

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

April 2, 2013

6:07 p.m.

MEMBERS PRESENT

Representative Eric Feige, Co-Chair
Representative Dan Saddler, Co-Chair
Representative Peggy Wilson, Vice Chair
Representative Mike Hawker
Representative Craig Johnson
Representative Paul Seaton
Representative Geran Tarr
Representative Chris Tuck

MEMBERS ABSENT

Representative Kurt Olson

COMMITTEE CALENDAR

COMMITTEE SUBSTITUTE FOR SENATE BILL NO. 21(FIN) AM(EFD FLD)
"An Act relating to the interest rate applicable to certain amounts due for fees, taxes, and payments made and property delivered to the Department of Revenue; providing a tax credit against the corporation income tax for qualified oil and gas service industry expenditures; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production; relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; establishing the Oil and Gas Competitiveness Review Board; and making conforming amendments."

- HEARD & HELD

PREVIOUS COMMITTEE ACTION

BILL: SB 21

SHORT TITLE: OIL AND GAS PRODUCTION TAX

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

01/16/13 (S) READ THE FIRST TIME - REFERRALS

01/16/13 (S) TTP, RES, FIN
01/22/13 (S) TTP AT 3:30 PM BELTZ 105 (TSBldg)
01/22/13 (S) Heard & Held
01/22/13 (S) MINUTE(TTP)
01/24/13 (S) TTP AT 3:30 PM BUTROVICH 205
01/24/13 (S) Heard & Held
01/24/13 (S) MINUTE(TTP)
01/29/13 (S) TTP AT 3:30 PM BELTZ 105 (TSBldg)
01/29/13 (S) Heard & Held
01/29/13 (S) MINUTE(TTP)
01/31/13 (S) TTP AT 1:00 PM BUTROVICH 205
01/31/13 (S) Heard & Held
01/31/13 (S) MINUTE(TTP)
02/05/13 (S) TTP AT 3:30 PM BUTROVICH 205
02/05/13 (S) Heard & Held
02/05/13 (S) MINUTE(TTP)
02/07/13 (S) TTP AT 3:30 PM BUTROVICH 205
02/07/13 (S) Moved SB 21 Out of Committee
02/07/13 (S) MINUTE(TTP)
02/08/13 (S) TTP RPT 1NR 4AM
02/08/13 (S) NR: DUNLEAVY
02/08/13 (S) AM: MICCICHE, GARDNER, FAIRCLOUGH,
MCGUIRE
02/08/13 (S) LETTER OF INTENT WITH TTP REPORT
02/09/13 (S) TTP AT 10:00 AM BUTROVICH 205
02/09/13 (S) -- MEETING CANCELED --
02/11/13 (S) RES AT 3:30 PM BUTROVICH 205
02/11/13 (S) Heard & Held
02/11/13 (S) MINUTE(RES)
02/13/13 (S) RES AT 3:30 PM BUTROVICH 205
02/13/13 (S) Heard & Held
02/13/13 (S) MINUTE(RES)
02/15/13 (S) RES AT 3:30 PM BUTROVICH 205
02/15/13 (S) Heard & Held
02/15/13 (S) MINUTE(RES)
02/18/13 (S) RES AT 3:30 PM BUTROVICH 205
02/18/13 (S) Heard & Held
02/18/13 (S) MINUTE(RES)
02/20/13 (S) RES AT 3:30 PM BUTROVICH 205
02/20/13 (S) Heard & Held
02/20/13 (S) MINUTE(RES)
02/22/13 (S) RES AT 3:30 PM BUTROVICH 205
02/22/13 (S) Heard & Held
02/22/13 (S) MINUTE(RES)
02/25/13 (S) RES AT 3:30 PM BUTROVICH 205
02/25/13 (S) Heard & Held
02/25/13 (S) MINUTE(RES)

02/27/13 (S) RES AT 3:30 PM BUTROVICH 205
02/27/13 (S) Moved CSSB 21(RES) Out of Committee
02/27/13 (S) MINUTE(RES)
02/28/13 (S) RES RPT CS 3DP 1DNP 2NR 1AM NEW
TITLE
02/28/13 (S) LETTER OF INTENT WITH RES REPORT
02/28/13 (S) DP: GIESSEL, MCGUIRE, DYSON
02/28/13 (S) DNP: FRENCH
02/28/13 (S) NR: MICCICHE, BISHOP
02/28/13 (S) AM: FAIRCLOUGH
02/28/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
02/28/13 (S) Heard & Held
02/28/13 (S) MINUTE(FIN)
03/01/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/01/13 (S) Heard & Held
03/01/13 (S) MINUTE(FIN)
03/01/13 (S) RES AT 3:30 PM BUTROVICH 205
03/01/13 (S) -- MEETING CANCELED --
03/02/13 (S) RES AT 10:00 AM BUTROVICH 205
03/02/13 (S) -- MEETING CANCELED --
03/04/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/04/13 (S) Heard & Held
03/04/13 (S) MINUTE(FIN)
03/04/13 (S) FIN AT 1:30 PM SENATE FINANCE 532
03/04/13 (S) Heard & Held
03/04/13 (S) MINUTE(FIN)
03/05/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/05/13 (S) Heard & Held
03/05/13 (S) MINUTE(FIN)
03/05/13 (S) FIN AT 1:30 PM SENATE FINANCE 532
03/05/13 (S) Heard & Held
03/05/13 (S) MINUTE(FIN)
03/06/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/06/13 (S) Heard & Held
03/06/13 (S) MINUTE(FIN)
03/06/13 (S) FIN AT 1:30 PM SENATE FINANCE 532
03/06/13 (S) Heard & Held
03/06/13 (S) MINUTE(FIN)
03/06/13 (S) FIN AT 3:00 PM SENATE FINANCE 532
03/06/13 (S) -- Public Testimony --
03/11/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/11/13 (S) -- MEETING CANCELED --
03/11/13 (S) FIN AT 1:30 PM SENATE FINANCE 532
03/11/13 (S) -- MEETING CANCELED --
03/12/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/12/13 (S) -- Delayed to 10: am --
03/12/13 (S) FIN AT 1:30 PM SENATE FINANCE 532

03/12/13 (S) Heard & Held
03/12/13 (S) MINUTE(FIN)
03/12/13 (S) FIN AT 4:00 PM SENATE FINANCE 532
03/12/13 (S) Heard & Held
03/12/13 (S) MINUTE(FIN)
03/13/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/13/13 (S) Heard & Held
03/13/13 (S) MINUTE(FIN)
03/13/13 (S) FIN AT 1:30 PM SENATE FINANCE 532
03/13/13 (S) Heard & Held
03/13/13 (S) MINUTE(FIN)
03/14/13 (S) FIN AT 9:00 AM SENATE FINANCE 532
03/14/13 (S) Moved CSSB 21(FIN) Out of Committee
03/14/13 (S) MINUTE(FIN)
03/18/13 (S) FIN RPT CS 2DP 1DNP 1NR 3AM NEW
TITLE
03/18/13 (S) DP: KELLY, MEYER
03/18/13 (S) DNP: HOFFMAN
03/18/13 (S) NR: FAIRCLOUGH
03/18/13 (S) AM: DUNLEAVY, BISHOP, OLSON
03/18/13 (H) RES AT 1:00 PM BARNES 124
03/18/13 (H) Scheduled But Not Heard
03/19/13 (S) RLS AT 9:00 AM FAHRENKAMP 203
03/19/13 (S) -- MEETING CANCELED --
03/20/13 (H) RES AT 1:00 PM BARNES 124
03/20/13 (H) Scheduled But Not Heard
03/21/13 (S) TRANSMITTED TO (H)
03/21/13 (S) VERSION: CSSB 21(FIN) AM(EFD FLD)
03/22/13 (H) READ THE FIRST TIME - REFERRALS
03/22/13 (H) RES, FIN
03/22/13 (H) RES AT 1:00 PM BARNES 124
03/22/13 (H) Heard & Held
03/22/13 (H) MINUTE(RES)
03/25/13 (H) RES AT 1:00 PM BARNES 124
03/25/13 (H) Heard & Held
03/25/13 (H) MINUTE(RES)
03/26/13 (H) RES AT 6:00 PM BARNES 124
03/26/13 (H) Heard & Held
03/26/13 (H) MINUTE(RES)
03/27/13 (H) RES AT 1:00 PM BARNES 124
03/27/13 (H) Heard & Held
03/27/13 (H) MINUTE(RES)
03/28/13 (H) RES AT 6:00 PM BARNES 124
03/28/13 (H) Heard & Held
03/28/13 (H) MINUTE(RES)
03/29/13 (H) RES AT 1:00 PM BARNES 124
03/29/13 (H) Heard & Held

03/29/13	(H)	MINUTE(RES)
04/01/13	(H)	RES AT 1:00 PM BARNES 124
04/01/13	(H)	Heard & Held
04/01/13	(H)	MINUTE(RES)
04/02/13	(H)	FIN AT 9:00 AM HOUSE FINANCE 519
04/02/13	(H)	Scheduled But Not Heard
04/02/13	(H)	RES AT 9:00 AM BARNES 124
04/02/13	(H)	- Cont. at 2:00 pm today from 4/1/13 -
04/02/13	(H)	FIN AT 1:30 PM HOUSE FINANCE 519
04/02/13	(H)	Scheduled But Not Heard
04/02/13	(H)	RES AT 6:00 PM BARNES 124

WITNESS REGISTER

JANAK MAYER, Manager, Upstream and Gas
PFC Energy
Washington, DC

POSITION STATEMENT: During the hearing on CSSB 21(FIN) am(efd fld), provided a PowerPoint presentation regarding the proposed committee substitute, HCS CSSB 21, Version K.

BARRY PULLIAM, Economist & Managing Director
Econ One Research, Inc.
Los Angeles, California

POSITION STATEMENT: During the hearing on CSSB 21(FIN) am(efd fld), provided a PowerPoint presentation regarding the proposed committee substitute, HCS CSSB 21, Version K.

DAMIAN BILBAO, Head of Finance
BP Exploration (Alaska) Inc.
Anchorage, Alaska

POSITION STATEMENT: During the hearing on CSSB 21(FIN) am(efd fld), provided a PowerPoint presentation regarding the proposed committee substitute, HCS CSSB 21, Version K.

BART ARMFIELD, Chief Operating Officer
Brooks Range Petroleum Corporation
Anchorage, Alaska

POSITION STATEMENT: During the hearing on CSSB 21(FIN) am(efd fld), provided a PowerPoint presentation regarding the proposed committee substitute, HCS CSSB 21, Version K.

DAN SECKERS, Tax Counsel
ExxonMobil Corporation
Anchorage, Alaska

POSITION STATEMENT: During the hearing on CSSB 21(FIN) am(efd fld), testified regarding the proposed committee substitute, HCS CSSB 21, Version K.

SCOTT JEPSEN, Vice President External Affairs
ConocoPhillips Alaska, Inc.
Anchorage, Alaska

POSITION STATEMENT: During the hearing on CSSB 21(FIN) am(efd fld), provided a PowerPoint presentation regarding the proposed committee substitute, HCS CSSB 21, Version K.

JOE BALASH, Deputy Commissioner
Office of the Commissioner
Department of Natural Resources (DNR)
Anchorage, Alaska

POSITION STATEMENT: During the hearing on CSSB 21(FIN) am(efd fld), answered questions regarding the proposed committee substitute, HCS CSSB 21, Version K.

