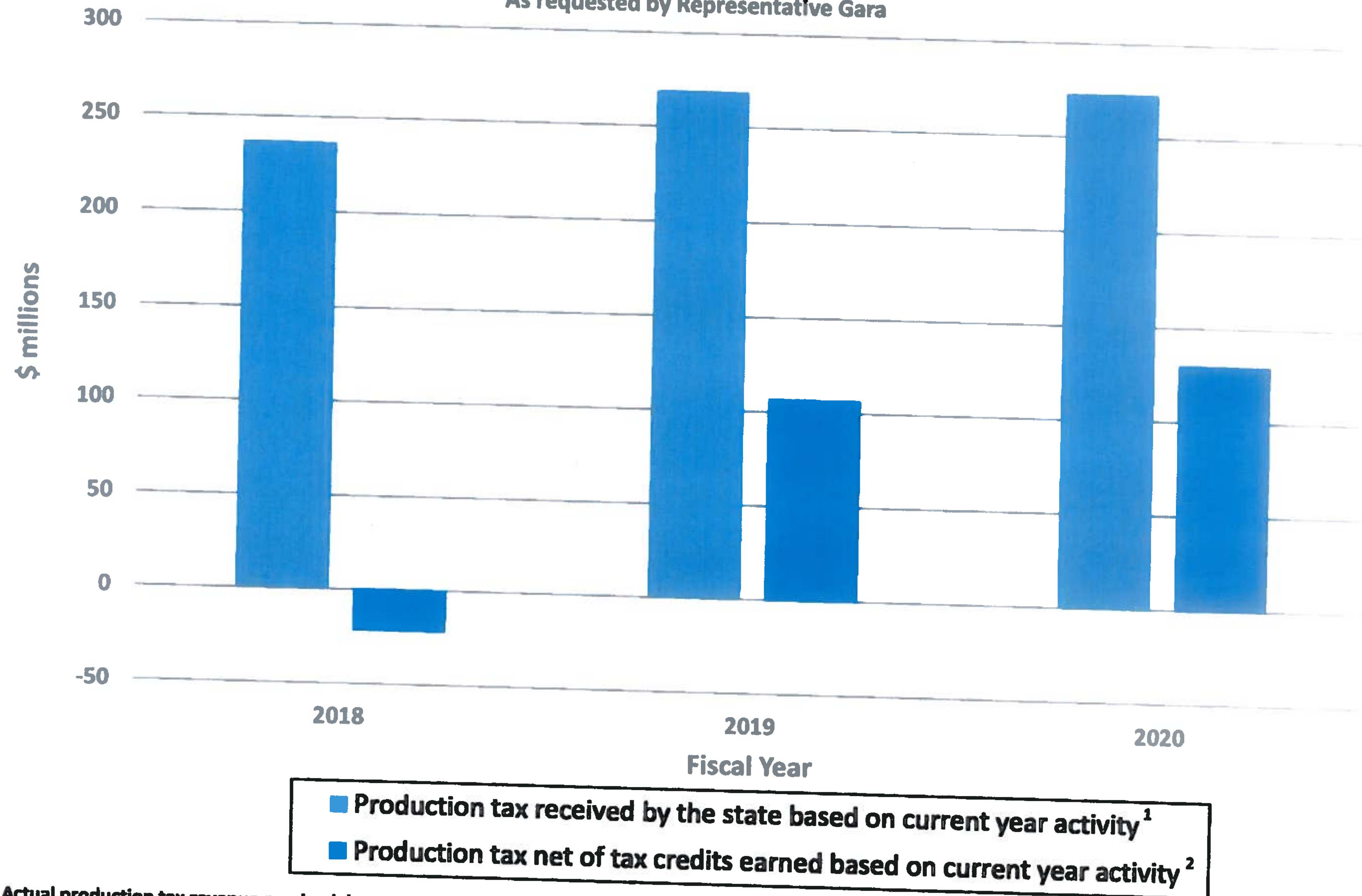
"The legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the state, including land and water, for the maximum benefit of its people."

Article 8, Section 2 of the Alaska Constitution

Title:	**Oil and Gas Tax Credits vs Production Tax, FY 2018 - FY 2020** For Representative Gara
Preparer:	Ky Clark, Economist, 465-8222 and Dan Stickel, Chief Economist, 465-3279
Date:	2/27/2017
Purpose:	To show production tax revenue received by the State and the production tax net of credits earned based on qualifying activity during the fiscal year.
Data Source:	Fall 2016 Revenue Sources Book, pgs. 24-25, 77-80, and supporting data/analysis
Key Assumptions:	Production tax amounts are total production tax revenues received by the State in the fiscal year after all credits against liability have been applied, but not including tax credits applied against liability that were based on activity in a previous fiscal year. "Credits earned" include credits earned for qualifying activity during the fiscal year. "Credits earned" are credits that will be available for state purchase or available to reduce tax liability, but may not necessarily be repurchased or applied against tax liability in the fiscal year in which they were earned. "Credits earned" are made up of credits from the North Slope and Non-North Slope areas, including Gas/LNG Storage and refinery credits under AS 43.20.
History:	This is the first version of this analysis and accompanying chart.
Disclaimer:	The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Oil and Gas Tax Credits vs Production Tax, FY 2018 - FY 2020

As requested by Representative Gara



[1] Actual production tax revenue received, but not including tax credits applied against liability that were based on activity in a previous fiscal year

[2] Production tax credits earned during the fiscal year that will be eligible for refund or application against a liability in a future year

