**ALASKA STATE LEGISLATURE**
**JOINT MEETING**
**JOINT COMMITTEE ON LEGISLATIVE BUDGET AND AUDIT**
**SENATE RESOURCES STANDING COMMITTEE**
September 1, 2004
10:03 a.m.

**MEMBERS PRESENT**

LEGISLATIVE BUDGET AND AUDIT

Representative Ralph Samuels, Chair
Representative Mike Chenault
Representative Mike Hawker
Representative Beth Kerttula (via teleconference)
Representative Reggie Joule, alternate

Senator Gene Therriault, Vice Chair
Senator Lyman Hoffman

SENATE RESOURCES

Senator Fred Dyson
Senator Ralph Seekins
Senator Kim Elton (via teleconference)
Senator Georgianna Lincoln (via teleconference)

**MEMBERS ABSENT**

LEGISLATIVE BUDGET AND AUDIT

Representative Vic Kohring

Senator Ben Stevens
Senator Con Bunde
Senator Gary Wilken
Senator Lyda Green, alternate

SENATE RESOURCES

Senator Tom Wagoner, Vice Chair
Senator Ben Stevens

**OTHER LEGISLATORS PRESENT**

Representative Norman Rokeberg
Representative Paul Seaton (via teleconference)

Representative Bill Stoltze
Representative Les Gara
Representative Bruce Weyhrauch
Representative Ethan Berkowitz
Representative Harry Crawford
Representative Eric Croft
Representative David Guttenberg (via teleconference)

Senator Hollis French
Senator Gretchen Guess

**COMMITTEE CALENDAR**

OVERSIGHT ON ALASKA NATURAL GAS PIPELINE ISSUES

**PREVIOUS COMMITTEE ACTION**

No previous action to record

**WITNESS REGISTER**

Presentations by:

JEFF BROWN, Managing Director
Merrill Lynch

BRYAN HASSLER, Executive Director
Wyoming Natural Gas Pipeline Authority (WPA)

GEOFF URBINA
George K. Baum and Company

MARTIN MASSEY, Joint Interest Manager US
ExxonMobil Production Company
ExxonMobil Corporation

RICHARD GUERRANT, Vice President Americas
ExxonMobil Gas & Power Marketing Company
ExxonMobil Corporation

JOHN CARRUTHERS, Vice President
Upstream Development
Enbridge Pipelines, Inc.

TONY PALMER, Vice President
Alaska Business Development
TransCanada Corporation

EDWARD M. KELLY, Vice President
North American Natural Gas and Power
Wood Mackenzie

RICHARD BONE, Director
State Energy Marketing Program
Texas General Land Office

KEVIN BANKS, Commercial Section
Central Office
Division of Oil & Gas
Department of Natural Resources (DNR)

**ACTION NARRATIVE**

**TAPE 04-20, SIDE A** [BUD TAPE]
Number 001

**CHAIR RALPH SAMUELS** called the joint meeting of the Joint Committee on Legislative Budget and Audit and the Senate Resources Standing Committee to order at 10:03 a.m. Representatives Samuels, Chenault, Hawker, Kerttula (via teleconference), and Joule and Senators Therriault, Hoffman, Dyson, Seekins, Elton (via teleconference), and Lincoln (via teleconference) were present at the call to order. Other legislators in attendance were Representatives Gara, Rokeberg, Seaton, Stoltze, Weyhrauch, Berkowitz, Crawford, Croft, and Guttenberg and Senators French and Guess.

CHAIR SAMUELS reviewed Mr. Brown's background in fixed income investment banking. He noted that Mr. Brown is a consultant to Alaska's Department of Revenue, Department of Natural Resources, and Department of Law with regard to financing alternatives for a gas pipeline.

Number 010

JEFF BROWN, Managing Director, Merrill Lynch, turned attention to his written remarks that were included in the committee packet. He paraphrased from the following written testimony [original punctuation provided]:

- Alaska is a Petro-State with stranded gas. Forget comparisons to other U.S. states. Look at "Petro-States" like Qatar or Indonesia.

- Government stranded gas owners sometimes take a measured amount of risk to jump start desirable projects.
- Buying 100% of the gas at a fixed price and either (i) committing to ship-or-pay contracts for 100% (on someone else's pipeline) or (ii) financing 100% of pipeline would be one option—but it involves a lot of risk that would have to be carefully managed.
- Committing to financing an amount of pipeline capacity that corresponds to the State's working interest in the gas seems manageable from a credit and economic perspective.
- There are lots of different ownership structures and different kinds of bonds that can be used. Big differences revolve around tax-exemption and ability to shield the State from risk.
- There are many ways to limit worst possible losses from such an investment, while preserving the fiscal upside.

MR. BROWN said that he would go through the risks and rewards from the option of the state owning all of the pipeline to owning a portion of the pipeline as well as the various structures by which the aforementioned could occur. He noted that he isn't going to provide any legal conclusions, but rather would address [financing] and manageability of economic risks. He then turned to the topic of what other state's have done and paraphrased from the following written testimony [original punctuation provided]:

- No State in the Lower 48 has sold billions of dollars of debt to buy/build an international gas pipeline
- But U.S. States have not shied away from <u>big infrastructure projects</u> when necessary:
- Wyoming Natural Gas Pipeline Authority--$1 billion bond authorization to increase gas transmission out of the Rockies (ML is lead manager for this program, and its Executive Director will testify next)
- New York State started Long Island Power Authority to run electric operations in Long Island when LILCO was going bankrupt (about $8 billion of debt)
- California Department of Water Resources has spent $5 billion to transmit water from the wet north to the desert south
- At the end of the day no other state remotely resembles Alaska

MR. BROWN addressed the difference between oil and stranded gas by paraphrasing from the following written testimony [original punctuation provided]:

- Every nation or province that has oil and gas extracts taxes and royalties. Typically a producer pays for 100% of the capital to extract the resource and the Petro-State puts in zero capital.
- Other than in the U.S. and other countries with big domestic pipeline systems, gas becomes stranded because of the enormous fixed, inflexible cost of building an international pipeline or LNG facilities. Producers are reluctant to take all of the risk when they only own part of the gas (i.e., gross production less royalty and tax).
- Petro-States end up investing capital in the pipeline or LNG because otherwise they get zero value for their resource.

MR. BROWN turned to the West Natuna Pipeline and paraphrased from the following written testimony [original punctuation provided]:

- Pertamina (Indonesia's oil company) leased blocks of West Natuna to Conoco, Gulf Indonesia and Premier.
- The three production-sharing contractors, acting as the West Natuna Group, partnered with Pertamina (Indonesian state oil company) to build [the] 656 km West Natuna Transportation System, with ultimate capacity of 1 BCFD
- The total pipeline cost was reported to be $1.2-$1.5 billion. Reportedly, the Government of Indonesia's investment was $400 million relating to PGN (state gas company) construction of pipeline infrastructure from Grisik to Singapore.

MR. BROWN highlighted that as a consequence of obtaining the [West Natuna Pipeline], the gas is shipped directly into Singapore, which uses the gas to fuel industry needs and power generation in Singapore. Therefore, the gas was near valueless, except [Indonesia] created a long-term pipeline that enabled [Indonesia] to enter into long-term, fixed-volume contracts with Singapore. However, Indonesia put up the money to "unstrand" its gas. A similar situation exists in the Middle East with Qatar, which has a large field. The production in Qatar was handed off to the Ras Laffan company. The Qatar General Petroleum Corporation (QGPC) put up approximately 66.5 percent of the equity, and ExxonMobil Corporation put up the bulk of the remaining equity. Together that entity borrowed money to build a couple of LNG [liquefied natural gas] trains to "squish the gas down into a product." That entity entered into long-term contracts for volume with the Japanese and the Koreans.

MR. BROWN drew attention to page 7 of his written testimony and referred to the box specifying "KOREA & JAPAN". Japan and Korea committed to volumes rather than price, he reiterated. In this arrangement, the price, commonly referred to as the "Japan crude cocktail," is [approximately] the price of oil divided by six per thousand cubic feet (mcf). Therefore, the price in this arrangement bounces around. If oil prices go below $12, approximately $2 [per] mcf, the transportation and manufacturing process is below the breakeven point. Mr. Brown clarified: "Not only did the government step up and put in money, but ... put money up as equity in this project where they took commodity risk; in other words, their investment would be valueless if the price of oil stayed at $9 a barrel for five years."

MR. BROWN pointed out that both the Indonesia and Qatar example raise the following questions: How deep are your pockets and how big is the risk? In discussing the aforementioned issues he paraphrased from the following written testimony [original punctuation provided]:

- How deep are your pockets?
- The total State unrestricted revenues are about $2 billion per year
- Rating agencies project "total available for appropriation" of $3.5 billion in 2010
- Alaska's pockets get deeper if gas successfully commercialized

MR. BROWN explained that the Department of Revenue's bond book discusses state debt service and capacity being related to a percentage of unrestricted revenues. The bond book says that it has typically bounced around 5-7 percent. Therefore, if the revenues are doubled from a successful gas commercialization, the state's pockets get deeper. He then turned to the issue regarding the size of the risk and paraphrased from the following written testimony [original punctuation provided]:

- How big is the risk? That depends on how big of a share you take of the whole enterprise and for any particular share:

- How much financing risk you lay off on other participants through non-recourse debt
- How much construction risk is laid off through pre-engineering, fixed price contracts, insurance, completion guarantees, etc.
- How much commodity price risk you lay off on other participants through hedging, fixed price sales contracts, variable gas purchase contracts, etc.

MR. BROWN specified that the total risk of something that looked really large and risky could be tempered through the financing, construction, and commodity price. He then posed an example in which the state takes all of the risk in a situation in which there is a really large amount of risk. He clarified that the following is merely an analysis to give the committees an idea, not a proposal. He reviewed the following from his written testimony [original punctuation provided]:

- Pretend producers would sell gas to State for $1 (fixed price) at North Slope. You sign a 20 year Gas Purchase Agreement with them
- Pretend a well-reputed pipeline company will build a pipeline, with $2 tariff. You sign a 20 year Ship-or-Pay Contract
- Pretend you know for sure that over the next two decades there will be: 15 years when the price in Chicago will be $6, 5 years when the price will be $1.50. You just don't know in advance which years are going to be the ugly years. You don't hedge and all your contracts are for spot Chicago prices
- Two bad years in a row (i.e., at $1.50 per MCF) loses you $4.4 billion.

MR. BROWN concluded that either the state would have to be more careful with regard to all the business deals along the line or the state would need to consider doing something smaller. With regard to doing something smaller, he explained that the state could put up capital corresponding to the amount of the state's present royalty interest in the North Slope gas. He provided the specifics of a smaller scale investment as follows [original punctuation provided with some formatting changes]:

- State Royalty Interest in gas produced on North Slope is now approximately 1/8th. Equitable argument for putting up 1/8th of the capital, if deal won't happen otherwise. If the project costs $24 billion, 1/8th is $3 billion.

- You could take your royalty as Royalty-in-Value or Royalty-in Kind. We'll discuss later that RIK makes issuing tax-exempt bonds easier.
- If you put up $3 billion (which gains you market access for 500 million cf/d of State gas):
- a lot (maybe 80%) could be in Revenue Bonds (of a new State Agency or AKRR), where the State is not on the hook
- 20% remaining ($600 million) as State-supported reimbursable debt (this means experts forecast that project revenues will almost always carry the debt, but the State is directly on the hook, in some fashion if things go awry for a long period)

Number 256

MR. BROWN turned to the question of how large the $600 million would be in the context of the overall picture. [The following information can be viewed in a chart on page 11 of Mr. Brown's written testimony.] Currently, there is about $359 [million] of general obligation (GO) that is directly supported by the state, excluding things such as GARVEE [Grant Anticipation Revenue Vehicles] bonds. Additionally, the costs for school reimbursement and state leases brings the total to about $1 billion. The state is contingently on the hook for bonds issued by the bond bank or the Alaska Energy Authority (AEA) or the Student Loan Authority, and the total debt reaches about $2 billion. Therefore, adding the $600 million would amount to approximately a 30 percent increase, which, he opined, isn't a ridiculously large increase in the total amount of securities for which the state is directly on the hook.

MR. BROWN referred to page 12 of his written testimony entitled "Drilling Down to Details on a 1/8th Investment Example," and to page 13 which pertained to possible business structures. He posed the following question: "If you only owned part of the pipeline, how would you do it?" Clearly it would be "dumb," he opined, to have two pipelines running in the same trench. In a municipal and private partnership, a typical concept is the undivided interest structure, which has been described metaphorically as a pipe within a pipe. The undivided interest structure is also known as a tenants-in-common structure, under which the state would own 1/8th of every molecule of the entire system. The undivided interest structure is common and provides a physical asset that can be mortgaged, moved around, and sold. Mr. Brown noted that there is also the option of a limited liability corporation (LLC) in which the state would contribute into the pipeline corporation an amount of money that purchases the state's particular interest. He explained that the aforementioned option is more like being a partner or stockholder, in the entire venture, who raises the money externally.

MR. BROWN turned to tax-exempt bonds. One of the reasons the state may want to be involved is if the state can issue bonds at 5 percent, for example, and the typical Federal Energy Regulatory Commission (FERC) regulated pipeline receives a "weight average cost of capital" of 10 percent. The state's money would be much cheaper, and if the state can finance with cheap debt the portion of the capacity that carries the state's gas, more money would return to the treasury. He specified, "The money you get is price in Chicago minus transportation cost," and so if the transportation costs are cheap due to cheap capital, more money would be "net backed" to the state. He provided the committee with a summary regarding what makes bonds tax-exempt under federal law by paraphrasing from his written remarks [original punctuation provided]:

> ▪At a bare minimum, to issue tax-exempt bonds the Issuer has to be a government entity. A governmental entity would need to own the pipe and use the pipe for gas the State owns (RIK gas). That is, under ordinary circumstances, you couldn't finance 100% of the pipeline tax-exempt and then have the three producers be the sole shippers under long-term ship-or-pay contracts

CHAIR SAMUELS asked if the amount of the tax-exempt bond would only be in the amount of the gas [the state] takes, or in [the state's] ownership in the pipeline.

MR. BROWN explained that the amount of the tax-exempt bond would be the amount that [the state] uses. He highlighted that for utility properties such as gas pipelines, the IRS has many rules with regard to what is permissible and not permissible when a government owns utility property. The basic guidance provided by the IRS is that an entity cannot sign "ship or pay" contracts for the usage of the pipeline the entity owns. Furthermore, when the physical gas arrives in Chicago, the transportation costs are already imbedded in the price and thus the IRS doesn't want an entity to sign a 20-year fixed-price contract with an electric utility in Chicago. The aforementioned is viewed as another way of paying for the pipeline capacity. He clarified that [the state] can't do a long-term "ship or pay" contract for the tax-exempt bond portion; [the state] would also be limited to "sub three years" contracts with nongovernmental entities. He noted that [the state] can do all it wants with governments and, for as long is desired, [the state] can do what it wants with industrial customers.

MR. BROWN emphasized that the state will have to review the contracts for either shipment or purchase to determine whether the state can go tax-exempt. He informed the committee that included in the now-stalled energy bill in Congress is a provision for $18 billion in federal guaranteed debt. If the state otherwise qualified for municipal debt, but a federal guarantee was placed on top of the bonds, the state couldn't go tax-exempt with those. The aforementioned isn't necessarily a bad problem because there really isn't much difference between where the State of Alaska "tax-exempt AA" finances and where financing occurs with a direct government guarantee from the United States on a tax-free basis. The aforementioned is even truer compared to a tax-exempt revenue bond, which would be fairly expensive because of the risk. However, if a federal guarantee is placed on it, it becomes significantly lower. He pointed out that there is a provision in the tax code that seems to allow the Alaska Railroad Corporation to issue tax-exempt bonds without many of the aforementioned provisions applying.

CHAIR SAMUELS posed a situation in which the royalty in-value (RIV) is taken, and asked if that eliminates the tax-exempt status.

MR. BROWN explained that at that point, the entity that owns the gas at the wellhead is ExxonMobil Corporation or BP Phillips Alaska, Inc., and they are shipping their gas through the pipes, and therefore there is no good reason to call it a tax-exempt bond. He clarified that the aforementioned is what he has been advised thus far.

Number 430

MR. BROWN, turning to page 15 of his written testimony, spoke to the types of bonds available under Alaska law. He specified that the GO bonds and a Certificate of Participation (COP) are equivalent to the equity investment that Qatar and Indonesia make in their pipelines. Theoretically, the aforementioned would be accomplished through the proceeds of state GO bonds or appropriation debt, such as the state currently uses to fund the seafood and food safety laboratory. Both the GO bonds and the appropriation debt have different requirements under state law.