ACTION NARRATIVE

[6:07:43 PM](#)

CO-CHAIR ERIC FEIGE called the House Resources Standing Committee meeting to order at 6:07 p.m. Representatives Hawker, Johnson, Seaton, P. Wilson, Saddler, and Feige were present at the call to order. Representatives Tarr and Tuck arrived as the meeting was in progress.

SB 21-OIL AND GAS PRODUCTION TAX **DRAFT**

[6:08:10 PM](#)

CO-CHAIR FEIGE announced that the only order of business is CS FOR SENATE BILL NO. 21(FIN) am(efd fld), "An Act relating to the interest rate applicable to certain amounts due for fees, taxes, and payments made and property delivered to the Department of Revenue; providing a tax credit against the corporation income tax for qualified oil and gas service industry expenditures; relating to the oil and gas production tax rate; relating to gas used in the state; relating to monthly installment payments of the oil and gas production tax; relating to oil and gas production tax credits for certain losses and expenditures; relating to oil and gas production tax credit certificates; relating to nontransferable tax credits based on production;

relating to the oil and gas tax credit fund; relating to annual statements by producers and explorers; establishing the Oil and Gas Competitiveness Review Board; and making conforming amendments." [Before the committee was the proposed committee substitute, HCS CSSB 21, Version B, labeled HCS CSSB 21, 28-GS1647\B, Nauman/Bullock, 3/29/13, adopted as the working document on 3/29/13.]

[6:08:17 PM](#)

CO-CHAIR FEIGE informed the committee that due to issues with the effective dates in Version B, a new committee substitute, Version K, was prepared to merge the effective dates into the sections of the bill. He advised that amendments submitted for consideration should be redrafted to the K version.

[6:09:17 PM](#)

CO-CHAIR SADDLER moved to adopt HCS CSSB 21, Version 28-GS1647\K, Nauman/Bullock, 4/2/13, as the working document. There being no objection, Version K was before the committee.

[6:09:44 PM](#)

The committee took an at-ease from 6:09 p.m. to 6:22 p.m.

[6:22:28 PM](#)

JANAK MAYER, Manager, Upstream and Gas, PFC Energy, as consultant to the legislature, said he will discuss the two significant changes to CSSB 21(FIN) am(efd fld) that are made in the proposed committee substitute, HCS CSSB 21, Version K, that affect the North Slope fiscal system. The first change is in the forms of new production that would qualify for the gross revenue exclusion (GRE), now being called the gross value reduction (GVR). The second change is the treatment of the per barrel credit. New production that qualifies for the GVR would maintain the fixed \$5 per barrel production credit. Production not qualifying for the GVR - which is production that is not from a new unit, a new participating area, or an expansion of an existing participating area, and thus, essentially, the base legacy field production - would have a stepped per barrel credit that is at a higher rate when oil prices are low and that is reduced to zero when oil prices are high.

[6:24:26 PM](#)

MR. MAYER demonstrated how a fixed \$5 per barrel production credit would work using a scenario of 50 million barrels of taxable production at Alaska North Slope (ANS) West Coast prices ranging from \$60-\$160 per barrel, with transportation costs of \$10 per barrel [slide 2]. He described the fixed \$5 per barrel production credit as being like a mild form of reverse progressivity - instead of going from a fixed base and building up, it decreases from a fixed top level. He reviewed the calculations on slide 2 for the price of \$60 per barrel: at a transportation cost of \$10, the gross value at the point of production (GVPP) is \$2.5 billion; after subtracting lease expenditures [of \$1.5 billion], the production tax value (PTV) is \$1 billion; application of the 35 percent production tax results in a tax liability of \$350 million; applying the \$5 per barrel production allowance to the 50 million barrels of production results in a total allowance of \$250 million; subtracting \$250 million from \$350 million results in a production tax of \$100 million. Thus, the tax rate after the allowance is 10 percent rather than the nominal 35 percent, a reduction of 25 percent. As prices increase, that tax reduction steadily decreases. For example, at a price of \$140, the tax rate after the allowance is 30 percent rather than the nominal 35 percent, a reduction of only 5 percent. As prices keep increasing, the tax rate keeps rising until asymptotically it approaches 35 percent, but never quite reaches 35 percent.

[6:27:25 PM](#)

MR. MAYER, responding to Representative Seaton, explained that on slide 2 the line for the GVR/GRE is blank, indicating its functions are working but at a 0 percent rate. Thus, it is not applying in this example and is not reducing anything from the overall tax; however, it will apply in a later example. In further response, he confirmed the difference in the tax percentage rate is totally from the \$5 per barrel credit.

[6:28:23 PM](#)

MR. MAYER, at Representative P. Wilson's request, repeated his review of the calculations on slide 2 for 50 million barrels of production at the ANS West Coast price of \$60 per barrel: from that \$60, subtract \$10 in transportation cost to arrive at \$50 in gross value at the point of production per barrel; multiply that \$50 by the 50 million barrels of taxable production to arrive at \$2.5 billion in gross value at the point of production (GVPP); multiply the lease expenditures of \$30 a barrel times the 50 million barrels of taxable production to get a total

lease expenditure of \$1.5 billion; subtract the \$1.5 billion in total lease expenditure from the \$2.5 billion in GVPP to arrive at a total production tax value (PTV) of \$1 billion (i.e. a per barrel PTV of \$20); taxed at 35 percent, the tax liability is \$350 million without any other deductions or exclusions; there is no GVR/GRE in this example; multiply the fixed \$5 per barrel credit times 50 million barrels to arrive at \$250 million in credit; subtract that \$250 million of credit from the \$350 million of tax liability to arrive at a production tax of \$100 million. That \$100 million represents 10 percent of the \$1 billion in production tax value, for an effective tax rate of 10 percent after the \$5 per barrel credit, rather than the nominal 35 percent.

[6:33:09 PM](#)

MR. MAYER, in further response to Representative P. Wilson, explained 35 percent is the nominal tax rate under Version K. So, at \$60 per barrel, the production tax without allowance on the \$1 billion in production tax value is \$350 million. The \$5 per barrel credit provides a total production allowance of \$250 million. Subtracting the allowance of \$250 million from the \$350 million leaves a production tax of \$100 million. That \$100 million represents 10 percent, rather than 35 percent, of the [\$1 billion] in production tax value, a reduction of 25 percent.

MR. MAYER reiterated that this is a mild reverse progressive effect, where the lower the price the lower the rate and the rate comes down in a curve. The shape of the curve is just enough to counteract the regressive nature of the royalty that is also in the state's fiscal system, thereby giving an overall flat, neutral level of government take.

[6:34:51 PM](#)

MR. MAYER next demonstrated how a variable production credit would work, as proposed in Version K [slide 3]. He again used a scenario of 50 million barrels of taxable production at ANS West Coast prices ranging from \$60-\$160 per barrel, with transportation costs of \$10 per barrel. At prices of \$60, \$70, and \$80, the per-barrel credit is \$8 rather than \$5. At a price of \$90 the credit is \$7 per barrel, going down by \$1 per barrel for each \$10 increase in price until reaching no credit at the price of \$160. At a price of \$60: the production tax without any allowance would be \$350 million, representing 35 percent of the \$1 billion in production tax value; with a credit of \$8 per barrel, the total production allowance is \$400 million, which is

greater than the \$350 million in production tax liability. It is explicitly stated that the allowance cannot take a taxpayer below zero, so there is no production tax in this case, as compared to an effective tax rate of 10 percent for the \$5 per barrel credit. At a price of \$70 per barrel: the production tax without any allowances is \$525 million; with a credit of \$8 per barrel, the production allowance is \$400 million; resulting in a production tax of \$125 million, representing an effective tax rate of 8.3 percent, as compared to an effective tax rate of 18.3 percent for the \$5 per barrel credit.

MR. MAYER pointed out that at a price of \$110 the variable production credit is \$5, so the effective tax rate of 27.9 percent is the same as it is for the fixed credit at this price. Under the variable production credit, the progressive nature of the effective tax rate is increased from that of the fixed rate - more comes off at prices below \$110 and above \$110 the effective tax rate is higher. Because the variable credit is zero at the price of \$160, the effective tax rate no longer asymptotically approaches 35 percent - it actually gets to 35 percent at this price and, therefore, the effective rate is the nominal rate of 35 percent. For production that does not qualify for the GVR/GRE, the effective tax rate is higher at higher prices and lower at lower prices.

[6:39:26 PM](#)

MR. MAYER then drew attention to the effective tax rates that apply to new production [slide 4], explaining that under Version K the definition of new production is narrower - only production from new units, new participating areas, and expansions to existing participating areas. This new production would receive a fixed \$5 per barrel credit, rather than a variable/stepped credit, and would qualify to receive the 20 percent GVR/GRE.

MR. MAYER, responding to Representative P. Wilson, confirmed that at a price of \$60 per barrel the effective tax rate after the per-barrel allowance and the GVR is 0 percent, so a producer would pay no production tax. In further response, he noted that a producer would still contribute other forms of tax, such as royalty, property tax, state income tax, and federal income tax. Because of the regressive nature of the royalty, he explained, a producer may well face still a relatively high level of government take. Responding further, he noted the nominal tax rate of 35 percent is reduced by 35 percent for an effective production tax rate of 0 percent.

REPRESENTATIVE P. WILSON returned to slide 3, which depicts a variable production credit and no GVR, and observed that at a price of \$70 per barrel the nominal tax rate is 35 percent, the effective tax rate after allowance is 8.3 percent, for a progressive tax rate deduction of 26.7 percent.

MR. MAYER confirmed this is correct.

[6:43:58 PM](#)

MR. MAYER turned back to slide 4, which depicts new production at the fixed \$5 per barrel credit and the 20 percent GVR for a scenario of 50 million barrels of taxable production. In response to Representative P. Wilson, he said the fixed \$5 per barrel credit is the line entitled "Production Allowance/bbl". The line entitled "GRE" shows the gross value reduction (GVR) [formerly called the gross revenue exclusion (GRE)], which is 20 percent of the gross value at point of production. In the previous slides the GVR/GRE was zero because the GVR/GRE did not apply to those forms of production.

[6:45:12 PM](#)

MR. MAYER continued his presentation, reviewing the calculations for a price of \$60 per barrel: \$2.5 billion in gross value at point of production minus \$1.5 billion in lease expenditures equals a production tax value of \$1 billion, for a tax liability of \$350 million; factoring in the 20 percent GVR/GRE [\$500 million] drops the production tax value to \$500 million; a 35 percent tax on \$500 million equals a production tax liability without allowance of \$175 million. The \$5 per barrel credit, which totals \$250 million, is more than the tax liability of \$175 million. Thus, at a price of \$60 with the GVR/GRE and \$5 per barrel fixed credit, the effective production tax rate is 0 percent. Comparing the overall rates on slide 4 to those on slide 3, it can be seen that in all cases the GVR/GRE combined with the fixed \$5 per barrel credit gives lower tax rates for new production than for production with the stepped-function credit and no GVR/GRE.

[6:47:07 PM](#)

MR. MAYER suggested a linear function for the variable credit may be preferable to the currently proposed step function [slide 5]. Under the step function the per-barrel credit goes down \$1 for each \$10 rise in price [in a scenario of \$10 per barrel transportation cost]. This means the marginal rate is, in

general, a flat 35 percent, but every time one of those steps is hit, that marginal rate spikes up to about 135 percent at that exact \$1 increment before coming back down to 35 percent. Instead of writing this as a step function, it could be written as a single linear formula. So, instead of this staircase, there would be a smooth line that determines exactly what the credit is at any point along that line. Rather than a series of thresholds at which a particular rate applies, it could be written that the credit is \$16 minus one-tenth of the gross value of production, and that it cannot exceed \$8 or go below \$0.

