ALASKA STATE LEGISLATURE
JOINT MEETING
HOUSE RULES STANDING COMMITTEE
SENATE SPECIAL COMMITTEE ON ENERGY
June 17, 2008
9:07 a.m.

MEMBERS PRESENT

HOUSE RULES

Representative John Coghill, Chair
Representative John Harris (AGIA Subcommittee, Chair)
Representative Anna Fairclough
Representative Craig Johnson
Representative Ralph Samuels (AGIA Subcommittee)
Representative Beth Kerttula (AGIA Subcommittee)
Representative David Guttenberg

SENATE SPECIAL COMMITTEE ON ENERGY

Senator Charlie Huggins, Chair
Senator Bert Stedman, Vice Chair
Senator Kim Elton
Senator Lyda Green
Senator Lyman Hoffman
Senator Lesil McGuire
Senator Donald Olson
Senator Gary Stevens
Senator Joe Thomas
Senator Bill Wielechowski
Senator Fred Dyson
Senator Thomas Wagoner

MEMBERS ABSENT

HOUSE RULES

All members present

SENATE SPECIAL COMMITTEE ON ENERGY

All members present

OTHER LEGISLATORS PRESENT

Representative Bob Buch
Representative Mike Chenault
Representative Mike Doogan
Representative Les Gara
Representative Carl Gatto
Representative Mike Hawker
Representative Lindsey Holmes
Representative Reggie Joule

Representative Mike Kelly
Representative Jay Ramras
Representative Bob Roses

Senator Gene Therriault

COMMITTEE CALENDAR

HOUSE BILL NO. 3001
"An Act approving issuance of a license by the commissioner of revenue and the commissioner of natural resources to TransCanada Alaska Company, LLC and Foothills Pipe Lines Ltd., jointly as licensee, under the Alaska Gasline Inducement Act; and providing for an effective date."

- HEARD AND HELD

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- HEARD AND HELD

BILL: HB3001
SHORT TITLE: APPROVING AGIA LICENSE
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

06/03/08	(H)	READ THE FIRST TIME - REFERRALS
06/03/08	(H)	RLS
06/03/08	(H)	WRITTEN FINDINGS & DETERMINATION
06/04/08	(H)	RLS AT 9:00 AM CAPITOL 120
06/04/08	(H)	Subcommittee Assigned
06/05/08	(H)	RLS AT 9:00 AM TERRY MILLER GYM
06/05/08	(H)	House Special Subcommittee on AGIA
06/06/08	(H)	RLS AT 10:00 AM TERRY MILLER GYM
06/06/08	(H)	House Special Subcommittee on AGIA
06/07/08	(H)	RLS AT 10:00 AM TERRY MILLER GYM
06/07/08	(H)	House Special Subcommittee on AGIA
06/08/08	(H)	RLS AT 1:00 PM TERRY MILLER GYM
06/08/08	(H)	House Special Subcommittee on AGIA
06/09/08	(H)	RLS AT 10:00 AM TERRY MILLER GYM
06/09/08	(H)	House Special Subcommittee on AGIA
06/10/08	(H)	RLS AT 10:00 AM TERRY MILLER GYM
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06/12/08	(H)	House Special Subcommittee on AGIA
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06/13/08	(H)	House Special Subcommittee on AGIA
06/14/08	(H)	RLS AT 10:00 AM FBX CARLSON CENTER
06/14/08	(H)	House Special Subcommittee on AGIA
06/16/08	(H)	RLS AT 9:00 AM ANCHORAGE

06/16/08	(H)	House Special Subcommittee on AGIA
06/17/08	(H)	RLS AT 9:00 AM ANCHORAGE

BILL: SB3001
SHORT TITLE: APPROVING AGIA LICENSE
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

06/03/08	(S)	READ THE FIRST TIME - REFERRALS
06/03/08	(S)	ENR
06/03/08	(S)	REPORT ON FINDINGS AND DETERMINATION
06/04/08	(S)	ENR AT 10:00 AM TERRY MILLER GYM
06/04/08	(S)	Heard & Held
06/04/08	(S)	MINUTE(ENR)
06/05/08	(S)	ENR AT 9:00 AM TERRY MILLER GYM
06/05/08	(S)	Heard & Held
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06/16/08	(S)	ENR AT 9:00 AM ANCHORAGE
06/16/08	(S)	Heard & Held
06/16/08	(S)	MINUTE(ENR)
06/17/08	(S)	ENR AT 9:00 AM ANCHORAGE

WITNESS REGISTER

Julie Houle, Chief, Resource Evaluation Section, Division of Oil and Gas, Department of Natural Resources; Steve Moothart, Petroleum Geologist, Division of Oil and Gas, Department of Natural Resources; Anil Chopra, President and CEO, PetroTel Inc.; Nan Thomson, Petroleum Manager, Division of Oil and Gas, Department of Natural Resources; Craig

Haymes, Alaska Production Manager, Exxon Mobil; John Zager, General Manager, Chevron North America Exploration & Production; Vince LeMieux, Manager, Alaska New Ventures, Chevron; Cathy Foerster, Commissioner, Alaska Oil and Gas Conservation Commission (AOGCC).

ACTION NARRATIVE

CALL TO ORDER

SENATOR CHARLIE HUGGINS called the joint meeting of the House Rules Standing Committee and the Senate Special Committee on Energy to order at 9:07:18 AM.

HB 3001-APPROVING AGIA LICENSE
SB 3001-APPROVING AGIA LICENSE

NAN THOMSON, PETROLEUM MANAGER, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES (DNR), introduced staff.

JULIE HOULE, CHIEF, RESOURCE EVALUATION SECTION, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, gave a brief history of the Resource Evaluation section, which provides technical support for the Division of Oil and Gas and Alaska Oil and Gas Conservation Commission (AOGCC). The resource section provides technical development to assure the state receives its fair share of the resource. The resource section completed an in-house geological simulation on Point Thomson prior to contracting with PetroTel Inc. for a reservoir engineering study.

9:10:53 AM

MS. HOULE explained that the term “hydrocarbon” encompasses oil, gas and condensates. Point Thomson has all three phases in its potential reserves.

9:11:58 AM

STEVE MOOTHART, PETROLEUM GEOLOGIST, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, introduced himself and thanked legislators for the opportunity to present his study of the Point Thomson field and reservoir. He previewed that his talk would include information about the scope of the project, answer technical questions proposed, and discuss results of geologic modeling. He said that Dr. Anil Chopra would explain the written findings of the study and give a more detailed presentation of the computer simulations that were conducted.

MR. MOOTHART reported that the study was initiated in the spring of 2007. He stated that his department wanted PetroTel to do an independent engineering and geologic

assessment of the Point Thomson reservoir. PetroTel is recognized as an industry leader in reservoir characterization, oil and gas simulation, enhanced oil recovery and exploration and recovery technologies. He reported that the objectives of the study were two-fold. The first objective used data available to the division to determine in-place volumes of oil, gas and gas condensates. The construction of three dimensional computer models enabled better understanding of reservoir properties and in-place volumes. These volumes have generally been referred to as reserves, which are recoverable to the surface and available for sale. He explained that the volumes of hydrocarbons, which are technically recoverable, are dependent on several factors: quality of reservoir rock, type and properties of hydrocarbons contained in the reservoir, and recovery method.

MR. MOOTHART shared that the second objective of the study was to analyze the potential recoverable reserves and impacts that different variables would have on those recoveries.

9:17:44 AM

MR. MOOTHART reported that once the geologic models have been constructed and populated, the information can be imported into a reservoir simulator and be analyzed under different scenarios employing the dynamic properties of reservoir pressures, flow rates, and ultimate recoverable hydrocarbons. This information can be analyzed throughout time and under different off-take scenarios. The ultimate goal using the best geologic representation of the reservoir available would be to input that information into a reservoir simulator to determine the range and potential impact that various recovery methods and different off-take scenarios could have on the ultimate recoverable reserves within the Point Thomson reservoir. There have been discussions about potential differences in hydrocarbon recovery methods such as gas blowdown or gas cycling. He stated that these are put out there without much understanding of the actual potential differences in hydrocarbon recoveries that would happen under various scenarios. He submitted that this was the first independent study.

9:20:23 AM

REPRESENTATIVE SAMUELS inquired whether the state has the same access to information that the lease holders have.

MS. HOULE explained that the state gets information from AOGCC and through the operators when applying for units. She said she gets lots of confidential information in that manner. The other way the state gets information is from the

permitting for seismic shoots. She emphasized that a lot of the oil companies' analyses is based on the state's raw data.

9:22:19 AM

MR. MOOTHART reiterated that this is the first study to quantify those impacts. He stressed that the study did not attempt to design or determine the best comprehensive economic development plan for the area. He noted that the study focused on the Point Thomson sand reservoir and not on the hydrocarbon resources in the underlying and overlying strata. The majority of the resource lies in the Point Thomson reservoir. He mentioned that the reservoir is generally perceived as a gas reservoir, but within the industry it is recognized as a high pressure retrograde condensate reservoir. The reservoir conditions manifest at the surface, as oil is held as a gas or vapor within the reservoir. Development for maximum recovery requires engineering and operating methods that are significantly different from most crude oil or dry gas reservoirs. He relayed that Dr. Chopra will give more details about this distinction.

9:26:17 AM

REPRESENTATIVE GATTO thought that the information just presented about liquids and gases was contradictory to what he had learned in school, that when you pressurize a gas it becomes a liquid.

MR. MOOTHART acknowledged that the issue is confusing. He explained that in addition to the gas and condensate, the reservoir is also known to contain a relatively thin oil rim that exists between the overlying gas cap and the underlying water aquifer. He noted that long term definitive tests of the oil rim are lacking. In a 1977, 18-hour test across this zone in Point Thomson number 1 well, flow rates revealed 2300 barrels of oil per day of over 18 degree gravity oil. Uncertainty still exists in the depths of the actual fluid contacts and a lot is unknown about the oil rim. As a result, a range of uncertainty exists in the thickness of the reservoir that is available to contain oil within the rim, resulting in a broader range of potential volumes contained in the rim. He reported that the wells drilled to date in the Point Thomson reservoir have not adequately delineated the oil rim at this time and additional wells are needed to specifically target and test the interval. This is needed to both determine oil volume within the oil rim and the ultimate producibility of the resource. He reported that uncertainty is one of the reasons why eleven different three dimensional models were constructed for the study.

MR. MOOTHART explained that the depths of fluid contact were varied in the different models to capture the range of uncertainty. Reservoir properties were also varied to account for the uncertainty in the distribution of those properties between the existing wells. From the eleven models that were constructed, the original in-place hydrocarbon volumes that were determined to exist in the reservoir ranged as such: gas volume in place ranged from about 8.5 to over 10 trillion standard cubic feet; and associated condensate, liquid hydrocarbons that are entrained in the gas, were roughly 500-600 standard stock tank barrels in place. He went on to define a stock tank barrel as 42 gallons. He emphasized that a stock tank barrel is 42 gallons at surface conditions, not at reservoir conditions. There are estimates of 600 to 950 million stock tank barrels in oil rim, which is a broad estimate due to uncertainties. He summarized that ultimately Point Thomson is the largest yet undeveloped oil field in Alaska. He noted that these volumes do not reflect the resource that has been tested in the underlying Pre-Mississippian strata or the overlying shallower Brookian in this area.

MR. MOOTHART observed that Dr. Anil Chopra would discuss the reservoir simulation portion of the study and potential recovery reserves from the various recovery methods that were studied.

9:32:23 AM

REPRESENTATIVE FAIRCLOUGH observed that the Commission agreed with the assessment that Point Thomson is the largest undeveloped oil field and asserted that the highest and best value for production of that field is going to be oil first and not gas. She inquired as to the timeline for extracting the oil, versus having access to the gas.

MR. MOOTHART indicated that Dr. Anil Chopra would respond to the question.

MS. HOULE interjected that it depends upon how much oil versus gas is taken out, and noted that there is a trade off between oil and gas recovery including how much you want to cycle gas.

