

**ALASKA STATE LEGISLATURE  
SENATE RESOURCES STANDING COMMITTEE**

March 21, 2018

3:30 p.m.

**DRAFT**

**MEMBERS PRESENT**

Senator Cathy Giessel, Chair  
Senator John Coghill, Vice Chair  
Senator Natasha von Imhof  
Senator Kevin Meyer  
Senator Bill Wielechowski  
Senator Click Bishop

**MEMBERS ABSENT**

Senator Bert Stedman

**COMMITTEE CALENDAR**

Overview: Department of Natural Resources' Role in Natural Gas Commercialization Efforts

- HEARD

**PREVIOUS COMMITTEE ACTION**

No previous action to record

**WITNESS REGISTER**

ANDREW MACK, Commissioner  
Department of Natural Resources (DNR)  
Juneau, Alaska

**POSITION STATEMENT:** Provided the overview: Department of Natural Resources' Role in Natural Gas Commercialization Efforts.

ED KING, Gas Commercialization Advisor  
Department of Natural Resources (DNR)  
Juneau, Alaska

**POSITION STATEMENT:** Participated in the overview: Department of Natural Resources' Role in Natural Gas Commercialization Efforts.

STEVE WRIGHT, Senior Project Advisor

Alaska LNG Gasline Project (AKLNG)  
Department of Natural Resources (DNR)  
Commissioner's Office  
Juneau, Alaska

**POSITION STATEMENT:** Participated in the overview: Department of Natural Resources' Role in Natural Gas Commercialization Efforts.

**ACTION NARRATIVE**

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**CHAIR CATHY GIESSEL** called the Senate Resources Standing Committee meeting to order at 3:30 p.m. Present at the call to order were Senators Bishop, Von Imhof, Wielechowski, Coghill, Meyer, and Chair Giessel. Senator Stedman was excused.

**Overview: Department of Natural Resources'  
Role in Natural Gas Commercialization Efforts**

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**CHAIR GIESSEL** announced that today the committee would hear from the Department of Natural Resources (DNR) about its role in the state's natural gas commercialization efforts. She welcomed Commissioner Mack who would go over the department's mission on this goal, the tools that it possesses, and what legislators can expect in the coming year related to natural resources.

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**ANDREW MACK**, Commissioner, Department of Natural Resources (DNR), Juneau, Alaska, introduced himself and invited Steve Wright, the Alaska LNG Gasline Project (AKLNG) Senior Project Advisor and a consultant to the Commissioner's Office, and Ed King, Gas Commercialization Advisor, to the table to help with the presentation.

**COMMISSIONER MACK** said he would discuss royalty in kind/royalty in value (RIK/RIV) and obligations the DNR has with respect to that decision, the process of royalty gas disposition, lease management considerations, and DNR engagement with the Alaska Gas Development Corporation (AGDC) and related DNR contracts and agreements, which are contemplated under SB 138.

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He said it's important to frame the first issue to give the committee a very clear look at where he believes they stand in the process. He has been asked how much progress they have made, and the truth is they are in the early stages of the evaluating

portion, but under the AKLNG process, he feels they are in good shape. A couple of critical points are:

1. SB 138, that created and established AGDC, is still the law they follow, and they take those responsibilities seriously.
2. They believe SB 138 as a legal structure fits very well with the way the project is currently structured, which is different than what was envisioned when it was passed. They have not been aware of any inconsistencies with how the project is currently formulated.

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COMMISSIONER MACK said he wanted to describe how the department is meeting its obligations, walk through where he feels the project is from a DNR perspective, and tell them what resources the department has available. In 2016, when he came to this position, the DNR Gas Commercialization Team had a dedicated budget and eight staff and facing a situation where the companies had collectively indicated that as an equity-based project they weren't sure it would pass muster. An offer was made, and the state accepted, to take the lead in the project.

He views 2016 as a transition year, he said, and in that process, he made the difficult decision of "right-sizing" their effort by laying off or moving those eight employees from DNR employment to other areas in DNR or other agencies. He worked very hard to maintain critical pieces of the team including Steve Wright, whose background is having been the working interest representative for Chevron at the two North Slope Units that are implicated by this project (Prudhoe Bay (PBU) and Point Thomson (PTU)); and maintained the contract with the consultants, Black and Veatch.

