Evaluation of SB 138 (HB 277) and Associated Proposed North Slope Natural Gas Commercial Arrangements

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I. Introduction

This report is an evaluation of SB 138 (also HB 277) and associated proposed commercial instruments related to the commercialization of North Slope gas. These other instruments include the Heads of Agreement (HOA) between the state, TransCanada, ConocoPhillips, BP, and ExxonMobil, and the Memorandum of Understanding (MOU) between the state and TransCanada. In addition, the role of the Alaska Gasline Inducement Act (AGIA) in these proposals will be discussed. "State" includes DNR, DOR, and the Alaska Gasline Development Corporation (AGDC).

The plan put forward by the administration is thoughtful and could be useful in moving a large scale North Slope natural gas commercialization project forward. This report contains observations about the plan, and offers some alternative options the legislature may want to consider.

This analysis is based on examination of public documents.

Two high level observations may be useful in deciding how to proceed on these issues: first regarding the outlook for the project's viability, and second, the timing.

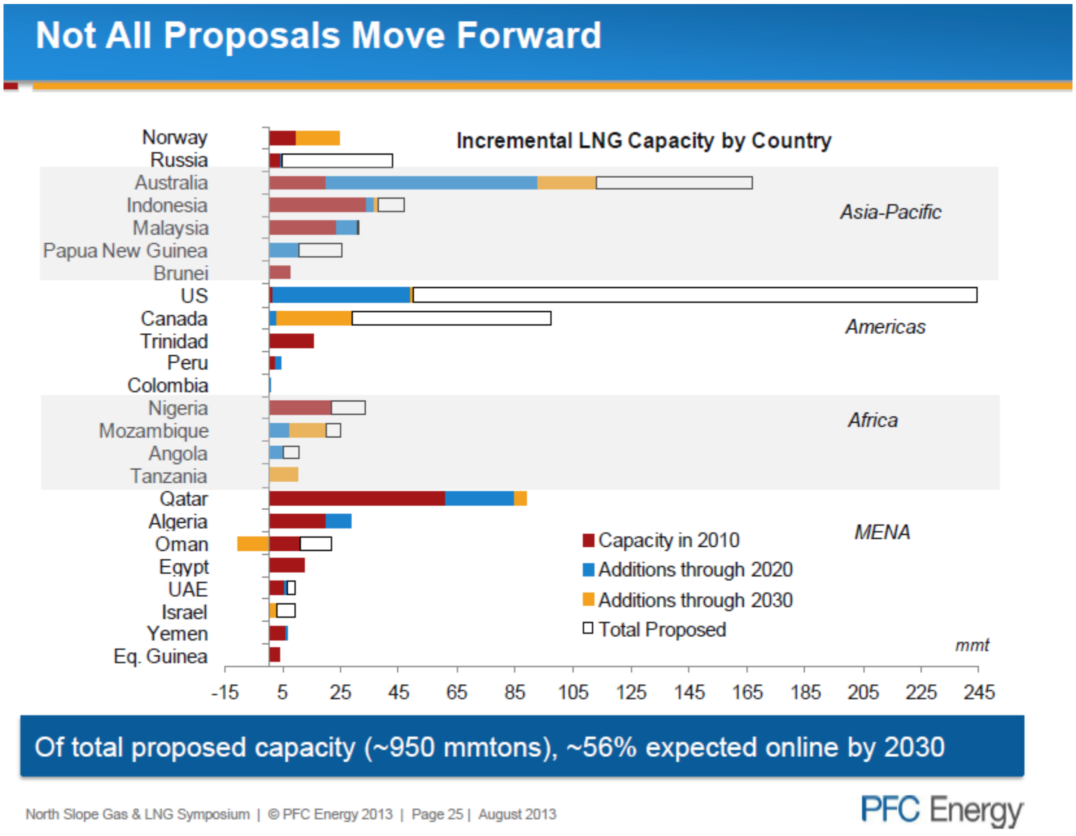
The economics of a large scale natural gas export project are challenging, and it is far from certain that the project will happen.

Expected LNG demand growth is encouraging, but the competition is considerable. Currently 19 nations actively export LNG and many are eyeing the Asian market. An additional one has a plant under construction, and four more are in various stages of feasibility studies. There will be nearly twice as much supply chasing the Asian market as there will be demand in 2030. (See Figure 1)

At the same time LNG prices in Asia may be falling. Prices have been linked to oil, but the link appears to be either softening or decoupling. Asian buyers realize that due to skyrocketing oil prices, suppliers were making a windfall. With the intense competition, buyers will be able to leverage lower prices based on actual costs, and sellers will have to compete based on cost.

While average prices in Asia currently may be high (approximately $14-$18 per million BTUs [mmbtu]), they reflect the high volumes of gas subject to older, higher-priced contracts linked to oil prices. Newer contracts in China average around $11-$12/mmbtu. Russia will be selling some

FIGURE 1



gas for as low as \$6/mmbtu, and Yemen at \$8/mmbtu.[1] Cheniere Energy, Inc. will be selling Gulf of Mexico LNG to Asia based on Henry Hub prices.[2]

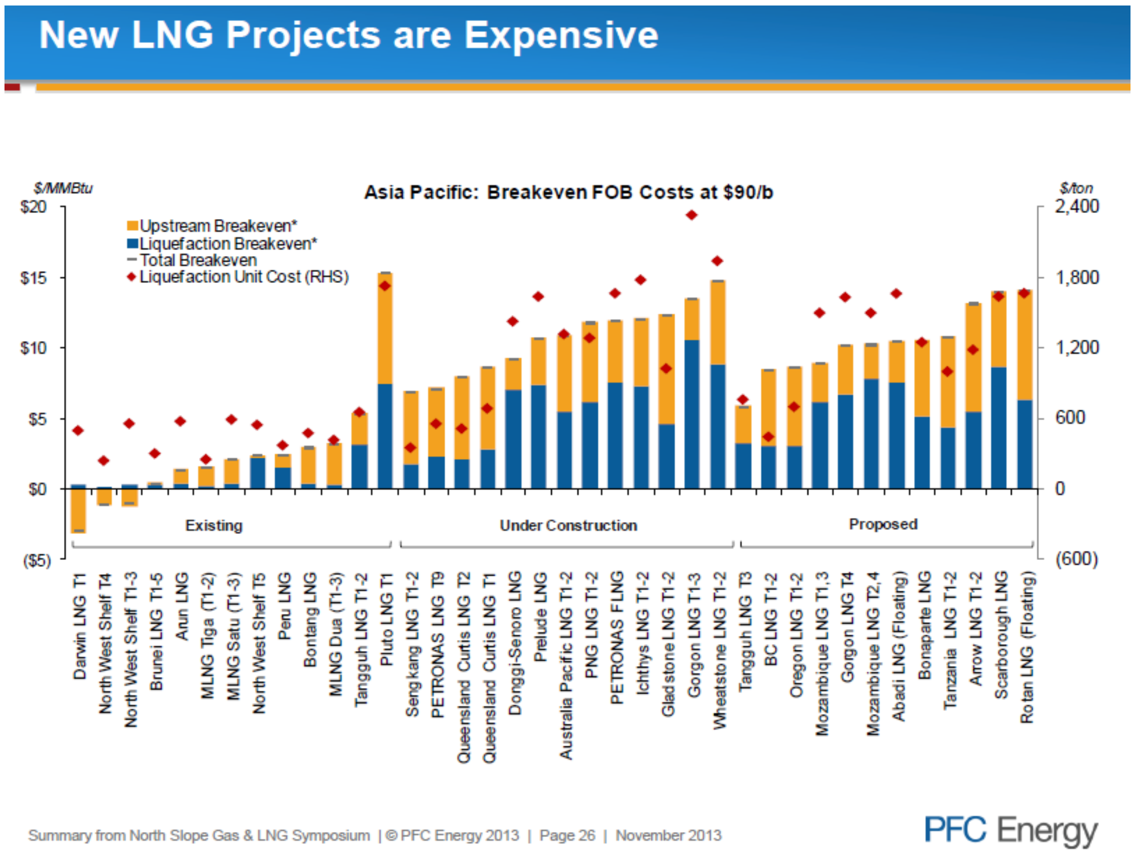
None of this bodes particularly well for Alaska. In 2012 the North Slope producers estimated the cost of the project at \$45-\$65 billion, including gas treatment, pipeline and liquefaction. It is unclear the extent to which this also includes the upstream costs for large-scale development at Pt. Thomson, which will be considerable.[3] It is likely inflation has occurred since these numbers were released.