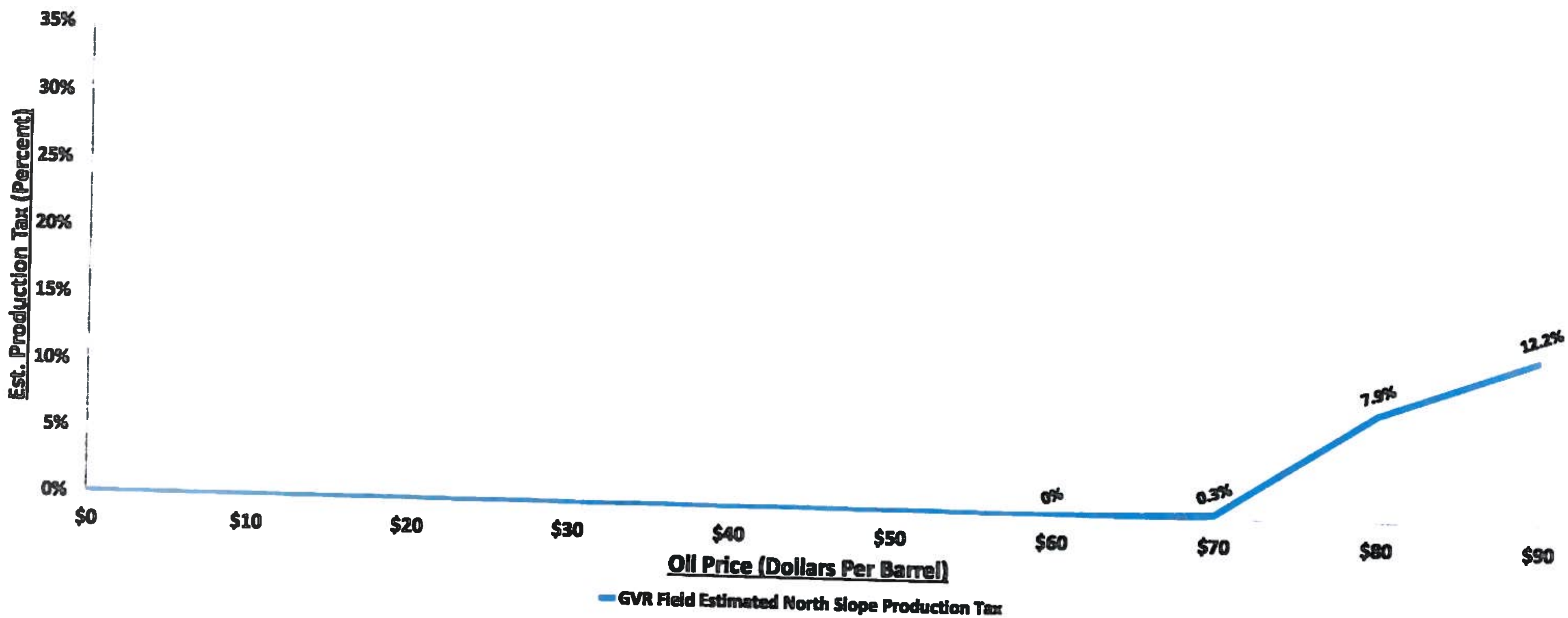
Oil and Gas Tax Credits vs Production Tax, FY 2018 - FY 2020

	$ Millions		
	Fiscal Year		
	2018	2019	2020
Production tax received by the state based on current year activity [1]	$ 237	$ 269	$ 273
Credits Earned - North Slope	$ 178	$ 125	$ 109
Credits Earned - Non-North Slope	$ 81	$ 37	$ 34
Credits Earned - Total	$ 259	$ 162	$ 143
Production tax net of tax credits earned based on current year activity [2]	$ (22)	$ 107	$ 130

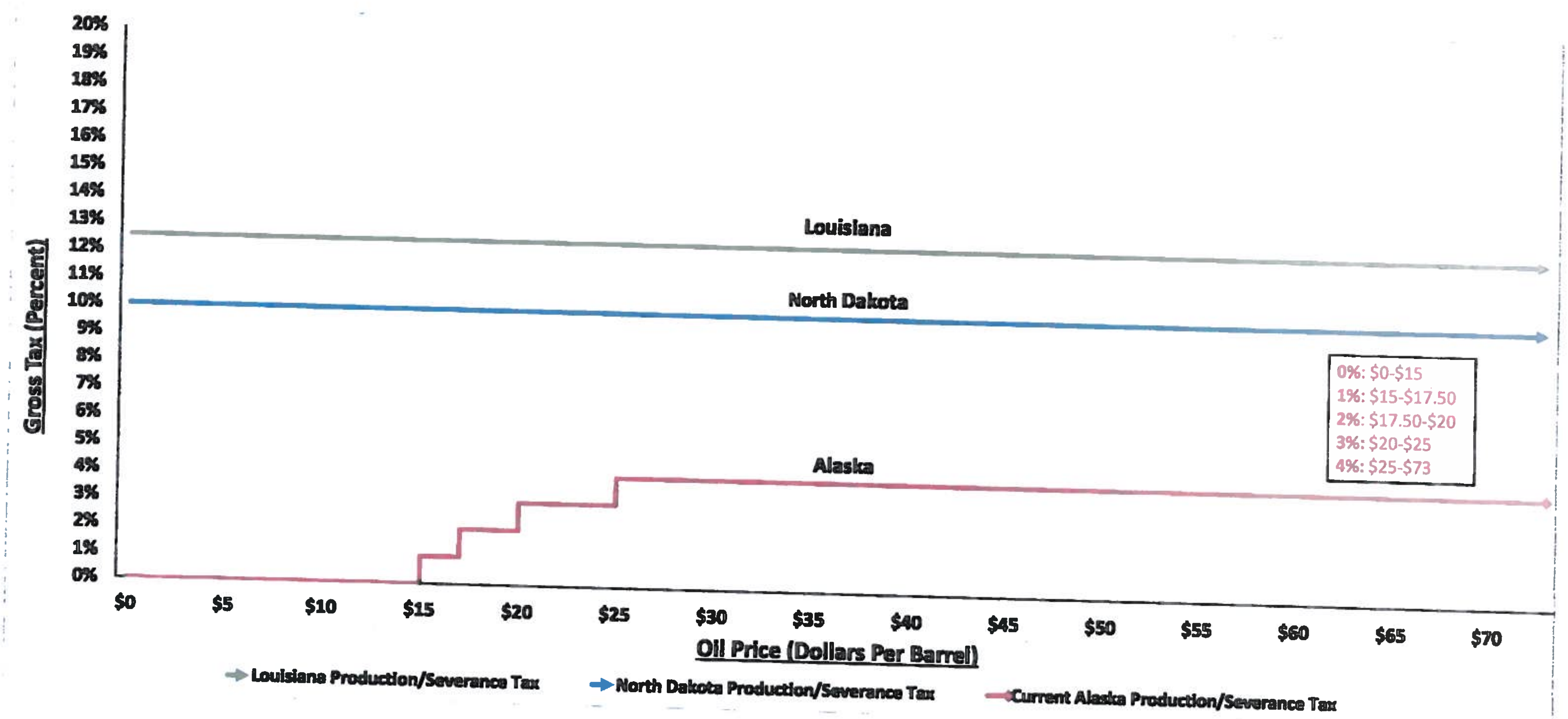
[1] Actual production tax revenue received, but not including tax credits applied against liability that were based on activity in a previous fiscal year

