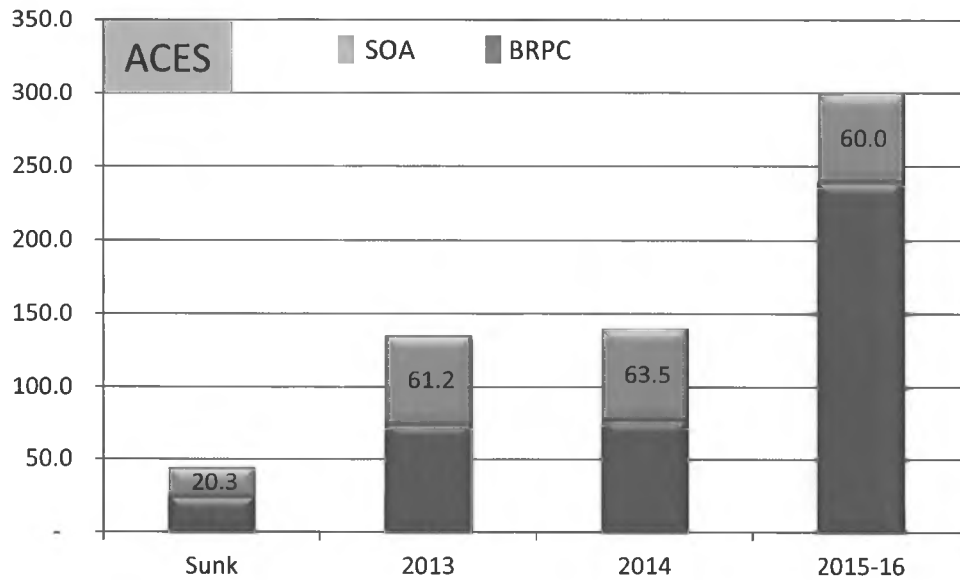
# Tax Credits History & Forecast



\* Estimated pending final true-ups

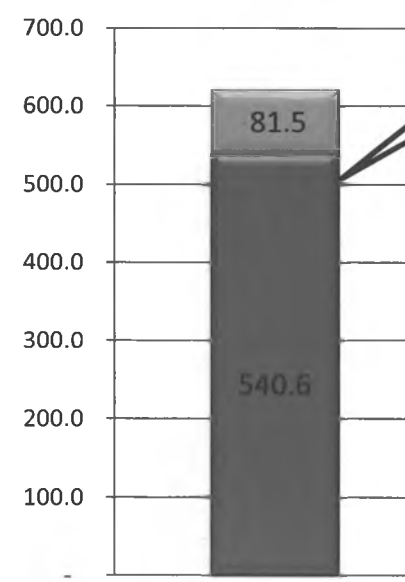
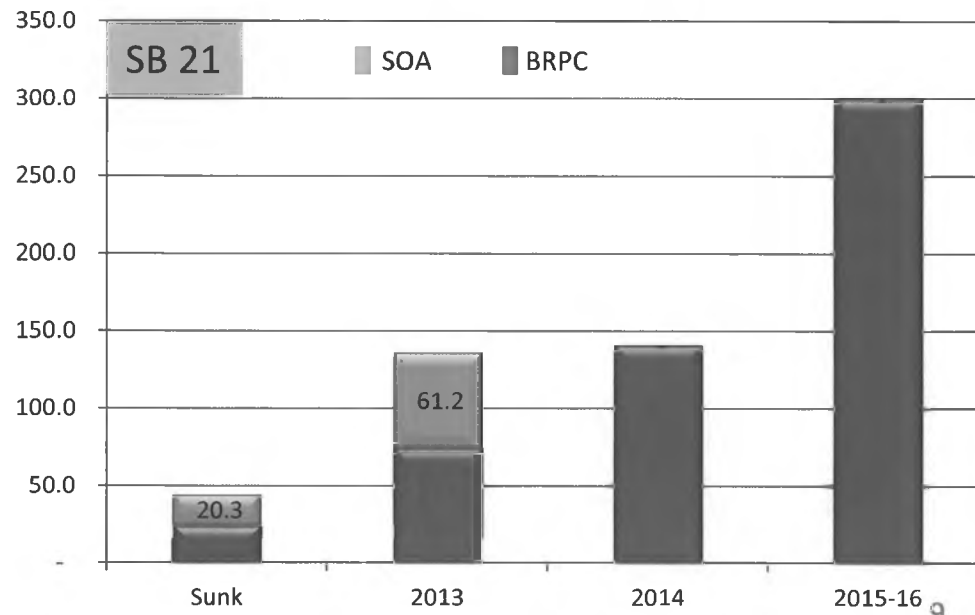
\*\* Fall 2012 Revenue Source Forecast

# Impacts to Mustang Development Funding



Under ACES, Mustang SOA revenues \$ 1.2 B Life of Field

Requires \$ 123.4 MM additional funding not planned in sanction process

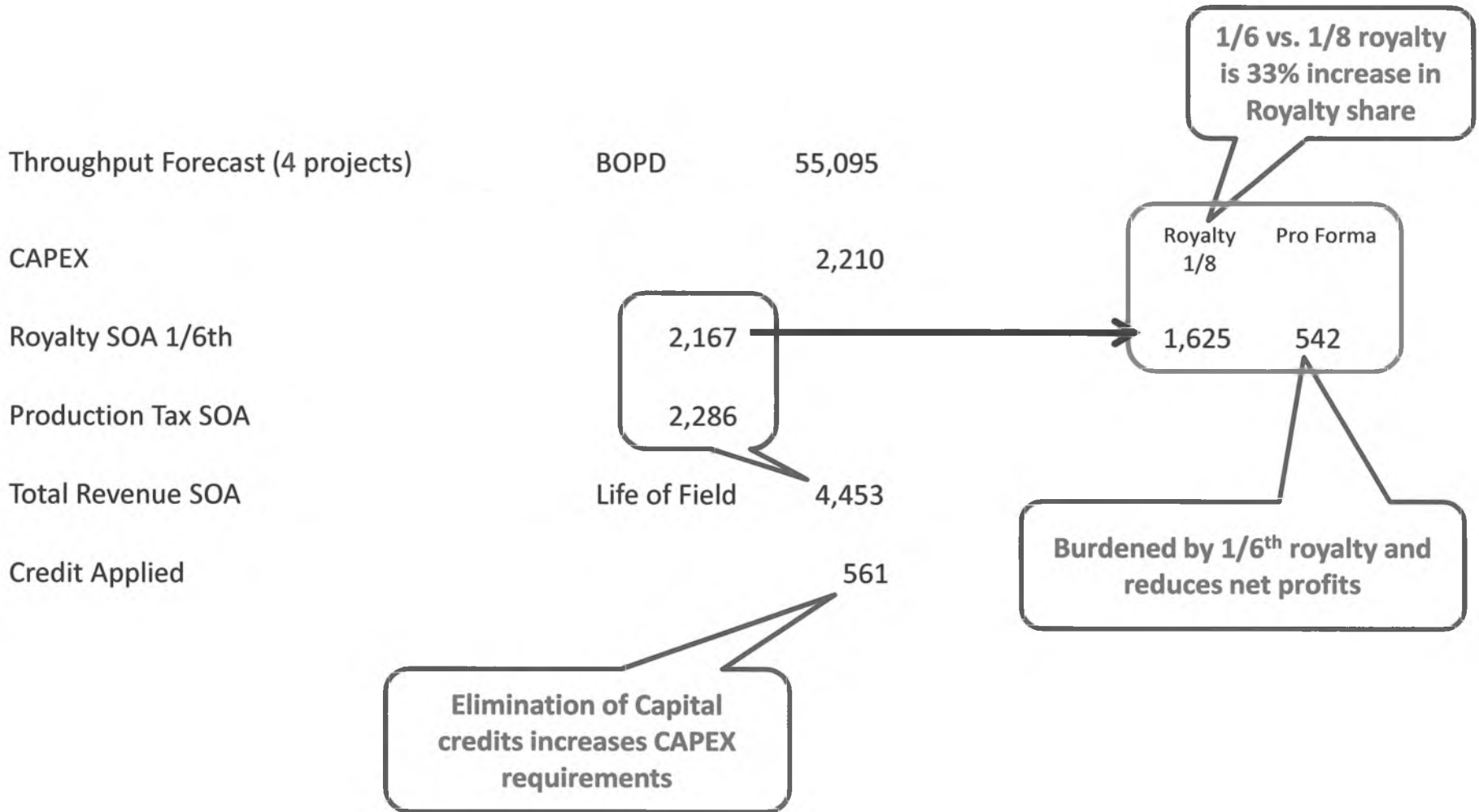


# Forecast by Development Project

	Peak Throughput	SOA Rev. ( B )
Mustang Development	14,806	1.2
Appaloosa Development	12,722	1.0
Tofkat Development	8,667	0.7
Beechey Point Development	12,000	0.9
Badami Expansion	6,900	0.6
<hr/>		
	55,095	4.4
Annual Average SOA Revenues		0.293
10 new entrants replicated		10
Annual Average SOA Revenues		2.933

Includes \$ 561 MM  
in credit support

# Combined Development Projects and Throughput Forecast



# One Size Does NOT Fit ALL

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- Legacy Tier.....
  
- Mid-size Production and Development Tier.....
  
- Exploration and Discovery Tier.....
  
- New Entrants Tier.....

# SB 21 Support / Considerations

---

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- ✓ Extends Small Producer Credits to 2022

## AS 43.55.160

- ✓ Gross Revenue Exclusion
- “Does not contain land that was in a unit on January 1, 2003” ( consider adjustment )

✓ Support

● Consider Adjustment

**TESTIMONY ON SB 21**  
**by**  
**THOMAS K. WILLIAMS**  
**SENIOR ROYALTY AND TAX COUNSEL**  
**BP EXPLORATION (ALASKA) INC.**  
**to the**  
**SENATE RESOURCES COMMITTEE**  
**20 FEBRUARY 2013**

Madame Chair, Members of the Committee:

Good Afternoon. For the record, my name is Thomas K. Williams and I am Senior Royalty and Tax Counsel for BP Exploration (Alaska) Inc. Thank you for inviting us here to testify on Senate Bill 21, which has been introduced by Governor Parnell and proposes to amend the so-called "ACES" production tax on oil and gas produced in Alaska.

There are three primary changes that SB 21 would make to ACES: one, repeal progressivity, which we think is good; two, change the system of tax credits that now exists, which threatens to harm some producers even if it may help others; and three, create a new "gross revenue exclusion" for new production that we view as innovative but largely misdirected. My testimony today will review these changes in the context of the tax issues that my employer faces under the present tax, which the Governor and apparently the entire Legislature, with the introduction of Senate Bill 50, agree needs to be reformed.

First, progressivity. As you know, progressivity is a sliding-rate tax that runs quickly up to a 25% rate and then rises more slowly above 25 percent. It is in addition to the basic 25% tax that is also levied on the "production tax value" of a producer's taxable production. Repealing progressivity is a good idea for a number of reasons, which AOGA has identified in its testimony on Monday and which other taxpayers will probably present to you as well. Many of those objections are for effects from progressivity that were intentional as part of the way progressivity was designed. What I'd like to do today is to describe two significant, unintended effects of progressivity that seem largely unknown and even less understood. I have eight slides to present that will show you exactly what these unintended consequences are.

To begin, let me quickly review how the tax is calculated for the example I will use.

		<b>Bbl</b>	<b>\$/bbl</b>
USWC Price	\$1,000,000	10,000	\$100.00
Transportation	<u>\$150,000</u>	10,000	<u>\$15.00</u>
GVPP	\$850,000	10,000	\$85.00
Field Expense	<u>\$300,000</u>	10,000	<u>\$30.00</u>
PTV	<u>\$550,000</u>	10,000	<u>\$55.00</u>
25% Base Tax	\$137,500		
Prog'y Rate	10.000%		
Prog'y Tax	<u>\$55,000</u>		
Total Tax	\$192,500		

**Slide 1. How ACES works**

If you look at this first slide, you will see the tax calculation for a hypothetical producer with 10,000 barrels of oil who sells it on the West Coast for \$100 a barrel and receives a million dollars. It cost \$150,000 – or \$15 a barrel – to transport that oil from the field in Alaska to the West Coast, which leaves \$850,000 as the gross value at the point of production or “GVPP.” The producer had \$300,000 of allowable lease expenditures, or field expense, to produce the oil, which leaves a taxable production tax value, or “PTV,” of \$550,000 or \$55 a barrel. The base tax is 25% of the PTV, or \$137,500.

The progressivity rate equals four tenths of a percentage point times the difference between \$30 and the producer’s PTV per barrel. Here the difference between \$30 and \$55 is \$25, and \$25 times four tenths of a point per dollar equals 10 percent. Ten percent of \$550,000 is \$55,000 of progressivity tax. That plus the base tax of \$137,500 equals a total tax of \$192,500. So far there is nothing here that is new to you.

So now let me begin to show you something you probably have not seen before. This scenario is not about what the producer has actually produced, but about an evaluation of what could happen from the development of a new reservoir or field if the investment is made. And let’s suppose that this producer sees three different ways that she could potentially improve this investment. One is that she knows of a buyer willing to pay a premium of a dollar a barrel for the oil delivered on the West Coast, the second is a way to save \$20,000 in transportation costs, and the third is a way to cut the costs for field operations by \$30,000. If she can do all three, what is the change in the tax?

	Base Case	Revision	As Revised	Bbl	Base Case \$/Bbl	Revised \$/Bbl	Change in Tax
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640 All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>	
GVPP	<u>\$850,000</u>		<u>\$880,000</u>	10,000	<u>\$85.00</u>	<u>\$88.00</u>	
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	
PTV	\$550,000		\$610,000	10,000	\$55.00	\$61.00	
25% Base Tax	\$137,500		\$152,500				
Prog'y Rate	10.000%		12.400%				
Prog'y Tax	<u>\$55,000</u>		<u>\$75,640</u>				
Total Tax	\$192,500		\$228,140				
Change in tax			\$35,640				

**Slide 2. Example – The three changes together**

In this slide we see the three changes. The extra dollar a barrel in the price increases the sales revenue from the oil to \$1,010,000. The transportation savings reduces that cost from \$150,000 to \$130,000. Between the increased price and the transportation savings, the GVPP of the oil back in the field is \$880,000 instead of \$850,000. And the reduction in upstream lease expenditures raises the taxable PTV by another \$30,000, for a total increase in PTV of \$60,000 from \$550,000 to \$610,000.

The 25% base tax is now \$152,500 instead of \$137,500. And with PTV per barrel now \$61, the progressivity rate is \$61 minus \$30, or \$31, times four tenths of a percentage point per dollar, or 12.4 percent. Twelve-point-four percent of \$610,000 is \$75,640, and the total tax is \$228,140 instead of \$192,500. This is an increase of \$35,640.

I have highlighted this change in yellow and recorded it in the upper right corner of the slide in order to keep it on screen so we can remember what it was, because in this scenario the producer next asks what the tax change is separately for each of these improvements to the investment. This next slide shows the change resulting only from the extra dollar in the West Coast price.

	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>	
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640	All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>		
GVPP	\$850,000		\$860,000	10,000	\$85.00	\$86.00	\$5,740	Price
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>		
PTV	\$550,000		\$560,000	10,000	\$55.00	\$56.00		
25% Base Tax	\$137,500		\$140,000					
Prog'y Rate	10.000%		10.400%					
Prog'y Tax	<u>\$55,000</u>		<u>\$58,240</u>					
Total Tax	\$192,500		\$198,240					
Change in tax	-		\$5,740					

**Slide 3 Example – Price change only**

The higher price increases the sales proceeds by \$10,000 to \$1,010,000. And as you go down the “As Revised” column you see this \$10,000 flowing down into the \$860,000 GVPP and then into the taxable PTV, raising it to \$560,000. The 25% base tax on \$560,000 is \$140,000. The progressivity rate is \$56 minus \$30, or \$26, times four tenths of a percentage point per dollar, which is 10.4 percent. Ten-point-four percent of \$560,000 is \$58,240 and the total tax is \$198,240, an increase of \$5,740 from the base case. Again, I have recorded this at the right side of the table so we can remember what it is without having to flip back and forth between slides.

The next slide shows the change in tax from the \$20,000 savings in transportation costs.

	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>	
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$35,640	All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>		
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00	\$5,740	Price
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>	\$11,560	Transpo.
PTV	\$550,000		\$570,000	10,000	\$55.00	\$57.00		
25% Base Tax	\$137,500		\$142,500					
Prog'y Rate	10.000%		10.800%					
Prog'y Tax	<u>\$55,000</u>		<u>\$61,560</u>					
Total Tax	\$192,500		\$204,060					
Change in tax	-		\$11,560					

**Slide 4. Example – Transportation cost savings**

The \$20,000 again flows straight down into the taxable PTV, increasing it from \$550,000 to \$570,000. The progressivity rate is now \$57 dollars minus \$30, or \$27, times four tenths of a percentage point per dollar or 10.8 percent. That plus the 25% base rate on \$570,000 of PTV yields a total tax of \$204,060, an increase of \$11,560 from the base case. This, too, I have

recorded on the right side of the table.

Finally, this next slide shows the effect of saving \$30,000 in field expense. The PTV increases by \$30,000 to \$580,000, the progressivity rate is 11.2 percent. The base tax and progressivity add up to \$209,960 — an increase of \$17,460 from the base case.

	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>	
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	<b>\$35,640</b>	All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>		
GVPP	\$850,000		\$850,000	10,000	\$85.00	\$85.00	\$5,740	Price
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560	Transpo.
PTV	\$550,000		\$580,000	10,000	\$55.00	\$58.00	<u>\$17,460</u>	Lease Exp.
25% Base Tax	\$137,500		\$145,000				<b>\$34,760</b>	
Prog'y Rate	10.000%		11.200%					
Prog'y Tax	<u>\$55,000</u>		<u>\$64,960</u>					
Total Tax	\$192,500		\$209,960					
Change in tax	-		<u>\$17,460</u>					

**Slide 5. Whole is greater than the sum of its parts**

And here at last, this slide shows what it is that you probably have not seen before. The sum for the three changes separately is \$34,760, which is in bold font to make it easier to spot. This is less than the \$35,640 change in tax when all three are factored in at once (also in bold font). In other words, with progressivity, the whole is greater than the sum of its parts.

And that's not all. The amount of tax that is calculated for each individual part changes, depending on what order you look at them. Here's a slide that looks at the \$20,000 savings in transportation cost and the \$30,000 reduction in field expense together.

	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>	
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$11,560	Transpo. Only
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>	\$17,460	Field Exp. Only
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00		
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560	Transpo. 1st
PTV	\$550,000		\$600,000	10,000	\$55.00	\$60.00	<u>\$17,940</u>	Field Exp.2nd
25% Base Tax	\$137,500		\$150,000				<b>\$29,500</b>	
Prog'y Rate	10.000%		12.000%					
Prog'y Tax	<u>\$55,000</u>		<u>\$72,000</u>				\$12,040	Transpo. 2nd
Total Tax	\$192,500		\$222,000				<u>\$17,460</u>	Field Exp.1st
Change in tax	-		<u>\$29,500</u>				<b>\$29,500</b>	

**Slide 6. ACES's continuously changing tax effect**

The two cost reductions together increase PTV by \$50,000, to \$600,000. The base tax on that is \$150,000. Progressivity for \$60 of PTV per barrel is \$60 minus \$30, or \$30, times four tenths of a percentage point per dollar, or 12 percent, times \$600,000, which is \$72,000. The total tax change from the two is \$29,500. From the previous cases where we considered each cost reduction separately, the tax increase with transportation only was \$11,560 and for field

expense only was \$17,460, and these appear in the upper right of the slide.

If we look at transportation first, it is equivalent to looking at it standing alone, and we have already calculated what that is — \$11,560. So \$11,560 of the combined \$29,500 tax increase is from the change in transportation cost, and the rest — \$17,940 — is for the change in field expense. But this means the field expense is almost \$500 greater than what it is when it's standing alone. And if you reverse the order, then the field-expense tax increase is the same as when it stands alone, but now the tax increase for the transportation savings is different — \$12,040 instead of the \$11,560 when it stands alone or is taken first.

What we have done here on this sixth slide is to look at the pair of cost savings for downstream transportation and upstream lease expenditures, and we've looked at that pair first, ahead of the change in market price. If we go back to the previous slide, we see that if we take transportation first and subtract its \$5,740 from the total \$35,640 tax effect for all three, then that leaves a different number — \$29,900 — for this pair of changes instead of the \$29,500 we have here on slide six when we calculate that pair back first.

There is nothing special about this particular pair of changes that creates this difference. There would be a similar difference if we pair price with transportation or price with lease expenditures. With either one, we'd get one set of tax effects for this pair if we calculate them first, and a different set of tax effects if we calculate the effect of the unpaired change first. And, as here, within each pair, there is a different cost for each change in that pairing depending on whether its effect is calculated first or the other's effect is first.

These examples involve a triplet of categories of change that could be made to improve the economics of the project: an increase in price, a reduction in transportation costs to market, and greater efficiency in field operations. But I have simplified these examples by using lease expenditures generically as a single cost category. In the real world a would-be investor would look at capital expenditures separately from operating costs because the timing for when the two kinds of cost are incurred is different and — especially important in the context of analyzing tax effects — the capex generates a 20% Qualified Capital Expenditure tax credit in addition to changing the PTV and the progressivity rate. So there are really four categories of change to look at: changes in sales price, changes in transportation costs, changes in operating expense, and changes in capital expenditures.

For each one of these four categories, its respective tax effect can be calculated separately from the other three, either ahead of them or after them. And each such triplet of changes has the same analysis and the same variations in tax effect for individual changes that we have seen in the entire analysis that we have just gone through in this and the four earlier slides — namely, the tax effect for the entire triplet being greater than the sum of the effects for the individual categories in it; the different amount for the unpaired category in each triplet relative to the pair of other categories, depending on whether the effect of the pair is calculated first or second; and within each such pair, the different amount depending on which category in that pair is calculated first. Each of these numerous variations and combinations will divide the \$35,640 total tax effect up into a different set of amounts calculated for the four categories. Yet even with all those sets of calculated amounts for the categories, none of those sets will add up to the tax effect for all the changes taken together as a whole.

And all this complexity doesn't begin to reflect the likelihood that there may well be several different changes that could be made within one or more of these four basic cost categories.

These bizarre effects are not mere abstract curiosities. If you are an investor and you have a variety of ways to try to improve the performance of an investment, these effects from progressivity mean there is no single correct answer about how much each one changes the tax and improves the investment. The more ways you have to improve the investment, the more the change in tax for each one depends on where you put it in the sequence of calculating the changes for all of the opportunities. This is because each opportunity in that sequence not only increases the PTV, but it also increases the progressivity rate applicable to the base case PTV plus all the PTV that has been added by the prior opportunities in the sequence.

Interestingly, the Department of Revenue has exactly the same problem when it audits a taxpayer and makes multiple changes to figures reported on the tax return and increases the amount of tax. The auditor can quantify the whole tax increase from all the changes, but he or she cannot make a definitively correct determination of the amount of any one of those changes. A taxpayer might have an interesting time in an appeal having an auditor admit, issue by issue, that there is no correct amount for each one.

There is a second important consequence of progressivity that was generally unintended or is greater than intended. I call it a tax on price volatility because it increases the tax when prices change during a tax year even though the total PTV is exactly the same as if the prices had stayed constant at the average price for the year.

	<b>PTV per Bbl</b>	<b>MM bbl</b>	<b>PTV (\$MM)</b>	<b>Prog'v'y Rate</b>	<b>Prog'v'y Tax (\$MM)</b>
<b>Jan</b>	\$61.25	2.00	\$122.50	12.50%	\$15.31
<b>Feb</b>	61.25	2.00	122.50	12.50%	15.31
<b>Mar</b>	61.25	2.00	122.50	12.50%	15.31
<b>Apr</b>	61.25	2.00	122.50	12.50%	15.31
<b>May</b>	61.25	2.00	122.50	12.50%	15.31
<b>Jun</b>	61.25	2.00	122.50	12.50%	15.31
<b>Jul</b>	61.25	2.00	122.50	12.50%	15.31
<b>Aug</b>	61.25	2.00	122.50	12.50%	15.31
<b>Sep</b>	61.25	2.00	122.50	12.50%	15.31
<b>Oct</b>	61.25	2.00	122.50	12.50%	15.31
<b>Nov</b>	61.25	2.00	122.50	12.50%	15.31
<b>Dec</b>	<u>61.25</u>	<u>2.00</u>	<u>122.50</u>	<u>12.50%</u>	<u>15.31</u>
<b>Full Year</b>	\$61.25	24.00	\$1,470.00		\$183.75

**Slide 7. Flat price scenario**

On this slide we see such a "flat price" scenario. To fit conveniently within the space available in a slide, the table omits columns for West Coast prices, transportation costs and field expenses, and starts instead with the PTV that is calculated from them. Here the PTV is \$61.25 per barrel, and with 2 million barrels of production a month, the amount of the taxable PTV is \$122.5 million a month.

Progressivity starts when the PTV per barrel exceeds \$30, and it reaches 25% at a PTV

per barrel of \$92.50. I have chosen \$61.25 as the PTV per barrel in this base case because it is half way between \$30 and \$92.50. The progressivity rate at this price is \$61.25 minus \$30, or \$31.25, times four tenths of a percentage point per dollar, or 12.5 percent. This also is half way between the zero rate at \$30 and the 25% rate at \$92.50. As you can see, each month the PTV is \$122.5 million, the progressivity rate is always 12.5%, and the progressivity tax is exactly the same for each month as \$15.31 million. Total progressivity for the year is \$183.75 million.

	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)
Jan	\$61.25	2.00	\$122.5	12.50%	\$15.31	\$30.00	2.00	60.0	0.00%	-
Feb	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Mar	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Apr	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	\$46.25
May	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jun	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Jul	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Aug	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Sep	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
Oct	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Nov	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
Dec	<u>61.25</u>	<u>2.00</u>	<u>\$122.5</u>	<u>12.50%</u>	<u>15.31</u>	<u>30.00</u>	<u>2.00</u>	<u>60.0</u>	<u>0.00%</u>	-
<b>Full Year</b>	\$61.25	24.00	\$1,470.0		\$183.75	\$61.25	24.00	1,470.0		\$277.50

**Slide 8. Progressivity increases taxes with fluctuating price even when the economics don't change**

In this next slide the left half is exactly the same as the previous one with the flat-price scenario. The right half of the table shows what happens when there are six months in the year when the PTV per barrel is \$30 and six when it is \$92.50. In this case the first three months and the last three have the \$30 PTV per barrel, and the middle six from April through September have the \$92.50. This price profile resembles what actually happened with West Coast prices for North Slope oil during 2008, when they peaked at the all-time record of \$144.59 a barrel on July 3rd.

For the six months when the PTV per barrel is \$30, the progressivity tax rate is zero because \$30 of PTV per barrel minus the \$30 threshold for progressivity is zero. So, as you can see, there is no progressivity tax for the first three months of the year and the last three. In the middle six, the PTV per barrel is \$92.50. That is \$62.50 higher than the \$30 threshold, so the progressivity rate is four tenths of a percentage point times 62.50, or 25.00 percent. At \$92.50 a barrel, the progressivity tax on two million barrels a month is \$46.25 million, so the total progressivity tax for the six non-zero months is \$277.5 million.

The progressivity tax under the changing-price scenario is 51% higher than the \$183.75 million of progressivity for the flat-rate scenario.

This tax increase is entirely the result of the fact that prices changed during the year instead of being flat. You can see this for yourselves. The total PTV for the year in the right-hand column is 1,470 millions of dollars, or \$1.47 billion — exactly the same as in the flat-price

scenario on the left. Total production for the year is exactly the same — 24 million barrels. Dividing \$1.47 billion of PTV by 24 million barrels equals \$61.25 per barrel, exactly the same. But progressivity is 51% higher.

And if you look at the monthly calculations in the changing-price scenario, you can see that the monthly progressivity tax will be exactly the same for each of the \$30 months no matter what order you put those months in. The same is true for the \$92.50 months. So this phenomenon is different from what I showed you earlier about the whole being greater than the sum of its parts, because here there are no changes in the actual progressivity calculation for a \$30 month or a \$92.50 one.

The bottom line here is this. The year under the changing-price scenario is just as profitable as the flat-price one, and for the same amount of production. The tax base to which progressivity applies is exactly the same for the year. Yet the tax is 51% higher when prices change during the year.

Now, I have chosen these PTV-per-barrel figures so they would show the greatest amount of tax increase resulting from prices that are not flat all year long. I did this because, if I showed you an example with a smaller effect, someone would surely ask me what the maximum effect could be. My example gives you that answer at the same time it explains the phenomenon.

Those of you who were here in the Legislature in 2009 may recall the surprise of the Department of Revenue when the actual ACES tax collected during its first full year of operation – the 2008 calendar year – came in about half a billion dollars higher than the Department had forecasted. This tells you why: 2008 was a very volatile year for prices. While that volatility did not generate the maximum 51% increase that my example illustrates, it did produce a very substantial increase in progressivity tax – on the order of half a billion dollars – from the mere fact that prices fluctuated during 2008, instead of being flat at the volume-weighted average price for the year.

So, to summarize: Progressivity has two major unintended consequences. First, when you are analyzing combinations of steps to take to improve an investment opportunity, the whole is greater than the sum of its parts. Second, if you, as a potential investor, do not take into account the effect from price volatility during each year in an investment's life, the progressivity could turn out to be 50% higher than what you have estimated. Both of these effects promise to increase the risks and reduce the competitiveness of an Alaskan investment relative to a comparable one elsewhere.

These negatives of progressivity complement what AOGA told you during its testimony last Monday. Without repeating that testimony here, I will only list AOGA's main points. One, progressivity sacrifices the one advantage Alaska has from its economic remoteness – namely, the greater improvement in financial performance for investments here if prices turn out better than projected. This sacrifice occurs because progressivity taxes away more and more of that improvement the better it turns out to be. And two, progressivity makes the tax extraordinarily complex and inconsistent to compute, and to analyze.

For these reasons BP fully endorses the proposed repeal of progressivity that Senate Bill

21 proposes.

Let me now turn to the second main feature in this Bill — the changes it proposes to the present system of tax credits, and in particular to the sunset of the credit for “qualified capital expenditures” or “QCE” at the end of this calendar year.

The first, and probably most important observation I can offer about tax credits in general is they would not be so significant for the economics of oil and gas production here if the production tax were not so high.

Second, the QCE tax credit depends solely on how much a company invests for oil and gas exploration, development and production in Alaska. Period. If you want to address the North Slope decline curve, there have to be investments here leading to more production — not just by finding and developing new fields and new reservoirs, but also by getting more recovery out of fields already in production. The QCE tax credit is a direct incentive for making these investments. And it costs the State nothing unless there are investments: if investment is zero, then 20% of zero is zero. The QCE tax credit arises only when it succeeds, and costs nothing if it doesn't.

The QCE tax credit is not affected by oil prices, the costs of transporting oil and gas to market, nor the operating costs of the field. Consequently its value to a business like BP's is the same for a given amount of QCE expenditure, regardless of the price and the transportation and field operating cost scenarios that the business estimates in its investment decisions. And it is the same regardless of how prices and those other costs actually turn out. Progressivity, on the other hand, is dependent on prices and costs in a twofold way: once in determining the amount of PTV that is subject to tax, and again in calculating the tax rate that progressivity will apply to that PTV.

Thus, the point where the cost of losing the QCE credit begins to outweigh the benefit from repealing progressivity depends both on the price of oil and, for each individual producer, on that producer's own unique portion of the lease expenditures for the North Slope. For BP's own business and expenditures, this crossover comes at a higher price level – in the mid to upper 90s – than that which Econ One and others are presenting for North Slope producers as a whole. So the improvement to our investment economics from the repeal of progressivity stands to be substantially undone by the sunset of the QCE tax credit. Since I am a tax man who is here to testify about this tax, I would ask, please, for your patience for just a few minutes if you have questions regarding this point, so I can quickly finish up and Mr. Bilbao can testify.

The third major feature in SB 21 is its proposed “gross revenue exclusion” or “GRE” which is something new. It would exclude from the taxable PTV (production tax value) a percentage of the gross value at the point of production for additional or new volumes of oil or gas being produced. This concept could have significant potential, and indeed it may prove very valuable for explorers and others who can bring new fields and reservoirs into production.

Unfortunately, the proposed GRE aims away from the significant opportunities for new production that BP has identified for its business. SB 21 would allow a GRE only for production “from a lease or property that does not contain land that was within a unit on January 1, 2003[.]”

or if it does have land that was in a unit before 2003, “the oil or gas is produced from a participating area established after ... 2011 [that] does not contain a reservoir that had previously been in a participating area established before ... 2012.”

BP’s business centers primarily around units that were established before 2003 — the Prudhoe Bay Unit, Kuparuk River Unit, Duck Island Unit and Milne Point Unit. These units are fully explored, and the likelihood is small that any significant new participating area will be established in them that “does not contain a reservoir that had previously been in a participating area established before ... 2012.” So these units are unlikely to receive any GRE, as the Bill reads now.

The present focus of the proposed GRE is misdirected. Econ One a week ago told you that an estimated 29.1 billion barrels of oil and barrel-equivalents of gas on the North Slope and offshore in the OCS is “Economically Recoverable @ \$90/bbl”. But, as AOGA pointed out in its testimony on Monday, only 10% of that resource is in an area that Alaska has any direct economic stake in and control over — the central North Slope. Of the 3 billion barrels there that Econ One identified, AOGA’s testimony (in which we and the other members of AOGA all concurred) estimated that “2.5 billion barrels or more stands to come from Prudhoe Bay, Kuparuk and other legacy fields already in production” that have little or no chance of getting any GRE under the Bill.

If you’re going to hunt for eggs, you have to look where the hens nest. The same is true for oil. If you are going to provide an incentive to increase production rates and ultimate recovery, offer it where the oil is.

There are several problems with the present ACES law that SB 21 does not address, and I will quickly brief you about them.

The first is the disallowance under AS 43.55.165(e)(19) of “costs incurred for repair, replacement, or deferred maintenance” of production facilities “in response to a failure, problem, or event that results in the unscheduled interruption ... or reduction in the rate of ... production ... or in response to ... an unpermitted release of a hazardous substance or [natural] gas[.]” This was enacted in 2007 in response to the partial shutdown of Prudhoe Bay in 2006 after two corrosion-caused leaks were discovered. BP is not seeking change to the substance of the disallowance itself, but we think the statutory language should be improved to establish clarity about its applicability.

There are minor hiccups in production operations almost every day in fields around the world, and Alaska’s fields are no exception. The present statute sets no standard of materiality for an “unscheduled interruption .. or reduction” in production. If production at a facility is “interrupted” for five minutes because of a temporary hiccup in operations, does that cause a disallowed expense? If production is “reduced” by five barrels a day for a field producing over 400,000 barrels daily, does that cause a disallowed expense? If production is interrupted for a material period of time, but ultimately it turns out to cost only \$10 to respond to it, is it worthwhile to identify and quantify this \$10 so it can be disallowed? There is no answer to these and similar questions in the statute, and the Department of Revenue has not adopted regulations that answer them.

We are not asking you to try to write the answers to these questions in the statute, although you certainly could if you want to do all that work. But we suggest, instead, that you expressly give the Department of Revenue not only the authority, but the duty, to adopt regulations that set reasonable thresholds for materiality about how long an “interruption” has to last, about how large a “reduction” in production has to be, about how much an unauthorized release has to be or in what circumstances must it occur, and about how much the cost “incurred ... in response to” such situations has to be, in order to trigger the disallowance.

As you know, I worked in the Department of Revenue some 30-odd years ago, and if I had to administer this statute in light of the circumstances and controversy that led to its enactment, I would be reluctant to adopt regulations on my own initiative to establish such thresholds unless I had some kind of go-ahead or permission from the Legislature. Perhaps the Department is waiting for such a sign from you.

The second unaddressed problem comes from the changes that ACES made to AS 43.55.150, the statute that determines the gross value at the point of production on the basis of destination prices or values minus the costs of transporting the oil or gas to those destinations from the point of production in the field. As amended, the actual cost that a producer pays to a regulated pipeline carrier to ship the producer’s oil could be set aside if the producer and carrier are “affiliated.” The Department has adopted regulations calling for “cost-based” tariff calculations in lieu of the actual regulated tariffs that are paid.

But under those regulations these calculations of the “cost-based” tariffs are made by the Department, not the taxpayer, and there is no deadline in the regulations or in AS 43.55.150 for the Department to make its calculations and share the results with the taxpayer. The only deadline is the six-year statute of limitations under AS 43.55.075(a). We concur with AOGA’s testimony about the interplay between this six-year statute and interest at 11% APR, compounded quarterly, for any tax underpayment that, in this regulated-pipeline situation, might result from the Department’s calculation of a lower tariff than the one allowed by the governmental regulatory agency having jurisdiction over that tariff. Six years at 11% almost doubles-up the amount of a tax increase from such a “cost-based” tariff.

Further, the tax laws of the State are not an appropriate place for Alaska to try to regulate pipeline tariffs. That is a function of the Police Power, and the Regulatory Commission of Alaska has been established as the executive agency to exercise that regulatory power. The Federal Energy Regulatory Commission has similarly been created by Congress to regulate pipeline tariffs for interstate shipments under the Congressional power created by the United States Constitution power to regulate interstate commerce. State tax authorities have no business trying to supplant either of these agencies.

Any further matters regarding SB 21 that we would bring to your attention have already been addressed by AOGA in its testimony to you on Monday.

Thank you for this opportunity to testify to you today.



## **BP Testimony to Senate Resources**

**Damian Bilbao, Head of Finance**

**Thomas K. Williams, Senior Tax & Royalty Counsel**

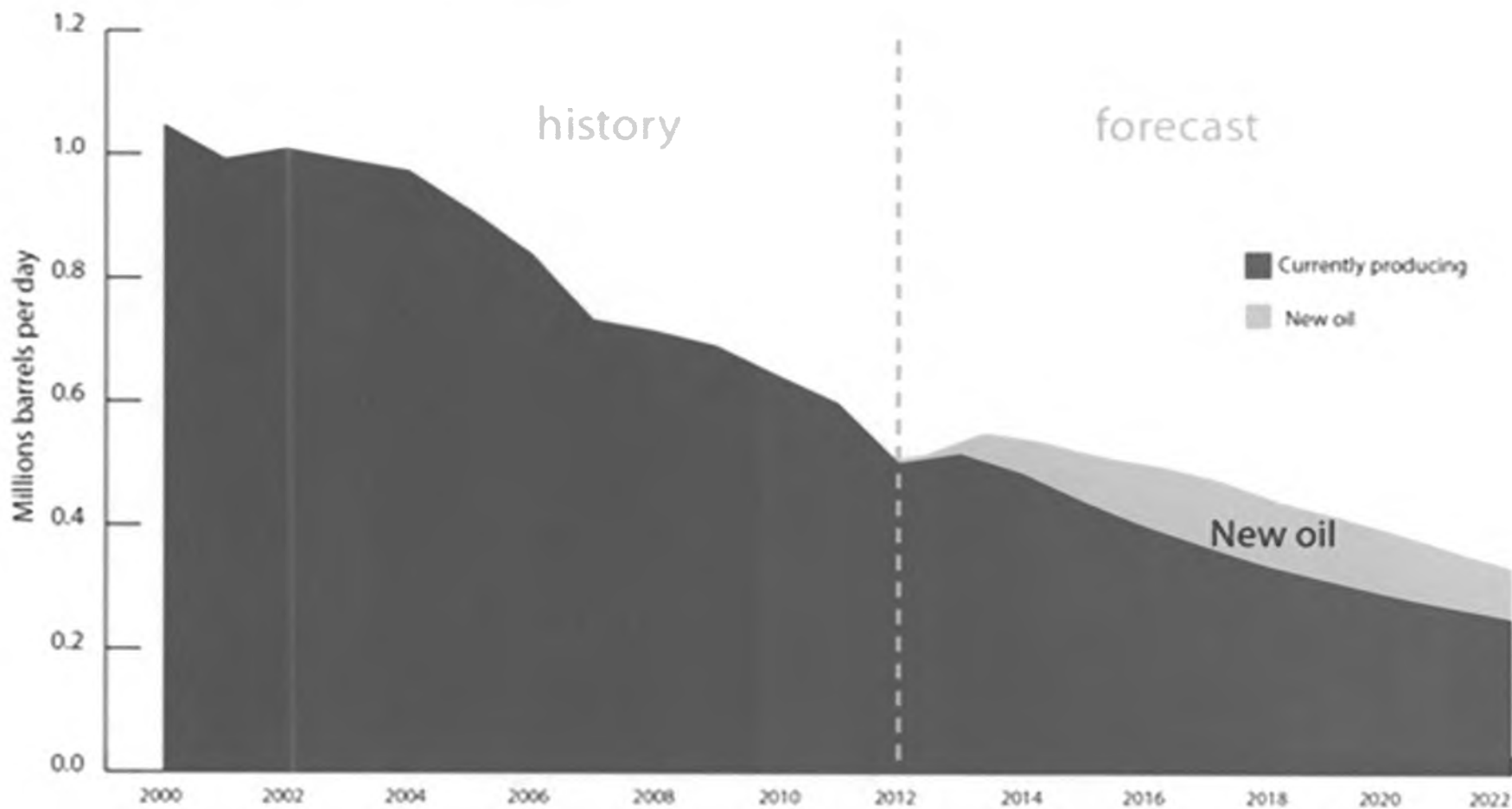
**February 20, 2013**

# Production Decline is Real



## Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



Source: Department of Revenue - Dec. 2012

# How ACES works



		<b>Bbl</b>	<b>\$/bbl</b>
USWC Price	\$1,000,000	10,000	\$100.00
Transportation	<u>\$150,000</u>	10,000	<u>\$15.00</u>
GVPP	\$850,000	10,000	\$85.00
Field Expense	<u>\$300,000</u>	10,000	<u>\$30.00</u>
PTV	\$550,000	10,000	\$55.00
25% Base Tax	\$137,500		
Prog'y Rate	10.000%		
Prog'y Tax	<u>\$55,000</u>		
Total Tax	\$192,500		

USWC – U.S. West Coast  
 GVPP – Gross Value at the Point of Production  
 PTV – Production Tax Value  
 Prog'y - Progressivity

## Example – The three changes together



	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>	
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640	All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>		
GVPP	\$850,000		\$880,000	10,000	\$85.00	\$88.00		
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>		
PTV	\$550,000		\$610,000	10,000	\$55.00	\$61.00		
25% Base Tax	\$137,500		\$152,500					
Prog'y Rate	10.000%		12.400%					
Prog'y Tax	<u>\$55,000</u>		<u>\$75,640</u>					
Total Tax	\$192,500		\$228,140					
Change in tax	-		\$35,640					

USWC – U.S. West Coast  
 GVPP – Gross Value at the Point of Production  
 PTV – Production Tax Value  
 Prog'y - Progressivity

## Example – Price change only



	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>	
USWC Price	\$1,000,000	\$10,000	\$1,010,000	10,000	\$100.00	\$101.00	\$35,640	All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>	\$5,740	Price
GVPP	\$850,000		\$860,000	10,000	\$85.00	\$86.00		
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>		
PTV	\$550,000		\$560,000	10,000	\$55.00	\$56.00		
25% Base Tax	\$137,500		\$140,000					
Prog'y Rate	10.000%		10.400%					
Prog'y Tax	<u>\$55,000</u>		<u>\$58,240</u>					
Total Tax	\$192,500		\$198,240					
Change in tax	-		\$5,740					

USWC – U.S. West Coast  
 GVPP – Gross Value at the Point of Production  
 PTV – Production Tax Value  
 Prog'y - Progressivity

## Example – Transportation cost savings



	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>	
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$35,640	All 3
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>		
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00	\$5,740	Price
Field Expense	<u>\$300,000</u>		<u>\$300,000</u>	10,000	<u>\$30.00</u>	<u>\$30.00</u>	\$11,560	Transpo.
PTV	\$550,000		\$570,000	10,000	\$55.00	\$57.00		
25% Base Tax	\$137,500		\$142,500					
Prog'y Rate	10.000%		10.800%					
Prog'y Tax	<u>\$55,000</u>		<u>\$61,560</u>					
Total Tax	\$192,500		\$204,060					
Change in tax	-		\$11,560					

USWC – U.S. West Coast  
 GVPP – Gross Value at the Point of Production  
 PTV – Production Tax Value  
 Prog'y - Progressivity

# Whole is greater than the sum of its parts



	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$35,640 All 3
Transportation	<u>\$150,000</u>		<u>\$150,000</u>	10,000	<u>\$15.00</u>	<u>\$15.00</u>	
GVPP	\$850,000		\$850,000	10,000	\$85.00	\$85.00	\$5,740 Price
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560 Transpo.
PTV	\$550,000		\$580,000	10,000	\$55.00	\$58.00	<u>\$17,460</u> Lease Exp.
25% Base Tax	\$137,500		\$145,000				\$34,760
Prog'y Rate	10.000%		11.200%				
Prog'y Tax	<u>\$55,000</u>		<u>\$64,960</u>				
Total Tax	\$192,500		\$209,960				
Change in tax	-		<u>\$17,460</u>				

USWC – U.S. West Coast  
 GVPP – Gross Value at the Point of Production  
 PTV – Production Tax Value  
 Prog'y - Progressivity

# ACES's continuously changing tax effect



	<b>Base Case</b>	<b>Revision</b>	<b>As Revised</b>	<b>Bbl</b>	<b>Base Case \$/Bbl</b>	<b>Revised \$/Bbl</b>	<b>Change in Tax</b>
USWC Price	\$1,000,000		\$1,000,000	10,000	\$100.00	\$100.00	\$11,560 Transpo. Only
Transportation	<u>\$150,000</u>	(\$20,000)	<u>\$130,000</u>	10,000	<u>\$15.00</u>	<u>\$13.00</u>	\$17,460 Field Exp Only
GVPP	\$850,000		\$870,000	10,000	\$85.00	\$87.00	
Field Expense	<u>\$300,000</u>	(\$30,000)	<u>\$270,000</u>	10,000	<u>\$30.00</u>	<u>\$27.00</u>	\$11,560 Transpo. 1st
PTV	\$550,000		\$600,000	10,000	\$55.00	\$60.00	<u>\$17,940</u> Field Exp. 2nd
25% Base Tax	\$137,500		\$150,000				\$29,500
Prog'y Rate	10.000%		12.000%				
Prog'y Tax	<u>\$55,000</u>		<u>\$72,000</u>				\$12,040 Transpo. 2nd
Total Tax	\$192,500		\$222,000				<u>\$17,460</u> Field Exp. 1st
Change in tax	-		\$29,500				\$29,500

USWC – U.S. West Coast  
 GVPP – Gross Value at the Point of Production  
 PTV – Production Tax Value  
 Prog'y - Progressivity

## Flat price scenario



	<b>PTV per Bbl</b>	<b>MM bbl</b>	<b>PTV (\$MM)</b>	<b>Prog'v'y Rate</b>	<b>Prog'v'y Tax (\$MM)</b>
<b>Jan</b>	\$61.25	2.00	\$122.5	12.50%	\$15.31
<b>Feb</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Mar</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Apr</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>May</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Jun</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Jul</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Aug</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Sep</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Oct</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Nov</b>	61.25	2.00	\$122.5	12.50%	15.31
<b>Dec</b>	<u>61.25</u>	<u>2.00</u>	<u>\$122.5</u>	<u>12.50%</u>	<u>15.31</u>
<b>Full Year</b>	\$61.25	24.00	\$1,470.0		\$183.75

## Progressivity increases taxes with fluctuating price even when the economics don't change



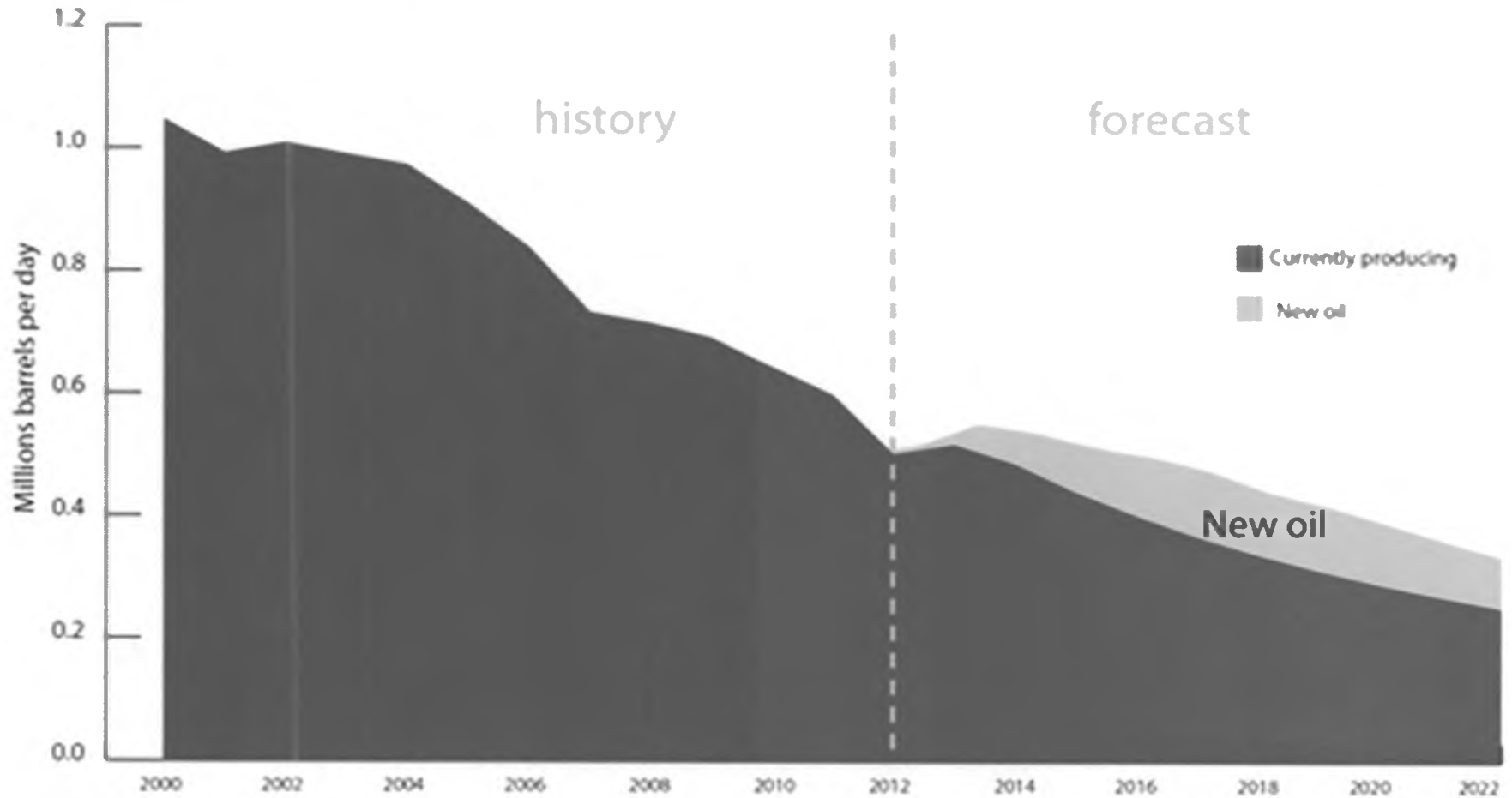
	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)	PTV per Bbl	MM bbl	PTV (\$MM)	Prog'v'y Rate	Prog'v'y Tax (\$MM)
<b>Jan</b>	\$61.25	2.00	\$122.5	12.50%	\$15.31	\$30.00	2.00	60.0	0.00%	-
<b>Feb</b>	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
<b>Mar</b>	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
<b>Apr</b>	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	\$46.25
<b>May</b>	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
<b>Jun</b>	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
<b>Jul</b>	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
<b>Aug</b>	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
<b>Sep</b>	61.25	2.00	\$122.5	12.50%	15.31	92.50	2.00	185.0	25.00%	46.25
<b>Oct</b>	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
<b>Nov</b>	61.25	2.00	\$122.5	12.50%	15.31	30.00	2.00	60.0	0.00%	-
<b>Dec</b>	<u>61.25</u>	<u>2.00</u>	<u>\$122.5</u>	<u>12.50%</u>	<u>15.31</u>	<u>30.00</u>	<u>2.00</u>	<u>60.0</u>	<u>0.00%</u>	<u>-</u>
<b>Full Year</b>	\$61.25	24.00	\$1,470.0		<b>\$183.75</b>	\$61.25	24.00	1,470.0		<b>\$277.50</b>

# Production Decline is Real



## Alaska North Slope Production

FY 2000-2012 and Forecasted FY 2013-2022



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# Senate Resources Committee