Because of the considerable length of the pipeline, a burden no other project has, Alaska is one of the largest and most expensive of all projects. At a \$45 billion cost, the tariff for gas treatment, pipeline, liquefaction, and marine transportation would be near \$12/mmbtu. Alaska's

[1] Enalytica, "Natural Gas Market Outlook & Fundamentals of LNG Business," Presentation for the Alaska State Legislature, January 28, 2014, p. 21.
[2] The formula is Henry Hub + 15% + \$3 liquefaction + shipping. Last year this was in the \$10-\$11/mmbtu range.
[3] Development costs for the large scale natural gas and condensate production at Pt. Thomson could approach \$10 billion.

estimated breakeven price is in the $11-$15/mmbtu range[4], while many of the proposed projects are $8-$12/mmbtu. (See Figure 2)[5]

FIGURE 2



In addition, the project is especially challenged in that because of its size, to sell all the gas it will be necessary to capture large shares of the incremental market demand in a short amount of time. These marking limitations have caused project sponsors to nearly halve the proposed volume of gas relative to the previous plan to move gas into North America. This smaller volume sacrifices the benefits of economies of scale.

Each of the three major North Slope producers would need to independently sanction the project within their corporate confines for it to go forward (though some companies could sell gas to other companies on the North Slope).

[4] Assuming the state takes its taxes and royalties as in-kind gas. The breakeven price would be $1-$2/mmbtu higher if it does not. See Section III.A.

[5] The estimated tariff is a nominal levelized amount. The estimated breakeven prices are in 2013 dollars. Due to inflation they will be nominally higher, and may exceed the levelized tariff.

It will be very important for project sponsors to bring down the costs to the low part of the estimated range; otherwise the project will be uncompetitive. This analysis assumes a $45 billion cost for treatment, pipeline, and liquefaction, and $4 billion for the gas share of Pt. Thomson development.

Accordingly, there is risk associated with funds spent or committed now for a project that may not materialize, or may not materialize for a long time.

The second high level observation is that these projects take a long time to put together. It is plausible that if this project does happen, it is not going to happen soon. Achieving commencement of commercial operations by 2024 is an ambitious goal.

The primary factors that will determine when the project is sanctioned are the producers being comfortable that prices will be sufficiently high, they can penetrate the markets, and they can make the Alaska costs competitive. At this point it is uncertain whether those will be achievable, and the state cannot affect those very much. (This is not to undermine the importance of state institutional arrangements.)

There are a myriad of commercial, institutional, and governmental arrangements that need to be established. Given the dramatic increase in the number of LNG projects under development, there are backlogs of orders for equipment and tankers, and labor is scarce. These issues are also creating cost inflation.

However, on the positive side, there is also no short-term "window of opportunity." Asian demand will continue to grow, and prices may rise. Notwithstanding the timely importance of the project to the state, an aggressive timeline to get Alaska gas to market may not be ultimately be in the state's long-term best interests.

Given this will be a 50-year project (or more) worth several billion dollars to the state, it is important to structure it carefully. The state has the time to figure out what is in its best interests without being hurried. At this point in time, if there were to be a better project that begins in, say, 2026, it may be preferable to a sub-optimal one that starts in 2024.

II. Proposed Commercial Arrangements and Legislation

The Heads of Agreement (HOA) between the state, TransCanada, ConocoPhillips, BP, and ExxonMobil provides guiding principles and objectives that would lead to commercial and operating arrangements between parties to develop the project. Particularly, it addresses state participation in the project through ownership of facilities (gas treatment plant, pipeline [in addition to the main line includes the Prudhoe Bay and Pt. Thomson feeder lines], and liquefaction plant and terminal) commensurate with the state's proportion of the total gas (estimated at 20%-25%), along with proposals for the state to take its royalties and production taxes as in-kind gas, pro-expansion principles, and provisions for in-state gas offtake.

The Memorandum of Understanding (MOU) between the state and TransCanada (TC) sets out the ownership arrangements for the state's share of the pipeline (in addition to the main lines includes the Prudhoe Bay and Pt. Thomson feeder lines) and gas treatment plant (GTP) described above. The MOU takes the state's equity share of the facilities and shifts the ownership to TC in exchange for shipping terms the state finds favorable. The LNG plant is not part of the MOU; TC would not own any of it. The major provisions of the MOU include:

- TC would hold an ownership interest in the GTP and pipeline commensurate with the state's share of the gas (20%-25%). This analysis uses 22%.[6]
- The state would have an option to buy back an equity share in that ownership (22% of the entire GTP and pipeline). The state could buy back up to 40% of that 22% interest, but TC would get at least 14% of the total GTP and pipeline. For instance, if the state's in-kind royalties and taxes were 22% of the total gas, and the state exercised its option to buy 40% of TC's share, TC would get 14% and the state would get 8%. (The state would carry a maximum of 36% [8% of the 22%] of its gas on its own capacity.)
- The state would have only one opportunity to exercise the option: at the earlier of December 31, 2015, or the date of execution of commercial agreements to commence the FEED stage.
- TC's financial structure for the tariff would be 70% debt / 30% equity, with a 12% cost of equity, and a cost of debt of 5%, both subject to plus or minus changes to 30-year U.S. treasuries between the effective date of the MOU and the time of project sanction.
- The state would be prohibited from selling its share (should it exercise the purchase option) to another pipeline company, and TC would have the right of first refusal to buy any interest the state might want to sell. TC has no such limitations.
- If the state or TC terminates the agreement, the state owes TC the net expenses it has occurred since January 1, 2014.

