

ALASKA STATE LEGISLATURE
SENATE JUDICIARY STANDING COMMITTEE

April 16, 2007

1:36 p.m.

MEMBERS PRESENT

Senator Hollis French, Chair
Senator Charlie Huggins, Vice Chair
Senator Bill Wielechowski
Senator Lesil McGuire
Senator Gene Therriault

MEMBERS ABSENT

All members present

COMMITTEE CALENDAR

SENATE BILL NO. 104

"An Act relating to the Alaska Gasline Inducement Act; establishing the Alaska Gasline Inducement Act matching contribution fund; providing for an Alaska Gasline Inducement Act coordinator; making conforming amendments; and providing for an effective date."

HEARD AND HELD

PREVIOUS COMMITTEE ACTION

BILL: SB 104

SHORT TITLE: NATURAL GAS PIPELINE PROJECT

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

03/05/07	(S)	READ THE FIRST TIME - REFERRALS
03/05/07	(S)	RES, JUD, FIN
03/14/07	(S)	RES AT 3:30 PM BUTROVICH 205
03/14/07	(S)	Heard & Held
03/14/07	(S)	MINUTE(RES)
03/16/07	(S)	RES AT 3:30 PM BUTROVICH 205
03/16/07	(S)	Heard & Held
03/16/07	(S)	MINUTE(RES)
03/19/07	(S)	RES AT 3:30 PM BUTROVICH 205
03/19/07	(S)	Heard & Held
03/19/07	(S)	MINUTE(RES)
03/21/07	(S)	RES AT 3:30 PM SENATE FINANCE 532
03/21/07	(S)	Heard & Held

03/21/07 (S) MINUTE(RES)
03/21/07 (S) RES AT 5:30 PM SENATE FINANCE 532
03/21/07 (S) Heard & Held
03/21/07 (S) MINUTE(RES)
03/22/07 (S) RES AT 4:15 PM FAHRENKAMP 203
03/22/07 (S) Heard & Held
03/22/07 (S) MINUTE(RES)
03/23/07 (S) RES AT 1:30 PM BUTROVICH 205
03/23/07 (S) Heard & Held
03/23/07 (S) MINUTE(RES)
03/24/07 (S) RES AT 1:00 PM SENATE FINANCE 532
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03/30/07 (S) RES AT 1:30 PM BUTROVICH 205
03/30/07 (S) Heard & Held
03/30/07 (S) MINUTE(RES)
03/31/07 (S) RES AT 12:00 AM BUTROVICH 205
03/31/07 (S) Heard & Held
03/31/07 (S) MINUTE(RES)
04/01/07 (S) RES AT 11:00 AM BUTROVICH 205
04/01/07 (S) Moved CSSB 104(RES) Out of Committee
04/01/07 (S) MINUTE(RES)
04/02/07 (S) RES RPT CS 6 AM SAME TITLE
04/02/07 (S) AM: HUGGINS, GREEN, STEVENS, STEDMAN,
WIELECHOWSKI, WAGONER
04/02/07 (S) RES AT 3:30 PM BUTROVICH 205
04/02/07 (S) Moved Out of Committee 4/1/07
04/02/07 (S) MINUTE(RES)
04/04/07 (S) JUD AT 2:45 PM BELTZ 211
04/04/07 (S) Heard & Held
04/04/07 (S) MINUTE(JUD)
04/11/07 (S) JUD AT 1:30 PM BUTROVICH 205

04/11/07 (S) Heard & Held
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 04/11/07 (S) MINUTE(JUD)
 04/12/07 (S) JUD AT 3:30 PM BUTROVICH 205
 04/12/07 (S) Public Testimony 5:30 pm to 7:00 pm
 04/13/07 (S) JUD AT 1:30 PM BUTROVICH 205
 04/13/07 (S) Heard & Held
 04/13/07 (S) MINUTE(JUD)
 04/13/07 (S) JUD AT 5:30 PM BUTROVICH 205
 04/13/07 (S) Heard & Held
 04/13/07 (S) MINUTE(JUD)
 04/14/07 (S) JUD AT 10:00 AM BUTROVICH 205
 04/14/07 (S) Heard & Held
 04/14/07 (S) MINUTE(JUD)
 04/15/07 (S) JUD AT 11:00 AM BUTROVICH 205
 04/15/07 (S) -- MEETING CANCELED --
 04/16/07 (S) JUD AT 1:30 PM BUTROVICH 205

WITNESS REGISTER

DONALD SHEPLER
 Greenberg Traurig
 Consultant to the Administration
 Washington D.C.

POSITION STATEMENT: Presented information on SB 104.

ANTONY SCOTT, Commercial Analyst
 Division of Oil and Gas
 Department of Natural Resources (DNR)
 Anchorage, Alaska

POSITION STATEMENT: Presented information on SB 104.

LARRY OSTROVSKY, Assistant Attorney General
 Division of Oil, Gas, and Mining
 Office of the Attorney General
 Juneau, AK

POSITION STATEMENT: Presented information on SB 104.

MARCIA DAVIS, Deputy Commissioner
 Department of Revenue
 Juneau, AK

POSITION STATEMENT: Presented information on SB 104.

NANETTE THOMPSON, Unit/Tech Support
 Division of Oil and Gas

Department of Natural Resources (DNR)
POSITION STATEMENT: Commented on SB 104.

BONNIE HARRIS, Senior Assistant Attorney General
Civil Division
Natural Resources Section
Oil, Gas & Mining
Department of Law
Juneau, AK

POSITION STATEMENT: Presented information on SB 104.

ACTION NARRATIVE

CHAIR HOLLIS FRENCH called the Senate Judiciary Standing Committee meeting to order at [1:36:43 PM](#). Senators French, Wielechowski, McGuire, and Huggins were present at the call to order. Senator Therriault arrived shortly thereafter.