One of the main requirements for a GO bond is that it must be a capital improvement, which is subject to much interpretation in Alaska. The key is that GO bonds would be the lowest cost at about 4.25 percent tax-exempt.

MR. BROWN then moved on to revenue bonds of the pipeline project for which the state isn't on the hook, which he estimated to be approximately 5.25 percent today. For the project portion, the state could issue revenue bonds with a "moral" obligation, such as the state currently does with the bond bank. Using revenue bonds with a moral obligation means that the bondholder has two sources of money as follows: the source of money from the basic revenues produced by the project, and a promise from the governor that if the reserve funds are depleted, the governor would ask the legislature to fill the reserve fund. Although the aforementioned is a standard mechanism in Alaska, it increases the ratings and lowers the cost.

MR. BROWN reminded the committee of the earlier-mentioned example of the LNG project in Qatar for which, depending on the variable prices for oil, one would either break even or not. The same would apply for this project, he said. He then turned to page 16 of his written testimony, which read [original punctuation provided with some formatting changes]:

- 4.1 BCFD delivered Chicago at 1080 Btu/cf
- Total Project to Chicago = $24 Billion (inflated plus capitalized interest). To AECO would be less.
- State Share = 1/8th or $3 billion
- Finance 80% with Revenue Bonds= $2.4 billion
- Of that $2.4 billion, $2.25 billion could be Federal Guaranteed (being our share of $18 billion max as was provided in last version of Energy Bill)
- So another $150mm would be non-Guaranteed Tax-Exempt Revenue Bonds
- The balance of 20%=$600mm might be:
- General Obligation Bonds (subject to various restrictions), or
- Appropriation debt similar to C.O.P.'s

MR. BROWN, turning to page 17 of his written testimony, reviewed the numbers for a bad year. He highlighted that the pie chart exemplifies the debt structure, which is a total of $3 billion. The flow chart on the right of page 17 begins based on the assumption of a horrid price - $1.25 for gas in Chicago - in order to create insufficient funds. The DNR would receive $1.25 in mcf multiplied by the state's share, which produces $253 million. After paying the operations costs, the revenue debt, and the federal guaranteed revenue debt, only $18 million is in the treasury. He pointed out that the debt service on appropriation debt would be about $47 million. Therefore, from a commercial point of view, the state will have to find money from other sources in order to cover the appropriation debt. He acknowledged that technically, the money is all going into the general fund (GF) and commingling with other things.

MR. BROWN moved on to page 18 of his written testimony, which reviews a good year in which excess money from selling gas is large and available for other programs. He noted that these figures use the prevailing gas price of $5.00. At that price, the state would receive about $1 billion in revenues and the same tariffs as in the bad years would need to be paid. After paying for transportation expenses [revenue debt and the federal guarantee], $47 million has to be paid out to cover the appropriation debt. Therefore, $728 million is free and clear and available to expend on other things. Mr. Brown said, "Another way to say it is you could've actually just gotten rid of all the debt in that year, all that appropriation debt."

MR. BROWN concluded by relating that Alaska is in a position analogous to other countries that have stranded gas. Furthermore, there is a maximum ceiling with regard to the amount of risk that can be taken that's not laid off in terms of project financing. Moreover, it's clear that there are many alternatives by which the state could reasonably finance an investment such as this. He noted that the central forecast case is somewhere around the $3.50 price point in Chicago for the time period of 2012. Mr. Brown said, "To me, the good end ... of the distribution of prices looks pretty lovely and the bad end does not look to me like it would sink you in a year. ... So, to me, as a finance guy, I see nothing wrong with continuing to explore this."

Number 589

SENATOR ELTON related his understanding that the state will incur debt costs prior to operations and the potential of profit. Therefore, he requested that Mr. Brown discuss the aforementioned gap and how much it will take to carry the state until operations begin and profits may or may not materialize.

MR. BROWN answered that's probably a matter that can be negotiated between the state and the producers. Mr. Brown recalled that in the public and private project financings that he has worked on, the private entity often has more access to the early capital.

SENATOR SEEKINS referred to Mr. Brown's scenario in which the state would have actual ownership interest in the physical pipeline. Senator Seekins noted that the FERC will allow up to a 14 percent return on the investment in the tariff and he surmised that the state would share in that return. He asked if that has been "netted out" in these numbers.

MR. BROWN clarified that the numbers he has provided are actual cash operating cost numbers not derived from a FERC model. Therefore, under a FERC model, presumably there will be one tariff that's charged by the entire the pipeline. He noted that his scenario doesn't include a typical FERC 10 percent "weight average cost to capital" return. If it was built into the numbers, the tariff of $235 million would be significantly larger, possibly $400 million. Furthermore, the state pipeline agent ... [tape changed mid sentence].

**TAPE 04-20, SIDE B** [BUD TAPE]

REPRESENTATIVE GARA related that during the legislative session he spoke with one of the company officials, who indicated that a 10 percent state interest in the project would make the project more economic for the company. Representative Gara asked if, since Mr. Brown is assuming a 12 percent state interest, the committees could surmise that there is some analysis that a 10-12 percent state interest will make the project more viable for the private entities owning the remainder of the project. Representative Gara also asked if Mr. Brown had any concerns with regard to engaging this project later in time, keeping in mind the possibility of a rising interest rate environment.

MR. BROWN addressed the latter question, and informed the committees that when he advises the Department of Revenue, various interest rate scenarios are run. The ultimate results are sensitive to interest rates, but the main swing factor is the price of gas and the competition from LNG during the year 2012. "The gas price swing factor, in terms of breakevens, is sort of an 'order of magnitude worse than interest rate' within ... the realm of averages [for] the last 10 years," he explained. In terms of the state's 1/8th interest and whether it would make the project viable when it wouldn't be otherwise, Mr. Brown viewed that as a negotiating province of the state that he shouldn't discuss.

Number 668

SENATOR HOFFMAN directed attention to page 9 of Mr. Brown's written testimony, and related his understanding that the state will not take all the risk in this project. However, he questioned why there has only been review of one scenario at the low end of the market, $1.50. He inquired as to why there wasn't review of $3.50 and $5.00 in order to obtain a feel of the spread between a "$4.3 loss" and potential profits. Senator Hoffman then turned to the energy bill [at the congressional level] and the $18 billion federal guaranteed debt, and asked if there are other, more advantageous avenues the state can request the congressional delegation to consider. With regard to the timing of this in relation to the price of steel and interest rates, Senator Hoffman opined that it seems the near future would be best for this project.

MR. BROWN, with regard to the issue of timing, confirmed that the price of steel, like interest rates, is a large driver of the total capital costs. Therefore, starting the project sooner would be significantly better than later. However, one doesn't really know what will happen to interest rates and steel prices in the next five years. Before the state signed any agreement, it would want to perform "sensitivities" that incorporated large steel price increases and high interest rates. With regard to the energy bill [at the congressional level], the project guarantee is really helpful. There were hardly any specifics on the $18 billion debt guarantee; it merely said that the secretary of treasury will write some regulations. Mr. Brown informed the committees that from the work he has done on programs that have involved federal guarantees and federal loans, he has gathered that the more details specified, the less ability a subsequent secretary of treasury would have to "gut" a provision. He agreed that there are many things that Alaska's congressional delegation could do to help the state in this venture.

MR. BROWN, in response to a question of why he used the scenario [with a very large degree of risk], explained that if one is taking really large risks, the issue isn't in regard to how much money can be made in a good year; rather, it's "how long you can stay at the table." He further explained, "It's the absolute amount of money that you're at risk for if you have a couple of bad years, and so that's what I was trying to illustrate."

CHAIR SAMUELS asked whether partnering with producers will result in a conflict of interest.

MR. BROWN related his understanding that the state has two hats, one of which collects royalties from around the state; the state is also in a loose partnership with the entities due to it's ownership for the physical capacity and running of the pipeline. However, the aforementioned doesn't seem to be at odds with the goal of extracting all the gas from the land from every other field within a gathering line distance of this particular line. He indicated that he is not concerned about a potential conflict of interest.

Number 751

BRYAN HASSLER, Executive Director, Wyoming Natural Gas Pipeline Authority (WPA), explained that the WPA ("Authority") consists of himself, an administrator, and two technical analysts. The WPA also has a five-member volunteer board that consists of industry executives. Furthermore, a group of investment bankers advise the WPA on projects it's reviewing. Mr. Hassler relayed the goals and mission of the WPA per his written testimony, which read [original punctuation provided]:

> **Goals:**
> > Reduce the price differential for all Wyoming-produced gas to historic levels of $0.50 or less.
>
> > Increase the market for and market access to Wyoming-produced gas by 2 Bcf/d in the next four years. (Currently produces 4.2 Bcf/d of which 4.0 Bcf/d is exported.)
>
> **Mission:**
> > Advance and facilitate all industry sponsored and supported projects.
>
> > Proactively promote infrastructure development within the state and Rocky Mountain region.
>
> > Promote efficient utilization of existing infrastructure in a cost effective manner.
>
> > Promote development of Wyoming's mineral resource base in a systematic, streamlined and environmentally responsible manner.

> Utilize $1 billion bonding authority to build or cause to be built infrastructure projects that will enhance state netbacks.

> Promote development of an energy resource base that is in the nation's best interests.

MR. HASSLER said:

Based upon what you see in the "potential gas" committees' study and National Petroleum Council studies, you need every bit of gas that you can produce, not only in the Lower 48 and development of the resource base within Wyoming, but you also need Alaska natural gas and LNG imports to make this country ... grow as it has in the past.

MR. HASSLER explained that the WPA is a corporate body within the guise of the state, and therefore the WPA is an independent body that is legislatively mandated. However, the WPA isn't a body within the political infrastructure within the State of Wyoming, and this is critical with regard to state investment in internal improvement projects. The WPA was established in July 1, 1979, after the giant over-thrust fields were discovered, and Wyoming had limited infrastructure in terms of moving production out of the state. The purpose of the WPA is to plan, finance, construct, develop, acquire, maintain, and operate pipeline infrastructure within and without the state of Wyoming. One of the major attributes of the WPA is its $1 billion bonding authority. "We can move a tremendous amount of gas over relatively short periods, ... at a very attractive tariff and a billion dollars of bonding authority if we were to serve as a conduit financer for a number of projects in development, [and] would develop probably three or four ... projects under a traditional 'debt to total capitalization' type structure," he highlighted. He reviewed the other major attributes of the WPA, as specified on pages 3-4 of his written testimony [original punctuation provided]:

•Use of bond proceeds immediately after the sale of the bonds rather than after completion of project construction.
•Permits the Authority to sell or lease capacity.
•Statutes allow the Authority to lend the bond proceeds to other parties.
•Authority can charge fees for the use of Authority's facilities including pipeline capacity.

•Authority can conduct hearings to obtain data, identify markets for Wyoming natural gas and be an advocate before FERC.
•Statutes allow the Authority to acquire natural gas supplies to fulfill its capacity commitments.

MR. HASSLER pointed out that some revisions were enacted in Wyoming's 2004 legislative session. Those revisions are as follows:

Provides the Authority access to pipeline capacity for its own purposes.

Permits the Authority to have an undivided interest in pipeline assets.

Allows conduit financings by the Authority.

Clarifies the purchase of the Authority's bonds by the State treasurer.

MR. HASSLER reviewed the similarities between the Alaska Natural Gas Development Authority (ANGDA) and the WPA by paraphrasing from the following written testimony [original punctuation provided]:

**Similarities:**
1) Both the ANGDA and WPA were established to promote the development of their respective State's natural resources.
2) Each was designed to be self supporting.
3) The Authorities can take an ownership interest in a project.
4) Each Authority can issue both tax-exempt and taxable bonds.

**Differences:**
1) WPA does not need legislative approval to issue bonds.
2) WPA is limited to $1 Billion of bond authorization.
3) WPA can not provide a moral obligation pledge.
4) WPA operations are funded by a state loan.

Number 854

SENATOR THERRIAULT asked if number four in the above-specified differences refers to the WPA's yearly operating expenses.

MR. HASSLER explained that the original loan to the WPA was approximately $280,000, which was granted in 2002. The board operated without any permanent staff until last May when he was hired. He emphasized that [the WPA] has been very conscientious in terms of where money has been appropriated and how that money has been utilized. In the last biennium, the legislature authorized the issuance of another $1.7 million loan to the WPA [after reviewing] the WPA's carefully prepared budget, which specified what projects it was reviewing, the resources the state might have, and the incremental increase of staff necessary to put together pipeline infrastructure projects inside and outside of the state.

MR. HASSLER said that the WPA intends to be self-supporting and pay back the loan the state has given it. He clarified that the WPA has five years to pay back the loan, which was issued with a 4 percent [interest rate], and explained that part of the reasoning behind [the State of Wyoming] loaning the WPA money and allowing it to be a body corporate is that it allows the WPA to have a direct investment in the pipeline infrastructure projects while simultaneously promoting such projects without circumventing constitutional issues within the state.

Number 894

MR. HASSLER returned to his presentation and highlighted the pictorial map on page 6 of his written testimony. He explained that the numbers in the circles represent a potential recoverable resource base. He highlighted that Opal, Wyoming, is a major supply hub with approximately 1.5-1.7 bcf through three to four plants that are active in that area of the state. As the pictorial illustrates, the bulk of the pipeline infrastructure within the Lower 48 is built to access Texas, Oklahoma, and Louisiana in order to move those gas supplies into the Midwest and the East. The pictorial also illustrates the major trunk line out of Alberta, Canada, which is associated with the NOVA system, TransCanada systems, and the Alliance pipeline. "When you look at infrastructure within the west, it's very anemic for the potential resource base that you see here," he highlighted.

MR. HASSLER turned to the question of why one would establish an authority. The Governor of Wyoming has said that the WPA [should be established in order] to develop the resource base within Wyoming and help [the state] achieve pricing parity with other portions of the country. Mr. Hassler relayed that over the last few years, the largest problem Wyoming has faced is low gas prices, which were due to growing supplies and lack of pipeline infrastructure to move gas supplies out of the state and the region. As the [graph on page 8 of WPA's written testimony] illustrates, in 2002 prices dipped on a monthly basis at close to $1. In the winter there is some pricing parity with the NYMEX [New York Mercantile Exchange] equivalent because of the tremendous swings in terms of the utilization of gas within the Rocky Mountain states. For instance, Denver consumption in the summer averages 200-250 million cubic feet (mmcf) a day. However, on a peak day in the winter, Denver consumption can reach in excess of 2.5 bcf a day. The Salt Lake City market has similar characteristics. Therefore, consumption with the Rocky Mountain states increases in the winter, which limits the need for pipeline export capacity. He noted that during the summer of 2002, there were daily reports of prices of less than $.25 mmcf on certain days, when there were constraints on the existing export infrastructure.

MR. HASSLER turned to the question of the cost of the limited infrastructure to Wyoming and mentioned that it amounted to $130 million-plus in federal and state royalties and severance taxes in 2002. He reminded the committees that in 2002, the NYMEX prices were much lower compared to today's prices. In March of 2003, the "opportunity cost" due to the lack of export capacity from the region approached $1 million per day. Furthermore, the cost of limited infrastructure led to stalled investment in development of mineral resources because producers can't be attracted to a resource base that has very little value. From the State of Wyoming's standpoint, low prices and the lack of development of the resource leads to limited ability to predict revenues with certainty and fund those projects the state finds necessary to fund. Moreover, growing supplies in Wyoming also lead to the need for export capacity. He pointed out that the graphs on pages 11 and 12 illustrate what is happening in Kansas versus Wyoming, and Oklahoma versus Wyoming. The graph on page 11 illustrates that Kansas production has declined by almost 1 bcf a day over the last 10 years, while over that same 10-year period, Wyoming production has increased by over 2.3 bcf [as illustrated on the graph on page 12]. The graph on page 12 further illustrates the loss of productive capacity in Oklahoma, which, over the last 10 years, amounts to almost 2 bcf a day. Therefore, there is a real need for incremental supplies to backstop declining production in some of the most productive areas of the country. Wyoming's 2.3 bcf a day is representative of Wyoming's productive capability over the last few years and of the need to develop incremental export capacity.

