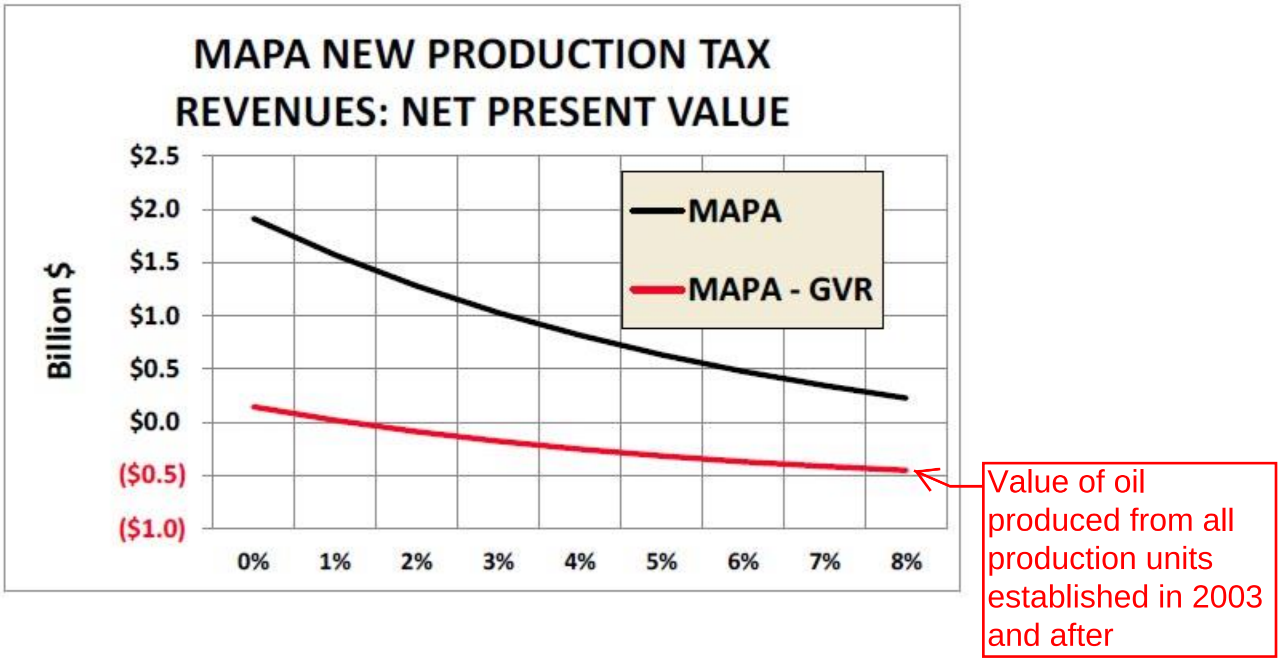
Pathway to Poverty: Why a Rewrite That Treats Alaskans as Equal Partners Is Needed

SB 21's Continuously Falling Tax Rate; Near Zero or Negative "Net Present Value" of Post-2002 Oilfield Units; A 0% Tax Rate Experiment Didn't Work Last Time

Rep. Les Gara

(Document Sources: State Of Alaska; Goldsmith Report Sections Not Discussed In the $10+ million Ad Blitz)



Source: Scott Goldsmith Report, May 2014, p. 19 (red line represents oil in all fields unitized after 2003)

