ALASKA STATE LEGISLATURE
JOINT MEETING
LEGISLATIVE BUDGET AND AUDIT COMMITTEE
SENATE RESOURCES STANDING COMMITTEE
September 2, 2004
9:00 a.m.

MEMBERS PRESENT

LEGISLATIVE BUDGET AND AUDIT

Representative Ralph Samuels, Chair
Representative Mike Chenault
Representative Mike Hawker
Representative Beth Kerttula (via teleconference)
Representative Reggie Joule, alternate
Senator Gene Therriault, Vice Chair
Senator Lyman Hoffman

SENATE RESOURCES

Senator Fred Dyson
Senator Ralph Seekins
Senator Kim Elton
Senator Georgianna Lincoln

OTHER LEGISLATORS PRESENT

Representative Bill Stoltze
Representative Ethan Berkowitz
Representative Les Gara
Representative Eric Croft
Representative Paul Seaton (via teleconference)
Representative David Guttenberg (via teleconference)
Senator Donny Olson
Senator Gretchen Guess

MEMBERS ABSENT

LEGISLATIVE BUDGET AND AUDIT

Senator Ben Stevens
Representative Vic Kohring
Senator Con Bunde
Senator Gary Wilken

SENATE RESOURCES

Senator Tom Wagoner, Vice Chair

COMMITTEE CALENDAR

ALASKA NATURAL GAS PIPELINE ISSUES

PREVIOUS COMMITTEE ACTION

No previous action to record.

WITNESS REGISTER

Lesa Adair
Vice President, Muse Stancil

Harold Heinze
Chief Executive Officer, Alaska Natural Gas Development Authority

Brian Rogers, Information Insights

Robert Cupina, Deputy Director, Office of Energy Projects

John Katz, Assistant General Counsel for Energy Projects, Federal Energy Regulatory Commission (FERC)

Margery Fowke, National Energy Board, Canada

Commissioner Dave Harbour and Administrative Law Judge Jan Wilson, Regulatory Commission of Alaska

Commissioner Daniel Seamount, Alaska Oil and Gas Conservation Commission

Mark Myers, Director of the Division of Oil and Gas, Department of Natural Resources

ACTION NARRATIVE

TAPE 04-24, SIDE A [BUD TAPE]

CHAIR RALPH SAMUELS called the joint meeting of the Legislative Budget and Audit Committee and the Senate Resources Standing Committee to order at 9:00 a.m. Chair Samuels introduced Lesa Adair, Vice President of Muse Stancil and Company and said Ms. Adair consults on issues related to valuations, damage assessment, market evaluations and transactional due diligence in the energy sector. Ms. Adair has over 20 years experience in the industry and is frequently obtained to resolve disputes and advise clients on mergers, acquisitions, project development and investment decisions in the transportation process, refining marketing, and electrical generation sectors.

NATURAL GAS LIQUIDS, IN-STATE NATURAL GAS PROCESSING AND PETROCHEMICAL FACILITIES

MS. LESA ADAIR, Vice President of Muse Stancil, told members she would review natural gas liquids, the market in general, and the options for in-state processing and petrochemical facilities, as well as the alternatives. She referred members to page 2 of her handout and said she would talk briefly about the natural gas liquids (NGL) market and focus on the United States and Canada, relative to potential NGL production from Alaska. She began:

> If we look at 2003 total year numbers, the production of natural gas liquids in the Lower 48 totaled about 1.7 million barrels. That production was primarily concentrated in the southcentral United States - no big surprise there - that's where the bulk of the oil and particularly, gas production, is in the Lower 48 with about 66 percent of the production coming from that particular area. In addition, we imported about 165,000 barrels per day of NGL production, primarily from Canada, coming through pipelines into the upper Midwest.
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> In contrast, let's talk a little bit about Canadian production. Their production was about 670,000 barrels a day and, of course, their exports just happen to equal our imports at about 165,000 barrels a day. Based on numbers we've been provided from the Department of Natural Resources and looking at the total potential production and throughput on NGP and the compositions that are expected of NGLs in the gas, it looks like the potential production from the Alaska gas pipeline (AGP) throughput for NGLs would be on the order of 160,000 barrels a day but about 120,000 barrels a day of that would be ethane. Contrast that with U.S. supply of about 625,000 barrels a day of 1.7 million barrels being total ethane, the AGP liquids are going to run about 50 to 60 percent ethane, as opposed to current Lower 48 consumption and production, which is about one-third ethane. Canada is

very much the same. They've got a slightly higher percentage of ethane at about 40 percent. So AGP is going to be more highly leveraged on ethane.

Let's look at how the market really works in terms of natural gas liquids today. In the Lower 48 we have two, really, principle market hubs - Mont Bellevue, which is located on the Texas gulf coast and Conway, right in the center of the United States near Hutchison, Kansas. Both of those locations are interconnected with large diameter transmission piping. Further, they are interconnected all the way back up into Edmonton, Alberta through a series of pipelines so that the entire Lower 48 and Canadian natural gas liquid markets are very well integrated.

As a result, what we tend to see, because the largest consumption of natural gas liquids occurs here in Pad 3, and it's specifically on the U.S. Gulf Coast, is that the prices are pretty much set by the consumption that occurs in Mont Bellevue and then the whole rest of the market adjusts, all the way back up to Edmonton, off basis differentials for transportation. From time to time, there can be regional disruptions in supply, seasonal supply and demand that may throw those particular relationships out of whack for a little while but, in general, the price is pretty much netback from a market clearing price at Mont Bellevue.

The other key thing to keep in mind about these market centers and again, the biggest ones in the Lower 48 are Mont Bellevue and Conway, Sarnia is also north of Detroit - is also a large NGL market center, and then Edmonton, Alberta. These particular areas have large fractionation units, multiple large fractionation units. And the other distinctive factor there is that they have both the demand for the NGLs in those areas and significant underground storage in the form of salt cavern storage. Salt cavern storage is the most efficient way to store natural gas liquids. In Conway, they really only have the fractionation in the underground storage. They're really a distribution point balancing the demand between the northern and southern parts of the United States and Canada, whereas in the other markets, they're all derivative, manufacturing polyethylene, polypropylene and so forth in those areas.

If we look at product price trends, and truthfully all we want to talk about here are the trends, the ethane natural gas liquid tracks the natural gas price very closely. It is correlated very well to the natural gas, while propane and butane track the crude oil price. The important thing to understand with gas processing, as opposed to refining, for example, where all of the products that are derived from crude oil generally follow the crude oil price, there are so many derivative markets for natural gas liquids that we don't have the gas price setting the price for all the products. They move independently. As a result, the margins move independently and you can have a lot more volatility in the margins.

Let me just point out a couple of spots here to make that clear. If we look here in the period of 1995, you can see that crude oil prices are tracking fairly flat in this area but you can see natural gas and ethane moving independently in a downward trend in this particular area. Propane and butane prices were likely relatively stable while gas prices were falling. The other thing to notice is that as these prices move, you don't necessarily get the same order of magnitude shifts, even though they may be following the same trend. For example, in the period towards the end of the curve out here in the 2001 forward period, crude changed about $10 a barrel or moved about 40 percent of its value, where gas moved $3.50 for about 140 percent of its underlying value so large change is not necessarily the same order of magnitude.

When we look at natural gas processing, we have to look at what is the value of extracting these natural gas liquids from the gas itself and that's really what the next page 5 is focusing on. Here, as opposed to the prior slide, what we're looking at is the dollars per MMBTU for both natural gas, the blue line - the bottom line in most of the chart, and ethane, which is the red line, the top line. And we're actually able to compare the value of the ethane if it's sold on the top line in red as a liquid directly to the value of the ethane if it's sold as natural gas.

The important thing to recognize here is if you look at the period of the early 1990s, you can see a fairly wide difference between those two lines indicating that if you take ethane out of natural gas, you don't sell it for the blue price - turn it into a liquid, sell it for the red price, you make the difference. As you track across time, move closer to current and, specifically after late 2000 where you see the great big lovely peak in prices, you can see those lines moving much closer together. As those lines move closer together, the value of ethane as a liquid is becoming almost equal to the value of ethane as a natural gas. What that says is there's no incentive for a processor to change it from gas to liquid. Rather, he's indifferent. He'd rather just sell it as natural gas and not have to pay the processing cost.

NGL pricing on page 6 - there's a lot of debate about what's going to happen to pricing and, frankly, one of the things that I think is going to create some disruption in the market may be the timing and the actual location of the extraction of liquids from AGP. EIA has rolled, I believe, Alaska natural gas into their forecasts. At least it appears to be in there for everything I've looked at and they're forecasting that on average, on an annual basis, they think NGL prices are going to remain essentially flat on a real basis in the long term. They're projecting the increase of something around 1 percent, slightly more than natural gas, which leads me to believe that their view is that we may see a slight improvement in gas processing margins over time. But specifically for AGP liquids, what we have to be concerned about is where those liquids are going to end up and specifically, how much it costs to get it there because obviously we're not going to have enough demand in Alaska for all of the natural gas liquids that can be extracted, therefore you're going to have to deal with export pricing and that really is going to be the biggest determinator really of what those prices are netted back to the wellhead or to the border, whatever basis you want to look at.

The other thing that you need to think about too is that because AGP liquids will be highly leveraged to ethane, we have to think about where will all of the ethane go but the best place for all the ethane may not necessarily be the best place for the propane and the butane. Because these products all go to different derivative markets, you may have widely differing economics, depending on the ultimate destination of each segment of the NGL production.

Let's talk a little bit about historic processing margins. We'll look at the Lower 48 and maybe that will help us get some idea of what you'll be faced with in looking at AGP liquids. My firm, Muse Stancil and Company, publishes every month an oil and gas journal - these NGL extraction margins. And really what they're meant to represent are hypothetical plants in the mid-continent and the U.S. Gulf Coast. And really, this margin is meant to represent economically how is gas processing doing. In each individual situation the margins may be higher or lower but, on average, this tells us how margins are changing over time. In the mid-continent we tend to see fairly rich natural gas streams. Those plants do require usually a little bit more compression. On the Gulf Coast you have less compression but much leaner gas, much larger plants. And you can see that if we look at the trend, over time, from early 1990, that we are in a significant long, very slow decline in natural gas processing margins. This particular calculation is done from the standpoint of the plant operator, assuming that he buys the gas, he extracts the liquids, and pays all of his operating costs. So this gives us the cash margin really, that he would earn for performing those services. It does not take into account the overhead, which can vary widely from company to company or the capital expenditures that may be going on - the return of or the return on capital. So this is sort of a before tax type number. But you can definitely see we're in a downward trend long term and, for gas processors in particular, the last three and one-half years have been pretty tough. On the U.S. Gulf Coast you can see that since 2001, margins have actually averaged negative cash return.

Now what is the producers' perspective on this same profitability for gas processing? One of the things that's pretty typical in gas processing contracts that we see all over the world, not just in the Lower 48, is what a processor agrees to produce or to process gas for a percent of the proceeds. In other words, he captures the percent of the product and that's what he takes as his payment for the services. So the producer is used to paying a percent of his proceeds over to the processor and so one other thing that we look at is from a producer's perspective, he usually pays for all the fuel. He has to bear the shrinkage - that is how much his gas volume decreases when he extracts liquids, and also the transportation and fractionation charges from moving those products away from the plant. So we look at it from his perspective and we say okay, if you're going to process your gas, how much of a liquid do you need to get back to pay for processing, to pay for fuel, for the shrinkage, and the transportation fractionation? And if you look back in the early '90s, you can see that a producer in the mid-continent or on the Gulf Coast was making money if he got 60 percent of his proceeds back.

But over time, just as we saw with the gas processing margin, that amount of liquids he needs to receive to pay for processing has continued to increase. When the value of the liquids exceeds the 100 percent bar that means that the producer has gone from earning some income for processing to paying for it; in other words, it's become a cost center. He can't ever get enough liquid back to pay for the cost of processing.

And so, in the period since late 2000, we have begun to see a shift in the mentality in the industry that more and more people view processing, at least in the short to medium term, as a cost center rather than a profit center. There are unique opportunities out there, depending on composition, capital expenditures and so forth, where some people are making money but, again, as a barometer in general, processing has become more of a cost than a profit center.

Now I'd like to shift gears a little bit, moving on to page 9, to talk about alternative dispositions for the AGP-NGL throughput. The Department of Revenue has obtained us to assist in developing their understanding of the economics of these different alternatives and so one of the first things we took a look at is what particular areas, what market centers, make the most sense. If we look at extraction in petrochemical manufacturing outside of the State of Alaska, the first place that you think of is the U.S. Gulf Coast, where over 80 percent of the capacity for [indisc.] production in North America is located.

Other centers include in Alberta, primarily in the Edmonton area, where about 12 percent of the capacity exists, and then Sarnia and other various locations in the U.S. Midwest, which tend to be large isolated manufacturing facilities. The nearest infrastructure of any plausible size, and this includes derivative manufacturing of ethane, the fractionation capabilities and the underground storage we talked about earlier, is really Alberta. If we look though, at Alberta's ethane balance, they're currently manufacturing just a little bit more, not even 10 percent more ethane than they utilize, and so they're pretty balanced on supply. We do know that their availability of liquids is going to go down over time as their gas continues to decline and so, over the medium to long term, there may be some opportunities to supplement the ethane that they're using in their petrochemical manufacturing there in Alberta. Their total demand currently is about 250,000 barrels a day. If we look at AGP's potential of 120,000 barrels a day of ethane, that's roughly half their current capacity, so that's an awful lot of NGL or ethane in particular to have to displace into Alberta. However, there could be additional capacity installed there or additional take-away pipeline capacity installed to handle the incremental ethane coming off of AGP.

Extraction in Alaska - first of all we'd have to think about the fact that when we pull out the ethane, other things are going to come with the ethane. It's not likely that we could come up with an economic solution, which says we build a natural gas liquids pipeline to take the excess propane, butane and so forth that comes out with the ethane to a market, as well as a gas pipeline. So our feasibility look really centered on the notion that you would extract what you need for manufacturing in Alaska and that everything else would go back in the AGP so that you would only have to build one piece of transportation infrastructure for the state.

To have a market for that primarily ethane would also require the development of a petrochemical manufacturing complex and, most likely, that would be ethylene going to polyethylene and then the infrastructure to support that, including the storage utilities, electrical and so forth. It's possible that you may require some additional transportation infrastructure but our design is not at a level yet to really determine that. Polyethylene is pretty easy to transport - you can put it in rail cars, hopper cars, in bags and transport it by rail and marine.

The facility would look something like this on page 10. The facility would handle about 1.4 bcf of throughput on the extraction plant. That's out of a roughly 4.3 bcf total throughput on AGP. From that we would produce about 40,000 barrels per day of ethane to be fed to the ethylene facility and another 1,000 barrels a day of propane or so for local consumption. Any incremental propane that couldn't be sold and butane that's extracted would go back into the pipeline for transportation to the ultimate pipeline termination point. You would also be able to produce commercial quality natural gas for local distribution off the top of the extraction plant. And any residue gas that you couldn't sell, which our figures show would be about a B [BCF] or a little over a B [BCF], would go back into AGP as well.

The design and construction of this sort of facility is probably duplicative in that you would ultimately size all the facilities at the terminus of the main line pipeline to handle 100 percent of the throughput because, obviously, if you're going to have one ethylene plant, one polyethylene plant, they're going to have to be in shut down and turn around for some extended periods of time and you wouldn't want to have to shut down your pipeline to do that so you would probably just have a slightly bigger extraction plant at the terminus of the pipeline to allow you the flexibility to mute that gas in either direction.

Downstream of the extraction plant, on page 11, your ethane would feed an ethylene cracker. You would produce ethylene, which would feed a polyethylene plant and then produce the polyethylene resin, which would be little pellets that look like little chips of wax. There are some by-products from the production of ethylene, however ethylene production is by far the most efficient process. If you try to use propane to propylene or naphthenic-type cracking, you get a lot more by-product, stuff you can't use. If you're in Edmonton or on the U.S. Gulf Coast, those by-products can be sold into other related petrochemical facilities in the area - refineries, other petrochemical manufacturing. Here we've assumed that all these by-products have to be burned as fuel because we are not anticipating that we would have additional available infrastructure to absorb those by-products.

In summary, if we look at Fairbanks versus other potential points for extraction and downstream processing of NGLs, we believe there will be an attractively priced feedstock at Fairbanks that, because you're exporting the gas, the price of gas at Fairbanks is likely going to be some Canadian border or Alberta-related price netted back from the tariff, which should lead you to a fairly inexpensive price for feedstock in Fairbanks. Fairbanks also does, with the rail connection, offer a link to waterborne transportation and there is demand for polyethylene resin in California. Now that demand is being met today so you would have to be able to penetrate the market at the right price to make sure you could get all the placement of that market.

There are synergistic benefits, including pipeline quality natural gas availability to Fairbanks and possibly other areas. You would have to have electrical generation within the complex and you could possibly oversize that facility and provide additional merchant electrical power delivery into the grid.

The disadvantages we see of the Fairbanks location is that there is some variability in the gas composition over time, that's just a function of how gas comes out of the reservoir and that's something we deal with everywhere. However, here it's going to be very localized. In the Lower 48, it's kind of spread out all over the place. What that means is you have to size your gas processing facility to be able to ensure that you're always going to be able to extract enough ethane to keep your ethylene plant going, which means it's probably a little bit bigger than it would generally need to be.

There's going to be a little bit of inefficiency in processing because you're going to process 1.5 bcf of gas in Fairbanks; 1 bcf of that is going to go back into the pipeline. When it does, it gets remixed with other components and has to be reprocessed again at the terminus of the pipeline so you do have to have the capacity and pay the operating costs for that to be processed twice. We talked about the non-optimal sizing. You're going to want to make your downstream facilities big enough to take all the gas in the event that you've got an outage in your ethylene production or just for routine maintenance of your ethylene facility.

In looking at capital costs - and I think this is one that's real important, especially since we've just in the last several weeks learned that there are at least three ethylene plants in the Gulf Coast that are going to be shutting down because they're at a cost disadvantage. Fairbanks appears to be about a 35 percent higher capital cost than installing similar facilities on the U.S. Gulf Coast, and perhaps 25 percent higher than an Alberta type installation. That is before we consider the fact that we're going to have to add infrastructure that already exists in Alberta or exists on the U.S. Gulf Coast that we could incorporate and use so there would be additional costs above and beyond that. The fixed operating costs are likely higher, due to wages and also due to the fact that you're going to have to fly in expertise, parts, and equipment, which are readily available in those other centers. We talked about the lack of supporting infrastructure and the fact that the by-products really don't have a market here so anything that we create out of ethylene manufacturing that's not pure ethylene is going to have to be burned probably as fuel in the facility.

If we look at the preliminary economics, and this is a very high level analysis, but it appears to us that the production of the ethane in Fairbanks is just economically less attractive than in either Alberta or on the U.S. Gulf Coast. You've got the advantage of potentially a lower feedstock price than your ethane. The lower variable costs, and by that we mean fuel, if your gas is cheaper, it's cheaper to burn as fuel as well. But that's more than offset by higher fixed operating costs, the location differential in a remote location, and the lower product value due to downgrading those by-products to fuel.

