ALASKA STATE LEGISLATURE
JOINT MEETING
HOUSE RULES STANDING COMMITTEE
SENATE SPECIAL COMMITTEE ON ENERGY
June 20, 2008
9:02 a.m.

MEMBERS PRESENT

HOUSE RULES

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

SENATE SPECIAL COMMITTEE ON ENERGY

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

MEMBERS ABSENT

HOUSE RULES

All members present

SENATE SPECIAL COMMITTEE ON ENERGY

All members present

OTHER LEGISLATORS PRESENT

Representative Bob Buch
Representative Mike Chenault
Representative Mike Doogan
Representative Les Gara
Representative Carl Gatto
Representative Mike Hawker

Representative Lindsey Holmes
Representative Reggie Joule
Representative Mike Kelly
Representative Gabrielle LeDoux
Representative Jay Ramras
Representative Bob Roses

Senator Hollis French
Senator Gene Therriault

COMMITTEE CALENDAR

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

- HEARD AND HELD

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PREVIOUS COMMITTEE ACTION

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

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

06/12/08	(H)	House Special Subcommittee on AGIA
06/13/08	(H)	RLS AT 10:00 AM FBX CARLSON CENTER
06/13/08	(H)	House Special Subcommittee on AGIA
06/14/08	(H)	RLS AT 10:00 AM FBX CARLSON CENTER
06/14/08	(H)	House Special Subcommittee on AGIA
06/16/08	(H)	RLS AT 9:00 AM ANCHORAGE
06/16/08	(H)	House Special Subcommittee on AGIA
06/17/08	(H)	RLS AT 9:00 AM ANCHORAGE
06/17/08	(H)	House Special Subcommittee on AGIA
06/18/08	(H)	RLS AT 9:00 AM ANCHORAGE
06/18/08	(H)	House Special Subcommittee on AGIA
06/19/08	(H)	RLS AT 9:00 AM ANCHORAGE
06/19/08	(H)	House Special Subcommittee on AGIA
06/20/08	(H)	RLS AT 9:00 AM ANCHORAGE

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

06/03/08	(S)	READ THE FIRST TIME - REFERRALS
06/03/08	(S)	ENR
06/03/08	(S)	REPORT ON FINDINGS AND DETERMINATION
06/04/08	(S)	ENR AT 10:00 AM TERRY MILLER GYM
06/04/08	(S)	Heard & Held
06/04/08	(S)	MINUTE(ENR)
06/05/08	(S)	ENR AT 9:00 AM TERRY MILLER GYM
06/05/08	(S)	Heard & Held
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06/06/08	(S)	ENR AT 10:00 AM TERRY MILLER GYM
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06/07/08	(S)	ENR AT 10:00 AM TERRY MILLER GYM
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06/07/08	(S)	MINUTE(ENR)
06/08/08	(S)	ENR AT 1:00 PM TERRY MILLER GYM
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06/14/08	(S)	Heard & Held
06/14/08	(S)	MINUTE(ENR)
06/16/08	(S)	ENR AT 9:00 AM ANCHORAGE

06/16/08	(S)	Heard & Held
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06/17/08	(S)	ENR AT 9:00 AM ANCHORAGE
06/17/08	(S)	Heard & Held
06/17/08	(S)	MINUTE(ENR)
06/18/08	(S)	ENR AT 9:00 AM ANCHORAGE
06/18/08	(S)	Heard & Held
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06/19/08	(S)	ENR AT 9:00 AM ANCHORAGE
06/19/08	(S)	Heard & Held
06/19/08	(S)	MINUTE(ENR)
06/20/08	(S)	ENR AT 9:00 AM ANCHORAGE

WITNESS REGISTER

Harold C. Heinze, Chief Executive Officer, Alaska Natural Gas Development Authority (ANGDA); Delma Bratvold, Science Applications International Corp.; Gene Dubay, Senior V.P. & Chief Operating Officer, Continental Energy Systems; Colleen Starring, Regional V.P., ENSTAR Natural Gas Company; John Lau, Director of Engineering, ENSTAR Natural Gas Company; Richard Peterson, Managing Member, Natural Resources-to-Liquids, LLC; Peter Tijm, Member, Natural Resources-to-Liquids; Barry Pulliam, Senior Economist, Econ One Research, Contractor, Legislative Budget and Audit Committee; Bill Walker, Project Manager and General Counsel, Alaska Gasline Port Authority; Craig Richards, Attorney, Alaska Gasline Port Authority.

ACTION NARRATIVE

CALL TO ORDER

The joint meeting of the House Rules Standing Committee and the Senate Special Committee on Energy was called to order at 9:02:20 AM.

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

HAROLD C. HEINZE, CHIEF EXECUTIVE OFFICER, ALASKA NATURAL GAS DEVELOPMENT AUTHORITY (ANGDA), gave a brief overview of ANGDA. He noted that ANGDA has been addressing in-state gas issues and spent six months before submitting an application under AGIA. The project ANGDA proposed consisted of a spur line running from Delta Junction through Glennallen to Palmer and Beluga, in order to capture gas leaving Alaska in a big pipeline. Without the spur line there would be no way to get the gas to coastal areas, which are the biggest users of natural gas. The project has moved forward over the last several years. They have a conditional right-of-way from the state covering the area between Glennallen and Palmer. The

other portions of the route follow existing pipeline right-of-ways; they should be easy to permit and design. Wetland determination teams have been in the field this summer. Preliminary work should be done by next summer. ANGDA has been working with utility companies, particularly the electric companies, who are major gas users, to get them organized so that they are prepared to participate in an open season process. The key question is when the open season will occur and how well they will be prepared.

9:07:34 AM

MR. HEINZE observed that the issue of North Slope gas to market must go beyond one big pipe out of Alaska; there should be many spur lines. Long term perspective must be kept in mind. He observed that ANGDA has tried to emphasize that not all Alaskans will be able to share in the energy source of the North Slope. However, the North Slope gas is rich in propane, which can be produced and distributed with minimal effort and 99 percent of Alaskans could potentially benefit.

9:09:37 AM

MR. HEINZE defined "in-state gas use" as measured in millions of cubic feet a day (MMcf/d). In 2006, 100 MMcf/d was used for residential heat and a little over 100 MMcf/d for residential electricity and light. In addition in 2006, industry used 250 MMcf/d. He estimated that growth in the Cook Inlet area would increase the need in heat and light to 250 MMcf/d. In addition, a pipeline through the spine of Alaska would go through Fairbanks, which would use another 50 MMcf/d. He spoke to future industry needs, which are harder to predict.

9:12:41 AM

MR. HEINZE pointed out seasonal gas use increases, which have implications in terms of storage, pipeline deliverability and other issues.

MR. HEINZE spoke to the cost of service tariff for a number of different assumed volumes and circumstances. The benchmark is the Black and Veatch work, which illustrated that pipeline costs from the North Slope to Alberta would be about $3.50 [$/mmbtu], not including the treatment plant on the North Slope, which could make the total tariff could be higher. ANGDA's estimates are comparable. He referred to the ENSTAR estimates related to a $3.3 billion bullet line from the North Slope to Cook Inlet. $2.3 billion of that was spent to get to Fairbanks. That works out to around $10 if only 100 MMcf/d moves through. At 250 MMcf/d, the number drops to $3.50, and then down to $2 at 500 MMcf/d. ("Gas

Pipeline Cost of Service Estimates" from handout "Connecting Alaskans to Their Natural Gas" (Copy on File)).

9:15:34 AM

MR. HEINZE referred to the threshold needed to build the line and reviewed the cost of a variety of options. He noted the $10 would be paid by the consumer, which seems like a lot, but Fairbanks currently pays over $22 for their gas. A large pipeline would decrease cost to $1.25, a dramatic difference. He reviewed the numbers for Cook Inlet consumers.

MR. HEINZE concluded that the scope of the line needs to be determined and emphasized the importance of getting to an in-state open season as soon as possible. He felt that the spur line offered the best opportunity for reduced cost in the long term. Large volumes are more tariff efficient.

9:19:22 AM

MR. HEINZE maintained that Alaska should retain some value advantage in terms of gas over the rest of the United States. He hoped the state could preserve the opportunity to be at least at the discounted price level.

MR. HEINZE urged the legislature to promptly approve the AGIA license to TransCanada; ANGDA believes that would keep the maximum amount of momentum and competition to negotiate and make things happen. A big pipeline built sooner would be advantageous for in-state service. Buying and shipping gas in a big pipe and a spur line could require a commitment from the state of over $10 billion. Alaskan utilities don't have that kind of money, but they have the customers that will pay for utilities over the long term. He spoke in support of an aggressive timeline as the best chance of striking a favorable long term deal for Alaska.

9:22:33 AM

REPRESENTATIVE RALPH SAMUELS questioned what would happen if the state chose to build the bullet pipeline with state capital and not fold the cost into the tariff. He asked if it would cost $3.5 billion and how that would affect Anchorage and Fairbanks tariffs.

MR. HEINZE agreed the volume range to meet Alaska's gas needs would be between 100 and 250 MMcf/d. If the state put up $3.3 billion for a bullet line, tariffs would be close to zero. Operating costs associated with a pipeline are very low.

REPRESENTATIVE SAMUELS concluded that if the gas was used in state, FERC would not require the state to get the capital back through the tariff.

MR. HEINZE responded that the gas would be intra-state gas and would be solely the jurisdiction of the Regulatory Commission of Alaska (RCA). If the money were put up with an expectation of zero rate of return, the tariff could conceivably be approved within 12 months.

9:25:43 AM

REPRESENTATIVE SAMUELS questioned how the deal would work between ENSTAR and the producers.

MR. HEINZE explained that the state would fund and build an in-state line, which would not have a toll other than operating expenses. The state would not own the gas; whoever wanted gas would ship it. If a company like ENSTAR wanted gas on the south end of the line, they would go to the north end and buy gas, or they would buy it from a company that has already shipped it down. This would be limited to an Alaskan market. The price would be as high as the next cheapest alternative.

9:27:34 AM

REPRESENTATIVE RAMRAS recalled when the legislature passed the resolution asking for a focus on small diameter pipelines and the governor's approach was to set aside $4 million for ANGDA. He asked what ANGDA was doing to address that resolution, which was responsible for the governor's response for the $4 million, to try and talk about a small diameter pipe that can happen in a time frame that is sooner than AGIA.

MR. HEINZE clarified that ANGDA received $4 million to study gas related issues. The money comes due July 1, 2008. ANGDA intends to move ahead with those things that directly influence how big the market is in Alaska, and identify industrial users that might be interested in coming to Alaska and help pay the bill. There are a number of similar issues; for example, ANGDA recently hired Tony Izzo as the Gas Supply Coordinator. He would be working with local electrical utilities to find a way to be of maximum assistance to them. He noted that in relationship to AGIA, ANGDA supports the granting on the license in the belief that that puts the process on a competitive commercial basis. They believe that is the best opportunity to achieve in-state service.

MR. HEINZE reiterated that once AGIA is settled, and two big pipelines moving forward, then the spur line becomes real. When he talks to financial people outside of Alaska about

the spur line, the biggest problem is that they know there is no gas in Delta Junction. Once people believe a big pipeline will happen, then it becomes much easier to work towards a spur line. In that mode ANGDA intends to take any steps to accelerate the timeline. For example, ANGDA has always advocated that the spur line be built as a pre-build into the big pipeline, that it be built and ready for the big pipe. They have advocated that the northern section be built first in preference to the Canadian section, and so on. There will not be an opportunity to make good decisions about the spur line until the bigger project is well underway.

