

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

May 11, 2007
1:43 p.m.

MEMBERS PRESENT

Representative Carl Gatto, Co-Chair
Representative Paul Seaton
Representative Peggy Wilson
Representative Bryce Edgmon
Representative David Guttenberg
Representative Scott Kawasaki

MEMBERS ABSENT

Representative Craig Johnson, Co-Chair
Representative Vic Kohring
Representative Bob Roses

OTHER LEGISLATORS PRESENT

Representative Mark Neuman
Representative Berta Gardner
Representative Bob Buch

COMMITTEE CALENDAR

PRESENTATION: SPENCER HOSIE, RICK HARPER, DON SHEPLER, KEN
MINESINGER, SCOTT HOBBS, AND W.H. SPARGER: BUILDING AND
FINANCING GAS PIPELINES

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to report

WITNESS REGISTER

SPENCER HOSIE, Attorney at Law
Hosie McArthur LLP
San Francisco, CA

KEN MINESINGER, Attorney at Law
Greenberg and Traurig LLP

Washington, D.C.

BILL SPARGER, Consultant
Energy Project Consultants, LLC
Colorado Springs, CO

DON SHEPLER, Attorney at Law
Greenberg and Traurig LLP
Washington, D.C.

SCOTT HOBBS, Consultant
Energy Capital Advisors

RICK HARPER, Consultant
Econ One Research, Inc.
Los Angeles, CA

ANTONY SCOTT, Commercial Section
Central Office
Division of Oil & Gas
Department of Natural Resources (DNR)
Anchorage, Alaska

ACTION NARRATIVE

CO-CHAIR CARL GATTO called the House Resources Standing Committee meeting to order at [1:43:19 PM](#). Representatives Gatto, Seaton, Guttenberg, and Edgmon were present at the call to order. Representatives Kohring, Wilson, and Kawasaki arrived as the meeting was in progress. Representatives Neuman, Gardner, and Buch were also present.

PRESENTATION: SPENCER HOSIE, RICK HARPER, DON SHEPLER, KEN MINESINGER, SCOTT HOBBS, AND W.H. SPARGER: BUILDING AND FINANCING GAS PIPELINES

[1:43:54 PM](#)

CO-CHAIR GATTO apologized for the late start of the meeting and thanked Gavel to Gavel for broadcasting the meeting. He then asked Mr. Hosie to begin his presentation.

[1:44:43 PM](#)

SPENCER HOSIE, Attorney at Law, Hosie McArthur LLP, a founding partner of the San Francisco law firm, told members he was asked to speak about the duty to develop under the Alaska lease form.

He informed members he has been a practicing oil and gas lawyer for almost 25 years. He began his law career working for the State of Alaska in the early 1980s on the Amerada Hess case. Today, his firm runs a national energy and intellectual property practice. His firm represents a wide range of private and public royalty owners. He has been the lead outside energy lawyer for the State of Louisiana for almost a decade in litigation and regulatory matters. His firm has represented the State of Hawaii, and worked with the U.S. Department of Justice in connection with federal royalties in the whistleblower context. His firm has deep experience in oil and gas matters.

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MR. HOSIE said he has personally had the occasion and opportunity to review millions of pages of oil company documents over the last two decades. He believes he brings a detailed understanding of how oil companies assess a capital intensive upstream infrastructure project: what matters, what doesn't matter, what gets built, what doesn't get built and why.

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MR. HOSIE presented the following information:

To understand the duty to develop, it is important to understand the nature of the relationship that an oil and gas lease creates between the royalty owner, which is the landowner on the one hand, and the oil company on the other hand because it is a relationship very unlike a typical commercial arms-length relationship.

The process starts with the landowner that had land that may or may not have mineral resources on it but the landowner typically doesn't have the expertise to explore the property, doesn't know how to develop the property, doesn't know how to produce any hydrocarbons found, and certainly doesn't know how to market hydrocarbons for the best possible price. The landowner needs a partner and that is, of course, the oil company.

The oil company has exactly the suite of expertise that a landowner needs. Oil companies are expert at development, at exploration, at marketing. And so what happens is the two get together and sign a very short contract called a lease. I mean short - I mean

it is two pages, two and a half to three pages long. It's a very short document given that the relationship created can last 50, 70, 80 years.

Now the landowner contributes the real estate the landowner owns. That's what the landowner brings to the table. For their part, the oil companies contribute their expertise. They promise to get the lease in the first instance, to use their expertise to explore the property, to develop the property, to produce the hydrocarbons and to market the hydrocarbons all for the mutual benefit of themselves and, importantly, the landowner, the royalty owner. That's how an oil and gas lease works.

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In return for promising to use its expertise to develop and to market, the oil company typically gets the lion's share of the value of production. In Alaska, under the largely prevalent lease form, the oil companies get a full 87.5 percent of the value of production. The state's royalty share is 12.5 percent and that, given modern standards, is very low but it was the norm back when the state's lease form was drafted in the late 1950s.

But, in return for the lion's share of the value, the oil company has the obligation to explore, develop, produce, and market diligently all with the mutual interests of both the oil company and landowner in mind. It is a relationship which the courts have characterized for many, many decades as one of mutual interdependence. The precise phrase the courts use; it's a relationship of mutual benefit. They are in it together and that means that the oil company, after it signs on the dotted line on the lease, is no longer free to use its unilateral economic self interest to make decisions. It's no longer free to say what makes us the most money and act accordingly.

To the contrary, in making development decisions, production decisions, it has to take into account the interests of its partner in this venture, the royalty owner, the landowner, so it's no longer a commercial relationship where one party acts according to its economic self interest alone. That's a critically

important thing about the royalty relationship that is really quite unique to that relationship and very much unlike a typical commercial relationship.

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MR. HOSIE continued:

Now, oftentimes the economic interests of the royalty owner and the oil companies are aligned but, every so often, there comes a situation where the interests diverge, where they depart. One common place where we see a diversion comes with development or further development and here's why. A landowner almost invariably wants the property developed. A landowner, royalty owner, only gets paid when the hydrocarbons are produced, severed, and sold. That's the event that generates the royalty payment to the royalty owner so they want the product developed so they can get paid. Of course that's why they've gone to the oil company in the first instance - produce this property for us.

On the other hand, you could have a situation where a given oil company, for any number of reasons, might prefer not to develop a given property, at least not right now. They might be long in the particular resource, e.g. long in gas in the West Coast in the Lower 48. They might be short of cash. They might have sufficient cash but prefer to spend those dollars somewhere else, on projects abroad where the oil company perceives that if it doesn't move development forward, it will lose the opportunity. The company may have what's known as a very high internal hurdle rate, which is a return on investment [ROI] rate that must be exceeded to green light a development project. For example, Exxon's return on investment for its upstream activity in 2005 was 46 percent. It's ROI across the company in 2006 was 33 percent. That's a very high return on investment and so there could well be a situation where a company says you know what? This might be an economic project but it's not economic for us because we want all projects to be at a 30 percent plus return before we go forward. Or a company might simply be spending its money in other ways.

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Another case in point - in the last two years Exxon spent \$41 billion buying back its stock on the open market - that's \$41 billion in two years. It did that to keep its stock price high and to keep Wall Street happy. And I'm not saying that that's an irrational thing for Exxon to do. From Exxon's perspective alone, that was probably a great idea because its stock price is high and Wall Street is happy.

Those are important goals for Exxon but the key point is this. Once Exxon was in a lease relationship with the State of Alaska, one going back 30 years, one under which Exxon and the other producers on the North Slope have made gargantuan profits from production to date, Exxon can no longer make decisions based solely on its own economic self interest. That's not the proper approach.

And so there's this inherent conflict in development circumstances. The landowner says listen, we really want you to develop because that's how we get paid. The oil company says well you know it's really not in our interest, at least not right now. We've got other things we'd prefer to do.

1:53:59 PM

MR. HOSIE continued:

That conflict is solved by the implied duty to develop. The implied duty to develop can be expressed very simply, in plain terms. An oil company has an obligation to go forward with a given development project if that project is, on its own merits, reasonably economic - full stop - period. That's the duty. If a given project is reasonably economic, the oil company has an obligation to go forward. Why? Because that's the deal it made to get the lease. It said I will use my expertise to develop this for you diligently and, in return, I want the lion's share of the value of production. That was the deal going in.

And so, if a given project is economic, the oil company has an obligation to its partner in this venture, the royalty owner, to go forward.

1:55:05 PM

One analogy I have used that I find helpful in this area relates to the following. Assume that Toyota is thinking about putting a new manufacturing facility in one of five or six Southern states in the Lower 48. It goes to the five or six states and says listen, we're ready to spend our development dollars. We're going to build a manufacturing factory. We're going to give jobs. We're going to help your tax base. This is great for you but, tell us, what will you do for us? That will start, essentially, an auction between the various states to see which state can put together the most attractive development deal with tax incentives, real estate rebates, and job promises, and educational benefits, and the like.

At the end of the day let's say that Kentucky wins that contest and Toyota agrees to put that plant in Kentucky. Let's also say that Kentucky does something that's pretty shrewd. It says as part of the first deal, listen Toyota, this is all great, this is all well and good, but if this first facility is profitable and there comes a time when you're thinking about putting a second factory in, you have to build it in Kentucky.

That is exactly the situation the State of Alaska is in with its leases. They made the obligation to develop diligently for the mutual benefit of both the State of Alaska and the oil companies when they signed the leases so many years ago. Under that obligation they don't get to come to the state now and say listen, we can get a higher rate of return elsewhere on our money. Or, there might be a more profitable project in Kazakhstan or Qatar. Or, we'd really prefer to spend our money buying our stock back. Tell us, make it worth our while. That is absolutely a breach of the obligation under the lease form these companies have done extremely well by.

That's the duty to develop. Now the question arises: well, all well and good, Mr. Hosie, but is that duty present in Alaska law and the deal on lease forms?

1:57:13 PM

I can tell you yes, unequivocally and absolutely, it is. And when was the last time you heard a lawyer say something about absolutely? It is absolutely present and here's why.

First, paragraph 19 of the lease itself talks about further development and specifically says that the producer oil company has to have due regard and I quote, "due regard for the interests of the state in making additional drilling and development decisions." That's the language of mutual benefit.

Second, this question has already been resolved in this state. In what was then known as the ANS royalty litigation in 1989, then Judge, now Justice, Walter Carpeneti issued a decision looking at the lease form and which duties were in that document and which not. In that decision, which was fully binding on the parties, the state and the oil companies alike, Judge Carpeneti said that the lease form contained a full array of duties including the implied duty to develop. There simply can be no question but that there is a duty to develop under the Alaska lease form and Alaska law generally.

And so, the question arises, given that the duty exists here, what constitutes a breach? What can't an oil company do? When would conduct qualify as a breach of the implied duty to develop?

[1:58:59 PM](#)

Well, if an oil company looks at a particular project, be it the Pt. Thomson Unit or a gas line in Alaska, and if the oil company concludes that that project is on its own terms reasonably economic but nonetheless refuses to go forward, that is a breach of the implied duty - full stop - period. If the oil companies refuse to do that economic analysis, but instead refuse to invest because they have an overall national or perhaps international policy of not spending on capital enhancements for the following year or five years, that would be a breach because they have to at least run the numbers and check to see if it's economic.

If an oil company refuses to go forward but then if a third party comes and says, listen we will build it if you'll sell us your production at a reasonable market price, if that happens and the oil company says no, we're not going to build it but you know what? We're not going to sell it to you either, that would be a breach of the implied duty. Why is that? Because effectively they're just bottling the resource up in the ground. The courts call that speculative in-ground warehousing. They're warehousing the resource and that violates every tenet of the oil and gas lease because it may be in their best interest but it surely is not in the royalty owner's best interest.

And so, there are cases going back 40 years that say listen, if they are in-ground warehousing, that is inappropriate. It's a violation of the lease. You can't just bottle it up and if they've done that, that's improper.

[2:00:41 PM](#)

CO-CHAIR GATTO noted Exxon does not have a pipeline in some situations in which to ship resources so, for 20 years, it has been recycling the gas. He asked at what point the state could say Exxon is no longer satisfying its duty in that case.