[6:49:01 PM](#)

MR. MAYER compared the overall government take and economic metrics for base production between the state's current tax structure of Alaska's Clear and Equitable Share (ACES), CSSB 21(FIN) am(efd fld), and the proposed committee substitute, HCS CSSB 21, Version K, [slides 6-8]. Under ACES [slide 6, top left graph], progressivity results in government take increasing to over 75 percent at a price of \$140. As oil prices rise, the state's share of total net present value of production diverges upward, while the company's share rises only relatively little [slide 6, top right graph]. Under CSSB 21(FIN) am(efd fld) [slide 7, top left graph], the degree of progressiveness in the fixed \$5 per barrel credit is just enough to offset the regressive nature of the royalty, resulting in an overall neutral structure at just a little under 65 percent government take. As oil prices rise, the state's share of total net present value of production is greater than that of the company's share, but the two shares are more evenly split than is seen under ACES [slide 7, top right graph]. Under the variable production credit of Version K [slide 8, top left graph], the production tax has a substantially more progressive slope. The effect of that is a bending down of the line for overall government take, rather than it being a flat line just below 65 percent. At \$80 a barrel, government take gets down to 63 percent, and even a little lower at lower prices, and at price levels above \$100 the government take gets as high as 67 percent. In the previous slides, it was seen that at about \$60 a barrel, there was little or no production tax, depending on the cost assumptions. Under Version K, using the base producer assumptions, there is no production tax liability at \$55, there is a slight production tax at \$60, and a steady increase from that point.

[6:52:16 PM](#)

MR. MAYER, responding to Representative P. Wilson, said the dotted line in the lower left graph on slide 8 is the after tax cash flow (ATCF). It represents the difference between all the revenues from production (the positive green bars in the graph) versus all the costs, including government take (negative bars in various colors). This difference is the dotted line, which is the after tax cash flow that the producer receives.

MR. MAYER, responding to Representative Tuck, confirmed the federal tax rate is 35 percent on slide 8, but said a number of tax shields available at a project level are factored in, such as being able to expense intangible drilling tasks. There is no treatment of any other federal rate effective reductions that might come through corporate shielding of income. Because it is the project and the project economics that are being looked at, it makes sense to look at the tax rate that applies to the project.

REPRESENTATIVE TUCK recalled an article that reported "Exxon" only paid 10 percent to the federal government last year because it shielded its income from offshore. He understood [slide 8] would not factor that in because the slide is just by project. He inquired whether state taxes are deducted from the federal taxes in the graphs on slide 8.

MR. MAYER confirmed they are deducted.

[6:54:04 PM](#)

MR. MAYER continued his presentation, pointing out that Version K has a lower level of government take at a price of \$80 per barrel [62.94 percent] than CSSB 21(FIN) am(efd fld) [64.22 percent, slide 7]. At higher prices Version K has a higher level of government take; for example, at \$100, government take is 65.26 percent under Version K and 64.54 percent under CSSB 21(FIN) am(efd fld). At \$110 there is parity in terms of the \$5 per barrel credit, he said, so it would seem there should be "exactly the same level of government take at \$110 and less below that." However, the answer to that comes back to the question of inflation. Moving to slide 9, he noted the time series at the top of the chart is the same time series that was used to generate the cash flow charts on slides 6, 7, and 8 ...

[6:55:28 PM](#)

MR. MAYER, in response to Co-Chair Saddler, confirmed that the labels on the left side of the slide 9 chart are in dollars for the ANS West Coast price per barrel, the transportation cost per barrel, and the gross value at the point of production per barrel. Returning to his overview of slide 9, Mr. Mayer explained why government take is higher at \$100 per barrel [under Version K than under CSSB 21(FIN) am(efd fld)]. At a price of \$100, less \$9 per barrel in transportation cost, the gross value at point of production is \$91 per barrel, which qualifies for a credit of \$6 per barrel. To hold the ANS West Coast price constant at \$91 as time goes on, it is raised by 2.5 percent inflation [per year]. The Trans-Alaska Pipeline System (TAPS) tariff is raised by 3.5 percent a year to be consistent with what has been seen in the past. The gross value at point of production rises accordingly, so in nominal dollars it rises from \$91 in 2012 to \$93.18 in 2013, and so on. The credit of \$6 per barrel applies [for years 2012-2015], falling to \$5 [for years 2016-2020], and continuing to fall over the years until the year 2034 when there is no per-barrel credit at all. The credit becomes zero because the gross value at point of production has risen in nominal terms even though in real terms it is still - in 2012 dollars - \$100 oil. Inflation results in the value of the credit being eroded over time in both real and nominal terms. In nominal terms the credit itself actually gets smaller year after year. "The reason for that is it is actually this series of credits at \$100 a barrel that is being used in that previous result and is why what we see is actually slightly higher government take at \$100 a barrel across the lifecycle of a project or, in this case, across the lifecycle of the base production, rather than slightly lower government take."

[6:58:17 PM](#)

MR. MAYER, responding to Representative Tuck, clarified government take at \$100 per barrel is higher in Version K as compared to CSSB 21(FIN) am (efd fld). Where CSSB 21(FIN) am(efd fld) has a steady credit of \$5 per barrel, Version K has a couple of years at \$6, five years at \$5, and a lower credit in the following years. Toggling back and forth between slide 7 for CSSB 21(FIN) am(efd fld) and slide 8 for HCS CSSB 21, Version K, he drew attention to the purple cash flow bars in the bottom left graph on each slide, explaining that government take is lower in the earlier years and higher in the later years, which is what leads to the slight increase in government take at \$100 a barrel, but lower government take at lower prices.

[6:59:35 PM](#)

REPRESENTATIVE SEATON noted that while it is interesting to look at it this way, Alaska's tax rate is based on overall individual corporate taxes rather than a ring-fenced production. He inquired what will be the way the state looks at this and what will be that impact when it is not a single ring-fenced field that is being looked at.

MR. MAYER answered that [slide 9] represents typical base production from the most mature fields for an existing producer; thus, no factoring in of new developments, and looking simply at a declining base portfolio. It is not a single asset ring-fenced; it is a collection of assets. In further response, Mr. Mayer clarified this is looking at base production rather than a 50 million barrel field.

[7:00:38 PM](#)

REPRESENTATIVE SEATON said he is trying to equate the previous slides, which looked at a 50 million barrel field, with Alaska's tax structure that is company-wide and has no ring-fences. He asked whether it is the proportion of an individual company's base production versus how much with GVR/GRE that must be looked at to understand how this would affect different players.

MR. MAYER replied that can be done, but said the administration and its consultant are in a better position to do that because they have access to confidential taxpayer data. The three big producers, by and large, do not have significant, if any, production that would initially apply for the GVR/GRE. Looking at it in terms of the variable credit and the impact on base production is the best way to understand overall what this looks like for them, not including any new things in new areas that they might do. One can distinguish between those and understand their economics separately without needing to perfectly layer them on top and put a final precise number on the combination.

REPRESENTATIVE SEATON said he would like to ask the question of the administration because the committee needs to see the proportion of what to expect, given there is quite a difference in the tax rates depending on what a company is doing.

[7:03:01 PM](#)

MR. MAYER commenced his presentation, outlining a hypothetical scenario for a new development of 50 million barrels with \$18 per barrel in costs [slide 10]. For this scenario under ACES,

he said the overall tax rate with progressivity would rise above 76 percent at the upper price levels.

MR. MAYER, in response to two questions from Representative Seaton, confirmed the \$18 is solely capital cost and does not relate to the \$30 per barrel in lease expenditure. He clarified the earlier slides are a very simplified way of looking at overall base production - they are 50 million barrels a year in production, not a 50 million barrel field. Slide 10] is looking at actual lifecycle economics of a hypothetical 50 million barrel field.

[7:04:32 PM](#)

MR. MAYER moved to slide 11, discussing the aforementioned scenario under CSSB 21(FIN) am(efd fld) with 12.5 percent royalty and 20 percent GVR/GRE. Rather than progressive rates rising above 76 percent government take, the rate is just under 61 percent. This 61 percent rate remains unchanged under Version K; the only change is the categories of production that qualify for this level of government take.

MR. MAYER, responding to Representative Tuck, said the \$18 is the total drilling and capital cost of development per barrel of reserves in the 50 million barrel field.

[7:06:08 PM](#)

MR. MAYER, in response to Representative P. Wilson, explained the top left graph on slide 11 tallies the total level of government take for this scenario, which is then reflected in the bottom right chart labeled "Economic Summary." The column in the bottom right chart labeled "GT0" is the undiscounted government take.

REPRESENTATIVE P. WILSON observed that at a price of \$80 per barrel the total government take is [60.56] percent and at a price of \$45 there is no tax except for royalty.

MR. MAYER replied that in this scenario of cost structure and 12.5 percent royalty, royalty alone at a price of \$45 gets to 100 percent government take. In further response, he explained that at a price of \$45, the government take with other taxes could be more than 100 percent, but it would not be productive to show more than 100 percent on the chart. The essential point is that at \$45 a barrel, all of the cash the project produces

net of its costs is taken up just in paying the royalty, nothing is left for anything else.

[7:09:17 PM](#)

MR. MAYER next looked at the aforementioned in the context of Alaska's competitiveness with other comparable regimes [slide 12], noting that for new production qualifying for the 20 percent GVR/GRE, the government take is decreased substantially from the very high levels under ACES. Interpreting the chart, he explained the [right-most red arrow] on the chart depicts government take for new production under ACES and the [left-most blue arrow] depicts government take for new production under Version K. Under Version K, the level of government take for new production is much more in the "heart of the pack" among Alaska's peer groups, particularly the peer group of the Lower 48. For production not qualifying for the GVR/GRE, Version K (the right-most blue arrow) puts Alaska in the heart of the pack at a price of \$80 per barrel; however, at prices of \$100 and above, Version K [is less competitive than the middle of the pack]. Responding to Representative P. Wilson, he confirmed the left-most blue arrow is new production and the right-most arrow is the legacy fields, both under Version K. He further explained that for new oil, government take is the same under Version K as it is under CSSB 21(FIN) am(efd fld). For legacy production, Version K is a little better at \$80-\$100, but slightly higher at \$100 and above, than under CSSB 21(FIN) am(efd fld).

[7:13:22 PM](#)

REPRESENTATIVE P. WILSON posited Version K accomplishes little for improving worldwide competitiveness of the legacy fields.

MR. MAYER responded that when looking across the lifecycle of an asset, if looking at just the next year or two, Version K is lower at \$100 and the same at \$110, so all of the change is below those levels. He suggested asking the companies that will testify after him as to whether lower take at those prices will make a material difference to them.

[7:15:25 PM](#)

MR. MAYER resumed his presentation, noting that the 12.5 percent royalty rate included in the aforementioned scenario applies to many of the older leases in Alaska [slide 13]. In a 50 million barrel field of new development at 12.5 percent royalty and a 20

percent GVR/GRE, the overall level of government take is just below 61 percent across the board. However, most of the newer leases have a 16.7 percent royalty rate [slide 14], which raises the government take to 63-64 percent and is the level of government take that will apply to many things that might be done across the North Slope, particularly by new companies coming to Alaska to invest. The impact of that high royalty is worth bearing in mind when thinking about competitiveness, he said. For those leases at 16.7 percent royalty, he suggested consideration be given to raising the GVR/GRE to 30 percent, which would lower the government take to 61 percent [slide 15].