MR. HEINZE stated that he did not feel that there was enough information yet to warrant a commitment about which way to go. The goal is to get to open season by the first of next year.

9:32:52 AM

REPRESENTATIVE RAMRAS questioned ANGDA's interpretation of the way to spend the $4 million for a spur line to be attached to the AGIA line in the year 2020, which does not help interior Alaskans now. He asked if ANGDA had any sense of urgency.

MR. HEINZE repeated that the language was the language chosen by the legislature, rather than the language of instruction he would have preferred; ANGDA was restricted to looking at market as opposed to a project. Regarding the immediacy of the energy situation, he described being in Fairbanks and discussing propane and getting a facility going on the North Slope within one year. He also wanted to use some of the money to study and advocate for a 40 mile pipeline into Fairbanks from the Nenana Basin to expedite getting the gas to Fairbanks.

9:35:02 AM

REPRESENTATIVE MIKE DOOGAN referred to the slide on demand and asked if it showed current demand with some increases for growth in population.

MR. HEINZE replied that the slide represents a reasonable growth in demand.

REPRESENTATIVE DOOGAN asked if there were a provision for people lowering use.

MR. HEINZE responded that homeowners don't have a lot of good alternatives. There could be an effect, but it was not considered in the figures.

REPRESENTATIVE DOOGAN turned to the slide with the tariffs. He asked if the actual price would have to include producer costs.

MR. HEINZE replied that the numbers reflected only the cost of the pipeline and that there may be other costs associated with preparation of the gas, shipping, distribution, and so on.

REPRESENTATIVE DOOGAN clarified that the total delivery charge could be in the $6.50 range.

MR. HEINZE answered that if the volume numbers are towards the higher end of the scale, the price is less because of a tariff break. Building the pipeline would require a 20-30 year commitment. He did not think anyone wanted to sign a purchase agreement with a floating price for that length of time. ANGDA wants a price decided on.

REPRESENTATIVE DOOGAN responded that people seem to use “availability of gas” and “cheap gas” as if they were the same thing, but they are two different things.

MR. HEINZE added that the supply has diminished in Cook Inlet. There is no assurance of a long-term supply. There is also the issue of deliverability. Both issues are addressed by bringing North Slope gas in. In addition, North Slope gas, in an open season process, may provide the opportunity to cut a deal for purchase and shipment for the next 20-30 years that basically gives a stable energy cost environment. He recalled a recent 30 percent price increase. The only way to get away from those is a longer term commitment. He referred to a company that made a long-term deal which was controversial at the time, but resulted in price stability.

REPRESENTATIVE DOOGAN asked if the utilities would be better off with a negotiated rate rather than depending on FERC to set the rate.

MR. HEINZE thought that if state could act decisively in the next year, whether choosing Denali Pipeline or TransCanada, ANGDA could assess needs and willingness to commit. That would not affect financing in any big way, but the utilities are an important piece. If Alaska has to assert any of its concerns through the FERC process, it makes it difficult for everybody.

REPRESENTATIVE DOOGAN asked if whoever built the pipeline would be better off going to FERC with a completely negotiated agreement about who the gas would be provided for and prices.

MR. HEINZE responded that when a tariff is filed, there should have been a strong effort to bring the parties

together. He cited an example in Wyoming of competing pipelines in a heated competition.

9:44:18 AM

SENATOR THOMAS WAGONER asked for the conversion between a gallon of propane and one MMcf of methane.

MR. HEINZE said he would get that information.

SENATOR WAGONER asked about an off-take at the Yukon point for propane. He wondered if it would make better sense to have an off-take at Delta Junction with a straddle plant, and to process there for shipment to the villages.

MR. HEINZE explained that a big pipeline would carry a lot of molecules other than methane: ethane, propane and butane as well. Each of those other molecules can be separated by just taking a side stream and running them through a fairly simple process at a straddle plant. Simply cooling the gas causes the propane/butane drops out. ANGDA expects there will be propane facilities all along the pipeline because at every compressor station, step one of conditioning the fuel to be put in the turban unit is to drop out the propane/butane. He reiterated that there will be wholesale propane facilities at least at every 150 miles along the pipeline. He continued that ANGDA believes that it is important to keep the ability to put a large straddle plant at Delta Junction, one that might be capable of assuring that there was up to 75,000 barrels a day of ethane available. That is a big plant, costing billions of dollars. ANGDA wants the state to have the possibility of making those kinds of decisions in the future.

MR. HEINZE referred to the pay-offs to Alaska in terms of value for our gas and in terms of jobs and plants and the tax base.

9:46:46 AM

REPRESENTATIVE SAMUELS wanted information about the capital cost difference between the 100 MMcf/d and 250 MMcf/d estimates.

MR. HEINZE answered that the capital cost is the same in all cases.

REPRESENTATIVE SAMUELS described a hypothetical of giving ANGDA $4 billion for a bullet line right now. He asked how long before the gas could be used in a home in Fairbanks.

MR. HEINZE observed that, presuming a 24 inch pipeline, moving a project forward rapidly would take a couple more years of preliminaries and three years to build. The biggest

issue would be what is at each end of the pipe, especially the north end.

REPRESENTATIVB SAMUELS thought that it was a matter of public policy to take care of the in-state gas needs. He asked how expandable the 250 would be.

MR. HEINZE said that ANGDA used ENSTAR's numbers for a 20 inch pipeline. The numbers could be low, but he thought the 20 inch high pressure pipe could be capable of 750 MMcf/d. A 24 inch pipe could carry 1.25 bcf/d.

REPRESENTATIVE SAMUELS queried about expansion to Nikiski with a zero tariff. He wondered if FERC would seize control.

9:51:57 AM

REPRESENTATIVE BOB ROSES wondered how ANGDA had enough data to endorse AGIA if they did not have enough data to decide how the spur line should go.

MR. HEINZE clarified that he didn't have enough data in terms of volumes on the chart. The direction of ANGDA is guided by what would be the best long term deal for the Alaskan consumer. While they are interested in market forces that affect the bigger project, the focus is on Alaskans. On the chart it is clear that the spur line offers advantages. He thought it would be a mistake to abandon the possibility of a competitive, big pipe that a spur line could connect with.

REPRESENTATIVE ROSES stated that he wanted competition as well. He asked if there had been discussions with Denali.

MR. HEINZE reported that discussions with Denali have been very limited, although there had been good dialogue with ConocoPhillips during the Alaska Stranded Gas Development Act (SGDA) considerations. ANGDA was glad that Denali has a leader but there has been no meaningful discussion. He had no reason to think Denali would not be open to discussion.

REPRESENTATIVE ROSES wondered if ANGDA shared the concern that came out during public testimony about limiting options by granting TransCanada the license.

MR. HEINZE responded that granting the license would effectively accelerate the timeline and promote openness. He referred to a recent report that Denali was opening a docket with FERC. He thought this created good competition. He related a story about well drilling and competition. He emphasized that leverage is needed as Alaska is a small competitor.

REPRESENTATIVE ROSES questioned whether pushing forward with the license would prohibit the state, because of the non-competitive clause on subsidizing other companies, from encouraging other companies.

MR. HEINZE replied that ANGDA's considerations flagged only the term "grant of money." The phrase would only apply to ANGDA. No one else has said that anything in the provision prevents them from doing what they want. The language is fine for an in-state spur line. For greater volumes, over 500 MMcf/d, there is a successful in-state market. All discussions with TransCanada indicate that the spur line and that volume are good. They make money and the consumer wins.

SENATOR DYSON stated concerns about the impact of a spur line on Cook Inlet and Nenana Basin exploration and production, especially related to added incentives. He worried that spending the money on the spur line would shut off new gas exploration in those basins.

MR. HEINZE commented on the Nenana Basin. If there was anything there he would like to see gas taken directly to Fairbanks or making electricity and shipping the electrons both north and south on the intertie. He did not think the spur line had anything to do with what was happening in Nenana Basin. He wished them well.

MR. HEINZE acknowledged the potential for development in Cook Inlet, as long as the price structure is reasonably supportive. He thought development would happen regardless of a spur line. The commerciality of moving ahead makes sense regardless of what we do about a spur line. If there were a discovery of a large deposit of gas, the spur line would be popular because it goes the other direction as well. These kinds of longer term infrastructure developments can fit with a wide variety of actualities.

9:59:38 AM

SENATOR DYSON wanted to know how much gas was in the Basin before committing to a spur line. However, having a spur line in place that would move Cook Inlet gas was also very attractive. He asked if exploration in either basin would be inhibited in any way by the spur line.

MR. HEINZE admitted that it was difficult to tell. He did not think the prospect of a spur line would affect exploration and development.

SENATOR DYSON asked if gas from new discoveries in Cook Inlet would be cheaper for the consumer because there would not be the capital cost to amortize. He questioned how much incentive Cook Inlet lease-holders had to drill now because the small increments in consumer demand would not make it

worth it. He thought the large industrial contracts were important as anchor tenants for the gas sales.

MR. HEINZE commented that the current Cook Inlet market is an isolated market, a small group of producers to a small group of consumers. He said the advantage of considering the North Slope gas coming into the area is that it is a huge, multi-generational supply that gives the opportunity for a long term deal.

SENATOR DYSON asked if the gas from the North Slope would be significantly more expensive in Southcentral than gas from new discoveries in Cook Inlet.

MR. HEINZE referred to the chart and said the price would be comparable to gas prices in other parts of the United States. If the basin remains isolated, the price might have to rise higher. The clearing price might be set by liquid natural gas (LNG) imports into Cook Inlet, which would mean a price higher than the North Slope.

10:08:20 AM

SENATOR HOLLIS FRENCH said an Anchorage hearing was planned to explore what the state can do within the confines of AGIA related to assisting the development of in-state gas. He asked why purchase agreements are important for a spur line.

MR. HEINZE advised that utilities need a long term supply of gas. A company like Exxon might be interested in having a relationship with an electric company over twenty years because they have opportunities to make money on money that they do not spend. The state, on the other hand, could bond at a very low interest rate, and against the pledge of monthly household payments for twenty years, broker a deal that bridges between the utility's monthly cash flow and the long-term purchase of gas in the ground.

SENATOR FRENCH asked how important the purchase agreements were to the success of a spur line.

MR. HEINZE did not think they were important at all. Everybody who has gas on the North Slope would like to sell into the in-state market because they only pay 5 percent severance tax, not 25 percent. It is a limited market; whoever gets there first gets it. That is why Exxon might be willing to make a twenty year deal.

10:11:36 AM

REPRESENTATIVE CARL GATTO asked if it was possible to run non-pipeline quality gas all the way into a gas turbine to generate electricity and not blow the turbine blades because of the presence of carbon dioxide.

MR. HEINZE explained that the costly part of the gas treatment plant in Prudhoe Bay is removing the carbon dioxide, which saves moving an inert molecule, thereby reducing the volume of the gas by 10 percent. There may be limited opportunities downstream to remove it as other things are done with the gas, especially interfacing with other pipeline systems unwilling to accept the carbon dioxide. On the other hand, pipeliners don't like carbon dioxide because with water it creates carbonic acid, which leads to corrosion and other problems. If the only use of the gas is to burn it, which makes water and carbon dioxide, the presence of the carbon dioxide doesn't matter. Turbines and stoves work fine on Prudhoe Bay gas with the carbon dioxide still in it.

MR. HEINZE emphasized that carbon dioxide removal is absolutely necessary if you are making LNG. Different pipelines tolerate different amounts of carbon dioxide.

10:14:35 AM

REPRESENTATIVE GABRIELLE LEDOUX thought the AGIA process was spurring the competition with Denali Pipeline. She wondered if it would be better to wait on AGIA.