**SB21**

Bob Heinrich, VP Finance  
Scott Jepsen, VP External Affairs  
**ConocoPhillips Alaska**

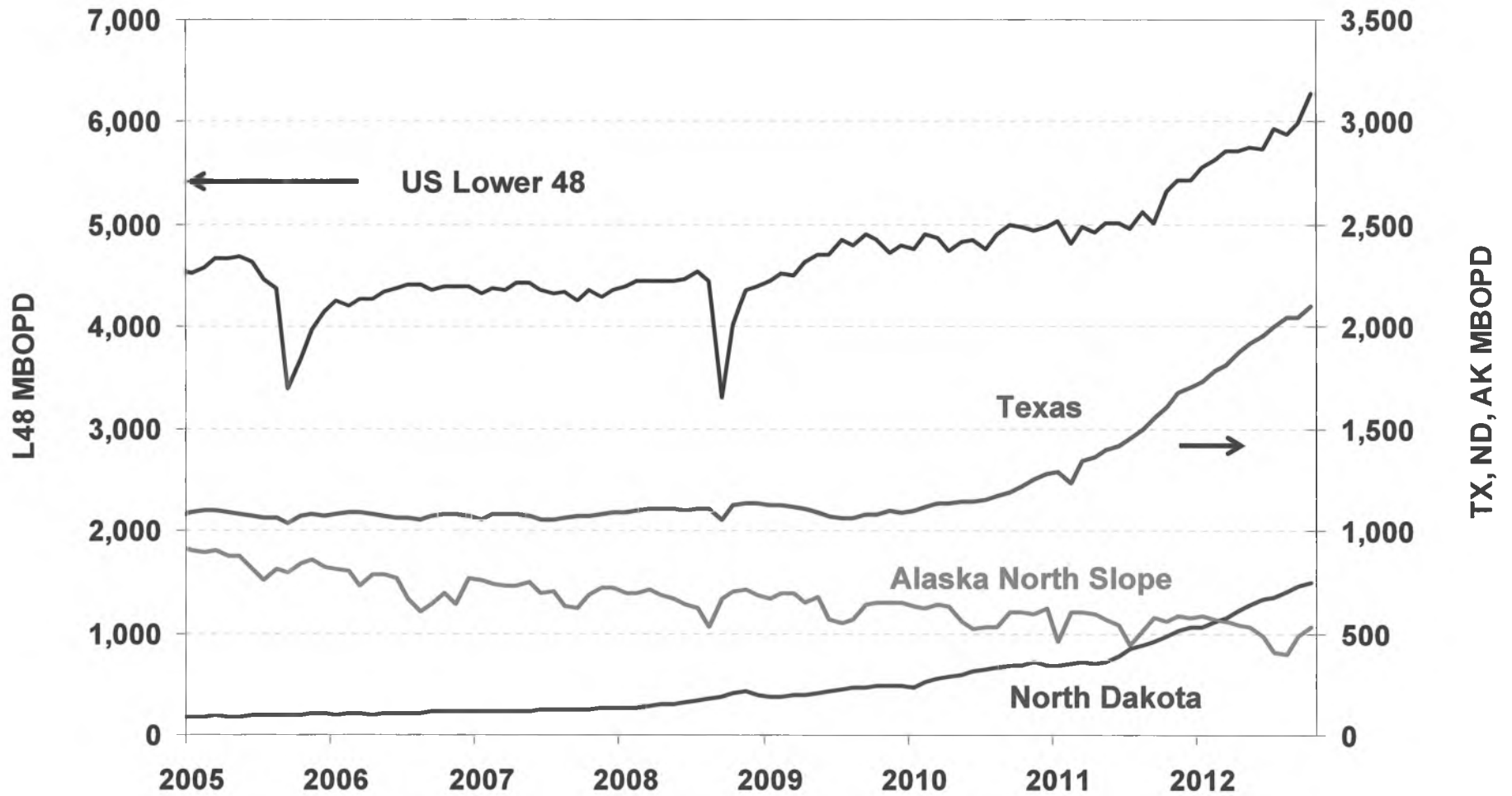
February 20, 2013

# Topics

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- Alaska's Production Challenge
- Investment Considerations and Alaska's Cost Environment
- ACES and SB21
- Observations

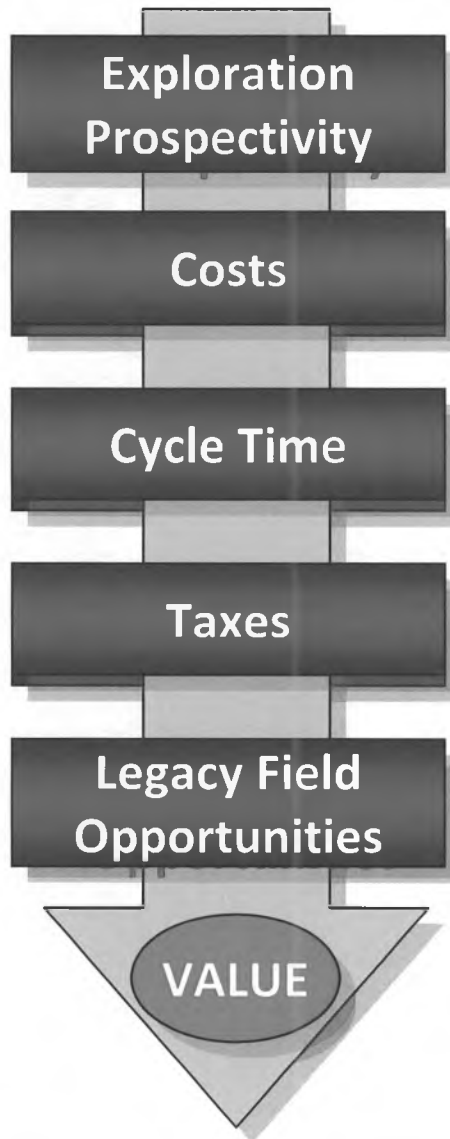
# Alaska Decline Continues While Lower 48 Production Continues to Increase



# Alaska – A Challenging Investment Climate

## Investment Criteria: How Alaska Ranks

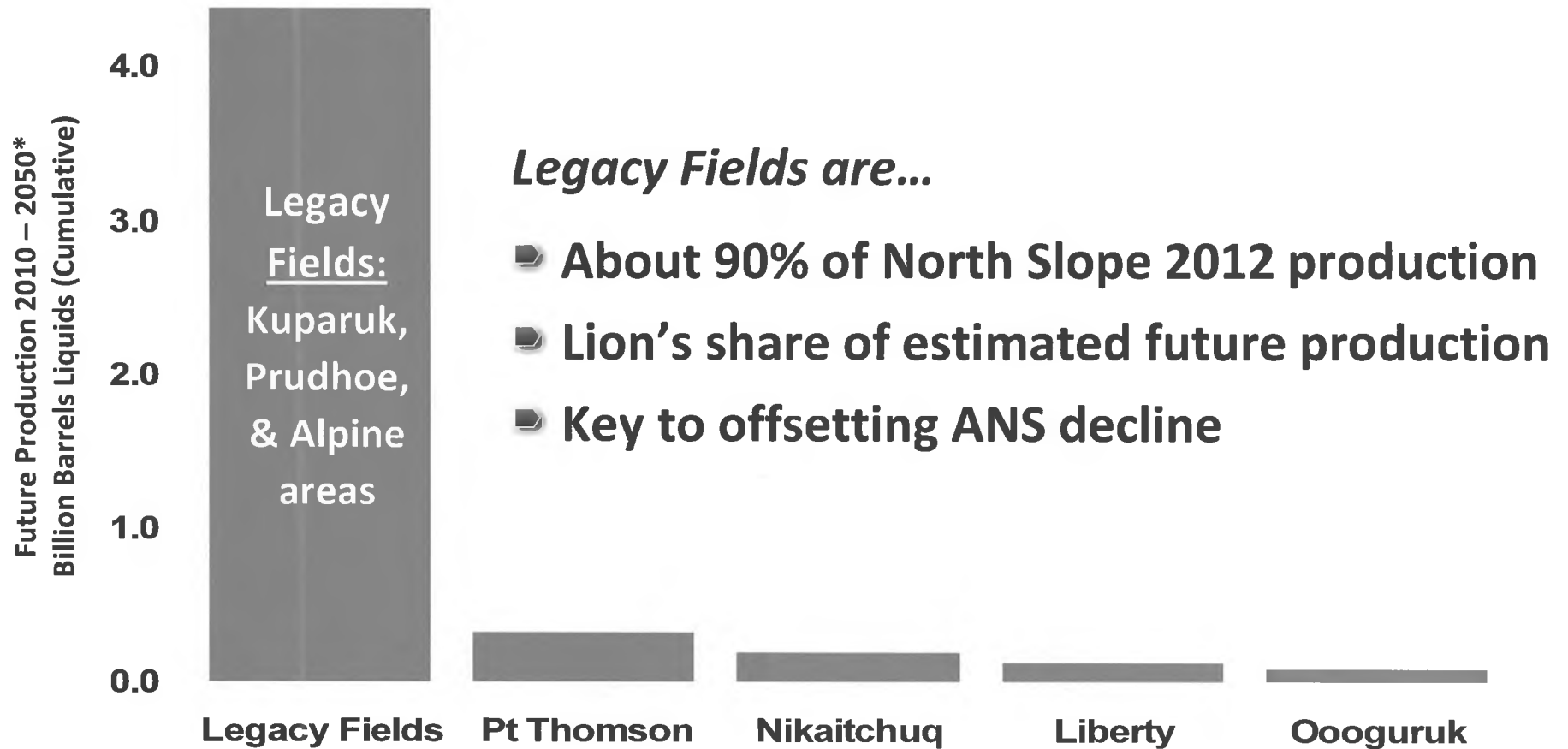
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- Expected field size/maturity
- Crude quality
- Exploration, development & production cost
- Transportation costs to market
- Time to production
- Permitting/regulatory environment
- Tax rates given challenged location
- Tax rates compared to other states & countries
- Billions of barrels left to be developed
- Significant production volumes

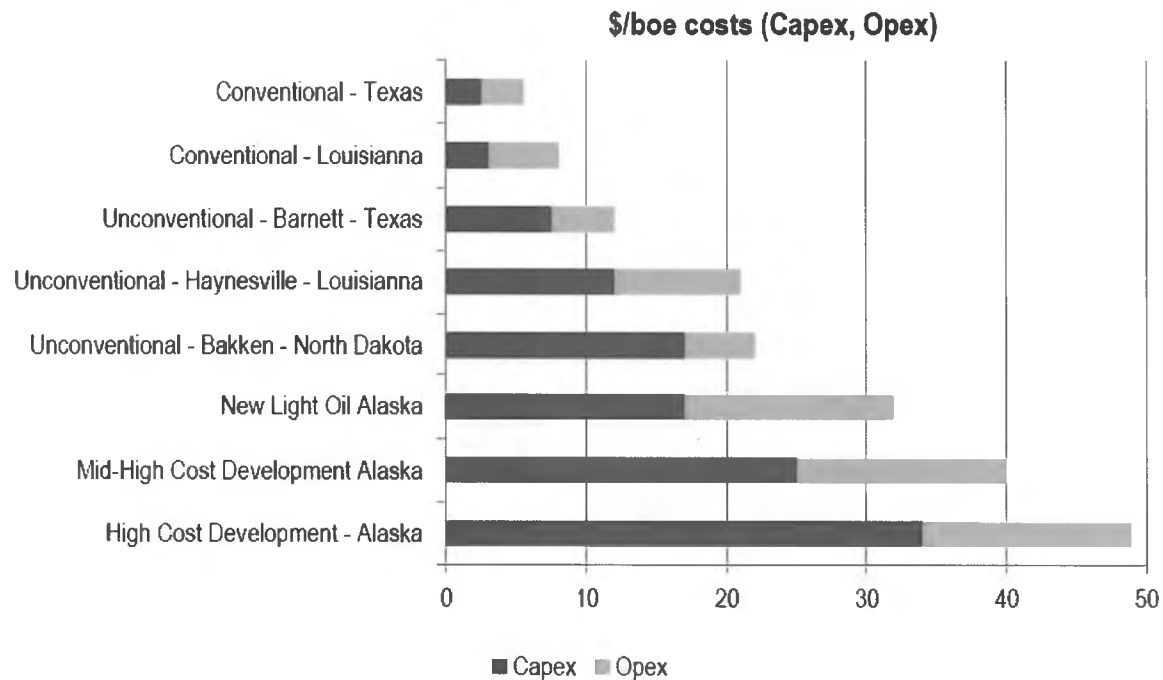


# Alaska Legacy Fields Still Provide Significant Opportunity



\*Source: DOR 2009 production forecast 2010 – 2050 volumes

# Alaska's Days of "Easy Oil" Are Gone: High Costs and High Government Take Present Challenges



Costs are significantly higher in Alaska than the Lower 48 – even compared to unconvensionals. Meanwhile, Alaska's Government Take has risen significantly over recent years, meaning new project economics can be very challenging

# “Easy Oil” In the Legacy Fields Is Gone

- Challenged oil remains
  - Complex, high cost wells
  - Smaller reserve targets
  - Fault blocks, flank oil
  - Satellites, viscous oil
  - Most new wells produce oil AND water
  - Facilities handling ~ three times as much water as oil
- **A billion dollars does not go as far as it used to...**
  - 2000 Alpine development ~80,000 BOPD
  - 2012 CD-5 Drillsite ~18,000 BOPD



Initial Alpine Development



CD-5 Type Development

# ACES Observations

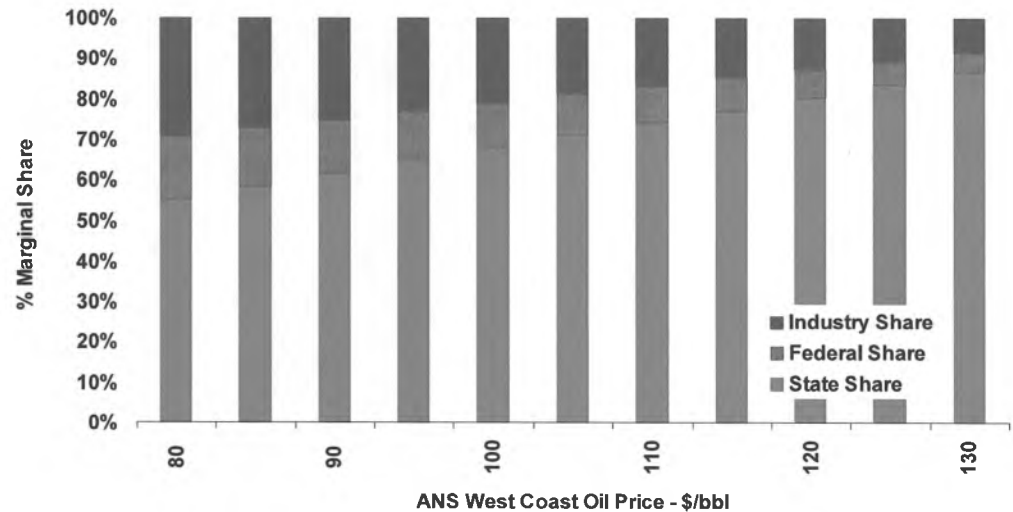
## Positive Elements

- Tax credits help offset Alaska's high cost environment
- Tax credits provided for both new and legacy fields

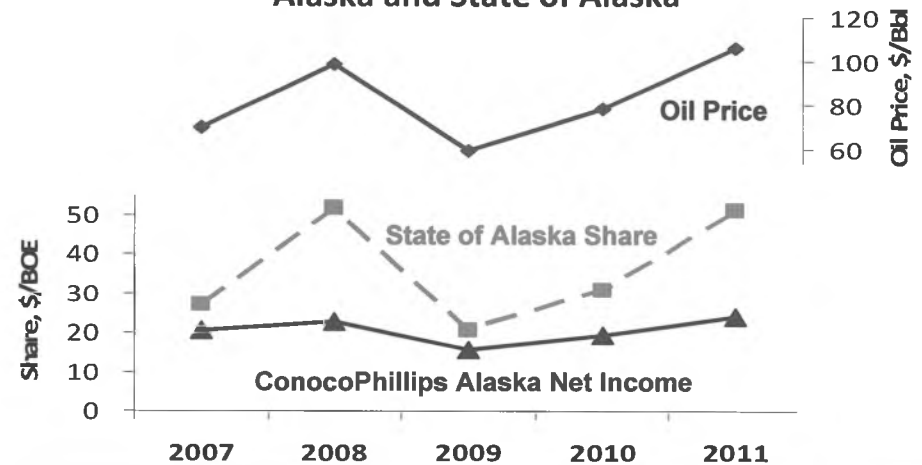
## Negative Elements

- High average tax rates
- High marginal tax rates
- Gross minimum tax
  - Tax still paid if revenues don't cover costs

Government and Industry Marginal Share in Alaska



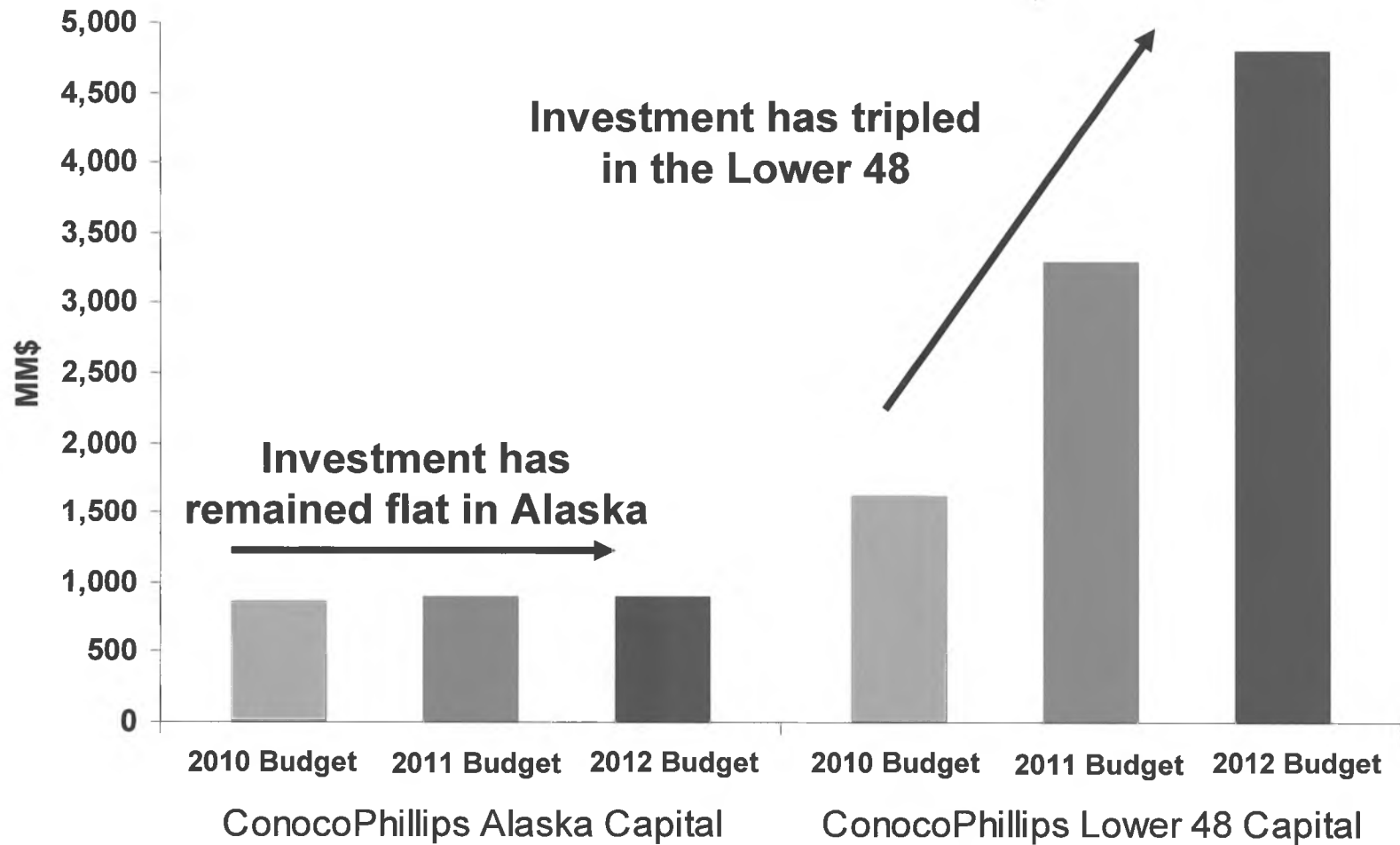
Earnings Per Barrel – ConocoPhillips Alaska and State of Alaska



Upper right plot based on Fall 2012 Revenue Sources Book data for FY2014

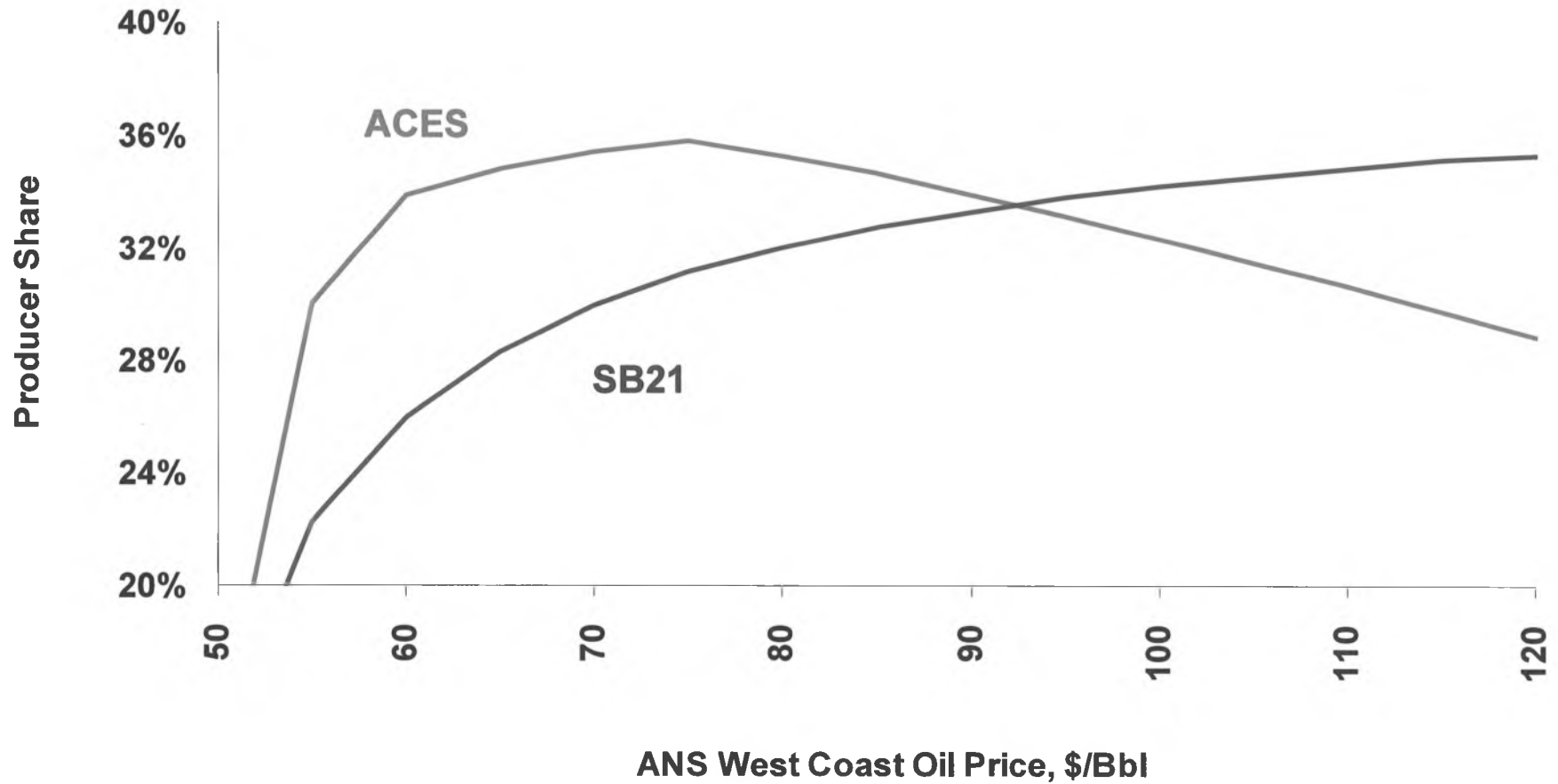
Lower right plot based on ConocoPhillips 2007 – 2011 10-K reports; State share is royalties (estimated), production tax, ad valorem tax and state income tax; oil prices are ConocoPhillips average realized prices on the West Coast

# ConocoPhillips Capital Allocation



Investment flows where investor has upside

# Producer Share under SB21



## Recap of ConocoPhillips Perspective

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### ■ ACES

- Progressivity takes the upside and discourages investment
- Tax credit investment incentives positive, but do not offset the negative effects of ACES progressivity

### ■ SB21 Positive Elements

- Positive step to improve Alaska's business climate
- Solves the high marginal tax problem
- Makes Alaska more competitive at \$100+ prices

### ■ SB21 Areas for Improvement

- Bill does not contain sufficient investment incentives for legacy fields to offset Alaska's high cost environment
- Does not encourage investment relative to ACES in a downward trending oil price environment



# Senate Resources Committee

## Alaska Fiscal System Discussion Slides

February 22 2013  
Janak Mayer  
Manager, Upstream  
PFC Energy



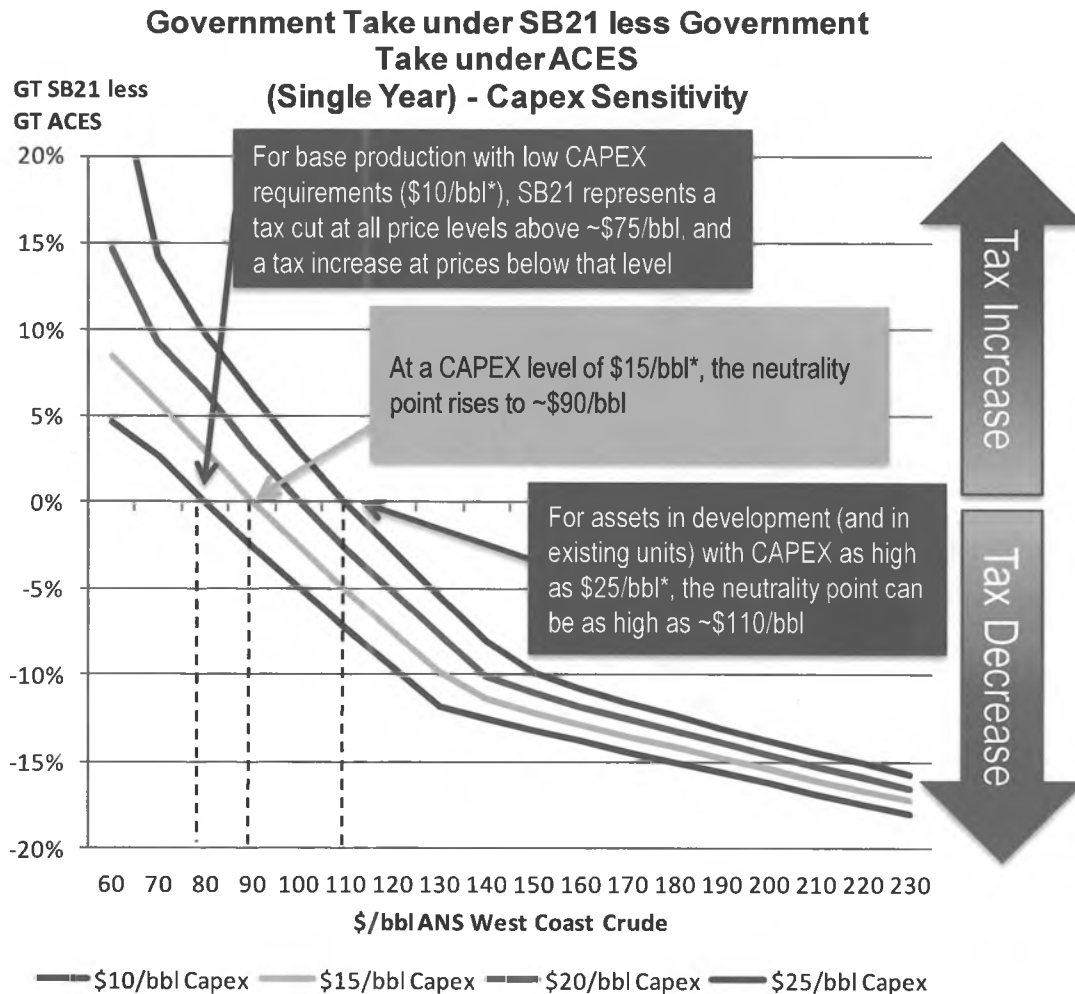
## Requested Analysis:

Letter of Intent recommendation for evaluation point 3 –  
impact of continuing capital credits for well expenditures

Impact of combining well credits with bracketed  
progressivity

Impact of instead using a 35% base rate tax, combined  
with a production-based credit of \$5/taxable bbl, claimable  
only in year of production

# Government Take under SB21/HB72 and ACES – Capex Sensitivity



\* All CAPEX figures are in gross bbl terms (\$15 per gross bbl is roughly equivalent to DOR 2014 average North Slope forecast of \$19.6 per bbl net of royalty, when adjusted for gross/net and for capital expenditures by non-taxable entities)

Alaska Hydrocarbons Fiscal System Analysis | © PFC Energy 2013 | February 2013

- As noted in PFC Energy testimony on 1/31/13, at low oil prices, Relative Government Take under SB 21 is higher than under ACES, due to the impact of low or no progressivity, combined with the elimination of the 20% capital credit under SB 21

- The **oil price level** at which this occurs is highly **sensitive to annual levels of capital spending**, since CAPEX both reduces the oil price level at which progressivity kicks in under ACES, and determines the size of the available capital credit under ACES

- Looking at a **single year of production** also slightly raises this neutrality point, since over many years, inflation reduces the real price level at which progressivity starts under ACES

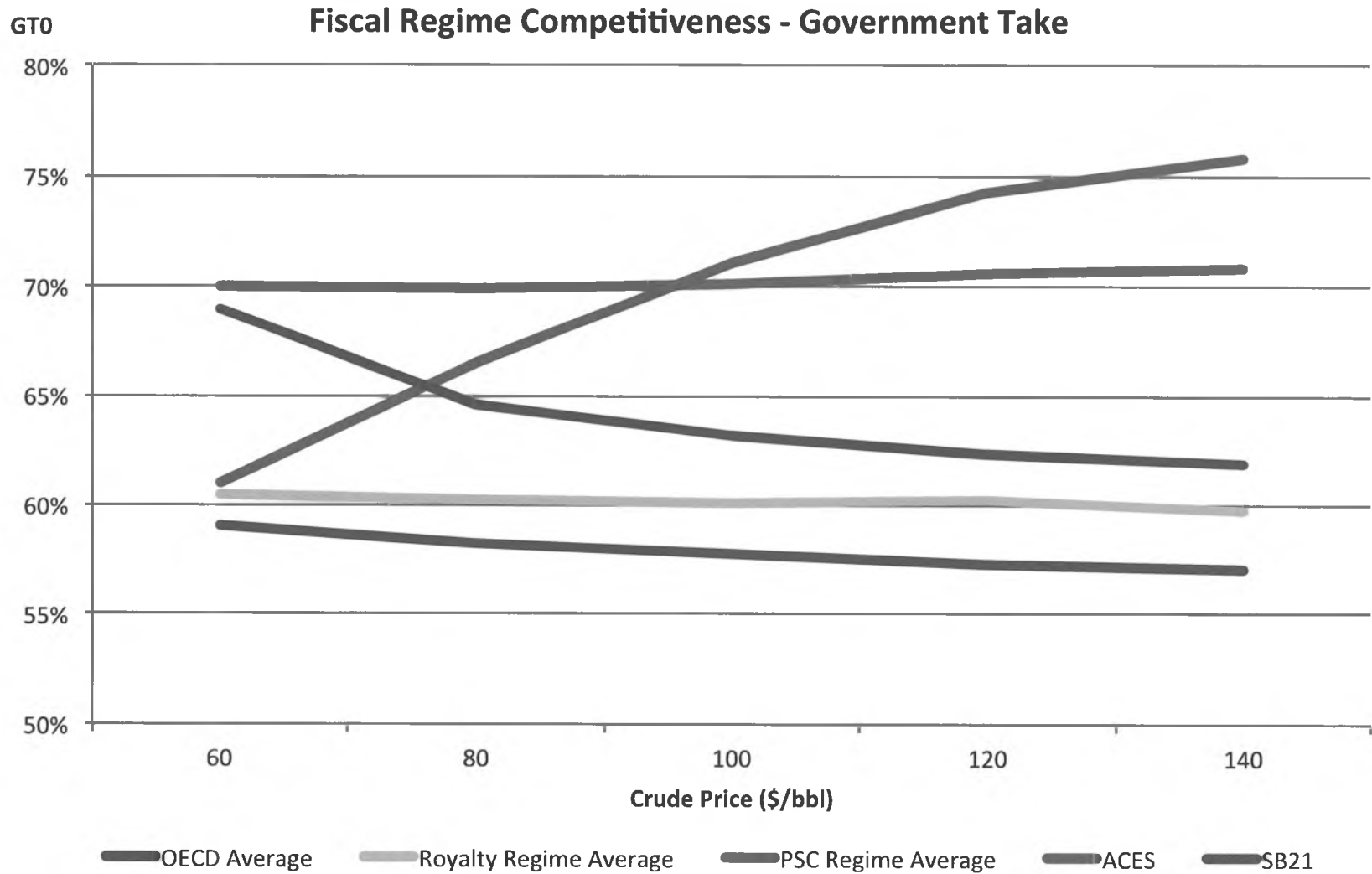
- For mature, producing assets with a low ongoing CAPEX requirement (\$10/bbl), SB21 represents a **reduction in government take at prices above ~\$75**, however for capital intensive new developments in existing units, that neutrality point can be as high as **\$110/bbl**

- It is thus important to understand that one impact of the removal of the 20% capital credit under SB 21 is that for companies with high development costs relative to overall production, it **can represent a tax increase at current prices**

Slide Number: 3

PFC Energy

# Fiscal Regime Competitiveness



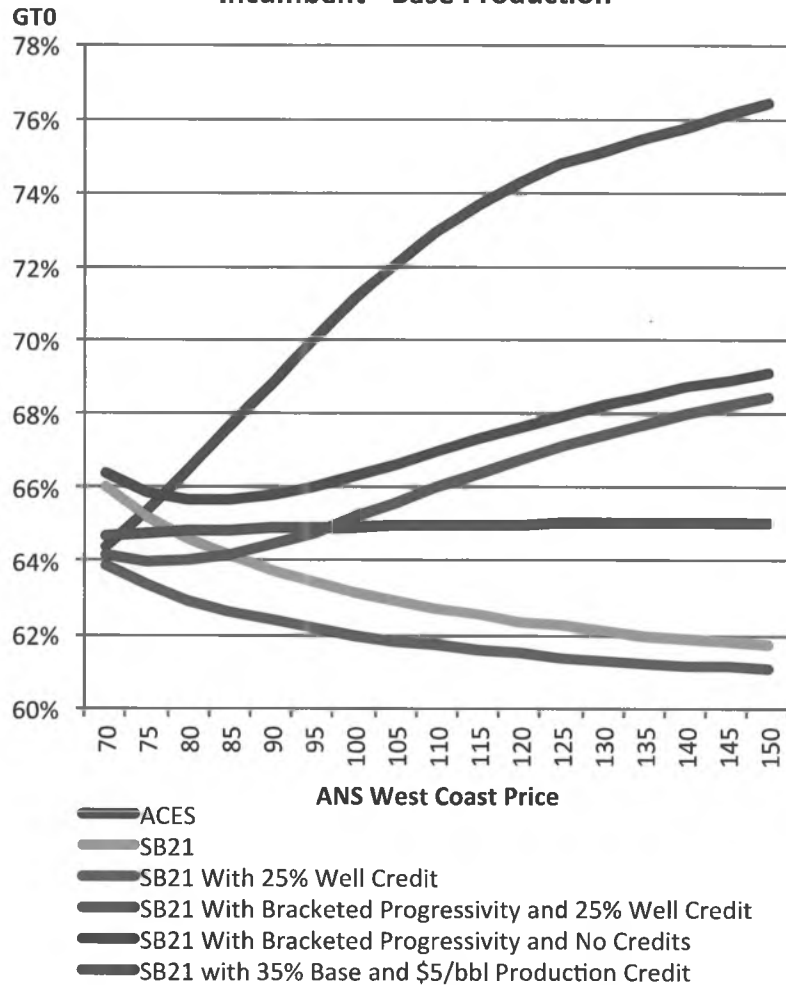
# Assumptions

- Well Credit
  - 50% of capex qualifies, credit level 25%
- Bracketed progressivity
  - Thresholds and rates as under HB110:
    - Base tax 25%
    - <\$30 PTV/bbl, 0% progressivity
    - \$30-\$42.5, 2.5% progressivity
    - \$42.5-\$55 – 7.5% progressivity
    - \$55-\$67.5 – 12.5% progressivity
    - \$67.5-\$80 – 17.5% progressivity
    - \$80-\$92.50 – 22.5% progressivity
    - >\$92.50 PTV/bbl – 25% progressivity

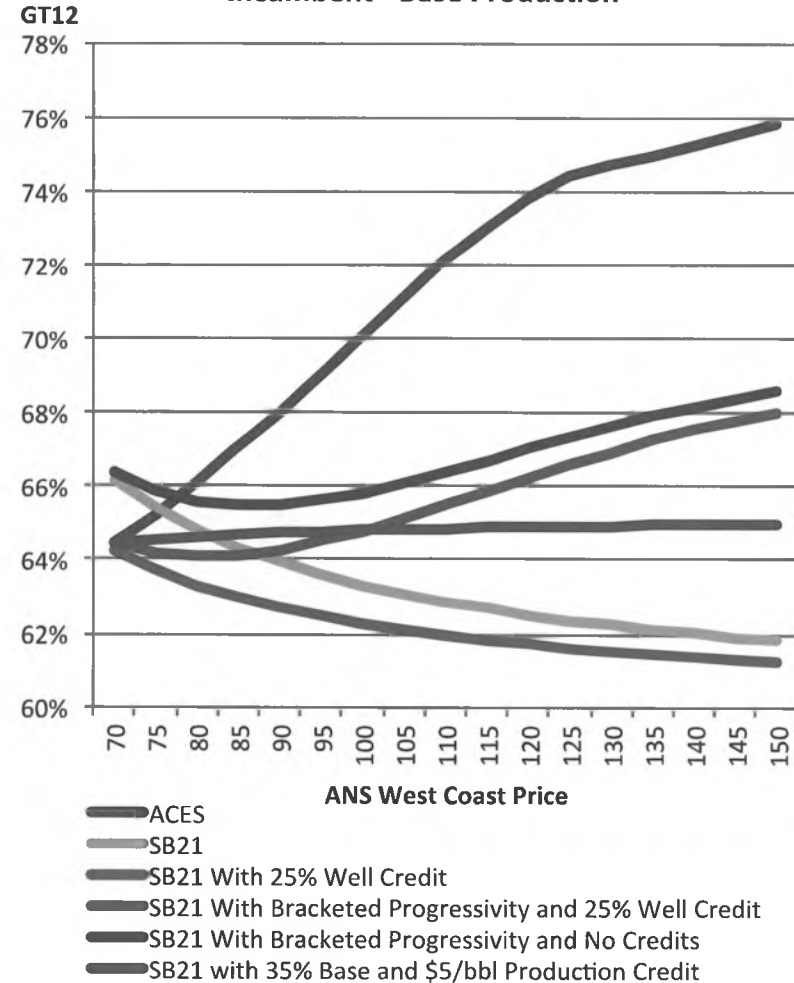
# Government Take Comparison

## Incumbent, Base Production

Undiscounted Government Take comparison - Incumbent - Base Production

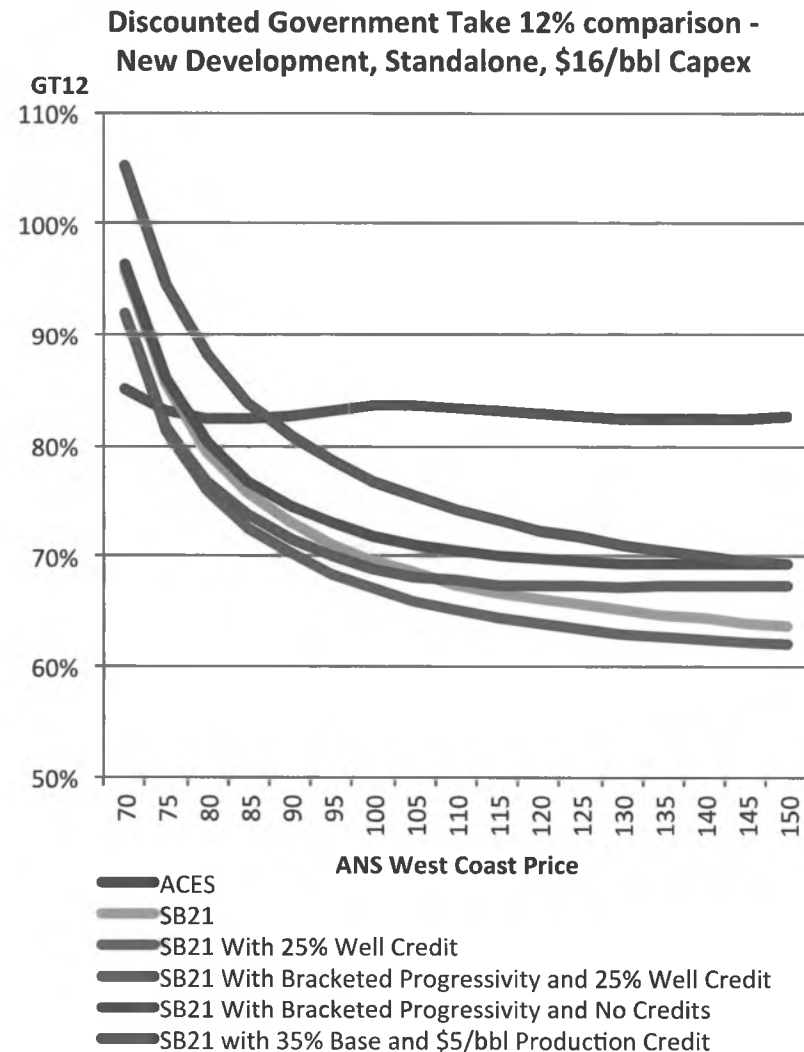
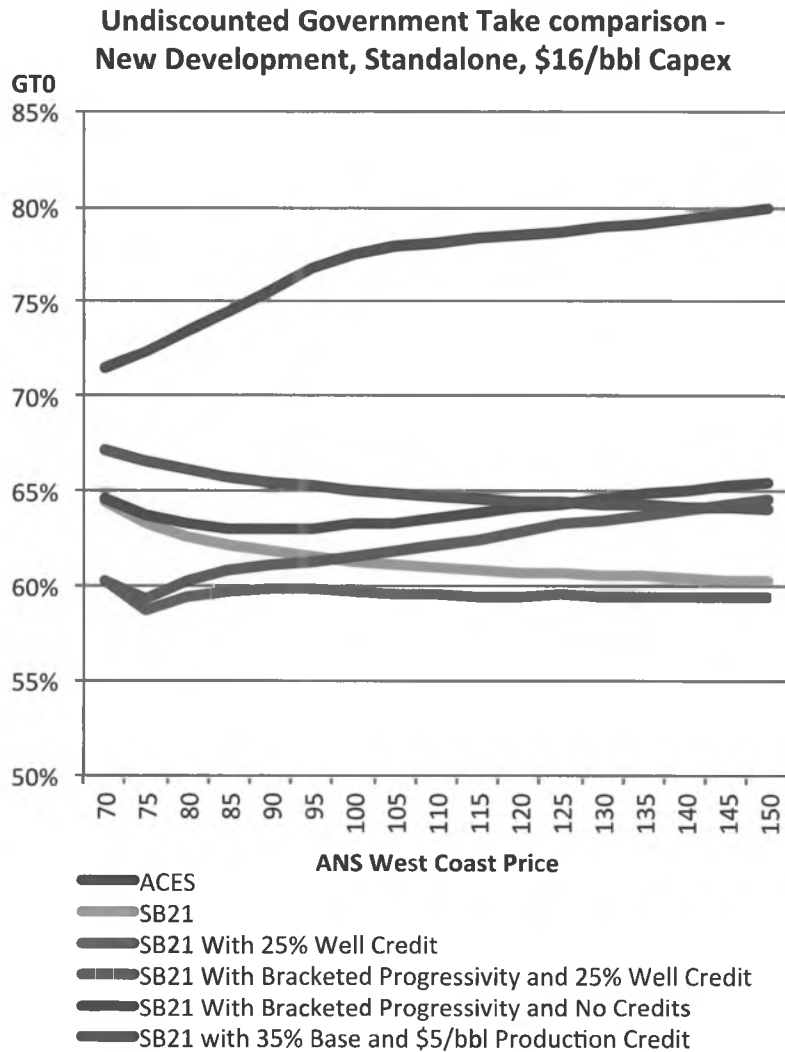


Discounted Government Take 12% comparison - Incumbent - Base Production



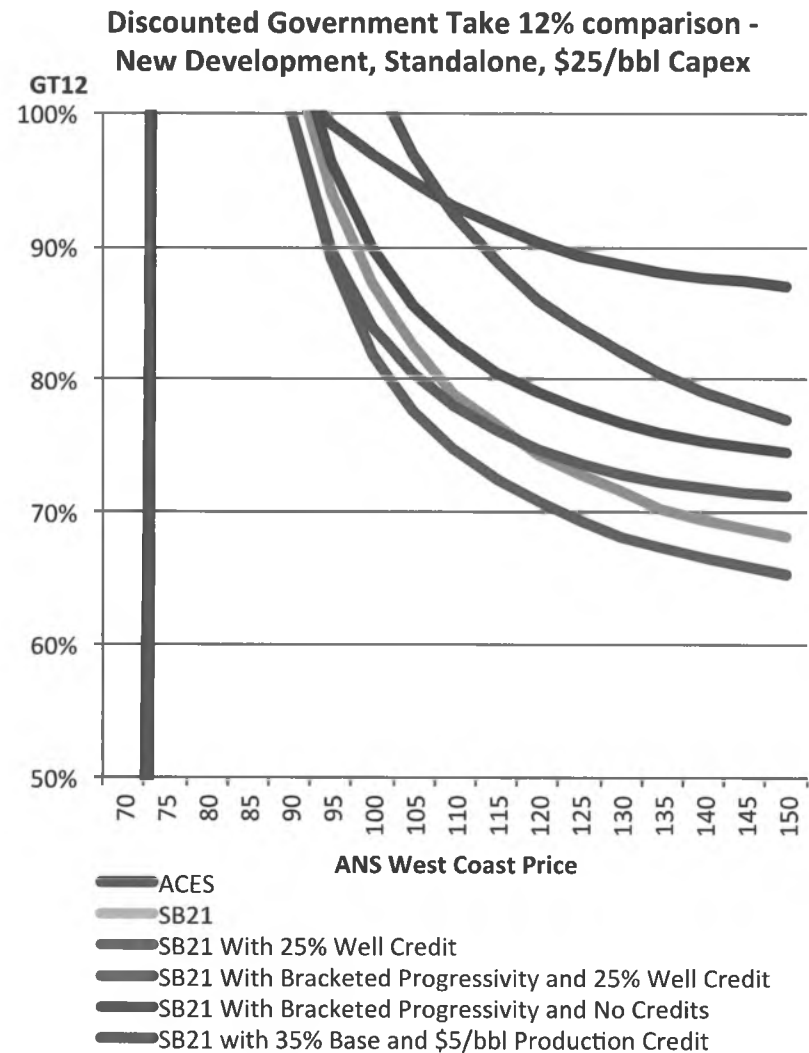
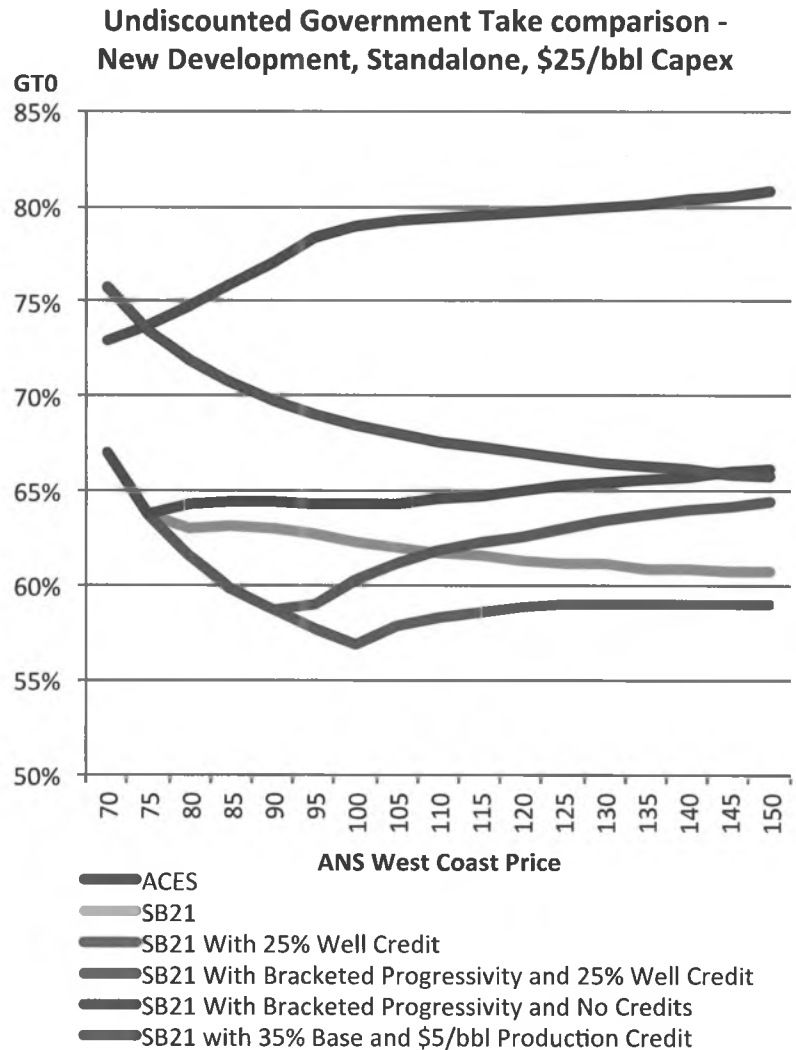
# Government Take Comparison

