MINUTES
SENATE FINANCE COMMITTEE
April 26, 2007
9:10 a.m.

CALL TO ORDER

Co-Chair Bert Stedman convened the meeting at approximately 9:10:25 AM.

PRESENT

Senator Lyman Hoffman, Co-Chair
Senator Bert Stedman, Co-Chair
Senator Charlie Huggins, Vice Chair
Senator Kim Elton
Senator Joe Thomas
Senator Fred Dyson
Senator Donny Olson

Also Attending: FREDERIC RICH, Head, Global Project Development and Finance Group, Sullivan, & Cromwell, LLP; ROBERT SWENSON, State Geologist & Acting Director, Division of Geological & Geophysical Surveys, Department of Natural Resources; KEVIN BANKS, Acting Director, Division of Oil& Gas, Department of Natural Resources

Attending via Teleconference: There were no teleconference participants

SUMMARY INFORMATION

SB 104-NATURAL GAS PIPELINE PROJECT

The Committee heard two presentations pertaining to the Natural Gas Pipeline Project legislation: one from Sullivan & Cromwell LLP on gas pipeline financing and one from the Department of Natural Resources on potential gas reserves in the State. The bill was held in Committee.

9:10:37 AM

#sb104

CS FOR SENATE BILL NO. 104(JUD)
"An Act relating to the Alaska Gasline Inducement Act; establishing the Alaska Gasline Inducement Act matching contribution fund; providing for an Alaska Gasline Inducement Act coordinator; making conforming amendments; and providing for an effective date."

This was the sixth hearing for this bill in the Senate Finance Committee.

Co-Chair Stedman announced that this would be another in a series of Committee hearings focused on gathering information pertinent to the Alaska Gasline Inducement Act (AGIA).

Co-Chair Stedman announced he had asked Frederic Rich with Sullivan & Cromwell, LLP, an international law firm based in New York, to review select information from a gas pipeline financing presentation he had recently presented to another Legislative committee which Co-Chair Stedman had attended. Sullivan & Cromwell, LLP is consistently ranked "in league tables and surveys" as one of the top leading advising law firms for oil and gas and pipeline financing. The firm has been a participant in five of the ten largest "and completed" international oil and gas pipeline financing projects.

Co-Chair Stedman noted that following Mr. Rich's remarks, the Department of Natural Resources would be presenting information regarding gas reserves in the State.

9:12:57 AM

FREDERIC RICH, Head, Global Project Development and Finance Group, Sullivan, & Cromwell, LLP, informed the Committee that Sullivan & Cromwell specializes in "mega projects" with capital costs "in excess of a billion dollars".

Mr. Rich noted that while Sullivan & Cromwell LLT has typically served as lead financial advisor to the producers group, his remarks would be his own and should not be viewed as the opinion or position of any producer group member.

9:14:18 AM

As noted by Co-Chair Stedman, Mr. Rich affirmed he would be elaborating on specific information in the "Project Finance Workshop, An Introduction to Project Finance for Oil, Gas and Pipelines" presentation, dated April 25, 2007 [copy on file]. First, however, he wished to elaborate on a question he had been asked the previous day regarding whether "the authority of the Secretary of the Department of Energy (DOE) to issue the federal loan guarantee, the authorization, had any sunset or expiration date…"

Mr. Rich affirmed there was no expiration date associated with the federal loan guarantee authorization; however, the Secretary of the DOE must "issue the federal loan guarantee instrument" within a two-year period after the Federal Energy Regulatory Commission (FERC) issues a project a Certificate of Public Convenience and Necessity.

Mr. Rich also noted that the certificate would be considered "issued" when all the certificates had been issued that "are required in connection with transportation of commercially economical quantities of gas".

9:15:39 AM

Mr. Rich considered it worthwhile to remind the Committee that "the scale and magnitude of this project and the extent to which it would likely make its own market" makes it difficult to compare its financing to other oil and gas projects. Here-to-fro, the largest completed financing for any industry project was $6.7 billion and "the largest previous pipeline financing was $2.6 billion".

Mr. Rich characterized this project, in terms of financing, as a "quantum leap into new territory". It is so large that no structures and procedures from any previous project could be "scaled up" to size. Thus, even "the magnitude of the risk is qualitatively different".

9:17:03 AM

Mr. Rich, understanding that the Committee desired more information on how "the presence" of the federal loan guarantee might affect other aspects" of the project such as project financing, shared that "the federal loan guarantee in effect only has the affect of interposing the federal government either

as the lender or as an additional lender". Thus, any reference to a condition imposed by the lender would infer it to be a requirement of the federal government, especially where the federal loan guarantee 100 percent.

Mr. Rich communicated that having a federal government guarantee on the project "is hopefully providing an incentive for the project to proceed by lowering the cost of the debt". One should be mindful that the federal loan guarantee is not free money; it must be repaid since the federal government "must behave" as any prudent lender would.

Mr. Rich specified that were the federal government to guarantee 100 percent of the debt, "it will have a financial advisor which will advise it on the terms and conditions and structures and covenants" and other components of project financing.

Mr. Rich stated that in the case of a federal government guarantee of less than 100 percent of the debt, there would be other "lenders taking full project risks post completion" in addition to the federal government.

Mr. Rich, referencing the immensity of the project, noted that if the federal government guarantee was 80 percent, the remaining "un-guaranteed portion itself would be one of the largest project financings … ever undertaken" for an oil and gas industry project.

Mr. Rich expressed that having a federal guarantee would likely not change any of the requirements or "lessen any of the pressures or requirements" associated with the project. Were the federal government to pay "under the guarantee" for any default in a loan, there would simply be "a change in lender; the borrowing company, the pipeline company, still owes the money, but instead of owing it to Citibank, if that was the initial lender, it now owes it to the federal government".

9:19:56 AM

Mr. Rich next addressed the "completion support or completion guarantee" agreements associated with a pipeline. The interplay between the required completion support and the federal loan guarantee is specified in federal statute, in that "the Secretary shall not require as a condition of issuing a federal guarantee agreement, any contractual commitment or other form of

credit support of the sponsors other than equity contribution commitments and completion guarantees".

Mr. Rich noted that equity contribution commitments and completion guarantees "are alternative forms of providing completion support". Equity contribution commitments are "a promise by the shareholders or owners of the pipeline company that they will put in the required equity portion under the base case budgeted capital costs and that they would put in an additional portion in respect of overruns". Other oil and gas projects have required an additional 30 percent of the estimated capital costs for project overrun expenses.

Mr. Rich disclosed that a "completion guarantee is an alternative form of completion support where the shareholders of the pipeline entity actually guarantee the debt when the debt is incurred during the construction period and those guarantees are in full force and effect until completion is met". He specified that "completion is defined as meeting a set of physical, operational and financial tests."