The significantly higher capital cost is probably also going to be a disincentive for most of your major manufacturers to invest. If they're looking at a location in Alaska where there's stranded gas versus a location in Asia where there's stranded gas and they can build a plant for 30 to 40 percent less than Alaska, they're more than likely going to go to Asia. We see an awful lot of manufacturing of facilities being installed in Asia today and, in fact, the U.S. Gulf Coast facilities are running at less than capacity because they're having trouble competing with the more efficient and cheaper product out of the Asia Pacific.

Looking at recent historical U.S. Gulf Coast margins for ethylene production, we're assuming - we believe Fairbanks could probably achieve a similar margin because its got the feedstock advantage but it's going to have higher investment costs. But, if it's able to do that, it will have a significantly less attractive rate of return simply because you've got a higher capital investment. Alberta's rate of return is probably a little bit higher. Their contracts are structured a little bit differently than the U.S. Gulf Coast. So, Fairbanks is pretty economically disadvantaged in terms of trying to compete in the world market. And that's all I have. I'm happy to take any questions.

CHAIR SAMUELS asked, regarding the capacity, if Ms. Adair said the capacity from Fairbanks south would have to be the same as the capacity from the North Slope to Fairbanks, just in case the plant was out and had to be modified.

MS. ADAIR said that is correct and, more than likely, to keep the gas flowing, the downstream facility would be sized as if Fairbanks wasn't there. That would provide the ability to keep the gas flowing if Fairbanks had to be shut down. The incremental cost in terms of the pipe size is not that great.

CHAIR SAMUELS asked what percent would be taken out if the plant was up and operating as intended as it goes by Fairbanks; and how much empty space would be headed for Chicago.

MS. ADAIR replied, "About 1/2 B [BCF] is what our numbers show because we pull off 1.5 and we put back in about 1, so about 500,000."

SENATOR RALPH SEEKINS asked how the NGL content of the gas envelope that comes off the North Slope compares to other areas or regions.

MS. ADAIR said the composition is more like a Gulf of Mexico type gas. It tends to have less propane and butane in it but has more ethane. From the extraction profitability standpoint, the propane and butane tend to be the higher value components of the gas. She noted as compared to the Lower 48 and Canadian production, Alaska gas is 50 to 60 percent ethane; the Lower 48 and Canadian gas is 30 to 35 percent.

SENATOR SEEKINS said the primary object is to get gas from the North Slope to someone who will burn it at a power plant or at a commercial application down the road. He asked, "Let's say we had a complete gas envelope that didn't have anything taken off from it and it got to the Canadian border. Is then that - what do we deliver out the other end? Is there any BTU per BTU relationship that exists when it comes back into the United States?"

MS. ADAIR replied the real question has to do with the way the major transmission line systems and local distribution systems are designed and, to a certain degree, how water heaters and stoves are designed to work with natural gas. She explained what you typically see in the United States are natural gas pipelines operating at 1,000 btu gas. Some operate as high as 1,050. In Alberta, the gas processing facilities that are remotely located do what is called dew point control. They strip out the heaviest liquids - propanes and butanes; and make it easier to move the gas in pipelines without a lot of liquids falling out. The problem with liquids falling out is twofold: a loss of efficiency and safety considerations. In the Alberta system, the heavier liquids are extracted in the field and then large straddle plants sit over their big gas transmission systems and extract the rest of the ethane. However, in all cases when looking at local distribution systems, the btus are very low so the producer does not have a choice. At some point along the value chain, the gas must be processed. The btu content must be reduced for distribution purposes and someone must pay for it.

SENATOR SEEKINS said everyone wants to make natural gas usable in Alaska in Fairbanks and with a line to Anchorage. He asked if the product that comes down that line to Fairbanks would be usable downstream in Alaska without any processing.

MS. ADAIR said it would not without some sort of processing, however, a petrochemical complex taking the product all of the way to polyethylene resin would not be necessary to make a commercial quality natural gas for local use.

SENATOR SEEKINS commented, "I've heard people talking about - well there are, on the other side of the border, there are people that are saying and they get to the Whitehorse area and they're saying if we can get that intact envelope here, we can strip that stuff off, we can get it down to the Alaska coastline and get it out to the markets if Alaska doesn't. Is that a possibility? Is there any discussion about that that you're aware of?"

MS. ADAIR said she is not aware of any such discussions and has not been asked to study that question. She noted the potential limitation revolves around having enough heavy-duty vessels to move that high-pressure product, particularly ethane.

SENATOR SEEKINS said many [legislators] want to have in-state processing to enhance Alaskans' overall quality of life. He asked Ms. Adair, with that in mind, if her basic conclusion is that may not be economically feasible.

MS. ADAIR said the problem is that Alaska will have a hard time competing in the worldwide market if it has integrated petrochemical manufacturing in-state.

CHAIR SAMUELS asked what type of processing facility would be required to pull the heavy liquids out to service Fairbanks and Anchorage.

MS. ADAIR explained the processing would require the same technology to produce the natural gas liquids but the processing plant would be a different size and the cost would be much smaller. It would not require any of the downstream processing and the liquids that were not used could be put back into the pipeline.

SENATOR SEEKINS asked if those liquids would be put back in the gas pipeline as opposed to the oil pipeline.

MS. ADAIR said that is correct and that it would be a relatively small amount compared to the overall throughput on the AGP.

CHAIR SAMUELS referred to page 8 and asked if demand for the liquids drops, the processing cost goes up for everyone, and whether the demand has dropped so low that the manufacturers cannot recover their operating costs.

MS. ADAIR said the margin for gas processing is very volatile and feedstocks, which are natural gas, work off a different supply and demand curve than the products do. What has happened is that the demand for natural gas in and of itself is so strong that, to the extent everything possible is left in the gas, it is more economically beneficial to do so. She continued, "And that's really what creates this situation is gas prices are so, so high. People would like to - producers would like to sell their propane as natural gas if they could in some places but, because of the safety considerations, they are not able to do that. So, demand is still very strong for all of these products."

SENATOR SEEKINS asked, " It appears to me then what we're saying when we look at this chart on page 8, that this is kind of a stand-alone - I'm buying the gas, what the price of the gas is. It's a separate accounting for that structure but what you're saying is it's necessary for them to take some of these liquids out?"

MS. ADAIR said it is.

SENATOR SEEKINS asked if the break-even chart is based on having to buy the liquids but not considering that they have to be stripped out.

MS. ADAIR explained that it is based on the producers' opportunity costs - the gas given by the producers to create the liquids. She continued, "Some of that he gives up because he has to shrink out the propane and the butane. Some of it he gives up because it's burned as fuel. That's gas that he could be selling for revenue. So it's that whole opportunity cost that he bears to produce those liquids. That's really what the chart is driving at; it's that his cost has gone up."

SENATOR SEEKINS said often the expense structure is a necessity, not necessarily a reduction in opportunity.

MS. ADAIR said the producer may have flexibility to a certain degree, depending on whether he or someone else is processing for him, to reduce the amount of processing done. Generally producers sell to someone else who does the processing but some producers in the Gulf Coast retain the right to not process their gas when prices get high.

CHAIR SAMUELS acknowledged that Senators Lincoln, Hoffman, Dyson, Guess, Elton, Seekins and Olson and Representatives Berkowitz, Joule, Chenault, Hawker, and Stoltze were present. He then announced that Mr. Harold Heinze would address the committee.

IN-STATE OFF-TAKE POINTS AND SPURLINE: COST AND DESIGN

MR. HAROLD HEINZE, Chief Executive Officer of the Alaska Natural Gas Development Authority (ANGDA), advised members that his presentation would mirror Ms. Adair's but would address a much smaller scale. He noted that at the last hearing, members talked about some access and opportunity issues, and some people "raised their eyebrows" over the assertion that these things would work economically. As a result, ANGDA hired some contractors to do some feasibility studies based on some worst case assumptions and came to the conclusion that there are gas off-take opportunities in Alaska worth understanding. He said he would focus on providing gas for a number of different options: electric power plants, propane distribution, and piped gas distribution systems. He also said he would talk about an approach that is on a different scale. ANGDA designed an entirely stand-alone facility to perform those functions and costed it. He pointed out that it is not an optimized design but ANGDA has identified many ways to lower its cost and improve the design. He advised members that they need to immediately start considering that any gas pipeline that runs any major volume down through Alaska will have compressor stations on it. If those compressor stations are 100 miles apart, there would be seven or eight of them. Every one of those stations must perform the function of conditioning the gas. They must make the gas usable as a fuel and, in the process of doing so, will extract products that are valuable to Alaska's citizens. He reminded members that may not be on the scale of a huge petrochemical industry but it is very important for Alaska. He said he would then talk about a spur line into the Cook Inlet area because that represents a major off-take opportunity for Alaska. He gave the following presentation.

> Again, to kind of put it in scale for you, if you go back to the previous presentation, one of the early charts there showed the U.S. propane production at 500,000 barrels a day. If you kind of look around

Alaska, how much propane is used in Alaska today, there's no exact number I could find but my best guess is it's probably a little over 1,000 barrels a day of propane is used in Alaska right now. And I went through and I did an estimate just - again, roughly off some previous demand studies that have been done related to gas and I estimated that if you supplied basically the whole interior of Alaska that was not on the highway system or not on the pipeline, in other words on the river system or the disbursed road system, that you'd need something maybe resembling 2,000 barrels a day of propane to do that. So, again, on the scale of the world, we're pretty small.

But also just to put in perspective for you, what you didn't hear in the last presentation is how much propane is going down the line. That number is anywhere from 50 to 100,000 barrels a day of propane is going down that line. So what I'm talking about here is a relatively minor extraction of something that's going by. It will not change the economics of anything related to the pipeline but it is important to the economics of Alaska and Alaskans. [END OF TAPE 04-24, SIDE A]

TAPE 04-24, SIDE B

MR. HEINZE continued.

...on the line. We sized - again, these kind of plants are very common. This is not brain surgery. This is off the shelf stuff. You can call people up and order these parts from a catalog and you can put them on a skid if they are small enough. As a matter of fact, the unit we are looking at here is smaller than any manufacturer really wanted to talk about but we were able, through a little cajoling, to get them to think really small. This facility process is only 10 million cubic feet a day of gas. Again, to kind of put that in perspective for you, Fairbanks would probably use a number two or three times that. Ten million a day would be enough for a large mine development but it would be an overwhelming number compared to any of our smaller communities or smaller opportunities that we would be looking at. In terms of scale, that was about as small as we could get people to kind of think about. And we said okay, we'll stop there, because

> even if it was too big, you obviously can turn this kind of facility on, run it for a period of time, and when the tank is full, you turn it off and then you turn it back on. You can do that in an operational sense here. Again, there's nothing very magic in all of this stuff here.

REPRESENTATIVE BILL STOLTZE asked Mr. Heinze if he has talked to the Matanuska Electric Association (MEA) because it will be ending its long-term contract with Chugiak in the not too distant future and the Matanuska Valley is the fastest growing part of the state.

MR. HEINZE asked to defer that topic to the spur line discussion. He then continued with his presentation.

> In terms of the propane issue here, this is a plant that again, you'll see summarized a little later. Again, the economics on this - basically, what we found out, this plant would cost a little more than $10 million. If you work the economics of it, basically you can extract propane under this situation for about 50 to 75 cents a gallon. Now, there are optimizations you could make on this plant. There are a lot of variations on this theme and, for instance, if I looked at the Yukon River, which would have a bigger plant than this, I could keep driving that number down. So the 50 to 75 cents is the upper number per gallon. On a broad feasibility sense, I'd like you to think about the fact that that is a potentially very attractive number to Alaska. In Alaska we pay basically the propane price in Alberta plus the transportation here. If the gas going by here is at some intermediate value compared to Edmonton, then our price would be lower. At 50 cents even, you can afford to be extracting it at some place that's very convenient for you to wholesale from and so there is at least worth understanding here. I'm not claiming this is a done deal but it's worth understanding.

CHAIR SAMUELS asked Mr. Heinze to also address, later in his presentation, the reduction in capacity and whether there will be empty capacity heading south.

MR. HEINZE replied, "You will see on the scale of the things we're talking about other than the gas off-take to come to the Cook Inlet area, other than the spur line issue, there's no issue I'm raising here - it gets lost in the round off, let me put it that way." He then continued.

> We also looked at the same plant because if you have to basically go through the same process to condition the gas for, say, to make a turbine fuel for either powering a pump station or compressors for providing electric power generation, or providing local distribution of gas, you have to go through these same basic processors. If you look at the front end of this plant, it's identical. All I've taken out here is the idea of reinjecting the gas and now I'm using the gas beneficially. And again, we looked at this plant. The economics are very attractive and, frankly, if I took credit for having both gas available for use and propane, now the price per unit on both of those goes down. So, again, I can improve on this.
>
> What we don't know at this point is - and we suspect only because the information, frankly, is not available to us, is that at every compressor station, there would be something that looked like this. Our engineering expertise says that to run a compressor station, you've got to do something like this at every compressor station. But, since we've never seen the plans or diagrams or process or anything at the stations, we don't know. But that is our engineering judgment at this point.
>
> That's interesting because if you already have a large amount of gas that's going to be used to fuel the compressor station and burned in the turbines and pushing that 4.5 billion cubic feet of gas south, that's in itself going to yield a lot of propane. And again, how you look at that cost structure and all those other things is very interesting.

SENATOR SEEKINS asked if the gas must be dehydrated before it is put in the pipeline.

MR. HEINZE said the water vapors are removed to a certain level but ANGDA does not know what that dehydration level is because it has not seen the exact specifications. He pointed out that [the dehydration requirement] could be removed to optimize the facility. If the pipeline specification was low enough it might not be necessary, depending on ANGDA's process design. That process is there to get to the necessary temperatures further in the process. The gas is chilled to a very cold temperature and any water vapor at all at that point creates difficulties. He noted the dehydration step accounts for several million dollars.

SENATOR SEEKINS surmised that if it is not dehydrated, it would produce carbonic acid mixed with CO_2, which would eat right through steel.

MR. HEINZE said ANGDA is very comfortable that the water specification would be such that that would not be a worry. He said the problem is that as you went through these facilities, the water temperatures achieved would be much lower. He repeated that for the feasibility study, ANGDA took the worst-case scenario it could think of.

SENATOR LINCOLN recalled Mr. Heinze saying a propane plant at the compressor stations would cost about $10 million and asked if that cost would increase by having the utility gas in there as well.

MR. HEINZE replied:

> This is actually a lower cost facility because we don't have to reinject the gas. Because we have a beneficial use for the gas and don't have to reinject it, it saves us the cost of a compressor. Every time I drop a box off of this thing, I think of it as $1 or $2 million shaved off the plant. It's just some pieces of the puzzle we don't have to have there to operate correctly. So this is a much simpler operation in our mind. And so what it argues very strongly is, again, as you look at what we would call a very small facility, for some parts of Alaska it is very large. But, on the other hand, we can make available through these kinds of facilities a fair amount.
>
> For instance, this facility yields 100 barrels a day roughly of propane. So in that sense it is small. But again, we could scale this facility up and achieve much greater economies of scale. Let's say you wanted 1,000 barrels a day at the Yukon River. All this feasibility work says is that might be very attractive because we could beat That 50 to 75 cents a gallon propane, by a lot probably, in a facility designed just for that purpose.

MR. HEINZE continued his presentation.

Again, I've kind of told you everything that's on that slide already. This was just kind of looking at it - every place you had a power plant, for instance, at North Pole. North Pole was putting in a 60-megawatt plant. It would take a facility about this size to condition the gas for use in that plant probably or some variation of it. You could produce propane there. You could probably produce 100 barrels a day of propane, is all we're saying, as a by-product of doing this. So that's important. We have no understanding of the combination of the pump stations on the TransAlaska pipeline, which are being electrified under their new program and how that might co-locate and co-act with compressor stations located, again, along a gas line. And from our perspective, there might be some wonderful synergies involved in co-locating those major facilities and operations, in which case - again, you would have a fairly large use for gas to fuel the turbines that run the generators that drive the motors that drive the compressors and trunks, so it's logical.

Again, I'm going to continue to emphasize to you that even though we are a small piece of the show, there's 4.5 billion cubic feet a day going down that line and we're talking about here something that's 1/1000th of that. It is very important that we define the ability and where and how those things might happen. I took a crack at it for you here. Again, last time I drew up a broad list. Here's my more definitive list of where I would, at least, see those kinds of points. And it seems to me that you'll notice some of the points I've tried to list were in Canada. And it's, again, my general understanding that this type of a pipeline going through Canada would have to make the revision for this kind of access that we're talking about. Now maybe the law is different there. Maybe something else is different. I don't know. I haven't researched it but it seems to me that we, in our own best interest, ought to be looking at something like that.

And then my final point is I think you ought to put the burden of what I'm trying to talk about here today, frankly, on any project proponent. These are issues and opportunities that are part and parcel of running the system through the public land, as far as

I'm concerned, and they need to be addressed as part of the design. We found our ability to do this was very hindered by the fact that there is, for instance, no publicly available information on the composition of the gas that's going down this pipeline. I mean you just heard a presentation on a whole petrochemical industry and I don't know what the basis of that presentation was. It's not publicly available. I don't even know how to design these facilities for sure.

The other thing you've got to worry about is the tariff issue and, again, I've got to just bring this back up with you because the key to this is physically we can take the gas off. I've shown you a facility that can do it. I've shown you feasibility economics that say it is possible economically to do it. But, it's dead in the water under a tariff structure that discriminates against taking gas off in Alaska. If you don't have a tariff structure that allows us to gain the benefit of being closer to the source, all bets are off. If I have to pay the same price in Fairbanks that I would in Edmonton, the economics don't work and it's that simple.

Again, I would suggest to you that you can include these things in either the grant of right-of-way by the state, or whatever Stranded Gas Act things you do.

Mr. Chairman, I'd like to just take a few minutes and talk about the spur line and some of the issues related to it. Part of the charge that ANGDA was given in Ballot Measure 3 was to look specifically at a spur line to the Cook Inlet area. It was not just to look at an LNG project but also to look at a spur line. Basically, a part of the report that we will be publishing in a week - we did do that and we have basically, again, completed preliminary work on it and I very briefly summarized it here. We did define an alignment for the 140 miles that's shown on these two poster boards behind you. It goes from Glenallen, basically, at the TransAlaska pipeline right-of-way and it leads into a place in Palmer that is basically - I would describe it to you as the place where the highways and the railroad intersect - the Glen and Parks Highway and the railroad and the new overpass and all that. That happens to be the point where you can get to the Enstar 20 inch system, which is the basic piping system in this whole area. And so we'd design that line to go between those two places. It's a high-pressure line. Its cost estimate was about $300 million.