COMMISSIONER MACK said that it's been pretty public that a transition was going on where the data and underlying resource reports which were provided to the Federal Energy Regulatory Commission (FERC) to support the project were being tied up and submitted. There was also the effort by the Governor, himself, AGDC, Keith Meyer, and John Hendricks of going out in the market, traveling, and meeting with potential interested parties. They took a couple of trips in 2016 to Singapore, Korea, and Japan and talked about the opportunity and the opportunity in terms of a project. He was there specifically,

because he was talking about the great potential on the North Slope.

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COMMISSIONER MACK said 2017 was really a marketing year, and until late in 2017, they didn't have a "close bead" on what the opportunity was. But obviously, with the announcement of the Joint Development Agreement (JDA), the department can now set its sights on that opportunity. This effort is being resourced within the DNR Commissioner's Office and within DNR itself including Mark Wiggin, DNR Deputy Commissioner, as the DNR Gas Commercialization Manager; Ed King, DNR Gas Commercialization Advisor; Steve Wright, AKLNG Senior Project Advisor; and they still maintain Black and Veatch as a contractor for commercial and upstream analysis.

For commercial support the Division of Oil and Gas (DOG) has three individuals: Rebecca Kruse, DOG legal counsel; Greg Bidwell, the lead commercial analyst; and Johnny Maisa, DOG commercial analyst. For legal support they rely on the Department of Law (DOL): principally on Martin Schulz, Peter Caltagirone, and outside counsel Matt Finley with Ashburn & Mason. For permitting needs, they have Heidi Hanson, DNR Deputy Commissioner; Faith Martineau, the new Executive Director for the Office of Project Management and Permitting (OPMP); Jason Walsh in the DOG's State Pipeline Coordinator's Office; and Don Perrin, the specific permit coordinator at OPMP for the AGDC project.

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COMMISSIONER MACK said the reality is that none of these people are exclusive to this project, but they all have many years of experience; this is just a part of their job. They do have the benefit of the experience of SB 138, which was passed in 2014.

With 2016 being the transition year, he said DNR didn't do a lot of work on the project in 2017. But, at the end of the year they saw the announcement of the JDA, and so they started to restructure and ramp-up efforts. The project doesn't have a dedicated budget, but it is poised, and this is the team that is going to be doing the work.

SENATOR BISHOP asked him to provide the committee with an Office of Research and Development (ORD) chart.

COMMISSIONER MACK answered, "Absolutely."

Slide 3: Primary responsibilities for DNR

COMMISSIONER MACK said AS 38.05.182 stipulates that DNR will elect to receive Alaska LNG royalty gas in-kind (RIK), unless the DNR Commissioner finds that taking gas in-value (RIV) would be in the best interest of the state. The normal process is for DNR to send a letter to the Senate President and the Speaker of the House - the last letter was sent March 31, 2017, and it stated that RIK is the default. However, in most cases, the state takes RIV. The letter points out where the state has actually gone through the process of determining where to take RIK.

Briefly, he explained the process. If there is an indication of interest before entering into an RIK contract, DNR has to do a preliminary best interest finding (BIF), which is usually being developed at the same time a contract is being negotiated. The department has two contracts currently: one with Endeavor and the other with Petro Star; both are in-state refiners which buy royalty oil. Ultimately, this issue has to go out for public comment and then to the Royalty Board before it comes to this body for legislative approval.

This process has been ongoing since there has been a royalty contract in Alaska. The most important parts of it are the BIF and the fact that any RIK contract has to come before this body for ratification. They would go through the same process if a decision were made to propose a RIK contract for gas sales.

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CHAIR GIESSEL asked what criteria he uses when making the decision to choose to do the default (RIK).

COMMISSIONER MACK said that decision implicates two statutes: AS 38.05.183(e) and AS 38.06.070(a). Generally speaking, biggest criteria are the cash value and the "projected effects on the state's economy." AS 38.06.070(a) provides that the decision is based on the revenue needed and the projected fiscal condition of the state, which he thinks is the most important element.

CHAIR GIESSEL asked what resources or experts he would rely on in making that evaluation.

COMMISSIONER MACK said he would rely on the team he just identified. Historically, when the state has done RIK contracts for oil, they have been done exclusively internally by DOG employees. Outside counsel has been used only a few times. For

this particular question, he would use both the lead commercial analyst, Greg Bidwell, Mr. Wright, a contract employee, Deepa Poduval with Black & Veatch, and other support employees. He would also consult with the Department of Law and the Department of Revenue.