MR. HASSLER then addressed the critical success factors for resource development. He explained that the study the WPA performed last year attempted to illustrate what limits markets from entering and requesting incremental capacity to access a cheap, long-lived, reliable supply resource base. The study further looked at what limits producers from making commitments to incremental pipeline capacity to fulfill long-term capacity commitments and continue to develop, grow, and explore the land base. He informed the committees that access to lands in a timely manner is a critical function associated with producers stepping up with capacity, especially in a state such as Wyoming that is heavily endowed with federal lands and [considers] the environmental impact associated with assessing the impact of oil and gas development on those federal lands. There has been a tremendous lag in the development of the resource base because of the environmental impact, he noted. Mr. Hassler pointed out that price, timing of regulatory approvals, gathering system capacities and pressures, transportation export capacity, capital efficiency, and public acceptance are all variables that can limit or accelerate the development of pipeline infrastructure as well as the resource base.

MR. HASSLER continued with [page 14] of his written testimony, which is a schematic that illustrates pipeline capacity moving out of the State of Wyoming, which consumes about 200,000 mcf a day within the state and exports about 4 bcf a day in natural gas produced outside of the state. Therefore, Wyoming is not a consumer of natural gas but rather an exporter of natural gas. He highlighted the Kern River pipeline, which was initially put in place in 1992 and allowed for export of natural gas supplies to California. That original pipe had roughly .9 bcf a day in capacity. In May of 2003, the Kern River pipeline was "looped" and was able to provide for export of almost an additional 1 bcf a day of supply from the state. The schematic also highlights the El Paso Cheyenne Plains project and the WBI [Winston Basin] Grasslands project, which Mr. Hassler reviewed for the committees.

SENATOR LINCOLN recalled that one of the critical success factors was public acceptance and access to the lands. She asked if any of the lands are Indian lands.

MR. HASSLER answered that the central portion of Wyoming, the Wind River Basin, has a large reservation, and , as the pipeline moves into Montana, there are Indian lands there as well. In further response to Senator Lincoln, Mr. Hassler specified that the individual producers with concessions negotiate the provisions regarding access to those lands for oil and gas development activity. Pipeline companies that want to move those supplies [on Indian lands], in conjunction with the producer, will negotiate with regard to how those supplies will be moved.

SENATOR LINCOLN asked whether the ability to access the gas could be one of the provisions that the tribes request.

MR. HASSLER replied yes, but noted that there is very little industrial activity within Wyoming. Therefore, he suggested, most of the natural gas and crude oil discovered and produced from tribal lands is looking for a market elsewhere, and, thus, [the tribal entities] are probably seeking to achieve the highest export price possible for the product developed on those lands.

MR. HASSLER returned to his presentation and highlighted that Wyoming is endowed with many existing and developing pipelines out of the state. Once El Paso Cheyenne Plains is "in project," Wyoming will have promoted almost 3 bcf a day of export capacity from the state. He then turned attention [to the graph on page 15 of his written testimony], which illustrates the spread between NYMEX prices at $9.00 and Wyoming prices at $5.00 that narrowed substantially once "gas on gas" competition within the region is eliminated and the capacity is exported to the market. Mr. Hassler moved on to the revenue facts [as specified on page 16 of his written testimony]. He informed the committees that Wyoming receives 50 percent of the royalty on gas produced on federal lands, and approximately 75 percent of the lands in Wyoming are federal lands. Wyoming also receives approximately 7 percent of the value received from all production of the state from a severance tax assessment. He noted that he hasn't included the value of royalties from state lands, which amount to two sections per township and range, and value created by ad valorem taxes. He explained that he's attempting to illustrate what developing incremental infrastructure within the state can do for the state from a revenue standpoint. Mr. Hassler provided the following [written] example:

> Wyoming receives 50% of Federal Royalties = approximately 6.25% of Federal lands. Assume 100% of production comes from Federal lands.

> Wyoming receives approximately 7% of the value received from all production in the State from severance tax assessment.
>
> Wyoming's current saleable production is approximately 4.2 bcfd.
>
> Wyoming's revenue share of production is approximately 4.2 bcfd X (.0625+0.07) = 556,500 Mcfd.
>
> At gas prices of $2 per MCF, Wyoming could expect to receive $1,113,000 per day in natural gas revenue. At $4 per Mcf, Wyoming could expect to receive $2,226,000 per day.

MR. HASSLER noted that if a 7 percent ad valorem tax is included, the state has ownership value in excess of 20 percent of the production.

SENATOR HOFFMAN inquired as to the life expectancy of the gas in Wyoming; that is, "How long do you see between $1 and $2 billion?"

MR. HASSLER referred back to page 6 of his written presentation, which refers to 170 trillion cubic feet (tcf) a day, and informed the committees that "we" are producing approximately 1.3 tcf a year from the state. At existing production rates, there's a 170-year reserve life. Mr. Hassler offered:

> To get into an efficient cycle, we believe that because of the tremendous resource base, if we can get access to lands, get producers to develop the resource base in an environmentally responsive manner, ... there's a very real thought process that we can grow production from the state substantially, relative to where it sits today. As I indicated, we think we can go from 4-4.2 bcf a day to 6 bcf a day over the course of five years if ... we are successful in promoting the resource in an environmentally responsible manner and ... working with the environmentalists in terms of developing that resource base.

MR. HASSLER pointed out that if Wyoming's resource base is reviewed relative to where Alberta, Canada, is, Wyoming could be able to produce 10-12 bcf a day of natural gas resource over the next 10 years. However, some of the resource sits in environmentally active areas in which there are problems with regard to surface access and water discharge. Mr. Hassler returned to [page 17] of his presentation and highlighted projects that the WPA has reviewed [and which are being forwarded], such as the Cheyenne Plains Project, the Jackson Hole Project, and the Rock Springs Project. He relayed to the committees that the WPA has found that before such an entity "swings for the fences" it would be appropriate to get the investment banking team and the bond council working on a smaller project with which it can work through any difficulties in terms of issuing bonds. The Rock Springs Project is such a project for Wyoming.

Number 172

GEOFF URBINA, George K. Baum and Company, informed the committee that for the Halliburton Rock Springs Project, it will be the first financing for the WPA, and the project is a "taxable lease" revenue bond. [Referring to page 19 of the WPA's written presentation], he indicated that the WPA will be involved in this project by issuing bonds to do the take-out financing. He explained that with this project, a limited liability company (LLC) signed a lease with Halliburton, and a short-term construction loan was taken out with permanent financing. The aforementioned, he noted, is typical of pipeline financings that are performed in the corporate world. The only difference is that this is lease revenue as opposed to revenues resulting from a tariff or shippers selling gas to the end market.

MR. URBINA turned attention to page 20 of the WPA's written presentation, which reviews state financing tools available to build pipelines. With regard to the option of conduit financing, Mr. Urbina pointed out that such financing was used to build the marine terminal for the Trans-Alaska Pipeline System (TAPS) in Valdez. The City of Valdez issued the bonds for the aforementioned project. With the Halliburton project, the [Wyoming] state treasurer was involved as an investor of the bonds. He noted that Wyoming has the Mineral Trust Fund, a fund similar to the Alaska permanent fund. The [Wyoming] state treasurer considered the Halliburton Rock Springs Project worthy for many reasons, including [the ability to purchase the bonds at a competitive rate]. Furthermore, this project develops a tax base in Rock Springs, which he characterized as a boomtown.

MR. URBINA highlighted the state financing tool of a "stand-by bond-purchase" agreement. He explained that such an agreement can occur when there is no market for the bonds, and the state can purchase/hold the bonds while the bankers try to find a market for them. The aforementioned is a way in which the state can provide liquidity or credit.

MR. HASSLER interjected that constitutionally, Wyoming can't provide certain [financing tools]. The State of Alaska will have to determine what fits [for Alaska].

**TAPE 04-21, SIDE A** [BUD TAPE]

MR. URBINA indicated that [the stand-by bond-purchase agreement] has been performed under the state umbrella. He then turned to the debt service reserve fund (DSRF), which he likened to a parent co-signing for his/her child's automobile. Ultimately, the financial institution will come after the DSRF if there is a default on the bonds; this is similar to when in-kind state/federal gas is used or there is a moral obligation pledge. Mr. Urbina turned to the option of state ownership of the [pipeline], which is the riskiest and should be reviewed on a number of levels [as specified on page 21 of the WPA's presentation]. If the state were to be involved in financing a portion of the pipeline or buying capacity, then 25-50 percent of the RIK revenues go to the permanent fund while the remainder goes into the general fund. There could be "opportunity costs" related to the [portion going into the general fund] because the legislature may want to fund other projects.

MR. HASSLER summarized that [the WPA] is serving as a common conduit to promote development infrastructure within and outside of the state from a natural gas and resource development standpoint. However, he noted that [the WPA] has the authority and ability to propose pipeline projects in the event that industry doesn't come forward and get the job done.

Number 029

MARTY MASSEY, Joint Interest Manager US, ExxonMobil Production Company, ExxonMobil Corporation, informed the committees that in his position he is responsible for the commercialization of ExxonMobil's gas resource in Alaska. Mr. Massey paraphrased from the following written testimony [original punctuation provided]:

> Today I have been asked by ExxonMobil, BP and ConocoPhillips to provide testimony to you on behalf of those three companies on the topic of possible State ownership in the gas pipeline project. Joining

me today is Richard Guerrant. Richard is Vice-President Americas in the ExxonMobil Gas & Power Marketing Company. He has been involved in worldwide natural gas marketing for 20 years. Richard will provide testimony on behalf of all three companies on industry trends of natural gas and natural gas liquids commonly called NGLs.

Before I turn it over to Richard, let me begin with a few remarks on State ownership in the gas pipeline project. As you know ExxonMobil, BP and ConocoPhillips submitted an application under the Stranded Gas Development Act in January of this year. That application was accepted and the producers, now referred to as the Sponsor Group, and the State are now in negotiations on a fiscal contract. The Governor and his staff have indicated an interest in evaluating the State taking its gas in kind and owning an interest in the gas pipeline project. This approach has the possibility of providing greater alignment between State and Sponsor Group interests. It would also facilitate the State's use of its gas to meet in-state demand as well as provide a source of revenue should the State decide to make the investment. At this point we are in the early stages of discussion with the State and both the Sponsor Group and the State are currently evaluating this possibility. However, much work remains to be done regarding the feasibility of this approach and it is premature to draw any conclusions at this time. Since this is a part of the current negotiations, it is not appropriate to comment on specifics that are being discussed. However, the Sponsor Group is encouraged that the Governor and the Commissioners are focused on negotiating the fiscal contract with the Sponsor Group.

Number 079

RICHARD GUERRANT, Vice President Americas, ExxonMobil Gas & Power Marketing Company, ExxonMobil Corporation, paraphrased from the following written testimony [original punctuation provided]:

**North American Supply and Demand**

First, I will discuss the gas supply-demand outlook for North America, and how Alaska gas fits into that picture. I will also address the fundamental market forces that influence how gas markets work. Lastly, I will cover the marketing of NGLs.

It is difficult to accurately forecast the supply, demand and price future across North America given all of the potential scenarios. In 2003, the National Petroleum Council (NPC) completed a comprehensive review of the outlook for North America gas supply and demand through 2025. The study had been requested by the US Department of Energy and has received much attention and praise for clearly describing the gas supply/demand challenges facing North America. The NPC study was prepared by a broad cross-section of industry representatives including ExxonMobil that chaired the Supply Committee. An important point for this committee to understand is that the NPC study highlighted that the North American market could accommodate Alaska gas.

Starting with the existing supply picture, in 2003, the US produced about 50 Billion Cubic Feet of gas per Day (BCFD) with Canada contributing 17 BCFD and Liquefied Natural Gas or LNG imports supplying an additional 1 BCFD. This total supply balanced demand of about 62 BCFD in the US and 6 BCFD in Canada. After supplying its local demand, Canada exports about 11 BCFD to the United States.

Looking forward, the North American supply outlook has been described as a treadmill in which new supplies are needed to offset the decline of existing production. Production from existing wells in North America declines at about 16 BCFD each year and requires continued new drilling and exploration to offset this decline. The recent high prices in North America have encouraged substantial drilling activity such that drilling rig counts are now reaching the highest levels in the last decade. Unfortunately, due to the maturity of North American producing fields, both reserves and production rate contribution per new well have declined in recent years. The NPC Study Outlook is that North American production will remain broadly flat to slightly declining over the next two decades. The geographic mix of supply will change somewhat as growth in production from the Rockies and deep water Gulf of Mexico will be offset by declines in the lower 48 states, Gulf of Mexico shallow waters and Western Canada.

Number 107

Demand for gas in North America has grown from 63 to 68 BCFD over the past 10 years, and the NPC forecasts that demand will grow an additional 20% to 85 BCFD by 2015 driven in part by annual US GDP growth of 3% per annum. Steady demand growth is forecast in commercial, residential and industrial sectors. The residential and commercial sectors accounted for over one-third of the US natural gas consumption in 2002. These sectors are expected to grow by 1% per annum in the NPC study. In part, this is driven by demographic growth with new residential construction heavily weighted to natural gas heating. In recent years, approximately 70% of newly constructed homes installed gas heat. But the main driver of gas demand growth in North America is expected to be gas-fired power generation. Approximately 200,000 megawatts of gas-fired generation are projected to be added by the end of 2005, representing a 31% increase in total generation capacity and a 290% increase in gas-fired generating capacity versus 1998. The result is that gas demand is being driven higher as North American electricity requirements grow with the economy.

In 2015, as I mentioned, NPC estimates North American demand of 85 BCFD with indigenous supply of 68 BCFD, leaving a gap of 17 BCFD. The NPC expects that this gap will be filled by a combination of new Arctic gas supplies from Alaska and the Mackenzie Delta, in addition to significant increases in imports of LNG and higher cost indigenous production. The NPC study predicts that long-term prices will be driven by the cost of these major new supplies, and constrained by competition from alternative fuels such as oil, coal and nuclear. The clear conclusion from the NPC work is that North America can accommodate significant supply additions from a variety of sources including Alaska gas.

**Gas Transportation, Pricing and Marketing**

Next, I would like to briefly discuss how Alaska gas would likely enter the North American market. The gas would be transported through a large diameter, high-pressure pipeline across Canada and perhaps continuing on to Chicago. This pipeline would pass through the heart of the Western Canadian Sedimentary Basin which produces about 95% of Canada's gas production. Alaska gas could be consumed in Western Canada or transported to other Canadian and U.S. Markets. Five major pipeline systems currently exist in Alberta and British Columbia to take gas to markets in Canada and the Lower-48. These pipelines feed border crossings with capacity of about 12 BCFD where gas is transferred to Lower-48 pipelines flowing ultimately to markets in the Midwest and on the East and West Coasts. In order to determine which market the Alaska gas will ultimately serve, we need to discuss market pricing and pipeline infrastructure which I will address next.

The key participants in the gas market include suppliers, transporters, and obviously buyers. Suppliers include hundreds of producers and marketers, and buyers include thousands of industrial consumers, power generators, and local distribution companies. With the large number of market participants, and the significant number of sales transactions, North America is the largest and most liquid market in the world, and has proven very efficient at matching available supplies to market demand. These participants primarily buy and sell gas on a month-to-month basis, with a small portion of longer-term arrangements, and some daily trading to manage short-term production and demand variations.

There is a benchmark gas price - the 'Henry Hub' price, which is similar in nature to the crude oil benchmark prices like West Texas Intermediate. Like West Texas Intermediate, gas is traded on a futures market, the NYMEX, and also trades on physical markets at specific trading points throughout North America. Near the end of each month, deals are arranged between buyers and sellers and these trades help set the price for the following month's gas deliveries. The very large number of transactions and multiple participants provide an efficient market, which yields a competitive market price for the product.

An important attribute of an efficient and competitive North American gas market is the high degree of price transparency. For more than a decade, industry trade publications have published price indices for physically traded gas on a daily and monthly basis, and have recently expanded their reporting to include details on number of trades and volumes. These published indices represent actual sales transactions at about 100 locations across North America.

Prices at these locations vary by region. The difference between the regional prices reflects the market's valuation of transporting gas between the regions to meet demand. In regions with excess transport capacity, the price difference may be less than the actual cost of transportation. In regions where capacity is tight, the price difference may exceed the actual cost of transportation. These pipeline balances can be further impacted by seasonal demand fluctuations.

Since deregulation beginning in the mid '80s, the North American gas market has evolved into a mature, liquid and transparent market. Consequently, we have well established market mechanisms, which allow suppliers to sell all their production at a market price, similar to other commodities.

**Natural Gas Liquids**

An additional consideration in marketing Alaska gas is the salability of the gas in meeting downstream pipeline and market quality specifications. Field gas production can contain water, $CO_2$, Sulphur, and other compounds. For Alaska gas, it is expected that most of these impurities would be removed on the North Slope.

