

**ALASKA STATE LEGISLATURE  
HOUSE RESOURCES STANDING COMMITTEE**

January 25, 2012

1:05 p.m.

**MEMBERS PRESENT**

Representative Eric Feige, Co-Chair  
Representative Paul Seaton, Co-Chair  
Representative Peggy Wilson, Vice Chair  
Representative Alan Dick  
Representative Neal Foster  
Representative Bob Herron  
Representative Cathy Engstrom Munoz  
Representative Berta Gardner  
Representative Scott Kawasaki

**MEMBERS ABSENT**

All members present

**COMMITTEE CALENDAR**

OVERVIEW(S): ECONOMICS OF GAS TO LIQUID AND METHANOL TO  
GASOLINE CONVERSION, PRODUCTION AND SHIPMENT IN ALASKA

- HEARD

**PREVIOUS COMMITTEE ACTION**

No previous action to record

**WITNESS REGISTER**

BRUCE TANGEMAN, Deputy Commissioner  
Office of the Commissioner  
Department of Revenue (DOR)  
Anchorage, Alaska

**POSITION STATEMENT:** Provided a PowerPoint presentation on  
Alaska's fiscal regime and incentives for gas-to-liquids (GTL).

CHERYL NIENHUIS, Acting Chief Economist, Commercial Analyst  
Anchorage Office  
Tax Division  
Department of Revenue (DOR)  
Anchorage, Alaska

**POSITION STATEMENT:** Answered questions during Mr. Tangeman's PowerPoint presentation about Alaska's fiscal regime and incentives for gas-to-liquids (GTL).

DAVID G. WIGHT, Principal  
David G. Wight Consulting  
Anchorage, Alaska

**POSITION STATEMENT:** Spoke about his positive work experience with Mr. Deo van Wijk of Janus Methanol AG.

DEO VAN WIJK, Owner  
Janus Methanol AG  
Porter, Texas

**POSITION STATEMENT:** Provided a PowerPoint presentation about gas to gasoline via methanol.

JOE DUBLER, Vice President, Chief Financial Officer  
Alaska Gasline Development Corporation (AGDC)  
Alaska Housing Finance Corporation  
Director of Finance  
Alaska Housing Finance Corporation  
Department of Revenue (DOR)  
Anchorage, Alaska

**POSITION STATEMENT:** Provided a PowerPoint presentation on AGDC's gas-to-liquids economic feasibility study for the Alaska Stand Alone Gas Pipeline (ASAP).

DARYL KLEPPIN, Commercial Manager  
Alaska Gasline Development Corporation (AGDC)  
Alaska Housing Finance Corporation  
Department of Revenue (DOR)  
Anchorage, Alaska

**POSITION STATEMENT:** Assisted with the PowerPoint presentation on AGDC's gas-to-liquids economic feasibility study for the Alaska Stand Alone Gas Pipeline (ASAP).

## **ACTION NARRATIVE**

[1:05:25 PM](#)

**Co-Chair Paul Seaton** called the House Resources Standing Committee meeting to order at 1:05 p.m. Representatives Foster, Dick, Gardner, Kawasaki, P. Wilson, Herron, Feige, and Seaton were present at the call to order. Representative Munoz arrived as the meeting was in progress.

**OVERVIEW(S): Economics of Gas to Liquid and Methanol to Gasoline Conversion, Production and Shipment in Alaska**

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CO-CHAIR SEATON announced that the only order of business would be an overview on the economics of gas to liquid and methanol to gasoline conversion, production and shipment in Alaska. He said the reason for looking at this is the concern about declining volumes in the Trans-Alaska Pipeline System (TAPS) and transitioning to the pumping of heavy oil through the pipeline.

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REPRESENTATIVE P. WILSON returned to the committee's 1/23/12 overview of invasive species in which the [Alaska Department of Fish & Game (ADF&G)] stated that the owner of the oyster farm [in Sitka] had not taken any action. She said the farm owner had received his contract with the state only one week before the structure escaped in a big storm. For two years things had gone on and he was not allowed to go onto the premises and she did not want anyone to think that the owner was at fault. The owner could not do anything with the oyster farm and could not make any money with the farm, so is in the hole because of this.

CO-CHAIR SEATON pointed out that [legislators] specifically asked that an emergency protocol be developed and he did not want to get into the situation of blaming. He said he would like the committee to have the Division of Agriculture and ADF&G come forward with mechanisms for avoiding this in the future. This immediate problem has to be resolved, and it must be ensured that these kinds of problems for addressing an issue do not come up in the future. He related that [the committee's] intention is to go forward with legislation if needed or regulations if legislation is not needed so that there are no roadblocks for handling an emergency in the future.

CO-CHAIR FEIGE asked whether the oyster farm owner was not allowed on the structure for the week prior to its breakup or the two years prior to the breakup.

REPRESENTATIVE P. WILSON replied that the owner was not allowed for two years and then a week before the breakup [the department] decided there should be a contract with the owner so he could go back onto the structure and do something.

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CO-CHAIR SEATON returned to the overview, saying that Department of Revenue Deputy Commissioner Bruce Tangeman would provide the first of four presentations.

BRUCE TANGEMAN, Deputy Commissioner, Office of the Commissioner, Department of Revenue (DOR), noted that a positive for Alaska is its resource on the North Slope (slide 1). Regarding DOR's role in any gas utilization discussion, he said it is not the department's responsibility to define what incentives the private sector may need to move forward with a gas-to-liquids (GTL) project or any other gas project. It is the private sector's responsibility to analyze the state's existing tax structure, point out the hurdles it may perceive as being barriers, and begin the dialogue as to possible solutions for moving forward on a potential project. While DOR's incredible team creates and operates models like he has never seen before, the department is by no means the expert in GTLs or any other gas utilization concepts.

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MR. TANGEMAN said there are several question marks on every slide in his presentation but not many answers. This is because he is here to point out some of the issues the committee needs to keep in mind as it discusses GTLs or any other gas utilization concept moving forward. It is important to know DOR's role in the process as well as that of other state agencies such as the Alaska Oil and Gas Conservation Commission (AOGCC). Both DOR and AOGCC will be key players in future gas utilization discussions.

MR. TANGEMAN reported that roughly 90 percent of Alaska's general fund revenue comes from the four petroleum revenue sources of royalty, production tax, corporate income tax, and property tax, which constitute Alaska's fiscal regime for oil and gas (slide 2). Any GTL project in Alaska would likely pay one or more of these elements to the state, and any potential hurdle that the industry might bring forward to discuss for incentivizing will no doubt reside in one of these four areas.