MR. HEINZE replied that deciding to not vote on the issue is a no vote. He liked the people at Denali Pipeline, but he did not have commitments from them. If the AGIA license was approved, he would at least have some leverage.

10:16:29 AM

SENATOR LESIL MCGUIRE commented that if AGIA were voted down, there would still be ANGDA, the legislature, the governor, TransCanada's interest in ownership of the right-a-way, the producers who have publicly shown their interest. She did not agree that a no vote would mean a forever no to TransCanada or to a gasline. It would mean no to a particular set of parameters that are too expensive and too limiting on the future choices.

MR. HEINZE stated that if at this point the legislature doesn't feel comfortable moving ahead with TransCanada as an alternative to Denali, then he wanted clear direction.

SENATOR MCGUIRE suggested pausing in the process and bringing in a mediator.

SENATOR MCGUIRE questioned if a yes vote for TransCanada would mean the state could not develop Cook Inlet and Nenana Basin for in-state use. She referred to ANGDA's concerns with the grant of money and that they believed it would not be considered a competitive or unlawful act subject to

treble damages. Given Alaska's tax structure, which is supposed to incentivize gas development equally for everyone, she wondered if the carve outs of Cook Inlet and Nenana Basic, designed to incentivize development for in-state use, could open the state to violating AGIA.

MR. HEINZE stated his recollection of ACES was that gas used as fuel in Alaska is subject to a 5 percent severance tax, regardless of which basin it is from. The idea was to provide an incentive for North Slope gas to be dedicated into the in-state market. He thought that was legitimate and insightful public policy, and helpful in terms of meeting in-state gas needs. It causes players to think about how to gain that advantage, which is significant; the difference between a 5 percent and 25 percent tax rate is a large incentive to a producer. He argued that those terms are unrelated to the non-compete aspect of being a good partner to TransCanada.

10:22:19 AM

MR. HEINZE referred to a handout with a draft bill. The packet is an excerpt of a public record from 2006. There were public hearings. The conclusion was that the statute was in need of change. The letter was written to then Governor Murkowski for its inclusion in the SGDA proposals that were to come before the legislature, but never did. He was surprised it has not been addressed before. It is an outgrowth of former Attorney General of Alaska Charlie Cole observation to an LB & A hearing in 2004 in which he passionately described why the existing portions of statute dealing with in-state open season North Slope gas could never work. ANGDA agreed and went to the Regulatory Commission of Alaska (RCA) who also could not figure out how it works. The solution offered here is a fairly minor change of statute; it eliminates regulation language and puts the jurisdiction back on the RCA to determine if a proper open season has been held.

MR. HEINZE asked that the legislature consider passing the proposal as part of the AGIA legislation. Without the change, ANGDA does not believe an in-state open season can be held.

REPRESENTATIVE SAMUELS requested that the two chairs of Judiciary work with Mr. Heinze.

10:26:28 AM

DELMA BRATVOLD, SCIENCE APPLICATIONS INTERNATIONAL CORP. (SAIC), explained that the study (see handout "Alaska Natural Gas Needs and Market Assessment: 2008 Update of the Industrial Sector," and PowerPoint presentation "Alaska Natural Gas Needs and Market Assessment: Update

Presentation," Copies on File) was initially done for the Department of Energy, the National Energy Technology Laboratory. It was published in the initial form in 2006; ANGDA requested an update of the portion of the study regarding natural gas needs and market assessment. The update concentrated on the industrial sector because there has been a substantial change in the price environment. The update concentrated on how the change in pricing structure and forecasts might affect demand of potential industries.

MS. BRATVOLD referred to Slide 2, which includes a graph summarizing the 2006 study findings. She explained that the Y axis represents the net back price, or maximum price that each industry or sector can afford to pay, given a forecast product price and all of their associated costs and a discount rate. The horizontal axis represents the demand for each of the industries or sectors. She noted that most of the industries fall below the horizontal bar representing the forecast prices of natural gas in Southcentral Alaska as forecasted for 2015-2035 (based on forecasts developed 2005-2006).

MS. BRATVOLD reviewed changes from the 2006 to 2008 report, as shown on Slide 3, which illustrates how product prices were changed. In the current update, there is both a low and a high case; the low case represents product prices determined based on their relationship to forecasts of natural gas and crude oil, and is based on Department of Energy, Energy Information Administration (EIA) annual forecasts, which is generally relatively conservative.

10:31:42 AM

MS. BRATVOLD reviewed the low case scenario depicted on Slide 4. The updated data shows that the horizontal bar, representing the market prices in Southcentral during the timeframe, shows that all the industries have a netback price (the maximum they could afford to pay given their estimated costs and discount rates in taxes) that falls within the estimated range for market prices. She explained liquid natural gas (LNG) and gas to liquids (GTL) industries have two lines representing their maximum price. For both LNG and diesel fuel, the higher bar shows the price if they were able to sell to Japan; the lower shows the California price.

10:34:24 AM

MS. BRATVOLD discussed Slide 5. She concluded that the maximum feed stock would exceed the expected market prices in Southcentral.

MS. BRATVOLD referred to Slide 6 showing estimated capital costs by industry. She concluded that total capital would be $8 billion for all combined industries.

MS. BRATVOLD reviewed Slide 7, a snapshot of revenue and cost estimates for year ten. She observed that on an annual basis for combined industries, revenues would be billions of dollars per year.

10:36:11 AM

MS. BRATVOLD pointed out that Slide 8 contained a short list of the companies that may be interested in Alaska if gas were available, based on current forecasts. Each industry would conduct its own analyses.

MS. BRATVOLD concluded that recent increases in NG and product prices have improved the feasibility of NG-intensive industries in Alaska. All the assessed industries appear feasible under the high price scenario. Under the low price scenario, LNG and GTL industries may need contracts in premium markets (e.g., Japan) for feasibility. Alaska is well positioned for competing with other producers in providing to a Japanese market. The greatest uncertainty is associated with GTL due to the combination of evolving market, costs, and technology. She added that they are least confident in the gas to liquid industry estimate.

10:39:45 AM

MR. HEINZE added that part of the new funding is to carry forward some of the themes, one of which is to ascertain the interest of industries. He emphasized that given the dramatic price changes in recent years, it is important to look at previous work.

10:41:59 AM

COLLEEN STARRING, REGIONAL V.P., ENSTAR NATURAL GAS COMPANY, observed that the company believes Alaska needs gas by 2014 or sooner. She described ENSTAR as the largest utility in the state and outlined details about the company. The Alaska Pipeline Company (APC) operates under the ENSTAR umbrella. For over 47 years they have constructed and operated 450 miles of transmission mains and 2,700 miles of distribution mains. Gas is under contract to 2014.

10:47:36 AM

MS. STARRING referred to the map depicting ENSTAR's distribution system on Slide 4 of the PowerPoint presentation (Copy on File). Slide 6 shows that there have not been significant finds of gas in Cook Inlet in several years. The in-state line is meant to address the decline.

Slide 7 shows the current outlook. ENSTAR has gas under contract through 2013. Further out, the brown bars depict uncommitted supply.

MS. STARRING reported that Anadarko approached ENSTAR and is currently drilling in the Gubik Field, which is just west of the Dalton Highway. The proposed ENSTAR Line would come from the Gubik Field to the highway and then to Fairbanks and NG distribution system in Anchorage.

The total estimated cost for a 20 diameter line would be $3.3 billion. The time frame to build is expected to be five to six years: two to three years of permitting, design, and procurement analysis; and another 3 years for construction.

10:49:27 AM

MS. STARRING reviewed time lines. The first drilling was done by Anadarko. After the second drilling season next winter ENSTAR will make a decision whether to go forward. Construction will begin following the third drilling season.

MS. STARRING emphasized that the advantages of the ENSTAR line:

- First gas by 2014
- Alaska would control its own destiny
- Ensuring a long-term supply for the Railbelt
- Complements both the AGIA and Denali projects
- Could revive Agrium plant
- Could extend the life of Kenai LNG plant
- Creates opportunities for natural gas-based industrial growth in Southcentral
- In-state markets qualify for lower tax burdens
- Achieves reasonable prices
- Ensures sufficient wellhead prices for exploration and future development

MS. STARRING added that Alaskans currently spend about $297 million for natural gas, $848 million for fuel oil, and $1.3 billion on propane. She referred to Slide 13 which graphs the difference in switching to alternative fuels.

10:52:12 AM

MS. STRRING reviewed the accessible in-state markets:

- ENSTAR
- Southcentral Electric Companies
- Fairbanks Natural Gas
- Military Bases

- Golden Valley Electric
- Tesoro Refinery
- Flint Hills Refinery
- Agrium
- LNG Export

MS. STRRING briefly reviewed Slide 15, "ENSTAR Pipeline Study, Throughput and Load Estimates."

MS. STRRING described some of the assumptions that the project is based on:

- Project based on utility grade gas
- 20" diameter high grade steel pipeline
- Operating pressure ~2500 psi [pounds per square inch]
- Operation pressure and design allow for additional hydrocarbon spiking

MS. STRRING noted ENSTAR's current pipeline status as depicted on Slide 17:

- Contracted engineering, environmental, and construction companies to assist with the project
- Update meetings scheduled with Anadarko in Alaska July 15th
- Aerial photography of both the southern and northern routes
- LiDAR [Light Detection and Ranging] Data
- Field work
- Agency and stakeholder communications
- Data gathering
- Document management system

MS. STARRING concluded the PowerPoint presentation with ENSTAR's development plan priorities on Slide 19:

- Continue regulatory and permit acquisition
- Prepare economic and financial models
- Address environmental work
- Public outreach and involvement
- State ROW [right-of-way] application preparation

10:54:56 AM

GENE DUBAY, SENIOR V.P. & CHIEF OPERATING OFFICER, CONTINENTAL ENERGY SYSTEMS [OWNER OF ENSTAR], concluded that ENSTAR has the solution to Alaska's gas needs. The state has a lot of options, but the timing is important. Given the choice between a 50 cent increase in tariff and obtaining

gas in a timely fashion, they would take the gas. He thought the tariff savings would evaporate if they have to go to other alternatives.

10:57:02 AM

REPRESENTATIVE SAMUELS asked for a description of events that would lead to the purchase of gas without the state sitting on an empty pipeline. He questioned if the purchase price paid by ENSTAR is footed by the public.

10:58:44 AM

MR. DUBAY observed that they do not make a profit on the purchase of the commodity. The company's purchase agreements are filed as a matter of public record and submitted to the RCA for approval. The company anticipated responding quickly if the state made the commitment to build the line.

11:00:01 AM

REPRESENTATIVE HARRY CRAWFORD queried regarding tax breaks for in-state fuel use. He also wanted to know about debt to equity ratio on the ENSTAR line.

MR. DUBAY answered that the debt equity on the ENSTAR line would be approximately 70/30. Regarding the in-state tax, he thought gas dedicated to any kind of in-state use, such as the Agrium plant, would come under the lower tax rate.

SENATOR CRAWFORD asked about the LNG facility.

MR. DUBAY thought the same would apply to the LNG facility.

11:02:09 AM

REPRESENTATIVE MIKE DOOGAN asked if there was a date for the preparation of economic and financial models.

MR. DUBAY stated that goals this year were to establish costs and review throughput on the line to come up with new tariffs. January is the projected deadline for costs. The throughput for analysis would be approximately in April, 2009.

REPRESENTATIVE DOOGAN asked if ENSTAR's economic analysis took into account potential competition from other resources such as the Susitna dam.

MR. DUBAY maintained that natural gas is the best resource at approximately one-fourth the cost of electricity. He did not think that hydro-electric would compete with natural gas for home heating. He asserted that they have been conservative on their demand estimates.

