

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

February 13, 2013

1:03 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 Kurt Olson
Representative Paul Seaton
Representative Geran Tarr
Representative Chris Tuck

MEMBERS ABSENT

All members present

OTHER LEGISLATORS PRESENT

Representative Mike Chenault

COMMITTEE CALENDAR

HOUSE BILL NO. 72

"An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; 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; relating to the determination of annual oil and gas production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

- HEARD & HELD

HOUSE BILL NO. 4

"An Act relating to the Alaska Gasline Development Corporation; making the Alaska Gasline Development Corporation, a subsidiary of the Alaska Housing Finance Corporation, an independent public corporation of the state; establishing and relating to the in-state natural gas pipeline fund; making certain information provided to or by the Alaska Gasline Development Corporation exempt from inspection as a public record; relating to the Joint In-State Gasline Development Team; relating to the Alaska Housing Finance Corporation; relating to judicial review of a right-of-way lease or an action or decision related to the development or construction of an oil or gas pipeline on state land; relating to the lease of a right-of-way for a gas pipeline transportation corridor, including a corridor for a natural gas pipeline that is a contract carrier; relating to the Corporation; relating to the review by the Regulatory Commission of Alaska of natural gas transportation contracts; relating to the regulation by the Regulatory Commission of Alaska of an in-state natural gas pipeline project developed by the Alaska Gasline Development Corporation; relating to the regulation by the Regulatory Commission of Alaska of an in-state natural gas pipeline that provides transportation by contract carriage; relating to the Alaska Natural Gas Development Authority; relating to the procurement of certain services by the Alaska Natural Gas Development Authority; exempting property of a project developed by the Alaska Gasline Development Corporation from property taxes before the commencement of commercial operations; and providing for an effective date."

- HEARD & HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 72

SHORT TITLE: OIL AND GAS PRODUCTION TAX

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

01/16/13	(H)	READ THE FIRST TIME - REFERRALS
01/16/13	(H)	RES, FIN
02/11/13	(H)	RES AT 1:00 PM BARNES 124
02/11/13	(H)	Heard & Held
02/11/13	(H)	MINUTE(RES)
02/13/13	(H)	RES AT 1:00 PM BARNES 124

BILL: HB 4

SHORT TITLE: IN-STATE GASLINE DEVELOPMENT CORP

SPONSOR(S): HAWKER, CHENAULT

01/16/13	(H)	PREFILE RELEASED 1/7/13
01/16/13	(H)	READ THE FIRST TIME - REFERRALS
01/16/13	(H)	RES, FIN
01/30/13	(H)	SPONSOR SUBSTITUTE INTRODUCED
01/30/13	(H)	READ THE FIRST TIME - REFERRALS
01/30/13	(H)	RES, FIN
02/04/13	(H)	RES AT 1:00 PM BARNES 124
02/04/13	(H)	Heard & Held
02/04/13	(H)	MINUTE(RES)
02/06/13	(H)	RES AT 1:00 PM BARNES 124
02/06/13	(H)	Heard & Held
02/06/13	(H)	MINUTE(RES)
02/13/13	(H)	RES AT 1:00 PM BARNES 124

WITNESS REGISTER

MICHAEL PAWLOWSKI, Oil & Gas Development Project Manager
Office of the Commissioner
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Provided a PowerPoint overview of HB 72 and answered questions related to the bill.

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

POSITION STATEMENT: Discussed the proposed gross revenue exclusion (GRE) provision in HB 72.

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

POSITION STATEMENT: As consultant to the administration, provided a PowerPoint presentation entitled, "Analysis of Alaska's Tax System, North Slope Investment and the Administration's Proposal, HB 72".

RENA DELBRIDGE, Staff
Representative Mike Hawker
Alaska State Legislature
Juneau, Alaska

POSITION STATEMENT: On behalf of Representatives Mike Chenault and Mike Hawker, joint prime sponsors of SSHB 4, continued review of the sectional analysis.

TINA GROVIER, Attorney, Natural Resources and Energy Law

Birch Horton Bittner & Cherot
Counsel to Alaska Gasline Development Corporation (AGDC)
Anchorage, Alaska

POSITION STATEMENT: Answered questions related to SSHB 4.

DARYL KLEPPIN, Manager
Commercial Team
Alaska Gasline Development Corporation (AGDC)
Alaska Housing Finance Corporation (AHFC)
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Answered questions related to SSHB 4.

FRANK RICHARDS, Manager
Pipeline Engineering & Government Affairs
Alaska Gasline Development Corporate (AGDC)
Alaska Housing Finance Corporation (AHFC)
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Answered questions related to SSHB 4.

ACTION NARRATIVE

[1:03:47 PM](#)

CO-CHAIR ERIC FEIGE called the House Resources Standing Committee meeting to order at 1:03 p.m. Representatives Tuck, Tarr, Seaton, Olson, Hawker, P. Wilson, Saddler, and Feige were present at the call to order. Representative Johnson arrived as the meeting was in progress.

HB 72-OIL AND GAS PRODUCTION TAX

[1:04:06 PM](#)

CO-CHAIR FEIGE announced that the first order of business is HOUSE BILL NO. 72, "An Act relating to appropriations from taxes paid under the Alaska Net Income Tax Act; 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; relating to the determination of annual oil and gas

production tax values including adjustments based on a percentage of gross value at the point of production from certain leases or properties; making conforming amendments; and providing for an effective date."

Co-Chair Feige noted today would be a continuation of the administration's presentation from February 11, 2013.

[1:04:22 PM](#)

MICHAEL PAWLOWSKI, Oil & Gas Development Project Manager, Office of the Commissioner, Department of Revenue (DOR), noted he is the advisor for petroleum fiscal systems to the Department of Revenue. He reminded members that during the committee's last meeting he provided a PowerPoint review of the broad provisions of HB 72 and where those are located within the bill, the elimination of progressivity, the elimination of the North Slope qualified capital expenditure (QCE) credits, and the North Slope net operating loss credits. Continuing that presentation with slide 5, he turned to the provision for small producer tax credits contained in Section 16 of the bill, page 16, line 26. The small producer tax credit is in current statute, he said, and is a credit consistent with the treatment of other credits in the North Slope in the governor's proposal in that it is a nontransferable credit that may only be taken against production taxes. The current small producer tax credit is set to expire in 2016 for new production, which means new production under the current law would have to come into production before 2016 to qualify for the credit. Page 16, line 29, proposes to change the date to 2022. Thus, HB 72 would maintain the current small producer tax credit, but allows production to come on line up to 2022 to qualify for the purposes of the credit.

[1:06:19 PM](#)

REPRESENTATIVE SEATON inquired whether there is any interaction between the small producer tax credit extension and the changing of when the credits can be applied for and received.

MR. PAWLOWSKI replied the interaction between the two credits will be discussed later by Mr. Pulliam [of Econ One Research, Inc.] when he reviews the lifecycle economics of projects. The small producer credit is for the first nine years of production. The carry forward credit is for 10 years. They are similar in length, but there is not a direct nexus between the two.

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REPRESENTATIVE SEATON said he is interested not only in the aforementioned, but also what classifies as new oil. He asked whether there is a different definition of new oil that would qualify for the small producer tax credit than the current definition. He further asked whether there is a change in that interaction that changes the applicability of the small producer tax credit; for example, would some of the current new oil production that qualifies for small producer tax credit be eliminated by restrictions on where the oil comes from.

MR. PAWLOWSKI responded a deeper conversation may be needed about the nuances of the relationship between the specific projects being talked about by Representative Seaton. He said the small producer credit is for any producer that did not have commercial oil or gas production from a lease or property in the state before April 1, 2006. So, that is new production coming on line for purposes of this small producer credit. The provisions in the governor's bill that relate to new oil are specifically the gross revenue exclusion, which Deputy Commissioner Balash will speak to later. A producer would certainly qualify for a small producer tax credit and the gross revenue exclusion depending on where that production came from. So, stepping forward, it would have to be a new participating area or unit formed after 2003 to qualify. There is no taking away of the credit, it is just extending the qualification period.

REPRESENTATIVE SEATON requested a flowchart that explains how the different credits interact to show whether one aspect of the bill impacts another.

[1:09:49 PM](#)

MR. PAWLOWSKI, returning to his sectional analysis, stated that Section 24 is the main section of the bill for the gross revenue exclusion (GRE) provision [slide 6]. He turned over discussion of this section to Deputy Commissioner Joe Balash.

[1:10:09 PM](#)

JOE BALASH, Deputy Commissioner, Office of the Commissioner, Department of Natural Resources (DNR), explained that Section 24, page 23, lines 1-10, is the primary incentive being provided in HB 72 for the production of new oil. From the debate over the past couple years, he said he thinks there is a consensus on a willingness to provide reduced taxes and a tax relief for the

production of new barrels. The mechanism employed in HB 72 is through the gross revenue exclusion, which starts at the gross value at the point of production. The GRE reduces that value before applying the costs in the determination of production tax value against which the tax rate is applied. It basically has the effect of reducing the tax rate. There are two ways to qualify for the GRE on the barrels a taxpayer is producing. The first is if those barrels are being produced from a unit that was formed after January 1, 2003, and the second is if those barrels are being produced from a participating area (PA) that was approved by DNR after January 1, 2012. During calendar year 2012 there were no new PAs approved, so there is not anything that falls in between, it would be anything that is approved prospectively. The language is clear that a taxpayer can qualify one way or the other, but cannot double dip, cannot qualify for two reductions.

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MR. BALASH defined a participating area, explaining that when DNR issues a lease, an oil or gas deposit found during exploration of the lease area does not confine itself to a single lease. It is generally present through multiple leases and the leases then are put together in a block called a unit. Leases in units are measured in two dimensions as just an outline on a map. A participating area measures that property in a third dimension with depth. For the property to be part of the PA, it must be contributing to production in the field, it must be contributing to oil or gas in the wellbore. Tried and true methodological practices are used by the geologists and the petroleum reservoir engineers to understand and agree on what is in and what is not. A certain amount of tension exists between the various owners inside the field because each owner wants to ensure that its barrels, its property, is getting counted if it is producing; the owner on the other side of the table wants to ensure that the other owner is not getting an extra benefit by counting barrels that the other owner is not actually producing. Within those columns of earth are pockets of oil and gas that are being tapped by the various wellbores. Any pool or separate reservoir that is not penetrated by a well, and not contributing to production, is not part of a PA. Companies can come back later to apply for a new PA that is separate and distinct from the existing production, and that is what is being talked about here - a method to allow the GRE to apply to new oil inside the legacy fields, but not part of the same legacy reservoir.

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REPRESENTATIVE SEATON recounted his tour of the North Slope this past year with ConocoPhillips Alaska, Inc. where he saw a working oil tube rig that was re-drilling existing wellbores and putting out eight spiders in different directions to get to places where there was not good continuity because of fault blocks and such, but it was the same sands, the same area. He asked whether the ends of each of those eight spiders would now be considered new participating areas.

MR. BALASH said the answer would be no if it is for drilling into the same reservoir and extending by using sophisticated drilling techniques that were not possible 25 years ago. That would be an expansion or extension of a PA because DNR's management system for PAs tries to keep like rocks in the same system in the same PA. Under the bill's current language, an expanded PA would not qualify; it must be a new PA. That is not to say there could not be a conversation about that kind of a mechanism. Using the horizons at Prudhoe Bay to provide an example, he explained that the initial production area in the Sadlerochit Reservoir is where the most prolific rocks are in reservoir and production comes from. However, there are other horizons that are separate and distinct reservoirs within the Prudhoe Bay Unit and over time there have been multiple PAs formed within the Prudhoe Bay Unit. It is those new areas within that third dimension of the unit that are being talking about. Prudhoe Bay has been pretty heavily developed and produced, but an example of something that likely would qualify at some point would be the Ugnu Sands. Ugnu has not contributed to production to date in Prudhoe Bay, so a new participating area could be formed for the Ugnu layer at Prudhoe Bay.

[1:17:59 PM](#)

REPRESENTATIVE SEATON understood BP was producing about 6,000 barrels a day of heavy/viscous oil from sands as a test pilot [in the Milne Point Unit]. He asked whether that area would be considered to have contributed production and therefore would not qualify for the reduced tax rate of 20 percent.

MR. BALASH answered he will double check that specific case with his staff, but offered his understanding that it is sustained commercial production of oil and gas that is being talked about. He said he does not know off the top of his head whether what was being tested at Milne is currently in, or was in, a PA. He suggested having Director Barron provide a presentation on how DNR utilizes PAs within the units to manage the resource.

Director Barron's presentation has an animated illustration that shows the different horizons and the different pools that are not the same reservoir in those horizons.

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REPRESENTATIVE SEATON posited he can see a big incentive for shutting down parts of the field for a while so there is no longer sustained production and then coming back so as to reduce the tax rate by 5-7 percent. He therefore requested that when DNR comes back with a presentation he would like to hear from "legal" as to what sustained production is and where it does and does not apply.

MR. PAWLOWSKI directed attention to page 23, lines 8-9, which state, "the participating area does not contain a reservoir that had previously been in a participating area" So, he said, if it had sustained production at one point and was shut down, it would have been in a participating area. That language was put in place to specifically prohibit the aforementioned type of scenario. He stated he will work with "legal" to get the requested analysis for the committee.

[1:21:27 PM](#)

MR. PAWLOWSKI resumed his sectional analysis, noting the vast majority of the bill is related to [Cook Inlet and Middle Earth] [slide 7]. Over the years, different tax ceilings and different tax treatments have been put into place for gas produced and used in-state, oil produced from the Cook Inlet, gas produced from the Cook Inlet, and gas produced from Middle Earth, which is the area not on the North Slope and not in Cook Inlet. Because the legislature's work on those specific, distinct policy calls must be preserved, much of the language in HB 72 is conforming language to account for those different tax ceilings and the way the language moves around when progressivity is repealed throughout the tax treatment.

[1:22:23 PM](#)

MR. PAWLOWSKI said the main change is on page 2, lines 19-24 [Section 3] and that this presented a bit of a conundrum for the departments in putting the bill together. Subsection (o) of the production tax [AS 43.55.011] is where preference is given to gas produced in-state and used in-state. Senate Bill 23, passed [in 2012], included a separate ceiling of 4 percent gross for gas and oil produced from the Middle Earth. That separate tax

treatment did not distinguish between gas or oil produced from that area, so the Department of Law and the administration went with the most recent treatment of that specific type of gas with the understanding that during that process operators had expressed concerned about having to do too much separate accounting between the oil and gas that were coming out of the same wellbore. The thought was that it was simpler to have the provisions that were passed in Senate Bill 23, which is AS 43.55.011(p) and which is the new language seen on page 2, line 23. This clearly says that gas produced and used in-state is subject to the existing ceiling, unless the gas comes from Middle Earth and then it is subject to the Middle Earth provisions that were passed last year. The relationship was never dealt with in the statute when Senate Bill 23 passed. Thus, this is the one place where there is a difference between the treatment of existing statute and recent statute. Everywhere else is a conforming section. For example, conforming Section 4, page 3, line 4, is the clarification language, "not subject to AS 43.55.011(o) or (p)" which gets back to the different tax treatments and preserving them.

[1:24:42 PM](#)

MR. PAWLOWSKI moved to conforming Section 13, page 12, line 18. He reminded members that [Section 11] changes the word "certificates" to "certificate" because the bill provides that the [qualified capital expenditure] credit will be issued in a single certificate [whether for north of the North Slope or for south of the North Slope]. Continuing, he stated that "there was already a statute, AS 43.55.023(m), which said contrary to the statute that says that you have to take a credit and divide it into two certificates, if the credit is earned south of the North Slope it can be taken as one certificate." The bill repeals AS 43.55.023(m), so page 12, line 20, states "of this section or former (m)" in recognition that (m) is being repealed. These conforming sections make it clear the existing credits that are retained can be taken as one certificate.

[1:26:20 PM](#)

REPRESENTATIVE P. WILSON referred to page 2 and said it is hard to visualize because "in the bill ..., after this is all done, there is going to be a (p) even though in here there is not a (p)".

MR. PAWLOWSKI replied that AS 43.55.011(p) was the provision in Senate Bill 23 that passed in the last legislature and

incorporating that provision throughout the statute is what is going on here.

[1:27:19 PM](#)

MR. PAWLOWSKI, proceeding with his sectional analysis, stated these conforming sections continue throughout HB 72. For example, Section 17, page 17, lines 3-21, references that at one point AS 43.55.023(m) existed. In that there was a credit issued under AS 43.55.023(m) that a company waited several years to bring back to the state, there needs to be a reference in statute that at one point a section did exist that allowed that credit to be issued as a single certificate rather than two certificates.

[1:28:12 PM](#)

REPRESENTATIVE SEATON noted that HB 72 pushes to limit capital credits so during low prices the state is not obligated to take money out of its savings to pay for credits. However, during times of low prices and a poor economy, would this requirement for taking the credits in one year instead of two be opposite the philosophy to limit the state's liability, he asked.

MR. PAWLOWSKI explained those sections preserve the existing treatment of tax credits south of 68 degrees [North latitude], meaning not the North Slope. It is for activity in Cook Inlet and Middle Earth, which under current law are already allowed to be taken in one year. In further response to Representative Seaton, Mr. Pawlowski explained that the credit for the North Slope that had to be divided into two years was the qualified capital expenditure credit and that credit is being eliminated.