## \$16/bbl New Development, Standalone



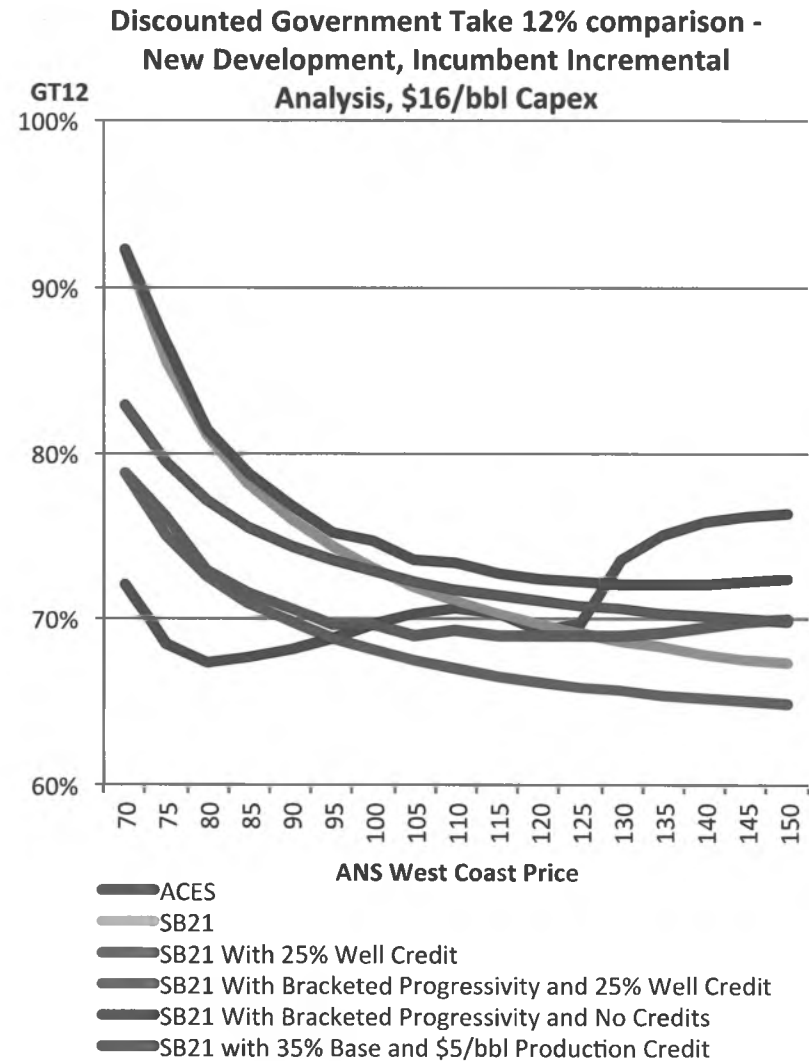
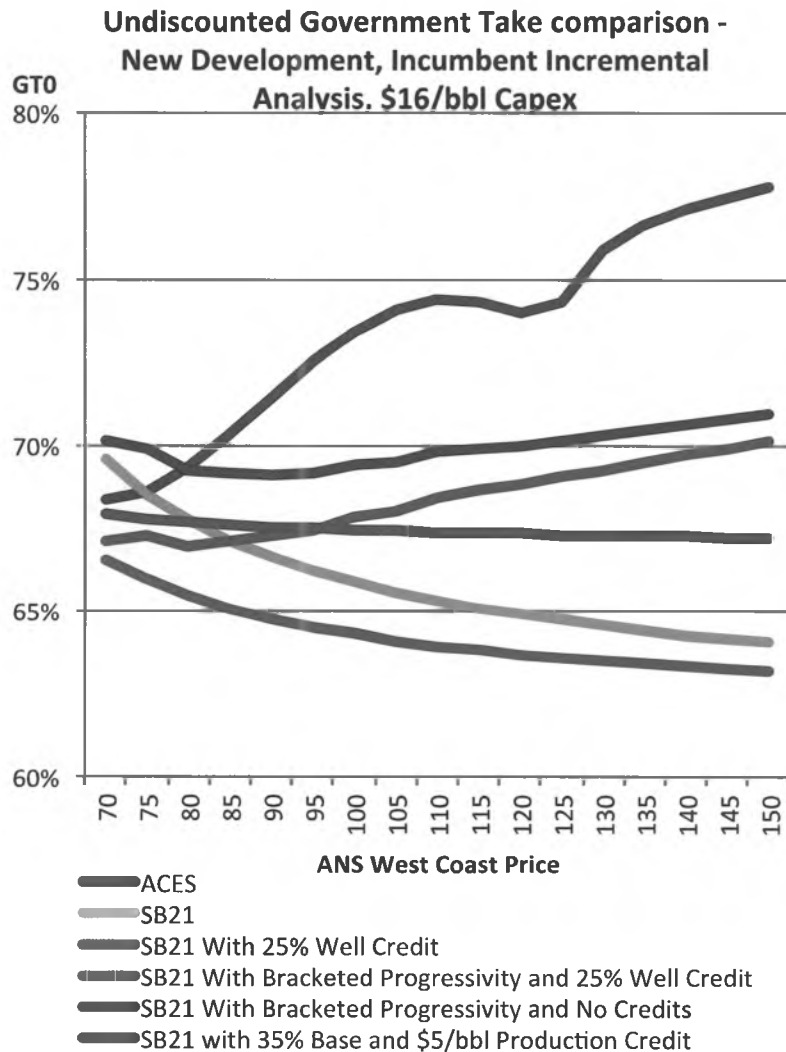
# Government Take Comparison

## \$25/bbl New Development (with GRE), Standalone



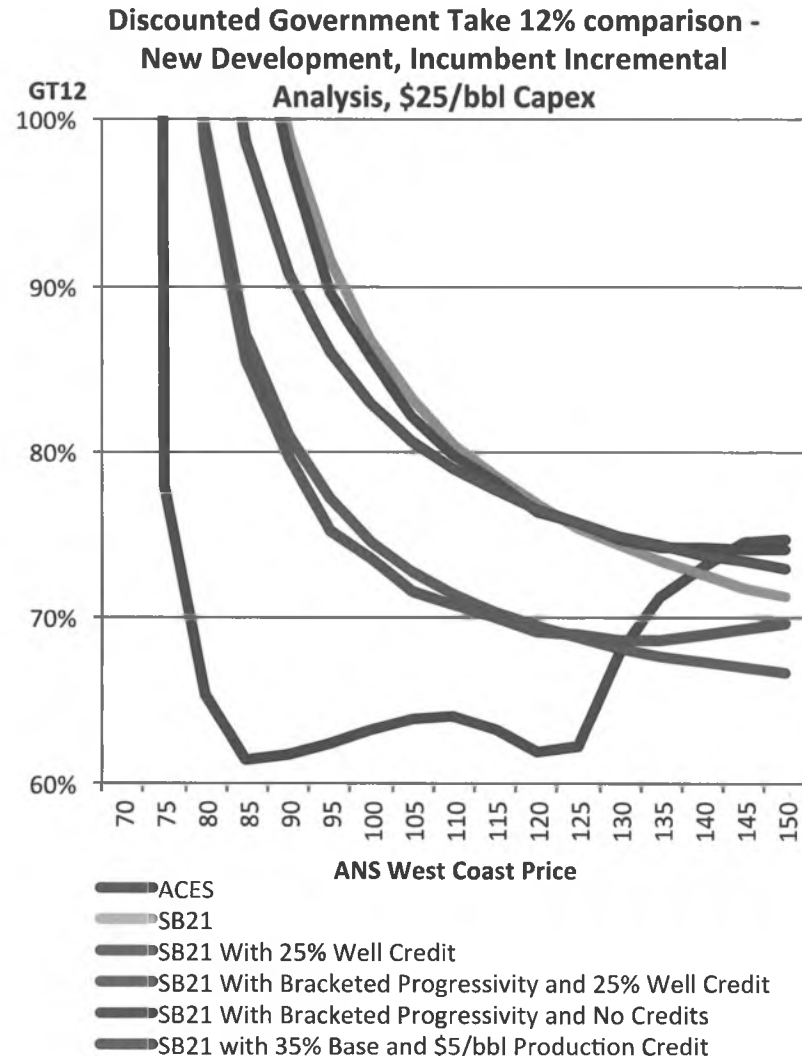
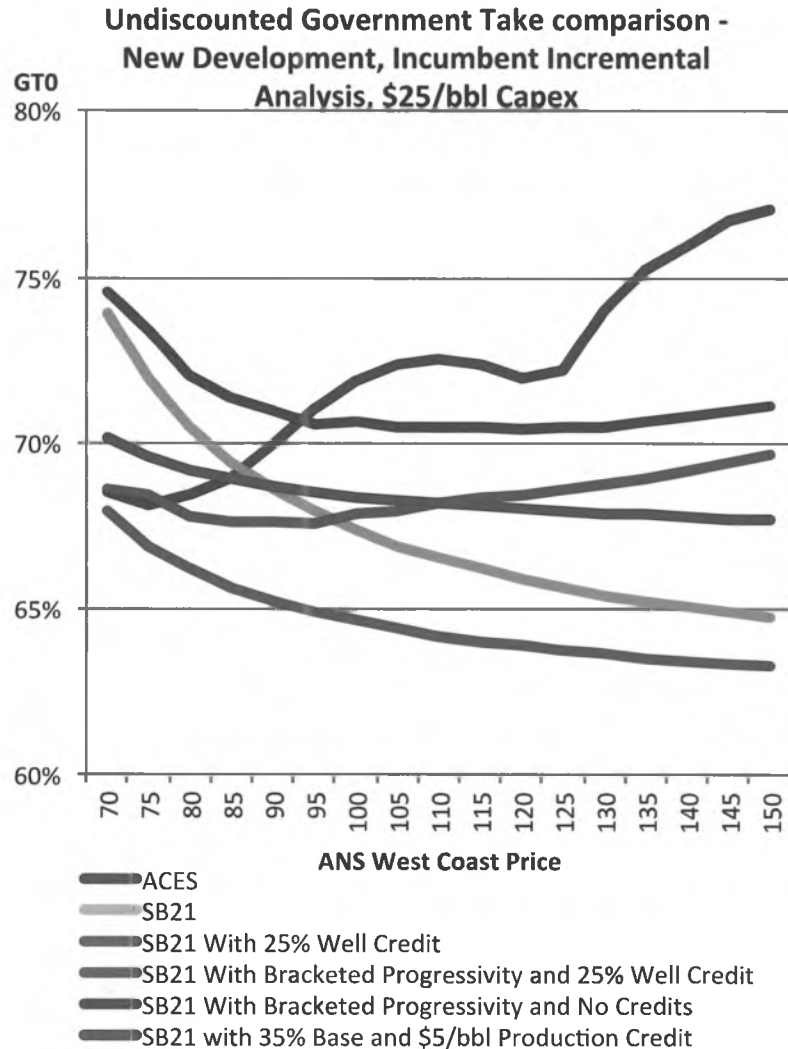
# Government Take Comparison

## \$16/bbl New Development, Incumbent Producer Incremental Analysis



# Government Take Comparison

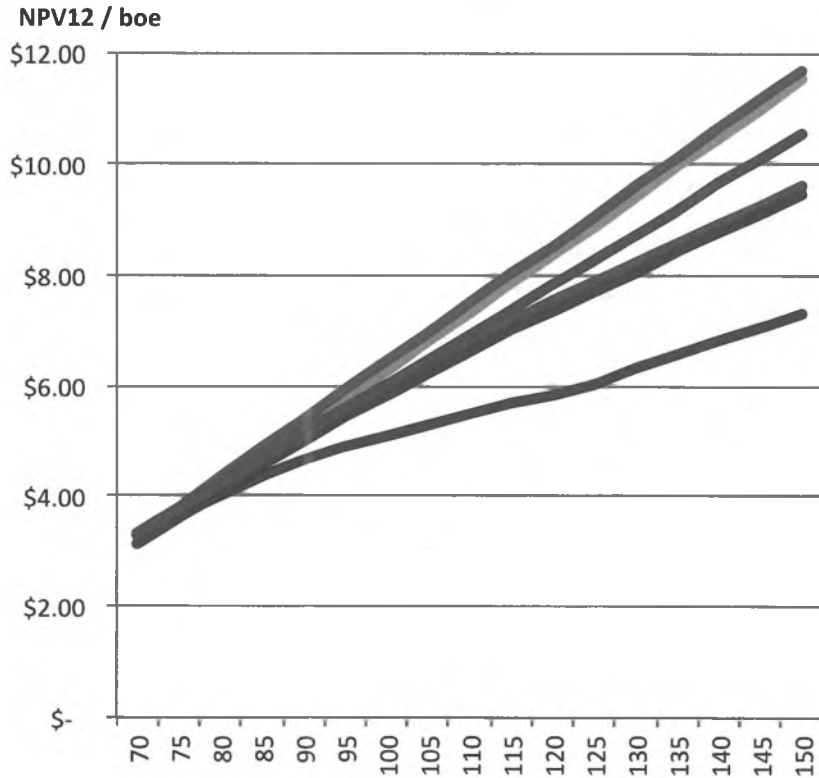
## \$25/bbl New Development, Incumbent Producer Incremental Analysis



# NPV12/bbl & Cash Margin Comparison

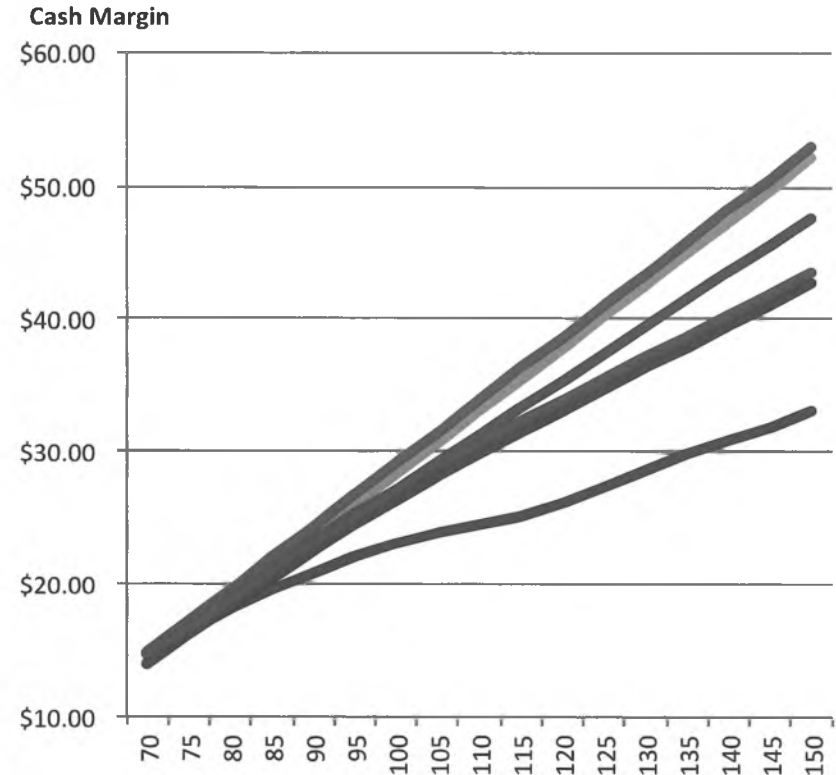
## Incumbent, Base Production

NPV12 / boe comparison - Incumbent - Base Production



- ACES
- SB21
- SB21 With 25% Well Credit
- SB21 With Bracketed Progressivity and 25% Well Credit
- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

Cash Margin (2017 - 2022) comparison - Incumbent - Base Production

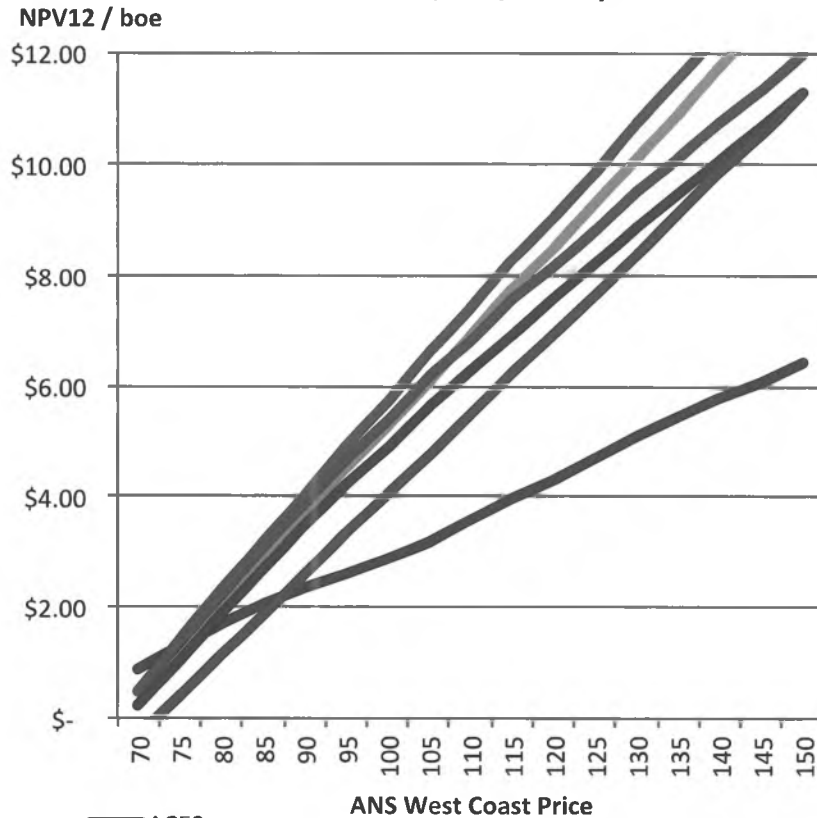


- ACES
- SB21
- SB21 With 25% Well Credit
- SB21 With Bracketed Progressivity and 25% Well Credit
- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

# NPV12/bbl & Cash Margin Comparison

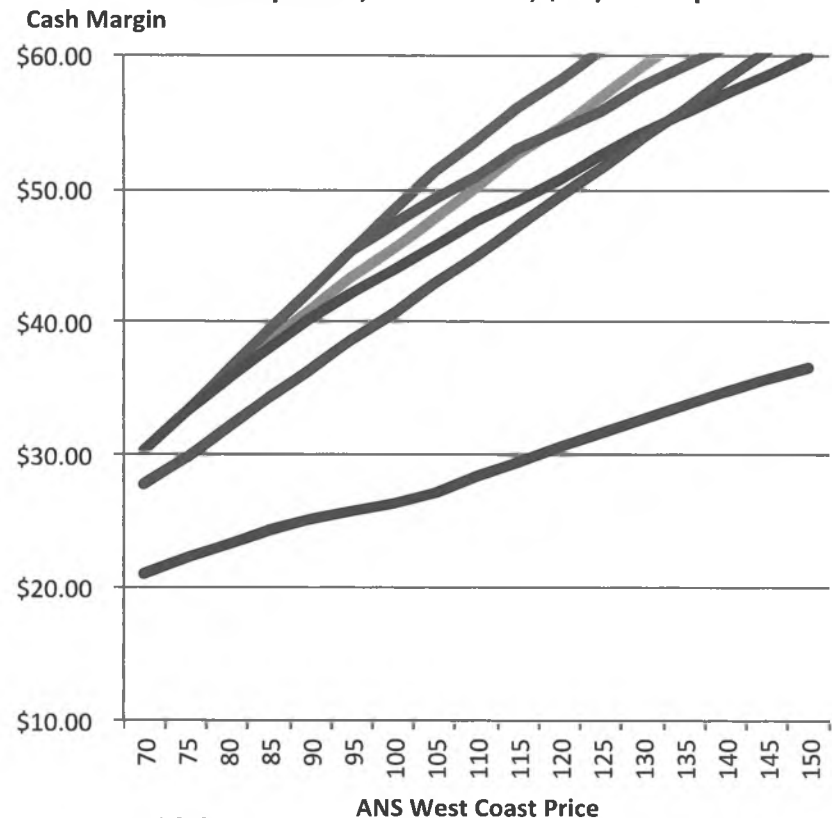
## \$16/bbl New Development, Standalone

NPV12 / boe comparison - New Development, Standalone, \$16/bbl Capex



- ACES
- SB21
- SB21 With 25% Well Credit
- SB21 With Bracketed Progressivity and 25% Well Credit
- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

Cash Margin (2017 - 2022) comparison - New Development, Standalone, \$16/bbl Capex

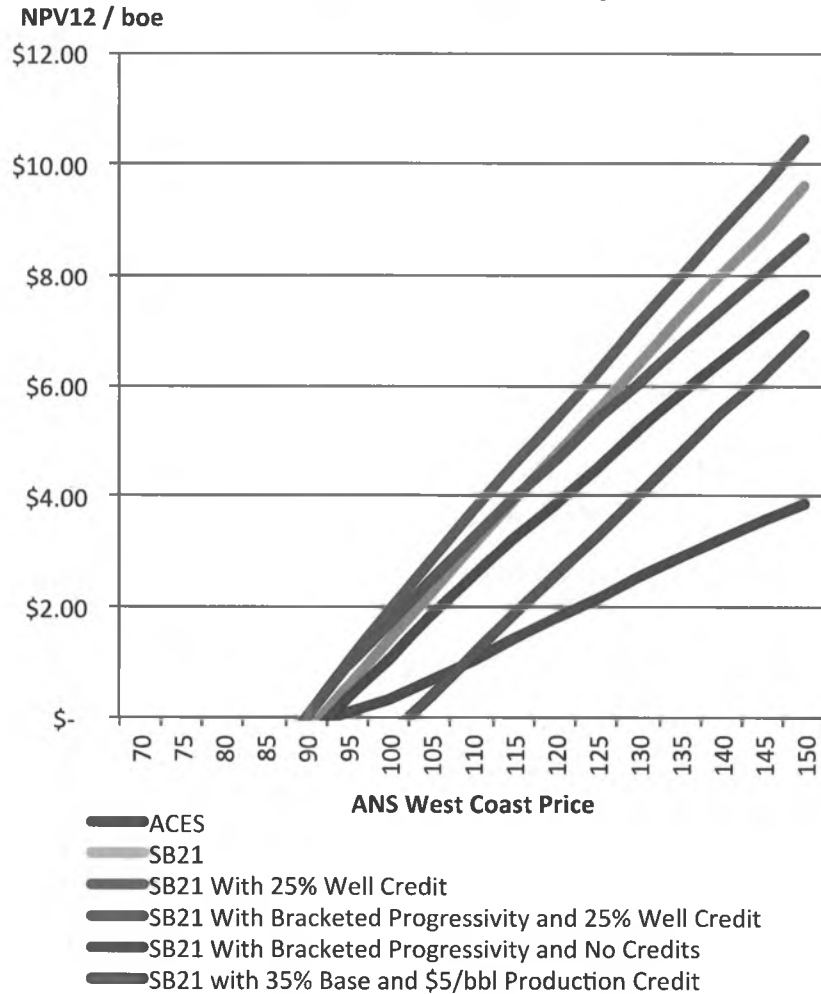


- ACES
- SB21
- SB21 With 25% Well Credit
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- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

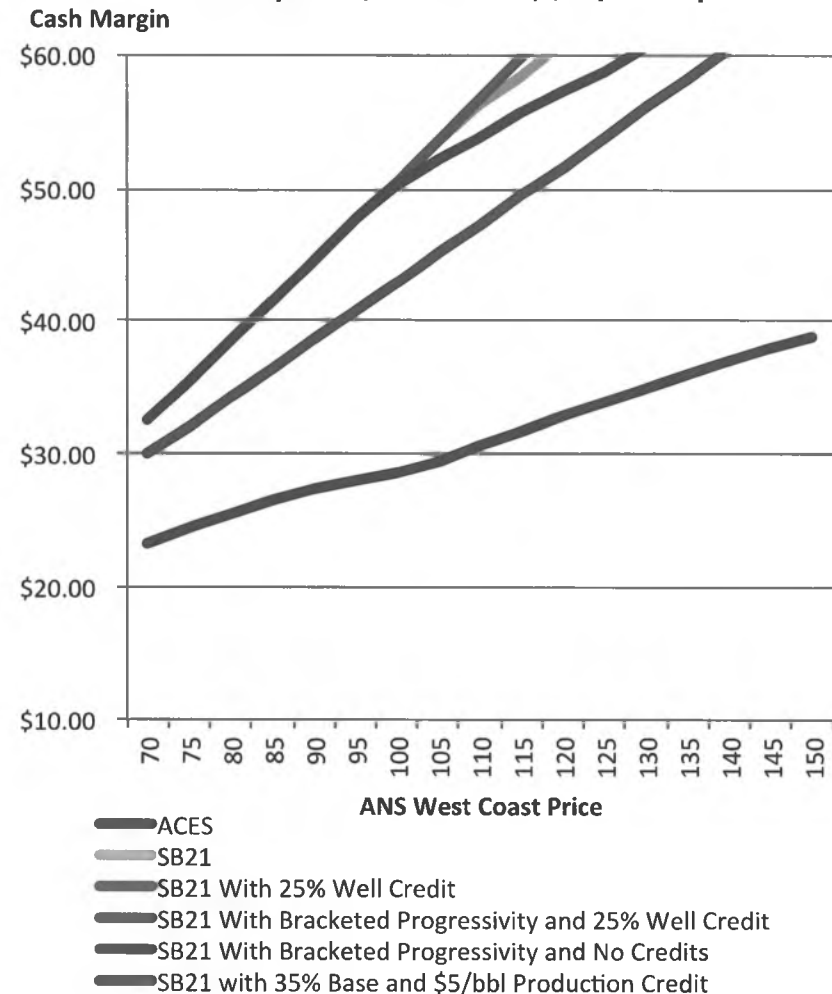
# NPV12/bbl & Cash Margin Comparison

## \$25/bbl New Development, Standalone

NPV12 / boe comparison - New Development, Standalone, \$25/bbl Capex



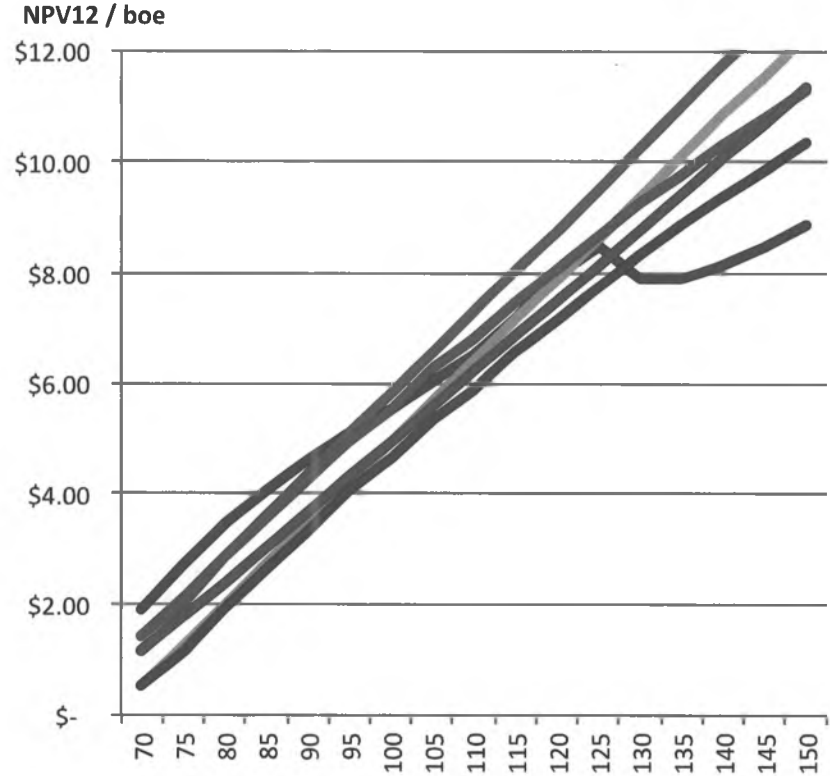
Cash Margin (2017 - 2022) comparison - New Development, Standalone, \$25/bbl Capex



# NPV12/bbl & Cash Margin Comparison

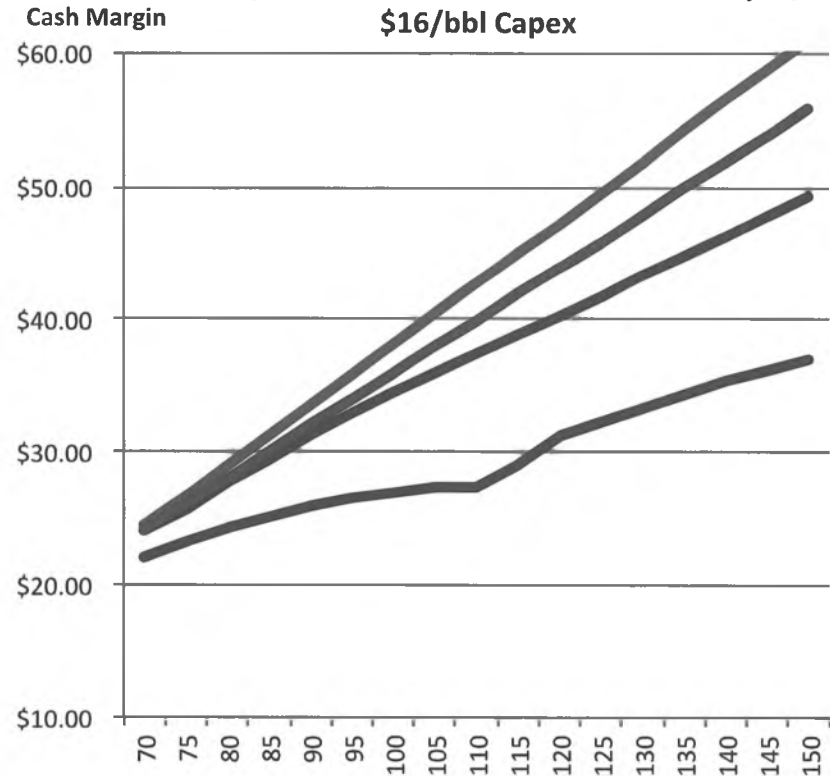
## \$16/bbl New Development, Incumbent Producer Incremental Analysis

NPV12 / boe comparison - New Development, Incumbent Incremental Analysis, \$16/bbl Capex



- ACES
- SB21
- SB21 With 25% Well Credit
- SB21 With Bracketed Progressivity and 25% Well Credit
- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

Cash Margin (2017 - 2022) comparison - New Development, Incumbent Incremental Analysis, \$16/bbl Capex

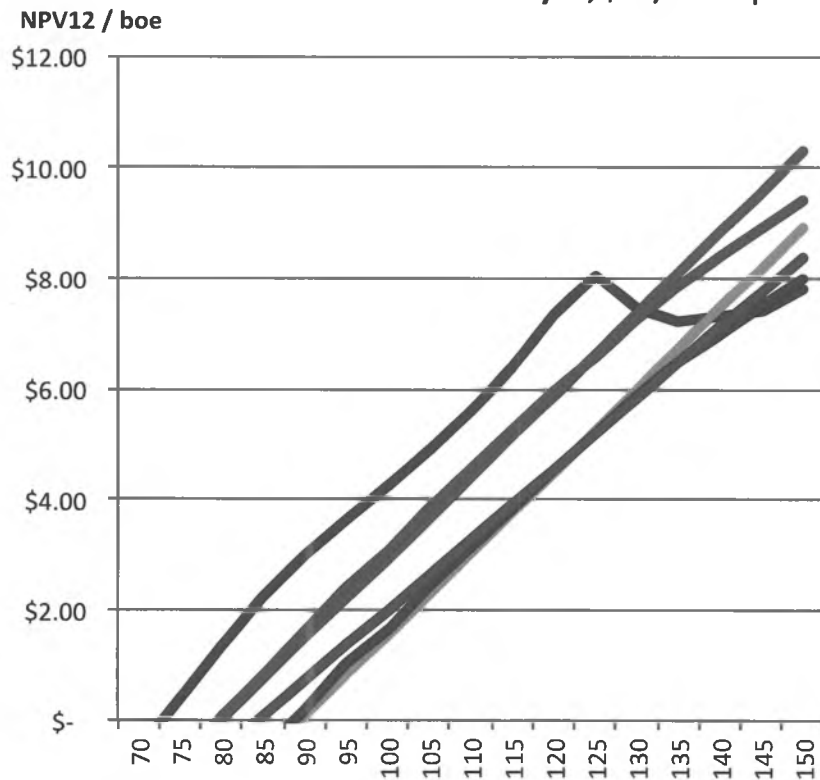


- ACES
- SB21
- SB21 With 25% Well Credit
- SB21 With Bracketed Progressivity and 25% Well Credit
- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

# NPV12/bbl & Cash Margin Comparison

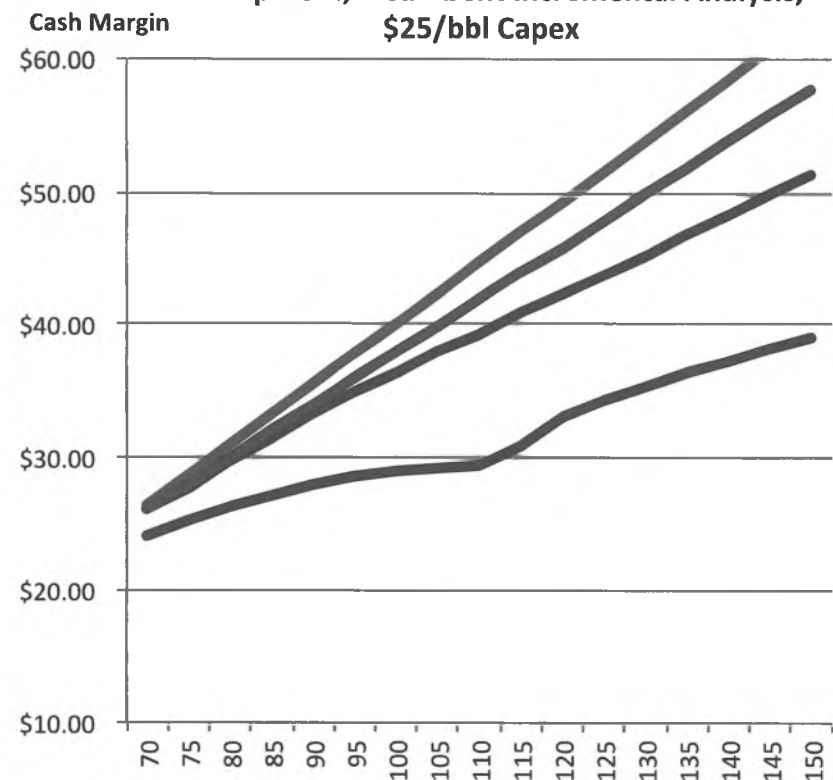
## \$25/bbl New Development, Incumbent Producer Incremental Analysis

NPV12 / boe comparison - New Development, Incumbent Incremental Analysis, \$25/bbl Capex



- ACES
- SB21
- SB21 With 25% Well Credit
- SB21 With Bracketed Progressivity and 25% Well Credit
- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

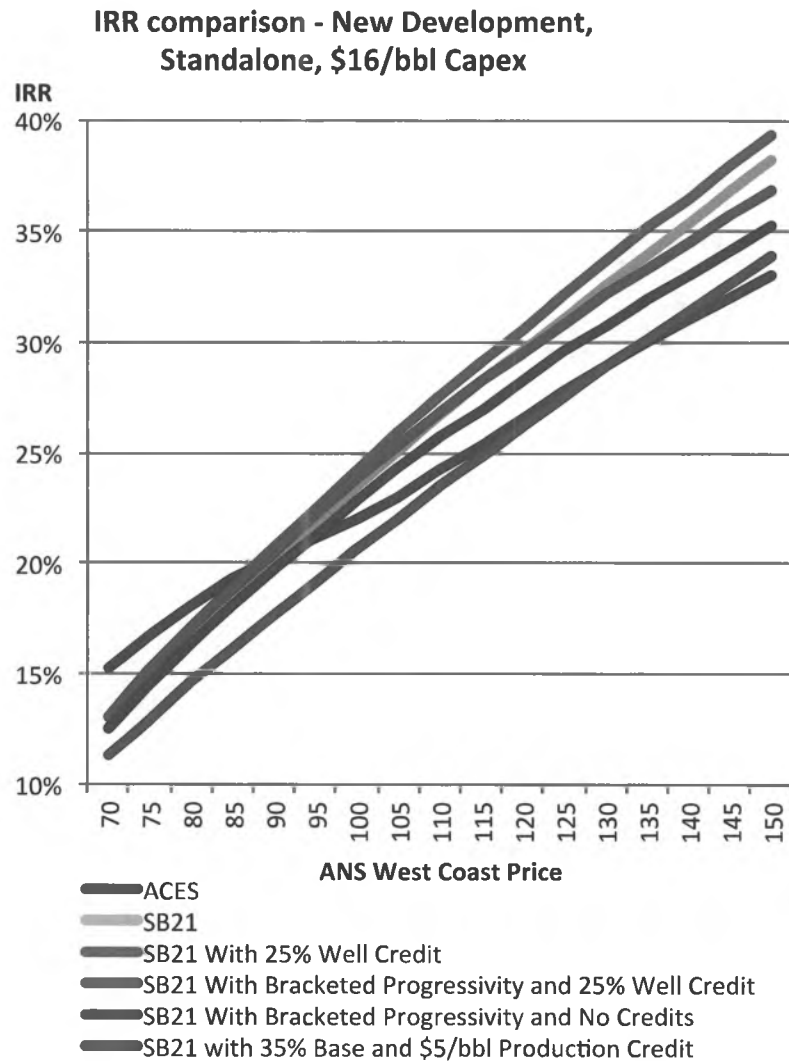
Cash Margin (2017 - 2022) comparison - New Development, Incumbent Incremental Analysis, \$25/bbl Capex



- ACES
- SB21
- SB21 With 25% Well Credit
- SB21 With Bracketed Progressivity and 25% Well Credit
- SB21 With Bracketed Progressivity and No Credits
- SB21 with 35% Base and \$5/bbl Production Credit

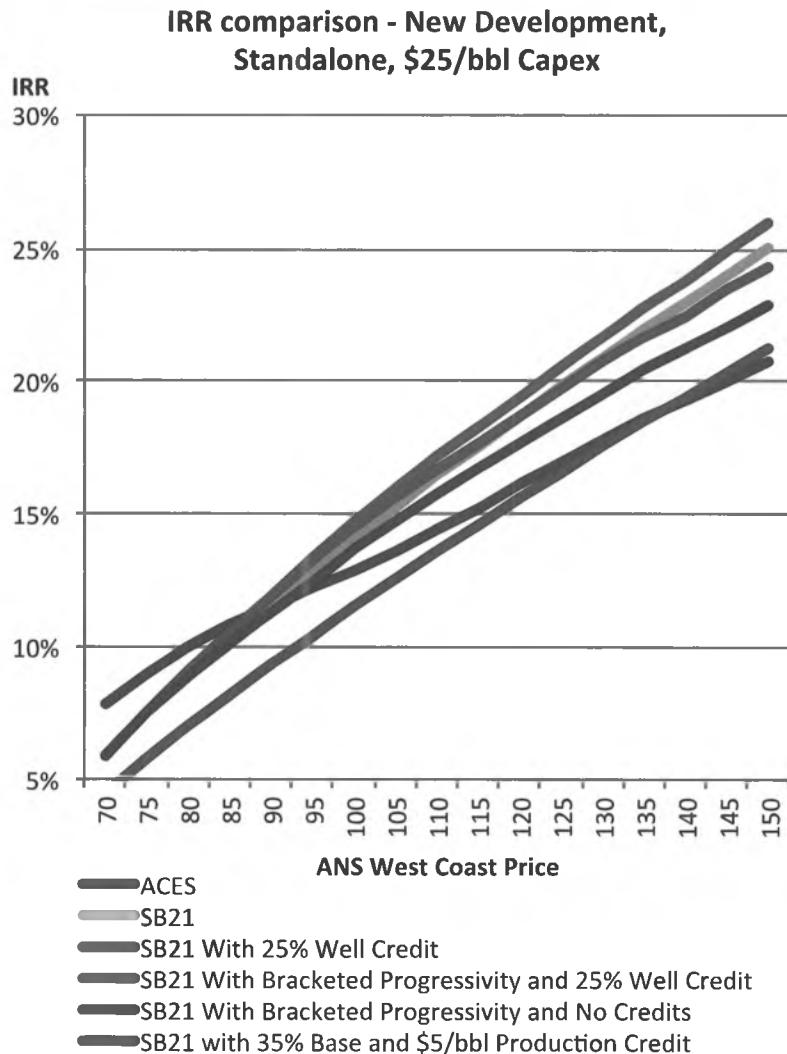
# IRR Comparison

## \$16/bbl New Development, Standalone



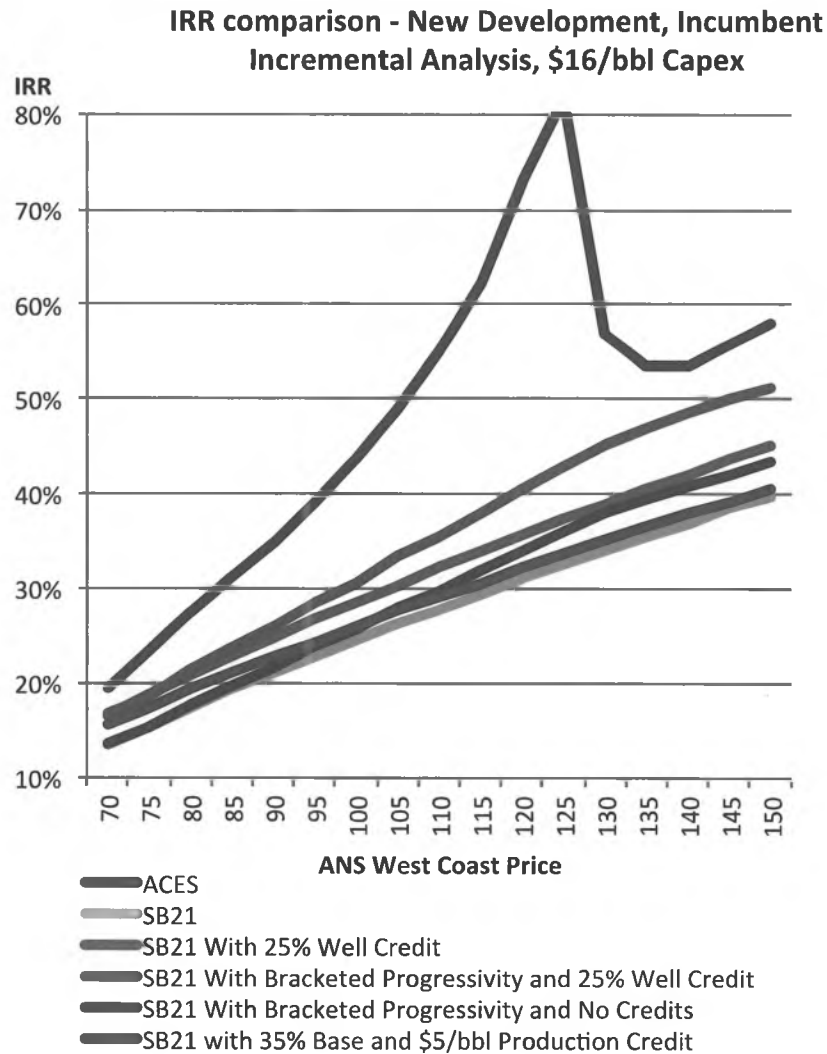
# IRR Comparison

## \$25/bbl New Development, Standalone



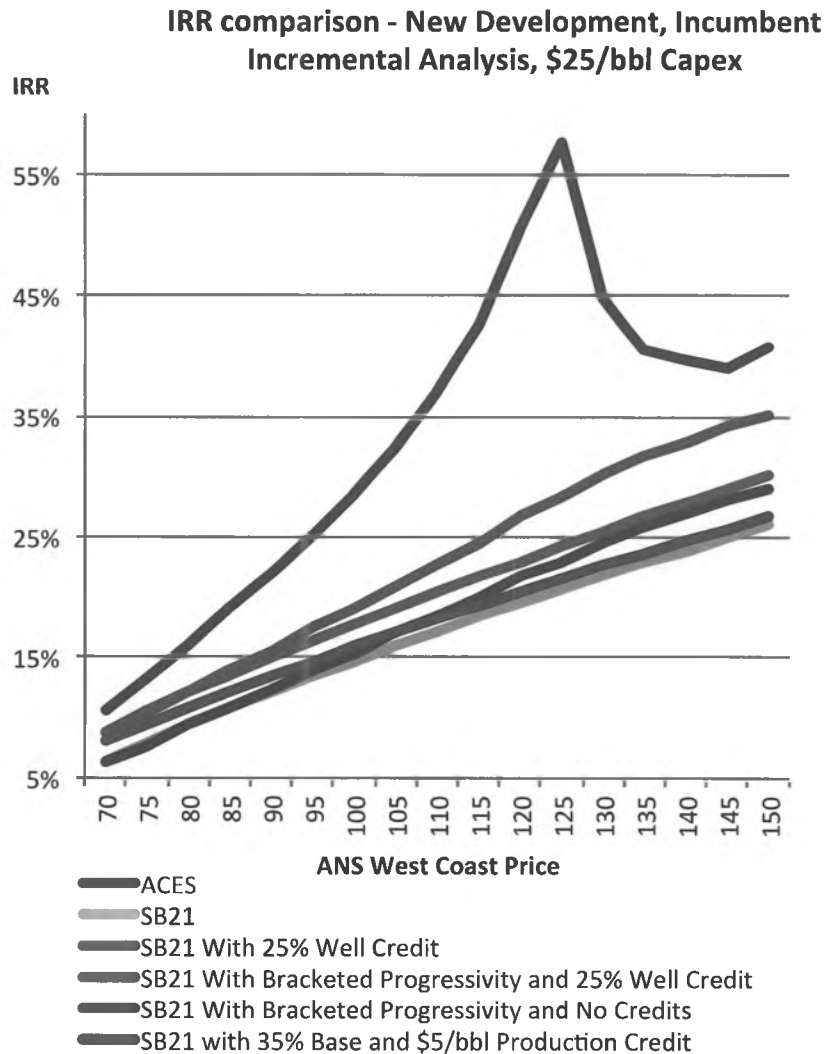
# IRR Comparison

## \$16/bbl New Development, Incumbent Producer Incremental Analysis



# IRR Comparison

## \$16/bbl New Development, Incumbent Producer Incremental Analysis



## Conclusions

- Elimination of credit has a significant negative impact on project economics at low prices, or high development costs – though for new developments outside existing areas, this is more than offset by the GRE.
- Partial reinstatement of credits (for instance more targeted well expenditure credit) can partially mitigate this, but not fully.
- Bracketed progressivity a feasible approach to balancing revenue impact of partial or full reinstatement of credits.
- Higher base tax and production-based credit an interesting approach, and may help question of tax increase for base production at low prices. Since credit does not contribute when costs are incurred, does not address impact on higher-cost development.

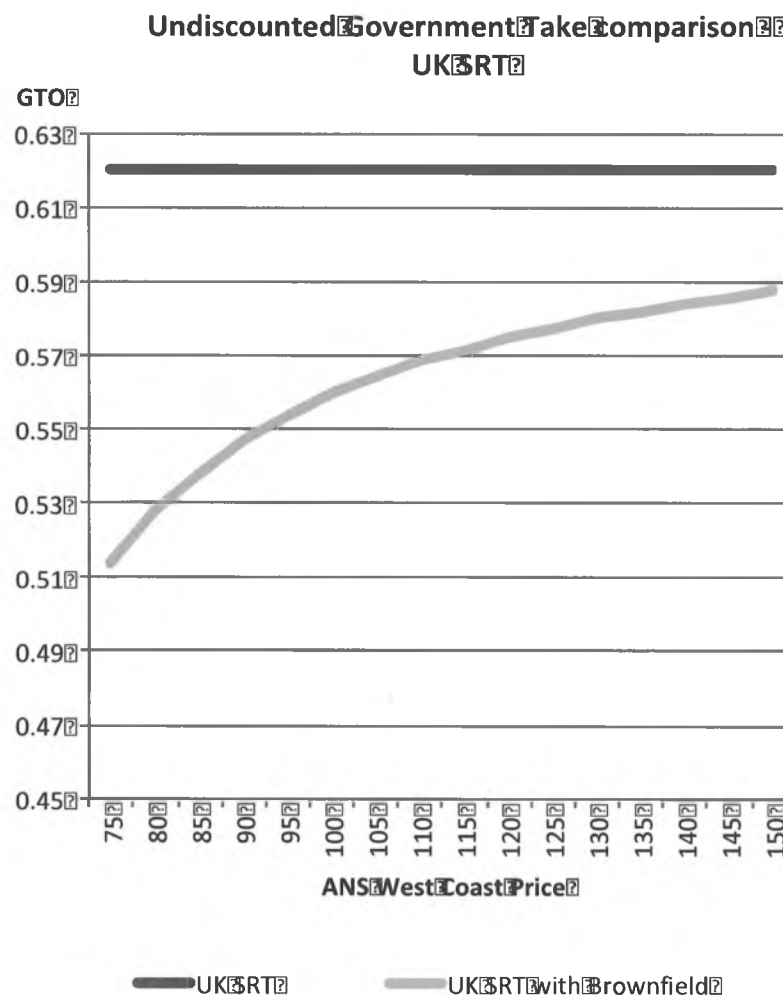


Requested Analysis:

Impact of UK Brownfield Allowance

# Impact of UK Brownfield Allowance

- The UK's fiscal regime is a relatively simple one, with two core components – a Corporate Income Tax (CIT) of 30%, and a Supplemental Resource Tax (SRT) of 32%, levied on the CIT tax base
- The UK Brownfield Allowance is an income exclusion, used in calculating the SRT. Up to a total £250mm of income can be excluded, with up to 20% of the exclusion amount allowed in a given year. For projects subject to the additional Petroleum Tax (pre-1993 projects), the exclusion is up to £500mm of income
- Because it is a fixed exclusion, it has a greater impact at lower oil prices
- Projects are individually assessed for qualification, and for the total amount of relief available. Qualifying projects are incremental projects increasing production from mature fields.
- A 100mmb incremental development, with costs of \$25/bbl, could see its government take reduced by to anywhere from 3 to 11 percentage points, depending on the oil price level



# Main Regional Offices

## **Asia**

### **PFC Energy, Kuala Lumpur**

Level 27, UBN Tower #21  
10 Jalan P. Ramlee  
50250 Kuala Lumpur, Malaysia  
Tel (60 3) 2172-3400  
Fax (60 3) 2072-3599

### **PFC Energy, China**

79 Jianguo Road  
China Central Place Tower II, 9/F, Suite J  
Chaoyang District  
Beijing 100025, China  
Tel (86 10) 5920-4448  
Fax (86 10) 6530-5093

### **PFC Energy, Singapore**

15 Scotts Road  
Thong Teck Building, #08-04  
Singapore 228218  
Tel no: +65 6736 4317

## **Europe**

### **PFC Energy, France**

19 rue du Général Foy  
75008 Paris, France  
Tel (33 1) 4770-2900  
Fax (33 1) 4770-5905

## **North America**

### **PFC Energy, Washington D.C.**

1300 Connecticut Avenue, N.W.  
Suite 800  
Washington, DC 20036, USA  
Tel (1 202) 872-1199  
Fax (1 202) 872-1219

### **PFC Energy, Houston**

2727 Allen Parkway, Suite 1300  
Houston, Texas 77019, USA  
Tel (1 713) 622-4447  
Fax (1 713) 622-4448

[www.pfcenergy.com](http://www.pfcenergy.com) | [info@pfcenergy.com](mailto:info@pfcenergy.com)

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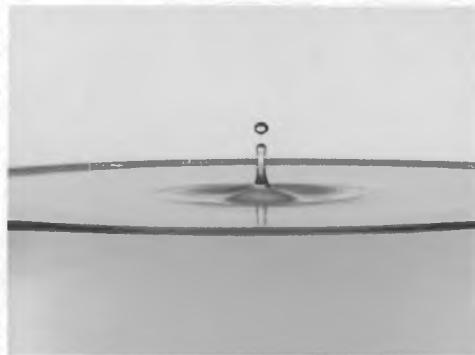
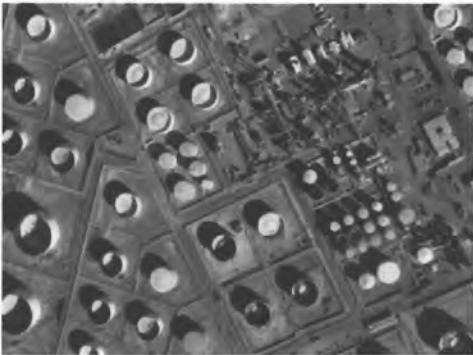
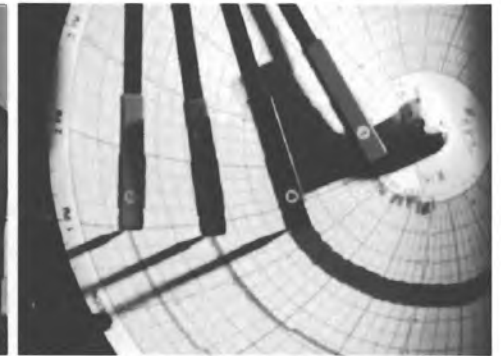
PFC Energy has adjusted data where necessary in order to render it comparable among companies and countries, and used estimates where data may be unavailable and or where company or national source reporting methodology does not fit PFC Energy methodology. This has been done in order to render data comparable across all companies and all countries.

