ALASKA STATE LEGISLATURE
JOINT COMMITTEE ON NAUTRAL GAS PIPELINES
November 8, 2001
9:00 a.m.

SENATE MEMBERS PRESENT

Senator John Torgerson, Chair
Senator Johnny Ellis
Senator Donald Olson

SENATE MEMBERS ABSENT

Senator Rick Halford
Senator Pete Kelly

HOUSE MEMBERS PRESENT

Representative Scott Ogan
Representative John Davies
Representative Mike Chenault
Representative Hugh Fate

HOUSE MEMBERS ABSENT

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Reggie Joule

COMMITTEE CALENDAR

9:00 - 9:30 a.m.
Department of Natural Resources, Oil and Gas Division

- 9:00 - 9:15 - Bill Van Dyke, Petroleum Manager and Tim Ryherd - Geologist
- 9:15 - 9:30 - Will Nebesky - Cook Inlet gas usage and demand

9:30 - 10:00
Agrium, Inc.

- Chris Tworek, Vice President
- Supply Management

10:00 - 10:30
Phillips Alaska, Inc.

- George Findling, Manager, External Strategies

- Scott Jepsen, Manager, Cook Inlet Asset

10:30 - 11:00
UNOCAL Alaska
- Dan Thomas, Land Advisor

11:00 - 11:30
Citizens Initiative for the All-Alaskan Pipeline
- Scott Heyworth, Chair

11:30 - 12:00
Foothills Pipeline, Ltd.
- John Ellwood, President

12:00 - 1:00
Lunch

1:00 - 1:30
ANGTL Co.
- Richard Peterson, President/CEO

1:30 - 2:00
ENSTAR Natural Gas Company
- Tony Izzo, President

2:00 - 2:30
Evergreen Resources
- Mark Sexton, President/CEO

2:30 - 3:00
Committee meeting

ACTION NARRATIVE
TAPE 01-25, SIDE A

CHAIRMAN TORGERSON called the meeting to order at 9:00 a.m. and gave a brief introduction.

MR. BILL VAN DYKE, Petroleum Manager, Division of Oil and Gas, said he would cover the gas reserves and production, Mike Ryherd would cover would address exploration for gas in the Cook Inlet area, and Will Nebesky would cover the gas supply and demand fundamentals and gas value. He noted a map in their 18-page packets and explained each of the slides, which indicated Cook Inlet gas production and reserves - 217 tcf were net production and 201 tcf was sold and 16 bcf were used in field operations - no big changes from previous years. Most of the gas came from the old gas field that was

discovered in the 1960's. He said there were no surprises on the reserve side. The numbers are down a little bit from the previous year, but that's mainly due to production.

> We haven't added any significant new reserves this year from new discoveries or new developments and with round numbers, 200 bcf production, the number naturally drops year to year until we add new reserves. That hasn't happened yet, but I expect that picture to change over the next decade. We can start adding some reserves to that column rather than just subtracting production every year.

Someone asked if this was his estimate of recoverable reserves or total reserves.

MR. VAN DYKE replied his definition of reserves is what's recoverable gas remaining to be produced. Of the remaining 2 tcf in Cook Inlet he said:

> It's important to understand what this table is and the assumptions that go with it and some of the caveats. The dates are hypothetical. I don't know when certain operations are going to shut down, when and why. I just picked things. The dates aren't unreasonable, but they're not based on gas supply contracts or specific reserve estimates. The consumption numbers are based on how much gas is being consumed today for LNG, the Agrium operation, for field operations.

He explained his slide further. He assumed that Agrium used 55 bcf/y, LNG used 80 bcf/y, and field operations used 15 bcf/y. Assuming those three industrial uses continue, he theorized how much gas is left for the utilities?

If all the industrial gas users and oil fields shut down in 2009, there would be about 1 tcf of gas left for the utilities, about a 17-year supply. "That's great for the utilities, but it's pretty harsh with respect to the industrial operations. That's scenario one."

He walked the committee through scenarios two and three. One scenario assumes that Agrium continues operations like today until 2015, LNG was extended out to 2015. "That scenario breaks the bank. There's literally no gas left for the utilities. In fact, the utilities sort of quit burning gas two years ago if you want to supply that much gas to the industrial uses."

He said scenario four is an exploration success case adding another tcf of reserves. You just assume there's going to be

discovered gas, assume it's going to be produced and you also assume it's going to be produced within that time period, which is a leap of faith, but that's the assumption behind scenario four.

MR. TIM RYHERD, Geologist, Division of Oil and Gas, said he would talk about exploration for oil and gas supplies in Cook Inlet. He also used slides with his presentation showing where exploration activities were occurring right now and by whom. He noted that exploration is on the increase.

He said that basically exploration activity in the Cook Inlet was done in the 60s and he showed a graph of the exploration wells for oil and gas drilled by year. The gas in Cook Inlet was discovered in the process of looking for oil. He pointed out that in the last four or five years four explorations wells were drilled per year and this year it looks like there will be more.

9:23

MR. WILL NEBESKY, Commercial Analyst, Division of Oil and Gas, said he was going to discuss the composition of the demands for gas produced in Cook Inlet and pricing relationships for gas distribution. He started with a picture of historic patterns of gas demand in Cook Inlet and pricing evaluation slides and then went to the outlook. Five major components were represented. LNG, which represents about 36 percent of the total consumption of gas in Cook Inlet has been fairly steady over the past five or more years. The ammonia-urea consumption of gas represents about 24 percent of the total and that's been fairly steady also. Next is gas utilities, essentially the Enstar system, plus some gas consumption to direct users such as Tesoro and that currently stands at about 13 percent of the total and has been steady also. Power generation with Chugach Electric Association plus the Matanuska Electric Association has been about 17 percent of the total demand. Together, the gas utilities, power generation and utilities count for about 30 percent of the total. The last category shown is field operations and other gas consumption for about 9 percent. Field operations use of gas has come down quite a bit and flaring has been cut back.

MR. NEBESKY next had a chart comparing gas produced in Cook Inlet with some Lower 48 benchmarks that might be of interest from August 97 through August 01. The next charts showed royalty values and he pointed out that the values are also driven by settlement agreements that the state has with producers, which supercede the lease. He said the balance between demand and supply of gas is interrupted around 2003 or 2004 pending no further discoveries. If 1 tcf of gas is discovered between now and 2004 and come on line, there is an additional 4 - 5 years of supply that is capable of meeting the demand delivery amounts. In 2009, the imbalance between supply and demand kicks in again. On pricing relationships, he said

the Regulatory Commission recently approved a proposed contract agreement to supply gas to Enstar's from UNOCAL, which includes indexing the price to the Henry Hub. He said they are seeing signals of rising prices in Cook Inlet by virtue of those contracts.

The next chart compared gas supply and demand for various situations in Alaska. The Prudhoe Bay Unit is recycling about 8 bcf/d. The proposed gas line [indisc] and the state royalty share of major gas sale greater than 4 bcf/d would be .5 bcf/d, which is not too different from the total area-wide demand of Cook Inlet, which is about .6 bcf/d.

TAPE 01-25, SIDE B

9:45

REPRESENTATIVE DAVIES asked what kind of use he assumed in the last chart.

MR. NEBESKY replied basically uses for space heating and electricity generation. "Right now there's a modest amount of natural gas use in Fairbanks, based on a small scale local gas distribution company effort. His estimate is based on the potential for expanding and reaching a fairly extensive community-wide space heating demand for Fairbanks.

REPRESENTATIVE DAVIES asked him to estimate the total demand for Fairbanks.

MR. NEBESKY answered at least 50 percent.

SENATOR OLSON asked regarding all the utility cost spikes in slide #17, if he saw legislation coming that would stabilize that volatile market.

MR. NEBESKY replied:

> In the RCA's decision, the public advocacy section made a proposal that would involve a different kind of pricing mechanism that would take into account local Cook Inlet prices to a greater extent than the UNOCAL/Enstar contract. The RCA decided against that proposal. I can't speak for the RCA, but the volumes of gas that would be involved in that particular supply contract would be one piece of a bigger pie of gas supply from the Enstar system, which would involve a variety of pricing points and mechanisms that banded together would tend to provide some stability and over time, some of the contracts of

earlier vintage will expire and be replaced by new ones. This is an example of a new one.

SENATOR OLSON responded, "I guess my real question is what kind of affect will that have on production."

MR. NEBESKY said he knew it was a major driver in creating incentive for UNOCAL to explore and that there was stepped up exploration activity in Cook Inlet today, which he thought was because of anticipated higher prices.

REPRESENTATIVE OGAN asked at what date we couldn't meet gas demands.

MR. NEBESKY replied 2004.

REPRESENTATIVE OGAN asked what happened then.

MR. NEBESKY replied they could anticipate the export license that permits LNG exports will probably be in for a stringent review by the U.S. Department of Energy. The LNG exports are licensed to continue through 2009. In the event that LNG operations cease exporting gas, that would create additional volumes that could be available for local use. "If you take the LNG component out of the total demand picture, you drop consumption of gas in Cook Inlet from 2010 bcf/y to perhaps 130 - 140 bcf/y less."

He said the likely outcome of the forecast that's reflected is continuing upward pressure on prices, which is going to put economic pressure on the industrial uses of gas.

> It's going to affect the economics of both fertilizer and LNG production; and electric power generation and local utility gas use for state's heating will also be affected and we are actually in the course of looking more closely into the instate demands for gas. Currently, we have a contractor employed with the division to investigate instate demand uses and part of that analysis is to examine the sensitivity of consumption to changes in prices - something we hope to get a better sense of.

REPRESETNATIVE DAVIES had a question about page 18, but his question was indiscernible.

MR. NEBESKY responded that he assumed they could get the gas out of the ground fast enough.

> The gas is there as far as gross reserves, but you can't get enough out in a given year. That's the difference. Just one comment on the graph that's up there. The gray

> area does not assume some of the production from some of the areas that are under development today and so, it's a pretty conservative production forecast, because we know that Marathon is developing new areas today - Anadarko, Aurora, UNOCAL is doing some work. It was based on some smaller pools on production soon, which will extend the gray area on that graph outward. We really think that one way or another, there will not be a production shortfall in 2004 and 2005…

SENATOR DAVIES asked what was the typical utility paying for gas now including delivery.

MR. NEBESKY replied that the red line in cell 13 shows the average royalty values for gas dispositions to electric utilities. "So it's about $2.50 currently."

REPRESENTATIVE FATE said he heard him say the consumption in Fairbanks is .045 bcf and asked if he modeled demand given a flat production without any other gas coming in from the North and had he done any modeling for future demands of not just the Fairbanks areas, but the rest of the state.

MR. NEBESKY replied that that effort was currently under way.

> As part of the study of instate gas demand, we're exploring the potential demand and the potential for gas related fuel switching opportunities in communities in the proximity of the pipeline route as well as communities further away that could in fact utilize a propane product generated from processing of natural gas. We're exploring the nature of demand in smaller communities as well as Fairbanks in and around the Fairbanks area and the different kinds of energy options that may be available that are tied to the major gas sale and the gas line project. We hope to have more on that topic before the end of the year.