We also hired a financial company to look at the financing of that where ANGDA would be acting as a state-owned utility. The advantage of being a state-owned utility is that basically you can do 100 percent debt financing for a project of this size and you can do it at a very low interest rate - lower than the interest rates that we talked about yesterday in the presentation. For that type of a design we estimated that we could move gas from Glenallen to the Palmer area for about 15 cents/million btu. That's a very low number. It's very difficult to move any gas anywhere in Cook Inlet for that number. Most of the time it's a bigger number than that just within the Cook Inlet area.

There are, obviously, in terms of the spur line, a lot of issues that are well beyond our control. Obviously there is not gas sitting there right now in Glenallen for me to go pick up. If you want to go to Delta and pick it up there, it's about twice the cost. It's about twice the pipeline and about twice to everything else. We did not work that problem in detail because the pipeline would follow the TAPS right-of-way, which is a well understood pipeline and corridor and there are just no big issues in laying a 24 inch pipe.

As you'll see on the map here, we did lay out a basic route that follows the Glen Highway because the state does have that right-of-way. We do have the ability to lay pipe in that right-of-way. From a technical point of view, there are places that we have identified where it was logical to deviate from that right-of-way and possibly improve the pipelining circumstances. Again, as anybody whose driven the road knows, there are places where the side slopes are pretty steep and where the river kind of comes up against the cliffs and those kinds of things. It would be hard to fit in the right-of-way. It could be done but it would be hard to and we've identified other areas that we'd like to go down.

SENATOR SEEKINS noted that Senator Wagoner was very interested in looking into the routing of a connection into the Palmer area from the Fairbanks area that would follow the Parks Highway and asked if ANGDA looked at such a route.

MR. HEINZE said at this point, ANGDA has looked into the record. The state has information on file sufficient to define a right-of-way from the Fairbanks to Palmer area. ANGDA also found there is no information on the Glenallen "on-in" route so ANGDA will take the step of submitting that right-of-way application. Regarding the study between the two different routes, at this point, ANGDA has formed no opinion that has allowed it to differentiate between the two. ANGDA is aware of advantages and disadvantages to each; the biggest advantage to coming through Glenallen is twofold. First, it would reach the greatest population of the state and, secondly, it is the easiest in terms of right-of-way issues because it follows the TransAlaska pipeline right-of-way through an area that is made up solely of state and private lands. On the other hand, the other route has a definable right-of-way. ANGDA will study that and look at the smaller projects for bringing North Slope gas to the area.

SENATOR SEEKINS said it is his understanding that Senator Wagoner believed the possible route from Fairbanks to Palmer did not cross any federal land either; it is all state and private land.

MR. HEINZE said the examples he has seen of that route contained some special state park land and federal parkland. He admitted he does not know whether ways can be found around that at this point.

SENATOR SEEKINS said he saw a relocation to the east side of the Parks Highway, which is totally outside of federal land but other people say it would have to go through the national park.

MR. HEINZE said at this point, ANGDA's preliminary assessment is that the cost to deliver gas either way is very comparable. ANGDA sees no cost advantage to one route over the other, the reason being that even though the Glenallen route is longer, it would be more economically attractive to "ride a longer distance in a big pipe to Delta" and, second, that route already has a right-of-way and road system.

SENATOR SEEKINS asked if the right-of-way from Delta south is already owned and would have to be purchased by the state.

MR. HEINZE said in one of ANGDA's studies about its broader responsibilities under Ballot Measure 3, it determined one of the specifics was to look at the permits and other certificates held by the Yukon Pacific Corporation. ANGDA determined that a large number of those permits are still good and valuable. ANGDA looked at that favorably in that it could buy a federal and state right-of-way held by Yukon Pacific that would go all of the way to Glenallen.

SENATOR DYSON asked if ANGDA anticipates the optimum use of in-state gas will exceed the state's royalty share.

MR. HEINZE said right now, 200 bcf is used in Alaska annually. About half of that amount is used in the LNG export facility on the Kenai, owned by Conoco and Marathon. They currently feed that with their own reserves. He does not know their future intentions. He continued:

> I have no idea, I have no way of knowing what they intend to do in the future on that. For the purposes of these economics, I have made the assumption that what I see today is what I have in the future. Obviously there is a case where they choose to do zero. There is also a case where they choose to expand based on a new and plentiful supply. At least one of the companies I just named is a major owner of gas on the North Slope. If their gas was used in that plant, I presume the state would not take it as their responsibility to supply that gas. Of the remaining 100 billion a year, half of that is roughly Agrium. And, again, I don't know exactly what role the state would play in that. The state might be a seller there or they might buy gas from other people commercially or whatever. I know they are interested in the fact that a spur line like this, hooked this close to a big supply up north, might give them the kind of pricing advantage they feel they have to have in the marketplace to continue to operate. Again, our focus has been much more on them frankly, than trying to build a new industry, because if we can't make their economics work, then again my experience says it's going to be very difficult to do something in terms of greenfield, so we have a lot of incentive to try to make that work.
>
> If I could, back to Representative Stoltze's question about the Matanuska area and all that, it is our

intention in the spur line that we would put major - we would like others to have major electric generation facilities at both ends of that spur line. It makes sense that where we take off in Glenallen to have a generating plant - that also wholesales propane. It makes sense to have an electric power plant and other things as we come into the Enstar system.

REPRESENTATIVE STOLTZE asked if an entity that might have the capacity to serve 20 percent of the state's population would provide more justification or impetus and whether that entity would need to "come to the table" formally.

MR. HEINZE said that early in the spur line discussions, he invited every utility, agency, and others to a meeting. MEA did attend that meeting. Since then, people have taken a greater interest in the dialog but that is the choice of each entity at this point. A spur line to this area may be a very attractive proposition for the citizens of Alaska. And while everyone hopes that a lot of gas is discovered in Cook Inlet, the DOE study put a multi-billion dollar price tag on it. Therefore, this alternative must be kept on the table.

SENATOR DYSON said everyone at the table feels responsible to make sure that Alaskans benefit from North Slope gas distribution but the bottom line question is whether the state is able to meet the foreseeable need for home heating and power with its royalty share.

MR. HEINZE said the portion he firmly believes the state is responsible for dealing with is in the range of 50 to 60 billion cubic feet per year. That is a very small amount compared to the state's share of several trillion cubic feet. However, regarding all other in-state uses, the arithmetic becomes a bit more problematic, but that is for commercial and industrial companies that are capable of taking care of themselves. His preliminary review says if ANGDA can bring a large supply to this area at a reasonable price, it makes sense for the industrial users to not only continue but to expand to help their own economics. He then alerted members that in one-week newspapers around the state will produce a 12-page report to the people, required by Ballot Measure 3. ANGDA has distributed 150,000 copies throughout the state for inclusion in all major newspapers in Alaska. He hopes it provides a positive view of what ANGDA can do related to gas use in Alaska. He noted that ANGDA will be powering up a website at the same time that will contain all consultant reports and everything it has done in its first year.

SENATOR SEEKINS asked Mr. Heinze if he is aware of any plans or consideration of a liquids line that would go from the Interior to the Cook Inlet area.

MR. HEINZE said he is not aware of any current consideration but when he mentioned that he looked at the right-of-way information on file with the state, the information was for a liquid line from Fairbanks south. That application was submitted a number of years ago. At that time, the parties were having difficulty discussing the cost of shipping on the railroad. Someone decided it was appropriate to look into alternative economics. He believes that design is legitimate.

SENATOR SEEKINS asked if there has been an ongoing discussion about that possibility.

MR. HEINZE said not that he is aware of but he is not in that business.

REPRESENTATIVE GARA recalled the Wood MacKenzie "folks" said, at the meeting yesterday, that contrary to what others have said, the state has a large window of opportunity to secure an LNG contract if it ships LNG to Valdez. He noted that contrasts with people who have said that time is of the essence regarding that sale. He asked Mr. Heinze to respond. His second concern is that Southcentral will always have an increasing demand for gas and no one knows what will be available in Cook Inlet in 10 years, so the amount that will need to come off of a spur line is unknown. He said five or six years from now, when the gas line is more definite, the Cook Inlet supply will be more definite. He asked if companies that are deciding whether to build a gas pipeline will base their decisions on whether natural gas will be offloaded in Southcentral because of an inadequate amount in Cook Inlet and whether they will have to analyze that now.

MR. HEINZE said in regard to the second question, ANGDA has made certain assumptions as to size, cost, volume and other factors and showed the low number of 15 cents per million btu. If that same line moved half the volume through it, the cost would be 30 cents per million btu. If half the volume came all the way from Delta, the cost would be 60 cents per million btu. He explained:

> If we are delivering into this area gas priced at the North Slope that's based upon a transportation distance to Chicago, and we're this much closer, even at 60 cents from Delta here, that is a price lower

than the world price. We have some advantage. Again, I don't know if it's $1.00, I don't know if it's $1.50, but it's a number. And again, we can see that clearly in our work.

What's also very clear is that while we don't know how much will be found in Cook Inlet, we do know it will be expensive. And again, I'll just go back to the statistics. DOE estimated [that] to find reserves to sustain this area would take $5 or $6 billion worth of exploration investment. Why wouldn't you look at a few hundred million dollars for a pipeline as a viable alternative? And again, that's the arithmetic we're lead to is that you don't, fortunately, have to decide right now which way you prefer or whatever, and certainly the spur line does not change the course of the big pipeline and all those other things. We're prepared to tack the spur line into wherever we can find the gas. In the ultimate, you'll see in this report, one of the projects we suggest looking at into the future is frankly going all the way to the North Slope to just supply this area and a bullet line. However difficult that sounds to you at this point, that may be a viable alternative from an Alaskan perspective - that may be attractive. Again, remembering that the advantage of getting gas to tidewater anywhere is that not only do we go through our communities in the Interior, but once we have it to tidewater, we can deliver it to coastal communities, which again, in essence reaches 99 percent of our population. If you can go down the rivers, you go down the highway system, and you can go on the coastal marine transport, you can reach just about everybody in Alaska one way or another.

So, that's kind of the feel we have for the spur line is that I've had producers or people looking at drilling in Cook Inlet and asked me whether they should drill. And I said can you get a good price? And if they answer yes, I say why wouldn't you drill? What are you worried about me for? On the other hand, I wouldn't sit around and wait for ten years to see if we do build a pipeline in and then expect you're going to get the same prices then that you can once there is a large supply hooked to the area.

On the flip side, about this report, again, not to steal its thunder, this is a feasibility at best report - okay? And what we looked at was in terms of the specific LNG project we were asked to look at 2 bcf/day to Valdez basically. Did we see things about it that said stop, don't work on this anymore, quit, this is a bad idea and the answer was no. If anything, we found encouragement frankly. And, for instance, Wood MacKenzie was one of the people, you'll see, was working this. And they, in particular rate, in a cost sense, all the LNG projects in the world. And I mean I will break it to you - it doesn't steal our thunder that we are not one of the low cost ones. But, on the other side of it, we're not so far out the top that it's silly for us to think about an LNG project. For instance, the example I use - the easiest one to understand is Shell Oil Company, a major knowledgeable player in the world, a mega-major, developed a place called Sakhalin, facing a lot of similar challenges to what we face here. If you go to the rudimentaries of that economic decision they made, our decision is probably actually more positive than theirs, I would contend. So, if they thought it was okay to go ahead, that tells me we need to understand our project better and that's all this report says is understand it better.

At the same time, it also has become clear from the consultive reports we've gotten back in trying to understand these projects, that Alaska clearly has some issues. We have some competitive disadvantages. We don't have workers that are brought in from Bangladesh. We don't pay third world wages here. So our labor component on a project that may involve 30 or 40 million man hours of labor is a pretty big factor in this thing and it may affect, somewhat, our competitiveness. And that's something we need to understand because again, I would hope that you all realize that if we were able to design the project in a way that it better fit the Alaska labor pool, such that even if we did have a lot of extra money in the project but it was money that you were comfortable was being spent in Alaska, that might not be all bad. If instead of doing something in one year we took five years to do it and made it happen in that way - that might be considered good by some people. Again, we have to do those kinds of factors in it.

> We are going to be, because of that, looking at other variations of the theme than we were given in Ballot Measure 3. We are going to look at smaller, more Alaskan sized projects and with some other variations that we think might help the competitiveness of the project.

SENATOR LINCOLN said she is anxious to read the ANGDA report and is pleased to hear about the potential take-off locations he listed. She believes that Alaskans must look at what this project can do in terms of delivering some of the by-product of the gas line to the people, not just solely the bottom line of extracting the gas for export to the Lower 48. She noted she is extremely encouraged to see how the take-off points might affect the smallest villages, not just the most populated areas of Alaska.

SENATOR HOFFMAN asked Mr. Heinze to expand on how 99 percent of communities can benefit and whether that will be from the state's royalty share.

MR. HEINZE said ANGDA took a hard look at the fact that Alaska has a small population that would not use a huge amount of energy, compared to the amount that would be shipped to the Lower 48. He said he was trying to draw attention to the fact that a pipeline route that goes through the Interior, down the highway system and intersects with the Yukon River, would reach a large number of people. But, to take that further to bring gas to anywhere on the coast, a compressed natural gas facility could be built so that it could be barged to communities of any size. ANGDA and a contractor are looking at that possibility, especially in the smaller communities, of providing a barge mounted gas supply with a large gas driven electric turbine generator next to it where the village plugs in. He cautioned that is not something that would instantly happen throughout every coastal community in Alaska, but it might within a generation. Regarding the state's role, he said to the extent that ANGDA makes a margin, it has not faced up to what it would do with that margin but it might provide an interest-free revolving loan fund.

TAPE 04-25, SIDE A

SENATOR SEEKINS said if the line was brought in, it would eventually become dominant and have to be designed for expansion. He asked if that wouldn’t have a chilling effect on exploration.

MR. HEINZE replied in reality, if a pipeline were brought in with a large supply at a certain price, his decision to drill would be based on that price. He couldn’t expect to command a higher price. Different companies have different economics, however. It would discourage some, but not others. Because the state has had a surplus supply for many years, it has enjoyed very low prices, about $2.50 MBTU wholesale or about half of what the world price is right now. He estimates that price will rise with more exploration money. If the spur line were brought in at a cost of $300 million that would drive the prices back to what they are today. If one translates that into potential disposable income of residential families, it would equal $100 million a year of additional disposable income.

SENATOR SEEKINS said the demand for that pipe would increase quicker than if there was still a competing force trying to find additional gas sources.

MR. HEINZE said the linkage here will supply a generation or two with a plentiful supply. If some of the bigger numbers presented by Mark Myers (Director, Division of Oil and Gas) were realized on the North Slope, they are talking about many generations of Alaskans.

SENATOR KIM ELTON said he had a comment about the report that he wanted Mr. Heinze to respond to.

> It would have been helpful to have a presentation or a document from you on what those findings or the elements of the report would have been, because we’ve gathered yesterday and today a great number of people with certain levels of expertise and it would have been great to toss the findings that you have into that mix to get their reaction. So, I’m frustrated that you don’t want to steal the thunder of a report that is going to be printed in the newspaper in the next week. If it’s going to be printed next, you know what the report says.

MR. HEINZE apologized, but said the reality is that he had to make a choice. He would have loved to have the release at this meeting, but he didn’t have control over both of their timelines.

> I assure you that all of you as legislators will be given advance copies tomorrow. Every one of you will receive that. We certainly respect the fact that as a number of the important leaders of our state, that you need to know what this looks like before it is widely available. On the other hand, Ballot Measure 3 was an initiative of the people; this is a report to the people and we felt that the proper approach was to find a way to let everybody know at one time and, frankly, not let any one segment of the media gain some advantage or control over what the message was. We carefully thought through a 12-page report and we wanted the message to be holistic and go out and let everybody see it at once.... I will also clarify to you that the report is not a bottom line. The report simply says, 'Here's what we found out and here's what we think needs to be done going forward. I honestly see the report more as a start than a finish of anything....

CHAIR SAMUELS said the committee set the parameters on topics that would be discussed and he had no idea that Mr. Heinze's report would be coming out next week.

SENATOR ELTON observed:

> Having been in the news business, I can tell you that if you don't have every comma in place two weeks before publication date of something like this - and it would have been very, very helpful to have those findings so that we could toss it into the mix – I'd be stunned I guess if they don't know where every comma is in their report at this point in time.

CHAIR SAMUELS announced a brief at-ease before the next presentation.

<u>NEGOTIATION OF STATE AND MUNICIPAL PROPERTY TAXES UNDER THE STRANDED GAS ACT</u>

MR. STEVEN THOMPSON, Mayor, City of Fairbanks, said he is chair of the Municipal Advisory Group (MAG), and that he would give them an overview of MAG and what it has agreed upon so far in resolutions regarding taxes and gas pipeline impacts. MAG was formed to advise and make recommendations to the administration on the anticipated social, economic and revenue impacts of a gas pipeline project as well as on the affect of any municipal tax relief the administration may negotiate in an effort to enhance the economics of a project.

> The group is made up of representatives from communities that will likely be impacted by construction of the natural gas pipeline, including Anchorage, the City of Delta Junction, the City of Fairbanks, the Fairbanks North Star Borough, the City of Kenai, the Kenai Peninsula Borough, Skagway, the Haines Borough, the City of North Pole, the North Slope Borough, the City of Seward, the City of Valdez and representing the unorganized regions, the Tanana Chief's Conference....
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> Today I'm here to talk to you about what's important mostly to our communities. Even though we are a very geographically and culturally diverse group, we have been able to identify many issues that we share similar perspectives on and those are reflected in our first resolution. I believe you have copies of those. We all agreed that no reduction or deferral in municipal taxes is acceptable without appropriate justification from the State of Alaska and the project sponsors. We are willing to help make the project happen, but if it means a reduction in revenue opportunities for us, there needs to be a clear, verifiable justification for it. We have also agreed that the State of Alaska should weigh the cost of benefit of a tax exemption with the difficulty of administering an exemption from specific taxes.
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> We've agreed that the State of Alaska should devise a payment in lieu of taxes structure that provides certainty for municipalities at least through the end of the stated contract period - that the State of Alaska should insure the payment in lieu of taxes structure recognizes the loss to present and future forms of local government of opportunity to respond to changing conditions through changing tax rates, and that the State of Alaska should provide incentives to the successful applicant under the Stranded Gas Act to insure the training and hiring of Alaskans for the construction, operation, and maintenance of the gas line.
>
> One critical point we all agreed on is that the State of Alaska should require that the successful applicant

will include takeoff points at strategic locations along the pipeline to make gas available to meet the reasonably foreseeable demand for in-state natural gas use – that the State of Alaska should insure there will be a fair tariff to the points of in-state takeoff of gas.

Finally, we agree that the State of Alaska should insure that affected municipalities' combined share of the economic rent of [an] approved project should correlate with the revenue stream of the project by negotiating that the present value of the aggregate amount of payment in lieu of taxes is not less than the amount that would have been collected under current Alaska law.

The points of our second resolution are that no property currently taxed under Titles 29.45 and 43.56 should become exempt under this contract. The contract should clarify how dual-use facilities will be taxed in order to protect municipalities' current tax base. No exemption should apply to existing gas infrastructure. Due to the relatively small amount and incredible complexity in administering a sales and use tax exemption, those taxes should not be on the table for negotiations.

