

**ALASKA STATE LEGISLATURE  
SENATE JUDICIARY STANDING COMMITTEE**

April 27, 2012

1:33 p.m.

**MEMBERS PRESENT**

Senator Hollis French, Chair  
Senator Bill Wielechowski, Vice Chair  
Senator Joe Paskvan  
Senator John Coghill

**MEMBERS ABSENT**

Senator Lesil McGuire

**OTHER LEGISLATORS PRESENT**

Senator Donny Olson  
Senator Dennis Egan

Representative Mike Doogan  
Representative Peggy Wilson  
Representative Kurt Olson  
Representative Beth Kerttula  
Representative Steve Thompson

**COMMITTEE CALENDAR**

Point Thomson Settlement Evaluation

- HEARD

Point Thomson Settlement Litigation

- HEARD

Point Thomson Settlement/DNR response

- HEARD

**PREVIOUS COMMITTEE ACTION**

No previous action to record.

**WITNESS REGISTER**

MARK MYERS Ph.D., CPG, representing himself  
Anchorage, AK

**POSITION STATEMENT:** Raised questions about the Point Thomson Settlement agreement.

CRAIG RICHARDS, Attorney  
Anchorage, AK

**POSITION STATEMENT:** Described the appeal he filed on behalf of Mr. Walker to reconsider the decision to enter into the Point Thomson settlement agreement.

MICHAEL C. GERAGHTY, Attorney General  
Department of Law (DOL)  
Anchorage, AK

**POSITION STATEMENT:** Provided supporting testimony for the Point Thomson settlement agreement.

JOE BALASH, Deputy Commissioner  
Department of Natural Resources (DNR)  
Anchorage, AK

**POSITION STATEMENT:** Provided supporting testimony for the Point Thomson settlement agreement.

JON KATCHEN, Inter-governmental Coordinator  
Department of Natural Resources (DNR)  
Anchorage, AK

**POSITION STATEMENT:** Provided supporting testimony for the Point Thomson settlement agreement.

#### **ACTION NARRATIVE**

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**CHAIR HOLLIS FRENCH** called the Senate Judiciary Standing Committee meeting to order at 1:33 p.m. Present at the call to order were Senators Wielechowski, Paskvan, Coghill, and Chair French.

#### **Point Thomson Settlement Agreement**

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CHAIR FRENCH announced the business before the committee would be a review of the Point Thomson settlement agreement. He provided a backdrop for the discussion by reviewing three news articles. The first was from 1992 when Governor Hickel began to talk about changing the rules for state oil and gas leasing because companies were "sitting on gas fields such as Point Thomson, which could play a crucial role in the gas pipeline project." The second article was from 1998, and was about the

state being satisfied with the 15<sup>th</sup> plan of development that ExxonMobil submitted for development of the yet undeveloped Point Thomson field that was created in 1977. The third article was from 2004 when ExxonMobil agreed to begin drilling development wells in the field by June 15, 2006 or face automatic surrender of the acreage plus a \$20 million penalty. The article said that ExxonMobil recently backed away from plans for a possible \$1 billion project to move Point Thomson liquids down the Trans Alaska Oil Pipeline because further evaluation showed the project wasn't commercially viable without a companion pipeline to the Lower 48 that could carry the gas reserves.

He introduced former oil and gas director Mark Myers as the first presenter.

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MARK MYERS Ph.D., CPG, representing himself, described his 25 year history as a petroleum geologist working on the North Slope in both exploration and development. He served as the director of the Division of Oil and Gas from January 2001 until November 2005, and in that role ultimately defaulted ExxonMobil for failure to develop.

MR. MYERS said it's not possible to understand the settlement agreement without understanding the details of the very complex gas condensate and oil field. He confirmed that he was only using public data and emphasized the importance getting briefings from experts in the fields of geology, engineering, and economics to understand the significance of the concluding information. He also emphasized the importance of getting the best legal support possible from attorneys who are experts in oil and gas law.

MR. MYERS said his presentation would have four parts: 1) a technical discussion of the details of the Point Thomson field; 2) a description of a few previous development commitments; 3) the current settlement; and 4) a summary.

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MR. MYERS described Point Thomson as the remaining crown jewel on the North Slope on state lands. The combined reservoirs may contain more than 1 billion barrels of technically recoverable oil and condensate, and 7 trillion cubic feet of technically producible natural gas. The field has two major reservoir integrals - the Flaxman Sands and the Thomson Sands. The Flaxman Sands was discovered in 1975 and is a conventional oil

reservoir. Although there are no public estimates of the total amount, safe estimates of this reservoir are in the range of several hundred million barrels. The Thomson Sands reservoir contains large volumes of retrograde condensate, oil and natural gas. He explained that a retrograde condensate field is under very high pressure and most of the hydrocarbons are in a gaseous state. But when those hydrocarbons are taken to the surface at atmospheric pressure, much of it is liquids that tend to have higher value sweet-like crudes.

Point Thomson nominally has gaseous state liquids along with natural gas in place, and it also has liquid oil at the base of the formation. He described it as a sandwich; the base beneath the field is water, followed by oil, followed by condensate with a little oil mixed in and natural gas mixed in the condensate. The pressure is about 10,000 PSI, which is equivalent to about five times the pressure of a scuba tank. This is good, but also challenging. Because of the high pressure, the entire Point Thomson field can be produced with perhaps 10 percent of the wells it would take to produce a similar Alpine-type field. It is technically feasible to cycle a field of this pressure.

Because it's a high pressure retrograde condensate field, the way it's produced determines dramatically how much of the hydrocarbons are recoverable. More than almost any other type of field, this one is critically sensitive to the production, the well, and facility design. It's important for the state to understand the consequence of various production scenarios and that some techniques bring in a lot more oil and liquids than others, he said.

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SENATOR WIELECHOWSKI asked him to discuss the significance of the Alaska Oil and Gas Conservation Commission (AOGCC) classifying Point Thomson as an oil field rather than a gas field.

MR. MYERS explained that the AOGCC by default calls Point Thomson an oil field because of the amount of oil in the liquids, and it will protect that field with respect to the rules that relate to oil. That default ruling could change over time and different rules would be applied to those pools.

SENATOR PASKVAN asked if the high price of oil relative to gas was a reason to continue to classify Point Thomson as an oil field.

MR. MYERS said the AOGCC is supposed to consider only physical waste, but he presumes that the more valuable oil is the more concerned the commission would be about loss of liquids and that mechanisms that would strip gas rapidly and not produce oil to the maximum should not be approved. He noted that he included in the presentation two documents that were written by the AOGCC chairman discussing how a condensate field works and supporting the classification as a gas field. The article written in 2006 indicated some frustration that if the operators wanted to use it as a gas field they should have approached the commission earlier. Mr. Myers said the AOGCC believes as he does that there is plenty of time to cycle the gas to produce the oil and produce the gas at a later time.

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MR. MYERS reviewed the key findings of the 2008 PetroTel Inc. study indicating that unless the Thomson Sands are developed using full field gas cycling, the majority of the recoverable condensate and oil will be wasted. The Department of Natural Resources commissioned the study and provided the data. Over 70 full field model simulations were run using a range of values.

He explained the two major ways to produce a field. One is to produce the field as a gas field in a process called blow down. The second way is called full field cycling. The liquids are stripped out after depressurizing and the gas re-injected to keep the reservoir pressure up. A version of that is being done at Prudhoe Bay in enhanced oil recovery using water alternating with gas. He said the consequence of blowing down the reservoir is that much (at least 50 percent and perhaps more) of the condensate falls out of solution and is permanently locked in the reservoir. Production is also lost when the gas drops out into solution because it reduces the overall permeability of the reservoir.

One model run indicates that with blow down only 26 percent of the in place condensate is recovered, or 127-156 million stock tank barrels (mmstb) of condensate. If the field is cycled for 20 years followed by blow down, 76 percent of the condensate is recovered, or 370-450 mmstb. This is a difference of 50 percent or 243-323 mmstb of additional liquids recovered. At today's oil prices, saving 243 million barrels of condensate is equivalent to more than half the value of the permanent fund.

