Stranded Gas Hearings

(0508311442 Minutes)

Net Present Value, Rate of Return, and Profitability Index on Producer Investments
Barry Pulliam, Senior Economist, Econ One Research, Inc.

MR. PULLIAM moved on to page 7-1 regarding Econ One's efforts in modeling a gas pipeline project. He noted that this modeling uses public information that's reasonable. He began on page 7-3 with the development of the model of a project that runs along the Alaska Highway to Alberta, Canada. The model was developed under the assumption that development would occur under the existing fiscal system and rules. Furthermore, different price, cost, and ownership scenarios have been modeled. He then reviewed pages 7-5 and 7-6, which relate the major assumptions of the model as follows:

Gas pipeline developed and gas sold under current fiscal terms

30-year project, with sale beginning by year-end 2012

Gas production of 4.5 BCF per day; approximately 50% from Prudhoe Bay, 16% from Point Thomson, and the balance from other fields

Gas sales of 4.2 BCF per day in Alberta (AECO Hub)

Gas prices in Alberta average $0.90/MMBtu below Henry Hub/Chicago levels

Average heat content of 1.1 MMBtu per MCF

Gas treatment plant, pipeline, and Point Thomson facilities financed with a combination of 80% debt (with federal guarantees) and 20% equity

Borrowing costs on federally guaranteed debt of 5% per year

FERC allows a 14% rate of return on equity for U.S. portion of pipeline; NEB allows a 12% return for Canadian portion

Costs and prices inflated by 2.5% per year from 2004

Capital costs consistent with producer presentation to legislature in August 2001 and June 2004:

> Capital cost include gas treatment plant, pipeline, and Point Thomson field development costs
>
> We have added additional capital for construction of a "feeder" pipeline from Point Thomson to the gas treatment plant and for development of gas reserves outside of Prudhoe Bay and Point Thomson

We assume gas sold on a "BTU" basis (i.e., no uplift for potential NGL extraction) --likely a conservative assumption

Consistent with this assumption, we have not included capital for a NGL extraction facility

We have not attempted to model any related impact on liquids production at this time

CHAIR THERRIAULT highlighted the assumption that the average heat content would be 1.1 mmBtu per mcf, and then related his understanding that the model used a blended stream.

MR. PULLIAM replied yes, and clarified that the assumption is that the gas would flow down to Alberta before any liquid extractions would occur.

CHAIR THERRIAULT then turned attention to the assumptions regarding the rates of return for FERC and NEB, and inquired as to whether the differentiation is based on what occurs now when a line that is located in the U.S. enters Canada. He asked if in such a situation the [rates of return] come close to normalizing.

MR. PULLIAM opined that such a scenario hasn't occurred yet, although he acknowledged that there are some lines from Canada that come into the U.S. Typically, the Canadian lines have a lower rate of return. He explained that once a project is running, FERC will want to hear from all the parties and discuss whether the initial rate of return should be adjusted. Oftentimes the [initial return] is adjusted down because what was initially perceived as risk is no longer perceived as such. He informed the committee that the model includes the ability to adjust the numbers and review different results.

MR. PULLIAM continued discussing the major assumptions, and emphasized the importance of capital costs of this project. Capital costs include the gas treatment plant, the pipeline, and Point Thomson field development costs. He related his understanding that the gas treatment plant and Point Thomson will be eligible for federal loan guarantees and thus have been treated as such in the assumptions. The assumption is that incremental costs would be required for the development of Point Thomson. Mr. Pulliam highlighted the inclusion of a "feeder" pipeline from Point Thomson as well as additional costs for additional development. It's likely that liquids extraction will be viable with this project. Under Econ One's assumptions gas would be sold on a BTU basis and thus the uplift or capital costs for a NGL facility haven't been included. Furthermore, there has been no attempt to model the potential related impacts on liquids because he opined that they wouldn't be likely to change the fundamental results.