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MR. TANGEMAN pointed out that Alaska's Clear and Equitable Share (ACES) production tax (slide 3) is the largest element of the fiscal regime in terms of revenue and is potentially the most likely element of the fiscal regime with which to create

incentives. However, it is the most complicated tax structure in North America and perhaps the world. He said there are two important concepts when relating production tax to GTLs: 1) Production tax is calculated on the gross value at the point of production (GVPP) minus qualified capital and operating expenditures. This has relevance in terms of a GTL plant's location and what costs of a GTL plant, if any, would qualify as deductions under ACES. 2) Production tax is levied on companies that produce the gas and these companies may not be the ones that build the GTL plant. One of the variables is who is going to own the plant itself.

MR. TANGEMAN discussed two questions that need to be answered with respect to GTL (slide 4): 1) Where will the GTL plant be located? 2) Who will own the plant, the gas, and the GTL products, and what will be the fiscal arrangement of any structure that is put in place? Regarding where to locate the GTL plant (slide 5), he noted that location of the plant makes a big difference in how the economics will play out. Facility siting is important because if the plant is located anywhere other than the North Slope or Cook Inlet the gas will need to be transported to the plant to begin the GTL process, and this will add additional costs to the project.

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REPRESENTATIVE P. WILSON requested Mr. Tangeman to explain the difference in economics that plant location would make to the state and to the producer.

MR. TANGEMAN replied that it would impact both the state and the producer, mainly depending on the capital investment that is required. If gas must be transported to the plant over a long distance, capital investment to pipe the gas would possibly be affected by the tax credit system currently in place, which would be a drag on state revenue and would offset some of the costs that the companies would incur. In further response, he confirmed that he is saying the difference is the upstream costs before the gas gets into the pipe.

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CO-CHAIR SEATON theorized that if the GTL plant was on the North Slope, what is transported would hypothetically go into TAPS, a currently existing pipeline; but a plant located elsewhere would require the expense of transporting gas to the plant as well as the expense of transporting the end product. He asked whether

this is part of the relationship being looked at regarding the economics of where the plant is located.

MR. TANGEMAN answered that that is part of it. For example, if a plant was located in Fairbanks, a pipeline would need to be built to Fairbanks where the gas would be processed and from there it would presumably go to TAPS, which is where the tariff would kick in. Because many variables and scenarios could be created and modeled, a simple way to start thinking about plant location is to assume it is somewhere close to TAPS and then look at how far the gas will have to be transported to the GTL plant itself.

CO-CHAIR SEATON noted that when transmitting gas the tariff on the gas is subtracted from the value of the gas, and the company must transmit the product that it will be using up in the conversion process. If the facility was on the North Slope the volume through TAPS would be more, so the tariff on all of the oil and other products would be lowered. Those elements must be considered, but the purpose for today is to just get a handle on the issues.

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CO-CHAIR FEIGE surmised that with no pipeline to the plant there would not be that transportation cost, so the check per million cubic feet (MMCF) to the producers for the gas would be higher.

MR. TANGEMAN replied, "To the gas producers, yes; well, it depends."

CO-CHAIR FEIGE further surmised the gross value at the point of production would be higher because ...

MR. TANGEMAN interjected that it depends where the GTL plant owner is taking ownership of the gas.

CO-CHAIR FEIGE asked where the tax would apply to the gas under current statutes, assuming the GTL plant is a separate entity and assuming that that entity takes possession of the gas as it comes into the GTL plant.

MR. TANGEMAN deferred to Ms. Nienhuis.

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CHERYL NIENHUIS, Acting Chief Economist, Anchorage Office, Tax Division, Department of Revenue (DOR), said she would guess that it depends on the fiscal arrangement. Qualifying that she could not say for certain, she said it seems like Alaska's point of production statutes require that when a petroleum product is accurately metered, that is considered the point of production. So, if that occurs upstream of the gas pipeline then that would be the taxation point under current statute.

CO-CHAIR SEATON noted that the point of production is determined by statute and therefore that issue could be looked at if the economics needed to be changed; the state legislature can set the point of production for taxation. He presumed the state is not stuck in one system and could change it.

MS. NIENHUIS responded she cannot comment because there could be other elements to the point of production that fall outside of the taxation realm, such as impacts to royalty.

CO-CHAIR SEATON said he was just clarifying that that is set by the legislature. For a bill dealing with GTLs and incentives the legislature would probably need to specify the point of production for taxation.

MR. TANGEMAN agreed.

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MR. TANGEMAN returned to his presentation and the second of the two questions that need to be answered with respect to GTL (slide 6): "Who owns the plant, the gas, and the GTL products?" He said the owner could be the North Slope gas producers, the Cook Inlet gas producers, or a third party. For example, the GTL plant could be set up similar to the Alyeska Pipeline Service Company, which is an independent third party owner/operator. Will the gas be transferred to the GTL plant owner or sold to the plant owner/operator? Who, if anyone, will need incentives is what will need to be fleshed out.

CO-CHAIR SEATON related a past situation of a producer that wanted to put an ultra-low-sulfur diesel refinery on the North Slope. The proposal was to have it on the lease so that it would qualify for the credits and it would be on the lease so there would be no royalty. The legislature said that was not the purpose of the ACES credits. If the legislature decides it wants something like that, then the legislature would have to make the change. The legislature determined that a refinery

placed on the North Slope was not upstream of the point of production regarding the 20 percent tax credits.

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MR. TANGEMAN said the aforementioned leads directly to slide 7 which depicts four potential areas where incentives could be manipulated to make a project economic. Referring to these four areas as "knobs," he said there are many available knobs that can be turned to incentivize a GTL plant, a gas plant, or any infrastructure the state sees fit for commercializing North Slope resources. Each situation calls for a different knob to be turned and will affect all of the other knobs in a different manner. For example, royalty relief or tax credits could be granted to producers selling gas for feedstock to the GTL plant owner. Corporate income tax credits could be issued for work leading up to the construction of the GTL plant. Or credits could be granted for research into feasibility of shipping GTL products down TAPS.

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MR. TANGEMAN pointed out that the price of gas is a huge, huge consideration when considering the economics of a GTL project (slide 8). Yesterday the Henry Hub price of gas was \$2.63 [per MMBtu], he related. There is plenty of potential, but the state needs to hear from the private sector (slide 9). It is known from modeling done for legislator's that there are a lot of variables that can be plugged into a model depending on what is being looked for, and the outcomes are going to vary depending on what is put in on the front end. So, it is important for the department, the legislature, and the state in general, to get more detailed feedback from the private sector as to what are the issues and hurdles that they see and need help on to make a project like this economic.