9:34:47 AM

REPRESENTATIVE COGHILL asked for clarification regarding assumptions from the number of wells compared to the size of the unit to help understand the modeling, whether it was 2 wells, 10 wells, or 100 wells.

MS. HOULE clarified that Dr. Chopra would provide more detail.

REPRESENTATIVE COGHILL observed that the scenarios become confusing when it is not clear whether empirical data or supposed data is being used. He wanted a clear picture in order to determine if the field was properly modeled. He wanted to know with confidence that the pipeline would be doable with or without [the Point Thomson gas].

9:36:46 AM

ANIL CHOPRA, PRESIDENT AND CEO, PETROTEL INC., distributed handouts and referred to slides of the Point Thomson field (Copy on File.) The field has, in broad terms, 20 Bcf (billion cubic feet) of gas. He explained that Bcf refers to standard cubic feet in standard conditions and is the unit of gas in which gas is traded or sold, and is equivalent to about 2 billion barrels of stock tank barrels. A stock tank barrel is a standard condition of barrels that is 50 degrees Fahrenheit, 14.7 psi where oil is measured in gallons.

DR. CHOPRA explained that there is good porosity overall for the reservoir with an overall average of 14 percent. He related that the reservoir has three dome-like structures with a fairly large reservoir, over 72,000 acres within the boundary. There is a gas cap with varying composition and an oil rim. He reiterated that the gas cap is called a retrograde gas condensate and referred to Representative Gatto's question regarding an increase in pressure resulting in the gas becoming more like a liquid. He stated that that is exactly what happens. At high pressures gas and liquids look alike, so it is a single phase in the reservoir. However, when the pressure is dropped, gas becomes more gas like and liquid stays like liquid, and the liquid drops out in the reservoir. This accounts for the two phases and separation of liquid in the reservoir when pressure drops. He pointed to the slide showing the Point Thompson simulation model and defined SG as gas saturation. There is a thin oil rim in a doughnut shape around the reservoir. This is a large area, almost 15,000 acres, with a significant amount of oil in the rim.

9:39:50 AM

DR. CHOPRA said the gravity is low at an api gravity of 18. He stated that those were the numbers used in the simulation models. This gives an idea about the pressure. The reservoir is around 12,500 feet on average. If the reservoir were normally pressured, it would be considerably lower. He pointed out that the reservoir pressure is on average 10,000 psi, making it a very high pressure reservoir. This makes it great for production because it provides excellent support to produce all of the gas and oil in the reservoir.

9:41:04 AM

DR. CHOPRA explained that about 70 different scenarios or simulations were conducted. The simulations varied the production of the reservoir from about six wells with primary depletion in the gas cap in the mini case to 22 producers in the oil rim, 14 producers in the gas cap and additional 12 injectors in the gas cap. There were quite a few variations over these 70 scenarios with a number of wells. He commented that it is very cheap to drill wells in simulations and study different scenarios; the beauty of reservoir engineering is the ability to plan ahead to see what kind of recoveries can be expected, what kind of rates can be expected as a function of time, and the optimal time to produce oil and/or gas. He stated that the scenarios were designed to look at well configurations, operating constraints of a high pressure reservoir, and the bottom hole pressure constraints of the producers as well as the number of wells. He observed that Point Thomson is 10 Bcf and 2 billion more or less oil. The central question of the study is how many wells, over how many years, it would take for production. The impact variables were evaluated on ultimate recovery. Methods were studied without physical constraints such as location, well size, or facilities, which were beyond the scope of the study. The study focused on rates and recoveries.

9:43:01 AM

REPRESENTATIVE GATTO questioned whether 2 billion barrels of oil, as cited by Dr. Chopra, was correct and referred to previous testimony that suggested there was 500 million barrels of oil.

DR. CHOPRA responded that he had been rounding up to get 2 billion and answered that the number is gross including condensate of the gas cap, plus the oil rim, plus other oil here and there. He continued that the number is closer to 1.5 billion and not 500 million.

9:43:47 AM

SENATOR HUGGINS questioned the age and reliability of the studies and data used for the modeling.

MS. HOULE explained that publicly available, in-house data was used from wells that have been drilled. Modeling was used since there is not enough drilling information pertaining to the Point Thomson reservoir to delineate the oil rim, the gas cap and the condensate. Given this fact, the department's data set was used in the PetroTel study.

9:45:28 AM

SENATOR HUGGINS questioned the reliability of the data was used for the modeling and asked for the well dates.

MS. HOULE replied that the department did the best technical evaluation possible with the data available.

MS. THOMPSON clarified that the last well in the unit was drilled in 1982. The earliest wells were drilled in the 1970s. She emphasized that the modeling project was done with the data they had available and acknowledged that it was imperfect and limited due to the number of wells that have been drilled in the area.

SENATOR HUGGINS summarized that the data is old and questioned if PetroTel Inc. attempted to update the data.

9:47:23 AM

DR. CHOPRA clarified that DNR data was used. His company looked at the quality of the data and accepted what they felt was reasonable and rejected what they felt was not. He reported that the fluid composition data was very good and reliable, with many samples taken with different condensate rates and condensate ratios. The porosity data was also very reasonable. He concluded that a large field with so few wells gives the 8-10 uncertainty that Mr. Moothart has suggested.

9:48:10 AM

REPRESENTATIVE SAMUELS questioned how much of the in-place gas would be recoverable.

DR. CHOPRA explained that the 70 scenarios were studied to look at how much gas and oil could be recovered over various time periods. The study looked at the number of wells it would take and the best recovery mechanism. For example, the study looked at whether the best recovery method was blowdown, gas cycling or an enhanced oil recovery process (EOR). PetroTel is a leader in EOR and the study examined if it would be possible to get both oil and gas at the same time. This was the purpose of running 70 simulations. The simulations were run on very high speed work stations with multiple central processing units. With today's technology it is very feasible to do these simulations quickly.

DR. CHOPRA discussed the simplest case first. He explained that to produce a gas reservoir you punch holes, start producing gas, and deplete the reservoir. As the reservoir is depleted the pressure drops down, the rates drop down and the reservoir runs out of life in 15-25 years. The first scenario concerns primary depletion. If 22 wells are operated over 12 to 15 years, 70 percent of the gas would be produced. If only six wells were drilled it would take 50 to 60 years to deplete the reservoir. Fewer wells result in a longer reservoir life, with a lower recovery rate. A larger

number of wells would produce the gas quicker. In the primary depletion case, as gas is produced the pressure falls and the liquid drops in the reservoir. As a result, gas condensate recovery is approximately 26 percent (74 percent of the condensate is lost). This phenomenon is very well known in the industry; when pressure drops below the dew point, condensate is left behind. He concluded that pressure maintenance is required to increase condensate recovery. Three adverse things happen during primary depletion of a gas condensate reservoir. One, gas condensate is left behind. Second, wells have a condensate bank, liquid sitting around, which hurts the productivity of the wells. This can result in a drop of productivity of up to ten fold. For example, if a gas well is producing 100 million a day, when the condensate drops out it may drop to 10 million per day.

DR. CHOPRA explained the difficulty of bringing the pressure up and the condensate back into the gas cap once the condensate drops out. The second scenario is a scheme that does not allow the pressure to drop below the dew point and cycles gas for a number of years, which recognizes that a blowdown is always possible after the liquids have been produced. During all of the gas cycling cases, gas pressure is maintained until all recoverable condensate and oil are produced. It is hard to produce the thin oil rim during primary depletion in the blowdown phase once the reservoir pressure drops. He reiterated that any oil in the rim requires pressure to be produced, but once the pressure has been dropped the thin oil rim will lose the pressure support and will not be able to be produced.

9:52:43 AM

REPRESENTATIVE ROSES questioned whether the statement "maintain reservoir pressure until all economically recoverable condensates are produced" contradicts slide 7, last item: "no physical constraints such as location of surface drill sites and facilities or drilling departures were modeled". He questioned how economic recoverability could be determined if there was no consideration for constraints, no risk application and nothing about economics or costs.

9:53:44 AM

DR. CHOPRA asked him to wait two more slides for the explanation. He noted that gas cycling was applied in the gas cap in conjunction with development of gas injection in the oil-rim. The study looked at a case of gas cycling for 20 years where the condensate recovery was increased from 25 to 76 percent. He concluded that gas cycling and maintained reservoir pressure enables 76 percent of the condensate to be recovered in the gas cap. Pressure in the reservoir

allows recovery of 43 percent of the oil rim and maximizes oil production. He added that gas can always be produced after the oil has been recovered.

The study also looked at the gas cycle for 10 years. This resulted in recoveries of 62 percent condensate and 39 percent oil rim. Subsequent blowdown of the gas cap after 10 to 20 years recovers almost 56 to 57 percent of the original gas in place in this particular gas cycling scenario.

9:55:02 AM

DR. CHOPRA discussed oil development. The oil rim as seen in the database is not very well defined. They tested oil production at 2,300 barrels per day at 18 degrees API. Prudhoe Bay oil is 27 degrees API and Kuparak oil is 23 degrees API. Once gas cycling is started and that gas is mixed with 18 API oil, it can lighten up the oil, and decrease viscosity and the swelling effect. Experience has shown that this oil production would require horizontal well technology. This technology, which is now common worldwide, was not available 20 years ago. He reported that long horizontal wells in the oil rim are necessary because without them the gas starts coning into the oil rim, resulting in the oil wells very quickly gassing out making it impossible to produce that oil.

DR. CHOPRA stated that if the horizontal wells are placed in the oil rim parallel to the gas/oil contact the wells can produce for a very long time. Gas injection in the oil rim also helps to reduce viscosity and should be considered in this reservoir. Carbon dioxide injection can expand the oil. Point Thomson will be an excellent place to sequester, store and recover oil if Prudhoe gas with 15 percent carbon dioxide content is available. Use of off-site gas from nearby fields can be injected to maintain the pressure (see Slide 10).

9:56:56 AM

SENATOR HUGGINS asked if it is accurate to describe the development of Point Thomson reservoir as necessitating state of the art technology and drilling capability that was not available some years ago.

9:57:41 AM

DR. CHOPRA agreed that Prudhoe Bay took state of the art technology to develop thirty years ago. He stated that horizontal wells like Prudhoe Bay were being drilled about 18 years ago.

9:57:57 AM

SENATOR HUGGINS concluded that Point Thomson as a reservoir is very complicated with uncertainty and risks. He wanted to know if techniques to develop Point Thomson have only emerged recently.

DR. CHOPRA responded that the main difference with Point Thomson is the high pressure. He felt development would depend upon how comfortable an operator would be working with this high pressure.

SENATOR HUGGINS asked if it was common in different well sites around the world to have pressure of 10,000 psi or is this unique.

DR. CHOPRA replied that there is a very large field in Kazakhstan called Kashagan with pressure of 10,200 psi that is very much like Point Thomson. The field has a content of 15 to 35 percent. The field will produce gas and do gas cycling with high pressure gas injection using compressors made by General Electric. He observed that the project is currently being implemented and production will begin in a couple of years.

REPRESENTATIVE SAMUELS queried the number of worldwide fields with a 10,000 psi that are producing or being developed.

DR. CHOPRA replied that there are at least ten high pressure fields around the world. There is one reservoir in the Gulf of Mexico with high pressure and high temperature and another field with pressure of 16,000 psi. There are high pressure fields being produced. Pressure provides energy so less wells are needed, thereby increasing producibility. The key issue when there is high pressure is gas cycling and the ability to get the compression necessary to cycle gas. He stated that in his opinion General Electric has the technology to do that.

SENATOR STEDMAN asked if there were any of these high pressure reservoirs located in the Arctic or Subarctic or if they were all in warmer climates.

DR. CHOPRA responded that the field in Kazakhstan has temperatures ranging from -40 degrees to very hot conditions.

REPRESENTATIVE SAMUELS asked if the carbon dioxide in Prudhoe Bay is needed for recovery or pressurization or if it was a waste.

DR. CHOPRA responded that Prudhoe has been undergoing gas cycling for over 30 years and injecting 7.5 Bcf of dry gas back into the reservoir. Prudhoe has been using an enhanced oil recovery process for almost 25 years, taking a solvent

and injecting in the oil rim for production. As a result, the utility of Prudhoe would be potentially less. He observed that Point Thomson is a virgin reservoir with the oil rim.

