JOURNAL OF ECONOMIC ISSUES
Vol. XLIII No. 3 September 2009
DOI 10.2753/JEI0021-3624430310

Why America May Not See Alaska Natural Gas Soon

Roger Marks

Abstract: The Alaska Gasline Inducement Act (AGIA) was enacted by the State of Alaska in 2007 in an attempt to progress the construction of a natural gas pipeline from the Alaska North Slope to North American markets. The Act conveys monetary inducements from the state to the exclusive licensee in exchange for certain performance requirements. The financing of any pipeline requires the contractual commitment from the shippers (producers) to pay to ship the gas over an extended period of time. However, many of the performance requirements of AGIA are antithetical to the commercial interests of the shippers. A flawed financial analysis of the project by the administration overstated the economic vitality of the project, and hence understated the severity of the commercial issues. Consequently, the prospects for success in getting a pipeline constructed appear doubtful.

Keywords: state policy, energy economics, regulatory economics

JEL Classification Codes: H7, K2, M2

On September 3, 2008, at her acceptance speech to be the vice presidential nominee at the Republican National Convention, Governor Sarah Palin of Alaska said, "I fought to bring about the largest private-sector infrastructure project in North American history. And when that deal was struck, we began a nearly $40 billion natural gas pipeline to help lead America to energy independence." On October 2 at the vice presidential debate she said, "We're building a nearly $40 billion natural gas pipeline, which is North America's largest and most expensive infrastructure project ever, to flow those sources of energy into hungry markets."

Not only is there is no such pipeline under construction, but to date no decision to build one has been made. What Palin was referring to was an act her

The author is a petroleum economist, retired from the State of Alaska Department of Revenue, where he specialized in tax and resource development policy. He is now in private practice in Anchorage where he consults, teaches, and writes. He can be reached at rogmarks@gmail.com.

administration developed and supported through legislative passage, the Alaska Gasline Inducement Act (AGIA), the goal of which is to construct a natural gas pipeline from the Alaska North Slope to the Lower 48 markets.

The purpose of this paper is to analyze AGIA's prospects for success. For any pipeline to be successful it needs shippers, the entities that pay the pipeline to transport the gas. In general these are gas producers. This analysis will depict how certain structures within AGIA are antithetical to the commercial interests that are necessary for making it successful. It will also depict how the administration exaggerated the economic attractiveness of AGIA, causing it to under-appreciate the severity of these commercial issues.

The following section discusses the historical context of AGIA, the act itself, and lays out the theoretical framework for evaluating its efficacy. It is followed by a discussion of the commercial problems with AGIA. These problems suggest why producers will be unlikely to commit gas to the AGIA project, and subsequently why it is unlikely to result in a project. The paper then offers a critique of the financial evaluation the administration used to measure the economic performance of AGIA and promote passage of the act. The analysis concludes that the evaluation methodology overstated the performance of AGIA, and suggests this may have led the administration to under-appreciate the commercial problems. The final section summarizes the conclusions.

AGIA Background and History

When oil was discovered on the Alaska North Slope at Prudhoe Bay in 1967, a very large natural gas cap was also found overlaying the oil containing approximately 24 trillion cubic feet (tcf). Subsequent discoveries of other oil fields on the North Slope have also led to additional natural gas finds, the most significant of which is the Pt. Thomson field. In all, proved natural gas reserves are about 35 tcf, but geologists believe there could be much more.

It has been the dream of Alaskans to commercialize the gas as a way to extend the prosperity that oil brought to the state and its residents. Despite a flurry of producer studies and various governmental attempts/political efforts over the years, the gas has never been commercialized. The gas, however, has not sat idle. As it comes out of the ground with the oil it has been reinjected to pressurize the field and bolster oil production from the reservoir, though this benefit is diminishing over time as the Prudhoe Bay oil reservoir is drawn down.