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MR. HOSIE explained when the state concludes that a gas pipeline is reasonably economic, it has the right to make Exxon and the other producers choose to either build it or let the resource go. He said the remedy has to be considered. If the state assumes it has a breach, has a lot of gas stranded and wants a gas pipeline but the company will not build it, litigation should not be the first option for remedy as it rarely provides a happy outcome. Fortunately, a royalty owner has a different remedy in the breach of implied duty context.

[2:02:01 PM](#)

MR. HOSIE continued:

That remedy is that the oil company must surrender the resource back if it says a project is not economic and it will not go forward. He pointed out the discovery wells were drilled in Point Thomson 30 years ago.

Point Thomson has not produced a drop of oil or cubic foot of gas. Instead, 30 years of studies have taken place. The oil companies have told the state repeatedly that Point Thomson is not an economically feasible project and have said they will not go forward with a gas line until the state compromises its economic position to improve their economics.

In my understanding, that's what they've said to the state repeatedly. I've seen language like that in the Point Thomson plans of development - the annual plans. In that situation they have said they are not going forward and they cannot say that, yet [they] continue to hold the resource indefinitely. Why not? Because they are just bottling it up in the ground and they're speculating with the gas and warehousing it until, for their own reasons, they think the time is right. Maybe that's five years, maybe it's 10 years, maybe it's 20 years. Maybe it's after they burn through the 900 trillion feet of gas they're producing in Qatar. I don't know when they are willing to do it but what we do know is that they sure aren't willing to do it today.

[2:03:43 PM](#)

MR. HOSIE continued:

I read an op Ed piece by Representative Doogan a couple of weeks ago. He said you don't have a pipeline because Exxon doesn't want you to have a pipeline and I think that's exactly right.

So the remedy isn't to charge off into litigation. It's not your job to compel them to honor their obligations and build a pipeline and, honestly, does the state want an unwilling partner in a project like this? No. Just make them choose. If they really don't think it's economic, they have to give the resource back. And then you can go to other oil companies that perhaps have a greater need for gas today as against 10 years from now or may have a greater need for reserves, e.g. Shell. Shell would love to have a deeper reserve base - e.g. Chevron. Chevron is working hard and spending money all over the world to increase its reserves. Different companies have different positions and different

needs. The royalty owner has the right to get the resource back if the first set of producers won't move forward on it and see if you can't get another group of producers to commit to build the project in concrete and specific terms.

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Now what do we know about North Slope development and the duty? As I said, we know that the producers have said that right now it's not economic to go forward. That's been, as I understand it, the entire justification to ask the state to give some economic concessions. Help us make it economic. It's not economic without help.

Well, two things on that. First, if that is true, they have to give the resource back and second, I know at least that that's not what Exxon really thinks. And here's how I know.

There are detailed accounting standards that govern how an oil and gas company reports reserves for its SEC filing purposes - SEC is the Securities and Exchange Commission - for annual reports and quarterly reports. They are called financial accounting standards and they are promulgated by the FASB or Financial Accounting Standards Board. Financial Accounting Standard 19 governs how an oil company accounts for exploratory drilling costs on properties that are not yet proven and not in production. That accounting standard changed on April 4, 2005. The new standard said the following. Oil company, you continue to capitalize, that is carry on your books, these expenses but only if you have no substantial doubt that the project is economically viable and two, economically viable under today's market prices and with today's technology.

Let me say that again because it's important. I am specifically quoting paragraph 31(a) of FASB 19-1, promulgated April 4, 2005, "An oil company can continue to ...capitalize development costs only if it has no substantial doubt that the project is economic and (b) economic based on today's market prices and technologies."

2:07:28 PM

MR. HOSIE continued:

Exxon reviewed that new accounting standard in May and June of 2005, and on July 1, 2005, reported that it had decided that Point Thomson was not a project with substantial doubt as to its economic viability based on 2005 technology and market prices. There is a one-line footnote in their 10K for 2005 that says they've adopted new accounting and when you look at the new accounting, that's what you see they have to have done.

So this was not a decision made lightly. SEC reporting for oil companies, especially given the Shell debacle of some years ago, is something they take very seriously and are careful about. So, Exxon will have looked at the economics, it will have talked to its outside auditors, Price Waterhouse Cooper - PWC. There will be paper going back and forth and Exxon would have determined and convinced its auditors, who had to sign off on this, that Point Thomson was not a project with substantial doubt about its economic ability.

That is inconsistent with what Exxon was telling the state right there and then and even this past couple of months. I've read testimony where Exxon officers have said, you know, this project is not economic without help from the state. If they really believed that was true, they could not have taken the SEC accounting they took. They did not - forgive me for being blunt - they did not mislead the SEC. They truly think it's economic but what they were doing with the state was negotiating. These are people that negotiate for a living. It was a negotiation. It wasn't actually accurate when they said it's not economic. It was just a negotiating position.

And so it's really important that the state understands that these are negotiations and, you know? Sometimes they are positions and sometimes they are negotiating postures. You have to be careful to take what you are told with a grain of salt.

2:09:21 PM

And so, I thought that was a significant discrepancy between what Exxon was telling the state and what it was telling the SEC, the investing public and Wall Street.

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MR. HOSIE stated his final point, as follows:

It's easy to talk about these oil companies as sort of a shapeless, faceless, "they;" some sort of monolithic they. They are not that. They are different companies. Exxon behaves, thinks and acts one way. Chevron is a very different oil company. It has different needs and desires. ConocoPhillips is very different too. It's very important, I think, for the state to understand that even though these companies are terrifically good at presenting a unified face to the state, internally they may have sharp disagreements about what is proper, what is not, and what should be done. It's important in dealing with them to keep that in mind.

Thank you. That's all I have but I would be delighted to answer any questions, Mr. Chairman [that] committee members have.

[2:10:22 PM](#)

CO-CHAIR GATTO announced the members present: Representatives Guttenberg, Edgmon, Seaton, Gardner, Wilson, Kawasaki and Buch.

[2:10:53 PM](#)

REPRESENTATIVE EDGMON asked if the term "reasonably economic" is well grounded in case law and federal law.

MR. HOSIE said it is. He explained that to be "reasonably economic," it is not the state's obligation to take all the risk out of the project. The oil companies accepted risk when they signed the lease and that is one reason they receive 87.5 percent of the value. Regarding what is reasonably profitable, that is a function of investment rates and rates of return in the industry in general. That could be 8, 10 or 12 percent. However, it is not 25, 35, or 40 percent. If the oil companies have a ROI [Rate of Investment] hurdle that is that high and has

not green-lighted Alaska because it is not screamingly economic, that is a violation of the lease. He added that all of these companies have written upstream investment guidelines that set their investment hurdle rates by region and hydrocarbon. They will have a hurdle rate for Point Thomson; he believes the state is entitled to see the hurdle rates if an oil company claims a project is not economic.

[2:12:57 PM](#)

REPRESENTATIVE WILSON asked if Mr. Hosie said the oil companies were posturing for the purpose of negotiating. She said when the state set up its "must haves" in Alaska Gasline Inducement Act (AGIA), the oil companies said meeting those conditions would be impossible for them to do and claimed, via radio commercials, the state was not allowing them in. She questioned whether they cannot get in or do not want to get in.

MR. HOSIE answered what they said was just another piece of a larger negotiation. An oil company wants a deal that is the most economically beneficial for it. He said he would not assume that they maintain the position that the "must haves" are deal breakers for them, but he does not assume they will be excluded. What the Legislature has done is sparked an open competitive process, which is a good thing. If, at the end of the day, the state forces the larger oil companies to commit to developing or relinquishing the leases, he believes the companies will not give the leases back.

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REPRESENTATIVE BUCH asked the name of the state's lease agreement.

MR. HOSIE replied it is named the DL-1 lease agreement; DL for Department of Lands and 1 because it was the first lease draft created in 1959 by a lawyer who worked for Chevron.

[2:15:26 PM](#)

REPRESENTATIVE BUCH asked for the name of the document he referred to earlier dated April 4, 2005, regarding an oil company's statement and position.

MR. HOSIE said he referred to several essential documents. The first is a 2005 10K annual report. It contains a category in the financial footnotes for suspended well costs and it

specifically refers to Point Thomson. In it Exxon says it is not expensing Point Thomson costs; it is continuing to carry them as a capital asset. It then cites the new accounting standard, FAS 19-1, particularly paragraph 31(a). That paragraph states what had to be included to take that accounting treatment. FAS 19-1 was a new standard that says, under paragraph 31(a), "no substantial doubt"; about the economic viability of Point Thomson. If [Exxon] told the state that Point Thomson was not economic, that accounting treatment was improper. He noted the inconsistency between what [Exxon] told the FCC and what it told the state is what he wanted to impart to the committee. He stated:

The final point on that, it's less a new accounting for them because they were capitalizing all along. What was new was the new accounting standard that made them ask and answer this question; specifically in that April, May, June 2005 period. That was new. They looked at it. They said we have no substantial doubt about economic viability and they took the requisite accounting benefit thereafter.

So again, the 2005 annual K - the 10K, the annual report, FAS 19-1, and particularly paragraph 31(a) therein.

[2:17:48 PM](#)

CO-CHAIR GATTO said he could imagine Exxon telling the SEC the project is viable at a 12 percent profit but telling the state it is not profitable below 33 percent and both statements would be accurate.

MR. HOSIE said they would be accurate had Exxon conceded to the state that the project was reasonably profitable with a 12 percent return, but would not go forward without the state taking action to increase the return to 35 percent. He felt the negotiation would have been different had Exxon conceded that. Instead Exxon told the state it needed help because the economics were not viable.

[2:18:54 PM](#)

REPRESENTATIVE SEATON asked if the same filings apply to the other participants in Point Thomson or whether they just apply to the operator.

MR. HOSIE said BP and Exxon took the same accounting in 2005. However, very recently BP wrote down its investment in the Point Thomson unit, probably as a result of the unit agreement litigation. ConocoPhillips didn't call it out, most likely because it did not have enough money invested to make it pivotal. He thought Exxon is the largest investor in Point Thomson.

[2:20:00 PM](#)

CO-CHAIR GATTO asked if the landowner and Exxon have an agreed-upon understanding of the term "specific clarity."

MR. HOSIE thought perhaps not. Exxon has been famous for high grading its investment. It wants to drive its ROI up every year. Its ROI is currently twice the average in the oil and gas sector. That is a sound business strategy because Wall Street loves it and Exxon's stock price remains strong. Exxon spent \$41 billion buying back its stock, which means that money is no longer available for upstream development. He pointed out that Exxon could easily decide to not go forward unless a project meets its own internal hurdle guideline.

[2:21:44 PM](#)

REPRESENTATIVE GARDNER asked if the state could request, through discovery, documentation of Exxon's internal hurdle if the case is in court, or whether a better way to get that information exists.

MR. HOSIE said the state would certainly have the right to see the documents in court. However the state may have subpoena powers as part of the process to move the gas line forward. He believes if the state made such a request, it would be difficult for Exxon to say it needs help economically but cannot show the state its own studies. The state and Exxon are in this together and Exxon has obligations.

[2:22:55 PM](#)

REPRESENTATIVE GARDNER asked who should make the request.

MR. HOSIE said he believes DNR, and said DNR should request copies of specific documents directly from senior Exxon officials.

[2:23:13 PM](#)

CO-CHAIR GATTO recalled reading [Exxon's worldwide] annual report in which the following caption caught his attention: Our Enormously Profitable Alaska Operation. He said he suspects that backing off from an enormously profitable operation is not a good idea. As a result, Exxon will wait. Alaska's gas is enormously profitable, in which case Alaska is broke but Exxon is happy.

MR. HOSIE said he thought that is exactly what Exxon is doing: waiting the state out.

[2:24:09 PM](#)

CO-CHAIR GATTO thanked Mr. Hosie for his testimony and said he clarified the topic of the "duty to develop" for committee members. He asked Mr. Hosie to send copies of the 10K report to the committee electronically.

The committee took an at-ease from [2:24:46 PM](#) to [2:30:07 PM](#).

[2:30:08 PM](#)

CO-CHAIR GATTO asked Mr. Minesinger to present to the committee.