10:02:55 AM

REPRESENTATIVE GATTO stated that Point Thomson is a very high pressure reservoir and if high pressure is a problem, it would not take much to lower the pressure. He asked if it is more desirable to work with lower or higher pressure, and if there were an ideal pressure.

DR. CHOPRA answered that from a recovery point of view pressure is good for every reservoir, but from an operational point of view people may say that high pressure is not good. The study looked at a scenario in which the pressure was dropped to 8,000 psi with gas cycling, which gave lower recoveries that were still much higher than blowdown. He suggested high pressure should be used where resources are available. Decompressors will go up to 19,000 psi, but may be cheaper at 10,000 psi. He emphasized that it is then an economic decision to increase the pressure and maximize recovery.

REPRESENTATIVE GATTO inquired about the benefit of bringing some of this high pressure into Prudhoe Bay. He wondered if it could be used for a gas line.

DR. CHOPRA said that pressure has been maintained for a very long time in Prudhoe Bay. In fact, 7.5 tscf per day has been used to maintain pressure and water has been injected in the periphery as a solvent. Pressure is always good, but in the late mature state of well life it becomes an economic decision.

SENATOR WIELECHOWSKI clarified that gas is needed in the field to produce the oil and condensates. He asked if it would be possible to pull off a portion of the gas now or in the future when the gas pipeline is on line, while oil and gas condensates are being pulled or if it is necessary to wait until all the oil and condensates are gone.

DR. CHOPRA stated that Slide 11 would answer this question. He continued by saying that in the primary depletion potential oil rim recoveries ranged from 3 to 16 percent and that gas cycling could recover 45 percent of the oil rim. He qualified that the oil rim volume and potential ultimate recovery and delineation of the oil-rim during gas cycling will determine the scale of development.

DR. CHOPRA referred to Slide 11 to answer Senator Wielechowski's question. He said that by looking at a scenario in which pressure is maintained, using 22

horizontal wells producing almost 160,000 barrels of oil per day, there would be a gradual decline over the next 15 years until the rate drops down to approximately 25,000 barrels per day. He noted that the cumulative oil production line on the graph shows a plateau, which is why the term economically desirable is used. He said that it is preferable to produce oil when going up that slope, as the more gas is being injected and producing oil. He added that the graph shows a slope change, which means the incremental value for continuing becomes less and less because much of the oil has already been produced. Optimization theory asserts that it is time to start producing the gas cap after 15 years when most of the condensate has been recovered.

10:08:05 AM

DR. CHOPRA restated that the earlier Point Thomson is developed, the earlier the gas will be available for the pipeline. In this case, if Point Thomson were started today, it would be available in 15 years. The gas would be available for production if the pipeline plan takes 10 years to get ready, and another five years after it gets commissioned.

SENATOR WIELECHOWSKI asked how closely this tracks Exxon's twenty third plan of development (POD).

DR. CHOPRA answered that he had not looked at that POD.

SENATOR WIELECHOWSKI responded that Exxon wanted to extract 10,000 barrels of condensate per day.

DR. CHOPRA pointed out where 10,000 would be on the graph (Slide 11).

MR. MOOTHART pointed out that the graph shows both condensate and oil rim development. "It's from the model and it's a full scale development of those resources." He reiterated that there are twenty-two horizontal wells in the oil rim.

DR. CHOPRA said that one case was run (see handout) with about five or six wells that produced 10,000 barrels per day of condensate.

SENATOR WIELECHOWSKI asked if this is the optimal Point Thomson production schedule for Alaska.

MS. HOULE responded that the analysis is only as good as the data and the data set is incomplete. As Nan Thompson pointed out, the last well was drilled in the early 1980s. The model is based on the information available.

10:11:11 AM

SENATOR WIELECHOWSKI questioned, based on Exxon's unit development, a decision could be made that will determine what is good or bad for the state. He queried how the decision can be made if the data is unknown.

MS. THOMPSON opined that that decision is not before the legislature today. She said that was the subject of Commissioner Irwin's decision on remand that was issued April 22. She specified that she was not trying to be evasive and suggested that there was a detailed analysis by the commissioner based on the existing information of the proposed plan of development. She offered to provide the page numbers if needed. She disclosed that the attorney general advised that there should not be a reiteration or further discussion of what was said in the decision due to pending litigation.

SENATOR WIELECHOWSKI replied that he was trying to figure out whether the twenty-third POD is in the best interest of the state. He understood Ms. Thompson's inability to comment. He understood the plan to say that 10,000 barrels of condensate a day would be produced. He thought the graph showed more production than proposed by Exxon.

MS. THOMPSON pointed out that Commissioner Irwin did not approve the twenty-third plan since it was not in the best interest of the state, which is the topic of litigation. Her comments were meant to convey that without further, more detailed information about the reservoir, which is not available because wells have not been drilled for many years, it is difficult for anybody to come up with the optimal recovery plan. She concluded that within that twenty-third recovery plan there was considerably less production than demonstrated on the graph.

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DR. CHOPRA reiterated that the reservoir has a big gas cap with condensate. Most of the uncertainty is in the oil rim, but the gas cap alone has 490-600 million barrels of condensate. He suggested that the focus should be on that certainty, which is pretty high because all the wells tested have produced condensate, all the logs have shown gas up and down, and all the wells have produced gas. That can be interpreted to mean that even with gas cycling for the gas cap, a lot more condensate can be produced. There is also one scenario in which just the condensate is produced without oil rim development with rates close to 100,000 barrels per day for some years.

SENATOR HUGGINS queried Dr. Chopra's confidence level and asked him to provide a benchmark.

DR. CHOPRA responded that the fluid data for condensate looks pretty reasonable and everything ties together. Dry gas cycling is an obvious choice getting fairly good rates since there are 600 million barrels of condensate in the gas cap.

SENATOR HUGGINS suggested a confidence level above 50 percent for and asked whether Dr. Chopra's confidence level in terms of development and extraction was about the same.

DR. CHOPRA responded that it was higher.

SENATOR HUGGINS asked about the likelihood of horizontal wells for oil rim production and what would be required if these wells did not work.

DR. CHOPRA clarified that there are a couple of ways to do the recovery. Horizontal wells are desirable in oil rim development if there are going to be coning issues. Coning issues take place when producing the oil rim and bleeding the pressure rapidly. Horizontal wells might not be needed with new methods, like carbon dioxide injections that pressure up the oil rim.

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REPRESENTATIVE GARA referred to Exxon's failure to develop Point Thomson. He pointed out that this has gone on since the 1970s with the last major work being done in the 1990s. He spoke in defense of the state's data, which is the data that Exxon produced. When Exxon stopped producing data the state stopped getting data. He maintained that the state would be closer to production at Point Thomson if Exxon had honored its lease. Estimates show that gas production at Point Thomson would be 10 to 20 years away if oil and gas condensates are produced before gas. He questioned if there is a way to force, through a lease-bid (after the lease is taken back from Exxon), to have the new lease owner produce the oil and gas condensates more quickly, maybe in an enhanced processing facility or by drilling more wells and operating more wells. He wanted to know if there are ways to get the oil and gas condensates out more quickly for use in the gas pipeline. He inquired if there was any chance of getting the gas out in 12 to 15 years to meet one of the early open seasons in conjunction with the pipeline designed as a larger capacity pipeline. He concluded that if this is not possible, the damage that the state has been caused by Exxon's failure to produce Point Thomson is that now the pipeline project is being scaled back.

MS. THOMPSON explained that in the state's development of its oil and gas lands, the lessees do the drilling and collect the data, and not the state independently. She

agreed that the lessees in this case are responsible for the dearth of data rather than the state itself. She reported that regarding moving production forward more quickly through another lease sale, the Division of Oil and Gas has looked into the structuring future sales of the leases in this area. It is possible under current statues to put conditions of development in a lease and it may be necessary to relook at the leasing statutes to provide more flexibility. In other areas of the world where lands are leased for oil and gas development, there are development conditions in the lease; the state is looking at this very carefully. She emphasized that these lands are unique. Usually when lands are first leased for oil and gas development, there is no knowledge about what is contained. The purpose of an oil and gas lease is to encourage exploration and development. In this situation, the state does have information, though it is somewhat limited. She surmised that the state could use a different method than what has traditionally been used and that the state should look at different options to maximize the value for the recovery of the resources on these lands.

REPRESENTATIVE GARA commented about Exxon's failure to develop Point Thomson resulting in an inability to explore and produce the collection of data.

SENATOR HUGGINS contended that the litigation piece is what it is. He responded that Exxon would speak for themselves later during their time.

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REPRESENTATIVE GARA asked if it would be possible to give the history of the failure to produce data, the failure to explore on Point Thomson, and the failure to produce.

SENATOR HUGGINS replied that this could be discussed later.

REPRESENTATIVE HAWKER noted that the data appears very precise and questioned the confidence level that can be had in this data. He said that there are three strata with the lower level of Brookian sands, medium strata of Point Thomson sands, and at the bottom, the oil rim and the pre-Mississippian issues that have not been looked into yet. He asserted that the full document is more cautious about the credibility of the interpretation, particularly for the oil rim. This is true especially for the oil rim where AOGCC is charged with looking at the best way to get immediately to the Point Thomson sands, the condensate development. He observed that AOGCC must also determine how to get the maximum of all the hydrocarbons by looking at the oil rim on the bottom. There are a lot of assumptions about the oil rim and about the other strata. "It seems to me that it is very much an unknown whether or not the premises you are basing

this analysis on are as accurate as it might be inferred in the presentation." He asked what is known about the properties of the oil rim and whether a high degree of confidence can be given regarding the accuracy of the modeling.

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MS. HOULE responded that the reason there is uncertainty in the conclusions is the lack of data. She said that the data the state has is basically the data the industry has. Part of the reason for this study was to take the available data, given that it is more in exploration mode than in delineation mode, to see what the realm of possibilities of the reserves were. As a geologist, she looks at the minimum (P10) and at the imagined potential (P90), and then there is the case of beyond one's wildest dreams. On the North Slope almost every field that has been produced has been beyond geologists' wildest expectations. Prudhoe originally was expected to recover 8 to 9 billion barrels and now expectations are at 14 billion. Most fields on the North Slope have done better than expected with two notable exceptions, Lizborn and Bendami. A lot of fields have been beyond the P90. She said that she did not see the Point Thomson sands as an extension of the Bendami. She stated that this is a different discussion.

REPRESENTATIVE HAWKER summarized that his concern is about the precision of the presentation when the properties of the oil realm are unknown.

MS. HOULE responded that that was because of the lack of delineation drilling.

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SENATOR STEDMAN acknowledged that the data set used in the analysis is old and that the data is derived from the industry. He asked what kind of dialogue there has been with the industry and various corporations and if there had been any agreement. He questioned if there was full agreement on the dew point or other areas, and if there been communication with industry.

DR. CHOPRA responded that there were three components of the study. The first component is the gas cap, the 8-10 Bcf of gas with condensate. The second component is how to get the condensate out of the gas cap. The third component is oil rim development, specifically what is there and how to develop it. There is old bad data and old good data. He emphasized that not all old data is bad data. Some of the data is very high quality and very comprehensive. Referring back to the precision of the study, he said that the conclusion about the gas is expressed as 8.5 to 10.5

trillion standard cubic feet, which is expressed in a range and relates to Point Thomson sands only. The condensate is 490-600 million stock tank barrels expressed as a range, which has been derived from averages. The potential oil rim is 580-950 million stock tank barrels. This range, while not precise, is big - half a billion to one billion barrels. He said that extensive uncertainty analysis was completed, which has given these ranges of what is believed to be in the reservoir. People have produced gas fields in the world with four or less wells. He pointed to the reservoir pressure slide and stated that it shows high pressure on the east side, south side and west side. He emphasized that this showed good continuity high pressure, which means that the sands are continuous and the gas is there. He inferred from this data that the gas is there throughout the reservoir. He emphasized that this information is from a large number of wells, not just one or two. The uncertainty is in the oil rim, as there are fewer tested intervals; hence the conclusion of first doing gas cycling, then developing the condensate and while doing that, do delineation of the oil rim. This is a typical way to proceed in terms of oil rim development, as it provides more confidence in its development.