Mr. Rich contended that "before completion exists, there is no project, there is no credit, there is no facility, there's no way for the lenders to be repaid so they are looking to the guarantor". In order to pass a completion test, the pipeline must be built as scoped, must be able to operate at the required capacity; and must meet the entirety of other requirements in the credit agreement. These other requirement might include such things as firm shipping commitments. "Once all those things are certified … the completion guarantees fall away".

Mr. Rich concluded that either a completion guarantee or an equity contribution commitment would be required by a federal guarantee. They could be in place "on day one so that the lenders would have the comfort of the federal guarantee and the parties providing the completion support would give the support to the federal government". One example of this is "a straight debt guarantee" which "would be a counter guarantee of the federal government by the shareholders". In this case, if a pre-completion default occurred, "the federal government would pay the bank, and then it would turn and make a claim against the shareholder under its guarantee".

Mr. Rich advised that a straight debt guarantee "would lower the cost of the debt because the bank lending the pre-completion will price it at a U.S. government risk margin".

Mr. Rich stated that if the federal government decided against taking completion risks, it could wait to issue its' guarantee until after the pipeline was completed. In this case "the shareholders would directly guarantee to lenders until the completion was met". "The cost of the guarantee would reflect the credit rating of the shareholders of the pipeline company…"

Mr. Rich concluded his comments regarding the "interplay between these completion issues and the federal guarantee".

9:24:29 AM

In response to a question from Mr. Rich, Co-Chair Stedman requested that Members hold their questions until Mr. Rich completed his presentation.

9:25:02 AM

Sullivan & Cromwell LLP
Project Finance Workshop
An Introduction to Project Finance
for Oil, Gas and Pipelines
April 25, 2007

Section 5

Project Finance for Oil, Gas and Pipelines

Page 48

Why do lenders like oil, gas & pipeline projects?

- Past experience has been good
- Resource based lending for upstream projects; contractual based lending for pipeline projects
- Technologies are usually well-proven
- Particularly suited to cash-based credit analysis - cash flows clear
- Either commodity products without market risk (oil), or highly credit-worthy off-take/transportation commitments

- One of the main post-completion risks is usually price risk - which, traditionally, banks understand and can price
- Sponsors can be
  - highly creditworthy
  - experienced with large projects, conservation culture
  - judged by lenders unlikely to abandon strategically significant projects

Mr. Rich directed attention to page 48 of Section 5 in the presentation [copy on file]. He noted that since lenders typically provide 70 to 80 percent of a project's funding, their primary focus is on being repaid in a timely fashion. This is a very different perspective than those of "the developers who stand to earn an equity return or upstream producers who stand to be able to market their gas and earn an upstream return".

Mr. Rich communicated that lenders tend to view projects in a "what could go wrong" manner. Nonetheless, "there is a good deal of enthusiasm" amongst lenders, specifically commercial banks, "about the oil and gas pipeline sector". The probability is high that this project could be financed.

9:26:50 AM

Mr. Rich cautioned the Committee to be aware that banks and other lending institutions "tend to be in marketing mode" during the initial stages of a project. They might label the project "fantastic" and state their willingness to help finance it. It is not until later in the process that intricate issues, such as the firm commitment contract agreements, are addressed.

Mr. Rich also noted that one of the primary questions shareholders of any project must address is whether to seek an independent financial advisor "who would not be competing to do the business of making the loans or underwriting the bonds or do they seek a bank that actually will both give them advice and then change to the other side of the table and be the counterpart negotiating the terms of the credit".

Mr. Rich considered there to be valid arguments for each approach; however, most of the "more sophisticated companies" as well as the United States government, prefer to have an independent financial adviser. This issue is being highlighted because it is likely that the information presented on page 48

would be experienced. Banks "love doing oil, gas and pipeline business, especially" projects in the United States. Currently only 15 percent of this lending market is for projects in the United States. Most of these capital requests to banks are for projects in places such as Russia and Venezuela, "and places where there's a whole different element of risk".

9:29:24 AM

Mr. Rich expressed that an oil and gas project in North America is attractive to lending institutions for the reasons specified on page 48.

9:30:05 AM

Page 49

Upstream vs. midstream (pipelines)

Upstream

- Oil projects involve commodity products with little or no market risk; transportation may not be an issue
- Gas projects depend on available transportation and market, and strength of off-take commitments

Mr. Rich reminded the Committee that the upstream and midstream marketplaces are "very different". In addition, gas is a more complicated commodity than oil to address.

Page 50

Upstream vs. midstream

Midstream

Pipeline credits vary widely - depending on

- Degree of project integration with upstream/downstream
  - Upstream and midstream as integrated project
  - Separate but with upstream producers as owners of midstream
  - Separate with upstream producers' role limited to customer
- Contractual and credit links into upstream

        - Producer transportation commitment vs. buyer as shipper
        - Nature of transportation commitment
    - Tariff structure
        - Unregulated - negotiated tariff
        - Common carrier
        - FERC/NEB
    - Emerging market vs. developed

9:30:16 AM

Mr. Rich reminded that issues pertaining to "a separately constituted midstream project" were discussed at length during the previous day's presentation. While there has been "successful financing of separately constituted midstream projects" in the United States, the current trend outside of the United States is that both producers and lenders are tending "to prefer the integration of the upstream and midstream" efforts. This project should be weighed to determine which precedents might apply to it.

9:31:22 AM

Page 51

Main Pipeline Financing Approaches

Degree of Integration with Upstream/Downstream

- Especially for large strategic projects which rely on single transportation system, producers want (i) timely development of transportation, (ii) control over construction and operating costs, and (iii) reliability - usually leads to integration with upstream or producer participation if midstream is separate
- Even if pipeline is organized as a separate project, development of upstream resources, transportation commitments and downstream markets are foundations of the pipeline credit

Mr. Rich declared that "as long as this project is separately constituted, which it will be, the key issues would be: what is the nature of the link or the contractual claim that the lenders to the midstream pipeline project have on the availability of

the upstream reserves … That of course is a function of the firm transportation contracts."

9:31:29 AM

Page 52

Main Pipeline Financing Approaches

- "Dual Project Risk"
  - Dual completion risk if separate upstream project is also greenfield
  - Crux of issue: midstream lenders exposed to upstream risks without normal covenants with and remedies against upstream project
  - Creates tremendous pressure (i) for common ownership or (ii) on terms and conditions of transportation agreements as only "link" into upstream
  - Financing complexity, time and costs also can increase

Page 53

Transportation Agreements

- Transportation Agreement defines cash flows for pipeline borrower
  - Producer or buyer as shipper
  - Nature of shipping commitment
    - Ship-or-pay (most common)
    - Ship-and-pay
- For ANGP, as FERC/NEB regulated project, open season bids would be on the basis of firm transportation commitments

9:31:40 AM

Page 54

Transportation Agreements

Firm Transportation Commitment (ship or pay)

- Key midstream financing issues are tenor, volume, tariff, shipper credit and force majeure
  - If Federal guarantees are available and used, these are issues for Federal government as guarantor, and for lenders as to any uncovered

portion of debt … but force majeure exceptions to "ship or pay" obligations are key

- Starting point for midstream post-completion credit is blended credit behind shipping commitments
- Shipper credit analyzed based on (i) financial strength, (ii) upstream development and operating costs and break-even net-back, (iii) end-user markets, and (iv) sufficient volumes to fulfill firm commitment
- In FERC regulated transaction, tariff adjusts - generally protects lenders because costs passed on to shippers
- Producers may be reluctant to enter into firm "ship-or-pay" commitments if they do not own the pipeline

Mr. Rich identified key elements a lender would consider when judging the adequateness of firm transportation agreements (FTs). These would include: "their duration in relation to the duration of the debt" as "the general rule is that the tenor of the off-take contract or the FT agreement" should be as long or longer than the length of the debt obligation; "the volume of the commitments must be sufficient to repay the debt"; and "the credit" behind the FTs.