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MR. TANGEMAN concluded by stating that GTL is one of several options for developing Alaska's gas resource. Incentives depend on the state's desired outcomes - with a very strong incentive just about anything can be done. Incentives are possible through production tax, royalty, corporate income tax, property tax, and other subsidies. Determining the goal is the bottom line. For example, is the goal to create jobs, diversify the state's economy, or to fully develop Alaska's natural gas through one major project? Instead of "or" the word "and" could

be used, so there are a lot of things to be considered when trying to figure out the best way to commercialize the state's resources on the North Slope.

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CO-CHAIR SEATON opined that sometimes industry does not present things because it figures the legislature would not consider them. Sometimes the state's various problems are addressed in isolation, including whether GTL is economic, so it was good to learn that where the GTL plant is located makes a difference. Another example is that if GTLs were produced on the North Slope the throughput in TAPS would be increased, and a diluent produced on the slope could help with viscosity and transmissibility at low flows. Another real problem is taxes where there is [both] oil and gas. Right now gas sales effectively are not taking place, but once they do and investments are made there is a huge potential problem in applying expenditures for gas, which are taxed at a low rate, against the tax rates for oil, which is the decoupling issue the legislature has looked at before. He asked whether Mr. Tangeman sees any problems for GTL or other liquid if, instead of taking royalty and production tax on gas, the outlet of the plant is determined the point of production so that royalty and tax is taken on the manufactured liquid at the end. This would tax the right value stream, he continued, because it would relate to the price of oil, which is where progressivity is, and would eliminate the need for differentiating investment in gas or oil. This would solve a multitude of problems at the same time instead of one at a time. He reiterated his question by asking whether DOR sees this as a potential, with statute change, point of production clarification, and willing partners, to eliminate the decoupling issue.

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MR. TANGEMAN said he thinks that will be a very, very big issue if something like this progresses. This goes back to the current debate on ACES and the governor's bill [HB 110]; it is that tax on the output. So taxing it as a petroleum/oil product falls back into the discussion of last session and the interim about how industry is going to view that and whether that is the main hurdle. If that is the main hurdle and industry says it needs relief on the production tax, then that is what will make a GTL project go or not go.

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CO-CHAIR SEATON added that the problem with taxing gas at barrel of oil equivalents is that comparison-wise it is a product that has very low unit value, so that problem is not escaped nor is the problem of having to differentiate investment. He said he does not know whether industry is hearing that [the committee] is willing to look at those issues and not have to deal with decoupling. He asked whether DOR sees anything that would prohibit this from being done with the proper legislation, which would be taking royalty and production tax on the output and not taxing the input to a plant under the right circumstances.

MR. TANGEMAN responded he does not see that [the committee] is prohibited from doing anything as a legislative body. It is whether it will be economic and the bottom line is how industry is going to view any change that is made. Whether it is on the gas as the entry point into the plant or the petroleum product as the exit product into TAPS is the biggest discussion. Decoupling will be discussed in the other body so it is certainly on everyone's radar.

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CO-CHAIR SEATON reiterated that he is trying to figure out whether taxing oil on the outlet side will eliminate the big problem with decoupling, because decoupling is taxing at a very low rate and allowing investment to be written off against the other tax rate if oil is being produced.

MR. TANGEMAN pointed out that another big issue with decoupling is the cost allocation - whether the cost of the plant is on the upstream side with the gas or the downstream side with the product or somewhere inside the plant.

CO-CHAIR SEATON agreed.

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CO-CHAIR SEATON directed attention to DOR's 1/18/11 letter in the committee packet regarding an economic analysis of Alaska North Slope gas-to-liquids plant. He offered his appreciation for the caveats included in the analysis because they allow for asking about what would happen if the royalty is not on the gas but is on the GTL product. He urged members to look at the internal rates of returns and the net present values in the analysis because that is helpful information for understanding

whether the project is in the range of being economic and whether any changes need to be made.

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CO-CHAIR SEATON then referred an attachment to the DOR letter entitled, "Additional Information on Gas-To-Liquids." Regarding BP and advances in GTL technology [page 2 of the attachment], he read the following statement: "... the reaction is highly exothermic and the reactor must be designed to remove heat quickly." He inquired whether there has been any analysis of the amount of heat to see whether it could be used for heating the oil being moved through TAPS.

MR. TANGEMAN said the aforementioned falls under the category of DOR not being an expert in GTLs.

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CO-CHAIR SEATON provided a biography of the next speaker, David G. Wight: served as president and chief executive officer for Alyeska Pipeline Service Company from July 2000 to January 2006, served as president of BP Amoco Energy Company in Trinidad and Tobago for eight years, and served as treasurer of the Alaska Oil & Gas Association. He said Mr. Wight's Amoco career involved him in activity in Texas, Kansas, Oklahoma, Colorado, Utah, Alaska, and Illinois where Mr. Wight developed engineering, operation, production, procurement, and management experience. Further, Mr. Wight served as the president of Amoco Trinidad, an exploration and production company, and he led the establishment of the first greenfield liquefied natural gas (LNG) plant in Trinidad and the second LNG plant in the Western Hemisphere. Co-Chair Seaton explained that Mr. Wight, a person familiar to committee members, will be relating his experience working with Mr. Deo van Wijk of Janus Methanol, someone who committee members are unfamiliar with although Mr. van Wijk did make a presentation to the committee last year.

The committee took an at-ease from 1:44 p.m. to 1:50 p.m.

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DAVID G. WIGHT, Principal, David G. Wight Consulting, stated that he was asked by the principal of Janus Methanol, or GigaMethanol, to facilitate discussions of [Mr. van Wijk's] gas to methanol to gasoline proposal. He said he accepted the opportunity because he has done business in the past with [Mr.

van Wijk's] company and its innovative technology, and he feels that it is an opportunity for Alaska to look at some ways to monetize its gas. He said the state should look at [Mr. van Wijk] to see if this fits some of the state's opportunities to move its gas to market.

MR. WIGHT said his experience with Janus Methanol comes from Trinidad where his company at that time, initially Amoco and then BP Energy, was an energy supplier. Mr. van Wijk came to Amoco wanting to enter into a long-term gas supply agreement for his double-world-scale methanol proposal, which he had developed the technology on. Amoco found it a good business opportunity and entered into a contract. Mr. van Wijk's facility performed as proposed - delivering on time and within cost, and during the period of time that he [Mr. Wight] remained in Trinidad, Mr. van Wijk met the gas purchase requirements of the agreement with Amoco. Since that time, Mr. van Wijk sold his interest in that facility and entered into a non-compete agreement. During that non-compete period of time on methanol Mr. van Wijk studied the technology and developed the proposal that he would like to speak to Alaska about.

