ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
April 18, 2007
4:03 p.m.

MEMBERS PRESENT

Representative Carl Gatto, Co-Chair
Representative Craig Johnson, Co-Chair
Representative Vic Kohring
Representative Bob Roses
Representative Paul Seaton
Representative Peggy Wilson
Representative Bryce Edgmon
Representative Scott Kawasaki

MEMBERS ABSENT

Representative David Guttenberg

OTHER LEGISLATORS PRESENT

Representative Anna Fairclough

COMMITTEE CALENDAR

HOUSE BILL NO. 177
"An Act relating to the Alaska Gasline Inducement Act; establishing the Alaska Gasline Inducement Act matching contribution fund; providing for an Alaska Gasline Inducement Act coordinator; making conforming amendments; and providing for an effective date."

- HEARD AND HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 177
SHORT TITLE: NATURAL GAS PIPELINE PROJECT
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

03/05/07	(H)	READ THE FIRST TIME - REFERRALS
03/05/07	(H)	O&G, RES, FIN
03/06/07	(H)	O&G AT 3:00 PM BARNES 124
03/06/07	(H)	-- MEETING CANCELED --
03/08/07	(H)	O&G AT 3:00 PM BARNES 124
03/08/07	(H)	-- MEETING CANCELED --

03/13/07	(H)	O&G AT 3:30 PM HOUSE FINANCE 519
03/13/07	(H)	Heard & Held
03/13/07	(H)	MINUTE(O&G)
03/15/07	(H)	O&G AT 3:00 PM BARNES 124
03/15/07	(H)	Heard & Held
03/15/07	(H)	MINUTE(O&G)
03/19/07	(H)	O&G AT 8:30 AM CAPITOL 106
03/19/07	(H)	Heard & Held
03/19/07	(H)	MINUTE(O&G)
03/20/07	(H)	O&G AT 3:00 PM BARNES 124
03/20/07	(H)	Heard & Held
03/20/07	(H)	MINUTE(O&G)
03/21/07	(H)	O&G AT 5:30 PM SENATE FINANCE 532
03/21/07	(H)	Heard & Held
03/21/07	(H)	MINUTE(O&G)
03/22/07	(H)	O&G AT 3:00 PM BARNES 124
03/22/07	(H)	Heard & Held
03/22/07	(H)	MINUTE(O&G)
03/23/07	(H)	O&G AT 8:30 AM CAPITOL 106
03/23/07	(H)	Heard & Held
03/23/07	(H)	MINUTE(O&G)
03/24/07	(H)	O&G AT 1:00 PM SENATE FINANCE 532
03/24/07	(H)	-- Public Testimony --
03/26/07	(H)	O&G AT 8:30 AM CAPITOL 106
03/26/07	(H)	Heard & Held
03/26/07	(H)	MINUTE(O&G)
03/27/07	(H)	O&G AT 3:00 PM BARNES 124
03/28/07	(H)	O&G AT 7:30 AM CAPITOL 106
03/28/07	(H)	Heard & Held
03/28/07	(H)	MINUTE(O&G)
03/28/07	(H)	O&G AT 8:30 AM CAPITOL 106
03/28/07	(H)	Heard & Held
03/28/07	(H)	MINUTE(O&G)
03/29/07	(H)	O&G AT 3:00 PM BARNES 124
03/29/07	(H)	Heard & Held
03/29/07	(H)	MINUTE(O&G)
03/30/07	(H)	O&G AT 8:30 AM CAPITOL 106
03/30/07	(H)	Heard & Held
03/30/07	(H)	MINUTE(O&G)
03/31/07	(H)	O&G AT 1:00 PM BARNES 124
03/31/07	(H)	-- MEETING CANCELED --
04/02/07	(H)	O&G AT 8:30 AM CAPITOL 106
04/02/07	(H)	Heard & Held
04/02/07	(H)	MINUTE(O&G)
04/03/07	(H)	O&G AT 3:00 PM BARNES 124
04/03/07	(H)	Moved CSHB 177(O&G) Out of Committee
04/03/07	(H)	MINUTE(O&G)