CHAIRMAN TORGERSON said:

> I'm not totally thrilled by RCA's decision to tie this to the Henry Hub. For Kenai Peninsula folks, with the industry base use of gas and now to have it reflect sales in the Lower 48 instead of Cook Inlet puts our industry potentially in jeopardy if we are a long term high priced…. We're reminded constantly - In fact I got a note from past Mayor [indisc] that Agrium is our largest employer and as great a corporate citizens, as well as Phillips. Those industries are on the line. I'm not sure

> the RCA in their decision, just based upon their wording that they want to drive prices up so it will spur production is the proper way to work with supply and demand curves through a regulatory agency. I can see a prudent contract and other merits, not on the merit that we want to drive the price up. Having said that, I wondered if you can chart out the price using the historical price in the 92 slide, using the Henry Hub pricing and let us see the difference in that with Agrium and LNG so we could see what that increase would be.

CHAIRMAN TORGERSON said he was trying to understand what using the Henry Hub would mean with the thought of what the legislature can do, if anything.

One of the Department of Revenue people said Enstar's demand substantially swings between summer and winter. "So, they are a hard customer to satisfy."

CHAIRMAN TORGERSON said that a low commodity like fertilizer would not survive high prices, unless one could drive the commodity market up to compensate.

10:02 - 10:11 BREAK

MR. CHRIS TWOREK, Vice President, Supply Management, Agrium, Inc., said the simple message behind his presentation is:

> Agrium makes a significant contribution to this community and we'd certainly like to expand and maintain that contribution. We realize we are in the international commodity business and it requires us to be more efficient to find ways of expanding our production. We realize this is a very complicated situation on how to improve our situation here. We would like to propose solutions and not just talk about problems. We think that there is a partnership that can be had here among the producers, government and ourselves to seek that solution and that's what my presentation is about this morning.

He wanted to talk about Kenai Nitrogen Operations, world competitiveness and issues that other speakers have brought up, the Alaska situation specifically and potential solutions.

> Agrium today is one of the world's largest fertilizer producers. We've got 14 production facilities stretching from Alaska down to Argentina through Canada and the Lower 48. While we're primarily a wholesaler in the world, we do have a retail division in the states, which

is the second largest, about 226 outlets that stretch from California to the eastern seaboard. Our sales are above $2 billion. While we're primary in all the nutrient groups - phosphate, potash, sulfate - we're predominantly a nitrogen company. Today we are the largest nitrogen company in the world with all of our ammonia and urea.

Generally speaking, very large world scale facilities - we really thrive on efficiency, low cost. Most of our plants are very strategically located near key markets and lately what we've been doing is moving from the continental North America into the offshore. This is why we want this facility here in Kenai and why we built the one we did in Argentina. Also, a highly skilled force - we've got about 5,000 employees world-wide and we've got a very strong commitment to both safety and the environment.

Let's just turn to the Kenai nitrogen operations. There might be some facts that you don't quite appreciate about this facility. This facility produces six percent of all the nitrogen that is made in all of Canada and the U.S. So, it's a very major facility here. You can see the products - ammonia and urea - and we do consume that 50 - 55 bcf/y of gas. We've got 300 full-time highly skilled employees at any point in time; we have at least 30 contractors on site, also. Our primary markets - and here's what's very important - and you'll see this as we get into competitive study a little later on - but, our primary markets for ammonia are Pacific Rim, predominantly Korea. Our urea goes to Mexico, South America, Taiwan and Korea.

I'll talk about this a little later on, but you'll notice that the Lower 48 and Canada are not in that marketplace. Our competition comes from the former Soviet Union (FSU), South America, Trinidad and the Pacific Rim. There's been many new plants. They're slightly more efficient than what we've got here. They've been built in the last decade. Generally speaking, the world product prices tend to be capped by trapped gas economics.

I do want to focus on what Kenai does contribute to the local economy. Obviously, we're probably the largest local employer. If not first, we are definitely second and again we've got those 300 highly skilled employees. We've got various donations and sponsorships, because we really do care for our communities - everything from

caring for the Kenai United Way, the Challenger Learning Center, the Boys and Girls Club, and again we've got that commitment to safety and environment.

I want to focus on the chart on the right of us. We spend something like $130 million and most of that is on gas power and pipeline, at least $70 Million. This year it's a little bit more than that, because some multipliers are gas contracts. You can see the wages and benefits - $25 Million that our people earn here. Property tax is about $3 million, federal taxes and, yes we do pay tax, is $18 million and other local spending $14 million.

What we've done here is we've only pointed out what we've spent. Most economists will talk about a local multiplier affect and depending on the category, it's anywhere from 2 - 6 times. The simplest way of thinking about it is the wages and benefits where $25 Million in this community supports a lot of other businesses surrounded by other activity.

Let's turn to world competitiveness. What we have to appreciate is that nitrogen is a world-traded commodity. It is really one of the easiest ways to monetize gas and move it around the world. In fact, once you've built your ammonia and urea plant, and if it's on tidewater, for $15 - $50 per ton, you can move that commodity right around the world very quickly. You'll see a little later on in this presentation what that really means in terms of world trade. The reason high gas prices in North America caused a lot of stress on the nation in production, a lot of it became uneconomic. North America does produce 14 percent of the world's nitrogen. However, when you saw some of those peak prices in previous presentations that caused up to 50 percent of North America production to shut in. The other thing you'll see in the balance is that not only was U.S. industry hurt in terms of having to shut down, but market was replaced by imports from offshore. The other key thing, especially concerning royalties and other multiplier affects on the economy is that gas producers lost sales during that period. Some of the demand destruction is still happening in the Lower 48.

Why does that happen? Let me explain in more detail why gas price is very key. Ammonia takes about 33 - 34 MMBTUs per ton of gas at any point in time depending on its price, about 75 - 90 percent of the cost of producing a

> ton of ammonia. This chart displays what really happened in the Lower 48 in the past year or so. [He continued explaining the chart.]

He said that plants in Saudi Arabia and Malasia can make ammonia for about $60. One of the columns on the chart shows what a dramatic impact a $5 gas price has. On the average, that's where the price has been in the Lower 48, notwithstanding a $10 spike. Mr. Tworek continued to review his slides of the international competition saying that the new plants being built in Indonesia and Malasia are in the $1 range. He reiterated the message that their prices are based on international markets and not some higher prices in the Lower 48. One of the reasons they are not selling to the U.S. is the Jones Act, where the United State requires a U.S. flagged vessel to move between U.S. ports. Today there is no U.S. flagged vessel for conveying ammonia. He explained:

> So, even if we wanted to sell ammonia, there are other restrictions…. It is easier for us to take ammonia out of our other plants,…buy it on the world market and move it to the states than take it out of here. Urea is still one or two sea-going barges, but there's really no other long carriers.

MR. TWOREK said that they want to continue to move ahead and do something positive about the business and there is expansion opportunity. Cook Inlet is close to the Pacific Rim markets, has a very good business climate, very skilled work force and today they have world scale clients. However, if they leave it the way it is, it's not going to be competitive. This plant is not the most efficient plant in their circuit. It's about 10 percent defensive in terms of efficiency just because of the year it was built. It needs to be updated. Today they use 50 - 55 bcf and have drawn up various expansion plans for over a five-year period and could easily add another 30 bcf.

> From the forecasts we've seen today, we'd be hard pressed to commit another $2 - $3 MM to the plants based on those gas outlooks. If you're going to spend that kind of money, you expect 15 - 25 years of economic life out of your facility. So, we do have to find a solution for this. Also, from what you've seen [indisc.], our base of 50 - 55 means a long-term extension.
>
> What are the benefits to Alaska if we do some of this? Well, obviously we're going to continue that contribution of $130 MM and grow it; we're going to increase the sales and exports; we're going to expand the field employment base; we've got greater community investment; as much as I hate to pay taxes, it does increase the tax base; and

it encourages gas exploration and more importantly it also opens up other industries to the export market. Every time we put an Alaskan name on that molecule and send it around the world, it opens up markets for other products. However, unfortunately, we are in the international commodity business. We've got to be competitive. I'd love to be able to pay extremely high gas prices, but you've seen the charts. It's not to be. So, we have to figure out a path to get there.

MR. TWOREK said a possible long-term solution would be a spur from the gas pipeline.

Coal bed methane could add another 8 - 250 tcf and if nothing else, could augment the utility supply or be the utility supply. Escopeta - no one is sure about that today. There could be another 5 - 18 tcf there if they're even half ways right. Even if they're only right by 20 percent, that's still a significant amount of additional gas that's not in today's estimates.

He said they're trying to set up a partnership; Agrium is willing to put up some preinvestment. It has to have the appropriate risk/reward ratio.

What we have done in the past is bought pregas production. We've invested in infrastructure like pipelines. We have done exploration and drilling partnerships. This is a way to reduce the risk for the explorer. It is a way of putting some more cash flow on the table to allow them to do that kind of exploration. It's extremely helpful [indisc].

There's other things. We've noticed that some of the larger producers have approached the state about potential royalty relief, something about three years for new drilling. We would certainly be supportive of something like that for any explorer.

The point we also like to make is we've got to be careful. You've seen the charts where the gap between the utility gas and the industrial gas has opened up and with paragraph 36, that could expose industrials to a higher royalty load than they now pay. We've got to be careful that extra tax does not reduce the competitiveness. So, we'd really like to see that royalties be kept at the existing level and be based on actual contracts or at

least some volume weighted price rather than just being exposed to the highest possible prices in the Cook Inlet.

The other thing that we talked about and this works more for North Slope gas, but it's the purchase of state royalty gas for industrial purposes and obviously supporting that North Slope spur line. All those things and anything else that the department suggests we're willing to work in a cooperative partnership to see if we can come to a solution to this rather ticklish problem.

In closing, we really feel that successful partnering is going to continue Alaska's development for all of its sectors and really when you think about it, building in the Cook Inlet strengthens the base for mega-projects such as the Alaska pipeline. Anything you can do to increase your skilled worker base, you're better off. We have certainly seen that in some of our other situations with these demographics and things of this nature…We obviously want to contribute to Alaska's export position. We want to not only maintain, but like to expand our contribution to this community.

REPRESENTATIVE DAVIES asked if coal bed methane was just in the Inlet area.

MR. TWOREK answered yes.

CHAIRMAN TORGERSON asked how the NOLA (New Orleans) price compares to Henry Hub.

MR. TWOREK replied that in over 20 years there hasn't been much correlation, but over the last few years the gas price finally got so high that it overpowered any other economic factor for ammonia and urea.

The reason the North American industry got into a shut down situation was they really tried hard to pass through the NOLA price into the price of fertilizer. There was almost a one for one correlation; you could take my simple formula of the btu value times whatever their price was, add $25 and that was essentially the NOLA price. Even today, it's pretty much there…

CHAIRMAN TORGERSON asked him to explain paragraph 36.

MR. TWOREK said he would try; paragraph 36 is what royalties in the state are based on. It says:

> Royalties will be no less than the highest three contract prices in the state. It basically has nothing to do with how much volume. So, you could have a peaking utility contract at $5 and your royalties, although you're paying $1.20 or $1.50 would be based on the $5 rather than what you're actually paying to your producer.

CHAIRMAN TORGERSON asked what system their international competition used to value royalty.

MR. TWOREK replied that it was a hodge podge that depended on how sophisticated their internal economic development is. Trinidad is the most rigorous and closest to what Agrium is used to. There would be a bench price called at .90 - $1, then oil and gas contracts in Trinidad would have escalators like ours.

