ALASKA STATE LEGISLATURE
JOINT MEETING
LEGISLATIVE BUDGET AND AUDIT COMMITTEE
SENATE RESOURCES STANDING COMMITTEE
July 28, 2004
10:00 a.m.

MEMBERS PRESENT

LEGISLATIVE BUDGET AND AUDIT

Representative Ralph Samuels, Co-Chair
Representative Mike Chenault
Representative Mike Hawker
Representative Beth Kerttula
Representative Reggie Joule

Senator Con Bunde
Senator Gene Therriault

SENATE RESOURCES

Senator Scott Ogan, Co-Chair
Senator Tom Wagoner
Senator Fred Dyson
Senator Ralph Seekins
Senator Kim Elton

OTHER MEMBERS PRESENT

Senator Gretchen Guess
Senator Gary Stevens

Representative Harry Crawford
Representative Les Gara
Representative Beverly Masek
Representative Ethan Berkowitz
Representative Paul Seaton – via teleconference
Representative David Guttenberg – via teleconference
Representative Bill Stoltze
Representative Lesil McGuire

MEMBERS ABSENT

LEGISLATIVE BUDGET AND AUDIT

Representative Vic Kohring

Senator Lyman Hoffman
Senator Lyda Green

SENATE RESOURCES

Senator Ben Stevens
Senator Georgianna Lincoln

COMMITTEE CALENDAR

Alaska Natural Gas Pipeline Issues/Access to Original Pipeline and Expansion Capacity

Presentations

In Need of Access: Alaska's known and potential gas resources – David Houseknecht, Research Geologist, US Geological Survey – Mark Meyers, Director, Division of Oil and Gas, Alaska Department of Natural Resources (DNR)

Original and Expansion Capacity: What volumes, when, on what terms and at what price – Joe Marushack, Vice President, ConocoPhillips, and Pete Frost, Director of Regulatory Affairs, Gas & Power Marketing Group, ConocoPhillips, on behalf of Producers BP, ConocoPhillips and ExxonMobil

Access to Capacity for Producers and Explorers Without an Ownership Interest in or Effective Control of the Pipeline – Mark Hanley, Manager, Public Affairs for Alaska, Anadarko

Access to Capacity for Alaskan Communities – Charlie Cole, Board of Directors, Alaska Gasline Port Authority

Letter from James Whitaker, Mayor, Fairbanks North Star Borough

State Revenue Issues of Gasline Expansion – Larry Persily, Special Assistant to the Commissioner, Alaska Department of Revenue

Access to Capacity for Alaskan Utilities – Anthony Izzo, President, Enstar Natural Gas Company

Access Under Current Law v. Access Under Proposed changes to Federal Law – Bob Loeffler, Senior Partner, Morrison & Foerster, for Alaska Department of Law

Volumes, Timing, Terms and Price of Access with 36”, 48” and 52” Pipelines – Eric Watson, Project Manager, Alaska Gas Development, Enbridge, Inc.

The Array of State Tools for Improving Access – Marty Rutherford, Deputy Commissioner, Alaska Department of Natural Resources

ACTION NARRATIVE

TAPE 04-13, SIDE A [BUD TAPE]

CO-CHAIR RALPH SAMUELS called the joint meeting of the Legislative Budget and Audit Committee and the Senate Resources Standing Committee to order at 10:00 a.m. Senate Resource Committee members present were Tom Wagoner, Fred Dyson, Ralph Seekins, Kim Elton and Co-Chair Scott Ogan. Legislative Budget and Audit Committee members present were Representatives Mike Chenault, Mike Hawker, Beth Kerttula, Reggie Joule, Co-Chair Ralph Samuels and Senators Gene Therriault and Con Bunde. Senators Gretchen Guess and Gary Stevens and Representatives Bill Stoltze, Les Gara, Beverly Masek, Harry Crawford and Ethan Berkowitz were also present.

CO-CHAIR RALPH SAMUELS announced that this meeting is the second in a series of three interim hearings on the issues surrounding the gas pipeline.

CO-CHAIR SCOTT OGAN said the decisions the Legislature would be making in the next months regarding the natural gas pipeline were the most important ones it would be making in the next couple of decades. He noted that statute allows the Legislature 30 days to consider a negotiated settlement once it is submitted. So, it’s important to do this work during the interim.

CO-CHAIR SAMUELS said the first segment is titled In Need of Access. He welcomed Dave Houseknecht and Mark Myers.

MR. MARK MYERS, Director, Division of Oil and Gas, Department of Natural Resources (DNR), acknowledged that the USGS does a lot of cooperative work on resource issues and that Brenda Pierce, Energy Coordinator, USGS, is attending the hearing. USGS assessments are done independent of him, although DNR input is used. Work in the federal government is focused primarily on assessing federal lands, but includes state lands and is on-going.

He said there is a big difference between reserves and resources. The reserve base on the North Slope is known and economic. Undiscovered resources is what you think is there, but don't know for sure. Probabilistic modeling is used for those resources and has a range of outcomes. The North Slope has a known reserve base that he is confident exists predominantly in two fields – Prudhoe Bay and Point Thompson, although there is undiscovered resource potential elsewhere. Access and expansion revolve around whether or not there is sufficient gas potential.

He demonstrated in a slide the known reserves in bright red at around 33 – 36 TCF (trillion cubic feet). The proposed project size, a 4.5 BCF (billion cubic feet) pipeline is only about a 20 – 22 year supply of gas and is insufficient to monetize a 30-year or longer project that Alaska would like. If that undiscovered resource base isn't there, the 4.5 BCF pipeline is too large. Furthermore, expansion of a pipeline bigger than that would not be logical or economic, because a 4.5 BCF pipe expanded through compression-only numbers gets you only 16 – 18 years of life. Then the undiscovered resource is looked at and the question is asked how much undiscovered resource needs to be there to justify the project. If 30-plus years is needed, 50 – 60 TCF of gas are needed – a significant amount. However, if those numbers are greater than 60 TCF, a 5.6 BCF line could produce for 50 – 75 years. Early expansion of that pipeline would be important to maximize both the economics of it and maximize the revenue stream to the state and federal government and encourage oil exploration overall.

> The issue of undiscovered resources becomes the critical lynchpin if you're worried about expansion, if you're worried about the economics, in general the pipeline, but also if you're worried about access terms.

MR. MYERS said he used $1.50 per MCF netback to the North Slope for demonstration purposes. A 4.5 BCF netback to the North Slope would be worth about $2.4 billion a year or about $6.6 million per day. Expanding to 5.6 BCF by adding pressure to the line changes the cash flow to $600 million per year or $1.6 million per day.

> What's important from the state's perspective on one front, at least, is the state will capture part of that differential. So, early expansion, if the gas is there, makes a tremendous difference on the economics

> of the project and the benefits the state receives.... Also, the earlier you define those reserve bases, the more secure the project is. It is a lot easier to fund and back a project that has 30 to 50 years of reserves than it is for one that has 20.
>
> So, understanding what the resource potential is and how likely you are to achieve that really becomes the critical issue on many of things you'll have to deal with through the Stranded Gas Application process....

MR. MYERS explained that an expansion would lead to an overall lower tariff on the pipeline for all shippers, initial shippers and expansion. If the cost of expansion is more through looping or other means, typically the people expanding the pipeline beyond that bear the full cost of the incremental expansion.

He said that the ability to expand early is almost required if the necessary reserve base is there. Exploration can't occur if gas is stranded for a long period of time, because the economics aren't there for the company to drill the exploration wells until there is capacity in the line.

Under the 4.5 BCF/day proposed scenario for Prudhoe Bay and Point Thompson, the initial gas producer who has the open season will fill the pipeline for the first 12 years. If it take eight years to build, there is a 20-year period before any new gas can come into the line. The state has 10-year leases and companies simply cannot afford to expend huge dollars upfront and wait 20 years to capitalize their investment.

> So, it is a chicken or egg situation, unless the rules on expansion are clear and that access is available. Again, that's not an important question unless you believe the gas resources are really there. If they're not there, then there is really no issue with expansion. That's why the technical assessments become critical.

MR. MYERS believed that the gas resources are highly probable to be in sufficient quantities for an expanded pipeline to have a 50-year life.

> Finally, one of the key things to recognize is there will be folks who tell you that expansion isn't that important and that it will happen naturally. Well, it won't with enough certainty to get the early

> exploration going. Again, from DNR's perspective, it's critical to the state to see that we have good access terms, that expansion is available for parties that wish to explore. That confidence, then, leads to exploration and valuation of state lands and will ultimately lead to accelerated revenue stream; it will lead to more oil and gas being produced. Because along with that gas, a significant amount of oil will be produced, as well.

SENATOR CON BUNDE asked him to explain why expansion might not be advantageous for some companies.

MR. MYERS replied:

> If you have down-stream markets that can take a limited amount of gas and you're selling into that market, you're competing with other gas coming from the basin. If you own the pipeline and also own the gas infrastructure, there may be cases where you have two profit centers and those two profit centers come in conflict, if there's more gas coming in and competing with your gas.
>
> So, there are natural competitive forces, that depending on the ownership and alignment of the pipeline, make your individual companies' economics different. I'll just say, if a lot of gas comes off the North Slope, it could have an effect on the value of gas say at the Acho Hub. In which case, the companies that have a lot gas in the Acho Hub now will see an overall lowering of that gas price for a short period of time until the market recalibrates, but it will affect their market position and other gas they own within other basins that are affected by the same markets. So, there's lots of complications in here....

He said the state wants all the gas to come because it helps our economics, but the individual company may have a slightly different set of economics. Much of today's discussion will be on the areas in the southern part of the basin that are in the North Slope Foothills and the NPRA (National Petroleum Reserve – Alaska).

In addition to known fields at Prudhoe Bay and Point Thompson, there are unconventional gas resources. Gas hydrates are basically gas that is frozen in a lattice that sits under much of the existing infrastructure. Current reserve estimates exceed that of Prudhoe Bay and Point Thompson combined, about 37 – 44 TCF. He would not talk about gas hydrates today, because they haven't been demonstrated from an engineering standpoint to be commercial, although drilling intervals have determined that they are geologically present.

SENATOR FRED DYSON asked a question about the chart, which Mr. Myers explained. He said there is a lot more unconventional gas between coalbed methane and gas hydrates.

MR. MYERS further explained that access and expansion issues affect other basins on the way to the North Slope - the Yukon Flats and the Nenana Basin, in particular, whose economics would be dramatically improved if it could not only serve the local market for gas, but could have export capacity all through the gas line. The Nenana Basin has a significant quantity of gas present; it's a question of whether it's present in commercial quantities and how it can be maximized. The access issue is important here in terms of development of rural energy strategies. Certainly, the best markets are local, but additional capacity could be exported making the project much more economic.

The Copper River and Cook Inlet Basins have exploration licensing that will benefit through access and expansion. A larger pipeline gives more options for marketing gas in multiple locations and companies are actively exploring in these basins specifically for gas.

MR. DAVID HOUSEKNECHT, Research Geologist, US Geological Survey (USGS), said he would summarize the work it has done to characterize the resource base of the entire state of Alaska and the North Slope, in particular. Part of the USGS's mission responsibility nationwide is to do assessments of undiscovered and other resources that may be added to the nation's energy base in the future. The USGS systematically work across the entire nation with a particular emphasis on federal lands. The work is restricted to the on-shore and state waters areas and his colleagues in the Department of Interior, Minerals Management Service, work in the OCS, the federal off-shore division. Their work compliments each other.

MR. HOUSEKNECHT emphasized that their assessments are reported in terms of probabilities. In frontier areas like the North Slope Foothills, relatively few exploration wells have been drilled and there is a range of uncertainty associated with their estimates.

Associated versus non-associated gas is an important concept on the North Slope, especially. Associated gas occurs in association with oil, such as a gas cap above an oil accumulation. Prudhoe Bay has a huge gas cap. Non-associated gas occurs in the absence of oil and that’s what is in the Brooks Range Foothills.

> Worldwide, the largest gas resources and reserves typically occur in those geologic provinces of non-associated gas rather than associated. So, it’s really important to understand that we really don’t know very much about the non-associated gas on the North Slope, because as wells were drilled and non-associated gas encountered, the companies simply moved on and didn’t delineate those accumulations because they were looking for oil. I’ll come back to that point as we go along.

MR. HOUSEKNECHT next presented a map of the State of Alaska that summarized the estimates of undiscovered conventional natural gas that was prepared by the USGS for onshore in-state waters and by the Minerals Management Service (MMS) for offshore. The point to be made is that first he shows a range for each province. For example, in northern Alaska NPRA he shows a range of 40 – 85 TCF, which represents a range of 95% probability to 5% probability.

> In other words, the USGS says there is a 95% probability of 40 TCF of conventional, undiscovered, technically recoverable natural gas resources in the National Petroleum Reserve in Alaska (NPRA). On the upside, there’s a 5% chance of 85 TCF. So, again, that range is quite large because of the lack of drilling data that exists in those gas prone areas of the North Slope and other basins of Alaska.
>
> The single number listed behind the mean is the statistical average or expected value of our probabilistic distribution. So, if you must use one number, and certainly legislators and the media tend to use one number whenever they can, we estimate 61 TCF of conventional natural gas that is undiscovered and technically recoverable in the NPRA, alone.

MR. HOUSEKNECHT summarized that in southern Alaska there are 2 TCF of known reserves in the Cook Inlet and the USGC onshore and MMS offshore mean estimates add up to about 20 TCF of undiscovered conventional resources. In central Alaska, there are no known reserves to date and a mean estimate of about 9 TCF. In northern Alaska, there are more than 33 TCF of existing reserves and a mean estimate of more than 150 TCF of undiscovered resources. This shows the importance of the North Slope in the natural gas resource base of the state of Alaska and why northern Alaska is really the driver in terms of the undiscovered resource base under discussion.

He emphasized that the estimates in northern Alaska do not include the Native lands. That study is under way right now and will be released later this year.

MR. HOUSEKNECHT said he would give a mini overview of the geology and exploration history on the North Slope. The white dots that are clustered along the coastline near the Barrow Arch are the over 400 exploration wells that have been drilled to date. That's where the industry has found oil and that's where exploration has been focused. He also showed the pipeline system and a subsurface regional feature indicating oil migration and accumulation during geologic history. Areas where the state and USGS would agree are more favorable for oil versus gas exploration are on the northern part of the North Slope. In the southern half of the North Slope, or the Foothills, there's a greater probability of encountering gas than oil. The Foothills province is where the oil industry in the early years of exploration drilled wells, encountered gas, and said oh, shucks, this isn't what we're looking for and moved north. For that reason, there is a lack of drilling data in the Alaska North Slope Foothills that increase the uncertainty of the estimates that are made. That's why there is such a wide range between the 95% and 5% probabilities in the numbers he quoted on the NPRA.

The next slide focuses on the nature of the gas resources that are present. The big red bubbles are known gas accumulations that have been discovered as a by-product of oil exploration. Some of the red bubbles have green rims around them and those represent associated natural gas, occurring either as a gas cap above an oil accumulation or as dissolved gas within the oil. The red bubbles with white circles are non-associated gas, gas accumulations that have been discovered where the exploration tested gas at significant rates that signify an accumulation is probably present, but where delineation of those resources did not take place because the industry was not interested in natural gas. The only non-associated gas resources that have been delineated are the relatively small resources or reserves that have been developed around Barrow for local consumption. All of those accumulations that have been discovered in the Foothills have not been delineated in any substantial fashion and their size is not known.

SENATOR FRED DYSON asked what DST and RFT mean.

MR. HOUSEKNECHT replied that DST means drill stem test and RFT means repeat formation tester.

> As a well is drilled, when the well encounters an interval of rocks in the subsurface and either oil or gas shows are detected in the cuttings that are coming up, the well is sealed off and actually a measurement of the oil or gas flowing out of the formations in that interval is measured. So, the DST and RFT tests are the most direct indication that we have during exploration drilling of a significant gas or oil accumulation that may be present.
>
> The other thing I will point out here is that among the exploration wells, I've assigned a color code with yellow being the most significant test, DST or RFT indications. A glance across the Slope notices a significant number of the exploration wells, especially in the Foothills, have encountered natural gas shows during drilling, either significant shows in the tests that we just discussed, or moderate or weak gas shows indicating more diffuse gas accumulations that may be present. So, the bottom line here is that most accumulations of associated gas are up on the coastal plane near the Barrow Arch and most known accumulations of the non-associated gas are in the Foothills farther south, but significant gas shows are pervasive in the wells that have been drilled, especially in the Foothills. What the USGS believes that this really defines is what we refer to as a natural gas province that has great potential in the Brooks Range Foothills. I have outlined that province in yellow on this map.