04/04/07	(H)	O&G RPT CS(O&G) NT 3DP 2NR 2AM
04/04/07	(H)	DP: RAMRAS, DOOGAN, OLSON
04/04/07	(H)	NR: SAMUELS, KAWASAKI
04/04/07	(H)	AM: DAHLSTROM, KOHRING
04/04/07	(H)	O&G AT 8:30 AM CAPITOL 106
04/04/07	(H)	-- MEETING CANCELED --
04/05/07	(H)	O&G AT 3:00 PM BARNES 124
04/05/07	(H)	-- MEETING CANCELED --
04/10/07	(H)	RES AT 1:00 PM BARNES 124
04/10/07	(H)	Heard & Held
04/10/07	(H)	MINUTE(RES)
04/11/07	(H)	RES AT 1:00 PM BARNES 124
04/11/07	(H)	Heard & Held
04/11/07	(H)	MINUTE(RES)
04/12/07	(H)	RES AT 1:00 PM BARNES 124
04/12/07	(H)	Heard & Held
04/12/07	(H)	MINUTE(RES)
04/13/07	(H)	RES AT 1:00 PM BARNES 124
04/13/07	(H)	Heard & Held
04/13/07	(H)	MINUTE(RES)
04/14/07	(H)	RES AT 1:00 PM BARNES 124
04/14/07	(H)	Heard & Held
04/14/07	(H)	MINUTE(RES)
04/16/07	(H)	RES AT 1:00 PM BARNES 124
04/16/07	(H)	Heard & Held
04/16/07	(H)	MINUTE(RES)
04/17/07	(H)	RES AT 1:00 PM BARNES 124
04/17/07	(H)	Heard & Held
04/17/07	(H)	MINUTE(RES)
04/18/07	(H)	RES AT 1:00 PM BARNES 124

WITNESS REGISTER

ANTONY SCOTT, Commercial Analyst
Division of Oil & Gas
Department of Natural Resources (DNR)
Anchorage, Alaska
POSITION STATEMENT: Presented information regarding pipeline project economics and answered questions.

ACTION NARRATIVE

CO-CHAIR CARL GATTO called the House Resources Standing Committee meeting to order at 4:03:17 PM. Representatives Gatto, Johnson, Wilson, Seaton, Roses, and Edgmon were present at the call to order. Representatives Kohring and Kawasaki

arrived as the meeting was in progress. Representative Fairclough was also in attendance.

HB 177-NATURAL GAS PIPELINE PROJECT

4:03:27 PM

CO-CHAIR GATTO announced that the only order of business would be HOUSE BILL NO. 177, "An Act relating to the Alaska Gasline Inducement Act; establishing the Alaska Gasline Inducement Act matching contribution fund; providing for an Alaska Gasline Inducement Act coordinator; making conforming amendments; and providing for an effective date." [Before the committee was CSHB 177(O&G).]

4:04:31 PM

ANTONY SCOTT, Commercial Analyst, Division of Oil & Gas, Department of Natural Resources (DNR), provided the committee with a PowerPoint presentation titled "Analysis of Producer Returns, Investment Attractiveness, and Fiscal Certainty" dated April 18, 2007. He described net present value ("NPV") as the "current value of a stream of future cash flows." He explained that future cash flows are discounted to account for inflation, impatience, and risk. He said that a cash flow 20 years in the future is less certain than a present day cash flow. He explained that companies discount future cash flows by what is called the "discount rate." He suggested that investors without any capital constraints will be likely to invest in "all projects that have a net present value greater than zero" because those are the type of projects that add value to the company. He opined that the discount rate is clearly an important factor in making an investment decision and that his presentation and analysis will assume a discount rate of 10 percent.

4:08:36 PM

DR. SCOTT explained that another measure of investment attractiveness is the internal rate of return, which is "basically solving for the discount rate that makes the net present value of a project's cash flow equal to zero." He offered that, "bigger numbers, in general, are better." He went on to say that an additional factor is the "profitability index," which is basically a measure of the present value of cash inflows." He reiterated that present value means the discount rate divided by the present value of cash outflow. For

example, a profitability index of two means if you invest a single dollar in a project you get two dollars of profit back."

4:09:28 PM

DR. SCOTT explained that the NPV per barrel of oil equivalent means taking the NPV and dividing by the undiscounted total barrel of oil equivalent off the project. He provided the committee with materials prepared by the state's consultant Econ One, which he said explains the meaning and use of numerous financial terms. He referred to slide 3 which sets forth the potential economics of a $20 billion gas pipeline with a 4.3 billion cubic feet (Bcf) per day capacity to Alberta, Canada. Under the scenario, a $4.00 "real gas price" provides a NPV to the producers, collectively discounted at 10 percent, of $6.1 billion. If one assumes a $5.50 gas price, the NPV of the project to the producers collectively is around $12 billion, with corresponding internal rates of return of nearly 40 percent and perhaps over 60 percent. He said the profitability ratios of the scenarios are estimated at 4.3 and 7.5.

4:11:49 PM

REPRESENTATIVE SEATON asked for clarification of "NPV 10" - does that mean one discounts future profits by 10 percent annually back to the present day to determine present value?

DR. SCOTT agreed that the aforementioned description "is exactly right." He explained that in a business analysis, one examines the profits as well as the investments. Since the investments occur before the profits, they get discounted less. The discount rates compound to result in an annual discount rate, he explained.

4:12:47 PM

DR. SCOTT explained that if the proposed pipeline project has a cost overrun of 50 percent, the predicted NPV of the project falls. If the price of gas is $5.50, a cost overrun of 50 percent would reduce the NPV from $12.1 billion to $9.2 billion. He characterized the project cost overrun risk as "real." He noted in the event of a cost overrun, the internal rates of return are still "quite high" and remain significantly above the company's "hurdle rates." He reminded the committee that the numbers presented are based on the producers' upstream returns. The predictions made assume that the producers invest in a gas treatment plant (GTP) and that the GTP is not subject to

production profits tax (PPT) deduction credits. Furthermore, the scenario assumes that the producers make all the necessary upstream investment for Point Thomson and associated pipelines, but "not in the pipeline itself" he said.