> If you head off into Saudi Arabia, it becomes an equation of we have no value for the gas that was sitting in the ground. Somebody, either under government sponsorship or whatever, built one of these plants, and so, whatever their well-head price is .50 - $1, their sum token royalty is around that, but it will slide usually with some sort of investment curve on the plant. If you put $600 MM in the ground, you get some sort of sliding royalty and gradually you will start picking up over time to something that looks like ours. But it gets very messy over there when you start digging into it, because they really try to extend some monetization of that trapped gas.

CHAIRMAN TORGERSON thanked him for his presentation.

10:38

MR. GEORGE FINDLING and MR. SCOTT JEPSEN, Phillips Petroleum testified next.

TAPE 01-26, SIDE A

MR. JEPSEN said:

> Mr. Chairman, for the record, my name is Scott Jepsen. I am employed by Phillips as the Manager for our Cook Inlet assets. I reside in Anchorage, Alaska. Thank you for giving Phillips an opportunity to provide its perspective on the matters requested in the attachment to your October 22, 2001 letter.

For clarity, my testimony is structured in question and answer format, addressing the 10 questions asked in your letter. These answers also provide our overall perspective on Cook Inlet, as requested in your letter.

[TRANSMISSION DIFFICULTIES TEMPORARILY SUSPENDED MR. JEPSEN'S TESTIMONY]

TAPE 01-27, SIDE A

11:00

MR. DAN THOMAS, UNOCAL Land Advisor, said Cook Inlet producing assets are climbing rapidly. Over the last 40 years there hasn't been much exploration for gas as gas prices have been very low, but that is changing. UNOCAL believes that the minimum long-term requirements for Cook Inlet can be met, but there has to be higher gas prices. "This is not a bad thing."

One of the committee's questions was what is UNOCAL's projection for demand and supply in Cook Inlet. His slide showed that there is about 5 tcf demand through 2022. This large demand will not be met with North Slope gas; there will have to be exploration. "North Slope gas is not going to get you here in time to meet this opening that's very imminent. This slide clearly indicates an opening as early as 2003."

MR. THOMAS said the committee also asked about coal bed methane.

Coal bed methane was a play that UNOCAL had an owner interest in a few years ago. We were the owner and operator of the Pioneer Unit. It was a large coal bed methane unit up in Matanuska Valley. We spent millions of dollars and drilled several wells. It was not a successful program for UNOCAL, but the gas is there, coal is there. However, it's very expensive, the pressure is very low; the cost to drill the wells and the technology is just not where it was a successful program for UNOCAL. We sold out our interest in the Unit to Evergreen Resources wishing them the best of luck. We spoke with several coal bed methane companies; Evergreen has expertise; they have their own completion rigs. We hope for above Cook Inlet and Evergreen's sake they are very successful. But we did choose to exit the coal bed methane area.

The committee also asked about the typical consumption by the various users. This slide was developed using information provided to the Department of Natural

Resources. They do a very good job of tracking and projecting the use. I use their information here and, again, I don't go into the detail as DNR did that this morning.

The next slide, however, is a very important and very telling slide. This one shows the average daily demand, peak day demand and then the reserves that we have in place and what reserve additions might look like and how they might help us. If you look at this slide, the points where the known reserves cross the peak day demand is about in 2003. That indicates that by the year 2003, we'll have a shortage on the very coldest day. Where I can see that the rate the gas can be developed and produced today is just about equal to the rate we're consuming the gas. These old fields are declining pressure, so we're going to have to have new resources added or we're going to have to move into some storage. UNOCAL this year for the first time put in place the gas storage facility to help facilitate meeting the customer's needs this winter. We injected gas all summer and we're drawing gas from that field. We see additional gas storage facilities being required in the very near term. However, if we look out on this slide a little further, about 2005 or 2006 is the point where the reserves cross the average use. So this is the year where you can't produce enough gas in the summer and put it into storage to meet the demands of the winter.

The line here will indicate about 1 tcf addition and the line out here is a 2 tcf addition to the current known reserves. These are numbers that we've seen from the U.S. G.S. and other sources as being very viable and options and opportunities that could be in the Cook Inlet. UNOCAL is committed to go out and explore for these, but we can't do so and we don't believe any company can do so at current prices. The reason UNOCAL activities in 1999 - 2000, UNOCAL has been attending the lease sales and has been negotiating with private land owners such as CIRI, other Native corporations and individual owners on the Kenai Peninsula. We've acquired a significant land position on the Kenai Peninsula.

In 2000 we sold the fertilizer plant to Agrium. [Indisc] was a corporate initiative world wide to sell off business like the fertilizer plant, placer mining and coal divisions in other parts of the world and focus world-wide on oil and gas.

Later in 2000, the new contract with Enstar to supply Enstar's gas needs for the coming year. That was presented to the Regulatory Commission last December and for the past year we've been going through the regulatory approval process. In 2001 we've drilled three exploratory wells here on the Kenai Peninsula. We've also been doing some innovative step out programs on some of the platforms and some of the West Sac properties, but these exploration wells that I'm talking about here are on the Kenai Peninsula and in the Ninilchik area.

Two weeks ago the Regulatory Commission approved the Enstar contract as you're aware of and the exploration wells that we have entered into and the exploration wells that we have designed and scheduled are as a result and directly because of the Enstar contract. Had it not been for the contract, UNOCAL would not have been drilling these exploration wells and not be having the exploration programs scheduled that we currently have. We anticipate two additional exploration wells to be drilled by the end of this year within the next couple of months. In 2002 we have eight exploration wells scheduled on the Kenai Peninsula. There is another well scheduled in South Ninilchik; we will then go to Deep Creek; we have multiple wells scheduled in the Anchor Point area and we will be back up in the Deep Creek area. So, we are very gradually exploring for gas on the Kenai Peninsula.

We also have an extended seismic program. The next slide shows prices in Cook Inlet that we have seen. The bottom line is the average utility price; this is the Department of Revenue's average weighted price for utilities and you see it fairly constant and fairly flat. This is the land of old contracts dating back into the 80s and these contracts are for gas that was discovered in the 50s and 60s. Again, it is a big bubble - the hundred years' supply. Most studies see the tail end of that, but that's what this slide is reflective of. Recently, UNOCAL has gone out on the market and had to buy some spot gas occasionally to supply our customer. We have a supply contract to Agrium to sell them gas at a fixed price. We bought gas at a very high price, but again this is reflective of new current market price. We recently saw in May of last year when Anadarko and Phillips entered into new contracts with Enstar to supply some of their needs that was at $2.75 price with an escalator and this price would be the Enstar/UNOCAL price. These are skewed

a little bit. These two lines should appear out in 03. These are what these contracts would be selling gas for out in 03, because we're not currently selling product. This was put on here for comparison purposes.

The reason for higher prices is that it just costs more to do business here in Alaska. The labor costs are higher; there's not an oil and gas supply store down at the corner like you would find in Midland or anywhere out in West Texas. It just costs more to get parts up here. Milk costs more and labor costs more. There's a high risk of doing business here. We're in a very undefined area. Down in West Texas there's a lot of wells drilled, so, one has a good idea of what may or may not be out there. Our utilities have a huge swing that we don't see in other parts of the country or that they manage differently because they have many, many different sources of supply. So, there's a lot of redundancy. You don't see the eight to one swing that we enjoy here in Alaska. I talked about the cost of doing business - we drilled a $15 million dry hole two years ago. That was actually a $4 million dry hole and an $11 million road to get to the dry hole. So, it just costs more.

There are environmental issues. This is a very environmentally sensitive area. We're going to use things that are necessary to protect the environment when we go out and drill these wells, but that costs money.

Very important and becoming more important is the competition for capital with other world-wide projects. It's tough to go down to the corporate offices in other parts of the country and convince management that they should spend tens or hundreds of millions of dollars in Alaska when they're going to get a price that's significantly lower than if it were invested in the Lower 48 or in another part of the world.

Finally, there's the royalty value uncertainty. When we enter into contracts for lower value markets such as industrial use where they have a flat profile, where they don't have this swing that is very expensive to develop deliverability to provide that market such as Enstar or Chugach, that market is a lower value market that competes world-wide as Mr. Tworek explained to us. Again, that swing is flat; they use the same amount of gas day in and day out and they use very large volumes. So, it doesn't cost as much to provide that gas to that customer

as it does the utility. However, when the state calculates royalties, again as Mr. Tworek indicated, the royalty is calculated on highest prices paid to send fuel to the area. So, the producers are exposed to paying royalty on a high price for gas that was sold to the utilities for that same gas being sold to the local industrial users.

All this gets us is what UNOCAL is up to for the next couple of years. Many people have asked if we are still in business. Absolutely we are. UNOCAL is very much dedicated and rededicated itself here to Alaska and to the Cook Inlet. In 2001 we spent $8 million on the Kenai Peninsula exploration program. In 2002 we're going to spend $49 million and in 2003 we've budgeted and approved in our budget $55 million. These again are for exploration wells on the east side of Cook Inlet up and down the road, the Sterling Highway between Kenai and Palmer, down in Anchor Point area. The dollars you see here are a combination of dollars that we expect to spend on exploration wells and in an equity position of a pipeline. We envision a pipeline being constructed from Kenai to Anchor Point. The dollars here again are about 50 percent equity ownership. If the ownership of that pipeline structure changes, the budget for UNOCAL would increase by about $20 - $25 million.

This is the area again where we're looking at exploring. This is the Ninilchik unit. We've heard some discussion earlier that Marathon was drilling a couple of wells there to go to number 1 and 2. These are also UNOCAL wells. We are in a partnership arrangement with Marathon with Marathon as the operator. We will then be going down to Deep Creek. We submitted an application for an exploration unit to the Department of Natural Resources just yesterday as well as the south Ninilchik prospect. These two prospects are 100 percent owned by UNOCAL.

MR. THOMAS indicated other prospects on a map and said they envision a pipeline being built all the way down to Anchor Point as a main transportation line. From Anchor Point south will be a distribution line constructed by Enstar taking gas to the residents of Homer. They do not focus on the North Slope and see exploration in the Cook Inlet for the next 15 - 20 years as what is necessary to meet the needs here. There will be a shortage before then.

UNOCAL has picked up a significant acreage position in the Foothills. We're very interested in the area. We would like nothing more than to see that come forward. However, it's not going to be the near-term solution.

As far as the legislation to consider, royalty is going to be a big factor. We would encourage this committee to consider a royalty valuation on arms-length transactions and make this consumer based. We're not looking at shorting the State of Alaska on its royalties. We want to pay the State of Alaska a very fair price on royalty valuation. However, it would appear abundantly unfair to require the producers to pay a higher royalty than the price that we receive for the products. We encourage the committee to consider investment tax credits for new gas based industries such as the expansion project, the Agrium facility, or investment tax credits for new gas exploration and development in the Cook Inlet. Again, it's one thing to take money out from a large country and let them export it to other parts of the world, but we believe that if a company is committed to spending tens of hundreds of millions of dollars putting it back in Alaska and back into the local economy, there should be some sort of tax credit to encourage them to do so.

Finally, we would encourage you to simplify the royalty valuation. Being able to understand and predict what the royalty is going to be on the gas that we sell when we enter into a contract is very important. It's hard to estimate what the value might be of gas that's going to be sold or transferred 10 - 15 years from now on a long-term contract. With that, we would finally request your support for the Kenai Homer pipeline. There's nothing in particular that I ask for in terms of legislation, but there is a significant proceeding that will have to be undergone. We'll have to go through the Regulatory Commission's approval process again for that pipeline; we'll go with the State Pipeline Coordinator and there will be a couple of dozen permits that will be required. We're looking at a very aggressive program. We're looking at if the pipeline does go forward, having gas all the way to the south end of the Peninsula by the end of 2003. We're looking at a two-year construction.