Data on sizes of accumulations that are known on the North Slope is taken from the DNR annual report. Prudhoe Bay and Point Thompson are the largest known reserves at 24 TCF and 8 TCF respectively. The sizes of the other known accumulations are also shown. The table on the right shows the possible sizes of some of the non-associated accumulations that have been discovered in the Foothills and a couple in the federal offshore. Size is difficult to estimate, because in most cases the accumulations have been encountered by a single well or one or two delineations wells – because industry was focused on oil.

Finally, in terms of known resources, he pointed out new discoveries in the NPRA. The Alpine play represents exploration for the type of geology that exists in that field. Lease sales in the NPRA during the last five years indicate that industry believes there are significant potential reserves extending westward across NPRA. The blue areas of the map show where the USGS has mapped the extent of the Alpine-type geology using seismic and well data.

Results from new discoveries in that area indicate that approximately 500 million barrels of oil will be recovered at a 40 degree API gravity (American Petroleum Institute measure for the lightness or heaviness of oil). Forty-degree oil is very light or watery as opposed to a thick oil. GOR is simply gas oil ratio per cubic foot of gas per barrel. Eight hundred is a very low value. Westward, a test of the discovery at Spark indicated 55 degree oil, a much lighter oil than at Alpine, probably a condensate (a petroleum compound that is a gas in the reservoir and precipitates to a liquid at the surface) and a GOR of 10,000. The Rendezvous Discovery reports 60-degree gravity and a GOR of almost 17,000.

> This is an astoundingly rapid increase in the gravity of oil and the GOR over a very short lateral distance, and frankly, our scientists are struggling to understand this.... This does lead to the question - is the big play, or plays, in the NPRA really going to be predominately oil or will there be a very substantial gas resource that...industry been treating primarily as an oil play.... So, what I'm really saying here is that there are lots of unknowns and every well that is drilled and the data from every well that is released gives us additional information to help us constrain how much oil and gas may be present on the North Slope and these results certainly indicate that there may be more gas present in NPRA than we estimated just two years ago.
>
> The estimates we've made over the last five or six years are limited to federal lands. What I'm showing

> here are the gas volumes that we estimate to be present as technically recoverable conventional resources in NPRA and in ANWR. Bear in mind that we have not yet released our estimates for the state and Native lands that are adjacent to the pipeline and those results will be released later this year.
>
> In addition to the range of numbers listed there, 40 – 80 TCF in NPRA and 0 – 11 TCF in ANWR, these histograms show you the sizes of gas accumulations that we estimate to be present.... So, what we are saying is that the largest accumulations that we expect in NPRA are approximately the same size as the known gas reserve in Point Thompson field – pretty substantial accumulations....
>
> I want to emphasize in red in those little inset maps in NPRA are the areas we expect the largest gas resources to exist and the point here is that every one of those gas plays extends eastward across the Coleville River and extends all the way eastward across the stated Native lands to the pipeline corridor.... So, although I can't give you specifics, the geology is essentially identical to the NPRA and it would not surprise me if a few months from now we are releasing numbers that are in the same order of magnitude as the NPRA estimates we've made and those would be in addition to the numbers that I've already reported to you here this morning.

MR. HOUSEKNECHT summarized that northern Alaska already has significant reserves that are already known, more than 30 TCF, and an undiscovered resource base of at least 150 TCF when combining onshore and offshore estimates. The onshore numbers will grow significantly when they are released for state lands later this year. There is also a huge non-conventional resource base that is not being discussed because of the engineering uncertainties in its development. A certain portion of the resources is located within easy access to existing infrastructures.

Central and southern Alaska, in contrast, have relatively modest accumulations, but resources that could add icing on the cake to the resource base in the state.

CO-CHAIR SAMUELS thanked him for his presentation and said the next question to be addressed was original and expansion capacity.

MR. JOE MARUSHACK, Vice President, ConocoPhillips, Gas Development, said his sole objective today is to establish a common link between the Alaska efforts here and pipeline access and expansion. He introduced Pete Frost, an engineer for ConocoPhillips, who knows that mechanical and technical reality must fit into regulatory and political policy. He has also spent many years working gas from development to marketing to regulation; so, he has a broad background into all the issues inherent in this business. Finally, he is part of ConocoPhillips' core Alaska gas team and is familiar with federal legislation and the challenges this project faces - and is trying to help them overcome.

MR. PETE FROST, Director, Regulatory Affairs, Gas and Power Marketing Corporation, ConocoPhillips on behalf of BP, ConocoPhillips and ExxonMobil (referred to as the sponsor group), offered a brief overview of the FERC's policies dealing with access to initial capacity, how expansion capacity might be offered and a summary of the sponsor group's preliminary estimate and toll estimates. He would also address how FERC's policies and procedures work to insure that all parties have equal and fair access to pipeline capacity. His primary background is in interstate gas pipeline procedures, rate making and tariffs and the role of the FERC and his comments were designed to provide insights into FERC's approach in establishing gas pipeline tariffs and rates as well as its procedures for obtaining access both for initial capacity and expansions that will be required of the Alaska natural gas pipeline.

> Interstate gas pipelines are required to operate as open-access contract carriers. Capacity on the Alaska pipeline will be offered and allocated based upon long-established FERC regulations and precedence. Access to pipeline capacity needs to be viewed in four contexts:
> 1. Initial access to a proposed new pipeline
> 2. Initial access to pipeline expansions
> 3. Access to pipeline capacity that may become available because of contract termination or exploration and
> 4. Access as a result of temporary or permanent capacity release

In each of these contexts, any credit-worthy party that is willing to make the necessary long-term shipping commitment has an equal opportunity to acquire pipeline capacity. For those of you who are primarily familiar with the Trans Alaskan Pipeline System (TAPS) it is important to remember that the procedures for allocation of capacity are different for gas pipelines than for oil pipelines. On gas pipelines, gas is allocated through an open season process that allows all perspective shippers to review the preliminary rates, terms and conditions and to bid for capacity on the pipeline.

The open season process is instrumental to the pipeline's ability to establish the economic viability for the project and to determine the optimum size of the pipeline. The open season process is designed to insure nondiscriminatory allocation of pipeline capacity and significant case law and precedent exists to insure that no shipper that is prepared to make the long-term shipping commitment has any advantage in taking pipeline capacity from another similarly situated shipper. In the United States, the FERC oversees this process, which must be open and transparent.

Although the FERC allows reasonable flexibility in the design of open seasons, significant precedent defines the open season process. Typically, open season processes are conducted as follows:

1. The pipeline will often engage in preliminary discussions with the marketplace and will sometimes use non-binding open seasons or solicitations of interest. This process helps the pipeline to judge the extent of the market support and to insure that the pipeline is neither too large nor too small for the apparent demand for the transportation services.
2. The pipeline then issues a public notice to announce its open season. The open season must be of sufficient duration to allow all interested shippers an opportunity to respond. The open season documentation will also outline the rules under which the pipeline will evaluate its bids. The pipeline's open season package typically

includes significant information about the project including receipt and delivery points, route, timing, services, pro-forma agreements, a proposed precedent agreement and estimated rates.

TAPE 04-13, SIDE B

3. If there's insufficient capacity to satisfy all the bids, the pipeline's open season package will specify the type of tie-breaker that will be employed to allocate the available capacity.
4. Once capacity has been allocated through the open season process, the shippers will normally enter into binding precedent agreements with the pipeline, which demonstrate the need and support for the project. The pipeline company uses these agreements to justify the project at the FERC and to underpin the financing of the construction of the pipeline. Pipeline owners and financial lenders require these long-term contracts for firm capacity to ensure repayment of the capital cost of building the pipeline. without these commitments, gas pipeline projects, which by their nature involve a longer payout than typical oil pipeline projects, could not be financed. Shippers need a contractual commitment from the pipeline to ensure capacity is available to support their own needs.

Once capacity is awarded through the open season and binding precedent agreements are executed, a shipper's contractual right to the reserved capacity is protected. A shipper's economics are founded on the availability of this contracted capacity. In exchange for the pipeline's commitment to reserve a specified quantity of capacity for a shipper, the shipper agrees to pay a monthly reservation charge that is due regardless of whether gas is actually shipped. A pipeline must have sufficient binding precedent agreements or executed transportation contracts prior to filing its FERC application. If the pipeline overbuilds, it is at risk for all unsubscribed capacity and cannot recover those costs from the contracted shippers.

The open season process is critical to determining the ultimate capacity of the pipeline. When additional gas is committed to the project, a larger physical pipeline may be justified (if operationally feasible), which may yield economies of scale that benefit all shippers.

In some unique cases in the offshore Gulf of Mexico, pipelines have offered a pre-subscription open season to attract sufficient base volumes to underpin the pipeline. In these cases, the anchor shippers were pre-assured access to some of the pipeline's capacity in the open season consistent with the risk associated with their large capital investments in related production facilities. It should be noted, however, that in all of these distinctive cases any party meeting the base requirements could be an anchor shipper and a meaningful portion of the total pipeline capacity was still made available to any interested shipper in a non-discriminatory open season. FERC has approved this anchor shipper concept in order to facilitate types of unusual project development requirements.

As proposed, the Alaska pipeline can be expanded to allow substantial additional capacity. Under FERC precedent, potential shippers are assured of fair and equal access to the pipeline expansion capacity without undue discrimination through an open season.

The current process for the allocation of expansion capacity is very similar to that described earlier for the allocation of initial pipeline capacity. However, prior to the expansion open season, FERC policy requires that the pipeline poll current shippers regarding their willingness to turn back their own capacity prior to the binding open season. An existing shipper does not have priority or right of first refusal for expansion capacity, but is treated the same as anyone else trying to obtain expansion capacity. All potential shippers must bid on expansion capacity during the open season and similarly situated shippers must be afforded the same rates, terms and conditions. When a project is economically and technically viable, this process allows a pipeline to efficiently identify customer requirements and to implement cost-effective expansions.

It should also be noted that the FERC has very specific regulations that deal with the relationship between interstate pipelines and all of their energy related affiliates. Under these regulations, known as Order 2004, pipelines may not treat their affiliates in a preferential manner. These regulations include strict limitations on information flow, shared employees and corporate structure. Virtually every pipeline employee must now be specifically trained in these affiliate regulations. The penalties for violation are severe.

If a pipeline is expanded, the resulting rate treatment is dictated by established FERC policy. The expansion rates are determined based upon the incremental costs of the expansion. If the resulting expansion results in a lower overall rate, then the cost is rolled in or basically included in the rate base of the pre-expansion pipeline. In this case, the existing shippers and the expansion shippers all pay a lower rate. If the expansion would result in an increase in rates to the existing shippers who hold the initial capacity, then the expansion rate will be incrementally priced. In this case, the existing shipper continues to pay their previous rate and the expansion shippers pay a rate based on the higher incremental costs to expand the system. The actual costs of an expansion will depend upon the design of the pre existing facilities and the specifics of the proposed expansion.

It should also be noted that the proposed federal enabling legislation has unique and unprecedented language allowing FERC to require an expansion upon request if the shipper requesting this service meets the requirement outlined in the legislation. These requirements include:

1. No subsidization of expansion shippers by existing shippers;
2. No adverse effect on the financial viability, economic viability or operations of the pipeline and
3. No diminution of the contract rights of existing shippers to previously subscribed certificated capacity.

There are other methods of allocating capacity. Any shipper who is paying the pipeline's maximum rate under a firm transportation contract that is 12 months or longer is granted a conditional right to extend its contract at the expiration of the primary terms. As a matter of FERC policy, this right of first refusal (ROFR) exists only at the end of the primary contract term and allows the shipper the ability to retain all or a portion of its contract subject to the expiring capacity if he is willing to pay the pipeline's maximum filed rate for the greater of one year or the term offered by a third party. This contract right of first refusal is not a right to obtain capacity in either an initial open season or an expansion open season.

The pipeline is also required to allocate capacity that comes available as a result of contract expiration on a nondiscriminatory basis. This can be done through an open season or by posting the capacity on the pipeline's public bulletin board. In any event, the FERC approved tariff will provide the procedures consistent with FERC precedent and regulations for the nondiscriminatory allocation of such available pipeline capacity.

Any method by which a shipper can obtain firm capacity is by obtaining capacity released by a firm shipper. This release can be for a temporary term or can be a permanent release. The FERC has established criteria that ensure such capacity is allocated to the party who values the capacity the most (subject to the FERC approved maximum recourse rate).

As has been previously communicated in other forums by the sponsor group, the total capital cost of the Alaska gas pipeline has been estimated at approximately $20 billion in 2001 dollars. This figure would be somewhat higher in today's dollars accounting for inflation since 2001. The figures that I'll be sharing with you will be quoted in 2001 dollars because they refer back to the joint $125 million feasibility study that was completed by the sponsor group in the 2011 - 2002 timeframe. That study evaluated the feasibility of constructing a pipeline from Alaska's North Slope to Lower 48 U.S. markets by way of either a northern route or a southern route with the conclusion that the project was technically feasible, but that the commercial risks outweighed the potential rewards. Because current state law prohibits the state from issuing a right-of-way for a northern route until a southern route is built, the cost estimates have focused on the southern route.

The southern route project was estimated to cost approximately $19.4 billion with an accuracy of +/- 20%. This capital cost estimate resulted in an estimated toll to the market of $2.39/MCF. This toll is merely a preliminary estimate of a toll that might ultimately be approved by FERC [Federal Energy Regulatory Commission] and the NEB [National Energy Board] for an Alaska gas pipeline. The ultimate toll will not be known for some considerable time, that is, until the pipeline is completed and the actual costs are known and better estimates will require more work as the project is further developed.

The process of developing and gaining regulatory approval of this toll and having it approved by the necessary regulatory authorities is well-established in both the U.S. and Canada. Pipeline tariff rates are a direct result of the cost of constructing and operating the pipeline. The actual formulation of the toll, indeed the entire tariff structure, of which the toll is one component, is subject to well-established regulatory standards with oversight provided by the FERC in the U.S. and the NEB in Canada.

The rate that gas pipelines will charge for transporting gas is based on what is referred to as the cost of service. This cost of service includes components such as operating expense, maintenance, taxes, depreciation and a fair and reasonable return on capital investment consistent with the specific risks of the project.

The FERC and NEB processes offer an opportunity to all interested and affected parties, such as the State of Alaska, to actively participate in the establishment of just and reasonable rates on pipelines in which they have an interest for both initial capacity and for expansion capacity. All parties have the ability to intervene in this process and have the opportunity to comment on the proposed pipeline’s tariffs prior to regulatory approval. The FERC will consider all such comments before it approves the pipeline's rates or specific tariff language. Once these tariffs have been approved by the FERC, the provisions would generally be applicable to all shippers. Furthermore, FERC staff is charged with representing consumer interest to ensure that these rates are just and reasonable. The FERC has outstanding resources and expertise and furthermore, is also permitted to audit the records of all regulated pipelines.

All parties including the State of Alaska, the pipeline, gas producers and other shippers benefit by ensuring that all gas has access to the pipeline on reasonable terms. Existing FERC policies and procedures ensure that all parties have a fair and equal opportunity to access pipeline capacity. Moreover, these policies and procedures help to ensure that no one class of shipper can be required to directly subsidize or guarantee access for another. In fact, this approach advances the national interest in encouraging future investment in natural gas pipelines. FERC recognizes that parties who have the potential to accept significant risks and make substantial investments in natural gas transportation systems will not do so if the benefits can be transferred to other third parties.