SB 104-NATURAL GAS PIPELINE PROJECT

CHAIR FRENCH announced the consideration of SB 104, and said the topics of the meeting would be the Federal Energy Regulatory Commission (FERC), rolled-in rates, and the Prudhoe Bay operating agreement. Before the committee was CSSB 104(RES), version K.

[1:37:19 PM](#)

DONALD SHEPLER, Greenberg Traurig, consultant to the administration, said he would explain the FERC roll-in policy and how it's based on congressional policy mandates. He added that Antony Scott would present the requirements for rolled-in rates in the Alaska Gasline Inducement Act (AGIA), and why such rates are so critical for the state. He then explained his work history with Greenberg Traurig, as a consultant for various gas companies, and as an attorney for the FERC.

CHAIR FRENCH said that the committee had received paper copies of the documents. He noted that Senator Therriault had joined the committee.

MR. SHEPLER said that since the body of analysis from the FERC orders was fairly compact, he thought it would be useful to the committee in the full-text form.

[1:40:36 PM](#)

SENATOR THERRIAULT noted that last week there was reference to quotes from the FERC documents, and asked Mr. Shepler to point out the quotes.

CHAIR FRENCH remarked that he thought he had found one of the quotes cited, and read it. He then asked if the document before the committee was the entirety of the FERC order.

[1:42:01 PM](#)

MR. SHEPLER replied that he excerpted the discussion on expansion prices within the order. He explained that the FERC was not working in a vacuum when it issued its orders; it was mandated by the Alaska Natural Gas Pipeline Act of 2004, which contains two mandates to the FERC as it relates to expansion of the line and expansion pricing. The first mandate was to establish rules to promote competition, and the exploration, development, and production of Alaskan natural gas. The second was to provide the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thompson units for any open season for capacity exceeding the initial capacity of the line.

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MR. SHEPLER explained that in implementing the policies, the commission concluded that incremental pricing of expansion could put expansion shippers at a significant rate disadvantage compared to initial shippers; accordingly, that could discourage exploration, development, and production of Alaska natural gas. Congress mandates that FERC rules encourage such development. Rolling in the cost of expansion is nothing new; from the 1960s to 1999, the FERC preferred rolled-in pricing for new facilities and expansions. This was set forth as a statement of historical fact in the 1995 policy statement. In the Lower 48 the policy changed in 1999 because it didn't fit with an industry increasingly characterized by competition. The current Lower 48 policy holds that any expansions and new facilities have to be incrementally priced; this policy is based on the fact of a mature pipeline grid and pipeline competition. The FERC wanted to establish a level playing field.

CHAIR FRENCH asked if the policy decision was based on the idea that a company not being able to expand would be able to use an existing pipe in a mature and complex pipeline network without being charged an incremental rate.

MR. SHEPLER replied that was largely correct; the policy was also predicated on the fact that an incumbent pipeline being

able to use rolled-in rates rather than charging incremental rates for another company using its line would make for an unlevel playing field. In Order 2005, the FERC said the Lower 48 policy didn't apply to the Alaska project because there will likely be only one Alaskan pipeline.

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He said that rolled-in pricing is going to have the effect of raising the price for the initial existing shippers; this may happen in any expansion. At some point, there will be potential rate increases as a result of rolling in prices. A low-cost expansion that adds great volume to the system will have the effect of reducing rates for all system users.

MR. SHEPLER said that the FERC has noted that a rate increase is not necessarily a subsidy. In that regard, it has offered an alternative view of what a subsidy might be in the context of this particular project. In Order 2005 A, the FERC stated that an alternate definition of subsidization could be whether the expansion rate is no higher than the actual initial rate, or of an initial rate without built-in subsidies. That suggests a hypothesis previously made by Senator Therriault, where with a day-one starting rate of one dollar, a low-cost expansion would result in rates going down to eighty-five cents for other shippers. The FERC doesn't see the existence of any subsidy as long as the shipper's rate goes back up to the initial agreed-upon rate. The issue then becomes what happens when the rate goes above one dollar.

[1:50:21 PM](#)

MR. SHEPLER said in that situation the FERC will have to decide whether a rate increase above the initial rate constitutes a subsidy within the context of the application. The FERC would consider the argument made by Pacific Star that the initial rates are already the beneficiaries of so-called government subsidies, including federal loan guarantees, accelerated appreciation, tax credit for the gas treatment plant, and the state's own potential contribution through AGIA. The FERC is saying that the question of a subsidy will have to be determined at the time of an expansion. It has also adopted a rebuttable presumption in favor of the use of rolled-in pricing for expansions of this particular line, irrespective of the Lower 48 policy. The FERC has advanced the process to the point where AGIA picks it up by requiring the applicant to commit to using rolled-in pricing for expansions up until the point that the rolled-in pricing results in a rate increase of fifteen percent above the day-one rate.

[1:53:04 PM](#)

MR. SHEPLER said that the state has tried to continue with the process where the FERC left it. There will be rolled-in pricing up until the point where the initial shippers signed up, and to the point where state and federal contributions have been consumed. That is the end of the obligation of the applicant to continue to pursue rolled-in treatment.

SENATOR HUGGINS asked when the limit would go into place.

MR. SHEPLER replied it would do so at 15 percent above the initial rate the shippers committed to. Presumably that would be the recourse rate or the negotiated rate. That has the effect of permitting the first expansion group, and perhaps the third - to share in some of the government contributions that resulted in a depression of the initial regulated rates that were enjoyed by the initial shippers. That is the basis for how the FERC got to its presumption in favor of rolled-in pricing and how the state came to its position on AGIA.