The commercial challenges are considerable. The most attractive market for the gas appears to be linking up with the North America pipeline network reaching out from northern Alberta to serve the Pacific Northwest, Upper Midwest, Midwest industrial states and as far as upstate New York. However, in order to capitalize on economies of scale, the pipeline would have to be very large, as well as very long. Cost estimates to the Upper Midwest vary between $30 and $40 billion in today's dollars for such an endeavor, and so in addition to the construction cost and gas market risks, there is a size risk; the cost of failure would be huge. These risks have been insurmountable so far. Nevertheless, the project potentially offers much value for the producers.

In addition, despite federal law to the contrary, many Alaskans believe that the producer ownership of the pipeline would lead to high tariffs (since tariffs are deducted in deriving the tax and royalty basis of the oil), and that a producer-owned gas pipeline would limit access to non-owners, stifling new companies from exploring in Alaska. Instead, they would prefer a third-party pipeline not owned by the producers. These beliefs were embraced by key resource development officials that came into power with the Palin administration in 2006. The Alaska Gasline Inducement Act (Alaska Statute [AS] 43.90) (AGIA) was drafted and submitted to the legislature by Governor Palin, and passed in the early days of the administration.

AGIA Overview

AGIA operates as follows: first, the state awards an exclusive AGIA license to a qualified applicant with a qualified application, henceforth the licensee. Then, in exchange for certain performance requirements the state will reimburse a share of the licensee's costs of: a) getting to open season, and b) trying to get a FERC (Federal Energy Regulatory Commission) Certificate of Public Convenience and Necessity ("certificate") for the pipeline.

"Open season" is the step in the FERC certification process where prospective shippers make firm binding contractual financial commitments, pre-construction, to pay to ship a fixed amount of gas for a set amount of time. These are called "firm transportation," or "FT" commitments. These commitments provide the financing for the pipeline. The certificate grants final approval for construction after satisfaction of several requirements, including regulatory and environmental review, and right-of-way procurement. In particular, the state will reimburse the licensee up to 50% of the costs of getting to the first open season, and up to 90% thereafter of the costs of getting to certification, up to a maximum of $500 million. The specific percentages and maximum dollar reimbursement are identified as part of the application.

The main performance requirements include:

- Conclude an open season within 36 months of the license award.
- Apply for a FERC certificate by a certain date as established in the application.
- Advocate rolled-in rates for pipeline expansion capacity, not to exceed 15% above the base shipping rate. (This is discussed later in a section entitled "Shipper Subsidization of Expansion Capacity.")
- If the licensee has credit support to finance construction, sanction the project within one year after the effective date of the certificate. If the licensee does not have credit support, sanction the project before the later of a) two years after the effective date of the certificate, or b) five years after the first open season.
- There are additional requirements for periodic assessment of market demand, capacity expansion when warranted, capital structure limits

> on equity, managing cost overruns, providing for in-state gas, and local hires during construction.

AGIA called for the state to award the license among competing project application proposals based on a combination of the net present value (NPV) of the proposal to the state coupled with an assessment of its probability of success. AGIA passed the legislature in May 2007. In August 2008, the state awarded the license to the TransCanada Corporation after receipt of five applications, four of which did not meet all the stipulated terms. Per TransCanada's application the state will reimburse them at the maximum AGIA dollar amount of $500 million and maximum reimbursement rates of 50% before open season and 90% thereafter.

In April 2008, BP and ConocoPhillips (two of the three large North Slope working interest owners) announced in a press release that they had formed the Alaska Gas Pipeline LLC (the "Denali project") to also pursue development of a North Slope natural gas pipeline project. It is proceeding completely outside the AGIA process.

Analytical Framework

The structure of AGIA is a monetary inducement in exchange for performance requirements. The monetary inducement is a $500 million contribution by the state. This would be out of a $26 billion (2007 U.S. dollars) project to Alberta (TransCanada 2007), after which additional costs would be necessary to move the gas to U.S. markets. The administration (State of Alaska (SOA) May 2008) estimates the inducement reduces the tariff by six cents per million Btus (mmbtu).