SB 138/HB 277 is the enabling legislation that allows the state to participate in these two transactions, statutorily creating an AGDC subsidiary to manage the state's equity interest, and authorizing the Department of Natural Resources to negotiate terms for project services, development and implementation. It also contains the associated modifications to the lease/royalty and production tax terms.

III. High Level Decisions for the State to Make

The administration has presented its recommended options forward, which calls on the state to have an equity stake in all infrastructure, handing over its gas treatment and pipeline piece to TC, and taking its taxes and royalties as in-kind gas in order to improve the project economics. Does the state want to participate? If so, what are the risk thresholds? What are the options?

The enabling legislation and associated agreements are designed around a scenario for the project that assumes the following:

- The state takes its royalties and production taxes as in-kind gas.

[6] 2.8 bcf/d into treatment: 2.3 bcf/d from Prudhoe Bay (12.5% royalty) and 0.5 bcf/d from Pt. Thomson (14.5% royalty). 10.5% of gross production tax. 2.4 bcf/d marketed.

- The tariffs and expansion provisions will not be regulated by the Federal Energy Regulatory Commission (FERC), or the Regulatory Commission of Alaska (RCA).
- To ensure reasonable operating conditions (tariff, expansion, in-state gas), the state needs to either own the facilities, or partner with a pipeline company that owns the facilities. Accordingly, the state owns a portion of the GTP and pipeline in partnership with TC, and the liquefaction facility commensurate with its in-kind gas.

The issues of whether to take the gas in-kind, whether to own the facilities, and how the facilities will be regulated are major decisions the state needs to come to terms with before engaging in these arrangements. They are discussed below. (In addition, these agreements appear to be structured to amicably transition out of the AGIA arrangement with TC. This issue is discussed in subsequent sections.)

A. In-Kind Gas

Under current practice taxes and royalties are paid in-value. The producers sell the gas and remit to the state its share of the revenues.

Under an in-kind system the state takes its share of the taxes and royalties as the gas itself, and then the state sells it. For many years DNR has taken some of its royalty oil in-kind to sell to in-state refiners.

There is a very compelling reason to take the royalties and production taxes as in-kind gas; doing so benefits the project economics from the producers point of view. When they are taken in-value, the producers have to make the firm transportation commitment for the capacity to treat, pipe, and liquefy the gas. But it is essentially not their gas. Thus they are paying for capacity for someone else's gas. But financially, the liability for the commitment, a ship or pay obligation, is no different than that of ownership. So again, in essence the producers are paying for a large piece of the facilities they do not use.

If the state takes the gas in-kind instead, it would take on the firm transportation commitment and the associated financial liability to ship gas on the capacity it needs.

Given the tight economics of the project, if the producers did not have to incur this commitment it could make a material improvement in the feasibility of the project. It is like a 20%-25% reduction in the capital cost. This could improve the rate of return by 1-2 percentage points, and reduce the breakeven price by $1-$2/mmbtu, depending on price, cost, and hurdle rate. For a project of this size this is a significant impact.

Other benefits of taking the gas in-kind include avoiding conflicts with transportation charges and LNG charges as can occur in the in-value scenario.

The state does not need to own the facilities to take the gas in-kind. It could simply make a firm transportation commitment to a carrier to ship its gas on the capacity procured.

If the state takes its gas in-kind it incurs the burden of marketing the gas. Currently under the in-value arrangement the state has the benefit of having some of the best gas marketers in the world, the producers, selling the gas. With an in-kind arrangement the state will be competing against these marketers.

The state would need to create a mechanism to market gas. They could pay a professional entity to do this, at a cost of several cents per mmbtu. Or the state could develop its own marketing arm. That would also entail costs. There were several million dollars for this in DNR's fiscal note.

At the time of project sanction the state would have to have a buyer under contract in hand (as well as be comfortable the market supports the project). Otherwise, the state itself would be holding up the project.

It may be possible to structure a side deal with the producers, that in exchange for taking the gas in-kind along with the large commitment, the state could deliver the gas to the producers at some point and have them market it with the rest of their gas.

When taking taxes and royalties in-value, there is a floor of zero for taxes and royalties; the state cannot lose money. The firm transportation commitment with taking the gas in-kind is a ship or pay agreement. The state is compelled to pay to ship the gas whether it actually ships it or not. If the market price is less than the cost to get the gas to market, the state will lose money.

B. Ownership

1. General

Under the proposal the state will partner with TC for ownership of the GTP and pipeline commensurate with its share of the gas, and own the liquefaction facilities itself (including the terminal) commensurate with its share of the gas.

For the GTP and pipeline the state's share would initially be given to TC and the state would have the option of owning up to a 40% portion of that share, with TC getting a minimum of 14% of the entire facilities. So if the state's share of the total gas was 22%, TC would get 14% and the state 8%. (The state would treat and carry a maximum of 36% of its gas on its own capacity.) The state would own its 22% of the total liquefaction facility and LNG terminal itself.

The arguments for state ownership have been previously described in reports by others. These include transparency, alignment of interests with the producers, income (the return on equity), risk sharing, and the proverbial seat at the table.

It is possible that any partnership with the private parties, who generally operate with greater confidentiality than public entities, could limit transparency.

Also, as a shipper, the state would have a greater alignment of interests with the producers, rather than TC, to keep costs down, especially cost containment for expansions.

The other benefit that could accrue from ownership would stem from the possibility of AGDC owning the facilities at attractive financing terms, which could add value to the state's gas. The capital structure and cost of capital terms (debt/equity ratio and costs of debt and equity) can swing the tariff widely, and better terms can save the state hundreds of millions of dollars a year.

AGDC financing could bring sizeable benefits. Previously AGDC represented they could finance the stand-alone pipeline with 100% debt, through both revenue bonds and backing by the state.[7] The state's credit is rated AAA, and AGDC may be able to procure tax-exempt debt, which generally costs about 25% less than conventional taxable debt. (The latter would provide some insulation from general increases in interest rates.) Both of these result in lower cost debt than is available from conventional pipeline company financing.

Each percentage point reduction in the weighted average cost of capital (WACC) (percentage debt X cost of debt + percentage equity X cost of equity), relative to conventional private terms, is worth about 80 cents/mmbtu in the tariff. By owning 100% of the facilities for the state's share of the gas (22% of the total 2.6 million mmbtu/day[8] [2.4 bcf/d]), each percentage point reduction in the WACC would be worth $165 million per year, or $4.1 billion over 25 years. This is what the state could save for each percentage point reduction if it were able to get it.[9] For example, if AGDC ownership were to be two percentage points less than conventional pipeline costs of capital, such as TC's, it would save the state $8.2 billion over 25 years.)

One of the benefits of the project would be in-state gas for Alaskans. Some of these savings from a lower cost of capital would directly translate into annual savings of hundreds of dollars to households from lower gas bills (which include charges for treatment and the pipe, as well as the gas itself).