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SENATOR STEDMAN wanted clarification regarding how much of the conclusions are in agreement with the administration and the industry, and how much are subject to debate. He also wanted to know if there has been any dialogue in the areas where there is disagreement. He wanted to sort out what information he should be paying attention to and what information is irrelevant to any decision making.

MS. HOULE clarified that data from industry is raw data, which the state interprets. This study took raw data and interpreted it. She said that the division did their own independent analysis, but PetroTel's expertise in reservoir engineering was needed. The state had to use the industry's data set. In general, the operator provides the data when the unit work is done. She said there is more dialogue with some companies than with others.

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MS. THOMPSON said the history of this unit and the dialogue between industry and the state would be articulated later.

REPRESENTATIVE FAIRCLOUGH expressed concern about engaging in litigation and how it would impact the timeline for bringing gas on line and making it economical for Alaska.

MS. THOMPSON replied that the timeline would be addressed by Commissioner Foerster later.

REPRESENTATIVE FAIRCLOUGH reiterated her question asking for an engineer's prospective. She wanted to know specifically how much oil will be removed along with a timeline showing when it gets to gas, which will help in determination of the timeline for Point Thomson and help support economically Alaska's natural gas pipeline.

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DR. CHOPRA responded by explaining Slide 11, which shows that producing oil only for 15 years, without producing any gas, would result in recovery of up to 650 million barrels of oil. Earlier the analysis showed just the blowdown case. In that scenario, the production is only 150 plus or minus barrels of oil. He queried whether it was worth getting half a billion barrels of oil in 15 years with current market value of $70 billion dollars and waiting 15 years to produce gas, or sacrificing that oil and start producing that gas today and delivering it to the pipe.

MS. FAIRCLOUGH responded that this would require two different sets of pipes in Point Thomson if oil is produced first because the gas line could serve to pipe the oil, but not vice versa. An oil line would have to come out of the field first as a capital structure infrastructure cost and a gas line to follow that.

MR. MOOTHART answered that some infrastructure would be required to get the oil from Point Thomson, but not all the way back to the North Slope since there is Badami.

MS. FAIRCLOUGH pointed out that gas would be needed to be brought in to maintain gas line pressurization.

MR. MOOTHART expressed that the report outlines this as a possibility because if the oil rim turns out to be as good as or better than expected and a full development ensues, which may include 30 wells, then you are increasing voidage or off-take. In order to maximize that full development something will need to be brought in to make up for that voidage and to maintain the pressure. This creates a balancing act, which is outside these analyses. He said this will be determined during initial gas cycling and further delineation of the oil rim and the scale of that development of the oil will be determined and is not a foregone conclusion.

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REPRESENTATIVE FAIRCLOUGH said that understanding Point Thomson and its timeline for natural gas production may give a better understanding of the economics regarding moving forward on the issue, at least from the private sector.

REPRESENTATIVE KERTULLA was not concerned about the old data being bad, but wanted to know the impact of the litigation. She wondered if there was not litigation, if there would be access to more data and a more cooperative working relationship.

MS. THOMPSON answered that it has been a long battle to get where they are today after 30 years with no development, and as a result they have not had the dialogue with operators and other units about how land should be developed.

REPRESENTATIVE KERTULLA requested a walk-through of that history, as it will be important later.

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DR. CHOPRA reviewed Slide 12 by saying that in primary depletion 6-7 tscf gas is recovered and gas cycling in 15-20 years gives 620-850 mmstb of condensate and oil. He stated that the conclusion of the analysis is that additional wells are needed to delineate and test the Point Thomson oil rim and pressure maintenance is definitely required to maintain maximum producibility of the wells as well as maximize the recovery of the condensate.

MS. THOMPSON provided background information on the Point Thomson Unit and the litigation history and status. She explained that the essence of an oil and gas lease is timely production. The state agrees to lease its land to a developer in exchange for a share of the production, which is paid as royalties. Oil and gas leases contain a commitment that the lessee will diligently explore and develop the property. When a lessee fails to fulfill this duty, the lease is forfeited. Article 8, Section 8 of the Alaska Constitution mandates that a lessee's breach of duty to develop results in forfeiture.

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MS. THOMPSON observed that oil and gas lease is a temporary (commonly 5 to 10 years) right to explore for and develop hydrocarbon resources. The purpose of the primary term of a lease is to allow the lessee sufficient time to explore, delineate, and produce the hydrocarbon resources. Leases expire at the end of their primary term unless the lease is producing oil or gas or the lease has become part of a unit.

MS. THOMPSON explained that units are formed when a group of lessees apply to the state to form a unit because their leases overlay a common geologic formation that holds recoverable oil or gas. She provided members with a map delineating different leases (Copy on File). It illustrates that geology does not follow straight lines along state

leases. So lease holders determine where the formation is and come together as a unit for greater efficiency. Oil and gas leases are owned by different entities. There are about 48 units in Alaska, 14 on the North Slope and 34 in Cook Inlet. Unitization extends the term of lease so that the discovered resources can be produced in an efficient and coordinated manner that will maximize recovery and minimize waste.

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MS. THOMPSON explained that Exxon Mobil acquired several leases in the Point Thomson area in 1965. Exxon Mobil and Chevron acquired 14 more leases in 1969 and 1970. The majority of the remaining leases were acquired in the 1980s and early 1990s.

MS. THOMPSON pointed out that the Point Thomson Unit was formed in 1977 with 18 leases comprising approximately 41,000 acres of state land. The boundaries have been expanded and contracted several times in the last 30 years. Unit boundaries can be expanded to include lands proven to overlay a producible resource. Unit boundaries are periodically contracted to exclude leases the unit operator fails to develop. The state's form unit agreement requires that all lands not included in a participating area or PA (a process used to allocate production for royalty accounting purposes) within five years of formation of the unit contract out of the unit. The Point Thomson unit included 45 separate leases with approximately 106,000 acres of state land when Commissioner Menge issued his decision to terminate it in November 2006. Therefore any discussion about a lease depends on which lease. The leasehold interests were held by Exxon Mobil (52 percent), BP (29 percent), Chevron (14 percent), Conoco (2.8 percent), and other minor interest holders.

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MS. THOMPSON explained that the working interest owners elect a unit operator to manage the unit's business; Exxon Mobil has been the unit operator throughout this unit's history. Under the Unit Agreement, Exxon Mobil was primarily responsible for exploring and developing the unitized lands. In the recent remand hearing, the working interest owners submitted amendments to the unit operating agreement to change the voting percentages, with the stated purpose of preventing one of the major owners from blocking an action the other two agreed upon. Those amendments were contingent on DNR's acceptance of the 23rd POD and not agreed to by ConocoPhillips; thus their current status is not clear.

MS. THOMPSON said that during the first five year of the unit's existence, Exxon Mobil submitted five one-year PODs

and drilled several exploration wells. The first POD promised that if oil was discovered in sufficient quantities to warrant future development, the Prudhoe Bay to Valdez oil pipeline will be the probable marketing outlet for the area. Since the early 1980s, Exxon Mobil has known about the existence of significant quantities of oil and gas condensate, but has not produced anything.

MS. THOMPSON continued that despite significant uncertainty about the unit's resources, the unit operator drilled no more wells after 1982. New wells would yield geophysical data that would resolve the remaining uncertainties about the reservoir. Two wells were drilled by BP and Chevron in the 1990s and several other wells were drilled by other producers on lands outside of the unit boundary.

MS. THOMPSON pointed out that the unit agreement originally provided for expiration after five years if lessees failed to form a participating area. Participating areas are formed before production begins to allocate the production to the appropriate lease. Thus, when the parties signed the unit agreement, they expected that the unit would begin production by 1983. Because Exxon Mobil was unable to commit to production by then, DNR agreed to remove the PA formation requirement to prevent the unit from terminating. The amendment extended rather than removed the obligation to produce. When DNR agreed to amend the unit agreement it expected that production would begin by the late 1980s.

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MS. THOMPSON observed that since 1983 can be characterized as a struggle between the state and the unit operator, with DNR demanding development activity and Exxon Mobil either insisting that it was not economic or promising to drill wells that were never drilled. The remand decision and decision on reconsideration detail the history.

MS. THOMPSON explained that in 1985 and 1990, DNR contracted leases from the unit because lessees failed to drill promised wells. In 1995 DNR rejected the 12th POD because it did not include a development commitment. Significant quantities of oil were discovered by Exxon Mobil in 1975, and by BP and Chevron in 1994. The unit plans have never included development of this oil. By the time the 13th POD was due, the Division of Oil and Gas had a new director who accepted Exxon Mobil's promise to develop the unit lands with "farm-out" agreements. Then Director Boyd dearly stated the division's objective: "Most importantly the division wants a fair and honest attempt to get this acreage explored and be appraised of efforts to develop and produce the Point Thomson sands accumulation itself."

MS. THOMPSON said that when the negotiations over the

Stranded Gas Development Act became active in 1997, Exxon Mobil linked Point Thomson development with construction of a gas pipeline. Exxon Mobil suggested that before the construction of a gas line, it would produce the hundreds of millions of barrels gas condensates through a gas cycling program. In 2001, Exxon Mobile also promised that the Point Thompson Unit's considerable oil reserves would be produced starting in 2010. From the late 1990s until 2005, DNR approved PODs with the expectation that wells would be drilled to further delineate the unit's resources and that Exxon Mobil was progressing towards production with development drilling to begin by 2006. During this period, Exxon Mobil drilled no wells.

MS. THOMPSON further explained that the DNR unit litigation has been successful so far and the litigation will probably continue to the Alaska Supreme Court. The basis for the litigation was the 2001 second expansion agreement and the 18th though 22nd PODs that were designed to implement the commitments made in that agreement.

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MS. THOMPSON discussed the unit litigation. In 2001, Exxon Mobil asked DNR to expand the unit and filed the 18th POD. They repeated their commitment to develop the land by saying: "The Owners have endeavored in the attached response to unambiguously demonstrate our commitment to the development of the Point Thomson Unit. We are committing to an aggressive work program and the expenditure of substantial funds that will put us in a position to initiate project execution activities as early as possible." That "unambiguous' commitment was to expedite permitting and engineering studies, drill an exploration well by 2003, a production well by 2006 and seven more production wells by 2007. DNR agreed to expand the unit based on these commitments, but none of the proposed development activity occurred. Exxon Mobil eventually paid a penalty of $20 million, plus interest, for failure to perform the promised work.

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MS. THOMPSON explained that since the 21st POD expired In September of 2005, this unit has not been operated under an approved plan of development. The first proposed 22nd POD was submitted and rejected because it did not contain adequate work commitments. Intense negotiations ensued, but the revised POD submitted months later was also rejected. The unit was put in default. The working interest owners asked for reconsideration and appealed to the commissioner. At the end of the Murkowski administration, Commissioner Menge terminated the unit because Exxon Mobil submitted a POD that did not comply with Director Myers' criteria for

what an acceptable POD must contain. Acting Commissioner Rutherford affirmed Commissioner Menge's decision when the lessees asked for reconsideration after the new Governor was sworn in.

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MS. THOMPSON clarified that the litigation began with lawsuits filed in Superior Court that were eventually consolidated before Judge Gleason. Exxon Mobil also separately filed an action for damages and injunctive relief that was dismissed by Judge Michalski. Exxon Mobil appealed the dismissal, but never filed their brief with the Alaska Supreme Court.

MS. THOMPSON continued that Judge Gleason ruled in December 2007 that DNR properly rejected the 22nd POD and that it had the legal authority to terminate the unit, but remanded the case to the agency because she found that DNR had not given the parties enough notice that the unit might terminate and the opportunity to argue about other alternative remedies. The unit litigation progressed till 2007, when the judge ruled and remanded to DNR that the case might terminate. The decision came to the same conclusion and sent back to the judge. The record is in the process of being the final decision is likely to be appealed to the Alaska Supreme Court, which normally takes two years to complete.