For AGIA to be successful it has to attract shippers. It has to be at least better than a non-AGIA project. Further, the value of the inducement needs to be higher than the cost of the performance requirements. As will be shown, these performance requirements create costs, or other commercial issues borne by the shippers. These costs are put into the tariff. Even though the licensee, TransCanada, would build the pipeline, the shippers ultimately pay the costs. The pipeline company automatically recovers all their costs through the tariff. Thus, the licensee would be constructing the pipeline with the proverbial "other peoples' money."

The AGIA process can be seen as two marketing transactions. First, the state solicited applications from prospective licensees. Second, the successful licensee will try to solicit shippers to commit to the project. Let's examine the first transaction. The state opened up the AGIA process to the world. Out of all the producers, out of all the pipeline companies, out of all other entities, it received five bids, four of which were deemed non-responsive. In other words, it received just one bid. Out of the other four applicants, three had virtually no assets. What does the low amount of interest suggest about what the state was marketing? We suggest it may be indicative of a problem with the risk/reward balance inherent in the AGIA structure; the costs are too high relative to the benefits.

The costs of the performance requirements are revealed in examining the second marketing transaction, the selling of pipeline capacity to shippers. Insofar as the AGIA structure creates commercial problems for the shippers, it reduces the attractiveness for them to commit to it, and limits the prospects for AGIA to be successful. The balance of the paper examines these issues.

This analysis will intimate why the one entity that did submit the qualified application may have chosen to participate in the process, and what that suggests about AGIA. Finally, one can question why the State of Alaska administration, aware of at least some of these issues, supported the act in the form it did. An examination of the financial analysis conducted by the state suggests it overstated the economic performance of an AGIA project. Thus the state was over-valuing what they were marketing, which again, could explain the occurrence of these commercial problems, and the lethargic market response to the solicitation of applications.

Commercial Issues

AGIA gives an exclusive license to TransCanada to receive certain benefits from the state in exchange for the company taking certain steps toward getting a FERC license. For AGIA to be successful, that is to result in pipeline construction, TransCanada will need the commitments of the producers to ship their gas. Otherwise, the pipeline cannot get financing and will not be built.

As indicated above, this can be seen as a marketing transaction. TransCanada will try to solicit shippers to commit to the project. For them to be successful AGIA has to be at least better than a non-AGIA project. Further, the value of the inducement needs to be higher than the cost of the performance requirements. However, many of the AGIA provisions run counter to sound commercial arrangements that the shippers need. The prospects for AGIA's success will be highly dependent on these issues. They may also explain the anemic interest in the application process. Five of these issues are examined here. They are:

1. Incomplete evaluation method of applications by the state;
2. Misalignment of interests between licensee and shippers;
3. Back-end loading of planning costs;
4. Shipper subsidization of expansion capacity; and
5. Non-marketer determination of the gas market.

Incomplete Evaluation Method

Section AS 43.90.170 of AGIA called for the state to award the license among competing project application proposals based on a combination of the net present value of the proposal to the state coupled with an assessment of its probability of success. The analytical framework established in AGIA only required the administration to compare the NPV's of competing applications. The administration never systematically compared the AGIA project to a non-AGIA project, such as the producers' plan. Whether the producer-owned pipeline would be preferable to the AGIA project such that they would not favor AGIA was never examined.

Misalignment of Interests

The producers ultimately pay the cost of the pipeline through the tariff. Thus they have a greater incentive to contain costs. Shippers lose money on cost overruns; the pipeline makes money through the return on the equity component. That is why the producers want to build it. Moreover, since TransCanada would only make money on the return on the equity component in the tariff, they would have a greater incentive to have more equity and a higher return on it. Since the producers pay the bills they would have an incentive to inject a lower cost of capital into the financing. Even though TransCanada agreed in its application to reduce its return on equity on cost overruns, the overrun is measured relative to their cost estimate. FERC does not, nor is it charged with, exercising due diligence on pre-construction cost estimates.