AGDC has been appropriated more than $400 million over time to develop the prowess to finance, build, and operate a pipeline. With the producers involved it could be less complex and less risky than the stand-alone pipeline.

About $8 billion in financing was expected for the stand-alone pipeline. For the large export project, at 22% of $45 billion that would be about $10 billion, not significantly different in amount. (The stand-alone pipeline did not incorporate the liquefaction facilities and terminal; this proposal does.) At 100% debt this should not present a cash flow problem to the state. It may have some short-term effect on the state's credit rating, but it would be offset by the potential of the new royalty and tax gas revenues via LNG sales.

It also appears that the state ownership mechanism here has been crafted around the proposition that the tariff and expansion provisions would not be regulated. Some regulation would occur under Section 3 of the Natural Gas Act; but essentially each shipper would place its gas in its own capacity, and the facilities would operate much like industrial transfer lines. This is discussed below.

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[7] AGDC, "Alaska Stand Alone Gas Pipeline: Project Plan," July 1, 2011, p. 4-8.

[8] Assuming 1.07 mmbtu/mcf.

[9] The issue is similar to a mortgage on a house. The difference between 5% and 6% interest on a $250,000 house is $150/month. Over 30 years this would be $54,000 in interest.

Accordingly, under the proposal, in order for the state to get reasonable tariffs and expansion provisions, it is necessary for the state to own the facilities, either alone or with TC, commensurate with its share of the gas, rather than shipping on the producers' capacity. In addition, the state (and TC) entity could be the expansion source of last resort for new shippers, managing expansion terms at reasonable rates.

2. Ownership under the Failure Outcome

In addition to the obvious cash flow issue, the main concern the state should have about getting involved with ownership now is the very non-trivial risk of spending a lot of money and a project not materializing.

The pre-FEED is expected to cost over $400 million, and FEED nearly $2 billion; pre-sanction costs could exceed $2 billion. Certainly it is likely that if problems emerge during pre-FEED the process would not evolve into FEED. And if significant issues appeared during FEED the process could be stopped.

Nevertheless, much of this could be spent before the viability of the project is ascertained, and result in no project. Much of the cost is targeted toward narrowing cost uncertainties. Detailed gas marketing terms cannot be developed until the costs are known in order to assure provisions account for adequate cost recovery. Certainly many other competing projects will simultaneously be in the FEED stages. And if just one of the producers is not comfortable with proceeding at FID, there is no project,

For example, at $2.4 billion, with a 22% share the state's contribution prior to FID (Final Investment Decision) would be $530 million. Under the TC MOU, as discussed in Section IV, regardless of whether the state exercises the ownership option, the state would have to pay TC's development costs for the GTP and pipeline if the project is not sanctioned (about $260 million).

While state participation is commercially valuable to the producers by partnering in the failure risk, the producers can arguably handle this risk better than the state through their own diversification. They are each analyzing many projects around the world, some of which will go forward. So they can handle the risk of Alaska not going forward, because something else will.

The state has no such diversification options, and thus is less capable of handling the risk of laying out a half-billion dollars for naught. The three producers' total capitalized value of $750 billion dwarfs the state's worth.

In addition, under the terms of the MOU the state needs to exercise its ownership option at the earlier of December 31, 2015, or the date of execution of commercial agreements to commence the FEED stage. It is possible the pre-FEED may not be complete by then and the state would be forced to make a very serious commitment with incomplete information.

It might be worth pursuing with the producers the possibility of buying into the project once it has been sanctioned, including reimbursement with interest for the pre-development costs, in exchange for taking the gas in-kind with the associated large commitment.

C. Tariff and Other Regulation

The proposal under the HOA is for a regulatory framework under Section 3 of the Natural Gas Act. FERC has jurisdiction to license facilities that import or export LNG, and the authority to approve applications for siting, construction, expansion, and operation of LNG terminals. Terminals are defined to include "all natural gas facilities located onshore or in state waters that are used to receive, unload, load, store, *transport*, gasify, *liquefy* or *process* (emphases added) natural gas that is imported to the United States from a foreign country, exported to a foreign country from the United States, or transported in interstate commerce by waterborne vessel."

As discussed above, under this arrangement the facilities would not function as either contract carriers or common carriers. Rather, each producer/shipper would place gas in its own equity treatment, pipe, and liquefaction capacity and take the gas out for its own use at the other end. There are no regulated tariffs. It appears there are currently no major gas pipelines in the U.S. treated similarly.

Also as discussed above, ownership by the state/TC has been proposed as a way to assure reasonable shipping rates on its in-kind gas in the absence of tariff regulation. For non-owner producers the state/TC would be the expansion capacity of last resort. The state would develop expansion and tariff terms for them, in short, finding itself in the gas pipeline business.

As an alternative to ownership, it appears the facilities could be regulated by the RCA, particularly the tariff and expansion provisions. (FERC would probably not regulate tariffs since there is no interstate gas involved.) RCA could be granted the legal authority to regulate the export gas (as well as the in-state gas), and ensure reasonable rates. There is precedent in law for the RCA to regulate export gas.

AS 42.08, enacted with HB 4 last year, authorizing the activity of the AGDC , incorporated such regulation on any export gas that was transported through the stand-alone pipeline. Specifically, in AS 42.08.900(7) "in-state natural gas pipeline" is defined as "a natural gas pipeline that transports or will transport natural gas by way of contract carriage." And "natural gas pipeline" is defined in AS 31.25.390 to be " ... a total system of pipe and connected facilities for the transportation, treatment or conditioning, delivery, storage, or further transportation of natural gas, including all pipe, compressor stations, station equipment, and all other facilities used or necessary for an integral line of pipe to carry out transportation of the natural gas." It is not limited to intrastate gas.

Other sections of AS 42.08 lay out how the RCA would regulate gas that goes through such pipelines. In the case of the stand-alone project, it is possible volumes of gas would be transported and liquefied for export, in addition to the volumes used in state.

AS 42.08 does not explicitly address liquefaction facilities, and is not entirely applicable for a large scale LNG export project. But the main point is that it appears the RCA would be able to assert regulatory authority for export gas in new legislation should the legislature want to pursue that option.

Though RCA regulation might be burdensome to the producers, it is generally considered the trade-off in exchange for the natural monopoly bestowed by the right-of-way permit. In the absence of ownership it would be necessary for ensuring reasonable charges, access, and expansion availability on all the facilities.

IV. The Constraints of AGIA

Based on the structure of the proposals, and public comments made by administration officials, it appears that the plan, at least in part, has been crafted out of a desire to avoid a potential lengthy and costly legal fight over ending the AGIA license. Given TC's material role, the proposed deal appears as if is being structured around the administration's perception that it is constrained by AGIA, there is an aggressive time frame to market the gas, and must give TC this role to end the license amicably. These constraints are discussed in the next section.

To be clear, these observations are based on conclusions drawn from examining public information and statements, and the author has no knowledge of the extent to which the administration may have legally analyzed its AGIA options, and no knowledge of what transpired in the negotiating process between the administration and TC in crafting the MOU.