In addition to methane - the primary component of natural gas - field gas production also includes varying amounts of ethane, propane, butane and pentane. Currently, the majority of butanes and heavier NGLs are removed on the North Slope, added to TAPS, and moved with the crude through the pipeline system. As a result, the gas to be moved on the Alaska Gas Pipeline will contain a light mixture of

NGLs, primarily ethane and propane, which will still need to be extracted so that the remaining natural gas can meet gas pipeline and market quality specifications.

NGLs are removed by gas processing plants, with the saleable natural gas moved onto market via pipeline. The extracted NGLs are then transported to an NGL fractionator where they are separated into their components -- ethane, propane, butane and pentane. The North American NGL market currently consumes about 3.3 million barrels a day of these products.

The ethane is primarily used as a feedstock to chemical plants, which convert it to ethylene for further use in making plastic products like plastic bags, milk bottles, toys, etc. The pricing of ethane is primarily linked to natural gas. The propane feedstock has multiple uses: first, as a feedstock to chemical plants to make propylene, a building block for plastics used in the production of food packaging, auto parts and carpeting, and second as a residential and commercial heating fuel principally in rural areas not supported by a natural gas pipeline infrastructure. Butanes are typically blended into motor gasoline to enhance the fuels performance characteristics. Pentanes are also used as chemical plant feed or in the production of motor gasoline. The prices for propane and heavier NGLs are linked to crude and other oil products.

In addition to the facilities required to remove the NGLs from the natural gas stream to meet pipeline specifications, substantial markets and petrochemical infrastructure, including pipelines, fractionators, chemical plants, storage and complex refineries are required to consume the NGLs. As with natural gas, the infrastructure and demand for these products is primarily available starting in Alberta and markets further south. Western Canada and Chicago have about 15 billion cubic feet per day of existing gas processing capacity. Current Alberta chemical plants have the ability to consume about 270 thousand barrels a day of ethane with the resulting ethylene and polyethylene production primarily sold into the Great Lakes region. In addition, western Canada also provides pipeline infrastructure to move excess NGLs to Lower-48 markets.

The need to adequately process Alaska gas to meet market and pipeline specifications is a key part of the project, and there are adequate markets and infrastructure in Canada and the Lower 48 to handle the volumes of NGLs in the Alaska gas.

Number 204

**Summary**

I'd like to now summarize my remarks regarding the North American natural gas and NGL markets:

- First, as detailed by the NPC Study, the supply / demand balance in North America signals the room for additional supplies, such as Arctic gas, LNG, and higher cost indigenous production in the next decade.

- Second, the North American gas market is a mature, liquid market with well established mechanisms to ensure suppliers can sell all their product at a transparent and competitive market price.

- Third, the NGLs will need to be removed to achieve downstream pipeline specifications, and the best approach is to take advantage of existing infrastructure close to available market for the products.

Before closing, I would like to point out that it will take a combination of factors for an Alaska gas pipeline project to be commercially viable. Those factors include a fiscal contract with the State of Alaska, U.S. federal enabling legislation, a clear and predictable regulatory process in Canada, a significant reduction in project costs, and a market outlook that is sufficiently encouraging over the projected life of the project.

Number 237

CHAIR SAMUELS asked if ExxonMobil's competitors, when it sells the liquids or the gas itself, are BP, ConocoPhillips Alaska, Inc., Texaco, and Chevron. He further asked if ExxonMobil sells [the liquids or the gas itself] to a broker or is in a situation in which the company is "vertically integrated" and in charge throughout the process. Chair Samuels posed a situation in which the State of Alaska owns a lot of gas, and asked if the state would be competing with some of the largest corporations around on something that [such companies] have done throughout their entire existence.

MR. GUERRANT reiterated his earlier testimony with regard to the fact that there are many, many participants in buying and selling gas. There are buyers who want to purchase gas directly from the producer or owner of the gas. There are also marketers who want to purchase gas from other producers and resell it. Furthermore, there are producers who sell their product; there are also producers who buy and sell. Mr. Guerrant explained that ExxonMobil Corporation has a diversified slate in which most gas is sold on short-term contracts, which range from daily to monthly to yearly. ExxonMobil Corporation has very few long-term contracts because today's customers in the marketplace aren't willing to sign up for long-term contracts. With regard to the type of customers to which ExxonMobil Corporation sells, Mr. Guerrant specified that it sells to a portfolio of customers, including local distribution companies (LDCs), industrials, and marketers. Mr. Guerrant posed a situation in which each of the producers and the state is taking its gas in Chicago. In such a situation there will be plenty of opportunity to sell. He noted that the mechanisms regarding how the market works are well established, although the key to that is the governance. "The buyers need the gas; ... they will be wanting to buy the gas from you," he added.

MR. MASSEY relayed that the state has the option to determine how it wants to handle the sale of its gas. The state could develop such expertise internally and sell the gas itself, or the state could contract out that responsibility. He echoed Mr. Guerrant's comment that in the current market, there are plenty of buyers for gas and well-established indices upon which to sell it.

MR. GUERRANT said that the state will develop its own expertise at some level, depending upon how far downstream the state goes.

Number 291

SENATOR ELTON remarked that ExxonMobil Corporation's testimony was fairly dismissive of any discussion regarding advantages to the state's owning or not owning a portion of the pipeline. He asked if the ExxonMobil Corporation representatives could provide the committees with even a hint on that matter.

MR. MASSEY apologized and reiterated that ExxonMobil Corporation is in negotiations with the state on this topic. From a broad viewpoint, though, the advantage is that if the state takes ownership in the pipeline, the state and the sponsor group would be aligned. Furthermore, if the state elects to take the gas in-kind, it can use it as it sees fit, such as meeting in-state demand. Moreover, if the state elects to invest in the pipeline, the state will receive the revenues from that investment. The reason the discussion isn't occurring in a more detailed fashion is that it would depend upon the deal made with the state. Mr. Massey informed the committees that ExxonMobil Corporation is encouraged with the discussions it's having with the state now.

SENATOR ELTON pointed out that a deal with the state would have to be consummated with the legislature. At some point, there will have to be a discussion with regard to the advantages and disadvantages of state participation in this pipeline. Senator Elton said that it would be helpful to hear that there are clear advantages or disadvantages related to state participation.

Number 334

SENATOR FRENCH expressed concern with regard to the state obtaining a fair deal for its resources. Therefore, he questioned where the liquids would be taken out. Currently, the heavy liquids are being taken out at the North Slope. He related his understanding that the "somewhat wet gas" will be shipped to Alberta and the remaining liquids would be taken out in the Alberta gas processing facilities.

MR. GUERRANT confirmed that the aforementioned is the base plan because there is existing infrastructure [in Alberta] that is close to the market and will provide the best value for the gas.

SENATOR FRENCH interjected that there are existing transportation infrastructures to move the separated products to market from that point on. He then questioned whether there is a price difference between the somewhat wet gas that would be shipped to Alberta and the separated components. In other words, which is more valuable, the wet gas or the separated components, he asked.

MR. GUERRANT pointed out that some of "it" has to be taken out in order to meet the pipeline specifications. There is another level of extraction, which is primarily the ethane extraction, that is based on market conditions. After the pipeline specifications have been satisfied, the amount of ethane extraction can be expanded or contracted based on the economics of extraction under the current market prices for ethane. Therefore, an economic optimization has to be performed in the marketplace. Mr. Guerrant specified that secondary extraction, that occurring after the pipeline specifications have been satisfied, occurs in order to obtain more value for the product stream than it would have if left in. The aforementioned, he explained, is why he mentioned the gas processing capacity in Alberta that could be utilized. That economic optimization will ensure that the maximum value for the product is obtained. In further response to Senator French, Mr. Guerrant specified that all involved will have such decisions to make. The first decision will be in ensuring the gas meets the pipeline specifications, then the question is regarding how deep of a cut does one make to obtain the best value for all the players. The aforementioned is usually done on an individual-entity basis, although each individual involved will optimize the stream based on the marketplace.

Number 399

REPRESENTATIVE HAWKER echoed the concerns expressed by Senator Elton and then turned to Mr. Guerrant's closing comments regarding the factors necessary to have a commercially viable project. He recalled that Mr. Guerrant's testimony relayed the need to have "a clear and predictable regulatory process in Canada" and asked if that statement implies that such a process doesn't already exist in Canada. Conversely, is that statement acknowledging that Alaska has a clear and predictable regulatory process? He also recalled that Mr. Guerrant's testimony suggested that "those factors include a significant reduction in project costs". Does this mean that under the current anticipated cost structure by the sponsor group, this isn't a feasible project? he asked.

MR. GUERRANT confirmed that predictable processes are necessary for permitting, in both the US and Canada. The US federal enabling legislation allows that predictable process. Although there is knowledge with regard to how the National Energy Board (NEB) does its pipeline permitting, fitting this all together must come to fruition in an orderly fashion in that specified cost estimates are met as well as the desired economic benefits and value for the gas are obtained. Mr. Guerrant said that more of an understanding of the Canadian side of the project has to occur.

MR. MASSEY opined that the sponsor group has been clear that today, the project isn't commercially viable. One of the things within the control [of the sponsor group] is to try to be able to drive down the costs of the project, and much effort amongst the sponsor group is being expended to that effect. For example, both BP and ExxonMobil Corporation have spent a great deal of money and effort to commercialize a higher strength steel, which would allow the [sponsor group] to not have to purchase as much steel in the pipe to make this project occur. Much progress has been made in that effort as test lines have been put in place in one of TransCanada's systems in order to test this high-strength steel technology. Mr. Massey reminded the committees that this is a huge, complex project that no one has done. Furthermore, as the situation moves closer to building such a project, the costs increase, and therefore the cost reduction items have to be in place in order to offset the increases.

Number 472

REPRESENTATIVE ROKEBERG recalled Mr. Guerrant's testimony regarding well-established mechanisms, price transparency, and a high degree of confidence in those. He asked if, in the negotiations between the sponsor group and the administration, it will be necessary to adopt/use any of the benchmark pricing in dealing with a contractual agreement with the state.

MR. MASSEY specified that it would depend upon the structure of the project. If the project is a royalty in-value structure in which the sponsor group pays the state cash, the sponsor group will have to determine the value of the gas. The value of the gas can be determined in a variety of ways, including benchmarks or actual revenues based on the sale of the gas. If the project is under an ownership structure and the state basically sells the gas, then some of the need to determine the value of the gas will be eliminated. The aforementioned is the topic of the current discussions with the state.

REPRESENTATIVE ROKEBERG expressed concern with regard to the presentation from Mr. Massey and Mr. Guerrant in relation to the [sponsor group's] high degree of confidence in the transparency of gas pricing in the US. He inquired as to whether the FERC study on the matter of transparency has been completed. He noted that as a member of the Energy Council, he has been privy to studies that have indicated there are substantial problems with the published prices, plats, and other publications.

MR. GUERRANT opined that over the past two to three years, there have been questions with regard to price transparency that have primarily been related to entities that have financial problems and have had players that have inaccurately reported things into indexes. Work was done with the FERC, which performed an extensive investigation along with the Commodity Futures Trading Commission (CFTC) and other jurisdictions. He offered his belief that improvements made to the indices, particularly revolving around the number and volume of trades for each sale, have provided the industry more confidence that the indices work. A survey was performed and reported to the FERC, and this survey rated the confidence in the indices at 7-8 on a scale of 1-10. However, he acknowledged that some indices are more liquid than others; for example, one of the most liquid transparent indices in North America is the Alberta index. The Henry Hub index is a physical trading point as well as a NYMEX regulated trading point. He characterized the Henry Hub index as a very valid index. In summary, Mr. Guerrant shared his belief that the difficulties with regard to price transparency are past and everyone feels good with regard to the indices. He surmised that sending the signal to the industry that those misreporting will pay the price has made a major improvement with regard to governance procedures. Still, the FERC and the industry continue to monitor this issue.

Number 597

REPRESENTATIVE GARA noted that many in the legislature want to access gas for in-state uses such as for the spur line to Valdez. Therefore, he inquired as to [the sponsor group's] thoughts on such access. He recalled testimony that [the sponsor group] doesn't believe this project is commercially viable at this point. However, he noted, the governor says that he will make an announcement with regard to a preliminary deal in September. Therefore, he requested follow up on this project's commercial viability. Representative Gara also inquired as to whether [the sponsor group] has any hesitance in selling its gas [on the North Slope] to an entity that believes the project is commercially viable.

MR. GUERRANT began by pointing out that "we all want to try to monetize and sell this gas". Furthermore, he said, [the sponsor group] recognizes that the in-state demand issue has to be addressed.

**TAPE 04-21, SIDE B** [BUD TAPE]

MR. GUERRANT then turned to Representative Gara's question regarding [the sponsor group's] propensity to sell gas to an entity that believes this project is commercially viable. He said that [the sponsor group] would entertain any realistic proposal. However, realistically, those who own the reserves, the state and the project sponsors holding the lease, are those who can take the risk to get the gas to the first liquid market point. After the first liquid market point, it's a different matter. Mr. Guerrant opined:

> I think we'll all listen ... to any proposal ... any party brings to the table. And if they add value and they're durable [and] ... they can [actually] deliver what they say they can deliver ... and [it] doesn't [put] undue risk on all of us ..., we'll consider that. But ... I haven't really seen those kinds of opportunities in all of the projects that I've worked on, that ensure that you get the right value. Those are things that you've got to be careful in ... considering because they may not be durable. ... In other words, ... someone coming in and [saying] that they [will] build and [then] buy your gas ..., that's a difficult issue to consider because you don't know what the value [is]. If you're down in the marketplace, you know what the cost [is]. We can ... build the pipeline to the first market point to where we know that there's a very liquid transparent market there. We know what the value of that is, and that's what you want to make sure that you're getting full value for.

Number 028

MR. MASSEY turned to the question regarding whether the project is commercially viable. He reiterated that since the sponsor group has completed its study, it has held the position that the project isn't commercially viable. "It doesn't mean we're not trying to make it commercially viable - we are," he relayed. Trying to make it commercially viable is the subject of the negotiations occurring with the administration. Furthermore, he said he is encouraged by the governor's comment that there will be something in September. However, there's a lot of work to do to reach that point. Mr. Massey mentioned that it's probably within the [sponsor group's] control to make this project commercially viable. He also mentioned that the sponsor group would like to reduce the cost, and so much work is going on in that vein. Mr. Massey concluded with the following:

> Just because we say it's not commercially viable doesn't mean we're not trying. We've got a lot of gas resource up there. We've got indications from the market that it can accommodate Alaska gas if we can get the cost down at the right level, ... make it get into the market at a good economic rate. So, the conditions are right to try to make it happen, and a large part of it hinges on the negotiations we have right now with the state.

SENATOR DYSON asked about in-state sales.

MR. MASSEY said that one of the advantages of the state taking an ownership position in taking its gas is that it will have gas available to meet in-state demand and divert [the gas] to wherever it wants, and that will depend upon where the best value for the gas lies.

MR. GUERRANT concurred and suggested starting at a baseline in which there is review of getting value from the marketplace and then backing up to review what things can be added to the project in order to create more value for the various parties. The study is complete and there is a plan, and therefore he suggested that now is the time, through these discussions and negotiations, to improve on the plan.

Number 059

SENATOR LINCOLN shared her frustration regarding the points stated in the last paragraph of Mr. Guerrant's written testimony. She questioned what a "significant reduction in project costs" would entail. The example of using high strength steel as something that could reduce costs isn't under the control of the state. She asked what [the sponsor group] wants the state to do that would significantly reduce the project costs and is something over which the state has control. She then turned to extracted NGLs and commented that the best value certainly isn't going to be in-state in Alaska. She surmised that when [the sponsor group's] testimony refers to rural, it's probably referring to rural America rather that rural Alaska, and therefore she didn't think in-state uses would meet the "bottom line" for the sponsor group. Senator Lincoln recalled the following testimony: "In a market outlook that is significantly encouraging over the projected life of the project." She inquired as to the "projected life" that the sponsor group would envision.

MR. GUERRANT said that the NPC study was one of the most comprehensive studies that has been done. That study provided the sponsor group and the entire industry with a much more encouraging view about the need for the future supply. Furthermore, the study extended into 2025, and has provided the sponsor group with the encouragement to start this process. With regard to in-state demand, Mr. Guerrant said that the sponsor group recognizes that that is something which has to be discussed and addressed in order to develop an acceptable package. When there is a full view of the project, there will be a discussion regarding how to make the project actually happen.