[7:17:16 PM](#)

MR. MAYER, responding to Representative Tuck, confirmed that the assumptions in slide 15 are not included in any version of SB 21. He said purpose of the slide is only to show what the impact would be if the GVR/GRE were to be raised for leases with 16.7 percent royalty to achieve the same level of competitiveness.

MR. MAYER, responding to Co-Chair Saddler, understood that new leases are more likely to be at one-sixth [16.7 percent] than one-eighth [12.5 percent]. He suggested the Department of Natural Resources be asked about this.

[7:18:25 PM](#)

REPRESENTATIVE P. WILSON observed that when the state's split of the net present value of production goes down, the federal government's split goes up, and vice versa. She asked why.

MR. MAYER explained this is because federal income tax is the last form of tax applied. Thus, all the costs for production, including state taxes, are deducted in calculating profit and loss for the perspective of paying federal income tax. In further response, he confirmed that if a company pays the state less, it will then pay the federal government more. Responding further, he said the companies do better, relatively speaking, when the state taxes them less, but the degree to which they do better is reduced slightly by having to pay the federal government that little bit more.

REPRESENTATIVE P. WILSON inquired whether it is good for the companies if the state taxes them less, but they then have to pay more in federal tax.

MR. MAYER responded the amount in federal tax that companies pay in addition is substantially less than the reduction that they get from the state because it is a 35 percent rate.

7:22:22 PM

BARRY PULLIAM, Economist & Managing Director, Econ One Research, Inc., as consultant to the administration, compared the fixed \$5 per barrel credit provision in CSSB 21(FIN) am(efd fld) with the sliding per barrel credit provision in the proposed committee substitute, HCS CSSB 21, Version K. He said the sliding credit starts at a high of \$8 per barrel when the wellhead value is \$80 a barrel or less, moving down at the rate of \$1 for every \$10 increase in the wellhead value until reaching \$0 credit at \$150 wellhead value. In Version K, this sliding scale credit applies only to areas without the gross value reduction (GVR); for areas with the GVR, the credit is fixed at \$5 per barrel.

7:24:10 PM

MR. PULLIAM provided an example of tax calculation [under Version K] using the sliding scale production credit for volumes not subject to the GVR [slide 3]. At an ANS West Coast price of \$100 per barrel, less a transportation cost of \$10 per barrel, the gross value at the wellhead comes to \$90 per barrel. Subtracting lease expenditures of \$30 per barrel, the taxable value per barrel comes to \$60. For 100 taxable barrels, the total production tax value comes to \$6,000 (\$60 times 100). Multiplying that \$6,000 by the tax rate of 35 percent results in a production tax before credit of \$2,100. At a wellhead value of \$90 per barrel, the credit is \$6 per barrel. Multiplying the 100 taxable barrels by \$6, the total production credit comes to \$600. Subtracting the \$600 of credit from the \$2,100 of tax leaves a tax obligation of \$1,500. Dividing the \$1,500 in tax obligation by the \$6,000 in production tax value arrives at an effective tax rate on the net value of 25 percent. Dividing the \$1,500 in tax obligation by the gross value of \$9,000 (\$90 gross value per barrel times 100 barrels) arrives at an effective tax rate on the gross value of 16.7 percent. Following the chart to the left, it can be seen that as the price per barrel falls, the credit amount increases until reaching the maximum of \$8. Following the chart to the right, it can be seen that as the price rises, the credit amount falls until phasing out at the wellhead head value of \$150. The effective tax rate, as a result of the interaction with the credit, is lower at low prices and moves up to a maximum of 35 percent at high prices.

[7:28:33 PM](#)

MR. PULLIAM, in response to Representative P. Wilson, restated how to calculate the production tax after credit at a price of \$100: the \$600 in total production credit is subtracted from the \$2,100 in production tax before credit, resulting in a production tax after credit of \$1,500. To arrive at the 25 percent effective tax rate after credit, the total tax actually paid of \$1,500 is divided by the production tax value of \$6,000.

[7:30:15 PM](#)

MR. PULLIAM then provided an example tax calculation [under Version K] using the fixed \$5 per barrel credit for volumes that qualify for the 20 percent GVR [slide 4]. Different than on slide 3 is that the per-barrel credit line (fifth line up from the bottom) remains fixed at \$5 per barrel rather than varying, and there is a line for the 20 percent gross value reduction (eighth line down). The bottom line on the chart illustrates that the effective tax rates are uniformly lower for volumes qualifying for the GVR. Responding to Representative P. Wilson, he confirmed that production fits into either the sliding credit scale or the GVR [and a fixed credit of \$5 per barrel].

[7:32:55 PM](#)

REPRESENTATIVE SEATON understood that, currently, all production would fall under the sliding scale production credit shown on slide 3.

MR. PULLIAM replied almost all. He believed some production, such as Nikaitchuq and Ooguruk, would qualify for the gross value reduction. In further response, he confirmed that except for Nikaitchuq and Ooguruk, all production would be under the sliding scale production credit.

[7:33:35 PM](#)

MR. PULLIAM compared the average government take across all existing producers for Version K, for CSSB 21(FIN) am(efd fld), and for ACES for fiscal years 2015-2019 [slide 5]. He explained the fiscal years match those in the fiscal note. The effect of the sliding scale credit and 35 percent base tax in Version K is to reduce government take below that of the fixed \$5 credit and 35 percent base tax in CSSB 21(FIN) am(efd fld) at ANS West Coast prices of \$100 and less, and to increase government take somewhat at prices over \$100 per barrel. Government take would

top out at about 67 percent when the sliding credit goes to \$0 at the price of \$150. Thus, at higher prices, government take under Version K is 1.5-2.0 percent higher than under CSSB 21(FIN) am(efd fld); at lower prices, government take under Version K is a few percentage points lower than CSSB 21(FIN) am(efd fld). Essentially, the line for Version K is tilted to be a more progressive line, with the axis point at \$100 per barrel where the \$5 credit applies.

[7:35:34 PM](#)

MR. PULLIAM, responding to Representative Tuck, confirmed that the percentage of government take depicted on slide 5 is an average for the five-year time period with all the credits and deductions.

[7:35:53 PM](#)

MR. PULLIAM, responding to Representative Seaton, confirmed that at the price of \$160 and above, the percentage of government take under the sliding scale decreases from 67 percent and that this is the result of royalty. He explained the royalty has a slight regressivity to it and there is no progressivity left in the tax system at that point, so the overall government take comes down slightly.

[7:36:34 PM](#)

MR. PULLIAM, responding to Representative P. Wilson, explained the chart on slide 5 is calculated across all producers on the North Slope, so some of those producers will not fall under the sliding scale. Some of them will fall under the GVR with the \$5 credit. In further response, he confirmed "all producers" means he lumped all of the producers together and then averaged it. He said this is done to protect confidentiality because these are based on cost projections that are provided by the taxpayers to the Department of Revenue (DOR) and those figures are used in DOR's forecasts. Essentially, the forecast values developed by DOR are used for both the volumes and the costs. To protect confidentially the information for a particular field or for a particular taxpayer is not revealed - it is aggregated over the total. He added that the production on the North Slope will be overwhelmingly based on just the sliding scale rates, as opposed to the GVR.

[7:39:16 PM](#)

MR. PULLIAM moved to slide 6, explaining that the calculations for estimated state revenues are his, not DOR's. The revenue depicted by the blue bars is for CSSB 21(FIN) am(efd fld). The revenue depicted by the green bars is for Version K and to calculate this revenue he replaced the flat \$5 per barrel credit with the sliding scale where that would apply. Comparing the two bill versions, the revenues under Version K would be: a little lower at an ANS West Coast price of \$80 per barrel, down ever so slightly at \$100, flat at the DOR forecast price because the \$5 credit would be applying to both versions, and higher at \$120 and above.

[7:40:55 PM](#)

MR. PULLIAM explained slide 7 is a pictorial representation of the tax rates; the lines on this graph correspond with the percentages shown in the charts [on slides 3-4]. Version K is depicted in green and CSSB 21(FIN) am(efd fld) is depicted in blue. The solid line for each bill version is the effective tax rate on the net value of the oil and the dashed green line for each bill version is the effective tax rate on the gross value of the oil. The tax rate for the sliding scale credit under Version K increases in a stair step function. The tax rate lines for both bill versions cross over each other between the ANS wellhead value of \$100 to \$110, so above that level the tax rates under Version K are higher than CSSB 21(FIN) am(efd fld) and below that level the tax rates are lower.

[7:42:42 PM](#)

MR. PULLIAM pointed out that at every increment of \$10 in wellhead value, the stair step credit moves by \$1 [slide 8]. For example, between the wellhead value of \$80 and \$89.99, the credit is \$8 per barrel and [at \$90] the credit drops to \$7. He recalled that Mr. Mayer showed committee members what happens with the marginal takes. He further recalled Mr. Mayer mentioning that the sliding credit could be structured as a straight linear function so that with each \$1 movement in the value of the oil the credit could be moved and accomplish essentially the same thing as would a stair stepped method.

[7:43:46 PM](#)

MR. PULLIAM, responding to Representative P. Wilson, said there is no benefit one way or the other between using either a stair stepped versus smoothed sliding credit. However, in his opinion, the smoothness to the linear function is somewhat more

attractive than the abrupt change at each \$10 level. Responding further, he said the tax would be just as simple for a stair stepped credit as for linear. Directing attention to slide 9, he said a linear credit, as opposed to a stair step, would flatten out the tax rate over the price range, which, in his view, is more attractive than the other method.

[7:45:18 PM](#)

MR. PULLIAM, responding to Representative Tuck, said he could provide a formula for a linear function. He explained that whether this linear line falls above or below the stair steps on a graph depends upon which dots are connected. For example, on slide 8 at \$150 wellhead value the credit is \$0, at \$140 and above it is \$1, so he connected the linear line at that portion of the stair because, in his view, that fits with what is written in the bill if one wanted to smooth out the line.

[7:46:41 PM](#)

MR. PULLIAM, responding to Representative Seaton, said he does not have these same charts with the GVR/GRE, but could provide one.

REPRESENTATIVE SEATON said he would appreciate that. He then inquired whether the administration has a time estimate for when 30 and 50 percent of the oil would be subject to the GVR/GRE and fixed \$5 credit rather than just the stair step credit.

MR. PULLIAM responded he would have to talk with the forecasters at the department. He offered his belief that it would be "a while out" before 50 percent was reached because the legacy fields would, by and large, be subject to the stair step and will continue to be more than 50 percent of the oil for "quite some time."

REPRESENTATIVE SEATON commented it would be helpful to see because shale oil could take off and in fifteen years could be 350,000 barrels a day.

MR. PULLIAM said he will talk with the department's forecasters.

[7:48:30 PM](#)

MR. PULLIAM returned to Representative Tuck's question about a formula and advised that a formula is easy to derive regardless

of whether one wants to connect it at the bottom or the top of the stair steps.

MR. PULLIAM concluded his presentation by drawing attention to graphs comparing the share of profits received by the state, industry, and federal government under ACES (slide 10, top graph) to the shares that each would receive under Version K (slide 10, bottom graph). To create the charts he combined the 2012 historical information for the two legacy fields.

[7:51:18 PM](#)

DAMIAN BILBAO, Head of Finance, BP Exploration (Alaska) Inc., testified it is important to remember that the benchmarking is against the ACES policy, the policy that has left Alaska uncompetitive relative to other locations where BP can direct its investments, and said that is fundamentally the policy decision before the committee. He reminded members that [on 3/26/13] he talked about how [CSSB 21(FIN) am(efd fld)] created a step change for Alaska in terms of competitiveness. It would position Alaska in a better place than under ACES, which is uncompetitive, complex to administer, and difficult for planning a business. It would create a more competitive environment and would provide a simpler model to administer and to plan a business. Being able to run models for what a business investment would look like is valuable for both existing and potential investors.