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PFC Energy

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# **Comments on SB21**

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

**February 22, 2013**

## Key Concerns Expressed by Industry and Legislators

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### ➤ Industry

- **Tax Rate Higher Than ACES at “Low” Prices**
- **Loss of Capital Credits**
- **GRE Not Applicable to Legacy Fields**

### ➤ Legislators

- **System Not Progressive (or Progressive Enough)**
- **Overall Government Take May Be Too Low**
- **Elimination of Credits May Harm New and/or Smaller Companies**

## Potential Changes to Tax Structure

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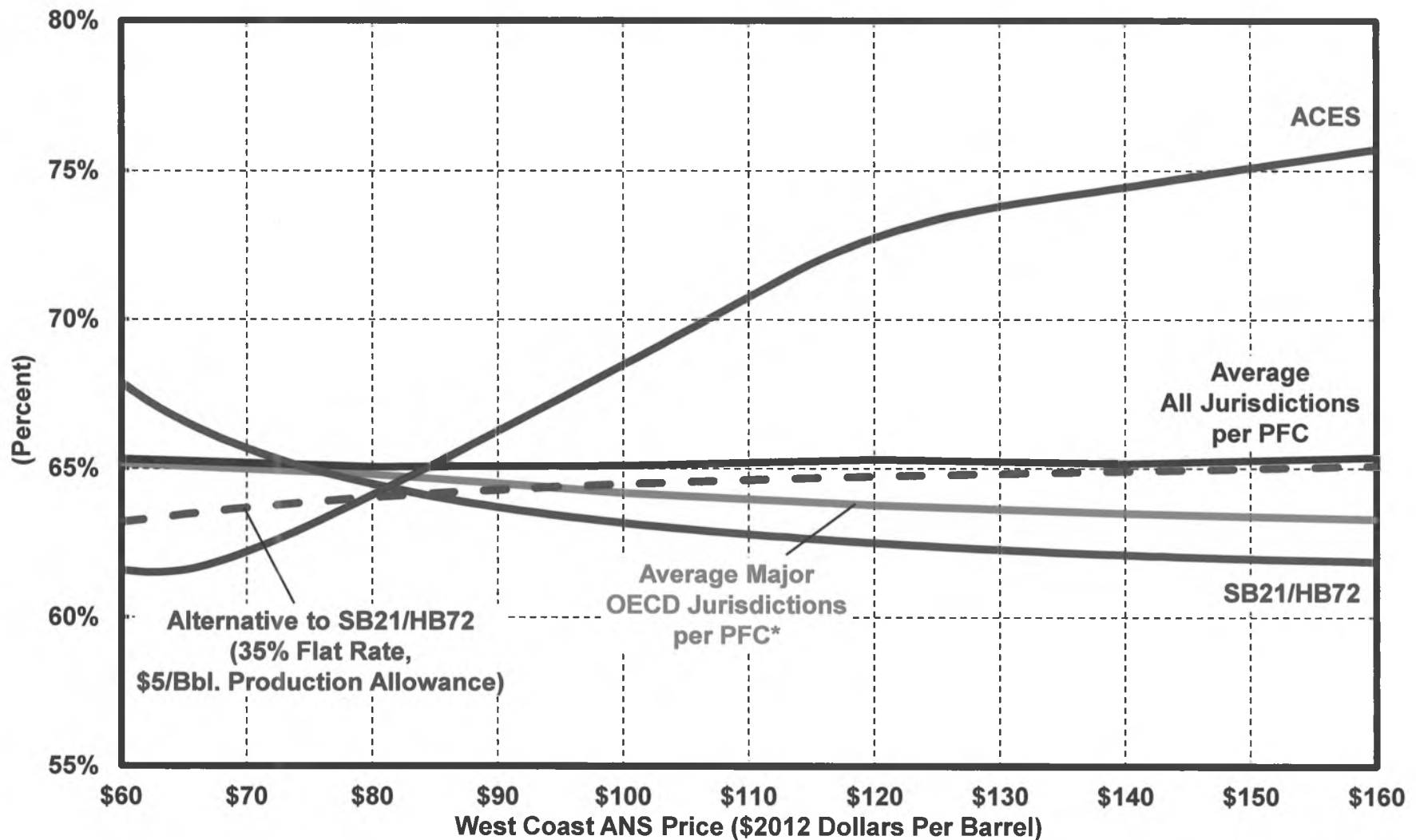
### ➤ **Changes**

- **Increase Nominal Tax Rate**
- **Introduce Fixed Allowance for Every Barrel Produced**

### ➤ **Impacts**

- **Reduces Effective Tax Rate at Low Prices**
- **Provides Progressive Overall Government Take**
- **Efficient Mechanism to Implement Progressive System**

# Average Government Take ACES v. SB21/HB72 and Alternative to SB21/HB72 for All Existing Producers (FY2015-FY2019) and Other Jurisdictions



\* Australia, Canada (Alberta Conventional), Norway, United Kingdom and United States.



# Tax Calculation Under Proposed Modifications

## 35% Tax Rate; \$5/Bbl Production Allowance

Taxable Barrels (Bbls)	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
West Coast Price (\$/Bbl)	\$60.00	\$80.00	\$100.00	\$120.00	\$140.00	\$160.00
Transportation (\$/Bbl)	- 10.00	10.00	10.00	10.00	10.00	10.00
Gross Value (\$/Bbl)	= \$50.00	\$70.00	\$90.00	\$110.00	\$130.00	\$150.00
Lease Expenditures (\$/Bbl)	- 30.00	30.00	30.00	30.00	30.00	30.00
Per-Barrel Taxable Value (\$/Bbl)	= \$20.00	\$40.00	\$60.00	\$80.00	\$100.00	\$120.00
Total Production Tax Value (\$)	\$1,000,000,000	\$2,000,000,000	\$3,000,000,000	\$4,000,000,000	\$5,000,000,000	\$6,000,000,000
Production Tax Before Allowance @ 35%	\$350,000,000	\$700,000,000	\$1,050,000,000	\$1,400,000,000	\$1,750,000,000	\$2,100,000,000
Production Allowance @ \$5/Bbl	- 250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000
Production Tax After Allowance	= \$100,000,000	\$450,000,000	\$800,000,000	\$1,150,000,000	\$1,500,000,000	\$1,850,000,000
Nominal Tax Rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Reduction in Tax Rate From Allowance	25.0%	12.5%	8.3%	6.3%	5.0%	4.2%
Effective Tax Rate After Allowance	10.0%	22.5%	26.7%	28.8%	30.0%	30.8%
Allowance as % of Gross Value	10.0%	7.1%	5.6%	4.5%	3.8%	3.3%

# Summary of Investment Measures for New Participant Alaska Development ACES v. SB21/HB72 and Alternative to SB21/HB72



West Coast ANS Price	\$16/Barrel Development Capex				\$25/Barrel Development Capex				
	ACES	SB21/HB72		SB21/HB72 Alt (35% Rate; \$5/Bbl. Allowance, 30% GRE)	ACES	SB21/HB72		SB21/HB72 Alt (35% Rate; \$5/Bbl. Allowance, 30% GRE)	
		With GRE	Without GRE			With GRE	Without GRE		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
<b>Producer NPV-12 / BOE (Dollars Per BOE)</b>									
\$80	\$2.55	\$2.54	\$1.94	\$2.81	(\$0.35)	(\$2.18)	(\$2.28)	(\$2.11)	
\$100	\$3.85	\$6.18	\$5.34	\$6.57	\$0.97	\$2.04	\$1.21	\$2.12	
\$120	\$5.48	\$9.74	\$8.71	\$10.00	\$2.58	\$5.61	\$4.59	\$5.97	
<b>Profitability Index-12</b>									
\$80	1.19	1.19	1.15	1.21	0.98	0.89	0.89	0.90	
\$100	1.29	1.47	1.40	1.50	1.05	1.10	1.06	1.10	
\$120	1.41	1.74	1.66	1.75	1.12	1.27	1.22	1.29	
<b>IRR (Percent)</b>									
\$80	19.7%	17.1%	16.1%	17.5%	11.3%	9.0%	8.8%	9.1%	
\$100	23.4%	23.9%	22.6%	24.5%	14.0%	14.6%	13.6%	14.7%	
\$120	27.6%	30.0%	28.6%	30.4%	17.1%	19.1%	18.0%	19.4%	
<b>5-Year (2017-2021) Cash Margins (Dollars Per BOE)</b>									
\$80	\$25.84	\$36.94	\$34.44	\$36.94	\$28.03	\$39.10	\$39.10	\$39.10	
\$100	\$28.84	\$45.89	\$42.59	\$47.86	\$31.03	\$51.15	\$49.51	\$51.15	
\$120	\$33.13	\$54.69	\$50.89	\$55.77	\$35.32	\$61.54	\$56.95	\$63.19	
<b>Government Take (Percent)</b>									
\$80	70.8%	61.9%	66.0%	59.4%	71.6%	65.0%	66.7%	63.6%	
\$100	75.8%	61.1%	64.7%	59.6%	76.9%	60.7%	65.5%	60.0%	
\$120	77.2%	60.8%	64.0%	60.1%	78.1%	61.0%	64.7%	59.8%	
<b>State/Municipal NPV-12/BOE (Dollars Per BOE)</b>									
\$80	\$6.67	\$6.68	\$7.60	\$6.27	\$3.24	\$6.06	\$6.21	\$5.96	
\$100	\$13.32	\$9.72	\$11.02	\$9.13	\$9.86	\$8.21	\$9.49	\$8.08	
\$120	\$19.46	\$12.89	\$14.48	\$12.50	\$16.02	\$11.36	\$12.92	\$10.80	

# Summary of Investment Measures for Incumbent Alaska Development ACES v. SB21/HB72 and Alternative to SB21/HB72



West Coast ANS Price	\$16/Barrel Development Capex				\$25/Barrel Development Capex			
	ACES	SB21/HB72		SB21/HB72 Alt (35% Rate; \$5/Bbl. Allowance, 30% GRE)	ACES	SB21/HB72		SB21/HB72 Alt (35% Rate; \$5/Bbl. Allowance, 30% GRE)
		With GRE	Without GRE			With GRE	Without GRE	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
<b>Producer NPV-12 / BOE (Dollars Per BOE)</b>								
\$80	\$3.71	\$2.71	\$2.02	\$4.00	\$1.34	(\$1.08)	(\$1.77)	\$0.66
\$100	\$6.14	\$6.20	\$5.30	\$7.27	\$4.68	\$2.41	\$1.51	\$3.94
\$120	\$8.82	\$9.69	\$8.58	\$10.55	\$8.10	\$5.90	\$4.80	\$7.21
<b>Profitability Index-12</b>								
\$80	1.28	1.20	1.15	1.30	1.06	0.95	0.91	1.03
\$100	1.46	1.47	1.40	1.55	1.23	1.12	1.07	1.19
\$120	1.67	1.73	1.65	1.80	1.39	1.28	1.23	1.35
<b>IRR (Percent)</b>								
\$80	26.2%	18.5%	16.9%	22.3%	15.4%	10.2%	9.0%	13.2%
\$100	41.1%	25.8%	24.1%	29.5%	27.2%	15.7%	14.4%	18.6%
\$120	65.3%	32.5%	30.6%	36.1%	46.0%	20.7%	19.2%	23.5%
<b>5-Year (2017-2021) Cash Margins (Dollars Per BOE)</b>								
\$80	\$24.26	\$30.63	\$28.57	\$32.07	\$26.45	\$32.79	\$30.73	\$34.23
\$100	\$27.22	\$40.27	\$37.61	\$41.17	\$29.41	\$42.42	\$39.77	\$43.33
\$120	\$31.18	\$49.90	\$46.65	\$50.27	\$33.37	\$52.06	\$48.80	\$52.42
<b>Government Take (Percent)</b>								
\$80	68.9%	64.1%	68.1%	59.3%	67.8%	66.1%	71.0%	59.1%
\$100	73.0%	62.6%	66.1%	60.2%	71.2%	63.7%	67.7%	60.1%
\$120	73.8%	61.9%	65.1%	60.6%	71.6%	62.6%	66.2%	60.6%
<b>State/Municipal NPV-12/BOE (Dollars Per BOE)</b>								
\$80	\$4.88	\$6.42	\$7.49	\$4.44	\$0.64	\$4.36	\$5.43	\$1.69
\$100	\$9.79	\$9.70	\$11.08	\$8.05	\$4.15	\$7.64	\$9.02	\$5.29
\$120	\$14.31	\$12.98	\$14.67	\$11.66	\$7.53	\$10.92	\$12.61	\$8.90

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

## Potential Solutions for New Participants

---

- **Expand State's Ability to Assist Producers Through AIDEA or Alternative Agency**
- **Potential Vehicles Include**
  - **Loans**
  - **Acquiring Overriding Royalty Interest**
  - **Acquiring a Working Interest**
- **Royalty Relief**
  - **Successful in Moving Recent Projects Forward**
- **Relax Requirements For Exploration Credits**

## Potential Solutions to Target New Oil in Legacy Fields

---

- **Expand DNR's Ability to Grant Royalty Relief**
  - **Can Only be Granted on Leases Not in Commercial Production**
  - **Allow Producers to Petition DNR for Royalty Relief for Approved Projects That Target "New Oil"**
    - **New PA / Unit or Expansion**
    - **Targeted Development in Existing PAs / Units**
  - **DNR Would Grant Royalty Relief on Case-Specific Basis**
  
- **Allow Producers to Apply for GRE on Projects in Existing PAs**
  - **Allow DOR/DNR to Grant GRE for Expansions or Targeted Developments**
  - **Producers Must Apply for GRE Allowance**
  - **Producers Must Provide Sufficient Evidence to DOR/DNR to Establish Proposed Development is New Production**

## Summary of Benefits

---

- **Change in Tax Rate Along with Production Allowance Provides Moderately Progressive System**
- **Changes Maintain Competitive Government Take**
- **Allowances or “Credits” Tied Directly to Production**
- **Value of Allowance Varies Inversely With Price**
  - **Higher Value at Lower Prices (Where Needed)**
  - **Lower Value at Higher Prices (Where Not Needed)**
- **Avoids Problems Associated with High and/or Changing Marginal Rates**
- **Expansion of AIDEA Access Would Provide Capital to Viable Projects If Needed Without Taxing State Treasury**
- **Granting DNR Royalty Relief Authority Allows Flexibility in Responding to Challenged Development Projects**
- **Granting of GRE to Targeted Projects in Existing Units Allows DOR/DNR to Aid Development**



# Overview of SB 21 Oil & Gas Production Tax



# The Proposal (Highlights)



1. Eliminate Progressivity and Credits Based on Capital Expenditures.
2. Reform remaining credits to be carried forward to when there is production.
3. Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units (NEW OIL).
4. Hold Cook Inlet and Middle Earth Harmless.

*January 29, 2013  
Alaska Department of Revenue*

1/28/2013

1

1/28/2013

3



# Principles



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

1/28/2013

2



# Eliminate Progressivity & Credits Based on Capital Expenditures



## Progressivity

Main Sections: 1,2,26

Conforming Sections: 5,6,22,23

## North Slope QCE Credits

Main Sections: 8

Conforming Sections: 7, 11, 12

1/28/2013

4



Reform remaining credits to be carried forward to when there is production.



Cook Inlet and Middle Earth



### North Slope Net Operating Loss Credits

Main Sections: 9, 15  
Conforming Sections: 10, 19, 20

### No Changes to Cook Inlet & Middle Earth

Main Sections: 3  
Conforming Sections: 4, 13, 14, 17, 18, 21, 25

### Small Producer Tax Credits

Main Sections: 16

1/28/2013

5

1/28/2013

7



Establish a "Gross Revenue Exclusion" for newer units and new participating areas in existing units.



### Gross Revenue Exclusion (The GRE)

Main Sections: 24  
Conforming Sections: 5

1/28/2013

6

# ConocoPhillips is using technology to increase production in Alaska, Outside

Published: March 8, 2013

By *ERIC LIDJI — Petroleum News*

Anchorage — ConocoPhillips says it plans to spend \$2.5 billion in Alaska over the next five years using innovative drilling technologies to mitigate declining production on the North Slope.

Conoco, the largest oil producer in Alaska, believes it can get 35,000 barrels a day of incremental production from its three legacy North Slope oil fields by using 4-D seismic, coiled-tubing drilling and casing drilling to lower costs and reach additional deposits. However, as with any discussion of investments, the company insists it could do more if Alaska policymakers would lower oil taxes.

The 35,000 barrels a day would cut production declines to about 3 percent a year by 2017, Matthew Fox, the company's executive vice president of exploration and production, told analysts on Feb. 28. And, Fox said, if ConocoPhillips brings the Alpine West/CD-5 satellite into production as scheduled in 2015-16, the annual decline could drop to about 2 percent.

The goal of the \$2.5 billion program is to use newly perfected techniques to suck additional oil out of Prudhoe Bay, Kuparuk River and Alpine.

The program involves two techniques "honed" in Alaska.

The first brings down the cost of developing smaller oil pockets. With it, ConocoPhillips uses time-lapse 3-D seismic (or "4-D" seismic) to "illuminate pockets of oil that are in separate fault blocks or for whatever reason are not producing into an existing well bore," according to Executive Vice President of Technology and Projects Alan Hirshberg. It's too expensive to reach such pockets with conventional drilling, he said.

With a small tool at the end of coiled tubing equipment, ConocoPhillips can "twist and turn through the rock." This tool can turn more than 60 degrees over a 100-foot stretch of well, which "allows us to go right to these pockets that we found with the 4-D," he said.

Using this technique, ConocoPhillips recently drilled an "octolateral" well at Kuparuk. The well is a vertical hole with eight horizontal wells snaking out in different directions to target bypassed deposits. "We've actually found eight different zones near this well bore that we could go and hook up using coil-tubing drilling. ... That's a very cost-effective way to get at those zones that weren't producing before," Hirshberg said.

The second technique allows ConocoPhillips to access deposits once thought unreachable. Using "steerable drilling liners," the company can drill through unstable reservoirs or low-pressure formations to reach deeper targets. "Normally when you have these well-bore instabilities, if you try to drill and then come back and run casing, you can't do it fast enough because the well bore collapses. So here, we're actually using the casing to drill," Hirshberg said. "And so the casings are already in place as we drill the hole."

It's unclear whether the investment plan differs from normal fieldwork.

Earlier this year, ConocoPhillips said it planned to spend "about \$1 billion" in Alaska in 2013 -- a slight increase over 2012 -- to accommodate CD-5 development.

"When you look at the base development speed and pace in the legacy fields, it's the same (budget) as 2006," ConocoPhillips Alaska President Trond-Erik Johansen said.

Between 2005 and 2011, ConocoPhillips spent \$733 million a year in Alaska, on average, with a low of \$666 million in 2007 and a high of \$1.4 billion in 2008. At \$2.5 billion, the announced five-year plan amounts to \$500 million a year, in addition to other activities in the portfolio, such as CD-5 and Chukchi Sea exploration.

ConocoPhillips says it believes legacy fields are the key to stemming production declines, but it can't justify the necessary investment under the existing tax system. The company says tax law revisions proposed so far do not "contain sufficient investment incentives for legacy fields to offset Alaska's high cost environment."

Meanwhile, ConocoPhillips is exporting its Alaska technology.

The \$2.5 billion Alaska program is part of a larger effort by ConocoPhillips to increase production across its portfolio by 600,000 barrels of "oil equivalent" a day by 2017.

"Of the growth that we're talking about, about half of it is going to come from oil production. ... About 70 percent of that oil production comes from the Lower 48 and the rest of it is coming from Malaysia and projects in Europe," Chief Financial Officer Jeffrey Sheets told analysts. "And so where it's not coming from is places (where) we've had relatively higher tax rates, like Alaska."

## ADN.com

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**Compass: Medicaid expansion is good for Alaskans**

### Compass: Alaska needs governor's oil tax overhaul

Published: February 20, 2013

By BILL ARMSTRONG

Gov. Sean Parnell has introduced new oil and gas tax legislation. The governor's proposal is a huge improvement over the current law and is a major step in the right direction for Alaska - and Alaskans.

You may not have heard of Armstrong Oil & Gas, Inc., but we, and our affiliates, began extensive work exploring new oil and gas potential in Alaska in 2000. Since then, we have been responsible for the origination of three of the most recent stand-alone developments in the state; two on the North Slope and one in Cook Inlet.

Our exploration efforts have provided significant revenues to the state, jobs for Alaskans, new oil production for the Alaska Pipeline, and new supplies of natural gas for Southcentral Alaska.

Armstrong is now one of the largest leaseholders in the state and one of the state's largest investors. We are true believers in Alaska's potential. But sadly, as we hear from so many of the companies that we try to encourage to invest in the state - Alaska is simply not competitive with other oil and gas provinces around the world.

There is a major energy boom happening in the United States, but Alaska is not benefitting from this boom. New drilling and completion technologies have been a godsend for the continental United States, and specifically to states where these technologies are being put to use. This energy boom, which is thriving in states like Texas, Oklahoma, North Dakota and Pennsylvania, has completely bypassed Alaska.

For the week of January 7, 2013, Texas had 830 active rigs drilling, Oklahoma had 183, North Dakota had 174, and Pennsylvania had 80. Alaska had 8. Alaska's constitution calls for maximum benefit from the development of natural resources, but how do Alaskans benefit if the state tax structure makes potential developers look elsewhere?

Oil production in Alaska is declining -- steadily and relentlessly. And yet, the entire state economy is based on the income from this vast resource potential. It is a resource that created the Permanent Fund, returning hard dollars from production to every man, woman and child in the state. Alaskans must confront the fact that prohibitive regulations, onerous permitting and an unprecedented tax burden are scaring away the kind of investment necessary to maximize production potential that benefits all Alaskans.

This is bad news - but the good news is that these are man-made problems and therefore, they can be fixed. Gov. Parnell's proposed tax law starts to do just that.

While not perfect, the Governor's changes are a major step toward increasing exploration activity and bringing substantial new investments to the state; investments that will increase production and generate new jobs for Alaskans.

The governor's tax bill is certainly not a giveaway to "big oil". It does not jeopardize the state's balance sheet with tax credits, and it firmly makes the state's fiscal regime competitive with the rest of the world. It is aimed at making Alaska provide maximum benefit from resource development to all Alaska shareholders - you and your family.

Alaska needs ConocoPhillips, BP and Exxon to aggressively conduct business in the state, but Alaska also needs new companies such as Pioneer, ENI, Repsol, Armstrong and others to compete and invest as well.

Gov. Parnell understands this, and he clearly has the state's long-term best interest at heart. The choice for Alaskans is simple and clear. The current ACES tax burden has crushed development and new investments and will jeopardize Alaska's economic health in the long-term. The governor's proposed oil and gas tax changes will increase production, provide more high paying jobs, and increase revenues for the state.

Armstrong Oil & Gas is a true believer in Alaska's energy potential, but we and the other new companies looking at playing a role in Alaska's future need to see a stable tax structure we can confidently invest in.

It's time for Alaska to get back in the game, bring drilling back to the state, and reap the economic benefits this will bring for all Alaskans. We look forward to being a part of an exciting new generation of development.

Bill Armstrong founded Armstrong Oil & Gas, Inc. in 1985 from the attic of his 100 year-old garage/barn in Denver. Armstrong Oil & Gas recent areas of activity are Alaska's North Slope and Cook Inlet Basin, the Gulf of Mexico, the San Joaquin Valley, the Williston Basin, Michigan Basin and the Wyoming/Utah Overthrust Belt.

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**Compass: Oil tax reduction? Not before production**

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**Compass: Medicaid expansion is good for Alaskans**

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## Alaska Oil Tax History Since 2006

### YEAR

### EVENT

2006

In February Gov. Murkowski introduces both his Petroleum Profits Tax (PPT) and the gasoline contract as a package deal. The message to the legislature is, "Pass the PPT, and they will build a gas pipeline."

At the announcement press conference Murkowski and chief of staff Jim Clark debate the linkage of the two bills -- see **Administration garbles oil tax message**, *Alaska Budget Report*, Feb. 23 2006

As the debate rages on through the regular and a heated special session the PPT undergoes multiple revisions. It passes on an emotional and frenzied Sunday night, August 6. The final product is an unwieldy combination of taxes and credits that will prove dizzying for state auditors. Producers are unhappy with what they see as a huge tax hike; Democrats are unhappy having lost the fight for a gross tax; Murkowski fears he will end up with a big tax bill and no pipeline -- which is what happens.

2007

A combination of FBI raids and indictments, historic unpopularity for a sitting governor and some key wins by Democrats in the '06 elections changes the complexion of Alaska government dramatically. Sarah Palin sweeps Murkowski aside with promises of ethics reform, a new approach to finally slaying the gasoline dragon and reform of the PPT that now carries the stigma of corruption and the realization that it will underperform by \$800 million in its first year. The Senate is now led by a coalition of 10 Democrats and five Republicans.

Republican Senator Tom Wagoner and Republican Representative John Coghill introduce legislation to prevent producers from deducting repair costs for improperly maintained property and equipment, the bills receive large-scale early support. Meanwhile Palin's new oil and gas team works on a new approach. By May the Wagoner bill loses steam.

Palin rolls out her new oil tax plan for a special session in October -- it is a significant departure from Murkowski's regime, and it is well received, particularly by many Democrats. "ACES" promises more aggressive progressivity and less generous deductions and credits.

Palin's ACES bill passes in November with some notable modifications and represents a projected increase of \$1.2 to \$2 billion over the previous PPT. Over the next five years the state would enjoy large revenue surpluses, and more activity from explorers and small producers while the large producers argue that the punitive tax structure will result in less investment and the continuing production decline.

2011

As the 2011 legislative session begins Gov. Sean Parnell unveils bill to slash production taxes. The plan aligns with large producers contention that to encourage investment and increase production Alaska must be more competitive with other oil provinces. The bill meets strong resistance from House Democrats and the bi-partisan coalition in the Senate. It does not pass in 2011 and is not on the special session call.

2012

Though Parnell's tax bill was eviscerated by the Senate's bi-partisan coalition, the administration did little to change its arguments in 2012. Holdover hard feelings between House and Senate leadership over budget and oil tax disputes in 2011 led to an ultimate stalemate, and the bill died in the Senate Resources committee. No special session was called.

Q's for Industry SRES 2-20-2013  
from SRES members

- How many/ much transferable credits have you secured from others and at what discounted price?
- How much incremental production have you developed with these 3 rd party credits?
- What is the Probability of low side product price in the next 5-7 years and really how much will that impact your business strategy for Alaskan investment as apposed to non-Alaskan investment?
- If production from PA expansion is included as an option for GRE, how will you measure the incremental oil associated only with the expansion area?
- Will including PA expansion in the GRE, encourage you to advance PA boundary edge development?
- Should GREs be tied to EPC contracts with local contractors? If not, why not?
- How many PAs do you have which haven't been fully developed? What are your plans for the exploitation of these areas? What are the technical and non-technical hurdles preventing you from this work today?

~~what~~

- How is your portfolio balance determined between smaller less productive PAs and larger prolific PAs?

all

- What is the blend (heavy to light crude) required to augment heavy and viscous development?



# Alaska State Legislature

## Senator Hollis French

February 12, 2013

Senator Cathy Giessel  
Chair, Senate Resources Committee  
Capitol, Room 427

Dear Senator Giessel:

Please submit the following questions to our experts PFC or the Department of Revenue, as appropriate:

- DOR 1. Quantify the number of additional barrels of new production (factoring in the GRE for new oil) it will take to offset the loss of revenue under SB21 at \$90, \$110, \$130/bbl oil.
- PFC 2. Provide a detailed description of the tax credits for brownfields the U.K. is providing in the North Sea. Include the current government take before the credits, how the credits are targeted, and whether the tax credits go on forever or are capped (and if so, how).
- DOR 3. What are federal tax implications for an oil producer in Alaska of any reductions in state taxes? If the state reduces its oil taxes by \$1 billion, for example, how much of that is available for reinvestment in Alaska?
- PFC or DOR 4. When total government take is modeled by PFC and DOR, are federal taxes modeled in the abstract, or are they tied to actual federal taxes paid? Since federal tax payment information is part of SEC filings, can we see a model of government take that reflects actual federal tax rates paid?
- DOR 5. Provide a chart of the effect on state revenues of adopting SB21. Using the annual production and prices from FY07 through FY13, report the revenue for each year under ACES, under PPT, and under SB21.

Yours,

A handwritten signature in black ink, appearing to read "Hollis French".

Senator Hollis French

Expand PA

Giveaway due to  
HORN TAPS

Ask Barron  
Torn  
Tabasco } Care  
these  
PAs

Senator Dyson questions

TAPS tariff – as it goes up, how does that change SOA competitiveness

Heavy oil incentives, why did BP set heavy oil aside?

Water treatment facility. Is there limited access? Ask CP is this true?

Barron-What is his read on shale? *what can we make (specifically) more economic?*

Credits to reduce tax – summarize what we have and what SB 21 proposes. Ask Big 3 if they will work

Explorers' increased credits-Ask DOR how far off the target are we?

Legacy production credits

Some windfall tax rate (half ACES)-brackets (where do we change the slope of line at high end)

DOR-pros/cons of OPEX deduction\*, allow these for all "challenged" oil

Big 3-what incentives to reduce OPEX and increase production

PFC/Big 3-maintenance shut down-what is the industry standard for routine operating /predictable equipment repairs?

McGuire

Can we adjust the \$80-90 Gov Take?

Credits for well workovers, technical advances (to be used only on production

*Wants more gov take @ high prices -*

*\$4 per barrel*

Micciche

Set baseline for production, then give credits for oil above the baseline

Treat heavy differently

Incentivize new producers

*Capital credits - how about technology costs*

*Is this comparable to UK Brownfield*

*how know if tax reform works? ↑ investment?*

*Are monthly tax payments removed*

*what credits = production how much do companies have in 40-60%*

*mentioned in meeting w/ French*

# ALASKA STATE LEGISLATURE

Sen. Cathy Giessel, Chair  
Sen. Fred Dyson, Vice Chair  
Sen. Lesil McGuire  
Sen. Anna Fairclough  
Sen. Click Bishop  
Sen. Peter Micciche  
Sen. Hollis French



State Capitol, Room 427  
Juneau AK 99801-1182  
907-465-4843  
Fax: 907-465-3871  
800-465-4843

## Senate Resources Committee

### MEMORANDUM

**Date:** February 6, 2013  
February 12, 2013 revised per request of JBUD

**To:** Senator Fairclough, Chair  
Legislative Budget & Audit Committee

**From:** Senator Cathy Giessel

**Re:** Questions for PFC Energy from Senator French

---

Herewith I am submitting two questions from Senator French which were raised in committee this afternoon. He requests they be addressed by our consultant PFC Energy. Also attached is Legislative Research Services brief dated January 17, 2013 (LRS Report 13.137), to which his questions pertain.

The questions as transcribed from Senator French's note:

1. Are these numbers accurate?
2. Why, if these #'s are accurate, isn't CP investing more in Alaska?

# ALASKA STATE LEGISLATURE

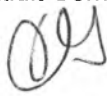
Sen. Cathy Giessel, Chair  
Sen. Fred Dyson, Vice Chair  
Sen. Lesil McGuire  
Sen. Anna Fairclough  
Sen. Click Bishop  
Sen. Peter Micciche  
Sen. Hollis French



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Feb 6, 2013

from Senfrench to LB&A  
for PFC energy to  
analyse:

1. Are these numbers  
accurate?

2. Why, if these #s  
are accurate, isn't  
CP investing more  
in Alaska?



# LEGISLATIVE RESEARCH SERVICES

Alaska State Legislature  
Division of Legal and Research Services  
State Capitol, Juneau, AK 99801

(907) 465-3991 phone  
(907) 465-3908 fax  
[research@legis.state.ak.us](mailto:research@legis.state.ak.us)

---

## Research Brief

TO: Senator Hollis French  
FROM: Chuck Burnham, Legislative Analyst  
DATE: January 17, 2013  
RE: ConocoPhillips: Net Income per Barrel of Oil Equivalent, through Third Quarter, 2012  
*LRS Report 13.137*

---

***You asked that we calculate ConocoPhillips' net income per barrel of oil equivalent for the first two quarters of 2012 for exploration and production activities in Alaska, the Lower 48 states/Latin America, and the remainder of its international operations.***

---

As the attached table shows, in the first three quarters of 2012, the exploration and production activities of ConocoPhillips Co. generated net income of roughly \$1.71 billion in Alaska.<sup>1</sup> This compares to approximately net income of approximately \$556 million in the Lower 48 / Latin America, and \$4.33 billion for its other international operations and those of its equity affiliates. On a "barrel of oil equivalency" (BOE) basis, the value of Alaska production—\$29.83 per BOE—is higher relative to those other jurisdictions in part because of the recent high price of oil, existing infrastructure, and the fact that most hydro-carbons produced in Alaska for market are in the form of crude oil, among other factors.<sup>2</sup> By contrast, operations in the Lower 48 / Latin America produce a much higher proportion of natural gas, which has been selling at historically low prices recently, resulting in a net value of \$4.42 per BOE.

The company's overseas operations generate large volumes of crude oil and natural gas but have received heavy capital expenditures. For example, in the first nine months of 2012, operations in Canada were the subject of capital expenditures and investments of over \$1.5 billion, while Europe and Asia Pacific / Middle East regions each received investments of over \$2 billion, compared to \$596 million in Alaska. These large expenditures serve to decrease significantly the company's net income per BOE in those geographical areas.

We hope this is helpful. If you have questions or need additional information, please let us know.

---

<sup>1</sup> "Exploration and production" income is derived from the extraction and sale of raw oil and gas. These "upstream" activities do not include operations that are considered "mid- and downstream" businesses such as refining and retail gasoline sales.

<sup>2</sup> "Barrel of oil equivalent" (BOE) expresses the amount of a given fuel required to equal the amount of energy contained in one standard U.S. barrel of crude oil (42 gallons). For instance, a generally accepted BOE approximation for natural gas is 5,800 cubic feet (5.8 Mcf). Please note, however, that the amount of energy provided by a given amount of crude oil (or any fuel) varies by production location or, more precisely, the grade of oil produced. Therefore, BOE figures should be viewed as estimates.

**ConocoPhillips: Exploration and Production Net Income per Barrel of Oil Equivalent  
in Selected Areas, through 3rd Quarter 2012**

Jurisdiction	Net Income (Millions)	Net Income per Day (Millions)	Production		BOE Value
			Barrels of Oil per Day	Total BOE per Day	
Alaska	\$ 1,706	\$ 6.2	185,000	209,000	\$ 29.83
Lower 48 / Latin America	\$ 556	\$ 2.0	119,000	452,000	\$ 4.42
International/ Equity Affiliates	\$ 4,329	\$ 15.9	308,000	908,000	\$ 17.18
<b>Total (Selected Areas)</b>	<b>\$ 6,591</b>	<b>\$ 24.1</b>	<b>612,000</b>	<b>1,569,000</b>	<b>\$ 15.15</b>

**Notes:** "Barrel of oil equivalent" (BOE) expresses the amount of a given fuel required to equal the amount of energy contained in one standard U.S. barrel of crude oil (42 gallons). For instance, a generally accepted BOE approximation for natural gas is 5,800 cubic feet (5.8 Mcf). Please note, however, that the amount of energy provided by a given amount of crude oil (or any fuel) varies by production location or, more precisely, the grade of oil produced.

The figures in this table are the results of dividing net income by the aggregate BOE production of oil, natural gas, natural gas liquids, and bitumen.

Due to the impact of rounding of daily production figures to the nearest thousand, area production may not sum to totals, and the result of our BOE value calculations may vary from actual results by a small amount. As a result, these figures should be viewed as estimates.

**Sources:** Income and production data are from ConocoPhillips' Quarter 3, 2012, "10-Q" filing with the U.S. Securities and Exchange Commission. The report is available online by searching for "ConocoPhillips" at <http://www.sec.gov/edgar/searchedgar/companysearch.html>.



THE STATE  
of ALASKA  
GOVERNOR SEAN PARNELL

Department of Revenue

COMMISSIONER'S OFFICE  
Bryan Butcher, Commissioner

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

MEMORANDUM

TO: Alaska Municipal League

FROM: Bruce Tangeman  
Deputy Commissioner BT

DATE: February 21, 2013

RE: Proposed changes to municipal revenue sharing fund under SB 21

There have been concerns raised by the Alaska Municipal League (AML) regarding proposed language in SB 21 that would change the source of revenue that funds the community revenue sharing fund from oil and gas production tax revenues received under AS 43.55.011(g) to corporate income tax revenues received under AS 43.20.030(c).

AS 43.20.030(c) states that "the total amount of tax imposed by this chapter is due and payable to the department at the same time and in the same manner as the tax payable to the United States Internal Revenue Service." Although this section doesn't specifically address the calculation of the tax due, it does provide for tax payments. Furthermore, by adopting the payment scheme required under the Internal Revenue Code, community revenue sharing would be based on when the tax was paid and not when the liability was calculated. Most corporate income taxpayers file returns based on a calendar year. As such, the majority of corporate income tax returns are due April 15<sup>th</sup> each year and reflect the corporate income tax liability for the previous calendar year. Corporate income taxpayers are required to make quarterly estimated tax payments and then a final payment on March 15<sup>th</sup> of the following year. Our intent was to base community revenue sharing on actual payments made throughout the year and not on the final liability determined on April 15<sup>th</sup> of the preceding year.

During the past three fiscal years, the State of Alaska received an average of \$656 million in corporate income tax revenue. Regardless of whether community revenue sharing is based on estimated tax payments made or final liability determined at the end of the year, the Department believes there is ample corporate income tax revenue to cover the maximum revenue share of \$60 million each year.

We hope this addresses your concerns and have clearly outlined our reasoning for identifying AS 43.20.030(c) as the statute governing the corporate income tax payments.

# CS (working draft 2.22.2013) for SB 21

February 26, 2013

Doug Smith, Alaska Support Industry Alliance  
President, Board of Directors

# Tax Rate

- Change
  - SB 21: retains the 25% base tax rate currently in ACES
  - CS: substitutes a tax rate equal to 35%, minus \$5/bbl
- Effect of CS (compared to SB 21):
  - Attempt to address the tax neutral point at prices where projects are evaluated
  - Levels out the tax rate but leaves a somewhat progressive feature
- Comment:
  - Accomplishes needed change at lower end of the price range
  - Some concern about competitive effect of increased rate at the higher end of the price range against our North American competitors
  - Perhaps an offset to the progressive nature is a slightly lower base rate

# Expansion of GRE

- Change
  - SB 21: 20% GRE available for production from *new* units and participating areas (PA's)
  - CS: GRE available also for production from *expansion* of existing PA's and increased to 30%
- Effect of CS (compared to SB 21)
  - Responds to the goal of leveling the playing field for new investments that produce new oil within existing fields and increases the incentive to develop new oil
- Comment
  - This is a step in the right direction however the known and currently producing legacy areas are still the best opportunity for increased production. Investment in the currently producing areas of the legacy fields will be best stimulated by a competitive base rate. The correct level of base rate is one that induces significant new investment in the currently producing legacy areas.

# Expansion of Exploration Credit

- Change
  - SB 21: does not change existing law, which limits exploration credit to wells drilled beyond 3 miles from previous well
  - CS: eliminates 3 mile limitation; retains existing requirement for advance DNR determination
- Effect of CS (compared to SB 21):
  - Significantly expands geographic area available for the credit
- Comment:
  - Improves the economics of exploration in affected areas

# Qualified industry service credit

- Change
  - SB 21: No similar provision
  - CS: Establishes a credit to Alaska corporate income tax for manufacture or modification in Alaska of tangible personal property “used in the exploration, development and production of oil or gas”
- Effect of CS (compared to SB 21):
  - Intent is to encourage in state manufacture of tangible personal property that will create jobs, stimulate our local economy, and make local suppliers more competitive with companies outside of Alaska
- Comment:
  - This is a positive step towards local job creation and continued improvement in the number of Alaskans working in the industry
  - Most likely this will result in downstream property taxes and income for businesses that will more than offset the value of the credits

## Trade Membership Total Annual Wages and Average Employment, by Sector, :

	Total Annual Wages (in \$millions)	Average Employment
Mining, Oil and Gas Extraction, and Support Activities	\$571.8	5,883
Construction	\$182.8	1,745
Manufacturing	\$22.0	389
Wholesale & Retail Trade	\$116.5	2,005
Transportation & Utilities	\$301.2	4,964
Information	N/A	N/A
Finance, Insurance, and Real Estate	\$161.5	2,738
Professional and Business Services	\$408.9	5,174
Education and Health Services	\$21.0	545
Leisure and Hospitality	\$76.9	2,395
Other Services	N/A	N/A
<b>State Total for Alliance Members</b>	<b>\$1,996.1</b>	<b>27,965</b>

Source: ADOLWD, compiled by McDowell Group.

# Senate Resources Committee Comments on SB 21 CS

**Investors: AVCG** (Alaska Venture Capital Group)  
**Operator: Brooks Range Petroleum**

Ken Thompson  
AVCG Co-Owner/Investor  
Former President, ARCO Alaska, Inc.

February 25, 2013

## Why Consider Our Company's Perspectives ?



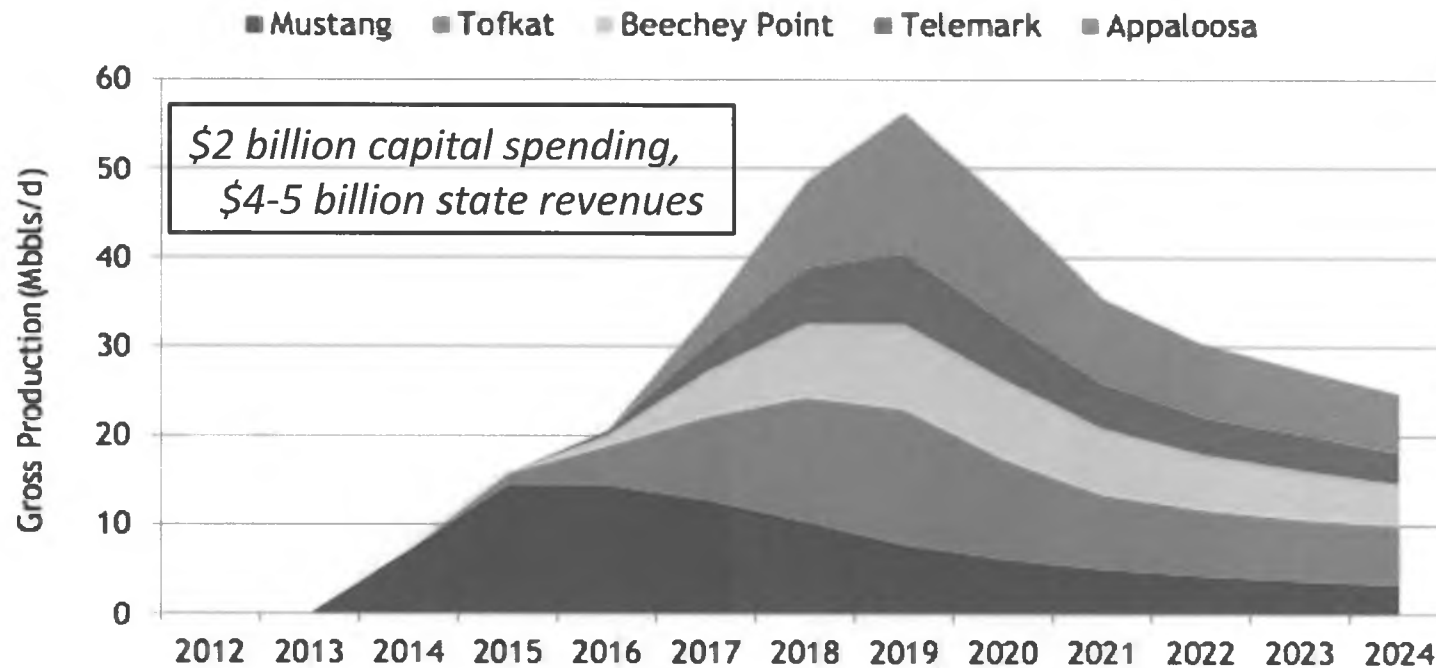
- 1) Most active exploration company exploring and developing solely on North Slope state lands
  - a) Drilled 10 of 36 exploration wells on state lands in 2007-12 (more than COP, BP, XOM, ENI, Repsol, Armstrong combined)
  - b) 105,000 leased acres in 3 core areas in JV partnership with Ramshorn Exploration (affiliate of large Nabors Industries)
- 2) ~ \$200 MM invested to date in Alaska North Slope projects...3 discoveries, acquired discovery
- 3) Mustang development project under construction...\$577 MM capital, 44 MMBO, 15,000 BOPD ... future level of capital spending/yr same as Pioneer Natural Resources and one-third the level of COP capital spending
- 4) Three other development projects in permitting/conceptual engineering stages...> \$1.5 B capital
- 5) First production and cash flow to state and our companies...startup of Mustang in 3Q 2014
- 6) On investment of \$200 MM, received refunded tax credits totaling \$69 MM but State will receive back this amount+ in the first year of Mustang production...and \$1.2 billion over field life
  - a) All credits have been redeployed on the North Slope for new drilling or seismic to find, develop oil...none sent Outside
  - b) Credits redeployed has allowed in some years the drilling of 3 exploration wells instead of 2...or 2 wells instead of only 1
  - c) Payment of credits in cash versus just an allowance against taxes critical to AVCG which has no current production

# What Difference Can Our Company Make?



## Production Profile (Mbbbls/d)

*“New work in existing fields to increase production above their existing declines will not – by itself – level AK’s oil production. Production from exploration discoveries are needed also. Alaska still needs E&P...not just P!”*



*Between 2012 and 2011, North Slope oil production declined 50,768 BOPD. Developments such as the above, if repeated, could help in replacing production fall off...AND ACHIEVE “NO DECLINE!”*

*Note: Mustang delineated and development underway. Tokfat, Beechey Point, Telemark, Appaloosa require delineation before sanctioning...not risked.*

## We See Positives In SB 21 CS To Help Grow Production



- 1) Increases “Carry Forward Loss Credit (CFL)” from 25% to 35% and interest on unused credits 43.55.023(b)..
  - ✓ *POSITIVE: incrementally more future cash flow to re-deploy into facilities & drilling*
- 2) Extends “Small Producers” Credits from to 2022...reduces small producers’ tax bill by \$12 MM/yr 43.55.024(c)..
  - ✓ *POSITIVE: more cash flow for small producers to re-deploy into facilities & drilling*
- 3) Specifies 20% QCE tax credit certificate payment in single year vs. 2 but does eliminate QCE on 12/31/13 43.55.023(a)
  - ✓ *POSITIVE: more immediate cash to put into Mustang development facilities and drilling 2014*
  - ✓ *NEGATIVE: no QCE payment in 2015 to redeploy into Mustang development drilling...“wish list” is extend QCE and cash payment to 12/31/14...project was sanctioned assuming QCE, requiring less Owners’ funding*
- 4) Eliminates progressivity factor, increases base tax rate from 25% to 35% but provides \$5/bbl produced bbl credit 42.55.011(e)..
  - ✓ *POSITIVE: Eliminating progressivity simplifies tax calculation and will be a public relations plus for AK*
  - ✓ *NEGATIVE: Increase in base tax rate from 25% to 35% not expected...but partially offset by...*
  - ✓ *POSITIVE: \$5/bbl produced bbl credit better balances relative state/producer takes at low oil prices*
- 5) For new oil, increases “20% Gross Revenue Exclusion (GRE)” to 30% GRE and amends definition of leases that can be included for this GRE 43.55.160..
  - ✓ *POSITIVE: Should incentivize new oil production on more leases, also help during low oil price cycles*
- 6) Removes old distance limitations and allows for a 40% “Exploration Incentive Credit” for exploration wells drilled that target new oil discoveries regardless of location 43.55.023(a)..
  - ✓ *HUGE POSITIVE: For exploration companies like ours-will result in more companies & more oil on State lands*
- 7) Overall? Thank you for the changes in the CS...this should help in attracting new capital & leveling oil production



THE STATE  
of **ALASKA**  
GOVERNOR SEAN PARNELL

**Department of Revenue**

COMMISSIONER'S OFFICE  
Bryan Butcher, Commissioner

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

February 21, 2013

The Honorable Cathy Giessel  
Alaska State Senator  
Chair, Senate Resources Committee  
State Capitol Room 427  
Juneau, AK 99801

Dear Senator Giessel:

The purpose of this letter is to provide you with a response to questions posed by Senator French, in writing on February 12, 2013. Please see questions in italics and our responses immediately below the questions.

1. *Quantify the number of additional barrels of new production (factoring in the GRE for new oil) it will take to offset the loss of revenue under SB21 at \$90, \$110, \$130/bbl oil.*

The legislature's consultant PFC Energy addressed this question in testimony before the House and Senate Resources Committees on February 15, 2013. On slide 5 of that presentation, PFC stated that at \$100 per barrel, "If an improvement in fiscal terms can stimulate sufficient new investment to stem declines, it has the long run potential to increase revenue, despite the near-term cost of the change. To maintain revenues to the state at a steady level in real terms, a reduction in government take such as that under SB 21 would need to spur sufficient investment to reduce the North Slope base decline from 6% as currently forecast to 1%."

Additionally, the DOR fiscal note for SB 21, on page 4, includes hypothetical examples of additional production. The additional production scenarios compare additional production under SB 21 to ACES without the additional production. At \$90 per barrel, revenue is equal or greater than ACES with no additional production. At \$100 per barrel, revenue is greater than ACES under "Additional Production Scenario B", and at \$120 per barrel, revenue is greater than ACES under "Additional Production Scenario C." These scenarios are not intended as forecasts, but give a helpful illustration of the order of magnitude of new investment and production that would offset the reduction in government take under SB 21.

2. *Provide a detailed description of the tax credits for brownfields the U.K. is providing in the North Sea. Include the current government take before the credits, how the credits are targeted, and whether the tax credits go on forever or are capped (and if so, how).*

It is our understanding that the expectation is for PFC to respond to this question. If not, please let us know and we will work to provide it.

3. *What are federal tax implications for an oil producer in Alaska of any reductions in state taxes? If the state reduces its oil taxes by \$1 billion, for example, how much of that is available for reinvestment in Alaska?*

Our modeling of producer take assumes a 35% federal corporate income tax rate. That is, a reduction in state taxes of \$1 billion would lead to a net increase in producer take of \$650 million.

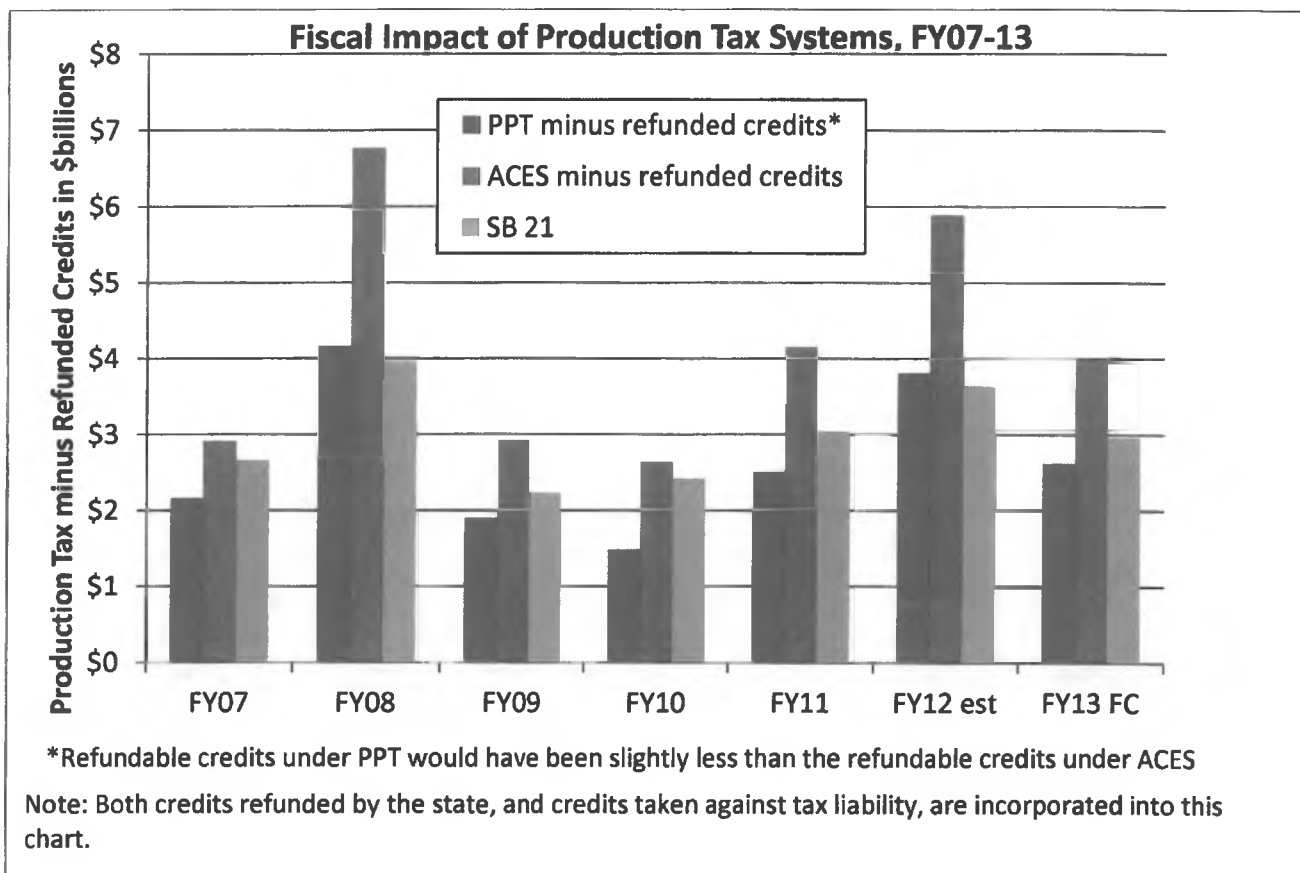
4. *When total government take is modeled by PFC and DOR, are federal taxes modeled in the abstract, or are they tied to actual federal taxes paid? Since federal tax payment information is part of SEC filings, can we see a model of government take that reflects actual federal tax rates paid?*

Federal corporate income taxes are modeled using an assumption of a 35% federal corporate income tax rate. Given the complexity and nuances of federal tax code and SEC required filings, as well as activities outside of Alaska, we would caution against using SEC filings as the basis for estimating the federal corporate income tax rate that is applicable to oil produced in Alaska. Also, since the marginal 35% federal corporate income tax rate is typically used to model government take, an Alaska government take number calculated using a different assumption would no longer be comparable to calculations and benchmarks for other oil producing jurisdictions.