And so, to summarize, I'd like to offer these closing comments. First, unlike oil pipelines, interstate gas pipelines operate as open access contract carriers. This means capacity must be awarded to shippers in a fair, equal and non-discriminatory manner. These shippers, however, must be willing and able to make the necessary contractual commitments to pay for the capacity. This open access requirement is met on a new pipeline through an open season. Once capacity is awarded, a shipper's contractual right to the reserved capacity is protected. Existing shippers, however, have no preferential rights to capacity on an expansion. Further expansion capacity is allocated under a non-discriminatory open season process similar to that which is used to allocate the pipeline's initial capacity. All parties, including the State of Alaska, the pipeline, gas producers and consumers benefit by ensuring that all gas has access to the pipeline on reasonable terms. Among other things, this means pipelines generally are prohibited from allowing one class of shippers to directly subsidize another class or from guaranteeing one class of shipper's preferential access over another class. In addition, FERC has regulations that ensure a pipeline owner operates independently from its other energy affiliates. FERC Order 2004 recently expanded these regulations to include all energy affiliates, including producer affiliates. This concludes my prepared remarks. I'd be happy to try and answer any questions you might have.

CO-CHAIR OGAN said he quoted figures from 2001 and that the benefits outweighed the risks at that time, but this is 2004 and he has heard projections at different conferences that the gas market has changed. He assumed the producers were recrunching their numbers.

MR. FROST responded that the sponsor group is continuing the analysis and efforts are under way to define the parameters of the project and the cost.

REPRESENTATIVE LES GARA said he understands that FERC allows a fair amount of flexibility in the rules for access. The amount of revenue the state takes in is dependent on the transportation costs for the particular amount of gas that gets deducted. So, gas that is 400 miles away from the main pipeline stem may make the state less revenue than gas that is five miles away from the pipeline stem. If there is an open season and two competing proposals for the same amount of gas are coming from one company that owns gas 300 miles away and another company whose gas is much closer and would make the state much more money, he asked if the state would have some sort of discretion to choose the access so that legislators could uphold the state's interest in getting the maximum revenue possible.

MR. FROST replied that the proposed pipeline would be regulated by the FERC, a federal agency. The enabling legislation includes a specific provision that requires the FERC within 120 days of signing the act to promulgate specific open season regulations that would define how the particular open season process would be conducted by the Alaska gas pipeline. During the promulgation of the rule-making all interested parties would participate.

REPRESENTATIVE GARA focused Mr. Frost back to his question of how the state would choose the company with gas located 5 miles away rather than 300 miles, because it would make more money that way.

MR. FROST replied that the open season process by FERC would have to be conducted in context with existing case law, which require that all open seasons be conducted on a non-discriminatory, open access basis. The FERC wouldn't view any party with a preference in that process. The parties would bid on the section that's available. No particular source or shipper has any preference to capacity.

SENATOR KIM ELTON said it seemed that for an initial open season, the producers would have somewhat of an advantage, because they have knowledge of where reserves are versus independents who would make a bid on undiscovered reserves. He asked him to comment on that situation.

MR. FROST replied that FERC regulations have no requirement on when an open season is to be conducted. A number of precedents define how it should be structured – how long it should be open, how long prior to the opening should the notice occur, etc. The decision for when the open season takes place is a commercial decision about when the pipeline feels it has sufficient support from potential shippers to move a project forward. FERC regulations and precedents dictate that certain things have to happen before the application is submitted to it.

When the open season is made, all parties who have an interest in participating in a open season have an equal opportunity to bid at the time it is conducted. Different parties will be in a different position to participate in an open season to develop a pipeline. To the extent that parties are not able to participate in one open season, the project sponsors could expand the pipeline and have an expansion open season. An explorer could force an expansion under FERC rules at a time later than the initial open season. The pipeline always has an economic incentive to expand and many expansions result in a lower rate for all parties.

SENATOR ELTON asked if it is very likely that an independent could become an anchor shipper under an undiscovered resources scenario.

MR. FROST replied:

> Maybe. If any shipper has reserves that are known and confirmed enough to support their desire to

> participate in an open season, they could participate as an anchor shipper. The anchor process is open to all parties....

SENATOR RALPH SEEKINS asked what he meant by the pipeline, as proposed.

MR. FROST answered that he was speaking generically. He was referring to any pipeline with an open season.

SENATOR SEEKINS asked if a gasline from Alaska to Canada to a hub versus one that went all the way through Canada to the Lower 48 would be treated the same.

MR. FROST replied yes. "The Alaska pipeline will be constructed under federal regulation and will be subject FERC regulation.

SENATOR SEEKINS said if the sponsor group built the pipeline, the only advantage for them would be based on making a profit on the construction and operation of the pipeline.

MR. FROST replied that construction of the pipeline would be first and foremost to move gas from the North Slope to the marketplace – to access the market. There is also an expectation that there will be a separate pipeline corporate entity. "In that sense it has a profit center of its own."

SENATOR SEEKINS mused if a person owned the pipe himself, he could see an advantage in keeping construction prices a little high to keep other people out.

REPRESENTATIVE MIKE CHENAULT asked if it was true that one had to be an owner to be able to sit at the table and negotiate rates and if Alaska is not an owner of the project, where would it be able to negotiate tariff rates, including in the future.

MR. FROST answered the FERC regulatory process allows all interested parties to participate.

> It is the norm for the individual state public utility commissions and their staff to regularly participate in these types of proceedings, because of the fact that the outcome of these proceedings impact the state and the state consumers. The state of Alaska would very much have an opportunity to participate in all regulatory proceedings at the FERC, both initial open

> season, initial application, and any subsequent regulatory proceedings at the FERC.

REPRESENTATIVE CHENAULT asked if it would be in Alaska's best interest to have more say at these meetings if it was part-owner of the project versus not being an owner.

MR. FROST replied, "If the State of Alaska is an owner in the pipeline, then they have a slightly different role. They are not a user of the pipeline; they are part of the pipeline, itself. The pipeline, of course, does represent its own interests at the FERC. And so, the State of Alaska, conceivably, would have two roles – one role as an owner of the pipelines that would be proposing applications at the FERC and one in your role as representing the consumers within the State of Alaska, itself.

CO-CHAIR SAMUELS asked if who builds the pipeline should be irrelevant to the producers.

MR. FROST answered:

> From a regulatory perspective at the FERC, the FERC is going to view the pipeline as a corporate entity in and of itself. The FERC doesn't particularly care who owns this pipeline. All of the procedures, all of the regulations, all of the case precedent, all of the judicial case law that has been developed over the last 80 years in the natural gas industry is going to apply to that pipeline regardless of who the owner is.

REPRESENTATIVE BETH KERTTULA said that tariffs are affected by the costs. "If you control the costs, you can control the tariff."

MR. FROST responded:

> There are various aspects of the cost. There are operating costs and capital costs. Speaking of capital costs, when the pipeline files its application, the capital cost will be a major component of the tariffs that are ultimately reviewed and approved by the FERC. The FERC has a statutory obligation to insure that the rates that come out of the application process are just and reasonable and they take their role very seriously. There is a whole host of people at the FERC in Washington, D.C. who tear those costs apart line by line and argue over literally dollars and cents. Their

> role is to insure those costs, all costs, are just and reasonable. One of the guidelines is to insure that the costs have not been imprudently incurred.

SENATOR SEEKINS asked if all costs are reasonable, what is the percentage of return on capital that FERC allows the owner of the pipeline.

MR. FROST answered that there is no specific number.

> It depends on a number of factors, one of which is the risk associated with the pipeline. The FERC has recognized a direct link between the riskiness of the project and the return on equity....

SENATOR SEEKINS asked if he could guess for this pipeline.

MR. FROST replied that it would be within a range of about 12 to 14.5 percent.

CO-CHAIR OGAN observed that one penny's difference cost in the tariff, if it's higher, lowers the value of the project $155 million over its life.

> If that's an accurate figure, based on throughput and a 30-year life of the project, it equates to – our tax a royalty on that is roughly 20 percent. Some quick figuring - that equals a little bit more than $30 million the state will not get for every penny of cost the tariff goes up.... We obviously have an intense interest in what those costs are going to be and what the alignments are going to be, who owns what and who is shipping what....

MR. FROST replied, "Pipeline rates and associated costs are always the subject of great debate and scrutiny at FERC. It's what they do."

CO-CHAIR SAMUELS thanked Mr. Frost and announced that Mark Hanley would give the next presentation regarding access to capacity for producers and explorers without an ownership interest in or effective control of the pipeline.

MR. MARK HANLEY, Manager, Public Affairs for Alaska, Anadarko Petroleum, said Anadarko is an explorer with an interest position, being partners with ConocoPhillips, and owns acreage at Alpine, NPRA and in the Foothills. Anadarko is very supportive of getting a gas pipeline built. He would focus today on areas of differences and concerns.

> You’ve heard a few things here and one of the issues you’ve heard is that FERC will guarantee - FERC is your protector. I would only say that we all look at what are the exceptions to the rules and where can we be disadvantaged potentially. Part of the problem in this process is it’s all speculation. So, we have to speculate things that many times they won’t all occur. But, if we don’t look at what possibly could occur, we’re not being responsible to our shareholders. I would say for you folks one of the things is that you’ve got to listen to all the parties, but you ought to have your independent folks. Because I would agree that generally, the FERC is going to regulate this pipe; they are going to be the ones that make a lot of the determinations. So, understanding the rules of the game...and looking at it from, maybe, the state’s perspective, as well, and saying how can we be disadvantaged....

MR. HANLEY reminded the committee that a few years ago the state chose its royalty in kind and actually put out a bid for its royalty gas. Anadarko bid on it successfully – wanting the gas so it could go to an initial open season. However, Anadarko doesn’t have reserves right now and is not likely to go to an initial open season. The three producers really didn’t like what Anadarko did a few years ago – because in the terms of its contract, it could get capacity and then go out and explore for the gas. When it found the gas, it could return the state’s gas with certain notice provisions. The state gas would then have to be carried by the other folks. So, they would get pro-rated even though they have a contractual right to that capacity.

Anadarko was told from the beginning to not worry about capacity because the pipeline could be expanded, but when the shoe was on the other foot, the producers were reluctant to expand capacity saying that would increase risk to the pipeline.

> That sends a message to us. Maybe when they’re telling us it isn’t a problem to get it, maybe it is. I don’t know what, but that gives you an example of one of the concerns that we have about this process when they say its fair for expansion....

MR. HANLEY moved to the subject of producer owned or independently owned pipelines and which is better. His general testimony in the March meeting was that Anadarko doesn't care who owns the pipe as long as there is fair access terms and conditions at a reasonable price. But, there's always a natural tension between the shipper, whose goal is to have the lowest rate, and a pipeline owner, whose actual goal is to make as much money as they can. "This is what all the protections are out there for."

MR. HANLEY read Bob Loeffler's comments in Petroleum News:

> What determines how high the rate of return is on equity is how risky the pipeline is. Pipelines will argue I'm not an average pipeline. I'm more risky than anyone else, so I deserve more. Of course, shippers on the pipeline argue they're not risky at all.

MR. HANLEY reflected:

> That's that natural tension.... If the shippers are largely the owners, as well, you've heard the natural tendency there – there's an incentive there to shift your profit as much as possible to the pipeline system. That's a concern for most of us.
>
> For the state it should be a concern because it decreases the wellhead value and it decreases the state's revenue if the profit is taken out of the pipe instead of out of the gas. For explorers, it means our costs are higher. So, it's a concern for us. When you get into a natural system and you're going before FERC arguing what is that rate of return - should it be 12%, 14.5% - everybody is arguing that this is a huge risky pipeline. I'm not going to argue that it isn't. But the tension isn't necessarily there, because if the big shippers didn't own the pipe, they'd be pushing as hard as they can to have it closer to a 12% rate of return, because that's going to mean the pipeline tariff is lower.
>
> In this case, if the pipeline owners own it, I'm not sure that the big shippers are not likely to be out there arguing. In fact, they won't be opposing the higher rate of return on the pipeline, itself, because they know that it also helps both competitively as

> well as through their overall rate of return, because the state's picking up about 20% of any increased cost in that. That's something that doesn't have to do with the pipeline costs.... I think anybody who is a shipper would want the pipeline operated at the lowest cost and not built over cost to try and capitalize that.

TAPE 04-14, SIDE A

MR. HANLEY related also that the Natural Gas Policy Council said:

> The state must develop a clear and sophisticated understanding of open season rules governing access to a contract carrier pipeline and devise strategies to facilitate access to the pipeline for firms exploring for or developing new gas discoveries on the North Slope or Interior basins.

The Legislature also passed a resolution in 2002 that said:

> Provisions for access to the pipeline by explorers on a fair and reasonable basis including a proper open season with fair and reasonable tariffs and...they and the state have the ability to obtain expansion of the pipeline if it's economically and technologically feasible.

A letter from Governor Knowles to Senator Bingham also states:

> Access for new discoveries - is necessary to mandate that in the event of new discoveries on or around the North Slope or Interior Alaska. And, whether on federal or state lands, the owners of these discoveries will have access to the pipeline in order to market their gas. It is estimated that undiscovered gas reserves may be in the order of 100 TCF or more. Legislation should give the FERC clear authority to require the owners of the Alaska portion of the Alaska Highway project to expand the capacity of the pipeline in order to accommodate all new discoveries. Absent such a provision, new gas discoveries could be left at the back of a long [line] of gas awaiting shipment or worse, indefinitely stranded in place, because, unlike most areas in the Lower 48 states, one pipeline will be the sole source of available transportation.

MR. HANLEY emphasized that Alaska is different in that it will have only one pipeline. Nan Thompson, who was chair of the Regulatory Commission of Alaska (RCA), said:

> A pipeline owned by producers will not have an incentive to transport gas developed by their competitors to market.... If the state wants to encourage competition amongst producers and full development of its gas resources, we need legislative authorization for our regulatory agency to evaluate the economics of the proposed expansion and require support for an application for expansion at the FERC when expansion promotes the state's best interest.

A letter from Governor Murkowski said:

> We also believe it is in the best interests of the state for the pipelines to be owned and operated by an unaffiliated pipeline company assuming that such a company is able to provide the lowest possible tariff.

MR. HANLEY suggested that there's enough people with concerns about ownership of the pipeline to urge the Legislature to look at the issue closely. Alaska is different than the Gulf Coast, which has competition, because it has a monopoly. Three producers control 90% of the gas on the North Slope. They have spent many years jointly working on the project.

> To be honest with you, there really isn't competition for that gas getting into it, nor can there be and I'm not saying it's their fault. But, when you're at Prudhoe Bay, BP can't just produce its gas and leave every body else's in the ground. There's a lot of legal precedence about overlift, underlift and lots of problems with that. So, there's going to be an agreement from Prudhoe Bay owners about what is the optimal off-take of gas from that field. There has to be. The same thing at Point Thompson - they have to come to an agreement among the owners on what's the optimal amount coming out. When they know that... they know how much they need to go to the open season and nominate capacity. It's not a negative thing; it just shows you they've worked together building the pipe.... There is one group out there doing this thing and when you get to the open season, they will say.... typically...it's conducted to determine how big the

pipeline needs to be, what interest there is going to be out there, are there other people that are willing to commit so they can size the pipe. To be honest with you, that's all done. I think they would be very surprised if anybody other than Prudhoe Bay and Point Thompson owners...if significant gas came in from somewhere else.

Whether or not there is an anchor shipper agreement or whether they can set aside capacity that isn't in there really isn't the huge issue, particularly in the initial open season, because frankly, they are the only ones that have expansion capacity. I think I've explained to you before, as an explorer, without identified reserves, and that's us or any of the other people out there, we can't go to the open season, nominate .5 BCF a day and make a commitment of $300 million a year, in that range, for 20 or 30 years without knowing we actually have the gas to put in there. It's a chicken or egg thing.

The explorers are going to be focused on the expansion, what the terms and conditions are, if the pipe is actually built so it can be easily expandable, how much it can be expanded. What those terms and conditions are are going to rely a lot on FERC and others to make sure that we do have that ability.

Again, who is going to look out for our interests? The FERC is out there looking at this stuff, but I would say the state has some ability. There is a Stranded Gas Act where the state can include provisions; they do have some leverage. I would say our RIK (royalty in kind) process has not been finalized and we haven't been actually granted, but I would say don't give up your right to take your gas in kind. That's one of the few leverage points you have. I suspect they would ask you to not do that, but I think as a state, you should not do that.