He said there is an old industry adage stating that the pipeline company proposes, but the FERC disposes. This means that a pipeline company has to file a rate proposal, and how that proposal gets resolved is up to the FERC. Nothing in AGIA affects that requirement.

[1:56:08 PM](#)

CHAIR FRENCH asked if a company wants rolled-in rates and the state forces the shipper to take rolled-in rates also, could FERC decide that is unfair.

MR. SHEPLER replied it could. He added that AGIA requires the licensee to propose rolled-in rates up to a cap, but at the end of the day the FERC makes the decision based on its policies and the facts that are presented in the specific instance for the expansion pricing.

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SENATOR THERRIAULT asked if it is unusual for Congress to have given that type of direction on what the FERC policy should be through legislation.

MR. SHEPLER replied the Natural Gas Act, the main gas statute that the FERC administers on the gas side, has nothing like this requirement in it. Instead it requires that the FERC establish just and reasonable rates and permit facilities that are

required by the public convenience and necessity. Against that backdrop policy, mandates such as in this 2004 law are unusual. Congress has certainly taken a step and told the FERC what the end result of their rule-making process must achieve. The FERC was certainly listening to that, because it concluded that incremental pricing of this particular project could well fly in the face of that first mandate.

[1:58:47 PM](#)

ANTONY SCOTT, Commercial Analyst, Division of Oil and Gas, Department of Natural Resources (DNR), said he would be offering two presentations that day. The first would be a review of how government contributions - both federal and under AGIA, affect rates. He began with a base rate of \$2 not including fuel, but including all government contributions, for a pipeline into Alberta. Stripped of its federal loan guarantees and the reduced borrowing cost that the feds provide to the cost of debt, that rate would raise it to \$2.10. Stripping out the seven-year accelerated depreciation for tax purposes and instead using 15 years (industry uses this generally) makes the rates go to \$2.19. Taking into account the full amount of the \$500 million AGIA contribution, rates would rise to roughly \$2.25. That amounts to about 12.5 percent of the overall rate to the shippers. Congress also provided the owners of the gas treatment plant with an additional 15 percent federal tax credit. If federal contribution were to be included, the total government contributions to the project would exceed 15 percent.

[2:01:20 PM](#)

CHAIR FRENCH asked if the 15 percent cap would apply to the \$2 tariff.

MR. SCOTT said yes.

CHAIR FRENCH said but the question of whether it's a subsidy is where there will be an argument about whether it's a \$2 or \$2.25 tariff from the start.

MR. SCOTT agreed.

CHAIR FRENCH asked if it will be two separate arguments or the same argument wrapped up as one.

MR. SCOTT said the foregoing was an attempt to arrive at the 15 percent threshold for rolled-in tariff treatment. Another approach was to ask what modest percentage cap would permit the

kind of expansions that would fully unlock the basin's potential. He offered to explain that in a moment.

2:02:45 PM

CHAIR FRENCH said it sounds like up until the 15 percent of the \$2-rate, the shipper has to agree to argue for rolled-in rates.

MR. SCOTT said the current committee substitute only requires that the pipeline propose rolled-in rates. The original bill referred to all parties.

MR. SHEPLER interrupted to clarify that the pipeline can propose up to 15 percent. Originally the recipients of the upstream inducements, presumably the shippers, had to agree that they would not oppose at the FERC, the proposal the pipeline made per its commitment in AGIA.

2:03:43 PM

SENATOR THERRIAULT said even if the pipeline and the shippers agreed with the rolled-in rate up to 15 percent, if the FERC determines there was a subsidy, the federal law would have precedence.

MR. SHEPLER said that's right; AGIA does not require anyone to bring home rolled-in pricing. It gets the company to the proposed stage and then lets the FERC do its job.

SENATOR HUGGINS asked if the state could contest that FERC determination.

MR. SHEPLER said the state can contest it; it's not giving up any commitments through AGIA.

MR. SCOTT said next he would speak about three separate areas relevant to the discussion of AGIA's rolled-in rate provisions. First is how they affect competition and incentives for exploration and development on the North Slope. Second is how they affect the state. Third is how the data suggests the provisions will affect the producers' decision to invest in the project or not.

MR. SCOTT said the first point is that rolled-in rates promote competition, which takes him to the second point which is that those rates are in the state's best interest given the uncertainty about where expansion gas will come from. Third, he said, rolled-in rates do cost producers, but that is mostly offset by the state's contributions in AGIA. The degree to which

rolled-in rates negatively affect the producers is unlikely to affect their investment decisions.

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MR. SCOTT said he is using a 4.5 bcf/day scenario with two expansions of 1 bcf/day with infill compression. He said a third expansion would be achieved by looping volumes.

CHAIR FRENCH asked for an explanation of infill compression.

MR. SCOTT explained that infill compression has compressors along the line instead of just at the pipe inlet and outlet. He showed a graph of the AGIA rolled-in rates for the initial shippers, the first expansion shippers in 2018, and the second expansion shippers in 2021. The third expansion shippers' AGIA rates aren't shown. Those are contrasted with the rates that would apply under the FERC's Lower 48 pricing policy. He pointed out that the third-expansion shippers will receive the FERC's Lower 48 policy. He said the rates slightly decline with the first expansion, so both initial and first-expansion shippers would receive slightly reduced rates in 2018. At that point the AGIA and FERC policy rates track, but at the second expansion in 2021 when fuel price effects are actually included, incremental rates rise very significantly (by nearly \$1). Under AGIA, everyone's rates rise modestly - about 15 cents. For the third and looped expansion in 2023, AGIA rates rise for all of the preexisting shippers about 15 cents. But the rates on an incremental pricing basis for the looped expansion, would be \$1.65 greater than the initial rates.

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SENATOR MCGUIRE asked him to explain first and second expansion rates under AGIA as compared to the first and second Lower 48 FERC expansion rates in 2018. She observed that the Lower 48 rates appear to decline after a while, but the initial companies that took the biggest risk have their rates increase.