5. *Provide a chart of the effect on state revenues of adopting SB21. Using the annual production and prices from FY07 through FY13, report the revenue for each year under ACES, under PPT, and under SB21.*

Shown below is a chart of the estimated fiscal impact of ACES, PPT and the proposed SB21 production tax systems. Production tax revenue under ACES has been reduced to illustrate the impact of the credits that were refunded under ACES that would not have been refunded under SB21. Production tax under PPT was reduced by the same amount, although the amount of credits refunded under PPT would have been slightly less than the amount refunded under ACES.

It is also important to note that the amount of production in each of these years might have been different under SB21 than it was under ACES and PPT.



I hope you find this information to be useful. Please do not hesitate to contact me if you have further questions.

Sincerely,

Bryan Butcher  
Commissioner

## Arctic Oil and Natural Gas Potential

Philip Budzik

U.S. Energy Information Administration  
Office of Integrated Analysis and Forecasting  
Oil and Gas Division

October, 2009

### Introduction

The Arctic is defined as the Northern hemisphere region located north of the Arctic Circle, the circle of latitude where sunlight is uniquely present or absent for 24 continuous hours on the summer and winter solstices, respectively. The Arctic Circle spans the globe at 66.56° (66°34') north latitude (Figure 1).<sup>1</sup>

The Arctic could hold about 22 percent of the world's undiscovered conventional oil and natural gas resources. The prospects for Arctic oil and natural gas production are discussed taking into consideration the nature of the resources, the cost of developing them, and the political and environmental issues associated with their development.

### Background

The area above the Arctic Circle encompasses about 6 percent of the Earth's surface area. While the Arctic is about the size of the African continent, most of the Arctic is oceanic.<sup>2</sup> About one-third of the Arctic is occupied by land. Another one-third of the Arctic consists of offshore continental shelves located in less than 500 meters (1,640 feet) of Arctic Ocean water. The remaining one-third of the Arctic is in Arctic Ocean waters deeper than 500 meters.

Jurisdictionally, the Arctic contains portions of eight countries - Canada, Denmark (Greenland), Finland, Iceland, Norway, Russia, Sweden, and the United States. Finland and Sweden do not border the Arctic Ocean and are the only Arctic countries without jurisdictional claims in the Arctic Ocean and adjacent seas.<sup>3</sup>

The sun does not rise above the Arctic horizon for days or weeks during the winter, depending on how far north of the Arctic Circle you are. Sunlight hits Arctic surfaces at an angle of much less than 90 degrees over much of the year, further diminishing the amount of incident solar radiation. As a consequence, the Arctic experiences freezing temperatures for most of the year with brief interludes above freezing. For example, at

<sup>1</sup> U.S. Geological Survey, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle," USGS Fact Sheet 2008-3049, Washington, DC (2008), page 1. USGS website URL is: <http://pubs.usgs.gov/fs/2008/3049/>

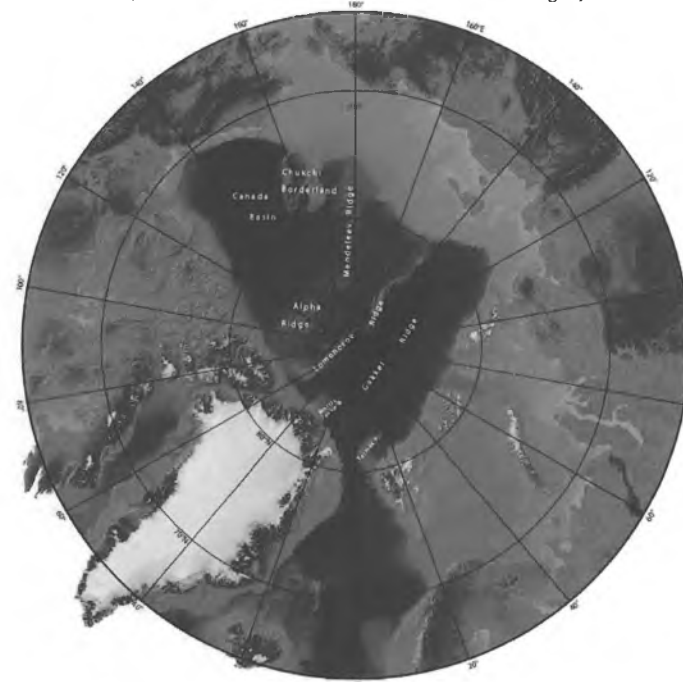
<sup>2</sup> Donald L. Gautier, et. al., "Assessment of Undiscovered Oil and Gas in the Arctic," *Science*, May 29, 2009, Volume 324, page 1175 - 1179.

<sup>3</sup> Sweden and Finland have onshore territory in the Arctic but none with any known or projected oil and natural gas resources.

Prudhoe Bay, Alaska,<sup>4</sup> winter temperatures can fall below -50 °F (-45 °C), while July temperatures range between 37 and 54 °F (3 to 12 °C) (Appendix A). The central Arctic Ocean is ice-covered year-round, and snow and ice are present on land for most of the year.<sup>5</sup>

The cold Arctic air inhibits evaporation so little precipitation occurs, with much of the Arctic having an average annual precipitation rate of 100 mm (4 inches) or less,<sup>6</sup> mostly in the form of snow.

**FIGURE 1**  
**Region within the Arctic Circle**  
(North America is to the left and Eurasia is to the right.)



Source: National Geophysical Data Center, Marine Geology and Geophysics Division, website: <http://www.ngdc.noaa.gov/mgg/bathymetry/arctic/arctic.html>

<sup>4</sup> Latitude: 70.2552778 (70-15'19" N) and Longitude: -148.3372222 (148-20'14" W); source: [http://www.lat-long.com/Latitude-Longitude-1408327-Alaska-Prudhoe\\_Bay.html](http://www.lat-long.com/Latitude-Longitude-1408327-Alaska-Prudhoe_Bay.html)

<sup>5</sup> National Snow and Ice Data Center website at: [http://nsidc.org/arcticmet/basics/arctic\\_definition.html](http://nsidc.org/arcticmet/basics/arctic_definition.html)

<sup>6</sup> Arctic Council, "Arctic Climate Impact Assessment," Cambridge University Press, 2005, page 10.

Because limited sunlight, limited heat, and snow and ice are all unresponsive of plant and animal metabolism, biological activity is limited. Harsh weather and low biological fecundity has limited human activity in the Arctic. In 2000, about 3.5 million humans lived in the Arctic,<sup>7</sup> mostly on lands bordering the Arctic Ocean.

"In the 20th century, immigration to the Arctic has increased dramatically, to the point where non-indigenous persons outnumber indigenous ones in many regions. The new immigrants have been drawn by the prospect of developing natural resources, from fishing to gold to oil, as well as by the search for new opportunities and escape from the perceived and real constraints of their home areas."<sup>8</sup>

### Discovered Arctic Oil and Natural Gas Resources

The best place to find oil and natural gas is where oil and natural gas have already been found. So the large, existing Arctic oil and natural gas fields are reviewed prior to the discussion of the undiscovered Arctic oil and natural gas resource base. In this review, "large" oil and natural gas fields are those that exceed 500 million barrels of oil equivalent of recoverable oil and natural gas.<sup>9</sup>

Large Arctic oil and natural gas fields are particularly crucial with respect to future oil and natural gas development because the cost of developing oil and natural gas fields in the Arctic is so high that large fields are initially necessary to pay for the infrastructure required to later develop the smaller oil and natural gas deposits. For example, the Prudhoe Bay Field with 13.6 billion barrels of recoverable oil<sup>10</sup> made the construction of the Alyeska Oil Pipeline<sup>11</sup> commercially viable. Without the Prudhoe Bay Field, it is unlikely that the smaller Alaska North Slope oil fields would have been developed.

Arctic infrastructure development is sufficiently expensive that many large Arctic fields remain undeveloped. For example, 35.4 trillion cubic feet<sup>12</sup> (6.3 billion barrels of oil equivalent) of the discovered Alaska North Slope natural gas resources remain unexploited due to the absence of transportation infrastructure. About two-thirds of this natural gas is in the Prudhoe Bay Field.

<sup>7</sup> Ibid. Table 1.1, page 14.

<sup>8</sup> Ibid. page 13.

<sup>9</sup> The exact recovery of oil and natural gas from a field is not known with certainty until that field has been permanently abandoned. Actual recovery is often greater than the original estimate, as the producer learns how to apply technology to enhance recovery rates. Ultimate field recovery rates are also affected by oil and natural gas prices, with higher prices resulting in higher recovery rates. Consequently, the exact number of large discovered fields above the Arctic Circle can only be approximate. Large field data source: Petroleum Source to Reservoir, Giant Oil and Gas Fields database, Version 14, 2009, website address: <http://www.sourcetoreservoir.com/index.html>

<sup>10</sup> Figure does not include natural gas. Source: Alaska Department of Natural Resources, Division of Oil & Gas, *Alaska Oil and Gas Report*, July 2007, Anchorage, Alaska, Table III.1(Oil and Gas Reserves), page 3-2 and Table III.3 (Oil Production – Historic), page 3-5.

<sup>11</sup> Also known as the TransAlaska Pipeline System (TAPS).

<sup>12</sup> Op. cit. Alaska Department of Natural Resources, Table III.1, page 3-2.

Large Arctic oil and natural gas discoveries began in Russia with the discovery of the Tazovskoye<sup>13</sup> Field in 1962 and in the United States with the Alaskan Prudhoe Bay Field in 1967. Approximately 61 large oil and natural gas fields have been discovered within the Arctic Circle in Russia, Alaska, Canada's Northwest Territories, and Norway.<sup>14</sup> Fifteen of these 61 large Arctic fields have not yet gone into production; 11 are in Canada's Northwest Territories, 2 in Russia, and 2 in Arctic Alaska.

Forty-three of the 61 large Arctic fields are located in Russia. Thirty-five of these large Russian fields (33 natural gas and 2 oil) are located in the West Siberian Basin.<sup>15</sup> Of the eight remaining large Russian fields, five are in the Timan-Pechora Basin, two are in the South Barents Basin, and one is in the Ludlov Saddle.

Of the 18 large Arctic fields outside Russia, 6 are in Alaska, 11 are in Canada's Northwest Territories, and 1 is in Norway.

### Arctic Undiscovered Technically Recoverable, Conventional Oil and Natural Gas Resources

In 2008, the United States Geological Survey (USGS) released an assessment of Arctic undiscovered technically recoverable,<sup>16</sup> conventional oil and natural gas resources.<sup>17</sup> The assessment excluded from consideration any sedimentary provinces that were less than 3 kilometers deep. Of the 33 Arctic provinces that surpassed this depth and that were evaluated by the USGS, 8 were not "quantitatively assessed" because they had less than a 10-percent probability of having an oil and/or natural gas deposit larger than 50 million barrels of oil equivalent in any of their assessment units.<sup>18</sup> The USGS therefore provided quantitative estimates of undiscovered oil and natural gas resources for 25 Arctic sedimentary provinces.

Because some of the sedimentary provinces evaluated by the USGS lay both above and below the Arctic Circle, the USGS apportioned the total resource base within those provinces into estimated resources above and below the Arctic Circle. Only the Arctic portion of each province's resource estimate is shown in Table 1.

<sup>13</sup> There are often multiple variations for the English spelling of foreign oil and natural gas fields.

<sup>14</sup> This number is approximate because it depends on the latitude coordinates provided in the Giant Oil and Gas Fields database. The oil and natural gas fields' latitude in the database had to be greater than the 66.56° latitude to qualify as Arctic fields.

<sup>15</sup> All sedimentary province names are those used by the United States Geological Survey.

<sup>16</sup> Technically recoverable resources are resources that can be produced using current technology.

<sup>17</sup> U.S. Geological Survey, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle," USGS Fact Sheet 2008-3049, Washington, DC (2008). The USGS is currently preparing a more extensive report regarding their Arctic assessment.

<sup>18</sup> Source: Personal communication with Ronald R. Charpentier of the USGS on May 12, 2009. Seven of the eight provinces that were not quantitatively assessed have only one assessment unit. The Franklinian Shelf province has three separate assessment units

**TABLE 1**  
**Arctic Mean Estimated Undiscovered**  
**Technically Recoverable, Conventional Oil and Natural Gas Resources**  
**By Arctic Province, Ranked by Total Oil Equivalent Resources**

USGS Petroleum Province Name	Crude Oil (billion barrels)	Natural Gas (trillion cubic feet)	Natural Gas Liquids 1/ (billion barrels)	Total Resources, Oil Equivalent 2/ (billion barrels)
West Siberian Basin	3.66	651.50	20.33	132.57
Arctic Alaska	29.96	221.40	5.90	72.77
East Barents Basin	7.41	317.56	1.42	61.76
East Greenland Rift Basins	8.90	86.18	8.12	31.39
Yenisey-Khatanga Basin	5.58	99.96	2.68	24.92
Amerasia Basin	9.72	56.89	0.54	19.75
West Greenland-East Canada	7.27	51.82	1.15	17.06
Laptev Sea Shelf	3.12	32.56	0.87	9.41
Norwegian Margin	1.44	32.28	0.50	7.32
Barents Platform	2.06	26.22	0.28	6.70
Eurasia Basin	1.34	19.48	0.52	5.11
North Kara Basins and Platforms	1.81	14.97	0.39	4.69
Timan-Pechora Basin	1.67	9.06	0.20	3.38
North Greenland Sheared Margin	1.35	10.21	0.27	3.32
Lomonosov-Makarov	1.11	7.16	0.19	2.49
Sverdrup Basin	0.85	8.60	0.19	2.48
Lena-Anabar Basin	1.91	2.11	0.06	2.32
North Chukchi-Wrangell Foreland Basin	0.09	6.07	0.11	1.20
Vilkitskii Basin	0.10	5.74	0.10	1.16
Northwest Laptev Sea Shelf	0.17	4.49	0.12	1.04
Lena-Vilyui Basin	0.38	1.34	0.04	0.64
Zyryanka Basin	0.05	1.51	0.04	0.34
East Siberian Sea Basin	0.02	0.62	0.01	0.13
Hope Basin	0.002	0.65	0.01	0.12
Northwest Canadian Interior Basins	0.02	0.31	0.02	0.09
<b>Total</b>	<b>89.98</b>	<b>1,668.66</b>	<b>44.06</b>	<b>412.16</b>

Source: U.S. Geological Survey, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle," USGS Fact Sheet 2008-3049 Washington, DC (2008), Table 1, page 4.  
 Note: The column totals do not equal the sum of the rows due to rounding. USGS website URL is: <http://nubs.usgs.gov/fsr/2008/3049/>. The relative location of these provinces is identified in Appendix B.  
 1/ Natural gas liquids are composed of ethane, propane, and butane.  
 2/ The USGS uses a natural gas to oil conversion factor in which 6 thousand cubic feet of natural gas equals 1 barrel of crude oil.

The USGS Arctic assessment estimated a total oil and natural gas resource of 412 billion barrels of oil equivalent, with 78 percent of those resources expected to be natural gas and natural gas liquids (NGL). The composition of undiscovered Arctic hydrocarbons is largely determined by the West Siberian Basin and East Barents Basin, which hold 47 percent of the undiscovered Arctic resources, with 94 percent of those resources being natural gas and NGL.

According to the USGS mean estimate, the Arctic holds about 22 percent of the world's undiscovered conventional oil and natural gas resource base, about 30 percent of the world's undiscovered natural gas resources, about 13 percent of the world's undiscovered oil resources, and about 20 percent of the world NGL resources.<sup>19</sup>

The fact that the Arctic is particularly rich in natural gas and NGL may impede the exploitation of its resources, because the world's natural gas consumers live far from the Arctic and the long-distance transportation of natural gas and NGL is considerably more expensive than oil transportation due to the significantly lower energy density of these fuels relative to crude oil. Although the low energy density of natural gas and NGL can be offset by liquefaction or pressurization, transportation as liquefied natural gas (LNG) is particularly expensive due to the large capital costs required to build the liquefaction facilities and the LNG tankers.

While the Arctic is rich in undiscovered oil and natural gas resources, the resources are concentrated in just a few sedimentary provinces. Table 2 illustrates the Arctic's cumulative oil and natural gas resource concentration for those provinces with the largest share of the Arctic resource base. For example, the 3 largest Arctic provinces account for 65 percent of the total Arctic oil and natural gas resources, and the largest 10 oil and natural gas provinces account for 93 percent of the total. The remaining 15 provinces (out of 25 qualitatively evaluated provinces) are estimated to hold only 7 percent of the Arctic resource base.

**TABLE 2**  
**Arctic Crude Oil, Natural Gas, and Natural Gas Liquids Resource Concentration**  
**for Provinces with the Greatest Share of Total Resources,**  
**Based on the USGS Mean Estimates**

Largest Arctic Resource Provinces	Cumulative Percent of Total Arctic Oil, Natural Gas, & NGL Resources (Percent)
Largest Resource Province	32
Largest 2 Resource Provinces	50
Largest 3 Resource Provinces	65
Largest 5 Resource Provinces	78
Largest 10 Resource Provinces	93

Source: Table 1.

<sup>19</sup> USGS Newsroom release dated July 23, 2008. USGS website URL: [http://www.usgs.gov/newsroom/article.asp?ID=1980&from=rss\\_home](http://www.usgs.gov/newsroom/article.asp?ID=1980&from=rss_home). Figures do not include or consider world unconventional oil and natural gas resources, such as Rocky Mountain oil shale, Canadian oil sands, Venezuelan Orinoco heavy oil, etc. Inclusion of these unconventional resources would reduce the Arctic proportion of total world oil and natural gas resources.

Arctic oil and natural gas resources are not evenly distributed among the Eurasian and North American continents (Table 3). Eurasia is estimated to hold about 63 percent of the total Arctic resource base, while North America holds about 36 percent. The Eurasian resource base is predominantly natural gas and NGL, which account for about 88 percent of the total Eurasian resource base. The Eurasian West Siberia Basin and East Barents Basin account for 194.3 billion barrels of oil equivalent of undiscovered resources, which is 74 percent of the total Eurasian resource base.

**TABLE 3**  
Regional Concentration of Arctic Oil and Natural Gas Resources  
By Continental Land Mass,  
Based on the USGS Mean Estimates

Region	Crude Oil (billion barrels)	Natural Gas (trillion cubic feet)	Natural Gas Liquids (billion barrels)	Total Resources, Oil Equivalent (billion bbl)
<b>Eurasia</b>	30.70	1,219.39	27.55	261.49
<b>North America</b>	58.09	435.40	16.20	146.85
<b>Indeterminate</b>	1.20	13.87	0.31	3.82
<b>Total</b>	<b>89.98</b>	<b>1,668.66</b>	<b>44.06</b>	<b>412.16</b>
<b>Eurasia</b>	34.1 %	73.1 %	62.5 %	63.4 %
<b>North America</b>	64.6 %	26.1 %	36.8 %	35.6 %
<b>Indeterminate</b>	1.3 %	0.8 %	0.7 %	0.9 %
<b>Total</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>	<b>100.0 %</b>

Source: Table 1. The column totals might not equal the sum of the rows due to rounding. Indeterminate regions are those that could not conclusively be assigned to either continent; includes: Lomonosov-Makarov, Hope Basin, and North Chukchi-Wrangell Foreland Basin.

While the Eurasian side of the Arctic is more natural-gas-prone, the North American side is more oil-prone. The North American side of the Arctic is estimated to have about 65 percent of the undiscovered Arctic oil, but only 26 percent of the undiscovered Arctic natural gas.

The Arctic Alaska region is estimated to hold the largest undiscovered Arctic oil deposits, about 30 billion barrels. The second largest oil province in the Arctic is the Amerasia Basin, located just north of Canada, and estimated to have about 9.7 billion barrels of undiscovered oil. The third largest Arctic oil province is the East Greenland Rift, which is estimated to hold about 8.9 billion barrels of undiscovered oil. Collectively, these 3 North American provinces are expected to hold about 48.6 billion barrels of undiscovered oil, which is about 54 percent of the total undiscovered Arctic oil. Approximately 2.5 billion barrels of oil have already been discovered in large fields in both the Amerasia Basin and the Northwest Canadian Interior Basins that are not yet being produced.<sup>20</sup>

There is considerable uncertainty regarding undiscovered Arctic oil and natural gas resources. Table 4 illustrates the wide variation in oil and natural gas resource estimates for the 2 assessment units within the most prolific Arctic province, the West Siberian

<sup>20</sup> Op. cit. Source to Reservoir.

Basin.<sup>21</sup> In both assessment units, the 95-percent probability estimates are about one-fourth the mean estimate, while the 5-percent probability estimates are over twice the mean estimate and about 10 times greater than the 95-percent probability estimate.<sup>22</sup>

**TABLE 4**  
USGS Assessment of the Oil and Natural Gas  
Resource Probability Distribution  
For the Arctic Portion of the West Siberian Basin<sup>23</sup>

Resource Category	Mean Estimate	95-Percent Probability Estimate	5-Percent Probability Estimate
<b>Assessment Unit 1</b>			
Crude Oil (billion barrels)	1.15	0.22	2.93
Natural Gas (trillion cubic feet)	29.28	7.48	68.39
Natural Gas Liquids (billion barrels)	0.85	0.22	1.98
<b>Assessment Unit 2</b>			
Crude Oil (billion barrels)	2.51	0.57	6.02
Natural Gas (trillion cubic feet)	622.22	157.86	1,409.29
Natural Gas Liquids (billion barrels)	19.48	4.86	44.85

Note: The 95-percent and 5-percent probability figures cannot be arithmetically added, whereas the mean estimates can be added together. With respect to the 95-percent and 5-percent probabilities, the proper interpretation of these probability estimates is that they represent an "X" probability of finding "Y" or greater volume of undiscovered resources. For example, there is a 95 percent probability that the West Siberian Assessment Unit 1 will contain 0.22 billion barrels or greater of undiscovered oil resources.

Though there is considerable resource uncertainty, the allure of the Arctic is great because of the significant oil and natural gas deposits that have already been found and the large areas that have not yet been explored. For example, Cairn Energy PLC<sup>24</sup> notes that the sedimentary provinces offshore of West Greenland are three times larger in extent than the North Sea basin and yet only six oil and natural gas exploration wells have been drilled off of West Greenland.<sup>25</sup> Offshore West Greenland is particularly intriguing to Cairn Energy due to extensive offshore oil seeps, thick organic shale beds, and oil shows in prior drilling. The company currently plans to commence a West Greenland exploratory drilling program in 2011. Only as more wildcat exploration wells are drilled in the Arctic will the actual Arctic oil and natural gas resource base become apparent.

<sup>21</sup> Ibid.

<sup>22</sup> From the perspective of mathematical probability and statistics, the resource probability distribution is skewed, such that the median value is less than the mean value.

<sup>23</sup> Donald L. Gautier, et. al., "Assessment of Undiscovered Oil and Gas in the Arctic," *Science*, May 29, 2009, Volume 324, page 1175 - 1179. Specific numbers came from the Excel spreadsheet file associated with the *Science* article, labeled as: "1169467TableS1s.xls".

<sup>24</sup> Cairn Energy PLC is headquartered in Edinburgh, Scotland.

<sup>25</sup> Cairn Energy PLC presentation, "Oil, Deserts, and Ice: A Focus on Challenges and Rewards in India and Greenland," presented by Dr. Michael Watts at the Scottish Oil Club on May 26, 2009, Slide 38. Available at: <http://www.cairn-energy.plc.uk/downloads/ScottishOilClubwebopt.pdf>

## Arctic Development Costs and Risks

Even if the Arctic oil and natural gas resources eventually prove to be considerably greater than the USGS estimates, they will be expensive to develop. As noted earlier, 15 large Arctic oil and natural gas fields are awaiting development. Most were discovered in the 1970s and 1980s. Thirteen of the undeveloped fields are located in North America, where oil and natural gas field development is governed by market-based economics, with fields only being developed if and when they are expected to generate sufficient profits. Of the 17 large Arctic fields located in North America, only 3 have been so-developed, all located in Alaska, around the Prudhoe Bay Field complex.

In contrast, Russia's Arctic resources were predominantly developed under a Soviet command-and-control economy. Many of Russia's large producing Arctic fields might not have been commercially viable under market-based economics, when they were originally developed.<sup>26</sup>

Finding large Arctic oil and natural gas deposits is difficult and expensive; developing them as commercially profitable ventures is even more challenging. Arctic oil and natural gas resource exploration and development are expensive because:

- Harsh winter weather requires that the equipment be specially designed to withstand the frigid temperatures
- On Arctic lands, poor soil conditions can require additional site preparation to prevent equipment and structures from sinking
- The marshy Arctic tundra can also preclude exploration activities during the warm months of the year
- In Arctic seas, the icepack can damage offshore facilities, while also hindering the shipment of personnel, materials, equipment, and oil for long time periods
- Long supply lines from the world's manufacturing centers require equipment redundancy and a larger inventory of spare parts to insure reliability
- Limited transportation access and long supply lines reduce the transportation options and increase transportation costs
- Higher wages and salaries are required to induce personnel to work in the isolated and inhospitable Arctic.

Economic studies involving onshore Alaska North Slope project development costs invoke a capital cost factor ranging from 1.5 to 2.0 relative to similar oil and natural gas projects undertaken in Texas.<sup>27</sup> The development of new Alaska North Slope fields near existing fields is economically benefited by the ability to use whatever infrastructure already exists, for example, roads, railroads, harbor facilities, air fields, electric power generation, and living quarters. Even so, Arctic oil and natural gas project costs and schedules can prove to be significantly greater than originally planned due to supply

<sup>26</sup> The future development of Russia's Arctic resources in a market-based economy is greatly facilitated by the extensive Arctic oil and natural gas infrastructure that was built under the Soviet regime.

<sup>27</sup> E.P. Robertson, Idaho National Engineering and Environmental Laboratory (Bechtel BWXT Idaho, LLC), "Options for Gas-To-Liquids Technology in Alaska," INEEL/EXT-99-01023, December 1999, page vii; and Charles B. Thomas, et. al., Idaho National Engineering and Environmental Laboratory (Lockheed Martin), "Economics of Alaska North Slope Utilization Options," INEL-96/0322, August 1996, page B-19.

chain delays, abnormal weather conditions, and court challenges emanating from environmental concerns.

As an example of supply chain difficulties, the multinational Italian-based petroleum company, Eni S.p.A. originally announced that the Nikaitchuq oil field on the Alaska North Slope would start production by year-end 2009.<sup>28</sup> More recently, Eni announced that the field would not begin production until year-end 2010 partly because the company had missed the summer season opportunity to ocean barge the field's processing and operations modules to the North Slope from a Louisiana fabrication yard. Such supply chain delays increase project costs and reduces the rates of return as expensive equipment remains idle.

Abnormal weather can increase costs by hindering transportation and drilling activity. The early onset of warm weather on the Alaska North Slope during April of 2009 stranded equipment and precluded some exploration well drilling.<sup>29</sup> Similarly, a late onset of winter weather delays construction of the ice roads required to transport heavy equipment across the tundra.<sup>30</sup>

Court challenges stemming from environmental concerns can also increase Arctic project costs. Shell Oil has paid over \$2.2 billion since 2005 to secure Federal oil and natural gas development leases offshore of Alaska (Appendix C) and was planning to drill three wells in its Beaufort Sea leases during the summer of 2007. On July 19, 2007, those plans were suspended by the Ninth Circuit Court of Appeals in response to law suits, filed by the North Slope Borough and the Alaska Eskimo Whaling Commission, regarding the potential impact of Shell's offshore drilling on subsistence hunting and on the environment.<sup>31</sup>

As part of its 2007 Beaufort Sea exploration drilling program, Shell had reactivated and towed the Kulluk arctic drilling ship to the Beaufort Sea,<sup>32</sup> constructed the Nanuq, a 300-foot, ice-strengthened oil-spill response vessel, and chartered the Arctic Endeavor, a 200-foot, 500,000-barrel, double-hulled tanker to hold any oil recovered from a spill.<sup>33</sup> In total, Shell Oil employed 24 vessels and hundreds of people just for the purpose of responding to an accidental offshore oil spill. Although public figures are not available, it would be reasonable to assume that Shell had also already spent hundreds of millions of dollars on its Beaufort Sea exploration program, in addition to the lease bonus payments. Shell currently hopes to begin its Beaufort Sea and Chukchi Sea drilling

<sup>28</sup> Eric Lidji, "Nikaitchuq oil in 2010," *Petroleum News*, Volume 14, Number 21, May 24, 2009, pages 1, 13.

<sup>29</sup> Yereth Rosen, "Sudden Spring jolts Alaska's oil exploration," Thomson Reuters, June 3, 2009.

<sup>30</sup> The movement of heavy equipment in the Arctic to drilling locations is usually confined to the winter months when the tundra is frozen. During the rest of the year, the tundra is too marshy and boggy to permit the off-road transportation of heavy equipment.

<sup>31</sup> Alan Bailey, "9<sup>th</sup> Circuit suspends Shell's Beaufort Sea drilling program," *Petroleum News*, Volume 12, Number 30, July 29, 2007, pages 1, 15.

<sup>32</sup> Alan Bailey, "Shell wells still possible," *Petroleum News*, Volume 12, Number 37, September 16, 2007, pages 1, 22.

<sup>33</sup> Alan Bailey, "Shell: Prepared for the worst," *Petroleum News*, Volume 12, Number 35, September 2, 2007, pages 9 - 11.

program in 2010.<sup>34</sup> If these drilling plans come to fruition, the drilling program will have been delayed 3 years at a substantial cost.

The long lead-times required for Arctic projects also add considerable risk because the business environment can change dramatically between a project's initiation and completion dates. For example, oil and natural gas prices could be considerably lower when an Arctic project begins producing than was anticipated at the planning stage. Also, at a given level of capital investment, longer lead-times reduce the return on that investment, all else being equal. Arctic oil and natural gas projects can exacerbate this problem by requiring considerably larger investments than comparably productive projects pursued elsewhere in the world.

As the Shell and Eni experiences demonstrate, already long lead-times can become even longer. A Deutsche Bank (DB) analysis notes that development of the Russian Shtokman natural gas project in the Barents Sea could take 5 to 8 years from the initiation of substantial capital investment to full production.<sup>35</sup> The DB analysis notes that "With the technical and environmental complexities involved in the development, we see a high risk of delays and cost over-runs."<sup>36</sup>

The Arctic physical environment presents special challenges not experienced elsewhere in the world. Several oil and natural gas fields have been discovered on Russia's Yamal Peninsula but have not been developed because of the daunting physical challenges. As noted in a Cambridge Energy Research Associates report<sup>37</sup> on this matter:

"Intermittent permafrost becomes continuous, winds rise to a steady 40 m per second, wind-driven water up to 10 m deep covers the low-lying land several months of the year, and solid ground gives way to friable sand that offers little support to drill pads or to pipelines and other infrastructure. In winter, instead of soil there is a frozen mixture of one part sand to four parts of ice, shot through with salt. At greater depths one encounters cryopegs—liquid saltwater lenses that slide under pressure, further weakening the load-bearing capacity of the soil. ... The most difficult part is getting gas and liquids to market as well as getting equipment and material in."

Currently, Gazprom is considering the construction of a new railroad line and a new harbor to move men and material into the Yamal Peninsula. The requirement to undertake such expensive efforts as a precursor to actual development underscores the high cost of developing the Yamal Peninsula oil and natural gas fields.

Arctic operating costs are also increased by the ice-pack conditions that extend over much of the Arctic Ocean. The requirement for ice-resistant tankers and ice-breaker

<sup>34</sup> Kay Cashman, "Shell pushes drilling out to 2010, '11," *Petroleum News*, Volume 13, Number 52, December 28, 2008, page 3.

<sup>35</sup> Dave Thomas, et al., "Shtokman – The big cod," Deutsche Bank Company Research, March 22, 2006, pages 14 – 16, 19.

<sup>36</sup> *Ibid.*, page 19.

<sup>37</sup> Cambridge Energy Research Associates, "Conquering Yamal," October, 2007, Cambridge, Massachusetts, page 14.

escorts adds to the cost of transporting oil and natural gas through Arctic waters. To deal with the ice-pack, Russian companies use ice-resistant tankers in conjunction with ice-breaker escorts to transport oil in Arctic waters throughout the year.<sup>38</sup> For example, Rosneft purchased 30,000 deadweight double-hulled, ice-reinforced shuttle tankers to transport oil to the Russian port of Arkhangelsk.<sup>39</sup> As of 2008, the Russian Arctic ice-breaker fleet consisted of 28 ice-breakers.<sup>40</sup>

Additional costs might be imposed on future oil and natural gas development if a warming of the Arctic region melts the permafrost and turns currently firm soils into marshes and bogs. On the other hand, warmer Arctic temperatures would shrink the ocean icepack,<sup>41</sup> thereby facilitating and reducing the cost of water transportation and offshore drilling.

The high cost of doing business in the Arctic suggests that only the world's largest oil companies, most likely as partners in joint venture projects, have the financial, technical, and managerial strength to accomplish the costly, long-lead-time projects dictated by Arctic conditions.

#### Arctic Oil and Natural Gas Development Issues

Arctic oil and natural gas development also faces political and environmental issues. Political issues stem from the overlapping and disputed claims of economic sovereignty. The environmental issues pertain to the preservation of animal and plant species unique to the Arctic, particularly tundra vegetation, caribou, polar bears, seals, whales, and other Arctic sea life.

#### Arctic Economic Sovereignty Claims

Denmark, Canada, Norway, Russia, and the United States have overlapping economic sovereignty claims in Arctic waters. The existence of these offshore boundary disputes could forestall Arctic oil and natural gas resource development in areas where the sovereignty claims overlap.

Some of the competing claims stem from the fact that the 1982 United Nations Convention on the Law of the Sea (UNCLOS) permits countries to claim economic sovereignty as much as 350 nautical miles (403 U.S. statutory miles) beyond the point where the sea depth exceeds 2,500 meters (8,200 feet) of water.<sup>42</sup> The existence of extensive Arctic continental margins<sup>43</sup> and numerous subsea ridges possibly related to those continental margins, permit the littoral nations to make competing claims for most Arctic waters (Figure 1).

<sup>38</sup> Sarah Hurst, "Varandey Arctic oil terminal starts up," *Petroleum News*, Volume 13, Number 25, June 22, 2008, page 10.

<sup>39</sup> Norwegian Barents Secretariat, "Oil transport from the Russian part of the Barents Region, Status per January 2009," Kirkenes, Norway, 2009, page 50.

<sup>40</sup> *Ibid.*, Norwegian Barents Secretariat, page 31.

<sup>41</sup> National Snow and Ice Data Center, "Arctic Sea Ice Down to Second-Lowest Extent; Likely Record-Low Volume," Boulder, Colorado, October 2, 2008.

<sup>42</sup> Part VI, Article 76, at [http://www.un.org/Depts/los/convention\\_agreements/texts/unclos/unclos\\_c.pdf](http://www.un.org/Depts/los/convention_agreements/texts/unclos/unclos_c.pdf)

<sup>43</sup> Defined in the UNCLOS, ANNEX II as being any water depth less than 200 meters (~656 feet).

Denmark, Norway, and Russia have made claims of economic sovereignty in Arctic waters under the auspices of the UNCLOS. Norway's recent territorial claims are separately located in the Barents Sea, the Norwegian Sea, and Arctic Ocean.<sup>44</sup> Russia's UNCLOS claims of economic sovereignty extend through much of the Arctic Ocean, based on the existence of the Lomonosov Ridge that extends from Russia's coast across the Arctic Ocean to Greenland.<sup>45</sup> Viewed in reverse, this situation makes Denmark a potential claimant to the same Arctic regions claimed by Russia.

Although the existence of the UNCLOS has increased the number of overlapping claims of economic sovereignty in Arctic waters, two pre-existing claims also remain unresolved.<sup>46</sup> One disputed offshore boundary exists in the Barents Sea between Norway and Russia. The other disputed offshore boundary exists between Canada and the United States in the Beaufort Sea.

#### Arctic Environmental Policies and Regulations

The extent to which environmental laws and regulations impact Arctic oil and natural gas development will depend on the specific laws and regulations of each nation having economic sovereignty over Arctic areas. However, the experience in the United States indicates that such policies can preclude the development of significant Arctic oil and natural gas resources.

In the Alaska Arctic, oil and natural gas development is banned within the Arctic National Wildlife Refuge (ANWR). ANWR is located on the northern coast of Alaska due east of Prudhoe Bay. ANWR was created by the Alaska National Interest Lands Conservation Act (ANILCA) in 1980. Section 1002 of ANILCA deferred a decision on the management of oil and natural gas exploration and development of 1.5 million acres of potentially productive lands in the coastal plain of ANWR. The coastal plain area represents about 8 percent of the total area of ANWR.

In 1998, the USGS estimated that between 5.7 and 16.0 billion barrels of technically recoverable oil are in the coastal plain area of ANWR, with a mean estimate of 10.4 billion barrels. These USGS resource estimates include State and Native lands in and adjacent to the Federal lands in ANWR.

Several legislative attempts have been made to open ANWR to oil and natural gas development, but none have been successful. The lack of support to open ANWR to oil and natural gas development comes from the concern that caribou migration and breeding could be detrimentally affected by ANWR oil and natural gas development and the concern that the ANWR is a unique, yet fragile wilderness that would be damaged by oil and natural gas development and production.

<sup>44</sup> Norwegian Petroleum Directorate, "Continental Shelf Submission of Norway," 2006, <http://www.regjeringen.no/upload/kilde/ud/prm/2006/0374/ddd/pdfv/299461-sokkel.pdf>

<sup>45</sup> Associated Press, "Russian Navy Staking Arctic Ocean Sea Bed," *Petroleum News*, Volume 12, Number 30, July 29, 2007, page 17.

<sup>46</sup> International Boundaries Research Unit, "Maritime jurisdiction and boundaries in the Arctic region," Durham University, United Kingdom, August 15, 2008. <http://www.dur.ac.uk/resources/ibru/arctic.pdf>

Similarly, the environmental challenge to Shell's offshore drilling program was motivated by concern that noise and potential oil spills could be harmful to migratory whales and the Beaufort Sea ecosystem.

#### Conclusions

The Arctic presents a "good news, bad news" situation for oil and natural gas development. The good news is that the Arctic holds about 22 percent of the world's undiscovered conventional oil and natural gas resources, based on the USGS mean estimate. The bad news is that: (1) the Arctic resource base is largely composed of natural gas and natural gas liquids, which are significantly more expensive to transport over long distances than oil; (2) the Arctic oil and natural gas resources will be considerably more expensive, risky, and take longer to develop than comparable deposits found elsewhere in the world; (3) unresolved Arctic sovereignty claims could preclude or substantially delay development of those oil and natural gas resources where economic sovereignty claims overlap; and (4) protecting the Arctic environment will be costly. The high cost and long lead-times of Arctic oil and natural gas development undercut the immediate importance of these sovereignty claims, while at the same time diminishing the economic incentive to develop these resources.

Given that the Arctic resource base is predominantly composed of natural gas and natural gas liquids, the importance of Arctic oil and natural gas resources is likely to be affected by the growing realization that shale beds in existing petroleum provinces around the world might be capable of producing 5,000 to 16,000 trillion cubic feet of natural gas.<sup>47</sup> This potentially large shale gas resource could significantly defer the future development of Arctic natural gas resources. Of course, there could be exceptions. Hypothetically, growing European demand for natural gas, the depletion of existing North Sea and Russian natural gas fields, and disappointing European shale gas exploration and development results could act as a strong incentive to develop Russia's Arctic natural gas resources in the West Siberian Basin and East Barents Basin.

Other aspects of the estimated Arctic oil and natural gas resource base are more neutral in character. For example, the fact that the expected undiscovered Arctic resource base is largely confined to a few sedimentary provinces might be more reflective of the fact that little, if any, oil and natural gas exploration drilling has been conducted in those provinces with low resource estimates. On the other hand, if the estimates for these unexplored and underexplored provinces prove correct, and they have little or no oil and natural gas, then the drive by nations to claim economic sovereignty over these offshore provinces would diminish.

The bottom line for Arctic oil and natural gas potential is that high costs, high risks, and lengthy lead-times can all serve to deter their development in preference to the development of less challenging oil and natural gas resources elsewhere in the world. Also, the less abundant Arctic oil resources will be more readily developed than the Arctic's natural gas resources. Thus, while the Arctic has the potential to be a more

<sup>47</sup> Barbara Shook and Leslie Palti, "Shale Gas Developed in U.S., Canada; Yet to be Exploited Worldwide," *Oil Daily*, April 7, 2009, page 4.

important source of global oil and natural gas production sometime in the future; the timing of a significant expansion in Arctic production is difficult to predict.

**Appendix A  
Weather Conditions at Prudhoe Bay, Alaska**

	Average High Temperature	Average Low Temperature	Mean Temperature	Average Precipitation	Record High Temperature (Year)	Record Low Temperature (Year)
<b>January</b>	- 11°F	- 23°F	- 17°F	0.15 in.	35°F (1991)	- 62°F (1989)
<b>February</b>	- 13°F	- 26°F	- 20°F	0.13 in.	39°F (1989)	- 57°F (1987)
<b>March</b>	- 7°F	- 22°F	- 15°F	0.14 in.	34°F (1998)	- 54°F (1995)
<b>April</b>	7°F	- 8°F	- 1°F	0.10 in.	43°F (1988)	- 47°F (1986)
<b>May</b>	27°F	16°F	22°F	0.08 in.	55°F (1996)	- 19°F (1992)
<b>June</b>	44°F	31°F	37°F	0.37 in.	83°F (1991)	18°F (1997)
<b>July</b>	54°F	37°F	46°F	0.72 in.	82°F (1994)	28°F (1996)
<b>August</b>	51°F	36°F	44°F	0.95 in.	80°F (1994)	23°F (1996)
<b>September</b>	38°F	28°F	33°F	0.65 in.	67°F (1986)	1°F (1996)
<b>October</b>	21°F	10°F	15°F	0.40 in.	45°F (1991)	- 30°F (1996)
<b>November</b>	2°F	- 10°F	- 4°F	0.14 in.	39°F (1997)	- 45°F (1986)
<b>December</b>	- 7°F	- 19°F	- 13°F	0.19 in.	34°F (1998)	- 47°F (1990)
<b>Total</b>				4.02 in.		

Source: <http://www.weather.com/weather/wxclimatology/monthly/USA00197>

**Appendix B**  
**Location of U.S. Geological Survey Arctic Provinces**  
**Based on the Maps Shown in the USGS Arctic Assessment**

USGS Petroleum Province Name	Countries Located Nearest To USGS Petroleum Province	Onshore/Offshore
West Siberian Basin	Russia	Onshore and Offshore
Arctic Alaska	United States	Onshore and Offshore
East Barents Basin	Norway, Russia	Offshore
East Greenland Rift Basins	Greenland (Denmark)	Mostly Offshore
Yenisey-Khatanga Basin	Russia	Onshore
Amerasia Basin	Canada, United States	Offshore
West Greenland-East Canada	Canada, Greenland (Denmark)	Offshore
Laptev Sea Shelf	Russia	Mostly Offshore
Norwegian Margin	Norway	Offshore
Barents Platform	Norway	Offshore
Eurasia Basin	Norway, Russia	Offshore
North Kara Basins and Platforms	Russia	Offshore
Timan-Pechora Basin	Russia	Mostly Onshore
North Greenland Sheared Margin	Greenland (Denmark)	Offshore
Lomonosov-Makarov	Canada, Greenland (Denmark), Russia	Offshore
Sverdrup Basin	Canada	Onshore and Offshore
Lena-Anabar Basin	Russia	Onshore
North Chukchi-Wrangell Foreland Basin	Russia, United States	Offshore
Vilkitskii Basin	Russia	Offshore
Northwest Laptev Sea Shelf	Russia	Offshore
Lena-Vilyui Basin	Russia	Onshore
Zyryanka Basin	Russia	Onshore
East Siberian Sea Basin	Russia	Offshore
Hope Basin	Russia, United States	Offshore
Northwest Canadian Interior Basins	Canada	Onshore

Note: The designation of the closest country or countries does not imply territorial or economic sovereignty by these countries over the petroleum province associated with them. Source: Op.cit. USGS, "Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle"

**Appendix C**  
**Shell Oil Offshore North Alaska Lease Purchases**

MMS Lease Sale Number	Date of MMS Lease Sale	Offshore Region	Value of Winning Bids (million dollars)
195	March 30, 2005	Beaufort Sea	\$44.4
202	April 18, 2007	Beaufort Sea	\$39.3
193	February 7, 2008	Chukchi Sea	\$2,117.8
<b>Total Bonus Bids</b>			<b>\$2,201.5</b>

Source: U.S. Minerals Management Alaska leasing website at <http://www.mms.gov/ld/AKsales.htm>

**Maximum Sustainable Yield:  
 FY 2014 Update**  
 by Scott Goldsmith  
 Web Note No. 14 • January 2013

In fiscal year 2014, Alaska's state government can afford to spend about \$5.5 billion. That's an estimate of the level of Unrestricted General Fund spending the state can sustain over the long run, based on the current petroleum nest egg of about \$149 billion—a combination of state financial assets (the Permanent Fund and cash reserves) and the value of petroleum still in the ground.

The size of that nest egg fluctuates, depending on the state's forecast of petroleum revenues, earnings on investments, and other factors. This Web Note presents the latest in a series of estimates of the maximum amount the state can spend and still stay on a sustainable budget path.

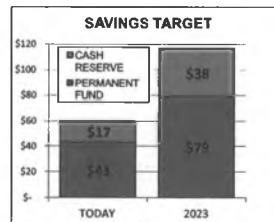
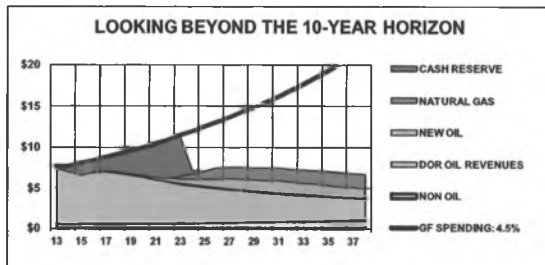
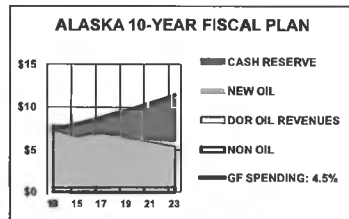
Right now, the state is on a path it can't sustain. Growing spending and falling revenues are creating a widening fiscal gap. In its 10-year fiscal plan, the state Office of Management and Budget (OMB) projects that spending the cash reserves might fill this gap until 2023, as the adjacent figure shows.<sup>1</sup> But what happens after 2023?

Reasonable assumptions about potential new revenue sources suggest we do not have enough cash in reserves to avoid a severe fiscal crunch soon after 2023, and with that fiscal crisis will come an economic crash. The figure on the right shows the growing General Fund fiscal gap—even assuming new revenues from natural gas production and more oil production—if spending increases at a rate of 4.5% annually.

What can the state do to avoid a major fiscal and economic crisis? The answer is to save more and restrict the rate of spending growth. All revenues above the sustainable spending level of \$5.5 billion—including Permanent Fund income, except the share that funds the dividend—would be channeled into savings.

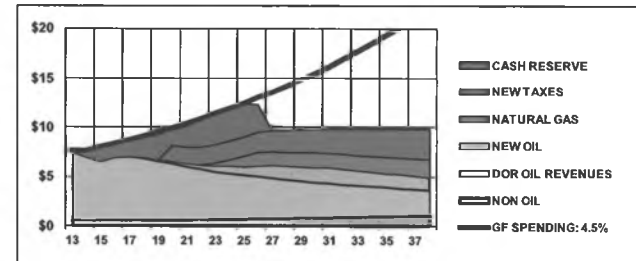
If Alaska had \$117 billion in cash reserves and the Permanent Fund by 2023, the state would be on the path to sustainable spending far into the future. But as the adjacent figure shows, that's twice what the state has in financial assets today. So the state needs to sharply step up its savings rate, starting now.

This research is part of ISER's *Investing for Alaska's Future* research initiative, funded by a grant from Northrim Bank.

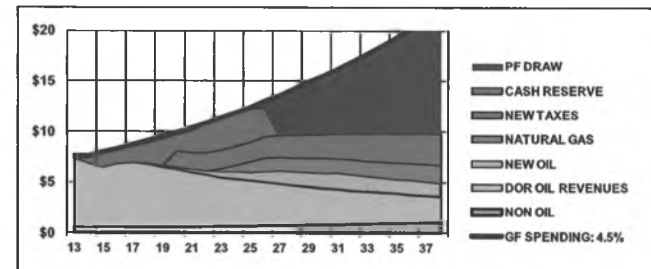


  
**Northrim Bank**

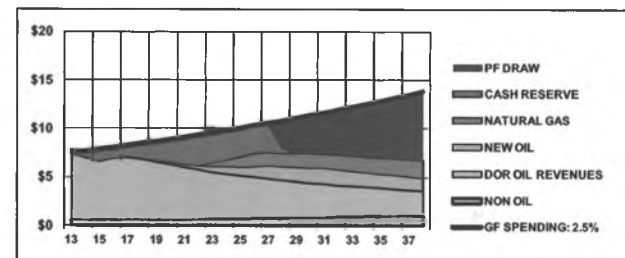
The graphs below show additional evidence of why the state needs to save more and restrict spending. New broad-based income and sales taxes (purple) would postpone but not eliminate the fiscal crunch.



Even using the entire Permanent Fund would not avoid the crunch, with the fund (brown) running out soon after 2038.



Alternatively, holding growth of the budget to the rate of inflation would reduce the size of the crunch when it arrived, but postpone it for only 5 years.<sup>2</sup>



**What is Maximum Sustainable Yield (MSY)?**

Maximum sustainable yield is the amount the state can spend each year from its petroleum endowment, or nest egg, and still sustain the value of that nest egg for future generations. The nest egg is a combination of the state's financial assets and the estimated value of petroleum still in the ground. The amount the state can safely spend each year depends on the size of the nest egg, the return it can achieve through prudent management of that nest egg, and the time over which it will need the nest egg to sustain public spending.

The table below shows that if the petroleum nest egg has a value of \$149 billion, if it can be managed to generate a 5% return (net of inflation), and if it is to increase over time to account for population growth, the maximum sustainable yield would be \$5.95 billion.

**MAXIMUM SUSTAINABLE YIELD CALCULATION FOR FY 2014**

<b>TOTAL NEST EGG (Billion )</b>	<b>\$148.7</b>
Financial Assets	\$60
Petroleum in the Ground	\$88.7
Rate of Earnings (net of inflation)	5%
Draw Rate (Earnings net population growth)	4%
<b>MSY FY2014 (Billion)</b>	<b>\$5.95</b>

Currently, spending from the petroleum nest egg goes to the General Fund and the Permanent Fund dividend. Constrained to no more than the maximum sustainable yield of \$5.95 billion, the split would be \$4.99 billion to the General Fund and \$.96 billion to the dividend (based on the current formula for determining dividends). Including the \$.540 billion of non-petroleum revenues in the General Fund, the maximum sustainable yield for the General Fund would be \$5.53 billion.

**GENERAL FUND MAXIMUM SUSTAINABLE YIELD SPENDING FOR FY2014**

<b>1</b>	<b>MSY FY2014 (Billion) (2+3)</b>	<b>\$5.95</b>
<b>2</b>	<b>PF</b>	<b>\$.96</b>
<b>3</b>	<b>GF</b>	<b>\$4.99</b>
<b>4</b>	<b>Non petroleum revenues</b>	<b>\$.54</b>
<b>5</b>	<b>GENERAL FUND MSY FY2014 (Billion) (3+4)</b>	<b>\$5.53</b>

The difference between the actual General Fund appropriation and the maximum sustainable yield is the "fiscal burden" passed to a future generation of Alaskans. It is the amount future generations will pay to cover current spending above the sustainable level. The "nest egg deficit" is amount the nest egg falls short of being able to support a sustainable spending path.

For example, as shown below, if FY 2014 General Fund spending were to be \$7 billion, the fiscal burden on future generations would be \$1.5 billion. Furthermore, it would take an additional \$37.5 billion in the petroleum nest egg for that level of spending to be sustainable.

