ALASKA LEGISLATURE
JOINT COMMITTEE ON NATURAL GAS PIPELINES
Anchorage, Alaska
July 17, 2001
9:11 a.m.

SENATE MEMBERS PRESENT

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Donald Olson, alternate

SENATE MEMBERS ABSENT

Senator Johnny Ellis

HOUSE MEMBERS PRESENT

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies
Representative Hugh Fate, alternate

HOUSE MEMBERS ABSENT

Representative Mike Chenault, alternate
Representative Reggie Joule, alternate

OTHER MEMBERS PRESENT

Representative John Davies
Representative Drew Scalzi
Representative Ken Lancaster

COMMITTEE CALENDAR

FEDERAL ISSUES
PIPELINE ACCESS ISSUES
REPORT ON MARKET CONDITIONS
UPDATE ON SB 158 & ECONOMIC MODELS
ROYALTY IN-KIND ISSUES & PIPELINE STUDIES
RIGHT-OF-WAY PIPELINE APPLICATIONS
ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

PREVIOUS COMMITTEE ACTION

None

WITNESS REGISTER

Mr. Mike Henry
Resources Aide to Congressman Young
United States House of Representatives
2111 Rayburn Bldg.
Washington D.C. 20515-0201

Mr. Mike Menge
Aide to Senator Murkowski
United States Senate
322 Hart Bldg.
Washington D.C. 20510-0202

Mr. Justin Stiefel
Aide to Senator Stevens
United States Senate
522 Hart Bldg.
Washington D.C. 20510-0201

Mr. Randy Methura
Office of Energy Projects and Pipeline Certificates
Federal Energy Regulatory Commission (FERC)
888 First St. NE Rm. 11A
Washington D.C. 20426

Mr. Robert Cupina
Director of Energy Projects
Federal Energy Regulatory Commission
888 First St. NE Rm. 11A
Washington D.C. 20426

Mr. Robert Petrocelli
Office of Energy Markets, Tariffs and Rates (OMPR)
Federal Energy Regulatory Commission
888 First St. NE Rm. 11A
Washington D.C. 20426

Mr. John Katz
Director of State/Federal Relations and
Special Counsel
Office of the Governor
444 N. Capitol NW, Suite 336
Washington DC 20001-1512

Mr. Anthony Scott, Staff
Regulatory Commission of Alaska (RCA)
Department of Community and Economic Development
1016 W 6th Ave.
Anchorage AK 99501

Mr. Will Abbott, Commissioner
Regulatory Commission of Alaska
Department of Community and Economic Development
1016 W 6th Ave.
Anchorage AK 99501

Mr. Ed Small
Cambridge Energy Research Associates, Inc. (CERA)
Charles Square, 20 University Road
Cambridge MA 02138

Commissioner Wilson Condon
Department of Revenue
PO Box 110400
Juneau AK 99811-0400

Mr. Roger Marks, Economist
Department of Revenue
PO Box 110400
Juneau AK 99811-0400

Commissioner Pat Pourchot
Department of Natural Resources
400 Willoughby Ave.
Juneau AK 99801-1724

Mr. John Goll, Regional Director
Mineral Management Service (MMS)
U.S. Department of Interior
949 E. 36th Ave.
Anchorage AK 99508

Mr. Jerry Brossia
Bureau of Land Management
U.S. Department of Interior
Address not provided

Mr. Bill Britt, Pipeline Coordinator
Department of Natural Resources
411 W 4th Ave., 2nd Floor
Anchorage AK 99501

Mr. Frank Brown, Co-Chairman
Alaska Highway Natural Gas Policy Council (AHNGPC)

Office of the Governor
550 W. 7th Ave., Suite 1700
Anchorage AK 99501

Mr. Mike Navarre, Chairman
Subcommittee on Alaska Hire/Buy/Build
Alaska Highway Natural Gas Policy Council
Office of the Governor
550 W. 7th Ave., Suite 1700
Anchorage AK 99501

Mr. Bill Corbus, Chairman
Subcommittee on State Pipeline Ownership and Tax Structure
Alaska Highway Natural Gas Policy Council
Office of the Governor
550 W. 7th Ave., Suite 1700
Anchorage AK 99501

Mr. Jack Roderick, Member
Subcommittee on Access for In-State Gas Use and
 Future Opportunities
Alaska Highway Natural Gas Policy Council
Office of the Governor
550 W. 7th Ave., Suite 1700
Anchorage AK 99501

Ms. Ronda Boyles, Member
Subcommittee on Access for In-State Gas Use and
  Future Opportunities
Alaska Highway Natural Gas Policy Council
Office of the Governor
550 W. 7th Ave., Suite 1700
Anchorage AK 99501

Mr. Ken Thompson, Chairman
Subcommittee on Access for In-State Gas Use and
 Future Opportunities
Alaska Highway Natural Gas Policy Council
Office of the Governor
550 W. 7th Ave., Suite 1700
Anchorage AK 99501

Mr. Harold Heinze
Special Assistant to the Legislative Majority
Alaska State Capitol
Juneau AK 99811

Mr. Scott Heyworth
Citizens for the All-Alaskan Gasline Initiative
P.O. Box 100531
Anchorage AK 99510

ACTION NARRATIVE

TAPE 01-1, SIDE A
Number 001

CHAIRMAN JOHN TORGERSON called the Joint Committee on Natural Gas Pipelines meeting to order at 9:11 a.m. and announced that the committee would first take testimony from Washington, D.C. He stated that President Bush, Senator Murkowski, Chairman of the Resources Committee in Energy, Senator Bingaman, and Representative Young have introduced separate bills in Congress that deal with energy packages.

Federal Issues - Congressional Staff

MR. MIKE HENRY, Resources Aide for Congressman Young, said since President Bush released his energy policy, Congressman DeLay, Majority Whip, formed a group entitled HEAT (House Energy Act Team), which meets weekly or more often. Each committee has jurisdiction over various parts of the energy policy and is marking up bills this week. He said:

> By Wednesday, leadership hopes to have all the committee's reporting bills relating to the energy policy. Next Wednesday, leadership plans to bring a bill to the House floor that has put all the various measures into one comprehensive energy bill. After the August recess, if not later, there will be various other small components come forward that were left out, but no other large comprehensive bill.

MR. HENRY said that most of the energy bills have been in the Resources Committee. Several Congressmen, including Representative Young, authored HR 2436, which contains a right-of-way provision to study current rights-of-way for new pipelines. The Alaskan Congressman has also introduced ANWR legislation similar to what passed the House and Senate in the FY 95 budget. He said the Senate bill is likely to get reported this afternoon or evening, depending on how long the amendment process takes. He commented:

> The one possible obstacle is the ranking member, Mr. Emerson Rayhall (D-West Virginia), who has introduced a committee substitute that is very different. It has the democratic philosophy on some of the energy issues and also excludes ANWR, which is an important component obviously for Mr. Young and committee members, as well as the President and Vice President. What it does do

specific to natural gas is that it recognizes the ANGTA route. It basically just instructs folks to look at that and work towards the ANGTA route and nothing prohibitive or nothing that requires that route, but highlights and revalidates the more current ANGTA route. It also provides right-of-way conditions for any new natural gas pipeline that crosses public lands, which is going to be problematic. It's not specific to a large pipeline that we think of in bringing gas through the state and to the Lower 48 or to ships for an LNG facility. It's for any natural gas pipelines. So in that sense, it is so broad that it is going to be problematic, but it specifically says that the pipeline must have a "buy American" component of it while the steel would have to be created in the U.S., which obviously [is] an issue considering there isn't any one that makes the pipe that we would need to build a pipeline of this type. It also requires project labor agreements. Those are the two - ANWR and the gas pipeline components that Rayhall's amendment would have. In the end, I don't think it's expected to pass and the full measure, as it stands now, the Resources Committee bill should be able to be moved out pretty easily today.

Specific to the gas pipeline, which I think is your focus, Chairman Young's bottom line is that he wants to bring gas to market.

MR. HENRY said that bringing natural gas to Alaskans is key in the way they look at a gas pipeline project or any gas project. He said:

The over-the-top route is certainly something that's problematic for Mr. Young and one that he has a great deal of heartburn over. Ideally, we want to see this gas delivered to the Lower 48, but in the process want to see it come through the state to the benefit of the state's economy, as well as Alaskans in general.

MR. MIKE MENGE, aide to Senator Murkowski, said in his position working with the Senate Energy Committee, he deals primarily with public lands, Bureau of Land Management issues, and to a lesser extent, mineral management, and any issues related specifically to coal and energy in Alaska. He noted he worked in Alaska for many years with the BLM and USGS and spent most of his career working on pipeline or pipeline related issues. He said the change to Democratic control has really slowed down Senator Murkowski's plans to move and expedite an energy package out of committee. Essentially, the Senate has been shut down while the reorganization takes place and is just beginning to hold hearings on Senator

Murkowski's and Senator Bingaman's energy bills. Discussions with Democrats have revealed that they are in a position to start marking up legislation next week. They will start with the Bingaman bill and try to blend it with the Murkowski bill and then amendments will be added. He thought that next week is optimistic, since it seems that every time they start, something else comes up. He reminded the committee that they would be working on the non-taxed portion of the energy bill. Their goal is to have it ready for floor debate by September. The House is moving quicker.

MR. MENGE said that [Congress] confirmed the appointment of a number of Department of Interior officials last Thursday night and he feels there are now enough people to begin looking at the various gas line proposals. He stated that, no matter what happens, the Department of Interior, Pipeline Safety, Federal Energy Regulatory Commission (FERC) and other federal agencies will play a pivotal role in determining the route and specifications related to bringing the gas south.

MR. MENGE said although there is a lot of disagreement with the Democrats about the various proposals the Republicans have put forward, just about everyone supports the concept of bringing Alaskan gas south. He pointed out:

> I think it is very encouraging that all of the participants, both in the major environmental community, our organizations and in the Democratic Senate, now have expressed a desire to work together to bring that gas south.
>
> The President has already directed the agencies to assist in any way they can in configuring a bureaucratic organization that will support bringing this gas south and we'll be working with them to try to work in organizational structures to facilitate that. As you know, Senator Murkowski has gone on record on numerous occasions in support of the Alaska route bringing the gas south. He does not believe that the permitting hurdles of the over-the-top route could be addressed in a way that could satisfy the Native community and the environmental community in a way that would allow us to proceed expeditiously. I don't think there's any question that would address the major hurdles related to bringing gas south in both the TransAlaska gas system (TAGS) right-of-way and also the work that was done on ANGTA. So we're kind of going across familiar territory there. In neither one of those exercises were any single flaws identified that would prevent the gas from coming south in a terrestrial route.

MR. MENGE said the gas going out of Alaska will be very wet gas. He thought serious consideration should be given to potential problems that might occur under the ice given an over-the-top route. He noted the Senate believes those kinds of things will make permitting the over-the-top route extremely difficult.

He has asked the producers and a representative from the ANGTA route to suggest language they would like to see in the energy package that would facilitate the project, but he hasn't heard from them yet. He offered to answer any questions.

9:30 a.m.

MR. JUSTIN STIEFEL, staff to Senator Stevens, said Senator Stevens supports Senator Murkowski's efforts to move a comprehensive energy bill out of the committee that would include the necessary provisions to build the gas pipeline. He said:

> Everyone should know that Senator Stevens is supportive of the highway route, the southern route, and he wanted me to stress this specifically. Senator Stevens sees no reason not to realize that the producers have to analyze all reasonable alternatives if they are going to prepare a future EIS. They have to do this both for the environmental side and possibly because they have a fiduciary responsibility to their shareholders. If they decide to choose a route, they are going to have a basis for that route decision. He wants to recognize up front that there is a reason they are probably pursuing multiple routes. While the producers need to do an EIS for route selection and for permitting and construction, Alaskans are not going to need an EIS when they make a selection and voice their preference for that selection.
>
> He wanted me to note that there is a specific difference between an EIS and an Environmental Impact Study and what Alaskans would perceive to be an economic analysis. That economic analysis is that when you have instate gas, you can have more gas for residential, for commercial purposes and for industrial purposes and because gas can be used to make anything from nylons to Frisbees, as we've all talked about on previous occasions. It's important that Alaskans have the gas and they can use it for themselves. So, supporting the Highway route and looking for the opportunities for instate use is going to be a critical determining factor, in his opinion.

> If we have an abundant supply, that means that we have more economic development and more jobs. The Senator thinks that if we stay together as a state, we stand a better chance of seeing the pipeline constructed and following the southern route.
>
> In summary, I can say his closing remarks were that, because the gas belongs to the people of Alaska, ultimately he thinks their preference is the one that's going to be selected and, if not, there will be several roadblocks to taking the gas out of state without being able to use it for Alaskans.

REPRESENTATIVE GREEN asked, with the change in the Middle East oil supply in Iraq, and prices going down, whether there might be a change in the attitude of those people who support the pipeline in that they might decide that timing is not as much of an issue as it has been.

MR. MENGE replied that because of the Democratic control in the Senate and the fact they have made such a huge issue of Alaskan export of oil, it would be very difficult for them to turn around and not push for domestic supply.

> It's becoming a recurring theme, particularly for the West Coast Democrats of developing secure domestic supplies in areas they feel are environmentally acceptable. Certainly, the Alaska gas at Prudhoe Bay could fit that category, not to suggest that they might not change their tune, but right now it would be very difficult for them because of the arguments they have put on the record for the export of Alaskan oil. I think they will stay with us for the domestic gas supply....

MR. HENRY said that low gas prices shouldn't stop us from going forward with something necessary to create this energy policy for the country.

CHAIRMAN TORGERSON asked if that is the message the [President's] administration was trying to put out. He stated, "It seems to me that they are almost in a panic mode the way they fanned out all their secretaries across America to talk about the energy policy."

MR. HENRY responded that low gas prices caught the administration by surprise, but he said it had already been planned for many months. He thought they were, in part, trying to drum up support for the energy policy. They were focused on tax cuts earlier and they are planning for the future and not worrying about how low the prices are today.

REPRESENTATIVE FATE informed the committee that a discussion took place at the National Energy Council meeting in New Orleans with a representative from Alberta. He stated:

> It was quite aggressive in that he wanted Alberta to try to supply the needs on a regional high use basis in the Lower 48 of the United States, very aggressively meeting the demand to the United States and, if necessary, through NAFTA, which was a surprise to me.

He asked Mr. Menge if he has heard anything about it in Washington, D.C.

MR. MENGE responded:

> The Alberta crew comes through here on a regular basis and we have an on-going dialogue with them. They are certainly interested in marketing Alberta gas and, in particular, Alberta oil. Based on their calculations and ours, there's not going to be any concern about stranded product, at least in Alberta, with the increased demand. They are going to very aggressively protect their interests, but they also recognize the best way to protect that interest is to lock in North American gas into the market. That way, if they start developing LNG projects around the country, that's going to lock out not only Alaska gas, but their gas as well. So they understand, better than most, the need to start moving northern gas south early on so that we protect the market.

MR. HENRY agreed and said, "LNG facilities are being planned and if the domestic market isn't self sufficient, then entries from abroad will come in and it's not good for anyone."

MR. STIEFEL said he didn't have any comment on that issue but noted that people in Congress have been clamoring for some kind of public action on the administration's part, similar to the tax cut, the state based initiatives and other things the President put on the top of his agenda. He stated, "The timing with the gas prices is not what people had hoped for necessarily."

CHAIRMAN TORGERSON asked Mr. Henry if he had been asked by any of the major producers or anyone to add incentives or provisions into the bill they are currently working on.

MR. HENRY replied no one had approached him, but the delegation had requested them.

CHAIRMAN TORGERSON asked if provisions for incentives in the House

have to be added in the Revenue Committee and not in the Resources Committee, as they would in the Senate.

MR. HENRY replied that it is largely the same. They could introduce a bill that includes incentives that would be referred to other committees, but a bill with tax incentives would have to go through the Ways and Means Committee. Since Congressman Young doesn't sit on that committee, there would be a little less control. He noted:

> A lot of people on Capitol Hill do realize that a gas pipeline is certainly beneficial to the country and would be a lot more helpful and would help us work through the process than on some of the other issues that they might have to fight with them on development issues. There's a lot of support here. Some of the jurisdictional issues might be a problem, but we'll have to deal with them.

CHAIRMAN TORGERSON asked Mr. Stiefel if he is aware of Senator Stevens' perspective on adding tax incentive provisions to an energy bill.

MR. STIEFEL replied that any tax measure would have to go through the Finance Committee, which Senator Murkowski sits on. A couple of the producers mentioned the need for incentives or streamlining processes, but they haven't brought forward any specific request. It's hard to move forward without them.

CHAIRMAN TORGERSON asked Mr. Henry, regarding the right-of-way for pipelines across federal lands, if there are additional provisions for limited environmental or judicial review in the bill that would mirror provisions of ANGTA.

9:47 a.m.

MR. HENRY replied that as far as a gas pipeline project, there is a very general provision authorizing a study for rights-of-way. The ANWR provision has a limitation on judicial review.

CHAIRMAN TORGERSON asked if Mr. Henry had any discussions with Ottawa or Canadian officials on the national energy plan as it relates to gas lines.

MR. HENRY replied that he hadn't been involved in those talks but that people from Ottawa have talked with Congressman Young.

MR. MENGE commented that they have had meetings with a lot of officials from provinces who have expressed their positions. An official position from Ottawa has been noticeably absent. He thought there may be competing interests within Canada and they are not eager to take a position until they know a pipeline is going

forward.

CHAIRMAN TORGERSON asked Mr. Menge what interaction he has had with the Bureau of Land Management (BLM) or the Department of Interior on any routes.

MR. MENGE responded that he worked in that agency for many years and knows almost everyone involved in energy-related issues. He said folks within the agencies are working on timelines, organization structures and potential budgets and regulatory needs but nothing official has come forward yet.

CHAIRMAN TORGERSON asked if he has heard anything about opening a federal inspector's office, "that would be some kind of a big boss over all the other bureaucrats that we've got running around back there."

MR. MENGE replied that people are looking at what and how their specific agencies might contribute, but no formal discussions have taken place.

CHAIRMAN TORGERSON asked Mr. Henry if the bill being marked up now contains a provision for an oversight agency.

MR. HENRY replied that it doesn't. He added that the large energy bill is expected to move in the next week or two and, although it won't be the only thing the House does on energy this year, it will be the largest.