[2:30:32 PM](#)

KEN MINESINGER, Attorney at Law, Greenberg Traurig LLP, told members he would address FERC and antitrust issues, specifically how AGIA addresses the competitive problems associated with a producer-owned pipeline. He stated the following:

FERC and antitrust issues are critical to understanding AGIA and how it fixes the core problems that would be associated with producer ownership of the pipeline that we all hope to be built.

[2:31:40 PM](#)

Specifically, and I have a slide presentation ... we're going to address four competitive issues. First we're going to look at the competitive problems associated with a producer-owned pipeline. Second, we're going to look at how AGIA's "must have" provisions work toward fixing those problems. Third, we're going to discuss why those "must have" provisions in AGIA are critically necessary to fix those problems. Finally, we're going to briefly discuss a

question that has arisen, the question being if an independent pipeline happens to win the AGIA license and holds an open season, what anti-trust implications are there, if any, if the producers don't show up to the open season and don't bid for capacity on this pipeline.

[2:32:34 PM](#)

Before we go into those issues, I'll just tell you a little bit about myself. I've represented several major interstate natural gas pipelines and other clients before the FERC, including the largest natural gas pipeline in the United States. I've represented these clients in FERC rate proceedings, certificate proceedings involving the construction of major pipelines, and in some of the largest market power proceedings at FERC in the last several years. I've also served as the chairman of the Antitrust Committee of the Energy Bar Association, and I've worked on numerous antitrust matters involving natural gas pipelines and other energy companies and I think bring a unique FERC and antitrust perspective to this issue.

[2:33:26 PM](#)

MR. MINESINGER continued:

Let's first talk about the competitive problems with a producer-owned pipeline. I would just say, first, we address these issues in detail in a memorandum that we prepared for LBA - actually two memoranda: one in 2005 and one, the most recent one, is December 21, 2006. It's posted on the LBA website if you want to read about this in even more detail.

The main competitive issue that we discussed in the memo that we wanted to talk about today is one of vertical market power. A producer-owned pipeline would own both the pipeline and the gas and, as a result of that vertical integration, would have an incentive not to ship gas produced by competing producers. The analogy I like to use - folks are probably tired of hearing me say it, is - imagine you have three railroads and there's one bridge across the Mississippi River. If one of the competing railroads buys the bridge, whose rail cars will have an incentive to let across that bridge first. It's going to have a clear incentive to let its trains go across and

discriminate against its competitors. That's what we're dealing with here.

The disincentive that a producer-owned pipeline would have could manifest itself in several ways. First, expansion, as we'll see, would have a disincentive to expand the line to serve its competing producers. There would be access and discrimination problems. They would have an incentive to find ways, sometimes subtle, to discriminate against its rival producers. It would also have an incentive to delay the project, to not move forward with the project in order to perhaps avoid flooding the market with not only its gas, but gas from its competitors.

And finally, the vertical relationship could facilitate collusion between the three producers. When I use the term producers today, I'm referring to Exxon, BP and Conoco.

[2:35:50 PM](#)

CO-CHAIR GATTO announced the committee would take a break to address a technical problem.

The committee took an at-ease from [2:36:05 PM](#) to [2:37:15 PM](#).

[2:37:15 PM](#)

MR. MINESINGER continued his presentation, as follows:

So let's talk about the vertical market power issue just a little more. It's important to recognize that this isn't just theory. This is something that the U.S. Department of Justice, the Attorney General, in 1977, found to be a major issue. In '77 the Attorney General stated it would be in the interest of producer owners to resist future expansion of this pipeline and discourage future entry into Alaskan gas production by others. Why? Because the producers' market power could be reduced by discovery and development of new fields by other producers in this state.

The Attorney General also stated a producer-owned pipeline would seek to restrict access and throughput to take monopoly profits. As a result, in '77, the Department of Justice recommended a complete ban on producer ownership of this pipeline.

Now, several years later, the Reagan Administration revisited the issue. And while they didn't recommend a ban, they issued what is sometimes called a conditional waiver. Essentially what they said was we might permit producer ownership but only if the producers can convince FERC that antitrust issues will not be a problem.

[2:38:43 PM](#)

REPRESENTATIVE GARDNER asked if the Department of Justice ban recommendation applied to all pipelines or just the Alaska pipeline.

[2:38:53 PM](#)

MR. MINESINGER informed members it applied to an Alaska natural gas pipeline to the Lower 48 states.

CO-CHAIR GATTO clarified it is a monopoly pipeline, which sets it apart.

MR. MINESINGER agreed the Alaska natural gas pipeline represents a very unique situation.

[2:39:09 PM](#)

REPRESENTATIVE WILSON asked if once the pipeline is up and running, the first expansion usually lowers the tariff. She questioned whether that has any relative significance.

[2:39:45 PM](#)

MR. MINESINGER said there are a variety of ways in which the producer-owner could resist the expansion of the line. One way is to simply delay. The FERC process takes a long time and the uncertainty about rates and when it will be built can really impact an explorer that is trying to bring its gas on line. He add it is important to note that the FERC chairman stated in 2005 that those antitrust issues are still valid and will be addressed by FERC in any certificate proceeding.

[2:41:10 PM](#)

MR. MINESINGER said it is also important to note that precedent, both at FERC, the Federal Trade Commission (FTC), and the Department of Justice since 1977, is consistent with the Attorney General's initial concern. A number of cases at all of

those agencies involve vertical market power and a series of FERC orders seek to address this issue and recognize it is a problem. He noted the producers cannot disagree with this point. When [the producers] participate in other pipeline proceedings, they complain about the same issue. He read the following quote from a BP filing:

The problem with an affiliate acquiring capacity on its affiliated pipeline is related to the pipeline and its affiliate in the aggregate accruing the ability to exercise market power. It relates to the combined incentive of the affiliate and the pipeline to withhold capacity.

He explained BP is saying, in other words, to exercise market power by discriminating against competitors. That is not a point subject to any reasonable dispute.

[2:42:08 PM](#)

MR. MINESINGER noted that this is an extreme situation because no pipeline in the Lower 48 states exists that has similar vertical market power issues where such a small number of producers would own the pipeline. He pointed out that is contrary to some of the testimony he heard while watching Gavel to Gavel. He said that testimony was simply incorrect.

[2:42:53 PM](#)

MR. MINESINGER continued his presentation:

Unlike the 1977 DOJ opinion, AGIA takes a different approach. Let's talk about how AGIA addresses the competitive problems that would be raised by a producer pipeline. AGIA does not advocate a ban. AGIA takes a middle ground approach, similar to the Reagan way in that AGIA invites applications by all parties, including both producers and independent pipelines. So, to answer your question Representative Wilson, AGIA absolutely seeks the producers to submit an application and includes them in this process. But instead what AGIA does, it attempts to fix the competitive problems that would arise if you had a producer-owned pipeline and simply didn't have these "must have" provisions that are in AGIA.

Let's go through those provisions briefly. Problem one, as we've discussed, there would be an incentive by the producers not to expand the line to serve their

competitors. AGIA directly addresses that. It requires that the applicant commit to expand this line in reasonable engineering increments and on commercially reasonable terms that encourage exploration and development of natural gas in this state.

[2:44:20 PM](#)

So AGIA directly speaks to the, perhaps, prime issue of the competitive problem with a producer owned line. Note here that contrary to what prior testimony has asserted, natural gas pipelines are not common carriers. They are not. They are contract carriers and it's an important difference. Common carriers must, like oil pipelines at least in theory, must serve all comers. If there's more demand than capacity, they serve all on a pro rata basis. Everyone gets a piece of the pipeline.

Gas pipelines however, are contract carriers. What that means is if new shippers come along and want an expansion, the only way they can get capacity is by expanding the pipeline or by obtaining capacity that the existing shippers perhaps don't want and want to relinquish. With a producer-owned pipeline, the producers would have control over both of those avenues of obtaining capacity. They could try and resist expansion and they certainly would be under no obligation to release their capacity to their competitors.

[2:45:48 PM](#)

MR. MINESINGER continued:

Also on the expansion issue, AGIA - another one of its "must haves" states that the AGIA pipeline must hold open seasons for expansion capacity every two years to determine whether there is interest in expanding the line. Again, AGIA directly speaks to the expansion issue.

Another problem related to the expansion issue. Suppose a producer pipeline says okay, we'll expand but they'll do it only on terms that are owners'.

[2:46:13 PM](#)

One of the key ways that AGIA addresses that is through the rolled-in rate requirement. Here we're assuming a

situation where the expansion would cause rates to increase. Were you to have incremental rates that would cause the explorers to pay significantly higher rates in many cases than the existing shippers, they'd be at a severe competitive disadvantage. AGIA, again, tries to strike a middle ground by requiring rolled-in rate treatment of expansion costs up to a 15 percent increase in the existing rates, trying to reduce again the barriers to entry, if you will, faced by competitors. These rolled-in rates are consistent with FERC policy in Order 2005, and with the federal law, [Alaska Natural Gas Pipeline Act of 2004] ANGPA, that mandates that FERC use rate criteria which promote exploration, development, and production of Alaska's gas.

[2:47:29 PM](#)

Another problem we mentioned is discrimination and access. In this case a producer-owned pipeline really is indifferent to having high transportation rates for the pipeline. Why? Because they're just paying money from one pocket to the other. They own the pipeline. They really are indifferent to how high the rate gets, except - except that that rate, if they can keep it high, adversely impacts their competitors. It acts as a disincentive to explore for more gas. AGIA directly tries to help address that problem by requiring certain things that tend to lower the rates in this pipeline system, mandating a 70/30 debt to equity ratio, for example, which has a significant downward effect on rates, as opposed [to] if you use a thicker debt to equity ratio. And there are other provisions in AGIA regarding cost overruns and so forth, which also help in this area.

[2:48:31 PM](#)

REPRESENTATIVE BUCH asked if, on the current oil pipeline in Alaska, the tariff is set and maintained and gives the producers the advantage of not only creating higher competition with their competitors, but also reduces at the wellhead the amount that they pay the state. He asked if that is addressed and whether a natural gas pipeline is different in that regard so that the state has a royalty accomplishment.

[2:49:22 PM](#)

MR. MINESINGER said it is addressed in that the provisions being discussed, such as the 70/30 debt to equity ratio, would tend to drive the tariff rate down, which would increase the wellhead price and the state's royalties. It essentially gives the state an opportunity to avoid some of the problems experienced in connection with the TAPS oil pipeline.

[2:49:52 PM](#)

MR. MINESINGER continued:

One other problem would be the problem of delay. AGIA requires that the AGIA pipeline hold an open season within 36 months and it requires the pipeline to also do certain things by a specific date certain. It must initiate the FERC pre-filing process and file for a certificate by a specific date certain. A producer pipeline, in addition, would be required to sanction this project within one year. So, AGIA would not permit a producer-owned pipeline to simply sit back and delay this year after year after year. It requires a specific timeframe for going forward, as opposed to some amorphous, you know, vague, optional promise of when they can go forward.

[2:50:48 PM](#)

Let's talk briefly about why these "must haves" are critically important, to the extent we haven't already. You know, some have suggested in prior testimony why not simply rely on FERC regulation. FERC regulates interstate pipelines. Why isn't that enough - some of the flexibility that we heard in the debate over this bill.

I guess it gets back to something Mr. Hosie said in a different context and, to quote from President Reagan, it's a matter of trust but verified. The state here has an opportunity to provide an additional line of defense. FERC regulation exists, sure, but why not provide an additional line of defense against some of these clear competitive problems?

TAPS - we've discussed that example. The state has already seen what can happen when you have a producer-owned pipeline that lacks the incentives a normal pipeline would have to increase throughput through the line and serve other shippers. In TAPS, that situation, there have been numerous complaints by other producers that they've been

discriminated against and there are examples of other producers that have simply exited the state because of what they perceive as just not a fair deal on that pipeline. AGIA gives the state a chance to avoid repeating that problem.

It's also important to recognize the FERC process - it exists, yes, but it can be a long, difficult litigation that you'd be facing for a producer to try and force expansion of the line or bring some sort of discrimination claim or so forth. AGIA takes that uncertainty out of the equation and says look, producers you have to expand this pipeline and so forth.