Finally, at our last meeting last week, we approved a third resolution that mainly focuses on issues surrounding the need for natural gas in communities all around the state and we requested the administration specifically to include the placement of municipal takeoff points in the rural and urban areas of Interior, Southcentral and Southeast Alaska [and] amend statutes to provide greater assurance that Alaska communities will have access to gas from any trans-Alaska gas pipeline – and that the State of Alaska should retain its right to take the state's royalty gas in kind to meet those needs. This third resolution has been approved by the group. However, there still needs to be ratification by community councils before it is final.

We have also had some great discussions on what shape of payment in lieu of taxes [PILT] might work best for us. Although we all have different tax structures, the municipal advisory group is working together to identify what our similarities are and make as many unified recommendations to the governor as possible. Again, the point I want to make very clear to you right now is that our communities need access to the gas. It is unthinkable that there may even be a possibility of a gas pipeline through Alaska that doesn’t allow us to use some of that gas right here in the state. And yet, for some reason, it’s apparently a point of negotiation in this proposed project application.

The MAG, in our first and third resolutions, made very clear that we expect any gas pipeline project be required by law to provide for adequate takeoff points and spur lines to meet the reasonably foreseeable demand for in-state use. We recommend in our third resolution that you change Alaska statutes to do just that. We also want to make it clear that we want the State of Alaska to insure a fair tariff to the points of in-state takeoff of gas and that the state retain its right to choose to take its royalty gas in kind or in value – as determined to be in the best interests of the state and to change that determination when conditions warrant.

We need to be able to share in the revenue benefits of a gas pipeline. Having said all that, if you have any questions before the Information Insights presentation, I would be very happy to answer them.

SENATOR FRED DYSON agreed with the spirit of what Mayor Thompson said but had a few questions. He referred to language on the last page that reads – be able to share in the revenue benefits of the gas pipeline. He asked if Mayor Thompson thought there should be a formula for the revenue that the state gets from the gas pipeline, similar to the revenue sharing program.

MR. THOMPSON said that is the point that MAG was trying to make.

SENATOR DYSON asked if he was implying that there must be a pipeline to Southeast or that there be a supply system for Southeast.

MR. THOMPSON answered that it means that there should be points from which take-off spur lines could advance. Ports and valves could be put into the line for a future time when a compression plant is built to service Southeast.

SENATOR DYSON asked if he thought there should be a pipeline to Southeast or whether a supply could be barged – not necessarily a pipeline everywhere.

MR. THOMPSON said that is correct.

SENATOR LYMAN HOFFMAN asked why Western Alaska was left out.

MR. THOMPSON said it wasn't left out. One of the take-off points would be the Yukon and areas in the upstream side.

SENATOR ELTON asked if he had identified what the statutory changes should be and communicated them to the governor's office.

MR. THOMPSON replied that MAG got to the point of adopting the resolutions, but not beyond that point.

SENATOR ELTON asked who the governor's office or a legislator would get in touch with to discuss the statutory changes MAG envisions.

MR. THOMPSON said he could get more information on that and that MAG would be adopting more resolutions.

SENATOR SEEKINS asked if he is suggesting that municipalities be able to tax construction of a pipeline on a property tax basis.

MR. THOMPSON replied that under the Stranded Gas Act, the state can exempt properties having to do with the gas line - an office building, for instance, from property tax through the contract period. The municipalities would receive payment in lieu of taxes from the state for that. How municipalities receive that payment is a problem that needs to be resolved. They need to figure out how to deal with a dual use facility as far as property tax goes.

SENATOR SEEKINS asked if the tax bill would be due after completion of the building or during the process. Discussions indicate that the impact would occur now and there is no way to meet the need for additional schools and services, etc.

MR. THOMPSON said MAG is addressing those questions.

> We're looking at the economic impact, which would be during the construction and then the revenue impact of

not having property tax for the length of the contract.... That will be in our reports. I think Information Insights will give you some of the economic impact during construction when he makes his presentation.... The ramp up period of construction is going to have an effect on communities along the construction route clear to Seward. If that's where a pipe comes in, there'll be an economic impact of upgrading their ports to be able to receive the pipe. Kenai could be building compression modules. There could be a big impact there. Influx of pipeline workers is going to definitely increase the need for police and emergency services. The schools part of it is going to be addressed.

CHAIR SAMUELS agreed with what he said, particularly about Alaskans using their own resource and being able to choose between royalty in kind and royalty in value.

I want to just make sure that it has a down side also, that internally your discussion – if you cannot adjust the compression from the North Slope to the distribution center in Fairbanks or Delta or wherever, and you have empty capacity going south, somebody has to pay – it either gets spread over the cost of the remaining gas, in which case at the end point our gas is now the transportation costs are higher and they are already very high or we have to charge more on the front end on the Slope to Delta portion. Internally, I'm assuming that your discussions have been taking place that there's not a line in the sand going - we're not going to pay a tariff one penny more than what it costs to go from A to B if it puts the whole project at risk to pay on the capacity in the pipeline headed south from Fairbanks or Delta.

MR. THOMPSON responded that those conversations continue to take place within the group. They want to make sure the State of Alaska benefits from the gas and not just see it all disappear.

CHAIR SAMUELS said the trade-off would be that you get the gas here, but you lose the cash at the end of the line.

MR. LARRY PERSILY, Department of Revenue, testified:

The state's ad valorem property taxes, which are AS 43.56, apply to oil and gas production exploration property. Just to run through some of the basics for people who may not be familiar with it – it’s generally based on the remaining value of the asset. That would be your value after depreciation. Under state law, it’s limited to 20 mils. The municipalities assess their tax first; the state gets the balance. So, if a municipality has an 18 mil rate, they would get 18 mils; the state would get 2 mils. If the muni is at 15, they would get 15; the state would get 5.

Property tax statute regulations treat pipelines different during construction than during operation. This gets to Senator Seekins’ question. First of all, under construction, the property tax is due from the commencement date of construction. When that pipe hits the dock and the front end loaders are there, the property tax is due – not at the completion of the project. That has been one of the issues certainly in the past and certainly of concern to any project sponsor – that they have to start paying property tax during the years of construction before there is any cash flow from the project. During the construction, it’s the full and true value of the actual cost. Then when it goes into operation, it becomes the economic value, which is based on the estimated life of the proven reserves. So, if you believe you’ve got 30 years of proven reserves, we’re going to use a depreciation schedule for that 30-year life-span of the project and in trying to appraise it – just to back up a minute – even though the municipalities collect oil and gas exploration production property tax, the state does the assessing, which has also in the past been an issue of contention between the state and municipalities. Because, of course, if you’re a municipality and the state is doing the assessing and you’re looking at your revenue drop as the assessments drop, you may think the state is doing a bad job of assessing. There is a state assessment review board that will deal with those cases. Of course, property owners would think the state is doing a bad job of assessing, because it might be too high. So, the state often gets caught in the middle between municipalities who want the assessments higher and the property owners who want the assessments lower.

In assessing pipeline property that’s in operation, we look at the life of the proven reserves; you look at sales comparison, which is difficult because this isn’t a home. You don’t have comps out there as you think of your home assessment. It’s not that someone has sold pipelines in Alaska or sold gas treatment plants on the North Slope. So, doing comps or sales comparison is difficult. Costs – you can get into a debate – what is the replacement cost, which is what state law talks about, not explicitly what did it just cost to build that facility, but what would it cost you today to replace it. And certainly, on older facilities, the replacement costs could be significantly less than what it cost you to build it with new technologies. You can look at the income approach and from all those hopefully come up with the right answer.

As you think of the importance of property taxes to municipalities on this gas line project, certainly there is the impact funding in the construction years as the mayor talked about, as Brian Rogers will discuss. Under property tax law, status quo tax payments are due the minute you start construction and during those years, in many of the communities, you’re going to have the most impact – schools, roads, ambulances, police protection and such. After construction, funding of ongoing general government – that’s what property taxes are for – and that’s going to be an important issue to municipalities who, when they look at this, are looking for certainty as they try working on their budget planning – as they are deciding whether to issue bonds. Are they going to have revenue to pay it off? They need to know with some certainty what kind of revenue stream they are going to have.

This is perhaps just the way the grid was set up – an exaggerated look, but it points out the problem. This is a very conservative scenario. This is based on pure cost of a gas pipeline – no new reserves that would extend the life. So, if you find new reserves that line that declines would hit a new plateau. If you think you’ve got 20 more years, it’s going to level it out and then it’s going to start declining again. It assumes no new investments, which would add to the basis value of that property. But what this points out, and this is an example if you had a $5 billion pipeline, during construction, you’re property tax

> payments increase very quickly and very steeply as all that money is being spent during the five years. At that point then, you now have the basis in your line, you're draining your reserves. Every year the value of that operating pipeline decreases. So, the property tax revenue decreases. As I said, this is a conservative scenario that shows no new investment and no new reserves. So, it really wouldn't be that steep, but it points out the problems for municipalities – you're getting a percentage of an asset that's declining in value, which, if it's your municipality, is maybe not where you'd want to be long-term.

SENATOR DYSON said he suspected the gas pipeline, like the oil pipeline, would have a much longer life than was originally anticipated. "When that turns out to be true, is there a mechanism for recapture and how does that work for the local folks?"

MR. PERSILY replied:

> As the Department of Revenue's assessors looked at the oil pipeline and we looked at extending the life of the line, adjustments are made and the assessed value of that pipeline is taken into account. If it's going to be producing income for a longer period of time, it should have a higher value as you extend it out. So, under law we do make adjustments and change the assessments. It's just like your home – every year a new assessment notice goes out.

SENATOR DYSON said a 15-year longer life than is expected would change the slope of the line considerably. He asked:

> Is there a mechanism to go back and recapture the property taxes that should have been paid based on now a more accurate assumption of the useful life of the line?

MR. PERSILY replied:

> The number doesn't go back up if you can visualize.... You still only had $X billion into the line. The cost basis didn't change. What you're doing now is not so much stopping the depreciation, but extending out. So, instead of going down steep, it might reach a plateau and go close to level and then start to climb again,

> but at a much more gradual pace because you're not going to retroactively change your collections, but you're going to extend your collections for many more years than you had expected collecting more money over the life of the project. But the total basis into it that you're depreciating hasn't gone up, so the value is still, say, a $10 billion line. Instead of collecting taxes for 30 years, now maybe you're going to collect tax for 50 or 60 years.

SENATOR SEEKINS inserted, "But at a low rate."

MR. PERSILY replied, "Right, but cumulatively it's going to be much more than you would expect at the beginning of the project."

SENATOR DYSON added, "And similarly, if the replacement costs go up, that would also change the basis?"

MR. PERSILY answered:

> Sure, you could argue if the replacement costs go up that could be a factor the state would take into account. I can certainly tell you that the owners of the TransAlaska Pipeline, well not so much the pipeline, but the Prudhoe Bay facilities, always argue that the replacement costs go down, because they would argue you could build those facilities today much cheaper than you built them then, because of what they know now as opposed to what they knew 30 years ago. So, I welcome your input, but I think they might disagree. Not surprising.

SENATOR SEEKINS asked what the statute says regarding the administrative codes he's quoting on page 3.

MR. PERSILY read from AS 43.56.060 (d), "'The department shall assess property for the taxes levied at the full and true value January 1' - and this deals with pipelines – 'The first assessment date shall be the construction commencement date.'"

SENATOR SEEKINS said if the legislature wants to change any of that, it has to be done in statute.

MR. PERSILY replied that is correct. Section (b) of that statute deals with construction; section (e) talks about once it's in operation. It says, "the full and true value of taxable property used in pipeline transportation" and then it goes on to say, "economic values based on estimated life of the proven reserves." Technically, economically recoverable talks about, "straight line basis for depreciation over the economic life of the project."

MR. PERSILY moved on to slide 7 and said:

> The commercial problems presented by the property tax in the current form – and I guess these would be commercial problems from the perspective of the project sponsors – front end loaded. As I explained, you start paying property taxes the minute the equipment hits state territory. If you're a project sponsor, you might say, 'Gee, that's a lot of money to pay before I start having cash flow," but certainly from a municipal perspective, that's when you start seeing the impact when the construction begins. You could say it's regressive in that it exacerbates the impact of cost overruns because your property tax is based on the value of what you're putting in there during construction or the basis when you go to operation. If project sponsors are worried about a 20 percent cost overrun on the project, that would mean not only do they have that problem to deal with, which leads to a higher tariff, but if you have a cost overrun, the property tax bill is going to go up.
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> Fiscal uncertainty is an issue certainly for the sponsors. They are not going to know what the property tax rate is going to be – not just the assessment, but the mil rate itself in the future. For the municipalities it's a problem too, as you think about municipal budgeting and wanting some certainty.
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> The uncertainty in the asset valuation is an issue just about every year. There's a lot of money at stake. This isn't whether your home is worth $240,000 or $220,000; this is whether the property might be worth $3 billion or $3.5 billion – disputes whether to use cost income market approach, asset life, capitalization rate. So, these are a lot of the problems that are faced under the status quo that we would hope to deal with in the Stranded Gas Act to help encourage construction of a project and setting up a fiscal system that would be best for the municipalities, too.

Under the Stranded Gas Act in terms of property taxes, first is that obligation that the payments are shared with the municipalities, that the state sets up in the Stranded Gas Act and it's approved by the legislature some system in lieu of the status quo for property taxes. The state is obligated under statute to share that with municipalities who would be losing that property tax ability on their own. It's to be shared with not just the economically affected communities, certainly, but the revenue affected communities. There are two different ones – a revenue-affected community might be someone who is losing the ability to assess property tax revenue on that pipeline. Someone who is economically affected might be someone who is not going to have any of the pipe in their community, but would have an economic impact, for example – if construction equipment is brought in at Haines, barged to Haines and trucked through the highway system to construction sites. Ultimately, when the line goes into operation, Haines will not have pipeline property, but during those years of construction, they're going to have an impact if you're talking of thousands of truckloads of equipment moving across the dock and moving through their community. So, you've got two different kinds of communities, both of which need to be accommodated in the Stranded Gas Act.

You certainly want something that's fair and reasonable with due regard to the size of the tax base that would be exempted under the Stranded Gas Act. You've got to deal with the economic and social burdens imposed by construction and operation in the communities. The Stranded Gas Act also calls on the Department of Revenue to consult with the Municipal Advisory Group in crafting contract language.

MR. PERSILY said the last slide looks at negotiation issues.

Certainly, one key is to improve the project economics. We want a project; you want a pipeline built; that's the whole goal of the Stranded Gas Act. One way you can deal with it, certainly, is the issue of the front end loading, the [indisc.] at the beginning during construction as long as you take into account certainly the strong needs for municipalities during those years, but you want to come up with something that improves project economics, recognizes the municipal issues, deals not just with the certainty for the sponsors, certainty for the municipalities as they budget and the issue of the declining tax base. The fact that under status quo every year in theory, that pipeline is going to be worth less as you get closer to the end of the economic life, impact aid during construction – that's when a lot of municipalities are going to see their highest costs – is during the construction boom. We don't believe it would be as much as during the oil pipeline, but it's going to be significant and as we heard at the last committee meeting from the Department of Natural Resources and the federal geologists, there could be a lot more gas there.

This project could have a much longer life than we're looking at now with just 35 TCF. You want to make sure that what's in that contract protects the municipalities so that if this project runs 50 or 60 years, they're still getting substantial revenue during all that time. And, at the end of the contract, because under the Stranded Gas Act, it's limited to a 35-year contract, you've got to look at what happens that next day. If you've got a 35-year contract, and you've got some payment in lieu of taxes, some mechanism set up and then the next day when you revert back, that needs to be dealt with in the contract rather than just saying you'll worry about it in 35 years.

One other thing to keep in mind is restructuring taxes is not necessarily lowering taxes. Improving the project economics doesn't mean giving away money or taking something away from the municipalities. Restructuring tax in the Stranded Gas Act, hopefully, would improve the economics and also enhance the revenue stream for the municipalities at the same time.

TAPE 04-25, SIDE B

MR. PERSILY, in response to a question from Senator Seekins, related that the Stranded Gas Act negotiators are looking at what is the best way to insure the municipalities' revenue most accurately reflects the economics of the project and the length of the project's life rather than the current status quo, which is tied to a declining number.

REPRESENTATIVE LES GARA asked, "If I'm correct, we've taken roughly $75 million per year in property taxes now, then distribute it to the municipalities from North Slope operations?"

MR. PERSILY responded:

> The last time I looked, I believe the total take of oil and gas production and exploration property tax was around $250 million, of which I think the municipalities get a couple hundred million and the state about $50 million – about 20 percent.

REPRESENTATIVE GARA asked if he could assume the ratio would be similar for pipeline operations and if he could guess at the amount property taxes would bring in during the construction phase.

MR. PERSILY said the state would be involved in receiving payments if there is a new structure in lieu of property taxes, because more of the gas line is going to be on state lands than with the oil line. He guessed that a property tax rate of 20 mils on a $10 billion project would bring $200 million. He reminded them that property taxes are not linked to the economics of a project.

SOCIAL AND ECONOMIC IMPACTS OF A HIGHWAY ROUTE GAS PIPELINE

MR. BRIAN ROGERS, principal consultant, Information Insights, Inc., said his report is really a work in progress. Information Insights was contracted by the MAG to look at the social and economic impacts of the gas pipeline, both construction and operations with a real focus on what it does for local governments, to look at the revenue impacts to municipalities under the Stranded Gas Act and to look at subsistence and cultural impacts to villages and local governments as part of gas pipeline construction. His focus is on the producer's application only and, to date, on just the gas pipeline portion, not the gas treatment plant or the upstream facilities or any in-state spur lines.

> As some background, just thinking about the TransAlaska Pipeline System (TAPS), the TAPS was a far larger project in its impact on Alaska - if escalating

those costs over today - larger than the total cost of the entire line and almost four times the size of the Alaska segment and that impact is placed on an economy where the population is doubled and it’s a far more robust economy than we had in the early '70s.

However, TAPS gives us some ideas as to what the impacts are likely to be. Looking at the pipeline corridor under TAPS, affecting the North Slope Borough, the North Star Borough, the Interior villages and Valdez, the impact on schools was lower than most expected. The workforce development was late in starting – very little effect. On public safety – very significant impacts – high staffing turnovers. As staff went to work for the pipeline construction, wages skyrocketed – municipal wages up 40 percent over a two-year period. Some increases in criminal activity, basically indexed pretty much to populations increases. Huge increases in road usage, both from the population and from the project and those road usages weren’t just on the primary industrial routes. In the health care – significant issues for the private sector – very little in the public sector for health care. Real improvements in health care availability occurred during that period. Acute housing shortages, particularly in Fairbanks and Delta, Valdez, right along the pipeline corridor - utilities were way overburdened. I expect Senator Seekins remembers the comment by the municipal utility system in Fairbanks in 1974 when they said they ran out of telephone numbers and it would be two years before they could get any new ones ready. It was just a way overburdened system.