[7:54:25 PM](#)

MR. BILBAO noted slide 2 is the same slide he displayed [on 3/26/13], except it includes checkmarks highlighting where the proposed committee substitute, HCS CSSB 21, Version K, makes additional progress beyond that of CSSB 21(FIN) am(efd fld). Both bill versions do well in their provisions to eliminate progressivity, include the GVR/GRE which positively impacts economics, and simplify Alaska's fiscal system. Version K takes an additional step by simplifying the GVR/GRE to make it clear that there really are two levers to work within the legacy fields - the base rate and the sliding scale [credit]. Version K takes an even further step in simplifying the fiscal system because a producer would not have to determine whether the GVR/GRE applies, which makes it simpler to model business and project economics.

MR. BILBAO recounted that [on 3/26/13] he testified to what CSSB 21(FIN) am(efd fld) could do better: below \$100 a barrel the

high base rate of 35 percent presents a challenge. Version K addresses this. Another provision to which he testified on 3/26/13 that could be better was the GVR/GRE: under CSSB 21(FIN) am(efd fld), it was uncertain what projects the GVR/GRE would apply to. Version K addresses this. This progress was partly accomplished by "taking the line ... and tilting it a bit to the right so it corrects some of the challenge below \$100 a barrel and takes away some of the upside opportunity above \$100 a barrel, effectively reintroducing a slight progressivity to the equation."

[7:56:45 PM](#)

MR. BILBAO said BP believes that, overall, Version K is another positive step forward and is a positive balance. Version K does not attempt to select winners or losers; it provides a level playing field that ensures the state, large producers, and small producers have opportunities to benefit. Although there is opportunity to take that even further, Version K repositions Alaska on the competitive landscape and it represents a policy shift because it shifts the burden to benefit from those credits from spend to production. It is a signal from the legislature that the policy will require the producers to deliver the production in order to benefit from the credits. He said BP believes this shift in policy is fair because the progressivity is also eliminated, which allows BP to capture the upside of its projects and places that opportunity under BP's control.

[7:58:23 PM](#)

REPRESENTATIVE SEATON, noting the elimination of progressivity, asked how many years it would take for BP, the largest operator on the North Slope, to see an increased investment and production to at least stem the decline and have equal production to that of 2013.

MR. BILBAO replied Version K encourages not only long-term investments, but also near-term and mid-term investments. If the bill passes in its current form, near-term opportunities could be expected as a result of additional drilling, additional pads, and some opportunities within the legacy fields.

REPRESENTATIVE SEATON related the committee has heard three to four years as a timeframe for seeing something in the legacy fields. His comment at that time was that if the bill is passed and within five years it fails to produce the rates of production that the state has now, he will consider the bill a

failure and not working. He asked whether five years would be a legitimate timeframe from BP's standpoint.

MR. BILBAO responded it depends on what the final bill looks like and how meaningful the tax change is. As stated by the legislature's consultants, different levels of tax change will lead to different levels of investment. If a bill passes in the current form, he would expect to see an impact to investment and production within the next five years.

8:00:41 PM

REPRESENTATIVE SEATON observed slide 2 states that prices averaged \$80 per barrel in 2010. Since people have been saying they do not like ACES at high prices, he is surmising that 2010 is considered high prices. According to the presentation by Econ One, he further observed, \$80 would have an effective tax rate after credit [under Version K] of 15 percent on the net and 8.6 percent on the gross. He inquired whether 8.5 percent on the gross is about where BP is thinking the tax rate should be for the legacy fields which already have facilities.

MR. BILBAO answered he cannot disclose what prices BP uses for its economic modeling or for planning its business. However, he advised, today's price futures typically assume for the next five years a range of between \$85 and \$95. The market expects that to be a mid-level range for prices - not high, not low, but where the market is expected to be; with that in mind, it is important that the bill is meaningful and impacts investment in that price range as well. The legislature is looking to incentivize not just BP, but investors across a broad range and of different sizes. The legislature's consultants have shown the impact at those levels, and at prices of \$80 and \$90 [Version K] shifts Alaska "to the left" in terms of competition. It is up to legislators to decide how far left to shift, whether to remain at the top of the middle of the pack or to be lower.

REPRESENTATIVE SEATON said he is hoping the committee will receive a fiscal note that is generated on the prices that industry expects, as well as the prices that DOR expects.

8:03:25 PM

REPRESENTATIVE HAWKER remarked he is not sure the base rate in Version K results in meaningful change. He requested Mr. Bilbao to discuss the problem/issue of joint interest billing (JIB), which is not included in Version K. He noted that AS 43.55.165,

which came into law with the original production profits tax (PPT), defines the basis for what is an allowable deductible expenditure in calculating production taxes. The initial PPT recognized the importance and validity of JIBs as a basis from which to begin determining what ought be considered and allowed in DOR's process of reviewing and auditing what are allowable lease expenditures. However, ACES substantially rewrote that section and now DOR believes it is prohibited from using JIB statements to determine what is a legitimate lease expenditure.

MR. BILBAO replied it would be BP's preference to leverage existing processes or instruments that industry has already created for use internally and between companies. The JIBs exchanged between companies are audited by the other co-venturers. In BP's opinion, those JIBs present an opportunity for DOR to leverage an existing instrument for informing DOR's analysis and audit process. The decision to not use the JIBs results in the creation of separate processes and separate instruments. Using something that is already being created and already being audited makes it easier and more efficient for BP to satisfy the requests of the state. In further response, Mr. Bilbao confirmed that JIBs are one of the fundamental instruments used by BP for its Internal Revenue Service (IRS) filings. Responding further, he deferred to DOR to say whether it is familiar with JIBs.

[8:07:55 PM](#)

REPRESENTATIVE TUCK related the committee has heard in the past that the bill is a great start, but may not get the investments the state would like to see. He inquired whether BP's overall investment per year in Alaska is directly proportional to the state's taxes, such that if taxes are reduced BP will proportionally invest more in the state.

MR. BILBAO responded the more robust the economics of the projects, the more likely they are to compete for capital. The more competitive Alaska is the more investment the state will see from BP as well as other existing and new players. The process used by BP is to regularly review what has changed - not just the fiscal policy but also technology, resourcing, and other factors. Once BP knows that a project meets a certain minimum threshold, that project will compete with other opportunities around the world. At the end of the day, good projects with good economics get funded.

[8:09:53 PM](#)

REPRESENTATIVE TUCK noted the goal is to at least flatten, if not reverse, the decline. He said the committee has heard that an [additional] 40,000 barrels a day over 30 years [is needed to offset the projected fiscal impact of CSSB 21(FIN) am(efd fld)]. The committee also heard 25,000 barrels a day is needed to lower the decline from 6 percent to 1 percent. If the state needs to get to 40,000 barrels a day, where does it need to be in the competition and will Version K get the state there and how soon, he asked. He understood the legacy fields are the quickest way for getting additional oil down TAPS. If the state saves BP 20 percent in taxes a year, can the state expect to see 20 percent more production out of BP's portfolio, he further asked.

MR. BILBAO answered it is not as simple as 20 percent here and 20 percent there. However, he continued, what is simple is that the more competitive it is the more investment from all players, and more rate-adding investment leads to more production. The more competitive the state is the more rate-adding investment the state will see. To provide context, he explained that if nothing was done at Prudhoe Bay the decline would be closer to 20 percent; it is only because of investing and running a fleet of rigs that BP is able to cut the decline to 6-8 percent. Those are tens of thousands of barrels that are being produced every year that were not flowing through that pipeline the year before. It is a significant investment to get to today's level of 6-8 percent decline and it will also take a significant investment to get above that. Often lost in the conversation is that Alaska has a fantastic resource base. Within BP there is only one other location that has the resource opportunity seen in Alaska. Additionally, Alaska has a fantastic talent pool of employees and contractors that develop technology and are recognized for it on a regular basis. Alaska's problems are not below the surface; they are that Alaska's policy does not make those projects economic. With the right policy, BP believes there is great opportunity for Alaska to create a new future and a different production profile than that seen in the past.

[8:13:16 PM](#)

CO-CHAIR FEIGE, assuming Version K becomes law, inquired what logistical hindrances BP might encounter moving forward with projects, such as sufficient drill rigs, service companies, and fabricators, that might prevent BP from increasing production.

MR. BILBAO acknowledged there are geographic and logistical challenges to shifting the activity profile in Alaska, but said

some are the result of seven years of no encouragement to invest in the aforementioned. There would need to be an appropriate time to correct for that and ensure the infrastructure is in place, whether that is ensuring rigs are available or even as simple as ensuring that BP is able to go back and look at opportunities to see if they compete under the new policy. It is the logistical and infrastructure challenges that will have to be dealt with first. Beyond that, it is the simple matter of ensuring BP does the right frontend loading of some of these projects. Once there is a green light BP would have to catch up with six or seven years of living under a policy that encourages a short-term focus. That may be as equal a hurdle as the logistical one, but BP is up for the challenge.

CO-CHAIR FEIGE asked what sort of timeframe could be expected.

MR. BILBAO replied he thinks it is realistic to say that in the next few years the state would begin to see an impact on additional production. That would likely be attributed to how BP allocates its rig fleet more so than constructing a new pad, for example. He offered to do the work necessary to provide a specific answer if the committee would like.

[8:16:21 PM](#)

CO-CHAIR FEIGE inquired whether it is a simple matter to reactivate the rigs that are currently stacked at Prudhoe Bay.

MR. BILBAO responded it is more complex than putting the key in ignition. The rigs would need a full safety and efficiency review and BP would have to ensure they are capable of operating to the standards that BP requires to be used in the fields it operates. Additionally, there needs to be the right people to staff them. Therefore, it can take several months to get a rig from zero to ready to drill.

CO-CHAIR FEIGE opined that the variable per barrel credit in Version K that would apply to legacy fields would induce what he would refer to as a progressivity type of effect, although not progressivity the way it currently is. It would take a slightly higher bite at higher prices and a lower bite at lower prices. He asked whether the variability of that tax credit makes the tax code simpler or is a complicating factor.

MR. BILBAO answered it has a dual impact. He confirmed it has a positive effect below \$100, but said that is problematic because the base rate is quite high. It reintroduces a slight

progressivity to the tax structure, which is concerning from an investor's perspective because at higher prices an investor may not have the trade-off opportunity versus some other factors. The shift of the burden to a production-linked credit is offset by the opportunity of the removal of progressivity. The more that progressivity is reintroduced it will factor into the equation to a certain degree and to what degree will depend on the individual company to determine.

[8:19:14 PM](#)

CO-CHAIR FEIGE recalled BP's [February 2013] testimony that the order in which deductions are taken affects the tax rate - changing the order changes the tax rate, which makes it difficult for an investor trying to plan a project to be able to determine what the tax rate will be. He inquired whether Version K still presents this same problem.

MR. BILBAO replied that while BP must make an assumption for the dollars per barrel to model, Version K is fundamentally much simpler to administer and to model from a business planning and economic perspective. It would be pretty hard to get much more complicated than ACES, he added.

CO-CHAIR FEIGE presumed BP could possibly have areas within its acreage that would fall under the GVR versus legacy field property. Thus, there would be two different tax schedules. In setting up this tax structure, legislators tried to keep the percentages of government take relatively close, especially at the price ranges the companies have indicated are used for basic planning. He asked whether there are any issues with this slight difference in percentages of government take between GVR and non-GVR production at prices of \$70-\$90 per barrel.