Back-end Loading of Planning Costs

The open season documents contain an estimate of what the tariff is going to be. Before an open season, a significant amount of front-end engineering needs to occur. This would ensure that subscribers are sufficiently confident in the estimate to be comfortable in making a binding commitment by signing a contract to use the pipeline. The relationship between spending and cost accuracy is very pronounced. The Association for the Advancement of Cost Engineering (AACE 2003) classification methodology depicts the relationship between level of project definition, expected accuracy range, and preparation effort. At the lowest level of project definition, the screening phase, the degree of cost accuracy is +200%/-100%. The final cost estimate prior to the commencement of construction will have an expected accuracy range of +10%/-5%. The difference in preparation effort in terms of spending between the two stages is a minimum of ten-fold up to one-hundred-fold.

It is generally recognized that for a project of this magnitude there should be a considerable amount of spending to get to a sufficient open season. For an idea of what these costs should be, the IPA Institute (2005) — a division of Independent Project Analysis, Inc. — has chronicled practices that cause large projects to succeed or fail as measured by cost control, adherence to schedule, and quality of the end product. IPA stresses how early project definition is essential for success and the spending that needs to occur commensurate with different stages of development.

IPA has segregated the front-end loading of costs into three phases: 1) Business Planning; 2) Facility Planning; and 3) Project Planning. What occurs during these phases is described as:

> 1) Business Planning – Validate the business opportunity and select the alternatives that will be analyzed in the next phase. Minimum level of expenditure (0.5% of total installed cost).

2) Facility Planning – Study identified options and narrow the project to one option, refine premises, update project economics, and begin project definition. Moderate level of expenditure (1.5% of total installed cost).
3) Project Planning – Develop detailed scope, execution plan, and cost estimate for the alternative selection in the Facility Planning phase. Higher level of expenditure (3% to 5% of total installed cost).

The level of detail necessary for an open season would be at least at the facility planning level, and justifiably higher. Given the $26 billion cost estimate to Alberta, the facility planning level of 1.5% would equate to $390 million. This is nearly five times what TransCanada is proposing. The Denali project announced it plans to spend $600 million to get to open season. Yet TransCanada is only going to spend $83 million to get to an open season, and $542 million after the open season to try to get to FERC certification. Why? Because under AGIA the state will reimburse TransCanada for 50% of the costs before open season and 90% of the costs after. The AGIA structure motivates the licensee to do a scant job of engineering, back-end loading its costs to the 90% reimbursement period. Thus the shippers will be asked to make a binding commitment with a low quality cost estimate. This could result in no significant commitments.

The AGIA performance requirements necessitated this structure. The licensee is required to try to get a FERC certificate even if the open season fails. Yet FERC has never granted a certificate for a natural gas pipeline in the absence of firm shipping commitments. It would make no sense for them to do so, and FERC officials (FERC 2008) have said that they do not know how they could do it. It is the FT commitments themselves that demonstrate the public need underlying the certificate. A certificate would be meaningless, anyway, without the commitments. Given the uncertainty of getting sufficient commitments in the open season, the state had to provide a very significant inducement (the 90% reimbursement) to motivate the licensee to try to get a certificate.

Shipper Subsidization of Expansion Capacity

Under AGIA, if expansion capacity (capacity that is added on after the initial pipeline is in operation) has a higher tariff than the base capacity, the licensee must advocate rolled-in tariff rate treatment before FERC, where the costs of the base and expansion capacity are combined and averaged in a single tariff, not to exceed 15% above the base shipping rate. Ordinarily under FERC rules if there is a pipeline expansion, and the new capacity is more expensive on a per-unit basis than the base capacity, the shippers on the additional capacity pay the difference. This makes perfect sense. Otherwise, the base shippers are subsidizing the expansion shippers. FERC recognizes this quite explicitly as a subsidy.

AGIA requires rolled-in rates, which means the additional costs are spread among everyone. The administration's intent is that this would help encourage exploration by having the base shippers help pay for new capacity. TransCanada's levelized tariff estimate for the Alaska portion of the pipeline is $1.03/mmbtu. Thus the rolled-in rates could increase tariffs to base shippers by 15 cents/mmbtu (in 2007 dollars). The producers, or any initial shipper, would likely not agree to this, as an unfair and unreasonable subsidy of the expansion shippers at their expense. Of course this is the reason why a pipeline company like TransCanada, and not a producer, could easily abide by the AGIA terms. They won't be subsidizing the expansion shippers; the producers will. TransCanada is spending other peoples' money.