[2] Production tax credits earned during the fiscal year that will be eligible for refund or application against a liability in a future year

The 0% Oil Production Tax Problem: GVR Fields



The 4% Oil Production Tax Problem: Non-GVR Fields



THE STATE of ALASKA

GOVERNOR BILL WALKER

Department of Revenue

TAX DIVISION

Juneau Office
333 Willoughby Avenue, 11th Floor
PO Box 110400
Juneau, Alaska 99811-0400
Main: 907.465.2300
www.tax.alaska.gov

February 6, 2017

The Honorable Les Gara
Alaska State Representative
State Capitol Rooms 511
Juneau, AK 99801

Representative Gara,

This letter is in response to your email dated December 23, 2016, in which you requested updates to several questions regarding the state's oil and gas production tax. These questions were originally addressed in an analysis provided by the Department of Revenue in January 2016. We are only updating those questions from the 2016 analysis which have different answers due to changes in forecasted costs. The questions are restated in *italics* below and our answers follow.

Your email also inquired about the oil and gas production tax rates for several US states. In it, you referenced the 2015 report from the Competiveness Review Board (CRB). The Department of Revenue does not regularly track changes in tax regimes outside of Alaska. However, the CRB is actively engaged in an update to their 2015 report. This should be looking at the tax systems for the jurisdictions you're interested in. It's also my understanding that the review will be modeling several of the tax and credit proposals that have been introduced or debated over the past year.

1. *What is the approximate effective net profits tax rate (the percentage of net profits actually taxed) for GVR, and for Non-GVR discounted North Slope fields at the following prices: $60, $70, $80, $90, $100, $110, $120, $130, $140, and $150/bbl?*

   Please see table below for approximations of effective production tax rates on net value of some "typical" fields with specific assumptions. For this analysis, we assume a "typical" field with $9.77 per barrel transportation costs and $33.64 per barrel deductible lease expenditures. We do not account for credits other than the per-taxable-barrel credits. Note that due to the nuances in the tax calculation, these results may not exactly match the Fall 2016 forecast.

Effective Tax Rates on Net Value using Current Assumptions*

Oil Price	Non-GVR	20% GVR Eligible
$60	12.1%	0.0%
$70	9.1%	0.3%
$80	13.1%	7.9%
$90	20.0%	12.2%
$100	24.4%	15.0%
$110	27.5%	17.0%
$120	29.8%	18.4%
$130	31.5%	19.5%
$140	32.9%	20.4%
$150	34.1%	21.1%

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

2. *At what prices does the 35% tax rate kick in for non-GVR fields?*

3. *At what price does the profits tax fall so low that the 4% minimum gross tax becomes the tax rate?*

We interpret questions 2 and 3 to be related and we have reframed them as follows: For non-GVR fields, at what prices does the minimum tax of 4% of gross value at the point of production exceed the base tax of 35% of production tax value minus per-taxable-barrel credits? In other words, at what price point do non-GVR fields begin to lose their sliding scale per-taxable-barrel credits? And secondarily, at what price point do non-GVR fields lose <u>all</u> of their sliding scale per-taxable-barrel credits? We have answered these questions with the example below.

Using assumptions of $9.77 in transport costs and $33.64 per taxable barrel in deductible lease expenditures, applied to a typical field, we estimate that the minimum tax of 4% of gross value at the point of production exceeds 35% of production tax value minus sliding scale per-taxable-barrel credits at between $73 and $74 per barrel, for a typical field. This is illustrated in the calculation below.

Minimum Tax Threshold - Base Tax and Minimum Tax using Current Assumptions*	
West Coast Price ($/tax bbl)	$73.55
Transportation ($/tax bbl)	-$9.77
Wellhead Value ($/tax bbl)	$63.78
Lease Expenditures ($/tax bbl)	-$33.64
Net Value ($/tax bbl)	$30.14
Base Tax Rate (%)	x 35%
Base Production Tax before Credits ($/tax bbl)	$10.55
Sliding Scale Credit per-Taxable-Barrel ($/tax bbl)	-$8
Base Production Tax after credits ($/tax bbl)	$2.55
Minimum Tax Rate (%)	4%
Wellhead Value ($/tax bbl)	x $63.78
Minimum Tax ($/tax bbl)	$2.55

Base production tax after credits equals minimum tax at this price

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

Using the same assumptions for transportation costs and deductible lease expenditures, non-GVR fields are unable to apply any of the $8 per-taxable-barrel credit against tax liability at oil prices of $47.75 per barrel and lower. At this price, the base tax before credits equals the minimum tax. This is illustrated in the calculation below. The exact prices will vary depending on specific economics for different fields and producers.

Minimum Tax Equal to Base Tax before Credits, Current Assumptions*	
West Cost Price ($/tax bbl)	$47.75
Transportation ($/tax bbl)	-$9.77
Wellhead Value ($/tax bbl)	$37.98
Lease Expenditures ($/tax bbl)	-$33.64
Net Value ($/tax bbl)	$4.34
Base Tax Rate (%)	x 35%
Base Production Tax before Credits ($/tax bbl)	$1.52
Sliding Scale Credit per-Tax-Barrel ($/tax bbl)	xxx
Base Production Tax after credits ($/tax bbl)	$1.52
Minimum Tax Rate (%)	4%
Wellhead Value ($/tax bbl)	x $37.98
Minimum Tax ($/tax bbl)	$1.52

Base production tax before credits equals minimum tax, therefore no sliding scale credits can be used

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

4. ***What is the effective profits tax rate GVR fields pay at $30, $40, 50, and $60/bbl? When does that rate hit 0%?***

As shown in the answer to question 1 above, the effective tax rates on net value for 20% GVR-eligible fields reach 0% at oil prices of approximately $69 per barrel and lower for an illustrative field. The exact price will vary depending on specific economics for different fields and producers.

We hope you find this information to be useful. Please do not hesitate to contact me if you have questions or need additional information.