REPRESENTATIVE GREEN asked if the resolutions sent by the Alaska Legislature to Congress are doing any good and if there is anything else the Legislature could do to help spur people who are on the fence on some of these issues.

MR. HENRY replied that the resolutions are helpful because they show the Legislature is advocating a unified position. Also, having members come to Washington, D.C. from time to time, especially when there is a big push, is helpful.

MR. MENGE added the resolutions show unity as a state and head off a lot of trouble at the pass. He said, "It's much more difficult for people to dismiss us if there's a person or they can conjure up a vision of an individual who has come and made a solid case in their office."

MR. MENGE also said that Senator Murkowski asked him to express his personal appreciation for leading this group in advancing this issue.

CHAIRMAN TORGERSON asked if Mr. Henry had the votes in hand on the ANWR provision in the House.

MR. HENRY said it would take work, but all indications look good.

MR. STIEFEL concurred with Mr. Menge and Mr. Henry on the resolutions. He said that he sees there are two lines being drawn. He didn't know of any real opposition to allowing the pipeline to go forward and be constructed from the executive perspective or the congressional perspective. The second is the decision the producers make, which is based on economics. Whatever the state could do to encourage construction of the pipeline by altering economics with incentives would help get gas to market.

CHAIRMAN TORGERSON said he appreciated their comments and thanked them. He announced the committee would take a short recess.

10:00 a.m.

PIPELINE ACCESS ISSUES

CHAIRMAN TORGERSON called the meeting back to order and said they were going to hear remarks from the Federal Energy Regulatory Commission.

MR. ROBERT METHURA, Office of Energy Projects and Pipeline Certificates, FERC, said he would have to speak in general since there was no specific project for Alaska yet.

MR. JOHN KATZ, Office of the General Counsel, FERC, said they had received Senator Torgerson's letter of June 25 and had discussed his questions. They didn't have any formal comments and asked him how he wanted them to present their information.

CHAIRMAN TORGERSON said he could go through the questions to stay focused.

MR. KATZ reiterated that it was inchoate for them because there weren't any specific proposals in front of them now. They would move as expeditiously as possible when that happened.

CHAIRMAN TORGERSON said the first question is the relationship between the Regulatory Commission of Alaska (RCA) and FERC over the jurisdiction of a gas pipeline from Alaska to the Lower 48. He noted that this question at least got the two agencies talking to each other.

MR. METHURA said they normally are interested in being open and cooperative with the state that is affected with a pipeline proposal.

MR. CUPINA added that as helpful as it would be for Alaska to coordinate its entities, a project's regulation would be under FERC

jurisdiction as an interstate pipeline.

CHAIRMAN TORGERSON said that his open season question and providing access to Alaskan communities seems to be a joint responsibility. His second question was about the process and timeline for handing in an application under either the Natural Gas Act or the Alaska Natural Gas Transportation Act.

MR. METHURA replied that there are so many variables, he couldn’t even speculate on a time frame. Typically for large gas pipeline applications under section 7 of the Natural Gas Act the environmental analysis is the critical path. They have gotten to be very efficient at managing and completing that process having done a number of major projects in up to a year and a half. A couple of projects have taken longer than that, but it's the exception rather than the rule.

MR. KATZ responded that he didn't think that processing an application under ANGTA would take any longer, but it's hard to speculate beyond that.

CHAIRMAN TORGERSON said his third question was whether such a pipeline would have a common or contract carriage, who controls when the open season occurs and how and when Alaskan communities sign up for service.

MR. CUPINA responded that their approach to interstate pipelines they regulate is that they are contract carriers on an open access basis, which means they can't unduly discriminate against any shipper in terms of rates, conditions and duration of service, etc. The common carriage characterization is more closely associated with the oil pipelines under the Interstate Commerce Act.

As to who controls the open seasons, he said the sponsors of projects are encouraged to conduct open seasons as part of designing the pipeline and properly sizing it and, more importantly, for open access purposes to insure that all potential shippers are aware of the availability of a new project and have an opportunity to respond to an open season in order to get served.

The third part of the question seems to assume that there would be mid-point delivery points along the way and that would depend on what the design of the project is. He said the Alliance Project from Western Canada down to Chicago has two points, the receiving point and the delivery point in the states. In an open season, he would expect any and all potential shippers to express an interest.

CHAIRMAN TORGERSON asked if the open season requested by the owners of the line does not correspond with actual resource data on resources that may be available, for instance, if some wells haven't been delineated, so another producer may not be sure of

what's there, whether we could force that timeline back or they could force it back for a period of time on the open season or whether they are locked into the time asked for by the owners of the line.

MR. CUPINA answered that they typically don't have information on the open season until the application is filed, unless there were problems with it, for instance, if potential shippers were denied access or it wasn't advertised sufficiently in the publications available to them. That's when FERC becomes involved in resolving disputes regarding open seasons. "We are not in the position up front to control the open season because we wouldn't be aware of the details of it until after the application came in."

CHAIRMAN TORGERSON asked if the open season was generally a part of the application.

MR. CUPINA said it is quite a bit ahead of time, because it helps inform the design of the pipeline; it helps in the sizing of it.

REPERSENTATIVE GREEN said he understood that the line might be designed initially for 4 BCF/D and since it's compressible, that could be increased later by adding more compression. He asked if a producer who missed the first open season would be able to participate in the next open season when adding compression.

MR. CUPINA explained that they encourage open seasons for every expansion.

REPRESENTATIVE GREEN said that mid-point delivery points might be affected if a discovery was made down the line someplace. He asked if that would trigger another open season.

MR. CUPINA replied that it could, especially if it created a need for additional capacity as opposed to simply providing another point of input into existing capacity. "If existing shippers were getting gas from an additional source, perhaps not. We don't think of that as an expansion. But if the additional source has created expansion to add new shippers, that would probably be an open season event."

CHAIRMAN TORGERSON said his fourth question was how access to the pipeline would be determined initially and how access will be made later. He asked if there were additional comments on that.

MR. CUPINA responded, "Once a pipeline becomes operational, it operates under a FERC tariff, an open access tariff, which controls the types of service that it offers, which are usually a firm transportation service and an interruptible service and the terms and conditions of that service."

He said, "This assures that shippers are getting some uniformity as far as balancing penalties, nominations, etc. On a continuing basis, the pipeline is under their open access requirement to advertise capacity and sell that capacity under the terms and conditions of its FERC tariff."

CHAIRMAN TORGERSON asked the fifth question: How will the expansion of the pipeline be handled and how will the Commission handle incremental costs?

MR. ROBERT PERTOCELLI, Office of Energy Markets, Tariffs and Rates, FERC, responded that generally expansions come under two categories. If they fall under a certain dollar amount, they are considered under the blanket and all of their costs are rolled in. If they exceed the blanket amount, they have to file a separate application and the extension would be treated as either incremental or rolled in. If they raised the rate at all, they would be treated as incremental. If the rates with the new volumes and costs together were the same, they would be treated as rolled in. If they lower the rates, they would also be rolled in.

REPRESENTATIVE GREEN asked how FERC worked with the pipeline traverse in Canada.

MR. KATZ replied there are pipeline treaties in effect between the United States and Canada that deal with coordination of international efforts. That's probably more under the purview of the Department of Energy. The Commission would certificate that portion of the line that is in the U.S. territory.

MR. METHURA followed up saying that while they don't have direct responsibilities with respect to the Canadian portions of the pipeline, they are in informal communication and cooperation with the staff of the National Energy Board so they keep each other updated about the project.

MR. KATZ agreed, but said they wouldn't have any jurisdiction over any portion of the line that wasn't in the U.S.

REPRESENTATIVE GREEN said there has been some concern as to how the TAPS rate was established and how it considered maybe too many things. "With FERC dealing with a gas line like this, what sort of process does that go through to ensure the net back is on a fair basis?"

MR. PETROCELLI answered, "The rates are generally calculated in accordance with cost of service methodology. We use a standard formula to determine the rate base, the investment, the expenses are generally estimated. Then we apply a rate of return that is within the bounds that's been accepted at the Commission for other pipelines of similar risks."

CHAIRMAN TORGERSON asked if adding the conditioning plant into the base rate was a standard policy since and if that would automatically be added to the tariff.

CHAIRMAN TORGERSON said it was his understanding that it would

MR. KATZ said the circumstances around [TAPS] were a little unique because they resulted from some presidential waivers and other things that related to ANGTS at that time. He couldn't say whether a conditioning plant would be included in the rates of the pipeline as a whole. Typically, such a plant is included in rates only if it's part way down the pipeline.

10:25 a.m.

CHAIRMAN TORGERSON referred to Representative Green's question about a future discovery, for instance in the Big Delta area, where another conditioning plant would be necessary. He said he assumes they could put provisions in the tariff to where they wouldn't automatically add in the one conditioning plant on the North Slope if you had your own or were required to build your own further down the line somewhere.

MR. METHURA said it seems like he is asking if FERC plays some role in requiring an existing pipeline to expand in the event of a discovery. Typically, they don't do that; it's up to the pipeline owner and new customers to get together and decide if there is an opportunity for expansion.

MR. CUPINA observed that the way they regulate pipelines now, they only perform the transportation function. In the Lower 48, the processing activities and preparing the gas for pipeline quality is part of the producing, gathering, and processing function that happens in the producing field at the producer's expense. Some issues he is raising may be the producer's or the shipper's responsibility.

CHAIRMAN TORGERSON said he didn't want the state to be regulatorily locked out of the expansion and that:

> We basically have one field that this gas is going to come out of to begin with and we have never, until recently, drilled looking for gas on the North Slope. So, we have a vast area where it's projected to be a lot of reserves, but there's no incentive for other companies, besides the ones who own the resource and who may end up owning the line, to allow other people into the line. That's a huge issue in the State of Alaska, as well as the other producers that may want to drill up there.

He wanted to know what FERC and the State could do to control that.

MR. CUPINA said:

> The Commission has nothing in their statutes requiring expansion of a pipeline. However, several months ago, in response to a court remand, the Commission issued an order on pipeline interconnection that permitted shippers to hook into a pipeline. As a result of that, it became more difficult for a pipeline to refuse to tap into its line. We expect there will be tariff provisions and we're seeing more and more of them that set out the terms and conditions under which the pipeline will consider these requests for someone to tap into their line.
>
> What I'm getting at is that it's getting more difficult for a pipeline to turn anyone down than it would have been before. Having said that, under open access, if there's no capacity available on the main line, even if you get hooked up, you may not necessarily get firm service and the pipeline is not required to prorate any other capacity as would a common carrier…

MR. KATZ agreed and said that typically the way these matters are dealt with as a matter of business negotiations. Everyone has a role to play in the certification procedure whether they support or oppose the project and general concerns about how a pipeline will be built, other routes, etc.

10:31 a.m.

CHAIRMAN TORGERSON said that brought him back to the question of the open season and how that can be controlled, if it is controlled. For example, he said:

> What if they had an open season that met the requirements and specifications they just laid out and do it well in advance of anyone having a field developed, can we or you postpone the open season to a later time line that wouldn't necessarily affect the overall start of the pipeline.

MR. METHURA said that would be a policy call for the Commission. Their general policy is that if someone has an acceptable project on environmental and other grounds, and if they are willing to put up the money to pay for that project, the Commission is going to consider it. An argument against it could be that it is too early and the area is not developed and it's not in the public's interest to approve a project at this time. He didn't know what the

Commission would do.

SENATOR KELLY said FERC couldn't assure that anyone could get access to the pipeline on a firm basis and asked if it's worth it for someone to develop a gas field and have their transportation be on an interruptible basis. "Practically speaking, are they able to go out and market their gas, if their transportation is interruptible?"

One of the FERC officials replied that would be a business call. There are other options in addition to interruptible, like capacity release. Under that provision, existing firm shippers who may not be using their capacity or all of it are authorized to sell it like a sublease. That is just as firm as pipeline firm. Another way to look at it is that the pipeline makes its profit by transportation gas. So, its got a business incentive to expand and to take on more business and increase it's revenues.

REPRESENTATIVE GREEN said:

> Up here there are occasions when the oil pipeline gets spiked with gas liquids - an undersaturated oil could take more gas liquids and stay stable and be shipped to a refinery to be worth more. There is a possibility with this high pressure line that there may be shipping of gas liquids from the start, but if down the road the producer was to be on the road system, find some gas, go with methane only, and the original producers may say no. That's what we don't want in our pipeline. To what degree does FERC get involved in something like that?

One of the FERC officials replied:

> The only thing that comes to mind is the Alliance system, which at one point was wetter than a typical pipeline. Those kinds of things would be spelled out in its quality standards in its tariff. Those issues would be considered and resolved up front, before we approve that pro forma tariff that's filed along with the construction certificate application.

REPRESENTATIVE GREEN asked, if there was to be a subsequent open season for a mid-point delivery point from a mid-point delivery point, the contract would originally have provided for that and there would be some sort of adjustment for that on a BTU basis or some other thing, whether it would be a FERC problem.

The FERC official responded that the pipeline's tariff would provide for that.

MR. METHURA added that at some point in the future a new prospective shipper and the existing pipeline owner could negotiate something different, like amended tariff provisions that would allow for dry gas.

REPRESENTATIVE GREEN asked if there was capacity and the original owners said they didn't want dry gas, whether that would be grounds to prevent another producer from getting in.

MR. PETROCELLI replied if they can't meet quality standards for delivering gas, that could be grounds to refuse entrance.

SENATOR KELLY asked if capacity release would be found mostly in an environment where they had demand that was low.

MR. METHURA said it varies. There might be capacity available at different times during the year. There are various reasons why capacity might be released. He explained if every shipper is using it's own capacity at maximum load factor every day, there won't be any available to be released but, on many systems, capacity is released every day throughout the year, even in the peak season in the winter.

10:40 a.m.

SENATOR KELLY said it seems if you were in a business environment where demand was very high, you wouldn't have a lot of opportunities for those who do not own the pipeline to get their gas transported through it on anything but an interruptible basis. He asked, "If there was a period of high demand, why would the people who own the pipeline have any incentive to allow space on their pipeline for those?"

One of the FERC officials replied they can only sell on an interruptible basis if some firm shipper is not using capacity. The interruptible capacity, itself, is a consequence of unused firm. It adds an incentive to expand.

MR. PETROCELLI said:

> You seem to be operating on the assumption that the pipeline owners would be the transporters. There's a whole class of rules that apply to affiliate shippers, but first of all, under our unbundling rule, the pipeline owners generally don't do the transporting. They just sell transportation to other shippers. Those shippers have fair access rights unto themselves. So, any shipper who wants access should be able to gain it. He wouldn't be competing supposedly against the pipeline owners. Although affiliates can transport, there are rules that

> apply so that everybody has equal access including the affiliates.

CHAIRMAN TORGERSON asked if that brings them back to the question of whether or not whoever files for this - it could be the producers - has to be a common carrier.

MR. PETROCELLI asked if he meant common carriage in the sense of talking about open access of contract carriage.

CHAIRMAN TORGERSON indicated yes.

MR. PETROCELLI said, "You can't unduly discriminate under the Natural Gas Act so you are open to all shippers whether they are affiliates or not."

CHAIRMAN TORGERSON added, "As long as you go through the provisions of the open season and the rest of that."

MR. KATZ responded:

> It comes down to business choices. If they conduct an open season and affiliates of folks who are proposing to build the pipeline want to sign up for 100 percent of the capacity, the question is whether there are other folks who want to sign up for capacity, too. Usually what happens then is that it gets allocated…. The question remains, are you willing to pony up the money to reserve space on that pipeline, and that becomes a business decision.

MR. CUPINA said the committee was imagining when an application is filed, there's going to be some tension. They want to slow down the open season versus those who are exhorting them to speed it up, their general direction.

10:45 a.m.

CHAIRMAN TORGERSON responded, "Not necessarily. The open season of the example I gave you may be two or three years before you're permitted."

He then asked Mr. Cupina if he knew of any regulations under their purview that would create a hub, such as coming down to Fairbanks and spinning off to other projects in the state. He asked whether FERC or the RCA would regulate that.

MR. CUPINA responded:

> We don't regulate hubs. We kind of stand back and let hubs develop and market centers. While we don't regulate hubs per se, there might be some services within that hub that the pipelines that interconnect there perform that we do regulate and that are additional services under their tariffs....

REPRESENTATIVE DAVIES said he is concerned about the common carrier aspects of FERC's regulatory framework. He asked how much of the regulatory environment is set by the pattern down south where most producers do not own the pipeline. He noted, in Alaska, we might have a situation in which the producers are the dominant owners and there is a serious possibility of anti-competitive situations developing on the North Slope. He asked how that might affect the way they regulate an Alaskan gas pipeline.

TAPE 01-2, SIDE A

MR. CUPINA replied that there are some producer-owned pipelines in the Gulf of Mexico and that:

> Although they transport some of their own gas, they are open access pipelines like we've been describing. We've held them to the same standards as the pipelines that are not producer owned or producer affiliated.... If you had a story to tell to persuade the Commission that something should be different, the burden would be on the sponsor to do that, or interveners, for that matter, in the case.

10:50 a.m.

REPRESENTATIVE DAVIES asked if he could provide an example of a producer-owned pipeline that transports other folks' gas at this point.

MR. CUPINA said that Shell's (Gordon Banks, now) initial business plan was to move its own gas. "They came in on a prefiling basis to discuss some of these things and we advised them accordingly and they have open access tariffs."

CHAIRMAN TORGERSON thanked everyone in Washington D.C. for their testimony and said they would now hear the RCA presentation.

10:52 a.m.

MR. METHURA said they appreciate being involved and want to leave the committee with the impression that they are anxious to cooperate.

CHAIRMAN TORGERSON assured them that the Alaska Legislature is not

trying to slow the project down, but "to understand a little bit more of what your function is compared to what we have to do with in-state functions...."

Regulatory Commission of Alaska

MR. ANTHONY SCOTT, staff to the RCA, said that the FERC is in charge if there is one molecule of interstate pipeline and on the TAPS they have joint jurisdiction with the FERC. He stated:

> Under the Natural Gas Act, there is a large body of case law, which says that if molecules that are interstate and molecules that are intrastate mingle in the same pipeline, all the gas in the pipeline is considered interstate even though some of it comes off earlier. There's a lot of case law suggesting [indisc.] Bob Maynard, when he was Attorney General back in 1976, wrote an opinion in which he suggested that authority over intrastate movement of natural gas would pretty much be preempted by the feds. Finally, there's express language in the Alaska Natural Gas Transportation Act, which seems to say pretty clearly that the feds have jurisdiction over tariffs for intrastate gas. What that means is that it looks like the RCA in terms of tariff setting and so on is pretty much out of the picture.