11:06:22 AM

REPRESENTATIVE LES GARA questioned what would occur if a bullet line was begun and then cheaper gas was found in Cook Inlet. He noted that half the state's gas goes to Asia and observed that the federal license only lasts another year or two.

MR. DUBAY explained that proposals for Cook Inlet gas were for 2013. ENSTAR did not get proposals from producers for the full requirements. He stressed that they must deal with what is before them. There is nothing that suggests another source.

11:10:03 AM

REPRESENTATIVE GARA asked what made ENSTAR's project viable.

MR. DUBAY responded that they have commitments from Agrium for the gas. Today there is not enough gas produced in Cook Inlet to keep all the industries that need gas on line.

REPRESENTATIVE GARA commented that given in-state needs he did not want Alaska gas exported from Cook Inlet. He asked how long the gas would supply Alaskan needs if the export contract were able to be cancelled or scaled back.

MR. DUBAY noted that they supported the export license extension because ENSTAR views the LNG plant as back-up for deliverability. The producers have diverted gas from the LNG plant for their needs. ENSTAR believes the community needs the LNG plant today and over the long term.

11:12:58 AM

REPRESENTATIVE RAMRAS noted that Fairbanks would have no gas for the first quarter of 2009. Most customers will not have the ability to do a fuel switch. He asked why an alternative route to Glennallen is not being reviewed.

JOHN LAU, DIRECTOR OF ENGINEERING, ENSTAR NATURAL GAS COMPANY, explained that ENSTAR has looked at a variety of lines and is in favor of a spur line coming off of a pipeline, especially the pipeline tied into Wasilla. Anadarko approached ENSTAR with an aggressive drilling program in the foothills that addressed problems in building a pipeline to Southcentral and Fairbanks. Anadarko needs a market and industrial base. Foothills gas is the current focus. Anadarko does not want to wait till 2020. ENSTAR currently plans to work with Anadarko to bring foothills gas down to Cook Inlet. Other projects are not being reviewed currently. The work that is being done would apply to any

line. He maintained that ENSTAR has the most experience and supports a route that would connect into Cook Inlet.

11:18:28 AM

REPRESENTATIVE RAMRAS referred to the discussion regarding potential for a transportation subsidy from the state. He questioned delivering gas through Delta Junction to Greely to Valdez if the corridor remains as it is. He wondered what would be required from the state to alter the corridor and reach stranded people.

MR. DUBAY stated ENSTAR wanted the lowest tariff gas to go to customers. A route to Valdez means an export plant that they have no control over.

REPRESENTATIVE RAMRAS clarified that he wanted to shift the route to Glennallen which would give Valdez the option to build infrastructure to meet a pipe in Glennallen rather than in Fairbanks.

11:22:03 AM

MR. LAU explained that ENSTAR would like to take a line to Seward, but it would not work out economically. It could cost $70-80 million. If the state wants to pay for that line, it could happen.

REPRESENTATIVE RAMRAS asked how many extra miles of pipe it would mean to build towards Glennallen.

MR. LAU estimated it would be around 90 additional miles. Construction difficulties would also add to costs.

REPRESENTATIVE RAMRAS concluded that ENSTAR would prefer the corridor down the Parks Highway to the engineering hurdles presented by a Trans-Alaska Pipeline (TAPS) corridor.

11:24:11 AM

SENATOR WAGONER asked if there had been any communication with Agrium regarding their willingness to buy and ship gas on a pipeline built by ENSTAR.

MR. DUBAY noted that there is a memorandum of understanding.

MS. STRRING added that the memorandum would be shared and clarified that Agrium supports the ENSTAR project.

RECESSED: 11:25:52 AM

RECONVENED: 12:43:25 PM

REPRESENTATIVE SAMUELS asked that questions be delayed unless necessary.

RICHARD PETERSON, MANAGING MEMBER, ALASKA NATURAL RESOURCES-TO-LIQUIDS, LLC (ANRTL), proposed an alternative to gas pipelines. He began the ANRTL PowerPoint presentation "A Legacy Decision for Alaska" (Copy on File). ANRTL believes the option of gas-to-liquids (GTL) provides more opportunities for natural resource development, provides a higher net back, and sets up a legacy program that will be available for the next several hundred years. Gas-to-liquids is a promising technology that is in operation in the world.

MR. PETERSON addressed AGIA concerns about GTL. The AGIA process was designed for commercial vehicles to get gas from the North Slope. The inference is that GTL is not commercial. He asserted that GTL may result in a higher wellhead value than a gas pipeline, more long term jobs for Alaska, and a larger tax base.

12:49:33 PM

MR. PETERSON covered Slides 5-7:

- The plant would require a substantial construction workforce. Although not as large as that needed for a gas pipeline, the construction workforce would be employed in Alaska for many more years.
- The GTL plant operations workforce would be much more substantial than that for a gas pipeline.
- All of the liquids remain in Alaska for marketing.
- Natural gas liquids can be transported through the TAPS pipeline along with GTL products.
- While a GTL project could use 2, 3, 4, 5, 6 billion cubic feet of gas/day or more if desired, the plant can be sized to use less gas, leaving gas production that could be transported south through a smaller "bullet" pipeline.
- If you are going to tax the Producers natural gas at a quasi crude oil price equivalent, the Producers might as well convert their natural gas to a liquid product and actually receive a premium price above crude oil.
- We believe the GTL option gives Alaska high value transportation fuels badly needed in the U.S. along with economic benefits and flexibility not offered with a just gas pipeline.

12:51:37 PM

MR. PETERSON spoke to converting Fischer-Tropsch (F-T) products into natural gas equivalents.

12:53:00 PM

PETER TIJM, MEMBER, NATURAL RESOURCES-TO-LIQUIDS, LLC RESOURCES, explained the technical, chemical aspects of F-T synthesis depicted on Slide 13. This technology was developed in 1923 and has been in operation ever since.

MR. TIJM reviewed the three steps in gas to liquids/coal to liquids/biomass to liquids (GTL/CTL/GTL) refining to make F-T fuels outlined on Slide 14:

- GTL/CTL/BTL processes use three distinct steps, all commercially proven to convert a gas, liquid or solid into synthetic transport fuels:
  - Step 1 – Syn=gas generation (hydrogen and carbon monoxide)
  - Step 2 – F-T reaction (long paraffin chains to wax)
  - Step 3 – Product upgrading (hydrocracking of the long chain F-T paraffin to produce the desired end product, similar to a crude oil refinery: Kerosene – diesel – gasoline – jet fuel – naphtha)

MR. TIJM reviewed Slide 15, which shows in more detail the three main processing steps of the F-T process. Slide 16 lists the plants and proposed plants worldwide. One of the big complexes in South Africa produces 150,000 barrels per day (BPD) if liquids, using coal as feedstock. This plant has been on line since the 1950s. Another plant in South Africa uses off-shore natural gas as feedstock and produces nearly 50,000 BPD. All over the world cars are being fueled by these liquids.

MR. TJIM explained that the synthetic diesel made in these plants is high quality. The molecules used are only carbon and hydrogen. There is no sulfur, no aromatics. There are almost no emissions when the fuel is burned. The fuel is approved as the EPA as non-toxic. It even has Food and Drug Administration (FDA) approval as food quality. He drank some of the synthetic diesel to demonstrate its purity.

12:59:46 PM

MR. TIJM provided additional information on F-T diesel facts and fiction:

- Myth: Majors are not pursuing F-T technology.
  - In December 2003 ConocoPhillips and in July 2004 Exxon Mobil both signed agreements to build 160,000 bbl/day and 150,000 bbl/day GTL plants in Qatar. They would not have made these

commitments if they did not believe in GTLs and possess the skills to build world-scale GTL plants.
    - Shell Oil, a new player in Alaska, has a 15,000 bbl/d GTL plant in Malaysia, is building a 140,000 bbl/d GTL plant in Qatar as well as designing a 70,000 bbl/d GTL plant in China.
    - Chevron, Sasol's world wide GTL partner, is building a 34,000 bbl/d GTL plant in Nigeria and had proposed a 130,000 bbl/d GTL expansion with Sasol and a new 120,000 bbl/d GTL plant, both in Qatar.
    - Marathon completed a pre-FEED study for a 120,000 bbl/d GTL plant in Qatar in 2003.
    - BP and Statoil are working on barge mounted GTL plants.
- Clearly, the North Slope majors possess all the skills necessary to build GTL (F-T) plants worldwide, including in Alaska.

1:01:59 PM

MR. TIJM spoke to the efficiency of GTL plants, delineated on Slide 27:

> Some say the GTL process is not efficient with only 65% of the energy contained in the natural gas reaching the end market in the form of transportation fuels.
>
> Like any manufacturing process that "adds value" to its products, the transportation fuels resulting from a GTL plant have a higher value.
>
> Also of importance is that the "lost" 35% really isn't lost.
>
> It is captured as waste heat and is used to generate electricity, heat buildings and run other processes that need heat, saving valuable natural gas for other purposes.

1:03:15 PM

MR. PETERSON discussed Slide 28, which compared GTL vs. LNG for efficiency and value, and concluded that the net back of GTL is of higher value.

1:04:31 PM

MR. TIJM returned to GTL facts and fiction with Slide 30:

- 2003 estimate $25,000/installed barrel.

- 2007 actual cost $32,000/installed barrel.
- 2008 Shell Pearl GTL plant $60,000/installed barrel (under construction today).
- ANRTL completed a $1.5 million Pre-Feasibility study for an 80,000 bbl/d CTL project for the Cook Inlet in February 2008. Cost estimates have risen from $4.6 to $12 billion from 2005-08.
- The CTL project still pencils out because product prices have risen even more.
- Some of the estimated costs of this Cook Inlet CTL project were derived from the $250 million Sasol/China engineering study completed in late 2007.
- North Slope GTL plant ~300% higher than the recently completed Sasol GTL plant in Qatar – we use a $92,000/ installed barrel cost.
- If anything, we believe the projected costs of a North Slope GIL plant program are high.

MR. TIJM noted that 4.5 bcf/d translates to 400,000 barrels a day in response to a question by Representative Samuels.

MR. TIJM explained that their study was generous in terms of costs. Slide 32 depicts how front-end design studies function, in engineering terms. The feasibility study is still in the early stages.

1:09:07 PM

MR. PETERSON explained that batching is one of the principles used to reduce costs and maintained that TAPS batching/pigging can be done. Slide 36:

- There is no question that the TAPS line can be operated as a dual/multi products/crude pipeline.
- Explorer Pipeline, owned by several major oil companies, has successfully operated a 1,400-mile large diameter pipeline carrying a full slate of refined products and crude oil. In fact the Explorer Pipeline model is used in many pipelines in operation today.
- Explorer Pipeline has offered to bring their expertise to Alaska to assist with the design and conversion of TAPS.

1:11:16 PM

MR. PETERSON explained that cleaning pigs must be used for physical separation of the crude oil and the product. Slide 37:

- Batching F-T products and NGLs (Products) without a physical separation between the Products and the ANS

crude oil will not work. Further batching of the Products without a physical separation between individual products is not recommended.

- "THE PIG TRAIN" - Physical Pigging will allow batch shipping of Products from the North Slope to Valdez.
- The outstanding question is how far can you batch/pig down the TAPS before you need to replace the pig due to wear?
- TAPS line can remain viable for moving crude oil produced on the North Slope to Valdez for 50 to 100 or more years.

MR. TIJM gave an example of a project in Europe where pipes were shared; his company's crude batches were effectively separated in spite of distance and other challenges.