Sincerely,

Ken Alper
Tax Division Director

Three Ways to Obtain GVR Tax Reduction for Post-2002 Fields

(1) the oil or gas is produced from a lease or property that does not contain a lease that was within a unit on January 1, 2003;

(2) the oil or gas is produced from a participating area established after December 31, 2011, that is within a unit formed under AS 38.05.180(p) before January 1, 2003, if the participating area does not contain a reservoir that had previously been in a participating area established before December 31, 2011;

(3) the oil or gas is produced from acreage that was added to an existing participating area by the Department of Natural Resources on and after January 1, 2014, and the producer demonstrates to the department that the volume of oil or gas produced is from acreage added to an existing participating area.

Source: AS 43.55.160(f)

Average Break- Even Point for Active North Slope Producers:

$40.21

Source: Fall 2016 Revenue Source Book P. 118

The 4% Oil Tax Problem

Current Law

Price	
< or equal to $15	0
$15-17.50	1%
$17.50-20	2%
$20-25	3%
>$25-approximately $73	4%

North Dakota 10-11%

Louisiana 12.5 %

HB 133

Price	HB 133*
< $25	3%
$25-50	4%
$50-58	5%
$58-66	6%
$66- 74	7%
$74-82	8%
$82-90	9%
>$90	10%

* Except for heavy oil

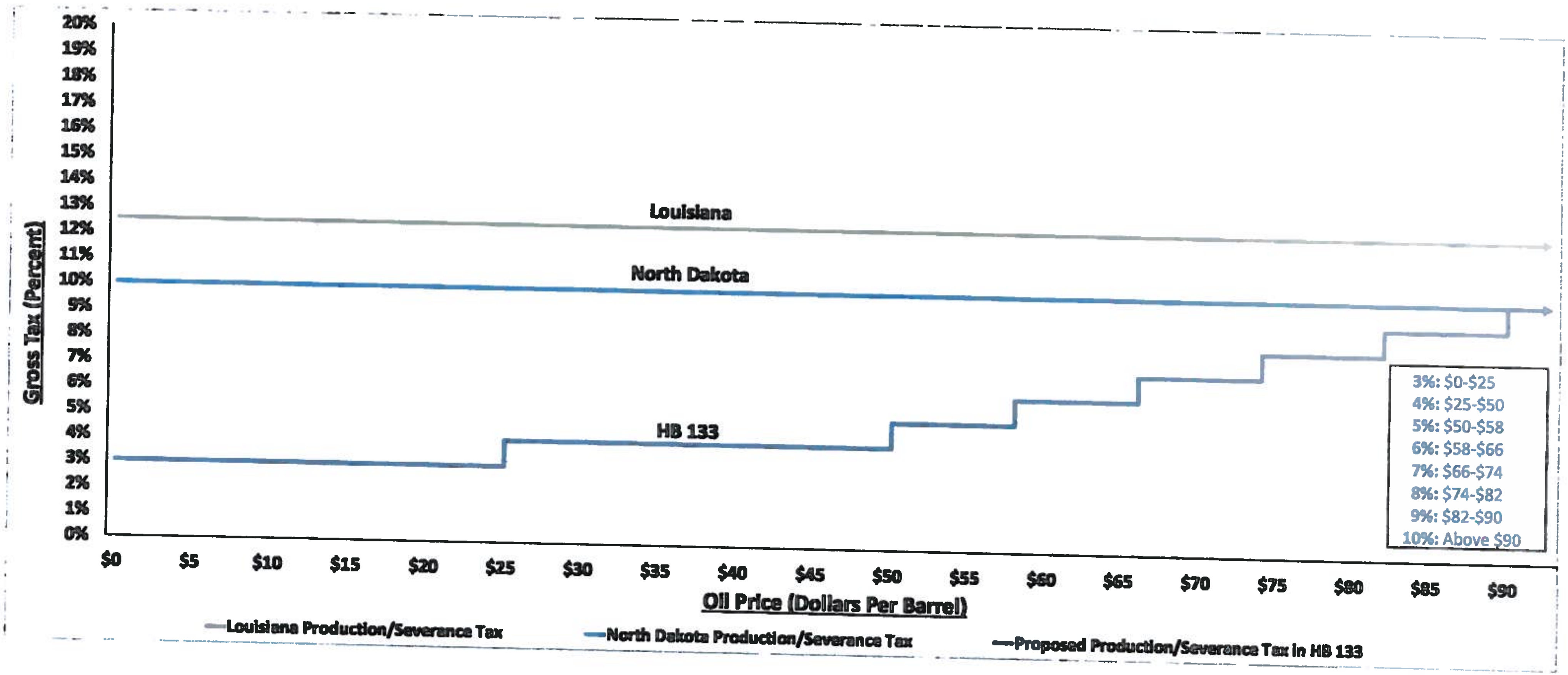
Much Criticized ELF Tax

Higher Tax Rate for Major Fields

Alaska's largest field, Prudhoe Bay, paid a 13% Gross Tax under the old ELF oil tax structure in 2005. Alpine and North Star were also higher-tax fields under the ELF.

Source: January 2005 Department of Revenue Information

HB 133 Tax Rate Compared to North Dakota and Louisiana



Molly Carver

From: Susan Haymes
Sent: Friday, February 17, 2017 12:57 PM
To: Molly Carver
Subject: RE: Oil Tax Rates

Molly,

The trigger price for 2017 is $84.56. If the average price of a barrel of crude oil exceeds the trigger price for each month in any consecutive three-month period the oil extraction tax rate increases to 6 percent.

Susan

Susan Haymes
susan.haymes@akleg.gov

From: Molly Carver
Sent: Friday, February 17, 2017 12:54 PM
To: Susan Haymes <Susan.Haymes@akleg.gov>
Subject: RE: Oil Tax Rates

Hi Susan,

He would also like to know what the price trigger is for this year- he suspects it was maybe 90 last year, potentially 80 this year?

Thanks,

Molly

From: Susan Haymes
Sent: Friday, February 17, 2017 11:35 AM
To: Molly Carver <Molly.Carver@akleg.gov>
Subject: RE: Oil Tax Rates

Molly,

Yes there is a gross production of 5 percent and the extraction tax of 5 percent for a total tax rate of 10 percent, which could increase to 11 percent if the trigger price is reached. Sorry for the confusion.

Susan

Susan Haymes
susan.haymes@akleg.gov

From: Molly Carver
Sent: Friday, February 17, 2017 11:23 AM

To: Susan Haymes <Susan.Haymes@akleg.gov>
Subject: RE: Oil Tax Rates

Hi Susan,

Rep. Gara wants to make sure that you're accounting for all of the taxes in North Dakota- not simply the extraction tax (i.e. is there a production tax on top of that and what is the rate?)