Nothing here is meant to undermine TransCanada's integrity or commercial ability. This is written from the perspective of the state's responsibility to look after its own interests.

For a very long-term endeavor worth several billion dollars to the state, the state should be very careful about structuring the deal based on perceived collateral damage from AGIA. (In many ways it would be the proverbial tail wagging the dog.)

If the enabling legislation is enacted, the state will essentially be giving TC a sole-source contract worth tens of billions of dollars to transport the state's gas.

TC's capital structure and cost of capital terms are laid out in the MOU (see above). Their capitalization terms are certainly not unattractive by conventional private pipeline standards. (There are some FERC regulated natural gas pipelines that have lower costs of debt and equity, and many with higher costs, as well).[10]

In this circumstance only part of the project would be financed for the state's capacity, with the other parts being built and financed by well-capitalized and experienced major international oil companies. The risk is arguably reduced. Also, as discussed below, TC faces no risk of the project not being sanctioned. Looking at the terms on existing pipelines may not be comparable or relevant. Perhaps that is part of the reason why TC came in with the terms it did.

Potential alternative parties could come in needing lower returns. Going out to bid, or negotiation, could generate better terms, especially given the unique situation here. There are

[10] For example, see FERC, Docket EL 12-77-000, Exhibit No. PSCo-24, or Natural Gas Supply Association, "Pipeline Cost Recovery Report," 2005-2009.

many other qualified major natural gas pipeline companies. A lower cost of capital would translate into lower prices to Alaskans for in-state gas. This is discussed below.

Mostly what the state gets out of the proposal is an arrangement for TransCanada to carry the state's gas at reasonable rates, and some expertise in pipeline construction and operation. As discussed prior, a similar, or possibly preferable, result would occur under RCA regulation or 100% AGDC ownership, with the expertise to build and operate the facilities coming largely with the producers' involvement. The extent of TC experience and expertise in gas treatment is unclear.

Absent the constraints of being connected to TC because of AGIA, the state would have additional options for proceeding. First, contrary to the MOU, it could solicit bids for the best terms, which in addition to a potential lower cost of capital, could include a higher ownership share for the state, the ability to divest to whoever it chooses, and more time to decide on ownership. Again, under the MOU the state may have to exercise the ownership option prior to the conclusion of the pre-FEED stage.

Under this proposal it also appears that the state may face very serious risks if the project is not sanctioned (not a trivial possibility), even if it has not exercised the ownership option. If the project is not sanctioned, TC (the Transporter) can terminate the agreement for a number of reason, including failure of the state to execute a firm transportation services agreement (which would likely be the case if the project is not sanctioned), or failure of TC's board at FID to approve the project.[11]

If TC terminates for these reasons, under the MOU the state (the shipper) would owe TC everything it has spent since January 1, 2014. Based on 22% ownership of the GTP and pipe, and estimated pre-FEED and FEED costs of $1.2 billion, this would be about $260 million, plus interest.

The MOU transfers all of the risk of a failed project to the state.[12] By going out to bid a potential alternative partner may be willing to share or absorb some of this risk.

Moreover, if the state should terminate and pay off TC, per the terms of the MOU, if the state participates in a similar project within 5 years, the state must offer TC similar participation terms to this MOU.[13]

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[11] See Midstream Services Term Sheet, Section 9:

Termination Event: Transporter Rights to Terminate (Transporter Termination Event):

- Shipper fails to execute FTSA by December 31, 2015
- At FID, if all Transporter corporate/Board approvals have not been obtained

[12] See Midstream Services Term Sheet, Section 8:

Development Cost Reimbursement:

If Shipper or Transporter exercises its right to terminate pursuant to any of the Termination Events set forth below (Section 9), the Shipper shall pay Transporter for all development costs incurred by Transporter after December 31, 2013 ...

[13] See Midstream Services Term Sheet, Section 9: Conveyance of Transporter Alaska LNG Project to Shipper

The absence of AGIA constraints could also open up the possibility through AGDC for the state of owning 100% of the capacity to ship (including treatment, pipe, and liquefaction) its in-kind gas in its own capacity. AGDC financing could bring significant benefits relative to TC.

As discussed above, AGDC has represented they could finance with 100% debt, through both backing by the state and revenue bonds. It is unclear what the portion of each would be. For the portion backed by the state, the state has a lower cost of debt than TC; the state is rated AAA by Standard & Poor's, TC is A-. That alone is worth about one percentage point in the cost of debt in today's credit markets.

AGDC also represented they could use tax-exempt debt. Generally this costs about 25% less than taxable debt. AGDC's credit has never been rated.

The above discussion in Section III.B.1 described how if the state itself owned 22% of all the facilities, each percentage point it could save in the cost of capital from AGDC financing would be worth $165 million per year, or $4.1 billion over 25 years.

If the state only owns 8% of the GTP and pipeline due to TC's other ownership share, and the state owns the full 22% of the liquefaction facilities and terminal, that would be a blended 69% share of all the facilities commensurate with its gas.[14] TC would own the other 31%.

By foregoing this 31%, each percentage point reduction relative to TC that it could have realized from AGDC ownership would cost the state $51 million per year, or $1.3 billion over 25 years.

For example, if AGDC could save 2 percentage points over TC, TC's ownership would cost the state $2.6 billion over 25 years.

One of the benefits of the project is in-state gas for Alaskans. Some of this cost would be paid for by Alaskan consumers as these higher costs would translate directly to their gas bill (which will charge for treatment and pipe in addition to the gas itself). The loss of a two percentage point reduction, for example, in the cost of capital on the portion of the GTP and pipe that TC is to own, could cost each household several hundred dollars annually.

TransCanada may have exercised bargaining leverage over the state to let the state extricate itself of AGIA. It may be useful for the state to do a deliberative analysis as to exactly what the state's exposure is, and whether there are better alternatives. A high level analysis is contained in the next section.

[14] The state's share of the facilities commensurate with its in-kind gas is 22%. The total cost is $45 billion. The GTP and pipe are $22 billion (49% of the total). The liquefaction facility is $23 billion (51% of the total). The state would have 36 % of the 22% share of the GTP and pipe (8%/22%), and 100% of the liquefaction facility. This would be 36% of the 49% (18%) and 100% of the 51% (51%) for a total of 69%.

V. Getting Free from the Constraints of AGIA

Insofar as the proposal is a) designed around the administration's perception that it is bound by AGIA, and b) because of the perceived time urgency of the project is not able to pursue potential legal remedies, and c) is thus conveying this role to TC, these constraints are limiting the state's options. It may be useful to explore legally the extent to which the state may not be so bound. There may be some legal arguments that the state is not so confined, and the state could proceed how it wants without incurring an AGIA liability. This could very well slow some of the process down.

To be clear, while the author is not an attorney, he is well-versed in AGIA and has consulted with attorneys in relation to this section. But as such, the forthcoming analysis should not be considered a professional legal analysis. The legislature may want to consider securing legal counsel to further explore its options under AGIA.