Mr. Rich disclosed that lenders analyze FTs on two levels. The technical analysis would consider the entity giving the commitment and their credit ranking. "There is no credit" accompanying a company whose sole business "was the production of upstream reserves in Alaska" as that company would not have "the cash to pay the commitment unless it is in fact monetizing the gas". This scenario might be acceptable to lenders if the company was a component "of a larger corporate group" and there was the "expectation that the larger corporate group will cause that affiliate to meet its obligations".

Mr. Rich expressed that that expectation would not typically hold true if the entity behind the FT "does not have a public investment grade credit rating". In that case, the lenders would require additional credit supports or guarantees.

9:34:39 AM

Mr. Rich stated that the second analysis would be a commercial and economic analysis of "how likely is it … that company would perform its obligations". In the case of a gas pipeline, this

analysis "leads right into an integrated economics of the whole enterprise". Questions would include such things as whether the netbacks would be positive, and, over a 20 or 30 year period, would "it make commercial sense to lift the gas and transport" it. The "entire value chain" of the project must be modeled and projected.

9:35:12 AM

Mr. Rich stated that the modeling would be comprehensive and would consider such things as operating costs, reservoir data, fiscal, and gas market forecasts. The ultimate question would be whether the company could pay back the $20 billion debt over the next 20 years under a negative netback scenario as compared to the scenario "where the upstream business is going fine and the netbacks are positive and they're continuing to produce".

9:37:17 AM

Page 55

Transportation Agreements

Force Majeure

- In "ship-or-pay", force majeure provisions define circumstances where shippers do not have to pay
- Of key importance to lenders, since force majeure events result in interruption in cast flow available to service debt
- Main force majeure provisions cover operational/availability risk in midstream - if midstream cannot accept gas, shippers not obligated to pay
- Result is keen lender interest in (i) quality of original design and construction, (ii) operational expertise and track record of midstream operator, and (iii) technical and financial capacity of midstream project company and its owners to address operational issues
- Project size and complexity, together with long tenor and large size of midstream financing, likely to increase these concerns in ANGP

Mr. Rich identified force majeure (FM) provisions as another key consideration in the lending process as contracts do not require shippers "to pay the tariff in 100 percent of the circumstances". Even though shippers "do take most of the risk"

of paying, "they are excused from paying … if pipeline is not available to accept and transport tenured gas … As a result, it's a risk the midstream lenders take". If the pipeline is not available due to such things as an environmental problem, "there's no cash flow".

Mr. Rich informed that consideration of the pipeline operators' "operational track record and expertise" as well as technology and operating support is "an essential part" of the lender's credit decision and "their pricing of the credit". "Force majeure provisions are heavily negotiated" and are not standardized. In addition, they are affected by the Federal Energy Regulatory Commission (FERC) process.

Mr. Rich, who professed not to be an expert in the FERC process, did know that "FTs are able to be negotiated prior to the open season so that these force majeure provisions [indiscernible] basically arise as a matter of negotiation".

Mr. Rich emphasized that FTs do affect the financing of a project. "If the owners of the pipeline are completely dependent on financing", an attempt would be made early in the process "to understand and anticipate" what financing would be required. Therefore, it is likely that at the time the FTs are being negotiated, a company would be anticipating finance requirements. "But there is always risk". He could not comment further as he was uncertain of this project's development timetable. Nonetheless he espoused that integrating the FERC timetable with the financing timetable "is a complex matter".

9:40:55 AM

Mr. Rich acknowledged, however, that finance commitments are "conditional ultimately on the issuance of the certificate" and other assumptions. "But at the end of the day, the FTs have to be acceptable to the lenders one way or another."

9:41:23 AM

Page 56

Structural issues for cross-border pipelines

- Separate entities in each country most common
- Can be separately tranched loans to each entity, but

- o Cross-completion risk
- o Sometimes structured to create unified credit

- Two loans can equal more complexity and cost and longer time to develop

Mr. Rich stated that the issue with cross-border pipelines "is that even if the pipelines were separately constituted in Alaska and Canada or had separate ownership groups" they would be considered a single "integrated" pipeline from a credit perspective.

Mr. Rich voiced that cross-border transactions are complex, costly, and require additional time to process and develop.

9:42:13 AM

Page 57 and 58

10 Largest Oil and Gas Pipeline Project Financings
(greenfield and expansion only - excludes acquisition financing and refinancings)*

[Listing of five projects by name and location, total capital cost (senior debt portion), sponsors, and financial advisors to the consortium.

For example, the Alliance Pipeline Project (Gas) in Canada and the United States cost $3,730,000,000 with $2,590,000,000 of that being debt. It was sponsored by Coastal, IPL, Williams, Fort Chicago Energy, and Westcoast Energy. Goldman Sachs, Scotia, Paribas served as the projects financial advisors.]

*Also excludes primarily upstream projects with an integrated pipeline component. Based on Dealogic database

Mr. Rich informed the Committee that the largest United States pipeline project cost slightly less than one billion dollars. The smallest of the top 20 largest pipeline project financing projects was in the vicinity of $10 to $20 billion.

Mr. Rich stressed that one of the toughest judgment calls associated with this project is whether the largest domestic FERC-regulated project to date could be scaled up to this project's size "and expect it to achieve the same result". The

effort must be to determine what components of the large projects would apply or not apply to AGIA. This would include consideration of upstream conditions, multiple producers, access to a variety of fields, the nature of the off-stream off-take. Particular attention and worry would revolve around the scale of the project.

Mr. Rich concluded his remarks.

9:43:46 AM

Co-Chair Stedman asked for further information about how "lenders deal with the debt to equity split", including whether a specific split ratio was favored. He also questioned the leverage a lender might have in "requiring a change in the debt to equity".

9:44:17 AM

Mr. Rich stressed that from a financing perspective, both "the percentage and the actual quantum of the equity in the project is one of the key foundations of the credit". What lenders like "to see is that somebody else has a lot of skin in the game." This is because the equity placed in a project is the element that would suffer the losses first. Thus, "lenders take a tremendous amount of comfort from the size and percentage of the equity interest".