Over the three years, household income went up almost 60 percent; there were cost of living increases as well over that period of time and population impacts significant throughout the corridor. Delta Junction’s population up by over 25 percent, Valdez - 76 percent increase, the Fairbanks North Star Borough – relatively low at 15 percent. Most of that focused in the city. The City of Fairbanks went up by 75 percent over that period.

But the impacts were felt outside the pipeline corridor. In Southcentral Alaska, you saw the Kenai population go up by a third over that period of time -

Anchorage population up by 15 percent. There were significant transportation challenges during the TAPS construction that affected areas throughout the state. This timeline is looking at 1973 – 1977. There was even more impact post-construction. If you look at cumulative impacts of oil and gas production, the big impacts happened once the state started spending money it was receiving once the line was completed and we saw the oil price increase of 1979. That ’79, ’80, ’81 period had even more impacts, particularly on education, but also on a lot of the other municipal services and state services.

Looking at the gas pipeline as we’ve looked at the socio-economic impacts, we’re focusing right now on what are the issues relative to population growth, what requirements are there for workforce development, how does it affect municipal and state infrastructure, what are the impacts on law enforcement and emergency services, impacts on education – although we expect those to be fairly light, health and human services and some other municipal impacts. Our study is based on the application data from the producers, which looks at construction costs, schedule, logistics, workforce and materials shipment and the infrastructure requirements that the producers have laid out. However, there is certain information that just isn’t there in their conceptual model – where certain construction and support activities take place, where they would spend by community, which really causes the impacts on the communities, or a hard timeline. The starting date in their application depends on action at the state and federal level.

We’ve had some challenges with the impacts of confidentiality. We have had access to confidential data and we cannot release any of that confidential data, but some of that drives some key assumptions – things like where is the freight movement, what’s the construction process, where are the camps and when are they operating and what are the costs of some of the components. We’ve used those to build our economic model, but those underlying assumptions - so far many of them are confidential ... we’re trying to make the model more transparent.... We can estimate some of the regional impacts, but can’t talk very much about exactly where those occur, because it might allow somebody to sort of reverse engineer what the confidential data would be.

This project schedule is one that was contained in the producers' application, however, I've added years to it - that is if we assume that the governmental frameworks were in place by the end of 2004, when do the activities take place....

[He then explained the chart.]

Permitting completed by 2008, procurement for the project beginning in '09 and preconstruction activities beginning in 2009 with full construction starting in 2010 and going through 2013, the actual delivery of gas at the beginning of 2014. This is based on their conceptual model without any changes based on their 2001 study. There may have been changes in their thinking since then, but that isn't available as part of their application.

Based on what information we have and looking at population impacts, we see about a 12,000 increase net to Alaska population over the three-year construction period. Some increases in services required by local governments for that population and that increased population and the other activities drives some other impacts in addition to population-induced impacts, which would be those that are wage inflation issues.

The net effect of the population based services throughout the Railbelt and the construction corridor and the areas that serve the construction, we've estimated at $21 million in direct costs to local government over the preconstruction and construction period from those impacts that are population-driven.

The second general area is workforce. If we look at direct and indirect and induced on an annual basis, an increase of about 8,500 jobs with some very significant opportunities for local hire during the construction.

SENATOR HOFFMAN said a population increase of 12,000 seems low compared to TAPS impacts.

MR. ROGERS replied that it does intuitively feel low, but TAPS was far bigger as a project and there is a lot more opportunity for local hire and contracts, which means less in the way of new population coming in. If the local hire efforts don't materialize, the impacts and numbers would go up.

> On the workforce, the seasonal factors and the long lead time that we have – if you look back at that schedule with preconstruction beginning in '09 – there's a lot of time to address workforce training between now and then to assist the industry in keeping the impacts of new population down and assist Alaskans in getting the primary benefits out of the construction process. We won't get all of the benefits obviously, but there will be some significant ones. Some local government costs in dealing with workforce development – primary activities here, though, we anticipate will be the industry, state and federal governments – and our focus is on the municipal impacts.
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> To give a sense – one of the things that is available in the public data looks at the overall sequencing of the craft trades during construction and the conceptual model assumes peak workforce in the winter months – actually January through March – is the peak period line wide. If we look from Prudhoe to Alberta – we don't have the data that's exactly to Alaska, but looking at line-wide and taking a proportion and looking at what the impact would be if you added it to the current construction workforce.
>
> This chart takes from the Department of Labor the construction employment in Alaska in 2003 and lays onto it the additional craft trade workforce that would be required during a typical year of construction. What you can see is there's an increase in the construction workforce in those winter months when there's a lot of unemployed Alaska construction workers who potentially could take advantage of many of those jobs. There's a second peak in the summer, which is a challenge, because that's right on top of our existing peak. This does not take into account any of the support activities. This isn't camp staff, contractor support, or any of the logistics materials moving. This is actually just the craft demand, but just looking at the proportion of it that is in those

> winter months and thinking about the structure of Alaska's existing construction, there are some great opportunities to use Alaskans for that and that then minimizes the need to import workers.

SENATOR LINCOLN said her concern is that outside workers are continuing to be imported for the existing pipeline rather than hiring Alaskans. Yesterday she heard that a contract can't state a percent of residents to be hired because it's illegal. She asked what he proposed to do to leverage the state's position to use state businesses and workforce.

MR. ROGERS replied that Information Insight's role is to develop specific policy level mitigating measures for that. There may be ways to set targets in the negotiations and have certain provisions take effect if those targets get reached. He was sure there would be other measures.

SENATOR LINCOLN asked if he had seen the hard numbers from the TAPS in terms of where we are today.

MR. ROGERS replied that he had looked at existing apprenticeship programs in Alaska today and how long it takes to complete by craft.

> Most of them, if we start soon, we are in a position to graduate sufficient journey-level workers to address many of the crafts. There are some crafts for which the skill level is beyond a beginning journey level and we can't get there. There are several skills that just aren't out there. An example cited by the producers is the equipment that will be used to lower the pipe into the trench – that's equipment – they'll be using more equipment on this line than exists in the world today and two to three times as many operators for that size as there are out there today. So, there's got to be a major training effort. The question there is how much of that is going to be Alaska-trained and non-Alaska-trained.... If we train Alaskans for skills that are good for one project that won't be replicated, what do they do post-project? They have to look elsewhere to find work with their skill level. So, there's a balancing act there. We don't assume that 100 percent hire is going to be possible even if we had all the training funds in the world.

SENATOR ELTON observed that one of the impacts he saw from TAPS was that people were leaving jobs in other communities around the state for higher paid pipeline jobs and the communities had to import people to fill their jobs.

MR. ROGERS replied that economically speaking, the higher paying jobs would offset the entry-level jobs that would be created by people moving up.

SENATOR SEEKINS echoed Senator Elton's concern and said that local hire requirements can have a negative affect on his business in Fairbanks, because his people are recruited and he has to go out and find qualified people and train them.

MR. ROGERS answered that some of those things balance out. A more complete socio-economic study would have to address those impacts on the private sector. The seasonal chart indicates that income may flow to families in terms of a member being able to work year-round as opposed to just eight months.

REPRESENTATIVE GARA asked what kind of population increase he envisioned if the local hire efforts can't be controlled.

MR. ROGERS replied that he hadn't calculated those impacts, yet. A poor effort would require more recruitment and hiring from out of state, which might have a secondary impact. People could hear there are jobs and move here.

CHAIR SAMUELS remarked that another impact to the private industry is that wages for local businesses will have to go up.

MR. ROGERS replied that would happen, but he estimated that it would be far more moderate than during the oil pipeline construction, although Delta and Tok might have those hyper-numbers.

> Transportation infrastructure is the single largest cost item. That has to do with the size and weight of the project loads that will be traveling on Alaska's transportation infrastructure. The volume of the direct traffic that's part of the project, as well as population induced traffic in the villages and off the main road system, issues of dust mitigation and the need for railroad improvements.
>
> When you think about Alaska's infrastructure – the major routes for freight coming into the state – ports

of Anchorage, Whittier, Valdez, Haines, Seward – we have the railroad, potentially Skagway all impacted during construction, barges into Prudhoe Bay, the Alaska Highway at the Canadian border – significant freight movements across all of these. In addition, potentially, Kenai, depending on competitive bidding for modules, Kenai and Anchorage numbers could vary significantly.

We've looked at the transportation maintenance needs affecting local governments and villages and estimated those maintenance needs at $14 million over the period of construction. That's a very low number because the biggest challenge comes post construction in any rebuilding that needs to occur. We're still working on how to get at those numbers, but this portion really focuses on what's needed in a construction payment in lieu of taxes to assist local governments.

In addition, we've got some major state transportation infrastructure – a series of highways and bridges in the Port of Haines, totaling $265 million. If all of that is federal aid available, that's $26 million state appropriation toward those highways and they need to be in place by 2009. So, in order to get them in place by 2009, that's going to affect the state transportation improvement plan and the municipal impact of that is it pushes back some projects that people would like to see sooner rather than later to the extent that the state chooses to make this infrastructure available. The industry has said that these really deal with load factors – some bridges. There are a couple that are height factors on overpasses and this is a core level that has been publicly released. There may be other roads, bridges, highways, ports in addition to this that would require some enhancement prior to construction.

MR. ROGERS said for a sense of TAPS impact on road usage, he picked a small street closest to his office in Fairbanks called Wendell Street. The preconstruction rate was about 10,000 vehicles per day and peak construction rate was about 18,000 per day. There would be similar, but smaller, increases throughout Fairbanks, Delta and certain areas of Anchorage. Part of it is traffic diversion from the highways that have the industrial traffic and part of it is just population induced.

Law enforcement emergency services – we're basically dealing with crime, traffic, subsistence resource protection. We looked at both increased state trooper presence and local police and VPSO. In addition, increased use of emergency services for both paid and volunteer fire and ambulance departments. Assuming that a portion of this is troopers, $20 million in costs to local governments, $4.5 million to the state. If the troopers aren't there, it will be a higher cost on local government and VPSO.

MR. ROGERS said the education increase is relatively minor. During the oil pipeline, for every 47 workers, there was one additional student. Increases in state funding as well as local contribution add up to $13 million.

Health and human services are relatively low, about $4 million. Health needs and emergencies are covered in the camps. About $12 million in wage inflation is estimated to vary by community. Subsistence issues, including village liaisons, subsistence research and monitoring preconstruction and during construction, for a total of $5 million.

MR. ROGERS said this all totals about $125 million for the preconstruction and construction periods from 2007 to 2014. That compares to $202 million that would be paid from property taxes. However the bulk of those taxes are paid in FY 2014 when construction is completed.

The challenge is that while the numbers are relatively comparable, if you exclude that amount after construction is completed, the municipal impacts hit before the tax impacts would be there and they hit differentially. The City of Fairbanks has no pipeline within city limits, but is one of the most impacted cities. So, a pure tax regime does not address the social and economic impacts. In addition, in the unorganized borough, there is not a way of addressing those needs today. Of those impacts, about $84 million would be the municipals' share and $41 million the state's share, which really is focused on the roads, education and on police.

There are some offsets to these municipals costs. New construction of property that won't be tax exempt – warehouses that aren't direct pipeline – that drives some new revenues to municipalities. It can be used as an offset. We’ve got a little more work to do to complete those offset numbers.

I’ll run quickly through the subsistence impacts and socio-cultural. The issues there really have to do with how does a project impact the availability of resources, the access to those resources and competition for the resources. Federal law would require certain mitigation measures and some monitoring and enforcement of those impacts. In the North Slope, those impacts would have to do with access, competition and disturbance - some cumulative impacts. North Slope impacts will be greater than what we’ve cited here because this does not include a gas treatment plant or upstream facilities, also impacts in the northern Interior and upper Tanana villages in terms of competition for resources, harvest levels and some cultural resource issues in the Interior.

The activities that affect those have to do with new road construction, truck traffic, the activities around a construction camp, and those things that happen during development or during some of the upgrades required to our infrastructure.

In total – impacts on villages – wage, employment, changes of structure of villages during the period of construction with a shift in focus from subsistence activities. If the population that would have been out hunting this week are instead working for wage income, there’s less resource to share with elders and others. We see some population shifts as occurred during TAPS and just as in the urban areas, some changes in the social fabric with effects of drugs and alcohol as there is more cash income.

Finally, some management and regulatory issues are out there. To close, our work is focused on the municipal impacts. We’ve just about finished the work on the gas pipeline portion, working on the gas treatment plant. Upstream, as other applications come in, their impacts may be different from those of the producers’ pipeline. We’d possibly also be looking at those.... Our final report [is] due to the MAG at the end of September.

SENATOR LINCOLN referred to the population chart and asked him if he had considered the shifting population in-state.

MR. ROGERS replied that his model looks at net impacts in each region based on the producers' conceptual model and he couldn't be precise about the effect of additional regional movement.

12:10 – 1:15 – recess

CHAIR SAMUELS called the meeting back to order and the committee moved to the next presentation by Robert Cupina, Deputy Director, Office of Energy Projects, Federal Energy Regulatory Commission (FERC), and John Katz, Assistant General Counsel for Energy Projects, FERC. Chair Samuels informed members that Mr. Cupina's office is responsible for processing applications for the construction and operation of interstate and international natural gas facilities including LNG and licensees for non federal hydro-electric projects as well as managing the dam's safety program. Mr. Katz is senior counsel at FERC where he specializes in hydroelectric licensing and natural gas pipeline certification matters.

PANEL DISCUSSION ON THE REGULATION OF GAS PIPELINES, GATHERING LINES AND PROCESSING FACILITIES

MR. CUPINA said that natural gas is a critical component of the nation's energy mix and informed members:

> The Department of Energy predicts that growth and demand over the next several decades will require a significant increase in gas production and delivery capacity. Supplies from the Lower 48 sources, imported LNG and Alaskan gas, will all be needed to meet projected demand. An application to construct and operate an Alaskan pipeline may be filed with FERC under either the Alaska Natural Gas Transportation Act (ANGTA) or the Natural Gas Act (NGA). We have no application before us right now and we would encourage sponsors to make a single filing to avoid time-consuming duplicative processing and potential litigation. Whatever form a proposal to us takes, we are positioned to review such a project comprehensively and expeditiously so that gas can reach the market in a timely fashion. Alaska gas pipeline provisions in the national energy bill will ensure such timely completion by clarifying that NGA proposals, to compete with ANGS, (A) and (D) be

considered by providing that FERC is the lead agency and by imposing strict processing timeframes.

So, our comments today and our answers are based on the commission's current competitive market non-subsidization approach to major new pipeline projects. These open-access policies under which shippers are able to buy gas directly from production areas and separately obtain transportation capacity on interstate pipelines should serve the interests of the state of Alaska as well as of all other shippers. At the same time, we are mindful that the size, scope, and importance and uniqueness of an Alaskan pipeline as well as certain provisions in the National Energy Bill may call for some variance in that approach to insure its development.

SENATOR GRETCHEN GUESS said that it has been implied that FERC doesn't consider rolled-in tariffs, but only considers incremental tariffs and asked if he could comment on that.

MR. CUPINA replied:

For a new pipeline, we'd just be talking about an initial rate. So, at that juncture you're not really talking about rolled-in or incremental. It's usually when there's an addition to that system or some expansion that the issue of how to recover the cost for that expansion arises. The policy has been in general for an expansion – we would consider rolling in, in fact we require rolling-in when [END OF TAPE 04-25, SIDE B]

TAPE 04-26, SIDE A

MR. CUPINA continued:

The new rate would be higher than the existing rate that is incrementally priced. So, there's roll-in when it benefits the existing shippers by lowering their rate.

MR. KATZ added:

As you probably know from reading [the proposed federal energy bill] and its impacts with regard to expansion and other issues... the draft energy bill

> required that if the commissioner was going to require an expansion of an Alaska gas pipeline, that it was required by the proposed law to insure that the rates established would not require existing shippers on the pipeline to subsidize expansion shippers. So, that is fairly consistent with the commission's existing policy.

CHAIR SAMUELS asked if the ability to roll in tariffs could be contracted away. "If in the Stranded Gas Act between Alaska and the applicant wanted to have rolled in tariffs, how would FERC view that?"

MR. CUPINA asked if he was talking about all expansions.

CHAIR SAMUELS replied yes – just in the instance:

> Let's say that the price was going to increase the tariff, not just decrease, could it be contracted away or how would FERC view the ability to contract away the ability to have incremental tariffs as opposed to mandating rolled-in tariffs?

MR. KATZ replied that it depends. The right to not have rates increased is a right of the existing shippers, not a right of the pipeline. He realizes that in some scenarios in Alaska the shippers are the pipeline, so that might be different than a typical case.

> In a typical case, I don't know that the commission would allow the pipeline to contract the rights of shippers. In a case where the shippers and the pipeline have the same identity, it might view it differently.

CHAIR SAMUELS indicated there were no further questions for FERC and said that Margery Fowke would testify next.

NATIONAL ENERGY BOARD'S REGULATION OF THE CANADIAN SEGMENT(S) OF AN ALASKA NATURAL GAS PIPELINE

MS. MARGERY FOWKE, National Energy Board, Canada, said she would speak on two matters with respect to the board's jurisdiction of practice – those are incremental and rolled-in tolls and the board's ability to order expansions of facilities in certain cases.

I thought I'd spend a few moments to talk about the board's mandate and jurisdiction and processes for anybody who might not be familiar with the National Energy Board (NEB). The board has both regulatory and advisory responsibilities, which have changed little since our inception in 1959. We have jurisdiction regarding the certification of pipelines, tolls and tariffs, construction of pipeline and ongoing safe operation of the pipeline and the ability of the board to require a pipeline company to provide facilities for other shippers. The board also regulates the export and import of natural gas and oil, the export of electricity, the construction of international power lines, the exploration on federally regulated lands - that's offshore and north of 60, and the board provides advice to the federal government of Canada. It's not that it's an exhaustive list, but it's the highlights of what we do.

This map shows generally the natural gas and oil pipelines that are regulated by the board, the ones in Canada, of course. The board regulates over 27,000 miles of pipelines, inter-provincial and national pipelines. The board is a quasi-judicial tribunal with all the powers of a court of record. We have nine full-time members and the Act provides for temporary members as well. We currently have eight full-time members. A quorum of the board to sit on most hearings is three members and the process at a board hearing would be similar to what most of you would be familiar with – witnesses are sworn, they're cross examined by parties of opposing interests, the board counsel and the board ask questions and then there's final arguments at the end of the hearing.

When an application for the construction of a pipeline is filed, the Act requires that we have a public hearing and that that hearing be oral. Section 52 of the Act sets out some of the things that the board must consider when we look at an application for a pipeline such as supply, markets, economic feasibility. With respect to economic matters, one of the main focuses of the board right now is with respect to third-party impacts. In addition, one of the main issues these days is environment. With respect to a pipeline of interest to you, the Canadian Environmental Assessment Act would apply. There would likely be a joint review panel, which would involve territorial, federal, including the national energy board and aboriginal representatives. I can’t say with any certainty what the process would be for an application that could be filed for a pipeline coming out of Alaska, but I can tell you that the model that is currently being used for the Mackenzie project is that there is a joint review panel, which will consider the environmental matters. The board has one member that’s appointed to that panel and I believe there are eight members on it.