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MR. WIGHT said Mr. van Wijk's proposal this time is twice as big as the one built in Trinidad, so on a world-scale basis it has doubled again. It uses less energy than the previous time and with an incremental capital cost it takes methanol, which is very difficult to transport due to its corrosive nature, and turns it into gasoline thereby affording the opportunity to put it into TAPS, which would be very beneficial in terms of transportation costs.

MR. WIGHT said he has had successful business relationships with Mr. van Wijk in the past and has found him to be a very credible, innovative technology leader and a very credible business person.

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MR. WIGHT explained that Mr. Van Wijk's proposal would start with a single train facility that would use about 320 million cubic feet (MMCF) of gas per day and would produce 30,000 barrels of gasoline per day that could be put into TAPS. Advantages to this include: no incremental pipeline costs because existing facilities could be used; improvement of the flow characteristics in TAPS because it is a lighter part of the

hydrocarbon stream; no corrosive natures; and the addition of volume - all of which are significant issues currently being considered. Because it is a capital investment on a single train facility it clearly is more cost effective because it does not have the pipeline cost that other facilities must look at for moving liquids or natural gas all the way to the marketplace. Mr. Wight said the disadvantage is it does not provide gas for in-state use. But, he added, it does not take away from that opportunity because the opportunity is incremental on volumes that would be available and would not prevent continuing to look at pipelines or other activities.

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MR. WIGHT allowed that some science and economics need to be worked on, but said the scoping economics look good. Another advantage if this works properly, he continued, is the opportunity to incrementally add both to the use of gas and the volume that could be put into TAPS in steps, which could be key to the availability of gas from the North Slope as producers need less gas for enhanced oil recovery and have some marketable gas. Additional trains could be scheduled incrementally to up the volume of gas utilization and monetization, with each train adding another 30,000 barrels of incremental liquids to the pipeline.

MR. WIGHT concluded by saying he thinks this has huge potential for early and incremental monetization of gas and that it merits serious further discussions and development opportunities with this company. He related that as an Alaskan and someone involved in the energy business a long time, he has continued to look at how to meet some of the challenges of highly expensive gas pipelines that require high volumes and seem to be the significant impediment to Alaska's ability to monetize its gas. He urged that this opportunity be looked at very, very carefully because it would move the state beyond those impediments.

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CO-CHAIR FEIGE inquired about the effects that gasoline would have on the refineries located along TAPS which utilize the throughput to produce refined products.

MR. WIGHT understood Co-Chair Feige to be asking about the downstream impact on in-state and out-of-state refiners that buy Alaska's product. He said that based on the science known today it would be a "quality bank" upgrade to the refining value of

the TAPS crude and would therefore have a positive impact on the economic value and the value and use to refiners in Alaska and other places.

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REPRESENTATIVE MUNOZ asked how gas and oil are shipped at the same time and what the impact of heavy oil would be on that mix.

MR. WIGHT replied that this is an excellent question because in the Lower 48 some pipelines operate on a batch system, changing the product that they ship from time to time. He related that in his asking of some preliminary questions, it seems to be the most attractive way to mix it, which means it cannot be taken out by itself at some later point and would have to be re-refined by the refineries. However, it would reduce the viscosity and help the flow characteristics. It would not be at all incremental damaging to the wax issues - and might help some, although that answer is not known right now - so it would be just part of the mixed product. Regarding heavy oil, incrementally it would have a positive impact on both the volume and the viscosity, whether it is today's conventional crude or the challenging heavier oil, because it is lighter and would reduce the viscosity.

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CO-CHAIR SEATON pointed out that the Alaska Gasline Inducement Act (AGIA) was done to enhance exploration on the North Slope so there would be a market for gas going into a common carrier pipeline with rolled-in rates. The problem being looked at with a smaller pipeline is that the existing players with natural gas could fully commit that line and therefore oil exploration would not be enhanced because any gas found in that exploration would be a non-sellable product. The nice thing about GTL is that if a small diameter pipeline is filled with gas for the state, there would still be an incentive to explore for gas because of the incremental GTL market. He said [the committee] is not necessarily saying that this is one or the other, but that more than one way might be needed to monetize gas to get the benefits of enhanced exploration, discovery, and production into TAPS. For example, a field that is mostly gas with some liquids is uneconomic if the gas cannot be sold.

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DEO VAN WIJK, Owner, Janus Methanol AG, first pointed out that his company does not want to build gas pipelines, it wants to build plants on top of where the natural gas is (slide 1). Regarding the idea of building a pipeline to transport 4.5 billion cubic feet (BCF) of natural gas to the Lower 48, he said that at today's economics the natural gas at the North Slope would have a negative value. His company is trying to solve Alaska's problem on TAPS as well as create value for the natural gas at the North Slope. He explained that 4.5 BCF of gas a day is the equivalent of 14 trains or 430,000 barrels a day, which is huge and a project that would probably take 15 years to build. Also being created, however, is increased value of the crude oil because its viscosity and quality would be improved. He reiterated that a pipeline is not built for moving the gas to somewhere, instead a plant is built on top of where the gas is.

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MR. VAN WIJK said the purpose of his presentation is to explain the idea of methanol to gasoline, which may sound like a new idea but is a 30-year-old technology developed by Mobil in 1982 (slide 2). However, it became uneconomic in the 1990s when the price of oil dropped to \$10 or \$12 a barrel. On top of that, Exxon purchased Mobil and the technology disappeared except for the Chinese who are checking out every technology worldwide and have the money to build and do it. Today there are two methanol to gasoline (MTG) plants which have proven to work. Alaska's problem is that as oil production reduces in volume its viscosity increases. Janus Methanol is saying the state should convert its natural gas to gasoline, rather than his original idea of methanol. Unlike methanol, gasoline does not have corrosive issues and can be put into the pipeline and sent with the oil to refineries in California or elsewhere.

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MR. VAN WIJK stated Janus Methanol believes it has a potential solution for the TAPS problem as well as the sale of large volumes of natural gas at relatively high prices (slide 3). No other alternatives come even close to the gas prices that his company could afford to pay to turn natural gas into gasoline. The gas-to-liquids (GTL) Fischer-Tropsch process has by-products like waxes, and what can be done with waxes in Alaska? Janus Methanol makes only three products - high grade quality gasoline, a little bit of liquefied petroleum gas (LPG) for which there is a local market in Alaska, and water.