[1:30:09 PM](#)

REPRESENTATIVE SEATON drew attention to Section 23, page 22, lines 12-31, and inquired whether the gross revenue exclusion (GRE), which effectively lowers the tax rate from 25 percent to 18 percent, has a sunset or will new oil be treated at 18 percent forever.

MR. PAWLOWSKI cautioned against picking specific numbers because each tax rate will functionally depend on the actual capital costs of that specific project because it is still in that system. The provision is saying that future development will get a benefit of 20 percent of the gross value of that future production. There is no sunset for two reasons. First, in

looking at the lifecycle economics of these more challenged, higher cost projects, there needs to be that help to the economics and the government take. Second, in looking at previous efforts that stopped or time limited that benefit, it was seen that it takes time to drill out a prospect; all of the wells for a prospect are not drilled in one year. From the start of sustained production, it takes 10-15 years to truly drill out the prospect, so it becomes functionally the same over time anyway. The concern with a timeline was that a company would be unable to realize the benefit that the gross revenue exclusion is actually trying to put on the table.

[1:32:23 PM](#)

REPRESENTATIVE SEATON stated that if the tax rate is going to functionally be changed permanently from 25 percent to more or less 18 percent, depending upon the capitalization of a project, he would like to see the effect on the point in the future at which 50 percent of the oil is considered new oil. Because this is for new oil and the state is counting on new oil, the bill as structured would, over time, drastically reduce the tax if there is no sunset date.

MR. PAWLOWSKI answered that DOR will work on that and bring it back for presentation to the committee, but explained that it gets back to the nexus of that participating area approach.

[1:34:07 PM](#)

BARRY PULLIAM, Economist & Managing Director, Econ One Research, Inc., began his presentation regarding Alaska's tax system, North Slope investment and the administration's proposal, HB 72. He noted he has been working for and with the administration, the Department of Revenue, and the Department of Natural Resources on this tax issue to help analyze what has been occurring on the North Slope, to look at Alaska's tax system relative to other areas, to look at what has happened with respect to investment in production in Alaska, and to think about appropriate changes to that system. He said he will be discussing the work that has been done over the last several months and how the changes proposed in HB 72 will affect the activity going on in Alaska.

MR. PULLIAM stated Econ One provides economic research to a variety of industries, with the energy industry being the area he works in [slide 2]. It has worked for and with the State of Alaska for about two decades on a variety issues, and has worked

for the administration as well as for the legislature. He said he spent a lot of time in Alaska in 2006 and 2007 when the legislature was considering the production profits tax (PPT), Alaska's Clear and Equitable Share (ACES), and gas line issue. In addition to Alaska, Econ One works for several oil producing states, the federal government, and energy companies.

[1:36:48 PM](#)

MR. PULLIAM first provided some background on the North Slope [slide 4], stating that to date the North Slope has produced about 16 billion barrels of oil. Approximately 5.5 billion barrels of economically recoverable oil are believed left in currently known fields. The vast majority of oil produced from the North Slope has come from the giant fields of Prudhoe Bay and Kuparuk [River]. About 90 percent of the resources discovered to date were discovered prior to 1970.

[1:38:11 PM](#)

MR. PULLIAM explained that slide 5 puts the historical production in context with what is believed to still exist on the North Slope. Estimates are that the North Slope contains about 40 billion barrels of additional economically recoverable resources at today's prices and about 5.5 billion barrels sits in fields that have already been discovered. Another 19 billion barrels sits in fields that are yet to be discovered on state and federal lands, according to the U.S. Geological Survey (USGS). Responding to Co-Chair Feige, Mr. Pulliam said he is talking about both onshore and offshore.

[1:39:18 PM](#)

MR. PULLIAM, in response to Representative Tuck, stated that the red portion of the pie chart on slide 5 depicts the amount of oil produced to date, and the red and green portions together represent [the total discovered resources] to date depicted on slide 4. Responding further, he confirmed that the purpose of HB 72 is to incentivize [production] from the [discovered conventional resources estimated at 5.5 billion barrels of oil]. The bill would also incentivize part of the [undiscovered conventional resources estimated at 19.2 billion barrels] and potentially the the unconventional resources [estimated at 5.5 billion barrels]. The aforementioned is everything that has not been produced to date that Alaska's tax system covers. He further confirmed that unconventional resources means shale and

heavy and viscous oil, which is not the light, conventional oil that has been produced to date.

[1:40:47 PM](#)

REPRESENTATIVE SEATON understood that in the pie chart on slide 5, the [undiscovered conventional resources], the [Arctic National Wildlife Refuge (ANWR)], and the [unconventional resources] would all be subject to the gross revenue exclusion.

MR. PULLIAM answered that part of the [undiscovered conventional resources] is federal or offshore production that the state does not tax and which would not be subject to HB 72. The portion that is on state property would be subject to HB 72.

REPRESENTATIVE SEATON requested that at some future date this be delineated for the committee.

MR. PULLIAM replied that the next slide shows a breakdown that will be helpful in this regard.

[1:42:10 PM](#)

REPRESENTATIVE TUCK referenced a report handed out to the committee on 2/11/13 that demonstrated the current natural decline of the major fields of Prudhoe Bay and Kuparuk. He inquired whether this natural decline can be prevented.

MR. PULLIAM responded it is ultimately unpreventable because the amount of oil there is fixed, although the exact extent of that oil is unknown. Finding new resources within the field itself is something that can be done and it can be done to slow the decline rate or it can be done to also increase the production. But that is going to require getting at pockets of oil within those fields that have not currently been gotten to. Some of that decline has to do with the way those fields are constructed and the facilities that are there. There is a certain amount of gas handling capacity, particularly at Prudhoe Bay, that limits what can be produced over time. As oil is produced, the ratio of gas to oil increases, which is a natural occurrence, and with that fixed capacity in place there is some limitation there. But if that capacity is changed, more oil can be produced. If the capacity to handle gas was doubled, then a lot more oil could be produced.

[1:44:21 PM](#)

REPRESENTATIVE TUCK surmised the aforementioned would affect the [discovered conventional resources] and [historical production] sections depicted in the pie chart on page 5.

MR. PULLIAM answered it would affect the [discovered conventional resources] but not the [historical production]. The [discovered conventional resources] is an estimate based on the technology known today. It is important to keep in mind, he continued, that these fields have produced much more oil than had been thought possible; technology has done wonders and prices have played a part as well. As technology gets better these portions of the pie will grow, particularly for the estimated 5.6 billion barrels of oil for discovered conventional resources.

[1:45:36 PM](#)

MR. PULLIAM resumed his presentation, discussing the locations of undiscovered conventional oil resources [on the North Slope, slide 6]. According to the U.S. Geological Survey (USGS), he reported, at \$90 per barrel there are about 3 billion barrels of economically recoverable oil on onshore state lands, 5.8 billion barrels in the Beaufort Sea, almost 10 billion in the Chukchi Sea, about 0.5 billion in the National Petroleum Reserve-Alaska (NPR-A), and close to 10 billion in the Arctic National Wildlife Refuge (ANWR), for a total of about 29 billion barrels. He noted that \$90 per barrel is a little less than the price of today. He said the size of these fields is likely to be in the range of 50 million barrels, which is a lot smaller than the typical field producing on the North Slope today, but in line with the more recent discoveries that Alaska has had. Responding to Co-Chair Feige, he explained that the columns on slide 6 for "P95" and "P5" indicate probabilities. If all the oil was found, P5 means a 5 percent probability that there would be more than that amount of oil, and P95 means a 95 percent chance that there is more than that volume. For example, the estimate for the Central North Slope is that there is a 95 percent chance of at least 2.8 billion barrels left and only a 5 percent chance of more than 3.9 billion barrels left; however, the mean in that range is about 3.4 billion barrels, which is a pretty tight range.

[1:47:55 PM](#)

REPRESENTATIVE TARR referred to slide 6 and inquired whether the figures in the economically recoverable column are under HB 72 or under ACES.

MR. PULLIAM replied he thinks this analysis was done under the current law of ACES.

[1:48:21 PM](#)

MR. PULLIAM, returning to his presentation, summarized the unconventional oil resources [on Alaska's North Slope, slide 7]. Not much is yet known about shale, he said. A [2012] USGS report put the mean technically recoverable barrels at about 1 billion. It has not been shown to be economic and that estimate is very preliminary. He noted that the early estimates by the USGS of recoverable shale oil in the Lower 48 were much lower than what they have turned out to be and what is being thought now. Regarding viscous and heavy oil, he said it is known there is a lot of that oil in place, somewhere in the range of 25 billion barrels, but the current estimate is that only 15 percent, 4-6 billion barrels, is economically recoverable. He reiterated that, historically, technology advances and allows getting more of that original oil out than was once thought, so it would not be surprising to see that number increase.

[1:49:54 PM](#)

REPRESENTATIVE TARR observed that the estimated 5.5 billion barrels of unconventional oil resources depicted on slide 5 is less than what is depicted on slide 7.

MR. PULLIAM responded slide 5 depicts the mid-point of heavy oil, which is 3.6-5.6, plus the 1 billion for shale.

[1:50:27 PM](#)

MR. PULLIAM, resuming his presentation, provided a history of Alaska's production tax system on the North Slope [slide 8]. He said the state began with a gross system when oil first started flowing in 1977 at a maximum tax rate of 12.25 percent, which was the highest rate in the country at the time. The economic limit factor (ELF) was also introduced at that time. In 1981 the maximum rate was increased to 15 percent, which was again the highest rate in the country. New fields were given a 12.25 percent rate for the first 5 years of production. Modifications to ELF occurred in the late 1980s. Not much happened between then and 2003, at which time exploration credits [of 20-40 percent] were introduced. In 2005 the Prudhoe Bay fields were aggregated for purposes of calculating ELF, which raised the effective tax rate on the satellites around Prudhoe Bay. In

2006, the petroleum profits tax (PPT) was introduced. The PPT, [a net-based tax system], was a fundamental shift from the gross system, which many at the time recognized had some real flaws, one being the operation of ELF and how it reduced the tax rate in areas where it was not really necessary. The other flaw was that the gross system did not always align the economics of the producers with the economics of the state and was thought to be inhibiting production, particularly high cost production.

[1:52:34 PM](#)

MR. PULLIAM, continuing the history of Alaska's production tax system, said the PPT, being a net-based tax system, allowed the deduction of operating and capital costs. The PPT legislation as originally introduced had a 20 percent base rate with a 20 percent credit. During the course of the 2006 sessions, that was ultimately changed to a 22.5 percent base rate with a 0.25 percent progressivity piece that kicked in when the net taxable value was \$40 per barrel, for a maximum combined rate of 47.5 percent. In 2007, PPT was amended to the current system under Alaska's Clear and Equitable Share (ACES). Key differences between ACES and PPT were that the base rate was changed to 25 percent, the progressivity was increased to 0.4 percent and the trigger point was dropped to \$30. At over \$92.50 net, the progressivity flattens out to a 0.1 percent increase and the maximum rate was increased to 75 percent, which is not reached until very high prices. However, he pointed out, the 75 percent number gets published and people associate that number with Alaska.

[1:54:14 PM](#)

MR. PULLIAM moved to discussing the benchmarking done for Alaska North Slope (ANS) activity and how it has behaved over the past decade compared to other areas [slide 10]. To control for price, technology, and general economic conditions that impact activity, the North Slope activity was benchmarked against other producing areas in countries belonging to the Organisation for Economic Co-operation and Development (OECD). Since no two areas are exactly alike, benchmarking looks at places that have as much in common as possible to allow for the most meaningful comparisons. Areas used for benchmarking the North Slope include the North Sea, the rest of the U.S. and some key producing states, Canada, and Australia. These areas are comparable to Alaska in that they have similar political and legal structure and they all have significant prospectivity, meaning there is a lot of oil left to find. However, the easy

oil has been produced in all of these areas and what remains is largely high cost conventional and unconventional oil. Also common to these areas is that their resources are developed for the most part by the private sector, so the people looking for and producing oil all respond to similar types of incentives.

[1:56:40 PM](#)

MR. PULLIAM said the aspects looked at for the benchmarking were crude [oil] production, capital spending, [petroleum sector] employment, and drilling activity [slide 11]. Production on the Alaska North Slope has declined to just over 40 percent of what it was a decade ago. Capital spending on the North Slope increased in the mid-2000s and has remained fairly level for the last 4-5 years. Employment in the North Slope petroleum sector increased in about 2006, partly in response to corrosion events and then the efforts to rebuild and renew much of the North Slope facilities, particularly in the legacy fields. Drilling activity has declined as production has gone down.

[1:58:19 PM](#)

REPRESENTATIVE TARR inquired whether the 2006 increase in petroleum sector employment could have been related to either of the two changes in the tax system.

MR. PULLIAM answered the activity on the North Slope has been largely related to facility renewal, and some of that may be driven and aided by ACES. The increase in employment has not seen a corresponding increase in drilling. There is a very real need to update many of those old facilities on the North Slope and ACES has been helpful, and the state has provided a lot of the funding for doing that.

[1:59:46 PM](#)

REPRESENTATIVE SEATON, in regard to benchmarking against OECD countries, asked why not benchmark against areas where industry is investing, such as Russia, because where industry is putting its capital would tell what is important to them.

MR. PULLIAM replied it will be seen in coming slides that industry is putting a significant amount of capital into all of these OECD areas that the benchmarking is looking at. Regarding Russia, a nice thing about the OECD areas is that a lot of trustworthy data is available; outside of that it is harder to find the same type and quality of information to do those

comparisons. For all of the reasons summarized on [slide 10], such as similarity of legal and political systems, the OECD areas looked at do provide a good benchmark without having to go outside of those areas, such as to Russia.

[2:01:34 PM](#)

MR. PULLIAM continued his presentation, summarizing the four activities for the benchmark areas [slides 12-15]. He noted that the appendix provides these same comparisons in detail. He said the North Sea (slide 12) is a good comparison to Alaska because the two are alike in many ways. The North Sea was discovered and developed about the same time [as the North Slope]. North Sea production has historically come from large fields and then smaller discoveries in and around those large fields. The North Sea has experienced the same kind of decline as has Alaska, being a mature basin in many areas, but yet with lots of oil still in the ground. The North Sea had the same pattern in capital spending as Alaska until the last few years when capital spending increased in the North Sea. Drilling in the North Sea declined then stabilized in the last few years.

[2:03:32 PM](#)

CO-CHAIR SADDLER returned to the history of Alaska's production tax system on slide 8 and asked what the overall effective tax rates were for ELF, ELF II, and PPT so the committee can have a basis for comparison of the take over those years.

MR. PULLIAM responded it changed over time and was different for each field, but said for 2005 he recalls an average tax rate of about 10 percent; with the rate being higher at Prudhoe Bay, lower at Kuparuk River Unit, and lower at the other fields. In further response, he confirmed that was on a gross basis and that today Alaska would be at a 20 percent or more tax rate on a gross basis. He agreed to calculate the gross tax rate for the decades between 1977 and 2007 and provide that information to the committee.

[2:05:01 PM](#)

REPRESENTATIVE TUCK said it appears from research he has done that the North Sea is naturally declining like Alaska. He related that according to a recent news story in London's Guardian, the North Sea's oil and gas reserves are running out fast. Since comparisons of capital spending and drilling for

the North Sea and Alaska are good ones, he inquired whether the North Sea has reduced or reversed its production decline.

MR. PULLIAM answered the United Kingdom (UK) has targeted several programs, one being the Brownfield Allowance, which is a reduction in the tax rate for approved development spending that is designed to get additional barrels out of existing fields. This would be like the Gross Revenue Exclusion (GRE). The allowance significantly impacts the economics for producers and there has been a lot of response from that.

[2:07:03 PM](#)

MR. PULLIAM returned to his presentation and reviewed the four areas for the U.S. excluding Alaska North Slope [slide 13]. Crude oil production has increased in the U.S., as opposed to Alaska's decline. Capital spending has increased in the U.S. Moving to slide 14, he said an increase in production has also occurred in Canada, much of that being from heavy oil in Alberta, an example of technology and prices coming together to allow this increased production. Turning to slide 15, he noted that in Australia much of the activity in recent years has gone from mostly producing oil to developing liquefied natural gas (LNG) from that country's significant gas resources. He offered to walk through the details of these comparisons that are in the appendix with any committee member wishing to do so.

[2:08:27 PM](#)

MR. PULLIAM next provided a side-by-side comparison of crude oil production between the Alaska North Slope, the rest of the U.S., and OECD countries [slide 16]. He said he indexed the values depicted on the graph to the 2003 level so as to put the comparisons on a comparable basis. In 2003, the North Slope produced about 950,000 barrels a day; by 2012, the North Slope produced a little over 500,000 barrels a day. During this same time period, production in the U.S. rose and overall the OECD declined a little bit, although after going down the OECD responded upward a bit as prices went up after the middle part of the decade. The U.S. increase has come at the same time as prices have come up and it has stayed high from 2008 forward.