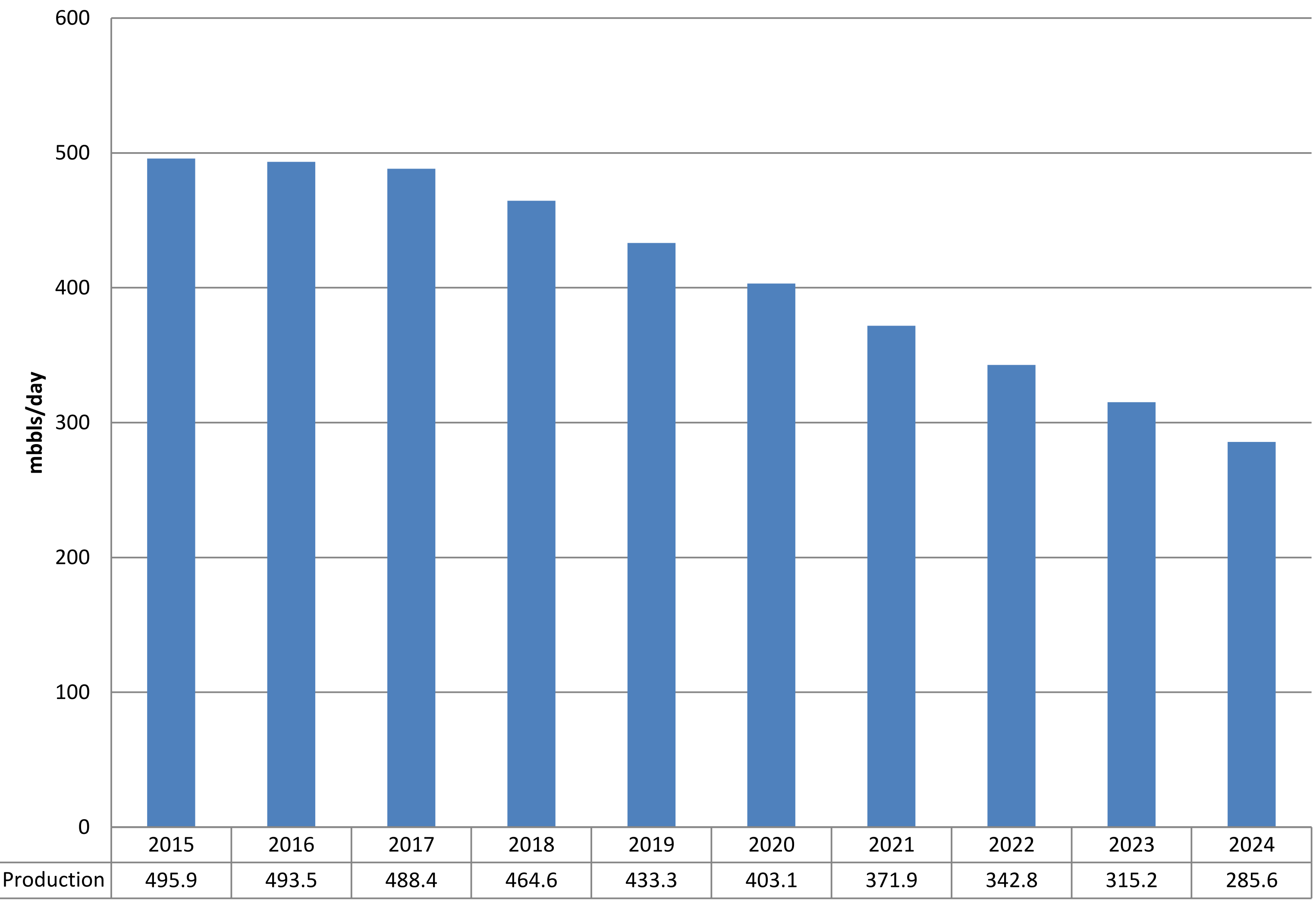
SB 21 Tax Rate Cut in Half for Every Field Unitized After 2003

AS 43.55.160(f)

“When production began the effective tax rate would be about 23%, unless the incremental production were eligible for the Gross Value Reduction (GVR), in which case the effective tax rate would be about 13%.”