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MR. VAN WIJK noted that Janus Methanol is a Swiss-based company with about 30 people with a total of about 500 years of methanol experience (slides 4-5). Some persons have 30 years or more in the methanol business; for example, he has been in methanol since 1977 and has done nothing else but methanol. Ten people have more than 30 years' experience each, the rest have less. The company's engineers are German doctors, called PhDs in the U.S., from a variety of companies, such as BP, Lurgi, Ferrostaal, and [KTI/Mannesmann and Metallgesellschaft]. Moving to slide 6, he said a virtual depiction of the slide shows several plants in 1989 and those same plants in 2009, with the growth of the plants being an investment of about \$15 billion; he personally built three of the plants in the picture. In response to Co-Chair Seaton he said it is a remarkable difference in 20 years.

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MR. VAN WIJK advised that Janus Methanol is suggesting for the North Slope a two-train project of 7 million tons of methanol; the two plants being built with a difference of about two years (slide 7). The second train would be substantially cheaper than the first because of utilities, site preparation, and so forth. The plant would produce about 2.66 million tons of methanol, about 350,000 tons of LPG, and about 4 million tons of water. He explained that 56 percent of methanol is water and when the water is taken out the remainder is gasoline, methanol, and LPG.

MR. VAN WIJK discussed the first phase of investment, explaining that Janus Methanol has studied building a facility like this one in the U.S. Gulf (slide 8). A plant of the size being talked about would, in the U.S. Gulf, cost about \$3.5 billion. From talking with the industry, he used a multiplier of 2.2 to get to a price of \$7.7 billion for the investment on the North Slope, and a study would be required to confirm those numbers. Revenues would be around \$3 billion per year and the plant should pay in 5 to 6 years after starting production.

2:15:00 PM

MR. VAN WIJK said he has done nine methanol plants in his life, seven or eight utilizing Lurgi technology (slide 9). He would again use Lurgi methanol technology and the ExxonMobil MTG technology that has been proven in both New Zealand and China. At 20,000 pounds a day - two trains of 10,000 pounds each - this

methanol plant would be by far the largest methanol complex ever built in the world. He pointed out that 7 million tons of methanol would flood the methanol market, but its conversion to 2.66 million tons of gasoline would be a drop in the bucket in the world market of gasoline and thus the original chemical market would not be destroyed.

MR. VAN WIJK explained the differences between Janus Methanol's previous plants and what it is designing today. Today's plant would be smaller and simpler than the one in Trinidad and at 10,000 tons [methanol] per day the cost would be substantially reduced. The seven-stage compressor has now been changed to a booster, and even with a spare booster \$17 million Euros would be saved.

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MR. VAN WIJK drew attention to a photograph of Janus Methanol's ATLAS and Titan methanol plants in Trinidad (slide 11) and explained that the steam reform and compression equipment shown in the picture would be eliminated in the next plant design, which would reduce the cost by about 30 percent. He said that in 2008 the ATLAS methanol plant ran at 108 percent of design capacity - 5,000 tons per day - for 360 days, which is quite remarkable. Reviewing the major sections of the ATLAS plant (slide 12), he said that the air cooling seawater unit shown on the left is substantial and difficult to deal with and the distillation section [at the top of photograph] will always be needed. In looking at where money could be saved, Janus Methanol determined that it would be the syngas compression and the syngas generation. He moved to the layout of two 10,000 ton methanol per day plants (slide 13) and noted that the MTG plants would come behind them and that those plants would be smaller than the ATLAS methanol plant in Trinidad.

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MR. VAN WIJK explained that with gas-to-liquids/Fischer-Tropsch process the gas must be taken to another place and by-products will be produced that the state may or may not know what to with (slide 14). However, for methanol to gasoline the products are LPG, water, and gasoline, and the gasoline is ready to go into the pipeline. In response to Co-Chair Seaton, Mr. van Wijk confirmed that LPG is propane.

MR. VAN WIJK said many companies have spent a lot of money on Fischer-Tropsch (slides 15-17). Only Mobil, now taken over by

Exxon, and the Chinese have researched a way to go from methanol to gasoline. The [MTG] technology can be licensed from ExxonMobil, he advised, and the methanol technology that Alaska would need can be licensed from Lurgi and Janus Methanol has certain rights to that. The key on [MTG] technology is the catalyst. ExxonMobil has licensed its catalyst [to Janus Methanol] and [Janus Methanol] will soon have a contract with another company for a catalyst as well. Additionally, Janus Methanol is working on making a jet fuel catalyst. He explained that two plants in China are gigantic because they are coal-based methanol to gasoline plants (slides 18-19). He related that 80-90 percent of the cost is in the coal gasification and the rest is in the MTG part.

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MR. VAN WIJK reviewed the specifications of the [MTG] gasoline (slide 20), saying it is very low in benzene and that it has no sulfur, which substantially increases the quality of the oil. Comparing GTL with MTG (slides 21-22), he reiterated that MTG only makes LPG and gasoline, whereas GTL has a whole range of products and another refinery would have to be built to get [to conventional fuels]. Thus, the process being proposed by Janus Methanol is much simpler and more direct.

MR. VAN WIJK related that ExxonMobil compared the costs of GTL to MTG (slide 23). However, because of its developments, Janus Methanol can come substantially below the numbers depicted on the slide because ExxonMobil used a much smaller investment and Janus Methanol would be looking at 10,000 tons per day.

MR. VAN WIJK, moving to slide 24, stated that the only thing MTG does not produce is diesel which, he allowed, is an advantage [of Fischer-Tropsch] and something that can be talked about. He again reiterated that MTG has no by-products and is a much simpler and cheaper process.

MR. VAN WIJK concluded by saying that Alaska has a problem with TAPS and Janus Methanol could add every two years 30,000 barrels a day to the pipeline and thereby the pipeline could be kept for a long time to come. He offered to come to Alaska to discuss this in more detail if legislators wish.

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CO-CHAIR SEATON understood that Mr. van Wijk will be coming to Alaska to talk to gas producers. He expressed his hope that

there are commercial agreements that can be met. He added that the legislature, or at least the House Resources Standing Committee, is willing to look at what can be done to enhance the opportunities for commercializing gas on the North Slope.

MR. VAN WIJK responded that it is the legislator who plays a very important role in this and if legislators decide to investigate this further, things will happen. He related MTG to the saying, "What a farmer doesn't know he doesn't eat," and said the oil companies are very familiar with GTL, but [MTG] is news to them.

CO-CHAIR SEATON replied that legislators will be asking the oil companies specific questions on MTG.

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REPRESENTATIVE HERRON noted that Mr. van Wijk is pursuing a market opportunity and asked whether a five-year horizon is the criteria.