Thanks,

Molly

From: Susan Haymes
Sent: Wednesday, February 08, 2017 12:43 PM
To: Molly Carver <Molly.Carver@akleg.gov>
Subject: RE: Oil Tax Rates

Hi Molly,

Briefly, in North Dakota, beginning January 1, 2016, the oil extraction tax rate is 5 percent (down from the previous rate of 6.5 percent) as a result of changes enacted by the North Dakota Legislature in 2015. The new tax law also established a "price trigger" based on an average price of $90/bbl for three consecutive months. The trigger price is subject to an annual adjustment, which for 2017 has been calculated at $84.56. If the average price of a barrel of crude oil exceeds the trigger price for each month in any consecutive three-month period the oil extraction tax rate increases to 6 percent.

The oil tax rate in Louisiana is 12.5 percent. Different rates apply to stripper oil, incapable oil (oil produced at wells that are incapable of producing an average of more than 25 barrels per day), and reclaimed oil.

I hope this is helpful.

Best—

Susan

Susan Haymes
susan.haymes@akleg.gov

From: Molly Carver
Sent: Wednesday, February 08, 2017 10:44 AM
To: Susan Haymes <Susan.Haymes@akleg.gov>
Subject: Oil Tax Rates

Good Morning,

Rep. Gara is wondering if you have a few numbers on oil tax rates in other states- no need to do additional research if you don't already have these, but we just wanted to check.

1) What is the gross tax rate in North Dakota- 6%? At $70 bbl does it go up to 7 or 11%?
2) Same for Louisiana- he estimated 12%
    a. No need to look at little (stripper) wells.

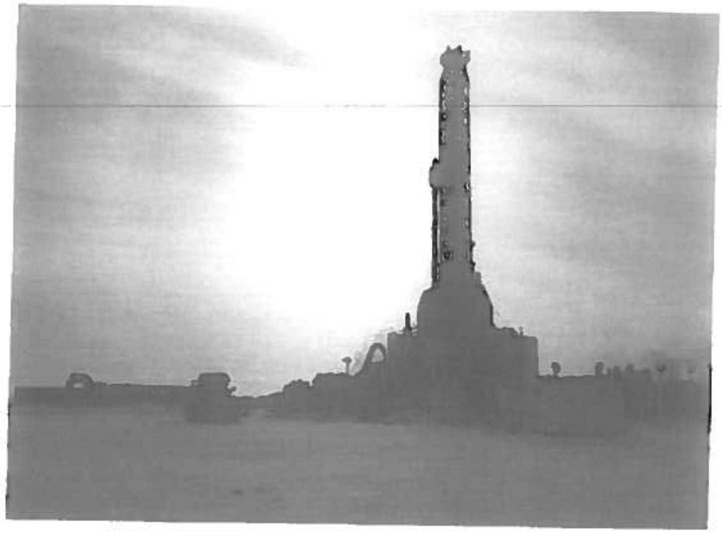
Louisiana Severance Tax on Gross Value

"The capable tax rate for oil and condensate is 12.5 percent of value and accounts for over 85 percent of the oil and condensate tax collections."

Source: DNR.louisiana.gov (Technology Assessment Division summary of the law)

Under 1994 Law, Louisiana provides up to two years of a tax exemption, or until a company covers the cost at drilling a horizontal well.

Source: nola.com/politics



Lower 48 States:

Higher Royalties- Private Landowners

Private Royalties prevail in the lower 48, where companies generally make royalty payments to private lease owners, and not to the state.

<u>Prevailing</u> Alaska Royalty Rate on Gross Revenue: 12.5% (very few smaller fields at approximately 16%)

Private Royalty Rates in Lower 48:

Texas	12.5-30%
California	16-25%
North Dakota	12.5-25%
Oklahoma	12.5-20%

Source: Alaska Oil + Gas Competitiveness Report

Relief Valve:

Royalty Relief When the Tax Rate Is Too High

AS 38.05.180

(j) The commissioner

(1) may provide for modification of royalty on individual leases, leases unitized as described in (p) of this section, leases subject to an agreement described in (s) or (t) of this section, or interests unitized under AS 31.05

(A) to allow for production from an oil or gas field or pool if

(i) the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;

(ii) the field or pool has not previously produced oil or gas for sale; and

(iii) oil or gas production from the field or pool would not otherwise be economically feasible;

(B) to prolong the economic life of an oil or gas field or pool as per barrel or barrel equivalent costs increase or as the price of oil or gas decreases, and the increase or decrease is sufficient to make future production no longer economically feasible; or

(C) to reestablish production of shut-in oil or gas that would not otherwise be economically feasible;

(2) may not grant a royalty modification unless the lessee or lessees requesting the change make a clear and convincing showing that a modification of royalty meets the requirements of this subsection and is in the best interests of the state;

(3) shall provide for an increase or decrease or other modification of the state's royalty share by a sliding scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs;

(4) may not grant a royalty reduction for a field or pool

(A) under (1)(A) of this subsection if the royalty modification for the field or pool would establish a royalty rate of less than five percent in amount or value of the production removed or sold from a lease or leases covering the field or pool;

(B) under (1)(B) or (1)(C) of this subsection if the royalty modification for the field or pool would establish a royalty rate of less than three percent in amount or value of the production removed or sold from a lease or leases covering the field or pool;

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Vol. 20, No. 4

Week of January 25, 2015

Providing coverage of Alaska and northern Canada's oil and gas industry

Royalty relief for Nuna

DNR makes final finding on 5% royalty rate for new Oooguruk development

Alan Bailey

Petroleum News

The Alaska Department of Natural Resources has confirmed that it will set a reduced royalty rate for production from Caelus Natural Resources Alaska's planned Nuna development in the Oooguruk field under the nearshore waters of the Beaufort Sea. Caelus had said that the development would be uneconomic without the royalty reduction. In a final finding dated Jan. 20, Marty Rutherford, acting commissioner of DNR, said that that DNR had determined that Caelus had met all of the necessary requirements for royalty modifications.

"Our extensive review and analysis of the proposed Nuna project indicates that it will not proceed without royalty modification. The benefits to the state - in terms of increased revenue, production, jobs and new information that will spur additional North Slope projects - starkly outweigh the cost of the royalty modification," Rutherford said when announcing the department's decision.