A Representative said one of his slides showed a decline in 2009 - 2010 of daily demand and asked why the decline was then and what did it signify.

MR. THOMAS replied that represents the export extension exploration for the LNG. "We don't know whether Phillips will extend their LNG export fabrication or not. There was no reason to assume that they would or they wouldn't. It's simply a state of the contract as it exists today."

The same Representative asked if they had decide on a size for their line.

MR. THOMAS replied that they are working under the assumption that the pipeline will be 16 inches, but there are wells yet to be drilled and they are hope to get to 20 inches. The terminus would be at the Kenai gas field.

CHAIRMAN TORGERSON thanked him for his testimony and said they were ready to resume testimony from Mr. Jepsen. The following is his printed testimony:

> 1) Provide the committee with an update on Phillips' LNG facility activities and its Cook Inlet gas field operations.
>
> Phillips is the operator of the Beluga River Field and the North Cook Inlet Unit (NCIU). Phillips' interest in the Beluga River Field is 33% and in the NCIU is 100%. The Beluga Field primarily provides gas to the local utility market with some sales of gas to the Agrium urea plant. Total gross yearly production out of Beluga is approximately 38 BCF per year. Gas from the North Cook Inlet Unit is produced from the Tyonek Platform. Currently, 100% of the gas from Tyonek is used to supply the Phillips portion of the feed requirements to the Phillips-Marathon LNG plant. The yearly production from the NCIU is approximately 53 BCF. Phillips' plan for these fields is to maintain deliverability within economic constraints. Phillips also has a 50% interest in the Moquawkie gas field, a small, one well, undeveloped, l998 discovery on the west side of Cook Inlet near the Beluga River Field.
>
> The Kenai LNG plant is jointly owned by Phillips (70%) and Marathon (30%). Total feed to the plant from Phillips and Marathon is approximately 77 BCF per year. The plant produces on average about 1.5 million tons per annum of liquefied natural gas, which is sold to Japanese utilities. Our current plans do not envision any significant changes to the operation of the LNG facility.

2) What is the expected length of time Phillips plans to continue
current levels of LNG production under the most recent production estimates from natural gas resources in the Cook Inlet?

On April 2, 1999, Phillips and Marathon were granted a renewal of the export license for the Kenai LNG plant for the period: April, 2004 to March, 2009 by the U.S. Department of Energy, Office of Fossil Fuels. For that renewal, a thorough analysis of reserve adequacy was conducted and substantial hearings were held. The results of that process demonstrated that reserve capacity was sufficient for LNG exports to continue through the approved period. It was also found that export was consistent with the public interest and would not result in a local or regional gas supply shortfall on an annual basis.

Phillips hopes to operate the Kenai LNG plant well past 2009. However, it is premature to determine whether we will seek another extension, but if we do, there will be adequate gas reserves to do so, as well as provide for the state's needs.

3) What, if any, expansion plans are being made in the event that a natural gas supply is made available from the North Slope?

Phillips is focusing its ANS gas commercialization efforts on a pipeline to the Lower 48/Canadian markets.

On the general topic of LNG, we would also note that Phillips has been part of the Alaska North Slope LNG Sponsor Group since its inception in 1999. A detailed review of the Sponsor Group work was given to the Senate Resources committee in April 2001. That review indicated that the Nikiski area and a pipeline from Prudhoe Bay would provide a technically feasible and permittable LNG plant site/route configuration. However, a cost competitive, economically viable Alaska LNG project has yet to be identified.

4) Do you plan to apply for an extension of your LNG export authorization past 2009 if North Slope gas is not available? Is your answer different if North Slope gas were available?

As mentioned in my previous answer, Phillips would like to extend the operation of its LNG operation past 2009, if the dedicated gas supply available to Phillips and Marathon in Cook Inlet allows us to do so. However, we do not see that an export license extension is necessarily contingent on ANS gas being available in the Cook Inlet area.

5) What is your assessment of the Japanese LNG market?

The East Asian LNG market is fiercely competitive and likely to continue to be so throughout the remainder of the decade. In round numbers, we see about 60 to 75 million metric tons per year of potential new LNG supply chasing after 20 to 40 million metric tons per year of new LNG demand through 2010. As a result, recently we have seen prices for new contracts trending downward and pressure for shorter contract periods.

This reinforces the difficulties that an Alaskan LNG project faces in the East Asian market over the next decade. While the market for new LNG is expected to grow, there is an over abundance of lower cost supply and in smaller increments compared to new LNG that would be delivered from Alaska.

That said, Phillips will continue to monitor and evaluate this situation for possible opportunities for Alaskan LNG.

6) What is your current assessment of proven developed gas reserves, proven undeveloped gas and unproven probable gas reserves in the Cook Inlet? What is your current assessment of undiscovered gas resources in the Cook Inlet?

For competitive reasons, Phillips does not increase its internal assessment of reserves for fields or basins. However, we can cite several published reports that provide estimates of Cook Inlet reserves. Schlumberger-Geoquest performed a study for Phillips/Marathon in support of the LNG export license renewal effort. The Schlumberger-Geoquest report estimated that, as of 1/1/98, total remaining proven reserves in Cook Inlet stood at 3.3 TCF (cited in the application to Amend Authorization to Export Liquefied Natural Gas, Department of Energy. Office of Fossil Energy). Adjusting for estimated production volumes since then, 1/1/2001 proven

reserves stood at around 2.7 TCF. The USGS has also estimated probable reserves at 1 TCF and possible reserves at 1.4 TCF (as reported in "A Review of Cook Inlet Natural Gas Supply and Demand", Northern Economics, 2001, p.8).

With regard to Phillips' assessment of undiscovered gas resources in Cook Inlet, one has to first step back a bit from the numbers. While the estimate of proven reserves is fairly precise, the assessment of possible new potential reserves is less precise. The only real significance of the USGS estimate is that it indicates we probably have not found everything there is to be found in Cook Inlet. The only way to know for sure is through drilling. Because of the historic overabundance of gas in Cook Inlet, drilling activity targeted at gas has not been as high as it might have been. The supply and demand relationship is starting to turn now, with the extreme supply overabundance relative to demand dropping to a level more çomparable to the Lower 48. While some see this as a matter of concern, it is premature to think that the market will not react and fill in the supply opportunities as they arise. From an exploration and production point of view, this is really a time for optimism, not pessimism. Let me explain.

By 1970, gas reserves in Cook Inlet stood at about 8 trillion cubic feet (TCF) and production was about 145 billion cubic feet per year: thus the Reserves to Production ratio (R to P ratio) was about 55 years. As would be expected with such a high ratio, there was little incentive to explore for gas, since it would either be a long time before revenues would be realized for the additional, discovered gas or the gas would have to be sold at inordinately low prices.

Over time, the known Cook Inlet reserves have been slowly consumed. As indicated above, reserves are about 2.7 TCP. Consumption is about 215 bet/yr and the R to P ratio is just under 13 years. Theoretically, this would suggest that developed reserves will be exhausted in about 2014. However, in reality, this is a very normal situation in the natural resource industry. For example, the R to P ratio of the Lower 48 is about 7 years and it has roughly been at 7-10 years, with a slight decline, for the last 20 years. New resources have been added at about the same level as consumption. The market for gas and the increased demand spurs exploration and development.

In the past, the overabundance of gas supply in Cook Inlet has served as a disincentive for exploration. However, for the first time in about 30 years, a company that finds new gas can actually sell at least some of its potential production at a price that may yield acceptable rates of return.

In fact, Phillips believes we are beginning to see the early signs of a new phase of exploration and discovery. We have seen public announcements showing that gas activity has begun to pick up. Phillips and Anadarko had success in finding gas in the Moquawkie Field. We also note the public announcement that Nikolai Creek No. 3 has been successfully recompleted and that Northstar Energy Group proposes a well to tap the North Fork gas field. Marathon and Unocal are actively exploring throughout the Kenai Peninsula. There is clearly a renewal of interest in gas exploration and production in the Cook Inlet area and the results of that effort are beginning to be seen.

Exploration for oil is also on an ‘upswing’. Forest Oil has made an oil discovery at Redoubt Shoal and Phillips is drilling an oil exploration well near Anchor Point. While these oil fields may not add significant gas reserves, they do provide infrastructure that could lower the economic hurdles for additional exploration and development.

On the price side, Enstar has shown willingness in its more recent contracts to tie gas prices to widely accepted gas indices such as Henry Hub. While Cook Inlet is not connected to the Lower 48, receiving Lower 48 prices or better for Cook Inlet gas makes it easier to evaluate gas plays in Cook Inlet relative to other options available to potential investors.

Beyond these basic observations, there are other reasons for prudent optimism. First, seismic technology has progressed and should significantly improve exploration chance factors. Second, there are more players, some new, in the picture. Besides the historical players such as Unocal, Marathon, Chevron and Phillips, companies such as Northstar Energy, Forest Oil, Anadarko, Aurora, Crosstimbers, Pelican Hill and Escopeta are investing in the Inlet. Clearly, there are players making it more likely that wells will be drilled and discoveries made.

In looking at Cook Inlet as typical of any large, prolific resource basin, there are a couple of characteristics that are common to all of these types of basins. First, there is invariably a distribution of field sizes in basins that have been well explored. Second, there are normally cycles of discoveries based upon technology or play concepts.

I want to first take the topic of field size distribution. We know that, typically, naturally occurring phenomena like hydrocarbon accumulations are distributed in what is technically defined as a log normal distribution. Simplistically, there should be a few giant fields and an ever-increasing number of smaller fields. In Cook Inlet, almost all of the currently known reserves are contained in what industry would consider large or giant gas fields. These are fields with more than 1 TCF of initial reserves. These fields have long been regarded as 'accidental discoveries' made while exploring for oil. There has also been a sprinkling of relatively small discoveries in the 50 BCF or less range, which are an inevitable result of the exploration wells that have been drilled. What are undiscovered are the expected field sizes in between. As the incentive to explore for gas in Cook Inlet increases, there is a high likelihood that explorers will start to find these middle-sized fields. With higher prices and increased infrastructure, many of these fields could be economic and in aggregate could contain relatively large amounts of gas.

Discovery cycles are also a common characteristic of basins like Cook Inlet. Typically, a number of discoveries are initially made in a basin based upon a particular geologic concept, often followed by a period of few discoveries. Almost invariably, there is a new with the peak gas demand of consumers. While such peak facilities are common elsewhere, due to high deliverability, there has been little incentive for them in Cook Inlet.

In public forums, we often hear the concern that the Cook Inlet is running out of gas. It strikes us that this assertion basically ignores the role that exploration is very likely to play in Cook Inlet. As long as the industry has incentive to drill, we believe the next five to ten years will yield much about the potential of the basin.

7) What are your current exploration plans within and outside known producing fields in the Cook Inlet? What is your proposed Cook Inlet drilling budget for the next five years?

As I mentioned in my response to the last question, Phillips is drilling an oil exploration well near Anchor Point. For proprietary reasons, Phillips does not release its specific exploration plans or strategies. In general, however, we will look at any Cook Inlet drilling opportunity on a case by case basis and determine if it competes with Phillips' world-wide opportunities, including those on the North Slope.