However, even if it was desirable to have the producers subsidize explorers, there are some very important reasons why rolled-in rates should give the state pause. Rolled-in rates will encourage explorers to postpone exploration so as not to commit gas at the first open season. Because their expansion capacity could be subsidized, they can afford to sit back and wait and see whether the pipeline has cost overruns, and how gas markets look down the road. If the pipeline turns out to be expensive, or gas markets falter, they can simply explore elsewhere in the world and avoid the project. But, if things turn out good they can explore and commit later knowing they won't be penalized for waiting. The rolled-in rates create a value to delaying commitment. In essence, the producers will be absorbing the explorers' exploration risk, with the result being deferred exploration and possibly a smaller base pipeline with higher tariffs, which reduces the value of the project.

Non-Marketer Determination of Gas Market

Under TransCanada's AGIA application the pipeline will bring Alaska gas into the Alberta Hub. The Hub is a series of pipelines within Alberta that transfer gas from one part of Alberta to another, where it can go on into existing pipelines to other North American markets. This was not a requirement of AGIA; it was part of TransCanada's proposal. It is adopted by reference into their license. TransCanada owns the Hub. It costs about 24 cents/mmbtu for shippers to put gas into the Hub, which devalues the Alaska gas. TransCanada will make lots of money off this. The reduction of 24 cents/mmbtu in value to the producers and state would not be insignificant.

TransCanada also owns the pipes going out of the Hub, where it would also make money. These pipelines go to the East coast, the Upper Midwest, and the Pacific Northwest. Bringing gas into the Hub may make sense if there is existing capacity in the pipelines exiting from the Hub *and* those pipelines go to the desired market. Gas production from Western Canada has been declining over the past few years, which may free up capacity in existing pipelines. However, there may not be capacity available to get gas to any one particular market if that is desired.

There are reasons it may not make sense to go into the Hub, particularly if there is insufficient capacity in the existing pipes. Rising gas prices have caused unconventional gas production (shale gas, coal bed methane) to explode in recent years. In the last 10 years, unconventional gas production in the Lower 48 has increased by three trillion cubic feet per year, or two North Slopes. In the next 10 years, the U.S. Department of Energy (2009) forecasts it will increase another three trillion cubic feet annually, again another two North Slopes. And, there is reason to think that may happen in Western Canada as well.

The gas shale potential of Western Canada is enormous. According to Wood Mackenzie (2009), Apache, Encana, EOG Resources Inc., and Nexen have announced estimated recoverable gas resources amounting to 24 to 37 tcf combined in the Horn River Basin of British Columbia. The Beaverhill Lake area in Alberta also has vast potential. This shale gas could absorb all the existing pipeline capacity out of Canada.

If all or most of the gas is going to the Upper Midwest, and it makes sense to bypass the Hub completely because there is not sufficient existing pipeline capacity out of Alberta to the desired market, there may be a need for a new dedicated line to Chicago, or use of existing capacity not owned by TransCanada, such as the Alliance Pipeline. But, if it makes sense for the gas to bypass the Hub it will not be done under the licensee's application proposal.

Forecasting most things beyond the short-term is notoriously inexact. And TransCanada's long-run supply forecast embedded in its 2008 AGIA application will be no different. It is premature to lock into one forecasted future where many others are plausible. This also provides an indication as to why the one entity that did submit a qualified AGIA application, TransCanada, did so, and what it further suggests about the AGIA structure. Given the prospect of diminishing supplies, putting gas into its Hub would be very important to TransCanada for offsetting underutilization of its system. Hence for TransCanada, the AGIA project only makes sense if it unfolds a particular way. That particular configuration, however, creates a commercial problem for the owners of the gas.

This discussion of the licensee's AGIA development plan provides another illustration of the perverse effects of the AGIA structure. Pipelines are initiated by producers and are built to transport a producer's gas based on where the producer wants to market the gas. Pipeline companies do not market gas, and they are not experts on marketing gas. They are passive carriers of gas to wherever producers have determined the best markets are. Producers who sell gas are the experts at marketing. What AGIA has set up is a structure where the pipeline company is determining the market.