Mr. Rich declared that "lenders do not desire to be over-exposed" and, therefore, as funding is spent, "the matching equity" contribution component" is constantly re-certified in order for the project to receive additional money.

9:46:00 AM

Mr. Rich advised that additional "financial drivers" included "the concept of a project's debt capacity". He detailed the added complexities of the debt capacity when FERC regulations are involved, including the role shippers play in the equation.

Mr. Rich also noted "that de-leveraging gives lenders a great deal of comfort". In contrast, a developer's financial objective is for "maximum leveraging". In today's financial arena, "the whole world of private equity is one where returns are increased

through the maximum use of leveraging. When debt is inexpensive, as it is today, you get those higher returns".

Mr. Rich noted, however, that from a lender's perspective, this serves to increase risk. Lenders would prefer "lower leverage, higher amounts of equity". This interplays with other issues. "None of them independently make it bankable or not bankable, but it's the cumulative affect of all of these that raise the cost, and make it ultimately less or more likely that the financing will get done".

9:49:50 AM

Mr. Rich communicated therefore that "one of the strategies used, if the developer has the financial capacity to do it", is to de-leverage the project. If the terms of the FTs cannot be improved in a way acceptable to the lender, then a lender could be enticed to participate by de-leveraging the project or changing another "risk factor that the lenders are unhappy about". De-leveraging is a commonly used strategy.

9:50:05 AM

Senator Elton struggled with his desire to seek specifics while understanding that Mr. Rich, whose role was not that of a consultant, desired to speak in terms of "generalities". Nonetheless, he directed attention to an AGIA provision which specifies a "must have" debt-equity ratio of a minimum 70 to 30 (70:30) percent. He understood that an 80:20 ratio would be acceptable, but a 65:35 would not, as that would result in a lower tariff. He concluded therefore that "if a hard line" was set, it could limit the pool of lenders.

9:51:12 AM

Mr. Rich stated that while he could not address the specifics of that provision in AGIA, he would stress "that flexibility is key". He reiterated a statement he had made during his full presentation as to "how important" it was "that the DOE not be prescriptive in the loan guarantee provisions". This is extremely important in "a project of this size and complexity". "… At the end of the day, de-leveraging the project somewhat could be what was required to get it to go ahead".

9:52:24 AM

Mr. Rich communicated that at the onset of a project this size, it would be impossible to have "utter confidence going into it …of what would be required". "It's only once the commercial arrangements have been set and contracts have been negotiated and the project has been designed, you know, the cost estimates been refined, that you can really get a sense of what the finance plan is going to look like. And what degree of equity is required and what leverage is permitted is one of those things you discover through that process".

9:53:01 AM

Senator Huggins spoke to an [unspecified] Library of Congress document that addressed the two year time period after the issuance of the FERC certificate. The concern was to what considerations might be made by the DOE Secretary in regards to a project when the time required to meet the conditions mandated by DOE exceeded the allotted time period.

9:54:28 AM

Mr. Rich admitted being worried about the two-year provision. He could foresee a multitude "of circumstances where, despite the best efforts in the world, we would not be in a position to close the financing and have the loan guarantee agreement issued within that two year window". The historical experience for financing mega projects has been approximately five years. Time must be permitted to address such things as litigation or permitting issues.

Mr. Rich was unsure how the DOE Secretary would address this. Usually this person forms a team of lawyers and advisors, develops financial models, conducts studies, and analyses the credits and the contract, and develops documentation.

9:57:00 AM

Mr. Rich advised of another worry. That being that "the promoters of the project will not only want a financing, but they'll want to optimize the financing because the cost of the financing is the major determinate of the economic viability of the whole project". Another consideration is whether the health of the overall financial marketplace is favorable.

9:57:42 AM

Senator Huggins declared that the operational concept of this project might be one that "could see the lapsing of the loan guarantee and we're continuing to move toward something that is scary."

9:58:12 AM

Co-Chair Stedman asked for further information about "the potential of the non-recoursability of the loan guarantee"; specifically whether "that loan guarantee could be issued using government bonds". This would allow the bond market "to generate the capital to build the line and then" having the entity desiring to build the line "have a non-recoursability against the note so we can't in any way have the corporate balance sheet exposed to back the loan guarantee". In other words, the question is whether a firm could "use the loan guarantee on a non-recourse basis so they don't have their balance sheet exposed".

Mr. Rich replied "yes, post completion ….The loan guarantee is available for a limited recourse project financing structure, so that after the completion tests have been met, the federal government in its role as lender … and its quite right as you say, there's bond holders out there…they don't care, if the guarantee covers 100 percent of their bonds, they hold a U.S. government piece of paper. So, they're indifferent as to whether the project is able to pay its debt, because, if there's any problem, the government pays them. And then the question is, 'what is the nature of the government's recourse?' And, post-completion, the government's recourse is limited recourse, i.e. it is to the project pipeline company and not to the balance sheet of its shareholders. So, the government is no different than if the guarantee was not into place. It's the same thing. Pre-completion, it's looking to recourse to the parent company balance sheets, if there's a guarantee, or to the parent company balance sheets for over-run funding if it's an overrun equity commitment. Post-completion, they're taking the risk that the pipeline company will have the revenue sufficient to pay."

Mr. Rich concluded by stating "pre-completion, full recourse; post-completion, limited recourse".

10:00:52 AM

Co-Chair Stedman surmised therefore that in the pre-completion phase, "it would be reasonable to expect the lender then to want a balance sheet or a consortium of 'em strong enough to handle the impact" of a project if things go amiss.

Mr. Rich agreed. "It's easiest to analyze if it's a classic completion guarantee", as referenced in federal stature, where it specifies "equity contribution commitments and completion guarantees. And if it is a completion guarantee, the party giving the guarantee has to be creditworthy." He noted having read a recent [unspecified] Notice of Intent document in this regard written by the DOE Secretary, "which is quite typical" to what "you see from the other federal guarantee programs: 'There has to be a reasonable reassurance of repayment of the debt. The terms and conditions provide adequate terms and security appropriate to protect the financial interests of the United States'."

Mr. Rich stated that the Secretary would "look at this just the way a bank would". He shared two points: first, "the credit behind the completion guarantee does have to be adequate. There is a binary element to this. It's highly improbable that a project of this size could be done without investment grade credit behind that completion support. There's also a pricing element" in that the interest levied pre-completion would reflect that credit.

Mr. Rich exampled therefore that the interest costs would be lower for a company with a AAA credit rating giving the guarantee. The costs would be higher for a company with a BBB or a BBB- credit rating, which both qualify as investment grade ratings.

Mr. Rich stated that there is an "availability, a do-ability, and a pricing aspect to that, absolutely".