8) What is your current assessment of South-central demand for gas over the next ten to twenty years. If you have pessimistic, optimistic and base cases, please generally describe each case.

The area utilities and the University of Alaska at Anchorage generally provide demand forecasts for the South central area on an ongoing basis. In general, we do not see any significant variances around their forecasts at this time that would influence our business strategies.

9) We have heard that deliverability, the ability to meet peak winter demand, may be a problem soon. Please discuss whether you see deliverability constraints in the next ten years. Please discus what can be done to reduce any deliverability problem.

Gas demand in the Cook Inlet is very seasonal. For a period of a few days to perhaps several weeks in the winter, consumption peaks perhaps 30 - 40 percent higher than for the rest of the year. However, meeting those demands is not so much a function of reserves as a function of the capacity of wells and delivery facilities. To meet the peak winter demand, investments must be made that are underutilized at other times of the year. For example, in the Lower 48, Canada and Europe, investments have been made for peak shaving, facilities specifically designed to supply gas during seasonal high demand. Common types of peak shaving are underground storage in converted reservoirs, LNG storage and facility capacity expansions such as additional compression. Typically, these investments are made by the utilities,

which have the ultimate responsibility to meet the peak gas demand of consumers. While such peak shaving facilities are common elsewhere, due to high deliverability, there has been little incentive for them in Cook Inlet.

Phillips believes that the tension of not over-investing, yet still meeting peak demands is something that the marketplace can and will ultimately solve through a variety of strategies. As a practical matter, as has been illustrated in numerous markets around the world, investments by the producers to increase peak deliverability must be balanced with development of true peaking facilities. Further, we understand Enstar has agreements in place with Unocal and Marathon to divert gas supplies to meet local peak requirements, should the need arise. In addition, Phillips is committed to working in support of Enstar's efforts to ensure that the needs of the community during critical periods are met.

10) Finally, do you have any recommended state legislation the committee should consider to advance development of natural gas related industry within the state?

Clearly, more frequent and wider lease sales and expedited permitting is an excellent policy. In addition, State support of increased federal lease sales in the potentia1ly gas prospective lower Cook Inlet would also be appropriate.

Mr. Chairman this concludes my testimony. Thank you for the opportunity to present Phillips' views on Cook Inlet gas. I would be happy to answer any questions you may have.

CHAIRMAN TORGERSON thanked him for his testimony saying there were no questions at the time and announced that Mr. Scott Heyworth, Chairman for the Citizens Initiative For the All-Alaska Pipeline, would give the committee an update on how the signature gathering is going and answer the question of what he expects this committee or the legislature to do.

11:28

MR. SCOTT HEYWORTH said:

Good Morning Mr. Chairman and members of the Committee. I was pleased to accept your invitation to attend these hearings and testify before you today.

1 am happy to report that the Citizens Initiative for the All-Alaska Gasline has just gone over the 50% mark of its goal of 37,500 registered Alaskan voter signatures. While it is a bit chilly outside these days, it is not discouraging Alaskan voters from signing it. As you know, we must obtain 28,700 valid signatures by January 14, 2002 to be on the November *5,* 2002 general ballot. We have almost 60 petitioners currently working across the State, mostly volunteers, who just believe in the Initiative and what it will do for Alaska. He said he needs to get about 265 signatures a day to reach his goal.

Also, in your packet you will find an article from Pacific Maritime Magazine, dated October 2001. You will notice strong demand for both new LNG tankers and receiving facilities being built in both Asia and U.S West Coast LNG markets, OUR NATURAL GAS MARKETS!!!

As the article points out, demand for LNG is obviously increasing, not declining anytime soon.

In the front of your packets, you will find the certification letter and ballot language agreed on by my group, the Attorney General's office and Lt. Gov. Fran Ulmer. Following it, please find a copy of my Anchorage only poll results. I agree with your comments, Mr. Chairman, in the Juneau Empire last week that you feel this Initiative will pass by 70 percent approval, as validated by many state-wide polls.

Mr. Chairman, I would like to share with your Committee some of the structure of this Initiative. This Initiative creates a State of Alaska Gas Authority that ensures an All-Alaska Gasline will at least be an option in developing North Slope Natural Gas.

Mr. Chairman, turning to your packet again you will find the complete Initiative language. I now wish to bring the Committee's attention to page 12, section 41.41.400, *Credit of state not pledged:*

a) Obligations issued under the provisions of this chapter do not constitute a debt, liability, or

obligation of the state or of a political subdivision of the state or a pledge of the faith and credit of the state or of a political subdivision of the state but are payable solely from the revenue or assets of the authority. Each obligation issued under this chapter must contain on its face a statement that the authority is not obligated to pay it or the interest on it except from the revenue or assets of the authority and that neither the faith and credit nor the taxing power of the state or of a political subdivision of the state is *pledged to the payment of the principal of or the interest on the obligation.*

(b) Expenses incurred by tile authority in carrying out the provision of this chapter are payable from funds provided under this chapter, and liability may not be incurred by the authority in excess of these funds.

This wording is the key to understanding that this Authority will not be encumbered by past deficiencies in past State ventures such as the Delta Barley project. I wanted to read you this section, which I consider to be the integrity of the Initiative itself.

The importance of this is that it is a stand-alone project. Creditors cannot access the Alaska General Fund or the Permanent Fund. To obtain the financing of this project, it will have to be economically sound on its own merits. In addition, the Committee should be aware that the model we used for the Initiative language is quite similar to SB 221 introduced and sponsored by Senator Robin Taylor last session. The legislative drafters of that bill included language on bonding and financing. While I do not profess to be an expert on all technicalities concerning bonds and finance, I think the drafters made it fairly clear as to how bonds and notes of the authority are issued for financing. See page 6, Section 41.41300.

The Initiative also states on page 4, Section 41.41.100 that the Authority's operating budget is subject to the Executive Budget Act, which allows for Legislative oversight. Succeeding sections allow for more oversight and public inclusion. Our concept of the structure of the Authority is that the Board of Directors, appointed by the Governor with approval of the Legislature, will oversee development of the project, similar to the Permanent Fund Board, but that we expect all project

construction, maintenance, and operations to be provided by the private sector.

The Initiative also calls for a spur line to bring our gas to South-central as an integral part of the project. I also believe an LNG project could provide shipments of Alaska natural gas to the Alaskan Interior, coastal, and river communities with LNG barges or spur lines. By moving gas to South-central, this project will ensure that gas will continue to arrive in [indisc] and Nikiski.

Mr. Chairman, you also asked me to comment on the Legislature's involvement with this Initiative. As you may know, Alaska law provides that any initiative for the general ballot must allow for a full session of the Legislature to assess, review and even pass "substantially similar" legislation. Senator Taylor's SB 221, for instance, is "substantially similar". I would encourage the legislature in the upcoming session to closely look at this legislation in order to expedite this project and save Alaska approximately one year in order to get our gas to market as soon as possible. I would hope the legislature would move quickly to appropriate the funds necessary for development of the project plan as called for in Section 41.41.900, DEVELOPMENT OF PROJECT PLAN, page 13. Completion of this project development plan would put Alaska into the position to seek long-term sales contracts for our gas.

In closing Mr. Chairman and Committee members, I know from personally gathering over 500 signatures myself, statewide polls…[END OF TAPE]

TAPE 01-27, SIDE B

MR. HEYWORTH continued:

…and from the reports of my petitioners all over Alaska that the response of Alaskan voters to this petition in the last 7 weeks allows me to state with assurance that this is the gas line project that Alaskans wish to see developed. Finally, for the record, I am not opposed to any gas project that brings Alaska gas to market. However, we do not want to wait on a Canadian highway project that may never happen before we explore developing the very gas pipeline project that Alaskan voters clearly want. I look forward to working with all of you in this exciting endeavor.

CHAIRMAN TORGESON asked Mr. Heyworth to tell them what interaction he had with Yukon Pacific (YPC) or the Port Authority.

MR. HEYWORTH said Jeff Lowenfels of YPC helped him understand the route issues.

CHAIRMAN TORGERSON said rumor on the street is that YPC might be for sale and he wanted to know if part of his discussion was that the Authority might purchase assets.

MR. HEYWORTH said that was right and they pledge they would sell the permits. It's in the suggested legislation under the word, "pledge".

CHAIRMAN TORGERSON asked what other discussions he has had with Senator Taylor.

MR. HEYWORTH said Senator Taylor introduced SB 221 on the last day of session and he used a lot of his language, "because it's good stuff." It's quite similar to the initiative.

> All the initiative is showing, in my personal opinion, is the shining will of the people to their elected legislators that this is the way they'd like to go and Senator Taylor's bill covers so much stuff that's in our initiative. In fact, the legislature could make it tighter, because as you know I couldn't get through the Attorney General's office if I had appropriations in there, for instance…

CHAIRMAN TORGERSON asked what he thought would be needed to jump start this.

MR. HEYWORTH replied that the project plan was on page 13 and he thought it would cost $1 - $2 Million.

REPRESENTATIVE DAVIES asked if he agreed with Roger Marks projections.

MR. HEYWORTH responded that he would be satisfied if the initiative suggested doing a best interest finding to look at LNG, because he didn't agree with Roger Marks.

CHAIRMAN TORGERSON said they were in the process of going out with an RFP now for the committee's own staff economists. He said that not many people agreed with Mr. Marks' inputs, although they agreed that the final product is correct.

CHAIRMAN TORGERSON announced a short break.

TAPE 01-28, SIDE A

12:30

MR. JOHN ELLWOOD, Executive Vice President, Foothills Pipe Lines, Ltd. offered the following testimony:

Mr. Chairman: Thank you for the invitation to appear before your committee and to report on the progress of the ANNGTC/Foothills (ANGTS) Alaska Highway Pipeline project.

Foothills appeared before your committee on July 18, August 15 and September 19, 2001. During the earlier appearances we spoke to issues of the ANGTS advantages, Alaska benefits, pipeline access, status of the pipeline and the various permits. The later appearance focused on our position regarding he federal legislation proposed by the Alaska producer group.

Since that, U.S. Senate hearings on Alaska natural gas were held in Washington and the Alaska Highway Natural Gas Policy Council forwarded its recommendations to the Governor. Foothills appreciates the efforts of policy makers involved in both of these proceedings.

Mr. Chairman, I would like at this time to express our appreciation to you and to the committee for your words and contribution to the U.S. Senate Energy Committee hearings.

Today I would propose to report progress by Foothills on three fronts:

- The Alaska Northwest Natural Gas Transportation Company (ANNGTC) partnership.
- Foothills commercial proposal.
- Work on the pipeline right-of-way.

We are aware of a lingering concern regarding the so-called withdrawn partners issue and alleged liabilities associated with that issue. When I appeared before your committee in July of this year, I indicated that Foothills had undertaken discussions to reenlist the Withdrawn Partners of the ANNGTC. In our testimony before

the U.S. Senate Energy Committee on October 2, 2001, Foothills said:

"In the initial stages of the Alaska Highway Project, numerous U.S. energy companies were partners in the Alaska Partnership. However, during the decade of the 1980s and the 1990s when the producers of Alaska natural gas were unwilling to commit that gas to Lower 48 markets because of low energy prices, all of the U.S. partners withdrew from the Alaska Partnership. Foothills and TransCanada as the two remaining partners have offered to the current holders of the withdrawn partner interests an opportunity to rejoin the Alaska Partnership. The negotiations with these companies have been productive and are ongoing."