Overstating the Economics

The Claims

The administration could not have been unaware of these commercial concerns. Many of them were advanced during the public review process during passage of the Act (SOA March 2008). Indeed, many of them were submitted by the very producers who would need to commit to the process to make it successful. Yet despite these concerns, the administration expressed great confidence in the success of the process, citing the economic results they had modeled. They cited high rates of returns and high NPVs, and made statements, for instance, about ". . . the Project is so solidly 'in the money' . . ." (SOA May 2008).

Let's examine how the administration derived these economic results. In 2007, when they were pushing passage of AGIA, the administration presented at various hearings before the Alaska Legislature, the following comparative internal rate of return (IRR) results to the producers in advocating for a third-party pipeline (SOA 2007):

Price ($/mmbtu)	Producer-Owned	Third-Party Pipeline
$3.50	12.6%	29.8%
$8.50	23.9%	95.6%

The third-party pipeline had a higher rate of return at a $3.50/mmbtu price than the producer-owned pipeline had at an $8.50/mmbtu price. These were presented as a straight "apples-to-apples" comparison.

Let's consider the veracity of these results. We suggest that the approach the administration used to value the third-party pipeline overstated its attractiveness. And consequently, insofar as the defects in the analysis may have led the administration to believe the project was better than it is, the administration may have over-valued the proposal they were promoting, and judged the commercial issues to be less serious than they really are.

The Nature of FT Commitments

An FT commitment to a third-party pipeline company is simply one of many financing options available to the producers. Prospective owners of natural gas pipelines can only get financing to build the pipeline if the shippers (the owners of the gas moving through the pipeline) make long-term commitments to the carrier (pipeline owner) to pay the tariff to ship a fixed amount of gas regardless of the price of gas or whether there are sufficient gas reserves to fill the pipe for the term of the commitment. They pay regardless of whether they ship gas. The shippers, therefore, take the risk of low gas prices and the risk that future gas reserves will be inadequate to keep the line full. Such commitments are also necessary to get a FERC certificate to build the pipeline. These commitments generally have a term of 15-25 years, or longer.

The fixed commitments can be used by the pipeline company as collateral for borrowing money to build the line. In the case of producer-owned pipelines, the upstream producing affiliate makes the commitment to the downstream pipeline affiliate. These commitments are considered liabilities, or debt. Liabilities are defined as "probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide service to other entities in the future as a result of past transactions or events" (Kieso and Weygandt 1986, 32).

In the case of a third-party pipeline, the tariff itself represents the shippers' re-payment of the principal and interest on the pipeline owner's obligation (plus operating expenses). The commitment is in essence like borrowing 100% of the costs for the capacity the FT supports, with the tariff being the principal and interest payments. The pipeline company (the lender) has priority claims to project cash flows to recover the tariff, much like any creditor in a debt arrangement. An FT commitment from the producers to a third-party pipeline transfers substantially all of the benefits and risks incident to pipeline ownership to the producers, so that the economic effect on them is similar to ownership. On the other hand, a third-party pipeline may provide the transfer of maintenance and administrative burdens from the producers, a differential tax status such that one party can utilize tax shields more efficiently, avoidance of capital expenditure controls, or the preservation of capital. From the point of view of the producers, engaging a third-party to build the pipeline would simply be a financial decision; it does not affect the fundamental economics of the project. "Financial" means the mechanism for obtaining the funds to construct the project. "Economic" means the risk/reward balance inherent in the project.

Leverage

The reason the administration's internal rate of return (IRR) was so high for the third-party pipeline was that it incorporated the straight cash flows associated with paying a tariff. As stated above, though, these cash flows represent debt, or leverage. Leverage will almost always yield higher returns, but the results between leveraged and unleveraged cash flows are not comparable.