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CHAIR GIESSEL called the meeting back to order at 3:50 p.m.

COMMISSIONER MACK said he was able to find the criteria under AS 38.05.183 (e) and it says: the cash value offered, the projected effects of the sale on the economy of the state (critical), and a couple that are focused on the benefits of refining in-state, which might not be particularly relevant.

Then the criteria lists AS 37.06.070, which talks about some very broad concepts including the revenue needs and projected fiscal condition of the state, the existence and extent of present and projected local needs for oil and gas products and byproducts, the desirability of localized capital investment, social impacts of the transaction, and additional costs and responsibilities which could be imposed upon the state and affect political subdivisions by development-related transactions.

These two statutes describe the criteria very thoroughly. Most recently, he said, and this body and this committee reviewed the Petro Star contract and ultimately ratified it. It has been done a number of times for royalty oil contracts, and the department has been able to show where the state can get a modestly increased price.

CHAIR GIESSEL thanked him for the explanation and said the cost of this project is massive and legislators want to make sure the state is getting an equally massive value out of it. She asked if legislators can expect the same level of detail in his document outlining decision points and data the decision was based on.

COMMISSIONER MACK answered yes. He added that royalty contracts contemplating selling royalty oil use a quantum of 10, 20, 30, and 40 thousand barrels and most royalty oil contracts are five years in length. Gas contracts are different in that they are much larger and presumably longer. Most people would agree that

in order for this evaluation to be found in the interests of the state for this body to deliberate, it would have to be a much longer contract, which adds complexity.

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CHAIR GIESSEL said she totally appreciated that and expects to see detailed modeling on those criteria and asked if he envisioned a particular time he would make the best interest findings (BIF).

COMMISSIONER MACK replied they are not on a specific time table, but it is somewhat sequential in the sense that they have to understand what the other gas sales contracts would look like for comparison. Now they feel they are in a good position to make that evaluation, but they are at the front end of it. A couple of years ago, the person had been identified and hired to start the process of writing the preliminary BIF on what an RIK evaluation would look like, but that never materialized. So, they know that is in front of them.

CHAIR GIESSEL said she thought it would be some ways down the road when he actually has data about what the price of the gas will be at the wellhead and what the construction costs of the project will be and those might be in ranges, and she asked if he would be able to provide the legislature with the analysis for the different price and cost ranges in terms of making their decision. They want to know how broad his data is and whether it covers those kinds of variables.

COMMISSIONER MACK replied the statute has opportunities for conversation around what those factors are. This is when they have an evaluation in hand, which they are relying upon to make a recommendation for an RIK selection, if that's the way it goes.

CHAIR GIESSEL said she suspected that the co-chair of the Finance Committee will be interested in that information.

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SENATOR VON IMHOF asked if he anticipated that the amount of RIK gas the state may be able to take may change depending on whether the state has a 25 percent, a 10 percent, or a zero percent ownership.

COMMISSIONER MACK answered when the state makes its decision to select RIK, a rate is set, but the producers also have to decide they want to provide their tax as gas. There is an opportunity

for that percentage to go up and down during negotiations if certain decisions are made with respect to other parts of the project. From his perspective, they are looking at this as a royalty portion and a TAG portion, a fairly well-laid-out sequence in the law. Either they go down that road and end up with 25 percent of the gas being available or it becomes an RIV situation.

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SENATOR VON IMHOF asked if the state gets any take in the scenario where a dominant equity investor owns the infrastructure and chooses to purchase the gas right at the beginning point before it goes into the pipe.

ED KING, Gas Commercialization Advisor, Department of Natural Resources (DNR), answered that the royalties that were due are lease-conditioned. At Point Thomson, 14.5 percent of the gas that is produced belongs to the state. Then the state has the option of either taking monetary value of that gas or taking physical custody of it and trying to sell it for a higher price. In Prudhoe Bay, all of the leases are 12.5 percent, so the state gets 12.5 percent of all of that gas regardless of who the leaseholder or purchaser of the gas is. The Department of Revenue also has a tax component, which is not a lease agreement but a compulsory requirement by the legislature that the state owns 13 percent of the gas that is produced with the royalty subtracted first. It works out that 24.2 percent of the total gas that is produced belongs to the state regardless of who the investor, lessee, or purchaser is.