MR. PETERSON continued with Slide 39-40:

- Once TAPS is modified to carry both crude oil and products, the currently recycled gas stream can be processed to extract additional NGLs for batching to Valdez.
- This allows for the receipt of this NGL revenue stream within a few years, certainly long before a GTL plant could be on line or a gas line to the lower 48 could be built.
- It is our opinion that the market for North Slope NGLs will be considerably higher at Valdez than at AECO [Alberta Energy Company] in central Alberta if for no other reason than the tariff on TAPS is at least 1/3 of the cost to ship on the proposed AGIA gas line.
  - o TAPS tariff $5/bbl (83.3cents/million btu)
  - o AGIA tariff $3/million btu ($18/bbl)
  - o AGIA tariff $4/million btu ($24/bbl)
- The interior of Alaska operates on a liquid energy economy.
- Batching products down TAPS will provide Interior Alaska with the opportunity to receive lower cost fuels at new delivery points along the pipeline without having to replace their existing energy infrastructure.

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MR. PETERSON continued with Slide 42:

- Batched products will be contaminated: One of the biggest advantages with a TAPS batching /pigging program is that butanes have been extracted from the gas stream and spiked into the crude oil stream since first flows.
- This same volume of butane will be placed in the front

end of the pig train and used to clean the pipe walls of contaminants.

- The “dirty” butanes will be blended with the ANS crude oil at Valdez.
- If any batched products behind the “cleaning” butanes are also contaminated, the batching program will provide for additional processing at Valdez to remove sulfurs and color.
- NGLs with a high vapor pressure can’t be transported in TAPS: The lightest products we would recommend for shipping on the TAPS would be propane C_3H_8 Propane has a vapor pressure of 207 psig [pounds per square inch gauge] at 110°F. This is far below the operating pressure of TAPS.
- Keep ethane in the natural gas as there is no petrochemical industry on the US West Coast. Ethane will be converted into F-T products.

MR. PETERSON pointed out that if Alaska does not want to do a GTL program, but still wants a gas pipeline (Slide 45):

- Batching/Pigging in TAPS could benefit the AGIA gas line if a gas line is the best option
- Modifying the TAPS line to batch crude oil and products will eliminate the need to transport liquids in the gas line.
- This will reduce the cost of the gas pipeline and make its operation easier, plus make delivery of in-state gas less complicated as you are not dealing with a dense phase gas.

1:20:04 PM

MR. PETERSON observed that America needs natural gas (Slide 47):

- The need for imported (additional) natural gas pales in comparison to the need for reducing imported crude oil and adding refining capacity.
- Natural gas has historically sold at a discount to the value of crude oil. Today that disparity is wider.
- Diesel has historically sold at a price at or below regular gasoline. Today diesel sells at a premium to gasoline.
- F-T diesel has, in addition to the higher value of crude oil, the value of the refining margin plus a lower tax rate resulting in a market price premium of between $33 to $55/bbl over the value of crude oil ($6.2 to $10.3/mcf).

MR. PETERSON observed that (Slide 48):

- Virtually everyone has a different opinion on the volumes of natural gas, crude oil and refined transportation products produced, consumed or imported in the U.S. For the purposes of this report, we use information gathered from independent two sources:
- U.S. Energy Information Administration (www.eia.doe.gov/) and
- The BP Statistical Review of World Energy June 2007 (www.bp.com/rroductlanding.do). This latter document is an excellent summary of world energy and BP should be commended for pro v/ding this public service update each year.

MR. PETERSON continued with Slide 49:

- If we look at the six month period from August 2007 through January 2008 (the latest EIA numbers) the U.S. on average produced slightly more than 5 million barrels per day of oil. (note: the EIA data does not include NGLs in the crude oil).
- During the same time period the U.S imported over 10 million barrels per day of crude oil and another 3 million barrels per day of refined products.
- The significance of the latter number is that the nation lacks over 3 million barrels per day of refining capacity to meet current U.S. transportation fuel demands.

MR. PETERSON emphasized that even if the Arctic National Wildlife Refuge (ANWR) was opened up immediately, there is not enough refining capacity to meet current demand. The U.S. imports three million barrels a day of gasoline, diesel, and jet fuel because of that.

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MR. PETERSON turned to Slide 50:

- While U.S. refiners have been adding capacity to existing refineries with process efficiency upgrades, no new refinery has been built in the U.S. since the 1970's.
- This could possibly be one of the reasons why refinery margins have crept up from the $5 to $6/bbl range in 1970 - 2000 era to over $30/bbl in 2007.
- A North Slope GTL plant represents new refining capacity for the U.S. and a potential threat to these higher margins, especially on the U.S. West Coast.
- This is one potential reason GIL's are not be in the

forefront of North Slope majors' gas development plans.

Slide 51:

- The U.S. currently (2008) imports roughly 70% of its crude oil/transportation needs. With approximately 13 million bbl/d of transportation fuel demand almost 29% of this demand (approximately 3 million barrels per day) is imported in the form of finished products.
- On an energy content equivalent scale this represents approximately 18 bcf/d of natural gas being imported just to meet the U.S. refinery shortfall.
- This is four times the volume of gas to be delivered through a natural gas pipeline.
- ~78 bcf/d for total transportation needs – 20 times.

1:29:12 PM

MR. PETERSON explained a graph on Slide 52 depicting U.S. oil companies have no control over the price of crude oil in the world. The largest independent oil company in the world cannot compare as far as crude oil production. He went on to Slide 53:

- During this same time period the U.S. was producing approximately 64 billion to 65 billion cubic feet per day (bcf/d) of natural gas and importing approximately 9 to 10 bcf/d of natural gas, primarily from Canada.
- Of this, approximately 1.6 to 1.8 bcf/d of the total U.S. natural gas is being imported as LNG.
- Thus 14.7% of U.S. natural gas consumption is imported, with LNG representing approximately 2.4% of total U.S. natural gas needs.

1:29:57 PM

MR. PETERSON reviewed Slide 54:

- Historically natural gas HAS sold at equivalent price compared to crude oil.
- From 2002 to 2007, natural gas averaged 68% of the WTI [West Texas Intermediate] price of crude oil (i.e. 32% below crude oil).
- In April 2008, the NYMEX closing price for May 2008 deliveries of natural gas was $10.60/mcf or, a crude oil equivalent price of $63.60, some 45% below the then crude price of $115/bbl.
- We believe that there was a fundamental severing in the price of natural gas compared to crude oil once oil hit the $60 to $70/bbl range.

MR. PETERSON thought the reason was that there is a maximum number natural gas will sell for in the Lower 48 and we are close to that number now.

1:31:50 PM

MR. PETERSON continued with Slide 55:

- All of the energy consumers who could have switched off crude-based products have done so but the gas industry is still able to meet demand.
- In fact, little LNG is currently being imported into the U.S. because markets elsewhere in the world, especially those linked to the price of crude oil, are paying much higher prices and few want U.S. dollars.
- If one compares a California ultra-low sulfur diesel price with an equivalent natural gas price one quickly sees a potentially greater return for Alaska in selling F-T products than selling natural gas.

MR. PETERSON emphasized the de-valuing of the U.S. dollar as the primary reason LNG is going to other markets. The Japanese market, which drives the high price of LNG, is going to re-negotiate to bring down this tracking of crude oil prices so that LNG worldwide may come down.

MR. PETERSON explained Slide 56:

- April 2008 [California Air Resources Board] CARB diesel wholesale price of $3.30/gallon ($138.60/bbl) plus the tax advantage of selling a natural gas based fuel in the transportation market of $13.02/bbl, one has a market gas equivalent price of $28.6/mcf.
- Compare this to the April NYMEX [New York Mercantile Exchange] number and one can see that the gas price would have to increase by 270% to equal that of diesel.
- On May 19th, the wholesale price of California diesel hit $3.91/gal or a mcf equivalent price of $33.4/mcf.

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MR. PETERSON presented the graph on Slide 57, “CARB Diesel Fuel Average Rack Prices (As of 5/19/08).” The average 2005 through 2007 price for finished diesel was around $2/gal. The average 2007 came up to $2.37/gal. The May 2008 price was $3.91, or $33.4/mcf. Slide 58:

- We point these facts out to show that the greatest energy need in the U.S. is not natural gas; it is replacing crude oil imports and more importantly adding domestic refining capacity.
- U.S. natural gas is not priced on a world crude oil

equivalent as it is in many other parts of the world. U.S. transportation fuels are, however, priced based upon the world price of oil.

- Plus in some areas, such as the U.S. West Coast, transportation fuels are priced at a premium due to higher quality requirements.

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MR. PETERSON turned to Slide 60, "Netback from California to Prudhoe Bay." He offered three cases:

- CASE A – Average California 2007 refinery wholesale rack price $2.37/gallon
- CASE B – May 19, 2008, California refinery wholesale rack price $3.91/gallon
- CASE C – Projected 2014 crude oil price of $200/bbl and $40/bbl refinery margin resulting in $5.71/gallon

MR. PETERSON also assumed:

- $2/bbl shipping cost, Valdez to market, and a $5/bbl TAPS tariff, for a total $7/bbl Prudhoe Bay to California
- 5.3 billion btu/bbl of F-T and 1 million btu/mcf of natural gas
- A debt service/equity recovery cost of $31.75/bbl (75/25, 20 years to recover the debt, 7.5% cost of financing, 20% return for equity for the producer)
- A GTL plant operating cost of $18/bbl

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MR. PETERSON reviewed slides 61 to 64, which detail the math for the three cases. He pointed out that the F-T process converts carbon contained in the natural gas into finished transportation fuels and heat. Approximately 65 percent of the BTUs contained in the natural gas will end up in the transportation fuels. Much of the BTUs contained in the natural gas will be captured either in the F-T fuels or waste heat to produce power. The end result is that product in:

- Case A would cost $2.37/gallon in California would cost $6.01/mcf natural gas at a Prudhoe Bay GTL plant;
- Case B would cost $3.91 in California and 12.98/mcf natural gas at Prudhoe Bay GTL plant; and
- Case C would cost $5.71 in California and $21.16/mcf natural gas at Prudhoe Bay GTL plant.

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MR. PETERSON emphasized the projected high costs of AGIA gas on Slide 65:

- A Prudhoe Bay price approaching $18 to $27 per mmbtu over 25 years.
- 2017 to 2042. WOW.
- What do Alaskans think they will be paying for natural gas?
- These AGIA projected gas prices are 300% to 400% higher than the 2007 prices in the Cook Inlet. This isn't "cheap" gas!

MR. PETERSON wondered how the people of Alaska would afford heat and energy at these prices.

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MR. PETERSON asked who receives the most value from gas sales, and directed attention to Slides 66-67:

- Tax the Producers natural gas at a crude oil price equivalent and the Producer may only receive a fraction of the value of the natural gas.
- At today's $120/bbl crude oil price the PPT on natural gas would be:
  - 25 + ((97.5-30)x .004)+(120-97.5)x.001= .543 or 54%
  - With a 1/8 Royalty (12.5%) + 54% = 66.5% of the value goes to the State – the Producer receives 33% (+ pays other taxes to the state and federal government)
  - At $200 crude the % of value to the State would exceed 75%
  - You can easily see why the Producer of the pipeline risk isn't who is expected to take all excited about AGIA
  - Ask yourself, "Why isn't the market guaranteeing the gas line payout instead of the Producers?"

MR. PETERSON asked who should be buying firm capacity supply or market. Slide 68:

> If Natural Gas truly was in short supply and projected short supply were real, then people who need natural gas, have no choice but to use natural gas (market) would be coming to Alaska to buy this "proven" resource. THEY would be contracting with whoever is building the pipeline for firm capacity to their market. Do you see this happening?