MR. SCOTT said he would provide the committee with some background as to what the RCA's authority is. He said that FERC's authority to border access is not as strong as RCA's appears to be.

> We have two different statutes under which we regulate intrastate natural gas pipelines and we have gas pipelines in the state that are under both. We have gas pipelines that are under the Pipeline Act and they are considered pipeline carriers and are common carriers similar to the situation that we have with TAPS. Then, we also have gas pipelines, both the Beluga line in Cook Inlet or Enstar System, which are regulated under Title 42.05, our public utilities legislation. They are not common carriers. They're also not contract carriers. We don't have such a thing as contract carriers for public utilities.
>
> The Commission powers insure access or [indisc.] depending upon the particular statute the pipeline falls under. For intrastate pipelines that are certificated at the pipeline areas of the public utilities, the Commission does have prorationing authority, so that if space on a line is limited and nominations exceed

capacity, we can proration or we can decide - our statute doesn't require that we can strictly proration, but we can decide how to allocate that capacity. We don't have that clear authority for public utility pipelines.

The Commission also can order a facility's expansion under [indisc.] by statute. Our expansion authority is actually a little bit clearer and stronger on the pipeline side than on the public utility side. So, unlike with the FERC, if we have a [indisc.] gas pipeline, which is certificated as a pipeline, we can order them to expand capacity. We also, under both our statutes, have interconnection authority and the language under both statutes is identical. Finally, for pipeline carriers during construction, the state can order the pipeline to install offsite facilities. The state has to pay for that, but nevertheless, if it was determined that it was cheaper to do up front, they could order [indisc.] facilities installed.

An unidentified person interrupted, "You had prefaced this by saying the state would not be involved. It was purely the jurisdiction of FERC. Is that true about during construction as well?"

MR. SCOTT answered:

That's a good question. I think so. I mean I think our ability to order that would probably be preempted. I'm less clear on that, though. What is clear is that we wouldn't be able during construction to order off-site facilities unless the pipeline was certificated by our Commission and there would be no need for an intrastate certificate if there are, during the open season, no nominations for intrastate shipment of gas. So, if nobody steps to the plate within the state and says we want some gas and we're willing to commit to it now, during construction, they wouldn't need an RCA certificate. There would be no intrastate sales. So, our ability to exercise that authority clearly does not apply.

An unidentified person asked if FERC would have to make that determination, anyway, "If there is a molecule of interstate gas in that line, you're out of the picture, right?"

MR. SCOTT replied that is correct.

REPRESENTATIVE FATE asked if, with construction, there is such a thing as a change order while in progress, rather than having to

plan ahead.

MR. SCOTT replied, "I'm not familiar with the language change order, but for pipelines that are certificated by the RCA, it's conceivable that we would be able to require during construction to order offsite facilities. If they're not certificated by the RCA, it's very clear we're out of the picture. Even if they were certificated by the RCA, we might not have that authority. We might be preempted."

REPRESENTATIVE OGAN said, "So, FERC regulates from the well-head to wherever the pipeline connects to the hub somewhere?"

MR. SCOTT answered, "Yes."

REPRESENTATIVE OGAN said there had been some discussion about a hub concept in Alaska and, although it's probably not an appropriate term because there's only one spoke coming from the supply side, there might be two or three spokes coming out of the demand side, and [indisc.]. He said that basically they were moving the wellhead to the hub point. He asked if that concept was put into statute, would the RCA have authority over who's in or who's out and then the FERC regulates from that wellhead that's moved from the North Slope to Delta or wherever from there on down.

MR. SCOTT said that was an excellent question, but they didn't have an answer for it yet.

REPRESENTATIVE OGAN said the House Oil and Gas Committee intends to explore that possibility in statute before next session.

MR. SCOTT said he was disappointed that the FERC people left, because he was interested to hear their input.

REPRESENTATIVE GREEN said he was confused and asked:

> Let's go from the hub down to some other market that would by its nature be under FERC, but that in route some gas is pulled off for one or more utilities. There was prior testimony in the Oil and Gas Committee that that portion would be under RCA - that portion that went to the utility. So, you would actually have a dual regulation. Any, yet, I just heard you say that if there's a molecule of FERC gas in there, it's all FERC.

MR. SCOTT replied:

> Even though there was off take of gas in Fairbanks, it's all regulated by FERC.... Even though those molecules are produced instate and they're taken off instate, the line

> to get it from the North Slope to Fairbanks is all instate, it's treated as interstate shipment of gas.

REPRESENTATIVE GREEN said, "So, that earlier testimony was not right. There wouldn't be dual oversight?"

MR. SCOTT said, "That's right.... If you commingle molecules that are bound for intrastate market, the molecules that are intrastate all become interstate."

MR. ABBOTT, RCA Commissioner, said another scenario is getting it off the pipe and taking it to a distribution center and then it goes into [indisc.]. We don't know where that cut off valve is going to be that says that belongs to the state to regulate and this belongs to FERC to regulate. [indisc.]

SENATOR KELLY said he thought he understood that they are talking about a federal molecule of gas that has gone to a distribution center where it becomes someone else's - a whole separate pipeline.

CHAIRMAN TORGERSON said:

> Assuming that access is going to be voluntary, I know you're talking about your power to demand an increase in capacity, I don't necessarily think you're going to have to do that, but in the hub, my definition of a hub might be different than yours. A hub is just a valve where you have a price set. Is that your definition, too? From Prudhoe to Fairbanks, that hub - you have a price predetermined at that particular location. So, if you spun off that....

MR. ABBOTT responded that it would be nice if it worked that way, but they needed to look at that further. His understanding is, "Absent the market, where ownership of gas changes hands and so on, that's a hub concept. Just the idea of a valve doesn't get you where you would like to go."

CHAIRMAN TORGERSON asked him to explain the process to him.

MR. ABBOTT replied they have had preliminary discussions with the Department of Law who indicated that their authority to regulate tariffs looks to be preempted [by FERC].

CHAIRMAN TORGERSON said:

> If this is federal law, what Representative Ogan was talking about, state law, really has no bearing on it. Is that correct? Tell me how this would affect your jurisdiction over an all-Alaskan route. It may be for

> export or maybe to the Lower 48 or somewhere else. Are you the main players in an all Alaska route or is that also FERC?

MR. ABBOTT answered that he thought that would be FERC, because of interstate commerce.

REPRESENTATIVE PORTER said, "An Anchorage spur that was not at its terminus for export, would the RCA have the line from where it hooked up to the line to its distribution in Anchorage?"

MR. ABBOTT answered, "Generally, I believe, yes, we would."

REPRESENTATIVE OGAN asked, "It looks like the FERC would hypothetically get involved in an LNG line to Valdez, for example, when the ship leaves the port, when the ship arrives, or would they be involved in it for the whole thing?"

MR. ABBOTT replied, "I think the whole thing from the North Slope down."

CHAIRMAN TORGERSON asked, "Who's looking after FERC if they have all this responsibility?...You're starting to worry me a little bit."

MR. ABBOTT replied:

> It strikes me, in terms of policy, we're supposed to take care of pipelines that are within our jurisdiction. Insuring that pipelines are within our jurisdiction is probably a matter for you folks to take up either directly or through the congressional delegation or what have you. I'm not sure. It's not clear to me that we want the RCA running around trying to grab turf.

CHAIRMAN TORGERSON agreed, at least until they get a legal analysis. "As an Alaskan, I'm territorial as all get out. And I want Alaskans to make decisions on what's happening. Not back in DC...."

MR. ABBOTT said he thought that concept had served them well on the TAPS. He used the Golden Valley tariff as an example for joint jurisdiction where it helps secure lower tariffs. He said they had discussions with FERC regarding who pays for capacity [indisc.]. RCA doesn't have existing precedent on the gas side. In general, if everyone benefits from the capacity expansion, the cost of it is generally shared.

CHAIRMAN TORGERSON asked if he had any interaction with Canadians on how they are going to handle this.

MR. ABBOTT replied that they hadn't. He said RCA would handle a distribution system.

CHAIRMAN TORGERSON asked if FERC would set the price at the valve.

MR. ABBOTT said that was right and it was a real concern in terms of Fairbanks off-take having to pay the Henry Hub price.

CHAIRMAN TORGERSON thanked them for joining the committee and asked to get copies of any legal opinions on this subject. He announced the committee would break for lunch at 11:19 am and they would start again at 12.45 pm.

12:45 p.m.

CHAIRMAN TORGERSON called the meeting back to order and asked Mr. Ed Small to testify.

Cambridge Energy Research Associates (CERA)

MR. ED SMALL, CERA, made the following statement.

> ...I intend to be as realistic as possible to describe to you the fundamentals as we understand them and as we expect to see them unfold. There is a window of opportunity for Alaskan gas. It is just that, though, a window of opportunity. It is not a done deal by any stretch of the imagination.
>
> That window of opportunity is probably larger than it has been at any time in the past. We have seen windows of opportunity for Arctic gas come and go. We think there is a reasonable probability or possibility of seeing Alaskan gas within the course of the next decade. I would have to suggest that, as one of my colleagues says, he's been suggesting that will be the case for the last three decades. So, again, it's not a done deal.
>
> What I do want to talk about is what some of the drivers and what has created this window of opportunity, what some of the opportunities are, and what some of the pitfalls as we see them will be.
>
> One of the biggest factors in creating this opportunity as you can see is we have gone to a point in time where the pricing level is significantly higher than it has been at any time in the past. We have gone from a level of below $2 to a level where we're going to see prices

averaging over $4, taking the average of 2001 and 2002. Again, I have to point out, though, the weak link in that is the 2002 price. It is being propped up by the prices we have seen over the past winter. We don't expect to see prices go down to those lower levels in the past. We also don't expect to see them staying in that $4 range.

The biggest driver behind the prices we see today is the demand. We see a situation in the Lower 48 where installed capacity has increased but it has not kept up with peak demand. The situation has been created whereby we've seen capacity margins, which have dropped down below 10 percent, are slowly coming back up to 10 percent, for which the conventional thinking is that they need to be around the 15 percent level in order to adequately handle peak demand and demand needs, because of whatever. We're a long way from that 15 percent margin.

It is that narrowing gap between the installed capacity and the peak demand that is creating the need for a lot of the natural gas demand going forward. We saw close to 30 gig watts of capacity installed last year. We're going to see between 45 and 50 gig watts this year and probably a similar number next year. Those are almost exclusively gas fired. This graphic only shows the projects going out to 2005 and it looks like a declining number. That's only because a lot of the projects close to 2004 have not hit the books, yet. So, we do expect to see power generation being one of the strong drivers of gas demand throughout the next decade.

What this picture shows is the two areas the Arctic gas would target are two of the strongest growing regions, the Midwest and the West. One of the things we do not subscribe to, though, is the 32 percent growth. We have heard a lot about that potential growth level, that demand level by 2010. We view that as being more plausible than probable. If you look at the upper line in this picture, it shows an unprecedented level of growth required to get there, growth both in supply and in infrastructure. We just do not see it happening. With the demand structuring and high prices we have seen over the past winter, this makes a 32 BCF world even less probable, in 2015 perhaps, but not in 2010.

MR. SMALL explained three different bars on his graph. CERA sets out different paths that the world may evolve on. They are

separate, have their own drivers and are all plausible. "Gas favored the world we were in up until two years ago. It is one where supply and demand grow in lock step. It was a very healthy economy and a robust world. It is the least likely at this juncture going forward."

Supplier realignment is the path that we are on currently. It is the one where supply has failed to keep up with demand. MR. SMALL said:

> It is also a world of strong growth going forward, though. Lower GDP's and gas favor a strong economic growth. It is the world that requires gas supply from other sources. Those frontier sources could be offshore Canada, they could be LNG, they could be a resurgence in existing areas…What it does show in this world, on that path we are on, we do not even achieve a 32 BCF world by 2015.

MR. SMALL continued:

> The aftershock is the scenario that we developed about a year and a half ago that said, "Well okay, what happens if we see a recession starting in the second half of 2001 going into 2003?"
>
> It is one where we see a slow down in growth in both supply and demand, but peaking out towards the end of the period when both of them get back to a comparable realignment with supplier realignment.

MR. SMALL explained that the producers' idea of the price softening [to $3] is almost amusing, because that's almost double what it was two years ago. Perspective can change quickly he said.

> What has brought the price down from the highs we saw this last winter has been the resurgence in storage refills in the Lower 48…It was extremely doubtful whether they could be filled to even last year's levels, which were considered low by the end of this injection season. That has turned around substantially. We have seen injections that will put us not only above last year's levels, but will probably approach 1999 levels. That will probably be adequate to prevent significant or serious price spiking that we saw over the past winter again this winter.

> What that means in the short term, in a pricing context, is we saw prices spike at over $9 last winter, which was significantly higher than we had seen on a sustained basis before. We do see softening next year. We expect next year's average to be $3.53 Henry Hub versus the $4.45 that we're seeing for this year. So, this year is probably the peak.

MR. SMALL reiterated that CERA didn't expect to see prices dropping down to the previous levels of 1998-99, but they should be significantly lower than the past winter. The same dynamics are at play with the Alberta price. "Even though there is excess capacity out of Alberta currently, we expect to see a wide differential in prices between Henry Hub, which is the U.S. prime pricing point, and AECO (Alberta Energy Company) of almost 70 cents."

They expect to see an Alberta price of $2.85.

He said the two target markets for Arctic gas are the Midwest and the West Coast, areas that command a slightly larger premium from the Henry Hub price, although he didn't know how sustainable that was in the long run. He said:

> It is subject to supply. Currently, there is a significant premium in California to Henry Hub and a modest premium in Chicago. For the purpose of Arctic gas, it is probably best to think in the context of Henry Hub, at least for planning purposes.
>
> One of the reasons that we got through last winter is that the system is flexible. There wasn't a crisis. There was a shock to the system, definitely. What we saw was 6.5 BCF of demand come off the market. That's how we made it through the winter. The price controls [indisc.]. That is going to have a long lasting impact. As you can see, switching to residual fuel oil and distillate fuel oil took off almost 4 BCF. Ammonia, methanol - the cessation of creation of those products - resulted in a demand drop of about .8 BCF/D. We saw ethane not being taken out of the gas stream, but sold as gas, which had an impact on the petrochemical industry and we saw decreased manufacturing of .7 BCF/D.
>
> Go to today's world, specifically the third quarter of this year, and the outlook that we expect to see is one where there is still demand that has not come back on. Seven hundred million per day of decreased manufacturing

we don't expect to come back. There is a question as to whether that was due to the high prices or due to the soft economy. The answer is probably both, but we don't expect to see that manufacturing come back on in the near term.

We expect to see residual fuel oil priced into the market, in other words, displaced gas demand for at least the next year, if not two years. There is 700 MCF of ammonia that is not being manufactured. That may not come back. Due to high prices, that product may go overseas or offshore of North America permanently.

The same with methanol. Distillate, we probably don't see that being in the market until next winter. If demand is strong enough next winter, you will see gas priced out of the market and distillate priced in. Ethane will probably be above that point. Those dynamics will continue to be in play going forward depending on the price. So, this is a structure one could expect to see not only in the past winter, but going forward. This just shows one aspect.

I wanted to pick one aspect to show what has happened with the high price today. You can see when natural gas prices spike, ethane production drops dramatically. This is something to keep in mind if there is any interest or intention of developing a petrochemical industry in Alaska. When you see the gas prices spiking, the source of the supply for the petrochemical industry is gone. So, your petrochemical industry is [indisc.]. That is a significant factor going forward, as well.

Do we expect to see softening going forward? Am I a pessimist? We expect to see prices that are above what we've seen in the past, but not anywhere like what occurred in the past winter. We expect to see through 2005 prices that will begin in the low to mid $3 range. The volatility will be more on the upside than the downside simply because that residual fuel oil I mentioned is providing a floor for gas prices and will probably continue to provide that floor until supply picks up. So, over the next five years we expect to see minimum downside spiking and potential upside spiking, but with a price that's in a range of $3 - $3.25 level.

On the supply side, which is the other side of the equation that gets you to price, the demand being one side and the supply being the other, what is the picture

in a North American context? We see both coming from four specific areas - western Canada, the U.S. Rockies, the Gulf Coast and U.S. Gulf of Mexico, and Sable Island offshore east Canada. A lot of the other areas in the Lower 48 are mature, are having trouble keeping their own and the record drilling levels in the U.S. probably will only support a limited amount of growth.

We are seeing record drilling both in the U.S. and in Canada. It is starting to have an impact. We finally got the actual numbers in for 2000 and supply decline in the Lower 48 was lower than we anticipated. The supply growth this year, largely because of the high drilling, is going to be higher than the recent estimate. We expect to see growth in the Lower 48 of between 500 and 700 MCF/D going to between 700 and 800 MCF/D next year. The large percentage of the drilling activity in the Lower 48 is gas directed. We don't think that the current prices are low enough that that is going to disrupt or discontinue the current drilling activities that we are seeing. So, we expect to see robust drilling over the next year, which should support the growth levels that I mentioned.

One of the factors that opened the window for Arctic gas was the gas production in the U.S. has been flat to declining (referring to graph illustration). What we do see, though, is for the Lower 48, we feel 2000 was the bottom point. We see the capacity in the U.S. Lower 48 growing. What is interesting though, is that it's going to take until almost 2005 to get back to 1995 levels. So, there's still a need when you couple that with the growing demand.

Onshore production in the U.S. is a bit of a different story. It is going to grow through about 2005, 2006 at which time we see it flattening out. So, even with the drilling levels we see, the conventional areas in Lower 48 onshore have limitations. What is going to happen is that growth in the Rocky Mountains, as one example, is going to offset declines in the Anadarko and [indisc.] areas.

The other offsetting factor is the Gulf of Mexico. There are two dynamics at play here. The one has been most responsible for the decline in the Lower 48 for the last several years and has been the steep decline in the shallow shelf. That is an area that has high productivity, but high decline. With the low prices that

we saw in both oil and gas in 1997, drilling activity almost ceased in this area. That steepened the rate of decline. It's an area, because of the high decline, that you have to continue drilling to replace production. We're starting to see that turn around. We don't expect to see the decline displaced or discontinued, but we see the rate of decline becoming more shallow. It is going to be offset by the deep water Gulf, though. Those are the projects that have been committed to, that have been under way for the past four or five years, that are just coming on stream this year. So, we see the deep water Gulf not only offsetting the shallow Gulf decline, but providing positive growth.

