ALASKA STATE LEGISLATURE
SENATE RESOURCES STANDING COMMITTEE
August 16, 2011
9:02 a.m.

MEMBERS PRESENT

Senator Joe Paskvan, Co-Chair
Senator Thomas Wagoner, Co-Chair
Senator Bill Wielechowski, Vice Chair
Senator Bert Stedman
Senator Lesil McGuire
Senator Hollis French
Senator Gary Stevens

MEMBERS ABSENT

All members present

OTHER LEGISLATORS PRESENT

Senator Charlie Huggins
Senator Fred Dyson
Representative Paul Seaton
Representative Les Gara
Representative Wes Keller
Representative Mike Hawker
Representative Chris Tuck - via teleconference
Representative David Guttenberg - via teleconference

COMMITTEE CALENDAR

Presentations on Cook Inlet oil and gas
TransCanada's AGIA Update
Alaska Oil and Gas Conservation Commission Update
Department of Natural Resources Update
USGS Update

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to consider

WITNESS REGISTER

TONY PALMER, Vice President

Major Projects Development
TransCanada Pipeline Corporation
POSITION STATEMENT: Provided update on the Alaska Pipeline Project (APP).

CATHY FOERSTER, Commissioner
Alaska Oil and Gas Conservation Commission (AOGCC)
POSITION STATEMENT: Commented on the AOGCC's role in the state's gas production and answered questions about production of Cook Inlet oil and gas.

PAUL DECKER, Manager
Resource Evaluation Section
Division of Oil and Gas
Department of Natural Resources (DNR)
Anchorage, AK
POSITION STATEMENT: Commented on Cook Inlet gas and oil production from the state's perspective.

JEFF DYKSTRA, Commercial Analyst
Division of Oil and Gas
Department of Natural Resources (DNR)
Anchorage, AK
POSITION STATEMENT: Commented on commercial aspects of Cook Inlet oil and gas production.

BRENDA PIERCE, Manager
Energy Resources Program
United States Geological survey (USGS)
Department of Interior
POSITION STATEMENT: Commented on USGS resource evaluation methodologies and on Cook Inlet resource estimates.

ACTION NARRATIVE

9:02:28 AM
CO-CHAIR JOE PASKVAN called the Senate Resources Standing Committee meeting to order at 9:02 a.m. Present at the call to order were Senators Dyson, Stedman, Stevens, Co-chair Wagoner, and Co-chair Paskvan.

AGIA UPDATE

9:02:34 AM
CO-CHAIR PASKVAN announced the first order of business would be to hear an update on the Alaska Gasline Inducement Act (AGIA) from TransCanada Corporation, AGIA licensee.

9:03:49 AM
TONY PALMER, Vice President, Major Projects Development, TransCanada Pipeline Corporation, said that he wanted to highlight the requirements needed to make the Alaska Pipeline Project (APP) a success. As the sponsors of the APP, TransCanada is responsible for maintaining the technical and regulatory schedule and for negotiating commercial agreements with shippers. The state also has a significant role as the licensor through the Alaska Gas Inducement Act (AGIA) to resolve the Pt. Thomson and gas fiscals and in its role in support of AGIA by appropriating for reimbursement.

The producers and shippers also play a key role because they are ultimately potential customers; their role would be to negotiate commercial agreements with TransCanada and to work with the state to resolve the Pt. Thomson issue. The U.S. government has significant roles as well because no project succeeds without having regulatory approvals: Mr. Persily as the Pipeline Coordinator and the Federal Energy Regulatory Commission (FERC) have significant roles in facilitating project permitting.

MR. PALMER said there is also the issue of the federal loan guarantee, which could be a large plus to this project. On the Canadian side, the Northern Pipeline Agency (NPA) must also facilitate project permitting. Despite all those roles, the project is still subject, as any major infrastructure project is, to external factors. That's the nature of this business.

9:06:38 AM
Gas supply and demand in North America changes globally, he said, and gas price forecasts are different today than three years ago. The parties that matter now are TransCanada's potential shippers and their view of gas prices in the long run, because they are the ones making the financial commitments. The LNG export market is changing, as well. Three years ago folks thought there would be significant imports of LNG into this continent and now those are very modest and a number of potential projects are being put forward by players in the Gulf Coast and Western Canada to export LNG off this continent into other markets.

9:07:37 AM
SENATOR FRENCH joined the committee.

MR. PALMER said that financial and debt markets have also changed significantly with the late 2008 meltdowns and the more

recent changes affecting both national and global markets. It has affected the debt capacity of major financial institutions in this country as well as global institutions making the federal loan guarantee part of this program even more important - because the financial capacity of banks is what has traditionally funded these types of projects. In the next three years more changes will be seen. This project will be in service by the end of this decade and will operate for 20 to 50 years after that.

9:10:03 AM
CO-CHAIR WAGONER asked what would happen to the federal guarantee if this project became a line to tidewater with a spur into Cook Inlet and how that would relate to the original project.

MR. PALMER answered that the original $18 billion federal guarantee, originally passed in 2004, was for both the U.S. and Canadian portions of the line. It wouldn't apply for an export project outside of U.S. markets, and Congress has considered upping the guarantee to $30 billion; but no regulations have been put in place. This is like a banker not providing terms on a mortgage, and many details still need to be resolved. The federal loan guarantee could be a very large positive if LNG went only to U.S. markets.

9:12:58 AM
SENATOR STEVENS asked Mr. Palmer to give a brief summary of current and future LNG supply and demand in North America.

MR. PALMER replied that he is not an expert in that field, but he had some views. For two decades U.S. production was in the neighborhood of 50 bcf per day; the range of production in the Lower 48 was the same. With the shale gas revolution in the last several years, that has shot up dramatically and is projected to hit 60 bcf per day. Thinking in terms of those numbers, that is a couple of Alaskan projects, a very significant explosion of supply in the Lower 48. As a result there has been some fall-off in conventional gas. Because gas prices are lower, unconventional gas, in many cases, struggles to compete on full cycle economics at $4 gas. They can compete on half cycle economics where the gas has been found and can be produced, but to go find and develop conventional gas at $4 in many basins is highly challenged. This is a very significant change in Lower 48 production over the last several years.

9:15:27 AM

On the demand side, Mr. Palmer said, a response is starting to be seen. Low gas prices cause higher demand generally, but the response is slow and residential consumers don't change their consumption much whether gas prices are at $4 or $8. "We all need to heat our homes..." he said.

Commercial usage is much the same. On the power generation side, demand is increasing as a result of low gas prices, but the established base of power production from coal, much of it 10 to 20 years old, is not going to be readily replaced. When those plants do come to the end of their economic life, the owners and regulators will have to decide whether or not they are renewed or get replaced with a new coal or gas plant. Here is an opportunity for gas if it stays at low prices on a long term basis.

9:16:49 AM
Nuclear power has some ups and downs. The U.S. hasn't commissioned any new nuclear plants for two or more decades. TransCanada is refurbishing one now in Ontario and that should be in service next year, but that is one of the few examples on this continent. The Fukushima Daiichi disaster may have deferred nuclear again, but that is still in question.

MR. PALMER said how long gas will remain in the $4 range is also an open question. At that price, some basins are highly economic, particularly if they have significant liquids. Liquids are comparable to oil in value and they are getting somewhere in the $80 to $100 per barrel range. Compare that with gas prices at $4 and you have a ratio between oil and gas that is in the 20:1 range and it has traditionally been a lot lower than that. For decades it was in the 8 to 12 range. Today, liquid-rich gas fields are being developed quickly, a number of them shale fields; dry gas fields are less economic. It is hard to predict if $4 gas will be sustainable, and at this point he didn't know what large producers think, but what they do think matters.

9:19:36 AM
SENATOR WIELECHOWSKI asked how Lower 48 shale gas will affect this project and what the status of his Valdez evaluation was.

MR. PALMER reiterated that public gas price forecasts are much lower today than they were three years ago. Economic forecasters are influenced by current circumstances and their forecasts are one of the external things customers will have to consider before committing to this project. Gas supply is projected to be higher in North America than it was three of four years ago.

The same impact hasn't been seen on the global side, although changes are happening. No one knows if the shale gas revolution will come to China. Currently, Asian gas prices continue to be priced off oil and that, today, yields a very high LNG price. Some LNG buyers are coming to North America seeking to purchase potentially North American natural gas just as they seek to purchase from Qatar, Australia, and so on. Some of those parties have advised that they are seeking to get North American prices. If successful in doing that they will break the linkage to oil - but that is still an open question also.

MR. PALMER summarized that the shale gas revolution hasn't made this project less economic to date. TransCanada is still negotiating with potential customers who haven't walked away from the table. TransCanada has two alternatives: one, to move gas to Alberta and the other to move it to Valdez, but customers haven't been obtained for either. The FERC regulations on this project require them to take late bids, so they are open to receive them. He reminded members that TransCanada has always had a component for in-state gas on this project and if a large line is put in service that will provide low cost gas to Alaskans just because of the economies of scale.

9:24:57 AM
CO-CHAIR PASKVAN asked what would happen to the market in general and in particular to the AGIA process if the shale gas revolution would come to China.

MR. PALMER replied that is a highly speculative topic. The cost of developing it is uncertain and more will be known in 2 to 5 years. If China has the same results North America has had, it would be very significant. China has a shortage of natural gas; they import from proximate countries via pipeline as well as LNG, and they are expected to have a hugely growing market. A domestic source at low prices will have a huge impact on how they purchase gas and the price at which they purchase gas from offshore. At the moment, they are principally purchasing gas on a "Japanese Crude Cocktail" at a crude oil-linked price. If there is no change and China continues to have growth that leaves an opportunity for producers or other shippers to nominate Valdez and sign a contract to move gas there. But if on the other hand, gas prices are very low in China that makes it much more challenging for Alaska gas to compete in the marketplace, because there is no other dedicated market for Alaska gas other than the domestic market within the state. If the gas goes to Alberta on the way to the Lower 48, Alaska gas

will compete with Lower 48 and Canadian supplies. If Alaska gas goes to Asia, it will compete with Australian gas, Sakhalin gas and Qatar gas and potentially Lower 48 and western Canadian gas.

He said there are four announced LNG export projects potentially from Kitimat [British Columbia] and three years ago there was an import project, but none of these projects has established all the necessary connections to go forward. Chenier out of the Gulf Coast is looking at projects to turn re-gas terminals into liquefaction terminals and exporting gas basically from the NYNEX Hub.

9:27:24 AM
SENATOR DYSON said the credibility of TransCanada's project took a big jump up in his view when ExxonMobil joined it. He has been told that ExxonMobil is more experienced on the financial side and that they are not all that impressed with today's prices, but rather look at the ones 10 or 15 years out. Is that true in general of major producers?

MR. PALMER replied that one division of ExxonMobil is TransCanada's partner in the pipeline project and there exists a distinct firewall between it and the ExxonMobil Production and Marketing division, which TransCanada wants as a customer along with the other producers. Those parties that are in every market and generally in every supply basin in the world succeed, in his view, by taking a very long view of markets - and their success over the last half-century has been remarkable.

SENATOR STEDMAN asked who their customers are.

MR. PALMER replied that he can't say because of strict confidentially provisions. He said this project has had remarkable transparency and that TransCanada revealed its entire commercial proposal before competitors had to "put their marker down." That is unique in the industry.

He explained that the reason for confidentiality is because until recently TransCanada's potential customers are the same companies that were in competition for the same project and secondly, because their potential customers, if they are producers, have potential confidential information with regards to where their gas will be received or delivered into the pipeline, which can affect the value of land leases and competitive markets at both ends of the pipe.