4:14:11 PM

CO-CHAIR JOHNSON asked for clarification as to whether field infrastructure is included in the predicted future scenarios regarding pipeline development.

DR. SCOTT responded that "it does include field infrastructure" and assumes that the producers invest in and own a GTP. However the model also assumes the GTP is not a deductible expense for PPT purposes.

4:14:52 PM

CO-CHAIR JOHNSON asked how a value was placed on the infrastructure used in the economic models.

DR. SCOTT explained that information provided by the producers and knowledge of Prudhoe Bay fields indicates that the incremental in-field investments required at Prudhoe Bay will be relatively modest. He noted there is a significant amount of infrastructure at Prudhoe Bay producing both oil and gas "except of course, the gas treatment plant." He said that the 2001 cost study estimated the cost for the GTP to be around $2.3 billion in 2001 dollars. He said the cost of the GTP has been "scaled up" to reflect the general estimate that the cost of the pipeline has gone from $20 billion to $30 billion [assuming a project to Chicago, Illinois.]

4:16:41 PM

REPRESENTATIVE SEATON noted that the future scenarios presented consider differing gas prices, but do not appear to incorporate predicted tariffs.

DR. SCOTT replied that the tariff for the economic predictions is assumed based on the parameters listed in an appendix to the Econ One report. The parameters used assume a 70 to 30 debt to equity ratio, a 14 percent return on equity, and a debt cost of 6.5 percent. When rolled together, these factors result in an estimated tariff from $1.96 to $2.00. He noted that if another debt to equity ratio was used or if the rate of return was different, the estimates would change.

4:17:43 PM

CO-CHAIR GATTO asked what the tariff would be were the gas to be converted to liquefied natural gas (LNG) for shipment on a tanker.

DR. SCOTT responded that he could not answer that question today.

4:17:59 PM

DR. SCOTT referred to slide 5 which predicts the producers' returns if they were both shippers and pipeline owners. He said that this scenario requires a much greater investment by the producers. He directed the committee's attention to slide 3 and explained that if the producers were both shippers and pipeline owners, one sees very substantial declines in internal rates of return, the profitability index, and net present value. The reason for the decline in NPV is because the tariff "off of the pipeline throws off a return of about eight and one-half percent on a weighted average cost of capital basis whereas the discount rate is greater than that", he explained. As a result, investment in the pipeline at a 10 percent discount rate "costs you money." If the discount rate is lower than 10 percent, then the "pipeline doesn't cost you money," he said. He explained that pipeline companies have different discount rates and that 10 percent is not a particularly low discount rate.

4:19:49 PM

REPRESENTATIVE WILSON suggested that if the aforementioned predictions regarding pipeline economics are factual, then the shippers would not want to own the pipeline.

DR. SCOTT responded by characterizing the above comment as "an extremely interesting and provocative question" which he would address shortly.

DR. SCOTT explained that slide 6 titled "Producer NPV: Relative likelihood," shows the distribution of NPV from an integrated upstream investment and the relative likelihood of different outcomes. He indicated that DNR believes that from an upstream only investment perspective, half of the time [represented by a blue bar] the NPV, discounted at 10 percent, is at least $13 billion. That means there is a 50 percent likelihood that the NPV will be at least $13 billion and a 50 percent likelihood it

will be below $13 billion. He said that the further one strays from the $13 billion figure, the "less likely the outcome is." He said there is a small chance the returns off the project will exceed $30 billion.

4:22:19 PM

REPRESENTATIVE ROSES sought further explanation about the likelihood that the percentage of return would be $13 billion.

DR. SCOTT referred to slide 6 and noted that if returns were $6 billion, then the likelihood that project returns would exceed $6 billion is considerably greater than 50 percent, indeed it is around 75 percent.

4:23:30 PM

DR. SCOTT explained that slide 7 shows the relative frequency distribution of the internal rate of return (IRR). He explained that for the upstream there is a median IRR of 57 percent, which means that there is a 50 percent likelihood that the IRR on the upstream investment only will be 57 percent. However, for an integrated project the "spread is much narrower" and the probability of the IRR reaching 60 percent is "essentially zero," he said. The reason is that an integrated project requires the producers to make an "enormous upfront investment in the pipeline and it drags the [IRR] down," he explained.

4:24:27 PM

DR. SCOTT explained that slide 8 sets forth the results of a frequency distribution analysis of the producers' profitability ratio for both an integrated project and an upstream-only project. He summarized the presentation to this point as having provided a general overview of potential producer returns from this project. He indicated that a response to Representative Wilson's question regarding why the producers would want to own the pipeline first requires acknowledgement that there are other investment opportunities worldwide as shown on slide 9 titled "Comparative Project Opportunities." He opined that the data used by Econ One to compile the graph on slide 9 is accurate and recent. He said the NPV predictions vary depending on the price of oil, noting that a higher oil price supports a higher NPV determination.