Certainly the state does not have a moral obligation to TC. TC willingly took on risks when it became the AGIA licensee, as did the state. To date the state has incurred more costs than TC.

A. Abandonment of Project

The easiest way out of the AGIA license is to abandon the project as uneconomic under AS 43.90.240. Under that clause, if the predicted costs and prices are such that the project is not economically feasible, the license can be terminated. If the parties disagree the issue goes to arbitration.

The original license was for a project to North America, which everyone agrees is now uneconomic pursuant to the large volumes of shale gas that have pushed prices down. These issues are cited in both the HOA and MOU.

Under AS 43.90.210 it is possible to modify or amend the project plan. In 2012 the administration and TC agreed to modify the plan to be an LNG export project, rather than a pipeline to North America. However, it is possible the modification was not made in compliance with the statute. The rationale for that follows. If this were the case, the default plan could still be for the North America project, which would be uneconomic, and the license could be legally terminated.

There are three possible reasons the project plan modification was not made within the provisions of the statute. The first two of these were spelled out in a memo by from Donald Bullock, Legislative Legal Services counsel, to Rep. Hawker on February 15, 2013.[15]

First, counsel opined that changing from the North America to the LNG export project is such a drastic transformation that it is more than just an amendment or modification, and nothing like the detail or scrutiny that accompanied the original application was applied:

[15] Memo from Donald M. Bullock, Jr. to Rep. Mike Hawker, "Assurances to a project licensed under the Alaska Gasline Inducement Act (Work Order No. 28-LS0457)," February 15, 2013.

> The commissioners specifically rejected an LNG option in their recommendation to the legislature. Therefore, under the terms of AGIA, the project licensed under AGIA is the project from the North Slope through Canada. If the route through Canada is the licensed project, changing the project to an LNG project is not a modification to the licensed project, but is a rejection of the AGIA project.
>
> Thus while TransCanada was open to soliciting interest in shipping gas to Valdez and expressed that possibility in its application to FERC, the project pitched under AGIA to the commissioners and the legislature was the highway project, that is, the project to the Canadian border.

Moreover, in recitals 11 and 12 in the MOU state that:

> Because it is not economically feasible that *two* (emphasis added) large-scale pipeline projects will be developed concurrently to transport Alaska North Slope natural gas to market, the Commissioners have committed to consider commercial agreements executed by and between the State, TADI and the ANS producer s for development of the Alaska LNG project as material evidence that the Licensee's AGIA licensed project is uneconomic as provide in AS 43.90.240(a). ... The Licensee has committed that upon the occurrence of the Trigger Event and the execution of the Transition Agreements, the Licensee will agree that the project licensed under the AGIA license is uneconomic within the meaning of AS 43.90.240(a).

The implication of the recitals are that since the LNG project is being pursued, it is not uneconomic, so the North American project must be uneconomic. And since the abandonment clause is being invoked, the North American project must be the AGIA project subject to the abandonment clause.

Second, per AS 43.90.210, any modification must be consistent with the requirements of AS 43.90.130, the original application requirements. This includes 20 requirements. These were not part of the modification process. For instance, AS 43.90.130(2)(D)(ii) requires a thorough description of the project, including:

> the marine transportation services to be provided and a description of proposed rate-making methodologies; an estimate of rates and charges for all services by third parties; a detailed description of all proposed access and tariff terms for liquefaction services or, if third parties would perform liquefaction services, identification of the third parties and the terms applicable to the liquefaction services; a complete description of the marine segment of the project, including the proposed ownership, control, and cost of liquefied natural gas tankers, the management of shipping services, liquefied natural gas export, destination, regasification facilities, and pipeline facilities needed for transport to market destinations, and the entity or entities that would be required to obtain necessary export permits and licenses or a certificate of public convenience and necessity from the Federal Energy Regulatory Commission for the transportation of liquefied natural gas in interstate commerce if United States markets are proposed; and all rights-of-way or authorizations required from a foreign country;

To the author's knowledge all of these have never been submitted for the modification. This information was publicly submitted in the original license application.

Third, another section of AS 43.90.130, section 7, calls for the licensee to propose and support rolled-in rates for expansion costs. Subsequent to the 2012 plan modification, TransCanada has been working jointly with the three producers, who are prime players in the plan modification. As the latest AGIA Fund Disbursement Report says:

> Thus for the first time in this project's history, the APP and the major Alaska North Slope (ANS) Producers (ExxonMobil, BP, and ConocoPhillips) have aligned under the AGIA framework to explore and develop a concept for an LNG project and associated pipeline through the state to tidewater in South-central Alaska.[16]

It is not unreasonable to assume that state AGIA reimbursements are flowing through TC directly to the producers for their share of the work. In any event, for all intents and purposes the three producers are functioning as de facto co-licensees, being the beneficiary of the AGIA inducements intended for the licensee. However, the producers have never supported rolled-in rates, but have actively opposed them.

For these reasons it is possible the plan modification may have been out of compliance, making the North American project the active plan. Insofar as it is clearly uneconomic, this would provide a vehicle for abandoning the license. If this were the case there may be legal remedies available, such as rescinding the plan modification. This would open up other financially preferable options to the state.

B. License Project Assurances

If the project is not abandoned as uneconomic, and the state were to proceed as it wants without TC, there is a risk it could create legal and financial exposure through the license project assurances clause in AGIA, AS 43.90.440. The clause says:

> AS 43.90.440(a) Except as otherwise provided in this chapter, the state grants a licensee assurances that the licensee has exclusive enjoyment of the inducements provided under this chapter before the commencement of commercial operations. If, before the commencement of commercial operations, the state extends to another person preferential royalty or tax treatment or grant of state money for the purpose of facilitating the construction of a competing natural gas pipeline project in this state, and if the licensee is in compliance with the requirements of the license and with the requirements of state and federal statutes and regulations relevant to the project, the licensee is entitled to payment from the state of an amount equal to three times the total amount of the expenditures incurred and paid by the licensee that are qualified expenditures for the purposes of AS 43.90.110 that the licensee incurred in developing the licensee's project before the date that the state first extended preferential treatment to another person.

[16] State of Alaska Department of Revenue and Natural Resources, "AGIA Fund Disbursement Report," Jan. 25, 2013, pp. 3-4.

So the question is whether the state would incur a liability under this section were it to proceed to own the facilities and modify taxes and lease terms. (If the license were abandoned as uneconomic the license project assurances disappear.)

Much in the clause is ambiguous, particularly:

- The meaning of "preferential" (line 4)
- The meaning of "grant of state money" (line 5)
- Whether the payment (line 12) is based on the licensee's gross or net expenditures

Regarding the meaning of "preferential," in hearings on the AGIA bill in 2007, administration officials testified that the intent of AGIA was never to restrict the legislature's ability to look at taxes and royalties:

> The word "preferential" is key because there is no intent to restrict the legislature's ability to look at taxes. If a future legislature decides to modify production taxes, nothing in the bill prohibits the legislature from changing tax rates.
>
> ... changing the tax rate to influence a pipeline project ... isn't a preferential tax change; everybody's affected by it ...
>
> By statute DNR is authorized to look at leases and agree to modify the royalty rates for leases that have been unitized. ... Another area in statute allows DNR to negotiate a more favorable royalty rate when a lessee can show by clear and convincing evidence that development in a particular field is challenged. ... These are existing statutes that apply under specific conditions; their focus isn't to support a specific competing gas pipeline.[17]

These sentiments were echoed by legislative legal counsel Donald Bullock both in committee testimony,[18] and in his aforementioned 2013 memo.