SENATOR STEDMAN asked, for the public's information, if their potential customers are the companies that own the North Slope leases: ExxonMobil, BP, ConocoPhillips and Chevron.

MR. PALMER responded that he didn't mean to be evasive; clearly the companies he listed are potential customers on any project, including theirs, but no contracts had been established yet and while he didn't think it likely, because the project is so large and long term there could be intermediaries like marketers as well.

9:35:49 AM
CO-CHAIR PASKVAN asked if he heard anything about the ability to off-take gas from the North Slope.

MR. PALMER asked if his question was in regards to the Alaska Oil and Gas Conservation Commission (AOGCC) requirement.

CO-CHAIR PASKVAN replied yes.

MR. PALMER replied that in the past the AOGCC has indicated the ability to produce 2.3 or 2.7 bcf/day off of the Prudhoe Bay field. A larger volume would need an application by the lease holders affirmed by the AOGCC if they were in favor of it and he didn't know what the Pt. Thomson volume would be.

9:37:12 AM
SENATOR MCGUIRE joined the committee.

SENATOR WIELECHOWSKI said he supported this project, but the state has to decide about how to proceed and it is increasingly difficult to make decisions without information on where it stands. When TransCanada had a direct competitor they had a compelling reason to not disclose information, but now they are also beyond the timeline, so he wanted to know if legislators could sign confidentiality agreements with TransCanada to get that information.

MR. PALMER replied that today he would tell him where they are on the commercial side, within the boundaries of the confidentiality agreement and while not putting anyone in a compromising position, and about the technical and regulatory work that has been done - as required by the AGIA statute.

9:41:23 AM
SENATOR DYSON remarked that a couple of years ago experienced industry people told him there will not be a long term supply of

unconventional gas in North America for two reasons: the startling decline rates generally on those plays and the environmental push-back that is already happening and asked Mr. Palmer his sense of what will happen with unconventional gas production in North America.

MR. PALMER replied that was an open question. At the moment most of the news about shale gas and unconventional gas is very positive. The production increases have been remarkable and at very low cost. As more development occurs in non-traditional areas for natural gas local folks are starting to want to understand that development a little bit better. It's clear that shale gas is very real in the short term and likely in the long run.

He continued that three years ago the Alaska legislature approved a license, but it didn't come into effect until December 2008 and said that TransCanada had met all of its regulatory and technical targets over that timeframe. They commenced work before the license was granted to maintain schedule and two years ago ExxonMobil aligned with them.

He has been saying for seven years now that this project needs five critical players to make it a success: the State of Alaska, ExxonMobil, Conoco, BP, and TransCanada. At present three of those are together: the State of Alaska, TransCanada and ExxonMobil. A team of 110 individuals works on this project full-time in addition to contract employees; 170 people are in the field this summer in Alaska and Canada and more than that last summer. This project is moving forward on the technical and regulatory side completely on schedule, he said.

At FERC's request, a pre-filing application was made in May 2009. TransCanada has updated and optimized the project technical and cost basis for the open season and published it, making it public three months before their major competitor had to put their marker in the ground.

9:46:14 AM
MR. PALMER stated that parties have said TransCanada needs to engage with communities along the right-of-way and they have held 56 community meetings in Alaska to date. He said the environmental and field work TransCanada has completed in the last three years is expensive, but it will continue, because their AGIA license obligates them to make a FERC filing in the fall of 2012 regardless of the outcome of the commercial open season. Forty Alaskan businesses and 500 Alaskan workers have

worked on the project and they are on track to submit the FERC permit application on time. TransCanada filed draft resource reports 1 and 10 in April 2011 and FERC recently issued its notice of intent to prepare an Environmental Impact Statement (EIS) in August 2011; they are on track to file all the draft resource reports with FERC by year-end, a "massive job." He related that regulatory work is also progressing in Canada under the Northern Pipeline Act.

In order for the project to succeed, he repeated, TransCanada needs two things: customers and legislative and regulatory approval. For any project to succeed, they must have both.

SENATOR MCGUIRE asked the status of TransCanada's negotiations with First Nations along the route and if any are still holding out.

MR. PALMER answered that TransCanada has a right-of-way through the Yukon and has held it since 1983, but they continue to have negotiations with both First Nations in Yukon and northern British Columbia (B.C.) and have executive participation agreements with several of them while continuing to negotiate with others. They are "well down the path," but there are still miles to go.

SENATOR MCGUIRE asked how many years of negotiations are left and how many miles of pipeline are affected in those rights-of-way.

9:50:11 AM
MR. PALMER replied approximately 1,000 miles for the Canadian portion of the pipeline: Yukon is approximately half of that and northern B.C., "traditional pipeline country," is the other half. The original Northern Pipeline Act gave the First Nations specific benefits, but TransCanada is negotiating to give them more. Other stakeholders are negotiating, too. At the moment, First Nations issues are not a roadblock for the Canadian portion.

CO-CHAIR WAGONER asked when companies can book their reserves and if it would be just ExxonMobil since they are already a partner in this project. Would other people be able to book reserves without being part of the project?

MR. PALMER replied that he didn't know that answer.

9:53:10 AM

MR. PALMER summarized that AGIA's commercial commitments to the state have been more than met in the last three years. TransCanada has aligned with ExxonMobil and invited BP and ConocoPhillips or any other major player to join them, and they are open to partnership discussions, as well.

He said they recognized that global gas markets are becoming more competitive not just on this continent, but internationally, and therefore significantly enhanced their commercial offerings by $500 million per year in tolls over 25-years, a reduction of $12.5 billion at 4.5 bcf/day. Yesterday he heard Mr. Fauske say he could not find any players that would take any of the development cost risk on the in-state bullet line, but TransCanada has already shared risk with the State of Alaska to the tune of $288 million to the end of second quarter 2011 and has received $94 million from the state in reimbursements.

He said also when the license was granted, TransCanada expected its floating rate of return (ROR) would be 14 percent and that was reduced to 12 percent in their open season, the ballpark figure Mr. Fauske said commercial parties would need in order to invest in the in-state gas line. Third, the license approved a 60/40 debt/equity structure for expansion and 70/30 during construction. In the open season TransCanada changed that to 70/30 during construction and 75/25 during in-service. Mr. Fauske said parties would require 30 percent equity.

Last, the license had an approved recovery of capital over the initial contract term of 20 or 25 years, so they would recover 100 percent of their initially invested capital over the life of those initial contracts through depreciation. In fact, Mr. Fauske indicated that's exactly what third parties would need to invest in the in-state gas line. TransCanada, in its open season, proposed to recover only 80 percent of its initial capital over the term of the initial contracts.

MR. PALMER summarized that all of those components increase the risk to the pipeline sponsors, TransCanada and ExxonMobil, that have invested their capital in the development costs, taken on more risk on the equity side, taken on more risk in terms of recovery of their capital - and they are doing so for a return of 12 percent. They have done all that to make this project more competitive.

9:59:10 AM

SENATOR WIELECHOWSKI asked how much TransCanada and ExxonMobil plan to spend until the issuance of a FERC license and how much do they anticipate the additional state reimbursements will be.

MR. PALMER answered if they are unsuccessful in getting customers and are still moving forward strictly with the certificate and still struggling to get customers on a long term basis, they have indicated spending in the order of $700 million to get to the certificate by 2014. During the course of that process, the state would have fully reimbursed the $500 million and the two sponsors will have expended the residual couple hundred million. If they do get customers, they would accelerate the spending, because at that point they would not only be seeking to get a certificate, but to actually be in service by a certain date.

10:01:42 AM
SENATOR STEDMAN said Mr. Palmer talked about flexibility in the negotiations he had with potential customers to make their post-project more competitive, but TransCanada has no customers. How are legislators to interpret that against other projects like the in-state gas line?

MR. PALMER replied that the proposed toll based on capital costs in their open season to Valdez was $2.45 to $3.15; their proposed toll to Alberta was $2.80 to $3.50. TransCanada has "negotiated hard" with customers post open season for a year and TransCanada and ExxonMobil have made even further concessions, and they are prepared to make even further concessions on other components of commercial terms "to try and get over the finish line."

He said the commercial side is behind schedule, but the pace of commercial progress is dependent on diverse external factors that they do not control like having collaboration with other parties. This is one of the largest commercial projects to be built in the world - two to three times the size of other private gas projects in the world and with a 10 year development timeframe. Commercial negotiations are highly complex. Progress has been made on Pt. Thomson gas, which is necessary to make this project viable to the North American market. But a smaller volume to Valdez might change that.

10:09:29 AM
CO-CHAIR PASKVAN asked for his thoughts on the Denali project folding and rumors of TransCanada's project folding soon, too.

MR. PALMER answered that the sponsors of the other project, ConocoPhillips and BP, also had a firewall between sponsorship of Denali and their shipping components. There are two ways to look at the Denali demise. From a glass half empty point of view, the sponsors were unsuccessful in getting customers and decided they no longer wanted to pursue the project. He said 18 months ago TransCanada put out its commercial offerings in their open season; it was public. Three months later Denali came out with a remarkably similar proposal. The fact that Denali could only match TransCanada's proposal suggests that the bid made three months earlier was very competitive. Why did Denali go away? TransCanada has always thought they have had an advantage in Canada and that they have the skill set to advance this project, and with ExxonMobil on board that was improved. TransCanada has always welcomed BP, ConocoPhillips or any other major player to join their project. So, if you're a glass half full kind of person, you could say it was necessary for one of these major projects to end. No one ever contemplated that both projects were going to be completed.

10:13:29 AM
SENATOR WIELECHOWSKI said AGIA guarantees fiscal terms for a decade so much so that if the gas pipeline would be turned on today the State of Alaska would probably lose billions of dollars because the price of oil and gas is coupled and asked what other fiscal terms are needed.

MR. PALMER answered that he was not the party to answer that; that is between the state and the producers.

10:15:10 AM
SENATOR FRENCH asked of the three issues he has talked about being out of their control, which one is the biggest holding up the project.

MR. PALMER replied it's not just what is happening in North America, but what is happening in global markets as well. At present, until the state and the producers have resolved their issues, it's very challenging to get customers. Those issues could be resolved and there could still be no project if the gas price is not right. At the point those issues are resolved, it has to be determined if the project is economic or not. The first two are necessary conditions and they may or may not be sufficient. As issues are resolved the next decisions must be evaluated based on current economics.

10:19:36 AM

SENATOR WIELECHOWSKI said the lease terms signed by the oil and gas companies require them to produce or develop their resource gas when it's reasonably profitable and asked if the terms TransCanada is providing makes gas production by those companies reasonably profitable.

MR. PALMER replied that he is confident that they have offered highly competitive pipeline tariff terms and they continue to negotiate to make it even more competitive. And in order to answer Senator Wielechowski's question you need to have a view as to what gas prices are going to be in whatever market these folks intend to deliver into and you need to have a view as to what their take will be and the state take will be - all questions that he couldn't answer.

10:21:09 AM
REPRESENTATIVE OLSON asked if TransCanada would still be doing this project without the state's $500 million subsidy, because that is the main difference between them and the project that folded.