1:03 p.m.

The Canadian story is an interesting picture. The western Canadian sedimentary basin is not a mature basin in the same context as the Lower 48. It still has a lot of potential. What has happened and what is the result of the less production we saw last year, was that the focus has been on shallow gas drilling. That does a couple of things. It increases your rate of decline, it decreases your initial rate of production, you get on a treadmill. You have to drill more and more just to stay in the same spot. What has happened in the past year is the significant increase in drilling that has occurred in western Canada, as well. Last year, while there wasn't a percentage increase in exploratory activities, just by the sheer number of wells drilled, there was an increase in exploratory wells. We're starting to see the impact of that now. After significant year over year growth in western Canada throughout the 90's, last year was flat. This year it was a slight growth for the first four months. We're now seeing growth in June and July of over 1 BCF/D, which is significant.

What has happened in this year because of the high prices? Exploratory well licenses are up 23 percent. To give an example of the significance of that, there is one discovery, a relatively small area geographically, in northeast B.C. called Lady Burn (ph). It had zero production as of the end of the year. It is now producing 500 MCF/D and probably going to 800 BCF/D by the end of the year.

Are there other areas out there like that? The answer is probably yes. We expect to see significant growth in

western Canada going forward. And while this graph is very confusing, what it attempts to show you is the year over year change from western Canada. As you can see, from '96 through '99 there was annual growth. Last year was flat, declining in the first half of the year [indisc.]. What's really significant is the growth this year. The growth in the first four months of the year was probably in the 350 - 400 BCF/D, but it is increasing dramatically so that the annual average growth for this year is probably going to be 700 MCF/D. We expect to see the same, if not more, next year. So, western Canada should not be counted out.

One of the other interesting aspects of western Canada is coal bed methane, which is becoming a significant portion of gas supply in the U.S. It has not, in fact, in Canada. There's been less than 70 wells drilled for coal bed methane in all of time. The estimate of coal bed methane reserves in western Canada alone are double the total U.S. Lower 48. So, it could substantially be the replacement for shallow gas drilling in western Canada.

Having put all that together, what it still says though, is that there is production required from what we call frontier areas in the future. One of those areas is Atlantic Canada. We saw Sable Island come on stream at the end of 1999. It is increasing in production; there have been new discoveries. We do expect to see growth from there. The Arctic is another region. This is just a range of potential gas from various areas. LNG is probably lower than we would put it if we were to redraw this graph today.

The Scotian shelf, which is offshore eastern Canada, Nova Scotia, is currently producing at about 500 MCF/D. We see that growing to 1 BCF/D by 2005 and 3 BCF/D by 2006. This could even be higher. Similar structures in geology could develop in Mexico. All that has been explored to date is the relatively shallow steep water areas.

One of the areas that used to be a wild card and has now become significantly more important is LNG. There are currently four facilities in the Lower 48, all of which were mothballed until last year. Two of them have come back on stream; Lake Charles last year; Everett has come back on; gas discoveries in Trinidad are ramping up; Cove Point in Elba Island will be coming back on stream next year. We see not only these facilities running at

capacity, but we see expansion of these facilities such that we see 3 BCF/D being imported to these four facilities probably by 2005. The [indisc.] capability will be probably higher than that, but because of storage and ship turnaround requirements, 3 BCF/D is probably the highest sustainable number.

What is really interesting though is if you look at the world LNG facilities. Not only are there significant and numerous liquefaction facilities throughout the world, there are significant plans for more going forward in the 2005 - 2010 as you can see in this graphic. So, we expect to see the supply side of LNG being very strong post 2005 on a global basis.

What does that mean for the Lower 48 and for the potential for Arctic gas? Over the course of the winter, we started seeing more and more starting with monthly, almost going to weekly, announcements of new projects. There are at least three for the Baja that are proposed and a year ago I would have discounted any potential of LNG gasification facilities on the West Coast. There are three that are being studied. The ones off California don't sound as outrageous as you might think because they are not located onshore. They would be gasified from a ship that would be tethered to a buoy probably out of sight and out of mind of California. So, it does have some feasibility.

The East Coast has an area that's being studied and one that has a high potential. The Bahamas, Florida, and the Gulf Coast all have projects that have been put forward. We see some of these projects going ahead. Even the Alta Mira one that has been announced in Mexico has an impact on the Lower 48 because it reduces the amount of gas that needs to be imported into Mexico from the Lower 48. We don't see Mexico as exporting gas to the Lower 48 certainly not within a 2010 timeframe and probably not until 2015. Any facility that is built in Mexico reduces the requirement for U.S. gas to flow into Mexico thereby having the same impact as new supply.

To touch on the Canadian side of things, one of the things I think everyone is finally getting around to realizing is that Canada is not a market. As I showed you on the pricing page, the AECO price is lower than Henry Hub price. There's reason number one - you don't want to stop that and here's reason number two - Canadian demand

is more than adequately supplied by Canadian supply. In fact, more than half of the Canadian supply is on export since the early 1990's. The growth in Canada is going to continue that. The majority of the growth in production in Canada is going to export to the U.S. Lower 48. In a sense, that is the competitor for Arctic gas.

What I wanted to do is get away from sounding like a pessimist. Here is the opportunity for Arctic gas. What this shows is absent Arctic gas and absent new LNG, there is a requirement that starts growing in 2007 increasing through 2010 for new supply. One of the wild cards is the demand decrease that we have seen. How much of it will come back; are we going to see a lower demand growth than we had anticipated? As I said earlier, the power generation demand is still there and will still be there. So, a good portion of it will not go away. What this also shows though, is new LNG projects and Arctic gas both can compete for this shortfall between the supply and demand going forward.

One of the things I find somewhat curious is it doesn't matter which road you take, roughly two-thirds of the pipe goes through Canada. Very little attention has been paid to that aspect. I think that is something that has not demonstrated its potential as an obstruction in this process, but may very well occur. Again, on the optimistic side, we do see potential for Arctic gas in the three scenarios I described before. That potential could start as early as 2007, although at this juncture I think that 2008 is probably the earliest. Under the three scenarios that we see there is an opportunity for Arctic gas starting that early. Under the supplier realignment scenario I described, where we need to see supply from frontier regions as opposed to conventional U.S. supply sources, it could be as early as 2008. In that instance, we would see gas of probably about 2 - 2.5 BCF/D in 2008 growing to 3.5 BCF/D by 2010 and probably peaking at 4 BCF/D by 2015.

In the recession scenario, because of the delay in the demand growth we would see as a result of that, we would see Arctic gas being deferred until probably 2009. In that instance, it would more likely be Mackenzie Delta gas that would precede Alaskan gas simply because of the lower need initially and the greater disposition of people to spend less money on. Even in the case where we have strong growth in North America meeting demand, we

would still be in need of more frontier gas in Arctic opportunities starting in 2011. None of these exceed 4 BCF/D by 2015. What that suggests is that there is a competition going on even among Arctic gas. Depending on the size of either the Mackenzie Delta or Alaska gas, there is a limited opportunity. Therefore, I would suggest that if you saw an Alaskan project of 3 BCF/D that preceded Mackenzie Delta gas, it would probably defer that development beyond 2015. That would be of significant concern to the Canadian government. Again, in our work, we've looked at the need to meet the demand. Four BCF/D is probably the highest we could see Arctic gas without having a significant price impact in the 2015 timeframe. What's also interesting in this graphic is that there is a growing commonality between Mackenzie Delta producers and Alaskan gas.

Having suggested that Arctic gas not stop in Alberta, how does it get to market and what are the markets? As I showed earlier, a lot of the power generation demand and requirement is in the West Coast, especially Northwest California and the Midwest. Those are the two logical markets for Arctic gas just as they are the logical markets for Canadian gas. We do not expect that there will be excess capacity from existing pipelines out of Canada in any timeframe that Alaskan gas can be brought on stream. It doesn't mean that there aren't expansion potentials, but the infrastructure is in place. What I mean by that is that - this isn't based on the Canadian exchange rate - what this shows is that for 4 BCF/D of Arctic gas, you need to build at least 5 BCF/D pipe capacity out of western Canada. The simple reason for that is we anticipate the existing pipe infrastructure being full and at least 1 BCF/D of expansion required for Canadian supply within a 2010 timeframe. So, within the same timeframe, you would have to see 5 BCF/D of pipe filled out of western Canada. You can do that in the context of the existing infrastructure either by the cheap expansion, which very well may be gone by the time Alaskan gas comes on stream, or by some of the more expansive expansions, all of which will be cheaper than building a pipe.

In our opinion, it is more likely you will see expansion of existing structure for a number of different reasons: lower costs and it goes to multiple markets. Four BCF/D of Arctic gas to one market is going to have a tremendous impact. Spread over different markets it's going to have

a lesser impact. One thing I always like to do is tell people, when you're building pipe, you're building pipe to capture an opportunity. The bad news is building that pipe destroys the opportunity you thought you had with it. What I mean by that is regardless of which market you build a pipe to, it is going to have a depressing effect on that market's prices. We don't see that as being significant or insurmountable.

Having said that, there is a window of opportunity and competitive forces out there. There are risks in northern pipeline development. We believe you need a sustainable price around $3. The project once built could survive a price probably as low as $2.50, but you're into cost economics then, but we believe you need a $3 sustainable price to justify Arctic gas.

Interestingly enough, with technology improvements, LNG is economical at $3. LNG is also a competitive force because you can build it in a short timeframe and it has a smaller environmental footprint. But in favor of Arctic gas, you have to build the whole bunch of them where you only have to build one pipeline to fill the need. So there are pros and cons to both. You need to have marginal growth; we need to see that power generation requirement; we need to see some of the manufacturing come on line, such that the demand is there to justify the need for the supply. We've talked about the supply potential in both the Lower 48 and Canada. There still is expected to be a shortfall between lapsed supply growth and demand. So, the supply growth is a risk, but it appears to be there.

The political side is something that I think has not been given enough attention. Mackenzie development is important to Canada. It appears that what is happening is that lines are being drawn in the sand as opposed to developing cooperation, such that a project of this magnitude can be built. Two-thirds of the pipe runs through Canada. The infighting, the delays that could result from any potential obstacle could be enough to close the window. While there is likely to be a new greenfield pipeline to Alberta, it is more likely to be existing infrastructure expansion and looping beyond that point.

In the categories of ongoing, once you start construction, delays can raise your cost. Resource

development is something that needs higher prices to sustain itself. I talked about coal bed methane, the deeper drilling in western Canada, as an example.

One of the things that I think has to happen is that there needs to be risk sharing. This is a project of such magnitude that it is unlikely any one player will undertake the risk. It's probably going to take a cooperative effort between markets, producers, and pipelines to see this done.

Liquids is an area that is just starting to get some attention. One of the ways of reducing the cost of a pipeline is to keep delivering wet gas. What that does is it reduces your heating value cost of transportation. Taking the liquids out increases that cost so there is a potential opportunity there. Once you get to Alberta, though, a large portion of those liquids need to be extracted. So, that's probably the last point that liquids need to be extracted. The reason for that is once you've [indisc.] the existing infrastructure, the majority is not capable of handling high liquid content gas. One of the biggest risks going forward and one of the reasons we now think 2007 is unlikely and 2008 is probably more likely, is you need to see some contracts before anything goes ahead. You need to see a commitment made before you can use this analogy.

I wanted to just touch on natural gas liquids because it is a significant factor here. Natural gas liquids are the next heavier hydrocarbon from methane, which is the prime component of natural gas. You get ethane, propane and butane. Those three components need to be at high pressure to stay in a gaseous state, which is why you need a high pressure pipeline. Once the pressure is reduced, propane and butane especially, turns to liquid. The uses of these components are largely in the petrochemical industry. Propane you may know from barbeque use, butane is used in cigarette lighters, but the majority of the uses are petrochemical. Butane is also used to enhance the octane of gas. Ethane and propane are the prime components of ethylene, propylene, polypropylene and polyethylene that plastics are made of.

To have a viable industry in Alaska would be difficult. It would also add to the cost hurdle of getting this project built in a narrow window. Not infeasible, but with a project in the size of 3 - 4 BCF/D, you would have

enough liquids for one world class ethylene manufacturing facility. You would have an industry that would be less than one third the size of existing infrastructure in Alberta. You would not have the same advantages. The gas supply isn't on a tidewater. It would have to be piped there or the liquids would have to be piped there. You do not have necessarily a price advantage. One of the reasons Alberta developed an industry was twofold: lower priced gas and that was largely because of the price differential between Canada and the U.S. dollar, both of those significant in the manufacturing and the product cost for ethylene.

The part I said I wanted to end on was there is still a window of opportunity. We see prices going forward, being at or above that threshold with the exception of the supply realignment and aftershock. Aftershock, you can see the reason why we don't see Arctic gas coming in until after 2010 or later. Prices just don't support it. Supply realignment, you see the price drop in 2007 and 2008 simply because of that factor I mentioned earlier. You bring gas into the market in less quantities; you will have a dampening impact on prices. It is not enduring as long as you continue to have some kind of growth, however. So, there is an opportunity.

1:26 p.m.

CHAIRMAN TORGERSON asked MR. SMALL to comment on LNG to the Asian markets.

MR. SMALL responded that was not his area of expertise, but they see adequate supply at a lower cost than Alaskan LNG being available until 2015.

SENATOR KELLY asked him to further expand on the 2007 - 2010 window for Arctic gas to be absorbed into the market.

MR. SMALL replied that 2007 is the earliest from two perspectives, one being need and the other being the ability to get it in place. The 2010 timeframe is the outside end of the window, depending on which scenario you're looking at. He noted, "The offsetting factor, though, is LNG and how many of the proposed projects we've seen over the last six months are going to come to fruition. That could push it out further."

SENATOR KELLY asked him to expand on the Canadian position on their Mackenzie Delta gas.

MR. SMALL said:

> I didn't mean to imply that there is a drive by the Canadian government to open Mackenzie in any timeframe. What I meant to suggest is that the Canadian government should be concerned if there was realistic probability of Alaskan gas precluding development of the Mackenzie.

SENATOR KELLY asked how long he thought our gas line would preclude development of that field.

MR. SMALL replied that 4 BCF/D of Alaskan gas would probably push to beyond 2015. He explained that TAPS approval was predicated on the Canadian government putting in the Dempster lateral, "So, there has been a precedent set as far as the Canadians are concerned over the linkage between the two projects and the development of Mackenzie."

SENATOR KELLY asked what the development of the Mackenzie would do to Alaska gas.

MR. SMALL replied that the current plans for Mackenzie Delta gas range from just under 1 BCF/D to 1.5 BCF/D, so, Mackenzie Delta development would not preclude Alaskan gas development. He said they could do both, but there would be a bigger impact on the pricing here. He pointed out, "If Mackenzie goes first, what that really means is a lower volume of Alaskan gas or that Alaskan gas phased in over time would be more probable."

SENATOR KELLY asked if there would be a bigger impact on price or the window when those competitive forces are at work.

MR. SMALL replied, "A bit of both. If Mackenzie goes first, I think it has more of an impact on the volume than the window. They have the same ultimate volume, but the window is longer."

CHAIRMAN TORGERSON said that Arctic gas needs a higher BCF in order to be economical. "In effect, it could have a slowing effect for many years - if you need 4 BCF/D out of Alaska and you're supplying 1.5 BCF/D out of Mackenzie."

REPRESENTATIVE PORTER asked if the risk factor in Arctic natural gas and LNG is about the same.

MR. SMALL answered, "Yes."

REPRESENTATIVE PORTER asked if that is assuming no Asian market, but a Lower 48 market for either route.

MR. SMALL responded:

> LNG for existing facilities is economic in [indisc.]. Arctic gas is probably economic and both routing and market destination have an impact on it. It is economic at about $3. So, they are very comfortable in the threshold needs with LNG probably having a slight nod. Shipping is one of the biggest cost factors for LNG.

He said that in shipping LNG to the East Coast of the U.S., distance is such that you could probably land it for less than $3. He tried to frame his answer in the context of North American demand. He didn't know what the price threshold was for the Asian market.

SENATOR HALFORD asked about the chart on page 33 that shows the breakdown of ownership on the Mackenzie Delta. He asked what the alliances were between the companies.

MR. SMALL answered that those were the net acreage positions of those different companies. There is some sharing of properties. For instance, BP has partial ownership in Burlington/Chevron/BP. Alberta Energy is trading its land position in the Mackenzie Delta with Anadarko, which has land positions in Alaska. He noted, "You're seeing a lot of consolidation."

SENATOR HALFORD asked if Exxon/Mobil was absent.

MR. SMALL replied that they are absent from the Mackenzie Delta. Imperial Oil is owned by Exxon/Mobil - Imperial Oil is the Canadian division of Exxon.

SENATOR HALFORD asked if any others are Exxon/Mobil affiliated.

MR. SMALL answered, "No."

REPRESENTATIVE GREEN asked if Canadian gas came on at 1.5 BCF/D and Alaskan gas was phased in, whether that would be practical.

MR. SMALL answered, "Yes."

REPRESENTATIVE GREEN asked how "some" gas could be phased in, if you're talking about economies of scale for a big line.

MR. SMALL said there are a couple of different ways. He explained:

> Routing is one way. Construction could be done in the context of fewer or more compressor stations. It's going to be difficult to phase it in between a low volume and a high volume simply because the capital cost doesn't allow you to do that, but the difference between 3 BCF/D and 4 BCF/D might be feasible. I don't know. I wasn't

> suggesting starting ours really low and building up to the 4 BCF/D. I'm just suggesting that if 4 BCF/D is the ultimate outcome, it's highly unlikely that the Mackenzie Delta would start out at 1.5 BCF/D. It would probably start out at 1 BCF/D building up to 1.5 BCF/D. I would think the same thing with Alaskan gas. Even with an ultimate of 4 BCF/D, it probably wouldn't start there just because putting into service a project of this magnitude would not be easy. Similar projects have taken a fair bit of time to phase in. This would be doubling or tripling the problem of even an alliance project.

CHAIRMAN TORGERSON said a large amount of exploration activity is going on in the Mackenzie and Alaska is basically ready to go. He asked how long he thought it would take to produce 1 BCF/D from the Mackenzie Delta.

MR. SMALL answered that it is conceivable for the Mackenzie Delta to be on stream in a similar timeframe.