MR. BILBAO responded BP does not expect for the GVR to be a factor in the fields it operates, at least not for near- to mid-term. When looking at its modeling, BP has kept it simple and has only looked at a base rate and a dollar per barrel. The company has not considered any unintended consequences of having dual systems within a single unit, although there is always a potential for that if there are different structures. He suggested that the base structure of the base rate and the dollar per barrel actually provide the legislature with a structure that could be used for specific types of developments in the future, which is a conversation for another day.

[8:22:48 PM](#)

CO-CHAIR SADDLER recalled hearing that the expiration of credits might induce frontend loading, such as some quick purchases and quick capital expenses. He inquired whether BP would spend more than it ordinarily would to take advantage of that if the qualified capital expenditure credit was sunset at year's end.

MR. BILBAO answered BP typically lays out its plans one year or more in advance, so he does not expect that BP would a shift to try to respond to a change in the policy. Rather, he would expect that BP's focus would be on how its plans may change for after the new policy is in place.

CO-CHAIR SADDLER asked about BP's perspective regarding what goes into making an investment decision no matter the location.

MR. BILBAO replied the decision making can be as much art as science, and depends on individual factors as well as opportunities. He may look at different factors for a deepwater Gulf of Mexico project than he does for an onshore project in Texas or Alaska, or even more so an unconventional hydrocarbon project like coalbed methane. So, it is not quite as simple as a certain number and another number and then comparing and whatever is above the line is undertaken, in particular because there are so many intangible factors, such as political stability or durability of the fiscal framework. Those intangible factors must be injected throughout the process and ultimately a business plan is developed that BP feels best reflects its strategy across a broad portfolio.

[8:26:00 PM](#)

CO-CHAIR SADDLER noted it is heard that the oil industry is making a profit in Alaska, so no matter what the state does the industry will continue spending money in Alaska. He inquired whether BP seeks profit or the highest profit when making investment decisions. He clarified he is asking whether the factor of being profitable is more important than the relative profit. He is asking whether BP actually evaluates where it can make the most money, not just make money.

MR. BILBAO answered BP has choices on where it invests the next dollar. First and foremost, there is a base level of investment that ensures the fields are operated safely and efficiently, which is typically constrained more so by logistics and resourcing than by funding. Beyond that, the dollars do compete. If BP is going to decide on whether to build a pad in

Alaska or spend those billions of dollars to drill wells in the Gulf of Mexico or offshore Angola, those opportunities are going to compete against each other. It is about competing for the rate-adding investment, not necessarily the rate-sustaining investment. Those rate-adding investments must compete because day the company's return per barrel is not the same everywhere.

MR. BILBOA, responding further to Co-Chair Saddler, explained that rate-sustaining investments are those investments that BP makes to ensure the fields are renewed for the long-term. For example, Prudhoe Bay was built for 30-something years and it has been more than 35 years and so there are new things that BP has to put in place to ensure that the field is prepared and renewed to produce for another 30 years. Those are large investments in facilities and pipeline. Also, it must be ensured that BP's employees are developed and learning the new technologies. Rate-adding investments are the ones that bring on an additional barrel, such as a rig that drills a well or a pad that provides a new location to drill multiple wells from, or a deepwater platform that allows drilling in several miles of water. All of those are rate-adding investments that must ultimately compete.

[8:28:57 PM](#)

REPRESENTATIVE P. WILSON related it is being heard that there are more workers on the North Slope than ever before, but Mr. Bilbao is saying BP must spend lots of money to keep production going, which tells her that much of that is maintenance work or bringing things up to par. She requested Mr. Bilbao to comment.

MR. BILBAO replied it is not just maintenance, but also renewing the facilities for the next 30 years. He agreed that today the level of employment on the North Slope is high, pointing out that five of every six people on the slope are focused on renewing the infrastructure - rate-sustaining, not rate-adding, projects. Only one person of the six is focused on a project that delivers new rate, which is consistent with the policy that is in place. If the policy encourages companies to maintain production in an efficient way and focus on near-term opportunities, then that is the ratio of how personnel will be deployed. If the policy were to change, the ratio might change to something different.

[8:30:38 PM](#)

REPRESENTATIVE TUCK recounted that when legislation was first before the committee, the [Department of Revenue and Department

of Natural Resources] stated the credits lead to investments but not necessarily production. However, the smaller oil companies have stated they are scratching their heads over those statements. He inquired whether BP has seen investments across the North Slope that do not lead to production.

MR. BILBAO responded that by definition an investment must either sustain the production for a longer period of time or add new production. So, fundamentally, the answer to the question is that new production comes from investment and sustaining production comes from investment. In further response, Mr. Bilbao explained if a company does not sustain it will not have the facilities to be able to decline; in fact, the decline would be 100 percent because there would be no pipelines or facilities to flow through. He specified it is important to differentiate between sustaining infrastructure and sustaining production decline. If one considers what it took to build the infrastructure to begin with, and that it has lasted 30-plus years, it can be seen that a significant level of investment is needed to ensure it lasts another 30 years. That is different from sustaining production decline. If BP continues to do what it is doing now with the same number of rigs, at best BP will continue to decline at its current levels of 6-8 percent, assuming things continue as they are.

[8:32:51 PM](#)

CO-CHAIR SADDLER asked whether the tax regime of net base, GVR, and credits as proposed in Version K looks similar to any other regimes in the U.S. or world.

MR. BILBAO replied he has worked in several countries and has never seen a structure with a base rate this high and credits the way they are. Remarking that similar questions have been asked in the past by the co-chair with regard to new and old production, he said that in every place he has worked all that was cared about was production without regard to whether it is new or old, so long as it is more than there was the day before.

[8:34:03 PM](#)

REPRESENTATIVE TARR inquired whether the employment information of five out of six and one out of six cited by Mr. Bilbao has a source or is anecdotal.

MR. BILBAO responded it is based on data from BP's human resources department. As operator of Prudhoe Bay and many other

fields on the North Slope, BP knows what its staff and contractors are doing and what projects they are deployed to. Additionally, BP knows what proportion of its investment is going towards rate-sustaining projects as opposed to rate-adding projects as opposed to drilling projects.

REPRESENTATIVE TARR asked whether Mr. Bilbao included employees of other companies in his numbers for exploration work.

MR. BILBAO answered BP does not do exploration, so that would be zero for BP. The numbers are primarily focused on BP operated facilities - Prudhoe Bay, Milne Point, Northstar, and Endicott.

REPRESENTATIVE TARR surmised the numbers cited by Mr. Bilbao are reflective of that particular employment situation and not encompassing everyone.

MR. BILBAO understood the numbers are reflective of other fields, but suggested those operators be asked.

[8:35:32 PM](#)

REPRESENTATIVE TARR said a concern about Version K is that it disadvantages small companies by the way it changes the credit system that is for bringing them up to do exploration. Given it has been suggested that both near- and long-term scenarios be looked at, there needs to be more exploration, she opined. She inquired whether BP anticipates returning to exploration on the North Slope.

MR. BILBAO agreed it is important that all good opportunities move forward for large players as well as new entrants and small producers. As a large operator, BP benefits from that because its facilities are underutilized. Just like TAPS is three-fourths empty, BP's facilities could benefit from having additional flow-through, which benefits existing operators as well as new entrants. While he cannot speak for BP's board of directors regarding strategy direction in Alaska, he can say BP has significant existing opportunities in its portfolio, in both light and heavy crudes as well as gas, and those are more than adequate to keep BP busy for quite some time.

[8:36:58 PM](#)

CO-CHAIR SADDLER said he has heard the argument that there are limitations to production and Alaska should not dare to hope for increased production because there is not enough capacity in the

North Slope for the handling, processing, and transit lines. Given that BP's facilities are underutilized, he asked whether there is any difficulty in ramping up production based on the current state of the physical plant.

MR. BILBAO allowed that is correct and said there are certain facilities where a bottleneck is possible. When considering new projects, BP looks at what additional investment is required to ensure the facilities have the capacity to accept that production. He requested that his statement not be taken as a broad application to all of BP's facilities, adding there are some where there is opportunity when a new project comes on to ensure that the production will flow through. In further response, he explained that currently in BP's fields, Prudhoe Bay in particular, a tremendous amount of water and gas is produced along with some oil. Thus, BP must work hard to manage that ratio and ensure that the water is properly managed. Oftentimes it is reinjected to maximize the recovery of oil, and that delicate balance can be more challenging in some facilities than others. So, when BP looks at new investments, that is one of the things considered.

[8:39:40 PM](#)

BART ARMFIELD, Chief Operating Officer, Brooks Range Petroleum Corporation, first provided an update on his company's Mustang development as a response to the question being raised in other bodies and committees about what the state is getting for its investment [slide 2]. He said his company is 10 days away from completion of an access road and production pad that is 4.5 miles off of the Kuparuk River Unit infrastructure. Results from this project are very good: the overburden, the amount of material that has to be removed to get to the gravel product, has been less than expected; the gravel quantity is much larger than was expected; and the quality is well above specification. The plan is to condition that road over the summer, to do facilities design, procurement, and some fabrication, and to begin onsite construction in second quarter 2014. The project is 17 months away from contributing new oil to TAPS at the rate of 15,000 barrels a day. Therefore, there are results from the investment the State of Alaska is making.

[8:42:40 PM](#)

MR. ARMFIELD, referencing BP's testimony about production, sustaining production, and increasing production within the legacy fields, he stressed the state needs both exploration and

production [slide 3]. "One size does not fit all - it means a totally different result for a major than it does for a small producer like Brooks Range Petroleum," he said. Brooks Range Petroleum as a small independent has delivered and has brought significant value to the state for the credits that have been provided. Overall, his joint venture has received \$69 million in credits over a period of 7 years for its total North Slope portfolio. The Mustang project alone will recover all those credits within a single year and over its project life Mustang will return \$1.2 billion in revenue to the State of Alaska - 17 times the credits paid out.

MR. ARMFIELD, responding to Representative P. Wilson about the Mustang project's timeframe, turned to slide 4, explaining the blue line at the bottom of the graph is Mustang, which will start production in 2014 and go 15 years through 2031. It will contribute 15,000 barrels per day to TAPS. With an aggressive schedule that his company has planned and with the other remaining projects in his company's inventory, a total of 55,000 barrels per day will be reached within five years (2018).

[8:45:08 PM](#)

MR. ARMFIELD returned to his presentation, providing his company's comments on the proposed committee substitute, HCS CSSB 21, Version K. He requested consideration be given to reducing the 35 percent base tax rate to 30 percent (slide 5]. Regarding elimination of credits, he requested consideration be given to extending the qualified capital expenditure (QCE) and exploration incentive (EIC) credits to 2016. Understanding the long-term effects on the fiscal note that extending the credits would create, he said his company supports the \$5 produced barrel credit. To offset the loss of the credits, he proposed that monetization of the 35 percent net operating loss be transitioned from a starting rate of 45 percent down to the 35 percent rate. He explained 45 percent is the equivalent of the 20 percent QCE credits and the 25 percent loss equaling the 45 percent that the Mustang project was originally sanctioned under. All of his company's acreage would qualify for the 20 percent GVR/GRE. Brooks Range Petroleum would qualify for the small producer credit that will expire in 2016 under Version K, but this will not impact the company because it will have production in 2014 thereby qualifying for the 10-year benefit of this credit. To support the exploration side of exploration and development, however, he suggested qualification for the credit be extended to 2022 in anticipation of new players coming in.

[8:47:53 PM](#)

REPRESENTATIVE TUCK asked whether Mr. Armfield's aforementioned suggestions would put the exploration back into the exploration and production.