- Scott Goldsmith Report, May 2014, p. 19

SB 21's Falling Oil Production



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Production	495.9	493.5	488.4	464.6	433.3	403.1	371.9	342.8	315.2	285.6

Sources: April 2014 Revenue Sources Book; February 2014 OMB 2024 Forecast

Market conditions in the previous thre years, shown as diamonds in the next figure, clearly resulted in higher revenues under ACES than would have been the case with MAPA. In those years the ACES revenue advantage was between $1 billion and $2 billion compared to MAPA.[xii]

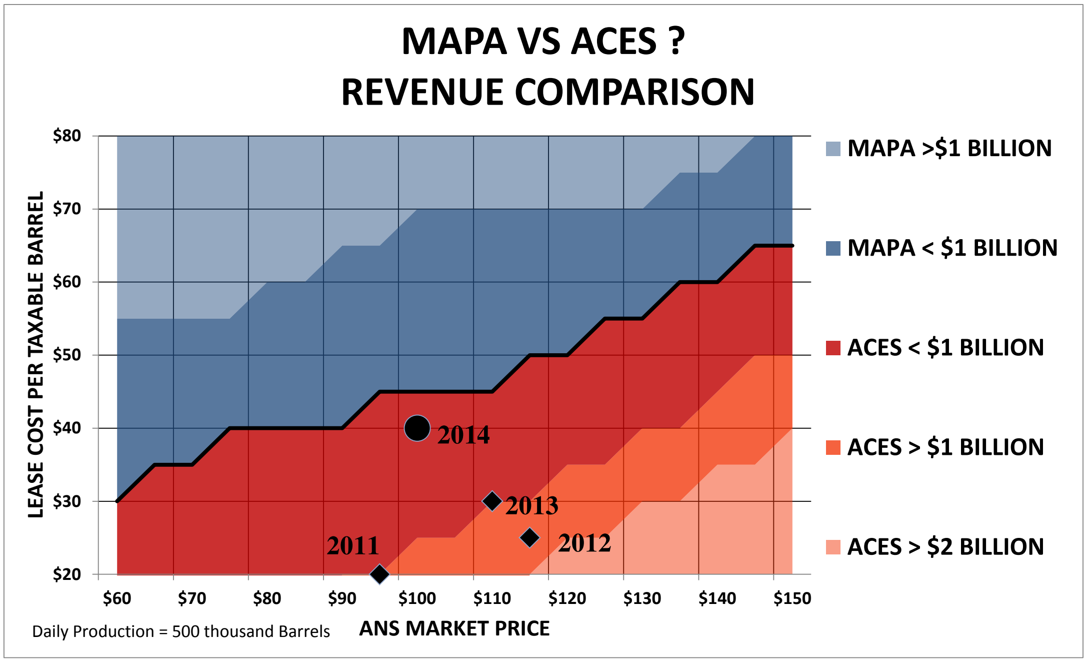


Table 2: Effective Production Tax Rates, by North Slope Field, FY 2006			
Field	Nominal Rate (AS § 43.55.011)	Economic Limit Factor (Annual Average)	Effective Rate (Annual Average)
Prudhoe Bay Unit	15%	0.85646275	12.8469%
Lisburne	15%	0	0
Niakuk	15%	0	0
West Beach	15%	0	0
North Prudhoe Bay	15%	0	0
Kuparuk	15%	0.0036615	0.0549%
Tarn	15%	0.00025325	0.0038%
Tabasco	15%	0	0
Meltwater	12.25%	0	0
West Sak	15%	0	0
Milne Point	15%	0	0
Schrader Bluff	15%	0	0
Sag River	15%	0	0
Endicott	15%	0	0
Sag Delta	15%	0	0
Eider	15%	0	0
Badami	15%	0	0
Alpine*	13.85%	0.856458917	11.8620%
Northstar	12.25%	0.72241975	8.8496%

NOTES: In January 2005, the Department of Revenue aggregated seven fields in the Prudhoe Bay Unit (PBU). Fields aggregated with Prudhoe Bay are Aurora, Borealis, Orion, Polaris, Midnight Sun, and Pt. McIntyre. Analysis performed under 2005 PBU ELF Aggregation regulations.
*Alpine's nominal tax rate was 12.25% until December 2005, when it became 15%.
Amendments filed in the future may change data shown here.
SOURCE: Jennifer Duval, petroleum economist, Tax Division, Department of Revenue, 907.269.1025.