Producers, it's worth noting, are currently appealing Order 2005, which is FERC's regulation involving this project. They're challenging the regulations that would facilitate the expansion of this pipeline so there shouldn't be any doubt that if you simply rely on FERC, you're in for a long, drawn out fight that AGIA would help to avoid.

[2:53:18 PM](#)

I would also note, before we move to the next slide that yes, you have all sorts of existing laws that seek to prevent anti-competitive conduct. FERC and the Natural Gas Act is one example but there are others, antitrust laws, for example. Simply having those laws though doesn't prevent necessarily companies from - they're going to try and evade those laws sometimes. Just to cite one example, one of these producers has been alleged and one of their key employees has admitted to trying to manipulate the entire United States' propane market. Simply having antitrust laws on the books that provide for treble damages and criminal penalties didn't prevent it. And so, why not try and build in an extra line of defense here in AGIA by mandating some of these things that are important to the state's interests.

[2:54:24 PM](#)

MR. MINESINGER said the final issue he would touch on concerns what would happen if the producers do not bid in an open season. He continued:

Assume you've got an AGIA licensed pipeline. It's an independent line and clearly the producers, they have the

gas, they have the leases currently. But, what if they just don't show up and bid for firm transportation capacity? You have to have firm commitments generally to build a pipeline.

I guess my answer to that is it depends on how the question is posed. If you have an agreement between the three producers not to bid in an open season, you would have a very serious antitrust issue. It would raise very serious issues of collusion under Section 1 of the Sherman Act.

That having been said, I think it's premature to go much further than that. I think we need to wait and see how the open season plays out, see first how the AGIA licensing process plays out and then evaluate the facts at that time. Then the state can determine - other interested parties can determine whether further investigation is warranted into whether there is any antitrust issue in that scenario, FERC issue, or perhaps some other type of issue that would be raised by effectively withholding those gas supplies from the market.

[2:55:56 PM](#)

In closing, I'd just like to say AGIA really charts a middle ground here between the two extremes of banning producer ownership in this pipeline, as was recommended by the Attorney General in '77, and then on the other extreme, simply negotiating a deal, in private, exclusively with the three producers.

[2:56:20 PM](#)

CO-CHAIR GATTO said that sounds like a deal that was put together about one year ago.

MR. MINESINGER said it does sound familiar. AGIA is right in the middle. He explained:

Instead of banning producer ownership, AGIA attempts to fix the competitive problems associated with a producer-owned line. It invites the producers into the process in a way that is consistent with the state's interest in promoting the maximum exploration and development of the abundant gas resources in this state. It establishes a level playing field, which all parties involved can compete to participate in this process.

2:57:03 PM

REPRESENTATIVE BUCH said in 1926, Standard Oil was precluded from vertical integration so we have come full circle. He continued:

The federal government - we now in our pipeline through one of the producers in particular - I know going back to the Midwest there's BP gas stations everywhere. So, they have the oil, they have the pipeline, they have the refineries, they have the gas stations. It would seem to me that times change, laws change. We're going to have to get FERC to change one of them in particular to make this all work. I'm asking you if there's any possibility of looking into your crystal ball to see if we're going to run afoul of the federal government somewhere down the road with this again so that this whole thing just gets mired in a federal court.

2:58:16 PM

MR. MINESINGER asked if Representative Buch was asking if an antitrust problem would exist if the producers own the pipeline.

REPRESENTATIVE BUCH replied affirmatively.

MR. MINESINGER said that depends because the antitrust laws do not impose a complete ban on vertical integration. Vertical integration can be pro-competitive at times. However, this situation is extreme where three producers would own 95 percent of the gas and the pipeline. The state needs to wait and look at the facts as they develop to see whether a FERC problem exists. FERC is obligated to ensure that jurisdictional natural gas and electric prices remain just and reasonable. The antitrust agencies are tasked with preventing and investigating collusive activity between competitors and preventing unlawful monopolization. He said one cannot just say a producer-owned pipeline would violate the antitrust laws, although it clearly raises serious, competitive issues. The concerns raised by the Attorney General in 1977 are valid today. The question is how one gets at those problems - through antitrust proceedings, FERC, or AGIA.

3:00:28 PM

CO-CHAIR GATTO asked how many miles of pipelines the producers own in the Lower 48 states.

3:00:34 PM

MR. MINESINGER said virtually none with small exceptions. For the most part, the pipelines are independently owned. A very small amount of the capacity might be owned by a pipeline affiliate in a few cases but those situations are much smaller than Alaska's pipeline.

3:01:15 PM

CO-CHAIR GATTO thanked Mr. Minesinger and asked Mr. Sparger to present to the committee.

3:01:52 PM

BILL SPARGER, Consultant, Energy Project Consultants, LLC, first congratulated members and said it's a great day for Alaska. He told members he is a consultant to the Administration's AGIA team with 35 years of experience in construction management and project management with two major Lower 48 natural gas pipeline companies. He has worked on all aspects of pipelines: onshore, offshore, LNG, compressor stations, process plants, et cetera. He gave the following presentation:

Very, very briefly from a terminology standpoint, everything I talk about I'll talk about the project meaning the Southern Alaska Canada route following TAPS and the Alaska Highway into Alberta, recognizing that that may not be the project that goes forward but that's what I'm talking about.

Like Mr. Minesinger, producers to me [are] the existing three North Slope oil producers. North America is the United States and Canada. I leave Mexico out of it for this discussion.

3:03:41 PM

I'm here to talk about what I call unfounded concerns. Over the last number of weeks and months, you have heard in testimony and in print statements that are couched as concerns or issues that appear to me to be unfounded. We're going to talk about all four of them so I won't go through this list because you will see them one at a time.

3:04:09 PM

The first one of these unfounded concerns is that the shippers bear all of the financial risks of project cost overruns. That is simply not true. For the last decade in the Lower 48, virtually all pipelines, the agreements between the shippers and the pipeline companies are what [are] called negotiated rates. Negotiated means exactly what it says. The two parties negotiate what the rate is and they negotiate who bears what risks and, quite frankly, in most instances, the pipeline bears 100 per cent of the risk of cost overruns on the pipeline - in most cases.

For this project I would assume that there will be some risk sharing in this negotiated rate. I don't know what it is. It won't be 100 per cent of the risk for the shippers, nor do I believe it will be 100 per cent of the risk for the pipeline company, but something somewhere in between.

These negotiated risks then turn into something - Mr. Hobbs will talk about some as firm transportation (FT).

3:05:33 PM

MR. SPARGER continued:

A good model, and I'll mention this several times, is Rockies Express. It's a new project. It will probably start construction next month, 1400 miles, 42 inch multibillion dollar project. It is being constructed and the majority ownership is a pipeline company in the Lower 48. One of the producers, Conoco, actually owns 25 percent of the project but has not executed the project. It's a minority ownership. And then they ship about 400 million cubic feet a day. One of the other producers, BP, ships about 200 million a day, going up to 300 as this project expands so they know exactly what negotiated rates are. They are in a negotiated rate situation in Rockies Express whereby the pipeline bears 100 percent of the cost overrun risk on the project.

3:06:37 PM

The other unfounded concern is that producers must have economic certainty and economic certainty breaks down into three areas. The first is supply, or the upstream side.

This is as certain as it gets. The gas is there. They know how much they can produce. They understand the reservoir, recognizing that it may act slightly differently during ... a gas blow down but, for most projects, when most people sign up for firm transportation on a new project, they don't know that all the gas is there. They haven't drilled all the wells and so they are taking a risk that they might not find the gas they think they're going to find. In this case, that risk is just simply not there.

The pipeline, or midstream risk - we've talked about the negotiated rate on the previous issue and so that is maybe a little risk but is certainly not 100 percent borne by the producers or the shippers. And the market downstream risk is simply what do you get for the product. That is a normal business risk that all producers take for all of their products everyday. It's the business they're in. No one guarantees them what they are going to get in the future.

[3:08:12 PM](#)

MR. SPARGER continued:

The next unfounded concern is that the producers are the only ones qualified to construct the pipeline. In the Lower 48 and Canada, producers do not normally construct or own onshore natural gas pipelines. There are, in round numbers, 200 plus thousand miles of pipelines in North America - interstate natural gas transmission lines in North America. The producers, if they own any, it's probably offshore and it's a very infinitesimal percentage of this 200,000 miles of pipe in the ground. You might ask yourself why don't they own it. Why don't they own it?

Well, Mr. Hosie talked about the rates of return or the hurdle rates that they want to see. Pipelines simply don't earn those kinds of rates and the rates are highly regulated, which is not the business that they want to be in, hence, pipeline companies who are in that business own and construct these pipelines.

Because they own and construct all the pipelines, they do it everyday for a living in North America; companies like Kinder Morgan, companies like TransCanada, and I can name many more. I'm just using them as examples. They do this day in and day out in North America for a living. They

understand the regulations. They understand the construction techniques. They understand the climate for purchasing materials and equipment. They simply understand how to execute these projects.

[3:09:47 PM](#)

CO-CHAIR GATTO asked whether El Paso is a pipeline builder.

MR. SPARGER said El Paso Energy Corporation builds pipelines.

[3:09:55 PM](#)

REPRESENTATIVE WILSON asked if pipeline companies, since they usually take the most risk, absorb any overruns and whether that is adjusted in the tariff rates.

[3:10:29 PM](#)

MR. SPARGER explained in a negotiated rate situation, if a pipeline company overruns the project cost, it earns less on the money it invested. The negotiated rate does not automatically increase because costs increased, unless that is part of the negotiated terms.

[3:11:04 PM](#)

DON SHEPLER, Attorney at Law, Greenberg Traurig LLP, told members he is working with the Governor's AGIA team and brings FERC experience. He said Mr. Sparger was spot on in his answer. He clarified the distinction comes down to recourse rates versus negotiated rates. If one assumes, at the end of the day, that most, if not all, of the capacity on this pipeline will be contracted for under negotiated rates, the best example is the Rockies Express. The pipeline committed to a fixed rate contract, he believes at \$1.10 for end-to-end service. The recourse rate was higher but would go up or down depending on the cost of the project. The anchor shippers in that project signed negotiated rate contracts. Therefore, if it cost Kinder Morgan two times more than it expected to build the pipeline, the recourse rate will probably increase but the fixed rate contracts will remain the same.

[3:13:09 PM](#)

REPRESENTATIVE GARDNER said in discussions of who might build an Alaska pipeline or come to the table with an offer, there have

been a limited number of parties but many other companies are out there. She asked if Alaska would have a larger number of interested builders, except for AGIA.

[3:13:37 PM](#)

MR. SPARGER said that is possible or a company might partner with another company with more history in Alaska. It is difficult for a company with no knowledge to catch up with a company with years of knowledge, like the producers or MidAmerica. However, nothing will prohibit a company from stepping forward.

[3:14:19 PM](#)

MR. SPARGER continued with his presentation, as follows:

I'm not trying to say here that the producers are not capable of building this pipeline because they are capable. They build pipelines all over the rest of the world, primarily in places like Africa and the Middle East and Indonesia. They just don't happen to do that as a business in North America.

[3:14:42 PM](#)

The other unfounded concern is that schedules with milestone dates drive up the project cost - in other words, almost a quote that "firm dates are bad." I've heard - seen - heard it in testimony. I've actually heard some of you express that concern. Once again, this is simply not true. Realistic schedules are a project necessity. Projects without schedules tend to go on indefinitely, forever. Schedules can and are adjusted as circumstances change. When the circumstances change so that it looks like your cost is starting to go up, if you hold to a certain schedule date, then the company is going to sit back, step back just a little bit and say, what am I going to make - what am I going to earn if I make the schedule date versus what additional is it going to cost me. They are going to look at economic decisions based on the total impact to the business. Sometimes the decision is I'm going to hold the firm date. I'm going to let the costs go up because the profits, when I get this in service, are so big that I can afford a little cost overrun. On the other hand, sometimes the schedule dates are simply moved back some to try to keep the costs more in line. But the fact

that you have those dates does not, in and of itself, drive the cost up unnecessarily without other economic justification.

[3:16:41 PM](#)

REPRESENTATIVE WILSON said last year when the Legislature was reviewing the contract before it, experts that talked about cost overruns were brought in. They said they researched projects around the world to find out why some failed and others were successful. They cautioned legislators to avoid fixed dates because most of the failed projects failed because they could not meet a deadline.