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MR. PETERSON addressed the topic of energy conservation and its impact on a gas line. He recalled when the price of gas was projected to go up to $9 in about five or six years, he wondered if he could afford to live in his house any more. He began winterizing. He reviewed Slide 70:

- 300 million people in America
- Take 1/3 or 100 million people
- Turn off two 100 Watt light bulbs or don't run a PC for half a day
- Save 480 billion watts per day or 20,000 MW-HR
- Assume a modern heat rate of 8,500 Btu/kw-hr
- Save 4.08 billion cubic feet per day of natural gas
- THAT'S THE ALASKA GAS LINE CAPACITY IN A FLICK OF THE SWITCH

MR. PETERSON turned to the subject of the nuclear threat to Alaska's gas, depicted on Slide 71:

- We are told that Toshiba is looking at installing up to five of their small nuclear power plants in Alberta to supply the tar sands projects with heat and electricity that would be CO_2 free energy.
- Helps Canada meet its Kyoto obligations. There goes 1 to 2 bcf/d of gas market.
- Canadian supplied gas will have to flow into the U.S. market competing with Alaska AGIA gas.

MR. PETERSON cautioned against thinking the price would just go up and up. The reduction in energy demand caused by conservation has to be figured in. He pointed out that gasoline usage comprises 70 percent of our import needs. If that is dropped 20 to 40 percent, we still need everything we can produce from GTLs.

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MR. TIJM described some of the benefits of GTLs at Prudhoe Bay, including the many by-products. Carbon dioxide has to be taken out of the gas. It can be used for secondary oil recovery. The process generates heat that can be used to generate local electricity. It can provide the electricity for the whole complex and make it self supporting. Pure water is also generated that can be used for drinking or secondary oil recovery. If the NGLs are batched, the TAPS tariff can be lowered. The liquids can also be diverted to other towns that need them, like Fairbanks and Valdez.

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MR. PETERSON described the uses of the waste heat produced by the process.

MR. PETERSON addressed Slide 75 and described Alaska's coal resources and reserves. The Northern Alaska Basin could potentially have more coal than the total proven reserves in the world today.

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REPRESENTATIVE SAMUELS asked about the large capital cost to build a GTL plant.

MR. PETERSON recommended building in a modular form. The cost for module is around $92,000/installed barrel, or $8-10 billion initial cost. Modules added over 14-18 years would bring the total to around $40 billion.

REPRESENTATIVE SAMUELS asked if producers did not build GTL plants because of the transportation plus up front capital.

MR. PETERSON responded that the transportation is in place. He speculated about the choices the major companies might make.

REPRESENTATIVE RAMRAS mentioned that Senator Stevens would be at a mid-July meeting with the governor on synthetic gas, coal to gas. In the 2004 National Energy Bill, the U.S. Air Force is mandated to get 20 percent of their energy from an alternative source; coal gasification falls in that category. He asked who requested ANRTL to present on the subject.

REPRESENTATIVE SAMUELS responded that Legislative Budget and Audit was requested by a member to have more information on GTLs. Mr. Peterson was contracted. He speculated that there would be more interest from the industry on GTLs and that there must be trade-offs the industry is not willing to make.

REPRESENTATIVE GATTO referred to Slide 14 and the fact that the carbon chains produced "wax." He asked if, given the North Slope winter environment, it was possible to batch wax down the pipeline.

MR. TIJM answered by saying that the wax is the ultimate form of the long paraffin chains that is cut in pieces before it has a chance to liquefy. It won't be exposed to the atmosphere. He emphasized the many uses of the wax as a very high value-added product.

REPRESENTATIVE GATTO pointed out that number 2 diesel has wax while number 1 diesel does not. Alaskans are forced to burn number 1 diesel in the winter to prevent waxing. He thought it would be very difficult to use anywhere, especially in a pipeline.

MR. TIJM said that the molecules delivered are clear cut.

MR. PETERSON added that the GTL plant on the North Slope would be indoors. The cold flow properties of F-T GTLs are superior to Alaska North Slope (ANS) crude oil. Crude oil creates wax in a pipeline at the lower temperatures, but none of the GTLs would have that problem.

MR. PETERSON closed by saying that coal to liquids (CTL) and biomass to liquids (BTL) F-T programs in the U.S. are economic today because Senator Stevens put the language in the 2005 transportation bill that gives the incentive to compete with these fuels at the same price as petroleum based diesels.

REPRESENTATIVE SAMUELS commented that Mayor Whitaker in Fairbanks was also looking at coal gasification.

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RECONVENE: 2:11:38 PM

BARRY PULLIAM, SENIOR ECONOMIST, ECON ONE RESEARCH, CONTRACTOR, LEGISLATIVE BUDGET AND AUDIT COMMITTEE, explained that Econ One had been asked to look at relative netbacks of potential LNG projects and how those might compare to pipeline projects. He referred to his handout, "Comparison of Netbacks from Potential LNG Project with ALCAN Pipeline Project" (Copy on File). The review looks at the economic assumptions and analyzes the netback values associated with both LNG and pipeline projects. It looks at the Port Authority's proposal in particular, at proposals that would have larger volumes (up to 4.5 bcf/d), and at TransCanada's proposal for purposes of the pipeline netbacks from an overland route. Econ One has also reviewed the administration's analysis of LNG and netbacks, and information from other LNG specialists and governmental agencies.

MR. PULLIAM said that the goal is to assess the netback value that will be available to the resource owners at the inlet of the gas treatment plant (GTP) and which project would maximize the total netback of the gas resource.

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MR. PULLIAM offered an overview of LNG and pipeline logistics to help understand how the netback works. He

pointed to Slide 6 detailing pipeline deliveries. The gas will go into a GTP, be conditioned, go into a pipeline and go to a hub where it will be sold. Along the way, there is a loss of around 9 percent of the fuel volume, as the fuel is used for various processes. LNG deliveries involve more steps and a loss of around 16.5 percent of the volume. The fuel used along the way is a cost of moving the gas.

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REPRESENTATIVE MIKE DOOGAN asked about the losses.

MR. PULLIAM replied that more gas is lost in the regas scenario; however, in the case of Asian sales, the buyer is responsible for the losses.

MR. PULLIAM addressed supply and demand factors. When calculating the netback, the cost of producing the product is subtracted from the price that the product can be sold for. Supply and demand for gas is a factor. Slides 8 and 9 illustrate world wide preserves. Russia, Iran and Qatar are the three largest proven gas reserves in the world, and control over half of the world's gas.

2:21:38 PM

MR. PULLIAM turned to Slide 10, depicting consumers of LNG; Asia, especially Japan, is the largest, taking up 65 percent of LNG demand. Europe is at 24 percent and the United States at 10 percent.

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MR. PULLIAM stated that Slide 11 projects LNG demand by region. In 2005, worldwide LNG demand was about 18 bcf/d. This demand is projected to triple through 2020. A large part of that growth will be here in the U.S. He continued by saying the projected demand in Asia would be about 24 percent in 2020. It is important to keep that in mind regarding pricing.

2:24:32 PM

MR. PULLIAM addressed regional liquefaction plant capacities for serving Asian markets, as depicted on Slide 12. The Pacific Basin, which includes Indonesia, Malaysia, Russia, and Australia, has about 10 bcf/d currently and is developing or considering another 10 bcf/d. The Middle East has 6 bcf/d currently operating and another 12 under construction or consideration. That totals around 37 bcf/d that would be available to deliver gas into Asia.

MR. PULLIAM said that the U.S. mostly relies on domestic gas production at this time. Slide 13 shows U.S. gas production

by source, both historically and projected. The projections are that conventional gas is going to be declining in volume. It will be replaced by unconventional, more expensive gas. The EIA projects that Alaska will fill some of that gap at the rate of 4.5 bcf/d starting around 2021, which would comprise 6 percent of U.S. gas needs.

REPRESENTATIVE DOOGAN pointed out that Mr. Robinson from FERC had said the sale of gas in Pennsylvania and West Virginia was almost unheard of three years ago but now will be almost pushing LNG out. There is much it has become economic. He asked the relationship of that information to the data on Econ One's report.

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MR. PULLIAM acknowledged that his data was from 2007. He said more recent forecasts would have more of the unconventional gas and less LNG coming into the U.S.

MR. PULLIAM turned to Slide 15 which shows usage in the U.S. going up. This is the 2007 data; more recent data would show a lower line. He noted that Canadian gas would affect the picture. It is projected to go down.

MR. PULLIAM discussed pricing, using Slide 16 on historical gas prices. The red line is the LNG price in Japan, which is higher over time. When oil prices started to go up in 2003, U.S. prices increased faster than Japanese prices, because of capping in Asia. Slides 17 and 18 compare U.S. natural gas and crude oil prices. More recently, oil has risen more quickly than gas. The longer term average has been 8:1, oil to gas.

2:32:02 PM

MR. PULLIAM turned to Slide 19, which compares Japanese crude oil and gas prices. Oil and gas tracked each other very closely because gas pricing in Japan and in Asia has been historically tied to oil prices. Many of the contracts in Asia have a cap on them. That is changing, which is reflected in the graph on Slide 20.

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MR. PULLIAM emphasized that contracts are done on a long term basis and market conditions determine price at the time of sale. Market conditions recently have been tight. Gas demand has gone up, LNG has been slow to respond, and so those who have supply have been able to get good prices recently. The question is how that will change.

MR. PULLIAM explained that the first step in the netback process is figuring out what the sale price will be. Econ

One has started with different oil price scenarios. The administration has used the Wood Mackenzie oil price estimates, as well as the EIA estimates, depicted as red and black lines on the graph on Slide 22. The blue line shows what oil would be if it was priced at $60 per barrel in real terms. The other lines forecast higher, but lower than the green line at $90 per barrel. The data is from the end of 2007 and may be considered conservative today. Econ One has used the Wood Mackenzie and EIA prices as the base.

2:37:34 PM

MR. PULLIAM turned to the prospects for Asian LNG prices (Slide 23):

- There is a wide range of prices depending on contract vintage.
- Recent contracts have reflected stronger links to oil.
- Many contracts are on a provisional basis as previously (low-priced) formulas have expired or are not applicable at current oil price levels.
- Relatively high priced opportunities in Asia will attract gas supplies to that region:
    - o Increasingly competitive among suppliers;
    - o Opportunities for buyers; and
    - o Price will be dependent on the supply situation at the time of contracts.

MR. PULLIAM said high prices will attract sellers. If there was gas to contract now, prices would be good. When Alaska's gas gets to market, the question will be what the supply picture will be. Potential pricing scenarios are highlighted on Slide 24. The four lines represent different forecasts for prices in Asia. They are all tied into the Wood Mackenzie forecast; the EIA forecast would yield similar results.

MR. PULLIAM put emphasis on the middle two lines. The top one is the base case scenario from the Gas Strategies consulting firm. Depending on how much gas would be sent from Alaska to Asia, Mr. Pulliam thought the estimate was reasonable. The Port Authority developed an estimate based on projections by the Japanese equivalent of the EIA. That projection was for gas to sell for 80 percent of the value of oil. Other projections are both higher and lower.

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MR. PULLIAM discussed volatility in U.S. prices (Slide 25):

- Historically, gas has been priced between 1/6 and 1/10 the value of oil, with the long run average near 1/8.
- The recent run-up in oil prices and relatively abundant domestic production of natural gas has kept that relationship above historical levels.
- Many see the oil/gas relationship returning to more historical levels (i.e. convergence) as:
  - Domestic supplies decline and become more costly to produce;
  - LNG imports are drawn to higher priced regions (e.g. Asia); and
  - Greenhouse/carbon emission concerns put coal out of favor and natural gas in favor as the fuel of choice for electricity generation.