4:27:18 PM

DR. SCOTT explained that slide 10 predicts the economics of an Alaska gas pipeline project which ends at either Alberta or Chicago. When based on oil prices of $25 or $35 per barrel the project is the "most attractive project," to the producers on an NPV basis. He said there is a "significant spread" in the NPV between Alberta and Chicago, with termination in Alberta providing a greater rate of return due to the need for significantly less infrastructure investment. He explained that he updated the information used in slide 10 for slide 11 to show the current gas pipeline economics using PPT instead of the prior economic limit factor [ELF]. The current gas line economic model, from an upstream perspective, indicates that the Alaska project is "still either the first or second most attractive project" in the producers' portfolio. If one considers it from the integrated perspective, the project's attractiveness drops to "maybe the third most attractive project in the portfolio." In response to a question, he clarified that the upstream analysis assumes "zero percent pipeline ownership."

4:31:41 PM

DR. SCOTT opined that when one considers profitability ratios from an upstream perspective, the Alaska project has "by far the most attractive profitability index ratio investment in the [producers'] portfolio." Its profitability does not even "fit on the chart," he explained, referring to slide 12. However, if this scenario is considered from the prospective of producer ownership of the pipeline, the profitability ratio decreases to around the 25th percentile, meaning that roughly three-quarters of the investment opportunities in the portfolio are more attractive than the Alaska pipeline project. He explained that the most important factors that decrease profitability are the increased construction costs and the change from ELF to PPT. He opined the change "really shows up" in Prudhoe Bay as the prior effective tax rate there was around seven to seven and one-half percent while the current effective tax rate on gas at Prudhoe Bay under PPT is around 20 percent, he explained. He went on to discuss the internal rates of return under PPT and noted that "if you don't own the pipeline ... in terms of internal rates of return, this is a very attractive project in the portfolio."

4:34:11 PM

DR. SCOTT directed attention to slide 14 and addressed Representative Wilson's prior question as to why the producers would want to own the pipeline. He suggested that some may believe that the producers "have to" own the project as they are

the only companies that can obtain the financing necessary to build the pipeline. He opined that this "isn't so," and noted that there are pipeline companies that are ready and willing to invest in the project and that "they can handle it, they can do this." He said that these companies require firm transportation (FT) commitments so as to obtain financing. He stressed that it is "extremely important" to recognize that this project will not be financed by "Exxon's balance sheet." He explained that the project will be financed on a "project finance basis" which means that the expected project revenues will provide the basis for lenders to provide project financing. He opined that "it's the gas in the ground that matters," as these proved reserves provide assurance that there will be enough gas to "keep the project full, with no decline, for at least 15 years." He characterized the existence of this large amount of proved reserves as an "exceptionally unusual circumstance" for a basin-opening project. He said that during debate on the extension of federal loan guarantees, it was determined that the Alaska gas project may be sufficiently attractive from a credit perspective that the federal government "will back this." He indicated that a federal report on this project stated that without FT commitments the project "will be rated - on a project finance basis, double B [BB] instead of triple B [BBB], investment grade." He stressed that it is the "gas in the ground that is providing the financing."

4:38:31 PM

REPRESENTATIVE WILSON asked whether even without FT commitments "they could still get the loan."

DR. SCOTT replied "that is exactly what we're saying." He cautioned that an independent pipeline developer needs an FT commitment from the producers in order to go forward with the project. If the builders contribute 20 percent equity, or approximately $4 billion, to the project and build without FT commitments they run the risk that the holders of the gas will leverage the shipper to reduce its tariffs prior to committing their gas to the project. He emphasized that the pipeline developer "absolutely has to have shipping commitments - it's because of what we call 'hold-up' risk."

4:40:53 PM

CO-CHAIR GATTO asked whether it is conversely true that a producer-owner could claim "the tariff is too low."

DR. SCOTT replied "not necessarily, no." He expanded his point by opining that for an integrated project, such as the Trans-Alaska Pipeline System (TAPS), the incentive is for the "lowest cost project" with the "highest tariff." He explained that commercial incentive exists because the taxes and royalties are paid after subtraction of tariff costs. A pipeline owner who also owns the gas is "indifferent to what the tariff is ... it only matters where you take your profits - do you take them on the pipeline or do you take them on the gas?" The tax and royalty burden decreases if the pipeline tariffs are higher, he indicated.