The board at the same time will conduct a hearing into all matters within its jurisdiction and will incorporate the joint review panel with respect to environment. The member that’s on the joint review panel will report back to the board on it. Once all of the hearings are complete, if the joint review panel allows for it and the NEB is of the view that it should be approved, then a certificate of public convenience and necessity would be issued. This allows the pipeline company to construct the pipeline and operate it.

In terms of our working with FERC, the board has recently entered into a memorandum of understanding (MOU) with FERC and I’ve provided that at tab 3. The parties recognized that it’s in the public interest to coordinate their efforts, that there may be cases where coordinated reviews may be considered, that timing should be coordinated and the parties agree to notify the other party if there is an application to it where the matter is being heard by the other tribunal.

I’d like to move to toll regulation by NEB. When new facilities, either greenfield or an expansion, are being applied for, the board usually considers tolling matters at the same hearing. The requirement in the Act is that tolls be just and reasonable and that they be charged equally to all persons for traffic of the same description over the same route in substantially the same circumstances. That is in section 62 of the board’s act.

The board can set tolls using a number of different methodologies. We can use the traditional cost of service methodology or any other to set tolls ourselves. Tolls can also be negotiated or they can be subject to a settlement. The board is very accepting of settlements. We have settlement guidelines, which can be found on our web and they require that all parties have a chance to participate in the settlement. A settlement can provide for unique and different arrangements and most new construction of pipelines in recent history have had tolls that are either negotiated in part or subject to a settlement. The only requirement the board has is that we be able to find that the tolls are just and reasonable. Pretty much everything else is up for grabs.

The board has broken down the pipeline companies that it regulates into two different groups. Group 1 companies are the larger companies, such as TransCanada Pipelines Ltd., Westcoast Energy Inc. and Enbridge. Group 2 companies are the smaller pipelines and they are regulated on a complaint basis.

I was asked to address the frequency of toll hearings and whether the pipeline has the option or the obligation to refile its tolls in the face of declining costs. The frequency of toll hearings really varies. For some group 1 companies, if they can’t come to a settlement with their shippers, it’s virtually an annual event and that’s the case with TransCanada Pipelines – the largest pipeline that we regulate. They are right now pretty much annually before us.

At any time after a board decision, the pipeline or an interested person can file a request for a review of the board decision. One of the grounds for the review is changed circumstances. So, if there were declining costs, a review application could be filed with the board. The board would then have to examine it to determine whether a review should be held and, if so, whether the previous decision needs to be changed. Some pipelines have multi-year settlements and in such a case, we wouldn’t expect the company or the participants to be back before us during the term of that settlement. In the settlements, usually changes that could come up through the term of the settlement are taken into account by some cost sharing factor or risk sharing factor. If the parties to the settlement were to agree that they needed to reassess the settlement in the middle of the term, it could be done and it is right now being done in one of the oil pipelines. I think, as well, my view, if you are in the middle of a long settlement and it could be shown that the tools were no longer just and reasonable, that you would have an argument to come back to the board and have it look at the settlement again. The onus would be on the party trying to bring the settlement back towards the board to show that it should be changed and that the tolls are not just and reasonable, but I think it could be done.

If you're talking about a group 2 company, they're regulated on the complaint basis and if there is a third party shipper, tolls have to be filed with the board, but it doesn't examine them to any great extent unless there is a complaint filed. So, if there were changes in the costs to the pipeline and a shipper wanted to file a complaint to request that the board look at those tolls, the board could do it at that point in time. So, in short, while there's no obligation on a company to file new tolls in the face of declining costs or any other change circumstances, there are means by which the pipeline or another interested party could bring the matter back to the board for consideration of the issue. As well, the board could of its own motion bring the matter up for discussion.

I'd like to turn now to the question of rolled-in versus incremental tolls. Let me start by saying that there are no rules at the NEB on this issue. There's nothing in the Act; there's nothing in the regulations and we have no policy that we have issued with respect to rolled-in versus incremental tolls. There are some past decisions where the board has considered the matter, but I'd like you to note that we are not bound by past decisions and, in fact, we must consider every relevant issue in a new hearing. So, we can't rely on past decisions alone. We have to reexamine issues. I'd also like to note that the seminal cases in this issue were in 1987 and 1989; so there's not a lot of anything recent.

Any expansion of a pipeline out of Alaska would be fairly far down the road and we all know, there's a lot of unanswered variables that could be at play. We also don’t know what the regulatory environment would be. I’ve seen a lot of changes in my time at the board; I foresee that there will be changes in the next 10 to 15 years. I can’t tell you what the board would do with an application at the time of an expansion in terms of rolled-in versus incremental tolls, but I can tell is what the board’s past decisions have said and I can tell what some of the considerations that the board has taken into account in making those decisions.

There have been a number of decisions, but unfortunately for our purposes, none of them are particularly recent. I’m going to focus on GH-2-87 and GH-5-89, which are TransCanada hearing decisions and those are the most helpful decisions on the matter. I’ve also included references here to the Westcoast Energy Inc. decisions, but Westcoast is a very different system. It includes gathering lines and processing plants; it has historically had a much different tolling regime with a lot of specific tolls for specific services. So, the Westcoast decisions aren’t particularly helpful. I’ve included the references for some oil pipeline decisions – Interprovincial Pipe Line Inc. and Trans Mountain Pipe Line Company Ltd. are both oil companies – and I’ll briefly touch on those. All of the board decisions are on the website. The last two numbers in the decision are the year of the decision. So, GH-2-87 was a hearing that started in 1987. I’ve included behind tab 4 some excerpts for our decisions from GH-2-87, GH-5-89 and GH-5-94, the Westcoast decision.

I’d like to discuss the specifics of just a few cases and what I think are the board considerations that run through these decisions. In GH-2-87, it was a TransCanada facilities application. The board decided that the rolled-in method of cost allocation and toll design would be appropriate for the proposed facilities. The board looked at practical and legal considerations. The board made it clear that existing customers do not possess acquired rights to enjoy the use of the older facilities at lower embedded costs. The payment of tolls in the past did not confer any benefit beyond the provision of the service at that time. The board didn’t equate those who paid with the service with those who paid for facilities. The board also endorsed the concept that TransCanada is an integrated system. In the board’s view, the new facilities contributed to the capacity and integrity of the system as a whole. Therefore, the board determined that the toll should be charged on a rolled-in basis. However, the board also found that if the services required by only a limited number of shippers and the facilities could be separately identified from the integrated rate base, that the principals of cost-causation and user pay would apply to insure that there was no undue cross subsidization by other toll payers. Therefore, in this hearing, GH-2-87, the provision of additional delivery pressure at any delivery point would be recovered through stand-alone tolls.

In GH-5-89, which was the biggest TransCanada expansion that we’ve ever considered, the board considered the rolled-in versus incremental tolling methodology. The board reaffirmed its findings in GH-2-87 that the previous toll-payers have to acquire rights. They can’t be exempted from a toll increase simply because they paid tolls in the past. The board found, again, that on completion, the facilities would be integral to the TransCanada Pipeline system. It looked at cost causation and found that the aggregate demand of all shippers gives rise to the need for additional pipeline capacity. The board looked at economic efficiency and stated that rolled-in tolls would send appropriate price signals. The board found that incremental tolls would create economic distortions because existing shippers would not be exposed to the appropriate market signals. The board was of the view that the magnitude of the expansion didn’t justify changing the methodology nor did the riskiness of the market. It stated that factors such as size, cost of impact on tolls might be factors that the board would take into account when determining whether or not to authorize the construction of the facilities, but they didn’t justify discrimination among shippers on the basis of when they commenced or would commence paying tolls.

The one Westcoast case that I did want to mention is GH-5-94 and in that case, the board found for rolled-in tolls placing significant weight on the extent to which the proposed facilities would be integral to the

Westcoast facilities in that specific area. The board stated that in its view shippers didn’t pay for specific facilities; they contracted for specific services.

There are a few oil pipeline decisions on rolled-in tolls. In all of the Interprovincial Pipe Line decisions, the board found that the toll should be stand-alone, not rolled-in. This was based on the fact that the facilities would only be used by a small number of shippers. Not all of the shippers are not all commodity groups. Therefore, the principles of user pay would be best reflected by stand-alone tolls. The board found there is no unjust discrimination in shippers, because all those using the specific services were being treated the same way. The board also noted the need to minimize cross-subsidization and to allow for business decisions to be made on the basis or appropriate price signals.

The Trans Mountain decisions that I referred to allowed all or part of the expansion to be rolled-in where it found the facilities would be for use of all of the shippers or where it would enhance the overall efficiency of the entire system.

So, from all of these decisions, I’ve pulled what seemed to be in my view, the important considerations that the board has taken into account. I would stress to you that this is not a board pronouncement. The board has not issued anything on it. I would also point out to you that although the board has stated in numerous decisions that it supports the principles set out in the GH-5-89 decision, any time the issue of tolling methodology comes up, it must be addressed on a case-by-case basis.

The second matter that I was asked to focus on was the ability of the board to order the provision of facilities. Subsection 71(3) of the NEB Act allows the board to order a company to provide adequate and suitable facilities for the transmission of, in this case, gas. There are two tests in this action; the board has to consider it necessary and desirable to do so in the public interest and the board has to find that no undue burden will be placed on the pipeline company by requiring the company to do so. This section has been very infrequently considered.

The few decisions that we have had that consider this section don’t provide much guidance for us on how the board would consider an application now. I’ve provided the excerpts from these decisions behind tab 5. In the first case that I could find, GH-3-86, the board considered an application by Cyanamid Canada Pipeline Inc. to construct facilities to require TransCanada Pipelines to provide interconnection facilities. If you look at that decision, you’ll note that they’re talking about section 59 instead of section 71 – just a change of numbering the late ‘80s. The board found that the application by Cyanamid to construct its own facilities should be approved and that the approval would have no significance if the board weren't prepared to grant the interconnection. Therefore, the board found the interconnection to be in the public interest and found there would be no undue burden on TransCanada. That’s just about the extent of the board’s reasoning. It was very short on the section 71 issue and doesn’t provide as much guidance on the matter. It’s also the only case I could find where the board actually ordered the interconnection of facilities.

In MH-2-88, the board was considering both subsection 71-2 and 71-3; 71-2 is the ability of the board to require a gas pipeline to receive, transport and deliver gas. In this case, the board found that the pipeline company could transport the gas with the current configuration of its system and therefore, it found it unnecessary to order a 71-3 to construct additional facilities.

In GH-4-91, it was again a TransCanada facilities application and the board heard an application under 71-3 from a prospective shipper to provide services and facilities. The board was not convinced that the applicant had demonstrated need for the facilities and therefore denied the 71-3.

Finally, in GH-3-96, it was again an application under both 71-2 and 71-3. The pipeline company was opposed to providing the service, but admitted on the stand that it could do so without additional facilities. The board told them that they had to provide the service, but didn't require them to construct any facilities under 71-3.

So, the important considerations that I take from those four cases are that first, there must be a clear demonstration for the need for the facilities and second, that the transportation can be provided by the pipeline company on its existing facilities, the board will not order new facilities to be constructed. There has been no discussion in any decision of the tests that are in 71-3. In my view, if an application came forward now, the board would have to be looking at what those tests are and what they mean and there would probably need to be some discussion of them. I know in recent hearings where there has been discussion on the record about 71-3, there has been quite a bit of debate about what the tests mean. The board has not found it necessary to discuss in any reason. So, we don't know what the board's view is, but we do know that there has been a lot of discussion on it.

That's all I was intending to present today. I hope it has been of some assistance to you....

CHAIR SAMUELS said he would eventually have a lot of questions on how the two regulatory bodies, FERC and NEB, work together when the pipeline crosses the border, but he wanted to continue with Dave Harbour.

MR. DAVE HARBOUR, Chair, Regulatory Commission of Alaska (RCA), introduced Judge Jan Wilson, Administrative Law Judge, RCA, who specializes in the application of oil and gas pipeline regulations, particularly under AS 42.06.

With your approval today, what I'd like to do is offer our panel participation as citizens. The reason for this is the decisions we make and the statement we make in public are the product of due process hearings and a legal record. So, we don't for a moving target like this express approval on the commission on what we say. We'll do our best to help today with your deliberations. Our goal is to provide you with this brief opening statement and then attempt to personally help with the questions you may have.

Bonnie Robson advised us today that we'd be talking about general regulatory issues affecting the Alaska gas pipeline. I think the statements you've got are going to be most to the point of the interests of this committee. However, I think I can provide a few points that might assist and round out your understanding.

First, the Alaska Pipeline Act establishes our commission's pipeline jurisdiction throughout the state except as it might conflict with federal jurisdiction. The legislature specified in AS 42.06 that the Alaska Commission has jurisdiction, 'of intrastate transportation of North Slope natural gas through a North Slope natural gas pipeline.' So, that is there.

Second, in chapter 15 of USC 15, we find language dealing with the regulation of interstate pipelines and a special note that federal regulation and matters relating to the transportation of natural gas in interstate and foreign commerce is in the public interest. So, that will be regulated by the federal government, but the jurisdiction is limited and does not include, 'local distribution of natural gas or to the facilities used for such distribution'. Federal jurisdiction also doesn't apply to 'persons engaged in the transportation in interstate commerce or the sale in interstate commerce for resale of natural gas received by such person from another person within or at the boundary of a state if all the gas so received is ultimately consumed within the state.'

Number three – jurisdictional decision. Where specific projects are involved, federal and state regulators are similarly situated. That is to say we can't make findings and issue decisions except when we have real applications, fact finding, a complete record, and an opportunity for all parties to have their due process. I think all the regulatory agencies that you hear from today have that type of a concept in common....

The RCA and the FERC have anticipated that an Alaska gas project could produce jurisdictional questions and we've created a memorandum of understanding (MOA). It's very similar in wording to the MOA in the pack Ms. Fowke handed to you from the NEB - between it and FERC. That is to say we don't have a specific application; we don't have specific projects to deal with, but there is an anticipation by the agencies, the FERC, the NEB, and the RCA that this is coming and that we need to work and will work effectively together to resolve jurisdictional questions.

A number of conversations we've had with Chairman Wood of the FERC and Commissioner Brownel have verified this. I think that the members can take comfort in that.

Finally, I draw your attention to the energy bill. Mr. Cupina made some reference to it earlier and Mr. Katz is highly conversant with it, but while several recent versions are interesting, I'll refer to the S 1005 version, not the whole 215 pages, but section 131 dealing with the Alaska Natural Gas Pipeline Act. I want to draw your attention to several provisions relating to jurisdiction that you've discussed at this meeting that should give Alaska comfort.

Number one, Section 133 requires the FERC to provide by an open season process support for exploration, development and competition - secondly, to provide for capacity beyond the initial capacity and access for gas other than from Prudhoe Bay and Pt. Thompson.

Second, the act requires the certificate holder to evaluate in-state needs including tie-in points for in-state access.

Third, the state can request that the FERC hear its concerns for access to the pipeline for transportation of royalty gas for local and state consumption.

Fourth, Section 135 provides for expansion of the pipeline in appropriate circumstances.

Fifth, Section 138 anticipates local distribution of North Slope gas, additional pipelines and rate coordination with us, with Alaska. Maybe the best contribution I can make to your afternoon is to give you a memorandum that Bob Loeffler gave me a couple of days ago anticipating this event. Bob is a lawyer; I'm not a lawyer. Bob, from his viewpoint representing the state, has summarized this jurisdictional question in a two-page memo. I think to some rights the FERC and

RCA are in a good position to efficiently coordinate processes as a project takes shape and an actual application is filed. I said an application; I'm kind of reflecting the sentiment that Mr. Cupina gave you earlier – the admonition to us all that a single application will be much more timely dealt with than multiple competitive applications through a regulatory process. Thank you, Mr. Chairman. Judge Wilson and I will be happy to answer any questions that members may have.

CHAIR SAMUELS asked if NEB ordered an expansion and FERC can't order an expansion, would that give Canadian explorers access to the pipe south of Alberta and then because that expansion was filled up, would that cut off Alaskan explorers.

MS. FOWKE asked if he was assuming it was Canadian gas coming in.

CHAIR SAMUELS said yes and clarified that he was asking if the Canadian companies would have an advantage because of their regulatory environment. "Has that happened before?"

MS. FOWKE replied that it hasn't happened before. The pipelines that are in existence now originate in Canada and the suppliers are all Canadian.

Because we have all rolled-in, one producer is not in a better situation than another producer, because they all pay the same toll. If your scenario is that if you had a pipeline coming from Alaska down through Canada and there was Alaskan supply coming through it and then there was a pool discovered in Canada that was then going to come on? Was that your scenario?

CHAIR SAMUELS replied yes.

MS. FOWKE replied:

I guess the producers that are producing in the United States and Alaska and the Canadians producing in Canada would pay the same rate for the Canadian portion of the pipeline. So, the toll that they would pay in Canada, assuming that the pool that you're talking about is relatively far north – if it's south, you might have a different issue – the toll that they would be paying would be the same or essentially the

> same depending on your tolling regime. So, they wouldn't be discriminated against in terms of the Canadian toll that's being paid.

CHAIR SAMUELS asked Mr. Cupina to respond.

MR. CUPINA replied:

> I don't think there's any discrepancy in that if we had an incremental expansion and, at the same time in Canada they had a rolled-in expansion, those two different rate regimes are applied. I'm not sure why they would have to be uniform.

MR. KATZ said he heard the question to be what happened to producers who are not initial shippers on the pipeline if gas was later developed and was ready to move and the pipeline declined to move that gas. I think you're correct that in the absence of the energy bill, the commission would not have the authority to require the expansion of that pipeline.

SENATOR ELTON added that the other instance is expansion of capacity in Canada that would preclude expansion of capacity at the northern part of the Alaskan component of the line. He said he'd be interested in knowing how the two regulatory bodies would deal with that issue.

MS. FOWKE asked how an expansion in Canada would preclude expansion in Alaska.

SENATOR ELTON was assuming that authorized expansion of capacity in Canada would limit expansion capacity for Alaskan producers.

CHAIR SAMUELS asked if the expansion caps out in Canada.

MS. FOWKE replied no, the engineers just get more and more excited about what they get to do. The cheapest expansion is going to be with compression; then you start looping the line, which might have economic restrictions. There aren't any physical restrictions.

> I don't see how an expansion in Canada would preclude an expansion for Alaskan shippers. If there was a pool to be developed in Canada, in the Yukon, that would then ship on this same pipeline that was bringing Alaskan gas down and if that somehow captured some of the cheaper expansion – the compressors – then it

> wouldn’t prohibit or restrict our ability to provide for more facilities if there was more gas being produced in Alaska that needed to be shipped and if it was in the public interest to provide for expansion.

SENATOR ELTON asked, “Doesn’t there have to be a protocol between FERC and NEB to accommodate U.S. producers for capacity expansion that would be conducted in Canada?”