[2:09:54 PM](#)

MR. PULLIAM then compared capital spending [for exploration and development] between the North Slope, the U.S., and worldwide [slide 17], saying he again indexed to 2003. From 2003-2006

spending in Alaska and elsewhere in the world was pretty similar, rising at a similar rate. But a big shift occurred in 2007 when spending in Alaska stayed relatively flat while the rest of the world jumped up as oil prices went up, including Prudhoe prices. In 2008, Alaska had a little increase in spending and the rest of the world had a bigger increase. In 2009, spending in Alaska, the U.S., and worldwide was back together again as oil prices dropped dramatically. However, as oil prices came up and stayed high in 2010, 2011, and 2012, Alaska's spending has stayed about the same while spending elsewhere really expanded. He clarified this comparison is limited to exploration and development spending for putting assets in place to get the oil out of the ground; therefore, the comparison does not include spending to acquire companies.

[2:11:17 PM](#)

MR. PULLIAM moved to reviewing how the ACES tax calculation works, stating it is important to understand the differences between ACES and HB 72 [slide 19]. He said ACES is a net tax, with the tax calculated on the net value of taxable production. Taxable production is total production minus the royalties. The net value that is taxed is the gross wellhead value, which is the West Coast price minus transportation, minus the cost of production. Costs of production are the operating and capital costs necessary to pull the oil out of the ground. The base rate under ACES is 25 percent and this rate applies across the price spectrum. Additionally, ACES has a progressive rate: as the taxable value of the oil rises over \$30 per barrel, an additional 0.4 percent of tax is added for each dollar [of increase]. Another way to think of the progressive tax is to add 4 percent for every \$10 increase. Once the price is over \$92.50 per barrel, the rate becomes 1 percent for every \$10. For example, at a production tax value of \$100 per barrel, which is roughly a West Coast ANS price of \$135 per barrel, the base rate is 25 percent, plus a progressive rate tax of 25.75 percent, for a total tax rate of 50.75 percent. In addition to the tax, ACES provides a 20 percent credit, taken over 2 years, against the tax obligation. Small producers have a credit of \$12 million per year that is phased out as a producer's production increases over 50,000 barrels per day. The state purchases the credits and net operation losses (NOLs) from those companies that have no tax obligation - purchasing 45 percent of capital expenditures and 25 percent of operating expenditures. The majority of expense for most exploration and development companies is capital related, he noted.

2:14:30 PM

MR. PULLIAM next reviewed the mechanics for calculating the tax under ACES and the effective tax rate after credits for 50 million barrels of production at three West Coast ANS price scenarios: \$80, \$100, and \$120 per barrel [slide 20]. At a transportation cost of \$10 per barrel, the wellhead value would be \$70, \$90, and \$110, respectively. At operating costs of \$15 per barrel and capital costs of \$15 per barrel, the taxable value would be \$40, \$60, and \$80, respectively. The ACES base tax rate for all three prices is 25 percent. The progressive tax rate (on the taxable value over the trigger price of \$30 per barrel) is 4 percent at the price of \$80, 12 percent at \$100, and 20 percent at \$120. [The total tax rate is 29 percent at an ANS price of \$80, 37 percent at \$100, 45 percent at \$120.] The total wellhead value is calculated by multiplying the wellhead value per barrel times the production volume of 50 million barrels. The total operating and capital expenditures are calculated by multiplying these per barrel costs times the production volume of 50 million barrels. The total production tax value is calculated by subtracting the total operating and total capital expenditures from the total wellhead value. The production tax before credits is calculated by multiplying the production tax value times the [total] tax rate. The production tax after credits is calculated by subtracting the capital credit (20 percent times the capital expenditures) from the production tax before credits. He noted the deduction happens over a 2-year period, but for simplicity in the example he is showing it all in one column. The production tax after credits is thus \$430 million at a price of \$80, \$960 million at \$100, and \$1.65 billion at \$120, for an effective tax rate after credits of [21.5] percent, 32 percent, and [41.3] percent, respectively.

2:17:36 PM

REPRESENTATIVE TUCK surmised taxable value is the same thing as profit.

MR. PULLIAM concurred taxable value is a proxy for profit.

REPRESENTATIVE TUCK concluded that at a price of \$120 per barrel, making \$80 in profit, a company could spend \$20 per barrel more on capital expenditures within the state of Alaska and drop itself to [\$60 in profit] per barrel.

MR. PULLIAM concurred, saying he will show this in a later slide.

REPRESENTATIVE TUCK further concluded that by investing back into Alaska, a company can significantly reduce its taxation by 8 percent or more.

MR. PULLIAM confirmed a company can buy down the tax rate by spending more in Alaska.

[2:18:39 PM](#)

REPRESENTATIVE SEATON inquired whether the credit, taken over two years, is applied to the tax liability as well.

MR. PULLIAM replied the tax liability in a given year is going to be based on half of a company's capital spending from prior year plus half of the company's capital spending from the current year. In the example on slide 20, he is assuming the putting of those two together, which amounts to \$15 a barrel over the current production, so the company's credit would be calculated that way.

[2:19:39 PM](#)

MR. PULLIAM resumed his presentation, moving to the calculation of tax under ACES at a West Coast ANS price of \$100 per barrel and varying costs [slide 21]. At [a constant transportation cost of \$10 per barrel] and combined operating and capital costs of [\$20, \$35, and \$50] per barrel, the effective tax rate after credits is [38.1 percent, 29.5 percent, and 19 percent, respectively]. At a West Coast ANS price of \$80 per barrel [slide 22], and the same aforementioned costs of \$20, \$35, and \$50, the respective effective tax rates after credits are [29 percent, 18.4 percent, and 5 percent].

[2:21:11 PM](#)

MR. PULLIAM demonstrated the impact of additional [capital] spending on the tax obligation under ACES using an example of 50 million barrels of annual taxable production at an initial expenditure of \$1.5 billion plus an additional expenditure of \$250 million [slide 23]. At a West Coast ANS price of \$80, the taxable valuable before that additional expenditure is \$40. The additional expenditure of \$250 million amounts to \$5 per barrel of production, reducing the taxable value from \$40 to \$35. The tax rate before that additional expenditure is 29 percent, which

is the 25 percent base rate plus 4 percent progressivity. The tax rate after that additional expenditure drops from 29 percent to 27 percent because the \$5 in additional expenditure reduces the taxable value from \$40 to \$35, which reduces the tax rate. The production tax would then be calculated based on the [27] percent and the \$35 tax value, so a lower tax rate applied to a lower taxable value after the expenditure. Thus, a \$250 million additional expenditure reduces the tax obligation at \$80 per barrel by about \$157 million, a 63 percent reduction; 20 percent of that is due to the credits and 43 percent is due to the change in tax obligation prior to the credits. That reduction increases as the price per barrel increases: at \$120 per barrel the total reduction in taxes after credits rises to \$237 million. Thus, the credit remains the same, the spending remains the same, but at higher prices the amount of the tax reduction for a given spending gets much higher. At \$120 per barrel the tax obligation is reduced by 95 percent.

[2:24:48 PM](#)

CO-CHAIR FEIGE commented "not a bad deal" and asked whether the spending under ACES leads directly to more production or is being spent on production.

MR. PULLIAM responded it does not have to be spent on production, as long as it is a capital expenditure it qualifies for the credit. An operating expenditure also still qualifies, but would not get the 20 percent. So, the buy-down effect still applies whether it is an operating or capital expenditure, but the additional credits come in for the capital expenditure.

CO-CHAIR FEIGE understood the money the state has been giving away to companies for credits and reduction in taxes has not resulted in any further oil for the state to tax down the road.

MR. PULLIAM answered the industry in general is making investments both in drilling and a lot in facilities. He said he thinks industry would argue that those investments are all necessary to support production today and in the future. However, he continued, the state is providing a significant piece of that spending.

[2:26:14 PM](#)

REPRESENTATIVE TARR inquired whether this same modeling could be done for a West Coast ANS price of \$60 since that was the approximate price in 2009.

MR. PULLIAM agreed to do so.

[2:26:32 PM](#)

REPRESENTATIVE TUCK understood the lower tax rate is based on the lower tax value. He related that industry talks quite a bit about lucrative in-field projects. Observing from the chart on slide 23 that at a price of \$80 per barrel, an expenditure increase of 17 percent reduces the taxation by as much as 63 percent, he asked why more oil is not being produced.

MR. PULLIAM replied people thought this would be a big incentive when ACES was being put together, but forthcoming slides will show why this is maybe not the case.

[2:27:37 PM](#)

MR. PULLIAM continued his presentation, turning to a graph [slide 24] excerpted from PFC Energy's 1/31/13 presentation to the Senate Special Committee TAPS Throughput, which depicts estimates of capital and operating expense on a per barrel basis [for projects in Texas, Louisiana, North Dakota, and Alaska]. He noted that the bar depicting capital costs of about \$16 for new light oil in Alaska is pretty consistent with what he used in his work for this presentation. The bars for capital costs for mid-high cost development and high cost development in Alaska depict about [\$25] and \$34 per barrel, respectively.

[2:28:46 PM](#)

MR. PULLIAM next reviewed the effective tax rates for new development by an incumbent producer with a large amount of production typical of the legacy fields [slide 25]. For light conventional oil at a West Coast ANS price of \$70 per barrel and a cost of \$16 per barrel, the tax rate after credits is 20 percent on the additional production value; the tax rate after credits rises to about 50 percent at a price of \$140. For high-cost light oil at a cost of \$34, the effective tax rate, or additional taxes paid on that new production, is negative until the price rises above \$90 per barrel. Another way of looking at it is that at lower prices the state's tax revenues fall if the producer makes this investment. Taxes for high cost light oil do not increase until the price per barrel is over \$90, [rising from -40 percent effective tax rate at a price of \$80 to 40 percent effective tax rate at a price of \$140].

2:30:42 PM

REPRESENTATIVE SEATON understood that high cost light oil would be at a base case limitation of 25 percent of profit.

MR. PULLIAM confirmed 25 percent would be the base, but pointed out that the aforementioned is additive to a producer's existing production. These areas are going to be places where a producer will be in a progressivity level anyway, so adding this higher cost oil will reduce a producer's progressivity and give a producer credits to apply against that even if the producer is in a base case.

2:31:57 PM

REPRESENTATIVE SEATON requested an explanation of the minus percentages shown on the graph for the effective tax rate [slide 25], given there is a 25 percent base case and a producer gets credits and deductions.

MR. PULLIAM explained the graph is showing the additional tax that the incumbent would pay as a percentage of the value of the oil that the company is developing, so that production tax value. The additional tax is actually negative in these cases of high cost and low price.

2:33:04 PM

REPRESENTATIVE SEATON presumed if the tax is negative it means the company is getting money.

MR. PULLIAM replied the company is not getting a refund, just paying less in taxes.

REPRESENTATIVE SEATON understood, then, that a negative tax means the company is paying less in taxes than it would be otherwise. So, not only does the company have the value of the oil, but it gets to reduce the tax on the rest of its oil.

MR. PULLIAM confirmed it is coming that way and through the credits provided by the state. He posed a scenario in which a company starting with a tax obligation of \$1 billion makes this investment and reduces its total tax to \$900 million. Thus, this company's taxes have gone down, the value of the oil that has been produced has gone up.

REPRESENTATIVE SEATON concluded that the negative is very positive to the company because it is getting the value of the oil plus reducing its taxes on all its other oil, meaning the company has a lot more money in its pocket.

MR. PULLIAM answered correct.

[2:34:21 PM](#)

REPRESENTATIVE P. WILSON surmised the companies have therefore been receiving credits for maintenance costs that they would have had to do anyway.

MR. PULLIAM replied, "Yes, those investments needed to be made anyway."

[2:34:59 PM](#)

CO-CHAIR SADDLER requested further explanation on how to read the graph on slide 25.

MR. PULLIAM posed a scenario to explain: A company starts out owing \$1 billion in taxes. It invests in new production. After making this investment in new production, the company's tax bill goes down to \$900 million. The company has saved \$100 million in taxes, but the value of that new production is positive. The graphs shows, as a percentage, the incremental tax generated from this new production. The tax is a percentage of the value of that new production. If a company's tax goes down, then the rate is negative. In further response, he agreed to meet with Co-Chair Saddler later for additional explanation.

[2:36:19 PM](#)

MR. PULLIAM resumed his presentation, moving to analysis of investments in Alaska under ACES relative to investments in the North Sea, Canada oil sands, and the Lower 48's Eagle Ford and Bakken. Displaying a graph depicting the production profiles of these five areas [slide 27], he noted that production for Alaska and the North Sea look similar: conventional plays that reach peak production in the first few years and then decline over time, with a long time period between making an investment to initial production. However, the Bakken and Eagle Ford, where much activity is currently being seen, are different: very high production at the outset that falls off very quickly, with a very short time period between making an investment to initial production. The difference in the time period between

investment and initial production is important in how the economics compare, he explained.

[2:37:45 PM](#)

MR. PULLIAM, in response to Representative Tuck, said that wells in the Eagle Ford and the Bakken can be drilled very quickly, getting to production very quickly.

[2:37:56 PM](#)

REPRESENTATIVE TUCK inquired whether the reason for that is the seasons and being unable to drill in Alaska year round.

MR. PULLIAM responded it is the seasons, the facilities, and the availability of the types of rigs. In the Lower 48, much of the equipment is interchangeable, which is not the case in Alaska.

REPRESENTATIVE TUCK concluded that when looking at what to do going forward, it must be considered that Alaska has a longer time period compared to these other investment scenarios that are being looked at.

MR. PULLIAM answered that is the case relative to the Lower 48, but less so for the North Sea.

[2:38:45 PM](#)

MR. PULLIAM returned to his presentation, noting that the investment metrics used in the analysis of how Alaska's tax system stacks up relative to elsewhere included: net present value (NPV), internal rate of return (IRR), cash generation/margin, profitability index, and government take, as well as the net present value of the state's revenues [slide 28]. Information for these metrics is collapsed into the chart depicted on slide 29, he continued, and details of the information can be found in the appendix. Information for Alaska is located to the left side of the vertical line in the chart and information for all of the other areas is to the right of the vertical line. Each metric was analyzed at three West Coast ANS prices: \$80, \$100, and \$120 per barrel. The numbers in the top line of the chart reflect the net present value (NPV) of the investment to a producer. He explained that NPV is the taking of all future positive and negative cash flows and bringing them back to today at the industry's standard discount rate of 12 percent. At \$80 per barrel, development of 50 million barrels [of light conventional oil] in Alaska would have

a net present value of \$2.55 to a new participant and [\$3.71] to an incumbent. The NPV is higher to an incumbent because of the buy-down effect in progressivity, which a new participant does not have. Development of 50 million barrels of heavy high cost oil at \$80 per barrel in Alaska [has an NPV of minus \$4.51 for a new participant and minus \$2.43 for an incumbent], so it does not pencil out and would not be undertaken at this price. At a price of \$100 and \$120 [the NPV for a new participant is minus \$2.45 and minus \$1.09, respectively; for an incumbent the NPV is positive \$2.48 and positive \$6.53, respectively]. However, these positive NPVs for the incumbent producer under ACES come at a cost to the State of Alaska [of \$7.81 at a price of \$100, and a cost of \$4.31 at a price of \$120].

[2:42:55 PM](#)

MR. PULLIAM then drew attention to the NPV figures on the chart for the Eagle Ford, Bakken, Canada oil sands, Norway, and the UK. He noted the UK has two different tax rates, one for pre-1993 fields and a lower one for fields brought into production post-1993. At \$80 per barrel, the NPV of a post-1993 UK development is \$2.41, fairly equivalent to that of a new participant in Alaska for light oil. The UK's recently implemented Brownfield Allowance greatly increases the attractiveness of investment, with the NPV rising to \$4.62 at a price of \$80. At a price of \$100 for light oil, Alaska projects do not stack up as well for a new participant as compared to the benchmark areas; for an incumbent participant the projects are more in line with the other areas but not as attractive as the UK brownfield. At a price of \$100 for heavy oil, the NPV of \$2.48 for an incumbent in Alaska does not look so attractive when compared to that of the other areas. So, while ACES increases the attractiveness of heavy oil in Alaska, it does not pencil out when an incumbent looks at what is available elsewhere at a price level of \$100.

[2:45:26 PM](#)

MR. PULLIAM, still referencing the chart on slide 29, he further noted that the profitability index, internal rate of return, cash margins, and government take are other important things the producers look at when making investments. The takeaway from the chart is that the economics are probably not yet quite right for Alaska heavy oil. For light oil, the economics under ACES are not great relative to opportunities elsewhere, particularly for new participants. Beside low NPVs, the cash margins for both new and incumbent participants in Alaska are not generally

as attractive as elsewhere. Additionally, Alaska's government take is fairly high, particularly for a new participant. For someone wondering why Alaska does not have more activity and more companies participating, he would suggest that Alaska does not look attractive relative to much of the rest of the world.

[2:47:16 PM](#)

MR. PULLIAM, in response to Representative Tarr, confirmed that the government take depicted on slide 29 includes the top federal tax rate of 35 percent.

REPRESENTATIVE TARR requested Mr. Pulliam to provide examples of how a producer could affect its federal tax rate based on its investments in Alaska.