MR. MYERS said PetroTel also modeled only 3-16 percent of the oil or 30-150 mmstb of oil is produced in blowing down the reservoir. By comparison, full field cycling for 20 years

followed by blow down produces 43 percent of the oil or 250-400 mmstb. This is a difference of about 200 mmstb of additional oil. He said there are challenges to recovering the oil and nobody knows how much can be recovered, but the scenarios run by PetroTel indicate that 300-500 mmstb of additional oil are recovered by cycling and most of the gas can be recovered 20 years later. How the Point Thomson reservoir is produced makes a difference of billions of dollars to the state, and there are also the challenges of physical and economic waste to consider.

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SENATOR PASKVAN recapped that he was advancing the notion that gas should be re-injected into the Point Thomson reservoir for the next 20 years to produce oil, and then the gas could be extracted.

MR. MYERS said yes; that method is logical economically and makes sense because there isn't a gasline. "In fact, in almost any scenario I could draw up for a gasline, you have plenty of time to cycle for 20 years before you're going to need Thomson gas for a gasline."

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MR. MYERS discussed four reasons the state and the producer may not agree on the method of production even if they agree on the geology, engineering, technology and costs. First, cycling costs more money up front, and in some cases the incremental oil recovery might give a lower rate of return on the field.

CHAIR FRENCH talked about the specialized equipment and associated challenges to cycle an extremely high pressure field.

MR. MYERS said another reason there may not be agreement is that the lessee/producer bears much of the development and production costs, although under ACES the state probably gives credit for about 50 percent of the development costs in a field like Point Thomson. Also, DNR has a mission and legal requirement as the resource steward and regulator to protect the public interest, promote conservation, and prevent the physical and economic waste, primarily through 11 AAC 83.303(a).

He said one would generally assume that if cycling were feasible and economic that the state would strongly argue for it. He said he did that as director of oil and gas when he defaulted ExxonMobil for failure to do the cycling project they committed to do a year or two earlier.

MR. MYERS highlighted another potential reason for disagreement on the method of production. The state of Alaska doesn't have another option if it loses its resources, whereas a producer has other investment options. It's not a criticism to recognize that their economic interest is served at a higher rate of return and that optionality is very valuable. Hypothetically, a company that has other investments that have similar rates of return might defer investment in Point Thomson because of not having a market for the gas, but present the case that gas is the highest use. The state logically wants development now, whereas the lease holder with many options may choose to keep the option value of the lease as the highest priority.

He said it's an important point that even given the same technical information, economics and knowledge base, a producer may have a different view than the state or any other subsurface owner. There's only a partial alignment of interests.

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SENATOR PASKVAN summarized that the state risks permanent loss of the oil resource if does not re-inject the gas, but if it first cycles the gas for 20 years to produce the oil it can then recover the gas.

MR. MYERS said that's right, but a small amount of gas is lost because of the energy used to cycle. He added that full field cycling was ExxonMobil's plan in 2001, and as oil and gas director his perspective was that it made sense to see the cycling come earlier.

He displayed a block diagram of the geology of the Point Thomson area and directed attention to the lands on the east and central side of the Thomson Sands reservoir that are delineated in the settlement. The west side of the field is unknown and there's only speculation as to how large it is.

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MR. MYERS said the Point Thomson Unit (PTU) was formed in 1977. Eleven wells were drilled in 1979-1983 and no more were drilled for a significant period of time. He said he was oil and gas director in 2001 and ExxonMobil agreed through an expansion agreement to test drill the western edge of the field and commence development drilling by June 2006 or pay a \$20 million penalty. They were required to complete 7 development wells by June 2008 or pay [\$27 million in] damages and increased royalty rates. The target of that production effort was about 75,000 barrels of condensate/day. It was a full field cycling project.

MR. MYERS said that in 2003 ExxonMobil decided it wouldn't drill. When it was clear that there was no common ground and the plan of development was unacceptable, he put the unit in default in 2005. He confirmed the Chair's observation that the 7 development wells were never drilled.

In 2009 Commissioner Irwin agreed to reinstate 2 of 31 leases, and ExxonMobil agreed to drill PTU 15 and PTU 16. He relayed that Commissioner Irwin represents that ExxonMobil unconditionally committed to drill the two wells by 2010. As agreed, ExxonMobil drilled and tested the wells and began permitting the pipeline to produce for a small scale cycling project.

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He displayed ExxonMobil's 2008-2014 clear and committed timeline for the Point Thomson project and the POD addressing DNR's requests. He highlighted that the POD commits to three oil and gas delineation wells and additional wells, and the timeline indicates the delineation program drilling will be completed [before mid-year 2012].

CHAIR FRENCH asked who prepared the slides.

MR. MYERS said the slides were prepared by ExxonMobil in late 2008. He reviewed the commitments through 2014.

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The Current Settlement

MR. MYERS described the current settlement as critical and extraordinarily significant.

CHAIR FRENCH observed that the settlement springs from litigation that essentially began when Mr. Myers put the unit in default in 2005.

MR. MYERS said that's correct. Then Commissioner Menge confirmed the decision and ExxonMobil appealed.

CHAIR FRENCH asked if it's fair to say that the 2012 settlement represents the culmination of those 7 years.

MR. MYERS said he was the first to default, but he was in a long line of frustrated oil and gas directors that wanted to see the Point Thomson field developed.

He said it's important to note that many of the issues addressed in the settlement are normally reserved for and resolved through statute and regulations using established public processes. However, the data that supports the decision making isn't available so he can only interpret pieces in the settlement.

He reviewed some of the major issues in the settlement. First, DNR is relinquishing its authority under 11 AAC 83.303(a) to manage the unit for a significant period of time. All the development options are at the sole discretion of the working interest owners (WIO). In this settlement the state is not determining whether blowing down the field is acceptable or cycling it on a small scale is acceptable. Responding to a question, he explained that ExxonMobil is the operator and the WIOs are all the companies that own a partnership in the field and are actually paying development costs.

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SENATOR COGHILL asked him to expand on the explanation of relinquishing the authority to manage the unit.

MR. MYERS said a lot of the traditional processes that go through the POD like the approval process, the unitization process, the process of producing a participating area for production are all either agreed to in the document or are at the discretion of the producer, and DNR will not participate in the process.

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SENATOR WIELECHOWSKI asked if he can envision any scenario where it would be in the state's best interest or even constitutional for the state to relinquish its authority to manage a unit.

MR. MYERS said, "Honestly, no." but a reason would be to get out of the court case. The prevention of physical and economic waste, appropriate development of a field, and protecting the rights of all parties all require the state to have authority in decision making as the subsurface owner. The lessee is obligated to meet the terms of their lease and follow the statutes and regulations. He said there's a natural tension, but in all cases it's better for the state to manage according to statutes and regulations.

SENATOR COGHILL asked if AOGCC retained its authority.

MR. MYERS said yes, but its authority is a little different because it does not represent the state as subsurface owner.

SENATOR COGHILL said he just wanted to make sure the commission wasn't out of the picture.

MR. MYERS added that under the settlement agreement, DNR generally agrees not to oppose any proposal before the AOGCC with the working interest owner.

SENATOR COGHILL asked if the POD is still in effect under the settlement agreement.

MR. MYERS said there is a POD, but until about 2019 the requirements are basically waived for most of the critical issues generally regulated under the plan. He continued to say that other pieces in the settlement relate to the typical conditions under which the state gets economic benefit from its oil and gas. One of the options is for the DNR commissioner to take gas in kind rather than in value. This is unusual. Normally there is a finding, a public process, and Royalty Board approval for a royalty in kind sale. The Alaska Stranded Gas Development Act (ASGDA) had language to do this, but it would have gone through the legislative approval process.

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SENATOR WIELECHOWSKI questioned why that wouldn't be good.

CHAIR FRENCH asked for a layman's explanation of royalty in value compared to royalty in kind.

MR. MYERS explained that the state has the right under its leases to take its royalty share in value (money). There is a complicated series of market baskets and settlements to determine that value, and the state may pay tanker and pipeline tariff structure costs on the oil, but it basically gets the rough equivalent of what the producer sells the oil for.

Under royalty in kind the state assumes responsibility for its royalty share of the oil as it leaves the unit. However, the state historically hasn't taken physical possession of the oil, electing instead to put a royalty sale forward for purchase of its oil on the North Slope. Flint Hills, for example, has purchased a huge amount of the state's oil on the North Slope, thereby assuming the responsibility for shipping. There is a very detailed and specific process including a finding and acceptance by a Royalty Board in order for the state to do that. And the state is required to get at least, if not more, value in kind from the sale than if the oil was left in value.