MR. PALMER replied when TransCanada received the license, they knew their substantial obligations to the state but that they also received certain benefits. Those obligations have been met, but it's not a one-sided arrangement. At present, TransCanada has invested $194 million in this project: they were obliged to have a maximum of 30 percent equity, relatively low in the U.S. pipeline industry; they were obliged to continue with this project regardless of the outcome of the open season and in order to meet the schedule they had to do work during the open season and before it in order to maintain schedule; they also took on tariff and terms that were distinctly laid out for any party that wished to bid. In return they received the $500 million state contribution. So, when people say TransCanada is somehow continuing with this project strictly because it is receiving a "subsidy" from the State of Alaska, it's more like the state is continuing to meet its obligations along with TransCanada.

REPRESENTATIVE OLSON asked at what point TransCanada would reach a decision on proceeding.

MR. PALMER replied if there is no optimism that the state and the producers will resolve their issues - and yesterday he heard a great deal of optimism about Pt. Thomson from Commissioner Sullivan - nothing will be resolved. And TransCanada will clearly have a decision point. If there continues to be optimism

that they will be resolved in a timely fashion, then "we're going to let the game play out...."

10:26:48 AM
MR. PALMER said TransCanada continues to meet its obligations to the State of Alaska under the license and they believe the state is meeting its obligations to TransCanada. Their regulatory and technical timelines are on schedule, but their commercial timeline is behind schedule, primarily because of issues out of their control. They are pleased with developments mainly at Pt. Thomson. TransCanada wants to work through AGIA and get over the finish line, but they need to see breakthroughs from the state and customers.

10:29:45 AM
SENATOR WIELECHOWSKI said one of the reasons for this meeting is because the state is at a crossroads and has to decide about moving ahead on the big pipeline or the in-state line. He asked if he had a chance to look at the Fauske report and if he agreed that the tariffs are reasonable. Is $2 a good price for gas off the North Slope?

MR. PALMER replied that he had read the report, but he had done no evaluation as to whether their capital costs are accurate; the producers will have to determine if the price is right. Mr. Fauske's project is a $7.5 billion project; TransCanada has completed the first part of the Keystone oil line from Alberta to Lotoka and Cushing for $6 billion, a massive undertaking, and is waiting for approval to do the second phase of that project at a cost of $7 billion.

Any major project needs some things in common like customers that can commit their gas to a project. And customers are saying they need a long-standing fiscal arrangement between them and the state. TransCanada needs long-term customer contracts with credit worthy partners enough to pay a 20 or 25 year contract. That is probably what Mr. Fauske is looking for. Both projects need to get permits and customers for the full volume of the project. Then you get into the debt/equity ratios that he has already described.

10:34:21 AM
SENATOR DYSON said part of the selling point for TransCanada was the spare capacity in their Alberta pipeline and asked if that had changed or if it would change in the future.

MR. PALMER replied it has changed in that they have more spare capacity now. The shale gas revolution and increased production in the Lower 48 has resulted in lower production in western Canada. Approximately 15 bcf/day of capacity leaves western Canada for the market in eastern Canada and the Lower 48 and that 15 bcf/day is not full today by a long shot. They hoped the shale gas development in northeast B.C. will refill the pipe over the course of the next decade.

10:36:24 AM
REPRESENTATIVE SEATON said they are pleased to see the resolution of Pt. Thomson possibly on the table. During stranded gas development legislators got a window into the Prudhoe Bay/Kuparuk joint operating agreement, in which, uniquely, if one of the companies decides not to invest or conduct a sale that would actually veto the project. He asked if one of the companies decides not to participate in this project would that veto it for the other two or the entire unit. Is that a negotiating point or an impediment for getting gas sales from individual producers?

MR. PALMER replied that he wasn't privy to that information.

10:38:54 AM
SENATOR WIELECHOWSKI remarked that if a total of $288 million has been spent and the state has reimbursed $94 million to TransCanada and Mr. Palmer said they would spend $7 million more, then there is $412 million left to be spent and the state is on the hook for up to $406 million. He said when AGIA passed, no one talked about shale gas and as a policy maker making decisions whether or not to continue investing he needs more information. He wanted to know if TransCanada's internal calculations show that this project is still profitable and if the producers are throwing up unreasonable stumbling blocks.

MR. PALMER responded that he appreciated that the state is investing its dollars with TransCanada and that they have major policy decisions to make, but what he is asking for is completely outside the bounds of pipeline processes across North America. He is asking him for highly confidential information, circumstances between customers and the pipeline on this project, to be put into the hands of 60 legislators. Negotiations are still ongoing and may still take turns. He said he would consider what he asked, but it is highly unusual.

SENATOR WIELECHOWSKI said he thought this was a highly unusual project because no other state in the country is putting up

hundreds of millions of dollars and as a partner still has no access to that information and stated, "I think we have a right to have that information." He offered to sign a confidentiality agreement saying it had been done in the past and that legislators have been very careful when they received information like that.

MR. PALMER replied that they have been able to share additional information with the administration under the confidentiality provisions of AGIA, but what Senator Wielechowski wants goes beyond the statute.

10:42:49 AM
SENATOR STEDMAN said it sounds like TransCanada needs to come up with another $20 million to go forward and the state has to come up with another $200 million, so an appropriation request would be needed this winter. At any rate, the $500 million is a "sunk cost" the state makes one year at a time regardless of which way the project goes.

10:44:32 AM
CO-CHAIR WAGONER asked if he had been faced with these types of external problems on other projects.

MR. PALMER replied yes; significant external issues have been out of their control with Keystone: one is if they will be granted a permit. The review process for that project is significantly beyond what it was for the original Keystone and other pipeline projects. Yes, they have faced significantly more opposition to what they thought was a straightforward pipeline project and have ended up investing more money than they expected, but they remain confident they will get to the finish line. He said the customers for that project are not public information; neither are the tolls. Contracts with this project have remarkable transparency because of the statutes the legislature has set up and FERC requirements; TransCanada has had business with other governments that also come with certain obligations and rights. It has faced other projects that have items outside the project that can delay and potentially stop it.

10:47:43 AM
SENATOR MCGUIRE said she understood if this project isn't successful that the state retains the license and the data as part of the $500 million it has contributed and asked what he believes TransCanada's future rights are to the data and the

license itself and what their role will be in the future in the event of a failed plan this go-around.

MR. PALMER replied that he didn't have the statute in front of him, but the abandonment provision says if the administration decided the project was uneconomic (both parties have the right to claim that) and TransCanada agrees, at that point the project is over and the state has the option, not the obligation, to purchase the asset for their out of pocket dollars (the non-reimbursed qualified expenses). Without an agreement, there would be arbitration and the state would have no obligation to buy TransCanada's assets. Another circumstance is if the project isn't abandoned but they just never get to the finish line. He recalled there were some obligations and rights for both parties, but couldn't recall exactly what they were.

SENATOR MCGUIRE said she recalled that the state retained the license, but she just understood him to say that the state has the *option* to purchase it.

MR. PALMER answered that it's clearly set out in statute, but he didn't have it in front of him.

SENATOR MCGUIRE asked in the final scenario if he had any opinion or recollection about whether or not the 500 mmcf/day goes away with FERC certification.

MR. PALMER replied that the rationale for the 500 mmcf/day limitation is that TransCanada needs just about all of the proven gas to make its project economic. In fact at 4.5 bcf/day TransCanada needs more than the existing proven gas and since it was taking on obligations to the state, they had to know they had access to most or all of the gas.

10:55:01 AM
REPRESENTATIVE SEATON said Commissioner Sullivan talked about synchronizing open seasons yesterday and it seemed like the only way to do that was to discuss fiscal terms and asked if was he was concerned that the administration might finalize fiscal terms by the 2013 date.

MR. PALMER replied that he listened carefully to the commissioner yesterday and felt that it clearly is in TransCanada's interest to see resolution between the state and producers as soon as possible, but when it happens is not in their control. He said TransCanada has an obligation to solicit the market again in 2012 and an obligation under FERC to take

late bids. He wasn't sure what context was intended in talking about synchronizing open seasons.

10:57:16 AM
SENATOR FRENCH said Mr. Palmer could probably sense the frustration here today that they are not further down the road on this project, but he is "a glass half full person" and has heard it suggested by one of Alaska's delegation on the floor of the House that we somehow missed the boat on the gas pipeline and the window is closed. He sees it differently; he's glad they didn't go with the pipeline 20 years ago and that they are not selling gas into a $4 market. That gas is still in the bank on the North Slope. He appreciated the enormous effort Mr. Palmer and his company has put into getting this far.

10:58:46 AM
CO-CHAIR PASKVAN, seeing no further questions, thanked Mr. Palmer for appearing today.

Recess from 10:58 to 11:17 a.m.

ALASKA OIL AND GAS CONSERVATION COMMISSION UPATE

11:17:00 AM
CO-CHAIR PASKVAN called the meeting back to order and asked Ms. Foerster to come forward.

CATHY FOERSTER, Commissioner, Alaska Oil and Gas Conservation Commission (AOGCC), said she is the engineering commissioner and explained that the commission is charged by the Alaska Constitution with ensuring that operators get greater ultimate recovery of Alaska's hydrocarbon resource, that their operations do not cause waste of that resource, that when they're developing and producing that resource they keep fresh groundwater from harm, that the development is in such a way that correlative rights are protected and that operations under their statutory control are safe (blowout prevention and well safety systems, specifically).

She said their role in selling gas from the North Slope is in ensuring that when those gas sales occur that the oil associated with that gas is not put at risk of being lost and unrecoverable.

SENATOR STEDMAN asked her to explain how gas is related to oil.

MS. FOERSTER explained that hydrocarbons can exist either as natural gas reservoirs by themselves or as reservoirs that have a combination of oil and gas. The reservoirs that have been discovered on the North Slope that contain the natural gas they are talking about are both associated with oil. The two big reservoirs are at Prudhoe Bay that has about 24 tcf of gas associated with the 2 bbl/oil left in the ground yet to be recovered (11 bbl have come out already) and Pt. Thomson that still has 2 bbl/oil left to recover. She said that gas is necessary for getting oil out of the ground providing the pressure necessary to make the oil move up a couple of miles through these wells to the surface among other reservoir phenomenon associated with producing oil.

So, when the AOGCC looks at how operators are managing, they make sure that both the oil and the gas are being taken care of as well as possible. For instance, if they were to just start taking gas out of Prudhoe Bay the remaining 2 bbl/oil would be put at risk of not being produced at all. To put that in perspective Thunder Horse, the largest offshore discovery in the Gulf of Mexico in the last 10 years, is 1 bbl/oil. So she said "our poor, old, limp, tired Prudhoe Bay reservoir is still twice as big as the biggest discovery in the Gulf of Mexico." It can't be abandoned. Pt. Thomson has 9 tcf/gas and has somewhere between .5 and 2 billion barrels associated with it as well. The oil is more valuable and it needs the gas in order to be recovered.

11:23:28 AM
SENATOR STEDMAN remarked that putting in a gasline in the 80s or 90s or even 10 years ago would have been a disaster.

MS. FOERSTER said she generally agreed.

SENATOR WIELECHOWSKI paraphrased concerns she expressed at the end of last session about turning on the pipeline and shipping gas and how that would impact the ability to recover additional oil.

MS. FOERSTER responded that she typically says the longer you wait the lower the volume of gas you produce and the more steps that the operators have taken to get as much oil accelerated out of the ground as possible.

SENATOR WIELECHOWSKI asked how dramatically a big pipeline or a bullet line in 10 years would impact oil production on the North Slope.