MR. SCOTT said the graph had an optical illusion; the rates didn't decline by more than a couple of pennies.

CHAIR FRENCH asked if that is due to depreciation.

MR. SCOTT said it is due to adding compressors along the line along with substantial capacity. Compression is relatively inexpensive compared to pipe, so the rates decline slightly. However, compressors burn more fuel so that offsets the savings somewhat.

SENATOR MCGUIRE asked for an explanation of later expansions.

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MR. SCOTT explained that in 2021, assuming incremental pricing, there wouldn't be any rate increases because of the rolled-in basis. The Lower 48 policy is not to allow rates to increase for those shippers; there would be only incremental treatment. A particular portion of the graph in question represented, for the 2021 expansion, the incremental rate paid by the second expansion shipper, and the cost for all the shippers if other costs were rolled in.

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SENATOR HUGGINS asked how reliable his data is.

MR. SCOTT replied his numbers are based on hired-out engineering work done on ANGTS design, TransCanada's 48-inch pipeline data. Unlike testimony received from TransCanada, the state doesn't assume that all expansions occur in year one; they will occur along the line. The cost of compression and pipe is escalating worldwide, so the further off the expansion, the more expensive it will be. The price of fuel will also increase. The chart assumes a \$5.50 Henry Hub price. The rates shown are nominal dollar rates, so they will continue to inch up along with the cost of fuel. Any modeling requires a number of assumptions, he added.

[2:16:01 PM](#)

SENATOR MCGUIRE said her concern is that under AGIA the state is asking the initial shippers to take on a big risk and in 2021 their rates rise slightly. The 2018 expansion shipper rates would remain equal from 2021 to 2022, but in 2023 the lines on the graph diverge. She asked why that is an acceptable policy.

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MR. SCOTT said he was incorrect when he said the graph had an optical illusion and the rates didn't decline by more than a couple of pennies. The line does decline because in 2023 it's a looped expansion with no added compression. That means that fuel use for initial and first expansion shippers declines so their effective rate does decline. The green bar reflects the consequence of rolling in the large capital cost of the expansion. With regard to the policy, he again mentioned government contributions to the project and the AGIA policy that rolled-in rates ensures that later shippers participate in those government contributions. He pointed out that it is also the

case that initial shippers bear the least risk. The shipping is a substantial commitment, but it also confers significant benefits - namely the right to ship an enormous crude gas resource. Subsequent shippers have more risk because they don't have the enormous reliability of proven reserves. They also face geologic and deliverability risk because less is known about the reservoir.

MR. SCOTT said it is too strong to say the initial shippers are subsidizing later shippers because of rolled-in treatment. Everyone is familiar with demand changes and how that changes price. However, a price change doesn't indicate that the first participants are subsidizing later participants. In general, one sees a single price for a product; in this case if the total demand increases, the cost of the supply to meet the demand is typically the same for all parties.

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SENATOR MCGUIRE said she understands the policy - that the benefits outweigh the risks - and in this case the goal is to expand and encourage exploration and development. While overall, she thinks the situation is fair enough, she just wants to make sure he is able to justify the policy.

[2:22:12 PM](#)

CHAIR FRENCH said the initial shippers are also getting a tax freeze all the way to the end of the chart.

SENATOR THERRIAULT said the amount of gas that can be put through a certain diameter pipe through compression is pretty much a science, but the cost of putting on compressors to push the gas into the pipe is a bit of a guess. Looping is more an artful guess. The data starts out at a negotiated rate of \$1.00, but considering the value of all the initial government subsidies, the initial recourse rate should have been \$2.30. The initial shippers are actually getting a break - taking advantage of the government subsidy from first gas flow into account.

[2:23:51 PM](#)

MR. SCOTT agreed that is a fair representation. In 2023 rates will rise to the level where they would have been without government subsidies.

SENATOR THERRIAULT said first gas is coming out of the ground right now and the entire infrastructure that is needed is already in place - pipes, buildings and dormitories. So there's very little risk; they just need to coax the gas out of the

ground. But when new pipe needs to be put into the ground and you just hope to find gas and coax it to the surface, and the entire infrastructure has to be built to do so, that risk balances the equation.

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MR. SCOTT explained that the green bar on the next slide represents the AGIA rates for the initial, first, and second expansion shippers; it doesn't apply to the third expansion shippers because the looped expansion tops out past the cap. In 2023, the new blue bar on the graph represents the third expansion shipper's rates. Those will be greater than those of the other shippers because the expansion has exceeded the 15 percent cap. Exactly where those rates will be will depend on negotiations between the parties and what the FERC decides. He cautioned that there are good reasons to think that, given the additional geologic and deliverability risks that that gas faces, it might not be developed at all.

MR. SCOTT said the second subject is how AGIA's rolled-in policy affects the state's interests. It is pro-exploration, but it is conceivable that rolled-in rates could actually hurt the state's interest. Under AGIA the state is free to do what it wants to protect its interests, but this policy will play out under a number of possible scenarios. No one can be sure which gas will come from where for each expansion. Given the uncertainties, the balance for the state's interests purely on a monetary, royalty and tax basis clearly favors the AGIA rolled-in rate policy.

He pointed out that state lands have a royalty rate of 12.5 percent along with production tax. On federal lands, the state typically gets half the federal royalty. Resources on the outer-continental shelf (OCS) have no royalty or production tax.

MR. SCOTT said he would examine three possible cases with the same expansion scenario as previously presented. One is the state gas first case - A. The first bcf expansion would be filled only with gas from state lands; this would be the biggest state take. The second expansion would be from gas only from NPRA (National Petroleum Reserve Alaska) lands resulting in significantly less state take. The third expansion would come from the OCS.