New development

Caelus' Nuna project involves the development of the Torok formation from an onshore drilling pad. The company already produces oil from a single well that penetrates the Torok from the Oooguruk drilling island, offshore in the Beaufort Sea. However, especially given the compartmentalized nature of the Torok reservoir, production from the thicker and more nearshore sections of the reservoir is not possible without the drilling of onshore wells. The Torok is the youngest and shallowest of the reservoir systems in the Oooguruk unit.

The compartmentalized and discontinuous nature of the Torok reservoir makes the reservoir particularly challenging to develop, possibly requiring multi-stage hydraulic fracturing, as in a shale-oil development.

Five percent royalty rate

Under the terms of its final finding, DNR is setting a 5 percent royalty rate for initial production from the Torok from five leases in the Oooguruk unit. That royalty relief will remain in effect until Caelus has achieved cumulative production with a total wellhead value of $1.25 billion as a consequence of the Nuna development. The normal legal minimum royalty rate for oil produced from Alaska state lands is 12.5 percent. However, under state statutes, the state can, at its discretion, reduce that rate to a minimum of 5 percent to encourage production from an otherwise uneconomic oil pool, or to a minimum of 3 percent to prolong the life of a currently producing pool.

In coming to its decision DNR used the second of those criteria - the desire to extend the life of Torok production - because of the existing production from the Torok from the Oooguruk island. However, the department has elected to set a 5 percent royalty rate rather than the minimum 3 percent rate that is legally permissible.

To obtain the reduced royalty rate Caelus must sanction the Nuna project by March 31; initiate capital expenditure by Sept. 30; and spend at least $260 million of that expenditure by Sept. 30, 2017, by which date sustained production must start.

Non-confidential report required

The DNR finding also stipulates that 24 months after the start of sustained commercial production from the onshore Nuna drilling pad Caelus must deliver a non-confidential project summary to DNR, to share project learnings with DNR and the other North Slope operators free of charge, "to better understand the challenges and successes of developing similar geologic formations to promote continued development of the state's resources." DNR will determine whether the summary contains sufficient detail. The department can, if necessary, require Caelus to add more detail and, ultimately, rescind the royalty relief if sufficient detail is not forthcoming.

The finding also allows Caelus to increase the rate at which it deducts the costs associated with North Slope facility sharing from the wellhead value of the Nuna oil, thus further reducing royalty payments, if the company can prove that 80 percent of its Nuna workforce is resident in Alaska.

DNR analysis

DNR has done its own analysis of the economics of the Nuna project and has concluded that the project would be uneconomic without royalty relief. The department's economic analysis used a range of possible recoverable oil reserves and oil prices ranging from $50 to $130 per barrel, with a median price of $90 per barrel. The results showed that, without the royalty relief, the development would lose money in at least 50 percent of the economic scenarios, under assumed rate of return requirements of 15 percent or more.

And the department recognized the risks and uncertainties associated with the project.

"Based on these mediocre economic results relative to the risk of loss, Caelus has made a clear and convincing case that without royalty modification the investment in the Nuna project is uneconomic," the finding says.

Net benefit to state

Being what is referred to as "new oil," under the new Alaska oil production tax system, Nuna oil will be taxed at a preferential rate. And, taking into account factors such as tax credits, the value of the resulting tax may be slightly negative, the finding says. However, both the Caelus and the DNR economic analyses have taken this tax situation into account, the finding says. And, given potential state revenues from sources including royalties, property taxes and possible corporate income tax, DNR has computed a total expected value to the state of around $1.2 billion if the Nuna development proceeds with the royalty reduction in place.

Caelus spokesman Casey Sullivan told Petroleum News in a Jan. 21 email that his company is still evaluating the final finding.

"We appreciate the considerable analysis conducted by Gov. Walker and his team at the Department of Natural Resources," Sullivan said. "The state's final findings and determination substantiates that the Nuna project, while challenged, could economically benefit Alaska, produce new oil through TAPS (the trans-Alaska oil pipeline) and create good jobs for Alaskans."

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http://www.newsminer.com/alaska-tweaks-royalty-relief-rules-for-oil-companies/article_80becb0a-1944-58df-9315-a6c33182d4ae.html

Alaska tweaks royalty relief rules for oil companies

By Christopher Eshleman /ceshleman@newsminer.com Fairbanks Daily News-Miner Apr 27, 2011

JUNEAU — State oil and gas specialists are clarifying the rules beneath a standing offer of "royalty relief" to oil companies needing help with projects in Alaska.

The proposed regulatory update would not include substantive changes to the state's standing offer of relief, an offer that oil companies have pursued five times in 16 years and that the state has seldom approved.

The Alaska Department of Natural Resources proposed the regulatory update early this month to help companies know whether they're eligible for "relief" and to lay out the standards state officials use to review and evaluate applications.

It said the goal is to make "Alaska an easier and more attractive place to do business."

The topic of royalty relief — breaks on a company's royalty payments to state government in return for pumping oil — caught airtime this winter during debate over Gov. Sean Parnell's proposed tax cuts. Skeptics of the governor's plan said the standing offer of help for companies needing it argues against the logic of cutting taxes for the oil industry.

But only five companies have applied for that help since the Legislature expanded eligibility in 1995, said Kevin Banks, who directs the state Division of Oil and Gas. Resource commissioners have approved two applications — for the Oooguruk and Nikiachuk fields — and in the latter case the break only arrives if the price of oil falls close to $42 per barrel.

Banks said the proposed regulatory modification, available to read on his division's website, aims to ensure companies know they'll need certain data and work product to provide "a clear and convincing showing" that they need help producing oil from technically challenging fields.

Contact staff writer Christopher Eshleman at 459-7582.