MS. FOERSTER replied if it comes on 10 years from now, it's going to depend on how big the line is, how much of the oil has been produced and what mitigating steps the operator has put into place to prevent the loss of the gas. She has always said that gas is not only useful for getting the oil out of the ground from the reservoirs it's in, but it gets exported for enhanced oil recovery (EOR) use in other fields and that gas has potential to be very useful in the huge heavy oil and viscous oil resource only beginning to be tapped up there.

She stated that the U. S. Geological Survey (USGS) says 100 tcf of gas hasn't been found up there yet, and the reason it's not being looked for is because it can't be sold. If we were to build a gas pipeline, who is to say how much of that gas would be found? So, do we worry about the gas being needed for the oil? Yes. Is there hope that we start selling the gas; that we find more gas and we quit worrying about it? Yes; and forecasts will be wrong.

11:27:46 AM
CO-CHAIR PASKVAN asked her to explain how gas is important to the development of viscous oil resources.

MS. FOERSTER explained the primary way that gas would be valuable to the heavy resource development would be through decreasing its viscosity; introducing gas into those reservoirs in a variety of different ways makes oil more movable. She asked them to imagine sand mixed together in a box with peanut butter and how easy it would be to extract that peanut butter from the sand and if you could magically change that peanut butter's viscosity to where it flows like water so more could be gotten out. Using steam and heat are other methods that need to be tried; she didn't know which ones would be successful, but they all require fuel and natural gas is the fuel to make those other things happen.

11:29:51 AM
SENATOR STEDMAN asked how the AOGCC deals with valuation for oil estimates.

MS. FOERSTER replied that the AOGCC just has to worry about the science and not which is worth more. Their job is to get them both out and it's easy to get gas out no matter what is being done to the oil, but the opposite is not true. Oil is the more valuable of the two resources, but the science says it's the harder one to protect.

SENATOR DYSON said it was represented yesterday that the bullet line hadn't gotten a commitment from the major producers on the North Slope to sell it gas, but they are required to make gas available. Yet he remembers conversations with the AOGCC and folks who understand the reservoir that it's probably seven or eight years before gas could be taken off without losing oil production.

MS. FOERSTER responded that it will be several years before the AOGCC will feel comfortable that gas off-take from the North Slope is a prudent move. No matter when it happens there will likely be oil losses unless all the oil is gone. Then there is the balance between how late you can wait to extract the gas before the infrastructure on the North Slope is starting to "peter out." She said operators are forecasting that they will be selling that oil until 2050, so she personally was not in a hurry to get the gas out of the ground. But based on what is publicly available about what the operators are doing to accelerate production - they're drilling lots of horizontal and multilateral wells - and what they are doing to mitigate losses - they're putting in pilots for testing like gas cap water injection - in the seven or eight-year timeframe, she thought the state would be comfortable with the losses that will be incurred if there is a gas sale. At that time the AOGCC wouldn't be the bad guy.

SENATOR DYSON asked under the existing legal regime if the producers are required to release gas.

MS. FOERSTER replied she didn't know what producers are required to do in their DNR leases, but they could be in a real dilemma if they are required to sell gas when the AOGCC told them they couldn't because it would be causing too much waste of the oil. If that's what their lease says, the AOGCC could probably trump the DNR, but the legislature could overrule the AOGCC.

11:34:51 AM
SENATOR STEVENS asked her to reflect on the administration's goal of 1 million barrels a day and what is best for Alaskans.

MS. FOERSTER replied that anything they can do to increase the throughput in the TransAlaska Pipeline System (TAPS) is a good thing. It's a lofty goal that is challenging and heavy oil resource development using natural gas is integral to achieving that goal.

SENATOR WIELECHOWSKI said in 10 years if the gas pipeline is built and if the oil/gas ratio is the same (20 or 25:1) it doesn't seem like there would be a whole lot of incentive for the oil companies to put gas in the pipeline when they can still use it to extract a much more valuable resource and asked to what extent that is playing into oil company resistance to commit gas to the pipeline.

MS. FOERSTER replied that she had three answers: one was that her experience is what is good for the oil companies (that are really working to maximize production) is good for the state and two; they are in the business of making money. Stockholders want that. And three, if the gas is still being used to get more oil out of the ground she thought everyone in the state would want them to do that.

SENATOR WIELECHOWSKI asked if they are being unreasonable thinking they should North Slope gas can be committed to a pipeline in the next decade in light of oil/gas ratios.

MS. FOERSTER replied that she didn't think it at all unreasonable for the legislature to be asking the oil companies to explain why they are doing what they are doing and why they are not doing something else and to urge them to do things that appear to be in the best interest of the State of Alaska and let them explain why it's not if they don't see eye to eye with them. It's also the legislature's responsibility to listen very carefully and very open mindedly to their answers and be open to the possibility that maybe they were wrong and as well as maybe they were right.

11:38:50 AM
CO-CHAIR PASKVAN said he heard earlier that AOGCC approved 2.5 bcf to be taken out of the reservoir and asked if that was accurate when that would commence and what her thoughts were on a 4.5 bcf extraction. And last, they are here today as part of the 0.5 bcf in-state gas line and how would that would affect the 4.5 bcf needed for the big line.

MS. FOERSTER replied that the 2.7 bcf off-take was put in place in the 70s. In 2006/7 after she had come to the AOGCC, that got reviewed. They conducted a study in which BP and the other Prudhoe Bay operators generously shared confidential data. At the hearing they decided that there was no reason to change the 2.7 bcf - and that by the time anyone could build a pipeline it would either be good or there would be plenty of time to see it coming that they could change it if needed.

She said the AOGCC was asked for an opinion on the 0.5 bcf line and used a similar rationale for saying that that small of a volume would probably be okay five or six years from now.

MS. FOERSTER said a 4.5 bcf line depends on when it happens, how much of the oil has been extracted and what mitigating steps the operators put in place to prevent loss of the gas. But the AOGCC could hold an emergency hearing and put a stay on production and sales into that line until they came to a conclusion which today would be no, you can't sell the gas.

11:42:58 AM
REPRESENTATIVE GARA asked if the legislature would still have to authorize a 4.5 bcf line in 2020 or afterwards and would the AOGCC say yes at that time.

MS. FOERSTER replied that is hard to say. By 2020, a 4 bcf line might be good for the state. That's nine years from now and she asked if they could even tell her what Alaska's operating budget will be then? No. She related that the operator is accelerating and putting in mitigation.

REPRESENTATIVE GARA stated that the governor says more oil is needed in the pipeline and asked what she thought was realistic to get out of the pipeline leaving aside offshore drilling for now.

MS. FOERSTER replied that offshore is going to be the key. She thought 1 million barrels was a very aggressive goal. She hoped it would happen even though she wouldn't bet on it. She said leaders are needed who will set goals.

SENATOR DYSON asked if she thought 500 mmcf could be taken off in five or six years.

MS. FOERSTER replied that she didn't think that would be a problem, but there will be losses; it's a balance.

SENATOR DYSON asked how realistic it is that rich gas plays are in the area.

MS. FOERSTER answered that discovering at least 150 tcf on the North Slope is very realistic. Every oil province she has worked in has had gas associated with it and every province she has worked in is where people have looked for the oil because it is much more valuable than the gas. Until they had a market for the

gas, they flared it until they were told they couldn't because it's wasteful. When people have drilled wells that have encountered something that doesn't look like oil, they have called it a dry hole and moved on.

SENATOR DYSON said people talk about how magic CO_2 is for lifting heavy oil and that is a by-product of gas conditioning.

MS. FOERSTER commented if there is a market for gas it's likely that people will find more. It could be used for pressure or sale. CO_2 production is association with the gas produced at Prudhoe and it will be the same at Pt. Thomson. She explained that when you sell gas into a gas pipeline you have to extract the things like CO_2 and H_2S that are corrosive to the metals in the pipeline. So CO_2 will be extracted from the gas and something will have to be done with it because it is not an environmentally friendly byproduct and just letting it go is a thing of the past. It will have to be sequestered. The best place to put it would be in the ground where it could help get more oil out. CO_2 is known as an enhanced oil recovery substance. These synergies will happen, but to what extent and where are yet to be determined.

CO-CHAIR PASKVAN asked if natural gas pressure is important to development of shale oil since Alaska may be entering into a new phase.

11:51:31 AM
MS. FOERSTER replied that shale oil is a slightly different animal. The reservoir is a harder rock and it won't have a gas cap or an oil rim. There is pressure and that is essential to the ability to lift the oil out of the ground. Other issues will be equally important or more like establishing permeability channels (through the hydraulic fracing process) to allow that resource to get out of the rocks. If you have heavy fluid that has to make it up out of the ground a mile or two it has to have something pushing and that's going to be pressure.

REPRESENTATIVE SEATON asked if the potential settlement on Pt. Thomson would override AOGCC criteria for hydrocarbon recovery.

MS. FOERSTER replied that she hadn't seen the settlement, but couldn't imagine ExxonMobil signing a contract agreeing to break Alaska law to get their leases back. She reminded people that the Pt. Thomson reservoir, although it's been called a gas reservoir by the state of Alaska's definition of what makes a gas reservoir, it's not. It's an oil reservoir, because the

gas/oil ratio makes it fall within the definition of an oil reservoir. So, Pt. Thomson would be another one of those reservoirs that the operator would have to get permission from the AOGCC to produce the gas, because producing the gas puts the oil at risk. Pt. Thomson is a little different than Prudhoe in that it's not a standard oil reservoir where the gas cap keeps the pressure up. At Pt. Thomson the worry is that the gas exists in the reservoir in a dense fluid phase; not really liquid and not really gas. So, it's not adhering to the rocks. But if pressure is dropped in this "retrograde condensate reservoir," then liquids (like liquid hydrocarbons) would drop out. As they drop out, they adhere to the rock like a sponge and right now they don't have a way to squeeze that sponge. As the Pt. Thomson fluids go from that dense fluid phase into a liquid phase they will adhere to a sponge which is the rock and a lot of it will never be recoverable again.

11:55:56 AM
SENATOR WIELECHOWSKI said he expected to see Pt. Thomson settlement terms soon and asked what specific rules the AOGCC would apply to its development.

MS. FOERSTER replied "the monkey is on Exxon's back to prove to us what the best way to produce the reservoir is." If it's economically viable to produce the liquids, the commission will make them do that. She added that the other place the liquids (a 150 ft. thick heavy oil rim) exist in Pt. Thomson is at the base of the big gas condensate reservoir and that is a concern to the AOGCC as well. So, Exxon has to demonstrate two things: they have to put in a small cycling project and demonstrate how that project will perform. Exxon is in the process of doing this. If they can get enough liquid recovery associated with that cycling project to justify the cost of expanding it, they will want to do that and the AOGCC will make them do it.

If the liquid recovery from cycling is only marginally better than the liquid recovery from blow down and that can be demonstrated, then Exxon can't be forced to spend money that they won't recover. At that point the AOGCC would back off. Right now no one knows the answers, but Exxon has great models and smart people and they are working on their small cycling project.

11:59:34 AM
CO-CHAIR PASKVAN, noting the time, thanked everyone and recessed the meeting at 11:59 AM.

DNR COOK INLET OIL AND GAS UPDATE

1:34:07 PM

CO-CHAIR PASKVAN welcomed everyone back and said this afternoon's session would be an update on Cook Inlet.

PAUL DECKER, Manager, Resource Evaluation Section, Division of Oil and Gas, Department of Natural Resources (DNR), said he is a petroleum geologist and in response to some questions, that the division is not equipped to evaluate undiscovered resources in Cook Inlet. Their primary focus is on regulatory oversight and providing the geological and engineering geophysical expertise to make good regulatory decisions about where to lease lands and once those leases are issued about how to manage them for production of the resource. They make no attempt to conduct the kind of probabilistic assessments that the USGS does.