MS. FOWKE replied:

> It may well be that we work out some kind of a protocol, but we can’t influence the other tribunal’s decision. FERC can’t influence what our decision is; our decision has to be in the Canadian public interest. The FERC’s decisions have to be in the American public interest.... I can tell you that in all the history that’s gone on, the pipelines have managed to meet at the borders and the expansions have been seamless. And there have been major expansions. The GH-5-89 expansion was a $2.6 billion expansion in Canada that went down into the States. It was huge at the time and it was seamless. They approved what they needed to approve; and we approved what we needed to be approved. So, it’s always happened....

MR. KATZ added, “That’s the situation where the MOU between the commission and the NEB would come usefully into play, because while I absolutely agree with what was just said with respect to each tribunal needing to make independent decisions. The MOU provides the framework where the two entities could work together developing the records they need and gathering requisite information and one would hope that having done that, the logical conclusions would be reached by both entities if they had the same information before them.

CHAIR SAMUELS said he hated to beat a dead horse, but the fear is that Canadians would take advantage of the cheap expansion rolled-in. Alaskan explorers would come on later with the incremental tariff and the exploration dollars flow to Canada then as opposed to flowing to Alaska.

MS. FOWKE responded that the tolls are just one of the issues that the explorers have to look at. However, in the scenario where the Alaskan gas were to come on and have more expensive expansion in Canada, because a pool in Canada was taking the cheaper expansion, there would still be rolled-in tolls in Canada.

> The producers who are producing in Canada that came on stream with the cheaper expansion would still be facing an increase in toll, the same increase as the producers that are producing in Alaska would face.

MR. CUPINA said he thought the timing of when to lock in capacity would be a market decision that the shippers or producers would have to take into consideration.

REPRESENTATIVE MIKE HAWKER said there have been references to a 25-year old treaty between the RCA and NEB.

MS. LOWKE replied that would probably be the Northern Pipeline Treaty, which is what preceded the Canadian Northern Pipeline Act dealing with the Foothills project. Since there are outstanding issues on that matter, she wasn't able to discuss it.

REPRESENTATIVE HAWKER said a statement was made by TransCanada that they have the right to build any pipeline that would be built in Canada. It was in response to sponsors in Alaska that want to be part of building a pipeline in Canada. He asked if TransCanada has a preemptory right.

MS. LOWKE replied, "That is their view."

REPRESENTATIVE HAWKER said that Alaska has a sponsor group that is interested in building a pipeline across Canada.

TAPE 04-26, SIBE B

REPRESENTATIVE GUESS asked what currently prohibits the RCA from having an approach like the NEB on taking it on a case-by-case basis on whether a roll-in on incremental tariff is in the best interest.

MR. CUPINA replied that it's the commission's policy choice, which has been in effect since 1999, and maybe since 1995 as opposed to any inherent bar. There is a written commission policy statement that spells that out, nothing at the federal level. "The statute requires what is called just and reasonable rates. Throughout the history of the Natural Gas Act, that's constituted different types of rates and different types of rate designs.

REPRESENTATIVE GARA observed that nothing jumps out at him as a problem under existing Canadian law that would prevent a fair transportation of Alaska gas.

> What is the guarantee that we have that at some point when a large new reservoir of Canadian gas is found that a rule wouldn't be adopted in Canada that would say all pipelines that go through Canada have to allow for a 50 percent transportation of Canadian gas? It would take a law change in Canada. Should we not even consider that something like that might ever happen?

MS. LOWKE replied that it's possible.

> The North American energy market is so integrated and the NEB is so aware of that as is our parent department, the Natural Resources Canada. I guess 10 years ago who thought we were going to be seeing $50 oil! I find that really hard to imagine. We've got NAFTA, too. So, I'm sure there's some arrangements in NAFTA that talk about this....

REPRESENTATIVE CHENAULT considered that the same rules could pass that would only allow us to accept so much from Canada

CHAIR SAMUELS asked if NEB chose to order an expansion and FERC chose not to order an expansion, even though they had the ability to, it can only order expansion on the pipeline that is physically in Canada and FERC could only order it for what is in the U.S. He asked if that issue would be in the MOU between the organizations and how many political battles are there between the two now.

MR. KATZ responded:

> I don't think we've ever had any such and as a reality, no shipper is going to sign up to pay a rate if they don't know that their gas can get to market. So, I think it would be exceedingly unlikely that shippers would sign up for a rate and start paying reservation charges or whatever else if they weren't assured that there was a way to get the gas through Canada....

MR. CUPINA added:

> In our experience...there have been a number of cross-border projects...and they match up because the commercial realities required that they match up. We have a good relationship with the NEB and we'll continue that, but that's not the only grounds on which these types of communications will occur.

REPRESENTATIVE HAWKER said that a certain Canadian interest believes it has grounds for a position that says they have an exclusive right to construct any gas pipeline that might be constructed and asked if it was across Canada or just in a certain province.

MS. LOWKE replied that it was in Alberta going down to the existing Foothills pipeline and through the Yukon.

REPRESENTATIVE HAWKER asked how that issue could be resolved.

MS. LOWKE replied:

> Absent the federal government coming out with some kind of policy that would say something, which they have not done or an act that would say that they would have exclusive authority and making it absolutely clear that they do. I assume the matter would have to come before the NEB either through the Foothills proposal that might require some modifications to what they have or through another proponent applying to the board and then Foothills could, if they wanted at that point, challenge the board's jurisdiction to hear the matter.... If an application is filed with us by any of the other groups, we will examine it to determine whether it is complete and absent anything else, we will set it down for a hearing. We can tell you that there have been meetings at the NEB with the other groups. The producers as a group has been in talking to us. The board has not said to them and we have no grounds to say to them that we will not consider their application.

REPRESENTATIVE HAWKER asked if anyone had filed a claim or protest with the NEB.

MS. LOWKE replied no and she didn't think any filings were imminent. She could only think of one circumstance in the last 20 years when expansions didn't go through, which was because market conditions changed – the Millennium Pipeline. The FERC approved it and NEB was still in the process, but the project just cratered. A lot of expansions had happened for oil pipelines and the regulatory agencies managed to come to the same decisions.

MR. CUPINA added that he wouldn't characterize the Millennium project as having cratered. Millennium is working with other agencies that have related statutes to FERC's and it remains to be seen where those discussions lead. There is talk that Millennium would amend its project.

MS. LOWKE said her point is that there were no disparate FERC and NEB decisions with respect to the pipeline.

MR. CUPINA agreed.

PANEL DISCUSSION ON THE REGULATION OF THE PHYSICAL AND ECONOMIC WASTE

COMMISSIONER DANIEL SEAMOUNT, ALASKA OIL AND GAS CONSERVATION COMMISSION (AOGCC), said he would begin by giving an overview of a preliminary study done by the owners and how AOGCC fits into that. He also would talk about the statute and the orders that would be appropriate to the North Slope gas project and give more details about a review of a study the owners did to determine what kinds of volumes to expect from major gas sales out of Prudhoe Bay, which resulted in an estimate of what the impact would be on liquids recovery as a result of bringing the project on. He would then recommend what future work would be needed.

> If Prudhoe Bay were to be developed for oil only, recovery would be over 13 billion barrels of hydrocarbon liquids. That includes oil condensate and natural gas liquids. Currently, the cumulative production from Prudhoe Bay has been over 11 billion barrels, which exceed the original 1977 reserve estimates by 2 billion barrels. The field has been managed very well – very efficiently. It has been a world-class operation up to this point. Gas sales will add about 3.5 billion barrels of oil equivalent. You can put gas on now or 30 years from now probably and you're not going to have any conservation problems with bringing the gas on. There is a question about the timing and rate that would affect how much oil you're going to recover.

Just a short technical explanation of where the concerns might be – this is a cartoon of a slice through Prudhoe Bay field. It can be any oil and gas field in the world. But normally, oil field practices produce as much of the oil as possible and then produce the gas later – after you're done with the oil and that way you'll maximize recovery of both oil and gas and you'll minimize the waste of the oil. So, what you want to do is produce all this oil down here; the gas cap will expand. After the gas cap has expanded as far as it will reasonably go and you've gotten all your oil, then you blow down the gas cap.

Normally, you need this to recycle the gas back into the reservoir to maintain pressure. This allows for mixing of EOR (enhanced oil recovery) fluids to cause the oil to flow easier and also maintaining pressure that pushes the oil out of the ground up to the well bores and into the pipeline. Generally, early gas withdrawal causes some challenges regarding loss of oil. What we're talking about now with the North Slope gas pipeline project is actually an early withdrawal of oil.

Where the AOGCC comes in is we have statutory responsibility to regulate reservoir management including the timing and off-take rates for conservation purposes. From this preliminary study that the owners did, the result was it looks like gas sales will negatively impact total liquid hydrocarbon recovery. The reduction could be in the hundreds of millions of barrels. It's a very preliminary study. More study needs to be done to see if it's actually going to be that high or not. The greatest impact would occur with earlier sales of higher off take rates. However, the good news is that the timing of the sales and the gas production rate doesn't appear to significantly affect the total hydrocarbon recovery. That's when you consider both oil and gas and total barrels of oil in place if you look at a reasonable life of the field. If you don't think the field is going to last – if the infrastructure is going to go down, if it's aging and you don't last past 2050, you probably won't lose that much oil in reality, less than 100 million barrels. But further evaluation is required to validate these preliminary findings.

So, where do we fit in? This is a pretty busy slide. It compares industry with DNR, with AOGCC's roles. There's been a lot of confusion about where an AOGCC fits in especially since all of the bru-ha-ha that's been going on in the Valley regarding coalbed methane. The AOGCC's role is only regulatory; it's not proprietary. DNR's role is proprietary. It manages the resource and Director Myers might have some comment on this later. The DNR manages its resources for revenue and other values and promotes prevention of both physical and economic waste through unitization. The AOGCC doesn't worry about value and economics, it regulates for conservation issues, prevent waste, protect relative rights and promote greater recovery. It's worried more about saving the resource than what the economic implications are. A lot of times both the economic and physical waste issues are intertwined. Mostly the AOGCC regulates subsurface activities. DNR, DEC and other agencies have regulatory authority over most the surface activities.

AOGCC was established under the Oil and Gas Conservation Act, AS 31, before statehood in the late 50s. It's an independent quasi-judicial agency where we report to the people of the state as represented by you, the legislature. We have authority over all lands in Alaska, not just state lands - state, federal and private lands. Our duties are to protect, prevent physical waste of the resource, insure greater ultimate recovery, protect relative rights and protect underground sources of drinking water.

As far as relating to the major gas sales project, our main concerns are to prevent waste and insure a greater ultimate recovery. We have been investigating to determine whether or not waste exists or is eminent and, as I say, the operators have done a very good job on Prudhoe Bay. We have had very few concerns over waste in the last 20 years. We have required plans of reservoir development and operation and we will require plans for the future development. Under the statute, this would include regulating the quantity and rate of production of oil and gas.

The definition of waste in the statute is the inefficient, excessive or improper use of or unnecessary dissipation of reservoir energy or operating or producing in a way that reduces the amount of oil or gas recovered under operations conducted in accordance with good oil field engineering practices. Like I said before, gas blow down or gas production is normally delayed to the end of a productive oil life to maximize the oil recovery. While Prudhoe Bay is very unique, it’s in a very hostile environment. The oil infrastructure – you’ve got to be able to handle the oil. It’s not that simple at Prudhoe Bay. This is something that needs to be looked at really carefully.

Under applicable rules, Conservation Order 341(d) is the pool rules that govern Prudhoe Bay. The three rules under that conservation order that would be applicable to the gas line project would be rule 9, which gives a maximum off take rate of 2.7 billion standard cubic feet per day. This was written in 1977. It contemplated 2 BCF/day pipeline saleable gas rate. Right now about 300 MCF/day of that 2 BCF are used for enhanced oil projects within the field and in the satellite fields.

Rule 12 basically says that the operator has to maintain reservoir pressure high enough so that the EOR gas mixes with the oil to make it flow easier and also to keep the pressure up so that the oil can flow out of the well bores.

Rule 17 is a more recent rule and it deals with – it’s a very ingenious idea where you inject water into the gas cap to displace the gas to keep the pressure up. This could be a very important mitigation measure when you start taking the gas off. It may save up to 100 million barrels of oil just by replacing the gas you’re taking out with the water.

Things about Rule 9 – AOGCC approval is required for sales rates in excess of 2.7 BCF/day. It also may be advisable that we revisit rule 9 assumptions, since that rule was written in 1977 at the field’s start up. It’s a very old model. It’s now obsolete; there was very little information on the production at that time. Now we have so much more information and the technology is so much better. The vitals are so much more improved that it’s time to relook at this. When we come up with the off take rules, we hope they will be based on current knowledge and sound reservoir management. With a project of this magnitude and cost, it's critical that we be given adequate time to evaluate prior to approval. We started that evaluation in August 2002 when we hired an expert consultant on reservoir simulations, Frank Vlaskovich, who has experience in working on the North Slope in the Prudhoe Bay reservoir. He completed a report in June 2003 and we have to emphasize that the results were based on very preliminary work by the owners and a very rough projection; so, today we can't come up with an answer of what the exact effect will be on the liquids recovery. We looked at sensitivities, the effect of a sales rate between 2.9 and 4.3 BCF/day, the effect of sales timings looking at starting dates between 2010 and 2020 and a number of options to mitigate the oil loss. One of them I mentioned earlier was gas cap water injection – increasing that. That could mitigate the oil loss by up to 100 million barrels. And then CO_2 injection. Prudhoe Bay gas is 12 percent CO_2, which is about 3.5 to 4.5 TCF of CO_2. CO_2 has been very successful in other parts of the world as an enhanced oil recovery fluid. Further studies could show that much of the oil could be recovered just by injecting the CO_2. There are also potential uses of the CO_2 because of the recent scare over global warming and CO_2 sequestration. People are starting to look at places like Oklahoma where 55 billion barrels of oil have been left in the ground because it was not produced correctly. Now they're thinking that putting CO_2 in those reservoirs will recover a lot more of the oil. If they had produced the fields in Oklahoma at the beginning of the last century the same way that Prudhoe Bay has been produced, they probably could have recovered 30 billion barrels of that lost 55 billion. So, that just goes back to the fact that this field has been operated in a very efficient way.

This next slide is probably redundant. I've beat it to death enough. As far as the reduction in liquid hydrocarbons, that's dependent on a number of factors – field depletion optimization, mitigation measures – a couple of which I just described and also just by producing the gas, the field life will be extended. So, that gives more opportunity to produce more of the

> oil. I’m not saying that the end result is we’re going to lose hundreds of millions of barrels. It’s we just need to do more study on it.

CHAIR SAMUELS said he assumed that was specific to certain fields.

MR. SEAMOUNT replied yes, but he was just at the beginning of looking at Prudhoe Bay and hasn’t looked at Pt. Thompson at all, except for some initial discussions of possible ways of developing it.

MR. MARK MYERS, Director, Division of Oil and Gas, Department of Natural Resources (DNR), said there are two plausible development centers at Pt. Thompson.

> One is a gas cycling project where you take the high-pressure gas and condensate. You cycle it out of the well to the surface, take out the liquids and put the gas back in. You continue to just pull out the liquids. Then you later blow down as Dan was describing.
>
> The second scenario would be to immediately start with gas sales, in which case, you recover less liquids, but you recover most of the energy back in gas. So, again, there’s economic and physical trade offs. It’s a very different reservoir mechanism that is present at Prudhoe Bay. Pt. Thompson pressure is almost double that of the original Prudhoe Bay reservoir pressure. It’s a very high-pressure reservoir. Prudhoe is a more standard pressure reservoir. Prudhoe has a much larger oil lake under laid by a water lake with a gas cap and Pt. Thompson is a condensate with a little lake and then a little bit of water underneath it. So, they are different animals and each field has to be looked individually and optimized. It’s not a simple equation, but for the gas line, it’s mainly those two fields, at least for initial production.

CHAIR SAMUELS asked if he had the geologic information he needs on the various fields to make the trade off decision.

MR. MYERS replied that he has the information from Prudhoe Bay; there’s lots of production data.

> The question is of optimization. With that the amount of oil loss you'll see is directly proportional to the amount of mitigation. The more water you put in the gas cap, the more efficient, but it costs money to reinject more water, but it maintains the pressure higher. More in injection in oil lake of water or CO_2, a faster cycling time on the reservoir. All of those would increase ultimate recovery, but they cost money and they trade off energy used in compression versus gas you could sell. So, there's an optimization issue that goes on and really Prudhoe Bay is at the stage where the knowledge base isn't going to increase dramatically. It's merely a matter of optimizing the time of sales and then optimizing the amount of money you spend on the various mitigation strategies.
>
> Pt. Thompson has yet to be developed. So, we have some good well control and we have some seismic; we have no production history and a lot less certainty about the reservoir. So, there's more uncertainty around that and as you start in production you gain more and more certainty. So, some tough decisions will have to be made on Pt. Thompson that are economic and they are also reservoir related. We have some good reservoir modeling that was done by the partners. We have a fair amount of good well control, but there is still a lot of uncertainty on the fringes of the reservoir of the ultimate size of the prize and the best technology to use to produce it.

CHAIR SAMUELS asked if the CO_2 injection technology has already been developed and does it cost more to operate.

MR. MEYERS replied that all the technologies talked about today are existing technologies, but the biggest challenge with CO_2 is corrosion and requires use of stainless steel and changing out some parts and pumps; there is money involved in doing that.

MR. SEAMOUNT explained another point:

> That with proper engineering, total hydrocarbon recovery – that's barrels of oil equivalent – is relative insensitive to gas sales and sales rate if you assume a reasonable end of life of the field. This is where Prudhoe Bay may be unique in that there may be a time element where you have to get this gas out before everything craters or something goes wrong and

> 2050 is a long time out. It's insensitive out to 2050 when you bring on the gas sales and what rate it is.
>
> Some of our recommendations here is with the AOGCC you should be part of a process of further evaluation. We need to participate before a decision is made to spend all this money starting the project up. We should be active in setting the producing rate or at least according to the statutes. We must have adequate lead time to complete due diligence and this will insure a good technical review that will help the legislature and others make informed decisions. The owners have told us they plan to continue updating the existing reservoir and facilities models. So far the work they've done is a very good start. We need to continue on this work, update our predictive tools and optimize our operating strategies to maximize oil recovery. Can oil losses be effectively mitigated? What are the effects on the other pools and reservoirs that depend upon Prudhoe Bay gas for their EOR projects for their future pools and reservoirs? The owners have told us we will be part of the reservoir evaluation process.

REPRESENTATIVE REGGIE JOULE asked him to explain updating predictive tools.

MR. SEAMOUNT replied:

> These would be the reservoir model, the software, the programs run to predict what kinds of rates to expect and what kinds of recoveries to expect. You take raw information from the wells, from the production, from pressure data and you run it through a computer simulator and it will spit out predictions as to what kinds of recoveries you can expect of oil, what kinds of gas, natural gas liquids.

REPRESENTATIVE JOULE asked if AOGCC has all this information.