MR. PULLIAM replied he could break down the take by state and federal, but advised that it is irrelevant from the investors' standpoint because the investors are interested in what they will walk away with. Alaska has no control over what that federal rate is. While it is true that tax paid to the state is deductible from the federal tax, the investor does not care where it is going when it is going someplace besides the investor's pocket.

[2:48:28 PM](#)

REPRESENTATIVE SEATON understood the aforementioned chart encompasses every kind of tax, including Alaska's 9.4 percent corporate income tax. He pointed out, however, that a company's effective corporate income tax rate could be 6.6 percent.

MR. PULLIAM responded he used 6.5 percent in the analysis, given that is closer to what the companies effectively pay.

REPRESENTATIVE SEATON presumed the [state/municipal NPV] is not included [for the benchmark areas] because it is included within the percent of government take.

MR. PULLIAM confirmed it is in the total government take. He said he included the state/municipal NPV for Alaska so it could be seen how Alaska's system works for the state.

REPRESENTATIVE SEATON inquired whether private royalties are included in the government take section for the Eagle Ford and Bakken areas.

MR. PULLIAM confirmed the government take is generically used for all royalties and taxes, and said it is correct that in the Eagle Ford and Bakken areas most of the production is from private lands and subject to private royalties.

[2:50:22 PM](#)

MR. PULLIAM continued his presentation, stating that even under ACES the economics of high cost heavy oil development are not yet quite right [slide 30]. Referring to the top left chart on the slide, he said that as prices climb above \$90 the net present value for an incumbent is positive under ACES, rising to nearly \$8 per barrel and then tapering off. But for the state (bottom left chart), the NPV is negative as a result of the buy-down and a result of the credits going out. He said he therefore looked to see if there was a system the state could put in place that would help make that a better deal. He found that even if the state had no taxes and no credits the NPV for high cost heavy oil is still not very attractive until very high price levels. However, he qualified, that is for today; it could be different in the future as technology advances making it cheaper and easier to get at heavy oil. But, right now, even a no-tax system probably would not bring on some of that heavy oil. Moving to slide 31, Mr. Pulliam noted that the economics for high cost light oil development are a little bit better than for heavy oil, but still not yet quite ripe even with no taxes. The state could pay companies to produce by giving credits, but that may not be something the state wants to be doing.

[2:53:19 PM](#)

MR. PULLIAM next looked at projected cash generation from other jurisdictions and ongoing North Slope production under ACES, based on the Department of Revenue's production forecast for the period 2017-2021 [slide 32]. He explained the chart depicts what would happen if investment was made today to bring on this production. As the price of oil goes up, the cash generation under ACES is not as attractive as it is in [Canada, Eagle Ford, Bakken, Norway, and the UK]. This is a result of Alaska's cost structure and the progressivity, he said.

[2:54:14 PM](#)

REPRESENTATIVE SEATON asked whether the line on the chart for ACES assumes no buy-down on the tax rate by re-investment

MR. PULLIAM answered there is some buy-down going on in the depiction because it assumes a continued level of investment and operating cost in Alaska and the advancing of new investments coming on. The line depicting ACES is done as an overall slope number, so it assumes a projection of the new investments that are going to be taking place in this time period.

[2:55:02 PM](#)

REPRESENTATIVE SEATON said the current system was designed to stimulate investment because prior to PPT and ACES there was not the level of investment that Alaska wanted to see. He said he is asking whether the analysis was done looking at investment in the status quo or looking at a stimulation of investment. If it considered stimulation in investment then it would also include the corresponding credits the state is paying out. Given the state is paying out a billion dollars in credits per year, he maintained that increased investment appears to be happening.

MR. PULLIAM clarified that [slide 32] is for the producers, not the State of Alaska. The graph looks at the cash that producers would expect to take out of Alaska assuming all of that activity occurs, so it does assume credits in there as well. This goes to Representative Tuck's question, he said. Why is Alaska not getting what was hoped for out of the ACES system? He suggested one reason is that when companies look at their Alaska operations, they see what is shown on this chart - Alaska does not generate a lot of cash relative to what the company can do elsewhere. That is an important aspect for companies that are looking to pay shareholders and to provide funds for reinvestment, he stressed.

[2:57:08 PM](#)

CO-CHAIR SADDLER asked whether the cash margin per barrel depicted on the graph is the same as profit per barrel.

MR. PULLIAM responded it is different than profit; it is the amount of cash that the producer gets. It is profit with depreciation added back in, which is an expense against profit and which is not an outflow of cash. It is a deduction when calculating a company's accounting profit. When looking at what a company's cash flow is, that deduction is added back in.

[2:57:46 PM](#)

REPRESENTATIVE SEATON returned to slide 29 and observed the 5-year cash margins for new and incumbent producers in Alaska compared to the Eagle Ford. He asked why the cash margins depicted on the chart on slide 32 are lower than the numbers shown on slide 29.

MR. PULLIAM answered that the slides are two different pieces of analysis. The table on slide 29 looks at the economics of a new investment; it looks at just that investment on a stand-alone. The graph on slide 32 looks at cash flow for the whole North Slope for this [same time period of 2017-2021], so it is more than just the new investment and is across all operations - both ongoing and new. In further response, he said the difference in the two is that [slide 29] is for a single investment whereas [slide 32] is the cash flow for all ongoing operations so there is melding that is going on. He agreed to provide further explanation to Representative Seaton at a later time.

[3:01:47 PM](#)

CO-CHAIR FEIGE announced the committee would stand in recess until 3:30 p.m. [HB 72 was taken up again at 7:49 p.m. this same day.]

[3:35:14 PM](#)

CO-CHAIR SADDLER reconvened the House Resources Standing Committee meeting. Representatives Hawker, Seaton, P. Wilson, Olson, Feige, and Saddler were present at the call back to order. Representatives Johnson, Tarr, and Tuck arrived after the call back to order. Representative Chenault was also present.

HB 4-IN-STATE GASLINE DEVELOPMENT CORP

[3:35:27 PM](#)

CO-CHAIR SADDLER announced that the next order of business would be SPONSOR SUBSTITUTE FOR HOUSE BILL NO. 4, "An Act relating to the Alaska Gasline Development Corporation; making the Alaska Gasline Development Corporation, a subsidiary of the Alaska Housing Finance Corporation, an independent public corporation of the state; establishing and relating to the in-state natural gas pipeline fund; making certain information provided to or by the Alaska Gasline Development Corporation and its subsidiaries exempt from inspection as a public record; relating to the Joint In-State Gasline Development Team; relating to the Alaska

Housing Finance Corporation; relating to the price of the state's royalty gas for certain contracts; relating to judicial review of a right-of-way lease or an action or decision related to the development or construction of an oil or gas pipeline on state land; relating to the lease of a right-of-way for a gas pipeline transportation corridor, including a corridor for a natural gas pipeline that is a contract carrier; relating to the cost of natural resources, permits, and leases provided to the Alaska Gasline Development Corporation; relating to procurement by the Alaska Gasline Development Corporation; relating to the review by the Regulatory Commission of Alaska of natural gas transportation contracts; relating to the regulation by the Regulatory Commission of Alaska of an in-state natural gas pipeline project developed by the Alaska Gasline Development Corporation; relating to the regulation by the Regulatory Commission of Alaska of an in-state natural gas pipeline that provides transportation by contract carriage; relating to the Alaska Natural Gas Development Authority; relating to the procurement of certain services by the Alaska Natural Gas Development Authority; exempting property of a project developed by the Alaska Gasline Development Corporation from property taxes before the commencement of commercial operations; and providing for an effective date."

[3:36:06 PM](#)

RENA DELBRIDGE, Staff, Representative Mike Hawker, Alaska State Legislature, continued her sectional analysis of SSHB 4 on behalf of the joint prime sponsors, Representatives Chenault and Hawker. She said SSHB 4 proposes a regulatory framework and highlighted reasons why the state regulates. The legislature decides if something should be regulated, how it should it be regulated, and who should regulate it, she explained. Generally speaking, the legislature has delegated that regulation to the Regulatory Commission of Alaska (RCA) for public utilities in the state and for oil and gas pipelines. There are overall good reasons to regulate something that provides a service to people, especially when there is little competition to provide that service. Thus, regulation protects the provider of the service, the consumers of the service, and members of the public when the public has a benefit from that service.

[3:37:55 PM](#)

MS. DELBRIDGE pointed out the particular things the RCA does when regulating. The RCA certifies that someone wanting to provide a service is qualified to do so. The RCA ensures that a

provider offers safe, adequate services and facilities, and that those services are provided at reasonable rates, terms, and conditions. The RCA also ensures that while providing for reasonable rates, the service provider has an opportunity to make a reasonable rate of return on its investment in providing that service. The RCA looks out for people needing access to that service by ensuring there is not undue discrimination in charges and in services. The RCA ensures that the carrier has enough financial ability to provide the service it is asking to provide. The RCA further provides a structure through regulation so the carrier can set out contract terms and provide changes to those terms as circumstances change over time.

[3:38:54 PM](#)

MS. DELBRIDGE reminded members of the need for an Alaska Gasline Development Corporation (AGDC) pipeline to operate as a contract carrier. Alaska currently has no regulatory framework for an in-state gas pipeline that operates as a contract carrier. Thus SSHB 4 creates that framework, essentially giving the RCA a new class of pipelines to regulate - contract carrier gas pipelines. This proposed regulatory structure applies to any contract carrier gas pipeline, not just AGDC, and applies only to gas, not oil, pipelines. This proposed regulatory structure does not apply to a pipeline that falls within a federal regulatory jurisdiction, such as that of the Federal Energy Regulatory Commission (FERC). Further, a pipeline regulated under this new contract carrier chapter is exempt from regulation under other regulatory chapters. Also included in SSHB 4 are housekeeping sections needed by the RCA in the chapters under which it regulates. These tell the RCA it can do the regulating job the legislature has told it to do, such as appointing panels to hear matters and including in an annual report its regulatory activities under a given chapter.

[3:40:32 PM](#)

MS. DELBRIDGE directed attention to the new regulatory structure specifically proposed by SSHB 4, starting with Section 29, page 38, through the end of Section 33, page 51. She related that over the past year and a half, the sponsors worked closely with AGDC and with the Department of Law attorneys assigned to the RCA to structure this framework. She related that the RCA told the sponsors it was very important to be clear in how the legislature would like it to regulate and to then give the RCA the direction and authority to carry out that regulation. This section is not perfect, she said. The sponsors are still

talking with attorneys assigned to the RCA and with the administration to ensure the appropriate accountability is included in the bill to protect all parties involved.

[3:41:53 PM](#)

MS. DELBRIDGE reviewed the provisions of SSHB 4 that empower the RCA, paraphrasing from the sectional analysis [original punctuation provided]:

Section 29 (RCA, conforming), amends AS 42.04.080(a), *Public Utilities and Carriers and Energy Programs, Regulatory Commission of Alaska, Decision-making procedures*, to allow the RCA to appoint a panel for hearing matters under the new 42.08.

The RCA needs the statutory authority to appoint a panel and hear a matter that comes before them under one of two existing regulatory statutes. This adds the new regulatory chapter created in HB 4, 42.08, to that statutory direction, so the RCA will be able to act on matters that come up under the new regulatory chapter.

Section 30 (RCA review of public utility contracts), amends AS 42.05, *Public Utilities and Carriers and Energy Programs, Alaska Public Utilities Regulatory Act*, by adding a new section related to RCA review of contracts entered into by a public utility with AGDC for transportation or for contracts public utilities sign to purchase gas or store gas transported on an instate natural gas pipeline regulated under 42.08. Public utility contracts with AGDC may include a covenant for public utilities to collect rates sufficient to meet contractual obligations. Contracts to buy or store gas to be shipped on an instate natural gas pipeline regulated under 42.08 must be submitted to the RCA before they take effect. The RCA has 180 days to disapprove contracts as presented or, if contracts are found not just or reasonable, to disapprove the contracts. Contracts approved are not subject to further RCA review. The RCA may extend the 180 day review period if a public utility fails to provide supplemental information that is available to the public utility.

This section provides an interface between regulation of public utilities, and regulation of a contract carrier natural gas pipeline. If the RCA approves a

contract involving a utility and the pipeline carrier, the utility has assurances that it will be able to recover its costs in rates charged to utility customers.

Section 31 (RCA conforming) amends AS 42.05.711, *Public Utilities and Carriers and Energy Programs, Alaska Public Utilities Regulatory Act, Exemptions*, to exempt a pipeline subject to regulation under 42.08 from regulation under 42.05.

Section 32 (RCA conforming) amends AS 42.06, *Public Utilities and Carriers and Energy Programs, Pipeline Act*, by adding a new section to article 7 exempting a pipeline subject to regulation under 42.08 from regulation under 42.06.

[3:42:23 PM](#)

MS. DELBRIDGE elaborated on Section 30, explaining that the provisions are like a pre-approval process, which more and more utilities are shifting towards. For example, when embarking on its extensive Southcentral Alaska power project, Chugach Electric Association, Inc. sought pre-approval from the RCA for that expenditure so the utility would know the money it invested in these upgrades and new facilities would be "certified" as things the RCA knew needed to happen and that the utility could pass on [to consumers]. Similar to this was the Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA) facility, where the RCA essentially granted utilities pre-approval so they would know that if they paid for storage the expense could be passed on to consumers. Under Section 30 a contract between a utility and AGDC can include a covenant that the public utility will be able to recover its costs in the rates charged to consumers. This is a good backstop for protecting consumers, as well as protecting the electric and gas utilities that will hopefully be participating in this pipeline.

[3:45:00 PM](#)

REPRESENTATIVE TUCK inquired whether this proposed structure is identical to an existing gas utility.

MS. DELBRIDGE replied the structure is very different. The RCA currently regulates gas or other public utilities under AS 42.05, Public Utility Regulation. The RCA can also regulate pipelines under AS 42.06, the Pipeline Act, which addresses oil pipelines or common carrier pipelines. Thus, SSHB 4 creates AS

42.08 for contract carrier in-state gas pipelines. Section 30 of the bill is the interface between this new structure and the way the RCA already regulates public utilities for tariff rates that can be passed on to consumers.

3:46:01 PM

REPRESENTATIVE TUCK posed a scenario in which ENSTAR purchases gas from a supplier that is shipping on this pipeline. He asked whether RCA will have jurisdiction over this purchase.

MS. DELBRIDGE responded the RCA will have jurisdiction over all shipping contracts on the AGDC pipeline. If ENSTAR procures a supply of gas from a producer in Cook Inlet, the RCA does not necessarily have to approve that supply contract, but the RCA does approve the second part where ENSTAR gets the gas to its customers. When, in delivering gas to its utility customers, ENSTAR looks to recover its costs of getting the gas in the first place, the RCA must go by the best information that ENSTAR and the producer had a reasonable agreement for that. ENSTAR might ship gas on the pipeline or it might buy gas that was shipped by someone else on the pipeline, so its contract might not be with AGDC for shipment. However, if ENSTAR has a related contract, SSHB 4 allows another level of RCA review of those contracts so the utility has assurance that it will be able to cover those costs later.

3:47:46 PM

REPRESENTATIVE SEATON charged that the RCA's gas distribution regulation is not at all transparent. He said the RCA does not seek to limit costs and many times the tariffs are agreed to by stipulation, thereby preventing the public from getting the background information from the RCA. Two cities he is dealing with are having this problem with gas distribution systems, he related. Two years ago there was \$1.21 in unallocated labor costs per foot of line being put in, which increased to \$21.00 the next year, but backup and justification information cannot be accessed because the tariff was adopted by stipulation. He urged a provision be put into SSHB 4 requiring that background information for stipulated tariffs be made publically available and maintained by the RCA. Rather than regulating and looking at the costs as it is supposed to do, the RCA acts like an adjudicatory authority. When one utility is objected to by another, the lawyers argue it out in front of the RCA and the RCA makes a decision, but all the background material then becomes confidential and is held by those separate companies.

He said he wants to ensure that this same system is not put in place [under SSHB 4] because it is a way for data that is supposed to be public to be hidden by the RCA process. Given SSHB 4 is a work in progress, it must be ensured going forward that if the public has questions about those contracts or distribution of that gas there is a way to find it. Clear criteria must be developed that things must be maintained transparently in the new RCA regulations.

[3:51:24 PM](#)

REPRESENTATIVE OLSON inquired whether anyone from the RCA is online.

CO-CHAIR SADDLER replied there is not today but the plan is to have someone from the RCA talk to the committee at some point.

MS. DELBRIDGE stated the Department of Law attorney for the RCA, Stuart Goering, is following the hearings and paying close attention, and would be glad to answer questions at the appropriate time.

[3:52:15 PM](#)

MS. DELBRIDGE, continuing the sectional analysis, explained that Section 33 lays out the new structure for regulating an in-state natural gas pipeline. She paraphrased from the sectional analysis [original punctuation provided]:

Section 33 (RCA natural gas pipeline contract carrier)

adds a new chapter to AS 42, *Public Utilities and Carriers and Energy Programs*, to create Chapter 08, In-state Pipeline Contract Carrier. Chapter 08 applies to an instate natural gas pipeline providing contract carriage, and exempts an in-state natural gas pipeline subject exclusively to federal jurisdiction.