10:02:50 AM

Co-Chair Stedman "assumed that the number of corporate entities" with either a AA or AAA credit rating that are able to back billion dollar projects would decline sharply "as the size of a project goes up in ten billion increments".

Mr. Rich emphasized that the size of a project is a major consideration. "You can't assume that the precedence can be scaled up".

Mr. Rich expressed that lenders might not view a company with an "A" credit rating and four billion dollars of capital on its balance sheet simply in terms of its "A" rating, particularly when "the amount of the guarantee is huge in relation to the debt".

Mr. Rich expanded his example. Were this company participating with two other entities on an $18 billion project with an $18 billion federal guarantee, the company, with only four billion dollars in capital, "would be adding a six billion dollar contingent obligation. That's not a single A credit". Lenders tend to view company's credits on a proforma basis in that they would, in addition to considering a company's position today, consider how it might look after it is "loaded with this large contingent obligation on its balance sheet".

Mr. Rich noted that if this was a completion guarantee, "it's a straight debt guarantee". In other words, the moment the completion test is not met or any amount is due pre-completion, the company "would be obligated to pay it as if it were their own debt".

Mr. Rich communicated that a small company wishing to participate in a large project might be required "to issue additional capital … and grow in size in order to have the financial capacity to cover the completion risk".

Mr. Rich stated that "if it’s a good project", the post completion guarantee approach is fine if a company had good viable credit. The problem is dealing with the completion. "It's classic in the resource sector", that, while developers and small mining companies might have all the required rights to a "sound, good, profitable" resource discovery, "they don't have the financial capacity to meet the completion support" criteria. This typically requires those small companies to join with a larger company to gain that completion support, or sell, or merge".

Mr. Rich characterized the project financing scenario as the "gating issue: you don't get past the starting line unless you can handle, somehow, the completion risk".

10:06:44 AM

Senator Dyson, referencing the cross border information depicted on page 56, asked how the loan guarantees would work if a Canadian firm was involved in the Canadian portion of the project. He also asked that the term "tranched" be defined.

10:07:19 AM

Mr. Rich explained that "'tranched' means a slice or piece of the loan". A loan could be divided up into different segments.

Mr. Rich stated that having different ownership interests on each side of the border in a cross-border pipeline is a common occurrence. This is acceptable "from a financing perspective, provided that …. the credit behind the completion support is strong enough on both sides of the border…" Lenders must be assured that some entity would ultimately take the completion risk. Sometimes one entity would assume the completion risks for the entire project regardless of which side faltered.

Mr. Rich expressed that separate loans or tranches might be assigned to the cross-border entities in order to recognize the different companies' credit ratings or other circumstances including whether the loan involved Canadian or United States funds.

10:09:46 AM

Senator Dyson clarified his question. He was interested in how the federal loan guarantee would apply to a cross border project.

Mr. Rich conveyed that the federal loan guarantee statute would allow this. "The Secretary may also enter into agreements with one or more owners of the Canadian portion of a qualified infrastructure project to issue federal guarantee instruments with respect to loans and other debt obligations for a qualified infrastructure project" utilized to "transport natural gas from the Alaska North Slope to the continental United States".

10:10:49 AM

Senator Thomas deduced that the Trans Alaska Pipeline System (TAPS) had not been included in the listing of the ten most expensive pipeline projects because it had been privately financed.

Mr. Rich affirmed.

Senator Thomas asked whether any other privately funded projects the size of TAPS have been undertaken.

Mr. Rich assured Senator Thomas that many such projects have been undertaken by "large integrated international oil companies". They are financed in a multitude of ways including borrowed funds or internal financing.

Senator Thomas asked whether having existing infrastructure in an area such as in Prudhoe Bay, even though it was oil related, was beneficial.

Mr. Rich stated that "anything that reduces cost is helpful". Not being required to build "expensive new infrastructure will either be beneficial to the midstream or the upstream netback, which the midstream lenders care about". Any activity occurring in the "upstream that provides lenders confidence that the reserves and the dynamics of the reserves are well understood and that the risk of bringing the gas into successful production is low is helpful, no question".

Senator Thomas asked whether lenders would view a project in Canada or the United States more favorably than a project in an area with a less stable political environment.

10:13:16 AM

Mr. Rich responded in the affirmative. He stressed however, that the fiscal aspects of a project "are universal: anything that hits that netback is something in which lenders are interested" regardless of its location. Aside from the fiscal risks of a project, political risks are a consideration. This project would generate a lot of interest due to its North American location.

Co-Chair Stedman thanked Mr. Rich for his remarks.

AT EASE 10:13:59 AM / 10:22:06 AM

Co-Chair Stedman stated that the Committee would now hear a presentation from the Department of Natural Resources. Of particular interest was how oil and gas activities in the federal offshore regions might impact the capacity of the proposed gasline, as the revenue the State receives from those areas is significantly lower than the revenue generated from resources on State land and offshore areas.

10:23:21 AM

Alaska Department of Natural Resources
Briefing for
Senate Finance
Current Gas Reserves & Resource Estimates
ANS & Offshore
Robert Swenson
State Geologist & Acting Director
Division of Geological & Geophysical Surveys
http://www.dggs.dnr.state.ak.us
http://akgeology.info
April 26, 2007

ROBERT SWENSON, State Geologist & Acting Director, Division of Geological & Geophysical Surveys, Department of Natural Resources stated that his Division and the Department's Division of Oil and Gas have collaboratively worked on developing the information included in this briefing [copy on file].

Mr. Swenson, whose professional background included 15 years as a field and exploration geologist in the State, informed the Committee that a significant amount of work was required to develop the reserve estimates included in this presentation.

10:24:44 AM

Page 2

Overview

- The State of Alaska does not perform quantitative, probabilistic resource assessments, but works closely with the agencies that do
- All numbers presented here are from US Geological Survey & MMS
- resource assessments published between 1999 and 2005.

- All estimates provided are based on rigorous analysis of all available data, geology, existing accumulations, and basin analogies
- All non-reserve estimates are presented as technically recoverable resources (as contrasted with economically recoverable or gross resources or gross in-place estimates).
- Resource estimates used represent the mean of a probabilistic Resource estimates used represent the mean of a probabilistic
- distribution with associated P5 & P95

Mr. Swenson read the information and noted that the Department works closely with the US Geological Survey (USGS) and the Department of the Interior Minerals Management Service (MMS). Further information on the "P5 & P95" elements would be forthcoming.

10:25:51 AM

Page 3

Oil & Gas Resources Team

[Graphic of a Viking sailing ship with "Resource Assessors" steering the ship and "Highly Trained Fearless Explorers and…." manning it.]

Mr. Swenson likened the agencies composing the Oil & Gas Resources Team to "highly trained fearless explorers that are out there looking for the next big find".

10:26:06 AM

Page 4

Overview of Regional Geology

[Geological diagram of the Brooks Range, the Foothills, the Coastal Plain, and the Beaufort Sea regions of the Central North Slope.]