MR. ARMFIELD replied they would provide a better basis for exploration than the current proposal under Version K.

REPRESENTATIVE TUCK inquired whether that would bring it back to the current exploration under ACES.

MR. ARMFIELD responded he does not believe it would because Brooks Range Petroleum will get out of the 45 percent credit basis once it goes into production and is profitable. At that time the company will fall under the same tax structure as everyone else. Hopefully, his company will provide the basis with its Mustang project to be able to sustain an exploration program moving forward to backfill the decline that is generated from the Mustang project and later those projects through 2018.

REPRESENTATIVE TUCK asked why there is such a concern with the base rate, given the effective tax rate is low when everything is combined.

MR. ARMFIELD answered the slides provided by both consultants are for a new producer with a 50 million barrel field, and in this scenario the government take at \$100 per barrel oil is in the range of 64 percent. A 5 percent adjustment in that base rate is a significant base position that creates added value for his company's projects.

[8:50:40 PM](#)

REPRESENTATIVE SEATON inquired whether the suggestion for a transition from 45 percent to 35 percent would be for a durational time or for anyone who qualifies for the net operating loss (NOL).

MR. ARMFIELD assumed that 35 percent is the legislature's target rate for a net operating loss. The only basis he has to request the 45 percent is to make Brooks Range Petroleum whole to the 45 percent combination of QCE's and 25 percent loss that was in the old program under which the project was sanctioned. Once the company becomes profitable, it would transition out of that 45 percent, which would also be the case at 35 percent.

REPRESENTATIVE SEATON noted that once Brooks Range Petroleum goes into production, it would depend upon company-wide expenditures, not just expenditures for Mustang. If the transition does not apply to a number of years, then that net operating loss could apply for as long as a company was continuing to invest and developing other fields. He said he is asking whether Brooks Range Petroleum needs a specific number of years or a duration that applies until it is profitable.

MR. ARMFIELD concurred a company could spend itself into a loss position, but that is not what Brooks Range Petroleum is looking for. In his company's forecast, the spend for those fields is driven by the revenue generated from the Mustang project; so, he is asking for the 45 percent relative to the Mustang project, which is two years, not the portfolio as a whole.

[8:53:53 PM](#)

CO-CHAIR FEIGE pointed out that although Brooks Range Petroleum may be reinvesting the profits so to speak, it is resulting in significant production as seen by the graph on slide 4.

[8:54:07 PM](#)

REPRESENTATIVE P. WILSON surmised Brooks Range Petroleum is saying it needs as much as possible in credits when it starts production because that cash flow will be used to continue the company's other projects.

MR. ARMFIELD replied yes, the front side support in an exploration company transitioning to a production company is very important. Effectively losing 23 percent of those capital credits by the elimination of QCE and EIC significantly impacts Brooks Range Petroleum. Going back to that forecast would require a more modest growth to that production profile than the aggressive nature that it is in now.

[8:55:13 PM](#)

REPRESENTATIVE TARR asked whether the [six] projects outlined on slide 4 were all sanctioned under ACES.

MR. ARMFIELD responded the only project currently sanctioned is Mustang. The graph is an extrapolation of his company's current inventory, tested oil, and application of the parameters that result in this profile.

REPRESENTATIVE TARR recalled previous testimony in which Mr. Armfield said the Mustang project would have been shifted out a few years had the credits not been in place. She inquired whether the timeline depicted on slide 4 is reflective of how investment opportunities would go under the current system.

MR. ARMFIELD answered this is his company's original forecast and it was based under the assumption of 20 percent capital credits and 25 percent loss credits.

[8:57:07 PM](#)

The committee took an at-ease from 8:57 p.m. to 9:12 p.m.

[9:11:47 PM](#)

CO-CHAIR FEIGE noted Pioneer Natural Resources Alaska, Inc. has submitted written testimony.

[9:12:01 PM](#)

DAN SECKERS, Tax Counsel, ExxonMobil Corporation, stated both CSSB 21(FIN) am(efd fld) and the proposed substitute, HCS CSSB 21, Version K, make significant progress to reforming ACES and represent a strong step forward towards improving Alaska's investment climate. Version K would make Alaska more competitive and would improve the state's overall investment climate. As to whether Version K would make Alaska more attractive across all prices compared to its competitors, the answer is yes and no. ExxonMobil's concern remains that the base rate is too high relative to competitors, especially the lower 48 states, which was demonstrated by PFC Energy's chart. Also, while Version K provides more attractiveness at lower prices, tying the GVR/GRE for legacy fields to price reduces the competitiveness of that as prices rise. Alaska represents a critical component of ExxonMobil's worldwide portfolio and the company looks forward to being in Alaska for many years. It is ExxonMobil's view that the need for Alaska to develop a competitive and attractive fiscal regime is one of the most, if not the most, important issues facing Alaska today. It is the legislature's policy call as to whether either bill makes Alaska as competitive and, more importantly, globally attractive against the state's competitors at all prices to attract the investment that is needed on the North Slope for Alaskans and for development of the state's resources going forward.

[9:14:42 PM](#)

REPRESENTATIVE TUCK understood Version K makes Alaska's investment climate better but not necessarily the best. He asked whether the bill will be able to stop the decline curve.

MR. SECKERS replied that is everyone's goal and ExxonMobil believes that with the right improvements to ACES the marketplace will dictate more investments be made. Investments coming forward from making Alaska more attractive will lead to more production and more investment in Alaska from all players.

REPRESENTATIVE TUCK surmised Mr. Seckers agrees that more investment leads to more production.

MR. SECKERS responded clearly there will not be more production without more investment, and it is critical to get that investment from all players.

[9:15:50 PM](#)

REPRESENTATIVE SEATON inquired whether it would mean the tax change was unsuccessful if within five years production is not at 2013 levels.

MR. SECKERS answered it will be important for the state to take a good look at that point in time to decide whether the changes went far enough. If the hoped-for production has not been reached by that time, the state could make further changes after conferring with its consultants.

[9:16:57 PM](#)

REPRESENTATIVE SEATON expressed his concern that, in regard to increasing production in Alaska's larger fields, it may not matter what short-term changes are made because investments made by the major oil companies are driven by the companies' long-term strategic plans. He inquired whether ExxonMobil makes its investments based on a long-term strategic plan or vacillates in its investments fairly rapidly with changes in tax rates.

MR. SECKERS reiterated ExxonMobil has been in Alaska for a long time and looks forward to staying for many years to come. The company is actively looking for investments in Alaska that are attractive to make, and will make them as they become attractive to do so. A number of variables are reviewed when making both long-term and short-term decisions. Most investments are long-term driven investments because it takes quite a bit of upfront

capital before recovery is ever made. However, that does not mean ExxonMobil cannot move on the shorter term if need be or if opportunity presents itself. The company makes as many investments as it can because that is the business it is in.

[9:19:37 PM](#)

CO-CHAIR FEIGE noted the governor's proposed legislation is based on several principles - make the tax code simpler, durable, and equally affect all players. He asked whether Mr. Seckers believes Version K has the potential to be a relatively stable tax regime and treats all taxpayers relatively equally.

MR. SECKERS responded it is up to current and future legislators to decide whether the proposed change has the chance to be durable. It is the legislature's purview to change taxes and policy when it deems necessary or desirable. ExxonMobil values stability, so the longer a good policy is in place and the more stable it is the better it is for investment climate. The more changes that are made the less predictable a structure is and therefore the less attractive the structure. The goal would be to establish a policy that is competitive and attractive for the long-term. Regarding equal treatment of all taxpayers, he said ACES does not because it has different rules for different areas within the state - Cook Inlet, "Middle Earth," and the North Slope - and Version K does not change any of that. On the North Slope, Version K distinguishes the legacy fields apart from the GVR/GRE, which creates disparity between the different taxpayers. The proposed \$5 per barrel credit is different for the legacy fields than it is for the others. So, no, Version K does not treat everybody the same and that could bear being looked at, at least for the players on the North Slope.

[9:22:33 PM](#)

CO-CHAIR FEIGE inquired whether Mr. Seckers sees any obvious instances in the bill that would create disincentives for various companies.

MR. SECKERS answered he cannot say how other companies might look at the bill, but ExxonMobil is looking to do all the investments it can that are attractive with its partners.

[9:23:06 PM](#)

REPRESENTATIVE SEATON noted the legislature is looking at gas pipelines and understood ExxonMobil is also looking. He asked

whether ExxonMobil plans to hold to the 35-year fiscal certainty requirement before it will engage in a gas sales agreement.

MR. SECKERS replied he cannot answer questions regarding gas.

9:25:55 PM

SCOTT JEPSEN, Vice President External Affairs, ConocoPhillips Alaska, Inc., provided one slide in a PowerPoint presentation regarding the proposed committee substitute, HCS CSSB 21, Version K. He said the left column on the slide [slide 2] lists the issues with ACES that ConocoPhillips believes need to be addressed to create an improved investment on Alaska's North Slope. The right column lists ConocoPhillips' perspectives on Version K. Progressivity is the most difficult element of ACES in terms of attracting new investment in the state, and needs to be changed. Version K has a slightly progressive tax structure, but would predominantly address the major issue under ACES and is therefore a positive. ConocoPhillips has advocated for a flatter tax rate over a broad range of prices where there is equal sharing in the upside as prices increase and as prices decrease and also as margins change, so Version K is a significant improvement over ACES. Relative to ACES, CSSB 21(FIN) am(efd fld) represented a tax increase at lower prices, and the progressive tax credit per barrel structure in Version K addresses that issue. ConocoPhillips would prefer there be no progressivity, but the company understands the balance the committee took into account when it changed the effective tax rate at lower prices in Version K.

MR. JEPSEN reminded members that ConocoPhillips has advocated for a competitive tax structure that creates a competitive attractive investment. This would include a competitive tax rate, incentives to balance the high cost environment on Alaska's North Slope, and the incentives and tax rates would apply to both legacy and new fields. The base tax rate in Version K is still too high, he specified. As seen in the data provided by the legislature's and administration's consultants, a 30 percent rate is about the average of the competition in the other areas that are attracting significant investment. As that dollar per barrel tax rate decreases as prices go up, Alaska moves backwards and ends up on the high end of average. While it is the committee's policy call on where it wants to position Alaska for investment, ConocoPhillips thinks this is an area to look into to potentially improve the bill.

9:29:01 PM

MR. JEPSEN pointed out Version K has no investment incentives inside the legacy fields, which have many challenged projects. He said ConocoPhillips is drilling around the periphery of legacy fields and drilling for bypassed reserves and isolated fault blocks inside fields like Kuparuk and Prudhoe Bay. Some very complex and costly wells are being drilled to try to access those reserves. Regarding what needs to be done to position Alaska to attract more investment, Alaska still is challenged by its location, weather, logistics, and environmental and tax frameworks. A positive change in Version K is the committee has looked at some of the comments ConocoPhillips made previously about the application of the GVR/GRE to participating area (PA) expansions inside the legacy fields. It appears there would be a greater likelihood of PA expansions inside legacy fields having the GVR/GRE application as well as the 35 percent/\$5 credit applied to those sorts of expansions versus the current progressivity structure.

MR. JEPSEN, addressing an earlier question about whether these changes will lead to increased investment, said ConocoPhillips believes Version K does change the investment climate on the North Slope and will lead to increased investment and additional production. However, until a bill is passed he cannot say exactly what projects ConocoPhillips is going to do, how much production the company will add, how many billions of dollars in investment on the North Slope might change. Once a bill is passed, ConocoPhillips can look more closely at all of its project economics and determine which projects to sanction. Version K, by and large, is a positive step forward, although there are some things that could be done to attract even more investment. Version K is a better bill than CSSB 21(FIN) am(efd fld) and is a good start towards putting Alaska on a path to a healthier longer-term economy.