Any law of general applicability isn't preferential treatment; everybody is affected by it. It could apply just as well to a bullet line, a gas-to-liquids project, ice-breaking LNG tankers out of Prudhoe Bay, a pipeline to North America, or a different LNG export project.

As far as "grants of state money" are concerned, administration officials testified that "grant" means an "outright unfettered financial grant."[19] (Perhaps it could be considered donations.) Arguably, buying equity in the facilities may not a grant; the state is making an appropriation and paying for an asset it is getting in return.

[17] Testimony of Deputy Commissioner Marcia Davis (Dept. of Revenue) on SB 104 before Senate Judiciary on April 13, 2007.
[18] Testimony of Donald Bullock on HB 177 before House Resources on April 10, 2007.
[19] Testimony of Deputy Commissioner Marcia Davis (Dept. of Revenue) on SB 104 before Senate Judiciary on April 13, 2007.

On the other hand, an appropriation could perhaps be considered a grant. Legislative legal counsel opined that "financial support for a competing pipeline could result in liability under the assurances"[20] (but not for certain).

If appropriations for ownership do create a problem, perhaps the state could take its gas in-kind without ownership, foregoing any appropriation, modify taxes and royalties in laws of general applicability as it sees fit, and be free of AGIA. The license assurances expire after the commencement of commercial operations, and perhaps the state could pursue ownership then.

Under AGIA, before the first open season in 2010 the state was reimbursing TC 50% of their expenditures, and afterwards 90%, up until $500 million. So if treble damages are invoked it is an important difference whether it is based on gross or net expenditures.

Per the latest AGIA Fund Disbursement Report, as of January 2013 TC was expected to have spent cumulatively approximately $550 million through the end of 2013, and the state reimburse them approximately $350 million.[21] Based on those figures, on net they have spent $200 million. Treble damages based on gross would be $1.65 billion. Based on net they would be $600 million, a billion dollar difference. Evidently TC spent less in 2013 than expected, so those figures would be slightly reduced.

On whether the payment is based on the licensee's gross or net expenditures, the administration in committee testimony suggested it would be based on net:

> If the state's share is larger the net to the licensee would be lower so exposure post open season would probably be a lot lower.[22]
>
> The limit would be the amount expended by the licensee, based on the expectation of what the licensee might be spending and depends upon the amount matched by the state.[23]

In the aforementioned 2013 memo legislative legal counsel Donald Bullock also opined that net may be a better interpretation:

> In my opinion the better interpretation is that the payment is on net amount paid by the licensee after reimbursement by the state. The reimbursement of expenditures, the benefit of an Alaska Gasline Inducement Act coordinator under AS 43.90.110(a)(2), and the assurances all reduce the risk of the licensee. Reimbursement by the state already removes a percentage of the risk, and the financial investment of the licensee that remains

[20] Memo from Donald M. Bullock, Jr. to Rep. Mike Hawker, "Assurances to a project licensed under the Alaska Gasline Inducement Act (Work Order No. 28-LS0457)," February 15, 2013.
[21] State of Alaska Department of Revenue and Natural Resources, "AGIA Fund Disbursement Report," Jan. 25, 2013, p. 10.
[22] Testimony of Deputy Commissioner Marcia Davis (Dept. of Revenue) on SB 104 before Senate Judiciary on April 13, 2007.
[23] Testimony of Commissioner Patrick Galvin (Dept. of Revenue) on HB 277 before House Resources, 2007.

> is the percentage not paid and the expenses incurred and not subsidized after the $500,000,000 has been exhausted.

The language in the act may suggest otherwise. The amount (from above) says:

> " ... three times the **<u>total</u>** amount of the expenditures incurred and paid by the licensee that are qualified expenditures ... "

There are two other sections in AGIA that involve payments from the state to the licensee. AS 43.90.200 addresses what happens if the licensee does not sanction the project as required. In that case the licensee transfers the FERC certificate to the state, and the licensee gives the state its data if the state wants it. In return the state pays the licensee:

> " ... three times the **<u>net</u>** amount of the expenditures incurred and paid by the licensee that are qualified expenditures ... "

When the language means net, it says net.

AS 43.90.240 addresses what happens if the project is abandoned for being uneconomic. Again, the licensee gives the state its data if the state wants it. In return the state pays the licensee:

> " ... three times the **<u>net</u>** amount of the expenditures incurred and paid by the licensee that are qualified expenditures ... "

Again, when the language means net, it says net.

In conclusion, the proposal arguably results from two possible perspectives from the administration. First, the administration may believe there is an aggressive time line to move the project, and it would not be fruitful to consider a time consuming legal strategy to try to break from the AGIA process (which could open up several additional preferential options). As discussed above, for a project this important it may be useful for the state not to act in a hurried manner.

Second, as explained above, some of the terms of the MOU create significant fiscal risk for the state. The AGIA constraints may have put the state in a weak bargaining position with TC, which put TC in an advantageous situation.

The state could consider proceeding along the following lines regarding both the abandonment of the project and the license project assurances. Perhaps the administration has done some of this non-publicly:

- Engage TC as to whether they would litigate if the state went in a different direction.
- If they would, assess the state's legal exposure and options.
- If the state believes the risk is reasonable, it could decide to go to court. Obviously that slows things down, and the outcome would not be certain. Some other development

activities could still proceed concurrently. If the state loses in court it could pay the treble damages and the long-run benefits could still exceed the cost.
- If the state believes it does have reasonable exposure, it could consider paying off the treble damages immediately and the long-run benefits could exceed the cost.

Finally, insofar as TC wants this project, the state does have some bargaining strength, and could push back for better terms with TC.

VI. Gas Production Tax

The proposal is for a gross tax rate of 10.5% that can be paid as in-kind gas. As discussed above, taking the gas in-kind improves the project economics, and should be seriously considered. If taxes are taken in-kind, it makes sense to have the tax based on gross to provide stability of volumes.

As far as what is the appropriate rate, as was emphasized last year in the discussion of oil taxes, fair share is what you can get in a competitive environment. Accordingly, it depends on government take among jurisdictions with a similar risk/reward balance as Alaska.

Figure 3 shows government take on LNG projects as derived by Daniel Johnston. These were published in the Black & Veatch report prepared for DNR.