MR. VAN WIJK replied that it would be more like six to seven years, including MTG and financing. This has potential geo-political, geo-social, and geo-economic consequences, he continued. Lots of countries, including China, have found shale gas, which can be converted into gasoline, and this makes them less dependent on the Middle East and countries like Venezuela because gasoline is the largest outlet for oil. Shale gas and natural gas are so readily available and becoming so cheap that making gasoline out of them is dirt cheap compared to oil. It is the equivalent of maybe \$40 a barrel and in 10-15 years this will have a huge impact worldwide.

[2:28:36 PM](#)

JOE DUBLER, Vice President, Chief Financial Officer, Alaska Gasline Development Corporation (AGDC), Alaska Housing Finance Corporation, Director of Finance, Alaska Housing Finance Corporation, Department of Revenue (DOR), introduced himself, his colleague Mr. Daryl Kleppin, and Dr. William Davey from Hatch Associates who produced the [gas-to-liquids] report being discussed today.

REPRESENTATIVE P. WILSON inquired whether gas to gasoline fits into the category of gas-to-liquids (GTL).

MR. DUBLER replied that gas to gasoline is a different process and he and Mr. Kleppin will be discussing the Fischer-Tropsch process, which has been around since World War II and converts [gas] either to jet fuel or diesel fuel rather than gasoline or methanol.

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MR. DUBLER first discussed why this GTL study was done, explaining that AGDC was tasked with preparing a report for the legislature about an [Alaska Stand Alone Gas Pipeline (ASAP)] from the North Slope to Southcentral and Fairbanks (slide 2). Going into the study it was known that the upper limit was half a billion cubic feet per day, the Alaska Gasline Inducement Act (AGIA) restriction, and the lower limit was zero since a negative number cannot be shipped. However, AGDC did not know where to target throughput for the gas pipeline, so it identified likely customers for the natural gas product that would be shipped and tailored the report to the most likely scenario of customers for that gas. Not knowing whether any of the commercial anchor tenants would be viable, AGDC commissioned three different studies: liquefied natural gas (LNG), which is similar to what ConocoPhillips Alaska, Inc. did for years in Nikiski; natural gas liquids (NGLs), and gas-to-liquids (GTLs), which is the study being discussed today.

MR. DUBLER stressed that the three studies were commissioned not as a way of ruling out any one, but for giving AGDC a confidence level in preparing its report that the throughput projected for ASAP was reasonable. Based on the study results, AGDC found that at least one of the three provided a sufficient netback, which is the price that the North Slope producers get for their gas after the tariff is taken out of the cost of the gas at the end of the pipeline. For example, Mr. Dubler continued, Southcentral and Fairbanks combined use about 240 million cubic feet (MMCF) per day. If all three studies had come back that any of these would be unlikely to produce a profit for a company, then AGDC would have stuck with 240 MCF as the throughput on the pipeline. However, it was found that the throughput could go up to the maximum of half a billion cubic feet per day because AGDC thinks there is a very high likelihood that one of them will work.

[2:32:38 PM](#)

DARYL KLEPPIN, Commercial Manager, Alaska Gasline Development Corporation (AGDC), Alaska Housing Finance Corporation,

Department of Revenue (DOR), directed attention to a diagram of the gas-to-liquids (GTL) process (slide 3). He said that Fischer-Tropsch technology is a proven process that has been around since World War II. The guidelines to [Hatch Associates] were to use proven Fischer-Tropsch technology. As with methanol to gas, Fischer Tropsch is not an incredibly efficient process. The Hatch study assumed a 57 percent efficiency in terms of converting input British Thermal Units (BTUs) to output BTUs in the liquids, and also assumed that some of the steam would be used to generate electricity for sale.

MR. KLEPPIN explained that the Fischer-Tropsch process tends to be high temperatures, 1,500 - 2,000 degrees Fahrenheit, and high pressure, with some of the vessels running between 300 and 1,500 pounds per square inch (PSI). The model looked at three different scenarios - one train, two trains, and four trains - at two different locations. A typical Fischer-Tropsch train produces about 16,000 - 17,000 barrels a day. The base case for the study assumed two trains. The two locations were a Cook Inlet site [Port MacKenzie] and a Fairbanks site.

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MR. KLEPPIN, moving to slide 4, noted that of the three cases depicted, Case B, the base case, produces roughly 33,000 barrels of liquids per day. He said the Fischer-Tropsch process can produce several products, the primary ones being diesel, naphtha, and jet fuel. The study looked at the combination that would create the largest value and in the base case it was assumed that roughly 74 percent of the product was diesel and the other 26 percent was naphtha. A market analysis of where that mixture of products would receive the highest price was also done, with Alaska being one market and Hawaii, the West Coast, and the Far East the other markets.

MR. KLEPPIN said the schematic on slide 4 provides a simplified view of what a facility would like and slide 5 shows what the GTL facility would look like. He explained that the acronym for auto thermal reactor is ATR. Continuing, he said the first step in the GTL process is to create a syngas, which is a mixture of carbon monoxide and hydrogen. The next step is the Fischer-Tropsch synthesis, followed by upgrading where the material is broken into the components of diesel and naphtha.

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MR. KLEPPIN related that there are a number of considerations when looking at a site, with transportation showing up as a key consideration under construction and under operation. Regarding the transportation issue, he directed attention to the photograph of a Fischer-Tropsch reactor on slide 6 and noted that a comparison of the people standing next to the reactor shows how big the reactor is. What that means for construction costs is that modular construction can be done at a Cook Inlet location, but at a Fairbanks location the reactor would have to be stick built, which means a higher capital cost.

CO-CHAIR SEATON inquired whether modules would be available for shipment to the North Slope and further asked whether the North Slope was specifically excluded or just not analyzed.

MR. KLEPPIN responded that a North Slope location was excluded because AGDC was looking at utilizing a gas pipeline and what an anchor tenant might be or where an anchor tenant might be in a gas pipeline, and if the GTL facility was located on the North Slope there would be no need for a gas pipeline to the GTL facility.

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MR. KLEPPIN, returning to his presentation, said that climate considerations for stick building the modules in Fairbanks would lower the productivity and that is the basis for the capital difference between Anchorage and Fairbanks; however, on the operational side it switches. He added that a facility of this size would have roughly 200 to 300 full-time employees and this is incorporated into the operating costs.