When you go back to the ownership of the pipe by a producer, where is the tension in the system? Let's just say that the producers own a third each of the pipe and I don't know what the interests are going to be, and they control 90% of the gas. If you don't count the state's gas, it's less, but they are probably going to carry it in value, well they're a net owner. Their interests are largely going to be 100% ownership of the pipe, so their interest is going to be as a pipeline owner. That’s the concern.

MR. HANLEY explained that Order 2004 (a) tries to put a firewall between the pipeline owner and the affiliates. There is an attempt to not share information, but one must look at the exceptions. He tried giving the committee an idea of how FERC balances this.

> Order 2004(a) - The commission (FERC) is balancing its concerns that a transmission provider (the pipeline) will abuse its relationship with a marketing or energy affiliate by providing it unduly preferential access to information about potential expansion plans or new production areas against the need to facilitate infrastructure development by allowing the transmission provider to coordinate construction and planning with an interconnecting gatherer pipeline or producers....
>
> Therefore, the commission clarifies that transmission also includes an interconnection to facilitate gas transportation service. Thus, discussions between a natural gas transmission provider and an energy affiliate to provide an interconnection or expansion for the energy affiliate would be covered by the transaction-specific exception.

MR. HANLEY translated that to mean that there is a transaction specific exception to the rule that says you can’t have conversations out there. They say that interconnecting entities may discuss the location, practicality and cost of potential interconnections with an affiliated transmission provider. The purpose is to encourage the transmission provider and interconnecting energy affiliate to work together to develop additional infrastructure to facilitate development of production.

> There are exceptions to the rules.... If they do that, they have to record the meeting, they have to keep a transcript of it, they have to keep it for three years and they have to make it available to FERC. This is all intended to make sure that nothing goes wrong.

The Order of 2004 had a discussion about whether a non affiliate could voluntarily consent in writing to allow a transmission provider of the pipeline to share the non affiliate’s information with the pipeline owner’s marketing affiliate. He didn’t know why he would want to get them information that they could share with their own affiliate, but it was allowed and says:

> Several commenters, including indicated shippers, urged the commission not to adopt the voluntary consent provision. They argued that it is anti-competitive, because even if a shipper agreed to disclose the information, the consent may not truly be voluntary, because the transmission provider could be exercising market power.... That’s the normal tension that occurs in these things....
>
> BP argues that the commission should eliminate the voluntary consent exemption in the natural gas area. There is no business reason why a customer would allow the transmission provider to share that customer’s information with a transmission provider’s marketing or energy affiliate.
>
> According to BP, transmission providers could coerce a customer to consent. Therefore, the consent is not truly voluntary. So, these are the comments. So, when people say am I being paranoid, I would just point to an example like this and say....
>
> This is a very complex field. There are lots of things that are out there. There are companies who are shippers who have very legitimate concerns about the pipeline companies and the power that goes with both.

MR. HANLEY concluded by urging the Legislature to watch the terms and conditions closely.

REPRESENTATIVE LES GARA said he also had concerns about letting FERC control the state’s destiny, but asked assuming the state is skeptical that FERC will get us the best price for transporting gas, what can the state do to ensure the lowest possible transportation price.

MR. HANLEY again pointed out leverage in the Stranded Gas Act, but he didn’t know if it was significant. The state needs to understand and participate in the FERC process.

REPRESENTATIVE MIKE HAWKER asked if he had any immediate concern that the state is abrogating its responsibility or is he being cautious.

MR. HANLEY replied that he is being cautious. One provision in the Federal Energy Bill says within 120 days of its enactment the commission shall promulgate regulations governing the conduct of open seasons for Alaska natural gas transportation projects, including procedures for the allocation for capacity and the regulations shall include the criteria and timing for any open seasons, promote competition in the exploration, development and production of Alaska natural gas and for any open season for capacity exceeding the initial capacity provide the opportunity for the transportation of natural gas other than from Prudhoe Bay and Point Thompson. That's part of the federal package that includes preliminary judicial review, expedited permitting, etc. It also has a provision specifically allowing FERC to force an expansion of a pipe.

CO-CHAIR SAMUELS announced a recess.

CO-CHAIR OGAN called the meeting back to order at 1:15 p.m. He said that he would be chairing the afternoon portion of the meeting and the next subject to be discussed would be access to capacity for Alaskan communities by Charlie Cole.

MR. CHARLIE COLE, Board of Directors, Alaska Gas Pipeline Authority, said he wanted to talk about the Gas Act's provisions at Fairbanks.

> I have to say preliminarily that I have some hesitation about speaking critically, you might say, about an item of legislation that passed the legislature by a vote of 20 – 0 in the Senate and 38 – 0 in the House. Obviously, any bill that passes the Alaska Legislature with votes like that has strong support and is viewed by informed legislators as good legislation for this state. So, with that caveat and that reservation, I want to speak a little bit today about the effect of that bill as I see it on Fairbanks and other Interior communities and in a sense, communities down river.
>
> One, Alaska is cold and Fairbanks is, on occasions, very cold. It is one of the restraints on growth that we have in Alaska and we'll always have in Alaska – is the cold weather. With that given, low cost economic

energy is vital for the economic development of, certainly, Interior Alaska and, as we have seen, how vital and how beneficial that has been to the Anchorage area. But, Fairbanks has not had that benefit and Fairbanks continues to struggle economically as respects quality of life for the high cost of energy there.

So, if one looks to the future of Fairbanks, if Fairbanks is going to have any economic growth... it must have cheap economic energy to offset the costs of living there.

The second given is that these Alaska resources should be primarily for the benefit of Alaskans. Isn't that what Governor Murkowski said? He said one of the fundamental purposes of the use of these resources of Alaska should be to benefit Alaskans.

Senator Seekins would know at times in Fairbanks when it's 50 degrees below zero, we have people there who buy 50 gallons of fuel oil to heat their house, to keep it from freezing, because that's all they can afford, if you can believe that. One of the givens for the Fairbanks community is we really need gas. There's only one place we're going to get that gas and that's off this gasline, if it's ever built. Presumably, it's going to be built.

Also, if we want to keep the military bases in Fairbanks – you know those base closure proceedings come up every once in a while. One of the criticisms we talk about keeping Eielson and Fort Wainwright there is how much it costs to keep those bases open. If we're trying to reduce the defense budget, maybe we're trying to, I'm not really sure that we are, but if we are, we've got to reduce the cost of power and heating at those bases. So, that should, in my view, be given as a policy.

So, what did the Stranded Gas Act do for Fairbanks in that regard? Given I think those unanimous policies – lets just read what AS 42.06.240 says in that regard.... starting with section (f).

In addition to the other requirements of (a) through (e) of this section, the provisions of this section shall apply to a certificate of public convenience and necessity for a North Slope natural gas pipeline carrier or a person that will be a North Slope natural gas pipeline carrier under this chapter.

(1) The person making the application shall dedicate a portion of the pipeline's initial capacity sufficient to transport the total volume of North Slope natural gas that has been committed by the producers and shippers of North Slope natural gas to tendering for intrastate firm transportation service at the time that the operation of the North Slope natural gas pipeline commences.

(2) Upon receipt of the certificate application under this subsection, the [RCA] shall issue a public notice inviting prospective intrastate shippers of North Slope natural gas to file a request for service. A request for service submitted by a shipper in response to the notice issued under this paragraph must include a proof of the shippers commitment to use the North Slope natural gas pipeline for intrastate firm transportation service, specifying the volume of North Slope natural gas that the shipper will tender for initial intrastate firm transportation service.

(3) In its review of an application submitted under this subsection:

(A) For the purpose of evaluating the total volume of intrastate transportation of North Slope natural gas to be accepted for initial intrastate transportation, the [RCA] commission shall determine the total volume based upon written commitments to tender North Slope natural gas for intrastate firm transportation service continuously for a period of not less than three years after the operation of the North Slope natural gas pipeline commences as follows (the RCA has to determine the total volume based upon written commitments (before the certificates of public convenience and necessity are issued and before pipeline construction begins – day one):

(i) Each request for service by an intrastate shipper that is a public utility, as that term is defined by statute, for the purpose of furnishing natural gas for ultimate consumption within the state by its customers that individually consume an average annual volume of less than 20 million standard cubic feet of gas per day shall be supported by a written commitment by the

> public utility that sets out the utility's best current estimate of the average annual volume that the utility will require during the three-years period.

MR. COLE emphasized that a written commitment gives the sense of something that is binding and obligatory, but after reading the next sentence, it may not mean contract.

> (ii) Each request for service by an intrastate shipper that is not a public utility, as that term is defined by law, and each request for service by a public utility for the purpose of furnishing natural gas for ultimate consumption within the state by a customer that individually consumes an average annual volume of 20 million or more standard cubic feet a day, that purchases North Slope natural gas from a North Slope natural gas producer must be supported by one or more contracts for the purchase of the North Slope natural gas on a take or pay basis that extends for a period of not less than three years after the operation of the North Slope natural gas pipeline commences.

MR. COLE explained that means that anybody who wants this natural gas, if it is not a public utility or it is a public utility with more than 20 million standard cubic feet per day, you have to reach a contract now to buy natural gas from the carrier on a take or pay basis. Fairbanks has no natural gas distribution system or facilities for converting natural gas to electrical energy; so, who in Fairbanks would enter into a contract like this, he asked. He didn't know how such a project would be financed and supposed that it would be impossible.

CO-CHAIR OGAN interrupted to say that LNG is being shipped from the Matanuska Valley to Fairbanks at $7 per thousand CF and it wouldn't take too much to set up a turbine to turn the natural gas into electricity.

MR. COLE responded that it wouldn't be very practical to enter into a contract now without knowing what rates the RCA will set and approve as just and reasonable. Fairbanks needs a whole distribution system for homes to be heated and no one knows what that would cost and no one would finance it. However, he noted that was only part of the dilemma. The next section says:

> (iii) The RCA may consider peak volume specified in written commitments of the North Slope natural gas producers and purchase contracts; and

> (B) The commission shall set out in its order granting a certificate of public convenience and necessity the total volume of intrastate North Slope natural gas that the North Slope natural gas pipeline carrier shall accept for intrastate transportation.

MR. COLE said that means the certificates of public convenience and necessity shall say the total volume of intrastate gas may not exceed the volume substantiated by written commitments and contracts that comply with the requirements of the chapter. Commitments have to be in place, then the RCA in the certificate of public convenience and necessity says, “You’ve got to send out X, but you can’t ship any more for intrastate transportation.”

He emphasized that it gets worse:

> If the North Slope natural gas pipeline carrier wants to transport gas in excess of the amount set forth in the statement of total volume of the pipeline carrier’s certificate of public convenience and necessity, the pipeline carrier may apply for authority to transport more.

MR. COLE explained that means the carrier has to see if it can get authority to do that.

> We’re looking at a gasline that’s going to potentially be running by Fairbanks for the next 30 years. How are we ever going to, for example, entice anyone else to come to Fairbanks and utilized this natural gas for a petrochemical facility? What about supplying natural gas to Fort Wainwright? Converting those bases? And how are we going to furnish natural gas to Eilson Air Force Base? Once, ten years down the road, it then becomes up to the gasline to decide whether they want to increase the intrastate capacity for Fairbanks. And I’m not talking just about Fairbanks and Eilson and Fort Wainwright, I’m talking about Tok, I’m talking about Delta Junction on the way down the Highway, but I’m also talking about the development of propane facilities to be able to ship propane down river to these other communities. I mean, once you do this, [it] is locked in. Then it’s up to the pipeline, itself, to decide whether it wants to increase the

capacity – and that's over the next 10, 20 or 30 years or maybe 50 years.

> This is legislation, which I think is ill-advised, if I may say. That's a little strong for people who voted 58 – 0; I realize that. But, I think for the reasons I've given you, this Legislature should take a look at it and decide whether it needs to be revised. Probably 90 percent of what you hear in these hearings you have no control over. It's under the control of FERC. This is something you can do something about – to encourage economic development, to improve the quality of life in the Interior, the Interior villages and down the highway and down river.

SENATOR BUNDE asked if he anticipated that the gas the state would sell in-state, because it's in the state's best interest to get the highest return, would be at the same price as the gas sold out of state, less the cost of transportation. He didn't see any incentive to not increase capacity for Fairbanks if the state would get the same net return.

MR. COLE responded:

> Why would you allow that decision to be made by the pipeline, itself? I think one of the vices of this is for the next 30 or 40 or 50 years, as long as this gasline is there, it is the pipeline, itself which makes the decision. Does it want to apply to the RCA to increase the intrastate capacity? We shouldn't, in my view, allow that decision to be made by the carrier. The decision should be made by either the RCA or by others and not grant it exclusively to the pipeline. They can stifle the developments of Fairbanks and the Interior and the villages and down river for the next 50 years by simply saying if the North Slope natural gas pipeline carrier wants to transport more, it can file the application? Why do we give them that exclusive right?

SENATOR BUNDE responded that a phrase comes from Fairbanks legislators fairly often – "A stranded gas tax would encourage them to be friendly to Fairbanks."

TAPE 04-14, SIDE B

MR. COLE responded that he would like to talk to the people from Fairbanks who voted on this.

SENATOR SEEKINS said he wasn't there during that conversation, but he wants to talk to Mr. Cole before the legislation passes. He also said that take or pay contracts are pretty standard in the natural gas industry and you generally need some of those on hand to show banks that you can borrow the money and repay it.

MR. COLE replied:

> Senator, this is a small infinitesimal amount of capacity of that line [BREAK IN THE RECORDING].... It's not a major accommodation to the pipeline carrier when you consider the consequences to Fairbanks. I tell you, Fairbanks is going to dry up and blow away over the next 30 or 40 years if somehow we don't reduce the cost of energy there. This is a barrier to that – plain and simple.

SENATOR SEEKINS noted for the record that all the new construction in his area is being heated by Fairbanks natural gas and their distribution system continues to expand there, even though they are bringing in LNG.

MR. COLE said his statement proves his point of the crying need for cheap gas in Fairbanks. He repeated:

> It's a crying need and why do we want to initiate, by legislation, barriers to that development, our policy should be the opposite. We should enhance it and further.
>
> Let me talk take or pay contracts. The problem with take or pay contracts is when you have the situation you have in Fairbanks. Sure, I can see Enstar taking a take or pay contract. It has the distribution system, it has the industrial development here to do it; I mean that's a no-brainer. But, we're talking about Fairbanks, which has none of that. We're starting from scratch. We shouldn't put that burden on the people of Fairbanks to have a take or pay contract when they don't know the price of it; they don't know how much it's going to cost to develop the distribution system in Fairbanks; they know nothing.... The problem is that it's going into the unknown. The problem is peculiar to Fairbanks.

REPRESENTATIVE HAWKER said he wasn't in the Legislature when this bill was adopted and said, if Mr. Cole's suggested remedy of repealing the Act would happen, there would be no statutory requirement for capacity dedicated to intrastate transportation.

MR. COLE replied:

> Not to totally repeal it, of course – to repeal this particular section and revise it with something a little more balanced for the need we have in the Interior. There could be, with expert testimony, the amount of intrastate capacity that needs to be reserved and then, within a given period of time or in segments over a period of time, if it's not used within that period of time, then it reverts. You see, I'm looking for 30 and 40 and 50 years. We look, too often, I think, to today and tomorrow and the next three years, but I'm looking for three generations of Alaskans.

REPRESENTATIVE HAWKER asked if he had this conversation with any of the major players who are proposing pipelines to solicit their support.

MR. COLE replied emphatically, "No."

REPRESENTATIVE GARA said he was trying to understand the disincentive for the pipeline owner to let gas be delivered in Fairbanks.

> Is it, if they are going to carry a full load of gas from the North Slope down to Fairbanks, they make more money by bringing it all the way down the pipeline than they do in just charging to drop it off at Fairbanks and that's the disincentive you're worried about?

MR. COLE replied that he hadn't spoken to prospective pipeline owners on what they are worried about.

> I would imagine they would want to make commitments down-line and they don't want to have to be monkeying around with this relatively minute capacity in Fairbanks. I can understand their incentives and their needs. I just think that we need to tinker with this a

little bit to allow Fairbanks and the Interior communities to have the incentives.