Note there is a wide variation in take. Alaska is a high cost, lower valued, higher risk project. It does have some advantages: it has low gas production costs (the gas is already being produced and shares the costs with the oil), and its reserves are proved up. In addition, with the in-kind mechanism it is taking on more risk and reflects a system more like a production sharing system (PSC), which have higher takes. Accordingly, it would not be unreasonable to look at the middle of the spectrum of government take for a target, perhaps about 70%.

At a $45 billion cost, and a $15/mmbtu price (real 2013 dollars) in Asia, at the proposed 10.5% production tax rate, the estimated government take is 70%.[24] It would vary from 71%-70% at prices from $10-$20/mmbtu, a fairly neutral system. This would appear to be reasonably close to the target range.

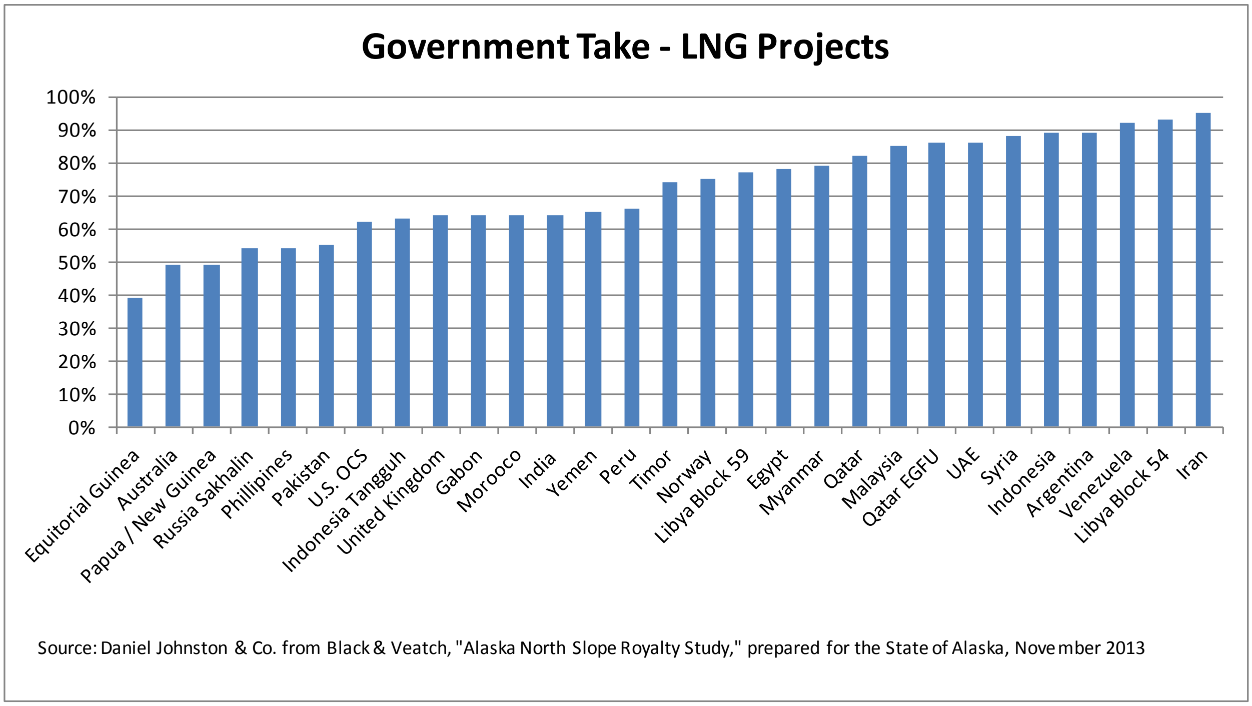
As discussed below, while the tax rate is based on gross, the bill appears to allow the deduction of upstream gas costs against oil production. This will mostly happen with Pt. Thomson. The take numbers above reflect this.

With the state taking its taxes and royalties in-kind, and paying its expenses accordingly, any increase or increase in the tax rate is associated with increases and decreases in the producers'

[24] The state could take its taxes and royalties in-kind associated with either no ownership, partial ownership, or full ownership of the portion of the facilities associated with the capacity it would ship. Insofar as taking the gas in-kind involves a firm transportation commitment financially equivalent to ownership, this analysis of taxation is calculated as if the state takes full ownership of the facilities commensurate with its share of the gas.

and state expenses. Accordingly, as the cash flows simply scale up or down, much of the financial metrics do not change very much. However, undiscounted cash flow, which is very important, certainly moves quite a bit with changes in the tax rate.

FIGURE 3



Some observations on the property tax: Currently the property tax is based on value and as such is very regressive. The higher the cost of the facilities, the more the property tax. It exacerbates the cost problem, especially on something that will cost in excess of $50 billion. In addition, over time there has been a plethora of litigation over the assessed value of the oil pipeline due to the theoretical difficulty of assessing value on such unique assets. Currently every assessment since 2005 is in some stage of adjudication.

Accordingly, as spelled out in Article 9 of the HOA, other project enabling terms, it would be well worth the effort to carefully examine converting the property tax to a cents per mmbtu basis. While clearly the local jurisdictions, who are the main recipients of the tax, need the funds for dealing with local social impacts associated with developments, there is probably not a strong relationship between the cost of the assets and the costs of dealing with the impacts.

Finally, there are two comments on the drafting of the bill. First, in Section 29, where the irrevocable decision to pay the production tax as in-kind gas is made, it may not be clear how the amount of gas is determined. Is it 100% of the gas? A set volume? Can a taxpayer make the decision on a portion of its gas?

Second, as discussed above, in Section 42, AS 43.55.160(h) is amended to say that the annual production tax value for oil is the gross value less expenditures to produce oil or gas. Does it make sense to deduct the costs for producing gas in determining the net value for oil? The proposed tax on gas is a gross tax, and so its rate is lower relative to a tax on net (since net is lower). As written, with the deductibility of the gas expenses, there is essentially a gross tax rate based on net value. The current AS 43.55.165(h) contains provisions for allocating costs between oil and gas. In addition, should there be a company with only gas, it would be unable to deduct its upstream costs and would be at a significant disadvantage.

VII. Conclusion

The administration's proposal may provide a suitable blueprint towards North Slope gas commercialization. It appears that it has been crafted around giving TransCanada an ownership role due to perceived AGIA constraints. Because of these constraints, the state may be making financial sacrifices and foregoing some options.

The main risk of state ownership stems from the possibility of going through an expensive feasibility process with the project not being sanctioned. Should this occur, the state is responsible for TC's costs even if the state does not exercise the ownership option.

The main benefit of state ownership would be the possibility of low cost state financing through AGDC. This could save the state several billion dollars. TC's involvement reduces that benefit by about 30%. Some of this would be paid for by Alaskan consumers in the form of higher gas bills.

If the state feels it needs a partner, TC's involvement eliminates the possibility of going out to bid for the best terms on cost of capital, risk sharing, and ownership percentage.

This proposal reflects an urgency to move forward on the project rapidly, and there may be wisdom to that. For a project of this size, this duration, and this value, an option for the legislature may be to reflect on how the state would proceed if it were not so encumbered. If the alternative is much preferable, it might be worthwhile to pursue.