Last month we followed-up our testimony with a letter expanding on the reenlistment process. Earlier this month we testified before the Committee on Energy and Natural Resources regarding our efforts to reconstitute the Alaska Northwest Natural Gas Transportation Company (Alaska Partnership) by reenlisting the withdrawn partners. We are writing today on behalf of TrnasCanada and Foothills and with the authorization of the withdrawn partners. - Duke, El Paso, Enron, PG&E Corporation, Sempra and Williams specifically with respect to the reenlistment process. We are pleased to report that continued progress has been made on the critical issues, including the key principles for reenlistment by any withdrawn partner who so elects in the Alaska Partnership for the purpose of constructing the Alaska Natural Gas Transportation System (ANGTS).

We have already scheduled further meetings so that we continue to work on the details for reconstituting the Alaska Partnership. It is anticipated that all parties will have signed a Memorandum of Understanding within the next month. TrnasCanada, Foothills and the withdrawn partners are committed to eliminating commercial barriers to construction of the ANGTS and in so doing would be prepared to release contingent claims against the Alaska Partnership related to previous investments in the ANGTS as part of a commercial arrangement to ensure a market viable project.

Our negotiations with the withdrawn partners are approaching the final stages and we are confident of

meeting our timeline for the successful conclusion of an agreement.

Commercial Proposal

A commercial agreement with the Alaska producers is an important prerequisite to any pipeline project. Achieving such an agreement has been delayed in part because of the withdrawn partnership issue overhanging the project and because the Alaska North Slope producers are focused on completing their project feasibility study. In October evidence before the U.S. Senate Energy Committee we said:

"An important first step towards commercial viability of an Alaska gas pipeline is a commercial agreement between the producers and potential shippers who, in turn, enter into transportation contracts with the owners and operators of the transportation system. In this regard, the Alaska Partnership has pursued discussions with the producers for the last several months. After several discussions with the producers over the last year, it has been agreed that we will develop a commercial proposal to present to the producers before the end of the year."

The above referenced October testimony also stated:

"The next step on our critical path will be to prepare, present to and negotiate with the producers of Alaska North Slope natural gas a comprehensive commercial proposal for a pipeline project. Based on the progress we have made since the Energy Committee hearings, we are confident that such a proposal will be presented to the producers before the end of the year. As companies with longstanding interest in building and owning an Alaska natural gas pipeline, we have every incentive to reach a commercial arrangement with the producers to develop a viable project. We believe that such an arrangement will be achieved on a timely basis, consistent with the energy needs of the nation."

With regards to the negotiations with he North Slope Producers, we remain confident that we will reach a commercial arrangement to develop a available project.

Pipeline Right-of-Way

The Alaska Natural Gas Transportation System from Prudhoe to Alberta is approximately 1, 750 miles long. Access to land is becoming a difficult challenge for all North American pipeline projects. Public lands constitute the majority of the property through which the pipeline will pass. Foothills is well advanced along the road of securing the pipeline right-of-way. More than 400 miles of right-of-way on federal lands has been acquired. Currently, we are making progress on securing the 200 miles of right-of-way on state lands with the Gas Pipeline Office. Work is under way to assess the information that was previously submitted in an earlier application and a process to move forward has been identified. With the state right-of-way lease expected to be in hand by 2003, over 90 % of the right-of-way for the project will have been acquired or reserved.

Let's summarize the progress of the Alaska Highway Pipeline project.

1. The United States and Canada have determined that the ANNGTC/Foothills (ANGTS) Alaska Highway Pipeline project is: (a) necessary, (b) in the public interest, and (c) should be granted a unique fast track status.

2. Foothills and TransCanada have offered to the current holders of the withdrawn partner interests an opportunity to rejoin the Alaska Partnership. Negotiations have been productive and we are well on our way to reassembling the Alaska Partnership.

3. A commercial arrangement between a coalition of North American pipeline companies and ask natural gas producer group is the next key milestone. We are working towards that end. A commercial arrangement will allow the project to move to the next phase of the project - "the countdown to construction" phase. A substantial amount of this work has already been completed and more is currently being done on spec to further expedite this stage of the project.

4. As I indicated, we have made substantial progress in the area of pipeline right-of-way.

5. In moving forward we will comply with the technical and environmental conditions established by President Carter when he approved our project. In doing so we intend to work with interested stakeholders. Over the

coming months we will take steps to establish a consultation process that will enable interested Alaskans to become involved in the project.

6. We are committed to maximizing Alaska benefits consistent with prudent economic efficiencies. The Governor's Policy Council has made reasonable recommendations in this regard.

Ultimately the final decision to construct a pipeline will rest with the gas producers. We remain confident that the long-term demand for and the price of natural gas in the North American markets will support his project.

12:45

CHAIRMAN TORGERSON said some of Foothills' partners sell gas in their own markets and asked if they are approaching this as a pipeline company or as a potential partner in the marketing of gas.

MR. ELLWOOD answered that the companies that are pure pipeliners, such as Foothills, and those who have a marketing arm are treated as two different businesses. "The pipeline part of this wouldn't necessarily be buying the gas."

CHAIRMAN TORGERSON asked if he wanted to comment on Senator Murkowski's proposed legislation.

MR. ELLWOOD replied, "Our position is that no new legislation is needed. The existing legislation, ANGTA, provides everything that is needed here…"

CHAIRMAN TORGERSON asked if the partners are owners in the Canadian portion of the pipeline or just the Alaskan part.

MR. ELLWOOD answered that they are working on restructuring just the Alaska partnership.

CHAIRMAN TORGERSON asked if the Canadian side would be Foothills.

MR. ELLWOOD replied that was correct and Foothills would soon be half owned by Duke.

CHAIRMAN TOGERSON asked an indiscernible question.

MR. ELLWOOD answer is that three - five entities will step up to do that. There is some inexpensive expandability of existing pipeline network in Canada, particularly on the Alliance Pipeline. There is presently some unused capacity on the Nova TransCanada System.

> There is the capability of expanding the Foothills PG&E systems and the capability to move southwest gas down the west coast system. There's also the possibility that a smaller, but new bullet line or greenfield project could be built. It wouldn’t have to carry all the gas coming from Alaska. Again, depending on the timing of when the volumes from here build up, it may be economic; it may be preferable to build another new, but smaller pipe to one or more markets.

CHAIRMAN TORGERSON asked if they were thinking about twin 30s or one large pipe.

MR. ELLWOOD replied that they hadn't given much consideration to twin pipes. They think this line will be 42 or 48 inch pipe.

REPRESENTATIVE DAVIES said he raised the issue of risk sharing and asked if they are contemplating the possibility of sharing the market risk with the producers.

MR. ELLWOOD replied that he didn't think that would be a useful thing for the pipeline company to do. He saw a marketing function where that risk might be taken up.

CHAIRMAN TORGERSON asked if they had a timeline for the resolution of the withdrawn partner issue.

MR. ELLWOOD replied that there is no drop dead date. "We're all working very diligently to get this thing done."

He was confident that it would be done in the month of November. All the companies are supportive of the project.

CHAIRMAN TOGERSON asked if any of the agreements needed the approval of a board of directors.

MR. ELLWOOD replied that in most of the cases it is a management decision, which helps their timeline somewhat.

REPRSENTATIVE DAVIES asked him to comment on Mr. Heyworth's initiative.

MR. ELLWOOD replied that he didn't know much about it. He wished them well. There is a lot of LNG capacity world wide chasing about a third or half as much market.

SENATOR FATE asked if he felt there was some exclusivity with ANGTA or if there would be more competition for constructing the line allowed under it.

MR. ELLWOOD replied that they are confident that it will come to fruition next year.

> It seems to us that things are coalescing around a highway route. There's less and less debate about what is the most viable route. The question now comes how do we pull together a consortium, a group of companies that can make this deal happen. Part of that is to bring in the U.S. pipeline marketing entities and we're doing that. And the other half of that is to bring the producers on and strike some suitable arrangement with them - something that's satisfactory for both sides of this equation. That is just beginning, but I am encouraged that we are under way now.

REPRESENTATIVE DAVIES asked what he thought the probability of this project coming together.

MR. ELLWOOD replied:

> If we put this commercial proposal in front of the producers towards the end of this year, my understanding is that their studies are going to be completed at about the same time…I would hope we could get around a table and into some serious negotiation in the early part of next year. My expectation would be that those negotiations are going to be challenging and that we will probably be at that for some months before we whittle down to what an agreement might be. By the end of next year we should be in a position to drop the flag and that's when things really start to happen - when the major money starts to be spent to get something done.

REPRESENTATIVE OGAN asked if the position of the assets by Duke was motivated by bullishness on this project or did it just happen because it came along with the package.

MR. ELLWOOD said he couldn't answer that; only Duke could. They hadn't announced any spin offs, so he thought they wanted to keep all of them.

REPRESENTATIVE OGAN asked what percentage of west coast assets that are now Duke's were involved in this gas pipeline project.

MR. ELLWOOD said he thought it was very small.

CHAIRMAN TORGERSON thanked him for his presentation and announced they would hear from Mr. Peterson next.

1:00

MR. RICHARD PETERSON, President and CEO, ANGTL Co., said:

I have long been a proponent of GTLs as one solution for Alaska's stranded natural gas. Coal based GTLs is one answer for reducing U.S. dependence on foreign crude imports. I want to say that there's a lot of other people over the last five or six years that I have run into who are interested in the GTL program around the country, but they want to see some interest from the federal and state governments. Typically, all you hear about is the LNG or a gas pipeline.

I want to talk about the national energy policy. If the U.S. really wants a policy that reduces dependence on foreign crude, we think they can look at the example of South Africa. South Africa pioneered GTLs in the 50s and expanded the program in the 70s when OPEC fortified the U.S. in order to reduce its imports of foreign crude. Today with advances in GTL technology, the U.S. can build more efficient gasification and GTL plants for far less than what it costs in South Africa. I would like to point out that the U.S. has enough coal reserves in 38 states across the nation to make over 10 million barrels a day of synthetic motor fuels for over 200 years.

I think most people don't know, but the United States has about 25 percent of the world's proven reserves of coal. It's a significant amount of energy. Also, the Alaska North Slope contains enough natural gas to make upwards of 1 Million barrels a day of synthetic fuels that can be transported down the existing pipeline to Valdez for shipment to the Lower 48. What else is of importance about that point is that GTLs as a batching program can also improve the economics of a gas line with more assets built in Alaska and more jobs for Americans.

GTLs from Alaska can start the process today educating Americans with the possibility of GTLs. Coal based GTLs can produce not only the cleanest motor fuels, but they can also produce some of the cleanest electricity known to man - a reliable, affordable, environmentally sound energy for America's future and if you have gas to liquids, I think you have a solution that President Bush would be looking for. If this Bush thing can happen today, we truly believe that Alaska can start the process

and show the rest of the nation how GTLs can work, whether it's on the North Slope or in Cook Inlet.