He said that case B is the state gas second and here there are an infinite number of different combinations that can be presented. The NPRA gas would go first, then state lands, then OCS gas.

Case C, the final case, is state gas last - first OCS, then NPRA, then state lands.

[2:30:16 PM](#)

MR. SCOTT said that without rolled-in rates it is very unlikely that all expansions will occur. However, he said in the unlikely event that all expansions occur (under incremental rates), the first column showed the state revenue losses under the AGIA policy (state gas first); The OCS expansion would only cost the state. In case B, state gas second, rolling in the more expensive expansion cost also costs the state. In the last case, state gas last, rolling in costs benefits the state.

He speculated if you assume that each of these cases is equally likely; in the unlikely event that all expansions would occur regardless of rate treatment, the state's expected value is negative. However, he emphasized that this is unlikely to occur because incremental rate treatment doesn't favor looped expansions.

[2:32:20 PM](#)

He said slide 8 assumes the last looped expansion wouldn't occur without rolled-in AGIA rate treatment. In the case C scenario - state gas last - the state would never get gas in without rolled-in treatment and the costs for that never occurring are very significant. If prices are low, the state would still lose, but at more realistic prices the state would benefit.

[2:34:19 PM](#)

MR. SCOTT said if the full infill compression scenario doesn't occur because of incremental rate treatment and if the looped scenario doesn't occur, you'll see positive state value across the board. Thus the rolled-in rate policy is important to insure that expansions occur. Clearly there are scenarios under which the state would be better off under incremental rate treatment, but given the uncertainties about where state gas enters, the robust policy for the state is with rolled in rate treatment.

The last slide shows different sustained real prices for producer upstream investments as affected by rolled-in rate treatment assuming the producers don't participate in the expansions. That's a worst case scenario because it only raises their costs and they get no benefit of incremental revenue. Given the robust comparative investment opportunities the producers have from an upstream perspective, the evidence does

not support the contention that rolled-in rates would preclude participation in the project.

2:38:06 PM

SENATOR HUGGINS said at \$5.50 what does minus 2.9 percent mean in round dollars over the life of the project?

MR. SCOTT replied it'd be on the order of \$400 million NPV.

SENATOR WIELECHOWSKI referred to slide 9 and asked if the state would lose \$5.83 billion if gas was at \$5.50/mcf without rolled-in rates.

MR. SCOTT said yes, on an expected value basis discounted to the present.

2:40:44 PM

SENATOR THERRIAULT said he'd been looking at a briefing paper that was previously presented to the FERC on the issue of rolled-in pricing. It stated that the mere possibility of incremental tariffs threatens exploration and competition and may doom an Alaskan gas pipeline to transporting no more than 6/bcf. That was a concern in 2004 and was presented to the FERC.

2:41:45 PM

CHAIR FRENCH asked for discussion about the duty to produce and the Prudhoe Bay Operating Agreement.

LARRY OSTROVSKY, Assistant Attorney General, Oil, Gas, and Mining Section, Department of Law (DOL), said he provided a copy of a DL1 lease to the committee. The lease addresses Prudhoe Bay and Point Thompson, and has gone through many variations and drafts since the first in 1959. It's similar to gas leases used in the Lower 48 with some exceptions, and represents a basic oil and gas lease, which is different from other contracts.

MR. OSTROVSKY said it is important to talk about the express provisions in the lease; the state contributes land with the prospect of mineral resources, and the oil company contributes capital and expertise to develop. In payment, the state gets bonus bids for major shares in royalty, specifically 12.5 percent; oil companies receive the lion's share. To understand the structure of the leases, one needs to understand the underlying goals. One goal of lessees is the right to develop the lease without the obligation to do so. Secondly, if lessees do produce on a lease, they want the right to maintain production so long as it's economically profitable.

MR. OSTROVSKY explained that the state's goals are simpler: the state wants production as soon as possible. Oil and gas leases balance the goals with primary and secondary terms and savings clauses. The initial primary term can be from 5 to 10 years in Alaska; the only obligation of the lessee is to pay rent. But, because the state wants production at some point, for a lessee to hold a lease beyond the primary term it must take active steps towards production or be excused by the state from production. The lease may be extended so long as there is production in paying quantities. If there is no production, one goes to the savings provision, which describe how a lease can be continued for a period of time beyond the primary term even when there is no production. That includes commitment to a unit agreement, suspension of operations with the consent of the DNR, and shut-in production. Oil and gas leases were historically drafted by industry; such companies prefer the option to develop, so leases have tended to favor the oil companies. Over time states have fleshed out the relationship with a series of implied covenants that take into account contingencies and protect the rights of states.

[2:48:10 PM](#)

CHAIR FRENCH asked why the implied covenants were not made express covenants.

MR. OSTROVSKY explained that implied covenants tend to express basic duties, which are not fiduciary duties but rather duties of due regard. These are fleshed out through common law. It would be difficult to express all those cases in a lease. The basis is expressed in a certain paragraph of the lease, which says that upon discoveries, lessees should drill wells. That is the basis of the implied covenant to develop, test and market. It is expressed in the leases, but not completely described.

[2:49:40 PM](#)

SENATOR THERRIAULT asked if that was the central issue the state previously litigated over when the judge determined that there was no fiduciary argument, but rather a covenant that there is an obligation to develop and take the state's interest into account. The producers can't place themselves on a higher plateau than the state.

[2:50:34 PM](#)

MR. OSTROVSKY responded that was exactly correct. There was a lawsuit about field costs and valuing oil where the state argued that the covenant was fiduciary, and producers owed a higher

duty. The judge ruled against the fiduciary relationship and ruled that there was a relationship of due regard. The producers can't treat the state worse than themselves. That might be manifest in favoring others over the state of Alaska.