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

Just Giving Away Revenue Doesn't Work:

Pre-ACES – Low Taxes Didn't Stop Alaska's 5 - 8% Production Decline

~ Under the old system, called "ELF", most huge fields by the end of 2006 paid a near 0% production tax, and no field paid more than a 13% flat gross tax.

ELF Near 0% Tax Fields

Field	Rank Among U.S. 100 Largest Fields	Annual Production (barrels)	FY '06 Production Tax Rate
Kuparuk	2nd largest in U.S.	51,100,000	0.81 %
Milne Point (Milne Point Unit)	13th largest in U.S.	9,490,000	0 %
Endicott (Duck Island Unit)	27th largest in U.S.	8,395,000	0 %
West Sak (Heavy oil) (Kuparuk River Unit)	39th largest in U.S.	10,950,000	0.075 %
Tarn (Kuparuk River Unit)	67th largest in U.S.	8,030,000	0.0004 %
Niakuk (Lisburne Prod. Unit)	93rd largest in U.S.	2,920,000	0 %
Meltwater (Kuparuk River Unit)	94th largest in U.S.	4,015,000	0 %

** Prudhoe Bay aggregated fields included Polaris (57th), Orion (83rd), Borealis (44th) and Pt. McIntyre (28th)

Low Taxes, Same Production Declines

ACES passed November 2007

- 5.78 percent decline from 1998-2007
- 8.72 percent decline from 2004-2007

Total North Slope Production, FY 98– FY 07

(million barrels per day)

fy 1998	fy 1999	fy 2000	fy 2001	fy 2002	fy 2003	fy 2004	fy 2005	fy 2006	fy 2007
1.279	1.170	1.033	0.993	1.010	0.991	0.974	0.911	0.840	0.740

SOURCES: "Production C-2a: Crude Oil Production–History," *Revenue Sources Book,* Fall 2007, Fall 2008, Fall 2009, Tax Division, Department of Revenue.

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A-6 Production Differences from Fall 2012 Forecast

(Figure C-1 in Fall 2012 RSB)
(thousand barrels per day)

FY	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Spring 2013 Forecast										
Alaska North Slope	538.3	526.6	512.8	499.7	476.9	443.3	422.4	399.4	372.3	344.5
Cook Inlet	10.4	9.6	8.9	8.3	7.7	7.2	6.7	6.3	5.9	5.6
Total	548.7	536.2	521.6	508.0	484.5	450.4	429.1	405.8	378.3	350.1
Fall 2012 Forecast										
Alaska North Slope	552.8	538.4	518.6	499.7	476.1	442.9	421.6	394.8	365.9	338.5
Cook Inlet	10.4	9.6	8.9	8.3	7.7	7.2	6.7	6.3	5.9	5.6
Total	563.2	548.0	527.5	508.0	483.8	450.1	428.3	401.1	371.8	344.1
Volume change from prior forecast										
Alaska North Slope	-14.5	-11.8	-5.8	0.0	0.8	0.4	0.8	4.6	6.4	6.0
Cook Inlet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	-14.5	-11.8	-5.8	0.0	0.8	0.4	0.8	4.6	6.4	6.0
Percent change from prior forecast										
Alaska North Slope	-2.7%	-2.2%	-1.1%	0.0%	0.2%	0.1%	0.2%	1.2%	1.7%	1.7%
Cook Inlet	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	-2.6%	-2.2%	-1.1%	0.0%	0.2%	0.1%	0.2%	1.1%	1.7%	1.7%

Table C-1: Production Differences from Fall 2013 Forecast

(mbbls/day)