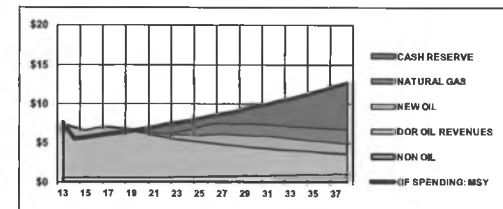
**FISCAL BURDEN AND NEST EGG DEFICIT AT DIFFERENT GF SPENDING LEVELS**

<b>FY2014 GF Spending (Billion)</b>	<b>\$6</b>	<b>\$6.5</b>	<b>\$7.0</b>	<b>\$7.5</b>	<b>\$8.0</b>
<b>Fiscal Burden (Billion)</b>	<b>\$.5</b>	<b>\$1.0</b>	<b>\$1.5</b>	<b>\$2.0</b>	<b>\$2.5</b>
<b>Nest Egg Deficit (Billion)</b>	<b>\$12.5</b>	<b>\$25</b>	<b>\$37.5</b>	<b>\$50</b>	<b>\$62.5</b>

Fiscal Burden and Nest Egg Deficit assume future budget growth constrained to be the combined rate of inflation and population increase.

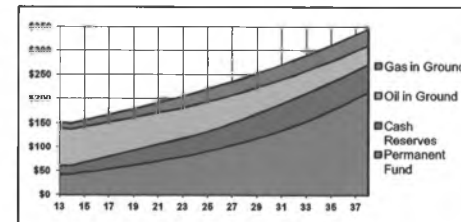
In contrast to business-as-usual, there is no fiscal cliff associated with the maximum sustainable yield strategy. Enhanced financial resources, combined with new revenues from long-term petroleum developments, would be sufficient to cover General Fund spending growing with population.

**MAXIMUM SUSTAINABLE YIELD: GENERAL FUND SPENDING (BILLION \$)**



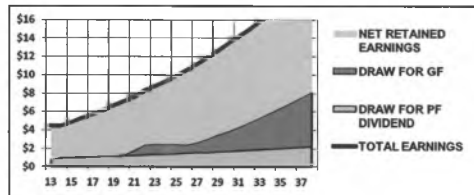
The petroleum nest egg would also increase at the combined rate of inflation and population. Over time, the declining value of oil and gas in the ground would be replaced by the growing value of financial assets.

**MAXIMUM SUSTAINABLE YIELD: COMPOSITION OF THE NEST EGG (BILLION \$)**



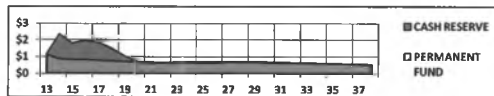
On this sustainable path the combined earnings of all the financial assets (solid black line) would initially all be reinvested, except the amount set aside to pay the Permanent Fund dividend, which would increase with inflation and population (orange)<sup>iv</sup>. The financial assets would gradually become the most important source of revenues for the General Fund (red)<sup>v</sup>. Retained earnings (light blue) would offset inflation and population growth.

**MAXIMUM SUSTAINABLE YIELD: USE OF FINANCIAL EARNINGS (BILLION \$)**



Financial account deposits would transform depleting petroleum revenues into a sustainable asset.

**MAXIMUM SUSTAINABLE YIELD: DEPOSITS IN FINANCIAL ACCOUNTS (BILLION \$)**



**What's In the Nest Egg?**

The nest egg consists of financial assets accumulated from past saving of petroleum revenues as well as the current value of the estimated revenues from future petroleum production.

The current value of financial assets is easily estimated at about \$60 billion, mostly in the Permanent Fund, and in cash reserves—the Constitutional Budget Reserve and the Statutory Budget Reserve.

The value of revenues from future production is \$88.7 billion. We determine this value by estimating future taxes and royalties for 50 years, assuming the current fiscal structure and energy prices as well as reasonable estimates of economically recoverable reserves, both known and unknown. We convert these revenue flows to their net present value at a discount rate equal to the rate of return on financial investments. (This method is similar to monetizing the flow of revenues that assets can produce by calculating their net present value.)

The value of revenues from future production is broken into three categories—oil in known fields, unconventional and new oil, and natural gas.

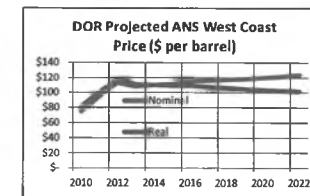
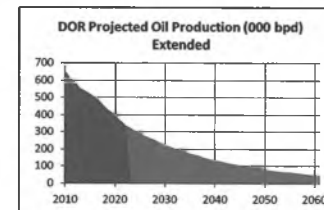
The values for these categories are modest for three reasons. Future production is likely to be more costly than current production on state lands, and production on federal lands generates no royalties directly for the state and is exempt from some state taxes. Therefore, the revenue “take” per barrel will

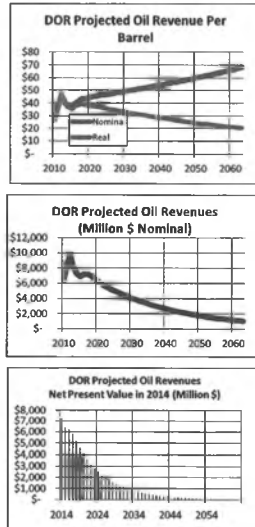
be lower than that on current production. Finally, the discounting of revenues that will not be received for many years reduces their value today.

**NET PRESENT VALUE: FUTURE PETROLEUM REVENUES, 50-YEAR TIME HORIZON (BILLION \$)**

<b>TOTAL</b>	<b>\$88.7</b>
<b>OIL IN KNOWN FIELDS</b>	<b>\$67.1</b>
2014-2022	\$43.1
2023-2063	\$24.0
<b>UNCONVENTIONAL AND NEW OIL</b>	<b>\$9.9</b>
Conventional from New Fields in Central North Slope	\$4.8
Shale Oil	\$1.7
Viscous and Heavy Oil	\$1.7
OCS	\$1.7
ANWR	0
NPRA	0
<b>NATURAL GAS</b>	<b>\$11.7</b>

Oil in Known Fields is estimated through 2022 from the annual forecast of the Alaska Department of Revenue. This is almost entirely conventional oil on state lands, but also includes small amounts of production on federal lands (OCS and NPRA) and private lands, as well as some unconventional oil (viscous oil). After 2022, we project production to decline at 5% annually and revenue per barrel to increase at 1%—about half the rate of inflation (2.5%). Based on these assumptions, the 50-year cumulative revenues would be \$168 billion (net present value of \$67.1 billion), generated from production of 3.5 billion barrels of oil.



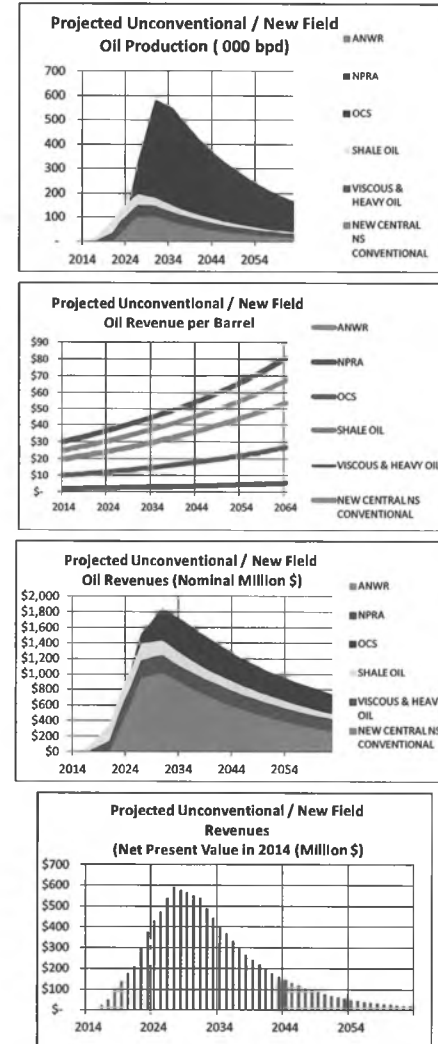


Unconventional and New Oil is divided into six categories, with revenues in each based on production and per barrel revenue—or “take”—assumptions summarized below.

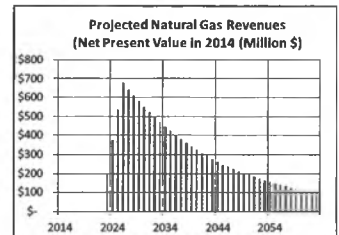
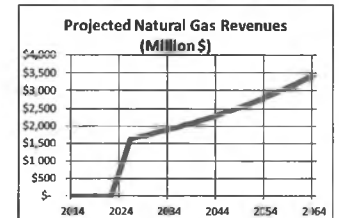
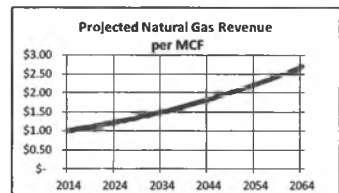
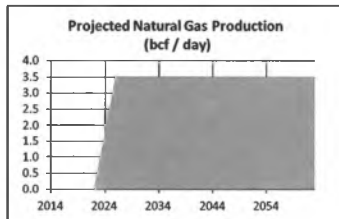
	Viscous & Heavy Oil		ANWR	NPRA	Shale Oil	New Central NS Conventional
START OF PRODUCTION	2026	2018	2200	2200	2016	2022
PEAK PRODUCTION IN BPD (000)	400	50	500	0	50	100
ANNUAL DECLINE RATE	4.0%	3.0%	5.0%	5.0%	5.0%	6.0%
REVENUE PER BARREL IN 2013	\$ 2	\$ 10	\$ 25	\$ 30	\$ 10	\$ 20
REVENUE PER BARREL GROWTH RATE (Nominal)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%

Estimated revenues assume no production from ANWR. OCS revenues exclude royalties and production taxes. And although there is no production separately indicated for NPRA, there is NPRA production, as well as a small amount of viscous oil production, built into the DOR forecast. These assumptions produce an estimate of \$52 billion in revenues over the next 50 years (net present value of \$9.9 billion), based on production—both on and offshore—of 5.2 billion barrels of oil.

	OCS	Viscous & Heavy Oil	ANWR	NPRA	Shale Oil	New Central NS Conventional	TOTAL
REVENUES FOR 50 YEARS (Billion \$)	\$ 12.4	\$ 8.7	\$	\$	\$ 6.5	\$ 24.8	\$ 52.3
PRODUCTION FOR 50 YEARS (Billion Barrels)	3.48	0.53			0.43	0.77	5.21



Natural Gas is assumed to be monetized through a pipeline to tidewater, exporting 3.5 bcf per day starting in 2023. Because of the high cost of getting the gas to market, the netback value on the North Slope—which is the basis for taxes and royalties—is small. So the “take” at start-up is about \$1.25 per mcf. The net present value of that gas production over the 50-year period is estimated at \$11.7 billion.



**Tracking Maximum Sustainable Yield (MSY)**

The estimated size of the nest egg has fluctuated over time, but it has stayed in a range between \$126 and \$160 billion. Consequently, the General Fund MSY has varied between \$5 billion and \$6.4 billion. Part of the reason for the upward revision in the size of the nest egg during FY 2012, from \$126 billion to \$155 billion, was the strong recovery in value of the Permanent Fund after the financial crash. This investment performance is not likely to be duplicated in future years.

Calculation Year	Nest Egg			General Fund		Fiscal Burden	Source
	Total	Financial Assets	Petroleum in the Ground	MSY	Actual Spend		
FY2012	\$126	\$45	\$81	\$5.0	\$7.0	\$2.0	Feb 2011, WebNote 7 & May 2011, WebNote 8
FY2012	\$155	\$55	\$100	\$6.2	\$7.0	\$ .8	March 2012, WebNote 10
FY2013	\$160	\$60	\$100	\$6.4	\$7.6	\$1.2	August 2012, WebNote 13
FY2014	\$149	\$60	\$89	\$5.5	?	?	Jan. 2013, WebNote 14

In both FY 2012 and FY 2013, actual spending exceeded the MSY, creating a fiscal burden for future generations. The nest egg estimate for FY 2014 is \$11 billion lower than last year’s estimate, mostly because the Alaska Department of Revenue’s forecast of petroleum revenues between FY 2014 and FY 2022 is \$8 billion lower than it was last year. The value of financial assets is the same in FY 2014 as in FY 2013, partly because of the \$1.2 billion fiscal burden passed forward from the previous year. The General Fund MSY has also fallen because the expected Permanent Fund dividend amount has increased.

**Sensitivity of Estimates**

Opinions will differ about the value of the petroleum nest egg, based on different assumptions about future energy prices, production, and government policies. Different assumptions about return on investment and the growth rate of spending also will influence the size of the MSY.

A partial set of possible scenarios generates a range of nest egg values from \$145 to \$195 billion—shown in the higher and lower scenario tables below—although the value could fall outside that range. Combining different assumptions about return on investment and rate of growth of the budget results in a General Fund MSY that ranges between \$2.5 billion and \$7.4 billion. Although that range is quite wide, the actual General Fund budget of \$7.6 billion in FY 2013 would have been non-sustainable under any of these scenarios.

HIGHER SCENARIOS	NEST EGG	GF MSY FY2014
ANWR @ 500 Thousand Barrels per Day	\$175	\$7.0
ANWR + OCS @ 500 Thousand Barrels per Day with Shared Royalties	\$182	\$6.8
Double Estimate of Post 2022 Revenues	\$195	\$7.4

LOWER SCENARIOS	NEST EGG	GF MSY FY2014
Lower Investment Return (4%)	\$160	\$4.4
Lower Investment Return (4%) + No Gas Revenue	\$145.2	\$3.9
Lower Investment Return (4%) + No Gas Revenue + General Fund Growth 1% Real Per Capita (4%)	\$145.2	\$2.5

**Other Forms of Petroleum Wealth**

The state has put \$45 billion of the \$170 billion of petroleum revenues collected through FY 2012 into financial assets that today have a value of \$60 billion.

The state has spent much of the rest to enhance the well-being of Alaskans through investments in physical capital like roads, harbors, and utility systems, and in human capital through spending on health care, education, and other services. Estimates of the value of those investments are not available, but they certainly enhance the size of the petroleum nest egg.

And although the value of those investments has not been quantified, the MSY fiscal strategy does not ignore them: the sustainable flow of earnings from the financial nest egg provides the state with the funding to continue to invest in the well-being of both present and future generations of Alaskans.

The strategy also provides a framework for deciding when an investment in physical or human capital would provide more benefit than a financial investment. That would be the case when it could be demonstrated that the flow of benefits from such an investment would exceed the flow of benefits that would come from spending the income from the financial investment.

**PETROLEUM WEALTH MANAGEMENT WORKSHEET**

	FY 2013	FY 2014	Change
<b>PETROLEUM WEALTH</b>			
	Billion \$	Billion \$	Billion \$
1 Financial Assets (2+3+4+5)	\$ 60.00	\$ 60.00	\$ -
2 Permanent Fund Balance	\$ 42.00	\$ 43.00	\$ 1.0 a
3 + Constitutional Budget Reserve	\$ 16.00	\$ 11.00	\$ (5.0) b
4 + Statutory Budget Reserve	\$ 2.00	\$ 5.00	\$ 3.0 c
5 + Other	\$ -	\$ 1.00	\$ 1.0
6 Petroleum in Ground (7+10+17)-Net Present Value discounted @ 5.0%	\$ 100.68	\$ 88.69	\$ (12.0)
7 Conventional North Slope-State Lands	\$ 80.54	\$ 67.11	\$ (13.4) d
8 DOR projection (thru 2022)	\$ 50.89	\$ 43.11	\$ (7.8)
9 DOR extended	\$ 29.65	\$ 24.00	\$ (5.6)
10 + Other Oil	\$ 6.75	\$ 9.85	\$ 3.1
11 Conventional	\$ 2.14	\$ 4.75	\$ 2.6 e
12 Viscous/Heavy Oil	\$ 1.56	\$ 1.72	\$ 0.2
13 Shale Oil	\$ 1.57	\$ 1.72	\$ 0.1
14 OCS	\$ 1.49	\$ 1.67	\$ 0.2
15 ANWR	\$ -	\$ -	\$ -
16 NPRA	\$ -	\$ -	\$ -
17 + Gas	\$ 9.88	\$ 12	\$ (1.7) f
<b>18 = TOTAL PETROLEUM WEALTH (1+6)</b>	<b>\$ 160.7</b>	<b>\$ 148.7</b>	<b>\$ (12.0)</b>
<b>SUSTAINABLE DRAW RATE</b>			
	Annual Rate	Annual Rate	
19 Real Rate of Return Net of Inflation	5.0%	5.0%	
20 - Projected Population Growth Adjustment	1.0%	1.0%	
21 - Projected Real Per Capita Budget Growth Adjustment	0.0%	0.0%	
<b>22 = SUSTAINABLE DRAW RATE (19-20-21)</b>	<b>4.0%</b>	<b>4.0%</b>	
<b>MAXIMUM SUSTAINABLE YIELD (MSY)</b>			
	Billion \$	Billion \$	
<b>23 = MAXIMUM SUSTAINABLE YIELD (18 x 22)</b>	<b>\$ 6.43</b>	<b>\$ 5.95</b>	<b>\$ (0.5)</b>
<b>GENERAL FUND MSY SPENDING CAP</b>			
	Billion \$	Billion \$	
24 Maximum Sustainable Yield (x-23)	\$ 6.43	\$ 5.95	\$ (0.5)
25 - Permanent Fund Dividend Distribution	\$ 0.57	\$ 0.96	\$ 0.4 g
26 = General Fund Petroleum Spending Cap (24-25)	\$ 5.86	\$ 4.99	\$ (0.9)
27 - General Fund Earnings Spending (from Petroleum Wealth)	\$ 0.18	\$ 0.07	\$ (0.1) h
28 = GENERAL FUND CURRENT PETROLEUM REVENUE SPENDING CAP	\$ 5.68	\$ 4.92	\$ (0.8)
29 + General Fund Non-Petroleum Revenues (excluding GF earnings)	\$ 0.56	\$ 0.54	\$ (0.0) i
<b>30 = GENERAL FUND MSY SPENDING CAP (27+28+29)</b>	<b>\$ 6.42</b>	<b>\$ 5.53</b>	<b>\$ (0.9)</b>

Source: Institute of Social and Economic Research, University of Alaska Anchorage

Assumptions: No new taxes  
 Growth of General Fund spending and Permanent Fund Dividend account constrained to the combined rate of population increase and inflation  
 All financial assets earn maximum rate of return  
 Notes: Financial Assets valued at start of fiscal year.  
 Fifty years of revenues from petroleum in the ground discounted to start of fiscal year.

a Growth from new revenues and earnings

b FY2013 GF spending higher and revenues lower than anticipated, resulting in lower surplus

\$ 6,238 Fall 2013 revenue forecast for FY2013

\$ 7,512 Fall 2012 revenue forecast for FY2013

\$ 7,041 OMB forecast for FY2013 GF spending

\$ 7,600 Final appropriations for FY2013 spending

c Re-assignment of some surplus to SBR from CBR

d FY2013 revenues spent and DOR forecast lower

e Lower DOR projection leaves more for future production

f Size of pipeline reduced from 4.5 bcf to 3.5 bcf per day

g Larger because of PFD formula mechanics

h Reduction in GF earnings

i No change in non-petroleum GF revenues

	BASE CASE	LOW CASES			HIGH CASES		
		LOW INVESTMENT RETURN	LOW INVESTMENT RETURN + HIGH GAS REVENUES	LOW INVESTMENT RETURN + HIGH GAS REVENUES + GP RPT. GROWTH	ARMED @ 50K BPS	ARMED @ 50K BPS + 50% WITH SHARED BENEFITS	SHOULD POST 2013 REVENUES
	FF 2014	FF 2014	FF 2014	FF 2014	FF 2014	FF 2014	FF 2014
<b>PETROLEUM WEALTH</b>							
1	Permanent Fund Balance	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00
2	+ Constitutional Budget Reserve	\$ 11.00	\$ 11.00	\$ 11.00	\$ 11.00	\$ 11.00	\$ 11.00
3	+ Statutory Budget Reserve	\$ 1.00	\$ 1.00	\$ 1.00	\$ 1.00	\$ 1.00	\$ 1.00
4	+ Other	\$ 1.00	\$ 1.00	\$ 1.00	\$ 1.00	\$ 1.00	\$ 1.00
5	Petroleum in Ground (27.6-17.5) - Net Present Value (discounted @ 5.0%)	\$ 88.69	\$ 100.00	\$ 85.24	\$ 85.34	\$ 115.00	\$ 121.70
6	+ Commercial North Slope - State Lands	\$ 47.11	\$ 73.77	\$ 73.77	\$ 73.77	\$ 47.11	\$ 47.11
7	+ Other Oil	\$ 43.11	\$ 43.11	\$ 43.11	\$ 43.11	\$ 43.11	\$ 43.11
8	+ Other Gas	\$ 34.00	\$ 34.00	\$ 34.00	\$ 34.00	\$ 34.00	\$ 34.00
9	+ Other Oil	\$ 8.85	\$ 13.87	\$ 13.87	\$ 13.87	\$ 36.39	\$ 42.47
10	+ Other Gas	\$ 4.75	\$ 5.74	\$ 5.74	\$ 5.74	\$ 4.75	\$ 4.75
11	+ Other Oil	\$ 1.72	\$ 2.04	\$ 2.04	\$ 2.04	\$ 1.72	\$ 1.72
12	+ Other Gas	\$ 1.72	\$ 1.98	\$ 1.98	\$ 1.98	\$ 1.72	\$ 1.72
13	+ Other Oil	\$ 1.67	\$ 2.13	\$ 2.13	\$ 2.13	\$ 1.67	\$ 1.67
14	+ Other Gas	\$ -	\$ -	\$ -	\$ -	\$ 38.34	\$ 38.34
15	+ Other Oil	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	+ Other Gas	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17	+ Other Oil	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12	\$ 12
18	<b>TOTAL PETROLEUM WEALTH (1-18)</b>	<b>\$ 148.7</b>	<b>\$ 160.0</b>	<b>\$ 145.2</b>	<b>\$ 145.2</b>	<b>\$ 175.0</b>	<b>\$ 181.7</b>
<b>SUSTAINABLE DRAW RATE</b>							
19	Rate of Return to Rate of Production	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
20	Rate of Return to Rate of Production	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
21	Rate of Return to Rate of Production	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	<b>SUSTAINABLE DRAW RATE (19-21)</b>	<b>4.0%</b>	<b>3.0%</b>	<b>3.0%</b>	<b>2.0%</b>	<b>4.0%</b>	<b>4.0%</b>
<b>MAXIMUM SUSTAINABLE YIELD (MSY)</b>							
23	<b>MAXIMUM SUSTAINABLE YIELD (18 x 22)</b>	<b>\$ 5.95</b>	<b>\$ 4.80</b>	<b>\$ 4.36</b>	<b>\$ 2.90</b>	<b>\$ 7.00</b>	<b>\$ 7.27</b>
<b>GENERAL FUND MSY SPENDING CAP</b>							
24	Maximum Sustainable Yield (MSY)	\$ 5.95	\$ 4.80	\$ 4.36	\$ 2.90	\$ 7.00	\$ 7.27
25	+ Permanent Fund Distribution	\$ 0.96	\$ 0.96	\$ 0.96	\$ 0.96	\$ 0.96	\$ 0.96
26	+ General Fund Petroleum Spending Cap (24-25)	\$ 4.99	\$ 3.84	\$ 3.40	\$ 1.94	\$ 6.04	\$ 6.31
27	+ General Fund Spending (24-25)	\$ 0.07	\$ 0.07	\$ 0.07	\$ 0.07	\$ 0.07	\$ 0.07
28	+ General Fund Spending (24-25)	\$ 4.92	\$ 3.77	\$ 3.33	\$ 1.87	\$ 5.97	\$ 6.24
29	+ GENERAL FUND CURRENT PETROLEUM REVENUE SPENDING CAP	\$ 0.54	\$ 0.54	\$ 0.54	\$ 0.54	\$ 0.54	\$ 0.54
30	+ GENERAL FUND MSY SPENDING CAP (24-29)	<b>\$ 5.52</b>	<b>\$ 4.38</b>	<b>\$ 3.93</b>	<b>\$ 2.48</b>	<b>\$ 6.58</b>	<b>\$ 6.84</b>

<sup>1</sup> The OMB plan includes four illustrative projections, all assuming the FY 2014 General Fund appropriation will be \$6.5 billion—\$1.1 billion below FY 2013. Three are clearly not sustainable. This graph assumes FY 2014 General Fund spending will be the same as last year and that revenues will equal the Alaska Department of Revenue projection published in December 2012.

<sup>a</sup> This case would be sustainable with the inclusion of income and sales taxes.

<sup>b</sup> This assumes all financial assets would be invested to generate an average over time of 5% (net of inflation).

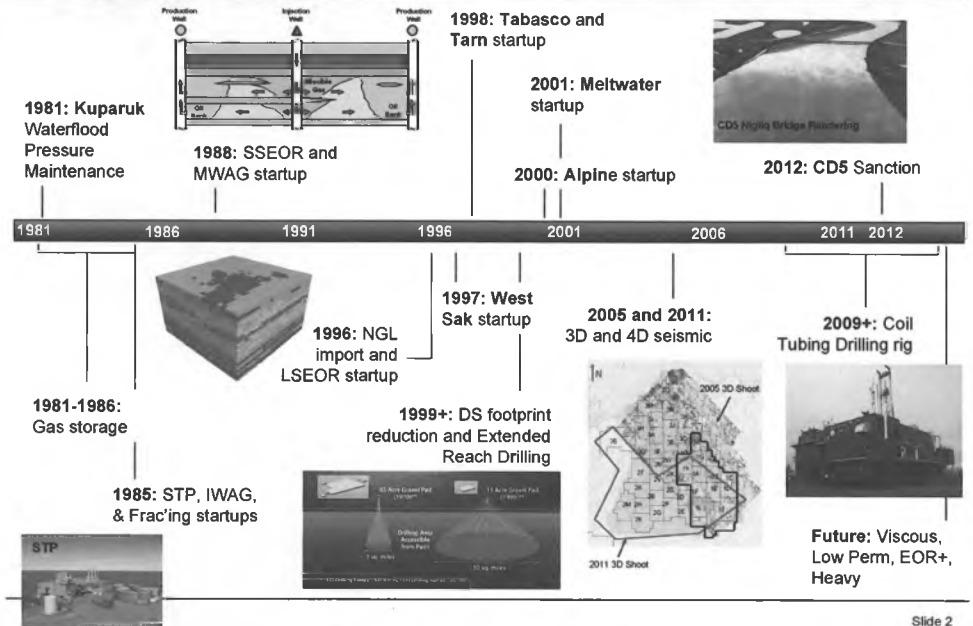
<sup>c</sup> Earnings to fund General Fund appropriations would come from any combination of cash reserves and the Permanent Fund.

## Senate Resources

### Technology Impact on North Slope Fields

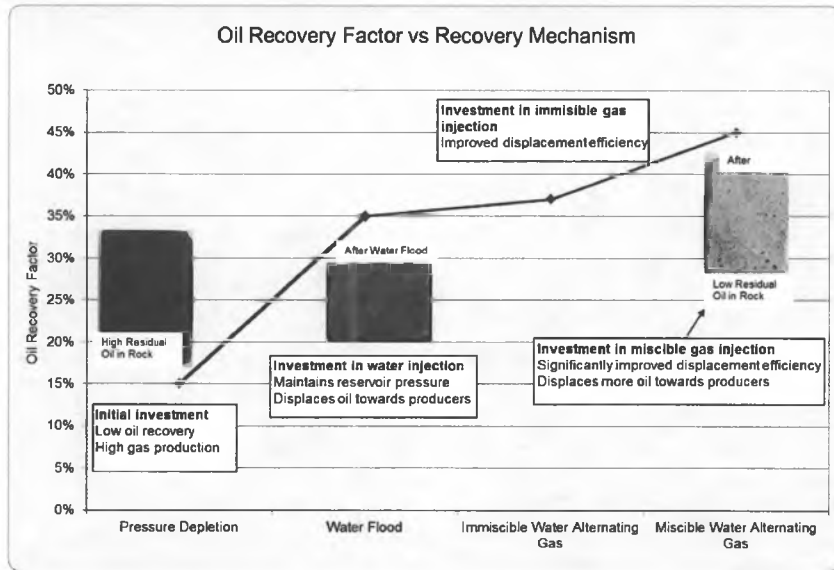
Scott Jepsen, VP External Affairs  
 Bob Heinrich, VP Finance  
 Alan Campbell, GKA Reservoir and Planning Supervisor  
**ConocoPhillips Alaska**

February 8, 2013



Slide 2

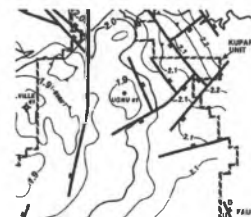
## Recovery Efficiency Evolution



Slide 3

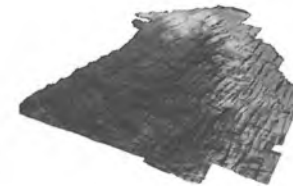
## Seismic Evolution GKA Legacy Asset

**Field Discovery  
1967**



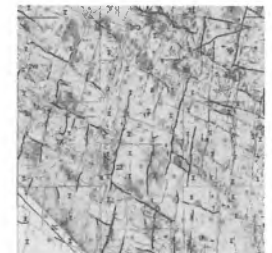
Sparse 2D seismic  
 Faulting believed to be simple  
 Few wells drilled

**3D Seismic  
1988-2011**



Improving 3D Technology  
 reveals 1000's of faults -  
 Reservoir Compartments  
 1000+ wells drilled

**4D Seismic  
2005 - forward**



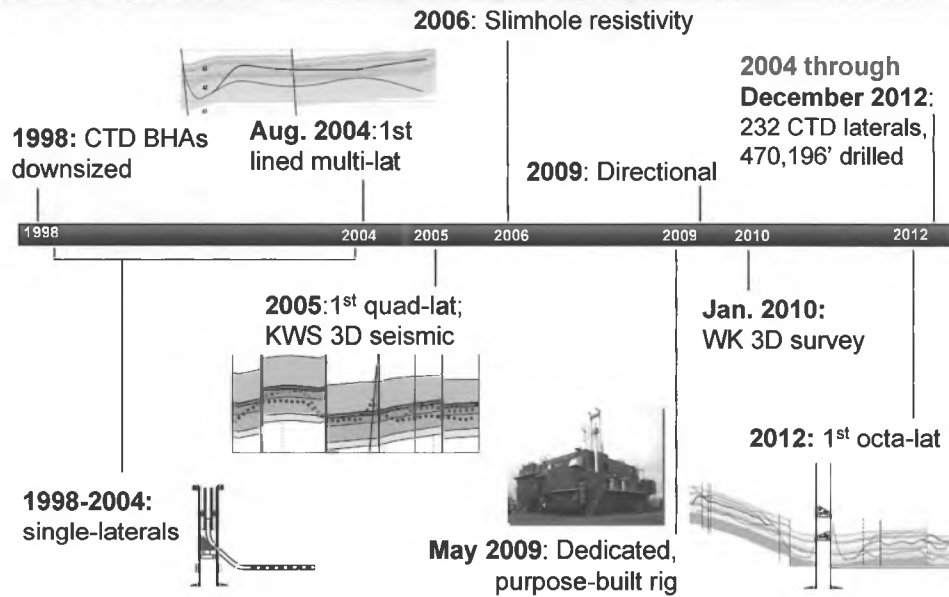
Emerging 4D Seismic  
 Technology reveals field  
 changes and more infill  
 targets/unswept oil

Slide 4

# Coil Tubing Drilling Evolution

## GKA Legacy Asset

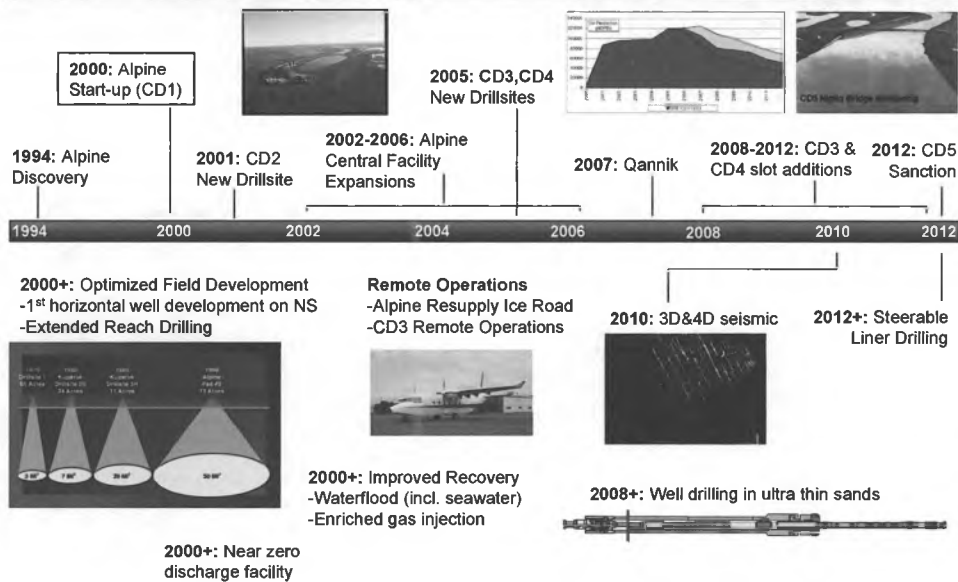
ConocoPhillips  
Alaska



Slide 5

# WNS Development Evolution

ConocoPhillips  
Alaska

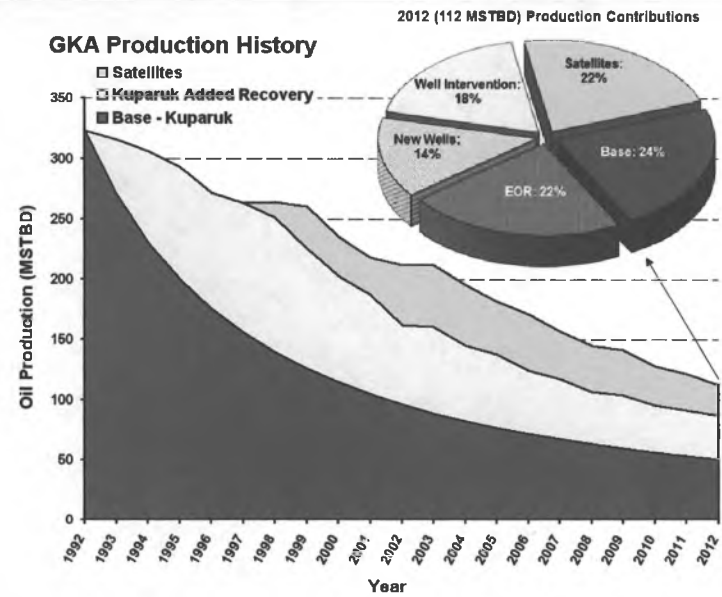


Slide 7

# GKA Legacy Asset

## Production History

ConocoPhillips  
Alaska

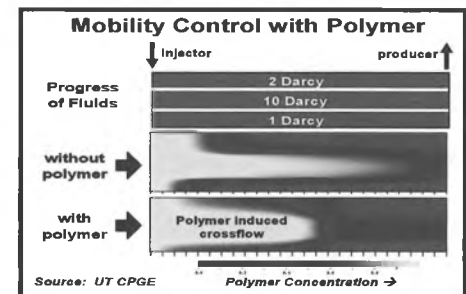
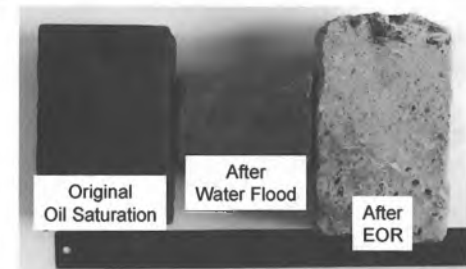


Slide 6

# Future EOR Technology Opportunity

ConocoPhillips  
Alaska

- Chemical EOR
- Flood Conformance Polymers
- Thermal & Non-Thermal Heavy Oil Recovery



No economically viable process

Slide 8

# "Easy Oil" In the Legacy Fields Is Gone

- Challenged oil remains
  - Complex, high cost wells
  - Smaller reserve targets
  - Fault blocks, flank oil
  - Satellites, viscous oil
  - Most new wells produce oil AND water
  - Facilities handling ~ three times as much water as oil
- A billion dollars does not go as far as it used to...
  - 2000 Alpine development ~80,000 BOPD
  - 2012 CD-5 Drillsite ~18,000 BOPD

~ \$ 1 billion



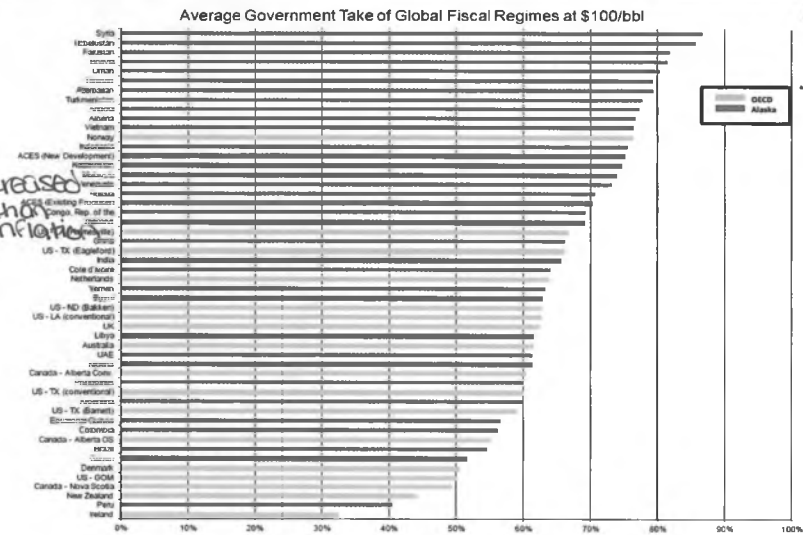
Initial Alpine Development



CD-5 Type Development

costs have increased higher than steel labor fluids

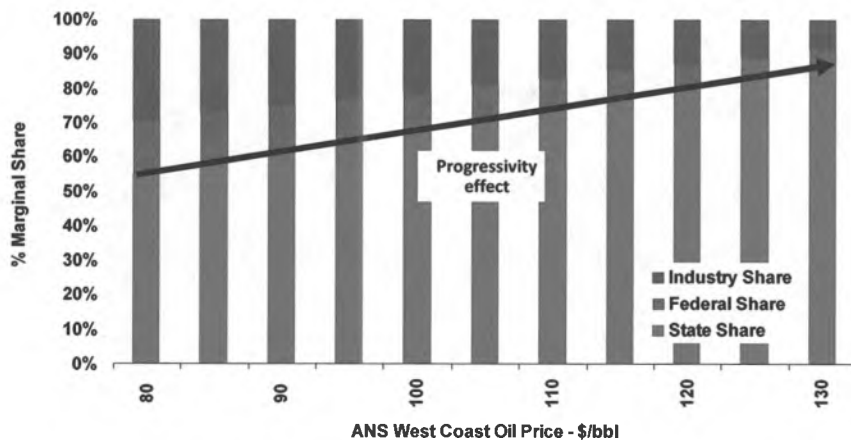
# Regime Competitiveness: Average Government Take at \$100/bbl



amount of compensation taken

# ACES Marginal Industry Share

Government and Industry Marginal Share in Alaska



# Summary

- Technology and innovation have played a key role in the development and increased recovery of North Slope legacy fields and satellites
- The legacy fields provide the resource base to continue development and implementation of new technology
- Application of new technologies is not inexpensive – costs can be high
- Alaska's oil tax system puts the North Slope business climate at a disadvantage

- BHA = Bottom Hole Assembly
- BOPD = Production rate in Barrels of oil per day
- CTD = Coil Tubing Drilling
- DS = Drill Site
- EOR = Enhanced Oil Recovery
- GKA = Greater Kuparuk Area
- ICD = Injector Control Device
- IWAG = Immiscible Water Alternating Gas
- KWS = Kuparuk West Sak Survey
- LSEOR = Large Scale Enhanced Oil Recovery
- MMBO = Million barrels of oil
- MSTBD = Production rate in 1000's of stock tank barrels of oil per day
- Multi-lat = Multilateral well
- MWAG = Miscible Water Alternating Gas
- NEWS = North East West Sak
- NS = North Slope
- NGL = Natural Gas Liquids
- Octa-lat = Octalateral well
- Perm = Permeability
- Quad-lat = Quadralateral well
- SSEOR = Small Scale Enhanced Oil Recovery
- STP = Seawater Treatment Plant
- WAG = Water Alternating Gas
- WK = Western Kuparuk Survey
- WNS = Western North Slope

**Sharon Long**

---

**From:** Cindy Smith  
**Sent:** Thursday, February 21, 2013 10:39 AM  
**To:** Sharon Long  
**Subject:** amendment descriptions

A.9 Caps the gross revenue exclusion at 7 years

*was Gardner*

A.10 Deletes new Net Operating Loss credit provisions, leaving the current in place

A.11 provides a sunset for the provision of SB21 of December 31, 2017, with provisions to revert to current law.

*takes back to ACES*

A.12 replaces the provisions of SB21 with the provisions of SB50 where they are different

*- SB 50*

A.13 adds a provision for state participation through AIDEA in oil and gas development work

*- State participation in facilities - leases*

A.14 extends the well work credit currently available in Cook Inlet at 40% to the North Slope at 20%.

Cindy Smith  
Office of Senator Hollis French  
(907) 465-3892  
alaskasenedems.com

**AMENDMENT**

**OFFERED IN THE SENATE  
TO: SB 21**

**BY SENATOR FRENCH**

- 1 **Page 23, line 3, following "section,":**
- 2 **Insert "for the first seven years immediately following the commencement of**
- 3 **production subject to tax under AS 43.55.011(e),"**

**AMENDMENT**

**OFFERED IN THE SENATE  
TO: SB 21**

**BY SENATOR FRENCH**

1 **Page 10, line 19, through page 11, line 3:**

2 **Delete all material.**

3

4 **Renumber the following bill sections accordingly.**

5

6 **Page 11, line 29:**

7 **Delete "sec. 11"**

8 **Insert "sec. 9"**

9

10 **Page 13, line 15, through page 16, line 25:**

11 **Delete all material.**

12

13 **Renumber the following bill sections accordingly.**

14

15 **Page 18, line 14, through page 19, line 4:**

16 **Delete all material.**

17

18 **Renumber the following bill sections accordingly.**

19

20 **Page 23, line 15:**

21 **Delete "Sections 2, 5, 6, 22 - 24, and 26"**

22 **Insert "Sections 2, 5, 6, 18 - 20, and 22"**

23

1 Page 23, line 17:

2 Delete "Sections 3 and 21"

3 Insert "Sections 3 and 17 of this Act"

4

5 Page 23, line 18:

6 Delete "Sections 7, 11, 13, 14, and 25"

7 Insert "Sections 7, 9, 11, 12, and 21"

8

9 Page 23, line 20:

10 Delete "Sections 9, 10, 12, 15, and 20 of this Act apply"

11 Insert "Section 10 of this Act applies"

12

13 Page 23, line 24:

14 Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

15 Insert "Sections 3, 7, 9, 11, 12, 14, 17, and 21"

16

17 Page 23, line 31:

18 Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

19 Insert "Sections 1, 2, 5, 6, 10, 18 - 20, and 22"

20

21 Page 24, line 2:

22 Delete "sec. 30"

23 Insert "sec. 26"

AMENDMENT

OFFERED IN THE SENATE  
TO: SB 21

BY SENATOR FRENCH

1 Page 2, following line 7:

2 Insert a new bill section to read:

3 **\*\* Sec. 2. AS 29.60.850(b), as amended by sec. 1 of this Act, is amended to read:**

4 (b) Each fiscal year, the legislature may appropriate to the community revenue  
5 sharing fund an amount equal to 20 percent of the money received by the state  
6 during the previous calendar year under AS 43.55.011(g) [AS 43.20.030(c)]. The  
7 amount may not exceed

8 (1) \$60,000,000; or

9 (2) the amount that, when added to the fund balance on June 30 of the  
10 previous fiscal year, equals \$180,000,000."

11

12 Renumber the following bill sections accordingly.

13

14 Page 2, following line 18:

15 Insert a new bill section to read:

16 **\*\* Sec. 4. AS 43.55.011(e), as amended by sec. 3 of this Act, is amended to read:**

17 (e) There is levied on the producer of oil or gas a tax for all oil and gas  
18 produced each calendar year from each lease or property in the state, less any oil and  
19 gas the ownership or right to which is exempt from taxation or constitutes a  
20 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), (o), and  
21 (p) of this section, the tax is equal to the sum of

22 (1) the annual production tax value of the taxable oil and gas as  
23 calculated under AS 43.55.160(a)(1) [AS 43.55.160(a)] multiplied by 25 percent; and

*rev  
sharing*

1                   **(2) the sum, over all months of the calendar year, of the tax**  
2                   **amounts determined under (a) of this section.**"  
3

4   Renumber the following bill sections accordingly.

5  
6   Page 2, following line 24:

7           Insert new bill sections to read:

8       **\*\* Sec. 6. AS 43.55.011(o), as amended by sec. 5 of this Act, is amended to read:**

9           (b) Notwithstanding other provisions of this section, for a calendar year before  
10           2022, the tax levied under (e) of this section for each 1,000 cubic feet of gas for gas  
11           produced from a lease or property outside the Cook Inlet sedimentary basin and used  
12           in the state [, OTHER THAN GAS SUBJECT TO (p) OF THIS SECTION,] may not  
13           exceed the amount of tax for each 1,000 cubic feet of gas that is determined under  
14           (j)(2) of this section.

15       **\* Sec. 7. AS 43.55.011 is amended by adding a new subsection to read:**

16           (q) For each month of the calendar year for which the producer's average  
17           monthly production tax value under AS 43.55.160(a)(2) of a BTU equivalent barrel of  
18           the taxable oil and gas is more than \$30, the amount of tax for purposes of (e)(2) of  
19           this section is determined by multiplying the monthly production tax value of the  
20           taxable oil and gas produced during the month by the tax rate calculated as follows:

21                   (1) if the producer's average monthly production tax value of a BTU  
22                   equivalent barrel of the taxable oil and gas for the month is not more than \$92.50, the  
23                   tax rate is 0.4 percent multiplied by the number that represents the difference between  
24                   that average monthly production tax value of a BTU equivalent barrel and \$30; or

25                   (2) if the producer's average monthly production tax value of a BTU  
26                   equivalent barrel of the taxable oil and gas for the month is more than \$92.50, the tax  
27                   rate is the sum of 25 percent and the product of 0.1 percent multiplied by the number  
28                   that represents the difference between the average monthly production tax value of a  
29                   BTU equivalent barrel and \$92.50, except that the sum determined under this  
30                   paragraph may not exceed 50 percent."  
31

1 **Renumber the following bill sections accordingly.**

2

3 **Page 5, line 27:**

4 **Delete "sec. 4"**

5 **Insert "sec. 8"**

6

7 **Page 8, following line 24:**

8 **Insert a new bill section to read:**

9 **\*\* Sec. 10. AS 43.55.020(a), as amended by secs. 8 and 9 of this Act, is repealed and**  
10 **reenacted to read:**

11 **(a) For a calendar year, a producer subject to tax under AS 43.55.011(e), (f),**  
12 **(h), (i), (p), or (q) shall pay the tax as follows:**

13 **(1) an installment payment of the estimated tax levied by**  
14 **AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each**  
15 **month of the calendar year on the last day of the following month; except as otherwise**  
16 **provided under (2) of this subsection, the amount of the installment payment is the**  
17 **sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be**  
18 **applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount**  
19 **of the installment payment may not be less than zero:**

20 **(A) for oil and gas produced from leases or properties in the**  
21 **state outside the Cook Inlet sedimentary basin but not subject to**  
22 **AS 43.55.011(o) or (p), other than leases or properties subject to**  
23 **AS 43.55.011(f), the greater of**

24 **(i) zero; or**

25 **(ii) the sum of 25 percent and the tax rate calculated for**  
26 **the month under AS 43.55.011(q) multiplied by the remainder obtained**  
27 **by subtracting 1/12 of the producer's adjusted lease expenditures for the**  
28 **calendar year of production under AS 43.55.165 and 43.55.170 that are**  
29 **deductible for the leases or properties under AS 43.55.160 from the**  
30 **gross value at the point of production of the oil and gas produced from**  
31 **the leases or properties during the month for which the installment**

1 payment is calculated;

2 (B) for oil and gas produced from leases or properties subject  
3 to AS 43.55.011(f), the greatest of

4 (i) zero;

5 (ii) zero percent, one percent, two percent, three  
6 percent, or four percent, as applicable, of the gross value at the point of  
7 production of the oil and gas produced from all leases or properties  
8 during the month for which the installment payment is calculated; or

9 (iii) the sum of 25 percent and the tax rate calculated for  
10 the month under AS 43.55.011(q) multiplied by the remainder obtained  
11 by subtracting 1/12 of the producer's adjusted lease expenditures for the  
12 calendar year of production under AS 43.55.165 and 43.55.170 that are  
13 deductible for those leases or properties under AS 43.55.160 from the  
14 gross value at the point of production of the oil and gas produced from  
15 those leases or properties during the month for which the installment  
16 payment is calculated;

17 (C) for oil and gas produced from each lease or property  
18 subject to AS 43.55.011(j), (k), (o), or (p), the greater of

19 (i) zero; or

20 (ii) the sum of 25 percent and the tax rate calculated for  
21 the month under AS 43.55.011(q) multiplied by the remainder obtained  
22 by subtracting 1/12 of the producer's adjusted lease expenditures for the  
23 calendar year of production under AS 43.55.165 and 43.55.170 that are  
24 deductible under AS 43.55.160 for oil or gas, respectively, produced  
25 from the lease or property from the gross value at the point of  
26 production of the oil or gas, respectively, produced from the lease or  
27 property during the month for which the installment payment is  
28 calculated;

29 (2) an amount calculated under (1)(C) of this subsection for oil or gas  
30 produced from a lease or property

31 (A) subject to AS 43.55.011(j), (k), or (o) may not exceed the

1 product obtained by carrying out the calculation set out in AS 43.55.011(j)(1)  
2 or (2) or 43.55.011(o), as applicable, for gas or set out in AS 43.55.011(k)(1)  
3 or (2), as applicable, for oil, but substituting in AS 43.55.011(j)(1)(A) or (2)(A)  
4 or 43.55.011(o), as applicable, the amount of taxable gas produced during the  
5 month for the amount of taxable gas produced during the calendar year and  
6 substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount of  
7 taxable oil produced during the month for the amount of taxable oil produced  
8 during the calendar year;

9 (B) subject to AS 43.55.011(p) may not exceed four percent of  
10 the gross value at the point of production of the oil or gas;

11 (3) an installment payment of the estimated tax levied by  
12 AS 43.55.011(i) for each lease or property is due for each month of the calendar year  
13 on the last day of the following month; the amount of the installment payment is the  
14 sum of

15 (A) the applicable tax rate for oil provided under  
16 AS 43.55.011(i), multiplied by the gross value at the point of production of the  
17 oil taxable under AS 43.55.011(i) and produced from the lease or property  
18 during the month; and

19 (B) the applicable tax rate for gas provided under  
20 AS 43.55.011(i), multiplied by the gross value at the point of production of the  
21 gas taxable under AS 43.55.011(i) and produced from the lease or property  
22 during the month;

23 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any  
24 credits applied as allowed by law, that exceeds the total of the amounts due as  
25 installment payments of estimated tax is due on March 31 of the year following the  
26 calendar year of production."

27  
28 **Renumber the following bill sections accordingly.**

29  
30 **Page 9, following line 11:**

31 **Insert a new bill section to read:**

1     **\*\* Sec. 12.** AS 43.55.020(d), as amended by sec. 11 of this Act, is amended to read:

2             (d) In making settlement with the royalty owner for oil and gas that is taxable  
3             under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable  
4             royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the  
5             time the tax becomes due to the amount of the tax paid. If the total deductions of  
6             installment payments of estimated tax for a calendar year exceed the actual tax for that  
7             calendar year, the producer shall, before April 1 of the following year, refund the  
8             excess to the royalty owner. Unless otherwise agreed between the producer and the  
9             royalty owner, the amount of the tax paid under AS 43.55.011(e), (f), and (g)  
10            [AS 43.55.011(e)] on taxable royalty oil and gas for a calendar year, other than oil and  
11            gas the ownership or right to which constitutes a landowner's royalty interest, is  
12            considered to be the gross value at the point of production of the taxable royalty oil  
13            and gas produced during the calendar year multiplied by a figure that is a quotient, in  
14            which

15                   (1) the numerator is the producer's total tax liability under  
16                   AS 43.55.011(e), (f), and (g) [AS 43.55.011(e)] for the calendar year of production;  
17                   and

18                   (2) the denominator is the total gross value at the point of production  
19                   of the oil and gas taxable under AS 43.55.011(e), (f), and (g) [AS 43.55.011(e)]  
20                   produced by the producer from all leases and properties in the state during the  
21                   calendar year."