4:42:01 PM

DR. SCOTT suggested that another reason the producers would want to own the pipeline is to control costs, a motivation he characterized as "fair enough." He offered that it is understandable that parties want some cost control abilities if they are going to enter shipping commitments since the shipping tariffs are based in part on pipeline costs. However, he cautioned that there is an incorrect perception that the shippers pay for the cost of the project "no matter what" since the pipeline business is a "cost plus" business in which the shippers charge "whatever it costs, plus a return." He opined that this characterization is not accurate when applied to today's pipeline business. He said that most newly built pipelines are built on the basis of rates negotiated between the shippers and pipeline entities prior to pipeline construction. He opined that the risk of cost overruns is addressed in the negotiated rate discussions. He offered that a great number of pipelines are built in the Lower 48 on the basis of "fixed price negotiated rates." In some instances, the shipper is then assured of a "set it and forget it," rate while the pipeline company bears all of the cost overrun risk.

4:44:37 PM

DR. SCOTT opined that the Alaska pipeline project will likely not have negotiated rates because the project lead times are so long that there are numerous cost factors "not in anybody's control." This factor of uncertain costs does not place the Alaska project "in a cost plus environment," rather "what we absolutely expect is that risk sharing is to be negotiated between the pipeline entity and the shippers," he opined. He gave as an example the Rockies Express Pipeline in the Lower 48, which has three different negotiated rates, each reflecting a different risk scenario and the parties' "differing appetites

for risk." He explained that one variable that could be included in negotiated rates for the Alaska project would be "steel price escalators," since steel prices are a significant, but uncontrollable factor that will affect pipeline costs.

4:46:07 PM

REPRESENTATIVE WILSON asked about the role of the Federal Energy Regulatory Commission (FERC) if negotiated rates are determined prior to open season.

DR. SCOTT explained that these rates will be negotiated prior to open season, but "consummated at the open season," He agreed that the parties will negotiate prior to any FERC determination of a "cost-based tariff." He said that FERC does not rule on whether a negotiated rate is in the public interest. He explained that FERC will exercise its regulatory jurisdiction only over the "maximum or recourse rate," which is the rate available to any shipper without negotiation. He said it is possible that there could be no shippers ever on the "FERC established rate," and explained that there are pipelines where all shippers pay at negotiated rates.

4:48:02 PM

REPRESENTATIVE WILSON expressed concern as to why issues have been raised about the tariff provisions of the bill if it is "irrelevant most of the time."

DR. SCOTT replied that the recourse rate will be important to the state's interest because it will provide a benchmark for the state to consider when determining the tax and royalty rates, particularly if the pipeline owners are also the shippers. In that instance, the owner/shipper may negotiate a rate that is much higher than the "FERC cost of service rate." In that instance, the state must decide whether to establish taxes and royalties based on the negotiated rate, or on the FERC cost of service rate.

[Co-Chair Gatto turned the gavel over to Co-Chair Johnson.]

4:49:54 PM

DR. SCOTT summarized that there are valid commercial reasons why a producer would like to own the pipeline, such as cost control. He suggested that there is a perception that the pipeline company has no incentive to control costs in an integrated

project, but opined that this conclusion is not accurate and is "not to be expected on this project."

4:50:28 PM

REPRESENTATIVE ROSES asked whether it is in the best interests of the producers for the state to create a mechanism that gives them the maximum amount of flexibility possible to allow them to "really play with the cards and the economics."

DR. SCOTT responded that the aforementioned statement could be considered a "commercially reasonable statement."

4:51:04 PM

DR. SCOTT went on to say that there will likely be further discussion as to whether a FT commitment is the same as a debt obligation. He offered his understanding that the producers' stated view is that an FT commitment is exactly like issuing a debt obligation. He indicated that DNR has studied and considered this issue "for a number of years." He said his opinion on this issue has been formed by market factors as "that's ... reality." He opined that the first thing to note is that an FT commitment shows up as a footnote on financial statements, but "does not go against" the company's balance sheet. He suggested that a contention that an FT commitment is a debt equivalent is akin to stating an FT commitment is the same as a lease. He offered that characterization of the nature of the obligation "does not really play out" in terms of "how the IRS {Internal Revenue Service] views it." He suggested that if the IRS viewed FT commitments as equivalent to leases, then depreciation benefits under tax provisions would flow to leases [lessees] as opposed to owners. He explained that the tax treatment of depreciation "does not flow from a pipeline company to a shipper." He reiterated that the IRS does not "view a FT commitment as a debt or lease equivalent."

4:54:57 PM

DR. SCOTT explained that analysts in the credit rating agencies have been asked by [state economists] if an FT commitment is a debt equivalent which would reduce the company's future ability to issue debt. He said that the credit rating agencies replied "absolutely not, that's not how we look at things." He put forth that credit rating agencies may potentially consider FT commitments in assessing the overall risk profile of the company. However, in general FT commitments are "not considered

at all," a point he indicated is supported by a Moody's Investor Service report of 2003 which states "in general we [Moody's] do not look at FT commitments when assessing E/P [earnings and profits] credit strength." He opined that this makes sense because FT commitments may actually increase a company's credit increase by establishing positive future cash flows.

4:57:47 PM

REPRESENTATIVE ROSES indicated he understands the aforementioned analysis, but asked what happens should the pipeline volume be insufficient to meet the FT commitment requirements.