MR. SEAMOUNT replied, "Yes we do. We have access to it."

REPRESENTATIVE JOULE asked if it had been interpreted.

MR. SEAMOUNT replied, "No, it takes a lot of man power, a lot of computer time to take all this raw information, stick it in the computer. It gets very expensive."

REPRESENTATIVE JOULE asked if AOGCC has the resources to do it.

MR. SEAMOUNT replied that it doesn't have the resources, but industry does. That's why he is proposing to work with industry when they are doing the evaluations. He has been talking with the owners now and then and they are getting along pretty well.

REPRESENTATIVE JOULE asked how far behind are we?

MR. MYERS replied:

> There are varying levels of accuracy in which you do this. Think of a computer model; think of a grid – think of a grid the size of a chessboard or you can have a grid with thousands of little squares. The more detail, the more computer intense and the more certain your model is. So, the level of detail, the model we have right now is pretty good at smaller than the chess board size, but not the tiny dot size. As you go through and get closer to the reality of a gas line, you get more and more detail. What we have now is pretty darn good. It gives you confidence in the initial conclusions that there will be a minimal amount of oil loss, but there will be some. Then it's the obligation of what mitigation you put in. So, the results we have now show us ... if we start gas sales at this date, we expect to have this much oil loss, if no additional mitigation. If more water goes in the gas cap, it might be this much; if more cycling occurs, it'll be this much. But we can't predict what investments companies are going to be willing to make at the time. That's why this joint work that Dan is talking about. So, you have to start running the what-ifs and the optimization of gas off take. For instance, if the producers propose 2.5 BCF out of Prudhoe Bay versus 3.5 BCF, there's a big impact in oil loss differential unless you pump a lot more water into the gas cap.... The baseline model work is done and we're pretty confident that the oil loss if nothing is done and the gas sales in the 2012 timeframe, the maximum oil loss might be 500 million barrels, but you recover a lot more energy in gas. Conversely, there are cases where you can run scenarios with enough pressure injection where that is way down to less than 100 million barrels. We already know that and we already have good production decline curves for Prudhoe given the current level of

> investment. But if that level of investment changes, if they change the rate of production in Prudhoe, any number of things could happen. If they do commit to reinject CO2 as miscible injectant, that changes the equation. Current development plans don't have any of those long-term things in there. There is sort of a segregation in the companies between those working the oil issue and those working the gas line and the gas sales. So, right now Prudhoe is managed as an oil reservoir to maximize oil recovery. They haven't made the switch over to gas, yet. So, all of these scenarios are hypothetical.... Both agencies have a say in what oil loss should be to meet the requirements of physical and economic waste.

CHAIR SAMUELS asked if they are going to participate before the decision in reference to page 15.

MR. SEAMOUNT replied:

> We have been participating. We haven't got into the next stage of final evaluation, yet, but we were able to participate. We were able to at least review the first simulation that was run.

SENATOR LINCOLN asked how AOGCC is going to achieve the goals he listed to be part of a review.

MR. SEAMOUNT replied:

> We reviewed their first simulation study and they allowed us in to review it and come back with some information. That was the first step. The next step is when they begin building their final new and improved model. We would like to be a part of that. We haven't made any agreements on that yet.

CHAIR SAMUELS asked if there was a barrier to their participation now that he needs help with.

MR. SEAMOUNT replied that he didn't see a barrier as the owners are working with him now.

SENATOR ELTON said he assumed that the state had a lot of the information on throughput already, but if it doesn't, how much more time does the AOGCC need to advise the legislature so it can make a good decision.

MR. SEAMOUNT answered that part of it depends on industry and how soon they would do their final evaluation. It would take AOGCC two years and $2 million to do it on its own.

SENATOR DYSON asked if gas sales and other waste might be useful in recovery of the heavy oil in West Sak.

MR. MYERS replied:

> The gas line, again, until there is final approval by AOGCC and by DNR on state lands, there will be no authority to authorize any significant off take of gas. So, fundamentally, there's a separate process independent of the pipeline proposals, because that sale event won't occur until 2010 to 2016, depending on who you talk to. So, fundamentally, that process of approval will occur much later that probably a sanctioning of the pipeline project. There will be a period of time in which folks will determine what gas they want to nominate knowing full well they still need agencies' approvals. It won't be a carte blanche that once you cut a deal that a pipeline will go and the pipeline goes to open season and people nominate gas. They will be taking risk in nominating that gas if they do not have approval to off take that gas. So, the processes are separate. The companies must believe at the point they nominate gas that they can demonstrate there will not be physical or economic waste or they're taking a big risk in that process. Again, DNR's & AOGCC's processes are separate and distinct, but they are somewhat aligned in the issue of having to deal with physical waste. The closer you are to the final development is when you run your final simulations and you go for agency approval....

TAPE 04-27, SIDE A

MR. MEYERS continued:

> We won't have that distinct information or a blessing and approval at the open season time for this pipeline, because that final engineering work won't have been done, because it'll be years and years in advance and they know they're going to have to run their models again later, because they'll have that much more information to find and they would have done

that much more mitigation in the field. In the meantime, the field will be managed for minimizing oil loss, which again is AOGCC's responsibility through their pool rules....

In a sense of the amount of gas and where it gets used, certainly a miscible injectant into the heavy oil will help recovery. The question is where is that miscible injectant going to come from and the timing of it. Ultimately, if you have a gas pipeline, you will put that down the pipeline. So, what's happened is in all these fields like Kuparak and Prudhoe Bay, miscible injectant has been created and injected into the main reservoir. At some point, it's less economic to put that miscible injectant into the main reservoir and they'll shift it over to the West Sak, in the case of Kuparak or Milne from the Kuparak formation into the Schrader Bluff. So, we'll see MI (miscible injectant) moving around the field that's already being used. They'll keep recycling and reinjecting at Kuparak, at some time, when it becomes more economically efficient to put in the heavy oil zone. At the same time, CO2 is a wonderful miscible injectant for heavy oil. So, they could, if it was optimized, just use a CO2 flood in a lot of the heavy oil. So, there'll be this optimization between sales and delivery of gas and where they take and the timing of that versus the use of miscible injectant. It's a balancing act. It's coming from multiple sources; it's already in the fields and they'll probably use that as their first miscible injectant for the heavy oil zones.

SENATOR DYSON said he has followed the Canadian efforts with their heavy oil and there is some talk about in situ combustion. He asked if that is a scenario that could work with Alaska's heavy oil.

MR. MYERS replied probably not – for two reasons. One is that our heavy oil is actually at the light end, 16 – 23 API (American Petroleum Institute) gravity, which can be produced better through conventional means in multi-lateral wells.

In situ burning would only be applicable, hypothetically, for some of the shallower parts of the heavy oil in the Ugnu Formation that is at 8 – 12 API that probably isn't very moveable.

> The problem is that you've got cold temperatures and permafrost.... My gut feeling is that there's a whole lot more studies that need to be done before you even consider it.... Most of the oil in the next 15 will probably be this lighter end of the heavy oil, which is volumetrically where they can get out of a multi-lateral well 15,000 barrels per day. That far exceeds the advantage of an in situ burning or a huff and puff steam type mechanism that they use in Alberta.

SENATOR DYSON mentioned that Representative Berkowitz has discussed a win-win where the state gets paid for sequestering CO2 and use that for driving oil recovery and asked if he thought that might work for us sometime.

MR. SEAMOUNT answered that there are a lot of CO2 emissions on the North Slope through flue-gas.

> If they come up with credits for CO2 sequestration to industry, that would be the first place to start. Then if you get really creative, possibly re-injection of the produced CO2 that'll get you both enhanced oil recovery and some tax credits. But that may be pushing it a bit.

MR. MYERS said there would be another opportunity in the gas hydrate zones where gas is present in crystalline form that's just below the permafrost. The estimates are that those volumes exceed that of the conventional gas at Prudhoe Bay. CO2 replacement of hydrates is very efficient.

> So, there are all sorts of other potential advance technologies and uses for CO2 sequestration, which could aid additional methane production as well as heavy oil production. CO2 will become extremely valuable rather than being a nuisance on the North Slope.

MR. SEAMOUNT said they didn't know what kind of mitigation measures are going to be required or even be possible. A more in-depth study is needed.

MR. MYERS said that DNR and the AOGCC have some overlapping authority. DNR's authority is limited to state lands and AOGCC's authority goes to federal and private ownership. DNR's authority is established in AS 38 and it is a broad mandate over economic and physical waste, conservation of resource and protections of the state's best interest. The Supreme Court has confirmed that. A lot of DNR's authority comes through its ability through unitization, which is putting oil and gas property together, multiple leases to produce from a single set of facilities.

> The Supreme Court said that unitization development and conservation of all natural resources belong to the state for the maximum benefit of its people....
>
> We also have regulatory functions.... A lot of them focus around unitization.... The commissioner may establish, change, revoke drilling producing and royalty requirements of leases. So the state has an active role. It can help regulate the rate of drilling, the number of exploration wells in a unit. The commissioner can also modify that through plans of development over time – and development of the quantity and the rate of production within the units....
>
> We're, again, required under unitization to make a public finding that it's in the public interest and to meet certain standards. Those standards that we have to justify in unitization or in plans of development promote conservation of the resource...promote, prevent, economic and physical waste.

An example of physical waste is when you flare gas instead of paying to have it reinjected. A pure economic waste is like at Prudhoe Bay if the operator chose to put the gas down a pipeline rather than reinject it and we lost economic value because we produced less oil. Drilling too many wells in an area is economic waste of resources.

MR. MYERS explained a slide of optimizing oil and gas geologic structures.

CHAIR SAMUELS asked if there are any other mechanisms the state has to insure access to the pipeline other than RIK or RIV.

MR. MYERS replied RIK and RIV are the only mechanisms in which the state would have total control. With proper negotiations it is possible to do things like require mandatory seasons for expansion at various times. The federal legislation gives FERC the ability to mandate access if it passes.

REPRESENTATIVE GARA had a question on page 9 of Mr. Seamount's presentation regarding rule 9 on the maximum gas off take that's allowed. Some people are talking about a 3.5 BCF/day gas pipeline and the current rule says the maximum allowable rate is 2.7 BCF/day. "Why isn't it absolutely time to revisit that to provide people with some certainty who are considering investing in a gas pipeline?"

MR. SEAMOUNT replied that a hearing would probably happen soon.

REPRESENTATIVE GARA asked when he anticipated having a reliable ruling.

MR. SEAMOUNT said that is difficult to answer until the testimony at the hearing is complete. He said the answer would be easier if the AOGCC had a new complete reservoir model that it could rely upon and it does not have that yet.

REPRESENTATIVE GARA commented, "And there are two flip sides. One is the rule that says as the leaseholder, you're allowed to produce this amount of gas and so maybe after the hearing process, it would be increased from 2.7 bcf/day to the amount needed for the pipeline. What about the flip side? Would the rule also say to the lessees that you're required to allow the release of that amount of gas or else that would be waste if you don't allow the release of that amount of gas?"

MR. SEAMOUNT said he cannot see how producing more gas would be required. He asked Representative Gara if he was saying it would aid in the ultimate recovery.

REPRESENTATIVE GARA asked if it could be seen that not allowing enough gas out to make a pipeline feasible could be a waste.

MR. SEAMOUNT said it could be an economic waste. Regarding physical waste, he said he could see that if one could foresee that the infrastructure is going to go down in a few years so that if it is not taken out now, it never will be.

REPRESENTATIVE GARA said if Rule 9 was updated to the 3.5 number as Mr. Seamount anticipates, all Rule 9 would say is that leaseholders would be allowed to send 3.5 bcf/day but would not be required to.

MR. SEAMOUNT said that is correct.

MR. MYERS pointed out that the size of the pipeline is determined by the pipeline builders who will be heavily influenced by the nomination process. The pipeline will have limited specifications - it will only have certain optimum ranges that are economically feasible. However, within that range, the builders will ask who wants to send gas through that line. If only 3 bcf is nominated, the builders will design a pipeline that can provide a reasonable tariff for 3 bcf. The companies nominating that gas will have to believe they can get regulatory approval to produce from those fields and prevent physical and economic waste. If they don't have the gas, they will be exploring to get the gas from the NPRA or Foothills if they can't get the gas from Prudhoe Bay. He emphasized that it is the individual companies, not the fields that will nominate the gas in and they will have to believe and have agreements to produce that gas and regulatory approval. Therefore, just because the pipeline is designed for 4.5 bcf does not mean at the end of the open season process it will be a 4.5 bcf pipeline. For example, if 6 bcf gets nominated from credit-worthy parties, the builders will try to build a 6 bcf pipeline from day one. He noted it is a commercial process that is used to design the size of the pipeline but that must be backstopped by good faith that the regulatory approval will come and that the economic standards can be met in the future.

REPRESENTATIVE GARA asked if the estimated available 3.5 bcf of natural gas includes Point Thomson.

MR. MEYER said the public numbers for the North Slope range from 33 and 35 trillion cubic feet of known proven reserves, largely from Prudhoe Bay and Point Thomson with some associated gas with other oil fields. He noted the undiscovered resource potential in the NPRA is significantly larger. He said the Prudhoe Bay and Point Thomson gas would supply 18 to 20 years at the 4 to 4.5 range and the rest of the gas would come from elsewhere. Or by the time of the actual development of the pipeline, the companies will be taking less gas from those two fields and more from other sources.

CHAIR SAMUELS asked for suggestions of where the legislature wants to "go from here" and said he would start by bringing up the local hire issue. He felt that although local hire cannot be mandated, knowing what jobs would be required in advance would allow the legislature to take steps to insure that the jobs that are available could be filled by people who would not otherwise have jobs and deteriorate the economy. He said he would like to get more information along those lines so that adequate training could be provided.

SENATOR LINCOLN said she would like to expand that idea so that Alaska businesses are utilized.

CHAIR SAMUELS agreed and said he was not satisfied with his questions or the answers to Exxon about marketing. He again asked members to think about where they wanted to go from here.

SENATOR ELTON thought that given the issues that have been put before the committees, from a process perspective, members need to consider how to keep those issues alive so that they can get a better sense of where those who testified are going and follow what they are doing. He suggested using existing committees or creating a subgroup of legislators and coordinating with the Executive Branch to avoid a lot of duplication and create synergy between the two groups.

CHAIR SAMUELS told members that during the previous legislative session, Senate President Therriault appointed Senators Stevens and Guess and Speaker Kott appointed Representatives Joule and Weyhrauch to be the liaisons between the legislature and the administration during the interim. He joined that group as the chair of the Legislative Budget and Audit Committee, as did Senator Therriault. When they met with the administration, they told the administration that their understanding of the Stranded Gas Act was to prevent all 60 legislators from "throwing rocks at each other" for political reasons. The point was the act was to establish one negotiating point. In addition, they told the administration what issues came up during their legislative committee hearings. He pointed out such a meeting has occurred already [during this interim].

REPRESENTATIVE JOULE commented, regarding the question of state ownership, he believes that needs to be explored further, particularly the RIK and RIV issue.

REPRESENTATIVE STOLTZE said he pursued that line of questioning in the Finance Committee but he didn't feel that he got an answer. The question there was if the state does have an ownership, what percentage would it need to have an impact and whether there is a minimum amount and he would like to follow up on that.

REPRESENTATIVE HAWKER said he would like to further pursue the state's participation in the broadest sense. He would like the committee to expand into whether the state should participate and to hear more from the capital market people about financing and cost of capital alternatives, especially since the committee will only have 30 days to review [any agreement]. He noted, "Secondly, the other one that really peaks my interest - and again we've got a regulatory authority person here saying I won't get into that one because it's such an undetermined issue and it seems to me to be a pretty significant issue - a route that would go across Canada if, in fact, we are legally prescribed going across Canada."

SENATOR LINCOLN said what she finds troubling is that there is a whole mass of people that are a part of this process. Right now the administration is negotiating and no one knows where that negotiation will lead or the timing. She said in addition, the AOGCC's role, its goals and interactions with the legislature, the role of the commissioner of DNR, which is very broad, ANGDA, and the role of the Senate Resources Committee, all play parts and she is unsure how they fit together in legislative deliberations and pursuing the best course of action.

CHAIR SAMUELS thought the committee can apply pressure to any mechanism it wants to, whether that be ANGDA or another, but the reality is that the legislature will have a minimum of 30 days to approve a contract and it will be deciding on a product put before it. He thought members need to be familiar with the subjects, such as the trade-off for RIK or RIV, or the choices and trade-offs that were made in the contract. He pointed out that some of the issues raised by members, such as vocational education, will be important to know about for the next legislature so that it can plan for training.

REPRESENTATIVE JOULE said all legislators will want to be ahead of the curve on the local hire issue and that the legislature now has some experience under its belt and the luxury of a little bit of time. He felt the more that opportunity can be maximized, the better off the state will be.

SENATOR DYSON noted that although all members are enthusiastic about Alaska hire, there will be great pressure for the construction to occur under project labor agreements and he guesses that will happen. He pointed out that project labor agreements are often touted as the best tool available to guarantee Alaska hire. He is sympathetic to that but some of the bargaining units have internal rules that do not allow them to add new people into the Alaska rolls if someone elsewhere in the Northwest bargaining unit is unemployed. He suggested adding incentives or doing something to help qualified Alaskans to get into those bargaining units ahead of other workers from the Northwest. He complimented Chair Samuels and Senator Ogan for organizing these educational hearings. He then asked that the presenters not use acronyms, as not all members are familiar with them.

CHAIR SAMUELS said he would consider and work on getting another meeting together in approximately one month.

SENATOR SEEKINS thanked the co-chairs as well, and then noted that, to quote from Dr. Martin Luther King, "without a dream, the people will perish." He said a gas line is a dream of many Alaskans and that with every dream, there is an intent to kill it. He said he feels relatively certain that any final gas line dream will not be what he or any other member prefers. He believes the challenge for members is to not kill any reasonable dream just because it is not exactly what each member wants. He hoped all members could work with the administration and other participants to bring this dream to fruition and make it profitable for those in the business and for the residents of Alaska, Canada and the United States.

REPRESENTATIVE GARA said the process of the Stranded Gas Act almost requires the legislature to say something to the administration sooner rather than later. He said if the committee keeps all of the information it has gathered over the last two years internal, the administration will not know what the committee is thinking and will enter into a deal it believes is best, leaving the legislature the right to only say yes or no to it. He said he believes the legislature has punted, and to be fair to the administration, the legislators can probably all agree on some issues that have been discussed in these meetings but the administration does not know which. He thought if committee members can agree on some of the concepts, such as access to the gas by in-state users, creative ways to deal with local hire, that it is important to convey those agreements now so that the committee does not address those after the deal is done.

CHAIR SAMUELS repeated that a group of legislators has met with the administration and discussed specific topics and that the administration was open to discussions. He said he would organize another meeting with the administration. Chair Samuels then asked members to contact him or any other subgroup members about individual concerns, which will also be relayed to the administration. He said he would work on getting more information on the issues of ownership and capital markets and adjourned the meeting at 3:45 p.m.