MS. THOMPSON explained that DNR had a hearing earlier this year on the 23rd POD, the remedy proposed by Exxon Mobil. Commissioner Irwin found that the proposal did not meet the statutory criteria for approval and did not protect the state or public interests. Commissioner Irwin also found that the lessees' failed to explain why termination was not an appropriate remedy given the unit's history. When asked to reconsider, he came to the same conclusion. The remand record will soon be sent back to Judge Gleason. Judge Gleason has not set a hearing or told the parties whether she would like briefs and/or oral arguments on DNR's decision. It is likely that her final decision will be appealed to the Alaska Supreme Court.

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MS. THOMPSON discussed the lease process and timing for reclaiming the 45 leases, which vary according to the lease. Almost all of the leases are beyond their primary terms, and thus held because they were a part of the unit. After the initial unit termination decision, DNR began the process of terminating the leases in February 2007 and the leaseholders appealed. Further action on the lease appeals was delayed until the status of the unit was resolved. Thus, agency action on the status of all 45 leases is pending. Some may be available for leasing in the next couple of years, long

before a pipeline is available. Others may be litigated longer.

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MS. THOMPSON referred to the map (Copy on File) and concluded that none of the leases are currently certified. Green dots on the map identify leases that were once certified. Red dots identify wells that have been plugged and abandoned. The two yellow dots identify wells are cauterized as suspended; they have been plugged and abandoned, but have not received surface clearance from AOGCC. Blue refers to leases beyond primary term that have not had a well drilled and is the easiest to resolve. Yellow indicates leases beyond the primary term that has had a well drilled. The one pink lease is in its primary term. Litigation is likely on the green leases. On the leases with wells that were once "certified" there is a factual dispute about whether the wells are still capable of production that is likely to be litigated.

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MS. THOMPSON referred to the future and how things might progress. The division may decide to release lands that are currently available or wait. It is likely that the conditions of the next lease sale will be different considering the knowledge regarding the resources underlying the leases.

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REPRESENTATIVE GATTO asked if there is drilling information that is considered proprietary, owned by the driller and not available to the state.

MS. THOMPSON observed that there is confidential data, which is available to the state, but not available to the public. The data for all but five wells is available to the public. Some data is confidential due to its proximity to the ANWR boundary.

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REPRESENTATIVE RAMRAS asked if the AOGCC's point of view was creditable. MS. THOMPSON expressed respect for Commissioner Foerster and felt that the information would be creditable.

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REPRESENTATIVE BUCH asked who controls the information data and what entities are involved with the map.

MS. HOULE responded that industry has the same data that is available to the state. Some data may not reside with AOGCC. It is the responsibility of the companies to provide well data to AOGCC.

MS. HOULE, in response to a question by Representative Buch, observed that the state has statutes and regulations regarding the collection of data. The AOGCC has its own regulations. She explained that most of the state's data comes from the unitization, summary of process, and seismic permitting.

REPRESENTATIVE BUCH asked for additional requirements for minerals management surveys, and other requirements on Bureau of Land Management (BLM) and Native lands.

MS. HOULE noted that the state would not have access to anything on private, Native lands. The BLM land is administered by the federal government and includes Natural Petroleum Reserves-Alaska (NPR-A). The state only receives NPR-A data through the Economic Incentive Credit (EIC) process. She observed that ACES provided tax credits and data. Minerals Management Service is off shore data, which releases seismic data after 15 years.

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CATHY FOERSTER, COMMISSIONER, ALASKA OIL AND GAS CONSERVATION COMMISSION (AOGCC), provided a brief overview of the AOGCC, which is tasked with the regulation of the operations of oil and gas throughout the state. The Division of Oil and Gas is responsible for maximizing the value to the state of Alaska of the oil and gas under state lands. The AOGCC regulates oil and gas operations throughout the state, not just on state lands, but also on federal, Native, and privately held lands. The state, by law, has no greater standing in adjudications than any other party.

MS. FOERSTER noted that AOGCC has five primary responsibilities: prevent waste of oil and gas, encourage greater ultimate recovery of oil and gas, protect sources of fresh ground water from harm by oil and gas operations, protect human health and safety related to down-hole oil and gas operations, and protect correlative rights, which is done throughout the State, regardless of land ownership.

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MS. FOERSTER discussed AOGCC's day-to-day regulatory oversight and focused on two responsibilities: preventing waste of oil and gas and encouraging greater ultimate recovery of oil and gas. She pointed out that the commission is not tasked with making the most money, balancing the budget, or making any particular set of constituents happy.

MS. FOERSTER explained that in engineering vernacular, Point Thomson is considered a gas condensate reservoir or a retrograde condensate reservoir. In such a reservoir, the hydrocarbons are in the gas phase until the pressure drops below a certain point called the dew point. When the pressure drops below the dew point, some of the hydrocarbons, the condensates, switch to the liquid phase and drop out of the gas. When this happens, a substantial portion of those liquids can be trapped in the reservoir and can never be recovered.

MS. FOERSTER further explained that in many retrograde condensate reservoirs, cycling (reinjecting the produced gas over and over again to maintain high reservoir pressure until the liquid condensate has been recovered) prevents these losses. Cycling the gas until most of the liquids have been recovered is the way to achieve greater ultimate recovery and prevent waste from a gas condensate reservoir such as Point Thomson.

MS. FOERSTER observed that publicly available estimates of recoverable liquid hydrocarbons associated with the gas at Point Thomson vary from 200 to 500 million barrels, depending on the source and the method of development. She emphasized that a significant portion of those liquids would be at risk if Point Thomson is produced as a gas reservoir without cycling first, and emphasized that the value of this liquid resource is the size of another Alpine Field.

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MS. FOERSTER noted that there is a second potential problem with not cycling first. As the reservoir pressure drops, liquids will drop out in the place where the pressure is lowest, adjacent to the wellbores if they are not cycled first. When liquids drop out at the wellbores, they damage the producibility of the reservoir and decrease the ability of the wells to bring the gas up to the surface. The operator can undo some of this damage through well interventions, but these cost money, must be repeated as additional damage is done, and eventually may no longer be effective at fixing the problem. This is important to AOGCC because it will result not only in liquid losses, but also in gas losses. It is important to the state for that reason and because, under ACES, the state shares the cost of these interventions that will likely be done over and over to keep the gas wells producing. She urged members to keep in mind that cycling will likely add significant capital costs, which the state would share via ACES.

MS. FOERSTER observed that a third problem exists regarding producing the gas from Point Thomson. Underlying this thick gas condensate reservoir is a relatively thin oil layer.

Much of that oil will be lost if the gas from Point Thomson is produced before producing the oil.

MS. FOERSTER clarified that since AOGCC is charged with preventing waste of hydrocarbon resources in Alaska and since producing gas from an oil reservoir can cause waste, they determine when and how much gas can be produced from every oil reservoir throughout the state with an eye to greater ultimate recovery of both the oil and the gas. The commission does not typically dictate to an operator what he must do. Rather, the operator typically comes to the AOGCC with a request for permission to do something and they allow it, disallow it, or allow some modification to the originally proposed plan. They do not tell an operator where or how deep to drill wells. The operator requests to drill a particular well in a particular location to a particular depth using particular procedures and AOGCC approves the request, denies it, or approves it subject to limitations or modifications. The same will hold true for gas off-take from an oil field, such as Prudhoe Bay and Point Thomson. Before the operator can produce gas from Point Thomson, the applicant must come to the AOGCC and request a gas off-take allowable. The applicant must prove that waste will not occur. Without that proof the request is not granted.

MS. FOERSTER maintained that not enough is currently known about the Point Thomson sand, either the gas portion or the oil layer, to know what the right answer is for the oil companies or the state. They do not know if there is adequate connectivity in the gas condensate part of the reservoir for cycling to work. If it doesn't work, then both the oil companies and the state will have wasted a lot of money. Not enough is known about the characteristics of the oil in the oil layer to know whether it is technically recoverable. In other words, even if all agreed to get that oil first, they don't know if it can be done. The oil may or may not be too viscous to produce; the gas above and water below it may cone into the oil layer and drown out the oil production; the extremely expensive wells required to attempt to produce the oil may or may not be economical. She concluded that they will never answer these questions without a bit of drilling, producing, and cycling.

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REPRESENTATIVE HOLMES questioned why there has not been an effort to recover the liquid condensates to date.

MS. FOERSTER could only guess, but observed that operators generally define the biggest prize. Development is designed around the recovery of the biggest prize. She thought that Exxon Mobile had viewed the gas as the prize and the technically challenged oil resource as the cherry. She guessed that it did not justify development until the gas

pipeline was imminent. Exxon Mobile will either have to get the liquids first or prove to AOGCC that it is not the right answer.

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REPRESENTATIVE GATTO wanted to know if gas would need to be imported to develop the oil.

MS. FOERSTER replied that it is possible that data will reveal the need for gas to stay above the dew point. The data seems to indicate that the dew point is close. Additional data will determine the dew point. She observed that Point Thomson is only one of the places that North Slope operators are looking at using the carbon dioxide.

REPRESENTATIVE GATO observed the high pressure and expressed surprise that the dew point would be so close.

11:51:20 AM

REPRESENTATIVE BUCH noted his visit to Calgary to see how the information was more complete and accurate than what we have here.

MS. FOERSTER stressed that data is difficult to extract due to the technical challenges of drilling the wells. Technology has advanced. The data dearth is not due to the lack of adequate requirements. Data comes from core samples. The state has access to all of Exxon's data. She did not think that the uncertainly comes from access or inappropriate data.

11:54:36 AM

REPRESENTATIVE BUCH asked the state's requirement for data and questioned if there is a repository for the data.

MS. FOERSTER stated that the repository for wells that are not confidential is the AOGCC's website. All of the data is put on the website as soon as the well information is not confidential. Confidential well data is kept in their office. The commission requires cuttings, mud logs, open hole and case hole logs, and core data. All additional data and analyses becomes part of the public record.

11:56:35 AM

REPRESENTATIVE FAIRCLOUGH referred to Prudhoe Bay off-take. She observed that AOGCC has an agreement with the producers that would take off 2.4 Bcf/d. She asked if the take-off for gas at Prudhoe Bay would be revalued and whether it would go up or down.

MS. FOERSTER noted that the current off-take for Prudhoe Bay is 2.7 Bcf/d. The only gas being used for anything other than reinjection is the gas used for fuel for the seal and a small amount of gas that is exported to other fields for enhanced oil recovery. The off-take is approximately 0.7 Bcf/d. She did not see this amount decreasing when there is a gas line because there will be additional facilities. Any off-take would have to include this volume.

MS. FOERSTER noted that AOGCC completed a confidential study with Prudhoe Bay owners, and that off-take would remain the same until an operator request an increased allowance. Providers must ask for a change. The answer would depend on how much oil has been produced when the gas line is ready, what mitigation steps have been adopted to decrease the risk of losing oil, and the off-take rate.

MS. THOMSON observed that the unit manager must make an application to the state of Alaska for the additional off-take that the administration has said would be available through Prudhoe Bay.

12:01:07 PM

REPRESENTATIVE KELLY asked for a timetable and expressed surprise that Point Thomson would not be available for 15 to 20 years.

MS. FOERSTER noted that Point Thomson is an oil field and the operator would have to prove to the AOGCC that waste would not occur if they went into a gas blowdown.

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RECONVENED: 1:32:00 PM

SENATOR STEDMAN pointed out that it is difficult to assess the situation without more knowledge of the volumes.

MS. FOERSTER noted that the off-take at Prudhoe Bay would be 2.7 Bcf/d. That volume includes approximate 0.7 Bcf/d for export for use in other fields, which would leave 2.0 Bcf/d for sales. The impact of gas sales on Prudhoe Bay recovery is confidential, but trends show that the later the gas is sold, the less it should take. The more the operator has done in the meantime to mitigate for losses, the small the oil losses would be.

SENATOR STEDMAN observed that the state has been waiting 30 years for the gas line, but that it would have been detrimental in terms of maximizing revenue to have built it then.

MS. FOERSTER agreed.