[3:17:34 PM](#)

MR. SPARGER said he reviewed that information, as well as the material from an IPA course that state staff attended. He believes no project management expert would say do not have dates. He emphasized that unrealistic and unachievable dates should not be set. He said some of the projects the experts looked at were not in North America and not executed by pipeline companies and, more importantly, no one knows how the dates were set to start with. As an engineer, he is aware that sometimes dates are set by a company's management and those dates are not realistic. If the company is not convinced that it should begin with realistic dates, problems can ensue. He repeated that he does not believe the experts were advising the Legislature to start off with no dates because the project will never be finished.

[3:19:33 PM](#)

MR. SPARGER continued his presentation:

Some other unfounded concerns and issues - and I'll very briefly go through these and I can expand if you want to. One of the statements is leading edge technology is required to produce project costs and I think it's just the opposite, leading edge being technology that is not commercially available - X 100 or 100,000 PSI yield strength pipe is not commercially available.

You want to use the best technology that is commercially available but when you start getting off into leading edge, you expose yourself actually to costs and overruns and project delays. If it's not commercially available, that

just simply means nobody has done it before on a production basis. They may have done it in the lab. They may have done it on small scale things but they haven't done it on a production basis. So, I would argue with that.

The other thing that keeps coming up in a lot of the discussions is mega projects are different. That may be true for certain mega projects, like the Panama Canal, things like that. In my opinion, it is not true for pipelines. A pipeline is obviously a linear project. You design and build pipelines one mile at a time and the complexity of it is not tremendously affected by whether it is 100 miles long or 2,000 miles long. It's the same pipeline as you go through. There are some differences and it does mean you have to have more resources. You have to have more surveyors. You have to have more right-of-way people. You have to have more environmental people. You have to have more contractors. But it does not make it more complex or more difficult to manage. It just makes it longer and more expensive.

[3:21:37 PM](#)

CO-CHAIR GATTO noted repetitiveness would make the project less complicated and less expensive.

[3:21:54 PM](#)

MR. SPARGER said the crew does get faster. He said to lay two miles of requires a lot of money to mobilize the people and get them ready to go. There is a learning curve. If the same crew lays 200 miles, they get better every day.

[3:22:20 PM](#)

MR. SPARGER continued:

The other thing is that AGIA - the requirement for a detailed project description is premature and costly. If you can't describe what it is you're going to build, how can you schedule it or come up with a cost estimate? So, you simply can't respond to AGIA. You can't respond to what's it going to cost and how long is it going to take unless you know what it is you're going to build to start with. You don't have to know all the details. You have to know how long it is. Are you going to bury it or are you not going to bury it? How many compressor stations [are]

you going to have? And once again, in North America we know what the requirements are. We know what the environmental requirements are. We know what the regulators want - Fish and Wildlife and EPA. We know what they want. The rules are laid out. These engineering firms and construction contractors know what the rules are. They know how to follow them so you can come up with a very good project description for not a whole lot of cost.

3:23:32 PM

The last point I want to make is just an observation of mine. The project ... schedule as currently proposed - the ones that I've seen are all 10 years long from start to ready for service. I think that with a timely commitment to firm transportation on the part of enough shippers, that a person could shorten that schedule two or three years.

I don't have an alternate timeline to tell you but intuitively these projects in the Lower 48, with the same regulations, the same FERC, the same EPA, these projects take three to four years. This would be longer because of the short construction season and because of the fact that you have to construct some of it in the summer, some of it in the winter. But even given that, I'm saying seven years maybe or eight, but not 10. Now that's assuming that somebody steps forward, the shippers, and signs FT agreements early on so that the pipeline company, whoever that may be, has a commitment and then we'll just move forward.

3:24:55 PM

CO-CHAIR GATTO said this mega project is going to follow a road where a pipeline already exists.

3:25:01 PM

MR. SPARGER advised members to not compare this project to TAPS, which was a true grassroots project. This project is going to build on the knowledge learned and mistakes made on TAPS so that those same mistakes are not made again. The road is in place, as well as the infrastructure. Very few new roads need to be built. He cautioned this is not a simple project and it is large, but it is still just a pipeline. He offered to answer questions.

3:26:07 PM

CO-CHAIR GATTO agreed the project is just a pipeline. He asked Mr. Barger to clarify X70, X80, and X100.

3:26:41 PM

MR. SPARGER explained that X70 stands for 70,000 PSI yield strength or the strength of the material. The higher the number for a given diameter of pipe, for example 48 inches, the thinner the wall. As the strength increases the thickness decreases. As the wall thickness decreases, the tons of steel that need to be purchased decreases. Therefore you would want to use the highest commercially grade steel available to keep the wall thickness down and the cost down. X80 is commercially available today; it was not five years ago. He said if he was designing the project, he would use X80. If he was to order it four years from now, he would want to know if the X100 was commercially available at that time. If it was marginal, he would bid both ways: using X80 and X100. However, he would not use it if it had not been used before because this is not a project for experimentation. He believed TransCanada has used X100 on about five miles of pipeline and has possibly used X120. TransCanada is experimenting on a small area of pipe to see how it reacts and bends. Maybe TransCanada will use it on 30 miles of pipeline on its next project but, he repeated, it is not wise to experiment with a 1700 or 1800 mile pipeline.

3:29:02 PM

CO-CHAIR GATTO asked what the wall thickness is on X80.

3:29:04 PM

MR. SPARGER said it is about one inch for a 48" diameter pipeline.

CO-CHAIR GATTO thanked Mr. Barger for his presentation and asked Mr. Hobbs to present to the committee.

3:29:46 PM

REPRESENTATIVE SEATON noted that after the Exxon Valdez spill, everyone felt the aging tanker fleet needed to be replaced. The old standard heavy thick steel tankers were taken out of service. Now the tankers are built with high strength steel and they are cracking because the high strength steel is less

flexible and hardens. Therefore, the new tankers need constant repair. He pointed out that when using the latest product, over time problems surface.

3:31:00 PM

SCOTT HOBBS, Energy Capital Advisors, related his background as follows:

I have been a consultant for about the last six years. During that time I was actually chairman of a midstream natural gas company that we recently sold. It was a natural gas gatherer and producer in Wyoming, in northern Louisiana, East Texas. During that time I've advised investment bankers, different potential investors on projects as well as some private equity firms that have been looking into investments into the energy business - all types, pipelines, and various and sundry energy ventures. I am here today on behalf of the Administration. I've been asked to look at a few questions that have been raised, points that have been made in some of the prior testimony and I'll try to make my comments as brief as possible but try to cover them as best I can.

3:32:19 PM

MR. HOBBS continued:

The discussion topics I'd like to cover today - it's been suggested in some of the previous testimony that there [is] really only one way this project can move forward and that's for the producers to own this pipeline and to move it forward essentially on their terms. I think they would like to own and build on their schedule. I'm going to take a moment and talk about the advantages and risk associated with a producer committing to a third party to build this pipeline because it may be that that is what the state ultimately pursues. It may be what's in everyone's best interest, perhaps not the producers and we'll talk about that. When I talk about producers as some of the prior folks have discussed, I'm talking about ExxonMobil, Conoco Phillips and BP.

There's also been a number of ... representations made about how firm transportation is accounted for and how that's going to create some real burden or impairment on the party that signs those contracts. I'll speak to that.

And then there also has been serious questions raised about the economics that were performed by Dr. Scott and DNR in trying to evaluate is this a commercial project. Is this an economic project for the producers? And I'm going to speak to that and I'll conclude with a few conclusive remarks.

[3:33:54 PM](#)

Let's start with the advantages and the risk of contracting for firm transportation on a pipeline as compared to owning it and building it yourself. Probably the most significant advantage for a producer with a substantial reserve base like we have here on the North Slope is they avoid the front end capital costs. You've heard, quite eloquently, Mr. Hosie discussed about the returns that the producers, and in particular Exxon, are earning on their typical investment. Actually they're making greater than 30 percent return on investment. That's what they showed in their most recent 10K. It's interesting when they say they need to own this project because this pipeline will provide on a comparable basis a return on investment of somewhere around 8 to 9 percent so I find that peculiar that they would want to own this pipeline with such a low return by comparison with what their alternatives are.

So, I'm here to tell you that I think it would be very advantageous for them to use that capital for those 30 percent projects and not an 8.5 percent project, but we'll get to that and maybe perhaps understand a little better why they want to own this project.

I think they have an ability to improve their project economics by not owning this pipeline. I think they can avoid a lot of risk by contracting with a third party. You've already heard Mr. Sparger talk about negotiated rates. They can actually allocate through negotiations with a third party pipeline provider. They can allocate risk to that party, most notably cost overrun risk and we'll talk about that. So, there are - and they can force certain schedule requirements if they do desire for this pipeline to be built by a certain timeframe.

So, those are commonplace in agreements between pipelines and producers or shippers. I failed to mention I was an executive at a pipeline for - well I was actually the chief operating officer for the last eight years. I worked for

two natural gas pipeline companies in the Lower 48, two major pipelines, for about 24 years so I do have a bit of experience to draw on in terms of talking about how producers, how shippers negotiate with pipeline companies and how those risks are shared or allocated between the parties.

3:36:48 PM

I will tell you that when you look at ExxonMobil, BP, Conoco, they all have major projects all over the world. Look at their annual report. They have LNG projects. They have major - more conventional gas projects. They have tremendous projects that are going on everywhere. By contracting with a third party for this pipeline, they can actually avoid what would be a significant drain on their human resources. You read in a lot of industry text now about - that is one of the major issues that the industry is facing. Its workforce is getting older. The young people have not been coming into the business. They need capable people to manage projects and to perform the functions they have to be successful.

By contracting with a third party, such as those that have come forth and made proposals, or at least provided testimony to the Legislature, that being TransCanada, Enbridge, MidAmerican - as we've said there may be other parties that become interested in this project. These people have very strong regulatory and construction expertise in building pipelines in North America. Mr. Sparger has talked about that. I think there's an ability to tap that capability, contract and protect yourself with the appropriate terms in that contract and lay off some of that work, that effort, that risk on a third party. That is not an unreasonable strategy for a producer to pursue.

Okay, well why wouldn't they do that? Well let's look at the risk. What you've heard is that if they don't manage this project, they are going to end up paying for all the cost overruns.

3:38:30 PM

Hopefully we've debunked that theory. The last ten years do not support that. Their own experience and contracts that they've executed support the fact that they can put off that risk or lay off that risk on a third party

pipeline. That's very prevalent in the Lower 48. In this case, I will tell you that I don't think that the producers would be able to lay off 100 percent of the cost overrun risk here. It will be some sort of negotiated sharing arrangement.

That's a logical outcome for a project of this size and complexity but, I will tell you, they can very easily force a pipeline company to take enough risk where they will [have a high incentive] to build this pipeline on budget, otherwise they will be facing substantial reductions in their return and potentially even a loss situation.

[3:39:22 PM](#)

MR. HOBBS continued:

The ability to finance the project - well, you've heard stated that really you have to be an ExxonMobil or a BP to get this project financed. I will tell you in my experience that is probably another overstatement. Think about it. You have a federal loan guarantee here. You have very capable pipeline operators that are operating very sizeable companies and you have world class reserves that have already been proven that are being recycled into the ground. Those are the components for a very solid project. This project will be financed. You do need ultimately, firm transportation contracts, which I think will ultimately be signed, but this project, although it's very large, will be financed and can be financed by parties other than the big producers.

So why is it that this project is in the position that it is and has been for years? I believe if the producers contract with a third party or put forth a proposal under AGIA, they lose control of the process. It's that simple. They can no longer dictate the design, the schedule, the tariff provisions or the rate designs that might promote competition or development by third parties. Once they fall into either a third party or an AGIA sponsored project, these types of, let's say - these types of items that are available to them - what they'd be able to accomplish if they were owner and the shipper, are no longer available to them and that is exactly what AGIA has been designed to do. Quite frankly I think that is one of the reasons that they have so much trouble with AGIA and why they also don't want a third party. They are going to

give up a lot of power, so to speak, negotiating power, market power, call it what you will. They are good businessmen. They are trying to maximize the value of their investment and, in so doing, they'd like to keep the position they currently enjoy.