MR. KLEPPIN reviewed the study's capital expenditure (CAPEX) estimate basis (slide 7). Assumptions included that it would be a greenfield and a new build GTL facility, that the two trains would produce roughly 33,000 barrels a day, and that the base case location would be at Port MacKenzie. Because the ASAP project report was issued in July [2010], this Hatch report assumed that all the costs are in 2010 dollars, but later reports apply a 3 percent escalator to get to 2011 dollars. The cost estimate is a Class 4 estimate, which means the accuracy is on the order of plus 40 percent or minus 30 percent. This wide range of uncertainty is because limited engineering has been done. The Hatch study used existing facilities and tried to scale them, accounted for climate variations and transportation costs, and used specific quotes for different pieces of equipment.

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MR. DUBLER acknowledged that the cost estimate is very broad, but said the only way to narrow that down was to spend a lot of money on engineering and actually design the facility, which was not in the scope of the project.

MR. KLEPPIN continued, advising that the engineering is less than 1 percent complete, so it is very much a screening study to give an indication of whether GTLs is a possibility for an anchor tenant either in Fairbanks or Cook Inlet. He said the location factor of 1.25 is based on historical analysis and is the adjustment for a facility in, say, Nigeria or Qatar, versus Alaska.

MR. KLEPPIN discussed the cost estimates for the three different scenarios A, B, and C, with B being the base case (slide 8). He reported that [for case B] the cost to build a 33,000 barrel GTL facility in the Cook Inlet is roughly \$3 billion, which is a unit cost of \$88,000 per barrel day of production. [The unit cost] for actual constructed GTL facilities ranges from \$30,000 per barrel day to \$175,000, so Case B would be in the middle of this very big range.

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CO-CHAIR SEATON asked whether that range is based on economies of scale; for example, are the big plants cheaper or is it a function of where the plant was built and the problems that were faced.

MR. KLEPPIN answered that it is a combination of both. The largest facility currently in operation is the Pearl facility built by Shell in Qatar and that facility produces 140,000 barrels a day. Other costs were included, such as drilling for gas wells, but Shell's total cost started at \$5 billion and the final project ended up being around \$24 billion. Another plant that may be of relevance is one that Chevron built in Nigeria, which produces a volume similar to Case B of around 34,000 barrels a day. He said he thinks the original cost for the Chevron facility started at around \$1 billion and went to \$6 billion. Apparently, an issue for that plant was that it was built in wetlands so construction costs were quite a bit higher.

CO-CHAIR SEATON surmised that the 40 percent was very conservative.

MR. KLEPPIN said not necessarily - there is also a 30 percent contingency. Even allowing for that it could be plus 40 percent and there are some components that are not included in the study. He allowed that much more work needs to be done to get to a firm cost estimate.

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MR. KLEPPIN, returning to his presentation, pointed out that the operating cost for the base case facility is \$83,000 per barrel and the significant portion of that is the cost of the natural gas. The cost of the gas is a key assumption, a point also made by the previous speaker, as well as the cost of the sales products.

CO-CHAIR SEATON inquired about the cost used to arrive at \$83,000 per barrel.

MR. KLEPPIN replied that the number used for Anchorage was \$7.61 per million BTUs. He said that was as low a cost that AGDC could assume for seeing if it could still work. The cost of \$7.61 assumes a North Slope netback of \$1 to the producer, so the shipping tariff would be \$6.61.

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MR. KLEPPIN next compared a base case scenario for a Port MacKenzie facility versus Fairbanks (slide 9), pointing out that the capital cost [for Port MacKenzie] is roughly \$3 billion versus \$3.6 billion [for Fairbanks]. However, he continued, the operating costs for a Fairbanks facility [\$773 million annually] are lower than Port MacKenzie [\$925 million annually] due to a lower assumed tariff.

CO-CHAIR FEIGE said he understands the difference between a facility at the end of the line and one midstream on the line, but asked whether there was any consideration of the land on the Kenai Peninsula where the Agrium plant had been located and which has the plumbing in place for a large amount of gas.

MR. KLEPPIN responded that the base case was Port MacKenzie because that location is near the terminus of the base case for the gas pipeline at Big Lake. It could have been extended to the Kenai Peninsula but then there would have been additional costs for moving that gas to the Kenai Peninsula, as well as potential capital costs, which would have driven up the tariff;

so construction costs would likely not vary much between [Port] MacKenzie and the Kenai because this is a greenfield facility which assumes all new infrastructure and buildup, which may not be the case if existing facilities can be used on the Kenai.

MR. KLEPPIN, continuing his presentation, noted that there is little difference in the fixed operating costs between Anchorage and Fairbanks; it is all in the variable costs driven by the cost of the gas.

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MR. KLEPPIN next addressed the assumptions in the economic analysis (slide 10). The market analysis assumed the product mix would be diesel and naphtha, he said. Another case looked at a combination of roughly 40 percent diesel, 40 percent jet, and 20 percent naphtha. Taking into account shipping costs, the likely markets would be the U.S. West Coast for the diesel and Japan for the naphtha. The project life of the plant was assumed to be 30 years, the debt assumption was 50 percent, and the equity assumption was 50 percent. The equity rate of return was assumed to be 12 percent and the debt is the London Interbank Offered Rate (LIBOR), which is essentially for the best lenders and which would be less than the equity rate.

CO-CHAIR SEATON, referring to slide 9 showing Fairbanks as being less in total operating cost because of the price of gas, recollected that every presentation to the committee so far has been that the gas tariff into Fairbanks was more expensive than into Southcentral. He requested an explanation for this difference.

MR. KLEPPIN answered that those were different cases that assumed the gas stream was an enriched stream where NGLs were injected on the slope and then those liquids had to be extracted before getting to the gas. In the base case scenario here the assumption is just a non-enriched gas line, so there is not the expensive straddle plant at Fairbanks and therefore, on a mileage-based tariff, Fairbanks would have a lower tariff. He reiterated that this study is trying to get to whether there is any way GTLs could work economically and trying to give [the Fairbanks] location an optimistic view versus the extra fee for a straddle plant.

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CO-CHAIR SEATON questioned getting two drastically different views from the same organization, but offered his understanding that apparently this calculation is one that would not be a wet line because that would need a straddle plant.

MR. DUBLER explained that these three studies were conducted simultaneously and started off a year ago as a dry gas line. The results of the NGL study showed that maybe an enriched stream might be more profitable - result in a lower tariff - because more BTUs could be brought down the line. At that point AGDC shifted to that and did not go back and re-run all the assumptions for all three scenarios. So this was based on the original projected dry gas line and dry gas does result in a much better outcome for a GTL plant because no additional processing is required to take the gas and make it available for a GTL plant.

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CO-CHAIR SEATON said AGDC's current best case scenario was for a wet line, which means that these would have to be changed significantly because Fairbanks would have a higher operating cost under AGDC's current proposal where it is charging the facility or community that wants to use dry gas along the line. If the line is built as wet gas those facilities and communities would be charged for removing and then re-injecting the liquids. Whether that is fair will be addressed at another time, but he wants everyone to understand this.