SENATOR STEDMAN pointed out the legislature's support of the administration's request to move the gas pipeline forward, especially regarding funding. He questioned if the state should be putting forth the question to the AOGCC regarding off-take amounts.

1:36:34 PM

MS. FOERSTER noted that there are different opinions regarding the standing of the state. The question has to be raised before the AOGCC makes a determination. The problem with the state initiating the process is that there would not be onus on the operators to provide confidential data to support the request. Without sufficient data entered into the public record to support a decision, AOGCC cannot make one.

MS. THOMPSON added that useful information about timing and off-take could also be gathered related to the proposal to the Denali pipeline.

1:38:11 PM

REPRESENTATIVE SAMUELS asked for clarification regarding a cycling project.

MS. FOERSTER responded that it was not yet determined if cycling would work. She noted that wells need to be further apart to sweep the condensate out of the greater portion of the reservoir.

REPRESENTATIVE SAMUELS asked if Exxon's proposal did that.

MS. FOERSTER answered that their proposal intends to do that in part.

REPRESENTATIVE SAMUELS asked if the administration thought it was a good idea.

MS. THOMPSON answered that the question raises issues she is not allowed to embellish upon.

1:40:55 PM

REPRESENTATIVE DOOGAN thought that the earlier testimony indicated that the solution to the lack of data available for Point Thompson was to produce condensate and that interjection of the gas would reveal more about the gas rim.

MS. FOERSTER explained that some of the questions regarding reservoir properties could be answered by drilling new wells and obtaining new data. There is debate regarding the API gravity and condensate yield. The economics would be decided by drilling into heavy oil and attempting production.

REPRESENTATIVE DOOGAN summarized that delineation wells are needed.

MS. FOERSTER pointed out that delineation wells often become development wells. It would not make sense to only drill for delineation.

1:44:17 PM

REPRESENTATIVE DOOGAN spoke to oil, gas, and gas liquids relating to Point Thomson and asked for more information about condensates.

DR. CHOPRA explained that condensates are light oil in the gas stage that drop off with the pressure. The oil is in the oil rim and has no gas in it. Its gravity is lower.

REPRESENTATIVE DOOGAN summarized that there is gas with two types of oil.

1:45:37 PM

SENATOR THOMAS asked for clarification regarding what needs to be done to delineate Point Thomson and if the entire North Slope is involved. He asked for additional clarification on the number of wells drilled, their value, and the time frame.

MS. THOMPSON explained that “sourdough” wells (wells drilled by other than the operator) were not in the unit. It is not the state’s role as landowner to come up with a delineation plan. Generally, more work is needed to learn about the reservoir. She acknowledged reserves in other areas outside of Prudhoe Bay.

1:50:20 PM

MR. MOOTHART described the need to narrow the range of potential volumes.

MS. FOERSTER responded to the question regarding other North Slope gas resources. The two known significant resources are the Prudhoe Bay gas cap and the gas section of Point Thomson. The rest are in the potential reservoir. The state is dealing with the only two proven sizable gas reserves in Point Thomson and Prudhoe Bay.

SENATOR THOMAS clarified that Alpine Field is not a large gas resource. He asked for elaboration on the operator’s role.

MS. FOERSTER explained that the operator can interject water into the gas cap. A pilot project has tested the gas cap

interjection, which seems to be working. Carbon dioxide could be interjected into the oil rim. Smaller pools of trapped oil are being gathered through lateral drilling.

1:55:44 PM

REPRESENTATIVE ROSES asked if modeling done at Point Thomson has been done at Prudhoe Bay.

MS. HOULE explained that there has not been a modeling similar to Prudhoe Bay. However, the department plans additional modeling, using outside resources as well.

REPRESENTATIVE ROSES referred to the validity of the information and suggested that the Prudhoe Bay data would be more accurate.

MS. HOULE agreed that there would be a surplus of data.

REPRESENTATIVE ROSES described how estimations on gas volume have changed. He stressed that members are dependent on speculation until further data is gathered. He stated concerns as the net present value changes according to the assumptions. He pointed out that TransCanada is the only company that does not need to know the return before investment.

2:01:07 PM

MS. THOMPSON emphasized that the Prudhoe Bay study was planned. She discussed Point Thomson seismic data. The department has confidence in the structural picture and reservoir continuity.

REPRESENTATIVE ROSES questioned the need for the study if they were that confident and asked how much the Point Thomson study cost.

MR. MOOTHART estimated that half a million dollars had been spent on studies to date.

2:03:07 PM

SENATOR STEDMAN observed that it costs money to make money. He suggested that the state would better off developing Point Thomson under the previous plans, in light of PPT, gas prices and progressivity.

2:05:25 PM

MS. THOMPSON could not determine whether the state would have been better off with production 20 years ago. She pointed out that costs have increased along with prices.

Analysis indicates that the project is economic even without Point Thomson gas. The off-take question must be determined.

SENATOR STEDMAN summarized that the economics look promising at this time.

2:07:54 PM

DR. CHOPRA, in response to a question by Representative Buch, explained that carbon dioxide is effective at recovering oil. When interjected in the oil rim through horizontal wells, 50-60 percent of the carbon dioxide is trapped in the reservoir. The gas that might otherwise have been released into the atmosphere is sequestered and the oil is recovered. He emphasized that carbon dioxide molecular weight is higher than dry or liquid gas.

REPRESENTATIVE BUCH noted discrepancies in the estimates of Bcf's available in Prudhoe Bay.

DR. CHOPRA noted that Prudhoe Bay recycling is an optimization exercise to see how much oil is recovered. The goal is to maximize recovery.

2:11:18 PM

REPRESENTATIVE BUCH questioned the adequacy of a proposal that includes only Prudhoe Bay.

MS. FOERSTER observed that all the gas produced in Prudhoe Bay is reinjected. She clarified that gas coming up with the oil wells has increased over time. That will continue until there is a gas line. Currently, two Bcf/d is the only gas demonstrated to the AOGCC as an acceptable off-take.

REPRESENTATIVE BUCH noted that there has not been new information in the last 40 years and questioned if anything had changed in that time regarding Point Thomson.

DR. CHOPRA acknowledged that there have been changes. Extensive seismic surveying was done in 1989 which was tied to the well data. The continuity of gas is excellent. Things have evolved.

2:15:00 PM

REPRESENTATIVE BUCH concluded that current technology allows for efficient production of oil or gas anywhere on the North Slope.

MS. FOERSTER agreed, with the caveat that the cost of economics is not included. The technology exists for production.

DR. CHOPRA agreed that the technology has existed for the last 25 to 30 years to produce the condensate at Point Thomson. Other issues are the availability of technology, implementation and understanding of the technology.

2:17:32 PM

SENATOR WIELECHOWSKI queried the value of condensate.

DR. CHOPRA noted that the value is slightly higher than a barrel of oil.

SENATOR WIELECHOWSKI asked if some of the northern and eastern tracts have higher royalty rates.

MS. THOMPSON explained that royalty rates are set at the time the lease sale and then they are sometimes re-negotiated later. In the unit referred to, there is a combination of both.

SENATOR WIELECHOWSKI questioned how much gas is being used on the North Slope for energy consumption.

MS. FOERSTER responded that the consumption is just under .5 Bcf/d in Prudhoe Bay.

SENATOR WIELECHOWSKI asked if the state received a production tax on that.

MS. FOERSTER responded that field use is not considered for royalty.

2:19:36 PM

SENATOR WIELECHOWSKI queried if that was included in the total off-take.

MS. FOERSTER stated that the allowable off-take in Prudhoe Bay is 2.7 Bcf/d, of which 0.5 Bcf/d is used for fuel. Other off-take is used for fuel for other fields, which makes that total 0.7 Bcf/d. This leaves 2 Bcf/d available for sale.

SENATOR WIELECHOWSKI questioned the need for operators to get permission to put their gas into the line.

MS. THOMPSON remarked on the complexity of the operating agreements involved. She noted that there are different provisions dependent on the volume and timing of gas. She offered to do further research.

REPRESENTATIVE KELLY questioned if there was a statistical confidence level at the lower end of the range.

DR. CHOPRA stated that there were two numbers for the oil rim. Confidence in the lower number was high. The higher number is based on analysis of the data.

2:24:51 PM

REPRESENTATIVE KELLY wondered how things got resolved in cases of disagreement.

MS. FOERSTER responds that the Attorney General's office would have more information about that. She described two ways a disagreement could be resolved. The operator could seek redress through the courts. It could also be dealt with through the legislative process.

REPRESENTATIVE KELLY asked for more information. He stated positive feelings and wondered why the producers and TransCanada should be less confident about the off-take numbers.

MS. FOERSTER replied that she is optimistic that explorers will find abundant gas and that the gas line would be filled.

REPRESENTATIVE KELLY asked if she was speaking of new gas.

MS. FOERSTER responded in the affirmative.

2:29:54 PM

REPRESENTATIVE GARA questioned if responsible law changes were needed. He was concerned about lost opportunities if various circumstances changed.

MS. FOERSTER responded that her office has sought a legal opinion regarding the question of considering economic waste in decision making. She hoped get this opinion in time to enact legislation in the next session.

REPRESENTATIVE GARA further asked if at some time in the future more Bcf/d could be authorized.

MS. FOERSTER responded that studies indicate that by the time the pipelines are ready, the allowable limits will be accessible and stated that there is no need to worry. She encouraged prudent accelerated production at Prudhoe Bay.

REPRESENTATIVE GARA wondered if the law was not changed whether the state would have the ability to order faster drilling to get the oil out in time.

2:36:46

MS. FOERSTER did not think the operator could be forced to spend money that they did not want to spend.

REPRESENTATIVE HAWKER asked if the known reserves would keep this line full or does this include unknown, yet to be discovered reserves.

MS. THOMPSON replied that they attempt to clearly distinguish between known and potential reserves. There are very few proven gas reserves, but there are significant other known reserves. She stated confidence that there will be enormous incentive for exploration when there is a gas line.

2:41:19 PM

REPRESENTATIVE HAWKER observed that "other gas sources" are not inventoried but they are there.

MS. HOULE described potential reserves.

REPRESENTATIVE HAWKER commented that he did not have confidence that there are tangible, adequate sources of gas.

MS. THOMPSON pointed that Black and Veatch was the consultant who did the economic modeling of the necessity for the Point Thomson gas.

2:43:25 PM

REPRESENATIVE CHENAULT summarized that a 4.5 Bcf/d line is the current proposal. If the line was built and running today, there would be a known excess. He thought there was around 2 Bcf/d of gas to fill a 4.5 Bcf/d line. He questioned where the gas is and how much was needed.

MS. FOERSTER replied that if there were a line today and someone were to ask for 5 to 6 Bcf/d from Prudhoe Bay, the state's answer would be no. There are approximately two billion barrels of oil left to be produced today that could not be wasted via statute.

MS. THOMPSON clarified that the proposed line is not a 4.5 Bcf/d line. The administration asked for several different options, as allowed by AGIA. The TransCanada proposal had some flexibility. It is also not helpful to discuss a line that is ready "today." She advised that Black and Veatch would talk the next day about proven reserves and other available gas on the North Slope. The state hired them to look at the question of whether gas would be available and the effect of different sizes of pipeline.

REPRESENATIVE CHENAULT thought it was relevant and important to discuss the 4.5 Bcf/d line. He emphasized that in order

to get financing, shippers would need to know the extent of the reserves.

2:51:27 PM RECESS

2:54:49 PM RECONVENE

CRAIG HAYMES, ALASKA PRODUCTION MANAGER, EXXON MOBIL, commented that the 27 leaseholders were surprised and disappointed with Commissioner Irwin's decision to reject the POD submitted February 19, 2008. The plan would bring Point Thomson into production by 2014 and ensure gas is available for a gas pipeline.

MR. HAYMES pointed out that the project is already underway. Alaskan contractors are in place. Over 50 million dollars has been committed in the past months. In spite of concern, the project will continue to move forward. He noted that the plan is supported by the AOGCC and even DNR.

MR. HAYMES described the POD as an unconditional commitment to production and to further delineate the oil and gas and learn more about condensate, which does not exist in the reservoir but only in the gas after it is removed from the ground.