[3:41:40 PM](#)

MR. HOBBS continued:

Moving on, there's been a lot said about the accounting for firm transportation agreements. It's been stated that FT agreements are debt or they are at least debt-like. Well, having reviewed the producers' 10Ks, Mr. Hosie explained to you that there's a lot of information in their annual 10Ks that they file every year. FT agreements, at least as these producers - and quite frankly as the industry generally handles them in their accounting, they are not debt, they are not debt-like in that they are not capitalized or recorded on the balance sheet. That is not the way firm transportation agreements are handled.

[3:42:45 PM](#)

If you look at their 10ks, and I brought ConocoPhillips' as an example ... this is a copy of an excerpt from Note 18 in ConocoPhillips' financial statements. Every major company will have a note that speaks to contingencies and commitments. What I've done is taken an excerpt, and I'll just scroll down. If you look at the highlighted portion, interestingly enough, you'll see a reference to the Venezuelan government and the fact that they may nationalize - they're considering it. Obviously that's happened - so much for fiscal certainty.

Here it is in highlight. This is the disclosure that ConocoPhillips makes for certain FT agreements. It's not on the balance sheet. It's in a note to the balance sheet and essentially to make this disclosure - it has to be directly tied to a financing of a project that's providing, in this case, the service that they've signed a long term throughput commitment on. They're called unconditional purchase obligations. I realize this is a little bit arcane from an accounting standpoint, but the point I'm trying to make is it has to fall into a very specific category. Look at the amounts - \$77 million was what they're estimating they would pay under throughput

agreements or take or pay agreements that are in support of financing arrangements. That's a key term. If the terms of this are not directly tied to the financing of this facility, it's not required to be disclosed.

You look at the amounts there. This is what is disclosed in a note to the financial. It is not debt. It is not on the balance sheet. This is what's required.

3:45:03 PM

They also have a section called The Management Discussion and Analysis of Financial ... Condition and Results of Operations. Again, I've tried to highlight the relevant points. Here they're spelling out all of their contractual obligations. This is a supplemental disclosure. This is not on the balance sheet. This is what's filed in what they call the MD&A of the SEC. Total debt you'll see there is \$27 billion. Interestingly enough, what we're talking about here falls under purchase obligations and if you read that note, Note B, they go through a litany of different purchase obligations that actually aggregate to \$93 billion. I can assure you ConocoPhillips does not want anyone telling someone else that they have \$93 billion of debt. That's not the case. This is just a disclosure of contractual commitments. Included in that is \$3.8 billion related to transportation. That's the sum total of all the agreements they've made to transport gas, oil, whatever, on pipelines where they've made throughput commitments. Compare that to the \$70 million that we were talking about earlier.

So obviously, what's disclosed in the notes of the financial has to meet very specific criteria. Here they've gone forth and said here's everything we've got out there and this is the way these agreements would be disclosed. So, in summary, it's not debt. You can see it's separate. There is a disclosure. That's just good management. They're trying to show what's going on but they do this everyday. This is done in the ordinary course of business. What a pipeline operator would be asking them to do here is no different than what they've done in countless situations where they operate.

3:47:27 PM

The last item I'd like to - actually there's two more items. It has been said that if they sign an FT agreement, that's going to create a real burden or impairment on the company. I will tell you that if they sign an FT agreement, it will actually enhance their financial position. The reason is they are unlocking this treasure chest of reserves that have been sitting in Prudhoe Bay or Point Thomson for a very long time. When you talk about a ratings agency, that being Moody's or S&P, it's also been said that they're going to look at this negatively. Actually they're going to look at the contractual obligation that one of these parties or all of these parties when they sign an agreement for firm transportation, they will in fact build that into their analysis. But, equally, and perhaps more importantly, they are going to look at the cash flow it creates. In this case, it's going to generate significant incremental cash flow because they now can sell gas that heretofore had to be recycled or left in the ground.

CO-CHAIR GATTO said he is glad Mr. Hobbs is commenting on this subject because Mr. Antony Scott told the committee the same thing and was immediately challenged by the producers, who said he failed to include that as debt.

[3:48:43 PM](#)

MR. HOBBS explained it is neither debt nor an asset. It is a contractual right to move gas in a pipeline. However, that right creates significant value for the holder of that capacity. If, ten years down the road, they don't need as much capacity, they have the right to sell it to someone else as "capacity release." They can release it to another party and lay off the risk of that capacity to that party. That right unlocks a tremendous value. He opined the rating agencies will see this as being very favorable because they will not commit to this FT unless reserves support it.

[3:49:49 PM](#)

REPRESENTATIVE SEATON referred to an e-mail that was circulated to members about debt consideration. It said a bankruptcy court only considers the first year of FT as a liability in bankruptcy. He asked Mr. Hobbs if he could verify that information. He thought regular debt is put into a bankruptcy court at full value. He questioned if, under FT, the bankruptcy would only look at debt for the current year.

3:50:39 PM

MR. HOBBS said, in his experience, it depends on the specific contracts. He explained:

Generally you have to look at who the party is that is bankrupt. In the case of a pipeline company, if the pipeline went bankrupt, more than likely the trustee will step in, or the court, and say this is a revenue producer for the pipeline. Whoever the new operator of that pipeline is - if they bring someone else or if it's a debtor in possession, they will order that party to continue to provide the service so the revenues keep coming in. The flip side I believe is what you are talking about where the party who actually has the obligation to pay the firm transportation charges and use it, that's where the one year limitation comes in. Generally if it was debt, it would be just what you said. They would have to look at the dollar amount in its entirety because at the date there would be a conveyance of money and a debt instrument created. In this case there's just a contract that says I will use your pipe for 10, 20, 30 years, whatever. It's paid over time. It's a commitment to use, and for that the provider has to give the service back. In that instance, if the party that signed the FT agreement to ship the gas - they would be probably limited to that one year amount you're talking about so another reason that it's really not debt.

3:52:07 PM

CO-CHAIR GATTO noted that Enron was a pipeline company that was not only bankrupt, but was zeroed out and the gas continued to flow.

3:52:19 PM

MR. HOBBS said he worked with a group of private equity players and industry players to purchase the Enron assets. Enron was bankrupt but the Transwestern pipeline, Florida Gas and their general partnership interest in Northern Border were operating every day because they were viable companies, as opposed to the parent company or trading operations, which is where the problems were. In that case the bankruptcy did not affect them. They continued to operate daily. Ultimately the trustee stepped in and said assets would be sold to pay creditors.

3:53:19 PM

MR. HOBBS continued:

If you look at producer economics, one of the comments that's been made is that the Department of Natural Resources, in particular Dr. Scott's analysis, was just really faulty. I have spent a good deal of time with Dr. Scott, reviewed the model. I will tell you that I think it is very reasonable. I think what they've done is reasonable based on the best information they have available. I think it's very important to know that the producers, and you know this of course, have not provided any economic studies to support their contention that this is not commercially viable. So, what happened is, I think DNR has had to use the best information they have available in trying to estimate is this an economic project for the producers. I will tell you that based on everything I've seen, it clearly is.

What they've done - if you step back and think about what is it that makes a producer project economic, I tried to list the factors there. Obviously the first and foremost is: Is there adequate gas reserves and deliverability getting the gas out of the ground? Is there adequate gas to make this project viable? This particular situation is unprecedented from my experience to have the volume of gas proven and already being produced and recycled. This volume is extraordinary. So that really is not a significant issue.

Then you have - what is it going to cost to treat and transport this gas to market? That's where the model that DNR has developed - they brought in consultants from Block and Beach, who are experts that work with Lukens (ph), the subsidiary of Black and Veatch. J. Lukens is very well known in the industry as an old rates guy from Transco. They did a lot of work to help them develop what the rates would be under a pipeline project because ultimately the shipper, the producer, will pay those costs. So they've tried to come up with a reasonable set of costs for that.

The commodity prices - well, obviously if you talk to anyone in the gas business they will tell you they have a guess cost estimate so they've created I don't know how many different price paths and possibilities and that's

what that distribution of possibilities was to try to come up with the best analysis of what is the most reasonable gas price. And then they showed different levels, which is really what you have to do. What if gas costs this much? What if it generates this much revenue? What if it generates this much? So they've looked at alternative commodity prices to a great extent.

Then you have to try to determine additional development costs. What's it going to take to bring Point Thomson in? Obviously Prudhoe is not going to cost much to bring that gas on. Most of the infrastructure is there. And then they've looked at operating costs, taxes and royalties, who better than the lessee, in this case particularly under the [petroleum production profits tax] PPT regime, to know kind of what these costs are.

So, I think the model is reasonable. I think it speaks to all of these, which I consider the primary drivers for producer economics.

[3:56:36 PM](#)

The conclusion I've reached is it is very difficult to construct a worst case scenario where the producers did not continue to make or have solid economics. It's really hard to find a scenario that's reasonable where they're not going to have rock solid economics. And I need to point out, that's with significant upside. We can try to create a perfect storm on the downside but what if the true perfect storm, i.e. Hurricane Katrina, hits and takes out almost the entire Gulf of Mexico production. Gas prices went to the low teens - actually about \$15 for a short period of time.

Under that scenario, gas prices - that's how you reach the astronomical returns that were cited. I don't believe they got anywhere close to that in the analysis they did. I think they stopped at \$9. So, the point is, under any reasonable gas price scenario, I think this is a solid project. If you give that gas price a 50 percent reduction, if you increase current estimated capital costs by 50 percent that is my reasonable worst case scenario. The producers would still earn in excess of a 20 percent rate of return.

So, when they say it's not economic - this is where they need to come forth and show us how, because I can't get there. So what have they done? They've said well Dr. Scott has not done his economics properly because he didn't capitalize the cost of FT or he didn't recognize that there are huge capital costs associated with this project. Well, if you contract with a third party, those are not your capital costs and you do not have to capitalize that FT agreement. In fact, as we've already shown, capitalizing that is entirely inconsistent with the way they account for it in their financial statements. So, once again there is an inconsistency between what they are stating needs to be done and the way they are accounting for it.

So, in this case, I think it is entirely reasonable to look at the FT costs exactly as the model and DNR have done. That is as an expense. They take it off the delivered cost of gas, the delivered price. They reduce that for the tariff costs, the transportation costs both in Canada, in Alaska and for the gas treatment plant to come up with a net-back price.

Let me put this maybe in perspective. If we could turn a switch tomorrow and this pipeline was built based on the best cost estimates we have right now and the ... rates that had been calculated under the tariff model that Lukens and DNR have created, I'll walk you through what I think the current day economics would be.

[3:59:23 PM](#)

Look at the current 12 month gas price. This is traded in the futures market. You take the current gas price. It's roughly \$8.60. That's the average price at Henry Hub. That's the benchmark price for natural gas right now over the next 12 months. This is from a couple of days ago. Back off what is a price differential called the Alberta price differential or basis swap. You can lock in by buying futures or - on a forward price curve you can lock in the price for what the differential between Henry Hub and Alberta is, you can actually go out and buy that on the exchange. That's roughly \$1.17, just to use rough numbers. That gets you to about \$7.50 is the price in Alberta. This is over the next 12 months. I'm assuming that we've turned the gas on and it's flowing down the pipe. Then you would subtract from that \$7.50 the \$2.00 pipeline and [gas treatment plant] GTP cost. That's what is currently

estimated at the \$20 billion project level. That gets you to \$5.50 is what the producers would enjoy for gas delivered into the pipe - actually into the gas treatment plant. That results in a \$5.50 net-back price for the producers. They would actually - what's been proposed - it would be about 4.5 bcf a day. That provides about 1.64 tcf a year. You take that \$5.50 price times 1.64 tcf and you have \$9 billion in the first year. So that is what the producers would enjoy in the current - obviously this is going to take 10 years to build but if they could turn the pipe on tomorrow using current pricing, using current capital cost estimates, the producers would enjoy \$9 billion in year one.

Now, they need to pay operating costs, they need to pay the state's royalty share, they need to pay any sort of Capex that's required. But they've got a substantial - so when I say it's difficult to construct a reasonable worst case scenario where this isn't economic, that puts it in perspective for you. \$9 billion is a big number.