CHAIRMAN TORGERSON said they have read a lot about the Premier of Canada wanting his cut of our liquids. He asked how much the Alberta petrochemical industry is in trouble as far as getting liquids.

MR. SMALL said he didn't think it was a problem and that the Premier's statement was twofold. He said:

> One, the province will not allow itself to be put into a position where it did have a shortfall of liquids and two, this is one of the lines in the sand I've talked about that I think was one of - if you're going to build a pipeline, you have to talk to us.

He added:

> At this point in time, there are more liquids than are being utilized in Alberta, but that doesn't mean it's not for industry. As an example, there is a liquids pipeline that goes to eastern Canada through the Midwest where a lot of the liquids are dropped off and sold. So, a lot of the liquids that aren't used for the petrochemical industry are shipped to both the U.S. and [indisc.]. So, all of the liquids are utilized. Not all of them are necessarily utilized in the petrochemical industry.

SENATOR KELLY said that some of this would be predicated on long-term contracts. He asked how much of the pricing is going to spot now and whether that will affect the long-range contracts he

perceives will be necessary before the project begins.

MR. SMALL answered:

> A high percentage of gas is being bought on the spot market; prior to this past winter, probably close to 100 percent. This past winter has had a profound impact on that psychology. Up until last winter, people were even acquiring pipe space on a spot basis. Hence the price runup. We've seen power generators, such as Alpine buy producing companies so that they would have a secured source of supply. We've seen people bid for pipe capacity signing [indisc.] contracts. So, there's been a dramatic reversal within a short space of time from a spot mentality to a longer term.
>
> Because of the impact on residential consumers in the Lower 48 and Canada, a lot of the distributors are now getting approval from the local government regulatory bodies to buy on spot [indisc.]. That's a whole different attitude than was prevalent a year ago. I think we're seeing a shift because of the high prices. Is it a strong shift? It probably will be in the context of a project of this magnitude. The buying of reserves by a power generator, I think, it's the implication that they seem to need the long-term supply. So, I think it's not as much of an obstacle as it used to be.

1:42 p.m.

Update of SB 158 and Economic Models

CHAIRMAN TORGERSON thanked Mr. Small for his testimony and said that last year the legislature passed SB 158, which directed the Department of Revenue to hire an expert to study the financing possibilities of a pipeline. He said Commissioner Condon was here to give an update on that project. Then, Mr. Roger Marks, an economist with the Department of Revenue would show models of different projects that have been discussed.

COMMISSIONER WILSON CONDON, Department of Revenue, said SB 158 requires the Department of Revenue to prepare and submit a report by January 31, 2001 to the Legislature and the Governor addressing five issues:

> 1. Should the state take an equity position in the North Slope gas line project?
> 2. Should the state participate in financing the project?
> 3. If yes, under what terms and conditions should it participate? If the state does participate, will that

participation affect the state's ability to provide services or negatively affect the state's financial integrity or credit worthiness?
4. Would state participation assist or damage efforts to complete and operate the enterprise?
5. Could or should the state make it possible for individual Alaska residents to become shareholders in the project?

COMMISSIONER CONDON said the legislation waived the competitive bidding solicitation of his department that would normally apply to purchasing contractual services. They canvassed a number of people and have offered contracts to two firms. Mr. David Gray with CH2M Hill is one. CH2M Hill does a variety of different kinds of consulting, including energy consulting, and it advises on a number of different kinds of issues including rate making and financing. Mr. Gray has participated in projects with AIDEA, AEA, private firms and public entities in Alaska. The other firm, Petrie Parkman, is in investment banking, with principal offices in Denver and Houston. The principal partners in that firm were with First Boston when they became Credit Suisse First Boston, but formed their own firm shortly after. Petrie Parkman specializes in the energy industry and was the investment banker for the United States government when it sold its interest in the petroleum reserve in southern California. They were recently investment bankers for half of Saudi Arabia, which privately financed and developed three gas infrastructure projects. Petri Parkman is experienced in both upstream and midstream hydrocarbon projects and transactions.

In preparing the reports, the department looked at the proposals from 20 years ago when ANGTS was front and center. Many things had changed and many things remained the same. The studies that were particularly useful for today's issues were done by Dillon Reading Company in February 1978 and presented to the legislature. The legislature commissioned a series of studies in '78 and '79 to be performed by Heiser at the University of Alaska. Affiliated with him at the time were Dr. Arlen Tussing and Connie Barlow. That study was presented to the legislature in three separate volumes, one in October '78 and two in '79. Finally, three and a half years later, the state commissioned another study to look at state financial participation, specifically by Kidder Peabody and Company. He said he had copies of the studies if they wanted to look at them.

COMMISSIONER CONDON said the question of state participation is one of weighing competing considerations. The following reasons have been advanced for state participation (pros):

1. [Indisc.]
2. If the state participates, it may provide the additional momentum required to get the project done.
3. The major producers have too many competing opportunities

and the only way we'll get our project done is if we do it ourselves.

4. Seat at the table arguments: a) If we have a seat at the table, we will learn information that is important to us and we'll learn it soon enough to protect our interests than if we are not at the table; and b) by having a seat at the table, we would have the leverage to protect special state interests that are important for us to protect. The incomplete list of those are: routing decisions, local hire and buying, gas for communities along the route, potential gas availability for communities not on the route but which are closer than others (Southcentral Alaska), gas for industrial development along the route, the size and pressure configuration of the facility such that it would enhance the possibility of having chemical development in Alaska, and gas availability for petrochemical industry in Alaska.

On the other side of the scale (the cons), COMMISSIONER CONDON said:

1. State ownership or investment would compromise the main responsibility for governing, which includes environmental protection, health and safety protection, economic regulation and taxation.

2. State investment would concentrate state assets in the oil and gas industry. When given our dependence upon the industry anyway, we ought to take any money we have and invest it somewhere else to diversify the investment portfolio of Alaskans.

3. Many people feel that governments don't do a particularly good job of running commercial enterprises. This is generally thought to be true around the world today and in Alaska, we've had some particularly bad experiences with government trying to act as a businessperson.

4. State ownership or participation could easily involve the project in governmental red tape and institutional tugging and pulling, like confirming members of the Board and the Executive Director, the question of how much of the financial activity would be put under the umbrella of the Executive Budget Act, and the way the corporation would involve the enterprise in governmental oversight.

5. Finally, there are those who say the return to a pipeline would be regulated and, therefore, not really such a great investment and the state would likely be able to make more by investing the same amount of money in THE Permanent Fund.

CHAIRMAN TORGERSON asked when the legislature would get a preliminary report on the interaction of this committee with his group of clients and how many of these questions he anticipates will be answered by his consultants' research.

COMMISSIONER CONDON replied that he doesn't anticipate any of the questions to be answered, but they would help the state evaluate information it gets, if any, if it has a seat at the table. He said that they would come to the legislature at its pleasure to report on progress.

CHAIRMAN TORGERSON said the committee will be meeting monthly through October, at least. He asked if he had signed the contracts since he said he "offered" them.

COMMISSIONER CONDON's answer was indiscernible.

REPRESENTATIVE OGAN asked if he thought it would be in the state's best interest to have a seat at the table.

COMMISSIONER CONDON replied that he would like to wait to answer that question until they have finished the study. He noted, "In the oil pipeline the things that were important to know were not discussed at the table we had a seat at." He said the [department] was on the Alyeska Owners Committee during discussions about whether or not the [department] was complying with the electrical code in the pump stations and what kind of request it was going to take back to the oil companies to fix it. The person from the state would be talking about how much money the legislature would appropriate to fix the electrical shortcomings of the pump station. The question about economics and return and that sort of thing was internal in each of the companies who were participating in the TAPS. He stated:

> Given the fact that the gas pipeline is organized very differently, I don't know whether my judgment would be the same. By the way, I would make the observation that if we really wanted a seat at the table on the oil pipeline today, I'm sure we could persuade Amerada Hess to sell us their share of that pipeline…They tried to talk us into buying it.

REPRESENTATIVE GREEN said two pro factors are that we would know what was being discussed and have lead-time, in which case we could buy a very small percentage. Having some say in what was happening would probably require a fairly significant percentage to have any clout. He asked if Commissioner Condon saw a need to wait before making that kind of analysis - going small rather than large.

COMMISSIONER CONDON answered:

> If folks think that in participating, if we conclude that there is some validity to the notion that we could affect a decision and that decision can be affected better if we take a larger interest, I think that we could tell you

whether or not we think that's true. Certainly, in terms of state decision making about what to do, it seems it's unlikely that all of the institutions that have to be mobilized to do something are going to be ready to do anything before our main report gets due very early in the session. We'd be in a position to give you our best judgment on the trade-offs on that issue in a couple of months.

CHAIRMAN TORGERSON said he assumed this could lead us into additional studies.

SENATOR OLSON asked if any other states have participated to this degree in other natural gas pipelines and, if so, what the result has been.

COMMISSIONER CONDON said he wasn't aware of any state participation in a natural gas pipeline but there has been governmental participation in natural gas distributing companies. There are other examples of state participation in various kinds of infrastructural projects throughout North American like airports, highways and canals.

SENATOR OLSON said those entities were utility-oriented as opposed to financial investments with considerations that would lead to business decisions.

COMMISSIONER CONDON said, "There are certainly people who would argue that a gas pipeline is a special kind of highway that hauls gas." He doesn't agree, but he thought it would be a valid way for some people to view it.

REPRESENTATIVE OGAN asked if he is looking at state ownership of a percentage or the whole project, in reference to the three or four-spoked hub they were talking about and whether the state should own the line going into the hub or the whole thing.

COMMISSIONER CONDON replied that they would look at as many possibilities that they think people might be reasonably interested in. He didn't think people would be serious about owning the entire project from Prudhoe Bay to Alberta.

SENATOR OLSON said he wasn't interested in looking at partial ownership in a segment to Fairbanks or Delta or wherever the hub would be. He asked if that would be within his scope.

COMMISSIONER CONDON said it would.

REPRESENTATIVE FATE asked what kind of participation he would have with the firms that are doing the studies based on specific

objective questions, like annualized rate of return of x number of years, accounting methods, etc. He asked if the Commissioner was going to be involved in that at all.

COMMISSIONER CONDON said yes, he would be spending a substantial amount of his time between now and late January working on this project.

REPRESENTATIVE PORTER asked if Alaska was interested in substantial or total ownership of the Alaska portion of the route, whether that would affect the regulatory authority in terms of FERC versus RCA and would a commitment for investment of the substance have an effect (and what effect it would have) on the Permanent Fund. He asked, for example, if it would require a constitutional amendment.

CHAIRMAN TORGERSON said he hoped the Commissioner would generate some financial principles that could be adopted to any one of the questions they hear today whether it's a spur line or excess capacity, particularly in response to question five: Is it even worth getting into a regulated industry? He also thought he should be able to establish whether it would make the same or more money than the Permanent Fund. He thought he should establish that as a set principle before the state would have ownership in any line. He thanked the Commissioner for joining the committee and invited Mr. Roger Marks, Department of Revenue economist, who has been working with different gas projects that have been suggested and created, to address the committee.

MR. ROGER MARKS, Economist, Department of Revenue, said he would present the department's economic model to the committee for the gas project. He said:

> Our model is something that evolved over a period of years and was originally put together in 1995 looking at LNG. It has since evolved to looking at gas to liquids and now it is looking at the North American pipeline project. It's been reviewed over time by a lot of entities including the North Slope producers, ARCO, I don't think Phillips has officially reviewed it yet. ARCO reviewed it back when we were putting together our report to the governor in 1997. Foothills has reviewed it; Yukon Pacific has reviewed it along with their parent company [indisc.] along with their financial advisors, First Boston; Dr. Pedro van Meurs' chart group; the Port Authority and their financial advisors, Taylor DeJongh. I will say it's a work in progress and continues to be a work in progress. It's changing and evolving all the time. It is also a public model; anyone who wants it can get a copy.

> Like all models, there are inputs to it. Basically, the inputs for this model are cash flows. The main ones are volumes, prices and costs. The main costs are capital costs, operating costs and taxes. The state tax system and federal tax system are modeled into it. The outputs are financial capability in terms of rate of return, what the tariffs of cost of service would be, what the wellhead values would be and what the state revenues would be. These are in terms of cash flows.
>
> There are a lot of tariff methodologies on the shelf. We used one, but basically they are all similar in that they provide a rate of return, cost of service and a rate of return on the costs. Again, this is a tool. What it does is explain how numbers work together, how things work together and you can answer budget questions. If the input is so, what is the output. It also can evaluate the economics of different routing options.

MR. MARKS said the numbers he used were not necessarily what the economics of the project are, but what the economics would be with specific inputs. The department doesn't claim any expertise relating the capital costs.

TAPE 01-03, SIDE A

CHAIRMAN TORGERSON asked what kind of interaction he had with producer groups that they have shared this with.

MR. MARKS replied that the producers reviewed the basic model he put together for the governor in 1996. In terms of the input, he said the producers were still studying what they thought the costs and routing would be.

REPRESENTATIVE GREEN asked if he had run sensitivities to see if price or cost was the major factor.

MR. MARKS responded that was exactly what he was going to cover next.

REPRESENTATIVE GREEN asked if the model was set up to run for a profit making organization. He asked if it could be tweaked so they could look at various ranges of input from the state's standpoint where at least the taxes would be different.

2:20 p.m.

MR. MARKS answered that it could be easily modified to show that. He pointed out some of the sensitivities using a less favorable scenario - a bare bones project. He used a route along the Alcan to

Alberta, a $3 Chicago gas price and 4 BCF/D. He explained that they used 4 BCF/D for two reasons. He thought they would need the additional volume to get the unit cost down to be competitive and, in terms of the Mackenzie Delta, there may not be enough productive capacity to build two pipelines at once. So, if there's a niche for 4 BCF/D, it would perhaps come from only one project initially.

MR. MARKS said he used a $1 charge from Alberta to Chicago, which represents the combination of new and expanded pipeline capacity there. To create a least favorable scenario, he used a $3 gas price in Chicago at 4 BCF/D. If you assume that a minimum rate of return required to make a project economic is 10 percent, he asked himself what is the highest capital cost you could have. That turned out to be $14 billion. Given the range of numbers he had seen, $14 billion was very high, but he wanted to illustrate the sensitivities of what happens when capital costs go down or prices go up. So, this model is a useful template to start out with. Of the $14 billion, $2 billion was for a conditioning plant on the Slope and the other $12 billion is for the pipeline, itself.

MR. MARKS said there were two other issues, oil losses for one, but he didn't factor that in nor any of the economics of the gas liquids mainly because, at this stage of the game, the producers are trying to figure out exactly what those are. He noted, "We [the state] frankly have no idea."

MR. MARKS said that the oil losses and the liquids directionally offset each other, although probably not exactly. The first sensitivity he used was capital costs and, given that less favorable scenario [4BCF/D and $3 Chicago gas price], produces a 10 percent rate of return [at least]. He explained that scenario produces a very low wellhead value of four cents. He used a representative year of 2015 to see what total state revenue would be and in that year with this project, it was $398 trillion.

He explained that the overhead was broken down into elements of state revenue. A big chunk of it was property tax, which is high because the cost is high. This underscores the point that a property tax is regressive. So, it is not the best thing for the project. Another element is royalties and he noted that it was $0 with a wellhead value of five cents. This is because the wellhead value represents the Chicago price plus the pipeline in Alberta, plus the pipeline from the conditioning plant and the conditioning plant. Upstream of the conditioning plant and downstream of the point of production, which is the point of royalty in taxation, is the central gas facility where there is a 20 cent processing fee deduction for royalty. He stated, "Any netback going into the conditioning plant less than 20 cents will actually negate the royalty."

SENATOR HALFORD asked if it reduced the tax to the same company

with regards to oil production.

MR. MARKS answered, "There is a 6.4 cent minimum severance tax at the field. So, you'll see the next column over, the severance taxes are positive, which reflects that 6.4 cents."

He modeled the state corporate income tax on a separate accounting basis, simply 9.4 percent of the net income. The state has a modified apportionment type of it, which reflects a variety of economics worldwide, impossible to model. So, it will likely not be 9.4 percent.

MR. MARKS said the next column is state corporate income tax and the pipeline tariffs. Whoever owns the tariff will pay taxes on their income, which goes to the state. He said the final column is additional severance tax from the economic limit factor (ELF) increase. He stated:

> For oil, depending on field size, 300 barrels per well per day are more or less tax-free. For gas, it's 3,000 MCF per well per day tax-free. For oil and gas coming out of the same well, which is what will happen at Prudhoe Bay, the tax-free barrels of oil and MCF for gas get pro-rated. So, as a result of having a gas field, there'll be less tax-free barrels. So the above taxes will go up.

MR. MARKS went back to the capital cost sensitivities and showed what happened when one goes from $14 billion to $12 billion leaving everything else constant. The rate of return goes up to 11.6 percent; the wellhead value goes up to 29 cents and the total state revenue goes up to $413 million. He pointed out:

> There are two reasons the state revenue doesn't go up that much. One is the property tax. When you decrease your capital costs, on one hand, you've increased the wellhead values, which means higher taxes and royalties and you've increased the property tax.

He said the wellhead value for anything between four cents and 20 cents for the $14 billion essentially has the same severance tax royalties. He took the committee to the $10 billion scenario. The rate of return goes up to 13.6 percent, the wellhead value goes to 55 cents, and the total state revenue goes up to $440 million. He stated:

> One interesting thing you can see with the sensitivities is that for every billion dollars that you change cost, the wellhead value changes about 13 cents. This suggests to him that for investors looking at this project, the gas price is very important. A small change in gas price has the same effect as a very large change in the capital costs.

2:32 p.m.

MR. MARKS said on the state revenue side, once you get over 20 cents on the wellhead, every billion dollars in capital costs is about $13 million instate revenue. He said the reason that number is so low is that when the capital costs go one way, wellhead values go down and the property goes up as well. The reverse happens when the costs go the other way.

He directed the committee to look at overhead number 8, capital cost sensitivities and reviewed "the same dismal case," $3 gas, a $14 billion project, 10 percent rate of return, 4 cents at the wellhead, and $398 in revenue. At a $4 gas price, the rate of return goes up to 14.6 percent, the wellhead value goes up to 96 cents and the state revenues go up to $684 million. For $5 gas, the rate of return is 18.3 percent, wellhead value of $1.89 and state revenue of $1.081 million. He noted that the change in the gas price of $1 leads to a 92 cent change in the wellhead value.