ConocoPhillips

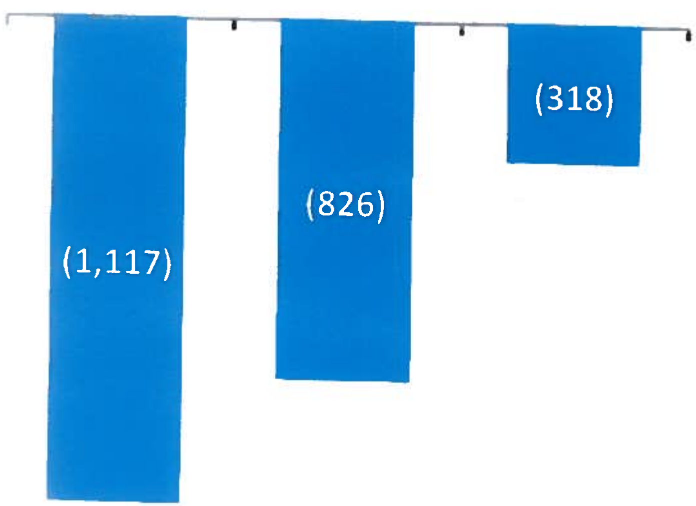
4Q16 Conference Call

Feb. 2, 2017

4Q16 Performance – Adjusted Earnings

ConocoPhillips

Adjusted Earnings ($MM)



	4Q15	3Q16	4Q16
Adjusted EPS ($)	($0.90)	($0.66)	($0.26)
Average Realized Price ($/BOE)	$28.54	$29.78	$32.93

Highlights

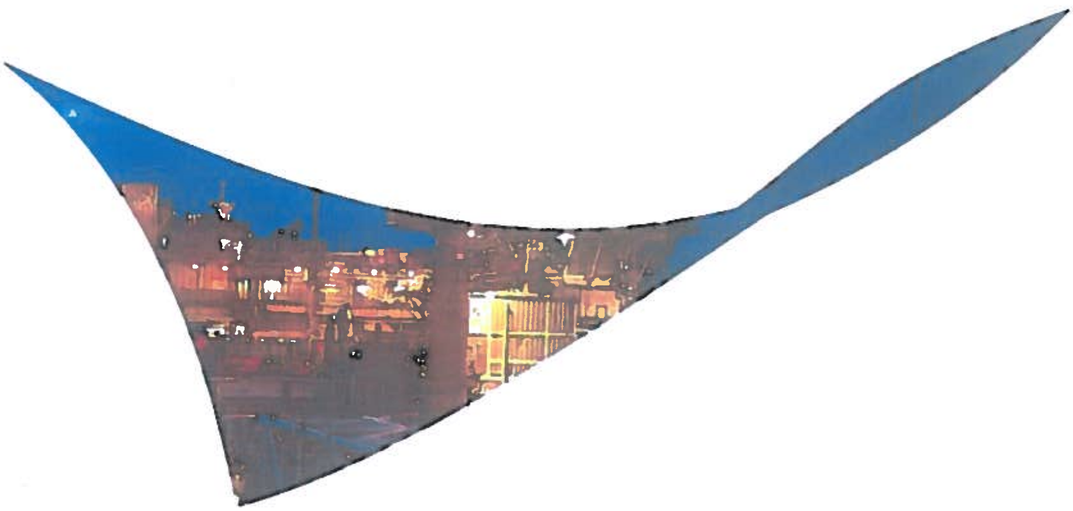
- Year-over-year adjusted earnings benefited from 15% improvement in realizations and lower exploration expense
- Sequential adjusted earnings benefited from 11% improvement in realizations and lower depreciation expense

4Q16 Adjusted Earnings ($MM)

Lower 48	($219)
Canada	($101)
Alaska	$116
Europe & North Africa	$82
Asia Pacific & Middle East	$182
Other International	($54)
Corporate & Other	($324)
Total	($318)

Adjusted earnings (loss) and adjusted EPS are non-GAAP measures A non-GAAP reconciliation is available on our website.

ConocoPhillips



2015 Annual Report

		Millions of Dollars		
		2015	2014	2013
Equity in Earnings of Affiliates				
Alaska	$	4	9	7
Lower 48		(5)	1	(2)
Canada		78	1,385	984
Europe and North Africa		23	37	27
Asia Pacific and Middle East		550	1,089	1,162
Other International		8	9	43
Corporate and Other		(3)	(1)	(2)
Consolidated equity in earnings of affiliates	$	655	2,529	2,219
Income Taxes				
Alaska	$	(71)	1,081	1,275
Lower 48		(1,119)	(92)	398
Canada		(223)	236	(44)
Europe and North Africa		(854)	1,590	3,258
Asia Pacific and Middle East		467	1,194	1,512
Other International		(456)	(102)	134
Corporate and Other		(612)	(324)	(124)
Consolidated income taxes	$	(2,868)	3,583	6,409
Net Income (Loss) Attributable to ConocoPhillips				
Alaska	$	4	2,041	2,274
Lower 48		(1,932)	(22)	754
Canada		(1,044)	940	718
Europe and North Africa		409	814	1,297
Asia Pacific and Middle East		(463)	2,939	3,532
Other International		(593)	(100)	223
Corporate and Other		(809)	(874)	(820)
Discontinued operations		-	1,131	1,178
Consolidated net income (loss) attributable to ConocoPhillips	$	(4,428)	6,869	9,156
Investments In and Advances To Affiliates				
Alaska	$	61	53	53
Lower 48		455	471	905
Canada		8,165	9,484	10,273
Europe and North Africa		70	126	143
Asia Pacific and Middle East		11,780	14,022	12,806
Other International		-	59	141
Corporate and Other		15	15	16
Consolidated investments in and advances to affiliates	$	20,546	24,230	24,337

ConocoPhillips

exclusively E&P

INDEPENDENT

2012 ANNUAL REPORT

	Millions of Dollars			
		2012	2011	2010
Equity in Earnings of Affiliates				
Alaska	$	10	(77)	8
Lower 48 and Latin America		86	99	80
Canada		726	677	505
Europe		29	46	41
Asia Pacific and Middle East		1,057	819	(17)
Other International		6	(324)	(532)
LUKOIL Investment		-	-	1,295
Corporate and Other		(3)	(1)	(4)
Consolidated equity in earnings of affiliates	$	1,911	1,239	1,376
Income Taxes				
Alaska	$	1,266	1,171	1,017
Lower 48 and Latin America		133	741	595
Canada		(252)	(45)	215
Europe		4,012	4,459	3,118
Asia Pacific and Middle East		1,578	1,887	1,340
Other International		1,485	162	1,170
LUKOIL Investment		-	123	505
Corporate and Other		(280)	(290)	(390)
Consolidated income taxes	$	7,942	8,208	7,570
Net Income Attributable to ConocoPhillips				
Alaska	$	2,276	1,984	1,727
Lower 48 and Latin America		1,029	1,288	1,029
Canada		(684)	91	2,902
Europe		1,498	1,830	1,703
Asia Pacific and Middle East		3,928	3,032	2,099
Other International		359	(377)	(418)
LUKOIL Investment		-	239	2,513
Corporate and Other		(993)	(960)	(1,304)
Discontinued operations		1,015	5,309	1,107
Consolidated net income attributable to ConocoPhillips	$	8,428	12,436	11,358
Investments In and Advances To Affiliates				
Alaska	$	56	58	143
Lower 48 and Latin America		1,133	1,168	1,190
Canada		9,973	9,045	8,675
Europe		242	195	211
Asia Pacific and Middle East		12,468	11,571	11,335
Other International		61	339	813
LUKOIL Investment		-	-	-
Corporate and Other		15	9	-
Discontinued operations		-	10,275	9,868
Consolidated investments in and advances to affiliates	$	23,948	32,660	32,235