MR. PULLIAM reviewed the scenarios with regard to pipeline ownership as presented on page 7-7. Scenarios with different gas price assumptions and different cost assumptions were reviewed as well. The range of plus or minus 20 percent is used in Econ One's modeling. He then turned attention to page 7-9, which discusses gas prices. The numbers were run using a base line average price of $4.90 from EIA's Annual Energy Outlook. The prices from EIA fall in the $4.05 to $5.10 range. The aforementioned is consistent with other public forecasts of gas prices. High and low price scenarios have been reviewed as well. He then moved on to the cost sensitivities as related on page 7-10.

MR. PULLIAM continued with the results of these models and directed attention to pages 7-11 and 7-12, which details the scenario in which the producers own 100 percent of the pipeline. The chart on page 7-13 details the different investment metrics that result from the assumptions specified on pages 7-11 and 7-12. He explained that the column headings with the 10 designation refer to a 10 percent discount rate. He noted that the IRR figures were calculated over the entire capital base, and thus don't incorporate the advantages of leveraging. He drew attention to the low price scenario, which relates that the IRR drops down to 17.2 percent. He then reviewed the charts on page 7-14 that detail the base case and a case with a 20 percent increase in costs. The charts on page 7-15 compare the base case to a case in which the costs decrease by 20 percent.

MR. PULLIAM moved on to page 7-16, which is the scenario in which the producers own 50 percent of the pipeline. Page 7-17 provides the specifics of this scenario. The chart on page 7-18 shows that in a situation in which ownership in the pipeline drops, the NPV at the 10 percent [discount] rises as does the IRR because the pipeline will have a regulated WACC and will earn about 6.5 percent. For purposes of project evaluation the 10 percent discount wouldn't be appropriate to use for regulated assets. However, in this exercise of different scenarios, keeping a constant discount rate allows one to see how the numbers change. The charts on page 7-19 provide a base case scenario versus a scenario when the costs increase by 20 percent while the charts on page 7-20 provide a base case scenario versus a scenario when the costs decrease by 20 percent.

MR. PULLIAM turned attention to pages 7-21 and 7-22, which review a scenario in which the producers own 0 percent of the pipeline and ship over a third-party owned pipeline. The results of the aforementioned scenario are related in the chart on page 7-23. The aforementioned chart illustrates that the NPV will increase because of the lack of the capital burden of the midstream investment, and the IRR will increase as well.

MR. PULLIAM, in response to Senator Stedman, confirmed that these [scenarios] are all unleveraged.

SENATOR STEDMAN inquired as to how sensitive the numbers would be if some leverage was employed.

MR. PULLIAM said that [the producers] typically don't have much debt in their capital structure. However, Econ One believes that they will incur some debt because of the availability of the federal loan guarantee. The assumption is that a large part of the investment will be debt financed, but the returns and NPV are over the entire capital base, unleveraged. In further response to Senator Stedman, Mr. Pulliam agreed that leverages and returns on the equity piece will be more than presented.

MR. PULLIAM then pointed out that the chart on page 7-24 compares the base case to a case in which the costs are increased by 20 percent. The chart on page 7-25 compares the base case with the costs decreased by 20 percent. He then moved on to the impact of leverage on project economics as related on page 7-26. He reminded the committee that thus far the analysis of the return reflect unleveraged economics, but it's true that FERC and NEB won't assume unleveraged economics. However, the [models] assume that the tariffs will be set based on the capital structure that's going to be used. Leverage, he stated, has a significant benefit in a project such as this because [it offers] the ability to significantly increase returns to shareholders. Still, companies remain mindful that increasing leverage comes at the cost of increasing risk, which is one of the reasons why shareholder returns increase as a company's leverage increases. Alaska's project is a different kind of project in which the leverage won't be viewed as very risky. The chart on page 7-27 returns to the integrated scenario in which the producers own 100 percent of the pipeline. The top chart is the base case, including the debt and the equity, while the lower chart is a leveraged case with equity capital only. The charts on page 7-28 show the same effect but in the scenario in which the producers only own 50 percent of the pipeline. Again, the effect of leverage is considerable on the returns. The charts on page 7-29 reflect the impact of leverage on project economics when the producers own none of the pipeline. He noted that in this case, the assumption is that the producers would use debt for the conditioning plant and the Point Thomson development costs but not for future development costs, which would be all equity.