MR. MASSEY said that he is as frustrated as Senator Lincoln is in regard to the continuing need for these items to be discussed. He stressed that for three years it has been his job "to try to check one of these off the list." However, that hasn't been achieved yet. Mr. Massey said that there needs to be a catalyst to get this project going. The one thing that is within the control of the sponsor group is the negotiation of the fiscal contract with the state. If the aforementioned can be negotiated and an agreement that the project is commercially viable can be achieved, it will provide great momentum for the project. So with regard to what Alaska can do, Mr. Massey suggested negotiating a fiscal contract.

Number 129

SENATOR SEEKINS recalled that the sponsor group has said that there is room for additional supplies of Arctic gas, LNG, or "higher cost" indigenous production. However, Arctic gas isn't economically viable, he opined, and so he questions what the sponsor group is planning.

MR. GUERRANT said that the market side is starting to look encouraging, such that the [process should move to the next level], that being the fiscal contract. But first many issues need to be sorted out in order to determine whether the project is commercially viable. Once the fiscal contract is in place, the regulatory issues could be tackled. In further response to Senator Seekins, Mr. Guerrant confirmed that [the sponsor group] is looking into other areas as a contingency. He noted that [ExxonMobil Corporation] has major land holdings and leases in Canada and the US, and drilling is taking place on the good prospects. Furthermore, [ExxonMobil Corporation] is involved in the LNG business and is looking to expand it in the right markets. [ExxonMobil Corporation] is also pushing ahead with Arctic gas. Mr. Guerrant highlighted that the NPC study specified the need to push ahead on all fronts, which is what [the sponsor group] is doing. The pieces of work for these projects have to be prioritized, which is what's occurring now.

CHAIR SAMUELS recalled the [Qatar] example and posed a similar situation in a Western democracy in which the [producer] partners with the regulatory agency. He inquired as to [the sponsor group's] experience in other governmental partnerships.

MR. GUERRANT said that in the early days, ExxonMobil Corporation, Shell, and the Dutch government came together in a joint venture to monetize the large field in the Netherlands. In this venture, the parties own [it] throughout the chain, and this venture has been successful. Recently, ExxonMobil Corporation and Qatar are expanding the largest natural gas field in the world, which is the North Field in the Middle East. He noted that the country of Qatar is investing throughout the [project]. Mr. Guerrant said that in the relationship with Qatar, there are more advantages to the joint venture because the groups have to be aligned as the process proceeds. Furthermore, all the parties know the value of the product in the marketplace. And although the aforementioned approach is difficult, it builds trust. Such an approach is being utilized with the producers in West Africa. Being aligned with a government partner is overall a good thing because it allows the [producers] to know what's going on throughout the life of the project.

CHAIR SAMUELS announced, at 12:42 p.m., that the committee would recess for lunch. At 1:30 p.m., Chair Samuels called the meeting back to order.

Number 227

JOHN CARRUTHERS, Vice President, Upstream Development, Enbridge Pipelines, Inc. ("Enbridge"), echoed earlier comments stating that the Lower 48 market is large and growing. He said that Enbridge recognizes the importance of Alaskan gas to those in Alaska based on the attendance of these meetings. However, it's more important for the Lower 48 consumers, who need to play a role. Although there needs to be greater recognition of that role, there are significant hurdles to achieve it. In fact, Enbridge would be one of the players. In order to place Enbridge's position in context, Enbridge participated as an owner in the Alliance Pipeline System that moves liquid rich gas from the western Canadian sedimentary basin to Chicago. The aforementioned gas has characteristics similar to those one would see in Alaska gas. Furthermore, Enbridge brings market perspective to the table in that Enbridge is the owner of Canada's largest LDC. In that vein, Mr. Carruthers turned to the earlier concern regarding the viability of the indices. He pointed out that Enbridge participates in those indices as a buyer, and characterized the indices as generally a very sufficient and sophisticated tool, though there has been some improvement with regard to [the transparency of the indices]. As long as the [indices] are liquid enough, which can be the case for Alberta and Chicago, it should be sufficient for [Alaska].

MR. CARRUTHERS noted the following potential end-use shippers: LDCs, power generators, marketers, large industrial users, and government as a commercial entity. He then focused on LDCs since they will be the key [end-use shipper]; as stated in a Purvin & Gertz study: "LDCs are one of the few market participants with the creditworthiness, client base, and commercial interest to encourage investments with long-term contractual support and/or equity participation. Their support is required to ensure adequate gas supply in a timely fashion." Mr. Carruthers opined that the aforementioned summarizes the issue from a Lower 48 market perspective. He said that there isn't much argument with regard to the need for gas in North America. In fact, most studies would say that over the next 10 years, approximately 15 bcf a day of new supply is needed, which would include Alaska's supply. What's important to note is that Alaska gas can economically access a lot of the market, the Midwest and Northeast in particular.

MR. CARRUTHERS turned to who could and who is going to take the risk on a pipeline. If one thinks of the benefits to consumers of an Alaska gas project with costs approaching $20 billion, the benefits to consumers are far more [than the cost]. The NPC study specified that consumers would see a price reduction of $.60-$.80 for three to four years after the arrival of Alaska gas to the market. Therefore, Alaska gas would be positive for consumers in the amount of approximately $50 billion. He noted that further studies have supported the aforementioned analysis. Although Alaska gas would be approximately 5 percent of the total supply, it impacts all gas. Mr. Carruthers specified that some consideration should be given with regard to the volume and the price that can be committed, as well as to contract length, delivery points, and regulatory acceptance of long-term capacity commitments. He noted that during the era when there was more supply than demand, contract lengths were shortened and some utilities were penalized for having long-term contracts.

MR. CARRUTHERS addressed market participation in supporting and taking on some of the risk in Alaska gas. Marketers have played a diminished role and they are unwilling to commit to long-term contracts. Therefore, sellers would probably hesitate to sell to marketers on a long-term basis unless they met some credit hurdles. The LDCs would like to commit to long-term contracts, but are restricted from doing so by public utility commissions. In order to commit to a long-term contract, there must be assurances that those contracts would be supported in future rate cases. However, there have been cases in which there weren't assurances and, as a result, there was an economic impact. Based on today's market, there has been little willingness to commit to fixed-price commodity contracts. It's easier to have floating price contracts with the liquid hubs. The aforementioned is exacerbated by the fact that Alaska gas remains in the future. "So, you've got the added complexity ... [of] going into a long-term contract but the first day of that isn't for a few years, so that does make it even more difficult," he opined. Even with the FERC's attempts to streamline, there has been an increase in legal challenges resulting in delay. However, the energy bill, should it pass, addresses a number of those issues.

Number 320

MR. CARRUTHERS relayed that Enbridge does see a need for long-term contracts. Although historically the producers have been the one to take the position on the pipe, he opined that in this case there is the potential, because of the significant benefits to consumers and lack of known long-term resources, for the consuming end to take a position on the pipeline. The aforementioned would require a shift in policy. The NPC study emphasized the aforementioned in the following quote:

> New pipeline and storage infrastructure are generally financially supported by long-term contracts for a period of ten to twenty years. Companies are less willing to invest dollars in needed infrastructure if contract durations for existing or new

pipeline/storage capacity are shortened by the impact of regulatory policies.

MR. CARRUTHERS said, therefore, that [Enbridge] has been focusing on whether the regulatory policies can be changed such that people could take a position. Because Alaska's resource is large and well known, there isn't the risk that occurs in some basins in which the gas still has to be found. He further explained that in Alaska's case, the cost of the pipeline is the market risk.

MR. CARRUTHERS moved on to in-state market participation, and informed the committee that currently, Enbridge is actively reviewing a spur line to Anchorage/Kenai. The spur line depends upon the quality of gas on the market side, the projected growth rate, and the existing infrastructure in terms of distribution. If the aforementioned is considered during the initial development of a gas pipeline, it could be more economic than if it is simply an add on. Mr. Carruthers noted that Enbridge will continue to also look at the Lower 48 market. He expressed the need to reaffirm that Enbridge believes there is potential for the market to share a risk in the Alaska gas pipeline by taking a shipping commitment. Although it makes sense conceptually, there are many regulatory hurdles that would be fairly time consuming. "But we do think that does align Alaska and the producers interests in the pipeline, and we could share risk more broadly," he said. He noted that Enbridge is reviewing that very notion to determine the amount of risk it might take and under what conditions.

Number 365

SENATOR SEEKINS turned attention to the Enbridge slide entitled, "Alaska Gas is Good for Lower 48 Market". He said he understood Mr. Carruthers to say that delay in this construction project raises prices for the consumer in the short-term. Would that be the case in the long-term, if this project came on-line in two years, he asked. If so, would it be in the best interest of an owner of a large supply of natural gas to delay construction of the project.

MR. CARRUTHERS replied no, adding that one would have to have an expectation that prices will increase at an even more significant rate. Mr. Carruthers said that he didn't expect people to delay [construction]. Furthermore, if prices increase too highly, demand will go offshore, from which it takes some time to recover. High prices could also result in fuel substitution or other "infrastructure builds." Therefore, if people don't foresee Alaska gas on the horizon, more LNG, coal, or nuclear may be developed. Mr. Carruthers opined that there is some risk of waiting too long.

SENATOR THERRIAULT asked if there is anything that the state controls in its regulatory scheme that could be problematic.

MR. CARRUTHERS reiterated that long-term commitments on gas have been discouraged. In this era, he said, he believes the utility commissions need to review things that support new sources of gas.

SENATOR THERRIAULT posed a situation in which there is more of a push for new power generation to use natural gas. However, natural gas isn't tied into long-term contracts, and this results in price fluctuations. The American consumer is accustomed to, and expects, a very level price per kilowatt from the producers. He asked if that dynamic will have to change as more generation moves over to natural gas, and therefore moves to more long-term contracts in order to ensure stability.

MR. CARRUTHERS opined that consumers would become more and more frustrated with the high prices and the volatility, both of which are [reduced] by long-term secure sources of gas, adding that Alaska provides the aforementioned.

Number 435

TONY PALMER, Vice President, Alaska Business Development, TransCanada Corporation, began by reviewing gas prices. He informed the committee that the long-term forecasts of NYMEX for natural gas is in the $3.00-$6.00 range and most forecasts converge near $4.00 after the current price spike subsides. He then turned attention to a graph on page 3 of his presentation, which is entitled "Comparison of Recent NYMEX Gas Price Forecasts." The graph provides forecasts from the NPC Balanced Future, the NPC Reactive Path, TransCanada, DOE AOE 2004, and six consultants. Although he didn't believe any party would say that the prices can never go outside the $3.00-$6.00 range, he said he would agree that the price would generally converge within that band. As the graph illustrates, the majority of the forecasts are in the $4.00 range in 2002 dollars.

MR. PALMER said that gas demand continues to grow, although current high prices are causing some demand loss, primarily in the industrial market. The expectation for long-term net growth continues to be more than 1 percent, and this is significantly influenced by power demand. He noted that the US and Canada demand growth from 2003-2015 is in the 15 bcf a day range. The graph on page 5 of the presentation provides a visual indication of various forecasts. The graph illustrates that demand has historically been in the 70 bcf a day range for the last five or so years, and a common forecast projects growth to 80-85 bcf a day in 2015.

MR. PALMER focused on the Western Canada gas demand, which is illustrated in a chart on page 6 of the presentation. In 2003, the Western Canada demand was at 4.4 bcf a day. Over the next decade, the primary sources of new demand growth will be electric generation, minable oil sands, and in situ heavy oil. There are modest increases for residential, commercial, and other industrial demands. Mr. Palmer turned to oil sands gas demand, which is a source of large demand growth. From the graph on page 7 of his presentation, he remarked, one can see that [TransCanada] has modified its gas demand in the oil sands. With the use of existing technology, current growth would range from volumes in 2003 of just above .5 bcf a day to 2.5 bcf a day without technological improvements. He noted that there are initiatives by a number of oil sands proponents to use the actual bitumen as a fuel source by upgrading it. The graph also illustrates TransCanada's change in forecast from 2003, which is significantly moderated from a year ago although it's still growth.

MR. PALMER moved on to the North American gas supply, and pointed out that the supply/demand is precariously balanced. Furthermore, new supply sources are required, but the only growth basin TransCanada sees are in the Rockies, although there is some modest growth on the East Coast. Moreover, existing LNG terminals are operational again and are planning expansions. In fact, there is either a plan or approval for expansion for about 2.3 bcf a day at the existing terminals, which have capacity of about 2.5 bcf a day. He noted that the MacKenzie gas is on track for 2009 in-service. Mr. Palmer directed attention to the Lower 48 dry production forecast comparison. Over the last decade, the Lower 48 supply has been in the 50 bcf a day range. Going forward, the US Department of Energy EIA forecast is very optimistic in it's forecast of growth toward 57 bcf a day. The aforementioned forecast is very different from most every other forecast.

MR. PALMER directed attention to page 10 of his presentation, entitled "WCSB [Western Canada Sedimentary Basin] Production

Forecast." The graph illustrates TransCanada's predicted decline from 16.9 bcf a day down to 16.3 bcf a day over the next decade. Basically, the production would experience a modest decline, with some replacement of conventional gas with unconventional gas - coal bed methane. Page 11 of the presentation illustrates why the Western Canadian supply may be flattening over the past decade in the 250-275 tcf range for most every forecaster. Page 12 of the presentation specifies TransCanada's view of the supply change. The green section of the graph illustrates that if one takes the WCSB, the Lower 48, East Coast, and existing LNG terminals plus expansions, it is fairly steady in terms of overall supply to the market. The aforementioned combination will be able to supply in the 70 bcf a day range and modestly decline beyond the year 2015. The aforementioned leaves an opportunity for new LNG and northern gas.

MR. PALMER continued with page 13 of his presentation, which reviews global LNG. Global LNG could fulfill 100 percent of the supply gap. Clearly, MacKenzie and Alaska gas are competitors for that market opportunity as is other domestic gas that was mentioned earlier. The existing [LNG] terminals have about 2.5 bcf a day of existing capacity and expansions in the 2.0 bcf a day range have been announced. Furthermore, there are proposed or approved projects for more than 30 bcf a day. TransCanada believes that those projects have a fixed cost structure comparable to Alaska gas, but they have scale advantages in that these [LNG projects] can be built in smaller modules than the Alaska project. The modules for these [LNG projects] can be 0.5-1.0 bcf a day whereas an economic increment for Alaska gas is nearer 4-4.5 bcf a day. Mr. Palmer informed the committees that today, those facilities need liquefaction facilities in the producing country, [as well as] ships and re-gasification.

**TAPE 04-22, SIDE A** [BUD TAPE]
001

MR. PALMER continued:

> Those issues are being resolved, slowly - some people would say - but in our view, as more and more projects get approved, project four, five, and six will be easier than [projects] one, two, [and] three. The large stranded gas reserves available worldwide: you've heard representations from others as to ... [the] magnitudes of those volumes available to the market, and they have strong support of their home or

host governments. To show you a forecast - on page 14 - [is] a representation of a number of forecasters as to the actual magnitude of LNG into the marketplace.

I would point [out] to you that the black line here is the [U.S.] Department of Energy - they have just over 8 bcf a day of new LNG, and I believe they have only 8 bcf a day ... because they have a very optimistic Lower 48 market. They have balanced the market, with the remainder being LNG. You can see that the balance future for the NPC [National Petroleum Council] also has both "Mackenzie" and Alaska in this timeframe, and they have in the order of 9 bcf a day. Other parties have in the order of 10 to 12 bcf a day of LNG in their forecast.

The next slide, which is a ... [Federal Energy Regulatory Commission (FERC)] map published in July just indicating to you ... [that] at that time, there were 44 projects proposed or approved in the Lower 48 - that's in addition to the existing terminals with approved expansions. About 5 bcf a day, today, has received approval from either the [U.S.] Coast Guard or the FERC. ... [This is] just a representation of the compensation in effect in the LNG market and for the marketplace.

And to wrap up, ... we believe the U.S. and Canada market opportunities [are] in the 10 to 15 bcf a day range for new gas sources through 2015. You will see [that] some parties may have it slightly below 10 and some parties will have it slightly below 15. And ... if I were to exclude the U.S. Department of Energy, most people would be in the 15 bcf a day range - that's the market opportunity if gas prices are in the $4 range. Clearly, if you have prices higher or lower, you change that market opportunity. "Mackenzie" gas appears on track for about 1 bcf a day by 2009.