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Slide 4: Royalty Gas Disposition - RIK

STEVE WRIGHT, Senior Project Advisor, Alaska LNG Gasline Project (AKLNG), Department of Natural Resources (DNR) Commissioner's Office, said he is engaged in North Slope gas commercialization efforts for the state. He said slide 4 discusses a few of the critical aspects to disposing of state's royalty gas under an RIK scenario.

MR. WRIGHT explained that under the current AGDC-led project structure, if DNR elects to receive RIK, the state could sell its royalty gas and tax as gas (TAG) to the Alaska Gas Development Corporation (AGDC), and AGDC has had extensive conversations about how to monetize gas.

Custody transfer of the state's RIK and TAG gas share from the Prudhoe Bay Unit (PBU) and the Point Thomson Unit (PTU) to any potential buyer would take place on the North Slope, either at the wellhead, at the fence line for either of the units, or at the inlet to the gas treatment plant (GTP). This point is still uncertain.

The DNR is actively engaged with AGDC on discussions regarding development of the Gas Sales Agreement (GSA). A contract for sale of the state's RIK and TAG gas will require a Royalty Board recommendation and approval by the legislature.

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COMMISSIONER MACK said in regard to custody, one of the things they are aware of (from the equity-based model with the three producer companies) is that the application to the Federal Energy Regulatory Commission (FERC) included the lateral between the two units. That is still pending at FERC. The two units were viewed as being critical to the development of the project, because the resource was needed to bring down the cost. So, in an equity-based project it was easy to foresee how that would get built. Now that AGDC has taken the lead, it's not entirely clear but it is contemplated that they would be the entity that would take the lead in building the project. The reason the second bullet point on slide 4 is unclear is because there is still room for negotiation.

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MR. KING remarked that the department has two options when it takes its royalty: it can take physical custody of gas in kind and then it has the responsibility of disposing of it, which requires a marketing team and a contract. Another option is to effectively let the producers sell the gas for the state (coat-tail on the producers' contracts), which is done by taking royalty in value (RIV). This is where the state receives the same value that the producers receive for the gas that it owns as royalty gas. If the state does that, all it has to do is determine what the value at the wellhead is in order to determine how much money is due. In order to do that, the state would need to be able to calculate what the royalty value is, which would require the state to see the contracts, the tolling arrangements, and transportation costs (the same as the state does to back up the costs for the oil fields). If the state can't beat the royalty value that the producers are selling their gas for, then the department has the option to simply take the same value that they are receiving.

MR. KING said SB 138 provided a provision to AS 38.05.180(ii)(2) that allows the department to modify leases in order to clarify the value of the methodology for determining the value of the gas, something that is lacking in current law, just because the North Slope has never had a commercial gas sale. If the state were to decide to do RIV, it's likely that some of those existing ambiguities would need to be rectified, and the commissioner would have the authority to amend the leases.

SENATOR BISHOP remarked that the Alaska Oil and Gas Conservation Commission (AOGCC) didn't provide the state authorization to make a gas sale until a couple years ago.

MR. KING apologized and said he didn't mean to imply fault.

COMMISSIONER MACK added that October 15, 2015, is when the Alaska Oil and Gas Conservation Commission (AOGCC) issued its first order approving offtake to match some of the volumes the project contemplated. It was a very critical juncture, because they pointed out to 2020, 2021, 2022, 2023, 2024, and 2025 as the probable dates when gas could be taken off the Prudhoe Bay Unit.

CHAIR GIESSEL went back to slide 5 and asked him to list what the "net allowable deductions" would be.

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MR. KING answered the lease terms require that payment be received at the point of production. A lot of times - when selling oil, for example - it has to be shipped down the TransAlaska Pipeline (TAPS) and down to California, and all the costs associated with that transportation are allowable deductions. The lease terms also have costs that are associated with producing the oil or gas that can be construed as allowable deductions. However, leases have changed over the years and companies have different allowable deductions called "field cost allowances" or "unit cost allowances."

CHAIR GIESSEL commented that field cost allowances were brought up in a written answer from questions to the AGDC implying that field cost allowances were somehow brought before the legislature for approval, and that is something she wasn't aware of. She asked for clarification.