MR. MYERS said one of the cases under the settlement agreement is that the gas that's produced will be shipped to and cycled in Prudhoe Bay. The state agrees to take the gas in kind even though it really has no market for the gas, and it agrees to pay field costs on that gas. He said he didn't know why that was part of the agreement.

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SENATOR WIELECHOWSKI asked if this could conceivably cost the state a lot of money.

MR. MYERS said the state agreed to take its gas in kind without a market so a lot of valuation questions are without answers. The state will own a lot of gas that's cycling in Prudhoe Bay, and it will pay fuel costs on that gas. Whatever market the state eventually has will depend on the pipeline that's built. He relayed that when he was director of oil and gas he was very constrained and careful in royalty sales to follow a formal process that had Royalty Board blessing.

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SENATOR PASKVAN asked if taking gas in kind with no market would expose the state to storage costs.

MR. MYERS said he didn't believe so, but the state has the liability of owning the gas until it's sold, and it has field cost obligations that have yet to be negotiated.

SENATOR COGHILL asked if the gas could be significant to recovering oil at Prudhoe Bay.

MR. MYERS replied there certainly could be some gain, but the countervailing argument is that there are lots of ways to maintain pressure at Prudhoe Bay. He mentioned water flood, CO<sub>2</sub> injection, and increasing the cycling rate as alternative mechanisms.

SENATOR COGHILL commented on its value along the Richardson Highway corridor.

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MR. MYERS continued to highlight issues in the settlement. The deferral of taxes on the gas injected into Prudhoe Bay is an indication of how broad the settlement is. Also, there are a number of options under which contraction of the unit is not automatic if there is no drilling.

It is also highly unusual that there is no technical calculation or review to figure out how much oil and gas is being contributed from which lease. That allocation matters to the state and producer because each lease has a different royalty rate and lessees own different parts. The responsibility for approving that tract allocation belongs to DNR, but the agreement lets the producers make the call on at least the initial participating area. This relates to plans of producing, not to keeping the acreage.

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MR. MYERS questioned the validity term in the statement that says the DNR commissioner has determined that the terms of the agreement are necessary or advisable to protect the public interest. This means that DNR has determined that whatever way the producers decide to produce is in the best interest of the state. This disregards the fact that the different production mechanisms mean very different economics to the state.

SENATOR PASKVAN asked if that agreement has to be determined valid under the settlement.

MR. MYERS replied the agreement is already made, even though the three alternatives have very different outcomes to the state. Another questionable provision is that DNR will not oppose an application to the AOGCC to blow down the reservoir provided it is consistent with applicable state law and the settlement agreement, which says the highest and best use is to get a gasline.

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MR. MYERS described the definition of "major gas sale" as unusual and problematic, because 500 mcf/day is on the scale of a bullet gasline. It is nine times less than the proposed AGIA gasline and six times smaller than the proposed LNG projects. Given the gas reserves at Prudhoe Bay, there's sufficient gas for a 3 bcf line until 2040 and for a small line it's actually 2146. He questioned why the agreement is linked to Point Thomson contributing to a major gas sale, and why the state used the definition of such a small amount of gas relative to the scale of gas that's already available at Prudhoe Bay.

SENATOR PASKVAN, referring to an earlier point, asked if the settlement says that [DNR] wouldn't oppose [an application to] blow down the Point Thomson reservoir despite the loss of hundreds of millions of barrels of oil.

MR. MYERS affirmed that under the settlement DNR will not oppose an application to the AOGCC that is consistent with the agreement, which includes blow down, and follows state laws.

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SENATOR WIELECHOWSKI commented that DNR would say AOGCC is the backstop to protect the state.

MR. MYERS said the statutes and regulations say that both agencies have responsibilities that sometimes overlap, but DNR has a wider mandate and a much more critical role and authority for the development of the field in general. Because of the economic interest responsibility, DNR also has a much broader technical staff than the AOGCC. The AOGCC is a quasi-judicial agency that was created in this and other states as an independent party to equally protect the correlative rights of all parties, because DNR is conflicted as landowner. The AOGCC commissioners are appointed differently and have different responsibilities. For example, DNR has no more standing in front of the AOGCC than does ExxonMobil.

SENATOR WIELECHOWSKI drew an analogy between the court and the quasi-judicial AOGCC with regard to protecting interests, and observed that the settlement removes DNR from the role of protecting the state's interest.

MR. MYERS responded that the AOGCC protects the public interest the same way a court does, but that DNR has no more standing before the AOGCC than does a private individual or company. By comparison, the law provides a fair amount of deference to DNR in terms of its responsibility as a subsurface owner and regulator. The agencies also have different functions. DNR has a stronger environmental role with respect to land management and conservation, whereas the AOGCC has an important responsibility with down hole safety. He spoke of balancing the parties' correlative rights while still protecting the landowner.

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SENATOR COGHILL expressed interest in seeing where the agreement supersedes statutory authority. He also questioned whether removing gas from Point Thomson would blow down the reservoir or if it was a reasonable amount.

MR. MYERS said at 500 mcf/day there is absolutely no need for Point Thomson gas early on. At 3 bcf/day there would be need for more mitigation, but there wouldn't really be challenges until

4500 mcf/day. At that point it would be reasonable to take 1 bcf/day from [Point Thomson] and 3500 mcf/day from Prudhoe Bay. The old AOGCC rule allows 2 bcf/day from Prudhoe Bay, and the settlement draws the line at one-fourth of that so it shouldn't be a problem with the AOGCC.

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MR. MYERS displayed development options called Alternatives A, B, C, and D and opined that there may be many other allowable options because of the way the definitions and parts of the settlement work together.

Alternative A defines "sanction" of a major gas sale as any pipeline that has a volume greater than 500,000 mcf/day. It doesn't require building it or even connecting the pipeline to Point Thomson. A pipeline from Prudhoe Bay off the North Slope qualifies as a major gas sale.

Alternative B is a cycling project that only requires 20,000 or 30,000 barrels per day depending on the type of compression used in field. He said he believes the field is capable of much more than that based on the reservoir studies and the previous work done in 2001. He opined that this will result in the loss of oil because there won't necessarily be production for 50-60 years and because parts of the reservoir won't be reached. Full field cycling costs more money, but there isn't an option for that.

[Alternative C is a cycling project for enhanced Prudhoe Bay oil recovery and gas for in-state use.]

He said he believes that under Alternative D, if ExxonMobil spends \$2 billion they don't have to produce at all from Point Thomson and can keep most of the acreage. If at a later date they commit to study a cycling project or a major gas sale they can keep basically all the acreage. Abandonment appears to be permissible.

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MR. MYERS expressed surprise about the use of the terms "without appeal." The settlement talks about losing acreage without appeal, but paragraph 5.1.4 appears to allow appeal to the superior or supreme court. He commented that the language in the agreement appears to allow a tremendous amount of discretion.

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MR. MYERS provided the following summary points:

- None of the three development scenarios maximize economic oil and gas recovery. They all could, and if produced will lead to significant physical and economic waste of the resource.
- The settlement provides several pathways that require little or no actual production.
- The settlement removes DNR's authority to manage the field through normal development procedures.
- Some of the settlement terms indicate fewer wells than ExxonMobil seemed willing to drill previously.
- None of the contemplated gas pipelines will require gas from Point Thomson for decades and, depending on the size of the pipeline, it could be 120 years before it's needed. Under any of the scenarios for an LNG project, the earliest that Point Thomson gas would be needed is 2040, which means that there is plenty of time for full field cycling.
- The royalty in kind provisions are inexplicable, and there is no finding process.
- This is a major oil and gas decision of the decade, and it was made without much public process. Given the breadth of the issues and the normal use of public processes, it's surprising what is contained in the settlement agreement.
- Damages were an integral part of the 2001 expansion agreement. Monetary consequences at least compensate the state for lost time and effort. Under the settlement, the consequences and loss of acreages are either minimal or nonexistent.

MR. MYERS concluded that it really does matter how Point Thomson is produced, and the state ought to maintain a significant role in that determination rather than leaving it as an option for the producer under a settlement.

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CHAIR FRENCH asked if he would have signed the deal if he had been commissioner.

MR. MYERS said no, but he was not impugning the current commissioner.

SENATOR PASKVAN asked if he believes the Point Thomson settlement is in the best interest of the state of Alaska.