Appendix E

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Production Tax Estimate for FY 2017

Using income statement format

Note: This table presents an approximation of the production tax calculation, and does not match production tax estimates throughout this publication.

	Price	Barrels (Thousands)	Value (Millions of Dollars)
Avg ANS Oil Price ($/bbl) and Daily Production	$46.81	490.3	$23.0
Annual Production			
Total		178,961	$8,377.6
Royalty, Federal and other barrels[1]		-21,314	($997.8)
Taxable barrels		157,647	$7,379.8
Downstream (Transportation) Costs ($/bbl)			
ANS Marine Transportation	-$3.13		
TAPS Tariff	-$5.81		
Other	-$0.39		
Total Transportation Costs	-$9.33	157,647	($1,470.6)
Gross Value at Point of Production (GVPP)			$5,909.2
Deductible Lease Expenditures[2]			
Deductible Operating Expenditures	-$17.68		($2,786.9)
Deductible Capital Expenditures	-$13.20		($2,080.8)
Total Lease Expenditures	$30.88	157,647	($4,867.6)
Production Tax			
Gross minimum tax (4%*GVPP)			$236.4
Production Tax Value (PTV)			$1,041.6
Gross Value Reduction (GVR)			($68.7)
Production Tax Value (PTV) after GVR			$973.0
Base Tax (35%*PTV after GVR)			$340.5
Total Tax before credits (base tax or minimum tax)			$340.5
North Slope Credits applied against tax liability[3]			($225.0)
Estimated Total Tax after credits[4]			$115.5

[1] Royalty, Federal and other barrels represents the Department of Revenue's best estimate of barrels that are not taxed. This estimate includes both state and federal royalty barrels, barrels produced from federal offshore property, and barrels used in production.

[2] Deductible Lease Expenditures represents the Department of Revenue's best estimate of lease expenditures that are applicable to companies that are likely to have a tax liability for the year. The per-barrel expenditures reflect expenditures per taxable barrel and do not reflect expenditures per all barrels produced.

[3] Some credits may reduce a producer's liability below the minimum tax; those provisions are reflected in these estimates. For more information on how specific tax credits may be applied, please see Chapter 8 of this publication.

[4] Estimated Total Tax after credits is a calculated total based on constant daily production, constant oil prices, constant expenditures for the entire year, and no company-specific information. Variations in these assumptions captured in larger revenue models will produce results that differ from the estimates in the simple model above. Therefore, the estimate shown here will not exactly match the Department of Revenue's official revenue numbers published elsewhere in this book.

Proposal: Rep Gara draft proposal

Revised 1-27-17 by Department of Revenue

NOTE: The fiscal impact of this proposal is an estimate based on the Fall 2016 revenue forecast. Estimates shown here are draft / preliminary based on our interpretation of possible changes, and do not include any changes in company behavior as a result of this proposal. We reserve the right to make modifications to estimates for any forthcoming fiscal notes.

Provisions in HB XXX and their Estimated Fiscal Impact based on Fall 2016 Forecast ($millions) - Fall 2016 FORECAST PRICE

Description of Provision	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027
1. No credits or deductions can reduce tax below the minimum tax effective 1/1/18.	$20	$15	$0	$0	$0	$0	$0	-$10	-$25	-$5
2. Effective 1/1/18, replace current gross minimum tax brackets with new brackets starting at 4% of gross at prices below $50, and increasing by 1% for each $8 increase in price up to 10% of gross at prices above $90. Price triggers for brackets are adjusted for inflation biennially.	$20	$125	$120	$125	$195	$200	$200	$200	$255	$245
3. Effective 1/1/18, establish an additional minimum tax calculation based on production tax value. The production tax may not fall below 22.5% of PTV.	$20	$95	$80	$90	$145	$180	$220	$270	$270	$265
4. Effective 1/1/18, establish a progressive surcharge based on production tax value for North Slope production. The surcharge is 10% of the portion of PTV per barrel between $40 and $50, 15% of the portion of PTV per barrel between $50 and $60, 20% of the portion of PTV per barrel between $60 and $70, and 25% of PTV per barrel above $70. The progressive surcharge is calculated before applying the minimum taxes and the brackets are not indexed for inflation.	$0	$0	$0	$0	$0	$0	$0	$5	$5	$10
5. Repeal the Gross Value Reduction (GVR) effective 1/1/18.	$0	$25	$30	$40	$35	$40	$15	$0	$0	$0
Additional impact of implementing above provisions together vs standalone	-$10	-$90	-$65	-$85	-$140	-$180	-$215	-$260	-$245	-$265
Total Revenue Impact	$50	$170	$165	$170	$235	$240	$220	$205	$260	$250
A. Budget impact of No credits or deductions can reduce tax below the minimum tax effective 1/1/18.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
B. Budget impact of new gross minimum tax brackets effective 1/1/18.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C. Budget impact of new net minimum tax calculation effective 1/1/18.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
D. Budget impact of new progressive surcharge effective 1/1/18.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
E. Budget impact of GVR repeal effective 1/1/18.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Additional impact of implementing above provisions together vs standalone	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Budget Impact	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Fiscal Impact - (does not include potential changes in investment)	$50	$170	$165	$170	$235	$240	$220	$205	$260	$250
Non-refundable carry-forward credits balance at fiscal year end - current law	$14	$0	$0	$0	$0	$0	$0	$0	$0	$0
Non-refundable carry-forward credits balance at fiscal year end - proposed	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31
Change in year-end balance due to proposal	$17	$31	$31	$31	$31	$31	$31	$31	$31	$31

Net fiscal impact of proposed changes at various prices