FY	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Spring 2014 Forecast										
Alaska North Slope	521.8	495.9	493.5	488.4	464.6	433.3	403.1	371.9	342.8	315.2
Non-North Slope	14.5	11.6	10.4	9.5	8.8	8.1	7.6	7.1	6.6	6.2
Total	**536.3**	**507.5**	**503.9**	**497.9**	**473.4**	**441.4**	**410.7**	**378.9**	**349.4**	**321.4**
Fall 2013 Forecast										
Alaska North Slope	508.2	498.4	487.6	482.7	459.5	429.1	399.6	368.8	340.1	312.9
Non-North Slope	13.5	11.6	10.4	9.5	8.8	8.1	7.6	7.1	6.6	6.2
Total	**521.7**	**510.0**	**498.1**	**492.2**	**468.3**	**437.2**	**407.2**	**375.9**	**346.8**	**319.1**
Volume change from prior forecast										
Alaska North Slope	13.6	-2.5	5.8	5.7	5.1	4.2	3.5	3.1	2.7	2.3
Non-North Slope	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**14.6**	**-2.5**	**5.8**	**5.7**	**5.1**	**4.2**	**3.5**	**3.1**	**2.7**	**2.3**
Percent change from prior forecast										
Alaska North Slope	2.7%	-0.5%	1.2%	1.2%	1.1%	1.0%	0.9%	0.8%	0.8%	0.7%
Non-North Slope	7.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	**2.8%**	**-0.5%**	**1.2%**	**1.2%**	**1.1%**	**1.0%**	**0.9%**	**0.8%**	**0.8%**	**0.7%**

Alaska Dispatch News

Published on *Alaska Dispatch* (http://www.adn.com)

Alex Demarban
June 23, 2014
Main Image Credit:
Main Image Caption:

A North Slope explorer relying on a generous tax credit offered under Alaska's previous production tax is moving forward to evaluate what it believes is a promising exploration play, with the drilling of two wells planned to start this winter.

Torey Marshall, chief executive of Rampart Energy, said he wouldn't wade into the debate over which is better, the state's old tax system or the new one that critics say favors existing producers over explorers. Supporters of the new law, Senate Bill 21, say it retains many similar benefits for small companies.

"It's a good way of getting yourself in trouble," said Marshall of the ongoing debate over which tax system most benefits Alaska and Alaskans, speaking by phone on Thursday from Adelaide, Australia.

But Marshall said the tax credit established under the old tax system, dubbed Alaska's Clear and Equitable Share or ACES, has provided the financial push the company needs to prospect for oil in Alaska, where the potential for a sizable find is big, at least for a small outfit like Rampart.

"Without ACES we couldn't participate," he said. "We're not the big guys, we take risks."

The new Senate Bill 21, implemented in January, has many benefits to encourage smaller companies like Rampart to invest in Alaska, said Mike Pawlowski, deputy commissioner for the Alaska Department of Revenue.

The tax credits offered under ACES allowed companies to recoup up to 45 percent of certain expenses, and Senate Bill 21 made sure to keep that level of reimbursement in place for two years, Pawlowski said. After the two years is up, the benefit falls to up to 35 percent, but small companies can cash in their credit more quickly and benefit from the new law's lower production taxes.

Rampart, a publicly traded company on the Australian stock exchange, came to Alaska in May of 2013.

Partnering with San Diego-based Royale Energy, Rampart recently completed a three-dimensional seismic survey on about 60,000 acres some 15 miles southwest of the village of Nuiqsut. The acreage is about 10 miles from a trio of other fields, such as ConocoPhillips' Greater Mooses Tooth Unit at the eastern edge of the National Petroleum Reserve Alaska.

At the moment, Rampart is zeroing in on a 20,000-acre section that showed intriguing "hydrocarbon indicators," perhaps oil or gas, said Marshall, an exploration geologist. The company is using consulting firm Netherland, Sewall and Associates to provide a third-party review of the acreage.