COMMISSIONER MACK answered that field costs in many cases have been negotiated and settled and it is not unusual for the state to be dealing with them. Most field cost allowances are

contained within the settlement agreements, although some are outstanding.

He said that field costs at the Point Thompson Unit are significant issues that need to be dealt with. It has a new production facility, unlike Prudhoe Bay which has been in production for a long time and the state has come to an understanding with the operator.

CHAIR GIESSEL said those are decisions between DNR and the producer or the company.

COMMISSIONER MACK added, "And the court, Madam Chair." A number of those issues have been litigated. But other cases have been negotiated and settled.

#### Slide 6: SB 138 Allows Lease Amendments

MR. KING said AS 138.05.180 (hh) and (ii) (authority and standards) had provisions giving the commissioner the authority to modify leases. The royalty contract terms are binding on both parties. So, they can't just be changed without approval by all. The department doesn't have general authority to renegotiate contracts unless the legislature gives them explicit authority or if the department takes the contract to the legislature. However, under SB 138.05.180 (j), the department has royalty modification authority to reduce royalty rates when it is required.

SB 138 gives the department additional authority to modify specific lease terms. One of those is the ability for the commissioner to decide to take RIK or RIV within a certain window. Usually, in a royalty oil contract, the tell the producer is notified that in 90 days the state wants its oil in kind, and that would satisfy the contract. When that contract expires or if the buyer were unable to accept the state's oil for some reason, the state has the ability to switch back to RIV.

MR. KING explained that when they were talking about the AKLNG project back in 2014 when SB 138 was passed, it was very critical to all parties to have supply security during the initial project term: producers were very afraid of the state being able to make switches from RIK to RIV. So, the legislature gave DNR the authority to remove that switching ability. They also gave them the authority to modify or create a new

methodology for calculating the allowable expenditure deductions (that generates the RIV amount).

As he said before, some ambiguities have been litigated in the past. The legislature gave the department some authority to remedy some of the ambiguities with the contract or on leases that were not fixed rate royalties (a sliding scale royalty that changes as production or price levels change or when there is a net profit share term (NPST), which is an additional payment to the state once capital is recovered). These two types of leases also gave rise to the ability for the amount of gas that was due to the state to change on a month-to-month basis. It was very difficult under an equity structure - where the state had a fixed amount of capacity - if it had fluctuating amounts of gas supply it was trying to move over a fixed amount of capacity. So, the authority was given to DNR to "levelize" the royalty rate. For instance, for a 12.5 percent royalty with a 30 percent NPSL, they would do the calculation and figure out what the right number was that gives the equivalent value. The sliding scales are similar where instead of being able to slide they would just calculate the equivalent value.

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He said this issue isn't as big of an issue any more under the new model, because the fixed capacity isn't really constraining the producers or the state. It isn't as important, and therefore, they have not done any work on it since the project structure changed.

Slide 7: DNR Commissioner's RIK Finding.

MR. WRIGHT said the North Slope has no other competitive major gas sales project to monetize the gas at PBU and PTU, and so a noncompetitive sale is most likely, and that is contemplated within the statutes. In that case, DNR must find that selling the gas to AGDC in a non-competitive contract is in the state's best interest. The gas sales contract will then need to be ratified by the legislature. Before entering into an RIK contract to sell gas, DNR must also issue a finding that in-state gas demand would be met under the project design. AGDC has said publicly that they anticipate setting aside up to 500 million cubic feet of gas, which is currently more than twice the state's gas consumption for future and current in-state gas needs. AGDC has the responsibility to assess those in-state gas demands along with support from DNR.

CHAIR GIESSEL said that probably DOG staff would do that assessment and determine if the 500 mcf is accurate.

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COMMISSIONER MACK answered that DNR has a lot of information and technical staff to evaluate what those needs would be, although they don't get into the distribution end of things too far. For instance, the Cook Inlet Natural Gas Storage Alaska (CINGSA) facility on the Kenai Peninsula had to have been approved.

CHAIR GIESSEL recalled that DNR originally was going to participate in marketing of the gas and asked if they would still be engaged in any in-state marketing for potential resource development projects that would be using gas, like mines.

COMMISSIONER MACK answered yes. DNR would be in a position to, and be in a position of ensuring that if there is an RIK event, that the project is poised to actually fill those needs. He invited Mr. King to respond to an RIV scenario.