Number 029

MR. PALMER went on to say:

As I said earlier, the new LNG re-gas sites ... have had approval in the order of 5-plus bcf a day by the FERC and the U.S. Coast Guard, and that leaves, in our

> view, a competition between the Alaska gas pipeline in the order of [4.5] bcf a day and 25 bcf a day of additional proposed global LNG projects. Those projects, in our view, will compete for the remainder of the supply gap, and if they over or under supply the market in total, they will affect market prices, and that will affect demand overall. ...
>
> That's clearly what will happen. We believe that there will be a "first mover" advantage for those projects able to get a green light in the near term, and once those projects are in service, they are long service projects; they could be expected to supply gas into the market place for 20 or 30 or more years, just as "Alberta gas" has served the market for 50 years and [Lower 48] gas has served the market, now, in the order of 75 years. These are long service projects with good gas supply behind them. Mr. Chairman, that's my presentation, thank you for this opportunity.

SENATOR SEEKINS surmised, then, that unless Alaska gas is visible to the marketplace in the near future, it could never be viable in the marketplace. In other words, the LNG expansion will fill the demand such that Alaska gas is no longer needed.

MR. PALMER expressed reluctance about characterizing the situation in that manner. He added:

> What I'm saying is that if we're seeking to hit the market for this project by 2015, ... I believe there's a competition between this gas and global LNG. And clearly those projects are competing to attract market and to obtain sighting and to complete their projects [just] as Alaska is. And I believe that the parties that are approved first have an advantage. I'm not suggesting to you that they are the only ones that can be constructed, not at all. But clearly they have an advantage if they're approved by their regulators [and] ... project proponents and they're going forward. They, as you've heard other people represent to you, may affect the way other people will play in the marketplace.

Number 059

REPRESENTATIVE GARA asked:

At what point in the Stranded Gas Act application process do you have to have an agreement from the producers to actually sell the gas to you so you can decide to build the pipeline? ... At what point can you not go any further in deciding whether or not you're going to build a pipeline? By when do you need to know, in the process, that you'll have gas made available?

MR. PALMER replied:

TransCanada, at this point in the stranded gas negotiations, is negotiating in effect what level of taxation ... the government of Alaska will apply to a pipeline project. So we can continue with that, and are continuing to do that. But we need to have a customer, we need to have a shipper for this project, to make it proceed. And we'll continue to try to attract the North Slope producers as well as other (indisc.) producers to become our customer, or other parties. And we will reach a point where we will not be able to proceed any further. We are also, as you're aware, proceeding to try to obtain the state right of way; that's also meaningful work that we are going to continue with because we think that that will accelerate the project when the commercial deal is ready to go.

We've also said publicly ... that if there's a commercial deal [that] can come together in 2005, we can have a project in service in 2011-2012. But there's about a seven-year timeframe between reaching a commercial deal, and by that I mean [having] ... a customer, and having a project in service. If we do not complete work like the Stranded Gas Act negotiations and the right-of-way negotiations, that would extend that timeframe. I'm contemplating that we would complete that work by 2005, we hope, and be in a position to move forward on a seven-year basis if there are commercial parties ready to sign transportation contracts with us.

Number 080

SENATOR ELTON asked whether there are things the state can do to encourage producers to ship gas in a pipeline built by TransCanada.

MR. PALMER replied:

> I would say that the state completing its negotiations on [the] stranded gas Act items like what royalty take will be, what you're production take [will be], is a fair thing to ask - completion of that is something that is appropriate that the state can do. The state defining its overall fiscal issues is an appropriate thing for you to do. And the state, in our view, needs to consider how best you ... can encourage the overall project to proceed, and that's everything from encouraging producers to become a customer on the pipeline to deciding if the state has the appetite for any of the risk components you heard testified to by some other participants this morning.

SENATOR ELTON asked: "Are you avoiding reserves tax on purpose?"

MR. PALMER replied: "I wasn't avoiding it on purpose. Clearly ... I don't profess to be an expert in what taxing authority the state of Alaska has, but clearly the state has a number of tools at hand that it can decide to use. You have everything from carrots to sticks, and I don't profess to give you advice as to how best you should do that."

CHAIR SAMUELS asked what the timeframe is of the competitors for capital dollars on LNG projects.

MR. PALMER offered that it might be a five-year timeframe, though the issue is really one of, "Can you ... get [sighting] with access in the Lower 48?" He relayed that such can take a considerable amount of time - perhaps as long as two years for approvals of 5 bcf a day - and this needs to be factored into the timeframe calculations; this project has, if not the longest, then nearly the longest lead time due to the magnitude of the project.

Number 120

EDWARD M. KELLY, Vice President, North American Natural Gas and Power, Wood Mackenzie, relayed that Wood Mackenzie would be considered consultant number two or three in the previous presentation [provided by Mr. Palmer]. Mr. Kelly mentioned that his presentation offers greater detail on some of the supply and demand factors previously spoken to by other presenters. Gas prices, now, are responding very directly to oil, and this is both a psychological and a fundamental reality with regard to the way markets are working now, he remarked, adding that Wood Mackenzie expects that linkage to continue, fairly consistently, due to that fact that there is approximately a trillion cubic feet of market that can switch from gas to oil products at various pricing levels.

MR. KELLY said that on the low price side, that's gas to residual fuel oil, and on the high price side, that's gas to distillate fuel oil. So either way, if gas moves into those alternative fuel prices - moves in one direction to compete against those alternative fuels - it tends to lose approximately a trillion cubic feet in annual market, and that's a strong force keeping gas bound in close relationship with oil. In addition, they're both traded on the NYMEX [New York Mercantile Exchange], and that creates a strong psychological linkage factor - excitement in one pit tends to lead to excitement in other pits. Also, noncommercial interests are trading both sets of products at once, so there are psychological correlations there as well. He said that from a fundamental standpoint, for the next decade or more, Wood Mackenzie doesn't see that changing a great deal - "there's not so much gas sloshing around that gas can price consistently below the level of oil products." With regard to outlook, as goes oil in the next 10, 15, or more years, so goes gas, he predicted.

Number 157

MR. KELLY then referred to page 3 of his presentation, and said it focuses on the Organization of Petroleum Exporting Countries (OPEC) spare production capacity, which is set to grow. He pointed out that in the third quarter of this year, spare capacity for "OPEC-10" was approximately 800,000 barrels per day, which is not a lot in the context of a 29-million- to 30-million-barrels-per-day OPEC production capability. Still referring to page 3, he pointed out that spare capacity for "OPEC-10" in the fourth quarter was approximately 2.2 million barrels per day, and suggested that one could expect spare capacity to expand a great deal. Geopolitical uncertainty being what it is, he remarked, oil prices can sustain at high levels due to psychological factors and the reality of geopolitical uncertainty; nonetheless, spare productive capacity is set to increase substantially in the fourth quarter of this year.

MR. KELLY referred to page 4 of his presentation, and said that as a result of [this increase], the oil price outlook does tend to decline significantly, beginning in the early part of 2005. Price outlooks for natural gas, he remarked, assume a long-term, real, oil price outlook of about $22.75, in 2004 dollars, per barrel - that's for Wood Mackenzie's West Texas Intermediate (WTI). At that price level, he noted, the gas price range is very consistent with that which has been presented by previous speakers - a gas price of between $3.50-$5.00. This is based on competing oil products in the end-use market in much of the U.S. In addition, one must also consider what is on the margin for supply. He relayed that Alaska gas would not be competing with LNG so much as with the cost associated with sustaining U.S. and Canadian production.

MR. KELLY said he concurs with some of the figures provide by prior speakers with regard to declines in North American production, adding that the cost associated with replacing 16 bcf per day of North American production essentially sets the floor price for natural gas. Therefore, if the cost associated with replacing that amount of production is $3.00, for example, then a price above $3.00 will encourage the drilling necessary to get that 16 bcf a day produced. Evidence in the marketplace now suggests that as prices decline below $4.00, a lot of activity "came off," which implies very strongly that at that point, in 2002, the cost associated with drilling many of the marginal wells in North America was between $3.50 and $4.00 per million Btu [British thermal unit]. This sets a pretty strict long-term floor price for gas, he remarked, under current drilling costs regimes, under current technology, and once the price declines below the cost of drilling marginal wells, native supply will decline pretty fast.

Number 231

MR. KELLY, on the issue of risk that Alaska and producers might face, indicated that residual fuel oil can also be a factor in setting the floor price - currently that is $3.00 to $3.50 in a $23 oil environment. Also, the cost of replacing production can be a factor, as can the type of technology being used. As technology improves and producers are able to extract more product, the floor price could decline as a result. He remarked that Wood Mackenzie is of the view that North American productive capability can be sustained as long as gas prices remain high enough to encourage marginal drilling, but that will require $3.75 to $4.00 gas under current conditions. He noted that various entities predict a range of Lower 48 production declines, and Wood Mackenzie is about in the middle of those predictions.

MR. KELLY detailed some aspects of Wood Mackenzie and the work that it does. He mentioned that the nature of production and the location of production will change over time. Also, changes in location will affect changes in the nature of production. For example, production could shift from historically defined conventional reservoirs with better porosity, better permeability, to unconventional reservoirs, which are historically defined as relatively tight reservoirs, coal bed methane (CBM), and shale. These unconventional reservoirs will make up over 40 percent of U.S. production by the year 2010, he predicted, whereas current production of these unconventional reservoirs ranges in the upper 20 percent.

MR. KELLY detailed aspects of the "Rocky Mountains," mentioned that the obstacles to increasing production are becoming more meaningful as the opposition to drilling activity becomes more organized and efficient, recounted some of the efforts put forth by those in opposition to drilling, and noted that the risk associated with attempts at increasing production is sometimes dependant on the pace at which drilling can actually occur. He also mentioned that almost all of the increase in the "Rocky Mountains" will be from unconventional sources.

Number 278

MR. KELLY indicated that with regard to Canada and Mexico, there is similar outlook through 2010 and beyond. Currently, the U.S. is exporting about 1 bcf per day into Mexico, even at $5.00 to $6.00 prices, but that should decrease due to Mexico importing LNG. He relayed that Wood Mackenzie expects the flow between the U.S. and Mexico to reverse by the year 2010, though this reversal won't be the result of an increase in native Mexican production. He mentioned that Mexico's upstream industry is the most closed in the world; at this point, it is virtually impossible in Mexico to get effective private investment in drilling. Mexico's potential to increase beyond 2010 depends on structural change in the Mexican upstream; if such a change occurs, Wood Mackenzie's production outlook for Mexico could be substantially exceeded, and this could provide a critical increment of supply into the North American marketplace, though it won't solve the gap.

MR. KELLY referred to page 11 of his presentation, and said that Wood Mackenzie's view on LNG and Arctic projects is that they are highly unlikely to fully address the supply/demand gap. Although the number of proposals has exploded in recent years, there are a couple of limiting factors that intersect, the first being the availability of liquefaction capacity on the upstream end, the second being re-gas permitting capability. Each re-gas project that's permitted has to have a supply source, but suppliers aren't necessarily rushing to do business with a re-gas project just because it's permitted, especially since some permitted re-gas facilities are expensive. "You've got to have both to make an LNG value chain work," he concluded. He mentioned that Wood Mackenzie anticipates that by 2010, there will be 6 bcf per day of LNG, total, in the U.S. main grid.

MR. KELLY remarked, "Our assumption on Alaskan gas, in our models, is 2015; that's a modeling artifice ... based on feasibility." One reason that many are rushing to build LNG facilities is that the cost basis for delivering LNG into a re-gas facility on the East Coast varies between $1.00 and $3.00, so there is a lot of money in the remainder of the value chain. This [cost basis] already assigns, to the producers, a 12 percent rate of return towards the upstream activity necessary to get the LNG into the ship. Although doing something similar on the West Coast is somewhat more risky, it has attracted a lot of LNG development interest. He mentioned that LNG will continue to be a seasonal fuel for a long time to come because Asian and other markets have no storage; since LNG [delivery] in those regions has to ramp up in the winter and ramp down in the summer, this leaves a lot of cargoes available for summer delivery to other places such as the U.S.

Number 356

MR. KELLY said that the supply/demand gap in the U.S. is large enough that it won't be satisfied only by either Alaskan gas or LNG, particularly given that the speed at which an LNG value chain can be built is somewhat limiting. Also, the U.S. gas market is limited by the number of molecules available to it; it would be much larger today if there were more molecules available to it. That limitation won't be overcome in the future, he predicted; instead, the gap will only get wider. He also predicted that although there is currently an overbuild of gas-based power generation facilities, more such facilities will have to be built beginning in 2010 in order to meet increased regional demand; he characterized natural gas as the default source for the majority of those yet-to-be-built power generation facilities.

MR. KELLY said that this is an organic growth in gas demand that is dependant on the growth of the economy, though the U.S. is consuming electricity much more efficiently and is not devoting energy to industrial usage as much as it had been in the past. He predicted that economic growth to energy usage will drop to 3:1.6, though regardless of this drop in increasing power consumption, demand will continue to increase depending on regional differences and seasonal changes. He went on to detail some of the uses for gas consumption, for example, in the making of steel, fertilizer, and paper. Broadly speaking, he remarked, this year is a strong year for industrial gas consumption, though it may be the last strong year for a long time to come. Referring to page 22 of his presentation, he relayed that the average "Henry Hub Spot Price Outlook" for 2005 is listed as $5.36 per mmBtu [million British thermal units], though that depends very strongly on a "$35 oil price."

MR. KELLY said that through 2010, it will be difficult to sustain gas above $4.00. He spoke of residual fuel oil and distillate fuel oil, and mentioned that gas gets priced between those two and that roughly a trillion cubic feet (tcf) of demand would go away if gas "went below [residual] or above distillate." Referring to his presentation, he stated:

> Longer term. Flat picture for supply. With Alaska, again, by assumption, coming in at 2015. This requires, again, that $3.75 to $4.00 minimum kind of price to sustain a heavy pace of drilling to replace that 16 billion cubic feet a day each year; that heavy pace of drilling has to continue to sustain U.S. Lower 48 and Western Canadian supplies, and that's the floor price setter for much of our gas price outlook - [it] is the price required to sustain that level of drilling.

Number 0488

MR. KELLY mentioned that a heavy effort will be required to sustain Western Canadian production, though there will be a slight increase in Eastern Canadian production through 2011-2012 due to "Arctic Canada" coming in. He predicted that Mexican production can increase, though that will depend very much on the structure of the business. Referring to Mexico, he mentioned "privatized upstream structure," "multiple service contract structure," and that Mexico suspects the U.S. of draining some reservoirs that are co-terminus with Mexico's portion of the deep water Gulf of Mexico. He concluded that Mexico has strong incentive to either allow a private structure or gain the expertise to access its own reservoirs, and predicted that it will be "a leftist" [government] that will allow such structural change.

MR. KELLY said that something to be aware of is that politically, "we" don't like to drill, and yet any of the anticipated increases that he's mentioned are based on the premise that drilling will continue. From a geological standpoint, uncertainty exists in "the deep water," though from a financial standpoint, "the financial stars have aligned for producers" and this has resulted in the kind of [drilling] activity currently taking place. Currently, long-term capital is plentiful, cheap, and available; this is because, relative to other sectors of the economy, producing energy is "somewhat hot" and the investor community is a very trendy and fickle community. "Right now, it's the best of all possible worlds for getting capital into the North American upstream, [but] that can change," he remarked.

**TAPE 04-22, SIDE B** [BUD TAPE]
Number 001

MR. KELLY, referring to "our" LNG outlook, said that an impending reality of an Alaskan gas pipeline would make other markets more attractive to LNG producers and would cause a slowdown in the increase in LNG deliveries directly into the North American continent. By the year 2020, the power sector will reign, he predicted, unless and until an alternative means of producing electricity is found or until there is a revolutionary shift in patterns of energy consumption. "We need the stuff for power generation, and power generation becomes by far the largest consuming sector by 2020," he remarked. He mentioned that Canadian demand is similar though Canada has a strong industrial demand as well.

Number 019

SENATOR THERRIAULT asked what the effect will be of "purchasers" going to longer-term contracts and whether this has been factored into possible price stability.

MR. KELLY said it is difficult to foresee that there will be longer-term fixed price contracts for the natural gas commodity.

He pointed out that when the Enron Corporation fell, the ability and willingness to take that kind of long-term price risk fell with it. The ability to "hedge forward" is a real service that requires a great deal of credit behind it. He predicted that utilities will hedge a portion of their gas price portfolio in order to limit [price fluctuations], and mentioned that he'd received a hedged deal from his competitive service provider in Texas that he'd taken advantage of. He suggested that [the state] will have more choice than it will know what to do with in the sense that some will provide a high fixed price and others will provide a floating price; the latter is already occurring at the "small customer" level. He opined that the ability and willingness to sign long term fixed price deals will not emerge as a major aspect of the supply business, though it may be a part of a portfolio strategy for producers and consumers.