MR. MYERS said his stewardship belief is strong and he wants the oil to be developed in a way that would allow his kids to see the benefit of the state developing its resources to the maximum

benefit to the people. He acknowledged there is a counter argument, but he would have done more reservoir simulations, a full field economic model, and made a determination that the rate of return on the cycling project was reasonable. If it wasn't reasonable but there was economic value, he would have entertained options for royalty relief. He would also have sought development beyond what Commissioner Irwin secured under the lease agreement, and he would have looked for something more akin to the previous agreements.

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SENATOR WIELECHOWSKI asked for an estimate of what it would cost the state if ExxonMobil were to choose to blow down the reservoir as opposed to full field cycling.

MR. MYERS replied he didn't have a number, and then talked about what factors would go into the calculation.

SENATOR WIELECHOWSKI asked if the state could potentially lose \$12 billion.

MR. MYERS suggested that DNR or DOR might be able to do those calculations but the numbers are staggering in scale because of the size of the field and value of oil. He also mentioned the value of the alignment agreement and the value of the Brookian section, both of which could be significant.

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CHAIR FRENCH recessed the meeting.

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CHAIR FRENCH reconvened the meeting and recognized Craig Richards as the next presenter.

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CRAIG RICHARDS, Attorney, Anchorage, AK, said he represents Bill Walker in an appeal filed on April 17, 2012 that asked Commissioner Sullivan to reconsider his decision to enter into the Point Thomson settlement agreement.

CHAIR FRENCH asked when he first learned about the settlement agreement.

MR. RICHARDS replied he learned about it on March 30, 2012, when it was announced in a press conference held by the commissioner and governor.

CHAIR FRENCH asked if he had knowledge of the negotiations before that time.

MR. RICHARDS replied he saw suggestions in the news that the parties were working on a deal over the last year or so, and that there was a rush in late March to meet the deadline the governor set in his State of the State Address. He said he wasn't privy to any of the specifics.

CHAIR FRENCH asked what happened after the settlement was announced.

MR. RICHARDS said he and Mr. Walker read the agreement several times, and with each subsequent reading more red flags were raised. Mr. Walker ultimately decided that the deal had to be appealed. Because of the 20-day appeal deadline, Mr. Walker's appeal was about the last chance to keep the issue alive to create some public process.

MR. RICHARDS said he would focus on why he believes the settlement is illegal and how it exceeds the commissioner and attorney general's authority to enter into. He would address some of the specific terms of the deal in order to discuss concerns about its legality. He acknowledged that his reading of some or all of the provisions and their intent may be incorrect.

He stated that as an attorney he found the document to be confusing and difficult to understand, because it is complex and in many instances it is not clear on its face. For example, the recitals do not fully reflect the substance of the deal. In particular, Section 1.6 talks about the Initial Production System (IPS) that appears to commit to [produce approximately] 10,000 barrels per day [of condensate.] But subsequent readings make it clear that other paths provide that the unit can be maintained where no development occurs. He described the recitals as a rosy version of the agreement.

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CHAIR FRENCH asked if the settlement agreement trumps the operating language in the recitals.

MR. RICHARDS responded that the more specific will control the general in most instances.

CHAIR FRENCH asked if the normal expectation is that the recitals would conform to the agreement.

MR. RICHARDS said yes or you would expect to see them used differently. It's common for recitals to be a description of the background without a summary of the deal. In this case the recitals had both background and light summaries of what the deal contemplated. This isn't generally done because it causes conflict between the recital and the substance of the deal.

He said another concern with the drafting of the settlement document is lack clarity. For example, if ExxonMobil chooses to meet one option of work commitments with the 10,000 barrel per day project, a major point is whether or not they spend \$2 billion. If they spend \$2 billion they get to keep a portion of 22 leases no matter what, whereas if they spend less than \$2 billion they get less acreage. But the \$2 billion is defined as backdated to 2007, so it's unclear whether or not that threshold was already met. The spending commitment doesn't have accounting rules and is defined so broadly that previous work done on a major gasline or bullet line or Prudhoe Bay re-injection project could conceivably count toward that \$2 billion. Because of the lack of clarity he assumes that the \$2 billion threshold is met as a matter of course.

MR. RICHARDS said a final drafting concern relates to some of the definitions in the document. The largest concern is that the definition of a "major gas sale" is not the definition that is commonly understood and used in the industry in Alaska. The document defines a major gas sale as greater than 500 mcf/day, whereas the Prudhoe Bay operating agreement defines a major gas sale as 2 bcf/day. He described the change as a head scratcher.

He said the magnitude of the deal is sweeping in terms of what it attempts to do and the value of the resources. Point Thomson is one of the largest undeveloped oil and gas fields in the world and the leases are some of the most valuable undeveloped leases in North America, if not the world.

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MR. RICHARDS said he considered ExxonMobil's history of delaying development and decided to look for the paths through the agreement that allow the options to do the least. The first is to undertake the 10,000 barrel/day IPS Project that ExxonMobil agreed to in 2009 to maintain 2 leases. If they undertake that project and spend \$2 billion, they retain most of the unit. They will get an additional 20 leases for no additional work commitments in one of the richest oil and gas fields in the world. Because of that 10,000 barrels/day production, ExxonMobil

and the other WIOs will own the unit in perpetuity with virtually no additional work commitments.

The other path of least resistance option is to sanction a major gas sale. He said his reading of that is that there has to be a major gas sale of more than 500 mcf/day and there has to be sanctioning. Sanction is defined in the context of a major gas sale, but it's not a firm definition and doesn't have the requirements he would expect to see. For example, internal commitments have to be in place but it's not clear whether they can be revocable. Also, there is no clarity as to the timing of the commitments. He opined that the only part of the definition of "sanction" that has teeth is the federal permitting requirement. If they federally permit for a major gas sale, they've met the obligations with no work (without the 10,000 barrels/day) to maintain the unit through 2020 and restart the POD process back to 2005. Although the new POD process is less favorable to the state.

He said the last point is that there doesn't have to be production out of Point Thomson. A bullet line permitted to Prudhoe Bay with no connecting infrastructure between Prudhoe Bay and Point Thomson meets the requirements to maintain the unit and restarts the POD process through 2020. He noted that this was Mr. Myer's reading as well.

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MR. RICHARDS said this deal pre-commits the state to allowing the WIOs to choose between a number of options to develop the field in the future. The state has pre-committed itself to lease dispositions, field development terms, and royalty and tax commercial terms under various development scenarios. He said his personal opinion is that the agreement is inconsistent with Alaska law in a number of ways.

He said the first legal concern is lack of public notice and comment. Art. IIX, sec. 10 of the Alaska Constitution provides that the state may not dispose of leasehold interests without public notice and the opportunity to comment. The Alaska Supreme Court in the Baxley case indicated that DNR could renegotiate terms of oil and gas leases in confidence and still meet the public notice clause of the constitution, because of legislative approval after the fact. He opined that renegotiating lease terms and dispositions with no public comment or legislative approval is extremely problematic under Alaska law.

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MR. RICHARDS said what past deals with British Petroleum, ExxonMobil and Conoco Phillips have in common is the massive public process and grinding debate about what is in the state's best interests versus the producer's best interests. Then there is either administrative or legislative action to get to resolution. He cited the North Star leases and Baxley as examples and opined that it was the legislative approval that made the agreements legally binding on the state.

He expressed particular concern with the way this agreement was made public and the associated multi-year litigation dismissed. As far as he can tell based on the clerk's stamp and records filed with the clerk, this settlement agreement was entered into by the attorney general on March 28th and all the other parties by March 29th. It was filed with the superior court at 3:20 p.m. on March 29th and the settlement agreement was approved and the case dismissed by 4:30 p.m. that same day.

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CHAIR FRENCH asked if he was saying it was agreed to within 60 minutes of its filing.

MR. RICHARDS replied, "Based upon the stamp of the clerk it does appear that superior court Judge Brian Clark had this agreement before him for less than an hour, assuming he approved it by the close of business at 4:30. It's possible he approved it late ... but in less than a day and it looks like maybe less than an hour this was, in secret, brought to the court, all the cases dismissed, and the deal announced the next day." He questioned why the Point Thomson litigation would be dismissed before the public had an opportunity to review the settlement. He suggested the administration should answer that question.

MR. RICHARDS said the second legal concern is that there are established processes for the state pre-committing to waiving its right to take royalty in value and there are processes for disposing of royalty in kind. To forgo royalty in value for a long period of time for this large amount of gas and to so heavily encumber the royalty in kind rights it seems clear it would require Royalty Board and legislative approval.