MR. KING said for an RIV scenario, the department is required to make sure that domestic needs are met, which falls under the gas sales statute, AS 38.05.183 (d). If the gas is going for export, the department has to make a finding that domestic needs are satisfied first. They would also be leveraging the work the AGDC is doing in the same way. If the state were to sell its gas to AGDC, AGDC would be required to meet those standards, as well.

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SENATOR MEYER asked where he would anticipate keeping this gas: in Nikiski, on the North Slope, or build storage somewhere?

MR. KING replied that it wouldn't be prudent for the state to elect RIK and then store the gas. An RIK election would be under an RIK sales contract in which case the gas would be transported through the pipeline to a consumer.

SENATOR MEYER responded that language says, "the AGDC anticipates setting aside," and that was confusing.

COMMISSIONER MACK replied that was maybe not the most artful way to say it, but it would be to commit a specific amount to sales contracts. The project contemplates five offtake points for domestic use. Presumably, if there is an RIK contract, that demand might be met by the state as a seller of gas, but those would be previously negotiated contracts to utilities that would

associate the costs of taking gas off the system and distributing it. If it were an RIV event, that obligation would probably fall to AGDC, and he didn't think a storage component was contemplated.

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SENATOR MEYER said that Donlin Creek is anticipating building a pipeline to its mine in Cook Inlet. He asked if DNR anticipates selling them some of the gas and would they be competing with the smaller companies in the Inlet.

COMMISSIONER MACK answered in an RIK situation, they would be marketing the gas and would contemplate selling it to a project like Donlin Creek. There would be competition because of existing production in Cook Inlet. He assumed people were talking about the energy needs for the project.

MR. KING clarified that the intent is that AGDC would not sell all the gas to foreign export users. It would withhold 500 mcf/day of gas that is not under a long-term, fixed contract so that it can meet in-state needs. It isn't intended to mean that gas would be put in storage for future use. If the need existed, it would be available; and if it wasn't needed, it could go to export.

SENATOR BISHOP commented that it could just sit in Prudhoe Bay until needed.

COMMISSIONER MACK said that was correct.

SENATOR COGHILL wondered how the gas would move through the pipe and what that does to the cost of transportation.

MR. KING replied that the cost of transportation is going to be effectively the cost of operations and capital divided by the number of molecules that are transported through the pipeline. So, AGDC would have to model a situation in which the gas was suddenly diverted to a mine.

COMMISSIONER MACK supported that answer. He said the thought is once the system is up and running that the pull will be so strong that those costs won't be significant in the long run.

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SENATOR COGHILL acknowledged that this issue was way out in the future, but if the state is selling its gas as RIV and then an

Interior community pulls off a small amount, 150 mcf, could the value be backed up enough to make up for some of the costs.

CHAIR GIESSEL said she assumed that would be part of their analysis.

COMMISSIONER MACK replied that the effect on communities is specifically one of the criteria in their evaluation and it is a big impact. Several communities have a rural energy component.

SENATOR VON IMHOF said earlier she asked what the state's RIK would be if the state ended up owning zero percent of the pipeline or a small percent. If the state ends up owning zero, but it is going to set aside 500 mcf, the dominant equity investor might not be happy about that. How is that addressed?

COMMISSIONER MACK responded that they have to be careful about investment and ownership. Early discussions didn't include a system owned by anybody other than the State of Alaska. The investments come from another spot.

MR. KING remarked that investors are always going to find a return on their investment and will require some revenue stream in order to get that. The way that is done in a pipeline is by charging a toll for moving gas through it, the transportation cost. The owners end up paying a toll (a tariff) to the midstream owners, the same as for the TAPS now. The big advantage the state had as an investor under the equity model was that the return on that capital would flow to the state rather than to the owners of the pipeline. The same thing would be true in this model if the state is going to put up its own money; it gets return on that capital. If state were to take its gas in RIK it would have to ship it over the pipe and pay a toll. But that is not the model that is being contemplated now. The model that is most commonly cited now would be a wellhead sale and then the AGDC or its investors would be responsible for the cost of transportation.

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SENATOR VON IMHOF recapped that as soon as the state takes its 24.5 percent, then it sets aside about 500 mcf in value for in-state needs regardless of the ownership of the pipe and infrastructure.

COMMISSIONER MACK replied that law states that has to be a requirement/condition of the financing package.