He launched into an activity update for Cook Inlet: in June the division conducted its annual Cook Inlet area-wide lease sale and had a good turnout. One hundred and nine tracts were sold, over 575,000 acres out of a total of 112 valid bids. The total of all the high bids came in at about $11.2 million. This was by far the best lease sale in the Cook Inlet in over a decade.

MR. DECKER said some of the key points to remember about this sale is for the first time, at least in his recollection, they created a Part B sale and held it as an exempt sale in which statute authorizes them to differ from the sort of standard leasing practices. In this case, specifically because there is known oil at the Cosmopolitan or Hanson accumulation not too far from Anchor Point, they decided to bundle the three open leases together so that any bidder would have to buy not just one lease, but all three.

1:38:00 PM

He said a couple of other tracts are still owned by Pioneer, the operator of the former unit. That means the new owner will need to come to terms with the previous operator of the other leases and make a deal.

He said the department also raised the minimum bid substantially, raised the rentals and shortened the primary term of the leases to five years. The work commitment requires a plan of exploration within six months and a well down to the oil zone by the end of the fourth year. All of these special provisions on those three tracts were geared at the same thing - to getting whatever company would be interested in buying those tracts to "get off the dime" and bring that accumulation into production.

Apache was the bidder that showed by far the largest interest in the sale picking up almost all of it (95 of the tracts for about $9 million).

MR. DECKER said the Escopeta Oil and Gas Spartan 151 jack-up-rig that is the one that arrived in Kachemak Bay over a week ago has its legs down and is rigging up for operation as he speaks.

Another really important consideration in Cook Inlet is the status of gas storage. Three gas storage facilities are online currently; together they have about 9 bcf of designed capacity and when fully charged up with gas can produce gas at a design rate of about 87 mmcf/day. The idea is to help temper the swings on the coldest weeks of the year and to produce out of storage.

1:41:03 PM
CO-CHAIR WAGONER asked the highest rate that ConocoPhillips has had to short their plant in order to meet peaking demand in the winter time.

MR. DECKER replied that he would get those numbers for him.

SENATOR FRENCH asked if those storage facilities are public or private.

MR. DECKER replied that he understands the three online storage facilities are owned by single parties. Of the two more in the works, the CINGSA/SEMCO facility is going to be the biggest and will add about 11 bcf of designed capacity and 150 mmcf/day of flow rate. It will to be open to third parties.

SENATOR DYSON asked if the enthusiasm over Cook Inlet leases was the result of more oil potential or more gas potential.

MR. DECKER replied that his understanding from Apache's press releases is that oil plays are being targeted and, of course, drilling for oil in Cook Inlet is almost certain to find by-catch gas.

SENATOR DYSON asked if at least a small expanding market for Cook Inlet gas will make exploration more attractive.

MR. DECKER answered that he expected other companies would be looking hard at what the more aggressive companies are doing and that where one company goes others will follow.

SENATOR DYSON asked if the increasing gas market and higher gas prices make this market more attractive.

MR. DECKER replied the expanding gas market and particularly the presence of new gas storage projects will make a very large difference for operators, because they can get a payout on gas production all year round not only on the coldest parts of the earth and they won't have to shut in wells to nearly the same extent.

1:44:20 PM
MR. DECKER said the three storage facilities on the map are: the Marathon Kenai facility that has a flow rate of 6 bcf/day and 6 mmcf/day of design capacity, and HilCorp at both Swanson River and Pretty Creek; and the Aurora Nicolai Creek Field has approached DNR about a gas storage facility, but has not made great strides in accomplishing it. The big one is the CINGSA/SEMCO project at the Cannery Loop, which would more than double existing capacity in the basin.

He said Apache now holds over 800,000 acres and he added that they will start a 3-D seismic program on the west side of the Forelands this year. They just completed a test 2-D seismic acquisition program that leads them to believe they will be able to gather some superior 3-D data with new technology. Hopefully they will start a well in 2012.

1:46:30 PM
CO-CHAIR PASKVAN asked his thoughts on the impacts the additional 11 bcf/day of storage capacity will have on drilling for gas.

MR. DECKER replied that it would give the operators market assurance. As an example, Buccaneer has drilled a well (Kenai 1) very close to the Cannery Loop called CINGSA Storage. That well has helped them identify some reserves and just yesterday they said they had reached an agreement with Enstar for production of that gas directly into the CINGSA facility.

SENATOR WIELECHOWSKI asked if importing 500 mmcf/day from the North Slope into South Central would have an impact on the exploration in Cook Inlet.

MR. DECKER replied that he isn't an expert, but he thought it would be positive.

SENATOR DYSON asked if he had any information on how productive the formations (inholdings) under the Moose Range look.

MR. DECKER replied that he thought it be wonderful to explore that area from a geologic perspective, but he hadn't seen data about it first hand. It's clear that limitation to access to lands in the basin is one of the key hurdles to overcome in meeting the state's energy demands.

SENATOR DYSON asked if his map shows the total size of the Moose Range.

MR. DECKER replied no; they do see the federal and state units where leases are held by production, but those aren't the private inholdings.

SENATOR DYSON asked if companies can only drill straight down in the inholdings.

MR. DECKER answered that is his understanding.

1:51:08 PM
REPRESENTATIVE GARA asked if he thought just the discussion of it happening might deter exploration in Cook Inlet and how long before they get a good grip on what is producible and whether or not there is enough gas to ship to Anchorage.

MR. DECKER answered that he didn't want to speculate on the psychology of the explorers, but companies' philosophies about how prospective an area is or how critical it is to them to pursue an exploration program in a given area will change from year to year, week to week and month to month. It's a very fluid market and most investors are used to the concept of the unknowns out there.

1:53:08 PM
REPRESENTATIVE GARA asked how long before they have a decent picture of how much producible gas Cook Inlet has and whether or not there is enough to satisfy Fairbanks demand with a pipeline.

MR. DECKER answered that he could show the department's assessments of reserves in known fields, but Brenda Pierce, USGS, would talk later about the undiscovered resource and its potential.

He said that Hilcorp is the privately traded company that has purchased the Union Oil Subsidiary of Chevron and has taken on a

lot of different properties including some of the gas storage facilities. He hoped they would continue Union's progress with the pipeline to bring the Nikolaevsk Unit into production in 2013. Escopeta has a rig in the basin for the first time since 1994. Buccaneer's Kenai Loop 1 has identified 26 separate gas-bearing zones in the Beluga and upper Tyonek formations. They are claiming 31.5 bcf of proven reserves that they expect to be able to market - possibly directly to Enstar. Buccaneer has also announced plans for another well, the Kenai Loop 2, and has plans to bring a second jack-up rig into the basin next year.

Nordaq Energy drilled Shadura 1 well just west of the Swanson River and hasn't released results, but has said they are preparing permits for facilities. This sounds somewhat optimistic. Anchor Point Energy is Armstrong and their working interest owners working at the North Fork project; they recently drilled and completed two wells, recompleted another one and brought the North Fork gas accumulation onto production last April. It is being produced now through a 7.4 mile pipeline over to Anchor Point.

MR. DECKER said Cook Inlet Energy is mostly on the west side and has restarted four of their oil wells in the west McCarthy River Unit and two in the Redoubt Unit. Their plans include bringing a custom rig to the Osprey Platform to drill more wells and getting three onshore exploration wells permitted at the Sting Ray Prospect.

Further north in the basin, CIRI is drilling some shall core holes to understand the capability up there for underground coal gasification.

1:57:02 PM
Linc Energy Alaska (LEA) drilled one well not far from Big Lake. Initially they had encouraging press releases, but later determined it wasn't commercial. They also have plans to drill a well in the Trading Bay area on the west side and have a long term interest in underground coal gasification in Cook Inlet, as well. They have also just gotten active on the North Slope. Which project goes first is to be seen; gas storage is a key piece in the basin.

1:58:01 PM
MR. DECKER stressed that the department conducted two different studies; the first completed at the end of 2009 and the second in 2011. The 2009 study was an integrated engineering and geological analysis to determine how much gas remains in known

fields using the department's figures; it didn't include undiscovered gas resources, which is covered by the USGS.

SENATOR WIELECHOWSKI asked him where the 19 tcf gas number came from.

MR. DECKER replied that Brenda would answer the detailed questions about the USGS methodology, but the basic idea of resource assessments is a probabilistic distribution from a low side case to a high side case. The reality is they don't know exactly where the resource lies and 19 tcf is simply the mean expected case.

CO-CHAIR PASKVAN asked in working with the USGS numbers, how much are they off compared to oil and gas probabilistic interpretation.

MR. DECKER replied that it is impossible to quantify what hasn't been seen. The DNR takes the opportunity to understand the geological basis for the USGS assessments and collaborates by giving them input - but USGS comes up with the assessment for unit numbers by itself.

CO-CHAIR PASKVAN said he was trying to figure out what numbers to rely on.

MR. DECKER advised that it's important to recall that how much of that resource will ever come to market is very unclear. Their task is to develop a wide range of estimates of what may be present in the basin that would be technically recoverable. But how much of that will become discovered resource and how much will become commercial resource are two very different questions.

2:03:14 PM
SENATOR WIELECHOWSKI said they have to decide in the next year or so on whether to rely on the amount of gas in Cook Inlet and build a bullet line to Fairbanks or to bring in gas from the North Slope and asked if he had any advice.

MR. DECKER replied that he had no silver bullet words of wisdom.

CO-CHAIR PASKVAN asked if he believed that USGS estimate of 19 tcf is a reasonable number knowing there is variability.

MR. DECKER replied that he thought it was a good estimate, but he didn't want anyone to believe that all of that gas will ever come to market.

He went to the 2011 study that asked what sort of investment would needed to get at those resources and reserves and how much money would be attractive enough for investors to do so. So, they assumed a 90 bcf/yr. to 2025 (different than historical amounts because of the LNG facility and Agrium closings). They generated dozens of development scenarios that consist of drilling wells, adding compression and doing rig workovers if necessary to specifically target the zones and fields where the 2009 study identified certain volumes of gas. Then they used a Monte Carlo probabilistic simulation technique (establishing a range of uncertainty and then sampling from all possibilities) and derived what seems like the most likely outcome to model the commerciality and production outcomes. He described various charts related to the scenarios (slides 8-13).

He said Cook Inlet has biogenic (bacterial) gas and that is being produced from the shallower horizons mainly from the Sterling, the Beluga and the upper part of the Tyonek formations. The Sterling has been a "gang buster" reservoir and tends to produce high rates, but it is nearing depletion now. Recent focus has been on the development of the less productive zones in the Beluga and the upper Tyonek. The oil in the basin has migrated up mainly from the lower part of the Tyonek formation, the Hemlock and the West Foreland - those deeper in the column, older rocks.

A contour map showed the base of the tertiary reservoir-bearing section in the Cook Inlet Basin prepared by the DNR staff using seismic data for which they have been given a generous license from the CGGVeritas. Engineers prepared a decline curve volumetric and separate material balance reserve volumetrics for all 28 of the existing producing fields in the Cook Inlet Basin. At the same time, the geologists and geophysicists prepared reserve estimates for four of the largest five gas fields in the basin. The four they chose were important because they are quite significant in size and they also have sufficient data to make this kind of analysis: the Beluga, the North Cook, the Trading Bay Grayling Gas Sands and the Ninilchik. The answers were compared and slide 13 showed green dots that are undeveloped gas leads that the presence of gas can be inferred from previous wells that were really looking for oil.