4:58:07 PM

DR. SCOTT replied that it is exactly right that an entity that makes a FT commitment does not do so on a risk free basis, and he did not mean to so imply. One risk related to FT commitments is that of price, the second is reserve risk, he said. He explained that an entity that makes an FT commitment does not pay if the pipeline is not completed or is not in operation. He said that the biggest risk facing the Alaska project is the risk of low production. The pipeline developer bears the risk that there may be insufficient production despite significant investments made in the development of the pipeline. One way to manage risk is to "bring in new parties and get them to bear some," he suggested. He said that shippers do not normally have to pay if for some reason the pipeline is not operating. In that instance, it is the pipeline company that "is on the hook," he said.

5:01:30 PM

DR. SCOTT explained that another reason for integrated pipeline ownership is control or influence over the pipeline terms, such as tariffs, recourse rates, and expansion. He opined that AGIA seeks to assure that the pipeline owner, whoever that may be, will act like a pipeline company, as those companies favor rolled-in rates and expansion. He said that although an integrated approach may appear to lessen the project's economic benefits to the producers, an integrated approach may improve "bargaining position with the state."

5:03:05 PM

DR. SCOTT referred to slide 15 which represents the financial commitment necessary to enter FT contracts for either a $20

billion or $25 billion pipeline project. He said that the total FT commitment costs for the producers could be around $3.4 billion a year; higher should the project costs increase. He indicated that even using conservative gas price estimates, and assuming no additional discoveries, the likely revenues would exceed the FT payments [as shown in slide 16].

5:04:42 PM

REPRESENTATIVE WILSON asked whether the peak revenues from the gas pipeline as depicted in slide 16 would plateau if there were additional discoveries of gas.

DR. SCOTT predicted that if additional gas reserves were to fill the pipeline to capacity, the revenue projections shown on slide 16 would not plateau, but would continue to rise. He explained that the prices used for the example are in today's dollars, which is why the prices continue to rise. He described the tariff as "not a real tariff" but a $2.00 "nominal dollar tariff." Over the course of 15 years, the cost of the nominal tariff is much less than in the beginning, he said.

[Co-Chair Johnson returned the gavel to Co-Chair Gatto.]

DR. SCOTT explained that economic forecasts predict "considerable positive cash flow" should the gas prices exceed the "AECO [Alberta Hub] price level," which they are predicted to do over 85 percent of the time.

5:06:54 PM

CO-CHAIR GATTO asked about recovery of exploration costs if no new gas is discovered despite exploration efforts.

DR. SCOTT replied that "they are out of pocket" for the costs expended.

REPRESENTATIVE SEATON clarified that the explorers would be "out of pocket" for basically 60 percent of the exploration costs due to PPT provisions which set a tax rate of 22 percent and a capital credit rate of 20 percent.

DR. SCOTT agreed that the aforementioned description is exactly right under the current PPT.

5:07:56 PM

DR. SCOTT explained that slide 17 sets forth the effect on revenue of raising taxes by 15, 30, or 50 percent on "day one" of the project. A tax increase of 15 percent would reduce the project's NPV by 5.1 percent, a tax increase of 30 percent would decrease NPV by 10.2 percent, and a tax increase of 50 percent would decrease NPV by 17.1 percent, results he deemed "material." However, he offered his belief that it is important to put the effect any tax increases in context. He indicated that a $0.50 change in the price of gas may have more of an effect on the NPV than a tax increase of 30 percent. He opined that the "big risk" on this project is price risk. He responded to an inquiry by noting that gas prices tend to change significantly and daily.

CO-CHAIR GATTO noted that the scenario discussed so far assumes a tax increase as of "day one."

5:13:11 PM

DR. SCOTT presented a prediction based on the assumption that production taxes would be increased in the eleventh year of the project. Under this scenario, a 15 percent tax increase would decrease NPV by 2 percent, which indicates that set production tax rates for a 10 year period "makes a material difference in terms of exposure to fiscal uncertainty," he said. Tax increases have less of an effect on NPV after 15 years, since a 15 percent tax increase in the sixteenth year may decrease NPV by only 1 percent, he said, referring to slide 20. He opined that the "value of fiscal certainty starts decaying rapidly," after a project's initial few years of operation.

5:15:19 PM

CO-CHAIR GATTO observed that the first ten years of a project appear to be the most important in terms of fiscal certainty.

DR. SCOTT agreed that the early years of the project are the most important period for which to have fiscal certainty. He noted "we are dealing with compounding" and explained that one needs to remember that companies make investments on the basis of discounted value.

5:16:28 PM

DR. SCOTT went on to explain that internal rates of return (IRR) do not "move very much with tax increases," and that 10 years of fiscal certainty is adequate from an IRR basis. He went on to

say that profitability indexes also show that the project is economically attractive. In response to an observation, he explained that a 30-year project life forecast is all that is needed to get a good understanding of the pipeline project economics.