22  
23     Renumber the following bill sections accordingly.

24  
25     Page 9, line 30:

26             Delete "sec. 7"

27             Insert "sec. 13"

28  
29     Page 10, following line 18:

30             Insert a new bill section to read:

31     **\*\* Sec. 15.** AS 43.55.023(a), as amended by secs. 13 and 14 of this Act, is amended to read:

1 (a) A producer or explorer may take a tax credit for a qualified capital  
2 expenditure as follows:

3 (1) notwithstanding that a qualified capital expenditure may be a  
4 deductible lease expenditure for purposes of calculating the production tax value of oil  
5 and gas under AS 43.55.160(a), unless a credit for that expenditure is taken under  
6 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or  
7 explorer that incurs a qualified capital expenditure may also elect to apply a tax credit  
8 against a tax levied by AS 43.55.011(e) in the amount of 20 percent of that  
9 expenditure; however, not more than half of the tax credit may be applied for a  
10 single calendar year;

*2 yrs  
to take  
credit*

11 (2) a producer or explorer may take a credit for a qualified capital  
12 expenditure incurred in connection with geological or geophysical exploration or in  
13 connection with an exploration well only if the producer or explorer

14 (A) agrees, in writing, to the applicable provisions of  
15 AS 43.55.025(f)(2); and

16 (B) submits to the Department of Natural Resources all data  
17 that would be required to be submitted under AS 43.55.025(f)(2) [;

18 (3) A CREDIT FOR A QUALIFIED CAPITAL EXPENDITURE  
19 INCURRED TO EXPLORE FOR, DEVELOP, OR PRODUCE OIL OR GAS  
20 DEPOSITS LOCATED NORTH OF 68 DEGREES NORTH LATITUDE MAY BE  
21 TAKEN ONLY IF THE EXPENDITURE IS INCURRED BEFORE JANUARY 1,  
22 2014]."

23  
24 Renumber the following bill sections accordingly.

25  
26 Page 10, following line 29:

27 Insert a new bill section to read:

28 "\*\* Sec. 17. AS 43.55.023(b), as amended by sec. 16 of this Act, is amended to read:

29 (b) A producer or explorer may elect to take a tax credit in the amount of 25  
30 percent of a carried-forward annual loss [; EXCEPT THAT A TAX CREDIT BASED  
31 ON LEASE EXPENDITURES INCURRED AFTER DECEMBER 31, 2013, TO

1 EXPLORE FOR, DEVELOP, OR PRODUCE OIL OR GAS DEPOSITS LOCATED  
 2 NORTH OF 68 DEGREES NORTH LATITUDE IS SUBJECT TO THE  
 3 PROVISIONS OF (p) - (u) OF THIS SECTION]. A credit under this subsection may  
 4 be applied against a tax levied by AS 43.55.011(e). For purposes of this subsection, a  
 5 carried-forward annual loss is the amount of a producer's or explorer's adjusted lease  
 6 expenditures under AS 43.55.165 and 43.55.170 for a previous calendar year that was  
 7 not deductible in calculating production tax values for that calendar year under  
 8 AS 43.55.160."  
 9

10 Renumber the following bill sections accordingly.

11  
 12 Page 11, following line 3:

13 Insert a new bill section to read:

14 **\*\* Sec. 19. AS 43.55.023(c), as amended by sec. 18 of this Act, is amended to read:**

15 (c) A credit or portion of a credit under this section may not be used to reduce  
 16 a person's tax liability under AS 43.55.011(e) for any calendar year below zero, and  
 17 any unused credit or portion of a credit not used under this subsection may be applied  
 18 in a later calendar year [, EXCEPT AS OTHERWISE PROVIDED UNDER (p) - (u)  
 19 OF THIS SECTION]."  
 20

21 Renumber the following bill sections accordingly.

22  
 23 Page 11, line 29:

24 Delete "sec. 11"

25 Insert "sec. 20"

26  
 27 Page 12, following line 17:

28 Insert a new bill section to read:

29 **\*\* Sec. 22. AS 43.55.023(d), as amended by secs. 20 and 21 of this Act, is amended to read:**

30 (d) **▲ [EXCEPT FOR A TAX CREDIT BASED ON LEASE**  
 31 **EXPENDITURES INCURRED AFTER DECEMBER 31, 2013, TO EXPLORE FOR,**

1 DEVELOP, OR PRODUCE OIL OR GAS DEPOSITS LOCATED NORTH OF 68  
 2 DEGREES NORTH LATITUDE, A] person that is entitled to take a tax credit under  
 3 this section that wishes to transfer the unused credit to another person or obtain a cash  
 4 payment under AS 43.55.028 may apply to the department for [A] transferable tax  
 5 credit certificates [CERTIFICATE]. An application under this subsection must be in a  
 6 form prescribed by the department and must include supporting information and  
 7 documentation that the department reasonably requires. The department shall grant or  
 8 deny an application, or grant an application as to a lesser amount than that claimed and  
 9 deny it as to the excess, not later than 120 days after the latest of (1) March 31 of the  
 10 year following the calendar year in which the qualified capital expenditure or carried-  
 11 forward annual loss for which the credit is claimed was incurred; (2) the date the  
 12 statement required under AS 43.55.030(a) or (e) was filed for the calendar year in  
 13 which the qualified capital expenditure or carried-forward annual loss for which the  
 14 credit is claimed was incurred; or (3) the date the application was received by the  
 15 department. If, based on the information then available to it, the department is  
 16 reasonably satisfied that the applicant is entitled to a credit, the department shall issue  
 17 the applicant two [A] transferable tax credit certificates, each for half of  
 18 [CERTIFICATE FOR] the amount of the credit. The credit shown on one of the two  
 19 certificates is available for immediate use. The credit shown on the second of the  
 20 two certificates may not be applied against a tax for a calendar year earlier than  
 21 the calendar year following the calendar year in which the certificate is issued,  
 22 and the certificate must contain a conspicuous statement to that effect. A  
 23 certificate issued under this subsection does not expire."

24  
 25 Renumber the following bill sections accordingly.

26  
 27 Page 12, following line 31:

28 Insert a new bill section to read:

29 "\*\* Sec. 24. AS 43.55.023(g), as amended by sec. 23 of this Act, is amended to read:

30 (g) The issuance of a transferable tax credit certificate under (d), (v), [OF  
 31 THIS SECTION] or former (m) of this section or the purchase of a certificate under

1 AS 43.55.028 does not limit the department's ability to later audit a tax credit claim to  
 2 which the certificate relates or to adjust the claim if the department determines, as a  
 3 result of the audit, that the applicant was not entitled to the amount of the credit for  
 4 which the certificate was issued. The tax liability of the applicant under  
 5 AS 43.55.011(e) and 43.55.017 - 43.55.180 is increased by the amount of the credit  
 6 that exceeds that to which the applicant was entitled, or the applicant's available valid  
 7 outstanding credits applicable against the tax levied by AS 43.55.011(e) are reduced  
 8 by that amount. If the applicant's tax liability is increased under this subsection, the  
 9 increase bears interest under AS 43.05.225 from the date the transferable tax credit  
 10 certificate was issued. For purposes of this subsection, an applicant that is an explorer  
 11 is considered a producer subject to the tax levied by AS 43.55.011(e)."  
 12

13 **Renumber the following bill sections accordingly.**

14  
 15 **Page 13, following line 14:**

16 **Insert a new bill section to read:**

17 **"\* Sec. 26. AS 43.55.023(n), as amended by sec. 25 of this Act, is amended to read:**

18 **(n) For the purposes of (l) and (v) of this section, a well lease expenditure**  
 19 **incurred in the state south of 68 degrees North latitude is a lease expenditure that is**

20 **(1) directly related to an exploration well, a stratigraphic test well, a**  
 21 **producing well, or an injection well other than a disposal well, located in the state**  
 22 **south of 68 degrees North latitude, if the expenditure is a qualified capital expenditure**  
 23 **and an intangible drilling and development cost authorized under 26 U.S.C. (Internal**  
 24 **Revenue Code), as amended, and 26 C.F.R. 1.612-4, regardless of the elections made**  
 25 **under 26 U.S.C. 263(c); in this paragraph, an expenditure directly related to a well**  
 26 **includes an expenditure for well sidetracking, well deepening, well completion or**  
 27 **recompletion, or well workover, regardless of whether the well is or has been a**  
 28 **producing well; or**

29 **(2) an expense for seismic work conducted within the boundaries of a**  
 30 **production or exploration unit."**  
 31

1 Renumber the following bill sections accordingly.

2

3 Page 16, following line 25:

4 Insert a new subsection to read:

5 "(v) For a lease expenditure incurred in the state south of 68 degrees North  
6 latitude after December 31, 2017, that qualifies for tax credits under (a) and (b) of this  
7 section, and for a well lease expenditure incurred in the state south of 68 degrees  
8 North latitude that qualifies for a tax credit under (f) of this section, the department  
9 shall issue transferable tax credit certificates to the person entitled to the credit for the  
10 full amount of the credit. The transferable tax credit certificates do not expire."  
11

12 Page 17, following line 21:

13 Insert a new bill section to read:

14 **\*\* Sec. 30. AS 43.55.028(e), as amended by sec. 29 of this Act, is amended to read:**

15 (e) The department, on the written application of a person to whom a  
16 transferable tax credit certificate has been issued under AS 43.55.023(d) or (v) or  
17 former AS 43.55.023(m) or to whom a production tax credit certificate has been issued  
18 under AS 43.55.025(f), may use available money in the oil and gas tax credit fund to  
19 purchase, in whole or in part, the certificate if the department finds that

20 (1) the calendar year of the purchase is not earlier than the first  
21 calendar year for which the credit shown on the certificate would otherwise be allowed  
22 to be applied against a tax;

23 (2) the applicant does not have an outstanding liability to the state for  
24 unpaid delinquent taxes under this title;

25 (3) the applicant's total tax liability under AS 43.55.011(e), after  
26 application of all available tax credits, for the calendar year in which the application is  
27 made is zero;

28 (4) the applicant's average daily production of oil and gas taxable  
29 under AS 43.55.011(e) during the calendar year preceding the calendar year in which  
30 the application is made was not more than 50,000 BTU equivalent barrels; and

31 (5) the purchase is consistent with this section and regulations adopted

1 under this section."  
2

3 **Renumber the following bill sections accordingly.**  
4

5 **Page 17, following line 31:**

6 **Insert a new bill section to read:**

7 **\*\* Sec. 32. AS 43.55.028(g), as amended by sec. 31 of this Act, is amended to read:**

8 (g) The department may adopt regulations to carry out the purposes of this  
9 section, including standards and procedures to allocate available money among  
10 applications for purchases under this chapter and claims for refunds and payments  
11 under AS 43.20.046 or 43.20.047 when the total amount of the applications for  
12 purchase and claims for refund exceed the amount of available money in the fund. The  
13 regulations adopted by the department may not, when allocating available money in  
14 the fund under this section, distinguish an application for the purchase of a credit  
15 certificate issued under AS 43.55.023(v) or former AS 43.55.023(m), or a claim for a  
16 refund or payment under AS 43.20.046 or 43.20.047."  
17

18 **Renumber the following bill sections accordingly.**  
19

20 **Page 18, following line 13:**

21 **Insert a new bill section to read:**

22 **\*\* Sec. 34. AS 43.55.030(e), as amended by sec. 33 of this Act, is amended to read:**

23 (e) An explorer or producer that incurs a lease expenditure under  
24 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar  
25 year but does not produce oil or gas from a lease or property in the state during the  
26 calendar year shall file with the department on March 31 of the following year a  
27 statement, under oath, in a form prescribed by the department, giving, with other  
28 information required, the following:

29 (1) the [EXPLORER'S OR] producer's qualified capital expenditures,  
30 as defined in AS 43.55.023, other lease expenditures under AS 43.55.165, and  
31 adjustments or other payments or credits under AS 43.55.170; and

1                   (2) if the explorer or producer receives a payment or credit under  
2 AS 43.55.170, calculations showing whether the explorer or producer is liable for a  
3 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount."  
4

5 **Renumber the following bill sections accordingly.**

6  
7 **Page 22, following line 11:**

8 **Insert a new bill section to read:**

9 **\*\* Sec. 38. AS 43.55.160(a), as amended by secs. 36 and 37 of this Act, is repealed and**  
10 **reenacted to read:**

11 **(a) Except as provided in (b) of this section, for the purposes of**

12 **(1) AS 43.55.011(e), the annual production tax value of the taxable oil,**  
13 **gas, or oil and gas subject to this paragraph produced during a calendar year is the**  
14 **gross value at the point of production of the oil, gas, or oil and gas taxable under**  
15 **AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the**  
16 **calendar year applicable to the oil, gas, or oil and gas, as applicable, produced by the**  
17 **producer from leases or properties, as adjusted under AS 43.55.170; this paragraph**  
18 **applies to**

19 **(A) oil and gas produced from leases or properties in the state**  
20 **that include land north of 68 degrees North latitude, other than gas produced**  
21 **before 2022 and used in the state;**

22 **(B) oil and gas produced from leases or properties in the state**  
23 **outside the Cook Inlet sedimentary basin, no part of which is north of 68**  
24 **degrees North latitude; this subparagraph does not apply to**

25 **(i) gas produced before 2022 and used in the state; or**

26 **(ii) oil and gas subject to AS 43.55.011(p);**

27 **(C) oil produced before 2022 from a lease or property in the**  
28 **Cook Inlet sedimentary basin;**

29 **(D) gas produced before 2022 from a lease or property in the**  
30 **Cook Inlet sedimentary basin;**

31 **(E) gas produced before 2022 from a lease or property in the**

1 state outside the Cook Inlet sedimentary basin and used in the state;

2 (F) oil and gas subject to AS 43.55.011(p) produced from  
3 leases or properties in the state;

4 (G) oil and gas produced from a lease or property no part of  
5 which is north of 68 degrees North latitude, other than oil or gas described in  
6 (B), (C), (D), (E), or (F) of this paragraph;

7 (2) AS 43.55.011(q), the monthly production tax value of the taxable

8 (A) oil and gas produced during a month from leases or  
9 properties in the state that include land north of 68 degrees North latitude is the  
10 gross value at the point of production of the oil and gas taxable under  
11 AS 43.55.011(e) and produced by the producer from those leases or properties,  
12 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the  
13 calendar year applicable to the oil and gas produced by the producer from  
14 those leases or properties, as adjusted under AS 43.55.170; this subparagraph  
15 does not apply to gas subject to AS 43.55.011(o);

16 (B) oil and gas produced during a month from leases or  
17 properties in the state outside the Cook Inlet sedimentary basin, no part of  
18 which is north of 68 degrees North latitude, is the gross value at the point of  
19 production of the oil and gas taxable under AS 43.55.011(e) and produced by  
20 the producer from those leases or properties, less 1/12 of the producer's lease  
21 expenditures under AS 43.55.165 for the calendar year applicable to the oil and  
22 gas produced by the producer from those leases or properties, as adjusted under  
23 AS 43.55.170; this subparagraph does not apply to gas subject to  
24 AS 43.55.011(o);

25 (C) oil produced during a month from a lease or property in the  
26 Cook Inlet sedimentary basin is the gross value at the point of production of  
27 the oil taxable under AS 43.55.011(e) and produced by the producer from that  
28 lease or property, less 1/12 of the producer's lease expenditures under  
29 AS 43.55.165 for the calendar year applicable to the oil produced by the  
30 producer from that lease or property, as adjusted under AS 43.55.170;

31 (D) gas produced during a month from a lease or property in

1 the Cook Inlet sedimentary basin is the gross value at the point of production  
 2 of the gas taxable under AS 43.55.011(e) and produced by the producer from  
 3 that lease or property, less 1/12 of the producer's lease expenditures under  
 4 AS 43.55.165 for the calendar year applicable to the gas produced by the  
 5 producer from that lease or property, as adjusted under AS 43.55.170;

6 (E) gas produced during a month from a lease or property  
 7 outside the Cook Inlet sedimentary basin and used in the state is the gross  
 8 value at the point of production of that gas taxable under AS 43.55.011(e) and  
 9 produced by the producer from that lease or property, less 1/12 of the  
 10 producer's lease expenditures under AS 43.55.165 for the calendar year  
 11 applicable to that gas produced by the producer from that lease or property, as  
 12 adjusted under AS 43.55.170."  
 13

14 Renumber the following bill sections accordingly.

15  
 16 Page 22, following line 31:

17 Insert a new bill section to read:

18 **\*\* Sec. 40. AS 43.55.160(e), as amended by sec. 39 of this Act, is amended to read:**

19 (e) Any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that  
 20 would otherwise be deductible by a producer in a calendar year but whose deduction  
 21 would cause an annual production tax value calculated under (a)(1) [(a)] of this  
 22 section of taxable oil or gas produced during the calendar year to be less than zero  
 23 may be used to establish a carried-forward annual loss under AS 43.55.023(b).  
 24 However, the department shall provide by regulation a method to ensure that, for a  
 25 period for which a producer's tax liability is limited by AS 43.55.011(j), (k), (o), or  
 26 (p), any adjusted lease expenditures under AS 43.55.165 and 43.55.170 that would  
 27 otherwise be deductible by a producer for that period but whose deduction would  
 28 cause a production tax value calculated under (a)(1)(C), (D), (E), or (F) [(a)(3), (4),  
 29 (5), OR (6)] of this section to be less than zero are accounted for as though the  
 30 adjusted lease expenditures had first been used as deductions in calculating the  
 31 production tax values of oil or gas subject to any of the limitations under

1 AS 43.55.011(j), (k), (o), or (p) that have positive production tax values so as to  
 2 reduce the tax liability calculated without regard to the limitation to the maximum  
 3 amount provided for under the applicable provision of AS 43.55.011(j), (k), (o), or (p).  
 4 Only the amount of those adjusted lease expenditures remaining after the accounting  
 5 provided for under this subsection may be used to establish a carried-forward annual  
 6 loss under AS 43.55.023(b). In this subsection, "producer" includes "explorer."

7  
 8 **Renumber the following bill sections accordingly.**

9  
 10 **Page 23, following line 12:**

11 **Insert a new bill section to read:**

12 **\*\* Sec. 44. AS 43.55.023(p), 43.55.023(q), 43.55.023(r), 43.55.023(s), 43.55.023(t),**  
 13 **43.55.023(u), 43.55.030(g), and 43.55.160(f) are repealed."**

14  
 15 **Renumber the following bill sections accordingly.**

16  
 17 **Page 23, line 15:**

18 **Delete "Sections 2, 5, 6, 22 - 24, and 26"**

19 **Insert "Sections 3, 9, 11, 37, 39, 41, and 43"**

20  
 21 **Page 23, line 17:**

22 **Delete "Sections 3 and 21"**

23 **Insert "Sections 5 and 36 of this Act"**

24  
 25 **Page 23, line 18:**

26 **Delete "Sections 7, 11, 13, 14, and 25"**

27 **Insert "Sections 13, 20, 23, 25, and 42"**

28  
 29 **Page 23, line 20:**

30 **Delete "Sections 9, 10, 12, 15, and 20"**

31 **Insert "Sections 16, 18, 21, 27, and 35"**

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**Page 23, following line 21:**

**Insert new subsections to read:**

**"(e) Sections 4, 6, 7, 10, 12, 38, and 40 of this Act apply to oil and gas produced after December 31, 2017.**

**(f) Sections 17, 19, 22, and 26 of this Act and AS 43.55.023(v), enacted by sec. 27 of this Act, apply to expenditures incurred after December 31, 2017."**

**Page 23, line 24:**

**Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"**

**Insert "Sections 5, 13, 20, 23, 25, 29, 36, and 42"**

**Page 23, line 31:**

**Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26 of this Act"**

**Insert "Sections 1, 3, 9, 11, 16, 18, 21, 35, 37, 39, 41, and 43 of this Act, and AS 43.55.023(p) - (u), enacted by sec. 27 of this Act,"**

**Page 24, following line 1:**

**Insert a new bill section to read:**

**"\* Sec. 49. Sections 2, 4, 6, 7, 12, 15, 17, 19, 22, 24, 26, 30, 32, 34, 38, 40, and 44 of this Act, and AS 43.55.023(v), enacted by sec. 27 of this Act, take effect January 1, 2018."**

**Renumber the following bill section accordingly.**

**Page 24, line 2:**

**Delete "sec. 30"**

**Insert "secs. 48 and 49"**

**AMENDMENT**

OFFERED IN THE SENATE  
TO: SB 21

BY SENATOR FRENCH

1 Page 1, lines 1 - 2:

2 Delete "relating to appropriations from taxes paid under the Alaska Net Income  
3 Tax Act;"

4

5 Page 1, line 2:

6 Delete "relating to gas used in the state;"

7

8 Page 1, lines 4 - 7:

9 Delete "for certain losses and expenditures; relating to oil and gas production tax  
10 credit certificates; relating to nontransferable tax credits based on production; relating  
11 to the oil and gas tax credit fund; relating to annual statements by producers and  
12 explorers"

13 Insert "; amending the minimum tax on oil and gas production"

14

15 Page 1, lines 8 - 9:

16 Delete "including adjustments based on a percentage of gross value at the point of  
17 production from certain leases or properties; making conforming amendments"

18 Insert "; relating to the financing of oil processing facilities on the North Slope by  
19 the Alaska Industrial Development and Export Authority"

20

21 Page 1, line 12, through page 24, line 3:

22 Delete all material and insert:

23 **\*\* Section 1. AS 38.05.180(h) is amended to read:**

1           (h) The commissioner shall [MAY] include terms in a [ANY] lease that  
 2 impose [IMPOSING] a minimum work commitment on the lessee to implement the  
 3 plan of development submitted by the lessee with a bid for an oil and gas or gas  
 4 only lease. The terms of the minimum work commitment must [. THESE TERMS  
 5 SHALL BE MADE PUBLIC BEFORE THE SALE, AND MAY] include appropriate  
 6 penalty provisions to take effect in the event the lessee does not fulfill the minimum  
 7 work commitment. If it is demonstrated that a lease has been proven unproductive by  
 8 actions of adjacent lease holders, the commissioner may set aside a work commitment.  
 9 The commissioner may waive for a period not to exceed one two-year period any term  
 10 of a minimum work commitment if the commissioner makes a written finding either  
 11 that conditions preventing drilling or exploration were beyond the lessee's reasonable  
 12 ability to foresee or control or that the lessee has demonstrated through good faith  
 13 efforts an intent and ability to drill or develop the lease during the term of the waiver.

14 \* Sec. 2. AS 38.05.180(x) is amended to read:

15           (x) A lessee conducting or permitting any exploration for, or development or  
 16 production of, oil or gas on state land shall provide the commissioner access to all  
 17 noninterpretive data obtained from that lease; shall provide the commissioner access  
 18 to all information necessary to perform an economic analysis under (ii)(2) of this  
 19 section, including the capital, operating, production, and development costs and  
 20 an estimate of total reserves; and shall provide copies of that data and information,  
 21 as the commissioner may request. The confidentiality provisions of AS 38.05.035  
 22 apply to the information obtained under this subsection.

23 \* Sec. 3. AS 38.05.180 is amended by adding new subsections to read:

24           (hh) The commissioner shall require each bidder for an oil and gas lease or gas  
 25 only lease and each lessee applying for an extension or renewal of an oil and gas lease  
 26 or gas only lease to submit a plan of development for exploring, developing, and  
 27 producing from the lease within the period of the lease or the extension or renewal of  
 28 the lease. The commissioner shall review each plan of development and determine  
 29 whether the proposed plan of development is reasonably expected to develop the lease  
 30 in the best interest of the state. The plan of development shall be included in a lease  
 31 along with penalties for failing to comply with the plan of development and other

1 terms of the lease. A bidder may not be a qualified bidder for the purposes of (f)(1) of  
2 this section if the commissioner finds that the bidder has not submitted a proposed  
3 plan of development that is in the best interest of the state or that the person that  
4 submitted the plan of development is not reasonably capable of implementing the plan.

5 (ii) The commissioner shall

6 (1) review each oil and gas lease or gas only lease each year for the  
7 purpose of determining whether a lease is being developed in the best interest of the  
8 state, whether the lessee is complying with the plan of development applicable to the  
9 lease, and whether revision of a plan of development, including the planned rate of  
10 development, would provide the maximum benefit to the people of the state;

11 (2) every five years, perform an economic analysis on each  
12 participating area and determine whether the participating area is capable of increased  
13 production in paying quantities over the current rate of production or plan of  
14 development;

15 (3) enforce the terms of each oil and gas lease or gas only lease,  
16 including imposing any applicable penalty or other remedy for noncompliance, within  
17 a reasonable time after finding that a lessee is out of compliance with the terms of the  
18 lease;

19 (4) submit a report to the legislature before the first day of each regular  
20 session that lists each oil and gas or gas only lessee that is found to be out of  
21 compliance and the action by the commissioner to bring the lessee back into  
22 compliance or to terminate the lease.

23 (jj) For the purposes of (hh) and (ii) of this section, a plan of development for  
24 a cooperative or unit under (p) of this section is the plan of development for a lease  
25 within the cooperative or unit, except where a different plan of development is  
26 established for a lease within the cooperative or unit.

27 (kk) For purposes of (ii) of this section,

28 (1) "participating area" means that part of an oil and gas lease unit area  
29 to which production is allocated in the manner described in a unit agreement;

30 (2) "production in paying quantities" means production in quantities  
31 sufficient to yield a return in excess of drilling, development, and operating costs.

1    \* **Sec. 4. AS 43.55.011(e) is amended to read:**

2           (e) There is levied on the producer of oil or gas a tax for all oil and gas  
3           produced each calendar year from each lease or property in the state, less any oil and  
4           gas the ownership or right to which is exempt from taxation or constitutes a  
5           landowner's royalty interest. Except as otherwise provided under (f), (j), (k), (o), and  
6           (p) of this section, the tax is equal to the sum of

7                   (1) the annual production tax value of the taxable oil and gas as  
8                   calculated under AS 43.55.160(a)(1), as adjusted by AS 43.55.162, multiplied by 25  
9                   percent; and

10                   (2) the sum, over all months of the calendar year, of the tax amounts  
11                   determined under (g) of this section.

12    \* **Sec. 5. AS 43.55.011(f) is repealed and reenacted to read:**

13           (f) Except for oil and gas subject to (i) of this section and gas subject to (o) of  
14           this section, the provisions of this subsection apply to oil and gas produced from each  
15           lease or property within a unit or nonunitized reservoir that has cumulatively produced  
16           1,000,000,000 BTU equivalent barrels of oil or gas by the close of the most recent  
17           calendar year and from which the average daily oil and gas production from the unit or  
18           nonunitized reservoir during the most recent calendar year exceeded 100,000 BTU  
19           equivalent barrels. Notwithstanding any contrary provision of law, a producer may not  
20           apply tax credits to reduce its total tax liability under (e) and (g) of this section for oil  
21           and gas produced from all leases or properties within the unit or nonunitized reservoir  
22           below 10 percent of the total gross value at the point of production of that oil and gas.  
23           If the amount of tax calculated by multiplying the tax rates in (e) and (g) of this  
24           section by the total production tax value of the oil and gas taxable under (e) and (g) of  
25           this section produced from all of the producer's leases or properties within the unit or  
26           nonunitized reservoir is less than 10 percent of the total gross value at the point of  
27           production of that oil and gas, the tax levied by (e) and (g) of this section for that oil  
28           and gas is equal to 10 percent of the total gross value at the point of production of that  
29           oil and gas.

30    \* **Sec. 6. AS 43.55.011(g) is amended to read:**

31           (g) For each month of the calendar year for which the producer's average

1 monthly production tax value under AS 43.55.160(a)(2) of a [PER] BTU equivalent  
 2 barrel of the taxable oil and gas is more than \$30, the amount of tax for purposes of  
 3 (e)(2) of this section is determined by multiplying the monthly production tax value of  
 4 the taxable oil and gas produced during the month, as adjusted by AS 43.55.162, by  
 5 the tax rate calculated as follows:

6 (1) if the producer's average monthly production tax value of a [PER]  
 7 BTU equivalent barrel of the taxable oil and gas for the month is not more than  
 8 \$92.50, the tax rate is 0.4 percent multiplied by the number that represents the  
 9 difference between that average monthly production tax value of a [PER] BTU  
 10 equivalent barrel and \$30; or

11 (2) if the producer's average monthly production tax value of a [PER]  
 12 BTU equivalent barrel of the taxable oil and gas for the month is more than \$92.50,  
 13 the tax rate is the sum of 25 percent and the product of 0.1 percent multiplied by the  
 14 number that represents the difference between the average monthly production tax  
 15 value of a [PER] BTU equivalent barrel and \$92.50, except that the sum determined  
 16 under this paragraph may not exceed 30 [50] percent.

17 \* Sec. 7. AS 43.55.020(a) is amended to read:

18 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)  
 19 or (p) shall pay the tax as follows:

20 (1) an installment payment of the estimated tax levied by  
 21 AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each  
 22 month of the calendar year on the last day of the following month; except as otherwise  
 23 provided under (2) of this subsection, the amount of the installment payment is the  
 24 sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be  
 25 applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount  
 26 of the installment payment may not be less than zero:

27 (A) for oil and gas produced from leases or properties in the  
 28 state outside the Cook Inlet sedimentary basin but not subject to  
 29 AS 43.55.011(o) or (p), other than leases or properties subject to  
 30 AS 43.55.011(f), the greater of

31 (i) zero; or

1 (ii) the sum of 25 percent and the tax rate calculated for  
 2 the month under AS 43.55.011(g) multiplied by the remainder obtained  
 3 by subtracting 1/12 of the producer's adjusted lease expenditures for the  
 4 calendar year of production under AS 43.55.165 and 43.55.170 that are  
 5 deductible for the leases or properties under AS 43.55.160 and 1/12 of  
 6 the adjustment to production tax value for the calendar year under  
 7 AS 43.55.162 from the gross value at the point of production of the oil  
 8 and gas produced from the leases or properties during the month for  
 9 which the installment payment is calculated;

10 (B) for oil and gas produced from leases or properties subject  
 11 to AS 43.55.011(f), 10 percent of the gross value at the point of production  
 12 of that oil and gas [THE GREATEST OF

13 (i) ZERO;

14 (ii) ZERO PERCENT, ONE PERCENT, TWO  
 15 PERCENT, THREE PERCENT, OR FOUR PERCENT, AS  
 16 APPLICABLE, OF THE GROSS VALUE AT THE POINT OF  
 17 PRODUCTION OF THE OIL AND GAS PRODUCED FROM ALL  
 18 LEASES OR PROPERTIES DURING THE MONTH FOR WHICH  
 19 THE INSTALLMENT PAYMENT IS CALCULATED; OR

20 (iii) THE SUM OF 25 PERCENT AND THE TAX  
 21 RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g)  
 22 MULTIPLIED BY THE REMAINDER OBTAINED BY  
 23 SUBTRACTING 1/12 OF THE PRODUCER'S ADJUSTED LEASE  
 24 EXPENDITURES FOR THE CALENDAR YEAR OF PRODUCTION  
 25 UNDER AS 43.55.165 AND 43.55.170 THAT ARE DEDUCTIBLE  
 26 FOR THOSE LEASES OR PROPERTIES UNDER AS 43.55.160  
 27 FROM THE GROSS VALUE AT THE POINT OF PRODUCTION  
 28 OF THE OIL AND GAS PRODUCED FROM THOSE LEASES OR  
 29 PROPERTIES DURING THE MONTH FOR WHICH THE  
 30 INSTALLMENT PAYMENT IS CALCULATED];

31 (C) for oil and gas produced from each lease or property

1 subject to AS 43.55.011(j), (k), (o), or (p), the greater of

2 (i) zero; or

3 (ii) the sum of 25 percent and the tax rate calculated for  
4 the month under AS 43.55.011(g) multiplied by the remainder obtained  
5 by subtracting 1/12 of the producer's adjusted lease expenditures for the  
6 calendar year of production under AS 43.55.165 and 43.55.170 that are  
7 deductible under AS 43.55.160 and 1/12 of the adjustment to  
8 production tax value for the calendar year under AS 43.55.162 for  
9 oil or gas, as applicable [RESPECTIVELY], produced from the lease  
10 or property from the gross value at the point of production of the oil or  
11 gas, as applicable [RESPECTIVELY], produced from the lease or  
12 property during the month for which the installment payment is  
13 calculated;

14 (2) an amount calculated under (1)(C) of this subsection for oil or gas  
15 produced from a lease or property

16 (A) subject to AS 43.55.011(j), (k), or (o) may not exceed the  
17 product obtained by carrying out the calculation set out in AS 43.55.011(j)(1)  
18 or (2) or 43.55.011(o), as applicable, for gas or set out in AS 43.55.011(k)(1)  
19 or (2), as applicable, for oil, but substituting in AS 43.55.011(j)(1)(A) or (2)(A)  
20 or 43.55.011(o), as applicable, the amount of taxable gas produced during the  
21 month for the amount of taxable gas produced during the calendar year and  
22 substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the amount of  
23 taxable oil produced during the month for the amount of taxable oil produced  
24 during the calendar year;

25 (B) subject to AS 43.55.011(p) may not exceed four percent of  
26 the gross value at the point of production of the oil or gas;

27 (3) an installment payment of the estimated tax levied by  
28 AS 43.55.011(i) for each lease or property is due for each month of the calendar year  
29 on the last day of the following month; the amount of the installment payment is the  
30 sum of

31 (A) the applicable tax rate for oil provided under

1 AS 43.55.011(i), multiplied by the gross value at the point of production of the  
2 oil taxable under AS 43.55.011(i) and produced from the lease or property  
3 during the month; and

4 (B) the applicable tax rate for gas provided under  
5 AS 43.55.011(i), multiplied by the gross value at the point of production of the  
6 gas taxable under AS 43.55.011(i) and produced from the lease or property  
7 during the month;

8 (4) any amount of tax levied by AS 43.55.011(e) or (i), net of any  
9 credits applied as allowed by law, that exceeds the total of the amounts due as  
10 installment payments of estimated tax is due on March 31 of the year following the  
11 calendar year of production.

12 \* **Sec. 8.** AS 43.55.024(d) is amended to read:

13 (d) A producer may not take a tax credit under (c) of this section for any  
14 calendar year after the later of

15 (1) **2022** [2016]; or

16 (2) if the producer did not have commercial oil or gas production from  
17 a lease or property in the state before April 1, 2006, the ninth calendar year after the  
18 calendar year during which the producer first has commercial oil or gas production  
19 before May 1, **2022** [2016], from at least one lease or property in the state.

20 \* **Sec. 9.** AS 43.55 is amended by adding a new section to read:

21 **Sec. 43.55.026. Heavy oil research and development tax credit.** (a) A  
22 taxpayer may apply 20 percent of the taxpayer's expenditure attributable to this state  
23 for research and development related to improving methods of producing heavy oil in  
24 the state for the taxable year that exceeds the base amount, but not to exceed  
25 \$10,000,000, as a credit against the state tax liability imposed on the taxpayer under  
26 this chapter.

27 (b) Research and development expenditures in this section are attributable to  
28 this state if the research and development is being conducted in this state or the payroll  
29 of employees conducting the research and development is in this state. In this  
30 subsection, payroll of an employee is in this state if compensation is paid to an  
31 employee in this state and reported as paid in this state in the quarterly contribution

1 report under AS 23.20 to the Department of Labor and Workforce Development.

2 (c) If the tax credit under this section exceeds the taxpayer's tax liability after  
3 other tax credits are taken under this chapter for the year in which the expenditure is  
4 incurred, the excess of the tax credit over the liability may be carried forward for up to  
5 seven years. If an unused credit is carried forward to a tax year from an earlier year,  
6 the credit arising in the earliest year is applied first against the tax liability for the year.

7 (d) A person may not claim a credit under this section for research and  
8 development expenditures that were deducted in the calculation of tax liability under  
9 AS 43.55.011(e).

10 (e) Each year, if three or more taxpayers claim the credit authorized under this  
11 section during the immediately preceding year, the department shall report to the  
12 legislature the number of taxpayers who claimed credits under this section in the prior  
13 year, the total cumulative amount of credits granted to all taxpayers under this section  
14 for the prior tax year, a description of the research and development projects for which  
15 the credit was granted, and the total cumulative number of employees conducting the  
16 research and development for which all taxpayers claim the credit.

17 (f) The commissioner shall establish in regulation a method for apportioning  
18 research expenditures of a producer related to heavy oil production in and outside of  
19 the state. When developing the regulations, the commissioner may consider the  
20 relative amounts of heavy oil the producer is seeking to produce in areas in and  
21 outside of the state or consider another reasonable basis on which fairly to apportion  
22 costs for research related to in-state oil production and oil produced outside of the  
23 state.

24 (g) In this section, "base amount" means the average of research and  
25 development expenditures related to improving methods of producing heavy oil and  
26 attributable to this state for the three tax years immediately preceding the taxable year  
27 for which the credit is being claimed.

28 \* Sec. 10. AS 43.55.030(a) is amended to read:

29 (a) A producer that produces oil or gas from a lease or property in the state  
30 during a calendar year, whether or not any tax payment is due under AS 43.55.020(a)  
31 for that oil or gas, shall file with the department on March 31 of the following year a

1 statement, under oath, in a form prescribed by the department, giving, with other  
2 information required by the department under a regulation adopted by the  
3 department, the following:

4 (1) a description of each lease or property from which oil or gas was  
5 produced, by name, legal description, lease number, or accounting codes assigned by  
6 the department;

7 (2) the names of the producer and, if different, the person paying the  
8 tax, if any;

9 (3) the gross amount of oil and the gross amount of gas produced from  
10 each lease or property, and the percentage of the gross amount of oil and gas owned by  
11 the producer;

12 (4) the gross value at the point of production of the oil and of the gas  
13 produced from each lease or property owned by the producer and the costs of  
14 transportation of the oil and gas;

15 (5) the name of the first purchaser and the price received for the oil and  
16 for the gas, unless relieved from this requirement in whole or in part by the  
17 department;

18 (6) the producer's qualified capital expenditures, as defined in  
19 AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other  
20 payments or credits under AS 43.55.170;

21 (7) the production tax values of the oil and gas under AS 43.55.160;

22 (8) any claims for tax credits to be applied; [AND]

23 (9) calculations showing the amounts, if any, that were or are due  
24 under AS 43.55.020(a) and interest on any underpayment or overpayment; and

25 (10) for each expenditure that is the basis for a credit claimed  
26 under AS 43.55.023 or 43.55.025, a description of the expenditure, a detailed  
27 description of the purpose of the expenditure, and a description of the lease or  
28 property for which the expenditure was incurred; notwithstanding  
29 AS 40.25.100(a) and AS 43.05.230(a), information submitted under this  
30 paragraph may be disclosed to the public and shall be disclosed to the legislature  
31 in a report submitted within 10 days after the convening of the next regular

1 legislative session following the date a statement is filed under this section.

2 \* Sec. 11. AS 43.55.030(e) is amended to read:

3 (e) An explorer or producer that incurs a lease expenditure under  
4 AS 43.55.165 or receives a payment or credit under AS 43.55.170 during a calendar  
5 year but does not produce oil or gas from a lease or property in the state during the  
6 calendar year shall file with the department on March 31 of the following year a  
7 statement, under oath, in a form prescribed by the department, giving, with other  
8 information required by the department under a regulation adopted by the  
9 department, the following:

10 (1) the producer's qualified capital expenditures, as defined in  
11 AS 43.55.023, other lease expenditures under AS 43.55.165, and adjustments or other  
12 payments or credits under AS 43.55.170; [AND]

13 (2) if the explorer or producer receives a payment or credit under  
14 AS 43.55.170, calculations showing whether the explorer or producer is liable for a  
15 tax under AS 43.55.160(d) or 43.55.170(b) and, if so, the amount; and

16 (3) for each expenditure that is the basis for a credit claimed under  
17 this chapter, a description of the expenditure, a detailed description of the  
18 purpose of the expenditure, and a description of the lease or property for which  
19 the expenditure was incurred; notwithstanding AS 40.25.100(a) and  
20 AS 43.05.230(a), information submitted under this paragraph may be disclosed to  
21 the public and shall be disclosed to the legislature in a report submitted within 10  
22 days after the convening of the next regular legislative session following the date  
23 a statement is filed under this section.

24 \* Sec. 12. AS 43.55.160(a) is amended to read:

25 (a) Except as provided in (b) of this section, and subject to adjustment  
26 under AS 43.55.162, for the purposes of

27 (1) AS 43.55.011(e), the annual production tax value of the taxable oil,  
28 gas, or oil and gas subject to this paragraph produced during a calendar year is the  
29 gross value at the point of production of the oil, gas, or oil and gas taxable under  
30 AS 43.55.011(e), less the producer's lease expenditures under AS 43.55.165 for the  
31 calendar year applicable to the oil, gas, or oil and gas, as applicable, produced by the

1 producer from leases or properties, as adjusted under AS 43.55.170; this paragraph  
2 applies to

3 (A) oil and gas produced from leases or properties in the state  
4 that include land north of 68 degrees North latitude, other than gas produced  
5 before 2022 and used in the state;

6 (B) oil and gas produced from leases or properties in the state  
7 outside the Cook Inlet sedimentary basin, no part of which is north of 68  
8 degrees North latitude; this subparagraph does not apply to gas

9 (i) produced before 2022 and used in the state; or

10 (ii) oil and gas subject to AS 43.55.011(p);

11 (C) oil produced before 2022 from a lease or property in the  
12 Cook Inlet sedimentary basin;

13 (D) gas produced before 2022 from a lease or property in the  
14 Cook Inlet sedimentary basin;

15 (E) gas produced before 2022 from a lease or property in the  
16 state outside the Cook Inlet sedimentary basin and used in the state;

17 (F) oil and gas subject to AS 43.55.011(p) produced from  
18 leases or properties in the state;

19 (G) oil and gas produced from a lease or property no part of  
20 which is north of 68 degrees North latitude, other than oil or gas described in  
21 (B), (C), (D), (E), or (F) of this paragraph;

22 (2) AS 43.55.011(g), the monthly production tax value of the taxable

23 (A) oil and gas produced during a month from leases or  
24 properties in the state that include land north of 68 degrees North latitude is the  
25 gross value at the point of production of the oil and gas taxable under  
26 AS 43.55.011(e) and produced by the producer from those leases or properties,  
27 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the  
28 calendar year applicable to the oil and gas produced by the producer from  
29 those leases or properties, as adjusted under AS 43.55.170; this subparagraph  
30 does not apply to gas subject to AS 43.55.011(o);

31 (B) oil and gas produced during a month from leases or

1 properties in the state outside the Cook Inlet sedimentary basin, no part of  
2 which is north of 68 degrees North latitude, is the gross value at the point of  
3 production of the oil and gas taxable under AS 43.55.011(e) and produced by  
4 the producer from those leases or properties, less 1/12 of the producer's lease  
5 expenditures under AS 43.55.165 for the calendar year applicable to the oil and  
6 gas produced by the producer from those leases or properties, as adjusted under  
7 AS 43.55.170; this subparagraph does not apply to gas subject to  
8 AS 43.55.011(o);

9 (C) oil produced during a month from a lease or property in the  
10 Cook Inlet sedimentary basin is the gross value at the point of production of  
11 the oil taxable under AS 43.55.011(e) and produced by the producer from that  
12 lease or property, less 1/12 of the producer's lease expenditures under  
13 AS 43.55.165 for the calendar year applicable to the oil produced by the  
14 producer from that lease or property, as adjusted under AS 43.55.170;

15 (D) gas produced during a month from a lease or property in  
16 the Cook Inlet sedimentary basin is the gross value at the point of production  
17 of the gas taxable under AS 43.55.011(e) and produced by the producer from  
18 that lease or property, less 1/12 of the producer's lease expenditures under  
19 AS 43.55.165 for the calendar year applicable to the gas produced by the  
20 producer from that lease or property, as adjusted under AS 43.55.170;

21 (E) gas produced during a month from a lease or property  
22 outside the Cook Inlet sedimentary basin and used in the state is the gross  
23 value at the point of production of that gas taxable under AS 43.55.011(e) and  
24 produced by the producer from that lease or property, less 1/12 of the  
25 producer's lease expenditures under AS 43.55.165 for the calendar year  
26 applicable to that gas produced by the producer from that lease or property, as  
27 adjusted under AS 43.55.170.

28 \* **Sec. 13.** AS 43.55 is amended by adding a new section to read:

29 **Sec. 43.55.162. Adjustments to production tax value.** (a) The annual  
30 production tax value of oil produced from a lease or property north of 68 degrees  
31 North latitude by the producer is reduced, during the first seven consecutive years

1 after the start of commercial production by 20 percent of the gross value at the point of  
2 production of oil produced during the calendar year. This subsection does not apply to  
3 a lease or property that

4 (1) was in commercial production before January 1, 2007;

5 (2) is located within a unit area that has never had commercial  
6 production; or

7 (3) is located within a unit for more than 20 years before the first  
8 commercial production on the lease or property.

9 (b) The annual production tax value of oil or gas produced by a producer is  
10 reduced during the first five consecutive years after the start of commercial production  
11 by 10 percent if the oil or gas is produced from a participating area established after  
12 December 31, 2012, that is within a unit formed under AS 38.05.180(p) before  
13 January 1, 2003, if the participating area does not contain a reservoir that had  
14 previously been in a participating area established before January 1, 2012. This  
15 subsection does not apply to production from a lease or property located within a unit  
16 for more than 20 years before the first commercial production on the lease or property.

17 (c) The annual production tax value of heavy oil produced by a producer is  
18 reduced by 10 percent of the gross value at the point of production of heavy oil  
19 produced, for the calendar year, from a lease or property that is located within a unit  
20 area existing on January 1, 2014.

21 (d) For a calendar year after 2012, the annual production tax value of oil  
22 produced by a producer that produced oil in 2012 is reduced by 10 percent of the gross  
23 value at the point of production of the volume of oil produced during the calendar year  
24 in excess of the total volume produced by the producer in 2012. The volume of oil  
25 produced by a producer in 2012 is the average daily statewide production of the  
26 producer, excluding from the calculation the days on which production is significantly  
27 reduced, multiplied by the number of days in the calendar year. For the purposes of  
28 this subsection, production is significantly reduced when the production volume of oil  
29 for the day is less than one-half of the quotient of the total volume of oil production  
30 that is produced by the producer for the year and the number of days in the calendar  
31 year. A producer that increases its volume of production through the purchase, merger,

1 or other acquisition of another producer is the sum of the producer's total target  
 2 volume and the total target volume for the producer that is purchased, merged with, or  
 3 otherwise acquired; however, if the producer that is purchased, merged with, or  
 4 otherwise acquired did not have a target volume determined under this section, the  
 5 volume of the increased production that is attributable to the purchase, merger, or  
 6 other acquisition may not be considered for the purpose of determining whether the  
 7 producer that acquired the additional production has increased the volume of  
 8 production above its target volume.

9 (e) A reduction in production tax value provided by this section may not be  
 10 combined with any other reduction in production tax value provided by this section in  
 11 the same year. Oil or gas from a lease or property that produces oil or gas that results  
 12 in a production tax reduction under (a) of this section is ineligible for a production tax  
 13 reduction under (b) and (c) of this section and may not be used in the calculation of  
 14 production volume under (d) of this section.

15 (f) A reduction in production tax value provided by this section may not  
 16 reduce the production tax value of a producer below zero.

17 (g) The rate of tax under AS 43.55.011(g) shall be determined before the  
 18 application of the adjustment provided by this section.

19 (h) In this section,

20 (1) "commercial production" means the production of oil for the  
 21 purpose of sale or other beneficial use, except when the sale or beneficial use is  
 22 incidental to the testing of an unproved well or unproved completion interval;

23 (2) "participating area" means that part of an oil and gas lease unit to  
 24 which production is allocated in the manner described in a unit agreement.

25 \* Sec. 14. AS 43.55.990 is amended by adding a new paragraph to read:

26 (14) "heavy oil" means oil with an American Petroleum Institute  
 27 gravity of less than 18 degrees.

28 \* Sec. 15. AS 44.88.080 is amended by adding a new paragraph to read:

29 (32) to acquire an interest in a project as necessary or appropriate to  
 30 provide working or venture capital for an oil or natural gas development project under  
 31 AS 44.88.800 and 44.88.810, whether by purchase, gift, or lease.

1 \* **Sec. 16.** AS 44.88 is amended by adding new sections to read:

2 **Article 9A. Interest in Oil and Gas Resources.**

3 **Sec. 44.88.800. Acquisition of interest in businesses.** (a) The authority may  
4 acquire, through purchase or other means, an interest in a lease held by a corporation  
5 or other business entity in an oil or natural gas field in the state that has been explored,  
6 but only if the authority determines the leaseholder has made reasonable efforts to  
7 obtain financing from the private sector to develop the lease and those efforts have, in  
8 whole or part, been unsuccessful. The authority shall exercise due diligence in  
9 acquiring a leasehold interest under this section.

10 (b) If the authority acquires a leasehold interest under this section, the  
11 authority may use the authority's assets, as appropriate, to aid in the development of  
12 the oil or natural gas field in which the business entity has a leasehold interest.

13 **Sec. 44.88.810. Alaska resource development fund.** (a) The Alaska resource  
14 development fund is established in the authority for the purpose of developing oil and  
15 gas resources, and consists of appropriations to the fund. The authority shall manage  
16 the fund and may create separate accounts within it. Income of the fund or of  
17 enterprises of the authority shall be separately accounted for and may be appropriated  
18 to the fund.

19 (b) The authority may use money from the fund to carry out the purpose of the  
20 fund set out in (a) of this section.

21 \* **Sec. 17.** AS 44.88.900(10) is amended to read:

22 (10) "project" means

23 (A) a plant or facility used or intended for use in connection  
24 with making, processing, preparing, transporting, or producing in any manner,  
25 goods, products, or substances of any kind or nature or in connection with  
26 developing or utilizing a natural resource, or extracting, smelting, transporting,  
27 converting, assembling, or producing in any manner, minerals, raw materials,  
28 chemicals, compounds, alloys, fibers, commodities and materials, products, or  
29 substances of any kind or nature;

30 (B) a plant or facility used or intended for use in connection  
31 with a business enterprise;

1 (C) commercial activity by a business enterprise;

2 (D) a plant or facility demonstrating technological advances of  
3 new methods and procedures and prototype commercial applications for the  
4 exploration, development, production, transportation, conversion, and use of  
5 energy resources;

6 (E) infrastructure for a new tourism destination facility or for  
7 the expansion of a tourism destination facility; in this subparagraph, "tourism  
8 destination facility" does not include a hotel or other overnight lodging facility;

9 (F) a plant or facility, other than a plant or facility described in  
10 (D) of this paragraph, for the generation, transmission, development,  
11 transportation, conversion, or use of energy resources;

12 (G) a plant or facility that enhances, provides for, or promotes  
13 economic development with respect to transportation, communications,  
14 community public purposes, technical innovations, prototype commercial  
15 applications of intellectual property, or research;

16 (H) a plant or facility used or intended for use as a federal  
17 facility, including a United States military, national guard, or coast guard  
18 facility;

19 (I) infrastructure for an area that is designated as a military  
20 facility zone under AS 26.30;

21 (J) development of an oil and gas field by providing  
22 working or venture capital in exchange for an equity interest:

23 \* Sec. 18. The uncodified law of the State of Alaska is amended by adding a new section to  
24 read:

25 APPLICABILITY. (a) Section 1 of this Act and AS 38.05.180(hh), enacted by sec. 3  
26 of this Act, apply to a proposed lease sale and the renewal or extension of a lease on or after  
27 the effective date of this Act.

28 (b) The reduction in production tax value under AS 43.55.162, enacted by sec. 13 of  
29 this Act, applies to oil or gas produced after December 31, 2013.