[4:02:19 PM](#)

CO-CHAIR GATTO noted that is [calculated] with current gas prices so in 10 years the prices will double.

[4:02:33 PM](#)

MR. HOBBS said the Department of Energy's (DOE's) forecast puts the price close to \$8.60. Over the next 15 to 20 years, the forecast has gas prices ranging from \$8.50 to \$9.00, not that the government forecast is better than others.

[4:03:00 PM](#)

MR. HOBBS continued his presentation:

So this number is not out of line but the pipe needs to be built. There are a lot of challenges that need to be overcome.

So, in conclusion, I guess from my perspective there are very real advantages for the producers contracting for FT with a third party versus owning the pipeline but that's their decision. They can go forward under AGIA or they can go forward outside of AGIA and build this pipeline themselves. I think there are very real incentives for

them to move forward. Contracting for FT on an independently owned pipe will not adversely affect the producer. In fact, it's actually going to enhance their financial position.

Finally, under any reasonable scenario, they should enjoy very favorable returns whether they decide to own this project or they contract with a third party.

[4:03:55 PM](#)

CO-CHAIR GATTO thanked Mr. Hobbs and asked Mr. Harper to address the committee.

[4:04:28 PM](#)

RICK HARPER, Consultant, Econ One Research, Inc., informed the committee that he is appearing as an advisor to the Legislative Budget and Audit Committee (LBA). He related that he has been involved in the energy business for over 34 years.

[4:04:50 PM](#)

CO-CHAIR GATTO noted the previous testifiers were paid by the Administration so one could almost say they represented the Administration. He felt their testimony was sound but said Mr. Harper is paid by the Legislature.

[4:05:14 PM](#)

MR. HARPER said he was with ARCO for 15 years and then served as an advisor for 10 years after that. He noted that he ran Atlantic Richfield's North American natural gas business activities. He also noted that he served as president of ARCO Gas and was also an executive member of ARCO's royalty policy committee, which dealt with the issues Mr. Hosie discussed. Those issues were alive then and are alive now. He was also the CEO and President of a Canadian oil and gas exploration production company operating throughout the Western sedimentary basin in Canada. Most recently, Mr. Harper related that he was senior vice president of Northwest Natural Gas Company, operating in the Pacific Northwest. For the past six years he has run an international oil and gas consulting firm headquartered in Houston, Texas. He has worked with the Legislature in collaboration with Econ One. He noted Mr. Leitzinger and Mr. Pulliam of Econ One could not attend today so he will make a few comments on their behalf.

4:07:26 PM

MR. HARPER began his presentation, as follows:

My presentation is a little different than it might have been, if not for the events earlier today. I will tell you that, as I've told a number of you who are here and listening, this is really just the beginning. I think it was said by some of you on the floor and then at the Governor's press conference that really, in some ways, the more important decisions for you may be yet to come so everything you are hearing today and have heard today is still very pertinent, not dated in the least, and I've tried to tailor my comments in light of what's happened today to help begin to equip you for what will be to come.

There's been a lot of hyperbole over the last months and years and, as Spencer and Scott and Ken and Bill have advised you, you would expect hyperbole and you would expect the parties to represent their interests because this has been to date in the context of a negotiation. So it's been our job as your legislative consultants to try to create a no spin zone for you and I feel that has been my job. I have no stake in this. I have no family member who is involved or employed. I own no stock interest in any of this so that has been my goal.

4:09:01 PM

So I guess my comments today are going to revolve around and actually will fit very nicely with many of the things that have been very accurately said here today by the Administration's team to talk a little bit about the risk parameters, the kind of decisions that go on in producing companies, how they make decisions, and in pipeline companies because you're going to be reflecting on that as projects and consortiums come forward, I believe, to you in the not too distant future. To talk a little bit about how economics are viewed and to talk also about how FT is viewed. We still think that's a live issue. We don't think - Mr. Hobbs and I don't think that this is the end of that subject coming before you.

4:09:28 PM

MR. HARPER continued:

At any rate, so my comments are generally qualitative in light of the events that have happened today. But I will tell you this. I support fully the thesis that this is not - not a high risk venture. It is an extremely large venture but there is a very big difference.

What we have in North America, certainly throughout the United States and Canada, is an extremely mature business infrastructure in natural gas. We have well developed legal and regulatory precepts. We have well developed markets. This project is not contingent upon market development in any sense of the word. It is not contingent upon downstream infrastructure development in any sense of the word and it is not, for the most part, contingent upon upstream reserve development. So when you look at both ends of this thing, you've got the greatest degree of certainty that I've seen in pipeline construction, in FT subscription in my business.

4:10:39 PM

I will also state, as I said before and created some excitement and support in some of those in the geological and geophysical roles in DNR, some of which I've known through the years, I really think what's at issue for you good folks here today, the key decision makers here in Alaska, this is not about 35 trillion cubic feet of gas. This is about a whole lot more because, just like Texas and Louisiana in the '50s and '60s and, to a large extent in the '70s, nobody's been up here purposely looking for gas for obvious reasons. That is going to change, I believe, beginning today and, in fact, I think it's changed before today. I think you've seen other companies coming in here recently who haven't been here taking very, very large land positions in gas-prone basins. So, as you think about this, I ask you to think about it well beyond the 35. I think it's the tip of the iceberg and, personally, and this is very subjective, I think the potential estimates that you've seen are understated.

4:11:24 PM

CO-CHAIR GATTO felt the big concern is whether the pockets are big pockets or many small pockets.

4:11:32 PM

MR. HARPER said it is one of the few areas in North America where there, he believes, is "legitimate elephant potential remaining," which is what the majors refer to for large development opportunities. He noted he was heavily involved in the Western sedimentary basin in Canada in the 1990s, which is a mature basin. The elephant days were over there in the '90s even though huge discoveries were found - enough to support the Alliance pipeline construction.

[4:12:21 PM](#)

He continued his presentation:

I think that a reasonable expectation of profit, just [indisc.] back briefly to Spencer Hosie's presentation, the producers under the lease obligations are not entitled to profits. They are entitled to a reasonable expectation of profit before going forward with development. Their obligation is not only to develop, given the express and implied covenants. Their obligation is to develop, to market, and to account to you accurately. Those are the three key obligations that they have. I believe that there exists, right now today, a reasonable expectation of profit for going forward in all regards for those producers.

[4:12:59 PM](#)

Looking at it from an economic perspective, you've heard a lot of talk about - and you've had IRR - Internal Rate of Return thrown at you throughout the Centennial Hall days and here recently and a lot of confusion over how decisions are made. I can tell you having sat at the decision table in collaboration with other executives many times, at the producers' as well as pipeline end, there are several indicators that you look at. IRR is always looked at and also cash flow is looked at. Return on capital employed is looked at, EBITDA - Earnings Before Interest Taxed Depreciation Amortization is looked at.

But key and number one in the final analysis is net present worth, net present value as it's sometimes referred to. That is king and Dr. Tony Finizza of Econ One has told you that. I've told you that. I think Antony Scott and others in the Administration have certainly told you that and I'd hang on to that because this issue is going to come around, I believe, for you as these projects roll forward.

4:14:00 PM

CO-CHAIR GATTO recalled at Centennial Hall last year that Pedro Van Meurs focused on IRR for days. He questioned whether that is quite the same value as net present value (NPV).

4:14:13 PM

MR. HARPER said IRR is a different creature. Dr. Finizza gave a presentation to the Legislature on either June 14th or June 15th of last year and provided a full expose on IRR. IRR is an important indicator but it is not the decision maker. It never has been and is not likely to ever be.

4:14:48 PM

MR. HARPER continued his presentation:

One thing I want to point out is that - and there has been confusion and I keep saying this - there is no gas supply commitment required to construct, expand, have anything to do today with a natural gas pipeline in North America. In the old days the supply commitment, when the pipelines were actually buying all the gas, was important. There is no supply commitment anymore. All that's needed is commitments to ship and that's what FT represents. Those commitments are typically made by electric utilities, gas utilities, marketers, producers and industrials. Those are the companies that typically make those. Now either they have some strong position from a market perspective or they have some strong position from a supply perspective.

Why they would take FT varies and I think you are going to be surprised once you get a project going, and there are actually subscriptions, as to who might show up. And you will see people taking FT on a speculative basis as well as a tangible, concrete basis associated either with reserves or with market. But just remember, there is no supply commitment required. They don't have to step forward with a supply commitment. That pipeline is subscribed, as Mr. Hobbs was just telling you about - that's going to move forward as Mr. Sparger said. Once that happens, you might be surprised how quickly this pipeline can move forward. I could not agree with Mr. Sparger's comments more on that.

4:16:15 PM

REPRESENTATIVE SEATON said when legislators were dealing with IRR and Net Present Value, the proposal presented contained evaluation terms for the state to use on a proposal on the NPV of future cash flow. He asked Mr. Harper if he feels that is an appropriate measure for legislators to look at and whether there are any others.

[4:17:07 PM](#)

MR. HARPER said he believes that is the right thing to look at. He suggested that members be up to speed on IRR, EBITDA and cash flow, the relative financial health indicators.

[4:17:45 PM](#)

MR. HARPER continued his presentation:

In my experience in the roles that I have played in corporate life, the question of whether to capitalize FT has always come up. Firm transportation is a relative part of a local gas distribution company's business - is a much bigger part of their business than it is of a producer's business because it is their life blood. It's a much bigger part transactionally, commercially and it's also a much bigger expense item relative to the total business operation. It also came up at ARCO, it came up in Canada - my operations in Canada. Not once did we decide that FT should be capitalized or constitute debt.

It is a substantial obligation - that is not to minimize it. But I will also tell you this. When it came time to sign an FT deal, it was sort of like you folks here today when the bill was done. It's a time of celebration. Gosh, I've heard this thing discussed as though oh, my gosh, we're going to have this FT thing, it's risky, oh God, it's going to show up as a footnote. Well, whether you're a producer or whether you're a local distribution company or marketer, if you've got the courage to step up for FT, it's because you've got a really good business reason, which means there's going to be a lot of revenue, you believe, when it's done. Mr. Hobbs, I think, did a terrific job of creating a very simple example "snapshotting" today and I will assure you when they step up and sign FT they will be toasting that evening. So, don't be misled by this dark cloud that seems to represent FT. It represents real opportunity.

As we said, here we have a situation, mature downstream infrastructure, well developed and continuing to grow markets - growing markets, and we've got a supply. We've got enough reserves in place to initially support the construction of this pipeline and tremendous potential to support it and expansions to it long term.

[4:19:45 PM](#)

I guess there [are] other things I could talk about but in light of where we are with the legislation, Mr. Chairman, at this time I'll stop and answer any questions that you might have.

[4:19:56 PM](#)

CO-CHAIR GATTO asked if he would comment on McKenzie.

[4:20:04 PM](#)

MR. HARPER said he could provide a limited perspective. McKenzie is in a slightly similar position to Alaska. Some of the same tension between some of the same producers exists in regard to building a pipeline. In terms of the hydraulics, from a market standpoint, within the last three weeks he has been talking to Canadians about supply and market trends in Canada. He is an advisor to the Northwest Industrial Gas Users and the Northwest Power Planning Council, which is a five-state commission appointed by the governors to handle hydro-policy. The western sedimentary basin decline rates have been steeper than anticipated, even with substantial improvements in current gas prices and long term gas prices. They are peddling hard to stay even.

MR. HARPER pointed out that two other dynamics are thrown on top of that with oil prices being relatively higher than natural gas prices: a movement to aggressively develop the oil sands, which requires tremendous amounts of natural gas to be used as an energy catalyst to extract from the sands, coupled with a shift in the infrastructure in the U.S. He suggested Mr. Sparger address the committee on that topic because he was involved in the Rocky Mountain Express project. He believes the Rocky Mountain Express will cause a complete shift in the way physical gas moves across America.

MR. HARPER further pointed out in the current situation, the Pacific Northwest and Canada have growing concerns about the physical availability of supply, specifically widening basis differentials where they will have to pay substantial premiums to attract supply. In addition, they have concerns that the Western Sedimentary basin gas may be used in oil sands carrying a risk that the very large lines coming out of the basin may have isolated or stranded capacity. The bottom line is Alaskan gas and McKenzie gas are much more attractive now than they were a year ago on a relative basis. He believes the McKenzie project will not compete, but will be complimentary to an Alaskan project. He offered to research the question more if desired.