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MR. PULLIAM concluded that the 8 to 1 ratio of oil to gas is the right perspective to use in thinking about pricing. Slide 26 compares the Wood Mackenzie forecast with the EIA forecast. The EIA sees more coal being used in the U.S.; some are skeptical about that forecast.

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MR. PULLIAM explained that Slide 27 adds the Henry Hub prices to an earlier graph about Asian prices. The black line shows the 8 to 1 ratio. If there were a weak oil/gas relationship in the U.S. and a strong relationship in Asia, there would be significant differences in the selling prices. He thought that was an extreme forecast.

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MR. PULLIAM listed the assumptions used in comparative netback analysis (Slide 28):

- First Gas: 2020
- Capitalization:
  - 70% debt/30% equity (pre-operation)
  - 75% debt/25% equity (post-operation)
- Debt costs:
  - 5.5% guaranteed; 7.0% non-guaranteed
- Equity returns: 14%
- Capex/Opex:
  - Administration (Westney): GTP and pipeline segments
  - Port Authority (Bechtel): LNG plant
  - Sensitivity at higher costs
- Fuel use:

    - Administration (Westney) for GTP/pipeline segments
    - Port Authority (Bechtel) for LNG plant
- Shipping costs:
    - Port Authority: Approximately $0.75/Mmbtu + Fuel
- Gas composition and NGL Extraction:
    - 1.118 Mmbtu/mcf
    - Full extraction at Alberta
    - Partial extraction at Valdez (LNG case)

MR. PULLIAM referred to discussion about whether or not Alaska gas would be too lean if NGLs were taken out before delivery to Asia. Econ One thought it would be fine to take some of the NGLs out, not the full amount.

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MR. PULLIAM discussed capital costs (Slide 30). He summarized that the Port Authority and administration estimates are similar. Differences occur in the LNG plant cost estimates that would lead to a difference in tolls of about $1/Mmbtu. The two roughly agree on the pipeline construction costs.

MR. PULLIAM described different scenarios run regarding capital costs for an LNG project and pipeline project, detailed on Slide 31. The administration's cost shows about a 20 percent higher capital cost than the Port Authority. Slide 33 shows the costs for the pipeline projects, using the administration's capital cost calculations developed by Westney.

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MR. PULLIAM, in response to a question by Representative Kerttula regarding the difference between plant costs on Slide 31, explained that one set of numbers corresponds to the different sizes of the plants.

REPRESENTATIVE SAMUELS observed a discrepancy.

MR. PULLIAM explained that there are different ways of estimating the costs. He referred to a graph put up by the administration (Slide 33). He explained the data points that were used to calculate probability. The points were based on Westney's analysis of other LNG projects throughout the world.

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MR. PULLIAM explained that the Port Authority, who are at $470/ton instead of $750/ton, had a cost estimate done by Bechtel. The discrepancy is explained by different methodology. There are specific differences for the Valdez

plant, which would receive gas at a high pressure and would not need as much compression as other plants. It would be more efficient.

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REPRESENTATIVE FAIRCLOUGH referred to a previous question on the plant cost discrepancy and asked if the administration's analysis had included higher costs for the cooling mechanisms for transport of the LNG.

MR. PULLIAM thought the administration tried to make adjustments across time. They looked at plants developed in the last five years. During that time plant development cost has gone up considerably. He was unclear about the specific methodology used. He did not know if they adjusted for different plants in different regions. The specifics of the adjustments were not available. The plant in Valdez is more efficient to operate than in the tropics, where many of the other plants are, and should be cheaper. In addition, gas is being delivered in a high compression pipeline; some of the compression needed in another plant will not be needed.

REPRESENTATIVE FAIRCLOUGH stated that the question she was referring to had been asked June 10 when Bill Sparger was speaking. The question was asked on a disparity on Slide 6. She asked for a follow up calculation regarding the compression.

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MR. PULLIAM reviewed comparative plant costs as depicted on Slide 34. The Port Authority estimated $470/ton. The administration's numbers are $755/ton. Costs for plants are difficult to come by. Jensen estimates between $600 and $650, but that would not be specific to Valdez. Tariff costs would be approximately $2.09 to $3.16. He felt that the Port Authority analyses would be reliable.

MR. PULLIAM discussed the different elements of the tariffs on Slide 36. He compared LNG and pipeline projects. Fuel costs are rising over time. Average transportation costs, including the fuel, are a little over $9/Mmbtu for the smaller LNG project. The 3.5 bcf/d pipeline comes out at $5.64/Mmbtu. One of the big differences is that less fuel is required to operate the pipeline. Overall, there is a $3.50 difference between the two scenarios.

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MR. PULLIAM moved to a chart on Slide 38 showing the netbacks for LNG delivery to Asia. The netback would be higher for the larger, more efficient plant. The pipeline

and the LNG on a per unit basis would give similar netbacks under certain pricing assumptions.

3:07:29 PM

MR. PULLIAM compared projected netbacks (Slide 41). He started with projects that were comparably sized, the 2.7 bcf/d LNG project and the 3.5 bcf/d pipeline project. The different pricing scenarios are ranked 1–6. The netback that would be highest would be for an LNG project at high gas prices in Asia. That is the most likely scenario; he thought the middle two pricing scenarios, suggested by Gas Strategies and Port Authority, were more reasonable. The netback would still be slightly higher than a small sized pipeline. When that is changed into present value, and the higher volume of the pipe is taken into account, the overall value is higher with the pipeline.

MR. PULLIAM then compared the smaller LNG project with the bigger, 4.5 bcf/d pipe, using Slide 43. He concluded that the pipeline would have the higher overall value. Comparing the larger (4.5 bcf/d) LNG plant with the larger pipeline meant competing with other world markets. He did not think there was value for the higher volume LNG plant.

MR. PULLIAM observed that the Port of Authority is not speaking to a 4.5 bcf/d LNG plant.

3:12:26 PM

MR. PULLIAM spoke to sensitivities: High sustained oil prices and the impact of project delay. There is a scenario (Slide 47) in which the LNG project could give Alaska a higher value than a pipeline project: very high oil prices ($120 real). A small LNG project, assuming very high correlation to oil, could have a netback of $25/Mmbtu. At the same time, comparing that to a small pipeline project with a weak gas/oil relationship, the netback would be closer to $17/Mmbtu. Bringing those numbers over to net present value, it is clear that LNG is higher, but not by a lot.

3:13:56 PM

MR. PULLIAM spoke to the impact of potential delays on projects (Slide 48). The top panel of the chart shows the net present value assuming both projects come on in 2020. The project with the highest value is the 4.5 pipe under the 8 t 1 oil/gas relationship. In the case where both projects come on, the pipe scenarios have higher value. Shifting the start date of the LNG back by two years, as the administration assumes, the value would fall. A delay in the pipe until 2022 would translate to the pipe still having a higher net value.

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REPRESENTATIVE SAMUELS observed that it would take a six year delay in a smaller pipe line.

MR. PULLIAM agreed.

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MR. PULLIAM pointed out that all of the numbers assumed that the LNG would be exported. Some of the earlier proposals talked about sending LNG to the west coast. He had not run the numbers, but it was clear that there were no reasonable price scenarios that would make that attractive relative to a pipeline project.

MR. PULLIAM asserted that he wanted to talk about export issues because export of the LNG is central to the notion of getting potentially higher netbacks. He reviewed Slide 50:

- Yukon Pacific permit for export
  - Issued in 1989
  - For a volume of 14 Mmta (about 1.9 bcf/d) to Japan, South Korea, Taiwan
  - 25 years from first gas
- Project will require DOE review
  - Different project
  - Time elapsed
  - Different circumstances (e.g., U.S. is net importer of gas)
  - Political
- Is recent Kenai plant decision comparable?
  - Smaller/shorter window
  - No perceived issues outside Alaska
  - Lengthy multi-year process for renewal
- Experience with oil
  - Initial ban on exports
  - 1996 lifting of export ban, but too late to benefit Alaska
  - Still significant perception issue at federal political level

3:21:13 PM

MR. PULLIAM continued reviewing LNG export issues (Slide 51):

- Exports must be “in public interest”
- Pros
  - Free trade
  - Efficiency (higher netbacks)

    - Balance of payments
    - More production for Lower 48
- Cons
    - Will lead to more LNG imports
    - Will lead to more high cost Lower 48 production
    - Will lead to higher gas prices for U.S. consumers

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REPRESENTATIVE CRAWFORD questioned if it could be viable to export to Trinidad in order to equalize costs. He estimated that the U.S. would not be the prime market, but India and China. He wondered if that was taken into account in the analysis.

MR. PULLIAM explained that the forecast does consider demographic changes. They anticipate an increased demand in Asia as the population grows. While China is a factor, they also have a lot of coal and may not use as much LNG. U.S. demand will also continue to grow and would still constitute a huge market for gas. He thought prices should equalize due to increased interconnection between regions in the LNG trade and prices. The U.S currently pays the premium on oil for the large demand in Asia; not all of that will be escaped with gas.

3:26:32 PM

MR. PULLIAM agreed that there is some potential for a swap including other countries. He added that the perception that the gas is leaving the country would remain an issue.

REPRESENTATIVE CRAWFORD observed that a case was made in Salt Lake City that the future for energy was LNG. He suggested that the leveling of world markets would come sooner rather than later due to the growth of the Chinese and Indian economies. He wanted to consider offsets to balance this.

MR. PULLIAM pointed out that the U.S. was an exporter of oil up to the 1950s but has become increasingly dependent on imported oil. The U.S. has been unwilling to export our oil because of being at a deficit.

MR. PULLIAM wondered what would motivate the public to support export. There is consensus that Alaska gas will decrease U.S. gas by $7.5 billion a year to consumers. He felt that it would be difficult to convince the public that it would be in the public interest to export.

3:31:12 PM

MR. PULLIAM continued with LNG export issues (Slide 53):

- Chance of federal intervention
  - Federal government assistance with permitting and loan guarantees in 2004 likely to lead to tension re: potential of exports
  - National security concerns
  - Arguments that consumers in Lower 48 would be hurt
  - Probably little federal support for exports if federal gas is involved
- Pipeline project must also apply for export permit
  - But 2004 legislation specifically addresses export to Canada

3:32:17 PM

REPRESENTATIVE GARDNER referred to a presentation by Governor Hickel and observed that there are other parties who believe they have valid export permits. She asked if those permits could be used or if the federal government could cancel them.

MR. PULLIAM explained that the permits, held by Yukon Pacific, will need to be reviewed by the DOE. Even if the permits are valid and can apply to this project, the process of review will take time and engender contentious debate. Congress could also step in if relatively high gas prices continue.

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REPRESENTATIVE GARA wondered if there was a flip side to the argument that would make it more likely that export would be allowed. He thought some of the exports could go to Canada or Mexico.

MR. PULLIAM noted that there is a faster track for exports to other countries on the continent. Particularly Canada and the U.S. are connected by a pipeline grid and viewed as being part of the same market. The federal government has already addressed the issue of oil coming through or to Canada.

3:35:21 PM

REPRESENTATIVE GARA asked if other countries have received export licenses for U.S. gas.

MR. PULLIAM stated that the Kenai plan had been approved and reiterated the assumption is that the [Point Thomson] gas is destined for the lower 48, while the gas in Kenai is not. There had not been potential for receiving LNG gas on the west coast so the assumption is that it would be used either

for Alaska or exported to Asia. The debate has been focused on Alaskan consumers.