5:20:11 PM

DR. SCOTT responded to a request to clarify his prior testimony regarding the relationship of FT commitments to possible federal loan guarantee provisions. He said that the authorizing language for the loan guarantees in the Alaska Natural Gas Pipeline Act of 2004 (ANGPA) states that "the Secretary of the Department of Energy ... may impose ... no condition on the loan guarantee beyond what the project proponent imposes on ... the shippers." He said that means if a project proponent does not obtain FT guarantees from the shipper, the Secretary of the Department of Energy cannot place "that as a requirement of receiving a federal loan guarantee." He explained that the potential cost to taxpayers of the federal loan guarantees for the Alaska pipeline project was analyzed by federal economists with the assumption that there would be no FT commitments. He reminded the committee that TAPS was built without FT commitments, although he noted that the economics surrounding the construction of TAPS were different.

5:22:41 PM

REPRESENTATIVE SEATON set forth a hypothetical assumption that there are FT commitments for the first five to seven years of the pipeline. In that situation, he asked whether the federal loan guarantee would still apply to the other 80 percent.

DR. SCOTT agreed that the aforementioned description is correct. The federal loan guarantee would apply to all the project debt, including debt service that extends beyond the terms of any FT commitments, he explained.

REPRESENTATIVE SEATON asked whether it is possible to reduce risk to shippers by asking "for an open season of seven years ... so then people could bid on whether they want seven or they want to guarantee themselves more time on that pipeline."

DR. SCOTT replied that such a scenario is possible, but unlikely because such a short FT commitment period by an independent pipeline company is due to "hold up" risk, he said. He went on to explain that the federal government will guarantee the

construction debt, but that the pipeline company will require a return on equity, which is not guaranteed by the federal government. He said that FT commitments for 15 years have been used for pipelines in the Lower 48, but opined that FT commitments for the Alaska project would more likely be 15 to 20 years. He said that a shipper does face some reserve risk as production will decrease after 14 or so years. However, he opined that shippers are best positioned to "wear that risk," so it makes more business sense for the shippers to take a 20 year FT commitment while the pipeline builder takes more of the cost overrun risk as it can better manage costs. He explained that in commercial negotiations, companies prefer to bear the risks they have the ability to manage.

5:28:12 PM

CO-CHAIR JOHNSON asked if a change in the debt to equity ratio would allow for a shorter FT commitment.

DR. SCOTT replied that he did not think so. He said FERC never permits pipelines to base rates on 100 percent equity. The situation is different from a residential mortgage, where debt is retired. In pipeline projects, the debt retirement schedule is not necessarily at all the same as the debt retirement schedule that rates are based on. FERC will not allow rates based on 100 percent equity - that is "outside the zone of reasonableness," he said. He stated that the lowest debt ratios are usually around 30 to 35 percent debt, and that debt is maintained throughout the life of the project.

5:30:08 PM

CO-CHAIR JOHNSON asked for further information on the effect of differing debt to equity ratios on the FT commitment terms and on the approaches available to provide an acceptable level of fiscal certainty.

DR. SCOTT answered that the debt to equity ratio will not effect the appropriate period for FT commitments. These two issues are "not linked," he opined.

5:31:57 PM

REPRESENTATIVE WILSON asked if negotiated rates are "solid deals," not subject to later adjustment by FERC.

DR. SCOTT replied that is correct. The contracts for negotiated rates are finalized at open season and are known as "precedent agreements" as there are often conditions that must be satisfied before the shipper must commit to the contract terms. He offered his belief that for this project one of the "conditions precedent" will be that the cost estimates be within the bounds estimated at the time of the open season.

REPRESENTATIVE WILSON asked if the shippers can "back out" under certain situations.

DR. SCOTT agreed that the shippers could "back out" if the contract had a clause that allowed them to under certain circumstances, such as a cost increase of a certain magnitude. He said that for large, complex projects, it is not unusual for parties to enter agreements which require the shipper to take certain actions as a "condition precedent" to contract performance.

5:36:32 PM

REPRESENTATIVE WILSON noted that previous producer testimony had expressed opposition to use of rolled-in rates, while the independent pipeline companies did not seem to oppose them. She asked for some further explanation of this issue.

DR. SCOTT explained that rolled-in rates are "unequivocally good" for a shipper interested in exploring for additional gas supplies. For a shipper that is not an explorer, rolled-in rates are "potentially a problem" because rates can rise, which is harmful to shippers. A pipeline owner who is also a shipper does "not care" what the rate is, assuming there are appropriate distribution rules in its limited liability partnership arrangement. The "rate is immaterial because you are paying yourself," he said. A pipeline owner who is also a shipper therefore does not support rolled-in rates because "they can only hurt ..." Therefore, an independent pipeline company that does not plan on owning the pipeline may support rolled-in rates as they can be less costly than incremental rates. He opined that incremental rates can be so much higher than rolled-in rates that it may affect the ability to expand the pipeline. For example, if expansion was done through compression, the rate increase under incremental rates could be around $1.00, while the rate increase under rolled-in rates could be around $0.15.