CHAIR FRENCH asked him to remind the committee who the Royalty Board is.

MR. RICHARDS explained that it's a board that was specifically created to make sure that the state doesn't enter into a royalty contract without a form of public process.

He said the third legal concern is that this is a DNR agreement that encompasses tax issues yet the DOR commissioner has not signed the document. Another provision says that production from Point Thomson that is re-injected into Prudhoe Bay won't be assessed the ACES severance tax until it is produced out of Prudhoe Bay. It also provides in express terms that the state won't tax that gas twice. The issue is that Art. IX, sec. 1 of the Alaska Constitution prohibits contracting away the power to tax. He noted that in 2006 some cited that as the fundamental constitutional problem with the Stranded Gas Development Act. It contracted away the power to tax.

The fourth legal issue with the agreement is that DNR is forgoing its regulatory oversight function under 11 AAC 83.303. The settlement allows the WIOs to decide the future course of development for the field without public interest findings. He noted that the Walker appeal letter lists, on pages 11-13, some of the areas where regulatory authority was abrogated, and an alternative process put in place by contract.

He said the core concept is that before many unit actions can occur it's necessary to get the commissioner's stamp of approval, and for many of those things the need for the stamp is gone. From a legal perspective, that's probably one of the biggest problems the settlement agreement has, he said.

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MR. RICHARDS said ExxonMobil has long argued that the state by contract can change the department's regulatory obligations, but the Alaska Supreme Court disagreed. He read excerpts from the 2001 ExxonMobil case that said the department should never need to contract in violation of its own regulations because it has the authority to change its regulations so long as the new ones have a reasonable basis and are within the scope of the Legislature's delegation of powers to the department.

He said he doesn't understand, given the explicit instruction from the Alaska Supreme Court in the context of the unit regulations, how many of the provisions that pervade through the settlement agreement are legal.

MR. RICHARDS said the next area of legal concern relates to the provision in paragraph 4.9 that says that within 90 days of the effective date, the commissioner preapproves any changes in the WIO alignment. He said it appears to have the practical effect of preapproving the rumored but yet to be announced transfer of

Chevron's interest in Point Thomson. That's problematic for a number of reasons the first of which is that major realignments of lease sales within units have a public consequence and it's been held a number of times that department approval is necessary. He cited the resolution of BP's attempt to acquire Arco Alaska as an example of the concept that unit realignments have to be approved by the commissioner.

He questioned the authority of the commissioner to pre-agree without having seen the agreements and without having done best interest findings to ExxonMobil, Conoco Phillips, or BP's acquisition of Chevron, if that has in fact occurred.

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MR. RICHARDS said the last major legal concern is that this deal abrogates regulatory authority and probably exceeds the current legal authority of the commissioner so it needs to be approved by the Legislature. He cited the Baxley case and the Alaska Stranded Gas Development Act (ASGDA) as evidence. In Baxley the saving grace for the BP in-state deal was legislative approval and the process that went along with it. One chapter in the ASGDA contract was the maintenance of Point Thomson and while it didn't succeed there it appears that similar goals have been reached through this settlement agreement.

MR. RICHARDS reviewed the attorney general's April 26, 2012 that disagreed with his and Mr. Walker's interpretation of the settlement agreement. The attorney general said paragraph 5.8 of the agreement constitutes public interest findings and because it's a settlement agreement those public interest findings are not appealable. Mr. Richards said this agreement was negotiated and the court cases dismissed before the deal was made public. There are preapprovals and changes in regulations for a decade to come, and it appears that it is not appealable by the public. "As an Alaskan citizen, I am concerned about the lack of public process," he stated.

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SENATOR WIELECHOWSKI asked if the executive branch has the authority to agree to waive its statutory obligations in a settlement agreement.

MR. RICHARDS said he didn't believe so. He offered the caveat that his critique was not aimed at any one individual and that he was an outsider with no financial interest in the deal. His hope was to shine light on the process and outcome so that an inquiry would be done to determine whether or not the deal is

legal, and if it is legal whether it's in the best interest of Alaskans.

Recess from 3:34 p.m. to 3:39 p.m.

CHAIR FRENCH reconvened the meeting and introduced Attorney General Geraghty.

3:40:00 PM

MICHAEL C. GERAGHTY, Attorney General, Department of Law (DOL), said he appreciates the opportunity to comment on the previous testimony and would like to submit a more complete written response.

CHAIR FRENCH assured him that his written comments would be distributed to both the committee and the public.

ATTORNEY GENERAL GERAGHTY stated the following:

The authority of the attorney general to settle litigation involving the state is plenary. The Alaska Supreme Court addresses the issue in 1975. "Under the common law an attorney general is empowered to bring any action which he thinks necessary to protect the public interest, and he possesses the corollary power to make any disposition of the state's litigation which he thinks best. This discretionary control over the legal business of the state, both civil and criminal, includes the initiation, prosecution and disposition of cases. When an act is committed to executive discretion, the exercise of that discretion within constitutional bounds is not subject to the control or review of the courts. To interfere with that discretion would be a violation of the doctrine of separation of powers."

This view has been reiterated and applied in a number of cases and a number of attorney general opinions since 1975. Those opinions point out that depending on the circumstances, the decision to compromise or settle a case is often a collaborative effort with the affected executive branch agency. For example, in 1996 an opinion by the attorney general advised the then commissioner of revenue Wilson Condon about the compromise of taxes assessed against several operators at Prudhoe Bay. Among other things, the opinion noted that it is not "appropriate to articulate a static

standard of review for the attorney general to review of a department recommendation to compromise a tax assessment. Each individual compromise will vary in many salient factors, including the degree to which the compromise involves questions of law, policy, and fact. The effect on the public interest, including the dollar amount at issue and the effect on future tax collections and the level of analysis which the department has applied in arriving at its recommendation are all considerations. The presence or absence of these factors will determine whether the attorney general's review should be more independent or more deferential."

Later in that same opinion (opinion number 5 issued in 1996), it was noted that "As the current commissioner of revenue you are extraordinarily well versed in the legislative history or the statutes in question. It would be foolish to adhere to judicial notions of standards of review and independently review a matter which you possess special expertise merely because the matter could technically be classified as legal rather than policy. Because we are both members of the executive branch, I believe that I can choose to defer to you on this legal question without compromising my duty to protect the public interest."

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ATTORNEY GENERAL GERAGHTY stated that it was his opinion that the Point Thomson litigation was a major impediment to the commercialization of Alaska's natural gas. The settlement achieved things the state sought in the POD process like firm deadlines and commitments for the development of the Point Thomson unit (PTU) and consequences to the owner if those commitments aren't met. Many of the consequences upon breach are automatic and without any right of appeal. The settlement also lays to rest the argument advanced by the operators that development of the field is not economic without a major gasline. Acknowledging that many obstacles and issues remain, he opined that any progress would have been impossible until the issue of the ownership of the leases and the timely development of the unit was established.

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ATTORNEY GENERAL GERAGHTY disputed some of the statements made in previous testimony, the first of which was that someone else would have negotiated a better deal. Also, the negotiations were

not a secret. In fact, he was informed that Commissioner Sullivan briefed at least one committee. He also disagreed that the Baxley case and the ExxonMobil case apply. None of the facts support the claim of alleged violations of law and no other cases were cited in the request for reconsideration. A lot was said about unconstitutional disposal of state lands, but it was unclear what interest in lands was being referred to because the Point Thomson leases were sold 30 years ago. Mr. Myers did terminate the leases in 2005, but by hanging on ExxonMobil arguably never lost those leases. He maintained that there was no disposal of state lands. There were modifications to PODs and participating areas, but that does not require legislative approval. He said the foregoing points out some of the fundamental flaws in the previous analyses.

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ATTORNEY GENERAL GERAGHTY directed attention to the 2005 amended decision (tab 7), and highlighted the use of the terms "may" and "theoretically" in the explanation of the findings under "Promote the Prevention of Economic and Physical Waste." He said he would defer to the DNR representatives on some of the points, but he had difficulty reading Mr. Myers' findings with some of the sweeping statements and conclusions he was arriving at in his testimony today.

He read from the Walker appeal on page 10, paragraph 7 titled "Terms of Taxation on Injected Gas Are Established by Contract." He said it's silly to say that paragraph 4.16 of the settlement "attempts to establish terms of future taxation by contract." He urged the committee to consider everything else that was said today in the context of that comment because it's emblematic of the entire analysis.