MR. KELLY, referring to page 37 of his presentation, said that a strong catalyst to demand is the fact that a lot of the coal infrastructure is "old stuff," as are a lot of the oil and gas steam units. So by the time an Alaskan [pipeline] came on line, "you're" going to be retiring fairly significant amounts of coal units, which must be replaced "one for one." Additionally, the likelihood that there will be a coal shortage east of the Mississippi River and Illinois/Indiana border is real, so even if new coal-burning plants are developed, there may not be enough coal to supply them. Referring to page 39 of his presentation, he said:

> The middle two bars are gas fired, so you've got another 150,000-plus megawatts of new gas-fired generation by the year 2020, assuming that somehow we build 80,000 megawatts of coal-generation. And it will be very clean-burning coal relative to what coal is today, but that's a lot of coal, that's a lot of time, [and] a lot of permitting efforts required.

Number 066

MR. KELLY remarked that "we're stuck on fossil fuels," so any risk the state might face by taking ownership of a pipeline and taking royalty in-kind (RIK), or taking a contract position on a pipeline, would be based on whether "we're" still dependant on fossil fuel consumption. Currently, he remarked, "we need more gas, ... and we need more ... than even LNG and Alaska are likely to provide." He predicted that in real 2004 dollars, the price will hang above $4.00 until an Alaskan pipeline is brought online, at which time the price will drop by about a $1 over two years due to annual declines not being replaced. He concluded that with regard to the state taking a contract on a pipeline, or having ownership of a pipeline, it's difficult to see the state's cash risk as being anything more than minimal unless there is some significant, fundamental transformation in the way North America consumes or produces energy.

REPRESENTATIVE GARA asked whether bringing Alaska gas to market will have a long-term impact on Lower 48 gas prices.

MR. KELLY predicted that after the first four to five years after Alaska gas comes to market, the price will begin an upward trend that will continue. In response to another question, he said, "I wouldn't characterize it as a race between Alaskan gas and LNG, because it's just difficult to see LNG accumulating fast enough to drive gas prices down below competing products, to result in a North American supply that's great enough for gas to recapture oil-based markets."

REPRESENTATIVE ETHAN BERKOWITZ, Alaska State Legislature, asked whether any consideration has been given to the role that gas-to-liquids (GTL) might play in terms of filling markets.

MR. KELLY said that Wood Mackenzie has addressed GTL as a monetization option for stranded methane pools worldwide. He mentioned that because the western world is relatively energy short, there is every incentive to invest in whatever means can monetize distressed methane pools worldwide, and so GTL will be used.

Number 0161

RICHARD BONE, Director, State Energy Marketing Program, Texas General Land Office (GLO), offered a [PowerPoint] presentation and said that he would speaking about Texas's "take in-kind" program, public customer gas program, and state power program. He went on to say:

> The take in-kind program ... was started in 1983 through state appropriations bills. The program operates by taking royalty payments in [the] form of production instead of receiving monetary payments. The program then sells the mineral interest, oil or gas, to customers, either retail customers or wholesale customers. The program contracts out with mainline transportation and local distribution

companies throughout the state of Texas. What I mean by that is, we hold approximately 26 different contracts with either intrastate, interstate, or local distribution companies to get service all the way to the end users.

Natural gas value is established by using ... location differential pricing points around Texas that are then equated back to ... Houston ship channel [prices]. In Texas we have several receipt points for natural gas ... or oil, and ... one of those points is very liquid, which is Houston ship channel. So basically we have production in West Texas, South Texas, some in the Panhandle, and some in East Texas. What we do is, we've [taken] historical differentials off of each one of those locations and did a comparison back to [Houston] ship channel [prices] to try to arrive at a price for the sale of the product. ...

Oftentimes, the product price is actually lower than NYMEX. In 1983, state agencies were directed to reduce their utility cost by buying lower priced gas that was being produced on state lands - that was one of ... the effects of the whole bill. [General Land Office] contracts went into effect in 1985 for state agencies; in 1985 we had contracts with 33 state agencies. That included our largest customers which [were the] Texas Department of Criminal Justice, [the Texas Department of Mental Health and Mental Retardation (TDMHMR), the Texas Department of Public Safety (DPS), and the Texas Department of Transportation (DOT), among others].

Number 194

MR. BONE, referring to his presentation, said:

This is a list of some of our producers that we actually have agreements with to take natural gas and oil from; all these producers are either on state lands or in what we call the "8(g)" territory, which is a [common] royalty share territory between Texas and the U.S. government. [With regard to the] type of contracts, we use several different types. One is [an] "interlocal" contract; that's between the General Land Office and other sister agencies or other state agencies such as universities.

The second one is [an] interagency, which is between state agencies. You'll notice there that [it says] "Last Look" ...; what that means is ... [that] the General Land Office has the right to look at the contract prior to it being signed by any state agency to see if we can get a better deal for them. If they go out for an open bid and we believe our gas can be sold cheaper and [transported] ... to them cheaper, then we have the right to come in and actually bump the competitive bid and take the business. We do [North American Energy Standards Board (NAESB) contracts], which is a standard in the gas business these days.

One of the questions that was asked of me was who negotiates contracts for the General Land Office. The staff has traditionally always negotiated all contracts for the General Land Office. We more or less take care of the day-to-day business, we "notice up" the oil producers for natural gas and oil, we work with the agencies, we work with our wholesale customers [and] our buyers of our excess natural gas and oil, and then, when it comes down to it, we send it up for the commissioner for signature. ... Who are our wholesale purchasers? Some of the larger names in Texas: "Reliant, Houston Pipeline, Energy Transfer, Kinder Morgan, Formosa, CrossTex, Trammo." "Trammo, Plains, [Sunco], and Sempra" are our oil buyers - they're the ones that buy about 750,000 barrels of oil a year from us.

Number 223

MR. BONE, on the issue of pricing models, said:

Over the last three years, our pricing model has changed significantly. I was hired three years ago ... and my job at that time was to treat the program and try to make it more like industry. In other words, [mirror] ... the current marketing practices [of] the natural gas business and the oil business. When I came on board, ... the model we had was, basically, we would just sell it for a price equivalent to what we were getting [in] royalty payments. Part of the legislative appropriations bill stated that we were actually supposed to enhance that value - not just take it, but actually enhance it.

The way we did that is through several different methods. One, we streamlined transportation agreements all across the state with a network of pipelines to try to get our gas from one location to another in a cheaper way, maybe by swapping it from one location; [for example], ... if we had gas in far South Texas ... [and] "Kinder Morgan" ... needed that gas to go into Mexico, then we would ... swap that gas ... [to them and they would] give it back to us at Katy, which is a more locational sensitive point for us to get to our customer base.

With that said, we continued to move from there and we went to a market-based pricing. And what I mean by that is, ... we actually looked at the market, we trended what the current marketing companies were doing in Texas ..., and we really went after that same type of market. So what you actually have is ... a state agency more or less competing in a deregulated market .... We also used ... differential base pricing points. ... [And] a lot of our product is competitively priced; in other words, ... we don't have a lot of our gas exposed to high-risk maneuvers in the gas market, we're not in the business to speculate on what it may be ... six months from now.

Our fiduciary duty for the [General] Land Office is directly to the [Texas] Permanent School Fund, so we have to be as risk adverse as possible. And the other ... pricing model ... is "request for proposal" [RFP] pricing: we'll actually go out once a year to sell our oil. We have some very specific things we do with our oil; we sell our oil to the four [entities] that we mentioned earlier, and ... we ... ask them to ... give us the payment in natural gas at a point that we request ....

Number 261

MR. BONE, on the issue of annual revenue, referred to his presentation and said:

You can see that we've grown somewhat. In [fiscal year (FY)] 02, there was a drop, more or less, in the market ... for natural gas and oil prices that somewhat ... put a dent in the program ... [though] volumes were still up. The percentage point on the right-hand side of the screen actually represents the percent royalty versus "take in-kind." In other words, ... in FY 01 we took 45 percent of our natural gas in-kind versus [55] percent in royalty. ... Total gross production for the state of Texas is about ... 150 bcf on state lands. Of that, we take approximately 15 percent. That's about [an] average royalty.

[With regard to] annual volumes, you see [that it has] significantly increased from FY 01: 16 bcf; 788,000 barrels of oil. Our oil program, because of the reservoir activity in Texas, has ... been dropping fairly steadily. ... [We're still] doing a lot of exploration; however, the reserves we're finding are a lot smaller and they're ... being depleted a lot quicker. Expected gas for FY 04 is about 36 bcf, so basically what we've done since FY 01 [is] ... more or less doubled the size of the program as far as gas. How do we pay for this program? ... What we do is we ... have an administration fee; we actually charge a fee of [$.03] ... on every mmBtu of gas that goes through our program, whether we buy it in the market or whether we take it in-kind.

In addition to that, we charge a [$.05] per barrel ... administration fee. What that does is it goes to our comptroller and then it's redistributed to the general land office for it's administrative program during the year, specifically for the state energy marketing program. [With regard to] state energy marketing customers, we have a wide spectrum of customers. We supply gas ... and electricity to city and county governments, school districts, and other customers. ... From the gas side, we now serve about 587 meters at 24 universities, 2 school districts, 1 city, 39 prisons, and 18 state agencies. ... I would say we're the largest supplier of natural gas to public retail customers in Texas. We sell gas or oil to 10 wholesale companies or oil companies and over 26 pipelines and [local distribution companies (LDCs)]. ...

Number 307

MR. BONE added:

> In 1986, we took approximately 2.2 bcf of gas, [and] we saved state agencies over $1.1 million. In 1991, the legislature expanded the program to give us the last look that we talked about earlier. In FY 03, ... the annual volume was 25 bcf, total ... gross revenue was $119 million, and savings to our ... public retail customers ... was $62 million a year.

MR. BONE relayed that the state power program was authorized in 1999 by the 76th legislature via a comprehensive electric restructuring bill. This included authorizing the state power program to sell electricity via exchanging minerals from state-owned lands for electricity. He went on to say:

> We started that program a full year and a half before deregulation in Texas; it's been very successful. The state power program ... began in June of 2000, full competition started in January of 2002. The mandate within the [legislation] ... says that we must take in-kind royalties from state mineral production, maybe convert it into other forms of energy, including electricity, for sale to public retail customers. ... Let me define public retail customers: that is a city, county, ... school district, ... university, or other state agency. More or less, any taxing entity in Texas, we have the right to sell electricity to. We don't sell electricity to [restaurants, for example, only to entities] where public tax dollars are used to pay the bills - that's all we do.

Number 339

MR. BONE relayed:

> These royalties are also defined as royalties from [Permanent] University Fund lands - ... in Texas we have a Permanent University Fund administered by the "UT systems," which basically takes control over the oil and gas on lands that have been granted to the universities - and also [from] ... the Outer Continental Shelf known as the "8(g)" and that's the common area I talked about earlier that's shared between the state of Texas and the federal government

- it's a three-mile-wide strip on the edge of our territory.

The program objectives [were], one, to increase revenues to the [Texas] Permanent School Fund, which we have done to the tune of about $32 million since 1999 - that has been what we've contributed as far as electricity proceeds - [and] 100 percent of the proceeds go directly back to the [Texas] Permanent School Fund; [two], utility savings to public retail customers combined with natural gas savings ... - that's about $62 million in savings for public retail customers, mainly school districts ...; and [three], to share the experience of competition in the retail marketplace prior to and continuing through deregulation.

What we found ... was that the average retail person ... [doesn't] have the expertise ... to know where the market's going, what it's doing, [and] what different product types [are available], so ... we kind of lead the state agencies and the public retail customers through that process all the way to contract and delivery. ... In the last [legislative] session ..., the commissioner ... was able to have military bases and federal veterans' facilities added [to the program]. ... We've successfully ... contracted with two separate military bases in Texas ... and we're in negotiations for others at this time.

Number 360

MR. BONE continued:

The state power program originally focused [on] and currently serves many of the independent school districts ... and other public retail customers in the Houston area. ... Today, under deregulation, we serve customers in all areas that are currently deregulated by the public utility commission. We had 93 customers prior to deregulation, we've added [or re-signed] 180 customers ... under the new market value contracts. ... Prior to deregulation, we simply gave the public retail customers a discount off of their tariff rates; after deregulation, we actually started competing ..., through RFP responses, with all the major marketing companies in Texas. ...

We have to take more gas, every day, off of our state lands to provide more power to our customers, so we felt this is a good way to kind of demonstrate the effect of natural gas on the electric market as we see it. ... We now serve 238 school districts in Texas - that's out of 1,040, and out of 1,040 school districts, only about 550 of them are able to actually receive deregulated power - 29 cities, 13 universities, 5 state agencies, 40 counties, [and] 30 municipal utility districts.

We're the largest supplier of public retail power in the State of Texas. [The state] power program has increased the value ..., by 50 percent, compared to the monetary royalty payment that we would have received. [What] that means is, we've actually increased our earnings on that same monetary royalty payment by 50 percent over the monetary payment, so we've actually had what we call an enhanced value. If we were to [have] put it in the treasury and earned 5 or 6 percent on it, it wouldn't have done anything like we've done [through the program].

[With regard to electricity, in] FY 01, we had 200 megawatts of power in our program; [in] FY 02, 400 [megawatts]; and [in] FY 03, ... after deregulation started, we have jumped to 1,200 megawatts. ... You can almost see the direct result tied back to the gas page [of the presentation] ..., where we went from about 18 bcf up..., this year, to 36 bcf. So it's quite a significant increase and a way for us to ... market our gas ... to our own customers, be less risk versed for the [Public School Fund], and ... at the same time be able to save money for the public sector. I'd take any questions.

Number 393

CHAIR SAMUELS surmised that Texas's program does everything in state.

MR. BONE concurred. In response to a comment, he indicated that the Texas program is competitive with regard to both gas and oil, and mentioned that the Texas program has a variety of contract lengths ranging anywhere from two years to four years.

SENATOR LINCOLN asked whether Texas would have lost some of its military bases if it had not been able have them as public retail customers.

MR. BONE said that he couldn't speculate on that point, but noted that having military bases as public retail customers ensured that they got lower utility costs.

SENATOR LINCOLN asked how much of a savings this generated.

MR. BONE indicated that he would research that issue, and mentioned that the Texas program was able to sell military bases "green" sources of power. In response to a question, he said that from a marketing standpoint, there are five different geographical points that traded all the gas in Texas, and by dividing Texas into five geographical areas and taking the historical data regarding price from each of those areas, the take in-kind program has been able to calculate a take in-kind value at each of the five locations. That calculation was then equated, on a monthly basis, to the value at Houston ship channel, which was one of the geographical points. For example, if Houston ship channel gas is valued at $5.00, the value of gas from another geographical point might be $5.00 minus $.50. In other words Houston ship channel provides a single point of reference for the purpose of valuating gas prices. This same type of calculation is also being used to calculate RIK values.

MR. BONE said that this method has allowed the program to provide its consumers with cheaper gas and oil then they would have gotten from competing commercial providers. He mentioned that since the Texas General Land Office has production and transportation capabilities, the Texas program affects pricing from a tariff standpoint.

Number 545

REPRESENTATIVE HAWKER asked whether, because everything is done in state, the Texas program avoids oversight from the FERC.

MR. BONE said that is correct, and mentioned that some LDCs in Texas do not allow competition, and so the state is the only other entity that can provide gas or oil to such areas. He noted that the state energy program also operates within an existing grid with regard to [electrical] power, and pays the same tariff rates as all other competitors. One advantage the state program has, however, is that it doesn't have to pay state taxes, and so this results in a savings of approximately 2.5

percent on both the commodity and the wire side of the business. Therefore, commercial power providers have to automatically lower their price by 2.5 percent in order to compete with the state program, though, again, the state program only provides to a certain segment of the market: the public retail customers, which are the customers that actually pay their bills with tax dollars.

REPRESENTATIVE CHENAULT asked where the program's funding comes from.

MR. BONE reiterated his comments detailing how the program is self-funded via administrative fees. In response to a comment, he mentioned that in the Texas program, a lot of the oil is converted into natural gas because there is no need for oil. In response to a question, he noted that the aforementioned 50 percent increase in value is strictly a revenue stream, and reiterated that any money the state power program makes goes directly to the Permanent School Fund, which only funds K-12 education.

**TAPE 04-23, SIDE A** [BUD TAPE]
Number 001

The committee took a brief at-ease.