I went down to Tok a couple of years ago and we had a hearing there. They said, ‘What’s in this for us? We want gas here, too.’ This gives them essentially no opportunity to ever have gas. Not today or tomorrow, but to ever have gas. That’s one of the problems that I see. It’s sort of shortsighted and I think it’s not unreasonable to ask the producers, the owners of this gas, to make these accommodations for the best interest of Alaskans.

SENATOR THOMAS WAGONER said Ninilchik has some new discoveries and it has the same scenario - a small community and the people want the gas, but the problem is do they want to pay for a station to depressurize that gas down to a lower pressure and pay for the infrastructure that it takes to distribute that gas. Do they want to do an LID (local improvement district) for 10 years?

MR. COLE responded that his sense is to give the people of this state the benefit of warm houses and a quality of life that other people in the Lower 48 enjoy.

We’re right there on the line and we can’t get it? Now, what are we missing? I mean, we’re right there on the line – and we can’t get it because we can’t tell the owners of this gas you have to make some accommodations to these Alaskans whose natural gas you’re piping out to the east coast. I don’t get it!

CO-CHAIR OGAN said that the gas in Cook Inlet has a lot of liquids and those have to be stripped out to process the gas. “Hopefully we’ll have a thriving petro-chemical industry in Fairbanks to get some of those liquids before Alberta gets it all.”

CO-CHAIR OGAN thanked Mr. Cole for his testimony and directed that a letter from Representative Whitaker be typed into the record before testimony from Mr. Persily, Department of Revenue was taken. The letter follows:

July 27, 2004

Senator Scott Ogan
Chair, Senate Resources Committee

Alaska State Legislature

Senator:

Senator Ogan, the request from Bonnie Robson, the consultant to the Legislative Budget and Audit Committee for Alaska Natural Gas Pipeline Issues, is very clear. The subject matter for discussion is to be: “What is your company willing to offer on access beyond what is required by law?”

My testimony was going to be and still is as follows:

Current Alaska law provides for a broad policy directive:

- The Alaska constitution, Article 8, sections 1 and 2 that directs: “It is the policy of the state to encourage... the development of its resources by making them available for maximum use consistent with the public interest.” And that, “The Legislature shall provide for the utilization, development and conservation of all natural resources belonging to the state, ... for the maximum benefit of its people.”
- AS 38.35 The Right of Way Leasing Act – “The natural resources of this state,...and in its land for transportation of these resources...toward markets both in and out of the state are capable of making a significant contribution to the general welfare of the people of this state. It is the policy of this state that the development, use and control of a pipeline transportation system be directed to make the maximum contribution to the development of the human resources of this state, the increase in the standard of living for all of its residents, the advancement of existing and potential sectors of its economy, the strengthening of free competition in its private enterprise system and the careful protection of its incomparable natural environment.”
- AS 43.82 Stranded Gas Development Act – “maximize the benefit to the people of the state of the development of the state’s stranded gas resources”

Unfortunately, with the passage of HB 290 by the twenty-first Alaska Legislature in 2000, that broad policy directive is precluded in that the law puts an overwhelming burden on local utilities and communities to commit to purchase for firm transportation a definitive amount of natural gas without knowing what their future demands will be, without knowing what the tariff rate will be or the methodology for gas valuation will be or from whom they will purchase gas or even if it will be available.

Further, HB 290 exempts a North Slope natural gas pipeline from a requirement to serve as a “common carrier” for anything other than instate use of gas. There is no realistic provision in law that requires the owners of a gas pipeline to provide access for out of state shipping capacity to any other would be competitor.

Simply put, despite a broad policy directive to the contrary, it is probably that under existing law, Alaska’s communities will have limited access to North Slope natural gas. Further, it is probably that would-be competitors will be precluded from shipping natural gas, thereby eliminating the potential for a competitive free enterprise market from which all Alaska benefits.

Fortunately, timely solutions do exist. When HB 290 passed, it was clear that a time of reckoning lay beyond; when the legislation would have to be reviewed and changed. We knew that because, while HB 290 was the best we could do at the time, ultimately it did not meet our constitutional obligation. That time is now. The first set of solutions will require that the law be changed to provide a more probable opportunity for community access and competitive access for would-be gas explorers and producers. A second solution is public ownership of a North Slope natural gas transportation system. The Alaska gasline Port Authority, a municipal entity created in 2000 by an overwhelming majority of voters and the Alaska Natural Gas Development Authority, a state entity created by initiative in 2002, and approved by a significant majority of voters, are both committed to ensuring access to any would-be producer and also committed to providing access to supply for all Alaskan consumers; be they utilities, industrial or other user groups.

Ready markets exist for Alaskan natural gas. The supply/demand dynamic is such that the economics of a project are predictable and positive. Supply at a fair value must be made available to the project that most benefits Alaska and Alaskans. It is the Legislature’s constitutional responsibility to ensure that supply at fair value be made available. That responsibility and subsequent action may from time to time require a reasonable legal and commercial confrontation or negotiation between the Legislature and the major leaseholders of Alaska’s North Slope natural gas: British Petroleum, Exxon and Conoco-Phillips. A negotiation or confrontation of this nature between the state as the owner and the leaseholders is necessary and healthy. After all, much can be gained or lost on both sides. The Legislature’s responsibility is to fairly gain a maximum benefit for the people of Alaska.

N. Jim Whitaker, Mayor

MR. LARRY PERSILY, Special Assistant to the Commissioner, Department of Revenue (DOR), said he wasn’t at the meeting when he got volunteered for this subject. His comments are not meant to depress anyone or contradict earlier comments.

All things being equal, collecting state revenues sooner is better than getting them later. You never know what the future will bring and, if you need the cash, you might say that a royalty or a tax dollar in hand is worth more than two in the ground – especially for a state that is so dependent on each year’s revenues to pay its bills.

But, on the other hand – the one without the dollar in its grip – Alaska needs the gasline money even more so in the future, if declining oil and gas production continues to cut into our state revenues. A steady, even longer-term, stream of cash to the treasury may be better than producing more gas in the early years and then less gas later on.

Just as the Alaska Oil and Gas Conservation Commission (AOGCC) is charged with managing reservoirs for optimal, long-term production, shouldn’t we also consider the optimal term for maintaining the gasline revenue stream? That’s something to consider, since at this time no one really knows how much gas is economically recoverable or if and when companies would be willing to invest in new exploration and production to prove up those reserves and put them in the line.

The proposal on most tables is for a gasline that would move 4.5 BCF per day. With the current proven reserves from Prudhoe Bay and Point Thompson, that’s about 34 TCF. A full 4.5 BCF a day line would run out of gas in 21 years. The truth is it wouldn’t run at full speed and then hit empty one day late in the 21st year. The decline would start soon after the half-way point after which the decreased flow would be steep. The major North Slope producers testified this past legislative session that the gas flow from 34 TCF would start to decline after about 12 to 14 years, leaving plenty of available capacity for new supplies to move down the pipe.

Looking at projections at Prudhoe Bay and Point Thompson, a 4.5 BCF project would be down to 4 BCF by year 15, dropping quickly to under 3 BCF by year 18 without new discoveries to feed the line.

And, yes, there are some additional known reserves on the North Slope, but not nearly enough to keep a 4.5 BCF line full for 30 years or more, which is what we’ve already gotten out of the trans-Alaska oil pipeline.

It would take closer to 60 TCF of reserves to keep a 4.5 BCF gas pipeline full for 30 years, after which the flow would turn sharply lower. Consider that explorers would need to find and develop those new fields just to keep the line full, much less worry about expansion.

Notwithstanding all the estimates of how much gas might be out there, 30 additional TCF is a lot of gas to find. By comparison, that is more than three times as much gas as has been discovered in the Mackenzie Delta. At $4 an MCF, that is $120 billion worth of gas.

Assuming explorers find that 30 TCF of gas or more on the North Slope and in the Foothills, does it make sense to expand the line to move that gas to market as soon as the engineers and welders can do the work to boost the pipe's capacity? Or is it better to pace ourselves for the long term, thinking of those additional reserves to extend the life of the line rather than expand its short-term flow? Should the market decide if and when more gas is needed?

We should keep our eyes on what's important, which is getting the gasline built sooner rather than later and do whatever we can to ensure that the gas flows for as many years as possible. That seems more important than deliberating expansion requirements now, especially if it affects the commerciality of the line.

It is natural to assume that as soon as the line is built, there will be an incentive to explore. No doubt explorers will find more gas on the Slope. The state's interest is to encourage exploration to always keep that line as full as possible. More gas in the line means lower tariffs, which means more royalty and tax revenue to the state from a higher wellhead value and more years of tax and royalty checks. However, too much expansion early on could lead to lower utilization of the line later on, meaning higher tariffs and less revenue to the state in those years. The pipe should be sized for the long-term efficiency, not short-term gains.

It also is natural to assume that some of the major North Slope producers might be motivated to explore, just as independents will want to find gas once there is a line to carry it to market. Therefore, the state should be very careful about creating any mechanisms to direct expansion capacity to any parties in a discriminating fashion – while being just as careful to ensure that the independents are treated fairly, with full and realistic opportunities to access the line.

But, in impersonal dollars and cents, as far as state revenue is concerned, a dollar from a major producer is as good as one from a smaller independent player as long as the majors remember where we are.

Having said that, I want to stress that competition at lease sales is good for the state and, for that reason, the state should take all reasonable steps to encourage and promote independents on the North Slope. It's clear that the independents will play an increasingly larger role in the state's oil and gas industry and without access to move their production to market they and the state would lose. That is unacceptable.

But getting back to the issue of gasline expansion, we believe companies' willingness to commit exploration and production dollars and the market's need for more gas should control expansion of the line. Let's be careful not to let any dreams of expansion jeopardize what we really want, which is the gasline.

The line's tariff structure could also affect the timing of any expansion. By adopting different methods for calculating the tariff, the recovery of capital costs over time, gasline charges can be decreasing or levelized. Each has its own advantages and disadvantage for different players and different times. There are good reasons for each and the state needs to think carefully about the options and the effect.

Through a decreasing tariff, where it starts high and decreases each year as depreciation reduces the line's cost basis, the project's equity investors recover their money sooner and, over time, the tariffs decrease as there is less cost recovery built into the transportation charge. Lower tariffs could encourage independent exploration, but not until those years of the higher initial tariff have passed. Also, under a decreasing tariff the state's take is less in the early years because of the higher tariff as a deduction against royalties and production taxes. That's a trade-off for the lower tariff and higher state revenues in later years.

A declining tariff also lowers the owners' production tax bills early-on assuming the producers are the owners, which back-end loads the fiscal system, a goal of the Stranded Gas Development Act. Because of the time-value of money, this could help the economics of building the project. The owners would pay less taxes early on, because of the higher tariffs, but would pay heavier taxes as the tariff drops in the later years. So, you could say a decreasing tariff with heavier upfront depreciation might be good for a producer-owned line and could be good for new producers if they come on line in the project's later years, but bad for those independents if they want access in the earlier years.

If a third party owns the pipeline, a decreasing tariff would put a burden on the majors as the early gas pays higher tariffs to pay off the pipeline. This could hurt their economics.

A levelized tariff, which is the other option, spreads out the burden of paying off the pipeline equitably over time among all parties. Regardless of the project owners' tax depreciation schedule, the cost recovery is levelized for the life of the project, meaning the tariff is the same in year 1 as in year 20. This would eliminate any burden on early producers to pay a higher tariff, but also would mean the later producers would not see any tariff benefit from a more heavily depreciated line.

Independent producers that come on board at any time in a levelized tariff project would pay the same as the majors. This would be better than a decreasing tariff for independents that feed gas into the line in the earlier years of the project.

And, as you heard at last months' hearing, there also is the issue of rolled-in or incremental tariffs for any expansion capacity. What's important to remember is that the entire issue of tariff structure may be subject to negotiations under a Stranded Gas Development Act contract where the state can negotiate fair access for all parties and help ensure that the line stays full for a long time.

SENATOR BUNDE asked if he recommended one of the three options he just presented on tariffs.

MR. PERSILY said he was sure tariffs were being discussed in Stranded Gas Act negotiations and he had only been on the job for five weeks and didn’t want to pronounce what the state’s recommendation is.

CO-CHAIR OGAN said one of his concerns about revenue is the effect of the draw down on gas on oil revenues. Currently the AOGCC can regulate the waste of hydrocarbons, but not the economic waste of drawing down a large amount of gas in units that would affect oil production and, ultimately, revenues.

MR. PERSILY said he knows that the AOGCC is looking at that.

CO-CHAIR OGAN noted that there were no more questions and that the next subject for discussion was access to capacity for Alaskan utilities by Anthony Izzo, Enstar Natural Gas Company saying that it is the sole gas distributor to Anchorage, the Mat-Su Valley and Kenai Peninsula. He said there is a lot of discussion in his area about whether there will be a spur to service the Valley.

MR. ANTHONY IZZO, President, Enstar Natural Gas Company, said it has been serving its Alaskan customers for over 40 years. He accompanies his comments with a slide presentation. The first slide showed a fuel cost comparison. Gas was the cheapest. The second slide showed Enstar’s pipeline infrastructure; the third slide showed a graph of the Cook Inlet gas supply from 1958 – 2002 and projects out to 2022, when it drops off significantly. A fourth slide showed a graph of consumer’s use of Cook Inlet gas.

MR. IZZO explained that Enstar’s supply strategy, as it sees production dropping off at the end of the decade, has been two-fold.

> We need to contract for additional supply. The reason it’s significant is that we’ve moved clearly from an excess supply market. Back decades ago – in our business we call it overhang – there was a lot of gas available and the demand was much lower and so the contracts at the time were all indexed against prices of oil. It made sense if oil prices were up, the economy was doing well, your natural gas bill went up. If oil prices were down, the economy was down, your natural gas prices for home heating and business use were down. We were not able to secure additional supply using that model – going back just a couple of years ago. So, what we clearly identified is the fact

that we've gone from an excess supply to a supply and demand market.

The second strategy was to clearly identify what really is left in the Cook Inlet - is there potential for additional discovery and can the existing reserves be expanded? What is the real situation from our perspective in terms of North Slope gas?

MR. IZZO presented more slides that graphed Enstar's gas supply from different fields and explained:

With the new strategy, understanding that this was going to be a supply and demand market, we had to look at how we contracted for supply very differently. The good news you'll see on the chart here is that we're now filled up to 2007 and what you see in green is what we refer to as the Unocal contract. It's not indexed against the price of oil; we couldn't get anybody to go and look for that. It's indexed against a trailing average of the Henry Hub. I guess simply put, it is indexed on Lower 48 prices. What we were able to do was to use a trailing 36-month average.

We did not want to subject Alaskans to the volatile price swings in the Lower 48. There have been times in California where natural gas prices would be $20 and then it's $6 and then it's $10. We didn't want that to happen because on a monthly or quarterly basis, bills would be changing; you couldn't plan or budget. It was just not something we found acceptable. So, the average allows us to, once a year, make the adjustment to the Regulatory Commission of Alaska and then it gets passed right through. The consumer pays for it and it gets passed through Enstar directly to the producer.

So, the good news is that we've got some investment going; we've spurred some exploration. That gas in green right now costs $4.39. Our weighted cost to the consumer is $3.11 and in the Lower 48, they're paying about $6. So, we're less, but prices will increase. As the Unocal gas makes up more and more of our portfolio...we move away from most of the supply being indexed against oil prices, which are up by the way, which means that gas prices will go up next year. But, we will be more and more connected to that Lower 48 pricing mechanism. Unocal has spent about $110 million in looking for new supply and there has been some success we’re very pleased about.

Step number two is to determine what is really in the Inlet and what are the options...to serve half the state’s population in this region. The final report was released July 6; this was done by the Department of Energy as a result of a federal appropriation to the DOE’s Arctic Energy Office in Fairbanks. A local firm in Anchorage actually did the work, brought in outside expertise when needed, and worked with all the various utilities and producers.

There are three observations...in the report that I think are relevant. One is potential reserves growth, two is new exploration and what is the potential and three, North Slope gas to Cook Inlet.

MR. IZZO explained some of the graphs that showed the gas supply line dipping below the demand for power generation and home heating in 2012. His real concern is, looking at fields that are dedicated for just power generation and home heating, that line intersects in 2009.