Mr. Swenson stated that the unique regional geology of the North Slope is a crucial element in the assessment numbers. This region is considered the definitive "world class hydrocarbon

province". Three primary areas of importance in this analysis of the North Slope are the Barrow Arch, the Colville Basin, and the Brooks Range. The Colville Basin is a collection point for sediment eroded off the Brooks Range.

10:27:30 AM

Page 5

North Alaska Stratigraphy & Petroleum Plays
- As used in USGS NPRA Assessment
- Play definitions will vary slightly among assessment provinces

[Cross-sectional diagram depicting the strata formations and Petroleum Plays during the Cenozoic, Cretaceous, Jurassic, Triassic, Permian, Pennsylvanian, Mississippian, and Devonian and Older ages based on a 2002 USGS assessment.]

Mr. Swenson explained that one component of the assessment includes comparing the various geological events in Alaska, such as continental "rift" areas, to other regions in the world. Rift analogies have been drawn to places such as the North Sea, the Suez Rift area, and other rift basins with significant hydrocarbon bases.

Mr. Swenson disclosed that the "thrust belt" in the foothills regions of the Brooks Range is another geologic occurrence with analogies around the globe, including "the Canadian Rocky Mountain front, where there has been a significant amount of exploration" and a significant amount of gas found.

Mr. Swenson stated that the North Slope "is unique" in that it contains these "two major types of oil provinces".

10:28:38 AM

Page 6

[Diagram depicting the variety of information gathered to develop the "probalistic resource potential of an area."

Mr. Swenson stated that this information is reflective of the intensity of the work conducted to complete a resource analysis

for, in this case, the National Petroleum Reserves - Alaska (NPR-A). The stratigraphic diagram on the right depicts rock formations deposited over time. To the right of that is depicted the "petroleum plays", which are based on seismic data, well logs, and the experience of discoveries across the basin. All of these factors are considered when developing the "probalistic resource potential for an area".

10:29:16 AM

Page 7

NPRA Assessment Area

[USGS Seismic Grid of the National Petroleum Reserve - Alaska, depicting exploration wells and known accumulations of oil, gas, and Announced Oil discoveries.]

Mr. Swenson noted that this diagram depicts known accumulations of oil, gas, and announced oil discoveries based on seismic data in NPR-A. The geological activities depicted on page 6 were conducted in order to project the area's "play types".

Mr. Swenson pointed out that the density of exploration wells in NPR-A is depicted by white dots on the diagram. It would be "fair to say that this is a very under-explored region". "This area would be completely covered up with white dots" were it a mature area that had experienced a significant amount of exploration. Information from exploration wells with discoveries is utilized in the resource assessment.

10:30:35 AM

Page 8

North Slope Oil & Gas Activities & Discoveries March 2005

{Map depicting oil and gas activities and discoveries. Oil accumulations, gas accumulations, recent discoveries, and exploration wells drilled in 2003, 2004, and 2005 are identified.]

Mr. Swenson stated that discoveries, specifically in the Barrow Arch region, are depicted on this page. A number of discoveries have been made in both the foothills region and the State's

offshore regions even though those areas have experienced a limited amount of exploration.

10:31:10 AM

Page 9

Proven Gas Reserves
Does not include Probable
(reserves growth through continued development)

North Slope	
Badami Unit	0 BCF
Barrow	34 BCF
Colville River Unit	400 BCF
Duck Island Unit	843 BCF
Kuparuk River Unit	1,150 BCF
Milne Point Unit	14 BCF
North Star	450 BCF
Prudhoe Bay Unit	24,526 BCF
Other Undeveloped	8,000 BCF
TOTAL NORTH SLOPE	35,417 BCF
Cook Inlet	1,650 BCF
TOTAL STATE	37,067 BCF

Source: 2006 Annual Report, Alaska DNR-Div. of Oil and Gas

Mr. Swenson explained that the collection of geological information assisted the Department in its analysis of the State's proven gas reserves, including reserves that are already discovered and delineated, proven and probable.

Mr. Swenson communicated that approximately 35 trillion cubic feet (TCF) of proven gas reserves are available on the North Slope. Geologists refer to these reserves as "behind pipe".

10:32:02 AM

Page 10

[Map of the State depicting Statewide Alaska Natural Gas Resource basins based on USGS estimates of State onshore and offshore natural gas resources, as well as MMS estimates of federal Outer Continental Shelf (OCS) natural gas resources]

Mr. Swenson stated that the important point regarding the USGS resource assessment of gas in the State, conducted in the year 2001, is that "these are technically recoverable reserves and undiscovered volumes". A range and mean of the reserves at each location is provided. These ranges are "estimates are volumes of gas at 95% and 5% probabilities". A 95 percent probability case would indicate there being "95 percent confidence that what will be found in the future in these resource assessments, it falls within that range". A five percent range indicates there being a 95 percent probability it would not. The mean is "the maximum occurrence within that distribution". The mean must be determined "in order to be statistically correct".

10:33:36 AM

In response to a question from Senator Elton, Mr. Swenson provided further information about the probability ranges. The "0.0%" lower range assigned to many locations in Western Alaska does not mean there are zero reserves there. It is instead indicative of the fact "there is so little data available to do the analysis" in those areas. A "0.0% range would indicate that, at that particular level of exploration, there is a 95 percent chance "that you will have found at least zero".

Mr. Swenson noted that the distribution range in areas where there is "a significant amount of data" would be "much much narrower". He compared ranges in highly explored areas of NPR-A to the ranges in western Alaska. "A broad distribution with a very very low end number on the 95 percent case, and a much higher end on the higher case" typically indicates there is very little data available.

10:35:56 AM

Page 11

Technically Recoverable ANS Reserve Estimates
Does not include economic thresholds

North Alaska Assessments of Undiscovered, Technically Recoverable Gas

USGS Assessment Segment	Year	F95	Mean	F05
State Lands oil-				

associated gas, BCF	2005	2,681	4,198	6,092
State Lands non-associated gas, BCF	2005	23,939	33,318	44,873
NPRA non-associated gas, BCF	2002	40,372	61,351	85,317
ANWR non-associated gas, BCF	1999	0	949	3,660
MMS Assessment Segment				
Chukchi Shelf gas, BCF	2006	10,320	76,770	209,530
Beaufort Shelf gas, BCF	2006	650	27,650	72,180
Hope Basin, gas, BCF	2006	0	3,770	14,980
Total Arctic OCS	2006	16,410	108,190	183,530
Total Onshore & OCS	2006		208,006	

Mr. Swenson communicated that as more seismic and geological data becomes available, it is periodically incorporated into the USGS and MMS analyses, as portrayed on page 11. Rather than dramatically changing numbers, it simply "fine tunes" some of the potential resources in the basins.