SENATOR VON IMHOF followed up asking since investors haven't been attracted yet, the department doesn't know what type of conditions and terms will be negotiated - rational or irrational - so, making any assumptions right now is theoretical. One of her concerns is if legislators will be privy to those terms prior to any inked signatures on the line.

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SENATOR BISHOP reminded them that "the law of the land is half a 'B' a day for Alaskans." He thought distance-sensitive rates had been built into SB 138 for the five offtake points in Alaska.

MR. KING recalled that conversation, but he didn't think distance-sensitive rates got into the final version of SB 138.

SENATOR MEYER followed up on Senator von Imhof's question asking at what point in the project DNR will find that selling the gas to AGDC in a non-competitive contract is in the state's best interest.

COMMISSIONER MACK replied that he is referring to an RIK situation, and that point has already been passed; DNR determined to go down the path of taking RIK. Was his question when that would happen?

SENATOR MEYER replied he already said he wasn't sure when that would happen and asked if it will happen prior to any deal being signed and ratified.

COMMISSIONER MACK replied they need to understand what the fundamentals of an RIV contract would be and what the other gas sales contracts fundamentals are and what the value to the state might be under that scenario before starting to evaluate RIK. DNR needs to figure that out before any final decisions about the disposition of royalty gas.

SENATOR MEYER recapped his question: before the state makes any commitments, that determination will have been made.

COMMISSIONER MACK responded "yes."

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Slide 8: DNR Commissioner's RIK Finding

MR. WRIGHT continued that AGDC currently contemplates buying gas from Prudhoe Bay and Point Thomson Unit from the working interest owners and possibly from the State of Alaska using an

alternative pricing mechanism that offers two alternative price structures: the first is a fixed price structure selling a unit of gas either in MMBtu at a fixed price set and determined in advance or second, by using wellhead netback pricing with a fixed floor. The objective is to establish a fair gas price structure for the sellers and buyers that will incentivize the completion and success of this very complex and unique project.

One of the key determinants on the state's side for revenue realization from the project is whether revenues get shifted up or down the value chain from the upstream units where it receives title to the gas and could transfer it to a seller. A key provision being discussed involves the terms for byproduct or CO<sub>2</sub> disposition and handling as it needs to be defined in the gas sales contracts that AGDC hopes to develop. The cost associated with byproduct handling and disposition could be a real value lever for some of the other stakeholders in the project in that the state doesn't want to work hard to establish a good revenue stream at the wellhead and then see some of those revenues or values eroded further downstream by a disproportional high cost for CO<sub>2</sub> handling and disposition. There will be many tcf of carbon dioxide and some other impurities that will need to be disposed of, and at this point very likely disposed of within the two participating units in the major gas sales project. So, they are going to be very careful to make sure that the provisions of the gas sales agreements have terms that are favorable for the state in terms of allocation of byproduct handling.

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CHAIR GIESSEL asked how the CO<sub>2</sub> was going to be paid for under the previous agreement with the three producer partners.

MR. WRIGHT answered that hadn't been firmly established, but what had been discussed was that the very large gas treatment plant (GTP) would be located in or adjacent to the Prudhoe Bay Unit. The gas impurities would flow back to the Prudhoe Bay Unit, which would incur operating costs to dispose of that gas into an underground reservoir. The unit operator would then be responsible for disposition of that gas and would receive some relatively equitable compensation for managing it. Scenarios were modeled around reinjection of the CO<sub>2</sub> into the gas cap at Prudhoe Bay Unit would be advantageous for additional liquids recovery, whether there were shallower reservoirs that would be technically capable of receiving those volume of CO<sub>2</sub>, and whether the reservoir has sequestration characteristics that would hold and store CO<sub>2</sub> volumes for an extended period of time as would be

required to make sure it didn't leak either into the producing reservoirs or back up to the surface. A tremendous amount of reservoir engineering work was going on around CO<sub>2</sub> disposal and none of it was fully completed on the last effort.

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SENATOR VON IMHOF said she is hearing that there are potentially two opportunities to buy the gas from producers: once when it comes out of ground or as clean gas if the GTP facility gets built.