In terms of reserves growth now, DOE looked at it and said well, we have these existing fields in Cook Inlet. What’s the potential if those were to be expanded – if modern technology was used and you enter those fields? So, this is highly speculative. They just used models from other fields around the world that were just as mature.... You might be able to get another 1.5 TCF out of there. Applying some of their information, they came up with a cost of about $.5 billion...to expand those reserves....

What that would look like is a slightly more optimistic slide on the next page. If 1.5 TCF were found in those fields at $500 million, we could be looking at a line that doesn’t dip down below until the end of the next decade. And so, it’s not a sure thing by any means and there’s no guarantee that trying to increase those reserves will actually result in this, but a best case scenario is for $.5 billion, that it might buy us some time to get us through most of the next decade.

In terms of new exploration, they found some good news. I thought it was some good and some not so good. They believe that based on the profile of the endowment in the Cook Inlet, the Department of Energy thinks that there could be 13 – 17 TCF additional in the Inlet and that's great. The concern I have is that once they put some analysis to the cost and we looked at the protected lands, we looked at the cost onshore versus offshore, they found that if you could find 50 percent of that potential gas – again, you're throwing the dice, in my view.... if you found half of it and if it were on land, then the investment required there would be $5 billion to $6 billion. That would certainly buy us a decade or two. The concern I have, again, is the economics.... It would have to be competitive and be passed through to the consumer.

Now, out of my own business interests, what are the alternatives? The alternatives, if it isn't natural gas, there's fuel oil, there's propane, there is electric, but you're talking about three, four, five and six times as much. You're talking about half the state's population in terms of the economic impact. That does not include what it would cost to convert, what it would cost to put in tanks, to convert furnaces, etc.

The last observation I'll share with you from my perspective was the North Slope pipeline ideally did have the potential to moderate prices in Southcentral Alaska. One thing that Enstar knows and that I'm here to share with you is that prices are going to increase. That's a conclusion. I know they will go up, because I couldn't get anybody to go and look for gas unless it was economic to go and look for it. So, the traditional model of all this extra gas and we'll sell it to you at a stranded gas prices. It just didn't work any more. So, they'll go and look, but we could end up by the end of the decade paying more than they do in the Lower 48. It still might be less than the next alternative, but it's not a good situation.

I was very encouraged that the DOE found that a spur could provide a $1 per MCF advantage over the Lower 48 pricing and that that could result in some energy intensive industry and some economic development.... What we're showing here is that gas from the Slope

> down into the Lower 48, if it cost $2.58 - $3.00 MCF, that using the various models, conservatively the DOE believed that it could be, in comparison, $1.50. So, we could enjoy $1 MCF reduction or a lower price compared to the Lower 48, which could mean with our deep water access and logistical advantages here in Alaska, that we could have an economic advantage. It's not a choice of paying whatever the tariff might be from the Slope to Anchorage versus paying the $2 that we've been paying for years for gas over the decades, because those days are gone. It's going to be at some point in the next few years, we're going to be paying more than the Lower 48, because we're technically not connected to them. But, for producers to economically go after the additional supply, it's the over-ripe fruit story. The low ripe stuff has been picked....
>
> The conclusions are that I believe from Enstar's perspective that access to Slope gas is absolutely critical. As I stated, I believe that prices will continue to rise because we're in this supply and demand market. That has clearly shifted in my world. We could enjoy a 20 - 25 percent price advantage over the Lower 48, which, I think, instead of being concerned about an economic decline associated with declining reserves, we could be looking at some potential economic boom in terms of energy intensive industry. To determine what that is, we have requested a phase-two appropriation to study energy intensive industry, what that might be and to also look at some conceptual engineering for a connection from Anchorage up to Fairbanks or Delta Junction. I've got my commercial blurb at the end and now it's time to focus and I'm preaching to the choir. That concludes my presentation.

SENATOR WAGONER asked if Enstar is still considering a spur line.

MR. IZZO replied that it is.

> That is very real and is in the forefront of our radar screen in the future. We believe that we have obvious interest in wanting to stay in business and wanting to be profitable, wanting to earn our rate of return that's allowed, but we have found that with the declining reserves in Cook Inlet that our interests

> are similar and parallel with the economic interests of this region. So, I would use the example of building a house. I don't think any of us, if we were building a home, would wait until the framing was up to pull out the yellow pages and find an electrician or a plumber. We'd have the estimates; we would know what it would cost. We'd have it ready to go and that's how we view the spur line – is that we need to know what that is and we are currently working such that we can do the responsible thing and be prepared.

REPRESENTATIVE GARA asked of the gas pipeline owner's incentive not to allow a spur to Cook Inlet:

> If they fill up the pipeline from the North Slope down to Tok, and then dump off a certain amount of gas in Tok, then that they're carrying a less than full pipeline from Tok all the way down to Chicago and therefore it makes the transportation in the remainder of the line less efficient? Do they have a disincentive to allow the spur because of that and also because it eats into the amount of gas they get to charge to pipe from Tok down to Chicago? Is that the disincentive or does the pipeline not work that way? Two, do you agree with Attorney General Cole that we have to take another look at the law to make sure that we guarantee our ability to have the spur lines in the state?

MR. IZZO agreed on his first point. Various interested parties have expressed concern to him directly that constructing a pipeline with X capacity and then finding themselves in a situation where only 75 percent or so of that capacity can be met from Tok or Delta Junction on south. My response to that has been more around what the needs of this community are as I know them.

TAPE 04-15, SIDE A

MR. IZZO explained that when the interested parties hear of the need for power generation and, potentially, some industrial use and home heating, which is much less than 1 BCF per day, the reaction has been one of reassurance. To Representative Gara's second point, he said he did not hear Mr. Cole's presentation, but, "The legal nature and critical need of a spur line in my view is something that we should do every bit of due diligence possible. So, if there's any doubt that we may have access, I would encourage the legislature or any responsible party to look at that."

CO-CHAIR OGAN suggested that Mr. Izzo review Mr. Cole's presentation, which has some very good points about Fairbanks' concerns with the take and pay concept in HB 290 of the 21st Legislature.

REPRESENTATIVE CHENAULT said Mr. Izzo talked about the price of new gas from Unocal being $4.39, which is based on some sort of sliding scale at the Henry Hub, and he projects the price will go up because of the price of oil. He asked him how he is tying the price of oil back to the price of gas when it is based on a sliding scale at the Henry Hub.

MR. IZZO referred to the slide of the gas supply in 2003 and said he refers to those contracts as legacy contracts. Those have been indexed, for some time now, on the price of West Texas sweet crude between May 1 and June every year. Based on that index, prices will change in the following calendar year. He continued:

> So as we've moved into where we are here in 2004, 24 percent of my supply is with the Unocal contract. That's indexed against the trailing average of Henry Hub. The remainder is still indexed on the price of oil so what's happening currently is within this transitionary period, is the price of oil is up. That is putting upward pressure on rates. As the prices are sustained at high levels in the Lower 48, that drives that average up over the 36 month trailing period....

CO-CHAIR OGAN responded:

> Once we indexed to the Henry Hub, the consumer prices went up quite a bit based on that – is what's going to have to happen to have people looking for gas, which we do have finally for the first time ever. People are leasing for the sole purposes of looking for gas in Cook Inlet and that was just something that happened with oil before that.

REPRESENTATIVE HARRY CRAWFORD said that he and Senator Bunde attended a NCSL conference and heard a presentation by the producers, during which they talked about the energy supplies in the country over the next 25 years. They said they don't even book the North Slope gas supplies in because they expect those supplies to be stranded for another 25 years. He asked Mr. Izzo what will happen to Enstar if that gas supply does not come off of the North Slope.

MR. IZZO said Enstar has been undergoing a very aggressive program. It has and continues to meet with producers on an ongoing basis. Enstar believes it is responsible to determine what it will take to spur exploration. It would continue as it has and, although there is a certain amount of uncertainty about the future compared to 20 years ago. He then said he does not subscribe to the 25-year theory. He believes that with free market forces, this is something that can happen. He has discussed that question with his peers throughout the country and has asked, at Western Energy Institute Board meetings, how many of them would have a difficult time getting a long term supply approved at $4 or $4.50 by their commissions and everyone had jumped up. He said he sees the need for some reassurance of supply and, to some degree, it is a national security issue. He said because of the volatility his cohorts are experiencing, they would embrace the ability to reserve capacity. He said the true test would be the number that would line up if there was an open season.

MR. IZZO said this has been discussed for almost 35 years and he is asked what is different now. As he looks at half of the state’s population that could see declining reserves, he sees how that is directly associated with Alaska’s economy and yet, Alaska is the richest resource state in the Union. He thinks with the confluence of those factors and free market forces, this is a very viable project.

CO-CHAIR OGAN noted that every expert on energy supply and demand trends who spoke to the Energy Council in the last year and a half factored in the availability of Alaska gas and that beyond the year 2020, the United States will have to import 20 percent of its gas from foreign LNG sources even with 4.5 BCF from Alaska. He asked Mr. Izzo to visit the Mat-Su Borough and relay his views on the gas supply.

Co-CHAIR OGAN announced an at-ease from 2:30 p.m. to 2:45 p.m. Upon reconvening, he asked Mr. Loeffler to testify. He informed members Mr. Loeffler is a senior partner of Morrison and Foerster LLP specializing in energy matters and has represented clients before FERC for more than 30 years. He has been advising the State of Alaska on oil and gas pipeline issues since the mid 1970s.

MR. ROBERT H. LOEFFLER, Morrison and Foerster LLP, gave the following testimony.

In my June 2004 testimony to the committee, I discussed the general methodology and standards that the FERC utilizes to set gas pipeline rates. Mr. Ives of the Lukens Group discussed access issues associated with initial pipeline capacity, in particular FERC's open season process. Today I want to address another pipeline issue that looms potentially large and important, namely, the law that governs expansions of an Alaska Gas Pipeline after it is initially sized and built. I will first address the law on expansion as it stands today and then turn to the provisions of the Energy Act of 2003 that for the first time gave the FERC the power to order expansion.

Based on information provided in the various Stranded Gas Act applications, the Alaska Gas Pipeline could be sized to carry anything from 2.6 to 5 BCF per day, with expansion capability designed in of up to 6 BCF. Any expansion would be accomplished not by replacing the original pipe with larger diameter pipe, but rather by adding additional compression – that is additional compressors at existing stations or building new compressor stations – and/or looping. That is adding smaller diameter pipe parallel to the main pipe in particular places. The question is whether the Alaska Gas Pipeline owners can be forced to expand the pipeline in the event they do not voluntarily agree to do so. Under current law, the short answer is no. Let me explain that.

We have to turn to the Natural Gas Act [NGA] and it does not use the word expansions. Instead, it prohibits enlargements but gives the FERC the authority to order extensions. Simply stated, while the FERC has the power to order extensions or improvements, it does not have the power to order enlargements to pipeline facilities.

What's the difference? It turns out there's no bright line, but the courts and the FERC have interpreted this language in a manner that treats expansions as prohibited enlargements. It took awhile after the act was passed in 1938 for the courts to get to this and by 1949 the courts were saying, literally, the act nowhere defines these terms and it's somewhat baffling to determine when and under what circumstances an extension or improvement of facilities ceases to be such and becomes enlargement.

The commission could see that in court way back in 1949 that it does not have the authority to compel enlargement by a natural gas company of a pipeline. Yet I think the language of the court is instructive. It says in light of section 7(a), we are compelled to conclude that Congress meant to leave the question whether to employ additional capital enlargement of its pipeline facilities to the unfettered judgment of the stockholders and directors of each natural gas company involved. So, what you're dealing with is really the belief that private people are building a project and you cannot force them to put more money into a project if they don't want to. And that really is the standard under existing law.

Very recently the commission reaffirmed this position and said it has the authority to order a pipeline to construct new interconnects or [indisc.] connections are made, but it also said that it cannot compel pipelines to expand capacity on their systems. Interconnects are literally the physical connection between two pipelines - if you wanted a lateral coming in or a lateral going off – that's an interconnect. And even there where it does have authority to order interconnects, the commission said in this particular case, 'The Commission emphasizes that this new policy, which relates only to the construction of new interconnections, does not require a pipeline to expand its facilities, to construct any facilities leading up to an interconnection, or even to construct the interconnection itself....' This modified interconnection policy seeks only to ensure that when pipelines respond to requests for interconnections, they do so in a manner that causes no undue discrimination and furthers the commission's policies favoring competition across the national pipeline grid.

Well, in short, a state and any private party who wanted expansion would be in a tough position to rely on the existing law to get an Alaska gas pipeline expanded by the FERC. The good news is that Section

375 of the so-called Alaska Natural Gas Pipeline Act, which is the subtitle of the Energy Policy Act of 2003, would grant the FERC the authority to order expansions subject to certain conditions. The bad news, of course, is the legislation is languishing in Congress.

Section 375, if it becomes law, would be the first time the FERC has been given the power to order expansion for any pipeline. This represents the recognition by Congress of the unique circumstances of an Alaska gas pipeline, and namely that it is likely to be the only road to market for North Slope resources. This provision was fashioned after much discussion and compromise of present and future North Slope producers, pipeline owners in the Lower 48, would-be pipeline owners of Alaska and the State of Alaska. Some urged that the FERC be given greater powers for expansion; others urged that there be no change at all. As you will see by reading the language, FERC's new powers do not extend to interstate gas pipelines in the Lower 48. This is a solution for an Alaska gas pipeline and only for that pipeline.

I'm going to quickly go through critical terms. The way it works is that one or more people would have to request the FERC to order the expansion of the pipeline. Before it could do so, it would have to satisfy eight conditions and they're stated at page 8 of my testimony. The first condition deals with the rates – will they be rolled in or incrementally priced for expansion - make sure rates do not require existing shippers to subsidize expansion – find that a proposed shipper will comply with the tariff that exists as of the date of the expansion – find that the proposed facilities will not adversely affect the financial viability of the project – find that the proposed facilities will not adversely affect the overall operations – find that the proposed facilities will not diminish the contract rights of existing shippers to previously subscribed capacity – ensure that all necessary environmental reviews have been completed – and find that adequate downstream facilities exist outside of Alaska to deliver the Alaska natural gas.

Now I want to comment on some of the details of these provisions that could affect the issues the committees are concerned with. The language of this new provision does not mandate how expansion capacity will be priced by the FERC. It gives the FERC power to use either rolled in price treatment or incremental price treatment. This is an issue of consequence to unaffiliated explorers because they want to know what the cost of transportation on an expanded pipeline would be.

A parallel provision requires that the rates for expansion capacity not require that existing shippers subsidize expansion shippers. Of course, what's a subsidy rise in the eye of the beholder? In some circles what is called a subsidy is viewed as an entitlement or a natural right by others.

Today, under existing law, the FERC has a clear policy on how expansion should be priced. It's changed its policy a number of times but its most current policy is that an expansion should be paid for by those demanding the expansion unless there is a system-wide benefit. A system-wide benefit would mean that when the costs of the expansion are rolled into the existing costs of operation, the costs of transportation for all is lowered. This is technically possible in some circumstances depending on engineering and throughput matters. If, however, the average transportation cost increases due to the expansion, then the expansion shippers, under current policy, would pay a different and higher rate to ship on expansion space. The rationale, simply put, is that those who cause the expansion should pay for it. Informed observers have noted that there is a 'heads I win, tails you lose' aspect to this policy. If expansion lowers the cost per unit for everyone, then those causing an expansion lose that benefit to the system as a whole. If, on the other hand, expansion costs are higher per unit than they were before, the expansion shippers are forced to bear the higher cost. Time will tell how this works out on an Alaska gas pipeline and I repeat that the legislation tosses that issue back to the FERC saying it can use either incremental or rolled in pricing.

There are other limitations in Section 375 worthy of mention. Parties in the legislative process were concerned that expansion not affect the financial underpinnings of the project. Certainly the language in Section 375(b)(4) would give financial institutions, who presumably will loan vast sums for this project, a voice in any expansion proceedings at the FERC. Similarly, the rights of those who have already contracted to ship on the pipeline are not to be diminished by any mandated expansion. I suspect that this means, at least, that there cannot be any reduction in existing shippers' shares of initial capacity.