Let's see how leverage works. Let's say I buy a $100,000 house. There are two ways to pay for it. Under Plan A, I can put down $100,000 cash. Under Plan B, I can put down $1,000 and get a $99,000 mortgage, the leveraged way. Suppose the value goes up to $101,000 the next day and I sell the house. Under Plan A, I have made 1%. Under Plan B, I have made 100%. But note, if the house had gone down $1,000, under Plan B, I would have lost 100%. (These volatile results are why the term "leverage" is used: similar to Archimedes claim he could lift the world with a long enough lever.) Similarly, there are two ways I can make 100%: under Plan A if the house goes up $100,000, or under Plan B if the house goes up $1,000. So going up 100% can mean very different things in terms of the value of the underlying asset.

The IRR results above included some field development costs for Pt. Thomson. If only Prudhoe Bay had been involved, which does not need any additional capital investment to commercialize the gas, all the costs would have been incorporated in the tariff, and this approach would have yielded an IRR of infinity for the third-party pipeline. So when a rate of return is stated, we need to know which way it was derived. Fortunately, accounting standards (Financial Accounting Standards Board [FASB] (1981) and Generally Accepted Accounting Principles) dictate which way. The liability is valued by capitalizing the debt payments. The resultant cash flows are very similar to what they would have been had they been unleveraged. In the Plan B example the cash flows would be re-structured as if it had been done under Plan A.

It is similar in economic analysis. The following is from the standard Brealey and Myers (2003, 2-5) finance textbook, addressing the general treatment of financial leases (which are very similar to FT commitments), particularly who *really* owns leased assets:

> From an economic point of view, you might say that the user is the real owner, because in a financial lease, the user faces the risks and receives the rewards of ownership. (The user) cannot cancel a financial lease. If the (asset) turns out to be hopelessly costly and unsuited for (the user's purposes), that is (the user's) problem, not the lessor's. If it turns out to be a great success, the profit goes to (the user), not the lessor. The success or failure of the firm's business operations does not depend on whether the (assets) are financed by leasing or some other financial instrument.

When one reflects on the similarity in the economic risk/reward balance between the leveraged and unleveraged structures, the fundamental economic outcome of an endeavor depends on the underlying economic inputs, costs and prices, not how it is financed. The drastic differences in the IRR's above could not be indicative of the actual differences in economic performance. Standard financial economic practice is to capitalize the debt very similar to how it was described for financial accounting above. Again, the economic results become very similar.

Consistent Standards of Performance

As indicated above, the fundamental economic outcome of an enterprise, that which establishes the risk/reward balance, consists of the underlying economic inputs: the costs to create it and the revenues it brings in. It lies outside of how it is financed. An FT commitment is a form of leverage (debt). Generally, companies perform economic evaluations and make decisions based on the economics without regard to financing (unleveraged), and then figure out how to finance the projects they want to go ahead with. This creates a clearer picture of the activity, and allows them to compare all their opportunities on an "apples-to-apples" basis (assuming the same business risk between projects).

Economic analysis can measure many things. One very important thing to measure is whether the project can pay back investors. Projects need money. It comes in the form of equity from shareholders and debt from creditors. For projects to be viable, they have to demonstrate that they can pay contributors a return for their money commensurate with the risk of the project. This is done with the internal rate of return (IRR) analysis. (The IRR is that discount rate that yields a net present value of zero for the net cash flows of a project.)

The weighted average cost of capital (WACC) is the percentage of capital that is debt, multiplied by the cost of debt, plus the percentage of capital that is equity, multiplied by the cost of equity. An unleveraged analysis represents the underlying economic inputs outside of financing: costs are expended and then revenue is realized. (The producer-owned pipeline was modeled as an unleveraged cash flow; the pipeline was purchased with cash.) The net cash flows (revenues less costs) go to pay off the debt and equity. The IRR has to exceed the WACC to show the project can pay off both the debt and equity investors for the money it is using. For this purpose the WACC is also known as the hurdle rate.