SENATOR THERRIAULT said that is very critical; some think that a company can demand that the state has to meet or exceed a certain rate of profitability, and in fact that is not the standard.

MR. OSTROVSKY agreed and cited a case where a lessee had a deal with a lessor but because of a price change made a deal with new lessors. The court held that the company could not play one lessee against the other. A company must act in a reasonably profitable way.

[2:52:48 PM](#)

CHAIR FRENCH asked what the difference is between a unit production agreement and a unit operating agreement.

[2:53:43 PM](#)

MARCIA DAVIS, Deputy Commissioner, Department of Revenue, explained that a unit agreement is a legal contract between Alaska and its lessees. The focus of the contract is a clarification and protection of the state's rights regarding production, costs, and the manner of operation of a group of leases as a whole. It also sets out the opportunity for the state to have a say at different junctures in the development of that unit.

CHAIR FRENCH asked how many units are on the North Slope.

NANETTE THOMPSON, Unit/Tech Support, Division of Oil and Gas, Department of Natural Resources (DNR), said the North Slope has about 20 active units.

[2:55:27 PM](#)

CHAIR FRENCH asked if it's too simplistic to say that there's one agreement per field.

MS. DAVIS said a unit is formed because oil is discovered and the resource is delineated. Relative ownership is determined for all the different partners and the pool of oil is formed like a state boundary. It is called a participating area because it delineates the participants and the monies they're entitled to. Once a unit is formed, there can be subsequent exploration and work so that another pool could be discovered within that same

boundary. The Prudhoe Bay unit contains several different areas: the initial participating areas - including the gas cap and oil rim, the Lisbourne area, and Point McIntyre. A unit is the initial boundary, and more areas can participate within it subsequently.

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CHAIR FRENCH asked her to compare that definition to a unit operating agreement.

MS. DAVIS explained that the unit operating agreement is the document by which the owners contract with each other, not the state. The owners come together and get an operator, and they determine the level of control and flow of information. Voting provisions are determined as well as an operating agreement. When the Prudhoe Bay Operating Agreement (PBOA) was formed, articles were created relating to the oil rim and gas cap areas. When a new field was discovered, supplemental provisions were created governing the new areas relating only to the new fields. All of these are considered together as the PBOA, but within it are provisions relating only to certain areas. The state is not a party to these provisions, but does receive a copy of the agreement.

[3:00:07 PM](#)

CHAIR FRENCH asked what level of oversight the state executes over the terms of the operating agreement.

MS. DAVIS said the state has no oversight other than receiving copies of the agreement. If an element of the agreement in violation of the unit agreement or another issue, that unit operating agreement wouldn't have immunity to other legal requirements.

SENATOR THERRIault commented that as the different agreements are peeled away, one arrives back at the original lease. He asked if there is a way the unit operating agreement can release a leaseholder from duties under the original lease.

[3:01:06 PM](#)

MS. DAVIS replied the lease is a contract between the state and the lessee. Only to the extent that the state relinquishes or modifies the lease could the rights be amended.

SENATOR THERRIault said from time to time one hears that a producer might be precluded from producing even if it wants to, because of the complexities of a unit operating agreement.

MS. DAVIS responded a producer could find itself in such a bind, but there should be a way out. If there's a provision in a unit operating agreement that would cause a company to violate unit agreement terms or state or federal law, there likely wouldn't be too much contractual debate. A company would rather sort out issues. Against the state or federal government, debate would not be excused.

CHAIR FRENCH asked if anything in the operating agreement prevents one partner from selling when others won't.

[3:03:04 PM](#)

MS. DAVIS said typically when the owners form a participating area, they're mindful of the obligation to make sure that hydrocarbons are removed from a field without violating waste requirements and how they are accounted for. A great deal of care is put into contractual management of product removal and accounting. The PBOA is one of the most complex agreements because an oil rim and a gas cap are operating simultaneously with different ownership interests. The original provisions were meant to anticipate all kinds of outcomes, like a major gas sale. It has provisions relating to what happens if gas is sold at less than or more than a major gas sale and the different consequences. Since the time the agreement was drafted, owners resolved their differences and reintegrated their interests to hold a single percentage in both; that removes complexity. However, the unit operating agreement has not yet been amended to reflect the new reality, so whether or not the owners are working on changing provisions or modifying rights hasn't been established yet. There might be additional changes, however.

[3:05:43 PM](#)

CHAIR FRENCH asked when that integration took place.

MS. DAVIS said she believes it took place in January 2000.

MS. THOMPSON added that there were a couple of realignment provisions. A copy of the first is available, but none from when Chevron and Force Energy were added. The state is aware of negotiations for a new amendment to the operating agreement, which haven't been concluded yet. The PBOA is a dynamic document and is frequently amended.

MS. DAVIS said it is a difficult process to work through because any party will look at the status quo and perceive its rights therein. As the agreement moves away from the status quo toward

a revision, each player has concerns about its position worsening. With the large number of players, it can take a lot of time to reach new agreements.

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SENATOR MCGUIRE asked if there are legal opinions available regarding the definition of "differentially harmed". That term strikes a chord because gas has been used for re-injection. One might argue that because one producer chose to sell its gas and another two didn't, that might cause differential harm. She asked if there are any related legal opinions.

MS. DAVIS replied the owners consolidated the oil rim and gas cap. In their operating agreement they provided the rights an owner has to take their gas in kind before and after a major gas sale and what the obligations are for taking gas in kind without harming other owners or unreasonably interfering with unit operations. The producers have been specific about that point in the process and the need for accounting for gas. Because the facilities are unit-owned, an owner doing anything above the bare minimum will ask for permission to take gas or use unit facilities. The more economic approach is to reach an agreement on how to use the existing infrastructure and make sure everyone is treated fairly.