MR. DUBLER agreed but said had ADGC re-done these with wet gas both of these would have looked much worse because both of the tariffs would have gone up. The reason ADGC did not re-do these is because the GTL did not look like a viable option anyway, so re-running it to see just how unviable it was did not seem to make much sense.

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MR. KLEPPIN, in response to Representative Dick, explained that naphtha can be used to make ethylene or propylene and sometimes it is used to make gasoline. However, using gas-to-liquids naphtha to make gasoline would lose a lot of the advantage of a very clean, pure product, which is stated in the study.

REPRESENTATIVE HERRON asked which method for predicted accuracy was used by the study, given that there are several methods.

MR. KLEPPIN replied that it is based on AACE methodology, the Association for the Advancement of Cost [Engineering], which has definitions on what standards must be met to get to that level of accuracy.

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REPRESENTATIVE HERRON inquired whether the Hatch report analyzed the market opportunity horizon, for which Mr. van Wijk's answer was six to seven years.

MR. KLEPPIN responded that Hatch's assumption for the economic schedule was that the permitting and engineering work would begin in 2012, the plant would be constructed the latter part of 2019, and it would be fully commissioned and operational in third quarter 2020.

REPRESENTATIVE HERRON, noting that people like Mr. van Wijk are always seeking areas of competitive strength, observed that page 115 of the Hatch report states this could be an even better project if advantage is taken of new carbon efficiencies and new technologies for GTL. He asked whether this consideration was rolled into the aforementioned horizon.

MR. KLEPPIN answered that AGDC's guidance to Hatch was to use proven, currently utilized Fischer-Tropsch technology, so the study stayed away from new technology. Conversations with Hatch have indicated, for example, that with new technology the product mix of 74 percent diesel and 26 percent naphtha could be upped to maybe as high as 90 percent diesel, but then he is not sure what to do with the cost estimates.

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MR. KLEPPIN, continuing his review of the study's economic assumptions depicted on slide 10, noted that the key assumptions included: \$80 [per barrel] West Texas Intermediate (WTI) pricing flat real and 3 percent escalation on that price; a product price at Port MacKenzie of \$7.61 [per MMBtu delivered natural gas to plant inlet] and at Fairbanks \$6.15, with the tariff and a \$1 North Slope netback included in that price; and power generated and sold on the market garnering a higher price at Fairbanks [\$60 per megawatt hour] than at Port MacKenzie [\$45], with the power generated and sold accounting for 4 percent of the total revenue stream.

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MR. KLEPPIN summarized his presentation (slide 11), stating that the key economic drivers are the price of crude, which tells what price the product can be sold at; the price of gas; and the capital investment. Assuming a hurdle rate of 12 percent, AGDC's base case scenario only gets a 5.7 percent return. To get to the breakeven point - the 12 percent hurdle - the [delivered natural gas] at Cook Inlet would have to be \$4.40 [per MMBtu]. Or said another way, the breakeven point for gas delivered to Cook Inlet at \$7.61 is a crude oil price of \$97 WTI. For Fairbanks, due to the capital costs, the breakeven price is even lower at \$2.19 per MMBtu.

MR. KLEPPIN lastly pointed out that AGDC's intention was not to select or eliminate any potential anchor tenant process. Rather, the intent was to figure out what the market might be for an anchor tenant and who might be the most likely - who will be the shipper and the final users. Noting that the graph depicted on slide 12 is from the July [2010] report, he related that the graph shows that GTLs are the least likely, and LNG is probably the most likely, for an anchor tenant.

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CO-CHAIR SEATON understood Mr. Kleppin to be saying that most all of the economic driver is the tariff on shipping the gas through the pipeline. He noted that the tariff could be taken away by building a GTL plant on the North Slope and using TAPS as the transmittal line. Diluting a previously pure product or taking it down the road in trucks is not the issue, he said. The issue is that if the tariff is taken away it makes a huge difference in the economics of GTLs for Alaska.

MR. KLEPPIN confirmed that the operating costs would be significantly reduced because no tariff would be paid on the gas pipeline. What that would do to the construction costs, capital costs, or shipping costs with TAPS was not analyzed, he continued, so he cannot compare the two projects. However, he agreed that that would be another option that may want to be studied.

CO-CHAIR SEATON realized that that was beyond AGDC's scope, but stated he was trying to determine whether the project said that GTLs anywhere in Alaska will not work or that GTLs shipped on a pipeline to either Fairbanks or Southcentral does not work.

MR. KLEPPIN agreed that that is a very fair characterization.

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REPRESENTATIVE HERRON inquired whether there was ever a collective epiphany within AGDC about why did "the big guys" or anyone else not do this before and just do the GTL project.

MR. DUBLER replied that last May AGDC offered a nonbinding expression of interest (EOI) and was expecting that anybody having a desire to build a project like a GTL, NGL, or LNG plant would submit a proposal. While the responses to an EOI are confidential, he continued, he can say that no one responded with a GTL proposal.

REPRESENTATIVE HERRON, re-stating his question, asked whether AGDC ever had a collective conversation about why someone has not yet done it since it make sense.

MR. DUBLER responded he does not believe so.

CO-CHAIR SEATON clarified that [AGDC's] study has said it does not make sense to do it in Southcentral or Fairbanks. The study did not analyze whether it makes economic sense to do it on the North Slope. Since the largest driver was the tariff for the transmission of gas, AGDC's study does not preclude that it would make sense to do it on the North Slope.

[3:04:56 PM](#)

REPRESENTATIVE DICK, returning to the Janus Methanol presentation, related that when the weather is cold the bar oil for his chainsaw gets pretty thick, so he mixes gasoline into the bar oil to thin it out. Regarding the challenge of heavy oil on the North Slope, he said he cannot stop thinking that gas-to-liquids might enhance the process of extracting heavy oil.

CO-CHAIR SEATON pointed out that GTL may have lots of waxes and paraffins, which may be a poor characteristic for injecting into TAPS. Noting that he has been a supporter of GTL on the North Slope, he pointed out that Fischer-Tropsch has a number of other products that could give problems depending upon where the process is done, so he does not want it glossed over that everything could be mixed.

MR. KLEPPIN agreed this may have been glossed over a bit. He explained that coming out of the Fischer-Tropsch process there

is the upgrading, which essentially has paraffinic compounds, and these are fractured or hydro-treated to make the diesel, jet, and naphtha.

[3:07:31 PM](#)

**ADJOURNMENT**

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 3:07 p.m.