KEVIN BANKS, Commercial Section, Central Office, Division of Oil & Gas, Department of Natural Resources (DNR), relayed that his [PowerPoint] presentation would touch on the development and status of Alaska's current royalty in-kind (RIK) program, on a couple of royalty contracts that the state has recently entered into, and on a possible future direction that the state might choose to go in. He explained that royalty is a share of production: the ownership of the oil or gas that the state keeps in a contractual arrangement with its lessees. The state can choose to take royalty in-value (RIV) or in-kind; when taken in-value, the mechanism used to calculate the value is subject to a "higher of" calculation. That [was] the case for Alaska North Slope (ANS) gas, although through various royalty settlement agreements and arrangements with respect to oil, that has changed.

MR. BANKS went on to say:

> We can look to how the producers, or the lessees, are selling oil and gas, compare that to what the market is, how others in the same field are doing, and [then]

we're entitled, under the provisions of our lease, to get the highest of those values. The lease also requires that the producers/lessees assume the responsibility of [marketing] our oil and gas along with their own ... share. And I think that's an important feature to make [note of], because if we take gas or oil in-kind, ... then it's our responsibility to market our royalty share.

Why take RIK? ... The commissioner ... may only award a contract if it serves the maximum benefit of all citizens. And even in the enabling legislation for the Alaska Royalty Oil and Gas Development Advisory Board, which we call the Royalty Board, ... [it states] that the decision to take royalty in-kind or in-value falls on whether or not it promotes and facilitates wise development of our resources and provides for economic growth and other kinds of benefits ... within the state.

Number 029

That's an important feature. ... The state develops this right ... by the arrangements we have with the lessees in a lease agreement. ... We offer leases for sale in a closed-bid auction; the lessees agree that we may take our royalty in-kind or in-value at our election, [and] ... the only provision that encumbers that right is that we have to give them appropriate notice. Under the old leases that are on the North Slope, that used to be six months' notice. The newer leases are three months, and, as far as oil is concerned on leases ... in Prudhoe Bay, it's been changed to three months as well.

MR. BANKS continued:

So we get a little [bit] of flexibility. As long as we tell the producers, with appropriate notice, that we want to take our oil in-kind or switch it back to in-value, that's something that they have to do. ... The rules [that] apply to oil and gas, under the lease, are the same, although, as I've said, various agreements have been entered into over the years with the producers that have changed the nomination procedures for oil. And this has been part of our leasing program for [40] years - all of the leases have a [similar] condition ..., you see it in leases in the Lower 48 as well.

Importantly, it gives us the right to switch from royalty in-kind [to] in-value, and we regard that as having value in and of itself. ... If we think that what we're getting for in-value is too low, for example, and we think we can do better if we take it in-kind, ... we can take it in-kind - and sell oil and gas - and improve our position. If we think that keeping it in-value is a better deal, ... we can switch it back to in-value. So that by itself imparts a certain value to the state in terms of revenues for its royalties. ...

Number 061

Switching on and off, or raising or lowering the amount of royalty in-kind, is important to us because that gives us the opportunity to sell to customers that the producers might not be willing to sell to - in-state refineries is a good [example] - and we can also offer terms that are different than what would be more normal contracting arrangements. And I'll give you two examples ... in a moment, but even about 12 years ago we entered a 10-year contract to sell oil to Petro Star [Inc.] to supply their refinery in Valdez.

They never took any oil under that contract, but just the possession of our contract and the assurance of a supply of oil for a period of 10 years was sufficient to get the financial backing they required to get the refinery paid for and constructed. And similarly we offered [Flint Hills Resources, L.P.] a long-term contract, which you don't normally see in the marketplace, so that they too could finance ... the purchase of the refinery. Of course, I believe the state was able to get a premium for that kind of arrangement, and also now we have a viable and what I think will be a fairly good customer in [Flint Hills Resources, L.P.] at the North Pole refinery.

MR. BANKS, referring to his presentation, said:

Just to give you an idea of what our switching has been like in the past, this chart shows that at times we've taken almost all of our royalty in-kind. The green area represents basically the total amount of oil that's produced on the North Slope ... since 1979 through 2002, and, as you can see, we've kind of jumped up and down over time in taking royalty in-kind. We've offered it in competitive sales, most often we've sold it to local refineries, and the situation now, if you were to forecast that out, will look a bit as it has been in the recent past, where a little over half of our royalty will be sold to [Flint Hills Resources, L.P.].

Now, there was a question earlier about whether or not RIK and RIV are equal, and [whether] the price we receive for our royalty should be the same. I think it's a principle that's stated in somewhat elliptical ways in our regulations and our statute that that should be a requirement, that when we decide to sell royalty in-kind, that we should at least get as much for it as we would have in-value. Arguably, ... we might even look to court decisions that would have said the same thing.

Number 082

MR. BANKS, referring to different pages of his presentation, said:

This chart gives you an indication of how well we have done. We sometimes miss, we sometimes do better. ... [This graph] says about the same thing, except in terms of differentials, that on balance, in the last 25 years of a royalty in-kind program on the North Slope, we've just about broken even. And that's in spite of the fact that there were times when we had contracts that had distinct [premiums] associated with them. There have been other times when we've just missed it, most notably when we sold oil to [Alaska Petrochemical Company (Alpetco)] in Valdez and the company went belly up and couldn't pay for the oil that we had nominated and dedicated to them, and [we] ended up having to resell it back into the market and ... to the producers at a loss.

Now I'll get to the recent contracts. .. As you know, we brought to you last session the [Flint Hills Resources, L.P.] oil contract, and, a couple of years ago, the department negotiated a contract with

Anadarko Petroleum Corporation and EnCana Corporation - EnCana used to be [Alberta Energy Company Ldt., AEC] before [it] was purchased by EnCana - and I'll touch a little bit on the terms of those agreements. All of our contracts have similar terms, and of particular importance are the four I've listed here for [Flint Hills Resources, L.P.]: price, special commitments, the kind of quantity that we're going to supply, and for a certain length of time - [term].

Number 099

MR. BANKS relayed:

Flint Hills's price is not what [we] have normally charged "royalty in-kind" kinds of customers for oil. The norm had been, since the very beginning on the North Slope when we first started selling oil to [MAPCO Alaska Petroleum Incorporated] in 1979, that the price would be based on what we would have received for the royalty in-value. ... It specifies, "You pay us the in-value price." In the Flint Hills contract, I think owing to the fact that we have a much better understanding of oil markets now for North Slope crude then we could ever have had in 1979, we modeled the pricing term for Flint Hills in a way that mirrors the same calculation that we make for our in-value oil, which, in turn, mirrors the calculation that the lessees themselves use when they sell oil.

So we have a market standard, so to speak, in the way oil contracts are priced, and the Flint Hills contract is priced off of an ANS spot price, so it's an index price - it will follow the market - and we believe that the term and the calculation that we've developed in this contract will yield a premium for our oil in-kind [versus] ... having kept it in-value. Flint Hills also promised to give us special commitments, and these are ..., I think, very important but are [of a] non-monetary value to the state.

In the Flint Hills contract, that included upgrades to the refinery for it to make clean fuels, ... voluntarily hiring Alaskans where they could, taking reasonable efforts to use all of the royalty oil that they buy for us to make products here in Alaska and to supply the jet fuel and consumer gasoline market, ...

> [promising] to abide by the commitments that Williams [Companies] had made ... as they [proceeded] to upgrade the tank farm in Anchorage, ... [promising] to ship [oil] ... and other products on the railroad, and ... [promising] to promote development of the international airport in Fairbanks and ... provide gasoline in Fairbanks and Anchorage at parity.

MR. BANKS remarked:

> And while those are non-monetary kinds of values to the state, it's something that we were able to negotiate with them. In return for the price and those kinds of special commitments, Flint Hills receives from us assurances of a quantity of oil that basically meets their requirements and with sufficient flexibility to adjust for seasonality, and we've also committed to supply them oil for 10 years. And so under those circumstances, I think we struck a fairly good deal for the state with Flint Hills.

Number 144

SENATOR THERRIAULT asked for more information about the MAPCO contract.

MR. BANKS said that there were two contracts with MAPCO. The original 1979 contract had a "schedule B" pricing mechanism, which was intended to capture an amount that matched what was anticipated would be received via the ANS royalty litigation. He noted that as a result of this mechanism, there was a fairly close match with RIV but not with RIK. A second contract with Williams [Companies] - the successor to MAPCO - was signed in 1998 that agreed to RIV plus $.15, and this outright premium had no restrictions with regard to retroactive calculations.

MR. BANKS, on the issue of the Anadarko Petroleum Corporation and EnCana Corporation contract, said that after negotiating the agreement, the department submitted, for review by the public, a preliminary best interest finding on March 29, 2002. No further action has been taken on the agreement, however. The two companies had had concerns about how they could nominate for firm transportation commitments in a pipeline when they didn't have any gas to nominate - they hadn't gone out and begun to explore for it; furthermore, how could they go out and explore for it if they didn't have the means to transport their gas off the North Slope. The department saw an opportunity to go about making arrangements to help them out for a price. The response from Anadarko Petroleum Corporation and EnCana Corporation involved a proposed contract that included a price equal to RIV plus a premium, and a cash option price to exercise a renewal on the contracts every five years for as long as it took to get the pipeline built, get their gas into the pipeline, and back out the state's RIK gas.

MR. BANKS said that the advantage of this type of contract is that it would give Anadarko Petroleum Corporation and EnCana Corporation the opportunity to take the state's gas and fill their pipeline space with it while they proceeded to develop their own gas supplies; then, upon discovery and development of their own gas, they would have the option to take the state's gas off the pipeline and replace it with their gas. At that point, the state could simply switch back to RIV and benefit from having two more gas producers on the North Slope with access to markets for selling gas.

Number 219

MR. BANKS, in response to questions, said that there are FERC regulations in place that are designed to offer open access through an open season process, though there are some shortcomings, since those regulations are designed to work in situations where there are more competitive opportunities to move gas from a particular place. Additionally, there are provisions in the federal energy bill that may improve access opportunities for folks like Anadarko Petroleum Corporation and EnCana Corporation. He reiterated his comments regarding aspects of Anadarko and EnCana's proposed contract.

MR. BANKS, in response to another question, said that the point the state would deliver gas to Anadarko and EnCana would be the same place, as yet undefined, where the state would receive its royalty if it were taken in-value, and it is as yet unknown whether the state would take gas as royalty before it moves through the treatment plant or whether it would take it after. Anadarko and EnCana could then acquire firm transportation capacity for the state's royalty gas and send it all the way to the marketplace, wherever that ends up being. The proposed contract also anticipated that there might be some offtake of a small volume of gas that Anadarko and EnCana would be willing to sell back to Alaskan communities if necessary. "It's a kind of a 'take or pay' capacity agreement, you see; they would commit to move 350 million cubic feet of gas down this pipeline [and] if they didn't have it, they'd still have to pay for it," he explained.

MR. BANKS said it is not an automatic decision that expansion of the pipeline would occur simply because there are customers available and looking for it to happen. The FERC cannot require such an expansion, and so normally Anadarko and EnCana would have to go to the producers and ask for expansion to take their new gas; thus the decision would be left up to the producers to a certain extent - they would have to find that it would be economically viable to take that gas. Under the proposed contract, however, it would be the producers that would have to take the royalty gas back in-value and find space for it, either by expansion or by backing out their "working interest" gas. He added, "We tried to accommodate for that eventuality in the contract by changing the nomination schedule that is currently embedded in the contracts."

Number 315

MR. BANKS said that under the proposed contract, Anadarko and EnCana would be required to give the state a much longer lead time to change the percentage of royalty gas that they were taking, and if their own gas were to be put into the pipeline in place of the state's gas, the state would get a two-year nomination notice period. This would give the producers sufficient time to make adjustments, to either plan for an expansion or otherwise accommodate the switch back to RIV. The proposed contract with Anadarko and EnCana contained commitments similar to those in the Flint Hills contract, including an exploration program of $50 million a year, instate preference for contracting and local hire, and a $25,000-a-year training program, which would last 10 years and train Alaskans [in the industry].

MR. BANKS, on the issue of future RIK challenges and opportunities, said:

> I've made two points about royalty in-kind that I think are important. The fact that we take royalty in-kind and have historically taken it at the point where it's delivered to us as in-value, is a rather important issue. With respect to oil, it's fairly easy for us to do that because the [Trans-Alaska Pipeline System (TAPS)] ... is a common carrier. Our customers have the same access to the TAPS ... as anyone else, and so they can step up and buy our oil

in Prudhoe Bay or at the inlet of a pipeline and pretty much be guaranteed the opportunity to deliver it to their refinery down the pipeline. ... As the Anadarko and EnCana contract illustrates, that's not the case for gas, where, if we were to take our gas at a delivery point upstream of the pipeline - either at the inlet of the gas treatment plant, or at the outlet of the gas treatment plant but ahead of the pipeline - our customers are going to have to find a way of moving it, [of] taking the gas away to market.

Number 341

The second issue that I think is important is that in the pricing mechanism for oil, we're now able to sell to Flint Hills mirroring what we appreciate is going on in the marketplace. The mechanism of relying on an ANS spot price, for example, is a very good indicator of what the market of ANS oil is, and so it's easy for us to point to that and say, "Here's how we'll index the price of our royalty oil.'" Gas is not there yet ... because we're not there yet; we haven't begun delivering gas to Alberta or Chicago or wherever it may go, and haven't yet established the kinds of market indicators that we might want to apply to a royalty in-kind contract. ...

MR. BANKS continued:

[So] where we take the gas and how we price it will become fairly important. If we take gas at the inlet of the pipeline, our customers will have to assume the risks of taking a firm transportation commitment on the pipeline, and the risk that when they sell gas ... in the marketplace, they'll get enough to pay for the transportation charges. The state could, as an option, assume that risk by delivering ... our royalty gas at the "ACO" (ph) hub in Alberta and assume the transportation risk ourselves and, presumably, we would then be able to charge our customers accordingly.

So now, as we move forward, we're going to be facing questions about how much risk the state is willing to take when it sells its gas, ... are we a "price taker" as we have been in the oil business for 25 years, or would we be willing to step out into the marketplace.

> If we do [the latter], what kind of marketing organization do we think ... we would like to develop. ... [Also, we should recognize] that people and expertise and the functions of a marketing organization all come with a cost. ... I think those are the questions [reflecting] where we are right now, trying to deal with those kinds of issues. If you have any more questions, I'd be happy to take them at this time.

SENATOR LINCOLN noted that there were only three months between the time the final finding and solicitation for offers was published and the time the contract negotiation with Anadarko and EnCana was completed, and said this seems like a very short timeframe. She asked whether such a short timeframe is normal for DNR.

Number 412

MR. BANKS said that the timeframe has historically been governed by the motivation of the customers, and the state takes a passive position with regard to selling royalty. And while the state will nominate oil when it can and sell it to someone, the terms of an agreement are designed to strike a balance of risk that favors the state, for example, by avoiding default risk. He characterized the aforementioned three months as incredibly long in terms of how producers and gas suppliers and oil suppliers behave in a regular market, where deals are done in a matter of hours depending on the quantity and the term of the agreement. For example, it might take three to four weeks, at the outside, to establish a one- or two-year contract between a producer such as ConocoPhillips Alaska, Inc., and a customer for oil in California. Those [producers] know their customers, they're in the business of selling, and, hence, they're much more nimble in the marketplace.

SENATOR LINCOLN asked whether the aforementioned commitments with Flint Hills and Anadarko and EnCana regarding Alaska hire and utilizing Alaska businesses are "set in stone" or involve certain percentages.

MR. BANKS replied:

> In the agreements that we've had and that I'm familiar with, going back to ... 1990, ... [they] all have some language with respect to local hire. And ... at this point, I think, the state, in its role as a

> government, can run afoul of constitutional problems in enforcing some kind of very specific local hire rule. I suppose [in] a deal between BP and ... Flint Hills, they could say anything they want about who to hire, but we can't. And so the agreements have always stressed, "To the maximum extent possible," or "As available," and "At times, ... [you] voluntarily will hire Alaskans." ...

SENATOR LINCOLN asked whether the local hire commitment is monitored by the department.

MR. BANKS said it is to a certain extent.

Number 467

SENATOR THERRIAULT asked why no further action has been taken on the Anadarko and EnCana contract.

MR. BANKS indicated that that decision was made during the previous administration and probably involved a variety of factors, adding that it was not an uncontroversial issue. "In the request for comments that accompanied the RFP, the producers all objected to the RIK sale," he noted, and so the attendant controversy prompted the parties involved to wait. In response to another question, he explained that the current contract, which is as yet unsigned by either party, contains some provisions regarding timeframes within which the parties could withdraw.

**ADJOURNMENT**

There being no further business before the committees, the joint meeting of the Joint Committee on Legislative Budget and Audit and the Senate Resources Committee was adjourned at 4:20 p.m.