3:10:19 PM

CHAIR FRENCH said he has a copy of the basic operating agreement and that it was very complex.

SENATOR WIELECHOWSKI asked if it has a provision where if one party takes gas it needs to ask permission of the other owners or if one party takes gas, then all the others must as well.

MS. DAVIS said under the PBOE, as it currently exists in the hands of the state, any owner has the right to take gas, but not an obligation to do so. If it chooses to do so, it takes it subject to the provisions of operating agreement. There might be need for additional discussion to talk about how the off-take is performed. Other owner approvals are procedural; refusal of off-take is not a unilateral right. The process is focused on problem solving.

3:12:16 PM

She said that when a major gas sale is reached, defined as 2 bcf/day in the first month after production or 1.75 bcf/day thereafter, all owners are required to take gas in kind.

SENATOR WIELECHOWSKI asked if ConocoPhillips wanted to sell its gas in a 2 bcf open season, would every other producer have to as well.

MS. DAVIS answered that she didn't know that ConocoPhillips would have that large an allocation of gas; assuming a company did do so, all other owners would be required to take gas in kind.

[3:13:28 PM](#)

SENATOR THERRIAULT said although the committee may be on track to move the legislation, legal questions would continue to come up and further testimony could be useful.

CHAIR FRENCH said dates were being set in May for further testimony.

Recess from [3:14:03 PM](#) to [5:39:30 PM](#).

CHAIR FRENCH said the committee would be addressing three specific topics: confidentiality and public records (Sections 160 and 170 of SB 104); license transfer provisions; and arbitration provisions, including definitions.

MS. DAVIS said that section 160 on page 10 of the CS was designed as the primary proprietary information of trade secrets section. It has gone through some revision since originally introduced as a result of information gathered from the industry and the last Senate Resource group. Under subsection (a) the opportunity has been created for an applicant to identify information in its application that it considers confidential as a trade secret. The company is required to justify the designation, and if the commissioners agree, the information is treated as confidential from that point forward. If the commissioners disagree, they do notify the applicant that it may decide whether to have the information returned and proceed without the benefit of that information. Second, if an applicant is selected as the winner, all the associated information associated with their application will be public. Third, any company that challenges the award will have its information made public.

[5:42:09 PM](#)

CHAIR FRENCH noted that Senator Therriault had joined the committee.

MS. DAVIS said that section 170 addresses confidentiality also. Under that provision, if information is designated as confidential, commissioners must receive a summary of that information. A summary of that information made available to the public. While not in this CS, an amendment will put forward language that gives legislators the right to review confidential information from the time commissioners have the information to the end of the process. Legislators must have signed a confidentiality agreement to do so.

She added that other confidentiality-related agreements are on pages 25 - 27, restating the statute that lists exceptions to the public record inspection rights. A new subsection is also added that addresses the proprietary trade secret designation and applications being held confidential until complete.

[5:44:01 PM](#)

CHAIR FRENCH asked when an applicant submits information that is determined to not be confidential, if the information would be eventually made public if the company were successful.

MS. DAVIS replied only the information in the state's possession would be made public.

CHAIR FRENCH turned to lines 13 - 14 on page 10 that said: "After a license is awarded, all information submitted by the licensee shall be made public."

MS. DAVIS acknowledged that "submitted by the licensee and retained" should perhaps be added to clarify that section.

SENATOR THERRIAULT said the language regarding access to information after the signing of a confidentiality agreement is important for the legislature so it is able to start processing the information as soon as a winner is selected.

MS. DAVIS added it might behoove the legislature to accelerate some reviews and that is why the administration is encouraging the addition of that language.

CHAIR FRENCH read a sentence on page 11: "If information is held confidential under this subsection, the applicant shall provide a summary of that is satisfactory, ...". He wondered if this is where the information is held confidential or if it is under section 160.

MS. DAVIS responded that it is probably referencing subsection (b), which is the core of applications received are not public records and are not subject to disclosure until they publish notice of the section. She speculated that this section is worth reexamining because it needs to be precise enough.

CHAIR FRENCH said the determination of proprietary is made in section 160 and he would ask the drafter if they should be concerned. He then asked Ms. Davis to address license transfers in section 550.

MS. DAVIS said that section 550 is on pages 22-23 and it addresses the assignment of a license, the assignment of resource inducements. A suggested amendment to this provisions deals with assignment of the voucher that covers individuals purchasing gas at the North Slope who will acquire vouchers which entitle them to negotiate for the royalty and tax benefits through the entity they are buying it from.

She explained that any assignment of a license requires state approval. The license assignment must not diminish the value of the project or the obligations to the state under the license or its likelihood of success. This section also reserves the state's right to enforce the audit provisions regarding monies received by the original licensee prior to the assignment.

She continued saying the assignment by a person with resource inducements took more thought; the state had to think in terms of capacity for shipping and associated tax and royalty benefits. It's more complex to track tiers of tax and royalty treatment. It was determined that it would be an undue burden for the administration to try to have a secondary market. So the right to transfer inducements to a new company was restricted to where the situation where either the entity itself has been transformed by the sale or merger of a company itself (essentially having a new company step into its shoes) or that entity has sold all of its North Slope assets. She summarized that because gas can be shipped from multiple fields into a pipeline, so just the sale of one field as opposed to all the fields would keep the state from having to split them up, they made the balance call of saying it can be transferred, but only in connection with the sale of the whole asset based on the North Slope or the sale of the company itself.

CHAIR FRENCH said presumably the Regulatory Commission of Alaska (RCA) would examine such a sale or merger thoroughly.

MS. DAVIS agreed and added that the standard the state is suggesting for the voucher would be a transfer of the entire capacity acquired by the purchaser entity.

SENATOR THERRIAULT asked if the issue would be addressed in subsection (d) under this section.