He said for a year and a half ANGTL has been looking at other potential gas to liquid options in Alaska and they focused on Cook Inlet. Various producers told them that there was no demand and that's the reason they're not exploring. Based on preliminary engineering studies, he thought they could build a plant in the $250 Million range. Gas availability limited the size of the plant. They proposed to sell gas on an impact basis determined by revenues received from the sale of the products in the U.S. market. A GTL plant produces excess hydrogen and nitrogen, the two primary feed stocks for the fertilizer plant. GTL plants can export these products to the fertilizer plant for incremental fertilizer and urea production exponentially lowering the overall cost to the fertilizer plant and its ability to pay higher than current market values for natural gas while still competing in their export market.

In the scenario of a gas shortage in the Cook Inlet area with gas prices well above $2 - we believe if you subscribe to that position, then the most ideal thing that we've seen on the market is to do what is called an integrated coal gasification combined cycle electric generation gas to liquid plant. It's a mouthful, but the DOE has sponsored several programs in the mid-1990s and these programs are very successful in the Lower 48 - taking coal gas and refining it and running the gas to produce electricity. When you add on a GTL complex or module to that use, it increases the overall efficiency of the process and create a well-balanced program. It is a fact that DOE is actually looking at some of these programs now. We'd like to point out that these programs have basically been in existence for 50 years in South Africa, so it's not an issue of do they work. It's what's the total economics.

In our proposal we look at upgrading the existing City of Anchorage MLP and Chugach generation plants in one location so that we get a higher base load amount of electricity being generated and using the latest fuel efficient combined cycle generators fueled by coal from a gasification facility and a small portion of natural gas. This gasification facility would now sell the same gas that would be needed for the FT [Fischer Tropsch - synthetic fuel] technology to produce healthy clean fuels. The combination of these technologies improve the process, extend the life of existing natural gas reserves in the Cook Inlet area benefiting the people in the area

giving them another choice of using natural gas such as Enstar.

MR. PETERSON said they proposed to target about 200 - 300 megawatts of combined cycle power and that's the base load of both Chugach and MLP. They could pick up some additional loads since they are connected to the rail belt. He said:

> As you can well imagine, this creates some sort of consternation with the existing electric generators in that they would wonder where the generation would come into play. Our proposal is to work with them, but we can also produce what they call power for electricity. Again, this process would produce between 8,000 and 12,000 barrels a day of ultra clean fuels and share the proposed background coal export facilities or utilize the existing [indisc] to Anchorage facilities if a crude oil line is built across the Inlet. As some of you know, Forest Oil has discovered additional amounts of oil and now it's looking like they are going to build a pipeline across the Inlet and eliminate the tankering from Drift River to the [indisc] facilities. If that happens, then this might be an advantage for use of these facilities for export down the west side of the Inlet - if we get a GTL plant that's built on that side.
>
> We're working closely with Polar Star both in Alaska and South Africa on GTL programs and hope to move forward on a GTL program in Cook Inlet shortly. But, I would say that a gas based GTL program and a coal based GTL program are mutually exclusive. There isn't enough demand for these products in the Alaska area and things that would justify going ahead with both projects. The thing that we find most frustrating over the last year in conversations with people who produce this gas is how much gas is available? What industries are going to be there? Can we do a viable project? If we do a coal gasification project, it will have a tremendous benefit for existing gas users. It should reduce gas prices, reduce demand, reduce load. But if we're wrong and another 3 - 20 bcf of gas is found, the gas price in Cook Inlet is going to be so low that it would make no sense to be producing electricity from a syn-gas base. So, we're at this point of - okay guys, try to tell us what's going on.
>
> From the producers point of view we understand they would like to get higher prices, but at $3 we see the LNG plant out of business, we see the fertilizer plant being out of

business. So, we're wondering just where is the industrial load in the Kenai going to be and what can we do to work around that. I guess one of the things I've found talking to various producers, the issues come up of what is royalty going to be. If we start selling to a GTL plant and we're also selling electric generation and we're also selling to Enstar, what is our royalty going to be? I think these are big issues for the commercial side of this equation. These questions are going to have to be addressed because there's too much risk on the producer's side to want to deal with a commercial project such as ours not knowing what they're going to have to pay on a royalty.

I'd say the other thing that we've been told is that the state needs to do something about the time lag date to go from buying a lease to physically getting production on line. Without being specific, that's just a general comment that we've heard.

From our point as a potential developer of a project in the Cook Inlet area that needs natural gas, we would like to have natural gas to do that. We'd like to see anything the legislature can do to encourage exploration, to speed up the exploration drilling production process, to look at ways that from an industrial point of view, the producer is not penalized for selling to us or promote buying gas at a flat level base that's year in and year out, day in and day out when there's other peak day markets and so on. That's basically all I wanted to say today…It's my strong feeling that if the nation and Alaska truly want a national energy program, it's going to reduce its dependence on foreign crude. I realize that's a double edged sword for Alaska, because reducing dependence on foreign crude can also mean reducing the price of crude in general and sales of crude oil is what this state lives on. We truly believe if we're going to have an impact, gas to liquids is going to play a major role and a gas based GTL plant is going to set the stage for a coal base. And when we talk about coal based, we talk about the huge potential of the country. We also would like to point out that half the coal reserves in the United States are in Alaska.

CHAIRMAN TORGERSON asked if he had discussions with Chugach Electric on his proposal and what were their comments.

MR. PETERSON replied that he had and they're betting that there

will be a lot of natural gas found in Cook Inlet and that the gas price is going to come dramatically down from what they are paying today.

CHAIRMAN TORGERSON asked if it was Forrest Oil who announced a year ago that the committee was interested in a GTL plant here.

MR. PETERSON replied yes.

CHAIRMAN TORGERSON asked if they had been talking with ANGTL then or did that happen later.

MR. PETERSON replied that the announcement that Forest Oil made was at a Senate hearing last September and the GTL plant they were talking about was on the North Slope. Forest Oil is extremely bullish on gas to be found in the Cook Inlet area. They believe that a large amount of natural gas will be found and that there really isn't a market to take these large quantities. GTL is just one option for that and because of the success of GTLs in South Africa, they thought this would be a good place to get involved in the U.S.

CHAIRMAN TORGERSON thanked him for his testimony and announced a short break so that Tony Izzo could give Enstar's overview on Cook Inlet reserves.

1:29

MR. TONY IZZO, President, Enstar Natural Gas Company, said he would give their perspective on projected gas usage as well as Southcentral demand and deliverability. Enstar is a local distribution company based in Anchorage serving the Mat-Su Valley, Soldotna and Kenai. They started operation over 40 years ago and serve over 106,000 customers with some of the lowest gas rates in the country and the highest residential usage in the country. He provided them with a snapshot of what rates are around the country. Anchorage is the least with .40 per cubic foot; San Diego is at the other end with $1.91.

MR. IZZO said their future plans include expansion of their system to Ninilchik, Anchor Point and Homer in the next year or two. Enstar owns and operates 2,700 miles of distribution and transmission pipeline operating at pressures of 1,000 psi. with line diameters up to 20 inches. On projected gas usage he said a little perspective helps. Enstar represents about 13 percent of the Cook Inlet consumption in any given year. They transport a good amount of the power generation and he showed the committee a chart of their projections.

Gas is purchased under long-term contracts with Marathon, Chevron, ML&P and Phillips and is indexed to changes in the price of crude

oil. They don't make money on the commodity, itself; they make money on the delivery. Their supply contracts are negotiated and go to the RCA for approval and move up over time based on the prices of oil and supply costs are passed through to customers. They have no take or pay liability, which means that if they don't take what they project to take from a producer, they're not required to pay anything. An example of this is a warmer than normal winter.

Enstar has two new supply contracts with Moquawkie (Anadarko & Phillips) deliveries starting in 1/1/02 and Unocal starting in 1/1/04. They are currently talking with producers about future supply. In the near term (2001 - 2008), it may become difficult to meet winter peak demands without new discoveries or development of peaking facilities, like LNG vaporization and underground storage. Industrial usage reduction may be needed to meet winter peak demand. Enstar, like others in the area, are very concerned about the economy of the community they serve and are pro-active. They have entered into new supply contracts at higher prices in an effort to spur exploration and increase reserves. Their new contract with Unocal contemplates that gas storage will be developed.

In the medium term (2009 - 2019) peak and daily deliverability become more difficult if approximately 2 tcf of additional reserves are not added and industrial use continues at the present rate after 2009. Along with that, the federal LNG license could be at risk. He showed the committee a chart called, "Estimated Deliverability Timeline Assuming that Industrial Use is Reduced by Half in 2010."

Average demand intersects known reserves around 2006.

TAPE 01-28, SIDE B

1:39

MR. IZZO pointed out that the chart, prepared in March 2001, shows there could be problems with peak demand in the year 2003. He is more optimistic than these numbers since he has seen the drilling programs with Marathon and UNOCAL and didn't think there would be issues with average or peak demand until closer to the end of the decade.

Long-term deliverability (after 2019) will most likely not be met in Cook Inlet unless 2 tcf of reserves are added and industrial use is discontinued after 2009. "After 2020, significant new reserves or North Slope gas is necessary."

He summarized that Enstar believes that the reserves of the Inlet are sufficient to meet residential and commercial needs in the near term and is optimistic that new reserves and/or storage will

improve near-term deliverability during peak demand. They are optimistic about future growth that is under way in Ninilchik, Anchor Point and Homer. "Enstar supports an in-state route for North Slope gas to ensure access to reliable low cost energy for future generations of Alaskans."

He said their primary concern is to keep homes warm and if they were pushed to the point of choosing, they would favor curtailing industrial use. He urged them to do anything possible to avoid that.

REPRESENTATIVE OGAN asked if there was a 20-inch gas line from Beluga into Anchorage.

MR. IZZO replied yes.
REPRESENTATIVE OGAN asked how big the line was from Anchorage to Kenai.

MR. IZZO replied that they have twin 12-inch lines that run parallel to each other across the Turnagain Arm.

REPRESENTATIVE OGAN asked how much capacity was in the lines, as Beluga was getting to be a real mature field. He asked if coal bed methane comes on line in the Matanuska Valley, do they have enough capacity to supply industrial users in Kenai.

MR. IZZO replied:

> Yes, we believe we do. If you were to average out through the year what our delivery is through our system, it's 128 mcf/d. We have endured some extreme periods, have tested that system up higher than 250 mcf/d and have had no problems. We know for instance that we could survive without one or the other of those lines. So, if we had maintenance to perform on the lines across the Turnagain from the Kenai, most days of the year, 99 percent of the year, we could survive with the Beluga line and the same would exists in reverse. If the Beluga line were down, we have enough capacity on the Kenai twin 12 inch lines that we could support our system throughout the Mat-Su Valley as well as Anchorage.

CHAIRMAN TORGERSON asked if the UNOCAL contract was capped at 450 bcf.

MR. IZZO replied:

> The contract provides them with the first option to provide additional supply. So, it is possible they could fill up the undesignated requirement in 2006 and provide

> much more in 07 as well as a layer going forward. The result of their drilling program would determine the actual specifics. What we see here is just what the contractual commitments are. The 450 bcf cap anticipates potential. So, if additional reserves are discovered, we certainly have an opening in the market and we'd be very pleased to fill it.

CHAIRMAN TORGERSON asked why go to the RCA if they have a contract for them to supply 20 years of gas.

MR. IZZO replied that was correct in the undesignated areas.

CHAIRMAN TORGERSON said they don't show anything after 07.

MR. IZZO replied if the drilling results were to provide additional reserves, there's a provision in the contract where they can fill up on designated needs.

CHAIRMAN TORGERSON asked if Enstar would go for the lowest price gas if they aren't bound to a contract with UNOCAL.