House Bill 4 provides for a new category of gas pipeline carriage, contract carriage, and includes a new regulatory framework for a contract carrier gas pipeline. The new 42.08 is a shift from traditional cost-based regulation, and directs the Regulatory Commission of Alaska to instead evaluate whether negotiated contracts are fair and reasonable. Checks and balances are included to set basic rules ensuring fair and open processes; to promote exploration and development of Alaska's gas basins; to protect the

public welfare; and to require heightened scrutiny for contracts entered into by affiliated parties.

MS. DELBRIDGE noted this is the only place in this regulatory structure in which special qualifications are included just for AGDC. She continued paraphrasing [original punctuation provided]:

Sec. 42.08.010, Application of chapter; exemption, applies this chapter to an instate natural gas pipeline providing service as a contract carrier. Exempts an instate natural gas pipeline subject exclusively to federal jurisdiction.

Sec. 42.08.020, Qualification of the Alaska Gasline Development Corporation; findings, determines that AGDC is financially and managerially fit, willing and able to provide service under 42.08. States that an AGDC pipeline is required by public convenience and necessity. Directs the RCA to determine whether any entity applying under 42.08 is technically fit, willing and able.

The findings made on behalf of the RCA in this section are findings that the RCA usually needs to make in issuing a pipeline building permit - a Certificate of Public Convenience and Necessity. The advance findings are not valid for an applicant other than AGDC. For AGDC and any applicant, the RCA will need to determine whether the entity is technically able to build the project and provide the service proposed.

[3:54:29 PM](#)

MS. DELBRIDGE moved to review of the general instructions to the RCA in Section 33, paraphrasing [original punctuation provided]:

Sec. 42.08.220, General powers and duties, provides enabling direction for the RCA under 42.08. Requires permits for construction, interconnections, expansions and abandonment. Enables the RCA to intervene in disputes that were not accounted for in contractual dispute resolution mechanisms, and that threaten the public safety and welfare. Prohibits the RCA from requiring rates or tariff regulations, except as provided in the chapter, and from conducting further review of contracts approved under 42.08.

[3:56:35 PM](#)

REPRESENTATIVE SEATON understood AGDC will be negotiating tariff rates with particular utilities. He asked whether "prohibits the RCA from requiring rates or tariff regulations" means the RCA really has no authority on requiring those tariffs or rates.

MS. DELBRIDGE responded a regulatory body can regulate using a cost-based approach or can regulate contracts that use a negotiated rate type approach. Typically, in some cases, the RCA has been able to decide what rates might be. Because SSHB 4 sets up the structure for an in-state gas contract carrier pipeline, it is trusting to contracts to create rates that are reasonable for the parties entering the contracts. Thus, the RCA would no longer need to go in and make the rates.

[3:57:52 PM](#)

REPRESENTATIVE SEATON posed a scenario in which AGDC is not the full financial contributor and the pipeline is built primarily by private enterprise. He asked whether in this situation the RCA would have input on the rate of return. He further asked what the RCA's duty and power would be in looking out for the public interest in those negotiated rates.

MS. DELBRIDGE answered the public interest can be defined as, one, the people using gas provided by public utilities or, two, the people shipping on an AGDC pipeline, i.e. AGDC's customers, which may or may not be gas that goes to public utilities. For a shipper with a contract for gas that is not going to a public utility, this chapter essentially says that as long as there was no duress or fraud or an affiliate relationship between those parties, then that contract is just and reasonable because two people said "this is the price we are willing to sell/this is the price we are willing to pay". If a public utility is involved, there is this additional standard of review that essentially requires the RCA to give a deeper look to the pre-approval that the utility will be able to pass that on to its customers.

[3:59:39 PM](#)

REPRESENTATIVE SEATON noted that with FERC there is a generally approved rate of return. However, given SSHB 4 is for contract carriage, he asked whether there is anything in the bill that prevents a negotiated rate of return of 25 percent.

MS. DELBRIDGE replied it will be seen in later discussion that the carrier must start with a recourse rate, which is a rate available to any shipper on the pipeline as a starting point for negotiation. The recourse rate is supported by a cost-of-service study that includes a rate of return. The RCA standard of review includes making sure that negotiations from that [starting] recourse tariff are done so in a reasonable way.

[4:00:51 PM](#)

CO-CHAIR SADDLER understood the starting point is based on a reasonable rate of service, but inquired whether there is anything to prevent a contractual agreement between the shipper and the pipeline owner from having a generous rate of return.

MS. DELBRIDGE responded [the shipper] entering into the contract will be able to see the rate of return being proposed by the carrier. To some extent, it is highly unlikely that [a shipper] would sign a contract that creates a 20 percent rate of return for the carrier. She said SSHB 4 provides a much higher level of scrutiny for contracts that are between affiliates; it essentially reverts to the RCA's standard level of review under AS 42.06, Pipeline Act, which goes into a full rate-based study.

[4:02:37 PM](#)

TINA GROVIER, Attorney, Natural Resources and Energy Law, Birch Horton Bittner & Cherot, Counsel to Alaska Gasline Development Corporation (AGDC), confirmed Ms. Delbridge's aforementioned statement to be correct.

[4:02:57 PM](#)

REPRESENTATIVE SEATON requested Ms. Grovier to re-state the issue and elaborate on why Ms. Delbridge is correct.

MS. GROVIER understood the concern is about affiliated entities and whether there is a tool in SSHB 4 for the RCA to take a closer look at that. She directed attention to page 45, lines 3-8, which state that if the parties are affiliated and it is not an arms-length transaction, then "the commission shall determine whether the precedent agreement or related contract is just and reasonable using the standards normally applied under AS 42.06.140", which is the existing RCA common carriage statute that regulates pipelines.

[4:04:37 PM](#)

MS. DELBRIDGE requested Ms. Grovier to address whether the rate of return that a pipeline carrier creates for itself is limited, or can the carrier sign contracts giving itself a 20 percent rate of return that the RCA has no review over regardless of whether the parties are affiliated.

MS. GROVIER answered that, as she understands it, the recourse tariff being filed will specify the rate of return in the cost-of-service study. If the RCA is reviewing that recourse tariff, that is the opportunity where that would be reviewed.

[4:05:33 PM](#)

REPRESENTATIVE SEATON understood the tariff is to pay back the people who have firm shipping contracts. If that is the case, will they be receiving a return on that investment, he asked.

MS. DELBRIDGE replied the pipeline will do its work over the next few years and before recruiting shippers it will do a cost-of-service study that contains a massive list of things, including its rate of return opportunity. The study is the foundation for the rate and the rate is part of the tariff. Also part of the tariff is all the other terms and conditions of service. For some shippers, having a greater volume available is more important than the rate, so there is room to negotiate some of the terms. The tariff, to start with, is called a recourse tariff. This recourse tariff goes to the RCA and all potential shippers, providing a starting point that is eligible for everybody to play on. Because no one wants to pay more than is reasonable, the cost-of-service study must support the elements in the tariff. During the open season the carrier is asking shippers to buy space in the pipeline. The recourse tariff is the starting point and the fine points are then negotiated because different shippers have different priorities; for example, a shipper may be willing to have its service interrupted at times in return for a better rate. The hope is that the negotiations end up with a precedent agreement and that precedent agreement would include the negotiated rates and the negotiated terms and conditions. Those precedent agreements are the contract and that contract has some conditions attached to it, such as the carrier needs to ensure its project is within a certain cost range, must start operations by a certain date, must obtain certain permits, or any number of things. For the next year or two after signing the precedent agreements and filling up the pipeline during open season, work is begun on resolving the conditions. Once the conditions have been met and

the financing is there, the precedent agreements are turned into firm transportation agreements and that is when the project is sanctioned and construction begins.

[4:10:07 PM](#)

REPRESENTATIVE SEATON said the concern he is trying to get at is when the shippers are actually the financiers or the owners of the pipeline or owners of major pieces of the pipeline, the Trans-Alaska Pipeline System (TAPS) being an example. He said he wants to ensure that the structure of SSHB 4 will ensure the tariffs are as low as they can be for generating a generous return to the financiers.

MS. DELBRIDGE understood the concern and said she will point out where those extra levels of precautions have been made as she goes along in her review. She acknowledged the possibility for shippers to be potential owners, as with any pipeline, and said the bill has additional backstops for this. That is also where the firewalls come into play, she continued; for example, "BP Producer" and "BP Pipeline Company" cannot give themselves unfair advantages either. If the pipeline is being financed through revenue bonds, the people rating those bonds and then financing the pipeline are going to take a very, very good look at these contracts to ensure it is a legitimate investment for them to make; part of that is whether the financier has a chance to earn a reasonable rate of return.

[4:12:50 PM](#)

MS. DELBRIDGE, responding to Co-Chair Saddler, said Section 42.08.220 is on page 29 of the bill. Resuming her review, she paraphrased from the sectional analysis [original punctuation provided]:

Sec. 42.08.230, Commission decision-making procedures, directs the RCA to appoint a panel to consider and decide matters under 42.08, and to expeditiously adjudicate matters.

Sec. 42.08.240, Publication of reports, orders, decisions and regulations, is the standard RCA direction for publishing reports, orders, decisions and regulations.

Sec. 42.08.250, Application of Administrative Procedure Act, is the standard RCA exemption from Administrative Procedure Act adjudication procedures.

Instead, the RCA's adjudication procedures would apply. The rest of the Administrative Procedures Act still applies to regulations adopted by the RCA.

Sec. 42.08.260, Annual report, requires the RCA to include in its annual report activities related to 42.08.

Sec. 42.08.300, Open seasons, sets rules a carrier must follow when holding an open season. Provides parameters for holding an open season to ensure fairness and openness for all interested potential shippers, including advance notice. Requires a carrier to hold an open season for pipeline expansion when the carrier has received requests for firm service from potential shippers that would enable a commercially reasonable expansion. Provides that expansions may not violate the terms of AGIA. Allows a carrier to make pre-subscription agreements before an open season begins. Requires a carrier to award firm transportation service without undue discrimination or preference.

[4:14:02 PM](#)

MS. DELBRIDGE elaborated that the advance public notice required by Section 42.08.300 must include the recourse tariff, the proposed form the agreements will take in the end, and information about such things as pipeline route, capacity, operating pressures, and quality specifications. The notice must also be clear as to how the carrier is going to allocate capacity to the bidders. Any pre-subscription agreements before an open season begins would still be based on the recourse tariff.

[4:16:06 PM](#)

CO-CHAIR SADDLER inquired who would make the determination that an expansion is commercially reasonable.

MS. DELBRIDGE answered the determination would be presented through the RCA. If there was any question as to whether the opportunity was commercially reasonable, an arbitrator would be there to decide that.

[4:16:32 PM](#)

MS. DELBRIDGE turned back to paraphrasing from the sectional analysis [original punctuation provided]:

Sec. 42.08.310, Transportation service, provides that firm service can only be made available through presubscription agreements or open seasons. Requires a carrier to offer a recourse tariff with rates determined on a cost-of-service basis. Allows that negotiated firm transportation rates may be different from recourse rates. Requires a carrier to provide interruptible service in capacity not used in firm service.

MS. DELBRIDGE explained a carrier must provide a recourse tariff developed from a cost-of-service basis. The carrier must be able to roll in rates for expansion, so long as resulting rates for the current shippers do not exceed the maximums under their contracts. The carrier must file the recourse tariff with the RCA. Starting with that recourse rate, AGDC and each potential shipper can negotiate the rates, the terms, and conditions for that given contract. She said this section also requires that things be done fairly. So, AGDC can negotiate, but it has to do so keeping in mind that that next level of RCA oversight is going to ensure that these negotiations were done fairly and that they are responsible and non-discriminatory. The earliest contracts must include a dispute resolution procedure. Section 42.08.310 also requires the carrier to provide interruptible, maybe short-term service, for any capacity that is not being used in firm service. For example, gas and oil fields might go through seasonal shutdowns for maintenance, leaving capacity available that could be filled during that shutdown period.

[4:18:58 PM](#)

REPRESENTATIVE TARR, returning to Section 42.08.300, asked how "holding an open season to ensure fairness and openness for all interested potential shippers" and "pre-subscription agreements" work together to ensure fairness for all interested parties.

MS. DELBRIDGE replied a carrier will be negotiating privately with different shippers, whether in a pre-subscription agreement or in an open season, and both opportunities must start with that recourse tariff. The contracts coming out of these will all be managed the same way - as precedent agreements going forward.

[4:20:00 PM](#)

REPRESENTATIVE SEATON inquired whether the negotiated tariffs in the contracts are generally lower than the recourse rate based on cost-of-service.

MS. DELBRIDGE responded she thinks it might be the opposite, but deferred to a representative from AGDC for an answer.

[4:20:35 PM](#)

DARYL KLEPPIN, Manager, Commercial Team, Alaska Gasline Development Corporation (AGDC), Alaska Housing Finance Corporation (AHFC), Department of Revenue (DOR), understood the question to be whether a rate negotiated off the recourse tariff could be lower than the recourse tariff. He said the answer would be yes, depending upon other terms and conditions as there are a lot of other issues besides the rate that a [shipper] may find important and may be willing to pay more or less depending upon those terms and conditions.

[4:21:14 PM](#)

REPRESENTATIVE SEATON pointed out that if negotiations can be for a tariff that is higher than a recourse rate that is based on cost of service and a fair rate of return, then that will be a cost to the consumers or whoever is on the other end of the pipe. He asked whether the potential here is for a higher rate or a lower rate and said it raises some concern if it is higher than the cost-of-service tariffs with no limitation.

MS. DELBRIDGE answered she thinks this is getting to the review of certain contracts by the RCA in which the RCA looks at how far above or below that recourse tariff the parties went and how that rate change was compensated for with other terms and conditions that are of value. For example, a utility shipper might feel that a long-term supply of gas is worth a little bit more than having less gas than it thinks it is going to need and paying less. There is a value in having certain terms and conditions met, she said, the price is not everything.

[4:23:00 PM](#)

REPRESENTATIVE SEATON stated he is trying to understand why a shipper would bid for a higher tariff, although a shipper might bid for a higher price from the seller. He suggested getting together for further explanation later.

MS. DELBRIDGE agreed to do so.

CO-CHAIR SADDLER surmised the recourse rate sets the benchmark from which to negotiate depending on other terms and conditions.

MS. DELBRIDGE replied correct and added that it is fairly common to let the rate fluctuate a little bit because a benefit is being gained in the terms and conditions.

CO-CHAIR SADDLER commented the provisions are that the contracts are reviewable.

[4:23:58 PM](#)

MS. DELBRIDGE continued her review, paraphrasing from the sectional analysis [original punctuation provided]:

Sec. 42.08.320, Review of certain contracts by the commission, requires a carrier to submit all precedent agreements to the RCA; precedent agreements with other than a public utility may be kept under seal. The RCA has 180 days to approve or disapprove precedent agreements as just and reasonable. Sets the standard for determining if a contract is made at arm's length and allows additional RCA scrutiny of contracts made between affiliated parties that are not substantially similar to transactions made between unaffiliated parties. Approved contracts are not subject to further review.

MS. DELBRIDGE noted Section 42.08.320 has a decision tree: the RCA looks at the contract and if it was done at arm's length between two parties, this structure says that that contract is just and reasonable unless the RCA finds that there was some kind of unlawful activity or fraud. If a contract was made at arm's length it is good to go. However, it must be decided what makes it arm's length. Under SSHB 4, a contract is arm's length if it incorporates the recourse tariff.

[4:25:23 PM](#)

CO-CHAIR SADDLER inquired whether a contract below the recourse rate will automatically be considered not at arm's length.

MS. DELBRIDGE responded such an agreement would be considered as not meeting that standard of incorporating the recourse tariff. [Citing from page 44, lines 27-31, and page 45, lines 1-13 of

SSHB 4], she said an agreement that does not include the recourse tariff would be considered arm's length if it is between two state-owned parties or between private parties that are not affiliated. An agreement between two affiliates would be considered arm's length if substantially similar to contracts made between unaffiliated parties. An agreement between affiliates that is not substantially similar to other contracts would not be at arm's length, so the RCA would conduct a higher level of review of that contract.

[4:26:25 PM](#)

CO-CHAIR SADDLER asked who within the RCA would make these evaluations, decisions, and judgments.

MS. DELBRIDGE believed the RCA as a whole would use its existing procedure, but said she is unsure whether that includes the whole commission or an administrative law judge. Often the commission begins hearing a matter and then delegates the follow through to an administrative law judge.

[4:26:57 PM](#)

REPRESENTATIVE P. WILSON read page 44, lines 24-26 of the bill, which state "a contract that is approved or considered approved under this paragraph and the associated firm transportation agreement are not subject to further review by the commission." She noted this is stated more than once and asked why.

MS. DELBRIDGE replied it was important to structure a regulatory framework that honored that contracts could be made between two parties to ship gas on a pipeline. Having a third party that can keep coming back to review that contract negates the concept that contracts freely entered into by people that are not under fraud are fair.

[4:27:51 PM](#)

MS. DELBRIDGE resumed the sectional analysis, reiterating that if a contract is not at arm's length, the RCA will go into a much deeper level of review and will use the same standards that it would apply in reviewing a contract under the Pipeline Act, which is existing regulation for common carrier pipelines, allowing the RCA to actually make just, fair, and reasonable rates or to require those. She said Section 42.08.320 is clear that the carrier must provide the RCA with a cost-of-service study so that the RCA actually has the tool it needs to do this

extra level of review. The section further provides that when contemplating approving or disapproving these contracts, the RCA must consider the consequences of failing to approve a contract.