SENATOR STEDMAN inquired as to how sensitive this analysis would be if the life of the line is 10-20 years longer.

MR. PULLIAM answered that this analysis, at a 10 percent discount rate, isn't very sensitive. The out years don't have a large impact on NPV and IRR, although the undiscounted cash numbers get large. If there was a pipeline that ran over the course of 30 years, the assumptions used here are that FERC would set a levelized tariff that would recover the capital in 30 years. However, if the project continued after that the capital couldn't be recovered again and thus the tariff would decrease considerably. In response to Chair Therriault, Mr. Pulliam confirmed that the leverage assumes an 80:20 ratio with the exception of the incremental investment, that would be required upstream. Although Econ One has modeled it with equity, [the producers] may use some debt.

SENATOR STEDMAN inquired as to how the three scenarios presented today compare with the international marketplace.

MR. PULLIAM answered that the scenarios, based on generally, publicly available information Econ One has reviewed, appear to compare favorably.

CHAIR THERRIAULT noted his initial surprise that the IRR increased with the lower producer participation in the pipeline.

MR. PULLIAM mentioned that there is also a perversity with regard to the borrowing costs. He then turned attention to page 7-13, which discusses the scenario in which the project is integrated. Intuitively one would think that if borrowing costs decrease, then the project should look better. However, in view of the NPV 10 it looks worse and drives down the IRR because it's the pipeline portion that's held to a regulated return. On the upstream [lower borrowing costs] drive the IRR up because there would be higher netbacks while driving down the return on the midstream portion. By making the midstream cheaper, it helps the upstream by lowering the tariff.

REPRESENTATIVE HAWKER turned to the base case scenario presented by Econ One, and asked if it had factored into the cash flows a provision for dismantlement, removal, and restoration (DR&R) for the pipeline.

MR. PULLIAM replied no. He echoed his earlier testimony that those costs would be so far in the future they would have a negligible effect. He said [DR&R] should be in the cost basis from the beginning.

REPRESENTATIVE GARA questioned whether there are other factors that need to be considered. He related his understanding that this [model] assumes the pipeline will deliver Prudhoe Bay and Point Thomson gas. However, how does this [model] address allowing additional gas into the pipeline, he asked. He also asked if the myriad of provisions a producer could impose for letting gas on and off the pipeline could impact this analysis and the state's revenue.

MR. PULLIAM acknowledged that those are important to consider, certainly to the extent that someone can create a bottleneck to the necessary infrastructure. However, to the extent that the facilities are regulated, there should be guarantees that access will be considered. With regard to the ability to increase the cost of transportation from a spur line, he expected those to be regulated assets. Therefore, he didn't believe there would be the ability to increase the price of a pipeline higher than what a regulatory agency would allow. Still, an access issue further upstream could be problematic.

REPRESENTATIVE HAWKER asked if this modeling is a triple net or is this a modeling of the netback before corporate income taxes.

MR. PULLIAM clarified that [the model] includes all taxes, after-tax cash flows.

The committee took an at-ease from 3:30 p.m. to 3:52 p.m.

SENATOR WAGONER asked why the oil companies seem hesitant to build a gas pipeline at this time if the documents presented today are even close to reality.

MR. PULLIAM said that he is mindful that the oil companies are in the midst of negotiating with the state over fiscal terms. Setting that aside, the oil companies may want to do other projects that they are at risk of losing to competition. Furthermore, the oil companies may take the view that gas prices are going to remain healthy and thus it becomes a matter of when to sell the gas.