ATTORNEY GENERAL GERAGHTY asked for the opportunity to submit more complete comments in writing.

CHAIR FRENCH said it was a fair request that would be honored.

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SENATOR PASKVAN said he had two basic questions. The first was why the state would agree to take royalty in kind rather than royalty in value. The second was why the agreement removes the DNR commissioner's ability to oppose any proposal before the AOGCC.

ATTORNEY GENERAL GERAGHTY said he would defer to the DNR representatives on the royalty in kind issue, and his

understanding regarding AOGCC is that DNR's right to protest is not forfeit if something is occurring that is inconsistent with state law.

SENATOR PASKVAN asked about the procedural posture of the case in light of the comment that there would be a remand one way or the other. His understanding was that the case was settled.

ATTORNEY GENERAL GERAGHTY replied he meant to say that if there was no settlement there would be a remand and the litigation cycle would go on for an undetermined period of time.

CHAIR FRENCH clarified for the listening public that there would be no remand; this case was settled.

ATTORNEY GENERAL GERAGHTY said his intention was to compare where the state would be if it hadn't settled, and to highlight that overwhelming uncertainty is a reason to settle a case. Each party negotiates the best deal possible.

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SENATOR PASKVAN asked why the agreement changes the customary definition of a "major gas sale" from 2 bcf/day to 500 mcf/day, and how that connects to Point Thomson.

ATTORNEY GENERAL GERAGHTY deferred to the DNR representatives.

SENATOR WIELECHOWSKI referred to the comment about briefings and relayed that his office contacted Commissioner Sullivan six times within a three month period to get a confidential briefing on Point Thomson, all to no avail. He asked if it was accurate that the settlement agreement was approved by the court within an hour of the filing. He also asked why the Legislature wasn't briefed given the high level of interest and promise of confidential briefings.

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ATTORNEY GENERAL GERAGHTY replied the dismissal of the case and the post settlement motions were handled by outside counsel, and he wasn't involved. He deferred to Commissioner Sullivan about the briefings beyond the fact that he did tell the committee that the negotiations were going on. He opined that it was with good reason that the framers of the constitution did not have the Legislature sign off on settlements. He said he respects the Legislature's oversight role, but he's never been a fan of trying to negotiate something in public.

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CHAIR FRENCH relayed that he received a letter from Commissioner Sullivan expressing deep regret at not being able to attend the hearing today. He said he knows that the commissioner is a passionate advocate of the Point Thomson settlement agreement and would like nothing more than to defend it before the committee.

SENATOR WIELECHOWSKI cited AS 38.06.055 and questioned why the state agreed to take its royalty in kind without approval by the Royalty Board and the Legislature.

ATTORNEY GENERAL GERAGHTY said there has been no delivery of royalty in kind gas, but he would defer to the DNR representatives for further comment.

SENATOR WIELECHOWSKI cited 11 AAC 83.303(a) and asked if giving development decisions to the WIOs and removing the ability of DNR to appeal to AOGCC adheres to that regulation.

ATTORNEY GENERAL GERAGHTY said yes; AOGCC has lost none of its authority to prevent waste from occurring and DNR has not given up the ability to participate if what is at issue is contrary to law. Mr. Myers' opinion in 2005 regarding the waste scenario was speculative.

SENATOR WIELECHOWSKI cited paragraph 5.7 of the settlement agreement and expressed hope that the AG's interpretation was that 11 AAC 83.303(a) does apply and DNR could oppose an application to the AOGCC if there was waste.

ATTORNEY GENERAL GERAGHTY said there are two qualifications to DNR not participating. One is that what is under consideration is consistent with the agreement, and the other is that it is consistent with applicable state law.

SENATOR WIELECHOWSKI expressed hope that all the parties agree with that interpretation.

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SENATOR COGHILL asked for confirmation that keeping the leases was dependent on completing the POD.

ATTORNEY GENERAL GERAGHTY deferred the question to the DNR representatives.

CHAIR FRENCH read excerpts of paragraph 5.1.4 on page 52 of the settlement agreement. He asked if he would agree that the state might be litigating whether or not \$2 billion had been spent or other factual matters relating to the development of the terms of the settlement agreement.

ATTORNEY GENERAL GERAGHTY said he would agree that some potential breaches of the agreement would allow either party to go to arbitration.

CHAIR FRENCH thanked him for appearing on short notice and recognized the DNR representatives.

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JOE BALASH, Deputy Commissioner, Department of Natural Resources (DNR), relayed that he was appearing in place of Commissioner Sullivan because of the slight possibility that an issue raised by Mr. Richards may be remanded to him by a judge. He explained that his role in the policy debate dates back to 2005 when he worked as legislative staff. In 2006 he transitioned into the governor's office as a member of the gas team, and in 2010 he moved into a decision-making position of as deputy commissioner of DNR.

He emphasized that he supported every decision leading up to the settlement and without reservation he supports the settlement as in the state's interest.

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JON KATCHEN, Inter-governmental Coordinator, Department of Natural Resources (DNR), stated that when he joined the Department of Law (DOL) in 2007 he was assigned to the Point Thomson matters of litigation. In 2010 he transferred with Commissioner Sullivan to DNR and continued to be involved in the settlement negotiations.

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MR. BALASH explained that he would use some of the slides from the PowerPoint presentation that Commissioner Sullivan delivered several weeks ago for illustrative purposes. He described the presentation format. First he would discuss the structure of the agreement, how it works and protects the state's interests. Next he would talk about the technical plan embedded within the agreement and how it will assist all parties in identifying the optimal path for development. Finally he would speak about the state's interests, why settlement of the litigation is in the

state's interest and why this settlement agreement in particular is in the state's interests.

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MR. BALASH stated that the overarching structure and fundamental premise embedded within the agreement is that this is the state's land the lessees are obligated to explore, develop and ultimately produce the field. If the field isn't put into production the state gets the land back. This is without appeal, even if they spend \$2 billion. The operators have to undertake certain activities to earn back portions of the leases and retain title.

He described the agreement as a series of commitments, timelines, and agreed-upon consequences for failure. These are clearly spelled out and various scenarios are identified within the agreement to make clear the understanding at the time the agreement was settled. The agreement has three basic stages through the end of this decade. The initial production phase runs from now until the end of 2015, and if there is no initial production system (IPS) or production or sanction of a major gas sale, everything returns to the state without appeal. The second stage, which occurs between 2016 and 2019, is the period during which the operator and the other WIOs will develop plans to put the field into further production. That timeframe includes a commitment to submit a POD and produce the Brookian oil in the unit. If there is no approved POD by 2018, that particular acreage returns to the state.

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MR. BALASH displayed a block map of the PTU and explained that the Brookian Unit is located in Area F. Mr. Katchen volunteered that the block map is Exhibit D in the settlement agreement.

CHAIR FRENCH asked for an explanation of the provision on page 18, paragraph 4.2.2.3 of the settlement agreement, and why year 2007 was selected.

If the WIOs Abandon the IPS Project and have incurred costs for Point Thomson Development during the period between year-end 2007 and year-end 2015 of \$2 billion or more, then only acreage listed in Area E and Area F on Exhibit C shall be released to the State Without Appeal at year-end 2015.

MR. BALASH said the intention is for there to be immediate consequences in year 2015 if the IPS is abandoned.

CHAIR FRENCH observed that the WIOs only lose Area E and Area F, not the entire unit.

MR. BALASH said that's correct, but if there is no additional work on the field or it's not put into production another way or if none of the other remedies are undertaken, the state gets it all back in 2019.

MR. KATCHEN said the decision was that they were entitled to earn some acreage for a temporary period but if the WIOs abandon the IPS Project, what the state will get back without appeal is at least Area E and Area F in 2015.

CHAIR FRENCH commented that the assumption is that they agree with DNR's definition of "abandoned the IPS Project" and the amount of money spent.

MR. KATCHEN responded that the state will get back Area E and Area F even if they spend \$2 billion. He said another point that both Mr. Myers and Mr. Richards raised is that they don't really lose acreage if a major gas sale is sanctioned in 2016, 2017 or 2018, but the language in paragraph 4.5.7 on page 29 of the agreement is unequivocal. Any acreage that contracts from the PTU under the abandonment provision shall not be recommitted to the PTU.