Two other aspects of Section 375 are worthy of comment. First, the FERC is required to examine whether there are adequate downstream facilities, mainly outside of Alaska, for new gas that would be shipped through the expanded facilities. This stands in marked contrast to the process spelled out for certificating the pipeline in the first place under this new statute. There Congress directs the FERC not to look at whether adequate downstream capacity exists, but to presume it. Second, subsection 375(c) requires that the party who requests an expansion at FERC execute a firm transportation agreement within a time to be set by FERC, a reasonable time, after an expansion order issues or lose the expansion rights. This, in plain language, is a put up or shut up clause. The expansion order becomes void unless the parties who sought the order sign a binding contract to ship on the expanded capacity.

There are other requirements in the proposed legislation concerning non-adverse findings on financial, economic, and operational grounds. On their face, these provisions appear to provide fertile ground for an opponent of expansion. They certainly invite litigation.

In the end, the proposed legislation allows, but does not mandate or require FERC to order an expansion. That's a better situation than the status quo but it's not perfect. I do not have to be a prophet to make the observation that in granting expansion rights to the FERC for, and only for, an Alaska Gas Pipeline, the legislation would lay a careful path with several potential hurdles to clear. How high those hurdles will be is left to the informed discretion of FERC. Based on everything else connected with this project, the first time around and again now, I would not expect the expansion proceeding to be short, uncomplicated, and uncostly. Nonetheless, the power to order expansion would exist for the first time. That alone will influence how parties approach expansion on a voluntary basis because the prospect of involuntary expansion lurks in the background.

I'm going to add a couple of points that are not in my prepared testimony that I thought would be of interest to the committee. If you recall, in June I commented on how the legislation would require the FERC to adopt quickly to situations that would govern open seasons on an Alaska Gas Pipeline. These regulations would not apply, that is they would not apply to any mandatory expansion of the pipeline. For reference, that's Section 373(e)(3). They would apply only to involuntary expansion of the pipeline. The rationale of Congress, I suspect, is that an expansion order would be sought by a specific shipper or group of shippers that had been unable to convince the pipeline to expand voluntarily. In those circumstances, those seeking expansion would have to convince the FERC to order this one-of-a-kind expansion and they would be responsible for signing binding contracts for the expanded capacity. Thus this appears to be a different kettle of fish than the normal allocation of capacity and open season process. FERC still might want to hold some kind of open season to see if anyone behind those seeking expansion also desire capacity in the event this pipeline is expanded. But it's not required to. It's [indisc.] from the normal open season requirements and we have to wait and see how the FERC interprets these provisions.

Second, the legislation also addresses access for in-state users. In Sections 375(g), Congress requires the applicant for FERC authorization under the Natural Gas Act, to demonstrate that the holder has conducted a study of Alaska's in-state needs, including tie-in points along the Alaska natural gas transportation project for in-state access. I believe the state would expect the study to cover access at least two to three points along the pipeline route in Southcentral

Alaska. Second, the special provision in Section 373 uses language that addresses access for royalty gas. That provision requires the FERC, after a hearing, to provide reasonable access to the State of Alaska for shipment of the state’s royalty gas for the purpose of meeting local consumption needs within Alaska. The language is specially designed to ensure that Alaska royalty gas could be used for in-state needs. The absence of new federal legislation does not necessarily mean there will be no expansion requirements for an Alaska gas pipeline. As I indicated a few moments ago, the expansion language in the pending federal legislation reflected a consensus that was reached among interested parties. These parties thought they could live with the expansion concept in specific conditions attached there, too. It would appear there would be no insurmountable obstacle to interested parties contracting to the very same terms contained in the proposed legislation, or even different ones. It is a fair bet to say that the existence of the compromise language, whether adopted or not, will also provide a framework for voluntary expansion negotiations.

The ongoing Stranded Gas Development Act contracting process could serve as one vehicle to ink an expansion agreement. Another contracting opportunity will arise in the negotiations attendant to the various ownership agreements. If the state is not a pipeline owner, its interests will probably not be directly represented in those ownership negotiations.

Would FERC honor such contractual agreements? I see no reason why the FERC would reject an agreement that required the owners to seek expansion authorization from the FERC after negotiations in the event that certain agreed upon conditions or events were to occur. So long as FERC remained free to make its normal certificate inquiry about the public interest, I think it would likely applaud rather than disapprove a voluntarily reached expansion agreement.

That concludes my presentation. I appreciate the ability to do this by teleconference and I’d be happy to entertain any questions.

SENATOR WAGONER asked if there is any chance of action being taken on the Alaska Gas Pipeline Act before the November election.

MR. LOEFFLER said there is a slim chance it will be brought up as a rider or on a special basis, but only a slim chance.

SENATOR WAGONER asked his opinion of action after that time.

MR. LOEFFLER said he believes it will come up again in the same exact form because a lot of people worked long and hard to compromise and there is no known opposition to the enabling provisions that contain this expansion authority.

CO-CHAIR OGAN asked what the best-case scenario is.

MR. LOEFFLER said the best case would be if something happened before the November election. He believes it is much more likely that something will happen next Spring, but no one knows who the president will be or who will be in Congress.

CO-CHAIR SAMUELS asked Mr. Watson to testify and informed members that Mr. Watson is the Project Manager for Alaska Gas Development for Enbridge. He is actively involved in all aspects of project assessment and currently leads the coordination of market participation on behalf of Enbridge. Prior to his employment at Enbridge, he spent 10 years directly involved in the Canadian energy industry, most recently as the vice president of corporate development for a leading solution provider to the North American energy industry.

MR. ERIC WATSON, Project Manager, Alaska Gas Development, Enbridge, reminded members that Enbridge has proposed a measured approach in its Stranded Gas Act application. It includes a 36-inch pipeline design, which contrasts with the 48 and 52 inch pipelines proposed by other parties. Enbridge views the 36-inch design as a better economic alternative to meet the pipeline needs. He asked to delve into that topic today and describe some of the factors that will drive the volumes and how that will impact the pipeline design and, inevitably, the cost of delivery. He began:

> For the benefit of those who could not attend the June hearings, I will spend 30 seconds just as a quick overview of who Enbridge is, just in case you don't know about the company. We operate the world's longest crude oil pipeline system. We have assets in excess of

$13 billion, a stable A credit rating, lots of cash in the bank and, as it relates to the Alaskan project, gas now makes up 40 percent of our earnings. Included in that is a 50 percent ownership in the Alliance pipeline, which is one of the major transporters of natural gas and liquids for the Chicago market and also the owner and operator of Canada's largest LDC, serving over 1.7 million customers in Ontario and northern New York State. So, we also have a bit of a market perspective on the other end as well.

As you may be aware, we're pursuing a greenfield project through FERC and the NEB. We are the only pipeline company with extensive experience in continuous and discontinuous permafrost construction operations [indisc.] pipeline. We have the most recent cross-border, large-diameter, high-pressure, rich gas pipeline experience, which is more than likely to be a similar scenario to the Alaska pipeline. We've participated in both study and field trials in Alaska to examine the practice of trenching in permafrost ... As I mentioned, we also have a market perspective through ownership in Canada's largest LDC.

As I mentioned at the outset, we're focused on a measured approach that reduces the risk of the project and aligns the interests of the stakeholders. I want to clarify that a measured approach doesn't necessarily mean a phased approach and that we are not stuck or bent on 36-inch as the only solution. We believe it is a potentially viable solution, depending on the volumes and timing of the volumes that come out of Alaska and that's really what I want to look at today. Based on what happens with these volumes and these timings is really going to drive the economics of this project and within that 36-inch is an option that we should still be looking at. So with this, we're seeking to add value within the project by working closely with other stakeholders in a collaborative and cooperative manner. Given the size of the project, we believe that not only the producers will have a role in it, but there will be other parties that are needed to also make this project a success and take on the substantial risk that it presents. We need to maximize economic opportunities for Alaskans and continental North America - I put a couple examples, such as steel supply and local labor.

We'll get into a little bit of perhaps some of the benefits that a 36-inch line might mean to North America and Alaska versus the alternatives. Investing resources into local communities and First Nations groups is something we've done in the past with all of our projects. The last point is fully leveraging existing infrastructure only to the extent that it reduces costs, minimizes tolls, and maximizes netbacks for Alaska gas.

During the last hearing we presented on the supply outlook within the Western Canadian supply basin and how it was starting to ramp down after 2015 and what the available ex-Alberta hub take-away capacity looked like. We do want to make sure that we reiterate that while generally an existing pipeline could be a cost-effective alternative, depending on where the gas is delivered and a number of other factors that may not be the most cost-effective, it could call for a new build as well.

Ultimately, the state and shippers are interested in a pipeline that's designed to offer the lowest cost of delivery – whether that's 36 inch or 52 inch. In order to achieve this, we need to understand a number of factors that impact the design capacity and ultimately the cost of delivery. So we've heard a fair bit today about open season contract commitments. Inevitably, the project needs to be underpinned by these long-term shipping contracts and with that, from this process, that's going to really decide what the volumes look like and what the contract length is going to look like and where the gas actually needs to move to. And from that, we're going to be able to tell what the best design and what the most economic design looks like. And you've heard lots before what the rest includes. Really, it's driving out what the expectation level of unproven reserves are going to look like into the future, what people believe the gas price is going to look like....

One thing we haven't talked about a lot is where the market is for the gas as well. Is it all in Chicago? Is it in the Northeast U.S. or is it even in California as well? It's going to play a role. We've also spent a lot of time talking about expansion as well, so we believe that exploration success will drive out the expansion volumes and the timing beyond the initially accepted risk. So whatever the market is going to accept initially, I think is going to be representative of what they believe can actually be delivered and then expansion beyond that, depending on how successful, how much investment is made into the state in refining resources and start to drive that expansion. Obviously, as an independent party, from our own selfish perspective, we'd always be looking at trying to add capacity for shippers as long as it's underpinned by a contract.

And the other element that goes with that is the take-away capacity that is actually available from Alberta. Obviously we can talk about moving all of these volumes into the Alberta market, but Alberta is a large net export market, therefore we need the capacity to actually move the gas out of Alberta as well. Based on when we move that gas and how much of it we move, it directly impacts the economics as well, whether we're able to use existing pipeline, where that gas is going, and how much gas we can actually send out.

And then construction factors – how will the construction costs be impacted by competitive supply if this project is, let's say, delayed or it's really the MacKenzie Valley – what is the labor availability going to look like? Will there be competition?

So let me just mention, the most important note, and we've heard it several times today, is that regardless, the pipeline needs to be underpinned by a long term shipping contract. Enbridge is currently working with certain parties within the market, including our own distribution. We try to align and see what the feel is for the demand and where that demand might be and what the overall commitment might be as well. But, once again, that might get fleshed out until the open season occurs.

The length and volume of the shipping contracts, as we've discussed, are impacted by such things as expected wellhead price, tolls, reserve life and government relations. Inevitably, if we get into what drives the volume's timing and design capacity has to do with our expectation of the reserve...

> What I’ve done is taken three different examples – practical examples of the potential reserves that the market may expect and how that flushes out volumes over service life. If you actually look at what we’re getting or expect or the proven out of Prudhoe Bay and take the volumes over the different service lives, we see that it ranges anywhere from 2 to 3.3 [BCF]. Based on the economics we’ve run, this drives preferably towards a dual 36-inch pipeline would actually provide you with the lowest toll. More reasonably, we’re not going to be looking at just the 24. We’ve talked a lot about the 35 area and here we’ve got a range of the 2.7 to 4.8 [BCF]. This is where you get into a situation where the economics actually start to transition as you move up anywhere from a 36 potentially to the 52 inch line. If you actually get beyond the 35 TCF, and how much risk the market is willing to take, beyond what’s proven into the realm of the probable, we’re looking at volumes in excess of potentially 5.6 to 9.7, which really goes back to what was said earlier. If we’re delivering all that up front, a 52-inch pipe is most likely the economic solution.

TAPE 04-15, SIDE B

MR. WATSON continued.

> If you’ve got a ramp-up that exceeds – and we did it on the basis of 5.2 BCF starting at 2.6 – as per our application, you actually ramp that up over a course of four years or more – once again the dual 36 inch pipeline from an economic perspective looks more attractive than the 52. So it all goes back to the same things you’ve been hearing earlier. If we send bigger volumes and we send them earlier, economically you’re looking at a 48 or 52-inch option. If we’re going through a phased ramp-up, or if we’re starting at smaller volumes, the 36-inch becomes more practical.

CHAIR OGAN asked if Enbridge would build both pipelines simultaneously.

MR. WATSON said if he is referring to dual 36-inch pipelines, the model Enbridge used had the [second pipeline] starting two years later but that will depend on the market commitment. He stated:

> So when we actually modeled it, let's say on the 52 or 48 inch basis, you'd put in all the pipe but you'd only put in enough compression that you need to start at 2.6 and then you ramp the compression up. Obviously you're not going to just – with the line you've got to put the whole line in first. With the 36-inch option, you build the first line and then after you're done, the first line you actually start to go through the construction of the next line using the same right-of-way. What that does...is it actually enables you to actually get gas to market...about one year earlier. If you use the 36-inch, you're going to get less volume to market earlier, but you're actually going to get gas to market earlier and to the extent that it's a benefit, it's going to potentially prolong the construction period as well, which is going to be more revenue for a sustained period on the construction phase within the state of Alaska.
>
> As we talked about earlier, one thing we obviously need to do is we need to align it with not necessarily available ex-Alberta take away capacity, but we need to understand what the actual take away capacity looks like and where we're actually shipping the gas to. If you kind of implant the supply forecast versus what's available out of the Alberta market right now, and the right graph there really extrapolates from the left graph, it shows us when and how much take-away capacity is available within Alberta – and you'll see here that up until around 2018, 2019, it's less than the 5 BCF we're talking about. So what that means is we're going to need to add new capacity out of Alberta into specific markets – Chicago, it could be west. It shows us when and how much take-away capacity is available within Alberta and you'll see here that up until around 2018, 2019, it's less than the 5 BCF we're talking about.
>
> So what that means is we're going to need to add new capacity out of Alberta into specific markets. It could be Chicago, it could be west – it's either going to go one of two ways but regardless, we're going to need to add new capacity if we're shipping those volumes when we're expected to actually commercialize

gas within Alaska within the 2012 to 2014 timeframe. The question becomes is it worth phasing it in, starting with, let’s say, 2.5 BCF per day, knowing that you’ve got the ex-Alberta capacity available there. You can use existing pipe and then ramp up the volumes, either through compression or through the construction of another 36-inch line, so that you start to match the available take-away capacity and which one of those is cheaper. We don’t know that because you don’t know – we’ve got an idea where the market is for the gas, but until the open season happens, until you know what the volume commitments are like, until you know where you actually want the gas delivered, we don’t also know from the ex-Alberta perspective where we need to get that gas.

So, in the event that the MPS 36-inch pipe does make sense and that we’re starting with lower volumes and ramping up over time, some of the advantages of the 36-inch line, one is the greater certainty around the cost estimates that we have. There are a number of companies within North America right now that manufacture 36-inch. There are none that actually manufacture 48 or 52-inch pipelines within North America so there’s a greater supply risk around the 48 or the 52- inch option.

A big benefit potentially to the state is that we’re in service one year earlier so you’re making revenues one year earlier as well. It’s easier to perform maintenance without service interruption. You’re going to find a more experienced and skilled labor force that’s actually worked with the construction. The big bang here as well is...more supplies can be sourced from Canada and the U.S. versus overseas. We’re just going to have a more positive impact on the North American economy, and potentially within Alaska as well. We’re going to be able to keep more of the revenue within the state and in the construction process as well, versus having to go over to Japan or Germany or Russia.

One of the disadvantages that we talked about is really just the reduced economy of scale if you’re able to bring on higher volumes right away.

> So...just to wrap up some of the key points here...is that one, and we've heard it all today, is that the open season volume commitments and ramp-up timing will drive the most economic pipeline design and we don't know what that looks like yet. The Alaska to Alberta volumes and timing need to be matched with the lowest cost Alberta to market take-away capacity and, as I mentioned, that may mean existing pipeline or that could be new pipeline. Alliance Pipeline, which Enbridge has a 50 percent ownership in, for example, has .5 BCF of cheap expansion – the cheapest expansion available into the Chicago market through compression. Other than that, we need to look at a new build out of the Alberta market, whether it's through TransCanada, through Northern Border, or through other options.
>
> So our measured approach is – it's not a phased approach, we're really just aiming to align the Alaska volumes, whatever they are, whatever the market's willing to step up to, what they're willing to take as far as risk and provide, either, you know, through an existing or for optimal cost efficiency and market alignment....