2:13:17 PM

MR. DECKER said the idea is to look at all the wells in all the fields in all the zones and add up the thicknesses in the two categories of pretty certain pay and potential pay and track them; then make contour maps for each zone and each of the fields. From those maps the bulk volume of the reservoir can be calculated. Knowing the bulk volume of the reservoir and knowing several other variables such as the saturation, the porosity and the net thickness compared to the gross thickness, a calculation can be run to determine how much original gas was in that reservoir. The final step is subtracting out the gas that has been produced to date from the original amount in each reservoir. That leaves them with the reserves remaining in the field figure.

Slide 16 is the summary slide coming out of the 2009 study consisting of decline curve analysis and material balance analysis (reserves in contact with existing well bores that can be recovered with minimal investment), the green (relatively certain pay) and the yellow (potential pay). The grey refers back to exploration leads where previous wells have identified from gas shows that might be worth following up. Forecasting the volumes assumed about a 15 percent decline per year. This study told them that the 90 bcf demand could be met with the relatively high confidence resources and reserves through about 2018/19 assuming that gas storage is available and that people make the investment. So, the state still has a few more years of breathing room if the producers continue to invest.

Slide 17 is a slight tweak because a few months after they published the 2009 study, Marathon and ConocoPhillips indicated they would very likely be applying to renew their export license for the next few years and that changed their demand forecast for a couple of years out. The effect of that may be to shorten the production life span from the reserves by up to a year.

He said slide 18 summarizes the geological, geophysical and engineering analysis and identified substantial volumes of producible gas that could be tapped in Cook Inlet. The volumes of gas were defined in different "tranches" by different techniques and the corresponding different levels of certainty. The big "if" is if the investment is made in redeveloping the older fields with infield drilling and other kinds of field redevelopments. Those gas volumes in existing fields might be enough to meet demand at least on a yearly annual basis through 2018 or so.

2:18:13 PM

MR. DECKER said the reason they feel redevelopment activities are a good bet is because the Kenai gas field (Beluga and Tyonek), for instance, shows three things. He explained that up through 1994 fewer than 10 wells were producing at any given time. Gas production peaked in 1979 (slide 19) and water started being produced in the 1980s which is when the decline started. In 1994/5 additional wells were drilled and water handling facilities were added. But importantly, the gas rate really increased dramatically by some 30 mmcf/day, which offset that decline so far that they were able to add 90 bcf of reserves to the field. This is their "local poster child" for why they believe redevelopment efforts are very worthwhile in the older Cook Inlet fields.

The 2011 study summarized how much investment it would take and what sort of scenario would be required to go out and get the gas identified in the previous study. So, the division put together a study team (petroleum geologists, petroleum geophysicist, petroleum engineers, commercial analyst and a petroleum economist) and brought in consultants (Ryder Scott) to do reservoir engineering and modeling, decline forecasting and development scenarios and Solsten XP to do drilling operations and facilities design requirements and costs. They also had a peer review group both internal and outside. Before the study was released it went through several iterations of peer review with the staff of the Alaska Gasline Development Corporation, Enstar, Davies Consultants, and PetroTechnical Resources of Alaska.

MR. DECKER said the 2011 study developed conceptual development scenarios (slides 21 and 22) including: how many wells it would take in what zones, where they would be placed, how much they would cost, how much compression should be added to a particular facility that would allow that fuel to be produced at a lower pressure and still get gas into the pipelines, et cetera. The next part was handing off the assumptions to the economic side of the study to estimate the risks and probabilities of success for various scenarios achieving their intended goals and to come up with other existing constraints.

2:23:33 PM
To determine what investments and revenue would be required to generate specific rates of return from identified gas reserves to meet demand of 90 bcf through 2025 the analysis was run through a Monte Carlo simulation. Adding compression, they felt, could add 288 bcf and drilling new wells to tap the untapped parts of the fields where existing wells just aren't draining it

could add another 600 bcf. Taking a harder look at the development leads revealed an expected case of around 250 bcf; for a total of 1.8 tcf that "might be out there in these existing fields." He stressed this does not include range exploration or unconventional gas resources such as coal bed methane, but what is just within the existing fields. And because they were doing the Monte Carlo statistical technique, each of their forecasts was built with a high side case and a low side case (just like the resources assessments).

2:25:40 PM
JEFF DYKSTRA, Commercial Analyst, Division of Oil and Gas, Department of Natural Resources (DNR), followed up saying his division built on the information that Mr. Decker just went through. All the caveats he mentioned are the same for the commercial group (starting with slide 25). He said they had a broader team of more than just the experts that reviewed the results as they stepped through the analysis.

The economic flowchart was broken up into two classes; the first class looked at baseline production wells (wells that are currently producing without additional investment) and range estimates were made as to how those are going to decline. The second was categories of wells that need additional investment; those were broke up into 38 different projects, some of which were single wells and some multiple. A project was defined as something that normally could be done in one drilling season; 26 projects were in existing fields and pools and didn't require extensive infrastructure and 12 projects were in identified leads and might require additional facilities and one or two drilling seasons.

MR. DYKSTRA said the sources of data were DNR, Ryder Scott and Solsten XP Consultants.

2:28:19 PM
SENATOR WIELECHOWSKI asked if they're assuming 1.8 tcf is the total of all the extractions and if it assumed the new USGS numbers.

MR. DECKER replied no; the idea here is that these numbers do not include undiscovered resource whatsoever. These numbers work with the known fields and those few development leads in the gray category that previous drilling has already sort of identified as candidates for follow up work.

SENATOR WIELECHOWSKI asked if the 1.8 tcf is part of the total 19 tcf.

MR. DECKER replied that it would be in addition to.

SENATOR WIELECHOWSKI asked if it would be possible to do an analysis like this regarding the 19 tcf of undeveloped reserves over the next couple of months.

MR. DECKER replied that would use a very different methodology that he couldn't really define it right now, but he noted the suggestion.

MR. DYKSTRA said slide 28 indicated reasonable rates of return assuming the existence of proper storage. He explained the "Expected Monetary Value" chart for particular rates of return and that most of the projects are in the less than $10 million range and about 25 percent are above.

2:34:52 PM
SENATOR WIELECHOWSKI asked if at $4/mcf a company is making far in excess of the 20 percent internal rate of return.

MR. DYKSTRA replied given the assumptions of the study that would be a correct interpretation, but that cost does not include the cost of storage or transportation. The assumption of storage is the biggest factor to evaluate.

SENATOR WIELECHOWSKI asked what cost of storage.

MR. DYKSTRA replied he meant the storage that must be available so the wells could be immediately produced.

CO-CHAIR PASKVAN asked if he was talking about the 11 bcf storage facility he mentioned earlier.

MR. DYKSTRA answered yes.

SENATOR FRENCH asked Mr. Dykstra if he knew of some uncertainty about completion of the facility that he hadn't heard about; he thought it was "on a very, very solid track for completion."

MR. DYKSTRA replied that they believe there is a very high probability the facility will be built.

SENATOR FRENCH asked what the presence of that storage facility would do to those numbers.

MR. DYKSTRA replied his numbers assume that storage is available now.

2:37:03 PM
CO-CHAIR PASKVAN asked him to explain slide 27 again.

MR. DYKSTRA replied that the IRR10, IRR15 and IRR20 [figures on the chart] solves the revenue requirements expressed as a dollar per thousand cubic feet that would require an expected monetary value of the euro discounted at those particular rates.

CO-CHAIR PASKVAN laughed and asked if he was saying less than $3/mcf of investment was needed to produce enough volume to sell at current prices (slide 28).

MR. DYKSTRA answered that would be the cost of the next mcf that would be required to meet that 90 bcf/year demand. It's only one financial metric and a lot of times producers look at multiple metrics. If this is the only metric looked at people should be investing like crazy. The other metric he used suggests it is not as favorable as this one suggests. Both metrics (expected revenue requirements and expected monetary value) have to be satisfied in order for producers to invest.

2:39:42 PM
SENATOR FRENCH said the committee needed a little more explanation of how the two slides [27 and 28] go together and asked what the 0 - 4, 4 - 8, and 8 - 12 on the lower axis [slide 28] represented - the total return or the total investment?

MR. DYKSTRA replied that would be the total return expressed in a net present value or expected monetary value (EMV) at those particular discount rates. [The 0 - 4, 4 - 8, et cetera indicates millions of dollars.] The other axis is how many projects fit into that particular value range.

SENATOR FRENCH said for the first pair of bars 12 projects will return a 15 percent EMV.

MR. DYKSTRA corrected that 12 projects would have an expected monetary value of between $0 and $4 million with a discount rate of 15 percent.

SENATOR FRENCH remarked that most projects will return a fairly small total monetary value.

MR. DYKSTRA answered yes.

REPRESENTATIVE SEATON asked if the first 0 - 4 means there is an additional eight projects that would be producing at 10 percent. It looks like a greater number of projects get produced at 15 percent.

MR. DYKSTRA clarified that the chart shows the same projects and it's showing the projects with a positive EMV. It's showing two different discount rates, one at 15 percent and one at 10 percent.

CO-CHAIR PASKVAN stated that slide 25 identifies 38 projects and asked if this was the distribution of those projects.

MR. DYKSTRA replied it is the distribution of the 38 projects that showed a positive net present value; they all don't show positive at that particular value. The negative ones were not plotted. In other words, some definitely require more than the $5.77 to have a positive net present value at those discount rates.

CO-CHAIR PASKVAN asked at $5.77 and assuming a selling value of $6.25 if more projects become recoverable.

MR. DYKSTRA answered yes. He said they did some projects both onshore and offshore. Capital costs for an offshore gas-only with no oil takes a substantial amount of revenue to offset the required large capital costs. The analysis of those truncated at $15/mcf showing at those rates projects were not economic.

CO-CHAIR PASKVAN asked if he used the $5.77 because he was trying to project whether resources will be available to meet that demand at current energy cost structures.

MR. DYKSTRA replied the assumption here as they looked at the supply curve is there will be continued investments. So, they were trying to see if there will be significant investment, and some metrics suggest that there will be.

2:45:19 PM
MR. DYKSTRA said slide 29 illustrated the supply curve coming out of the Monte Carlo simulation. For each of those projects they estimated low cases, high cases and what the expected case was; then used Monte Carlo techniques to simulate 5,000 possible ways that information could manifest itself in the future. The 90 bcf/yr. supply target starts a decline in 2018 and they did

not see any point in extrapolating the "uncertainty band" of data out to zero. His interpretation of slide 29 is that he could say with 90 percent confidence that the blue curve or better would be the future given the assumptions of the study and that there is a 15 percent chance of a decline in the 2020 timeframe.

SENATOR WIELECHOWSKI went back a slide and said his understanding of EMV is you have to assign a probability of occurrence of a risk and then a monetary value to the impact of the risk and asked what the risk is, what the probability of the risk is and what the monetary value is.

MR. DYKSTRA answered that the risk is largely made up of the probability of failure that you would drill and not be able to monetize anything.

SENATOR WIELECHOWSKI asked what the expected probability of failure is for infield and exploratory activities.

MR. DYKSTRA answered the study used a range of 5 percent for certain failure and 90 percent for most uncertain.

2:48:48 PM
CO-CHAIR PASKVAN said slide 28 was based on $5.77 and asked what the supply curve would look like if it changed.