CHAIR FRENCH asked the meaning of "recommitted" in that context.

MR. KATCHEN replied it means the acreage is gone and there's no way to get it back into the unit. He disagreed with the characterization that the abandonment provision is illusory and that the acreage comes back with the sanction of a major gas sale.

SENATOR WIELECHOWSKI reviewed the consequences of abandonment provisions in paragraphs 4.2.2.1-4.2.2.3 that include the \$2 billion spending requirement. He asked how much the WIOs have spent to date.

MR. KATCHEN said the amount that's been mentioned publicly is about \$1 billion. Responding to Senator French's earlier question about why cost accounting for the \$2 billion threshold starts in 2007, he explained that's when the WIOs started work on the IPS Project.

SENATOR WIELECHOWSKI asked how he would define "have incurred costs."

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MR. KATCHEN replied DNR's understanding is that those are development costs at Point Thomson that are submitted to the other working interest owners of the field.

SENATOR WIELECHOWSKI asked if that definition was included in the settlement agreement.

MR. KATCHEN replied paragraph 4.2.2.4 has to be read together with the definition of Point Thomson development to understand what costs can be claimed for the \$2 billion expenditure.

MR. BALASH said year 2019 and beyond is the final or reckoning stage when DNR can begin to settle out the acreage that will contract out of the unit. At that point DNR will know what the WIOs have or have not done or committed to financially and contractually.

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MR. BALASH said the foundation of the settlement agreement is the initial production system (IPS), and the technical plan embedded within the agreement itself is essentially what was proposed in POD number 23 that was rejected in 2008 by then Commissioner Irwin. His primary concern was how he would know that the operator would actually drill the wells and put in the facilities and pipeline and start cycling 200 mcf/day and yield 10,000 barrels/day of condensate. He wasn't confident that would actually take place. He was also concerned about what would happen after the IPS was put into production because it wasn't clear that the size or method of cycling was going to be optimal. His assessment was that the IPS was the right technical approach to understanding the field and how it was going to perform. The AOGCC reservoir engineer commissioner, Cathy Forester, concurred with his assessment.

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MR. BALASH said that when Mr. Myers highlighted the work done in 2008 by PetroTel, he put the committee's attention on a study that did not take into account economic or physical constraints.

SENATOR PASKVAN asked Mr. Balash precisely what he means by "economic constraints" because he was concerned about the potential loss of the oil resource by an earlier as opposed to later blow down of the reservoir.

MR. BALASH said he was referring to the costs of drilling wells and installing facilities without year-around road access as well as the cash flows induced by the ultimate production and recovery of the hydrocarbons. He relayed that DNR was granted access to ExxonMobil's confidential data room subsequent to the 2008 study and that caused both DNR and PetroTel to change their conclusion about the loss of liquids.

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SENATOR PASKVAN questioned how economic constraints factor in the issue of putting oil at risk.

MR. BALASH said the operator and the working interest owners will have to satisfactorily demonstrate to both DNR and AOGCC that ultimate liquid recovery is not being wasted.

MR. BALASH said the settlement agreement clearly and directly addresses the two primary concerns Commissioner Irwin articulated when he rejected POD number 23. A binding contractual obligation for the WIOs to follow through on the IPS schedule is embedded as an exhibit within the agreement, and can be used in the event there is a disagreement as to whether or not the WIOs are pursuing the project diligently and expeditiously.

CHAIR FRENCH read the definition of IPS on page 8 of the agreement.

"Initial Production System" or "IPS" means the gas cycling facilities designed with capacity to produce and re-inject (cycle) 200 million cubic feet of gas per day utilizing reciprocal compression and with the objective of a minimum of 10,000 barrels per day of condensate for delivery into the Trans Alaska Pipeline System ("TAPS").

He asked if that would be the minimum the state could expect to get.

MR. BALASH said yes, but it's important to point out that while there is a very real expectation that 200 mcf/day will result in 10,000 barrels/day of condensate recovery, there is no guarantee and less recovery will not be a reason for declaring abandonment.

CHAIR FRENCH asked about the potential circumstance of recovering only 5,000 barrels/day of condensate.

MR. BALASH replied "that is going to tell us an awful lot about how the field can be recovered."

CHAIR FRENCH said that wasn't the question.

MR. KATCHEN added that nobody thinks the yield will be just 5,000 barrels/day and if it only produces that amount there will be serious questions about the viability of full field cycling. But technically if they produce 200 mcf/day of gas, they're in compliance with the agreement, he said.

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SENATOR PASKVAN mentioned an earlier description of the basin as a layered sandwich with water at the bottom. He asked if the agreement includes a requirement as to extraction points and if location might make a difference as to quantities of liquids that might be produced.

MR. KATCHEN said there is a requirement that they drill the two wells from the Central Pad, which is close to Area A. Later the contractual requirement is to drill the West Pad well, but there is no requirement to bring that production to the Central Pad. If there are problems with the two wells that are cycling the gas, DNR's understanding is that they will be supplemented by bringing Area B, the West Pad, into production.

There is no requirement as to specific locations to drill wells for additional production, and everyone agrees that the real focus is the Thomson Sands reservoir. As Mr. Myers testified, there are real questions about the oil rim and its productivity.

SENATOR WIELECHOWSKI read an excerpt from paragraph 4.16.1 on page 40 that exempts from taxation, gas that is injected at the time of its production. He asked if the current law is that gas is taxed when it's produced.

MR. BALASH explained that when gas is produced to the surface and moved to another area of the state and injected for purposes of enhanced oil recovery, it is not subject to production tax. He said the agreement in this provision is that the sky is blue, meaning that the current law will not be reinterpreted.

CHAIR FRENCH asked who would keep track if gas was pulled out of a lease that has a 20 percent royalty and injected into a lease that has a 12 percent royalty.

MR. BALASH said he'd talk about the royalty provisions shortly.

MR. KATCHEN added that ExxonMobil wanted it abundantly clear that this is the law and it will apply to the gas and DNR agreed, thus the sky is blue comment. He said the fear that the agreement contracts away the right to taxation is misplaced.

4:51:06 PM

MR. BALASH discussed how the settlement agreement satisfies the concerns with POD number 23. He said one of the more important provisions related to the IPS stage is that the WIOs may not rely on economic arguments for not pursuing the development of the IPS. He said this was a big "gulp" for the operator and the other WIOs because the costs will be significant on this development.

MR. KATCHEN directed attention to paragraph 4.2.1 on page 17 of the settlement agreement that in part says the "economics or costs of the IPS Project cannot be used as a rationale or justification for not completing the IPS Project." Mr. Myers talked about the operator backing away in 2000-2001 because of economics, but under this provision that is no longer an excuse.

4:53:06 PM

MR. BALASH explained that with the startup of the IPS the WIOs earn Area A and Area B on the PTU block map. Start-up is a defined term in the agreement and it means that hydrocarbons have to go into the pipeline and make their way to Pump Station One. Once there is production at Point Thomson the agreement spells out that the WIOs will commit to additional production under one of three alternatives.

MR. BALASH said Alternative A is the sanction of a major gas sale. That is defined in the agreement as a project that delivers more than 500 mcf/day of gas, but DNR believes it will lead to something much higher. He explained that 500 mcf/day was arrived at in the previous administration because it represented 100 percent more than the volume of gas that could be used in-state for power and to heat homes. The idea is to develop an export project to commercialize these resources, but a much greater volume than 500 mcf/day of gas will be needed to satisfy the demands of the three big companies.

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CHAIR FRENCH asked him to explain again, in the context of that last sentence, why the number is so low.

MR. BALASH replied it's because it's an agreement with the WIOs at Point Thomson who by themselves won't necessarily be the ones to sanction a pipeline. It might be the state that sanctions a pipeline and it was decided that 500 mcf/day is a threshold that goes beyond anything the state is doing for itself, as an export line.

CHAIR FRENCH commented that 500 mcf/day is half or one-fourth the volume needed to make it economically viable.

MR. BALASH agreed and added that DNR anticipates there will ultimately be a much larger project than that threshold.

[4:59:43 PM](#)

CHAIR FRENCH asked for assurance that the state doesn't pay for a bullet line that gets ExxonMobil off the dime on Point Thomson.

MR. BALASH said he finds it hard to believe that either this Legislature or this administration would be party to letting ExxonMobil and their WIOs off the hook in this agreement.