MR. IZZO replied that additional contracts would have to be approved through the RCA. Their goal has always been to obtain the lowest price they can, but it was determined that it was going to take a higher price to spur some exploration for additional reserves.

CHAIRMAN TORGERSON said the Henry Hub had the potential of taking the state in some drastic price swings. He appreciated Mr. Izzo's willingness to help them figure things out.

CHAIRMAN TORGERSON announced a short break.

2:09

MR. MARK SEXTON, President and CEO, Evergreen Resources, Inc., said Dennis Carlton, Senior Vice President, Exploration and Operations, and John Catigala, Alaska Project Manager were with him. Mr. Sexton gave an overview of their company, which is a public independent oil and gas company traded on the New York Stock Exchange with the symbol of EVG. He said:

> Our operations involve extraction of natural gas from coal seams in coal beds primarily from our leases in the Raton Basin in Southern Colorado. There are certainly other coal bed methane operations in the Lower 48, some larger than ours and some not as extensive as Evergreen. But none have been executed with more care for the environment, we believe, nor for the communities in which

> we operate. On that point, the Colorado Oil and Gas Conservation Commission recognized us for excellence in three of the last five years - in 96 and 2000 as outstanding operator specifically cited for community relations and in 97 as an outstanding operator specifically citing production enhancement. Closer to home in May of this year, Governor Tony Knowles gave Evergreen the Environmental Stewardship Award at the annual Interstate Oil and Gas Compact meeting that was held in Anchorage. We've added quite a few jobs to express regions bringing prosperity and vitality where previously the southern Colorado economy was stagnating and notoriously so.
>
> In the following discussion you'll hear the term coal bed methane. Please keep in mind that coal bed methane is just really another word for natural gas. They're almost chemically identical except in this case it's just natural gas that comes from coal seams directly. A lot of natural gas that you think of as natural gas was actually sourced from coal seams that migrated into more conventional sandstone type reservoirs.

MR. SEXTON showed the committee graphs of the coal content in coal methane and their prospects in Alaska.

Evergreen plans to drill 6 - 10 wells next year in the Unit and to complete a disposal well. He said it's important to differentiate between resources and reserves. Resources are simply estimates of the amount of the physical gas in place without regard to what would be economically extracted. Reserves are resources in place that are proven to be economic through existing wells at existing prices with existing technology. So, there is a huge difference between reserves which are tied to economics and resources which are simply estimates of in place supply.

He said that it is well documented that groups of wells do better than single wells producing in isolation. Once they get results from exploratory wells, they would know how fast development of this resource would go forward. Coal bed methane would alleviate the need for a natural gas pipeline from the North Slope and that gas could be rerouted to other markets. He said:

> Natural gas in the Cook Inlet will provide a steady and long-lived source for jobs and provide the most efficient use of capital in that area. It's probably the most secure and reliable way of providing Cook Inlet with a long-term supply of natural gas, which is the nature of coal bed methane. It is very long-lived, typically 20 -

> 30 years of reserves. As far as our current assessment of what's going on, we're going to have to rely on statistics published by the Alaska Division of Oil and Gas and the Conservation Commission. In the case of coal bed methane, our own studies suggest that coal bed methane does have the potential to replace the decline in gas production of reserves in the Inlet if economic. Our estimates are that we can get probably 1 tcf in the Pioneer Unit area alone. More gas on the order of several tens of trillion cubic feet are possible. Again, the long-lived natural gas suggests it could be a long steady course. I do know, however, that the six prior attempts to produce coal bed methane gas in the Cook Inlet were not successful and after reviewing those histories, we're not surprised that those wells did not produce gas. As I indicated earlier, through our own experience, we know that very slight variations in [indisc], completion techniques, production practices have a huge and profound impact on the success or failure of a coal bed methane well.

MR. SEXTON said they use their own companies and aggressively use local people and contractors getting their work done. For exploration plans they also have shallow gas lease applications pending with the state that were applied for in February 2000. Once those leases are granted by the end of this year, Evergreen will negotiate with the successful lessees and unitize the acreage. If unitization could be accomplished next year, permitting and exploration activity could also begin that year and they would be drilling wells in 2003 and beyond. Their next year's budget is roughly $5 million. If successful, they hope to accelerate as in the Raton Basin - slowly and prudently to make sure they are doing it right. They are spending over $75 million in the Raton Basin this year, but their investment actually exceeds a quarter of a billion in drilling and almost a quarter billion in acquisition.

Their demand has grown by 2 bcf per year and they see no reason that trend won't continue. As delivering peak volumes on the coldest winter day becomes more difficult, they use short-term solutions like additional compression, recompletion of existing and drilling new wells in established fields to increase peak recoveries. The real long-term solution is to develop new gas supplies with long-term life, such as coal bed methane.

MR. SEXTON said there is legislation that could advance the development of coal bed natural gas. He couldn't stress the word, "if" enough.

> I am confident that if coal gas is produced in Alaska, then Evergreen is the company to do it. We have the

> technical expertise to do it and the state of the art equipment required to make coal bed methane a technical success. We have a very integrated group that works well together to do all this with the highest level of quality assurance and quality control…Coal bed methane is different from other types of gas development that's occurred in the state. We can get it; we can get in and out very quickly, drill wells, be in and out within a couple of days and fracture simulate in a day.
>
> Doing this development requires streamlining the permitting and regulatory processes. I'm sure in the upcoming session bills may be proposed that attempt to fill in the regulatory gas gap. We ask that you consider this and to hear Evergreen's opinions on them, because it will profoundly affect our ability to go forward.

Probably their greatest challenge to developing coal bed methane in Alaska, MR. SEXTON said, is dealing with the issue of gaining surface access for subsurface mineral development. For this reason they believe legislation must be passed that encourages the surface owner to cooperate with the gas companies wanting to develop natural gas on their land rather than allowing the surface owner to discourage this development. He said that coal bed methane development is an environmentally friendly process inherently and they are proud of their track record in this area.

MR. SEXTON'S concluding remarks were:

> First and foremost our goal is to secure a long-term supply of secure natural gas for Alaska just as we have for the citizens of Colorado. We specifically target Alaska because of its favorable business climate, its experience and sophistication with oil and gas matters in development and, of course, we believe coal bed methane resource is highly prospective there, particularly around Anchorage.
>
> Second, coal bed methane is a long-lived resource naturally and provides us the opportunity to make a long-term investment in Alaska. That's not just a lot of gas; that's a lot of jobs. We've grown from just a few jobs in southern Colorado to directly or indirectly employ several hundred people in the Raton Basin. Just as our activities there have resulted in long-term jobs and growth and prosperity, so too could our investment with you in Alaska…

> Thirdly, we support Alaska's efforts to build a natural gas pipeline to the Lower 48 and hope that Cook Inlet has sufficient gas to allow us to transport some of our own gas into that market. Above all else, we want to be contributing citizens in Alaska. We want to provide jobs; we think we can; we think we can provide environmentally responsible development that result in a long-term clean energy source, which this state needs and particularly the Anchorage area requires. We've done exactly that in the Raton Basin; we're proud of our track record and look forward with great anticipation to replicating that success here with you.

CHAIRMAN TORGERSON thanked him and said this was his first exposure to Evergreen.
2:39

REPRESENTATIVE OGAN said he was concerned about the conflicts between the surface owners and the subsurface owner (state). He asked him to describe ways that he had worked through that issue in Colorado.

MR. SEXTON said the first thing they do is talk to people.

> We don't tell people the way it is; we tell people this is what our program is; this is what we'd like to do. This is how it might benefit you. What do you want? And we find out that people generally have very strong ideas about what they want…

TAPE 01-29, SIDE A

MR. SEXTON said their wells are small with very small footprints. Their well pads are 200 x 125 ft. They also do visual and sound mitigation; but mostly they talk to people in the local communities and lett them see it's not really a big deal.

SENATOR OLSON asked how successful he thought a coal bed methane source of energy would be for people in western Alaska where energy prices are expensive.

MR. SEXTON replied:

> Probably one of the better examples of that is the Red Dog mine area, an area where they're importing diesel fuel about three months out of the year and have to stock pile it. We're examining the potential of a shallow gas play up in that area, which probably wouldn't be coal methane, but shale-type sand development. As an example

there, even with the economies of scale they have, it still costs them with the diesel fuel they have to import, the equivalent of paying $10 - $12 per mcf. The residents of Fairbanks are having to take liquefied natural gas costing on the order of $7 mcf. Coal bed methane is fairly economic at $3 - $4. If we can get a large enough area, get the process going and keep the economy in scale going, the reality is a coal bed methane play is the potentially perfect solution for these people that can't otherwise get energy.

They could in fact with a little bit of help and effort - a few pilot projects to show that it's economic - this has the potential to supply natural gas to a lot of areas which simply would not be available, where it's hard enough to get the diesel and fuel oil brought in. We'd be very interested in working with the state outside of the easy to access areas and to look at areas where there's a critical need in the outer communities for energy and see if we could work with the state to establish a viable coal bed methane project. If it works, you've got a 30-year supply of gas to help these people out.

SENATOR OLSON asked if they were looking at extensive pipelines reaching across the tundra for long distances or at a different well sight for each community.

MR. SEXTON replied that each community could be serviced with a very few wells.

A typical coal bed methane well produces 100 - 500 mcf/d. This is about the amount of gas that a 1 megawatt generator requires. Even if you could not get a pipeline system through there, if you got a few wells in a cluster and brought them to a central point, you could generate power and supply to power people, but could also supply the gas to people. You don't need a whole lot of wells drilled to supply a community…

SENATOR OLSON asked a question about reserves.

MR. SEXTON replied that there is some potential on the Yukon Flats east of Fairbanks. There are huge deposits of bituminous coal.

The great thing about coal bed methane is if you do it right, it's very environmentally friendly…. No petrochemical burns cleaner than pure methane. It is the simplest form of hydrocarbon and it's the environmental solution. Water disposal is the issue and where the water

doesn't meet the surface use requirement, we simply reinject it into deeper formations where the water quality obviously isn't very good.

SENATOR OLSON said the Yukon Kuskokwim Flats are quite a ways away.

MR. SEXTON said he didn't know about that area, coal bed methane as a process can be done just about anywhere as long as you can get it out economically. The only way to know that for sure is to drill a few wells.

MR. SEXTON thanked the committee for the opportunity to speak with them.

CHAIRMAN TORGERSON thanked him and said they would be getting back to him and announced that concluded the public testimony portion.

2:50 - 2:58 BREAK

SENATOR TORGERSON announced that they would begin the committee meeting portion of the schedule. He said that Williams Petroleum offered to meet with this committee in Tulsa in early December and show them how gas is traded on the open market. He also announced that the Premier of Alberta appointed Mark Glady to the International Committee. It now includes Alaska, Alberta and they are trying to get B.C. to join. The first meeting was set for December 6 in the Yukon and will be very informal.

He informed the committee that the Legislative Council approved $300,000 to hire an in house economist, either an individual or a firm. He is in the process of getting an RFP ready to go and the goal is to have done the hiring by mid-December.

The chairman said that he didn't think there would be a lot of new information to go over in regards to the producers' application, but there are on-going studies that should be released close to mid-December, primarily one that compares pipeline ownership around the world including ones that are financed by government. He left the date of the next meeting open and adjourned this meeting at 3:13 p.m.