10:36:39 AM

Page 12

Arctic Alaska Province Resource Estimates Summary

[Map depicting undiscovered oil and gas assessments for the Chukchi Shelf, Beaufort Shelf, Central North Slope, Hope Basin, NPRA, and ANWR 1002 Area]

Source: Houseknecht and Bird, 2006, USGS PP 1732-A, fig. 4

Mr. Swenson informed the Committee that this is the most recent assessment of reserve estimates in the areas depicted, including federal offshore reserves. This information is depicted in graph form on page 13.

10:37:45 AM

Co-Chair Stedman asked for further information about the term "proven reserves".

10:37:55 AM

Mr. Swenson explained that "proven reserves" indicates that exploration has occurred and a zone of hydrocarbons has been found. The hydrocarbons in the zone are further tested and delineated as either "P1" or "P2" proven reserves.

Mr. Swenson noted that another type of reserve is a "Probable" reserve. This references an area within a unit which "has not specifically been penetrated but" to which both the seismic data and the surrounding well data would suggest that reserves are there.

Mr. Swenson noted that the entirety of information depicted on pages 12 and 13 are "potential reserves". Geologic information such as seismic and well data, surface information, and individual discoveries in an area was applied to similar but relatively unexplored geological areas within that area to develop a probalistic analysis of probable field sizes there.

10:41:20 AM

Mr. Swenson explained that "technically recoverable" areas are those to which there is land access, regardless of the economics. An economic "filter" would be applied to a field to determine whether it was an "economically recoverable" field.

Mr. Swenson declared it would be unlikely that a field 300 miles from the nearest infrastructure with surface access obstacles would be included in an economic resource analysis unless either the access issue or the economics significantly changed.

10:41:49 AM

Co-Chair Stedman asked that "bookable reserves" be addressed.

Mr. Swenson deferred to Kevin Banks.

10:42:15 AM

KEVIN BANKS, Acting Director, Division of Oil and Gas, Department of Natural Resources explained that "bookable reserves" are those in a field that has both access to market and favorable economics. The process undertaken by the Division when conducting reserve estimates for oil fields in Prudhoe Bay, would consider the current development status of the field

including known and predictable activities that might occur in the area within the next few years.

10:43:41 AM

Mr. Banks stated that when considering "bookable gas reserves under AGIA, the Division considers the level of the commitment made by a producing company and the probability that the pipeline would be successfully completed. That would assist in calculating proved gas reserves. Once there is a commitment for the construction of the gas pipeline, "the owners at Prudhoe Bay would be able to "book" the gas reserves there.

Mr. Banks noted that the term "other undeveloped" gas reserves would apply to the Pt. Thomson field. Gas there is not considered "bookable, proved reserves" even though the field has been sufficiently delineated, there is "a fairly good notion of how big the bucket is", and "the likely recovery capability" is known. The economic challenges to developing Pt. Thomson are a consideration.

10:46:00 AM

Co-Chair Stedman asked for an estimate of the bookable reserve numbers for Pt. Thomson and Prudhoe Bay.

Mr. Banks referred the Committee to the reserve information on page 9 of the Department's presentation. Of the total 35.4 TCF North Slope proven gas reserves, Prudhoe Bay holds approximately 24.5 TCF. The 8 TCF quantity depicted for "other undeveloped" reserves on that page primarily refers to the Pt. Thomson field.

10:46:50 AM

Co-Chair Stedman estimated therefore that were the gas pipeline to advance, the State could expect an immediate production of approximately 35.4 TCF less the 8 TCF in the Pt. Thomson Field. The 8 TCF in Pt. Thomson would be available within the next few years as development progressed.

10:47:04 AM

Mr. Banks affirmed. The timing for the 8 TCF would depend on how the development plans for Pt. Thomson progressed.

10:47:17 AM

Senator Thomas asked whether a history of the gas reserve estimates was available as he was curious whether the reserves increased annually or over time. The current 35.4 TCF North Slope estimate appears to be a stagnant number.

10:48:01 AM

Mr. Banks, agreeing that "the number has been relatively static", reminded the Committee that the estimate does consider the fact that gas is used as fuel in Prudhoe Bay. This has had the affect of lowering the estimate slightly over time.

10:48:41 AM

Mr. Swenson advised that gas estimates in Prudhoe Bay are based on oil producers' field data.

10:48:58 AM

Mr. Banks affirmed. Seismic data provided by oil producers and explorers in Prudhoe Bay and other fields does provide a great deal of information to the Department.

10:49:38 AM

Senator Huggins asked for examples of the economic return the State might garner from gas reserves in the Chukchi and Beaufort Seas.

10:50:06 AM

Mr. Banks advised of being unfamiliar with "the economically recoverable" reserve potential for either the Chukchi or Beaufort Sea areas.

Mr. Banks commented, however, on the fact that the State does receive 27 percent of the royalty the federal government receives from oil and gas development between three and six miles off the State's coastline. The State has no taxing authority outside of the State's three-mile from shore boundary.

10:51:05 AM

Senator Huggins asked for confirmation that the federal Outer Continental Shelf (OCS) jurisdiction applied to reserves up to six miles offshore.

10:51:35 AM

Page 13

Table 4. Estimated mean volumes of undiscovered, technically recoverable petroleum in conventional accumulations for areas in the Arctic Alaska Petroleum Province.

[Table depicting oil and natural-gas liquids in billion bbl and natural gas in trillion cubic feet, in onshore and State offshore areas; federal offshore areas; and the Arctic Alaska Petroleum Province onshore and offshore areas.

Total undiscovered, but technically recoverable liquids amount to 50.75 billion bbl. Total undiscovered but technically recoverable gas is 227.34 trillion cubic feet. There is a total of 35.42 trillion cubic feet of known gas fields for a total of 262.74 TCF.]

Mr. Swenson stated that this information, which is based on the 2006 assessment, should address Senator Huggins' question. The State's rights extend to three miles offshore; the federal jurisdiction is between three and six miles offshore. 32 percent of the total 227 TCF of undiscovered but technically recoverable gas reserves in the State is in NPR-A. The Central North Slope accounts for 16.5 percent, ANWR accounts for four percent, the Chukchi Shelf accounts for 33.5 percent, the Beaufort Shelf accounts for 12 percent, and the Hope Basin accounts for approximately two percent.

Mr. Swenson noted that, when known gas reserves are added in, there is a total of 262 TCF of available gas.

10:52:39 AM

Page 14

Undiscovered Mean Field Size Distributions - USGS

[Diagram depicting undiscovered oil and gas accumulations and an assessment of recoverable quantities on State Lands; in NPRA, and in ANWR 1002.]

Mr. Swenson informed the Committee that one of the activities conducted in the gas analyses is the development of a distribution of field sizes. "Any geologic basin when it's fully explored will have a distribution of field sizes." As depicted on this graph, there would typically be many small fields and only a few, if any, large fields. Charting field sizes helps to ensure there being a "realistic analysis". An analysis would be suspect if, for example, the majority of field sizes were large.