[4:29:09 PM](#)

MS. DELBRIDGE moved to Section 42.08.330, paraphrasing from the sectional analysis [original punctuation provided]:

Sec. 42.08.330, Contract carriage certificate, requires a certificate of public convenience and necessity (CPCN) for a carrier to construct a pipeline and to transport gas. The RCA has 180 days to issue a CPCN once application is made, providing that the applicant is found fit, willing and able to perform the services proposed. The RCA may attach conditions to and amend, suspend or revoke a CPCN. Operating authority may not be transferred and service may not be abandoned without RCA approval.

MS. DELBRIDGE elaborated that the CPCN describes the service area and the scope of operations that are allowed. The RCA must do a full course of fit, willing, and able if the applicant is someone other than AGDC. She allowed the 180 days for the RCA to issue a certificate is a tight timeline, but said it is reasonable and the point is to not delay a project with overly long timelines. The RCA may include terms and conditions in the CPCN if those mutually benefit both the carrier and the public. If a complaint about the service being provided is filed, the RCA can modify, suspend, or revoke the CPCN if there is good cause.

[4:31:11 PM](#)

REPRESENTATIVE JOHNSON inquired whether it is automatic approval should the RCA not act within 180 days.

MS. DELBRIDGE responded she does not see that standard in the bill language.

REPRESENTATIVE JOHNSON asked [what happens if the RCA does not act within 180 days].

MS. DELBRIDGE replied she does not know how to answer the question. In other instances in SSHB 4, she noted, the failure to approve within a certain timeframe is inherent approval.

4:32:06 PM

REPRESENTATIVE JOHNSON inquired of the sponsor whether this is something that should be put in the legislation because there is no motivation for the RCA to do it unless there is automatic approval.

REPRESENTATIVE HAWKER responded by asking Ms. Delbridge whether the question is driven by page 45 of the bill, lines 28-29, which state that "within 180 days after receiving an application ... a contract carriage certificate shall be issued ... if the [commission] finds ... the applicant is fit, willing, and able" Regarding what happens if the RCA does not act within that timeframe, he asked Ms. Delbridge whether page 46 of the bill, lines 4-6, provide that if the commission fails to find the applicant fit, willing, and able, the application must be denied.

MS. DELBRIDGE confirmed that they do.

4:33:24 PM

REPRESENTATIVE JOHNSON expressed his concern that in a situation where the RCA did not want to grant a permit, the commission could stall past 180 days and it would be automatically denied. He said he would prefer language that grants automatic approval of the application if the RCA stalls past 180 days because he wants to build pipelines, not give people reasons not to build pipelines.

MS. DELBRIDGE answered there are some other instances where [the sponsors] have incorporated that concept. Speaking for the sponsors, she said they would like to look at doing so.

4:34:26 PM

MS. DELBRIDGE returned to the sectional analysis, closing her review of Section 42.08.330 by stating that the rest of this section is housekeeping. She continued paraphrasing from the sectional analysis [original punctuation provided]:

Sec. 42.08.340, Filing requirements; public inspection, requires an instate natural gas pipeline carrier to file all recourse tariffs, rules, regulations, terms and conditions pertaining to service, and all contracts with shippers. Requires

changes in tariff rates/rules and service conditions to be filed with the RCA.

Sec. 42.08.350, Uniform system of accounts, requires a carrier regulated under 42.08 to maintain records and accounts in accordance with the uniform system of accounts.

Sec. 42.08.360, Expansion; dispute resolution, enables contracts to provide for expansion, unless an expansion would violate the terms of the Alaska Gasline Inducement Act. Requires contracts to include procedures for resolving disputes.

Sec. 42.08.370, Regulatory cost charge, implements the standard RCA assessment of a user fee on regulated entities; includes a cap and directs administration of the user fee.

Sec. 42.08.380, Effect of chapter on taxes and royalties, declares that nothing in 42.08 will change the calculation of production taxes or of royalties due the state.

[4:35:11 PM](#)

MS. DELBRIDGE elaborated that Section 42.08.380 is special to SSHB 4. She said that just because the RCA and the carriers have determined a cost of transportation, the bill does not take away the ability of the Department of Revenue and the Department of Natural Resources to determine their own reasonable transportation costs for purposes of a production tax or royalty.

CO-CHAIR SADDLER surmised Ms. Delbridge to be saying the bill is not setting a precedent.

[4:35:48 PM](#)

REPRESENTATIVE SEATON requested clarification about whether the pipeline would be subject to property taxes.

MS. DELBRIDGE replied that Section 42.08.380 is strictly about oil and gas production taxes and royalty valuation of the gas. She requested the question be held for the appropriate section.

[4:36:42 PM](#)

MS. DELBRIDGE continued her review, paraphrasing from the sectional analysis [original punctuation provided]:

Sec. 42.08.400, Public records, requires RCA records be available to the public, except as provided by law. Precedent agreements will be kept confidential. Firm transportation and other contracts will be public, except for information that the carrier and the RCA agree could cause competitive harm.

[4:37:17 PM](#)

REPRESENTATIVE SEATON observed there are several places in the bill regarding public information and that it can be viewed at the RCA or by pay copying costs. He noted, however, that almost everything is now submitted electronically. He asked whether this could be re-structured so that the material is required to be provided to the public electronically.

MS. DELBRIDGE allowed that is a good point and said she will consult with the RCA about what its existing regulations are and whether that is already provided for. If it is not, she said she will try to find a way to make electronic filing work.

CO-CHAIR SADDLER noted that could be added to the questions for the RCA when it comes [before the committee].

[4:38:20 PM](#)

MS. DELBRIDGE resumed paraphrasing from the sectional analysis [original punctuation provided]:

Sec. 42.08.410, Investigations, allows the RCA to investigate matters in 42.08, and maintains the role of the Department of Law's Regulatory Affairs and Public Advocacy section.

Sec. 42.08.510, Designation of service agents, requires an instate natural gas pipeline carrier to file a named, permanent resident as its agent (standard RCA provision).

Sec. 42.08.520, Effect of regulations, states that regulations adopted by the RCA under 42.08 have the effect of law (standard RCA provision).

Sec. 42.08.530, Judicial review and enforcement, makes RCA final orders subject to standard RCA judicial review, except in the circumstances set forth in HB 4, Section 13, addressing the development, construction and initial operation of a natural gas pipeline by AGDC.

Sec. 42.08.540, Joinder of actions, allows appeals to be joined under applicable court rules (standard RCA provision).

Sec. 42.08.900, Definitions, defines terms standard to the RCA (commission, commissioner, record) and includes HB 4 terms (instate natural gas pipeline, instate natural gas pipeline carrier).

[4:38:56 PM](#)

REPRESENTATIVE TARR requested further elaboration of Section 42.08.530.

MS. DELBRIDGE responded Section 42.08.530 essentially says that final orders of the RCA are subject to judicial review, except as provided for under AS 38.35.200, which is the place earlier in the bill [Section 13] that limits judicial review. If an appeal is not taken from a final order of the commission within 10 days after an investigation, the commission can apply to the superior court for enforcement of the order of the commission. That is essentially a standard RCA provision that lets the commission have a little bit of an outlet for enforcing its decisions.

[4:39:46 PM](#)

CO-CHAIR SADDLER inquired whether this issue was addressed in the responses included in the committee packet.

MS. DELBRIDGE answered the packet should have a response from Legislative Legal Services related to judicial review and specifically to Representative Tarr's previous question as to whether the legislature can limit a court's jurisdiction.

CO-CHAIR SADDLER noted that that is a February 12, [2013], letter from Don Bullock to Representative Hawker.

[4:40:40 PM](#)

REPRESENTATIVE SEATON understood the property tax exemption under Section 34 is only for the duration during construction and that the private sector would need to pay property taxes regardless of the ownership structure in a pipeline with AGDC.

MS. DELBRIDGE responded to Representative Seaton by paraphrasing from the sectional analysis [original punctuation provided]:

Section 34 (property tax exemption) adds a new subsection to AS 43.56.020, *Revenue and Taxation, Oil and Gas Exploration, Production and Pipeline Transportation Property Tax, Exemptions*, exempting an AGDC-owned or financed project from state and local property taxes during construction.

This is one way the state can help an AGDC project succeed. Waiving property taxes for a period of time will help keep construction costs down during a highly risky time in pipeline development. Cost savings during construction would be reflected in the tariffs paid for gas shipped on an AGDC line.

[4:41:44 PM](#)

MS. DELBRIDGE continued paraphrasing from the sectional analysis [original punctuation provided]:

Section 35 (repealer) repeals 11 statutes.

- Repeals AS 36.30.850(b)(45) *Public Contracts, State Procurement Code, Application of this chapter*, a prior exemption that applied to an AHFC pipeline.
- Repeals AS 38.34.030, *Public Land, In-State Natural Gas Pipeline, Joint In-State Gasline Development Team*; 38.34.040, *Duties of the Development Team*; 38.34.050, *Cooperation and access to information*; and 38.34.060, *Conflicts of interest*, all of which were part of [House Bill] 369 in 2010 and relate to the Joint In-state Gasline Development Team.
- Repeals AS 41.41.030, *Public Resources, Alaska Natural Gas Development Authority, Term of office*; 41.41.040, *Removal and vacancies*; 41.41.050, *Quorum and voting*; 41.41.080, *Legal counsel*; 41.41.100, *Budget*; and 41.41.990(4), *Definitions*, all related to the transition of

ANGDA [Alaska Natural Gas Development Authority]
to a marketing role and to an AGDC subsidiary.

[4:43:16 PM](#)

Section 36 (repealer) repeals Section 1 of 2002 Ballot Measure No. 3, the findings of which are no longer necessary with ANGDA's revised authority.

Section 37 (transition and intent) expresses the legislative intent that the existing state right-of-way lease between AGDC and DNR is amended to reflect the contract carrier covenants in HB 4 (the Alaska Constitution bars the Legislature from passing laws that apply retroactively to contracts in place). Also expresses intent for a smooth transition for AGDC from its status as a subsidiary of AHFC, to an independent corporation.

Specifically, this section includes:

- The intent is that this repositioning does not interfere with, delay or disrupt AGDC's work.
- The intent that the governor should appoint the new AGDC board within 90 days of the effective date.
- The AHFC board will remain in place until a new board is appointed; and will cooperate with the new board in a smooth transition.
- The intent is that the transition is a change in placement only, and will not require dissolving AGDC and creating a new corporation.
- The intent is that AGDC, including employees and directors, continue in-place while the boards are transitioning. This is not explicitly stated but rather is implied.

Section 38 is revisor's instructions

Section 39 sets an immediate effective date.

[4:45:45 PM](#)

REPRESENTATIVE SEATON drew attention to page 5, second question and answer, of the [undated] letter to the co-chairs from Representative Hawker [answering questions from the 2/4/13 and

2/6/13 committee meetings]. He recalled committee discussion about timelines for release of confidential information and noted the answer in the letter states that the bill "does not restrict the confidentiality by time, this information may be of public benefit once a pipeline is operational." He said what was being looked for with the question was having timelines for release of information that no longer needs to be held confidential. He requested that such an answer be prepared and brought to the committee for incorporation into the bill.

[4:47:13 PM](#)

CO-CHAIR SADDLER requested Representative Seaton to re-state what information he is requesting.

REPRESENTATIVE SEATON read the first sentence in Representative Hawker's answer: "HB 4 allows for certain information to be held confidential, and does not set time limits for that protection." However, Representative Seaton continued, the question posed was whether a provision can be put into the bill for releasing confidential information once it no longer needs to be held confidential. For example, release of that confidential information after the pipeline becomes operational or at certain other time periods identified by AGDC.

[4:48:53 PM](#)

The committee took a brief at-ease.

[4:49:05 PM](#)

FRANK RICHARDS, Manager, Pipeline Engineering & Government Affairs, Alaska Gasline Development Corporate (AGDC), Alaska Housing Finance Corporation (AHFC), Department of Revenue (DOR), , at the request of Co-Chair Saddler, responded to Representative Seaton's question. He explained that a variety of items would be deemed confidential, such as information in commercial agreements, information held by third party or other state entities that has been deemed confidential and that AGDC would gain access to through the bill's provisions, and information that AGDC acquires through its own work or has contracted for that will be held confidential. As identified in the response [on page 5], commercial terms in precedent agreements, for example, would be released after going through the RCA process to the extent that the individual shippers did not hold commercial interest or wanted that to be held confidential. A specific listing and a timeframe for when that

information will be released would be hard to ascertain at this time. Currently, AGDC holds information that it acquired from the predecessor of the project, ENSTAR, and that information is held confidential by AGDC as it works this process forward until the point of actually constructing and completing the process. Then it will have been used by AGDC as a public entity and it would then have gone into the public realm. When accessing information held by another department, AGDC is unable to control the release of that information. Mr. Richards offered to address specific information that Representative Seaton would like and provide a timeframe that AGDC thinks it might be able to release it.

[4:51:09 PM](#)

REPRESENTATIVE SEATON noted that a lot of information on this project is confidential and said he thinks the public's confidence in the process becomes much greater if it is known that information not required to be held confidential will be released at some point, such as when the pipeline becomes operational. He agreed to discuss this issue further to see if specific areas can be identified.

MR. RICHARDS said he would be glad to talk with Representative Seaton and with AGDC's commercial manager about which specific commercial issues would likely be held confidential through the precedent agreements. He added that AGDC will also be acquiring information as a state entity that will be held as confidential up to a certain point and, once released, will be a benefit to the citizens of the state.

[4:53:01 PM](#)

CO-CHAIR SADDLER held over SSHB 4, saying it will be taken up again on 3/15/13. He then recessed the meeting to a call of the chair.

[7:49:24 PM](#)

CO-CHAIR FEIGE reconvened the House Resources Standing Committee. Representatives Seaton, P. Wilson, Johnson, Saddler, and Feige were present at the call back to order. Representatives Tarr and Tuck arrived as the meeting was in progress.

HB 72-OIL AND GAS PRODUCTION TAX

[7:49:32 PM](#)

MR. PULLIAM continued his review of projected cash generation per barrel from ongoing production under ACES in comparison to other jurisdictions [slide 32]. He explained the graph is an average across all of the North Slope and is not reflective of an incremental investment. Cash is generated from all ongoing activity and the graph compares it with the cash that is available from other locations, and it can be seen on the graph that the effect of progressivity keeps the cash generation lower in Alaska than in other jurisdictions.

[7:50:27 PM](#)

CO-CHAIR FEIGE inquired why the line depicting Canada is stair-stepped while the lines depicting the other areas are smooth.

MR. PULLIAM replied Canada has different brackets in the way its very complex system is applied.

[7:50:52 PM](#)

REPRESENTATIVE SEATON noted Norway has a 78 percent tax and a 28 percent [*indisc.*]. Observing from the graph that at \$100 per barrel the cash margin for Norway is \$40, he concluded this depicts a tax rate of 60 [percent].

MR. PULLIAM responded no, there is still that [78 percent] tax rate at least in the initial period. He explained Norway has some uplifts and some recovery of costs that add to the producer's margin in the first number of years of production, so the complexity of Norway's overall system gives the look seen on the graph. That higher margin is a function of the uplifts and the recovery of that initial investment against the different taxes in Norway.

[7:52:12 PM](#)

REPRESENTATIVE SEATON related that when [Alaska legislators] met with Norway's oil finance minister, the minister said the uplift was to partially mimic or get to where Alaska is with allowing deductibility in the year. Given that Alaska's and Norway's tax rates are very similar, he asked why the graph depicts such a huge discrepancy between the two areas. He further asked whether the graph depicts the initial years for Norway rather than the ongoing.

MR. PULLIAM answered the graph is for the initial years in and a lower margin will probably be seen later in the lifecycle in Norway.

[7:53:05 PM](#)

MR. PULLIAM resumed his presentation, specifying it is important to think about investment opportunities as well as industry's perception of Alaska's system [slide 33]. He related that reports published about the different systems around the world talk about Alaska's tax rate being between 25 and 75 percent, which is an accurate description. For example, in 2011 the consulting firm IHS CERA did a report for the U.S. Department of Interior. [Page 225] of that report describes Alaska's fiscal system and states Alaska's profit tax is between 25 and 75 percent. People looking at this kind of report do not scratch down through the surface to figure out what rate applies, they see the report and that is their initial perception of the state. This is consistent with what Commissioner Sullivan is reporting about his talks with companies interested in Alaska - their impression right off the bat is that Alaska's tax rates go up pretty high.