In a leveraged analysis, the principal and interest payments (the tariff) are already included in the cash flows. Since the debt payments are included in the leveraged cash flow, all net cash flows go solely toward paying off the equity (whereas in the unleveraged analysis all net cash flows go toward paying off debt and equity). Thus the hurdle rate in a leveraged analysis will be the cost of equity and equity commands a higher rate of return than debt (and the WACC) because it is more risky. Debt creditors are paid off first; if there is insufficient capital the equity contributors risk not getting paid. Further, as in the case with a third-party pipeline, where the percentage of debt is very high, the equity is at even greater risk, which increases its cost further. Consequently, the hurdle rate for leveraged cash flows will be greater than that for unleveraged. Thus, whereas the leveraged cash flow may generate a higher return, it also has a higher hurdle rate. Leveraged cash flows cannot be simply compared with unleveraged cash flows because they reflect different considerations and have different standards of performance.

NPV'S: More Claims

While the rate of return analysis was not trivialized by the administration, more emphasis was put on the NPV's; it is the primary measure of how much value the project will add to the company. The administration used the same leveraged third-party cash flow approach to calculate the NPV's as it used to calculate the rates of return.

The net present value is the present value of the net cash flows discounted at a certain interest (discount) rate. For the same reasons specified above that the WACC is the hurdle rate in unleveraged economics, the WACC is also the discount rate in an NPV analysis. And, for the same reason that the WACC is inappropriate for the hurdle rate using leveraged cash flows, it is also inappropriate for the discount rate in NPV analysis; the higher cost of equity is appropriate in both cases. However, the administration used the WACC for the discount rate in these leveraged cash flows (SOA May 2008). The discount rate represents the cost of capital; lower discount rates generate higher NPV's. Accordingly, the NPV's generated by the administration were too high, which exaggerated the perceived benefits of AGIA.

Summation on Economic Analysis

The following is from the Administration's Findings and Determinations:

> A lessee's internal hurdle rate, however, is irrelevant to the duty to produce and sell gas from leased state lands. So long as participation in the Project would provide the Major North Slope Producers the ability to earn a reasonable profit, they must provide assurances to support the Project — or

> *unequivocally* commit to some other means of commercializing the gas — regardless whether those profits would surpass their internally set hurdle rates.

Whereas surpassing the hurdle rate is necessary to pay back investors for the use of their money, the administration still sees a profit less than that as commercially acceptable.

There is an old adage in finance that you cannot make a bad project good by borrowing money. AGIA was in part a reaction to the administration's belief that the increased rate of return and high NPV's made the project unquestionably economic, and why they championed a third-party pipeline. It may also explain why they may have understated what are serious commercial defects in AGIA.

Conclusion

Natural gas pipelines are simply conduits for producers to get their gas to market. The producers ultimately finance and pay for the pipeline. They ultimately incur the market risk and they decide when they are comfortable proceeding.

There are legitimate commercial reasons why the major North Slope producers have yet to commercialize the resource, and there is no doubt that at best it will be a long process. There is also little doubt that AGIA does little to change the commercial landscape. When the producers are ready to build the pipeline, the financing will follow. All AGIA offers is $500 million; certainly in a $30 billion-$40 billion project it is not want of $500 million that is slowing it down. As much as some Alaskans may want a third-party pipeline, creating additional commercial challenges ensures the process will not work.

Many of the Alaskans behind AGIA have long maintained that the state leases compel the producers to develop a gas pipeline. They may see AGIA, and the eventual producer non-response to it, as a way to create evidence in some future "duty-to-perform" challenge to the companies' right to retain the leases. Surely the commercial failures of AGIA will be defense enough against that.

And finally, AGIA even threatens non-AGIA projects. First, it provides an opportunity to introduce a divisive wedge between producers, some of whom may wish to leverage participation in AGIA against a non-AGIA project. And second, Section AS 43.90.440 of AGIA, the license project assurances, otherwise known as the "triple damages clause," says that if the state extends preferential tax treatment to a non-AGIA project, it will owe the licensee three times the amount of its *gross* expenditures (pre reimbursement). This would amount to nearly $2 billion. So if the state believes it is necessary to enact fiscal modifications to enhance the producer project, or another project, either a) the state may be unable to do so because of the large financial penalty it would incur, or b) the state would incur the financial penalty itself for doing so. AGIA leaves no room for the risk if it does not work.

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