Mr. Swenson noted that while 35 percent of the State's resource potential might be located in offshore areas, those reserves are technically recoverable not economically recoverable numbers. They do not reflect the field's accessibility or economics.

Mr. Swenson specified that the first area of any field being explored and developed would be that with the highest economic viability. They would be close to infrastructure and have easy access and permitting issues.

Mr. Swenson also noted that the size of a field would also be a consideration in the economic viability analysis. A large field would drive exploration.

10:55:27 AM

Mr. Swenson exampled a large oil basin off the coast of Greenland. While it has been viewed as "very very attractive", ice and other environmental issues would likely delay the recovery of that oil for many years.

10:55:58 AM

Page 15

Arctic Alaska Province Leased Acreage

[Map depicting existing leases and high bid tracts from April 18, 2007 Beaufort Sea OCS in NPRA, ANWR 1002 area, and the Beaufort and Chukchi Seas.]

Mr. Swenson reiterated that even though an amazing amount of data is utilized in the resource assessment effort, some people still might not consider the outcome of the "rigorous mathematical analysis" believable. Thus, he avowed that one of "the best indicators" of an area's resource potential is to study "what type of lease activity there has been" there. The level of activity in areas depicted on this map would indicate strong resource potential. The companies who lease tracts "are very very good at what they do and they have to spend a lot of money well out in front of any possible viable market".

10:57:25 AM

Page 16

Unconventional Gas Potential

Page 17

Known Gas Hydrate Accumulations

[Modeling of known gas hydrate accumulations and hydrate-associated free gas accumulations in the "Tarn trend" and "Eileen trend" regions in the vicinity of the major North Slope oil fields.]

Mr. Swenson stated that while the primary focus on the North Slope to date has been to conventional gas reserves, this information focuses on the potential of gas hydrates, which are considered "unconventional gas" reserves. While research is being conducted on hydrates, it has not been "proven that we can produce hydrates economically into a well bore yet".

Mr. Swenson informed the Committee that he had recently attended an international conference on gas hydrate reserves. The economics of this resource is a "huge issue" and efforts to identify the location and type of hydrates are being conducted. However, these reserves are not considered technically recoverable as the technology needed to bring them to the well bore has not yet been developed.

Mr. Swenson noted that the "Tarn trend" has 60 TCF of gas hydrates and the "Eileen trend" has 44 TCF of gas hydrates.

10:59:01 AM

Page 18

Eileen and Tarn Trend Gas Hydrate Accumulations

[A cross-section of the gas hydrate accumulations in these trends]

Mr. Swenson reviewed the location of the gas hydrate accumulations in relationship to such things as the permafrost level. Hydrates are essentially a "methane molecule that is encased in a ice cage". Further research must be conducted to determine "how to disassociate that methane from that ice cage".

10:59:58 AM

Page 19

ANS Potential Hydrates Resource

All Values Trillions of Cubic Feet (TCF)

- 32,965 Tcf - Gas Hydrates in Place Resource
- 104 Tcf - Gas Hydrates in Place Prudhoe - Tarn area
- Technically Recoverable Numbers cannot be determined at this time

Mr. Swenson deemed the potential of gas hydrates to be significant. For instance, there is approximately 104 TCF of natural gas hydrates in Prudhoe Bay and Tarn trend area. He reviewed some of the technological theories being considered to extract this resource.

11:01:05 AM

Page 20

Energy Sources in Remote Alaska

[Map depicting the location of villages and population centers and the locations of coal basins and coal units in the State.]

Page 21

[Map of State depicting the locations of 1) Exploration/Prospective Phase resource basins; 2) Pre-Development Phase resource basins; 3) Producing Mine; 4) Major port; 5) Alaska Railroad; 6) Highways; and 7) Coal fired power plants and coal technology projects.

Mr. Swenson stated that little discussion has focused on the "tremendous amount" of coal reserves on the North Slope, even though it has not been analyzed well. There are multiple demands for this resource in the United States and internationally.

Mr. Swenson concluded his presentation.

11:02:21 AM

Senator Olson asked how much of the proven gas reserves depicted on page 9 were beyond the six mile offshore limit and therefore exempt from paying royalty to the State.

Mr. Banks responded that all of the undeveloped gas reserves depicted on page 9 are located on State land or within the State's three mile offshore area.

11:03:48 AM

Senator Thomas asked that the royalty revenues to the State at the various offshore distances be revisited.

11:03:59 AM

Mr. Banks explained that zero to three miles of offshore reserves fall under State jurisdiction and would therefore be subject to the Petroleum Profits Tax (PPT) and State royalties. While resources in the three to six mile offshore area are under federal jurisdiction, the federal government would share 27 percent of its royalty revenue with the State. The State would receive nothing from development occurring beyond six miles offshore. 100 percent of those royalties would go to the federal government.

11:04:37 AM

Senator Elton understood that the federal government could negotiate their royalty share with the leaseholder.

Mr. Banks acknowledged that in recent sales, the federal government has offered leases within their jurisdiction with "royalty suspension volumes" in that, depending on the size and location of the lease, up to 45 million barrels of oil would be exempted from the federal royalty tax. This federal incentive effectively precludes the State from potential royalties.

Mr. Banks noted however, that bidders on royalty suspension leases do take the suspension into account in the bid. The State might benefit from "the bonus" generated from that situation.

11:06:00 AM

Mr. Swenson stated that in the Gulf of Mexico and other areas of the country where there is offshore production, "royalty sharing agreements have been developed with the federal government" in consideration of the offshore developments impact on on-shore areas.

11:06:24 AM

Senator Huggins suggested there would be "merit" to the State conducting an analysis of when and how much of the gas in federal areas might come on line, and how that might affect the State.

Co-Chair Stedman agreed that such analysis had merit. Measures should be taken to ensure that the States does not "build a gas line for the federal government".

11:07:20 AM

Co-Chair Stedman asked the Department to alert the Committee to any area of concern pertaining to any federal offshore activity's impact on the State.

11:07:38 AM

Mr. Banks pointed out that there was a significant amount of gas between Deadhorse and the Chukchi Sea. The likelihood of developing gas in the mid-area of this region was higher than that of the Chukchi Sea area due to immense costs associated with developing offshore areas.

Mr. Banks also noted that, as depicted in the presentation, most current leases were on-shore.

11:08:16 AM

Co-Chair Stedman acknowledged that development of offshore areas in places like the Chukchi Sea were years into the future. Nonetheless, there were federal leases off the coast of Prudhoe Bay, and those leases would have "fairly easy access into the" online distribution system.

Mr. Banks affirmed.

Co-Chair Stedman identified this as an area of concern.

11:08:41 AM

Co-Chair Stedman reviewed the schedule for the afternoon hearing on AGIA.

The bill was HELD in Committee.

#

ADJOURNMENT

Co-Chair Bert Stedman adjourned the meeting at 11:09:05 AM.