SENATOR WAGONER asked what would happen to Enbridge's interest in this project if, in fact, the gas liquids were stripped out in Fairbanks and shipped down the TransAlaska pipeline to be used for other industries.

MR. WATSON said that would not have any impact on Enbridge's decision in the project. He noted, "It's really what's best for the producers, where they're going to get – and the state itself, or the gas owners, wherever they're going to get the best netbacks, I think there potentially could be some resistance from the Province of Alberta itself...." He said whether it is moved into the Alberta market or not will have no bearing on whether it's good or bad for Enbridge. He continued:

> So if Alaska wants to build a petrochemical industry up here and the gas and the liquids need to be left within the state, that's fine, or, if the producers in the state feel that liquids need to go into the Province, certainly the infrastructure exists there to handle the liquids.

SENATOR ELTON asked Mr. Watson to discuss the tension between access and capacity and those with the proven reserves and those who may be more dependent on undiscovered resources with a 36-inch pipe. He asked what happens with a smaller pipeline transmission system.

MR. WATSON said he does not see a smaller pipeline making it more challenging to get access. Initially there would be less access because of the smaller design capacity but the plans could allow for a ramp up to 5.2 over the course of 3 to 4 years, so that capacity would become available at the same time as a 52-inch line.

SENATOR ELTON said during testimony by Department of Revenue staff, members learned they may need to have a discussion on smaller amounts of gas moving over a longer period of time. It would seem easier, during an open season for those with reserves but less capacity to have it easier than those without, because if capacity is increased over time, that would make it more difficult for explorers who have to wait.

MR. WATSON said Senator Elton hit the nail on the head when he said the producers or shippers themselves would decide during the initial open season because:

> You hit a crossover there where the 52-inch line becomes a more economical choice. It really depends what the market's willing to step up to initially so you don't go into the open season and say, okay, we're proposing a dual 36-inch pipeline. The market comes to the open season and [you] say, okay, here's the gas we need within the Lower 48 and then you take that away and say okay, what's the most economical pipeline design.... So, to that extent, that's where we're coming with the measured approach, is that we need to come in with an understanding of what the market needs, what volumes they need and really where they need it as well. Obviously, it's not going to impact the design from Alberta or [indisc.] from Alaska to Alberta but also what needs to happen from Alberta to market as well.

CHAIR OGAN expressed concern about the disadvantages of higher capital costs, which will translate into higher tariffs, and questioned whether Enbridge has run any models on the differences.

MR. WATSON said Enbridge has and [the answer] depends on the volumes. As you start to shift into lower volumes, that's where the 36-inch will come up with a smaller capital cost because an asset will be buried in the ground that is not being utilized. The other consideration is the ramp-up time. It gets back to the open season and matching a design that produces the lowest toll for what's needed in the marketplace. That is why Enbridge is not saying the 36-inch pipe is the most economic; other alternatives may be more economic, depending on what the market needs. He pointed out:

> And from our numbers, once you get... over 4 BCF a day, if you can take that initially, and that's what the market is willing to accept, that's kind of the crossover where it becomes more economic to look at the larger line. If the market's stepping up for less initially, you've got kind of two factors. If they're stepping up for a lot less for a long period of time, the dual 36-inch is more economic. If they're stepping up for less initially and you've got a ramp-up that occurs over a period of four more years, the numbers we used were 2.6 up to 5.2 over the course of four years, you're pretty much at a break even as far as the tolls that work out. So, a 48 or 52-inch option would come up with about the same toll as a 36. A lot has to do with being able to bring the capacity to market a year earlier and some of the economic factors and depreciation as well.

REPRESENTATIVE GARA said it seems counter-intuitive to him that if Enbridge plans to build two 36-inch pipes, that it would be as efficient to come up and down the corridor with a crew of workers twice. He asked Mr. Watson to give an estimate of the production costs of the dual 36-inch pipe and one 48-inch pipe. He then said that many people want to be able to tap into the pipeline to use some of that gas, but Mr. Watson said that would not impact Enbridge. He questioned how that could not but impact Enbridge since it would create less capacity after the tap-in point.

MR. WATSON responded, in regard to Representative Gara's first question, Enbridge has estimated the cost of construction at $1.3 billion more to build the dual 36-inch pipe versus the 48-inch option. He noted from a total capital cost in-the-ground perspective, it might cost a little more, but there would be less risk. Regarding the second question, he said his point is it is the same issue for Enbridge as a pipeline company as it would be for any other. If gas was taken out of the system at Fairbanks, that would definitely have an impact on the total system, but he can’t answer what the industry would plan to do to make concessions for that.

CO-CHAIR OGAN asked if it would be a matter of stationing the compressors a little farther apart after Fairbanks.

MR. WATSON said a number of things could be done but that he is not in a position to say what the best alternative would be.

REPRESENTATIVE BETH KERTTULA asked if the dual pipelines would require two open seasons and two tariffs.

MR. WATSON replied there would be one open season – the dual pipeline would be a design element that would entail looping the line. He explained,

> Now it depends, if it’s not part of the initial open season for the commitment, then yes, if it was labeled expansion, you’d certainly have to go back, but I think the intent would be to include it. If you don’t need the 5.2 BCF a day right now, but you need it in the four years, you may apply saying okay, this is all part of it. We’re building from 2.6 up to 5 and it’s going to take four to five years longer to build it so you make that all part of the initial commitment....

REPRESENTATIVE KERTTULA said she understands the arguments but it seems that right from the beginning, it undersells Alaska’s resource. She explained that she understands the market but it makes her nervous because Alaska’s best interest is to get the gas up and to the market.

MR. WATSON said it is not the pipeline company that decides what the reserves are and what the market is willing to take. They are trying to get more commitment. Building bigger and sooner is a benefit to his company.

> We just want to present that as a potential economic alternative, if the case happens that the market only steps up for this or you need a phased approach – because we also need to look at the economics, as well as what the tolls look like, not only from Alaska to Alberta, but what the tolls look like from Alberta to the market, as well. If we can use existing pipelines and fill existing pipes, it could reduce tolls or tariffs from Alberta to Chicago by, who knows, maybe

> five or ten cents.... This is just one potential option.

MS. MARTY RUTHERFORD, Deputy Commissioner, Department of Natural Resources (DNR), said her presentation addresses both the regulatory and commercial tools available to the state to improve access to pipeline capacity, including expansion capacity. She would discuss the Stranded Gas Development Act as a key commercial tool giving the state the ability to negotiate conditions for access along with other contract terms.

> Another key tool are the oil and gas lease provisions, specifically the state's ability to take its royalty either in value or in kind and our discretion to switch between these periodically.
>
> On the regulatory front, the state has the opportunity to influence other policy makers, both the regulatory and the legislative arms, including Ottawa, Canada and Washington D.C., also the U.S. Federal Energy Regulatory Commission (FERC), Canada's National Energy Board (NEB), which is an independent federal agency in Canada that regulates several aspects of Canada's energy industry and the Regulatory Commission of Alaska (RCA). My comments are organized around the structure of relationships, specifically, government to industry, government to agency and government to government.
>
> So, let me begin with the first category, which is government to industry. I might note here that the first category will take the bulk of my time, the second and third categories will be pretty brief.... As I said previously, and other parties like Bob Loeffler from Morrison and Forester has said, negotiations under the Stranded Gas Development Act do provide significant commercial tools that could, not necessarily should, include scheduled open seasons for expansion with, of course, very specific terms that are fair to all parties. I want to note here, and I think that Bob Loeffler noted it as well, that scheduled open seasons are not standard FERC practices. Another potential Stranded Gas Development Act tool is our ability to require pipeline design specifications that are favorable for expansions. For example, the initial design should allow for efficient

expansion. It should be preplumbed for intake, off-take and expansion points. These could include:

1) An intake in the Foothills in order to by-pass the Prudhoe Bay Unit gas treatment plant
2) An intake at Fairbanks for the Nenana and Yukon Flats Basin development when it occurs as well as an off-take at Fairbanks for several possible purposes, including various spur lines, such as to Valdez in the Cook Inlet, for petrochemicals and for rural Alaska. I believe that ANGDA has probably talked about some of the ideas that group is discussing for providing rural Alaska energy such as propane shipped in tanks or barges to rural Alaska and compressed natural gas
3) Future compression stations for expansion purposes
4) Intakes for other gas basins, such as Susitna and the Copper River Basin.

In addition to requiring open seasons for expansion and design specs, the state could consider ensuring through the Stranded Gas Development negotiations, tariff structures that are favorable to the entry of new gas. There are known devices that could assist...rolled-in tariffs, for example, for both expansion of the main line and for feeder pipelines. Rolled-in tolls for expansion means that the cost of expansion are rolled into the existing base rates. Then, even if the expansion is expensive, the overall tolls only increase modestly. The effect of this is to promote exploration and development of new gas. This is Canada’s National Energy Board policy, but not the usual U.S. FERC policy. FERC’s policy provides that expensive expansion costs are assigned to only those parties who will use the new capacity, in other words, the new guy on the block.

When this same rolled-in tolls approach is extended to new feeder pipelines, such as at National Petroleum Reserve Alaska (NPRA), and they are treated as an expansion of the existing main project, then the cost of bringing new gas to market will also be reduced. Here again, the effect is to promote exploration of new gas. Canada has, in one circumstance that we are aware of, adopted such a policy as this.

Conversely, an incremental tariff structure, which is the normal approach that FERC assigns to extensions, and to expensive expansions, is to assign costs to only those parties who will be using the new capacity. I want to emphasize that both of these rolled-in toll approaches could be a very difficult exercise to sell to FERC, because it is outside their normal policy and they must approve all tariffs including negotiated tariffs.

Another example of a tariff structure that could favor entry of new gas into expansion capacity is a negotiated levelized tariff rate. The use of a levelized tariff allows any producers lower costs in the early years, maintaining this rate over time. This may improve exploration and development economics. Conversely, a recourse rate will start off high and it may be reduced if shippers successfully request lower tolls with FERC.

One additional point here on tariffs, one means of improving the use of a recourse rate might be regular updates of that rate. As you heard at your last hearing and today, again, the FERC hasn't been exercising authority under the Natural Gas Act to require a pipeline company to periodically file new rates. A shipper can protest rates, but relief is provided only prospectively, not retrospectively. As a result, recourse rates paid by shippers on a pipeline such as this one can often be too high. As well, there is some incentive for pipeline companies to prolong litigation. However, if the pipeline company were contractually required to periodically file new rates with the FERC, then much of this problem might be resolved.

The final point I want to make under tariff structures is that it might be appropriate for the conditioning plant rates to also be reasonable and transparent. Again, this could be accomplished either by negotiations or by making them subject to a rate-making process.

Moving away from the Stranded Gas Development Act, another key tool available to the state is the oil and gas lease provision. That provides the state its ability to take its gas either in value (RIV) or in kind (RIK) and our discretion to switch periodically. This tool could be used to promote explorer access to early open season. This term of the state's lease could be used to backstop explorer commitments to initial pipeline capacity and this was the concept that DNR invented in the proposed RIK gas sales to Anadarko and EnCana [USA, Inc.] in 2002. That was never moved forward for legislative approval or even a royalty board approval, but we did send it out for RFP and EnCana and Anadarko did win that. This could allow explorers to ensure they have the necessary gas available to fill an open season commitment if there is insufficient time to explore and develop their own lease acreage prior to open season. In the interests of full disclosure here, I want to note that this proposed RIK gas sale in 2002 was endorsed by independent explorers and opposed by the producer sponsor group.

The last two items I would like to briefly note under the government to industry category are the state's right-of-way leasing provisions. It is conceivable for the state to condition a state pipeline right-of-way approval on reasonable access provisions and we could encourage the federal government to do the same with their federal rights-of-way. I must note that we have not so conditioned any right-of-way such as this to date.

And finally, using our oil and gas lease terms, it is also conceivable that we could develop provisions in new leases that require facility sharing and pipeline access, but again that would be prospectively, not for existing leases.

So, moving on to my second category of tools, or what I call government to agency, the first of these are the state administration's existing ability to provide input to FERC on rate cases. This is an opportunity that the state may avail itself of currently. It provides no surety that that input is welcomed by the FERC and as Bob Loeffler mentioned a little bit ago, under the yet to be adopted U.S. federal energy legislation, that legislation provides that open season regulations shall (mandatory) be promulgated by FERC and, of course, the state will have the opportunity to affect those regulations to our benefit. That legislation provides capacity expansion regulations may (this is discretionary) be promulgated and it might be possible to encourage FERC to promulgate these optional regs and if they do to try to affect that package of regulations to the state’s benefit.

The final issue that I might note in this area, and I’ve never discussed it with Morrison and Forester, but that would be to approach FERC regarding open season regulations in advance of U.S. federal energy legislation. If the legislation passed this fall or early next spring, it might not be necessary, but if it does not, it is something that I think the state might pursue.

Another tool available to the state under government to agency category is the Regulatory Commission of Alaska’s influence with FERC. Under the existing Natural Gas Act, the FERC may establish a FERC/RCA joint board for consultation purposes. While this is currently an option under the Natural Gas Act, it becomes a mandate under the proposed federal energy legislation and we have successfully used this device in the past on at least one tariff structure on the Alpine pipeline, I believe.

Finally, I think it’s appropriate to reiterate the obvious. A tool available to the state is to maintain our options for all gasline projects. This includes LNG, the natural gas pipeline into or through Canada and other pipelines within Alaska.

My final category is what I refer to as government to government. Briefly, this category includes the state’s influence on the federal energy legislation provisions that support access. This influences has been and continues to be, until passage, extremely important. Finally, the state has begun to develop relationships with Canada to encourage favorable outcomes for design and access of a Canadian portion of the natural gas pipeline. This can be pursued both on a federal level in both the U.S. and Canada as well as in the Canadian provinces and with the First Nation Tribal entities.

> In closing, while I've identified a whole suite of tools the state has available to it, I also believe there are a limited number of truly effective tools that are under the state's direct control. You'll note I spent more time focusing on the Stranded Gas Development Act negotiations and the RIK/RIV switching option because I believe these offer the greatest leverage to the state. Therefore, it is important that the state has full knowledge of what they're worth. That completes my testimony.

SENATOR ELTON asked if the state can condition right-of-way approval on reasonable access provisions.

MS. RUTHERFORD replied, "I believe that is a possibility, yes."

SENATOR ELTON said that seemed to be a rather bold intrusion into something FERC has control over. "Would FERC have to endorse any provisions that were contractually agreed on in a right-of-way contract?"

MS. RUTHERFORD answered:

> FERC has to approve of tariffs, no matter whether they are negotiated or not. I know they have policies on open seasons; I don't think they have regulations on open seasons. I believe they would probably be open to a negotiated agreement on open seasons for expansion purposes.

SENATOR ELTON asked if that was included under right-of-way agreements.

MS. RUTHERFORD responded, "Well no; I think that would be under the Stranded Gas Development Act negotiations."

CO-CHAIR OGAN plugged the up-coming September Energy Council meeting in Anchorage with Alberta and British Columbia attending as official first-time members.

> We literally run coast to coast from Canada now – Nova Scotia and Newfoundland to British Columbia. So, it's a good opportunity to get to know some of our Canadian friends and help keep those relationships going.

He thought a pipeline would provide better opportunities for creating long-term jobs once it was built and gas had gone down it.

MS. RUTHERFORD agreed that a lot of jobs in the future would be associated with looking for new gas and trying to fill the pipeline. “Based upon what USGS said earlier today and in which DNR concurs, that we feel there are significant undiscovered resources, more than adequate to fill expansion capacity.”

CO-CHAIR OGAN said the AOGCC regulates the waste of hydrocarbons and DNR deals more with the economic waste issues and asked if she has the statutory authority to insure the state has no economic waste.

MS. RUTHERFORD replied, “We believe we do, Senator.”

CO-CHAIR OGAN said there were no further questions and adjourned the meeting at 4:05 p.m.