The reason that is not a dollar-for-dollar change is that there are some losses along the way in volume of about 8 percent. He said:

> If you put 100 MCF into the conditioning plant, you only get 92 MCF out. You still get only 92 MCF in Chicago, but have to allocate that over the 100 MCF that went in and that works out to less than a dollar.

The $1 billion change represents the same change as 13 cents in price. A one dollar change in market price has the same effect as $7 billion in capital costs. The change of 50 cents in the market price has the same effect as $3.5 billion in costs and underscores the fact that investors are very concerned about the gas market price.

The final sensitivity beyond capital cost and gas price is volume sensitivity. He used the same dismal scenario again of 4 BCF/D, $3 gas, 10 percent rate of return, 4 cents wellhead and state revenues of $398 million. If you increase the volume and keep everything else constant, and you go from 4 BCF/D to 5 BCF/D, economy of scale raises the rate of return to 12.3 percent, 40 cents wellhead value and total state revenues of $532 million; going from 5 BCF/D to 6 BCF/D is 14.5 percent rate of return, 64 cents wellhead value and state revenues of $695 million.

REPRESENTATIVE GREEN asked why, in going from 4 BCF/D to 5 BCF/D, he used 36 cents and, when he went up one more billion, he used 24 cents.

MR. MARKS answered because the ratio of total capital costs is $14 billion to the volume is on a percentage and changes those numbers. "In reality, your costs would go up with your rate of volume."

REPRESENTATIVE OGAN asked if the feasibility of the project was based more on price to market than routes.

MR. MARKS responded that a small change in gas price will have a much more profound effect on the project than capital costs.

CHAIRMAN TORGERSON asked if he had put together similar sensitivities for LNG and PTL.

MR. MARKS said they had done that, but there are limitations using the models. He noted, "What really matters in terms of measuring economics is how you can compete with competing projects."

REPRESENTATIVE GREEN asked if these numbers were adjusted for inflation.

MR. MARKS said he kept inflation out so that, "These are real numbers."

CHAIRMAN TORGERSON thanked Mr. Marks for his presentation and said the committee would next hear from the Commissioner of Natural Resources, Pat Pourchot.

2:50 p.m.

Royalty In-Kind Issues and Pipeline Studies

CHAIRMAN TORGERSON announced that the committee would next hear from Commissioner Pat Pourchot, who would respond to six questions posed to him in a letter from the committee.

COMMISSIONER PAT POURCHOT, Department of Natural Resources (DNR), introduced Bonnie Robson, Deputy Director of DNR's Division of Oil and Gas, and Kevin Banks, a petroleum market analyst with the Division of Oil and Gas. He explained they have been responsible for developing the Request for Proposal (RFP) for the study that is the subject of one of the questions posed by the committee. Commissioner Pourchot noted he distributed a handout to committee members that covers DNR's primary objectives. He said he would discuss some of DNR's broad objectives and then respond to the questions.

COMMISSIONER POURCHOT said the administration's work on this issue cuts across both his department and the Department of Revenue. They are both looking at maximizing income to the state to benefit Alaska citizens when looking at the various aspects of a gas pipeline project. Their first objective has been to look at how Alaska can maximize its royalty impact value and how that will affect tariffs, selling prices, field costs, conditioning costs and how gas may or may not affect oil revenue loss. In addition, fuel

dynamic interaction might take place under different scenarios. DNR is vitally interested in all of those topics and is trying to learn as much as possible about them. Regarding the benefit to the people of Alaska, the second objective, DNR is looking at in-state jobs and at state uses of natural gas. The third main objective is to maximize benefits to Alaska businesses and businesses operating in Alaska and how access may or may not occur under different scenarios. He pointed out those objectives are not mutually exclusive.

COMMISSIONER POURCHOT stated that the answers to some of the questions are not as simple as "yes" or "no" because ultimately, DNR is keenly interested in developing a common project. Some things might be traded so that maximizing one aspect could be at the expense of another. At some point the viability of the project will be affected. He briefly covered the "tools" that will be necessary to accomplish DNR's objectives, such as legislation, and noted that both federal and state agencies will be involved in studies and permitting. In terms of the permitting, a whole conglomerate of entities will be involved; DNR is trying to bring some of those entities together for some of those tasks.

COMMISSIONER POURCHOT said the first question he was asked by the committee concerned the state's rights to take gas in-kind for major gas sales, commonly known as overlifting, or alternatively, the state's right to defer taking royalty gas, commonly called underlifting. There is no expressed ability in statute or regulation or in the terms of any lease agreement that gives Alaska the right to overlift or underlift Alaska's royalty gas in advance of gas sales. However, there are ways of accomplishing that, most notably, if Alaska has implied that if there is a viable market, that producers under the terms of the lease sales shall market that gas. If, for example, there was a proposal to seek as-is gas right off of the North Slope at some market rate and there was a viable purchaser at a credible market rate, there is an obligation to market that gas.

Alternatively, if there was a viable proposal with a sensible market price, the state should work cooperatively with the producers to overlift its royalty gas on the Slope, a negotiated process.

The Alaska Lands Act had a provision many years ago that gave the DNR commissioner authority to negotiate with companies to underlift oil. It was specifically mentioned that there was a strategy prior to bargaining that allowed DNR to affect the routing of the oil pipeline. He believes the likelihood of success of such a strategy is debatable. The legislature specifically put in that element, but it did not grant a lateral authority to negotiate with the producers.

CHAIRMAN TORGERSON asked if the negotiations with producers fail, the state would have no right to assert a claim to overlift or underlift.

COMMISSIONER POURCHOT said he believes that is correct, and that DNR deals with the companies on so many issues, such as development plans, exploration plans, lease terms, participating areas, etc., that overall it is their desire to cooperate and to negotiate in good faith on a variety of issues. He said he believes there is a climate of cooperation.

CHAIRMAN TORGERSON asked Commissioner Pourchot if he feels using a legislative route would constitute a breach of contract with the existing lease sales.

COMMISSIONER POURCHOT replied that in the event of a breach of contract, the state has no lateral expressed right. That could potentially lead to legal action.

COMMISSIONER POURCHOT said the second question the committee posed was in relation to the state's right to control access to the pipeline for potential users that come later. He acknowledged that he deferred part of the answer to the RCA and to the FERC. However, in the area of state regulation of pipelines, there is a big body of law surrounding federal preemption in this arena. The state has several options. It can go through the FERC process. It could make recommendations for how an open season will be conducted. Alaska statutes and permitting procedures could conceivably be tried but, in the end, the state can be preempted by federal law or federal regulatory action. Conversely, federal law changes.

COMMISSIONER POURCHOT said DNR is very concerned about open season and that there be a fair nomination process both initially as well as ten years down the line when a producer might discover large gas reserves. DNR is also concerned about the possibility of a process that barely addresses a potential looping expansion and how costs are allocated and how access to facilities are handled. DNR is concerned about establishing a process that is as open and fair as possible. More access for potential interests means more value because it will create an incentive for further exploration and production.

CHAIRMAN TORGERSON asked the commissioner if he is continuing to seek legal advice on those issues and what process he is using to give the committee final answers prior to next session.

COMMISSIONER POURCHOT said DNR has received additional legal advice but he has not asked for a formal legal opinion. The question is whether the committee wants the information in black and white. He could request that the advice he has received be formalized and

made final and available soon. Regarding whether he is continuing to seek legal advice, he would have to reframe some of his questions to the Department of Law and he has not done that.

CHAIRMAN TORGERSON said the open season question is one of the largest issues facing the state right now. He asked:

> If the producers build a 4 BCF line and won't let anybody else in there for the next 20 years, where does that leave any oil and gas sales on the North Slope - or gas sales. To me, you can't sell anything up there. Who would buy acreage or, if they did, it wouldn't be at any good price for the State of Alaska.

COMMISSIONER POURCHOT said there are a couple of options. DNR has asked that same question of economists and believes it always pays to have more people participate in a project of this type because of the per volume cost of the line and, presumably, once the upfront costs of the initial line are incurred, the cost of running a second parallel line for another volume of gas, if necessary, would be cheaper. Pressurization can move significantly more gas and provide for a significant increase in capacity. The producers' argument is that if somebody comes with more gas, they would welcome that because it would reduce the per volume cost of gas in the line.

CHAIRMAN TORGERSON said he appreciated that statement but he wants some assurance that will happen. He expressed concern that the opposite could happen so, if the producers let another producer in, the market price could be affected quite a bit. He pointed out this situation is different from Calgary or other places in which 10,000 wells are being drilled each year. Alaska has a very controlled resource going into a very controlled line that has the potential of having other players involved or left out for a number of years. He said he hopes that DNR continues its legal analysis of that question and he said he will recommend that the legislature do some of that on its own.

COMMISSIONER POURCHOT stated the third question posed by the committee was in regard to DNR's support for common carrier versus contract carriage of a pipeline. DNR would prefer a common carrier status for all leases because it would be easier to expand the line for later gas reserve discoveries. Again, he said that DNR is concerned that there be a process for expanding the line. The Alaska Natural Gas Act provided for contract carriage and is a matter of federal law, the argument being that contract carriage provided the kind of arrangement necessary to finance a project. Most gas pipelines in the United States are contract carriage but, as Chairman Torgerson pointed out, shipping through different pipelines will not be an option on the North Slope.

COMMISSIONER POURCHOT, in response to the fourth question, said

DNR obviously favors open seasons for both initial nomination and for subsequent nominations, as well as for additional capacity to take on volumes of gas.

COMMISSIONER POURCHOT said the next question [number 5] raises another element - how to deal with the export [indisc.] capacity volume for coming years. That question is in relation to the committee's question about agreements to backstop non-pipeline owner/producers firm capacity obligation with the state's royalty in-kind (RIK) gas. DNR has been approached by companies who are not producers, but hope to be producers or owners of gas in the future. They are not in a position now to make a firm commitment for nomination and do not know whether or not they will find gas, but they do not want to be locked out. The committee asked whether the state would be willing to take their gas in-kind at a later date and have those companies make a nomination for a quantity of gas but, if they did not find gas or could not meet that commitment to ship that volume of gas, they want the state to take that gas in-kind and sell it to the people with the reserved space in the pipeline. DNR is open to that notion. DNR wants to protect its ability to take its gas in-value or take it in-kind and be able to use it for in-state purposes. The gas would still be shipped out, but there may be some economic value. The state could get a premium for it; it could get a tariff component for that off of the state's netback. It is a way of meeting the goals of keeping the values high on the North Slope.

COMMISSIONER POURCHOT said it would be part of the whole mix. One wouldn't presumably over commit if you only had 500 MCF per day.

TAPE 01-3, SIDE B

CHAIRMAN TORGERSON said he is not sure that it would be necessary if the open season question on additional access to the line is solved. He said he posed the question to find out whether the commissioner would be willing to consider it. He repeated if the open season is early, the state may not be prepared to respond.

COMMISSIONER POURCHOT said the next question posed by the committee asked about the current status of discussions with Netricity. He said DNR took the Legislature's resolution [HCR 17] on this matter seriously. Not only is the proposal intriguing, it is a good focus for the larger question of state in-kind gas. DNR is in discussions with Netricity. He noted he provided committee members with specific information about Netricity that DNR is looking at, regarding the dollar amount if the state accepted Netricity's proposal of 36 cents per cubic foot. He noted the worksheet only contains Netricity's initial offer. In his opinion, that offer does not appear to be in the state's best interest, particularly when the state's cost of extracting gas on the oil grounds is unknown. There will be some cost associated, if it is computed

back in terms of a gas price. It could amount to 10 or 20 cents but, beyond that, the amount could get to zero quickly on this kind of a proposal.

CHAIRMAN TORGERSON asked if DNR is still in contact with the principals of Netricity.

COMMISSIONER POURCHOT said DNR is participating in on-going negotiations with Netricity. He then said DNR would like to talk about its study for the component of this evaluation of the values associated with gas. He noted that Netricity has approached producers also. DNR is in disagreement with Netricity on some issues. Netricity has a methodology for how it arrived at 36 cents. It used a fairly aggressive discounting schedule. Obviously, there is some value in selling gas in advance of a gas sale that might be seven years down the line, but DNR believes the discounting would be less than 18 years' worth; it might be four to seven years, which would change the value considerably.

3:26 p.m.

COMMISSIONER POURCHOT stated that the last question Chairman Torgerson asked was in regard to ongoing gas pipeline studies. DNR has proposed several different studies. He believes DNR has figured out how to pay for the in-state demand study and, pending the upcoming Legislative Budget and Audit (LBA) meeting, he will know more about how and whether the other studies will be funded. DNR has published a request for proposals (RFP) for the in-state demand study and the deadline is July 23. DNR is hoping for a completion date in early or mid-November. The study is designed to determine at what price North Slope gas can be delivered to different regions of the state; how can it be used in-state relative to the price of other fuels; and what new uses might arise if natural gas were more readily available from the North Slope. Other questions regard where a pipeline might go and how much it will cost to access gas in Southcentral versus Fairbanks. The study is designed to try to get a better handle on the demand for in-state gas, which directly relates to a price and route.

COMMISSIONER POURCHOT informed the committee that a value study is due back next week. It will review various factors that will impact netback values of North Slope gas and will identify pricing policies and practices used elsewhere. The goal is to determine methodologies that provide the most transparent ways of calculating netback value and transportation costs. DNR has had a lot of experience with oil and has spent a lot of time litigating how costs should be calculated to arrive at a netback. Their settlement agreements over the years have made oil netback calculations easier and more clear.

DNR wants to maximize the state's resources and avoid more

litigation, COMMISSIONER POURCHOT said, and hopes to avoid having a complex system of calculating netback prices. DNR is also looking at a larger supply structure and trying to assess the supply of other kinds of gas, not just Prudhoe Bay gas, and how those might come into play. Obviously, transportation makes other things more economical. DNR hopes to do an in-house effort and compile known information describing it by different kinds of gas sources and making assumptions relative to proximity to transportation.

COMMISSIONER POURCHOT said that DNR has proposed a component of a reservoir study using the economics of the impact of gas extraction on Alaska's oil reserves, primarily at Prudhoe Bay. AOGCC has the major responsibility for this and would be the lead agency. He noted that funding issues in regard to that study have not been resolved because of the way the budget items were structured, the issue being whether the AOGCC has the ability to reimburse for those costs. Some of that will be discussed at the upcoming LBA meeting. DNR would not do its component of that without the Alaska Oil and Gas Conservation Commission (AOGCC) study, but DNR views that study as very important. It will provide the information the state needs to have going into negotiations. There is information, but DNR needs an evaluation so that the state's own views can be represented. He offered to answer questions.

CHAIRMAN TORGERSON commented that regarding the LBA meeting, he will probably be less than friendly towards the Commissioner's request until a method is accomplished in which the Legislature and administration work hand-in-hand on this project instead of running parallel courses. He noted he has had that conversation with the commissioner and with other department and division heads. He said he has recommended to the Chairman of Legislative Council that the Council fund many of those projects so that the information can flow to the committee. He then announced the committee would take a short recess.

3:35 p.m.

Right-of-Way Pipeline Applications

CHAIRMAN TORGERSON introduced John Goll, Alaska Regional Director of U.S. Mineral Management, and Jerry Brossia, the federal pipeline coordinator with the Pipeline Office.

MR. JOHN GOLL, Regional Director for the Minerals Management Service (MMS), U.S. Department of the Interior, said he would present information on the right-of-way for an offshore route and that Mr. Brossia would answer questions afterward in regard to onshore responsibilities of the Department of the Interior.

MR. GOLL gave the following testimony.

I know that the offshore route is not the popular route. I want to emphasize that we, the Department of the Interior, are new to a lot of [indisc.]. It is not our job to propose or advocate the selection of the route. However, we are required to review any application that might come before us. So, I will try to outline the right-of-way process that we would use for an offshore pipeline through federal waters, but I would also like to take this opportunity to make some brief remarks on future gas supplies from the perspective of our agency. Our agency is one that is deeply involved in the nation's energy production picture. I think it might complement some of the things that you heard a little bit earlier this afternoon.

Natural gas resources, including those in the Arctic, are very significant and a visible part of the Department of the Interior's strategy for managing U.S. energy resources. So, the issue of getting an Alaska gas pipeline permitted and constructed is a challenge for you and for us and an opportunity.

First of all, I would like [indisc.] the Minerals Management Service and who we are. The Minerals Management Service, also known as MMS, is an agency in the U.S. Department of the Interior. We are responsible for managing the mineral resources on U.S. offshore lands under the jurisdiction of the federal government. Our jurisdiction covers nearly 1.7 billion acres of the submerged lands called the federal Outer Continental Shelf, or the OCS. This includes about 1 billion acres offshore Alaska.

Along with managing the leasing of OCS minerals resources and estimating the amounts of resources that may be there, our responsibilities include regulating offshore operations of the oil and gas industry, helping to ensure worker safety and protecting the environment. We have a robust technical research program, which includes research on pipelines, drilling safety, oil spill response, and other topics and we are also responsible for collection of the revenues that are generated by the leasing rights to produce the minerals owned by the United States and individual Indians and tribes, both onshore and offshore, and for distributing the funds to the U.S. Treasury, to the states, and to other accounts. For example, the CARA bills are totally funded from the revenue that we generate on the OCS.

Today the OCS, primarily in the Gulf of Mexico, accounts for 25 percent of the nation's oil production and 27 percent of its natural gas production. Our agency provides oversight there on about 31,000 miles of seabed pipeline. And, over 50 percent of remaining oil and gas resources in the U.S. are located on the OCS.

I would like briefly to review first what is going on in the Lower 48, part of it, again, to complement what was said a little bit earlier because this, again, can influence some of the issues that you're facing with regard to the supply and demand in the future.

As I mentioned, the Gulf of Mexico accounts for about 25 percent of the nation's oil and gas production. On the Gulf, activity is going gangbusters with continued discoveries in the traditional shallow waters and the step out into the deeper waters of the Gulf, as you heard earlier. The fact is some of the shallow waters will be more likely to produce the gas in the future than the deeper because it will take a little bit longer to do the production from the deep water. So, we'll be talking beyond what we have here on this chart, most likely before the deep water can start taking effect. The natural gas potential in the Gulf remains very high - around 190 TCF. The present gas production has been about 5 TCF, but the future, as I mentioned, is with all predictions a little uncertain as I've noted on the chart depending on the continuing discoveries, trying to stabilize the production there and getting projects under production to shore which, again, takes longer. So, we really do see in the Gulf things staying pretty much even this side of the Gulf - not tremendous rises as some people maybe have noted.