MR. WRIGHT replied yes, but what is being discussed now is either within the production units at the wellhead or the flange going into the GTP. So, the raw gas as its produced from the unit would be sold and ownership transferred, and the byproducts stream coming out of the GTP would be returned to the sellers. That would be a viable setup for working interest owners. That would prove to be problematic for the state without its ability to participate in unit operations at Prudhoe Bay. That is one of the aspects of a gas sales contract the state needs to work with AGDC.

SENATOR VON IMHOF asked him to provide a range of dollar amounts for raw gas.

MR. WRIGHT replied that speculative values have been placed on it. AGDC negotiations with the producers are confidential and he didn't know what terms are being discussed.

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Slide 9: RIK and RIV Benefits and Risks

MR. WRIGHT said slide 9 depicts a set of known and assumed benefits and risks associated with either an RIK or an RIV election to summarize some current understandings. Under the benefits portion of the RIK column, AGDC's purchase of the state's royalty and TAG gas would benefit and support the state's LNG marketing relationships that are being developed globally. The state in an RIK election process would also avoid the necessity of having to audit the producers contracts and procedures around gas sales. The audit process under RIK could be fairly fraught and finding ways to mitigate that might be considered beneficial by some of the project stakeholders.

Potential risks associated with RIK elections include the possible disadvantage the state might pay in cost allocation for byproduct handling and disposal. Also, locking in a long-term

RIK election for the initial project term, which is estimated to be 20-25 years, could eliminate the opportunity to switch from RIK to RIV if problems arise during the execution of the project that hadn't been anticipated or if the economic outcome of the project didn't match pre-investment for gas. Finally, field cost allowance issues related to production and gas processing certainly have the opportunity to shift value up and down the value chain and could impact state revenues.

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On the RIV column, benefits include the state would have no exposure to negative netback risk. This was a concern under the previous project structure where it was envisioned that there would be a wellhead netback pricing structure that didn't include a fixed floor. Under the current pricing mechanisms that AGDC is looking at currently, they seem to have found ways to mitigate that negative netback risk using either fixed pricing or a wellhead netback with a fixed price floor. Under an RIV scenario the state would also receive its value if the producers elect to market their own gas to foreign buyers and potentially benefit from the global marketing expertise that these major international oil companies who have LNG portfolios world wide could sell into and could potentially capture greater value than markets that the state or AGDC could tap into.

One of the risks in RIV is there is always future uncertainties regarding the RIV value to the state around commodity price fluctuations globally, transportation deductions which may change over the life of the project, and scenarios where in an RIV world the state revenues could be fairly dramatically eroded.

MR. WRIGHT said they are now looking to characterize and compare and contrast the relative benefits and risks around RIK as opposed to RIV.

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Slide 10: Engagements with AGDC

COMMISSIONER MACK added that the DNR commissioner's office is engaged with AGDC on a number of parallel paths, and actively engaged on royalty and TAG gas sales. The OPMP Office is providing agency coordination and support of the AKLNG project and the very experienced Don Perrin has been retained to coordinate that effort.

One of the things that has come up recently on the permitting side is the activity at FERC, which is going very well. It's common to have lots of questions. The application put together as part of the process which was led by ExxonMobil is still intact and moving forward.

COMMISSIONER MACK said he personally traveled and DNR participate in engagements with potential LNG markets and buyers in 2016 and those have led to successful securing of interest in the project under the ADA that was signed last November. And they are working on the integration of the LNG projects ongoing commercial analysis, too, with a team of folks including some at the table, Black & Veatch, and others.

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Slide 11: DNR's Role in Contracts

MR. KING said for completeness he wanted to talk about the role of DNR in contracts and contract negotiations. Under SB 138, DNR had two sections: one was a new authority for the commissioner to enter into contracts related to North Slope gas sales; the other being the lease amendments talked about earlier.

DNR now does have the authority to enter into contracts. That was very important under the equity model when trying to figure out things like gas balancing agreements. They were able to enter into confidentiality agreements and enter into commercial agreements with producer partners. But they aren't currently under any of those contracts, but as they move forward, they will probably need to use this authority to enter into contracts in the future.

SENATOR BISHOP editorialized that the commissioner had some big decisions to make and he didn't envy him.

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CHAIR GIESSEL said the committee is aware of the importance of hearing from DNR. She thanked the presenters saying that members would watch closely as they make the BIF and RIK decisions.

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CHAIR GIESSEL adjourned Senate Resources Committee meeting at 4:55 p.m.