REPRESENTATIVE SAMUELS observed that Shell has stopped drilling in the Beaufort Sea.

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MR. PULLIAM concluded with Slides 55-58:

- Gas prices in Asia are likely to maintain a premium over U.S. gas prices, though not at current levels
- U.S. prices will likely strengthen relative to Asian and European gas prices as U.S. domestic production becomes more expensive and LNG flows away from the U.S.
- LNG project would likely be viable under reasonable price scenarios, assuming gas can be exported
    - Economics of LNG delivery to U.S. West Coast would be worse than pipeline delivery under any reasonable set of assumptions
- Under the reasonable price scenarios, 2.7 bcf/d LNG project offers $/MMBtu netbacks that are similar to pipeline netbacks
    - Difference in some cases is not large relative to potential estimation error
- However, larger volumes for pipeline deliveries produce higher overall values (NPV) for resource owners under more likely price scenarios
    - 3.5 bcf/d pipeline > 2.7 bcf/d LNG by $11Bn to $16Bn
    - 4.5 bcf/d pipeline > 2.7 bcf/d LNG by $25Bn to $30Bn
- LNG project could produce somewhat higher NPVs if in the long run:
    - Oil prices stay high
    - Gas/Oil price ratio in U.S. remains weak
    - Gas/Oil price ratio in Asia stays strong
    - LNG can be exported and project advances at some time earlier than the pipeline
- Gaining Federal permission to export LNG to Asia will likely be very difficult
    - DOE permission
    - Potential Federal legislation
- Export via Y-line will face similar challenges

- Federal acceptance of exporting may be more favorable if majority of gas is already flowing to U.S. markets
    - But don't count on it
    - Oil experience along those lines was not particularly favorable
- Impact of potential delays
    - Delay in pipeline relative to LNG does not change results under more likely price scenarios
- Does the State have to choose between the two projects?
    - Market-based outcome is more favorable
    - Shippers can nominate to LNG project if they see it is more economic
    - Potential buyers of LNG can go "upstream" and negotiate to buy gas
    - Economics of LNG relative to pipeline not compelling enough to suggest that the State needs to "intervene" to make LNG happen at expense of pipeline

RECESSED: 3:42:48 PM

RECONVENED: 3:50:18 PM

BILL WALKER, PROJECT MANAGER AND GENERAL COUNSEL, ALASKA GASLINE PORT AUTHORITY (AGPA), thanked the legislature for the last presentation and the opportunity to meet and present their case with assistance from Econ One.

MR. WALKER discussed AGPA's relationship with Mitsubishi Oil Corporation. Mitsubishi had approached AGPA the previous year regarding Alaska LNG. During that year, Mitsubishi looked at the financial info of the Port Authority and all pieces of the potential project. Mitsubishi has remained committed to the project even after AGIA and some doubts about LNG. Both parties were hopeful that they could work with AGIA.

MR. WALKER related that 50 percent of the LNG into Japan is by Mitsubishi. Many of the issues about whether the gas is too lean or too hot have been resolved. Mitsubishi is pleased about the security of supply.

3:58:43 PM

MR. WALKER asserted that their base case is for the 2.7 bcf/d project. Less gas is required at start up. The timing is very important as well. The work done to date gives a significant start. AGPA is not looking at a single number to

a wellhead as a litmus test of success, although on several scenarios, they did have the highest wellhead number.

MR. WALKER said the Port Authority was created to get gas to Alaska and to get it there quicker. He agreed with Mr. Pulliam's description of the issues, although he disagreed with his conclusions.

MR. WALKER pointed out that most of the issues they had disagreement with had been presented in Fairbanks. They have more agreement with Econ One's economics. They would like to get the model the administration used in order to compare those economics. They think expansion potential is equal for the LNG and pipeline options.

MR. WALKER stated the BTU content is not an issue; hence Mitsubishi involvement.

MR. WALKER said that the value added was important in Alaska and worth a significant amount in terms of jobs. Having the facility as a fractionation unit in Valdez where the liquids would be split off is also significant.

MR. WALKER stated the Jones Act is not a stumbling block.

REPRESENTATIVE GARA asked for clarification about first gas to Alaskans.

MR. WALKER replied positively and said he would talk more about the simultaneous open season.

MR. WALKER said the heart of the issue is the export license out of Valdez. The currently existing license was obtained by Yukon Pacific Corporation 19 years ago. There will need to be an additional review of the license. It is not clear if the license will be taken from Alaska. He agreed with Mr. Pulliam that the recent export license for Kenai was for much smaller volume.

4:06:20 PM

MR. WALKER recounted the history of the Alaska pipeline which originally limited shipping Alaska oil to the U.S. That remained in place until Governor Hickel's administration. Currently there is no limitation on Alaska to ship its resources anywhere in world.

MR. WALKER referred to predictions regarding fractured shale. Many presenters have said that when the price of gas is high, Alaska would be in trouble because other technology would come forth. The Port Authority does not want to stop the project because of concerns about what has been granted to Alaska. He referred to a letter from DOE regarding the export license, saying: first, that they had not heard from

the Yukon Pacific in 19 years; second, that there is a requirement on the license about 48-hour notification to the federal government on the first shipment of LNG out of Valdez; and third, that there are conditions that require notification to DOE before the export takes place. There is a process. He urged continuing to build the all-Alaska line.

SENATOR FRENCH referred to the stance that the export license is the number one issue for this project. He asked what steps needed to be taken to make the license bigger and get to a final decision.

MR. WALKER replied that not enough is being done. He said that he needs the support of the administration and the DOE to decide once and for all how this will benefit Alaska. He referred to testimony in Fairbanks about the price of energy in rural Alaska. He emphasized that this is an Alaska issue, not a Port Authority issue. He strongly urged that all Alaskans take control of the process. He thought the project through Canada has some significant issues that have not been addressed, especially land claim issues. There has been no one from First Nations.

4:16:11 PM

SENATOR FRENCH asked when the debate about the Valdez export license took place.

MR. WALKER answered that the debate took place in the mid-1980s. He said that TransCanada was the only opposing party to the license.

CRAIG RICHARDS, ATTORNEY, AGPA, did not think each source of delay needed to be talked about. He made the point that both projects have problems and the outcomes are unpredictable. He urged developing both options as far as possible, so that if one of them does not come through, the other is available.

4:19:08 PM

MR. RICHARDS said there were two issues. There was a group put together on the U.S. side of the project in the 1970s and 1980s to advance the Alaska portion of the route. One of the issues was whether the now $9 or $10 billion liability could be put into the rate base. Credible opinion is that it probably will not be allowed. There is still an issue as to whether the liability holders are going to expect TransCanada to make recompense. TransCanada has gotten around this by saying they would not use the original permits or data. That may or may not work. It does create a delay. He thought that until the issues were resolved, the project could not move forward.

REPRESENTATIVE DOOGAN stated that the export license is a deal killer. If there is no export license, LNG cannot be shipped. He assumed that the Port Authority has known this. He asked why they hadn't tried to solve the issue.

MR. WALKER replied that the Port Authority has not had the administration's support to go through the process. AGPA has been concerned about the timing.

REPRESENTATIVE DOOGAN asked if now three governors had not responded to AGPA's request regarding an export license.

MR. WALKER answered in the affirmative.

MR. RICHARDS added that they wouldn't go with TransCanada either.

REPRESENTATIVE DOOGAN said he was not speaking about getting support but getting a useful export license.

MR. WALKER stated that he believed the current administration would support the effort. The issue was getting through AGIA and then asking the question.

REPRESENTATIVE DOOGAN wanted a timeline regarding the LNG export license.

MR. WALKER guessed six months on the outside.

4:25:02 PM

REPRESENTATIVE GATO asked about "Mackenzie goes first" on the slide presentation.

MR. WALKER said Tony Palmer had answered the question in Fairbanks by saying there is a preference in Canada for the Mackenzie Valley project to go through first.

REPRESENTATIVE GATO asked if there would not be a preference in Alaska that Alaska goes first. He thought that had a lot to do with availability of materials and workforce. He thought an opinion like that should not affect decisions about policy.

MR. WALKER replied that two different companies have said that it makes sense for the Mackenzie project to go first.

REPRESENTATIVE GARA pointed out that there were risks for all projects. Until something moves forward, the outcome will not be clear. He wondered if the AGIA process was creating some of the problems. He referred to statements by Mr. Palmer that the way the pipeline is going to be built is based on the producers providing a commitment to the end buyer. If the producers provide a 2.7 bcf/d commitment to a

buyer who takes from Valdez, then the pipe to Valdez is built first. If there is no proposal to sell gas in Valdez, that pipe does not go first. He asked why the project could not move ahead.

4:29:40 PM

MR. WALKER stated that they liked the concept of the simultaneous open season, but they have concerns. Under the application, TransCanada has said that they would have an open season for off-take points at Delta or Valdez in the initial open season. If that initial open season is not successful, then they are obligated under AGIA to continue on with the FERC process, but only on the Canadian leg. They are required to continue on for a second open season prior to FERC certification, and a third open season post-certification, but not on the LNG side. That would stop after the initial open season.

MR. WALKER stated that TransCanada has said that if later in the process someone was re-designated for off-take in Valdez, they would circle back and begin the process again. The concern is that there would be only one open season for an LNG. The second issue would be that if there were enough gas at the initial open season for both, the timeline would be on the Canadian leg and not on the Alaskan leg. TransCanada has been very clear that if at the first open season there was enough gas for a Valdez line and not enough for a Canadian line, they would build the line to Valdez. There are a couple scenarios that we need to get clarified as far as what happens post-first open season. The consensus is that the first open season will not be successful. Knowing that going in makes it difficult without further clarification. He stated concerns about what was offered later in the process.

4:34:08 PM

REPRESENTATIVE GARA requested clarification about what could be done in the different open seasons.

MR. WALKER explained that the problem between the first and second open seasons is that it is two or three years. If there was no work done on the Delta Junction to Valdez portion, he was not sure how a second nomination would work.

REPRESENTATIVE LADOUX referred to Senator French’s questions and asked why AGPA didn’t get the federal permits before now. She asked what criteria the federal government would use in granting and denying the permits and what the state’s role would be in the process.

MR. WALKER responded that they wanted the state to testify regarding the advantages of getting the gas to Alaska as

soon as possible. He thought the process was about getting gas moving on a route that could be controlled.

REPRESENTATIVE LADOUX queried other criteria the federal government would use.

MR. WALKER replied that they would look at the availability of gas to other regions, and into the U.S. They would look the presumption of export to say why the gas should not be exported. They would look at the balance of payments, and at shortages of gas into the U.S. They would also consider price.

4:38:56 PM

REPRESENTATIVE LADOUX asked if there were anything in the criteria that specifically addressed how the gas is developed by the state.

MR. WALKER responded that the state is usually allowed to do what the state feels is in its best interest. He thought the state's interests would be considered. He said the commitment of companies such as Mitsubishi demonstrated the seriousness of the situation.

MR. WALKER expressed concerns that AGIA as presented has the potential for closing out LNG options. After AGIA is awarded, companies would have to be convinced that there is reason for them to continue with the project. He reiterated concerns about a disadvantage after the first open season. These kinds of issues caused Mitsubishi to reconsider their commitment. He wanted written clarification to be assured that AGIA would not be a hindrance to the process. He stressed the enormity of the issue. The Port Authority does not want to be a hindrance to the process. They were created to get a gas pipeline as quickly as possible and they are concerned about impediments.

HB 3001 and SB 3001 were held in committee.

ADJOURNMENT

The meeting was adjourned at 4:43 PM. 4:45:16 PM.