30 \* Sec. 19. The uncodified law of the State of Alaska is amended by adding a new section to  
31 read:

1           **LEGISLATIVE APPROVAL; NORTH SLOPE OIL PROCESSING FACILITY. (a)**  
2   **The Alaska Industrial Development and Export Authority may issue a loan to a producer of**  
3   **oil or gas to finance the construction and improvement of an oil processing facility on the**  
4   **Alaska North Slope and flow lines and other surface infrastructure for the facility. A loan**  
5   **under this section shall**

6                   **(1) be issued to a producer that produces less than 100,000 barrels of oil a day;**

7                   **(2) be issued for the purpose of financing a facility to facilitate production**  
8   **from a unit established after January 1, 2014; and**

9                   **(3) have an interest rate that does not exceed the prime rate of interest plus one**  
10   **percent.**

11           **(b) In this section, "prime rate" means the lowest United States money center prime**  
12   **rate of interest that is published in the Wall Street Journal.**

13    \* **Sec. 20. Section 19 of this Act is repealed June 30, 2017. Repeal of sec. 19 of this Act**  
14   **does not affect loans issued by the Alaska Industrial Development and Export Authority under**  
15   **sec. 19 of this Act before June 30, 2017.**

16    \* **Sec. 21. This Act takes effect January 1, 2014."**

*AIDEA*  
*- Forms fund*  
*- SOA buy in*  
*on Facilities*  
*Leases*

**AMENDMENT**

OFFERED IN THE SENATE  
TO: SB 21

BY SENATOR FRENCH

1 Page 1, line 9, following "properties;":

2 Insert "relating to the financing of oil processing facilities on the North Slope by  
3 the Alaska Industrial Development and Export Authority;"

4

5 Page 23, following line 10:

6 Insert new bill sections to read:

7 **\*\* Sec. 25. AS 44.88.080 is amended by adding a new paragraph to read:**

8 (32) to acquire an interest in a project as necessary or appropriate to  
9 provide working or venture capital for an oil or natural gas development project under  
10 AS 44.88.800 and 44.88.810, whether by purchase, gift, or lease.

11 **\* Sec. 26. AS 44.88 is amended by adding new sections to read:**

12 **Article 9A. Interest in Oil and Gas Resources.**

13 **Sec. 44.88.800. Acquisition of interest in businesses.** (a) The authority may  
14 acquire, through purchase or other means, an interest in a lease held by a corporation  
15 or other business entity in an oil or natural gas field in the state that has been explored,  
16 but only if the authority determines the leaseholder has made reasonable efforts to  
17 obtain financing from the private sector to develop the lease and those efforts have, in  
18 whole or part, been unsuccessful. The authority shall exercise due diligence in  
19 acquiring a leasehold interest under this section.

20 (b) If the authority acquires a leasehold interest under this section, the  
21 authority may use the authority's assets, as appropriate, to aid in the development of  
22 the oil or natural gas field in which the business entity has a leasehold interest.

23 **Sec. 44.88.810. Alaska resource development fund.** (a) The Alaska resource

1 development fund is established in the authority for the purpose of developing oil and  
2 gas resources, and consists of appropriations to the fund. The authority shall manage  
3 the fund and may create separate accounts within it. Income of the fund or of  
4 enterprises of the authority shall be separately accounted for and may be appropriated  
5 to the fund.

6 (b) The authority may use money from the fund to carry out the purpose of the  
7 fund set out in (a) of this section.

8 \* Sec. 27. AS 44.88.900(10) is amended to read:

9 (10) "project" means

10 (A) a plant or facility used or intended for use in connection  
11 with making, processing, preparing, transporting, or producing in any manner,  
12 goods, products, or substances of any kind or nature or in connection with  
13 developing or utilizing a natural resource, or extracting, smelting, transporting,  
14 converting, assembling, or producing in any manner, minerals, raw materials,  
15 chemicals, compounds, alloys, fibers, commodities and materials, products, or  
16 substances of any kind or nature;

17 (B) a plant or facility used or intended for use in connection  
18 with a business enterprise;

19 (C) commercial activity by a business enterprise;

20 (D) a plant or facility demonstrating technological advances of  
21 new methods and procedures and prototype commercial applications for the  
22 exploration, development, production, transportation, conversion, and use of  
23 energy resources;

24 (E) infrastructure for a new tourism destination facility or for  
25 the expansion of a tourism destination facility; in this subparagraph, "tourism  
26 destination facility" does not include a hotel or other overnight lodging facility;

27 (F) a plant or facility, other than a plant or facility described in  
28 (D) of this paragraph, for the generation, transmission, development,  
29 transportation, conversion, or use of energy resources;

30 (G) a plant or facility that enhances, provides for, or promotes  
31 economic development with respect to transportation, communications,

1 community public purposes, technical innovations, prototype commercial  
2 applications of intellectual property, or research;

3 (H) a plant or facility used or intended for use as a federal  
4 facility, including a United States military, national guard, or coast guard  
5 facility;

6 (I) infrastructure for an area that is designated as a military  
7 facility zone under AS 26.30;

8 (J) development of an oil and gas field by providing  
9 working or venture capital in exchange for an equity interest;"

10

11 Renumber the following bill sections accordingly.

12

13 Page 23, line 15:

14 Delete "26"

15 Insert "29"

16

17 Page 23, line 18:

18 Delete "25"

19 Insert "28"

20

21 Page 23, line 24:

22 Delete "25"

23 Insert "28"

24

25 Page 23, line 31:

26 Delete "22 - 24, and 26"

27 Insert "22 - 27, and 29"

28

29 Page 24, line 2:

30 Delete "sec. 30"

31 Insert "sec. 33"

**AMENDMENT**

OFFERED IN THE SENATE

BY SENATOR FRENCH

TO: SB 21

1 Page 12, following line 31:

2 Insert a new bill section to read:

3 **\*\* Sec. 14. AS 43.55.023(f) is amended to read:**

4 (f) A producer or explorer may apply for a tax credit for a well lease  
5 expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE]  
6 after December 31, 2012 [JUNE 30, 2010], as follows:

7 (1) notwithstanding that a well lease expenditure incurred in the state  
8 [SOUTH OF 68 DEGREES NORTH LATITUDE] may be a deductible lease  
9 expenditure for purposes of calculating the production tax value of oil and gas under  
10 AS 43.55.160(a), unless a credit for that expenditure is taken under (a) of this section,  
11 AS 38.05.180(i), AS 41.09.010, AS 43.20.043, or AS 43.55.025, a producer or  
12 explorer that incurs a well lease expenditure in the state [SOUTH OF 68 DEGREES  
13 NORTH LATITUDE] may elect to apply a tax credit against a tax levied by  
14 AS 43.55.011(e) in the amount of 20 percent for a well lease expenditure incurred  
15 in the state north of 68 degrees North latitude and 40 percent for a well lease  
16 expenditure incurred in the state south of 68 degrees North latitude [OF THAT  
17 EXPENDITURE]; a tax credit under this paragraph may be applied for a single  
18 calendar year;

19 (2) a producer or explorer may take a credit for a well lease  
20 expenditure incurred in the state [SOUTH OF 68 DEGREES NORTH LATITUDE] in  
21 connection with geological or geophysical exploration or in connection with an  
22 exploration well only if the producer or explorer

23 (A) agrees, in writing, to the applicable provisions of

1 AS 43.55.025(f)(2); and  
2 (B) submits to the Department of Natural Resources all data  
3 that would be required to be submitted under AS 43.55.025(f)(2)."  
4

5 **Renumber the following bill sections accordingly.**

6  
7 **Page 13, line 3:**

8 **Delete "south of 68 degrees North latitude"**  
9 **Insert "[SOUTH OF 68 DEGREES NORTH LATITUDE]"**

10

11 **Page 13, line 6:**

12 **Delete "south of 68 degrees North latitude"**  
13 **Insert "[SOUTH OF 68 DEGREES NORTH LATITUDE]"**

14

15 **Page 23, line 15:**

16 **Delete "Sections 2, 5, 6, 22 - 24, and 26"**  
17 **Insert "Sections 2, 5, 6, 23 - 25, and 27"**

18

19 **Page 23, line 17:**

20 **Delete "Sections 3 and 21"**  
21 **Insert "Sections 3 and 22 of this Act"**

22

23 **Page 23, line 18:**

24 **Delete "Sections 7, 11, 13, 14, and 25"**  
25 **Insert "Sections 7, 11, 13 - 15, and 26"**

26

27 **Page 23, line 20:**

28 **Delete "Sections 9, 10, 12, 15, and 20"**  
29 **Insert "Sections 9, 10, 12, 16, and 21"**

30

31 **Page 23, line 24:**

1 Delete "Sections 3, 7, 11, 13, 14, 17, 21, and 25"

2 Insert "Sections 3, 7, 11, 13 - 15, 18, 22, and 26"

3

4 Page 23, line 31:

5 Delete "Sections 1, 2, 5, 6, 9, 10, 12, 15, 20, 22 - 24, and 26"

6 Insert "Sections 1, 2, 5, 6, 9, 10, 12, 16, 21, 23 - 25, and 27"

7

8 Page 24, line 2:

9 Delete "sec. 30"

10 Insert "sec. 31"

Testimony  
Senate Resources Committee – Tax Reform  
February 20, 2013  
By  
Dave Harbour, Publisher  
Northern Gas Pipelines

Twenty years of tax and investment climate stability began in Alaska with a press conference on March 18, 1981, along with associated legislation. I would ask you to enter this video link of the press conference to your record in this proceeding:  
<https://vimeo.com/10293150>.

This new era of tax and investment climate stability followed about a decade of annual tax increases as Alaskans struggled to define the 'fair share' of oil and gas revenues that would have them achieving their constitutional mandate to maximize natural resource benefits.

**The press conference featured: Governor Jay Hammond, Senator Jay Kerttula (Senate President), Senator Don Bennett, Senator Ed Dankworth, Representative Jim Duncan (House Speaker), Representative Hugh Malone, Representative Sam Cotton and Representative Tony Vaska.**

Together they announced that with bi partisan legislation (i.e. which they jointly supported) they had achieved for Alaska a "fair share" of oil revenues: 30%. In fairness, we should note that the general sentiment seemed to be that Alaska's share should not be 'less than 30%'. Citizens should also understand that while this group of officials made a decision and established a tax policy, such action does not automatically bind future legislatures to adopt or maintain the same policy. A student of government would also appreciate that while government policies may be changed, *the degree that they remain stable or unpredictable affects the reliability of the investment climate and the resulting inflow of investment.*

The first ten years of Y2K resulted in a very large, retroactive industry production tax (i.e. severance tax) increase, contentious debates among taxpayers and tax authorities, a return to tax instability and lack of clarity for investors who were considering gas pipelines and other projects. By 2013, Alaska's undiversified operating budget has become 90% dependent on oil revenue. Therefore, the fact that the Trans Alaska Pipeline System (TAPS) is nearly 3/4 empty and becoming further depleted at a rate of about 7% annually has put the social and economic future of our state in significant jeopardy. (Detroit has become fiscally insolvent and has lost over half its population, as reported this week. Part of its problem is an unfunded pension liability exceeding \$6 billion; Alaska's unfunded pension liability, with a population similar to Detroit's, is over twice that of Detroit.)

Compounding Alaska's Post-Y2K anti-investment message was a 'natural gas reserves tax' voters' initiative sponsored by several Alaska lawmakers. The initiative failed in 2008, but its sponsors vowed to support it in upcoming election cycles.

Last year, legislators began talking of new, anti-industry legislation that would convert the State's oil and gas income tax from an 'apportionment formula' to a 'separate accounting' income tax. The 1981 press conference documented in the [video](#), memorializes the Legislature's and Governor's successful effort to repeal a "separate accounting" income tax experiment that resulted in a lawsuit the government felt it would lose. While changing from "separate accounting" back to "apportionment", among other things, the Legislature increased the severance tax from 12.25% to 15%, including an economic limit factor to encourage production from depleting fields. Such stability led to much more oil production than the proven reserves (i.e. 9.6 billion barrels) upon which the original field development and Trans Alaska Pipeline System investments were based.

Alaska production is now dropping quickly as production blooms in competitive oil and gas regions. At the time of the 1981 press conference, Alaska was America's leading oil producing state, transporting about 2 million barrels per day through TAPS. The 49th State was providing the United States with about 20% of all domestic oil production. Now, Alaska provides less than half of domestic oil production and has fallen from its position as top domestic producer to 'also-ran' status behind North Dakota, Texas and possibly even California.

Thus, as Alaska had by 2008 become among the most costly places to engage in the oil and gas business, it had also become one of the most risky venues for new investment based on its uncertain initiative process and its unreliable--if not hostile--tax and regulatory policies.

Much of the anti-investment climate atmosphere here flows from a highly disciplined cadre of environmental activists. Some, but not all, labor unions oppose tax reform and seem to be more interested in short term, tax-revenue-supported, [Davis-Bacon](#) capital projects than in [the State's long-term, economic sustainability](#).

Many private sector citizens and organizations have confronted this challenge but with the Obama Administration also executing a withering array of regulatory and lease sale policies and attacks, hope for free enterprise nourishment from Federal land activity in and around Alaska is also uncertain.

If asked what course of action to follow, in view of my observations over the last several decades, **I would suggest that the Legislature and Governor:**

1. Take appropriate steps to make Alaska a more competitive oil producing state and investment destination, by

2. Clarifying, simplifying and stabilizing Alaska's tax structure.
3. **I further recommend that decision makers:** recognize and appreciate Alaska's competitive **liabilities**, including: remoteness to the markets, high logistical costs, high labor costs, climactic and volcanic risk, added cost of pipeline and tanker transportation, etc., and
4. Recognize the **strengths** of competitors, almost all of whom have lower labor costs, great resource potential, are closer to markets (i.e. and, are mostly located near transportation hubs or at tidewater), operate in friendlier climates (i.e. many of which are tropical), have experienced and less expensive labor forces, have shorter logistical chains, and
5. That they carefully evaluate competing oil and gas jurisdictions using various tools, including statistical surveys performed by organizations like the Fraser Institute, and
6. That they agree on an oil and gas taxing regime that puts Alaska, statistically, in the low median range<sup>1</sup> of our competitors -- in the eyes of investors -- and
7. That they seek a way to offer guaranteed tax regime stability for one to two decades, perhaps by boldly creating a constitutional amendment permitting the Legislature more flexibility when trying to develop Alaska's resources in a world full of aggressive competitors.

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To follow energy-related economic and energy activity in Alaska, rely upon: [northerngaspipelines.com/content/today-important-anniversary-29-years-ago-today-alaskas-leaders-defined-fair-share-oil-and-ga](http://northerngaspipelines.com/content/today-important-anniversary-29-years-ago-today-alaskas-leaders-defined-fair-share-oil-and-ga)

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<sup>1</sup> "Low median" placement is intended to compensate for the non-statistical liabilities noted under 3. above.

Testimony of Resource Development Council for Alaska to  
Senate Resource Committee,  
Regarding SB21  
February 18, 2013

Good evening, Madam Chair Giessel and members of the committee. My name is Rick Rogers, Executive Director of the Resource Development Council. RDC is a diverse statewide business association representing forestry, oil and gas, mining, tourism, and fishing industries.

Stop the give away! The real give away is the oil locked in the ground because we're simply looking at maximizing short-term tax revenue at the expense of encouraging investment and production. Consider that since 2007 we have lost over 210 million bbls. of production, with a gross value at point of production of over \$17 billion<sup>1</sup>. If a less aggressive tax regime could cut our decline rate in half, over 8 billion new dollars would be circulating in our economy. The give away is giving away our future for short term and clearly unsustainable tax revenue.

Some of the most vocal proponents of production tax reform among our membership are from those not directly involved in the oil and gas industry. The business community is fearful what continued TAPS throughput decline will do to our economy as a whole.

The Governor has shown leadership in outlining four guiding principles that we firmly support: fairness to Alaskans; encouraging new production; simplification and durability over the long term.

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<sup>1</sup> Production from table C-2a, real 2012 dollar values from tablesB-1a 2012 DOR Revenue Sourcebook

The discussion needs to be how to encourage more production, a more long-term view. Taxing ourselves to prosperity is not a strategy. We remain concerned that the legislative process will result in a tax policy that is too timid and does not encourage substantive investment. We urge you to keep your eyes on the prize, more investment leading to more production. It is of utmost importance that such a meaningful tax reform bill passes this session.

So in closing on this President's day I leave you with two quotes that I hope can help guide your deliberations, not from Washington or Lincoln, but from Lyndon Johnson and Calvin Coolidge.

LBJ said, "The most dangerous thing you can do to any businessman in America is keep him in doubt and to keep him guessing on what our tax policy is."

Coolidge said, "The method of raising revenue ought not impede the transaction of business, it ought to encourage it."

That concludes my comments, thank-you for hearing from me on behalf of RDC.



## Interior Alaska – The “Place” To Do Business

100 Cushman St., Suite 102 | Fairbanks, Alaska 99701-4665  
ph (907) 452-1105 | fax (907) 456-6968 | www.FairbanksChamber.org

February 20, 2013

Good Evening, members of the Senate Resources committee; thank you for the opportunity to testify this evening. For the record, my name is Lisa Herbert and I serve as the Executive Director for the Greater Fairbanks Chamber of Commerce.

The Chamber represents over 700 businesses and organizations throughout the Interior of Alaska. Our primary purpose is business advocacy but our mission is to promote and ensure a healthy economic environment for the greater Fairbanks area so that it can remain an attractive place for both business and community.

One of the Chamber's top critical priorities this legislative session is to encourage increased oil production by encouraging the legislature and the administration to establish competitive investment opportunities through taxation and regulatory policies that will facilitate additional oil exploration, development and increased production, therefore reversing the dramatic, decline of throughput in the pipeline. The need exists now to take the steps necessary to ensure the health and viability of the Trans-Alaska Pipeline.

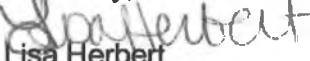
The Chamber supports the Governor's four key guiding principles for tax reform:

- 1) That it must be fair to Alaskans;
- 2) That it must encourage new production from ALL sources;
- 3) That it must be simple; and
- 4) That it must be durable for the long term and keep Alaska competitive

For the last three years, thousands of business owners, employees and residents have testified before the legislature or submitted comment cards supporting reform of Alaska's oil tax policy to make our great state more competitive. We support continuation of vetting the Governor's bill and exercise due diligence to reform oil taxes in a fair, meaningful way. We will remain engaged with you all as the bill moves through the legislative process. We encourage you to continue the dialogue surrounding the guiding principles for tax reform.

On behalf of the Chamber's Board of Directors and membership, thank you for your leadership on this critical issue facing our state. I appreciate the opportunity to comment here tonight on behalf of the businesses and organizations that make up the Fairbanks Chamber of Commerce.

Sincerely,

  
Lisa Herbert  
Executive Director

### INVESTORS

#### DIAMOND

BP Exploration  
ConocoPhillips  
ExxonMobil  
Fairbanks Daily News-Miner  
Fairbanks Memorial Hospital & Denali Center  
Flint Hills Resources Alaska  
Mt. McKinley Bank  
Santina's Flowers & Gifts

#### PLATINUM

Alyeska Pipeline Service Co  
Doyon, Limited  
Fred Meyer Stores  
Golden Heart Utilities  
Wells Fargo Bank Alaska

#### GOLD

Alaska Railroad  
Birchwood Homes  
Carlson Center  
Denali State Bank  
Design Alaska  
Doyon Utilities LLC  
First National Bank Alaska  
Kinross Fort Knox Mine  
Lynden  
MAC Federal Credit Union  
Northrim Bank  
Sumitomo Metal Mining Pogo LLC  
Usibelli Coal Mine

#### SILVER

ACS  
Alaska Airlines  
Alaska USA  
Dr. Christopher Henry – Henry Orthodontics  
Everts Air Cargo, Everts Air AK  
Exclusive Paving/Univ. Redi-Mix  
Fairbanks Natural Gas  
Flowline Alaska  
GCI  
General Teamsters Local 959  
GVEA  
Hale & Associates, Inc  
JL Properties, Inc  
Key Bank  
Personnel Plus  
Sam's Club  
Shell Exploration & Production Co  
Spirit of Alaska FCU  
Tanana Valley Clinic  
TDL Staffing  
Totem Ocean Traller Express, Inc  
Tower Hill Mines-Livengood Gold Project  
University of Alaska Fairbanks  
Verizon Wireless  
WAL-MART Stores, Inc  
Yukon Title Company

Good evening. I appreciate this opportunity to speak to the committee.

I am Cynthia Henry. I live in Fairbanks, and have no affiliation with any oil company or any of the stakeholders on the North Slope. I have owned and managed a retail business for more than 30 years. Even though we have no connection to the oil industry, my company and my family depend on a healthy Alaskan economy. I am here to support and encourage your work on new oil tax legislation that will make Alaska competitive again.

The decline in throughput in the pipeline indicates a problem with Alaska's current tax policy – with ACES. It is a basic business tenet that if you are selling something, and you are not competitive, your customers will go somewhere else. That's exactly what has happened with the oil industry in Alaska.

I will close by urging you to move the legislation forward to ensure it passes this session. I fear that waiting longer could have dire consequences.

Thank you.

Cynthia Henry  
Fairbanks, AK  
District 4

**From:** Linda Leary

**Sent:** Monday, February 18, 2013 3:56 PM

**To:** Sen. Cathy Giessel; Sen. Fred Dyson; Sen. Peter Micciche; Sen. Click Bishop; Sen. Lesil McGuire; Sen. Anna Fairclough; Sen. Hollis French

**Subject:** Support for SB 21

Dear Chair Giessel and members of the Senate Resource Committee,

I am writing in support of SB 21 regarding increased oil production. My support comes from my business experience in running a company, Carlile Transportation, which relies on revenue from the oil and gas industry –not just producers but the support companies that accompany them as well. This is not our only slice of the pie in Alaska; however, I and our 650 employees are gravely concerned over the course of this industry as we plan for our own futures. It represents an extremely important industry and market for us.

As a state, we need to be competitive for investment dollars in a world market. When we are looking at changing our tax structure we need to keep in mind that these companies are competing with markets all over the world. They have the option of coming or going –we want them here!

The Governor's proposal supports fair progressivity. This is a must for a win- win situation.

Alaska's tax policy needs to encourage investment in legacy fields, as well as new fields. The Governor's proposal encourages this new production. It takes an average of 5-7 years to reach production when an exploration well is successful. It doesn't just happen overnight. We don't have time to keep waiting.

Tax policy changes of the past have certainly had a reduction effect on new revenues. Three out of every four dollars being spent currently, are on repairs and maintenance instead of enhancements. We should be able to say the opposite is true and we can. Change the tax structure to be fair and encourage new production for the long term.

The oil left in the legacy fields such as Prudhoe and Kuparuk requires significant investments to recover it, and we need it, to fill the pipe. The short term work going on is nice, but for the long term viability of The State, bottom line is we need to increase production.

It is more important to our children and grandchildren than to us. That is what legacy is all about. Now is the time to take action and create a plan that is sustainable for the long term.

Our managers at Carlile are reading a book titled *A Sense of Urgency*, in the book author John Kotter stresses the importance of "a determination to move, and win, now." It is an ambitious determination to push beyond the obstacles. I ask, with urgency, that you support SB 21. We need this win for Alaska, our economy, our citizens and generations to come.

Regards,

Linda Leary

President

Carlile Transportation Systems

CEA Ak Testimony  
Senate Resources Committee – Tax Reform  
February 18, 2013

Thank you, Madam Chair for allowing public comment on tax reform. My name is Steve Pratt, Executive Director of Consumer Energy Alaska, a regional chapter affiliated with the national Consumer Energy Alliance. We believe there are several reasons why we need to look at tax code revisions:

Business and residential consumers of energy have a direct interest in consuming competitively priced energy supplied from domestic sources, and also have a direct interest in robust overall economic activity to maintain livelihoods.

According to the Alaska Institute for Social and Economic Research, at least 30% of working Alaskans are dependent upon oil and gas exploration and development for employment.

Unfortunately, oil production has declined from a peak of over 2 million barrels a day to a little over 500 thousand barrels, and is in freefall at the rate of 5 - 7% per year. Remarkably, these declines have occurred during times of high and increasing oil prices.

Alaska is capable of making a substantially greater contribution to U.S. domestic oil production and gross domestic product than it does today.

Madam Chair, a sustainable increase of only 500,000 bbls/day from today's levels, at \$100/bbl., would add \$1.5 Billion per month to overall U.S. economic activity. It might also reduce the export of 1.5 Billion U.S. consumer dollars per month to OPEC nations.

Developing Alaska's abundant natural resources and oil production potential are vital to the energy security of the entire nation as well as the state.

However, new exploratory and development drilling is both a risky enterprise and necessary to stem the decline in Alaska oil production. Just as Alaska North Slope natural gas will need to compete globally if it is to secure export markets, Alaska needs also to compete globally for investment dollars. Your work here can enable that ability.

The rates and progressivity structure of Alaska's current tax regime provide a disincentive to attracting risk capital to the state as evidenced by declining production during times of high oil prices. Increased prices have resulted in substantial increases in oil production in other locations around the United States, but not in Alaska, and not because more oil is not available.

Increased investment through increased global competitiveness will enhance Alaska's ability to fulfill its constitutional mandate to develop natural resources for the maximum benefit of the people.

Alaska's remoteness from the markets, Arctic climate, high labor and logistical costs argue for a more competitive tax and regulatory structure.

Consumer Energy Alliance – Alaska is in favor of the Alaska State Legislature reviewing and approving revisions to the Alaska Tax Code that ~~would~~ improve the investment climate in Alaska.  
*will*

Something is terribly wrong and I thank you, Madam Chair and members of the Senate Resources Committee, for taking on the task, with the Governor, of coming up with useful changes.

~~Pioneer  
Armstrong  
Brooks Range~~  
~~Pie Growing Necessary~~  
~~Co Investment Model~~  
*Fair  
Necessary  
Simple  
Durable*

**GOOD EVENING MADAAM CHAIRMAN AND MEMBERS OF THE SENATE RESOURCE COMMITTEE – THANK YOU FOR GIVING THE PULIC THE OPPORTUNITY TO TESTIFY THIS EVENING.**

**MY NAME IS GAIL PHILLIPS; I AM A FORMER MEMBER OF THE LEGISLATURE AND AM SPEAKING TONIGHT ON MY BEHALF AND ON BEHALF OF MY YOUNG GRANDSONS.**

**I SUPPORT THE WORK THIS COMMITTEE IS DOING ON TRYING TO FIND A REASONABLE AND LONG-TERM SOLUTION TO OUR OIL TAX CONFLICT. WHEN I SERVED IN THE LEGISLATURE, WE WERE FORTUNATE IN THAT WE HAD A STABLE TAX REGIME AND DIDN'T HAVE THE GRAVE ISSUE OF SERIOUSLY DECLINING OIL PRODUCTION THAT YOU FACE TODAY. AT THAT TIME, WE DIDN'T HAVE TO WORRY ABOUT ALASKA'S COMPETITIVE STATURE IN THE WORLD MARKET – WE WERE STRONG AND PRODUCTIVE AND COMPETITIVE.**

**TODAY, ALASKA'S STANDING IS TOTALLY DIFFERENT. IT IS UP TO YOU TO SET POLICY THAT WILL INSURE A COMPETITIVE REGIME THAT WILL TURN THINGS AROUND AND MAKE US ONCE AGAIN A LEADER IN OIL PRODUCTION.**

**FINDING A LONG-TERM SOLUTION TO AN ECONOMICALLY-BENEFICIAL TAX POLICY IS CRITICALLY IMPORTANT TO ALASKANS – ESPECIALLY THOSE OF US WHO, LIKE MANY OF YOU, HAVE CHILDREN AND GRANDCHILDREN HERE WHO WE HOPE WILL BE ABLE TO MAKE THEIR HOMES AND HISTORY IN ALASKA.**

**I RESPECTFULLY URGE YOU TO "STAY THE COURSE" AND FIND A WORKABLE SOLUTION THAT WILL CHANGE THE CURRENT ACES LAW THIS SESSION. I PERSONALLY DO NOT BELIEVE WE HAVE MUCH TIME LEFT BEFORE IT WILL BE TOO LATE TO TURN THE DECLINE CURVE AROUND AND MAKE ALASKA COMPETITIVE ONCE AGAIN.**

**THANK YOU FOR YOUR ATTENTION AND TIME.**

**February 20, 2013**

**To the Members of the Senate Resources Committee,**

**I'm Doug Schwartz, employee of Arrowhead Transfer, agents for Alaska Marine Lines and Lynden Transport. I simply want to state my support for a fair oil tax reform. In my opinion, Alaska needs to be #1 again in oil production!**

**Doug Schwartz**

**Box 19**

**Wrangell, Alaska 99929**

**907-874-3314**

**Cell: 907-305-0383**

# 70 & 148, LLC

• 1421 Blake Street • Denver, CO 80202 •  
Phone 303-623-1821 • Fax 303-623-3019

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February 20, 2013

Senator Cathy Giessel  
The Alaska State Legislature Senate  
State Capital Room 427  
Juneau, AK 99801

Re: Senate Bill 21

Dear Chairperson Giessel,

Thank you for the opportunity to testify to the Senate Resources Committee concerning Senate Bill 21. I would like to commend your committee on its diligence in assessing the key issues surrounding increasing activity and production on the North Slope of Alaska.

70 & 148, LLC (hereinafter referred to as "Armstrong") is a strong supporter of Governor Parnell's Senate Bill 21 and his efforts to increase production on the North Slope. Armstrong supports the Governor's proposal to offer a more equitable tax policy for the legacy fields as this will provide the quickest new barrels on the North Slope, however as we are not a working interest owner in any legacy field, we feel it is inappropriate for us to comment on this portion of the bill.

We do feel that the bill does need some modifications in order to place Alaska in a more competitive position relative to the rest of the U.S. and other producing provinces around the world. As such we would recommend the following modifications:

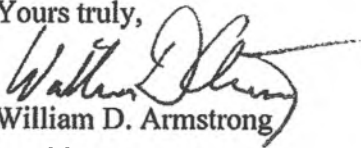
1. Keep the Qualified Capital Expenditure Credit and the cash purchase of the same in place until January 1, 2015. This will allow those projects that are based on a business plan that incorporates this concept time to transition more smoothly to the new system.
2. Extend the ability to utilize the Loss Carry Forward Credit from ten (10) years to fifteen (15) years. We believe this is very important given how long it takes to:  
a) sanction a project for development, b) successfully drill and complete wells on the North Slope and c) bring production on line.
3. Increase the Gross Revenue Exclusion for new fields from twenty percent (20%) to twenty five percent (25%). This will assist new entrants economics in overcoming the high costs and long lead times associated with getting a new project sanctioned.

Please note we believe that this is the minimum the legislature should do to incentivize new production on the North Slope. The activity level on the North Slope will be driven by the oil and gas production tax and ease of permitting for projects. Further any accommodation made for

new field development will result in a gain in revenue for the state as currently the state is receiving no revenue in these areas.

Armstrong thanks you for the opportunity to comment on Senate Bill 21. We look forward to the passage of meaningful tax reform which will pave the way for us and our partner to work towards sanctioning developments which will boost the state's revenue, increase the life of TAPS and provide high paying jobs for Alaskans.

Yours truly,

A handwritten signature in black ink, appearing to read "William D. Armstrong", with a long horizontal flourish extending to the right.

William D. Armstrong

President

February 20, 2013

To the Members of the Senate Resources Committee,

My name is Ron Rice. I would like to see the Governor's Bill require some specific performance from the oil companies to qualify for the lower tax. I want to see increase in dollars invested in Alaska. Big oil already has tax credits.

Increasing oil production is a function of oil demand not lower taxes.

Ron Rice

Box 1451

Wrangell, Alaska 99929

907-874-4242

3521 Andree Drive  
Anchorage, AK 99517

February 20, 2013

**RE: Testimony to Senate Resources Committee on SB 21**

Madame Chair Giessel and Senators on the Committee:

My name is Peter J. Stokes a professional petroleum engineer working for Petrotechnical Resources of Alaska.

Thank you for your service and for letting me and others of the public testify on this important piece of oil tax reform that is needed to increase investment and new production in Alaska.

I live and work in Anchorage. I am on the Board of the Alliance and Chair of the UAF's CEM Advisory and Development Council.

I am testifying on behalf of myself, my wife, my 3 offspring who work in Anchorage and my 2 grandsons and their future.

I grew up on the Kenai Peninsula, went to college in Fairbanks and have worked in oil and gas, starting in Alaska, with jobs in other states and overseas and working for the last 10 years in Anchorage.

I support the Governor's concepts to make Alaska more competitive in attracting increase investments to increase Alaska North Slope production and I urge passage of legislation to make meaningful reforms this year.

Mr. Bill Armstrong, of Armstrong Oil and Gas made some compelling arguments on Monday explaining why there isn't more drilling activity in exploration in the state.

Senate Bill 21 is a good start to achieve this goal, especially the elimination of progressivity but modifications should include:

- 1) Ensure that there is no "increases" in tax (or government take) in changing ACES for existing producers for price ranges from \$50-90 per barrel.
- 2) Incentivize development within existing PA's by making more new oil production eligible for GRE credit. These existing PA's are the areas that can bring the quickest and largest increases in production.
- 3) Allow new explorers to continue to sell loss credits generated from exploration prior to production. Taking away this ability will negatively impact those that are currently exploring as it will change the terms which were used to attract exploration funding, it will significantly increase the cost of exploration, and in the unsuccessful case will mean that credits are not redeemable, thus changing the economic risk and rewards of exploration in Alaska. Without these new explorers, the production growth from exploration outside of the existing units will not occur, as Armstrong and Brooks Range Petroleum have testified.

In summary, I applaud you in your efforts to allow Alaska to become more competitive in investments for new oil production for both explorers and existing producers. Without new exploration and the continued development of new production within existing PA's, the efforts to lower or flatten production decline will likely not occur.

Madame Chair and Senators, thank you again for all of your efforts.

Testimony (as prepared) delivered to Senate Resources Committee

Chair Senator Cathy Geissel

The 28th Alaska State Legislature, 1st Session

Good Evening Chair Geissel and committee members. I am *Ivalu* Eric Fox, Vice President of Operations for Camp Services at NMS, a NANA Development Corporation subsidiary. NANA Development Corporation is the business arm of NANA Regional Corporation, owned by the 12,500 Iñupiaq people who originated in Northwest Alaska. I am proud to call myself one of them. I started working for NANA as a security officer 20 years ago on the North Slope. I take great pride in being an owner/shareholder of my employer.

I support changes in Alaska's oil tax structure to bring more business to the NANA subsidiaries that work in the oil industry in Alaska, which in turn brings economic opportunities to NANA's shareholders.

As you all are aware, unemployment is a problem in most of the 11 villages in our Region, as it is in most of rural Alaska. As a shareholder and a manager at NANA, I work to provide opportunities to people from my home region. I take NANA's mission, to improve the quality of life for our people seriously. I am here to represent the interests of my company, my Region and my people. The tax structure that was passed in 2007 is having a negative impact on all of them.

NANA began working on the North Slope not long after the passage of the Alaska Native Claims Settlement Act. NANA Oilfield Services Inc. or NOSI and NANA Management Services have been serving the industry for over thirty five years. More recently, companies like NANA Worley Parsons have designed and engineered new North Slope facilities and NANA Construction is building modules for use in Alaska's oilfields.

My company, NMS, sees the direct impact from the growth, or lack of growth, of the oil and gas industry in Alaska.

A major part of our mission is to provide employment and career advancement for NANA shareholders. I am an example of the NMS' commitment in this area. Nearly a quarter of our workforce is Alaska Native. We work with the oil industry to provide air transportation for NANA shareholders to travel from their villages to North Slope jobs. Any contraction of the oil industry reduces work opportunities and earnings for our entire workforce but especially Alaska Natives living in rural Alaska. As the oil and gas industry declines, so do opportunities for Alaska Natives to work close to home.

Oil industry investment fuels the contracts for the NANA companies, and the jobs those contracts create. We are seeing those opportunities going to places in the Lower 48 – like North

Dakota and Texas – where the oil industry is booming. In fact, NMS has opened a Houston office to pursue work in Texas. Alaska’s investment climate is driving away business. We do not have a lack of oil in Alaska. We have a lack of investment.

We have heard that the industry has billions of dollars in projects that could be done in Alaska if the tax structure was more competitive – projects that would increase oil production but more importantly, projects that NMS and the other NANA companies have the skills, experience, and people to carry out. We’d like a chance to do that.

Chair Geissel, thank you for this opportunity. I would be pleased to answer any questions.

**ConocoPhillips Alaska**  
**Senate Resources Committee**  
**CSSB21 – February 25, 2013**

Madam Chair, members of the committee, for the record my name is Bob Heinrich, and I am the Vice President of Finance for ConocoPhillips Alaska. I want to thank the committee for inviting ConocoPhillips to provide brief testimony today on the committee substitute adopted this past Friday. While we have not had time to do an in-depth analysis, we do have some initial thoughts we would like to share.

First, we appreciate the committee's efforts to incorporate the feedback and testimony of those who have come before the committee. We understand the committee's desire to develop an oil and gas production tax framework that fits with the governor's principles for oil tax reform. Namely, reform that is fair to Alaskans, encourages new production, is simple and balanced, and is durable.

In our prior testimony, we have advocated for changes to ACES that eliminates progressivity; that creates a flat tax rate over a broad price range; and that provides the business climate to attract investment and overcome Alaska's inherent cost disadvantages. The committee substitute introduced Friday moves towards achieving several of these goals. In particular, the CS clearly has resulted in a relatively flat tax rate with only a slightly progressive nature over a broad price range – something we view as a positive step.

The increase in the GRE and the ability to apply the GRE to production from expansions of participating areas within existing units is also positive. However, at this point, we have not yet had time to fully evaluate the impact on potential projects.

We do have a few areas of concern, however. As your consultants showed you in their analysis on Friday, the CS under consideration remains a tax increase relative to ACES at lower price levels. That could be fixed by decreasing the base rate, which we are concerned is too high. Also, even though the overall level of government take, as estimated by Econ One, appears to be in the ballpark with the average government take in other jurisdictions, the question remains whether that will be enough to compensate for the high costs in Alaska. We have not done enough analysis to tell you if we can answer that question from ConocoPhillips' point of view. The answer is likely to be different for every company given each company's differences in cost structure, economic hurdle rates, and suite of opportunities.

Our comments today have been brief as requested and have focused on those elements of the bill that are of most interest to ConocoPhillips. We appreciate the opportunity you have provided today to present our initial impressions.

We look forward to working with the legislature as the governor's bill continues through the committee process.



**Repsol E&P USA Inc.**

**Statement on Proposed Alaska Senate Bill CS SB 21 (RES.)**

**To the Senate Finance Committee**

**March 6, 2013**

Repsol E&P USA Inc. is the US upstream operating subsidiary of Repsol S.A., an integrated international oil and gas company headquartered in Madrid, Spain, with exploration and production activities in 31 countries worldwide. It is now the 15th largest petroleum refining company in the world according to the Fortune Global 500 list, and employs over 25,000 people worldwide.

Repsol strongly supports Governor Parnell's efforts to improve the investment climate for the North Slope and endorses CS SB 21 (RES.) (the "Bill"). We welcome the opportunity to present this statement of our views and opinions of CS SB 21 (RES.). This statement reflects the specific views of Repsol based on its own perspective as a new entrant to the North Slope that is engaged in the discovery and development of new fields in Alaska.

The most salient aspect in our view, and one that is shared with our co-members of AOGA and much of the rest of Alaska, is the undeniable decline in production from Alaska's North Slope and the negative impact that this will have on the continued viability of what is arguably currently one of Alaska's main assets, TAPS, the Trans-Alaska Pipeline System. Regardless of one's view of how long TAPS can continue to operate without action to increase production, the tremendous negative impact of the loss of TAPS cannot be denied. The State must actively seek ways to encourage additional production.

*Repsol E&P USA Inc.  
2001 Timberloch Suite 3000  
The Woodlands, TX 77380  
Tel: 832-442-1000  
[www.repsol.com](http://www.repsol.com)*

Repsol is a new player on the North Slope. We came to the North Slope in 2011, after many years of reviewing numerous opportunities and turning them down. We considered the North Slope to be an especially promising area that has shown to be oil rich and with lower exploratory risk than other regions. It is an area that met Repsol's objectives to balance our exploration portfolio with lower risk, in onshore oil opportunities in a stable environment, preferably in OECD countries. Offsetting these positive aspects were the extreme climate, and a short exploration season in a remote, expensive and environmentally sensitive area with little established infrastructure. The biggest negative factor, however, was a tax system that did not encourage long-term investment. Repsol has invested in offshore Alaska, both in the federal waters of the Beaufort Sea where we have interests in 71 blocks and the Chukchi Sea where we have 93 blocks. However, with regards to investment in onshore state lands, we found that in all but the best scenarios, the progressive nature of the ACES petroleum tax structure did not allow for returns that were competitive with opportunities in the lower forty-eight states or other parts of the world.

This view changed in early 2011 when it appeared that serious reform of the ACES tax structure would be enacted. House Bill 110 was introduced on the 18th of January, 2011. Repsol viewed the terms of the proposed HB 110 favorably and we were convinced that the State of Alaska was serious about providing the necessary incentives for new investment. We were also convinced that if we waited for meaningful tax reform to be enacted, we would risk being lost in the rush of companies to Alaska to invest in North Slope exploration and development projects. By the 7th of March, 2011, Repsol completed negotiations to secure its North Slope position and announced its entry into the State of Alaska lands through a partnership with Armstrong Oil and Gas and GMT Exploration.

The process of meaningful oil and gas tax reform has continued over the last two years. Repsol firmly believes that Governor Parnell's new proposal now before the Senate Finance Committee as CS SB 21 (RES.), addresses many of the

shortcomings of ACES that were causing Alaska to be uncompetitive in attracting oil and gas investment. First and foremost, it proposes to remove the progressive nature of ACES which is what deterred investments in Alaska at the very time that investment was being stimulated in other states by rising oil prices. It is counterintuitive that Alaskans would want investment to leave their state and go to North Dakota, Texas, California or Oklahoma as oil prices increased, yet that is exactly what ACES encourages. Repsol believes that Alaska should reap the benefits of higher oil prices, but that the increase should be shared fairly and that investors should be encouraged to invest more, rather than less, as prices increase. Repsol and other companies have long argued that the current progressive tax structure is detrimental to new investment in Alaska and we endorse the repeal of progressivity that is proposed in CS SB 21 (RES.).

Repsol and other companies look to benefit from several tax credits, namely the Qualified Capital Expenditure Credit, or QCE credit, the Small Producer Credit and the Exploration Credit. These credits have encouraged newcomers like Repsol to come to Alaska in what would otherwise be an unattractive investment climate. The credits have the effect of reducing our initial capital investments in the early phases of investment, especially during the exploration phase. With these credits, Alaska was subsidizing our initial investment in return for a larger piece of future production revenues for Alaska, if any. In essence, the taxpayers of Alaska were partially insuring and mitigating our potential losses from an unsuccessful exploration program in order to stimulate more exploration and to develop marginal fields that might otherwise be uneconomical to develop. The credits have certainly encouraged Repsol and its partners to enter into a robust exploration program that will result in total investments of some half billion dollars in our North Slope leases by year end of 2013. The credits do not, however, encourage long term developments of any discovery when those developments must compete against developments in states with more favorable tax regimes. These credits help to reduce the cost of coming to Alaska, but we invest in exploration with the expectation that we can have a long term, economical development of any discovery. Oil companies must consider the full life cycle

economics of a project when making investment decisions, not just the early economics of exploration. While the credits have encouraged exploration, in most cases they are not enough to offset the negative aspects of progressivity when considering the full life cycle economics of development and production, which are the stages where more intensive investment and job creation occur. We are encouraged that the Bill proposes the extension of the Small Producer Credit and the Exploration Credit. These credits will continue to motivate new players and new exploration. We would like to see the continuation of the QCE in some form, at least for the near term, but we recognize the tradeoff that is offered by the Bill. We must acknowledge that there are scenarios in which the terms of the Bill are less favorable to new developments. Those scenarios occur when oil prices are low. The threshold value will vary somewhat between companies, depending on their individual circumstances. While we would prefer that the Qualified Capital Expenditure Credits continue, we view that the value from elimination of the progressivity at higher oil prices will offset the protection offered at lower oil prices by the QCE credit.

Our analysis in the preceding paragraph is based on Repsol's individual circumstances. We understand that there could be situations besides low oil prices in which the continuation of the QCE will be more attractive for some investments than the elimination of progressivity will be. Some companies with limited access to capital, or those that are investing in marginally economic projects, may find that the QCE credit is preferable to the elimination of progressivity. This is not Repsol's case.

Repsol makes investment plans on a multi-year cycle, looking ahead more than one year at a time. Major investment decisions are based on full life cycle economics, as was our decision to invest in onshore North Slope exploration. Future investment decisions to develop any discovery will also be based on full life cycle economics that result from a number of assumptions including, among others, our forecast of the future price of oil. Our major investment decisions are based on our long term outlook for oil prices, capital costs, operating costs,

availability of investment capital and other major factors. We do not change those investment decisions based on short term price fluctuations, but only if our long term projections change. With Repsol's current forecasts, the provisions of the Bill are more favorable to Repsol for future investments and will encourage more investment than under the current terms of ACES.

Repsol views the "carry-forward annual loss" tax credit, with compounding interest rate, as a positive step to address the loss of the buy-back of QCE credits by the State. However, Repsol has concerns about the proposed 10 year "shelf life" of the carry-forward annual loss, especially given that we will no longer be allowed to transfer those credits to other companies. In many cases, it may take an oil company more than 10 years from initial investment in exploration until significant production revenues are earned to claim the credits. Repsol views the 10 year limitation on use of the credits as too restrictive and strongly encourages the legislature to increase the period of time that an investing company may use these credits to 15 years or to allow transfer or sale of the unused credits to other taxpayers.

As stated earlier, the positions in this statement represent the views of a newcomer to the North Slope. While Repsol has a favorable opinion of the Bill, we must not forget that new production is not the only contributor to TAPS throughput. We have not attempted to analyze the Bill from the perspective of the established producers. We encourage and support the State to continue its efforts to incentivize increased production from the existing legacy fields. This production is vital to maintaining sufficient oil volumes in the pipeline. Legacy producers, new explorers such as Repsol, and all Alaskans need and want the same thing – increased production in TAPS.

Repsol is pleased that Governor Parnell has taken steps to address many of the concerns that Repsol has with the Alaska tax structure under ACES. While we believe that there is still substantial room for improvement, overall the proposed bill is a viable cornerstone for tax reform that we consider significant and meaningful in returning Alaska's competitiveness for investment opportunities.

The proposed reform is fair to Alaskans and will encourage more production as well as investment. The proposed Bill goes a long way to simplify what was a very complex tax regime and it will restore a balance in which the State and the companies investing in Alaska will both benefit from in the longer term. Alaskans will see more investment in the North Slope if CS SB 21(RES.) is passed and signed into law. This additional investment can only lead to more oil in TAPS, and in the long term, more revenue for Alaska and more high paying jobs for Alaskans. Our hope is that the legislature and all Alaskans will see the wisdom in this approach to North Slope investment.

Thank you.

## Senate Resources Testimony in Support of SB 21; Committee Substitute

My name is Deborah Brollini, I'm a 37 year Alaska and I am testifying on behalf of myself, and my two children Lyndsey, and Van. I would first like to thank the committee for their work on SB 21 the Governor's oil tax reform bill. Although I may not agree with all the committees' decisions... I do respect the process, and Alaskans can be proud of the due diligence Senate Resources is taking regarding oil taxes because 710,000 Alaskans livelihoods are at stake.

I was pleased to learn that the Competitive Review has been included as a committee substitute to SB 21. It has been something that I've been advocating for several years now and I am encouraged that this might be the year that a Competitive Review board is implemented, and that we can start making sound business decisions rather making decisions based on politics and emotions.

I am supportive of the Competitive Review because it takes the politics out of the debate. I visited with Ben Parks last spring who is the former CEO of Boeing. Boeing won the national Baldrige Award for manufacturing excellence under his leadership. Ben Parks now resides in Homer. I asked him whether or not the state's natural resources could be managed by a Baldrige model, and if a Competitive Review Board could manage, and make recommendations on what is in the best interest of the state in terms of our oil and gas resources. His answer was an overwhelming yes.

The reason it was a yes is because data is not personal. When we look at this country's well data the only thing that we can get worked up about... is that North Dakota, Texas and California are kicking our behinds. The well data is not personal. It is my hope that a Competitive Review will help lawmakers make long-term business decisions, and provide my children with a future they deserve.

Again, I appreciate your due diligence and including the Competitive Review as part of your committee substitute. Thank you.

SRES 2/20/13

KODIAK --- Charlie Powers  
RDC

PRO Incentives are changing, Kodiak is joining  
bus leaders, industry (interconnected)

SEWARD --- Skip Peterson

concerned, AK needs to claim place as oil  
producer

FOLKS

MIKE Leonard

PRO SB 21, Gov Parnell's 4 pts plus commitment  
to AK hire

Dan Finney Teamsters 959

PRO SB 21, solid future to Alaskans, AK hire,  
new prod, bal

Carl Colby  
Working Alaskans

TAPS decline 1/4 of capacity, taxes put us  
uncompetitive, AK will be 5th

PRO SB 21

Jim Plaquet AK Supports Indus Alliance

AK has 6 rigs, other states much more  
ACES makes decline.

compete for investment dollars

Pbks

Roger Burgraff

Pro SB 21

oil comps are going elsewhere

Robert Tott Local 1243

con SB 21

Price for oil will return to revenue, ACES can be treated  
BP is in harvest mode

Cynthia Henry

unaffiliated, owned & managed a co

Pro SB 21

decline in throughput is bad  
waiting longer could be bad, pass this session

Lisa Hebert

FCinamber

priority to incr oil prod

Anch

Rick Pollock

Rick Canoy Teamsters 959

jobs are affected by SB 21

SB 21 is good start

encourage

tax structure prices out of market

Anch

John Dickens self  
 live in Bethel  
 AK on edge of fin apocalypse  
 Prob w/ socialism - Thatcher  
 Caps have shareholders  
 Why would ones go here  
 Pro SB 21, may be too lit'l too late

Eric Fox VP for NANA management services  
 support changes to taxes  
 D7 Tax is having neg impact on AK & NANA

Priscilla Simmons  
 grad from E. high  
 My gen is concerned by decline

Kennath Caron

Rachel Petro AK chamber  
 AK chamber pro meaningful oil tax reform  
 plus local chambers echo, make AK competitive  
 Pro SB 21

Graham Green  
 things we can control w/out growth  
 resist mini depression, current structure is  
 uncompetitive

1800

OFFNET

Jim Ayes

worked for KNOLES worked w/ oil producers  
there is no indication

Support direction

Anch

Gary Dixon Team Local 959

make us competitive again

Carl Portman

support meaningful tax reform to reverse  
oil prod.

new investment will help econ, revenue

jobs connected to oil

Aces is broken

SB 21 is step in right dir

Paul Friese

From Wasilla/Lyndon trans

oil & gas supports whole state

Brian Hove

Make sure opp for other gen

Support SB 21, get into prob solving

Paul Galvinovich

native AK, concern for state econ

AK depends on oil rev, only high prices

have kept us from dipping into sav.

Anch

Katy Capozzi  
 decline in TAPS  
 CALIF will soon pass in AK prod  
 in this session pass reform

Rada Kradjinova  
 from RUS, 3 degrees from UAA, wants to  
 continue to work in AK, AK isn't  
 competitive, AK is a res. prod state.  
 want the golden goose to lay the golden  
 eggs  
 Pls. pass in current econ ops

MATSU

Jim Sykes  
 Palmer, drive to speak against SB 21,  
 ACES Net profits tax hasn't been audited,  
 progr'y gets better return from res  
 price not throughput  
 don't pass

Folks

Ron Johnson?

Offset Retired UAF Eng. faculty member, opp SB 21

~~Dave~~

Anch

Dave Harbour  
 in 1969 AK hadn't defined max benefit use  
 of resources, decension by oil co, tax adj  
 1981 gov Hammond,  $\frac{1}{3}$  fair rev  
 Leg. should analyze where we stand just  
 offset AK costs

Eagle Rv  
Offnet

Jim Falmer Eagle Rv CC

can't rely on high prices to maintain revenues  
need to max benefit of resources

Sen. Fairclough snow blowing

Mary Brahm

(Self, Eagle Rv CC)

Eagle Rv

Offnet

Support reeval of ACES to make,  
highest priority is ACES reform

Joe Henga

past prez of Eagle Rv CC

Eagle Rv

Offnet

support gov 4 key principles of SBA  
meets them. dev investment is down  
b/c of taxes & particularly prog. y.  
Short term tax & spend.

Eagle Rv

Offnet

John Sims (enog. cc)

concern about deline in oil

JNU

Stuart Cohen

agree w/ general things said.

SB 21 doesn't improve things

Anch

Pete Stokes

Petrotech Res AK

prod res dev.

ref Armstrong from Mon.

w/out more prod

Phillis Spencer - Belz

Small biz owner ASRC shareholders, tax breaks not fair, why not give them to Nat. corps. Sarcastic.

Rock Hengen

NANA achieved peak growth earlier in 2000s, difficult to keep employees, talent is leaving AK

Jason Brund

SB 21 doesn't go far enough Royalties are our share, Fam depends on TTP

Paula Easley 1845

excellent testimony. 1980s depressing stores closed, don't want that to happen again. Short term gain over long term pros is bad

Concluded 1846