3:00:27 PM

MR. HAYMES referred to the Point Thomson handout (Copy on File). Slide 2 shows that Point Thomson is on the North Slope, 60 miles east of Prudhoe Bay and the TransAlaska Pipeline in a remote and environmentally sensitive area adjacent to ANWR. The reservoir is about 80,000 acres and 12,000 feet beneath the surface. It is a high pressured reservoir and is costly to develop.

MR. HAYMES turned to Slide 3, depicting the 19 wells drilled at Point Thomson. Exxon Mobil is the operator for 14 of the wells. Over 3,600 feet of core have been collected from the wells and have completed 20 well tests. Data from eight 3-D seismic programs have been collected. The permafrost thickness is 2,000 feet. Seismic uses sound waves to learn more about the reservoir; permafrost mitigates that effect and adds to the complexity of interpreting seismic readings.

3:03:58 PM

MR. HAYMES asserted that Exxon Mobil has fulfilled its commitments. He defined the POD as a plan of work activity to develop hydrocarbons. It consists of studies, activities, engineering for drilling wells that are approved up-front by DNR. As the lease-holders move forward with the work plans, things change. Further discussions result in a revised POD.

There have been 21 PODs approved by the DNR from 1978 through 2005.

3:05:57 PM

MR. HAYMES listed the reasons the most recent POD is unique. He talked about Slide 5, which graphs historical oil and gas prices. He noted that the crude price prior to 2002 was less than $20 per barrel. Six years later it is at $130 per barrel. Up until 2002, the gas price was $4 Mcf. Only recently have prices increased. The technology needed at Point Thomson did not exist even ten years ago. This will be the largest, high-pressure gas cycling project in the world when operational. The project's estimated cost is $1.3 billion for the initial phase.

3:09:54 PM

MR. HAYMES turned to Slide 7, which depicts what Point Thomson will look like by 2014. Production facilities will be capable of producing a minimum of 10,000 barrels per day of condensate by cycling 200 Mcf/d of gas through a production well and an injection well. The export liquids pipeline will be built to handle 70,000 barrels per day. There will be an airstrip, camp and warehouse facilities. He described measures to minimize environmental impact. He did not anticipate permitting issues.

MR. HAYMES described guarantees to production rate. The facilities have been designed to be expanded in any direction needed.

3:12:17 PM

MR. HAYMES pointed to Slide 9, with a picture of the 27A rig, which is being upgraded to handle the pressure at Point Thomson. He described the 50 mile ice road (depicted on Slide 11) that will be built by an Alaskan company this winter to get equipment to the site. There will be an ice runway build adjacent to the road. The ice road will cost tens of millions of dollars to build, and it disappears in summer.

3:15:08 PM

MR. HAYMES discussed permitting activities. Materials will be barged from Prudhoe Bay to Point Thomson next summer by an Alaskan company. Slide 14 is a photograph of the present site. He pointed out there would be around three hundred jobs created for just this initial phase drilling the first well.

3:17:43 PM

MR. HAYMES showed Slides 16 and 17, showing the building and use of ice roads, which are up to 13 feet thick and protect the tundra from heavy equipment moving to site.

MR. HAYMES turned to Slide 19 and discussed the subject of cycling gas and producing condensate. Cycling gas needs two wells: a production well and an injection well. The wells are four miles apart to test whether they work. The reservoir temperature is 230 degrees Fahrenheit and the pressure is 10,200 pounds per square inch. "Wet gas" is produced in the right hand well, meaning the condensate is contained in the gaseous vapor. After the pressure and temperature are reduced, some of the gas turns into condensate, which is stripped off and sent down the new oil pipeline to market. The remaining dry gas will be re-pressured and reinjected through the other well back into the reservoir. This hopefully will sweep the wet gas from the right to the left. This conserves the resource for future development phases.

3:20:10 PM

MR. HAYMES listed DNR's concerns: timely development, reservoir delineation, and a firm commitment. He asserted that the POD addresses all three, and expounded on details as depicted in Slides 20 through 24. He addressed timely development using a detailed timeline on Slide 21. He described activities that are already underway. The drilling is a multi-year drilling activity. There is only a 90 to 120 day window to drill, which allows for drilling one well per year.

MR. HAYMES turned to DNR's second area of concern, reservoir delineation. Slide 23 depicts planned wells to access different kinds of oil in the reservoir. To provide perspective, a Prudhoe Bay well costs $6-8 million; a Point Thomson well will cost between $60-100 million and will take up to five times longer to build, due to the pressure and depth. He described further wells and incentives for Exxon Mobil to succeed.

3:27:22 PM

MR. HAYMES addressed DNR concerns about commitment. He described proceedings such as a court order and changes in voting processes that indicate Exxon Mobil's commitment to the project.

MR. HAYMES covered five risks at Point Thomson, illustrated on Slide 25. He addressed the first and second risks, health and safety environment, and reservoir management. The third area is production technology. Separation facilities will be needed that are rated at 10,000 pounds per square inch. This is one of the highest separator pressures in the world and

requires wall thickness of six inch steel. He emphasized that it is critical to execute this project well. He described the "A team" that would work on it.

3:32:41 PM

MR. HAYMES addressed the fourth risk, operability and reliability. Until the wells are in place, it is difficult to tell if the reservoir quality is homogenous throughout the reservoir. There is a risk that once the gas is cycled, the gas will not flow as hoped. He discussed the graph on Slide 28, "Cycling at High Injection Pressure," which depicts the result of a study of high-pressure projects.

3:35:56 PM

MR. HAYMES spoke about the high pressure well-head depicted on Slide 29. The well is about three times the height of well-heads at Prudhoe Bay. The reservoir is not only abnormally high-pressured, but it straddles the coast line. Wells have to be drilled from the land to get to the reservoir under the ocean. They also need to be clustered in discreet areas to minimize environmental impact. These will be some of the longest reach wells in the world and they will require some of the heaviest drilling mud in the world. He described engineering challenges. This is what drives the cost of the wells up to 100 million dollars.

3:39:37 PM

MR. HAYMES summarized the proposed POD for Point Thomson depicted on Slide 31:

- Provides for production
- Further delineates reservoirs
- Provides information about reservoirs
- Conservation
- Minimizes environmental impacts
- Expandability

MR. HAYMES talked about the importance of Point Thomson gas to a gas pipeline. Point Thomson represents 25 percent of the known resource (Slides 32-33). This will be the largest private infrastructure project in the history of North America, well in excess of $30 billion, plus hundreds of billions of dollars in firm transportation commitments. Those commitments are critical for securing project financing. A lower through-put, less availability of gas, or fewer fields, will cause more doubt, which can not be afforded with the gasline.

3:42:03 PM

MR. HAYMES pointed out that more fields will translate to better prices for the consumer. He discussed yet-to-find gas. He emphasized the importance of the project moving forward.

3:44:15 PM

MR. HAYMES noted the importance of low tariffs, which the governor encouraged. Without Point Thomson gas, the tariff will increase by one dollar. There will be a 20 percent increase in tariffs if the pipeline size is reduced from 4.5 Bcf/d to 3.5 Bcf/d, according to consultants. The net present value is $15 billion in today's value. The increase in tariffs would discourage exploration.

3:45:48 PM

MR. HAYMES observed that Point Thomson gas is critical, but the timing is unknown. A dollar increase in the tariff will result in $1.3 billion dollars a year. This is discouraging to explorers.

3:47:28 PM

MR. HAYMES spoke about the DNR summary of PetroTel's report (Slide 34). There is still a significant amount of technical work and analysis needed, which is essential to understand Point Thomson resource potential. He emphasized Exxon Mobil's experience and expertise.

3:49:55 PM

MR. HAYMES observed that PetroTel's report depends on the drilling of horizontal wells, which he did not think was realistic. He maintained that a horizontal well would have to be traversed for two miles without breaking through the top gap or bottom water. The well would be compromised if water entered the well. Exxon Mobil's technical work shows that over 90 percent of all the resources at Point Thomson will be developable through a gas sales development. Significant production data is still needed. He emphasized the need for flexibility and stated that they would share information with DNR. The department does not have the last two years of technical work available to Exxon. He stated that the company does not want litigation.

3:53:39 PM

MR. HAYMES concluded that the 27 lease holders were disappointed with the DNR decision. He asserted that there is not a faster way to bring Point Thomson into production. He reiterated Exxon Mobil commitment to the project.

3:55:09 PM

SENATOR THERRIAULT asked for clarification on regulations and questioned the need for a retroactive clause.

MR. HAYMES acknowledged that a retroactive date was included, and explained that the intent was to share information that had been collected. The date is not firm.

SENATOR THERRIAULT discussed mechanisms for returning the leases described by another company, and wondered why Exxon Mobil did not have similar consequences and if they would be willing to have such consequences.

MR. HAYMES explained that there are different levels of assurances. Exxon Mobil had talked about lease relinquishment and other remedies such as fines. They wanted feedback on what the state was looking for. The court order was an attempt to reach out and engage in a process towards agreement.

4:00:26 PM

REPRESENTATIVE GARA stated that he wanted the lease back. Exxon Mobil has conceded to 16 work commitment violations since 1983. He referred to differences in amounts of money spent.

MR. HAYMES believed that work commitments have been met. Entwined in the plans of development were references to expansion agreements, which are like contracts with the state. The agreement was that the leases could be included if a well is drilled. Because the leases were adjacent to the existing unit, it made sense for the current leaseholders in the unit to look at those leases and determine the best way to develop potential resources in those leases. They decided that in some of those cases it was not prudent to drill. Agreement was obtained with DNR that those wells should not be drilled and then those leases were released back to the state, in some cases with compensation. He disagreed that there was a commitment to drill a well.

MR. HAYMES addressed the second question regarding the $800 million. Most of the money was spent early on the unit; in today's dollars that would be $5 billion dollars to get the level of information available to the current lease holders. New lease holders would need to spend an equivalent amount.

4:04:42 PM

REPRESENTATIVE GARA questioned the timeframe Exxon Mobil proposed to get to 10,000 barrels a day.

MR. HAYMES noted that 90 percent of the resource would be recovered through gas sales development, based on the technical work done. They are in the process of sharing information to the AOGCC. There is a lot of incentive to drill and produce as much oil and gas as possible. In six years, a lot will be learned. The gas pipeline is at least ten years away. Within six weeks of production, they will know if there is a small tank in Point Thomson, or not.

4:07:52 PM

REPRESENTATIVE GARA felt that there was an overstatement on the ability to advance the gas pipeline without Point Thomson.

MR. HAYMES argued that 45 to 50 Tcf/d is needed. Prudhoe Bay is around 25, without off-take rates.

4:08:58 PM

SENATOR WIELECHOWSKI referred to Slide 33 and questioned when gas would be put into the pipeline according to the analysis. He estimated they would not have gas for 43 years.

MR. HAYMES clarified that the state's Black and Veatch model was used, which assumes gas production in 10 years. That model looks only at gas, and does not take into account the value of the condensate or oil. Condensate is not the ultimate development plan for Point Thomson. There is a lot of incentive for rapid expansion.

4:11:05 PM

SENATOR WIELECHOWSKI observed that in 1986, Exxon projected a gas pipeline with eight producing wells by 1992. He questioned why it was not completed.

MR. HAYMES explained that early exploration focused on oil. When they drilled at Point Thomson then, they found a lot of gas and not much oil. They recognized condensate could be gotten from the gas. At that time Exxon focused on cycling and believed that it was economic. However, the complexity of the geology and the fact that the high-pressure technology did not exist presented a problem. More work was needed. Cycling has been looked at three times, but each resulted in problems.

4:13:46 PM

SENATOR WIELECHOWSKI asked at what point in time Exxon would feel the lease should be returned to the state.

MR. HAYMES emphasized that value remains and they have a unique and firm POD, which provides greater confidence. There is improved technology.

4:15:16 PM

REPRESENTATIVE KERTTULA asked about the status of the Endicott Causeway and its relation to the proposed ice road.

MR. HAYMES stated that the plan was to connect the ice road with the Causeway.