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CO-CHAIR GATTO said a lot of pipes from Alberta to the states are not full and Alaska gas will help put more pressure in those lines.

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MR. HARPER assured members that regarding the notion of price effects of Alaska gas and McKenzie gas, the price expectations are already factored in.

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REPRESENTATIVE BUCH asked Mr. Harper or one of the other team members to address the prospects of LNG, an interstate gas line, and the possibility of a Y line.

[4:25:30 PM](#)

MR. HARPER responded:

Thank you - very insightful and complex questions. I would say with regard to LNG, LNG from a world perspective is going to become increasingly important because there are certainly more future hydrocarbons and methane than there is apparently in oil, based on what we know and there's a growing trade and it's a different kind of a market because those cargos move around depending upon price signals that are occurring real time - a little different than a pipeline.

What we're seeing is a great deal of difficulty in getting ...import projects sited. It's a very slow process. There's a great push in the Pacific Northwest and California right now to get something done - one, maybe two projects, just one or two projects to help with the supply hydraulics. Do I think Alaska gas is competing with LNG? No I do not. Certainly the more supply that you have, relative to supply demand obviously improves the supply configuration and intends to moderate price outlooks, the more that you have. But on the other hand, the more moderated the price outlook gets, then the more energetic you get in terms of looking at future demand.

We're not looking at a static demand market and this is the problem I had with the argument a year ago. You've got LNG and Alaskan gas that when they hit the market from a cost perspective they're not too far off. Now Dr. Finizza, Econ One, will tell you even in that analysis you're not competing with LNG, you're competing with the highest cost source. That's the first one that gets threatened by new supplies, which is non-conventional gas and some of those things. That really is what you're looking at from a pure economic standpoint. But I can tell you, the folks in the Lower 48 states right now are hoping for more LNG and they're hoping this Alaska gas comes on soon and the price outlooks now are so robust. I think - if I'm not wrong Mr. Scott, your high side case in your economics was in the \$8.50 range. We're at \$8.00 gas right now. This was the perfect storm on the upside in his economics and in the Econ One models.

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And oh, by the way, I meant to say earlier that in addition to Mr. Hobbs' work separately from the Administration group, Econ One who did not have time or the information to do a full scrub of the Administration's work, looked at the methodology in the model, the way FT was treated, and also endorsed fully the methodology that Mr. Scott used.

But, anyway, I hope I've begun to answer your question anyway. I don't think they're mutually exclusive. I don't think they're directly competitive and LNG is going to be a bit slower than everybody down there is hoping for with these high prices.

[4:28:27 PM](#)

CO-CHAIR GATTO asked Dr. Scott to give the committee a brief comparison of the economics of LNG versus Alaska gas.

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REPRESENTATIVE GARDNER asked Mr. Harper if it is fair to say that some people are "crying in their beer" given the current possibilities for Alaska as opposed to where the state stood a year ago with the proposed contract.

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MR. HARPER said certainly. He noted there are good and well meaning legislators who probably still view that as a logical alternative. He feels certain the part of the industry that was advancing that contract is very disappointed.

REPRESENTATIVE GARDNER said she was referring to members of the industry, not legislators.

MR. HARPER said he has no doubt the counter parties to that Stranded Gas Development Act (SGDA) contract are very disappointed. He pointed out they are not denied an opportunity to step forward and compete now. If they want to drive the cost down they should up the ante in the competitive bidding on this pipeline.

[4:30:28 PM](#)

CO-CHAIR GATTO commented these presentations have been very beneficial to the committee and everyone watching on Gavel to Gavel. He thanked all members. He noted while AGIA passed today, it is just the beginning. The Legislature will have to choose a licensee and will be addressing other important votes in the future. He felt this presentation was just as valuable after the floor vote as would have been before. He asked Dr. Scott to address the question about the economics of LNG versus Alaska gas.

[4:32:19 PM](#)

ANTONY SCOTT, Commercial Section, Central Office, Division of Oil & Gas, Department of Natural Resources (DNR), said he is not an expert on LNG. He asserted that discussions about LNG coming and the window of opportunity for Alaska gas closing have been considerable. ConocoPhillips' CEO recently said LNG, Alaska

gas, and McKenzie gas are all needed. North American supply is having a hard time keeping up. Most of the inexpensive gas has been produced so what sets prices in North America will be the marginal cost of supply, that being the most expensive gas. He noted that LNG displaces that a little bit, but not a lot. Although LNG will affect the price in North America, it will not set the price. It is clear there is plenty of room for LNG and Alaskan gas given North American demand.

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CO-CHAIR GATTO asked, if [Alaska gas] would still be a good project if, in a worst case scenario, tons of LNG are produced and new terminals are built.

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MR. HARPER told members:

I can tell you that we at Econ One have looked at this and we do not see a scenario where it's still a good project. What you can see is a re-ordering of the way product moved around in the U.S., depending upon where these things are sited and how they come in, which may ultimately affect the downstream movement of Alaskan gas but from an economic impact standpoint, and the economics of this project given the upside case the downside case and expected case that your consultants at Econ One have run, that the Administration has run and others in the industry have run, we haven't seen a scenario where it doesn't work. And Mr. Hobbs did his work here for you today. We don't see a scenario at this time - not that one couldn't exist, but we haven't seen one.

[4:34:50 PM](#)

REPRESENTATIVE SEATON referred to an article he read that said LNG would not come on at the anticipated rate because of the high cost of projects and that several in Qatar had been put on hold. He asked if the perception is that not only are the loading points unavailable, but that LNG supplies are short because of increased demand.

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MR. HARPER asserted he does not have a good understanding of LNG on the upstream side. He reiterated that on the downstream

side, the siting of these [facilities] has become very difficult because of local resistance. When it comes in it actually has a quality problem because it is so incredibly dry. The AGA is looking at quality specification issues right now. Local distribution companies are looking at piping infrastructure and other changes that will need to be made. Those changes will occur over time but he believes LNG will be slower rather than faster in arriving here than what was projected a year ago. However, over the next 50 years, LNG will be huge so its development should be encouraged.

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MR. HOBBS added that everything else being equal, it is in the United States' long term strategic interest to get this pipeline built, which is the reason for the federal loan guarantee and other federal support. This gas will be sold to U.S. consumers. LNG can be sourced in many places in the world and many issues could arise that may effect that, sometimes purely economic because, for example, Japan might want more than the U. S. does. He concluded, "Everything else being equal, Alaska gas will beat out LNG but obviously it's going to have to compete on an economic front as well."

CO-CHAIR GATTO said he appreciates the "second opinion" the presenters are providing.

[4:38:02 PM](#)

REPRESENTATIVE SEATON said his question has to do with one of the provisions in the contract about the evaluation terms number 6 (page 12 of the work draft). He continued:

This is evaluating the Net Present Value and then it was other factors found by the commissioners to be relevant to the evaluation of the Net Present Value of the anticipated cash flow to the state.

REPRESENTATIVE SEATON noted that provision is different than the wording used in the House Resources version. He furthered:

I was wanting to see if we could get Mr. Shepler to give us some evaluation of that as far as with FERC and also we have - you know one of the reasons we put this in there was because we had one of the proposals coming forward doing a profit share system with us that was a Port Authority proposal. It was talking about several things. One was a

PILT, payment in lieu of taxes, for the property tax on the pipeline, a payment in lieu of taxes possibly for offsetting corporate taxes because of course it's a municipal entity so it wouldn't pay corporate taxes. The third thing that we had considered or that we incorporated in the language was a direct contractual profit sharing with the State of Alaska of the profits. I'm wondering if we could have him address those issues.

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MR. SHEPLER said despite his commitment to Representative Seaton he was unable to corral the Commissioner of Revenue to assure that his answer was consistent with one the commissioner gave in testimony. Evaluation factor number 6 is one of the factors the commissioners will consider when evaluating competing bids under the AGIA process. He read, "Will be economic value resulting from payments required to be made to the state under the terms of the proposal." It goes to the Port Authority's project but could apply to other projects in the context of a payment in lieu of taxes or profit sharing. If one project is going to give the state more value in some form, the state should recognize that.

MR. SHEPLER explained that comes up in several contexts. One was the notion that one way the state could receive economic value might be in the form of an applicant offering to repay part of the \$500 million over time. Another was the concept of a payment in lieu of taxes or profit sharing. Obviously, the more elevated the value to the state, the more elevated that project proposal would become. However, one issue does surface, that being whether the payment to the state is coming on the back of the shippers. If, as a result of the payment to the state, the rates or the project for the shippers goes up, that will have an offsetting negative value to the state because the netback to the state will be reduced. His perception is that if the economic value is actually coming from the applicant's pocket that would be a positive factor in the evaluation process. If it is coming from the shipper's pocket or the state's pocket, that would offset the economic value.

MR. SHEPLER stated in the context of the Port Authority agreeing to give half of its equity return, which it is allowed to recover in the rate making process, to the state that would be one thing. However, if the Port Authority proposes to collect money from shippers for payment in lieu of taxes, which they would charge the customers for, that would be problematic

because it would raise and lower the benefits to the state. He added whether FERC would even allow the Port Authority to collect rates that reflect costs, the PILT, that the Port Authority is agreeing to make but not required to make is questionable. It's almost as if the Port Authority is allowed to recover costs it is not incurring. He opined that such a proposal would have to be evaluated on the totality of the economic value - whether the applicant is contributing value from its pocket or whether it is contributing value by raising rates.

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REPRESENTATIVE SEATON recalled the commissioner stated in the House Finance Committee that it wouldn't be countered if it could be charged to the shipper or increased a tariff; however he doesn't see anything in the language that says that.

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MR. SHEPLER replied AGIA requires that the \$500 million must come from the rate base, which has a rate reducing effect at the outset. He thought Commissioner Galvin was saying the effect of the consideration written into the law is that if it is going to raise the shipper's rates, consumers' rates will rise so that will not count. If it does not raise customers' rates but gives the state more value that would be recognized as a value for the state.

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REPRESENTATIVE SEATON said he is trying to make sure everyone who is thinking about submitting a proposal understands the situation. He gave the following illustration and asked for an analysis: an entity has a 20 mil property tax, which would be a cost that goes into the tariff. However, if that entity is a tax exempt municipality, that would not go into the rate. He said in one case, the 20 mils would not come to the state as a property tax payment but it would lower the tariff. He said the 20 mils is a positive in that it lowers the tariff but the state does not receive any of the 20 mils.

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MR. HARPER deferred to Dr. Scott but added AGIA contemplates the RFP process, so to the extent something was unclear, the RFP would focus on that.

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DR. SCOTT gave the following example to illustrate the concept brought forward by Representative Seaton. Assume the effective tax rate on gas is roughly comparable to oil, 12.5 percent. The royalty is typically about 12.5 percent. That puts the state's value in terms of the flow of gas at 25 percent. If the costs on the project are reduced by \$1, the state receives a quarter of that. If local property taxes are \$100 million less on the project, then the state receives a \$25 million benefit through the tariffs and the netback in terms of looking at royalty and production tax revenues. He acknowledged the point Representative Seaton raised is important in terms of the potential of a municipally owned project, which commits to providing payments in lieu of tax but is not required to. Assuming the municipality is FERC regulated, whether it is permitted to flow those costs through to rate payers is something the state would have to take a hard look at in terms of the likelihood of the promised cash flow.

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REPRESENTATIVE SEATON felt it is very important to think about these things and address them before proposals are solicited so that potential applicants know how value will be evaluated. He said it is likely the state will receive a bid from one municipality so the discussion may be characterized by that municipality. However, it is similar to the \$500 million. If an entity decides to increase its benefit to the state by saying it will pay that back, the \$500 million could not be included in its equity. He felt the language in number 6 is not as clear as the language inserted by the House Resources Standing Committee.

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DR. SCOTT said it is incumbent upon the Administration to explain how all of the different situations will be evaluated in very clear terms in the Request For Applications (RFA) so that it is completely transparent.

[4:54:01 PM](#)

CO-CHAIR GATTO thanked all participants.

[4:54:05 PM](#)

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 4:54 p.m.