5:40:23 PM

REPRESENTATIVE WILSON suggested that the 15 percent cap on rolled-in rates in AGIA is designed to protect the producers somewhat and still provide some incentive to explorers.

DR. SCOTT characterized the aforementioned description as exactly right.

REPRESENTATIVE WILSON asked whether the 15 percent limitation on rate increases [AS 43.90.130(7)] is reasonable and fair to the producers.

5:41:21 PM

DR. SCOTT responded that "fairness is in the eye of the beholder." He explained that the 15 percent provision was developed after considering issues described in slides 1 and 2 titled respectively, "Effects of Government Subsidies on Rates," and "Summary of Government Subsidies on Rates," from a presentation on "Government contributions to rates" to the Senate Judiciary Committee, 4/16/07. He explained that the various federal and state subsidies granted the Alaska project reduce the pipeline tariff by $0.25. On a tariff of $2.00, a $0.25 reduction is about 12 and one-half percent, he explained. He noted that the owners of the GTP will receive an additional 15 percent federal investment tax credit. He suggested that one way to view the 15 percent cap in AGIA is to assure that government subsidies are shared by all shippers in the system, and are not "enjoyed only by the initial shippers." A further consideration that supports the 15 percent cap is the state's interest in assuring future pipeline expansions are not "artificially capped," he explained. He opined that a 15 percent cap is likely to get the pipeline through full compression and perhaps through a first looping on the project. After the first looping, he suggested that rates may decline or at least hold steady. He said there is uncertainty regarding the effect of expansion on rates as it depends on when the expansion occurs and the costs thereof.

5:46:14 PM

REPRESENTATIVE WILSON noted that the producers can negotiate for certain rates prior to the project. She asked why the producers claim that AGIA does not allow them to negotiate with FERC.

DR. SCOTT opined that the producers object to provisions that require the pipeline company not negotiate rates that would preclude it from rolling in expansion costs up to the 15 percent

cap. He suggested that if the producers own the pipeline, business considerations would favor that they negotiate rates with themselves which would prevent expansion costs from being rolled-in to them as shippers. He offered that this matters because if there is a subsequent expansion, it will be "exceptionally difficult" for FERC to order rolled-in rate treatment of expansion costs because there are "no shippers to spread it over." As a political matter, the ability of FERC to roll-in such expansion costs would be affected, he said. He noted that a compression expansion of one billion cubic feet (Bcf) would cost approximately $1 billion in compression equipment.

5:48:32 PM

DR. SCOTT responded to a concern regarding the focus of the DNR and the Department of Revenue (DOR) by explaining that it is not the case that DNR is engaged solely in regulatory activities. The Division of Oil and Gas has a crucial commercial function since it is bound by contractual lease relationships with oil and gas explorers. In comparison, the DOR acts in more of a sovereign capacity. He opined that DNR and the lessees can be considered equals under the bounds of contract law. The DNR, through the Division of Oil and Gas, tends to have more expertise on matters of geology, pipeline tariffs, and rate making.

5:52:07 PM

REPRESENTATIVE ROSES said that the presentation really added some clarity to issues of flexibility. He opined that those "who were hollering the most" about flexibility appear to be the parties with the greatest control over both sides of the pricing structure. Additionally, he noted that until the ownership of the pipeline is clear, the parties may want to wait to negotiate the rate structure.

CO-CHAIR JOHNSON stated he was intrigued by the suggestion that a 15 percent federal subsidy applies to the rates on the project as it seems to lessen any conclusion that the pipeline owner subsidizes shippers up to the 15 percent.

5:53:51 PM

DR. SCOTT said there is some confusion regarding the economics of what a subsidy actually is. Initial shippers do not necessarily subsidize later shippers as long as all shippers are

at least paying the "marginal cost," he explained. He noted that in business expansions, very often costs rise and all users pay the same increased costs. The only way expansion costs could be a subsidy is if an initial shipper believes it has a property right to a rate, and if there is a property right to a rate, "what we're talking about is not subsidy, we're talking about theft," he opined.

5:56:57 PM

REPRESENTATIVE SEATON asked for further discussion of whether the 15 percent limitation could be characterized as a subsidy. He suggested that all AGIA establishes is the state's preference for rolled-in rates and that FERC will ultimately decide if there is a subsidy.

5:58:18 PM

DR. SCOTT replied that an independent pipeline owner will want to expand its business by expanding the pipe. He said it would be in their interest to roll-in rates so as to decrease the cost to new entrants. He offered that the pipeline company has no commercial interest in assessing whether something is a subsidy or not. Under AGIA the pipeline company is required only to propose rates, while FERC "disposes" of rate issues. He explained that the state's approach does not infringe on FERC's jurisdiction; rather it helps assure that the pipeline company "acts like a pipeline company" regardless of who owns the pipeline.

[HB 177 was held over.]

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 6:00:13 PM.