Looking at the rest of the Lower 48, the picture is not as bright. Most of the Lower 48 of the Outer Continental Shelf is off limits. In the Atlantic, there is very likely prolific gas, with estimates ranging from 24 to 34 TCF. The extension of discoveries off Southeastern Canada most likely go down the eastern seaboard. The Eastern Gulf of Mexico's border opposes development off the coast and we just scaled back a proposed sale in the Gulf in the Eastern Gulf of Mexico. On there, the mean estimate is about 12 TCF. On the West Coast, gas areas are likely off of Washington, Oregon, and Northern California with a range of 15 to 23 TCF. Some production

does continue off California, primarily oil. Leasing is unlikely in any of these offshore areas in the foreseeable future, although groups such as our national OCS policy committee is trying to get the discussion going by simply thinking about what resources these areas may contain. But, right now most of these states do not want production off of their coast even though it may benefit [indisc.- coughing] the localities there. It is noted in the national energy report, much of the Rockies have been off limits or with great restrictions and there the estimate is around 137 BCFs - again off limits.

The point of this overview is that the nation has not been exploring, much less producing, in many areas with good potential and this does give Alaska a step up with known reserves. We see great potential offshore of Alaska for natural gas. This is the chart of the potential on the Outer Continental Shelf. These are [indisc.] undiscovered and eventually recoverable so they do not include economics. But the Chukchi and Beaufort Seas look very promising, as noted on the chart, with estimates ranging on the Chukchi from 14 to 154 TCF and, in the Beaufort, perhaps as high as up to 163 TCF, and likewise, also favorable for oil. But we are a number of years away for gas development to proceed there. Of course more exploration would be needed and the infrastructure developed, but the message is there can be plenty of gas in Northern Alaska to sustain a pipeline, or pipelines, well into the future if we all want to pursue the [indisc.] chance and develop those resources.

Just a few other side comments on the Alaska offshore - maybe not totally on the North Slope but.... In the areas off of Alaska's west coast, from the Chukchi down into the Bering Sea, we have indications for good gas potential that could be used for communities in those areas, especially if onshore sources of gas or some other alternative energy that is being looked for there, are not found or available. The economics, of course, may be the limiting factor but the potential is there off the west coast. Also for future reference, and maybe this is dreaming more wide into the future, there is the potential for significant quantities of the presently unconventional resource of gas hybrids. Estimates of 590 TCF onshore and, what I would call an unbelievable amount, 170,000 TCF offshore around the state. That's primarily up in the Beaufort and even along the Shelf break south of the Aleutians. This is probably not for

us but maybe for our children or grandchildren or something, maybe to look forward to in the future with regard to hybrid development. But there are, of course, hybrids on the North Slope that may be a little bit easier in the nearer future.

But then again, the message remains that the energy sources are likely there if we want to look for them and if we want to use them.

Let me go into some of the regulatory authorities again if an offshore route were ultimately selected. If the northern offshore pipeline route were selected, the MMS has specific authorities to grant pipeline rights-of-way and maybe also to approve oil spill contingency plans. Our right-of-way authorities are established under the Outer Continental Shelf Lands Act, the OCSLA. Other than the right-of-way permits, MMS exercises approval and oversight responsibilities for the installation, operation, maintenance and abandonment of the pipeline. An oil spill contingency plan may also be required if the pipeline were carrying naturally occurring condensate or if condensate is injected into the pipeline. MMS contingency plan authorities are established under the OCS Lands Act and the Oil Pollution Act of 1990 and would apply to all segments of an offshore pipeline, whether around the federal OCS or the state's submerged lands. In the event there is the potential for a spill, additional demonstration of financial responsibility will be required under the Oil Pollution Act.

REPRESENTATIVE GREEN asked if Mr. Goll was referring to condensate as opposed to natural gas liquid.

MR. GOLL said that is correct, but clarified that these provisions would likely come into play for any liquids going into the pipeline if there was potential for a spill. He then continued his presentation.

The MMS would share management responsibilities for this pipeline with the Federal Energy Regulatory Commission, the U.S. Department of Transportation's Office of Pipeline Safety, and the State of Alaska's Pipeline Coordinator's Office and with our Canadian counterparts also. MMS is also a new member of the State of Alaska-Federal Joint Pipeline Office. At this point, I'd like to mention that the Department of Energy and the national energy report - there was a provision in there for the Department of Energy to pool together the federal

agencies and recently, over the last two or three weeks, the Department of Energy has pooled together themselves, the U.S. Department of State, the Department of the Interior with representation from our agency, Minerals Management Service, and from the Bureau of Land Management, and the Federal Energy Regulatory Commission to get together again, to investigate ways to expedite permitting for a gas pipeline and then to make recommendations to Congress and the President on how to proceed. So, that work will be going on over the next couple of months and I believe they do plan a trip up here, perhaps in September. I'll make sure that you are informed. That would be the regulatory authority. Other agencies would be involved in the project depending on the proposal and issues, many in some indirect ways with regard to some other laws.

MMS has regulations and guidance that outline the information requirements in detail for right-of-way applications. First we encourage the pipeline permittee to collect information prior to submitting a request for a permit. This allows important geotechnical, geophysical, archeological and biological information to be available earlier in the process. The producers' group plans to collect such information this summer as part of its study of the two routes. MMS will do a full safety and engineering design review, including consideration of site-specific issues using data from a survey and other sources. We would proceed doing this jointly with the State Pipeline Coordinator's Office and in coordination with the U.S. Department of Transportation. The MMS will also provide an opportunity for public comment and would conduct an environmental analysis under the provisions of the National Environmental Policy Act. In the event of an environmental impact statement, which is very likely for these pipeline routes, a lead federal agency would be designated. Which agency has the lead would depend on the scope and the nature of the specific proposal and relative responsibility of the various agencies. In the case of the over-the-top pipeline proposal, MMS, the U.S. Department of Transportation, the U.S. Army Corps of Engineers or FERC are all possible lead agencies for the EIS.

I can give an example in the Gulf of Mexico that we've just completed. We worked with the federal - with FERC on the Gulf Stream gas pipeline that ran from Mobile Bay

to Tampa Bay, across the Gulf. FERC was the lead of contracting the EIS, with post-coordination with our staff. Our staff within MMS did a full engineering review that considered the specific route and environmental issues and technical issues and it was also doing inspections as the pipeline was being constructed.

The project would also be subject to coastal consistency review, with the State of Alaska's Coastal Management Program. [Indisc.] consultations would be required with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service. We foresee a number of environmental and technical considerations for an offshore pipeline and I'm sure there's more. But, the paramount environmental consideration is the bowhead whale and associated subsistence hunting activities that occur during the open water periods across the Beaufort Sea. One would need to ensure that construction or operation of a pipeline would not unreasonably interfere with the whales or subsistence. Seasonal broken ice conditions in the fall and spring will also pose challenges for construction, maintenance and repair. Permafrost, ice gauging and strudlescour (ph) are other design considerations. Metering and lease protection would be of concern even though this is not an oil pipeline. Strudlescour can be at spring break-up. When the water is starting to come out of the rivers, it will go across the ice and it finds a hole; it will go down like your toilet flushes and it essentially moves gravel or whatever the seabed is. Why take that into consideration when you [indisc.] a pipe?

One of the main efforts that we or any lead in this project if, really, any of these projects go forward, but of course we're talking here about the over-the-top route, would be consult with all concerned parties, such as the list that I have here. We and other agencies would need to work closely with the many stakeholders to make sure that their concerns are addressed in our decision, but we would also want to ensure that the process that we were working under was done in a timely way.

So, in conclusion, Alaska does have significant untapped natural gas resources that can go a long way to serving the nation's need for natural gas in the coming decade and well beyond. It may be a step ahead of other areas of the U.S. that have good potential, but again, the

country [has] not developed that way. The right-of-way procedures do exist for offshore permitting. But, first I'll emphasize again that the route is not ours to propose or advocate and, regardless of the route that is ultimately chosen we, within the Department of the Interior, being MMS and I think I can speak for BLM, that we would work where we can to assist through whatever route is decided on. The challenges that face us with getting these resources out of the Arctic while ensuring that it is done safely and with maximum protection of the environment. Also, within the department, again because of the importance of Alaska, I think it's - of course you are all very aware that Secretary Norton went to the trouble of having two special representatives for Alaska to give views to people back in Washington and here and to be her eyes and ears and to provide advice and counsel. So, you'll also be able to work with Senator Drue Pearce and Cam Toohey as these projects go forward. So, the wrap up. If you're interested in more information, of course we can provide it. We also have a web page that goes into much more detail in regard to our rules, technical research and environmental research that we're doing and other information about MMS. Thank you very much for your time. I'm here to answer questions or if Jerry would like to ....

CHAIRMAN TORGERSON asked Mr. Brossia if he would like to add to Mr. Goll's presentation.

3:54 p.m.

MR. JERRY BROSSIA introduced himself as the representative to the Secretary of the Department of Interior, located in the Bureau of Land Management, and said he will administer the TransAlaska pipeline, as well as the Trans-Alaska gas system right-of-way and the ANGTS right-of-way.

MR. BROSSIA made the following comments on the status of rights-of way.

Both the ANGTS route and the TAGS route have federal rights-of-way in place. They also have a couple other important documents in place. In order to get those federal rights-of-way, you're essentially, as John mentioned, going through the National Environmental Policy Act or what will become the EIS process. Both of those projects have EISs in place. They have another significant document in place, they have under the Alaska Natural Gas Act, they have a presidential claim. And that presidential claim [indisc.] for both projects so

those are significant documents. The right-of-way that BLM issued to the TAGS project required a presidential decision - again, the process.

The third project that we recently started to look at, and we're not fully geared up to [indisc.] but the owners, Phillips, BP and Exxon's gas project. We just recently started meeting with those folks. They would be required to go through a pretty similar process to what John outlined, with the exception that instead of the Outer Continental Shelf laws, we would be using the Minerals Leasing Act of 1920. Again, BLM would - once we receive an application that would trigger the legal process it would probably require an EIS. Again, as was discussed, any new project would also look at some kind of a permit with FERC. The other two projects have the usual permits from FERC. The Corps of Engineers would also want to be involved and we would also be involved with the state as far as issuing a right-of-way. When these projects come through the Joint Pipeline Office, in the past, we've looked at it as one process with many steps. In this case, the two primary drivers for a new project, obviously for the [indisc.] as well as the right-of-way, both again would trigger the EIS process, both would be coordinated with the state right-of-way process as well as the CZM being done by the Corps. I don't have prepared remarks but I am willing to take questions on how we've worked on these projects in the past.

3:57 p.m.

CHAIRMAN TORGERSON asked whether either department has geared up for pipeline applications by hiring staff or doing studies.

MR. BROSSIA said that both the BLM and MMS have policy quotes just coming out of Washington, D.C. They have formed several task forces to look at various aspects of the project. While the Department of Interior issues the right-of-way for the ANGTS project and BLM was the lead on the TAGS project, the Office of the Federal Inspector may or may not be resurrected as the overall lead agency on the ANGTS project. That is being discussed now in Washington, D.C.

Locally, BLM has been looking at the status of each project and developing a project RIK plan, a project legend, a project schedule, looking at agreements with the State of Alaska and other federal agencies and developing a budget and organizational plan. BLM has met with the owners three or four times and discussed their

need to do field studies in preparation for EIS and right-of-way work. Some of BLM's district offices have issued permits for stream studies. BLM is in a very preliminary stage of looking at this project.

MR. BROSSIA said if BLM is chosen as the lead agency on a new project or on the ANGTS, it would use the joint pipeline model, which has been fairly effective over the last 12 years. BLM would probably spin off of [indisc.] and work with the state on that. However, they have not finalized any plans.

4:00 p.m.

MR.GOLL said, likewise, the MMS has not hired anyone at this point. MMS met with the producers who wanted to know what kind of information they would need to collect for the surveys he mentioned. They plan to do the surveys this summer and need to collect information for alternative plans. MMS does have a representative on the Department of Energy group but, overall, they have been very low-key and will continue that way until the direction is decided upon. He noted the MMS has a process so that several models could be used and can foresee taking the lead on the EIS.

CHAIRMAN TORGERSON asked if one of the producer groups filed under the Natural Gas Act or anything besides ANGTS, whether BLM would require a presidential decision before proceeding with that application.

MR. BROSSIA said that has been the past practice. That was a condition for the right-of-way permit for TAGS. He would recommend it.

CHAIRMAN TORGERSON asked about an offshore application.

MR. GOLL said he was not sure. That is one thing the DOE group could look at. He guessed the answer would be no.

CHAIRMAN TORGERSON asked if the original 1977 presidential decision to deny the ANWR over-the-top route that was onshore would hold for the offshore route, or whether the offshore route substantially differs enough that the original decision would not apply.

MR. GOLL said he did not know.

4:02 p.m.

REPRESENTATIVE OGAN referred to an earlier slide shown by Mr. Goll about limitations in the Lower 48. He added the numbers and calculated that 188 to 206 TCF are off limits. He asked what percentage that is in comparison to the total reserves.

MR. GOLL explained those are not reserves in the sense of being discovered, they are potential.

REPRESENTATIVE OGAN asked if about one-half of it is off-limits.

MR. GOLL said that probably 20 to 25 percent is off limit. He said the point he was trying to make is that the areas that need gas, particularly the East Coast, are not looking to produce local gas. Alaska gas will probably end up in the Midwest and West, but right now some of that could be heading toward the East Coast where there is a great peak. Likewise, there is gas off of the west coast, but they are not looking to use it. He added that it would be easier to produce locally, but many areas of the country are not going in that direction right now.

REPRESENTATIVE OGAN asked if that gas is off limits because drilling would raise environmental concerns. He noted gas is probably the safest thing to drill.

MR. GOLL said that is correct, but people are concerned about oil spills on beaches.

CHAIRMAN TORGERSON thanked Mr. Goll and Mr. Brossia and asked Mr. Britt to testify.

4:05 p.m.

MR. BILL BRITT, Gas Pipeline Coordinator, Department of Natural Resources, informed committee members that he distributed a packet of information, including his written testimony. He gave the following synopsis of that testimony.

There are three modes available to move gas out of Alaska: pressurized natural gas, LNG, and gas to liquids. Four routes are being discussed: Prudhoe Bay to Prince William Sound; Prudhoe Bay to Kenai; the highway route; and the over-the-top route. He counts at least eight projects with groups of proponents:

- Yukon Pacific TAGS project;
- ANGTS route;
- A producer group of North Slope natural gas producers (BP, Phillips, Exxon Mobil);
- A sponsor group led by Phillips that includes Foothills and BP;
- The Alaska Gasline Port Authority;
- The Cook Inlet pipeline terminus route;
- The Municipal Energy Resource Group (MERG), which advocates the over-the-top route;

- BP gas-to-liquids plant.

TAPE 01-04, SIDE A

MR. BRITT emphasized that neither routes nor modes are being exclusively considered and that more than one project is certainly possible. Two of the pipeline projects have received right-of-way and other permits from both federal and state agencies. Foothills has received various permits for the ANGTS route. BLM completed an EIS for the TAGS route and granted Yukon Pacific a right-of-way in 1988. The FERC EIS on the Anderson Bay terminal was completed, the presidential finding and export license is in place and a conditional state right-of-way was issued and renewed. He noted that Section 2 of the conditional lease pertains to the requirements of the conditional state right-of-way.

For the ANGTS route, BLM completed an EIS and granted a right-of-way in Alaska in 1980. A treaty between the United States and Canada was signed in 1978, which sanctions the project, and Canadian permits and approvals are in place. The state right-of-way process was begun, but is not completed.

The state right-of-way process is described in the Right-of-Way Leasing Act (AS 38.35). The steps are:

- Public notice of an application;
- Analysis of the application;
- Negotiation of a draft lease;
- Preparation of Commissioner's analysis and proposed decision;
- Public notice of the availability of the Commissioner's analysis, proposed decision and public comment period;
- Public comment period and public hearings;
- Consideration of comments;
- Preparation of final decision; and
- Execution of the right-of-way lease, if that is the final decision.

MR. BRITT said the right-of-way lease is one of a whole variety of requirements that would come into play with a project this large. The Producers' Consortium consultants recently issued a draft report entitled, "Data Review and Permitting Requirements." Their list of permits, approvals and consultations for one or both of the routes contain 29 categories of federal authorizations, 22 categories of state authorizations, and 8 categories of local and private authorizations. Each of these categories would have anywhere from one right-of-way lease to many land use or water use permits. These lists are incomplete as they only considered the pipeline and gas treatment plant and not associated or support facilities, such as compressor stations, construction camps, access roads, material sites, disposal sites, staging areas, and other

temporary use areas.

MR. BRITT noted another frequently asked question is how long it will take to permit a project. That will depend on two variables: the applicant's ability to provide information in a timely manner and the federal approval process. A reasonably ambitious schedule would be in the 18 to 24 month period. On a project-by-project basis, this will be highly variable and will be based on the amount of work that has already been done and the controversy associated with it.

MR. BRITT said regarding what is happening now, Yukon Pacific submitted a refined pipeline centerline alignment for the TAGS project on July 2. It is being reviewed in the Joint Pipeline Office and it may or may not result in amendments to the federal and state rights-of-way. Regarding the Alaskan Northwest Natural Gas Transportation Company (ANNGTC) project, they requested that the state proceed with processing their application, which it did on March 6. He requested ANNGTC to identify documents relevant to their applications. ANNGTC responded on July 2. He said he made that request because he has no estimate of the tons of paperwork relative to the ANNGTC's project that was processed 20 years ago. It seemed more expedient to ask ANNGTC to let him know what it considered to be relevant in this point in time. He has not finished reviewing those documents yet. In summary, ANNGTC completed a large amount of work relative to their right-of-way application.

MR. BRITT said the Alaska Gas Producers Pipeline Team (AGPPT), the producers' consortium, has about 90 personnel. They've awarded about $75 million in contracts for feasibility work. The contracts they've issued have been for pipeline engineering, gas treatment facility engineering, natural gas liquids extraction facility engineering, environmental and regulatory work and land status work. The number of people involved is very, very large. For example, the two prime contractors for the U.S. environmental and regulatory issue have 11 specialized subcontractors and, according to the producers, they have over 500 full-time equivalent people engaged in these efforts right now. On July 6, the producers provided a list of field studies for the summer. There are 21 studies in Alaska, several of which have been completed, some are in progress, and many have not begun. The state has begun processing the permits necessary for them to do this work. They need a collection permit from the Alaska Department of Fish and Game (ADFG) for the drain work. The Pipeline Office has communicated its expectations of the studies to the producers.