4:16:08 PM

REPRESENTATIVE DOOGAN asked the definition of "retrograde" in connection with the reservoir.

MR. HAYMES explained that "retrograde condensate" means that when you get to a certain pressure, condensate will drop out of the reservoir. Point Thomson wells do not have a liquid drop out issue. The quality of the well in the immediate vicinity of the well neutralizes the effect.

4:18:49 PM

REPRESENTATIVE DOOGAN referenced Slide 34 and asked for explanation of the phrase: "Our technical work shows that over 90 percent of developable hydrocarbons (gas, condensate, and oil) can be produced today through a gas sales development." He thought gas was measured differently than condensate and oil. He wanted to know what was being measured by the "90 percent."

MR. HAYMES answered that there are two kinds of resources at Point Thomson: gas and oil. Condensate does not exist in the reservoir. If there was a move to gas sales, 90 percent of that gas, and the possible recoverable condensate, and the oil will be produced.

REPRESENTATIVE DOOGAN summarized that Exxon does not agree with the AOGCC's assessment of Point Thomson as an oil field first.

MR. HAYMES responded that Exxon Mobil agrees with AOGCC's representation of Point Thomson in accordance with regulations, which stipulate that if the liquid yield is over 50 barrels per million cubic foot, the reservoir is deemed an oil field. The reality is that the predominate, recoverable economic resource at Point Thomson is gas and along with it, condensate. Most of the condensate will be produced with gas sales. Cycling will accelerate what is available.

REPRESENTATIVE DOOGAN thought that he had heard from AOGCC that the development scenario was getting the condensate and the oil and then producing the gas. He asked if Exxon Mobil was saying there would be simultaneous production of gas, condensate and oil.

MR. HAYMES replied that the next best step for Point Thomson would be to attempt to get as much condensate out of the reservoir while waiting for the gas pipeline. The best time to delineate and produce oil is when the pressure is available. He agreed that more oil and condensate would be developed (up to 90 percent) with gas sales development. He maintained that there are still many challenges. Expansion in multiple directions would be available.

4:24:08 PM

JOHN ZAGER, GENERAL MANAGER, CHEVRON-ALASKA, provided members with a PowerPoint presentation (Copy on File). He explained that Chevron has interest in the North Slope and is a 25 percent working interest owner at Point Thomson. The majority of their interest is in Point Thomson. At a minimum, the recent DNR decision would delay the 2008–2009 drilling season.

MR. ZAGER introduced Slide 3, a visual map of Chevron assets on the North Slope.

4:28:30 PM

MR. ZAGER reviewed items that have been brought forward as fact or fiction:

1. Point Thomson is not needed for a gas pipeline.
2. The lessees are warehousing Point Thomson.
3. DNR rejected the plan of development on its merits.
4. The lessees are not doing any work on Point Thomson.
5. Point Thomson is “wildly economic.”

MR. ZAGER turned to Slide 5, “Point Thomson is not needed for a gas pipeline.” He maintained that:

- There are insufficient proven reserves available to back a commercially viable 4.5 Bcf/d gas pipeline without Point Thomson.
- Will anyone commit FT (ship-or-pay) for the ‘yet to find’ (YTF) resources? Without Point Thomson, this is a significantly bigger number.
- A Prudhoe Bay-only pipeline delivers less value to the state and producers through higher tariff rates and the loss of oil resulting from blowing down Prudhoe Bay.

4:31:51 PM

MR. ZAGER addressed Slide 6, "The lessees are warehousing Pout Thomson":

- At no time has there ever been a way to get the gas to market; it is disingenuous to say it has been warehoused.
- Until the recent ramp up in prices, the condensate resource was clearly uneconomic; it remains challenged.
- The oil resource is problematic due to its depth, range in quality, and potential range of recoverable volumes. It is currently viewed as economically challenged. The proposed POD is designed to resolve these uncertainties.

4:33:07 PM

MR. ZAGER discussed the third point, "The DNR rejected the plan of development on its merits" (Slide 7):

- The prior plan and amended plan were rejected because they did not "commit to put the unit into production." The current plan commits to put the unit into production as well as delineate all reservoirs.
- In its April 2008 decision, the DNR stated that the current plan is "a technically reasonable first step for developing these lands."
- But instead of considering the plan on its merits, the Commissioner of DNR has:
    - Taken the unprecedented step of decertifying wells for the purpose of terminating a unit through administrative action.
    - Has ruled that the proposed PODs do not coincide with his preferred development, while refusing to specifically lay out his preferred development.
    - Moved to expropriate the asset despite acknowledging the plan's merits by claiming a lack of "trust" of the lessees. (For over 27 years, the Commissioner of DNR and the lessees agreed the PODs set out the appropriate course of action for the development of Point Thomson as evidenced by the ongoing DNR approval up to August of 2005.)
    - Refused to meet with the lessees to outline his expectations.

MR. ZAGER disavowed point 4, "The owners are not doing any work on Point Thomson" (Slide 8):

- Over the last 30 years, the owners have spent over $800 million on the exploration and development of Point Thomson.
- Despite the state's move to expropriate the leases, the lessees have dedicated significant resources to continue technical work:
  - o Reservoir simulation and flow stream modeling;
  - o Planning for development;
  - o Initiating engineering design for facilities;
  - o Making financial commitments for drilling oil rig and long-lead items; and
  - o Progressing permitting applications.

MR. ZAGER addressed the claim that "Point Thomson is wildly economic" (Slide 9):

- The complexity and unique nature of this reservoir makes it a very challenging and expensive field to develop.
- While the upstream has been described as delivering a greater than 50 percent rate of return (ROR), specific to PTU it appears that the Black and Veatch base case depicts the value at a modest 13 percent ROR:
  - o Aggressive assumptions on gas price and cost trends; and
  - o Base case of an initial gas blowdown (i.e., no gas cycling).

(4:37:45 PM)

4:39:24 PM

VINCE LEMIEUX, MANAGER, ALASKA NEW VENTURES, CHEVRON, noted that they had looked at PetroTel's report and that DNR Commissioner had said that the new information changed everything. The work done is strictly theoretical. It does not take into consideration the full and practical aspects of economics and concrete considerations about the wells. Most of all, the report overstates the oil.

MR. LEMIEUX argued that the incremental recoverable liquids at Point Thomson are substantially less than 500 million barrels. He estimated that there could be less oil produced on the North Slope as a result of this. The entire system has to be taken into consideration.

MR. LEMIEUX emphasized the complexity of the field. He spoke to the continuity of the field, which relates to how the rocks are put together. That cannot be assessed through seismic. This is absolutely critical to figuring how the field will be developed. Chevron operates some of the highest pressure cycling projects today, but those projects

are difficult and risky, both from economic and safety standpoints.

4:44:07 PM

MR. LEMIEUX thought that PetroTel's report did a very good job regarding the immediate work that needs to be done at Point Thomson is consistent with the proposed plan of development. It has to be a phased approach; the initial information will inform the next step. He asserted that the proposed POD is the right first step.

4:46:40 PM

MR. LEMIEUX argued that the project needs to get started, and that the current lease holders are in the best position to get results. There is no magic bullet; the work needs to be done to get the information, and the time frame proposed is necessary. He did not think that cycling was likely to work, given the stratigraphy of the field. If it doesn't work, then the move can be made to gas sales. If it does work, there will be a productive oil field. A delay could result in a smaller pipeline. He reiterated the importance of moving forward with the proposed plan of development.

4:48:54 PM

MR. ZAGER referred to Slide 13, which delineates Chevron's position regarding AGIA and any pipeline. Chevron is not a participant at this time, although they would like to own shipping capacity. If Point Thomson is resolved favorably for Chevron, they would be a significant player in a pipeline.

MR. ZAGER asserted that Chevron will commit firm transportation for known gas reserves to a pipeline that they are confident provides reasonable upstream economics and terms. There would have to be a tariff that allows Point Thomson to have reasonable economics. By "confident," Chevron means they will look at the open season materials to determine economics.

MR. ZAGER spoke to key variables and assessed the controllability of each. Point Thomson resolution is controllable, but future gas prices are not. Construction costs are partially controllable; some components such as the price of steel and labor will escalate at an unknown rate, while design and management of the project are controllable. He raised the question of the actual costs of open season.

4:55:28 PM

MR. ZAGER observed that cost risk allocation is controllable, although Chevron would like to see it spread out so that there is real incentive for the developer to meet the number in the open season proposal. State taxes are controllable and will be a real issue. Many of the elements are aligned with the state to assure the highest price available. He concluded that both Chevron and the state want the projects done in the most economic way. A certain amount of capital invested will be picked up by the state in the form of credit. Producers are looking for a greater partnership with the state to find the most prudent investment.

4:58:38 PM

MR. ZAGER concluded with Slide 14:

- The Point Thomson Unit is critical to any major gas pipeline.
- Point Thomson development should begin as soon as possible; the POD is the right plan.
- DNR should have approved the proposed PTU plan on its merits.
- The current lessees can and will (if allowed) develop Point Thomson better and faster than anyone else.
- Chevron is being forced to litigate to protect its rights.
- Chevron wants to sell its North Slope oil and gas as efficiently and rapidly as possible.

5:02:11 PM

MR. ZAGER noted that Chevron is in protracted litigation and Point Thomson is outside of the proposed gas pipeline. Everyone agrees that the substance of the proposed POD is right and Chevron stands ready to perform the proposed plan. Owners remain ready to drill in 2008-2009. He proposed that an independent, objective review of the pipeline analysis should be undertaken. More outside resources are needed. In an open and honest government, the parties to the Point Thomson litigation would sit down and talk through their differences.

5:05:06 PM

REPRESENTATIVE FAIRCLOUGH asked for more information regarding acceptance by DNR regarding submitted permits. She observed that FERC typically can look at two proposals and will discern which project should go forward and let the finance markets decide. She questioned the disadvantages for the producer of voting “yes” on AGIA.

MR. ZAGER stated that Chevron did not want to comment on AGIA or if the $500 million would be well spent. The issue remains whether or not AGIA would result in production.

REPRESENTATIVE FAIRCLOUGH summarized that many thought there is no reason to vote no. She wanted to know how producers stood in order to inform her constituents.

5:07:53 PM

SENATOR WAGONER asked how much of the $1.2 billion estimated for the development would be taken up by the state through ACES credits.

MR. ZAGER did not have a figure and observed that it would different for each company. He acknowledged that there will be credits on capital, but he did not know which would be covered and which would not.

SENATOR WAGONER requested those figures.

5:09:28 PM

SENATOR THERRIAULT asked for comments regarding the change in the Point Thomson Unit voting rights to a simple majority.

MR. LEMIEUX observed that the voting change was most dramatic for Chevron. Prior to the change, both Exxon and BP could make a decision which would carry Chevron. A simple majority meant that any two of the three could decide that a project needed to be carried forward. The motivation is significantly changed.

MR. ZAGER added that one way to look at it was that no one would carry the risk of carrying someone else. On the other hand, if two say yes, the other would not take the risk for staying behind.

SENATOR THERRIAULT pointed out that the possibility that a company would go non-consent in a circumstance like this is low.

MR. LEMIEUX agreed that the penalties for non-consent on a big project are very stiff and a company would most likely not take that risk.

5:12:31 PM

SENATOR THERRIAULT raised the issue of meaningful penalties. Exxon did not have meaningful penalties under the POD. Under the unit agreement, if the state were to impose that, there is a shift of burden of proof from the producers to the state. He asked if Chevron had a position.

MR. LEMIEUX stressed Chevron wants to sell its oil and gas. He thought that there was a lack of honest dialogue regarding the proposed plan. Chevron would consider a broad range of consequences, including lease relinquishment.

5:15:28 PM

REPRESENTATIVE DOOGAN asked for clarification regarding "practically recoverable reserves."

MR. LEMIEUX answered that practical is closely linked to economic reserves.

5:17:04 PM

SENATOR HUGGINS noted that $700 thousand was spent for PetrolTel's contract. HB 3001 and SB 3001 were held in committee.

ADJOURNMENT

The meeting was adjourned at 5:18:16 PM.