MR. DYKSTRA replied that they didn't run that case, but they could do it.

SENATOR WIELECHOWSKI referring to slide 27 said the in-state gas line is scheduled to come on line around 2019 with a price of $9.63 and at a 20 percent IRR gas is $7 and he asked if the distribution costs would be more then.

MR. DYKSTRA answered that this would be the expected case and was based on a revenue requirements model that is not necessarily a proxy for the market.

SENATOR WIELECHOWSKI said it looks like at 10 percent ROR gas is $5 gas, but at 20 percent ROR gas is $7. So, it looks like you would get lower cost gas if this were correct and you were to bring gas from Cook Inlet today. Is that correct?

MR. DYKSTRA replied that he was looking at only one metric and there is danger in that. That is why they look at various

metrics. It's unclear whether producers are driven only by rates of return and they most likely are not.

SENATOR WIELECHOWSKI asked if the other metric would be expected monetary value.

MR. DYSTRA replied that is one, but he would assume the producers are looking at a lot of different things and he didn't know their business process.

2:52:09 PM
CO-CHAIR PASKVAN asked if the $5.77 is the cost at the well with tariff and local distribution charges in addition to it.

MR. DYKSTRA replied that it does not include the tariffs, but he wanted to verify that.

REPRESENTATIVE GARA said if the in-state line is built that obligates people to 20 years of $11 or $17 gas and there could be cheaper gas sitting in Cook Inlet. Will explorers keep exploring in Cook Inlet because they know that they can beat the price of the in-state gasline?

MR. DYKSTRA responded that was in the realm of speculation and this study was based on what Cook Inlet can do by itself.

REPRESENTATIVE GARA said the last thing they want to do is to leave $7 gas in the ground, sign on to a $30 deal for 50 percent more expensive gas and then have to tell constituents they didn't have the information. How do they get the information?

MR. DYKSTRA replied this particular study shows depending on how they want to define their risk preference that the state will need either additional gas or to have some success via exploration. The question will be when to bring that gas in and he didn't think that answer was needed quite yet if the study suggests looking at what investment took place every year or couple of years and redo the numbers.

2:56:21 PM
REPRESENTATIVE SEATON said this chart is capped at $15/mcf, but they aren't anywhere near that. Through 2021 they are talking about a maximum price of gas at less than $12 at a 20 percent IRR. Is that right?

MR. DYKSTRA answered this chart is expected value and there are two dimensions in play, one is price and the other is supply. In

2021 some cases in the study run out of gas. If you look at that particular scenario, you would have been at that $15 cap whenever it ran out of gas, but this particular graph aggregates those 5,000 results into one number.

CO-CHAIR PASKVAN asked if he had discounted the USGS numbers to zero, because he was only addressing the known reserves.

MR. DYKSTRA replied yes, and added that exploration can change their results as can unconventional and some other things.

CO-CHAIR WAGONER commented that this didn't even include the latest find by Buccaneer that was put into the known reserves.

MR. DYKSTRA replied that was correct.

REPRESENTATIVE SEATON asked if slide 28 in which the lower investment projects have been used up earlier relates to slide 27 where projects incrementally go up over time and prices get higher in the outer years.

MR. DYKSTRA answered yes; the modeling is done in stages so that the most economical projects get done first.

2:59:38 PM
MR. DYKSTRA wrapped up saying that they have probably all come to the same conclusion in that given sufficient investment the results show there will be sufficient gas supply to 2018 and the second point is that natural gas storage will play a key role in that.

CO-CHAIR WAGONER asked if DNR's plan is to continually update this study on a two-year basis so they can see what exploration has been and how many proven reserves have gone into the system.

MR. DECKER responded that he had not heard discussion within DNR that this was going to be an ongoing study. If it is to be useful information, perhaps something it could be freshened with new information.

CO-CHAIR WAGONER said he wanted to make that request right now - at least on a two-year basis if not a one year.

CO-CHAIR PASKVAN added that the two co-chairs of Senate Resources agree with that as certainly everyone on the committee.

SENATOR DYSON underscored Representative Gara's point that they need the best estimates they can get on what this basin will produce in order to have a base on which to make big and important decisions.

REPRESENTATIVE GARA asked since there is enough gas until 2018 or 2020 that given existing fields and new successful exploration it could go beyond 2020.

MR. DYKSTRA replied that is correct.

SENATOR WIELECHOWSKI said this is critical information and he looked forward to other presentations as they move forward. One of the things he has heard is that producers of a lease will tend to not produce or at least discover reserves more than eight years longer than the demand will account for and asked if that is normal and a good timeframe to use.

MR. DECKER replied that a long lead time is needed in Alaska as compared to other jurisdictions, and the North Slope needs 10 years of lead time.

3:05:05 PM
CO-CHAIR WAGONER said the 10-year timeframe is not generic for all wells drilled in Alaska and could maybe be used on the North Slope from discovery until infrastructure is built out. But Buccaneer just got a lease and permits, put in the pad and drilled the well and will be in production by the end of the year. That is an 11 or 12 month timeframe! It depends on the logistics, the location and the availability of infrastructure to put the product into.

MR. DECKER agreed and said he was thinking specifically of remote large projects on the North Slope.

3:07:12 PM
Recess from 3:07 to 3:21 p.m.

USGS ASSESSMENT OF COOK INLET NATURAL GAS RESERVES

3:21:49 PM
CO-CHAIR PASKVAN welcomed Brenda Pierce to the meeting and thanks her for coming all the way from the East Coast. He said the 19 tcf in Cook Inlet has peaked a lot of interest in Alaska.

BRENDA PIERCE, Manager, Energy Resources Program, United States Geological survey (USGS), Department of Interior, said the

department appreciates their interest in USGS work and she would do her best to answer their various questions.

MS. PIERCE said she would first give them a summary of USGS results, how they did what they did and where the resources might be found. She said the USGS gives a range rather than just a mean; it looks at the undiscovered resources that have great uncertainty and are in addition to the known reserves. Even though those are undiscovered they can be technically recoverable with today's technology and industry practices which the USGS goes to great lengths to determine using proprietary databases and looking at other development in the area. In areas that have no production and truly frontier areas, they look at areas that might be analogous that are being produced.

For the Cook Inlet, Ms. Pierce said, they looked at the onshore and state waters and not the outer continental shelf (OCS). They found the mean, the 95 percent probability (F_{95}) and the 5 percent probability (F_{05}). Emphasizing again how uncertain these numbers are because the resource is "undiscovered," she said that Cook Inlet has about 600 million barrels of potential oil at the mean, but it ranges from at least 100 million barrels to more than 1 billion barrels. For gas, they found a mean of 19 tcf. There is a 95 percent probability that at least 5 tcf or as much as 40 tcf of gas is there to be discovered.

3:27:48 PM
MS. PIERCE explained for perspective the mean amount of the undiscovered gas in Cook Inlet is 19 tcf and almost 8 tcf has been produced in the Cook Inlet to date. U.S. gas consumption in 2009 was about 21 tcf. Proved gas reserves on the North Slope are about 35 tcf.

Using the same type of comparison, the mean amount of undiscovered but technically recoverable oil in the Cook Inlet is 600 million barrels. In 2010 cumulative oil production in Cook Inlet was a little over 1 billion barrels. U.S. oil consumption in 2010 was about 7 million barrels.

Slide 6 illustrated the four areas that are producing reserves now which they didn't assess as well as areas of undiscovered but technically recoverable oil. That doesn't mean they are economically recoverable. She also pointed out that not all areas are accessible for development and that it's important to know what might or might not be possible and they think they have a good understanding of the area's potential.

3:29:54 PM
SENATOR FRENCH asked how much of what is technically recoverable is also an area that is not closed to development by refuges and critical habitat.

MS. PIERCE replied when USGS assesses a basin or a province, they break it down into assessment units. Some of them cover the whole area and some are much smaller. They can allocate to certain areas, but she didn't have those numbers today.

SENATOR WIELECHOWSKI asked how often she is right.

MS. PIERCE replied that their estimates are very viable, but sometimes they are wrong. One of the uncertainties is whether the resource is oil or gas; another is whether they are dry holes or not. Industry is wrong all the time as well, but often they are both right and sometimes discoveries are made exactly where USGS predicted them. She couldn't give him a specific answer because some resources are technically recoverable but not always economically recoverable, and they hadn't done that kind of analysis. And what a company will or will not develop doesn't always depend upon just what is technically recoverable. There are access issues and what a company wants to do with its portfolio and the economics of the situation. Her numbers provide a best estimate at a given time based upon available geology and science and those numbers change sometimes because of new information.

3:32:26 PM
MS. PIERCE said because USGS does undiscovered resources, it's very important to get the best geology available to build their geologic models and try to put the uncertainty in a quantitative mode. They work very closely with geologists from the DNR, the Division of Geological and Geophysical Surveys (DGGS) and the Division of Oil and Gas (DOG) to develop very robust geology and estimate the number of sizes and fields they think the geology of the area can accommodate. That is what is run through a Monte Carlo simulation.

She said the USGS has spent the last several years building a new geologic map of the Cook Inlet region and have new seismic reprocessing, interpretations and new gravity and magnetics modeling. The rock has to be understood in order to know if organic materials are there to begin with and that they have been heated enough to form the oil/gas and that the timing was right that conventional resources migrate through the system into a trap. All of these pieces need to be present in the

geological models in the right sequence and with the right parameters for the oil and gas to form to have even been preserved.

Each part of the geologic model is risked and then it is run through the Monte Carlo simulation to get the quantitative numbers.

3:35:22 PM
CO-CHAIR PASKVAN asked if it's fair to assume that information about an area with decades of production like Cook Inlet increases the probability of accuracy.

MS. PIERCE replied that was a fair statement. USGS spends a considerable amount of time developing these resources with a lot of help from others, but they run the final numbers themselves.

3:36:53 PM
SENATOR STEDMAN asked to spend a little bit of time on slide 9 "Geologic setting: Cook Inlet is a forearc basin."

MS. PIERCE said it is a fairly complicated and unusual area; it's the only forearc basin in North American to have oil and gas in it. The Pacific Plate is moving northwest along Alaska being subducted under the Aleutian Plate (Megathrust) and that is causing a lot of the volcanos and seismic activity. You don't normally have oil and gas resource even expected in this type of area. She went to slide 10 and said the Aleutian Range and Kenai Chugach Mountains are not going to be prospective for oil and gas at all. A lot of that is controlled by what is happening in the larger geologic picture.

She said that Cook Inlet oil has 33 discovered fields with oil and gas production; 8 are mostly oil and 25 are mostly gas. Even so, large parts of the basin are undrilled or sparsely drilled.

3:39:26 PM
SENATOR WIELECHOWSKI asked if she anticipates any unconventional or shale gas or oil in this reservoir.

MS. PIERCE replied there is unconventional, but a couple of their geologists thought the sequences were too "clayey" to be prospective for shale gas. However it has tight gas and other kinds of unconventionals. She said because conventional and unconventional are assessed differently different methodologies are used. She said they built a new geological map out of this

assessment and inserted what is known about the oil and gas using that as a starting place. She said the basin is very deep and very thick, which is why it is so prospective. The non-marine strata are fairly young from 0 to 66 million years ago. Older strata are marine sedimentary rocks and they are underlain by very thick volcanic rocks which are not prospective for oil and gas. The brown, orange and tan areas have the coal beds that are sourcing the biogenic gas (gas from microbial activity). The greens indicate deeper rocks that have the thermogenic gas that comes from cracking up the hydrocarbons and the higher temperatures that has helped it migrate up the faults into conventional reservoirs.