MR. BRITT said the sponsor group is continuing to assess the feasibility of the Kenai LNG project. He has proposed that they start assessing markets for LNG, exploring possible synergies for the highway project and working to reduce the contingencies for

their project plan and thus increase the commercial viability. He has also been told their consultants recently completed an environmental and regulatory evaluation of the project with the emphasis on permitting of the Parks Highway Route. Depending on the conclusion of that study, he would expect to begin contact with them.

MR. BRITT noted the State Pipeline Office has had very little contact with the Port Authority, the Cook Inlet Terminus Group or the over-the-top route. Regarding a brief overview of state government, his specific role is defined by Administrative Order 187. He has been directed to coordinate state permitting and authorization processes and to lead communications and coordination with federal and Canadian agencies related to permitting and authorizing projects. He included a document in packets entitled, "Gas Pipeline Office - Anticipated Pre-application and Application Processing Tasks for FY 2002." It contains a list of short-term tasks that are associated with the roles.

The point of these tasks is to positively affect the time required to permit the project by integrating the state and federal government processes, as was done with the Joint Pipeline Office. They also want to make the permit authorizations more responsive to Alaskan interests when they are issued by others and they want to make the financial return on the project greater for the state. Progress on these tasks has been limited due to a lack of funding and lack of staff. He does not have a funding source at this time, but perhaps will get one during the upcoming Legislative Budget and Audit meeting. The limited funding provided in the last fiscal year allowed the hiring or assignment of liaisons from DEC and ADFG, an ADFG field leader and his position. Existing staff in several state agencies are performing very limited gas pipeline work, paid for with discretionary funding. He has negotiated reimbursement MOUs with Foothills and with the producers for the tasks on the list. He cannot execute those agreements until he receives funding from LBA.

MR. BRITT noted the staff at the State Pipeline Coordinator's Office made remarkable progress in collecting and organizing ANGTS files. The Gas Pipeline Office (GPO) staff is working with Foothills and the producers to move their efforts forward. He has received expressions of interest in GPO positions from a number of excellent candidates, which he is very happy about. In addition, he has found inexpensive housing for the office until the end of the year. Hopefully, they will move into those temporary, but co-located offices, in August.

In conclusion, MR. BRITT said a lot has been happening and the pace of proponents' efforts is increasing. If general funding for the GPO is approved, he will sign reimbursement agreements with Foothills and the producers. They will then begin a detailed work

plan and hiring to support the work plan. If general funding is not approved, the state will continue to fall behind the proponents, both in the staff necessary to process their authorizations and, of particular interest to legislators, in the knowledge necessary to promote state interests. He offered to answer questions.

CHAIRMAN TORGERSON thanked Mr. Britt for doing such a great job. He noted that he participated in the memoranda of understanding (MOUs), as that was part of the legislation he worked on this session. He also does not anticipate a lot of opposition to Mr. Britt's request to receive the funding through the MOUs as they relate to what the producers are willing to pay for. He pointed out the percent the producers are willing to pay for differs from the percent the administration wants to fund and that is what they are trying to work through. Another problem he has is in regard to interaction with the administration is the legislature's lack of access to documents that it is funding. The legislature has found it is running a parallel course, to some degree. He does not favor putting more money into that kind of a procedure. He would rather fund the studies directly through the Legislative Council. He told Mr. Britt the general fund request is above and beyond what the producers are willing to pay for. So, LBA is questioning why it should fund things that the producers are not willing to pay for. He asked Mr. Britt to be prepared to explain the difference to the LBA Committee.

4:21 p.m.

The committee took a short recess.

4:30 p.m.

ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

CHAIRMAN TORGERSON called the meeting back to order and welcomed the members of the Governor's Alaska Highway Natural Gas Policy Council (GAHNGPC). He introduced Mr. Frank Brown, Co-Chair of that Council, and noted that Mr. Sampson had to be out of town today. He asked Mr. Brown to proceed.

MR. FRANK BROWN, Co-Chair, Alaska Highway Natural Gas Policy Council, informed committee members that Jim Sampson could not attend as he was called out of town on family business. He explained that Governor Knowles appointed 28 Alaskans to the AHNGPC in January. The group's mission is to develop recommendations promoting a natural gas pipeline project that maximizes the benefits to all Alaskans. The AHNGPC will formulate its recommendations and report back with its findings on November 30. Since January, because the group is so large, members spent time getting to know each other, learning how to work together and

educating each other. The group's task is formidable so a key part of the early stage has been educating the group. The group has also been engaged in a public process in which it has been going out and sharing information with, and listening to, the public. To handle so many issues, the group was divided into five subcommittees. In addition to the public meetings and subcommittee work, the AHNGPC has held statewide hearings in Fairbanks, Kenai, Tok and Anchorage and it will travel this summer to Barrow, Juneau and Southeast. He noted he would introduce the members and ask them to discuss their work, and then AHNGPC members would answer questions. Mr. Brown commented that the 28 members and four ex-officio members of the Legislature have no staff so they have been working very hard.

MR. BROWN introduced Bill Corbus, who is chairing the State Pipeline Ownership and Tax Structure Subcommittee; Mayor Rhonda Boyles, who is on several committees; Jack Roderick, who is involved in the Access of In-State Gas Use and Future Opportunities Subcommittee; Charlie Cole, who is chairing the Federal-International Action Subcommittee; and Mike Navarre, who is chairing the Alaska Hire/Buy Subcommittee.

MR. MIKE NAVARRE informed the committee that he asked to serve on the AHNGPC because, as a former legislator, he couldn't resist the opportunity to keep an eye on the Administration and because he wanted to be involved on the policy level to make sure the project is done right and will benefit Alaskans. The Alaska Hire/Buy Subcommittee is focusing on several things. First, it wants to identify what type of training will be needed for workforce development and to identify the numbers of the necessary workforce. The Subcommittee is also looking at socio-economic studies and it is trying to dovetail those with other studies related to GARVEE bonds, and other work and at the potential impact to the communities and to the state. The Subcommittee will make recommendations and have a report ready that the legislature or anyone else can use.

MR. BILL CORBUS informed the committee that, in civilian life, he is the President of Alaska Electric Light and Power Company in Juneau. He believes it is important that everyone get behind the gas pipeline. He is chairing the Subcommittee on the State Pipeline Ownership and Tax Structure. The Subcommittee is made up of six members who have met with the Alaska Permanent Fund Corporation (APFC), the Alaska Industrial Development and Export Authority (AIDEA) and Department of Revenue staff to discuss various aspects of financing the pipeline. The Subcommittee will also be gathering ideas for the tax structure.

MR. JACK RODERICK informed committee members that he has been helping Ken Thompson, who chairs the Subcommittee on Access for In-State Gas Use and Future Opportunities. He noted that Carl Marrs

also had a committee, but the two were merged with a new emphasis on in-state access to gas. The Subcommittee heard testimony in Fairbanks about the use of gas, which was quite impressive. DNR is doing a study on in-state use. The Subcommittee is looking at LNG and GTL projects. He said he believes Ken Thompson was correct when he suggested the subcommittee should be thinking about the use of this gas 50 years down the line. He suggested that legislators put on their business hats as the state will be in the business of gas and that negotiations will be coming on down the line with the producers and gas owners. He believes it is critical that the legislature and administration use a partnership approach on this issue. He pointed out that the Governor has given the Council carte blanche to conduct its investigations on a natural gas line. The Governor has not given the AHNGPC specific mandates or said that he wants certain results or information that exclusively favors the highway line. The Governor has only said that he believes that is the preferential line. Beyond that, the AHNGPC will provide the state with the information it develops. The AHNGPC certainly wants to work with the legislature. He believes it would be disastrous for both bodies if they do not cooperate fully. He pointed out that no one on the AHNGPC is getting paid for the time they are putting in on this project. He noted that two members of his subcommittee are super lawyers, who are getting a workout. The subcommittee has also met with Bob Loeffler of the Division of Mining, Land and Water, and John Katz in Washington, D.C.

4:43 p.m.

MS. RHONDA BOYLES informed the committee that she serves on two subcommittees and had two points to make today. One is that the importance of the gas pipeline rises above any party politics or the issue of administration versus legislature or Native versus non-Native. She said, "We have to worry about the entire state." Second, she said they need to share good information and not spend time being redundant.

REPRESENTATIVE GREEN asked if sharing of information includes the legislature.

MR. BROWN replied that was his understanding.

CHAIRMAN TORGERSON said he was concerned with the legal end of things and that the legislature does not have access to studies they have funded for the administration. He said they probably get the same paperwork from the producers. He asked Mr. Corbus if he was looking at incentives the producers might want.

MR. CORBUS replied they would be looking at the tax structure.

CHAIRMAN TORGERSON asked if he would look at the ELF or royalty tax. He said that experts in the administration would not share

that data with the committee.

An unidentified person said the producers don't really know the economics of the processing plant or the line yet.

CHAIRMAN TORGERSON said his question didn't have to do with the plant. He stated, "We know in the early '80's the cost of the plant was included as part of the tariff. There is no alliance yet and there is no tariff."

His question had to do with other companies downstream that may have their own conditioning plant. He wanted to make sure the state was not locked into a tariff on a conditioning plant where somebody else can probably build their own. It's a question that has been posed to him by other producers.

MR. NAVARRE said his committee was looking at tax structure policy.

MR. KEN THOMPSON spoke to the issue of the processing plant:

> That's an important issue that we really need to look at legally as well as what the leases allow for. For example, some North Slope leases were modeled after the Texas Oil and Gas Lease Law. No state leases in Texas conditioning gas for market is often considered on the lease as lease cost and is not included in pipeline tariff calculations. However, if there's a situation where you have a lot of leases and it's not economical on one to put that plant, sometimes a pipeline consortium would build that and that can be included.
>
> I think we'll need to review the Prudhoe Bay leases and see, but I think there may be some clauses in there that really dictate that it not be in the pipeline tariff or it could be the other. This is an issue we haven't examined yet, to my knowledge.

CHAIRMAN TORGERSON said he understood that an amendment to the presidential decision allows that so, it probably will not show up in a Prudhoe Bay lease. He commented, "It still needs to be looked at."

MR. THOMPSON informed the committee that he chairs the Instate Gas Use Committee. It has looked at the Anchorage Economic Development Corporation's study on Cook Inlet gas supply for the Anchorage area. An Enstar representative stated during testimony at an AHNGPC hearing that a major concern for Anchorage residents is that by 2007 or 2008, deliverability of the Cook Inlet reserves will fall below the projected needs at that time. While reserves will be there, deliverability will fall short of demand. At that point, things have to be done, such as storage or whatever. He commented,

> Those solutions will likely be costly and will increase, we think from our committee's viewpoint, the cost of natural gas in Anchorage. That will affect businesses as well as citizens.

MR. THOMPSON said that by 2017, the deliverability problem of gas becomes even more extreme. To solve that problem would cost even more because of costs associated with increased exploration, exploration incentives, gas storage and bringing in LNG. He noted:

> We believe bringing natural gas down from the Slope through a spur line off the line that goes south would really allow gas prices to be much more reasonable for all Anchorage residences and businesses. This whole thing of south or north interestingly in my own mind is becoming clean energy, self-sufficiency for Alaska. If it goes north, we will not have clean energy, self-sufficiency 10, 20 or 30 years down the road. If a line comes south and we can build spurs off of to our major interior cities, Anchorage and other locations, we can have that self-sufficiency. What a shame to have a huge resource if our own state cannot be self-sufficient in energy ...
>
> Another thing - we have this in the state of Texas to see how they handle their royalty state leases. We found that they market about 50 percent of their royalty gas in-kind, market it themselves, use a portion of it to generate electricity for state government buildings and schools. It's trimmed their electricity bill by 30 percent for the state. They also allow 50 percent of the royalty gas to be sold by the producers. Fifty percent of the time they're able to get a higher netback price than the producers. That's an interesting observation and we will examine that as kind of an option for Alaska's royalty share of gas, as well ....

REPRESENTATIVE FATE said he noticed when reading a report on one of the charts on the chemical industry based on the liquid components of gas (ammonia specifically), that it's either moving overseas or it's in danger of moving overseas permanently. He asked if that creates a vacuum that could be filled by a chemical industry in this state.

MR. THOMPSON replied that they are looking at that issue and whether there can be value-added processing for petrochemicals, expansion of fertilizer and potentially some limited LNG to the West Coast or to very select Asian markets on a smaller scale than a large Valdez project, but viable. Petrochemicals, such as olephins, are made from natural gas and are used in feed stocks.

Asia has a rapidly growing need for more olephins. Japan has expressed interest in DME (dymethyl ether), which is used like a propane butane (LPG). Williams Energy testified that they had an internal study that assessed a broader natural gas liquids business within Alaska.

REPRESENTATIVE GREEN said 20 years ago Dow Chemical was looking at the possibility of a petrochemical plant at Fire Island and that met with a lot of resistance, but he was thinking of something like that. He asked if it was within his committee's purview to study a line to Kenai.

MR. THOMPSON replied yes. They are looking at a spur line into Anchorage for domestic use and if that takes place, there could be an additional spur off of a hub that would go to Kenai for a natural gas refinery. They are assessing whether that would be economical. He said the Dow study looked at an assessment of not shipping natural gas, but instead taking all the natural gas liquids like propane and butane out on the North Slope and shipping down a separate liquids line to Fire Island and some other locations. His committee is looking at something different like taking the gasoline itself and manufacturing some of the other products he described. They are looking at the Kenai Peninsula.

REPRESENTATIVE OGAN said, "Don't rule out Pt. Mackenzie."

MR. THOMPSON said that was an excellent point.

MR. BROWN added that everyone needs to recognize that there is a market window out there and it's going to get subdivided. He commented:

> If we're not part of the solution, something else will be - nuclear, LNG from other sources, plane coal technology, whatever ... We should all work together to make sure Alaska's North Slope gas is ready.

CHAIRMAN TORGERSON thanked everyone for their participation and announced an at-ease from 5:03 p.m. to 5:06 p.m.

MR. HAROLD HEINZE, resource consultant for the Legislative Majority, said he is under contract to help evolve alternative strategies on the gas issue. There are three major areas where studies are not being done or they are way behind. He stated:

> Number one is, I was struck by the fact that we need to seriously understand the state of Alaska as a shipper and in a strategic sense, what we would achieve by being a shipper. Frankly, we need someone in the state government to kind of look at that as almost an advocate and develop that idea. I think it is almost intuitively obvious that

we would get many of the same benefits from ownership as you would to be a real shipper in the pipeline. It's something you could probably manage as a business a lot easier than investing millions of dollars. It would help a lot on the access issue that we were concerned about this morning. So, there are some real payoffs there.

Clearly, being a shipper under federal law gives you special standing before FERC and what I mean is if the State of Alaska [was] to make modified contracts contingent on [indisc.] in Fairbanks, [indisc.] city of Chicago, for instance. That might be an interesting position to be in as far as all the FERC proceedings and all the other things that would happen. The producers would have to deal with you as another shipper and not be discriminated against in terms of [indisc.].

I also noted that the state is not using a royalty board. If you look back, there's a reason the Royalty Board was put in place and it would really be a pity if the seller of gas would make the same mistakes we did on [indisc.]. Whether it's Netricity or whatever, it seems to me those are triggering provisions and we should be using that.

CHAIRMAN TORGERSON said the resolution that required them to look at the Netricity proposal directs them to use the process that's in place, which is the Royalty Board. He said, "So, we have not forgotten."

MR. HEINZE said he knew the Chair had not forgotten, but he was surprised that there was no mention of it. He stated:

The second broad area that I notice is from a strategy point of view and trying to look at the gas issue. It's obvious that we're trying to maximize the benefit and minimize, eliminate or mitigate the impacts, the negatives.

MR. HEINZ said that there are human impacts as well as environmental and the TAPS experience is fully documented showing a good idea of what all the impacts are for a large project. He didn't see anyone studying them. He asked, for example, what is the impact on school systems and public facilities like airports and roads - and how to pay for them. Those issues need to be reduced to dollars so you know if they have a big or small price tag.

Finally, MR. HEINZE said he was struck by what he didn't hear from the AOGCC. While FERC is going to dominate the regulation of the interstate molecules, there's not one molecule coming out of those wellheads that is going to be sold until AOGCC changes its rules.

The reason that's important is that the [indisc.] rules right now prohibit gas sale. He said that creates a huge range of uncertainty until this gets resolved. He said he looked forward to working with the committee on these issues to get something done.

REPRESENTATIVE GREEN said he thought he was right on the gas sales and asked how they circumvented that by spiking the oil with gas liquids.

MR. HEINZE replied that the original definition of oil in the TAPS provided for 90 percent crude oil and up to 10 percent natural gas liquids. There are also minor gas [indisc.] that occur in the field right now, but no one has questioned those volumes.

Public Testimony

CHAIRMAN TORGERSON then took public testimony.

MR. SCOTT HEYWORTH, Citizens for the All-Alaskan Gasline Initiative, gave the following testimony.

> The State of Alaska, both the administration and the legislature, must insure that the new Prudhoe Bay unit operating agreement is a public document and here's why. The hydrocarbons at Prudhoe Bay remain Alaska's single largest and most valuable natural resource. Right now nobody outside the producer companies knows anything about the underlying intercompany contractual arrangements governing its operation and development. The Prudhoe Bay unit members stated in 1996 in hearings before the AOGCC that the Prudhoe Bay operating agreement in no way inhibited a major gas sale. In 2000, they announced that they had totally realigned the oil and gas interest to remove all the major conflicts and impediments which were not even supposed to exist at all.
>
> If it wasn't broken in 1996, why was it changed in 2000? Is realignment of those interests the only thing that changed with the new ownership arrangement and operating structure and has realignment actually even taken place? The State of Alaska simply cannot allow the basic tenets governing future control of its single largest revenue resource to be confidential. I urge you to ask the appropriate industry witnesses tomorrow when they testify just exactly when the state and the citizens of Alaska will have our opportunity to examine and judge this critical agreement. It is the most important question and one that you must ask them tomorrow and hope we will get an honest answer.

REPRESENTATIVE OGAN said he plans to follow up on that issue.

CHAIRMAN TORGERSON thanked everyone for sitting through this marathon and adjourned the meeting at 5:17 p.m.