The company has contracted a rig through 2016 to drill the wells, an effort set to start in January, said spokesman Jay Morakis. The company announced this week it's teaming up with California-based Roth Capital Partners and is working to raise money for the drilling, Morakis said.

Marshall said the company hopes to discover an oil field containing 25 million to 50 million barrels, something in the range of what Brooks Range Petroleum plans to unlock later this year at its Mustang field, a 40-million-barrel pool with peak production expected to reach 15,000 barrels a day.

Those are small finds compared to the Slope's giant Prudhoe Bay and Kuparuk fields that have produced billions of barrels of oil over the decades. But such small fields may be the wave of the future in the Arctic oil patch.

The North Slope has long been explored, but it's generally been done with old two-dimensional seismic tests and drilling that has been widely spaced, said Paul Decker, resource evaluation manager for the Alaska Division of Oil and Gas.

Three-dimensional seismic testing like that conducted by Rampart can offer a more refined look that could lead to the discovery of small pools.

"The basin is what we'd still call relatively under-explored or not completely explored," said Decker. Compared to Texas, for example, Alaska has far fewer wells and they are widely peppered across the landscape, while seismic assessments of underground features are also relatively limited, he said.

The U.S. Geological Survey estimated in 2005 that the North Slope contained a mean of 4 billion barrels of undiscovered, technically recoverable oil. There could be dozens of midsize to small pools of oil with fewer than 64 million barrels, and perhaps one or two big fields with up to half a billion barrels of oil, according to the USGS' broad estimate.

Of course, whether such small fields are economic is another matter, Decker said. Some may be far from a pipeline, road or other infrastructure, and installing that infrastructure may be costly.

Marshall sounded optimistic, but cautioned that there's no certainty until wells are drilled.

"We feel it's something that's reasonably sizable," he said of the hydrocarbon potential. "It's quite big, it's quite broad, and we need to explore that properly."

By ALEX DEMARBAN
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Source URL: http://www.adn.com/node/1594781

Links:
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Source: Parnell Administration Fiscal Note Estimating Revenue Loss From SB 21 When Bill Passed, April 2013

FISCAL NOTE ANALYSIS #14

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. HCS CSSB 21(FIN)

Analysis Continued

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

Brief Description of Provision	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
1. Elimination of progressive portion of tax	-$725	-$1,400	-$1,725	-$1,875	-$1,650	-$1,525
2. Base tax rate changed to 35% of production tax value	$550	$1,050	$1,100	$1,100	$1,000	$925
3. Limitation of credits for qualified capital expenditures for North Slope	$300	$675	$650	$525	$475	$450
4. Net operating loss credit rate increased to 45% until 1/1/16 then 35%; transferable and refundable	Minimal revenue impact - see "Impact on Operating Budget"					
5. Gross revenue exclusion for oil production in new units and new or expanded participating areas	$0	$0 to -$25	-$25 to -$50	-$25 to -$50	-$25 to -$50	-$50 to -$75
6. Provision requiring credits be taken over 2 years eliminated[2]	-$225					
7. Amendment to the community revenue sharing fund	$0	$0	$0	$0	$0	$0
8. Credit of $5 per taxable barrel for GRE-eligible oil production	-$5	-$10	-$25	-$25	-$25	-$25
9. Sliding scale $0-$8 credit per taxable barrel for non GRE-eligible production based on oil price	-$420	-$815	-$750	-$725	-$675	-$650
10. Credit under AS 43.20 for qualified oil and gas industry expenditures	Indeterminate (possibly up to -$25 million annually)					
11. Reduced interest rate for late payments and assessments on most taxes	Indeterminate (possibly up to -$25 million annually, increasing over time)					
12. Removal of 3-mile requirement for frontier basin tax credit	$0	$0	$0	$0	$0	$0
13. Extends limitation on tax rate for Middle Earth from 2022 to 2027	$0	$0	$0	$0	$0	$0
14. Extends credits under AS 43.55.025(a)(1)-(4) for Middle Earth from 2016 to 2022	Indeterminate					
15. Establishes Oil and Gas Competitiveness Review Board	No fiscal impact for Tax Division					
Total Revenue Impact	**-$520 to -$570**	**-$490 to -$565**	**-$750 to -$825**	**-$1000 to -$1075**	**-$875 to -$950**	**-$850 to -$925**
Impact on Operating Budget of provision requiring credits be taken over 2 years eliminated	-$150					
Impact on Operating Budget of limitation to Qualified Capital Expenditure credit		$150	$150	$150	$150	$150
Impact on Operating Budget of increase in Net Operating Loss credits to 45% until 1/1/16 then 35%		-$80	-$80	-$40	-$40	-$40
Total Fiscal Impact - does not include potential revenue impacts from potential increases in production[3]	**-$670 to -$720**	**-$420 to -$495**	**-$680 to -$755**	**-$890 to -$965**	**-$765 to -$840**	**-$740 to -$815**