[7:55:09 PM](#)

MR. PULLIAM noted the 2011 IHS CERA report also ranked fiscal systems throughout the world to help the U.S. Department of Interior gauge the competitiveness of the federal system [slide 34]. Alaska's fiscal system was ranked second to the highest, which is not a good place because from an investor's perspective the lower the ranking the better. While he does not necessarily agree with the complex way that this rating system was done, he said it is published and is what people are seeing when looking at participating in Alaska. Responding to Co-Chair Saddler, he said the parameters used in this ranking include government take, profitability index (PI), internal rate of return (IRR), and progressivity/regressivity. He explained the method used in this ranking gives a poorer score to systems that are highly progressive or regressive, so relatively neutral systems get better scores from an investor's standpoint. Another parameter used is revenue risk, which has to do with the timing of when the sovereign receives its money. Also used as a parameter is the stability of the system over time, which considers the types of change that have occurred in the fiscal system, as well as the applicability, degree, and frequency of change. There is subjectiveness to the way the ranking is done, but this is what people are looking at and from an investor's standpoint Alaska

is at the tougher end of the spectrum. This ranking is consistent with what is seen in government take statistics generally in which Alaska has some of the higher numbers in government take.

[7:58:11 PM](#)

REPRESENTATIVE TUCK noted chapter 4 of the book, [The Taxation of Petroleum and Minerals: Principles, Problems and Practice], discusses that the effectiveness of a tax regime cannot be looked at by the tax rates alone. He therefore asked what else legislators should be considering with the fiscal system of Alaska when comparing slides 33 and 34.

MR. PULLIAM replied the chart [on page 34] looks at a lot of different categories. The take is a measure of the tax rate. The type looks at whether it is progressive or regressive system. The PI and the IRR measure whether the system is designed in a way that provides acceptable profitability for the investor. The four categories of [type, applicability, degree, and frequency of change] measure how stable a system is and how responsive it is. Stability and competitiveness are important components for investors in thinking about a fiscal system. So, yes, the tax rate is important, as are the competitiveness of the government take and the degree to which the system is going to stay in place and not be subject to change. A frequently changing system makes it difficult to plan, so the risk of the investment is greater. People want to see a system that is durable and will last for as long as is reasonable. Circumstances in the world change and that necessitates at times that systems change. Investors appreciate that systems are dynamic in some ways. A key factor is that investors can be confident that if changes occur, the system will remain competitive and attractive relative to what the investor can be doing elsewhere.

[8:01:28 PM](#)

MR. PULLIAM next addressed the administration's proposed changes in HB 72 [slide 36]. He outlined key aspects of the proposal, saying it would: establish a 25 percent flat [net tax] rate, which is the current base rate, and eliminate progressivity; eliminate capital credit and state purchase of losses; establish a 20 percent gross revenue exclusion (GRE) to incent production of new oil; allow producers to recover losses from the development phase by carrying them forward to when production occurs and a tax obligation is incurred to count them against;

extend the new entrant or small producer credit through 2022; and not change the tax structure outside the North Slope.

8:03:05 PM

MR. PULLIAM reviewed benefits of HB 72, specifying it would provide a balance between the state and the producers [slide 37]. Reduction of tax rates at higher prices would be balanced with elimination of credits. The state would continue to receive the largest percentage of oil production revenues at any price - larger than the federal share and larger than the producer share. The bill would provide tax relief and higher margins in a sustainable price range, which is about \$80 to \$140 per barrel. He noted that prices above and below those levels would be hard to sustain on an ongoing basis, but that does not mean such prices might not occur from time to time. Another benefit of the bill is that it would greatly simplify Alaska's tax system and provide better clarity for planning. It will be easier to factor in how the system is going to impact investments, will eliminate the high marginal tax rate, and will eliminate the uncertainty of what a producer's tax will be at different prices. It eliminates incentive for producers to "gold plate" by spending money less efficiently at high prices when the state's share of spending rises to almost one for one.

8:05:58 PM

MR. PULLIAM, continuing his review of the bill's benefits, said it maintains an alignment between the state and the producers' economics by staying with a net tax system. The gross revenue exclusion (GRE) provides a way to lower the effective tax rate for new development without the treasury having to provide significant funds upfront to do the same. The GRE substitutes economically for those credits that the state provides because it allows the producers to keep a greater share of what they produce when it actually comes on line. Finally, the bill will send a very positive message to potential investors as well as to those already here. It will encourage broader participation on the North Slope, which is something the state needs. The bill will move the economics of new participants closer to what the incumbents enjoy.

8:07:47 PM

REPRESENTATIVE SEATON, in regard to maintaining the incentives, recounted that when the legislature was developing the production profits tax (PPT) and Alaska's Clear and Equitable

Share (ACES), the companies testified that tying investment credits to production would not incentivize them because of the long lead times; that it was most appropriate to tie it to investment because those investments are made up front and are a known quantity. He inquired whether industry told the legislature wrong, given that now the proposal is to tie the credits to production.

MR. PULLIAM responded that is a good recollection of the history and said he can understand from the beneficiary's viewpoint why the beneficiary would rather have that credit guaranteed by tying it to the outlay of capital as opposed to performance-based production. However, he continued, what is being talked about here is eliminating the credit itself and the need to provide that outlay, but rather letting the producer keep a greater portion of the profits that come from the production itself. Some people say that the credits do not offset the increased take of progressivity at prices of \$90 per barrel and higher. Progressivity bites more than the credit provides from the producers' standpoint. Under HB 72, eliminating the credit and also eliminating the progressivity maintains the appropriate economic incentives, and inclusion of the GRE enhances those incentives without having to provide that credit up front.

[8:11:17 PM](#)

REPRESENTATIVE SEATON recalled testimony before the committee about new oil where the companies stated that if expenditures were made in a new field that turned out to be dry there would be no help from the state and so no security. The testimony was that to incentivize development it was much more appropriate to have it tied to investment. Now it is being said they will invest, when before the companies said it would not stimulate investment.

MR. PULLIAM answered he does not think the context of what was put forward to the companies before was whether they would rather have the credits and pay a higher tax rate or not have credits and pay a lower tax rate. What is being talked about here, he said, is a credit versus a higher tax rate tradeoff. The system proposed under HB 72 maintains appropriate economics for the incumbents to continue and expand investment by lowering the tax rate even though the credit is being removed. Also, it enhances those economics particularly for new participants even though the state is not going to be buying those credits from them up front, because it removes progressivity and offers them the GRE and allows an uplift on their initial outlays for

development. All of those things factor in to enhancing the investment decision.

8:13:50 PM

REPRESENTATIVE TARR said a criticism of the credits is that they are being applied to maintenance costs and things not related to production. However, [the state] needs the companies to keep making those maintenance investments for some period of time until the new production comes on. So, it appears there is a timing issue where there is a disincentive now for some of those costs because the companies would not have the credits. She requested Mr. Pulliam to speak to how other jurisdictions deal with credits and whether they are up front.

MR. PULLIAM replied that from his review, where those types of things are offered they are typically taken against production and taxable income. He surmised that imbedded in the question is a concern that removing the credits removes the appropriate incentives to continue with necessary maintenance.

8:15:10 PM

REPRESENTATIVE TARR agreed that is correct in part, but said it seems to her that the timing is not totally in sync with ongoing costs that might be happening in the near term related to what happens when new production comes on.

MR. PULLIAM responded part of any business endeavor involves making an investment up front in hopes of making a profit on that investment, and the oil industry is very typical that way. The companies make an investment up front - they explore, shoot seismic, drill exploratory wells, and then develop. The largest part of the expense is in the development and then after that the company gets production. The industry is very well accustomed to footing the bill for that development in anticipation of receiving a profit on it down the road. When Alaska went to the PPT system, and more so when it went to ACES, the state said it was going to provide companies a bigger incentive to make that upfront investment by giving them this credit, but would recover that by taking more of the profit down the road. The state tried to tilt the scale to accelerate that investment, thinking that by providing more up front, it would be sufficient for industry to forego a bigger piece of the revenue stream down the road; however, it has not worked. The proposed legislation, he continued, removes those upfront credits and significantly reduces the amount of the

progressivity down the road when the production actually comes on. This would put Alaska to being more like what the companies experience in the rest of the world, which is the norm and is an environment in which the companies know how to play.

[8:17:47 PM](#)

REPRESENTATIVE TUCK stated that at high oil prices more capital is available for producers to buy down their tax rates by making sure they invest in Alaska. It does not help them investing it outside of Alaska, but it greatly benefits them here in Alaska. There is 17 percent more investment from one year to the next, and by adding that 17 percent, industry can get 63-95 percent more tax break [slide 23]. He said it seems that reducing the tax rates at high prices and then balancing that with eliminating the credits is doing just the opposite - the state is giving more profit back, but there is no guarantee that that is going to be spent in Alaska, especially when those tax credits are eliminated. [For new participants] the state has a 10-year period in which those tax credits can be carried. The span between investment and start of production is much longer in Alaska than elsewhere due to the seasonal limitations on when work can be done. Giving upfront credits frees cash for the company to invest next year. He asked whether the problem [the administration] has with this provision of ACES is that it is hard to know whether [the credits] will lead to production. He further asked why the state would not want to have more investment in Alaska and let industry determine what is best to get oil down the line, given that is what industry wants to do.

[8:20:02 PM](#)

MR. PULLIAM answered industry wants to make money and getting oil down the line is industry's way to make money, but only if it can keep a competitive portion of what it puts down the line. He agreed that moving the tax rate down and eliminating the credits is opposite of where the state is now. Providing those big credits and having the progressivity means that as long as a company brings that money back to Alaska, then it is a good deal. But if the company decides not to, then it is not a good deal. If you were an investor looking at where to invest, would you want to invest someplace where you have the freedom to respond to oil and market opportunities and reinvest your profit where it makes sense? Or, would you rather spend your money in a place that says it will let you earn those profits, but only if you keep them here? Alaska's current system provides for bringing the funds back to Alaska, but that does not produce the

same quality of profit that can be produced elsewhere. That is like owing money to someone and asking whether that person would like cash or a gift certificate. Which would you rather have, which is more valuable? The norm elsewhere is you get the cash. Investors would find it much more valuable and would find Alaska much more attractive as an investment opportunity if they have the freedom to use their profits in the best way possible. While there would be no guarantees that they would reinvest in Alaska, the state can provide a competitive system that allows investors to then respond to normal market incentives to put that money back here. If investors can earn in Alaska what they can earn elsewhere, the state ought to see it put back here. Alaska is allowing them to earn essentially gift certificates, and giving them something they can get elsewhere. He said he thinks that is part of the reason why Alaska is not seeing the behavior it thought it would see under ACES.

[8:23:19 PM](#)

REPRESENTATIVE TUCK said he is having a hard time with bringing down Alaska's system to the lowest common denominator and hoping to see investments in Alaska. All activity on the North Slope leads to production at some time because everybody wants to be profitable. It almost makes more sense that getting companies to produce and then reducing will guarantee that money comes into Alaska and is reinvested in Alaska, he argued. During the days of the economic limit factor (ELF), Alaska's fields, some of the largest fields in North America, still declined and did not flatten out. The declines are natural and Prudhoe Bay has been [producing] for 35 years. He asked how long the North Sea has been [producing].

MR. PULLIAM replied they were developed about the same time.

[8:24:59 PM](#)

REPRESENTATIVE TUCK stated he does not see the North Sea curving up any differently than is Alaska.

MR. PULLIAM responded the United Kingdom (UK) has recently made significant changes to its system to try to address that. The UK and other places got caught up with trying to increase taxes as those natural declines were occurring and prices went up. They found that it continued to scare off investment and, unlike in many other places, as prices have come up the UK has not gotten the kind of response it was looking for. North Sea production is down just like it is in Alaska and the UK has

taken measure to address that. Recognizing that not everyone will agree with him, he said he thinks it is a fundamental matter of economics that incenting activity requires being competitive with the other opportunities that are out there. Also, he continued, a system that does not attach strings to the profit earned is better quality and more attractive. Those are the appropriate kinds of incentives to provide to profit-seeking companies to make investments. When those freedoms are not allowed, there is not the same quality of opportunity that exists elsewhere and a natural result of that is that the desired kind of activity will not be seen.

[8:27:13 PM](#)

REPRESENTATIVE SEATON disagreed with Mr. Pulliam's earlier statement that the reaction under ACES was not as anticipated or was not very good. He pointed out that a number of new companies, such as "Repsol, Brooks Range, ENI, Stat Oil, Loyal, Great Bear, Savant," are now on the North Slope that were not there before [ACES] and just about half of the total investment credits are in that investment. He allowed that tweaks could be made, but asked how it can be said that ACES has not had the desired effect given that activity and that many new companies have come into Alaska.

MR. PULLIAM maintained a great number of those companies were in Alaska before enactment of ACES. He said Pioneer is a company that has gone through ELF, PPT, and ACES and is still here.

REPRESENTATIVE SEATON noted he did not mention Pioneer.

MR. PULLIAM continued, saying ENI bought its interest in Nikaitchuq before ACES was in place. Repsol was courted and attracted to Alaska by Armstrong, the same folks that attracted ENI. He said he thinks the interest is due to the resource and given where prices have gone there would have been more interest had there been a more simple system without the high take that Alaska has.

[8:29:28 PM](#)

REPRESENTATIVE TARR said the 7-10 year timeframe that has been discussed as the amount of time it takes to bring on production is affirmed in HB 72 because the proposed certificates are good for 10 years. She therefore asked whether the situation is being assessed prematurely because there has not yet been the typical timeframe to bring on new production.

MR. PULLIAM answered that is certainly something to keep in mind, but said he does not think it premature to look at the effects five years into ACES and six years since PPT passage. As indicated by the slides earlier in his presentation, production was looked at along with other measures of activity, such as drilling and investment, and those things have not increased under ACES as they have elsewhere in the world. As prices have gone up, those activity levels have gone up elsewhere. Looking at all of that in combination is instructive. Given the kind of price increase and what is seen elsewhere, it would be expected to have a bigger increase in Alaska and the question is why not. He charged that ACES has been an impediment to more activity and to putting Alaska in a more robust situation.

8:31:31 PM

REPRESENTATIVE P. WILSON cautioned members about going under the premise that ACES was totally planned out and that it planned for certain things to happen. She pointed out that amendments were made on the floor with no clue as to how they would interact with each other, so there is no way to look at ACES and say there was a plan.

MR. PULLIAM replied he was less involved with the ACES debate than he was with PPT. The PPT was a major change from the prior system and a lot of thought went into it, he said. It was new ground that was being charted and a lot of analysis and consideration was paid to what was an appropriate tax rate and what kind of progressivity could be put in place so that if prices went up substantially the take would go up. While he was less involved with ACES, where he was involved he was telling people to be very careful about moving up that progressivity piece. A lot of the reason for moving it was based on some analysis strictly involving internal rate of return. While internal rate of return is a measure to use, it is certainly not a deciding measure and one that he would be very cautious in using on its own. He recalled that the move from 0.25 percent progressivity to 0.4 percent came very quickly at the end of session and the ramifications of the 0.4 were not as well considered, particularly given the kind of changes in price. Back then people did not think high prices of \$100 per barrel could happen and that if they did it would not be sustained for more than a month every three or four years, and therefore the high progressivity would not do much damage. However, it is a different situation if that is where the price is on a regular

basis. He offered his agreement with much of Representative P. Wilson's characterization.

8:35:29 PM

REPRESENTATIVE SEATON pointed out that credits were adopted before PPT and ACES, and then noted that nothing is being said about the balancing act that took place when PPT and ACES were being discussed. Under the previous gross tax, a company paid tax whether it made or lost money. The companies asked for protection on the downside, but he is not seeing any balance with the downside protection coming back in with taking away the progressivity. The two elements of balance - giving downside protection while taking more of the upside - are not being looked at. He requested Mr. Pulliam to discuss this.

MR. PULLIAM addressed the request by moving to slide 38 in his presentation regarding the average government take under ACES versus HB 72 for all existing North Slope producers for fiscal years 2015-2019. He explained that under ACES the percentage of government take rises [as the price per barrel rises]: at just above \$80 per barrel, government take reaches [approximately 64 percent], which is the take also envisioned under HB 72 at that price; the take continues upward until reaching 75 percent at higher prices [of \$150 and above]. Under HB 72, government take at [\$70 per barrel] is actually greater [about 66 percent] than under ACES [about 62 percent], then it [decreases] and flattens out as prices increase [about 62 percent take at \$160 per barrel]. So, HB 72 actually has a little more downside protection than there currently is under ACES.

8:38:31 PM

MR. PULLIAM next compared the average government take at \$100 per barrel for jurisdictions throughout the world for fiscal years 2015-2019 (slide 39 prepared by PFC Energy). He said he used PFC's data from slide 39 to develop the graph on slide 40 [depicting average government take for all existing producers in Alaska under ACES and under HB 72, and the average of government take for the other jurisdictions]. The average government take for the other jurisdictions stays at about 65 percent [at prices ranging from \$70 to \$160 per barrel]. Looking at only the major OECD jurisdictions, the average government take starts at about 65 percent [at \$70 per barrel] and falls to about 63 percent as prices go up [to \$160 per barrel]. He said this decline reflects a slight regressivity due mostly to the effect of the gross-based royalty and tax system used in the Lower 48 which

gives a somewhat regressive take. [Under HB 72, the average government take begins at about 65 percent at \$70 per barrel, falling to about 62 percent at \$160 per barrel; under ACES, the average government take begins at about 62 percent at \$70, rising to about 75 percent at \$160.]

[8:40:05 PM](#)

REPRESENTATIVE SEATON inquired whether the aforementioned graphs include downside protection in credits, as he does not see any change in HB 72 as far as changing the production tax downside protection.