[9:31:51 PM](#)

REPRESENTATIVE TARR understood it is more expensive to invest in Alaska, but noted much infrastructure is already developed on the North Slope. She asked how that factors into investment in the state.

MR. JEPSEN responded that in many areas where ConocoPhillips is currently investing considerable amounts of capital, such as the Bakken and the Eagle Ford, significant infrastructure is not required to bring those wells on line. Also, the infrastructure the company is building [in those locations] does not begin to

compare with the costs and infrastructure on the North Slope. So, even though there is infrastructure on the North Slope, it is still highly constrained by the regulatory environment.

REPRESENTATIVE TARR inquired as to the exploration activity of ConocoPhillips.

MR. JEPSEN answered there was a hiatus, but ConocoPhillips has been active in exploration for quite a while on the North Slope. The company will probably drill two exploration wells on the Cassin prospect, and has other opportunities where there has been success in the National Petroleum Reserve-Alaska (NPR-A).

[9:33:56 PM](#)

CO-CHAIR SADDLER asked whether ConocoPhillips believes it has a good understanding of the proposed system.

MR. JEPSEN replied he cannot say ConocoPhillips has a 100 percent confidence factor that it understands all the potential unintended consequences of Version K. For example, he is unsure he fully understands the impact on the marginal tax rate as the thresholds are crossed over. However, his company understands it well enough relative to the current tax framework to say that it is a big improvement.

CO-CHAIR SADDLER asked whether the looming deadline for qualified capital credits would encourage ConocoPhillips to make additional frontend loading investments.

MR. JEPSEN responded there are many structural issues with attempting to do that - it takes time to get additional kit on site, to gear up people to do work, and to order materials. The system basically has a built in governor regarding the level of activity that can be ramped up quickly. So, the answer is no.

[9:35:45 PM](#)

CO-CHAIR FEIGE, assuming Version K becomes law, inquired what logistical hindrances ConocoPhillips might encounter in moving projects forward and what things could the legislature do outside of taxes that would help smooth some of those logistical road blocks.

MR. JEPSEN answered there are obviously things that have to be done to mobilize, but they are what ConocoPhillips does and so it knows how to do them. What his company is looking for is to

create the investment climate on the North Slope that will allow it to make those decisions and implement those new projects.

CO-CHAIR FEIGE asked whether Mr. Jepsen believes the changes made to the GVR/GRE definitions in Version K are clearer and provide certainty as to whether a project qualifies.

MR. JEPSEN replied ConocoPhillips might like to expand the PA for its West Sac development inside its Kuparuk River Unit. As Version K reads now, it is clearer the acreage that would be expanded onto would probably qualify for the GVR/GRE. While there is still some discretion, he could go into it with a much higher degree of confidence than he would have before - before he would have thought it would not qualify or much of it would be unlikely to qualify. Also, there is still some uncertainty about how to measure the production, but there is history and precedent for how the company monitors production without actually having a meter on every well. This change is a positive, although the company will have to test it to know exactly how it will be interpreted.

CO-CHAIR FEIGE commented the committee will look forward to see if the expected results of the change in policy do pan out.

[9:38:55 PM](#)

REPRESENTATIVE SEATON noted ConocoPhillips has quite a bit of experience in shale in the Lower 48. He understood the company holds interests on the North Slope that have shale underlay. He inquired how ConocoPhillips would interpret the GVR/GRE in the development of shale and how shale developments would fit into PA or PA expansions where the wells are not contiguous with anything else.

MR. JEPSEN responded that in the abstract, not paying attention as to whether the economics of shale make any sense, it would be a separate PA or production from these horizons and his belief is that it would probably qualify for the GVR/GRE. There is currently no production on any of the leases that ConocoPhillips has coming out of the shales and the company has no PAs that encompass the shales or production from shales.

REPRESENTATIVE SEATON surmised, then, that Mr. Jepsen's estimate is that each well would qualify for the exclusion and \$5 credit because it would not have continuity with another reservoir.

MR. JEPSEN answered his understanding of Version K, as written, and the definition of what would qualify for GVR/GRE, is that ConocoPhillips would probably form a single PA that encompasses the entire area it would be developing in this contiguous shale. Rather than thinking about it well by well, he would think about it as any well inside that PA that was producing from that horizon because that horizon is qualified. For example, as discussed by Mr. Armfield, every well in the Mustang field would qualify for the GVR/GRE - it is not individual well by well, it is any well inside that PA.

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REPRESENTATIVE SEATON inquired whether it would mean the tax change was unsuccessful if within five years production is not at 2013 levels.

MR. JEPSEN replied the answer is a relative answer because right now he cannot say what might happen to the existing production from the current fields. Based upon all his years in this business, he can say it is difficult to predict how reservoirs are going to perform, particularly as they age. It is not beyond the realm of possibility that base decline might actually steepen for some reason and there could be a much bigger gap to overcome by the investment that this bill might attract to the North Slope. At that time in the future, there would need to be a look at how much new investment happened, how many new wells were drilled, what was the production from those wells, and what was the base decline, and then make a relative judgment rather than sitting here today making an absolute judgment based upon preconceived ideas of what would constitute success.

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REPRESENTATIVE SEATON, noting there would no longer be credits [as a way to track investments], asked what Mr. Jepsen would suggest for providing a handle on what investments have been made during that time period; for example, whether there should be something in the bill requiring companies to report their investments so a comparison of investment levels can be made.

MR. JEPSEN responded DOR receives investment numbers from all producers and explorers, so that would be a gauge as to how investment levels might be changing. However, he added, it is again a relative answer. If the price of oil were to go down but the tax environment or the investment climate on the North Slope competes favorably with other locations, maybe investments

are down but relative to other places it is robust. Judgment needs to be made at that point in time when the current environment can be considered.

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REPRESENTATIVE SEATON addressed the co-chairs, saying the committee needs to hear from DOR whether the legislature has the right to know or whether it is in-house knowledge regarding the level of investment in terms of determining whether changes were successful. He said something may need to be included in the bill that requires aggregated investment data.

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CO-CHAIR SADDLER requested Mr. Jepsen's opinion about the Oil and Gas Competitiveness Review Board proposed under Version K, and the board's composition, mission, activity schedule, and confidentiality provisions.

MR. JEPSEN answered all of those could be somewhat problematic, depending upon how they are handled. He suggested the bill be given time to work and, if the legislature wants to have such a board, to push it out far enough in time where there is the opportunity to have a meaningful look back. He would argue the legislature should ensure the board has the ability to hire qualified consultants to make that assessment. It could work under the right setup, but doing it on a very frequent basis would not be terribly helpful because it takes time to do things on the North Slope and for investors to react.

CO-CHAIR SADDLER said he thinks the board is on a four year schedule. He asked whether Mr. Jepsen believes ConocoPhillips would feel safe sharing confidential information with the board.

MR. JEPSEN replied he has not looked at the provision close enough to answer the question.

CO-CHAIR SADDLER asked whether the review board would be seen as a benefit to the industry as well as a possible negative.

MR. JEPSEN responded that is a possibility.

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REPRESENTATIVE TARR said she thinks Version K provides for the board to meet no more than once a calendar year. She asked

whether Mr. Jepsen meant once a year is too often and commented she does not think that to be too often.

MR. JEPSEN said his comment was about how often a pronouncement is actually made as to whether the state is competitive. He reiterated he thinks the state needs to give it time to work.

[9:48:52 PM](#)

CO-CHAIR FEIGE requested the Department of Natural Resources to address the shale issue brought up by Representative Seaton.

JOE BALASH, Deputy Commissioner, Office of the Commissioner, Department of Natural Resources (DNR), replied that as the hypothetical is laid out, the question that must be asked is, "Where is the production from the shale resource taking place?" If it is taking place in a unit that was formed after 2003, then clearly it will qualify for the GVR/GRE. If it is taking place in a PA that is newly formed in a unit that formed before 2003, it will qualify for a GVR/GRE. If it is acreage that is not currently in a unit, and if a unit is not being formed for shale production, then it will not qualify for a GVR/GRE; what it will qualify for is the per barrel credit that slides from \$8 to \$0. The way the definitions unfold is that the per-barrel credit is determined based on whether or not the production qualifies for the GVR/GRE. If production does not qualify for the GVR/GRE, then it gets the sliding per barrel credit.

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REPRESENTATIVE SEATON presumed there would be two different tax rates for production out of the same source rock in a unit such as Prudhoe Bay or Kuparuk where there is no previous participating area.

MR. BALASH interpreted the question as whether - because the Prudhoe Bay Unit was formed before 2003 - that source rock is going to be in a participating area. He said: "If it is not going to be in a participating area, if it just going to be drilled and produced, then it will not qualify through any of the three buckets for the GVR. So, ... it will get the slider."

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REPRESENTATIVE TARR inquired whether there is an established process for the expansion of participating areas, given there has not been a reason previously to do so. She understood

participating areas were previously developed with the idea that that was the acreage needed for development.

MR. BALASH confirmed there is a procedure, saying it is an amendment to Exhibit C in the unit documents. A change in the file would correspond with a date, an action, and a review that comes in through the division process.

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REPRESENTATIVE SEATON related that his understanding from testimony is producers anticipated the source rock would be established as a PA and wells drilled in that PA would get the GVR. However, DNR is saying if it is source rock then it would not be certified as a PA at all, whether it was inside or outside an existing unit.

MR. BALASH said the question goes to the particular hypothetical being looked at. Due to the time, effort, and expense that would be required, it is unlikely a PA will be formed for each well that is drilled in a resource play development. Because the drainage from a fractured well is fairly limited - measured in feet - it would not be worth the effort. Establishing PAs for the dozens of horizontal legs out from the well is not going to make much sense, so DNR does not expect that is the way it is going to work out. Returning to the Prudhoe Bay scenario, he said a unit established prior to 2003 and not in a new PA, would not qualify for the GVR. However, a PA recorded for each of those wells would qualify because it would be in a new PA in a unit formed prior to 2003. For the operator, the question is the price environment and whether it would be better to get the \$8 or the higher side that the GVR affords. Because of the steep decline that occurs in a shale well, maybe the operator would play a little bit of a price game there, he allowed. That would be the operator's choice coming into the department and the department would have the discretionary tool of whether to grant the PA. The operator can still drill and produce that well if a PA is not granted.

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REPRESENTATIVE SEATON stated this is fairly critical in terms of a durable system. There is potential for significant finds and developments, so there should be something that actually deals with the entire play since it is different than conventional, rather than leaving it up to whoever happens to be in the office

at the time. He urged this be considered as the committee goes forward.

CO-CHAIR FEIGE allowed the aforementioned is a legitimate point, but said it is a policy decision on the committee's part whether to incentivize shale oil development and there has been no testimony from a company trying to advance such a project. A GVR could be defined to apply to that and would be a reasonable way to provide an incentive, if an incentive was necessary. Since the costs of such a project are unknown, it is unknown what amount of incentive would be needed and would be a guess at this point.

MR. BALASH advised that unconventional resources, such as shale or heavy oil, might require different treatments. There is no answer right now because today it is not economic. As the understanding of those resources improves, that opportunity will afford future legislatures the opportunity to make a reasonable decision. However, the current structure of Version K does provide tools to deal with that.

[CSSB 21(FIN) am(efd fld) was held over.]

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ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 10:00 p.m.