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

[2]Provision 6 above, which eliminates the requirement that credits be taken over 2 years is revenue neutral, and simply shifts the tax liability from future years to FY 2014. The total impact of that provision is $375 million, with $225 million taken against tax liability as a revenue impact and $150 million impacting the operating budget. The total fiscal impact consists of both revenue impacts and operating budget impacts of the bill.

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

STATE OF ALASKA
2013 LEGISLATIVE SESSION

BILL NO. HCS CSSB 21(FIN)

Analysis Continued

Differences in General Fund Unrestricted Revenue under Proposed Bill from Current Tax System in $Millions*

*Note: These hypothetical examples of additional production assess the impacts from the change in tax rates, per barrel allowance and gross revenue exclusions only and do not attempt to quantify impacts of other parts of the bill, such as the removal of the credit split, or the impact on the long-range budget from the elimination of QCE credits or changes to NOL credits. Values are generated from a scenario model and may vary slightly from other models.

At Forecasted Production

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$225	-$150	-$200	-$325	-$275	-$400
$100	-$275	-$250	-$325	-$475	-$375	-$450
$120	-$575	-$800	-$925	-$1,125	-$925	-$925

All additional production scenarios below compare additional production under the proposed bill to ACES without the additional production.

Additional Production Scenario A

Forecasted production plus 50 million barrel field developed by a New Entrant

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$225	-$150	-$200	-$325	-$275	-$375
$100	-$275	-$250	-$325	-$475	-$375	-$425
$120	-$575	-$800	-$925	-$1,100	-$900	-$900

Assumes field outside of a current unit and subject to 30% gross revenue exclusion, first oil in 2017 and peak production of 10,000 barrels per day in 2019. Total development cost of $500 million.

Additional Production Scenario B

With addition of 4 oil rigs to legacy fields drilling from 2014-2019

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$175	$50	$125	$50	$225	$25
$100	-$200	$25	$75	$0	$225	$50
$120	-$475	-$425	-$400	-$475	-$125	-$250

Assumes each oil rig drills 4 new production wells per year, with each well producing 1,000 barrels of oil per day beginning in FY 2014, with a maximum production rate of 60,000 barrels per day for a total of 140 million barrels. Development costs for each well assumed to be $20 million. None of this oil is assumed to qualify for the GRE under the provisions of this bill.

Additional Production Scenario C

With new well pad and 4 additional rigs in legacy fields, plus new 10,000 bopd field starting in 2017

Oil Price in $/barrel	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
$90	-$275	$0	$175	$300	$950	$725
$100	-$300	$0	$200	$350	$1,100	$925
$120	-$525	-$350	-$125	$125	$1,100	$925

Assumes new well pad within major North Slope unit producing a total of 125 million barrels of new production over an 8-year period starting in 2014 at total development costs of $5 billion, none of which is assumed to qualify for the GRE. Also includes scenario B above with 4 oil rigs in legacy fields and scenario A above with the addition of a new field.