MR. PULLIAM responded yes, credits are factored into this analysis as they are part of the government take. Under ACES the state provides a tax credit of 20 percent even when prices go down and that is a big part of what is being seen.

REPRESENTATIVE SEATON surmised that [HB 72] does not change the downside protection in the production tax, but just takes away the upside.

MR. PULLIAM understood current law has a floor of 4 percent on the gross and said he does not think the proposal changes that. The base level of 25 percent is maintained [in HB 72], so at low prices the tax is 25 percent without credits, which provides a higher take than currently under ACES.

[8:41:55 PM](#)

REPRESENTATIVE SEATON observed that slide 40 is for all existing producers and asked whether Mr. Pulliam will be addressing the effect of the GRE when it becomes a large percentage of the oil.

MR. PULLIAM answered he will have analysis later in his presentation that looks at how the GRE would play out. He pointed out that the gross revenue exclusion does apply here because it is a forecast of fiscal years 2015-2019 and some of the production during those years will qualify for the GRE.

REPRESENTATIVE SEATON asked which production is included.

MR. PULLIAM replied Nikaitchuq and Ooguruk would qualify for the GRE. In further response, he said those two fields are on right now.

CO-CHAIR FEIGE noted the unit was formed after January 1, 2004.

8:43:13 PM

REPRESENTATIVE TARR observed slide 40 only goes down to a price of \$70 and inquired whether Mr. Pulliam thinks prices will not go down below that. Perhaps the prices should go down lower, she suggested, in the interest of being cautious given that during the ACES debate no one predicted that oil prices would go so high.

MR. PULLIAM agreed to provide an expansion of the graph, but cautioned against putting too much weight on it because the challenge of \$60 per barrel is whether it is a sustainable number. That price would be uneconomic, he explained, and therefore a lot of production that is occurring now would just fall off. That is not to say there would be no time periods in which the price could fall below \$70, he continued, because in 2009 prices dropped \$100 per barrel in the course of 6 months, but they did not stay there very long.

8:45:00 PM

MR. PULLIAM resumed his presentation, moving to slide 41. He pointed out that under [HB 72], cash generation [from ongoing North Slope production during fiscal years 2017-2021] moves up [as prices increase from \$70 to \$160 per barrel]. He said this cash generation is in the range seen elsewhere in the OECD, a positive for the investment community.

MR. PULLIAM next posed a hypothetical scenario of a 50-million-barrel field of light conventional oil developed by a new participant in Alaska [slide 42]. He compared the annual state revenues and producer cash flows of ACES with HB 72 for this hypothetical field at a West Coast ANS price of \$100 per barrel. He said he used this field size because it is the kind of field that is recently being discovered and which is expected to be seen more often than a large field. Under ACES, the NPV is \$192 million and the cash flow for the producer over the course of the project would be [\$981 million]. Under HB 72, the NPV is \$309 million and the producer's cash flow would increase to [nearly \$1.6 billion]. For state revenues, there would not be the large outflow under HB 72 like there is under ACES during the development period. This is because under HB 72 the state would not be buying back the credits and the NOLs; however, the state would be allowing recovery of those losses when production starts. As a result, the NPV of state revenues would be reduced [from an NPV of \$666 million and total revenues of \$2.5 billion

under ACES to an NPV of \$486 million and total revenues of \$1.6 billion under HB 72].

[8:47:54 PM](#)

MR. PULLIAM then posed this same hypothetical scenario for an incumbent participant [slide 43]. For producer cash flows under ACES, an incumbent's NPV would be \$307 million and under HB 72 it would be \$310. For state revenues, the NPV would also be pretty comparable [\$489 million under ACES, \$485 under HB 72]. What these two graphs show is that HB 72 would have the effect of enhancing the new participant's economics and bringing them in line with what an incumbent already enjoys. In response to Co-Chair Feige, he explained that \$0 in the Y axis represents when the first spending starts to occur, so the decision to proceed to develop would have been made shortly before that and some production would start in year four.

[8:49:22 PM](#)

MR. PULLIAM summarized investment metrics for a new participant in a hypothetical light conventional oil development in Alaska under ACES and under HB 72 versus the other benchmark areas [slide 44]. At a [West Coast ANS] price of \$100 per barrel, the NPV under ACES would be \$3.85 a barrel. Under HB 72 the NPV rises to \$6.18 with the GRE, which a new participant should qualify for and which compares favorably with the Lower 48 and the UK [\$6.75 in Eagle Ford, \$4.29 in Bakken, \$6.04 post-1993 in UK, \$8.25 post-1993 with Brownfield Allowance in UK]. The other metrics [under HB 72] are improved as well; for example, with the GRE the government take falls [to 61.1 percent] and without the GRE it is [64.7 percent], both of which are significantly lower than is currently the case under ACES [75.8 percent], making it attractive relative to what exists elsewhere.

[8:51:46 PM](#)

REPRESENTATIVE SEATON noted the government take, both with and without the GRE [under HB 72], is lower than the Eagle Ford, Bakken, and other provinces.

MR. PULLIAM responded it is lower than some provinces and higher than others. The average for all OECD countries is around 63 percent and the average for all jurisdictions is 65 percent, so Alaska would be a bit better than that, which is a good thing.

[8:52:35 PM](#)

MR. PULLIAM continued his presentation, looking at the same hypothetical scenario but this time from the standpoint of an incumbent [slide 45]. At \$100 per barrel, the NPV under ACES is \$6.14 compared to [\$3.85] for new participants. He reiterated that [HB 72] brings up the economics for new participants to where an incumbent is. For an incumbent under HB 72, the NPV [of \$6.20] is comparable to ACES and at a higher price [\$120] the NPV is better than ACES [\$9.69 versus \$8.82]. This compares favorably to other development opportunities in the rest of the world. Thus, it can be seen that the cash margins are enhanced quite a bit under HB 72 relative to ACES. Government take under HB 72 is a little different [62.6 percent at \$100/barrel] for an incumbent than for a new producer since new producers have a tax credit that the incumbent does not have.

[8:54:11 PM](#)

REPRESENTATIVE TARR, observing that the five-year predictions are for fiscal years 2017-2021, inquired whether it would be more appropriate to be looking forward for the coming years in a closer timeframe given that HB 72 would take effect immediately.

MR. PULLIAM answered he looked at the period of 2017-2021 for this hypothetical development because the field was developed out in that [earlier] time period and the producer is starting to earn revenues during the 2017 period. It should not look different if a different five-year period is used looking at that same development cycle.

[8:54:59 PM](#)

REPRESENTATIVE TARR said it seems like the heavy investment cost that comes in those early years would affect this.

MR. PULLIAM specified that what is being looked at is once production gets on line because margins are not generated until production gets on line. A hypothetical development started this next year would be on line and producing in about 2017, so that is the reason for using the time period of 2017-2021. A development started before now and just now beginning production under this system should show the same picture. In further response, he confirmed it would show the same picture even though the elimination of credits.

[8:55:53 PM](#)

REPRESENTATIVE TUCK surmised that of the jurisdictions listed on slide 39, the North Sea is close to what Alaska has in Prudhoe Bay. He asked whether any of the other jurisdictions are similar to Prudhoe Bay or the North Sea, and whether any of those have reversed their decline. He said he does not think the North Sea's decline has yet been reversed.

MR. PULLIAM responded he knows some reversal has occurred in the North Sea. The emphasis, though, is that there has not been an aggregate turnaround. Turning around a basin is a different issue than turning around a field, he stressed. Fields have a natural decline and making that decline go as slowly as possible is the goal. Prudhoe Bay has produced much longer than anybody ever expected; the decline has been extended and extended. It is one of the most prolific fields in the history of the world. He said he does not think the view is that it can be turned around by adding a significant amount of gas handling capacity. The decline can be stemmed by doing certain things and is something people would like to see happen. But the decline overall is really a basin-wide thing and to stem that, oil must be brought in from other areas. As far as pointing to a field, he said there have certainly been some, such as Apache doing that in a North Sea field. But, in general, the effort there is to incent oil production in and around existing fields and find new oil. He said his experience is that turnaround is more basin-wide or area-wide than it is field-wide.

[8:59:24 PM](#)

MR. PULLIAM concluded his presentation by directing attention to the appendix [slides 46-62], which provides more detailed comparisons of Alaska activity to places elsewhere in the world. He pointed out that many of the investment metrics he reviewed in tabular form are in chart and pictorial form in the appendix.

[9:00:48 PM](#)

REPRESENTATIVE SEATON recalled an earlier discussion with the Department of Natural Resources commissioner about the Forties Field, the only example of a turnaround field. A legacy producer that was been in decline for years sold the Forties Field; so, the only turnaround was one that came due to a change in the culture of the operating company. It has been stated in testimony, he related, that the companies' strategic view of Alaska is to generate income for other investments around the world. Therefore, he asked, how does going from ACES to [HB 72] function to actually change the decision making culture that has

been ongoing on the North Slope since pre-PPT and is continuing in the legacy fields.

MR. PULLIAM, rather than talking about a culture, replied that these companies are in the business of making money and the way they make money is by producing oil. To the extent that [HB 72] is an attractive, profitable proposition, the companies can be expected to respond to the incentives. The companies should respond if Alaska puts the right incentives in front of them, the opportunity to make money, to make a competitive return on their investment similar to what they are getting elsewhere. Some of the more mature basins do attract other companies that are not the companies that developed those basins. That is what is wanted in Alaska. A system can be provided that is as welcoming to those companies as possible. The changes being talked about in HB 72 do exactly that.

9:04:22 PM

MR. PULLIAM, continuing his response to Representative Seaton, said examples similar to what was done in the Forties Field can be found in California where Occidental bought out the interests of companies that had developed fields and that those companies had decided no longer fit with their strategic interest. Alaska cannot really do anything to determine who the producer is or is not. But Alaska can try to make it attractive for them to operate here and do so in a way that makes the opportunity in Alaska competitive with what they have elsewhere, whether it is a new or incumbent producer. Culture notwithstanding, it can be expected that rational investors would respond to that. There is no reason to believe that these folks are not rational. They may not always do things that Alaska likes and they may do them in a different time frame, but they are rational investors and if incentives are put in front of them to earn in Alaska what they can elsewhere, then [policy makers] have done their job. And if they get down the road and decide an asset no longer fits with their strategic desire and they want to sell out to a smaller company, then Alaska would have the right system for them to operate in.

9:06:36 PM

REPRESENTATIVE TUCK agreed with the statement that companies are rational investors; they want to make money. He said Alaska's aggressive tax credit system is one of the best in the world and he is led to believe the companies are making rational decisions

in investments on the North Slope. More investments are happening now than under prior tax regimes ...

MR. PULLIAM interjected, stating he disagreed. Alaska has seen a higher level of investment, he said, but when the worldwide increase in prices is controlled for, Alaska does not have a significantly higher level of investment. Investment in Alaska has lagged relative to that elsewhere in the world. Yes, it is higher than it was in, say, 2003, but it is higher everywhere and the increase is much, much higher elsewhere than it is in Alaska. So, he sees that as a slowdown and that Alaska has not kept pace. It has become more expensive to operate in this higher-price world, he continued, so just the same things a company was doing back in 2003 cost more today and because of that, more has to be spent to maintain the same kind of activity.

[9:08:10 PM](#)

REPRESENTATIVE TUCK pointed out that more companies are now in Alaska and said more may have sprung up around the world because the profits are so high. He understood that existing producers will not put themselves out of business any quicker than they have to, so they are going to maximize the price that they can per drop of oil. It may not be in their best interest to just produce, produce, produce, especially if they can maintain those prices high - the basic laws of supply and demand. He noted that tankers are coming back to Valdez with their hulls still full because the refining capacity is full. What is in the best interest of the companies may be against the best interests of what Alaska wants to see. So, there is this balance of trying to get to that million dollar barrel a day that the governor has put forth. It would be nice to have more concrete ways of getting there, but it goes back to making sure the investments stay in Alaska as best as possible.

MR. PULLIAM responded that, from his perspective, he would say it a little differently: It is not to make sure the investments stay in Alaska, it is to make sure Alaska attracts the investments. What is wanted is for the people who are here now to have more incentive to invest here and for the people who are not here to have incentive to invest here. He said he thinks Alaska would do a better job with that under HB 72 than the current system. While there are more companies on the North Slope, what is wanted is even more. The proposed changes would move Alaska in that direction in a real positive way.

[9:10:56 PM](#)

CO-CHAIR FEIGE offered a correction regarding the tankers, saying the reason they came back to Valdez with oil in their holds was because the storage facilities at the refineries could not take it. Part of that was a capacity problem due to two fires, a major one being at Cherry Point, Washington, that shut down the refinery from February-June 2012. Another was a maintenance issue at the refinery in Oakland, California. The tankers had to return, not necessarily because the refineries could not take their oil, but because Alaska needed those tankers back in Valdez to take oil out of the tanks because the Trans-Alaska Pipeline System (TAPS) was approaching 90 percent fill. Had those tankers not come back, wells would have had to be shut in, which would have adversely affected the state's production of oil.

[9:12:14 PM](#)

CO-CHAIR FEIGE understood Mr. Pulliam to be saying that while ACES incentivizes spending, there is nothing in ACES that ensures that that spending results in production. Even though there is no guarantee in ACES, that guarantee has led to a lot of new pipes and many well maintained facilities, but ACES has not led to production, and production is what the State of Alaska makes its money on in the future. He said he thinks Mr. Pulliam has highlighted very nicely that credits must be tied much more closely to production and, hence, future tax revenue for the State of Alaska.

[9:13:10 PM](#)

REPRESENTATIVE SEATON requested runs be made for when Alaska reaches 50 percent new oil because if the state is trying to have a durable system, the economics must be known for the time when half of the state's oil is at an effective tax rate of 18 or 20 percent instead of 25 percent.

MR. PULLIAM said he will talk with the modeling folks at the Department of Revenue who can run those types of scenarios.

REPRESENTATIVE SEATON further requested that those runs be done going down to \$50 per barrel.

MR. PULLIAM agreed to do so.

[9:14:09 PM](#)

REPRESENTATIVE TARR commented she is still having trouble with the idea that, given it is so expensive to invest in Alaska, why the tax credits are not a good idea. She asked whether [the administration], when first contemplating a proposal, considered adjusting progressivity for the higher prices that were not anticipated at the time ACES was passed.

MR. PULLIAM answered that reducing progressivity was an option he and others considered, such as going back to what the state had under PPT or what was proposed originally under ACES before the progressivity was increased or another way of reining in that progressivity. In looking at all of the options, it was concluded that a cleaner system, one that accomplishes the goals over all that is wanted, is the one that eliminates progressivity. The proposal eliminates some of the strange incentives that are caused under progressivity and at the same eliminates the credit. It is a more straight forward system and it matches better with what is seen elsewhere. From the standpoint of a company, the planning and investment decision making will be cleaner and more straight forward. It removes some of the problems with the decoupling issue, which is the issue about when gas comes in and the effect on the state's tax revenues. A similar issue to that, but on a smaller scale, is the high cost heavy oil that he talked about and which has the effect of reducing the tax rate and dramatically reducing the state's revenue. He said he and the people at DOR and DNR felt that this proposal is a "better mousetrap".

[9:17:02 PM](#)

CO-CHAIR SADDLER said he has heard it argued in committee and elsewhere before that the economic limit factor (ELF) is proof that low taxes do not affect production because taxes were lower under ELF and there was declining throughput. Under ELF the tax rates were different for larger and smaller fields; taxes on large fields rose and production from those fields decreased, satellite fields sprung up and net production from those fields increased. He requested Mr. Pulliam to provide an analysis of the argument that ELF proves that tax rates do not affect the decline in oil production.

MR. PULLIAM replied he does not think a conclusion can be drawn that low tax rates do not affect production and do not affect investment, it is nonsensical. Clearly, there is a relationship between the tax rate and the attractiveness of that investment, it is basic economics. There is no causality between a decline

in production while there is a low tax rate. The time period of ELF was a period of relatively low oil prices, about \$30 per barrel, and the cost for moving that oil to the West Coast was \$8 per barrel, for a netback of \$22. Additionally, there were the production costs, so what was left over was not a lot. This was the same for both Alaska and elsewhere. Investment in Alaska was going on at that time - Alpine had just been developed and satellites around Alpine and Kuparuk were being developed. Referring to the capital spending depicted on slide 17, he pointed out that investment in Alaska tracked the rest of the world from 2003 to 2006 and it increased as prices went up. Yes, production continued to decline during that period, but that does not mean there was no activity going on. Newer fields were being brought on, they just were not replacing all of the oil that was going away from the declining large fields. So, there was activity and investment going on in new fields during those times of lower tax rates and it was consistent with that in the rest of the world. In his view, he continued, the decoupling occurs from 2007 forward, when the rest of the world accelerates and Alaska stays flat.

[9:21:00 PM](#)

REPRESENTATIVE TUCK requested that slides 20-23 be done in the same manner as was done for ACES, but for HB 72. He further requested that columns be added for oil prices up to \$140 and down to \$60.

MR. PULLIAM agreed to do so.

REPRESENTATIVE TUCK thanked Mr. Pulliam for his presentation, the new information, and the opportunity to ask questions.

[9:23:33 PM](#)

[HB 72 was held over.]

[9:23:40 PM](#)

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 9:24 p.m.