MS. DAVIS replied yes.

CHAIR FRENCH said it seems as though there has been lots of effort to select the licensee, but a licensee could almost immediately hand the license off to another company. He asked why that provision was there.

MS. DAVIS said the applications would be ninety percent focused on the project itself. A portion of the associated analysis would be for financial strength in an applicant, and its track record. Any company stepping into the position would encounter the same fixed analysis. The review on the assignment will be very narrow and will include the unique parameters. Changing a licensee wouldn't be allowed to affect the value of project or the ability to perform. In a project of this size, commercial evolution needs to be realistic. Identities within a consortium will change and two limited liability companies (LLC) could form a third. The state wants an ability to accommodate that somewhat easily.

CHAIR FRENCH asked if it was conceivable that an initial licensee could decide to sell its interest in the project and the state would be asked to okay that.

MS. DAVIS replied that the state would only be looking at the transfer of the license; it would focus on the validity of assignee. If that was not approved, the licensee would be in default or it would have to find a better assignee.

CHAIR FRENCH asked why the legislature must approve the licensee, but have no role in the change.

MS. DAVIS replied that the state felt the criteria binding the commissioners were sufficient. The financial community would be supplying the financing for a large portion of that.

CHAIR FRENCH asked if there was any requirement for notice to the public or legislature.

MS. DAVIS answered that had not been written in.

CHAIR FRENCH asked if she would object to writing that in.

MS. DAVIS said no.

SENATOR THERRIALT asked if that the section was meant to accommodate the business structure of a situation like that.

[5:58:10 PM](#)

MS. DAVIS replied that is correct; the state wanted to be commercially realistic in terms of how the license might end up needing to be changed.

CHAIR FRENCH said the state is more concerned about protecting the project than the entity and maintaining the integrity of the project is the core of the state's role. He said some language should be added regarding a public notice period and commented that Senator McGuire had arrived.

[5:59:40 PM](#)

CHAIR FRENCH said the last topic to be addressed is arbitration in section 43.90.120.

MS. DAVIS said that page 3 of the CS addressed the abandonment of the project. The state may have the best licensee and project possible and still could conceivably have an abandoned project. This section provides the commissioners and licensee the ability to agree that a project isn't economic. If they don't agree, there is a third-party arbitration structure. As a result of earlier discussion, the structure was converted from a one-person situation to the American Arbitration Association's (AAA) three-person structure. In this section, the arbitration boundaries are supplied. In the earlier drafting the arbitrator was asked to decide whether the project was uneconomic, but that requirement also suggested a separate finding on whether the project should be abandoned. The state recommended the latter portion be removed, but it remains there awaiting a decision. Missing from the section is a definition that the arbitrator would use to define an uneconomic project. Such a definition has been created, and would be presented to the committee shortly.

[6:02:39 PM](#)

SENATOR WIELECHOWSKI went to page 3, line 20, that says "each party shall select an arbitrator" and asked if that was envisioning an arbitrator from the AAA's national roster or from somewhere else.

6:03:20 PM

MS. DAVIS asked Bonnie Harris to answer the question.

BONNIE HARRIS, Senior Assistant Attorney General, Department of Law, said she would get an answer to that question; she assured the committee that the arbitration provisions are very thorough.

SENATOR WIELECHOWSKI noted that typically parties select from a list of 10. This drafting is unusual and it could allow the selection of biased arbitrators, he said.

MS. DAVIS clarified that this section is meant to be written this way. The sentence suggests that the third arbitrator would come from the American Arbitration Association's national roster, but it doesn't put that limitation on the first two arbitrators that are selected by the parties. The way it is currently written would allow each side to pick an individual they wanted to put forward and without contest. That's their arbitrator. Then they would have to get together and appoint a third arbitrator from the roster.

CHAIR FRENCH said the committee would hear more on this issue before sending out the CS.

MS. DAVIS said there may be other options within the American Arbitration Association rules.

CHAIR FRENCH said each side picking its most vociferous champion might make it difficult to agree on a third. He then asked where the arbitration would take place.

MS. DAVIS replied there is no designated location.

CHAIR FRENCH said the only question that would require arbitration would be whether a project is economic.

MS. DAVIS agreed that was correct, and said the definition would be fact-based, which wouldn't appear to have any legal principals associated.

SENATOR WIELECHOWSKI said the way this section is currently written he thinks it means that Alaska law wouldn't necessarily have to be applied unless specified and the arbitrators would apply the general law of the nation.

MS. DAVIS said because the project doesn't have firm transportation commitments, there is a question of contract. One

might want to designate the State of Alaska law for arbitration purposes.

SENATOR MCGUIRE said even if one says the matter is only factual, if legal principles come into play there is the implied covenant of good faith and fair dealing; so the applicable laws should be defined.

MS. DAVIS agreed.

[6:08:10 PM](#)

CHAIR FRENCH referenced page 4, lines 7-12, and said it looks like if the licensee and the state agree a project is not economic, the state keeps all the finished work including engineering designs, contracts, permits and other data. If the licensee says it's uneconomic and the state disagrees, if the licensee wins in arbitration, the state still keeps it all.

MS. DAVIS agreed and added that the only situation in which the state isn't covered is if the state "dumps out" by saying it is uneconomic and wins the arbitration.

MS. DAVIS reasoned that if the state is saying the project is no good, it seems fair that it doesn't get the work.

CHAIR FRENCH pointed out that the state would have paid for 50 to 80 percent of the work, however.

MS. DAVIS replied that a different policy call could be made. The House version of the bill changed that section to allow the state to keep the work.

[6:10:46 PM](#)

CHAIR FRENCH said there is no other area in the bill that called for arbitration. There being no other business to come before the committee, he adjourned the meeting at [6:11:30 PM](#).