MS. PIERCE explained that those units of rock that have common geologic traits but are unique from others are called assessment units (AU). Cook Inlet has four assessment units (slide 14): Cook Inlet coalbed gas, tertiary sandstone oil and gas, Tuxedni-Naknek continuous gas, and Mesozoic sandstone oil and gas. Stratographically they are overlying each other in the subsurface.

3:43:32 PM
MS. PIERCE explained that the conventionals are discrete accumulations that are water-bounded; they are either in structural or stratigraphic traps. They can be oil or gas and are relatively easy to find and develop compared to the unconventionals. Unconventionals are called continuous because they include shale gas or tight gas, and then there are the truly unconventional like hydrates or oil shale. They are called continuous because geologically they're continuous across the basin - so they are coalbed gas, tight gas, basin-centered gas and shale gas.

She explained the difference between stratigraphic traps versus structural traps because it is important to know in Cook Inlet. Production has all come from structural traps and none from stratigraphic traps and there may still be significant resource potential in the untapped stratigraphic traps.

The Tertiary Sandstone Oil and Gas AU was more detailed on slide 16 and she noted they looked at the Middle Jurassic shale near the Red Glacier. The map had points for oil and gas fields and wells and indicted significant well penetration. She pointed out the reservoir rocks on slide 17 saying one of the biggest differences between conventional and unconventional is source rock and the reservoir rock. Conventional has been formed at depth when organic material gets heated and forms oil and gas;

it rises up through the strata and becomes reservoired in impermeable areas. The biggest difference between that and unconventional tight and shale gas is that those are still in their source rock; they have not moved. And because they haven't moved they are more difficult to produce. You have to fracture them or do something else. That is why until recently they have really not been economic to produce.

She explained that the Tertiary Sandstone AU is a conventional reservoir assessment and has about 1,200 well penetrations and about 30 known accumulations. Over 1 billion barrels of oil have been produced along with almost 8 tcf of gas. The source of the oil and the thermogenic gas is in the marine shales in the Middle Jurassic shale group, but the gas listed earlier is mostly microbial (biogenic) forced from the coals. So there is significant resource potential there. The reservoirs are mostly tertiary fluvial sandstones and all the discovered traps are structural. Stratigraphic traps are still out there and most likely to be found. The undiscovered traps are probably both structural and stratigraphic, but significantly stratigraphic. They think this area is underexplored and has the most potential. The source of gas is marine shale and that is also underexplored and has the most potential.

3:49:16 PM
MS. PIERCE said it's important to understand that the thin discontinuous sands show the potential with Cook Inlet geology and a very important consideration there is that a well could completely miss the sand that has oil and gas in it. Slide 20 showed seismic lines, potentially untested oil and gas, potentially undrilled structures and potential stratigraphic traps that are untested. Cook Inlet has a lot of potential.

Slide 21 was of land ownership that helps get at what may or may not be available for both exploration and production.

SENATOR FRENCH asked if her estimate assumes that the undiscovered oil and gas is uniformly distributed across the area within the yellow boundary.

MS. PIERCE answered that they don't assume that the resource is uniformly distributed, because the geology is not uniform. They say that the resource is within this area. They don't assess the parcels because that goes beyond what the available data provides.

SENATOR FRENCH said this area seemed to be the source of the greatest amount of undiscovered oil and gas.

MS. PIERCE agreed; more than 300 million barrels of oil and 12 tcf of gas.

SENATOR FRENCH asked how many penetrations it would take to get to an "explored" basin level.

MS. PIERCE replied that she didn't have a pat answer. It would take sitting down and looking at the seismic and what is known and mapping out what they think is happening.

SENATOR FRENCH asked if she had just a ballpark figure. He wanted a feel for how unexplored it is. "Do we have to double the number of wells before we get there?"

MS. PIERCE repeated that there just isn't a good answer to that. It's not so a much a number; it's an area that doesn't have any data.

3:52:42 PM
CO-CHAIR PASKVAN said another issue is how long into the future the reserves are created and, "Why spend the money for 30 years if you only need to spend the money for 8 to 10 or 12 years?"

MS. PIERCE responded that companies keep the reserves on the books fairly constant and replenish what they have produced. That information is kept "on the back burner at all times." It depends on what you need and the timeframe you need it in and today's economic analysis may change tomorrow.

3:54:22 PM
SENATOR WIELECHOWSKI said Cook Inlet is a stranded gas market and asked if she would expect to find companies booking 30 or 40 years of reserves when they have no market for it.

MS. PIERCE answered that she is a geologist; companies do very different things and it's hard to judge.

She explained that the Mesozoic Sandstone AU is also conventional and has more than 100 well penetrations, but few reach the top of the Talkeetna formation. So, the stratigraphic potential is below where most of the well penetrations have reached. M-28 AU has one oil accumulation with cumulative production of 300,000 barrels. She said there are oil seeps onshore in this area and that indicates that there is other oil

potential. The source of the oil and thermogenic gas is from the Middle Jurassic Tuxedni group, which has migrated up from the depths. They also think there are potential and undiscovered traps probably both structural and stratigraphic.

3:56:46 PM
SENATOR WIELECHOWSKI asked how deep Mesozoic is versus Tertiary and how deep jack-up rigs get versus what typical rigs get in Cook Inlet.

MS. PIERCE replied the Tertiary is about 25,000 ft. thick; the Jurassic and Cretaceous is another 30,000 ft. thick.

REPRESENTATIVE SEATON asked her to define the difference between structural and stratigraphic.

MS. PIERCE replied that stratigraphic and structural traps are both conventional resources. So, if you had organic material at depth that has been heated to sufficient temperatures to form oil and/or gas, and because oil and gas is buoyant and if it can move out of the source rock, it will and travel up through the system until it hits an impermeable layer where it forms into the pores as either structural or stratigraphic traps. The structural trap is where the rocks have been flexed; so it has a structure within like an anticline that has moved up in the system and hit an impermeable layer, like a shale or a clay, and fills the pore spaces (in a sandstone, for instance) in the structural trap. A stratigraphic trap, on the other hand, is something where a fault with two different rock types placed upon each other that has formed an impermeable layer. The structural traps are the ones that have been discovered and produced in the Cook Inlet; none of the stratigraphic traps have been explored.

SENATOR WIELECHOWSKI asked if one particular kind of formation tends to hold more oil and gas.

MS. PIERCE replied the Tertiary Sandstone.

SENATOR WIELECHOWSKI asked if the structural ones tend to hold more oil and gas versus the ones that haven't been explored.

MS. PIERCE replied that there has been no production from the stratigraphic traps. All the gas and oil in Cook Inlet has been produced from the structural traps.

SENATOR WIELECHOWSKI asked traditionally do the stratigraphic traps have more oil or gas.

4:01:10 PM
MS. PIERCE replied that it depends on where you are in the geology of a specific area and she didn't know about the Cook Inlet because none of them are produced. Tuxedni-Naknek Continuous Gas has no known accumulations. It's entirely unexplored with no known well penetrations.

She recapped that the Mesozoic layer is mostly unexplored and is a slightly small area geographically. The results from the Mesozoic Sandstone oil and gas AU show a mean of more than 200 million barrels of oil and about 1.5 tcf of undiscovered gas.

REPRESENTATIVE SEATON asked if this indicates that M-28 AU and four wells down in the lower left are the only penetrations.

MS. PIERCE answered the M-28 AU is the one that has produced oil, but it is pretty unexplored. The Tuxedni-Naknek continuous gas structural unit is a very small deep. It is hypothetical, but bears looking at for the future. It has no known accumulations, but it is thermogenic gas and there may be low permeability sandstones at that depth that can be produced as evidenced elsewhere.

The very large Cook Inlet Coalbed AU is also unconventional and has no discovered commercial accumulations, but about 25 wells have been drilled in search of coalbed gas by Wasilla. These are microbial gas sources. Because there are no commercial accumulations, they used the Powder River basin as an analogue; it has very thick coals and is highly commercial. An area deeper that 6,000 ft. was excluded, but has technically recoverable potential. It is mostly unexplored, but they allocated it 4.6 tcf of gas.

In a nutshell, Ms. Pierce said they have recently completed this assessment of volumes of undiscovered but technically recoverable resource for both conventional and continuous gas accumulations for the onshore state waters. The geology based assessment is a probabilistic quantitative based on USGS and State of Alaska DGGS and DOG data; it indicates 600 million barrels of oil and 19 tcf of gas.

4:04:19 PM
SENATOR WIELECHOWSKI asked for a more detailed analysis of where a find is.

MS. PIERCE replied that their results estimate for an entire region. They can allocate certain parcels of land, but their data simply don't support saying there is X tcf or X billion barrels in a small parcel. These are not assessments but allocations based upon their expert judgment of the geology of the area from the assessment.

SENATOR WIELECHOWSKI said there must be some raw data somewhere that would show traps.

MS. PIERCE replied where they have seismic data they have more detailed information, but a lot of areas don't have the seismic data.

SENATOR WIELECHOWSKI asked if their data is public and if it is shared with the State DNR or the companies.

MS. PIERCE replied it's a combination. Companies often share proprietary data with them, but they don't share that data; rather they share the results of their assessment. USGS also buys proprietary databases of production both in the U.S. as well as globally. They look at what is being produced in areas with similar geology and do field work themselves. They put together geologic models to say if there is organic material even in the area and if so, was it robust enough organic material and what kind is it - and then build a burial history curve for each basin while guessing if it got hot enough to form oil and gas and if the timing was right.

4:07:52 PM
SENATOR STEDMAN said there is oil development off of coastal B.C. and that Alaska has a lot of coastline running up to Cook Inlet and asked if she knew of any oil in between.

MS. PIERCE replied that is a good question, but she hadn't looked at that.

CO-CHAIR WAGONER asked what she meant. There has been some drilling in the Gulf of Alaska.

MS. PIERCE replied that USGS hadn't assessed it.

CO-CHAIR WAGONER asked if it been assessed by USGS prior to the drilling off of Yakutat.

MS. PIERCE replied that she would have to go back and look.

4:09:34 PM
CO-CHAIR PASKVAN asked where the concept of economic viability comes in.

MS. PIERCE replied that is somebody's next study.

CO-CHAIR PASKVAN asked if one combines her 5 tcf with the 1.8 tcf of known reserves, would that mean a 95 percent likelihood of 6.8 tcf. He was comparing that number to the 7.8 tcf of production that has already occurred and was trying to determine magnitudes of probabilities for the next 50 years. Is that a reasonable way to look at that?

MS. PIERCE replied yes and that they have 95 percent confidence that 5 tcf is there. There is real potential.

4:12:29 PM
SENATOR WIELECHOWSKI asked if the 5 tcf is on top of the 1.8 tcf of known reserves.

MS. PIERCE replied yes. The USGS does not include reserves in its estimates, but they do assess potential reserves.

CO-CHAIR WAGONER said until someone goes out there and proves it's an economical reserve, they can't count on anything.

MS. PIERCE replied "absolutely correct."

SENATOR WIELECHOWSKI asked if an oil company could get detailed information from USGS on where they believe those traps and structural formation are.

MS. PIERCE answered it depends on where the data came from and who it belongs to and what their agreement is.

4:15:17 PM
CO-CHAIR PASKVAN thanked her for traveling to Juneau and giving the presentation. Finding no further business to come before the committee, he adjourned the meeting at 4:15 PM.