[5:01:14 PM](#)

MR. KATCHEN added that it misconstrues the agreement to say that the producers don't have to do anything once they sanction a major gas sale. The reality is that it is an express requirement to then submit a POD and develop the gas. He cited paragraph 10 of the unit agreement and paragraphs 4.6 and 4.6.1 of the settlement agreement as evidence.

[5:02:27 PM](#)

SENATOR WIELECHOWSKI expressed concern about giving ExxonMobil the alternative to meet their commitments by what appears to be a blow down of Point Thomson. He referenced slide 13 of the presentation that describes Alternative A.

MR. KATCHEN interjected that the development alternatives come after the IPS Project.

SENATOR WIELECHOWSKI questioned how it is that Point Thomson can be so critical to the gas pipeline when DNR agreed that ExxonMobil need only commit 500 million cubic feet/day to a gas pipeline. He also asked if the settlement agreement allows

ExxonMobil to meet its commitments by taking 500 million cubic feet/day of gas from Point Thomson and sending it in a small diameter line to Prudhoe Bay for injection.

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MR. BALASH said to do that the WIOs would have to demonstrate to DNR and the AOGCC that it would not waste liquids. If it happens that Point Thomson gas is moved to Prudhoe Bay and injected, it will be because the AOGCC ultimately determined that doing so would result in greater liquid recovery on balance. He reiterated that DNR retains the ability to appear before the AOGCC to oppose an application by the WIOs if it does not meet state law.

SENATOR WIELECHOWSKI asked if he agrees that under Alternative A, "major gas sale" could be defined as a small diameter pipeline from Point Thomson to Prudhoe Bay for the purpose of enhanced recovery of oil from Prudhoe Bay.

[5:06:25 PM](#)

MR. KATCHEN said no; that development plan is more like Alternative C. Alternative A is for a major gas sale off the North Slope.

SENATOR WIELECHOWSKI asked if the AOGCC has ever allowed a cross subsidization of one unit to another when it interpreted the waste provision and requirement to get the maximum benefit for the resource.

MR. BALASH said no, but DNR believes the AOGCC could take that into consideration.

MR. KATCHEN added that it raises the question of do you look at maximum recovery and benefit to the state from that individual field or from the North Slope as an integrated whole.

[5:08:11 PM](#)

CHAIR FRENCH said the committee expects to get supplemental testimony from DOL and because of time constraints DNR may elect to submit written testimony as well.

MR. BALASH described Alternative B - expanded liquid production into TAPS - as a "lip of the funnel" situation. It requires an additional 20,000 barrels/day (30,000 bpd total) of condensate recovery into TAPS. DNR believes that if the WIOs are going to undertake the effort and expense to put the additional 20,000 barrels/day into the pipeline, they'll go well beyond that

volume. Whether they'll go as far as 70,000 barrels/day is yet to be determined.

MR. BALASH discussed the important points of Alternative C - expanded liquid production into TAPS, enhanced Prudhoe Bay recovery, and gas for in-state use. He said the WIOs will have to demonstrate the merits of this alternative to both DNR and the AOGCC, including comprehensive information sharing with DNR. With regard to the questions about the state taking its royalty in kind rather than in value, he explained that if Point Thomson gas is used for enhanced oil recovery at Prudhoe Bay its value would be quite low. Rather than taking a very low value for the gas at that time, the agreement was for the state to take the gas in kind and retain the discretion to market that gas at its choosing. DNR believes this is a benefit because for the first time the state will be in a position to actively market a significant volume of North Slope gas in and around the Prudhoe Bay infrastructure.

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MR. KATCHEN added that it's ironic that this is being criticized as being like the ASGDA, because the agreement establishes that if there is a major gas sale the state may switch back and take the royalty in value. He cited paragraph 4.16.2.2(b) on page 43 as evidence. He said another critical element is that the gas will be available in 2019.

MR. BALASH said the commitment to Alternative C must take place by year 2019, but the movement of gas from Point Thomson to Prudhoe Bay will probably be a couple of years after that. The agreement also obligates the WIOs to approximate the volume of gas that would come over from Point Thomson if the state elects to market it.

MR. KATCHEN pointed out that subsection (iii) on page 46 says the state is not responsible for field costs for the RIK gas delivered to the PTU, which is contrary to what Mr. Myers said. Subsection (c)(i) on page 48 says the state may elect to take its royalty share in kind or in value after a major gas sale.

[5:20:01 PM](#)

SENATOR WIELECHOWSKI asked for further explanation because the last sentence on page 46 says the state will be responsible for field costs for Point Thomson gas produced after project start-up of a major gas sale.

MR. KATCHEN said that provision only triggers if and when there is a major gas sale.

SENATOR PASKVAN asked if the decision as to a small diameter pipeline or a large diameter pipeline will not be made until 2019.

MR. BALASH replied the decision on what project to sanction and the decision on development of an LNG project to tidewater could reasonably be made in late 2015.

SENATOR PASKVAN commented that anything the Legislature might do between now and year-end 2015 potentially impedes the decision under the settlement agreement for when a major gas sale would occur.

MR. BALASH said if anybody sanctions a major gas sale between now and 2019, the WIOs are required to produce a POD for the development of Point Thomson.

MR. KATCHEN added that if full field cycling is viable and concurrently there is sanction of a major gas sale, the WIOs can still do full field cycling. They aren't required to produce the gas. Also, the volume has to be more than 500 million cubic feet.

[5:24:26 PM](#)

SENATOR PASKVAN asked if a major gas sale off the North Slope, whether it's a small or large diameter pipeline, is a decision that will be made by the WIOs between late 2015 and 2019.

MR. BALASH replied it could be but it doesn't have to be.

SENATOR PASKVAN asked if the WIOs will make the decision.

MR. BALASH replied anybody can sanction a major gas sale, but it will depend on their ability to attract gas or customers to fill that pipeline.

[5:25:36 PM](#)

SENATOR PASKVAN asked if a decision tomorrow to build an in-state gas pipeline from Prudhoe Bay going south would conflict with this settlement agreement.

MR. BALASH replied the state could sanction a pipeline under the terms of this agreement, but he didn't believe it would do so

knowing it would obviate some of the obligations for fuller development under the agreement.

SENATOR PASKVAN said that means the decision to build a large or small diameter pipeline from the North Slope going south should not be made until the end of 2015 at the earliest, and probably between 2016 and 2019.

MR. BALASH said he expects the decision will be made after 2015 and his hope is that it will be private companies that make that decision. This agreement is to step toward working together in the mutual interest to commercialize the North Slope and realize the associated benefits.

SENATOR PASKVAN asked why under this agreement the pipeline would potentially be developed under the AGIA statutory framework.

MR. BALASH replied it's important for a number of reasons the first of which is that the pipeline has to operate in a way that is consistent with the state's interests.

SENATOR PASKVAN questioned why a major gas sale under the settlement agreement is defined as 500 mcf/day when the AGIA structure is so much larger.

MR. BALASH offered to meet to discuss the matter.

[5:30:37 PM](#)

CHAIR FRENCH said the major gas sale definition from the Prudhoe Bay Unit Operating Agreement implies a certain flow rate leaving the North Slope, whereas the definition in paragraph 2.16 on page 9 of the settlement agreement does not have a flow capacity requirement. He asked for an explanation.

MR. KATCHEN explained that once a major gas sale is sanctioned, the producers have the ability to choose the other development options. However, gas won't be flowing once the sanction happens.

CHAIR FRENCH asked him to submit the answer in writing.

[5:33:44 PM](#)

MR. BALASH discussed the choice to settle and whether or not the state's interests were satisfied. In 2006 the estimate to navigate the litigation was 3-5 years, but it didn't take into account an adverse decision by Judge Gleason in 2007. In 2010

she issued a decision that was devastating to the state's ability to manage its oil and gas fields. An important element of the settlement agreement was that the decision was vacated with prejudice. At the end of the litigation and assuming the leases were terminated, they would be leased to new operators. Optimistically, first production out of Point Thomson would be somewhere in 2025. Under the settlement agreement, first production will be in 2015. That ten years is critically important to the state and the overall development of the North Slope resource, he concluded.

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MR. KATCHEN concluded by saying he was troubled about the representations about the lack of public process because it was more than ample and both Mr. Walker and Mr. Richards submitted hundreds of pages of documents during the proceedings that all relate to this development.

[5:38:59 PM](#)

There being no further business to come before the committee, Chair French adjourned the meeting at 5:38 p.m.