

HOUSE FINANCE COMMITTEE
March 28, 2014
1:39 p.m.

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CALL TO ORDER

Co-Chair Austerman called the House Finance Committee meeting to order at 1:39 p.m.

MEMBERS PRESENT

Representative Alan Austerman, Co-Chair
Representative Bill Stoltze, Co-Chair
Representative Mark Neuman, Vice-Chair
Representative Mia Costello
Representative Bryce Edgmon
Representative Les Gara
Representative David Guttenberg
Representative Lindsey Holmes
Representative Cathy Munoz
Representative Steve Thompson
Representative Tammie Wilson

MEMBERS ABSENT

None

ALSO PRESENT

Janak Mayer, Partner, enalytica; Nikos Tsafos, Partner, enalytica.

SUMMARY

^PRESENTATION BY ENALYTICA: ALASKA LNG: KEY ISSUES

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Co-Chair Austerman discussed the meeting agenda.

Co-Chair Stoltze requested that questions be held until the end of the presentation.

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JANAK MAYER, PARTNER, ENALYTICA, provided a PowerPoint presentation titled "AK LNG: Key Issues" dated March 28, 2014, (copy on file). He discussed his professional background.

NIKOS TSAFOS, PARTNER, ENALYTICA, provided information about his professional background.

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Co-Chair Austerman asked for the presenters to provide full detail prior to using acronyms.

Mr. Tsafos provided an outline for the presentation. He pointed to slide 4 titled "LNG Projects Evolve: QC LNG (Australia) Case Study." He addressed the different sections of the presentation shown at the top of the slide including project pathways, alignment, equity, midstream, risks, and cash-in/cash-out. The section on project pathways focused on the current status and what may occur going forward. He remarked that the term "alignment" was the buzzword of the season. The company had done extensive economic modeling to determine whether equity was a good deal for the state; whether taking ownership of the project made sense. He intended to address the financial and nonfinancial aspects of the midstream portion of the project including the proposed partnership with TransCanada. Additionally, they intended to address risks to the state and various ways it could mitigate risk. Lastly, they would talk about money - what the state may be expected to invest upfront and what it could expect to earn over the project's lifetime.

Mr. Tsafos relayed that Liquid Natural Gas (LNG) projects evolved quite dramatically from inception to the time they went online. The slide depicted an example of the Queensland Curtis LNG project in Australia beginning with the FEED [Front End Engineering and Design] stage. He drew attention to the fact that Alaska LNG as proposed was looking to initiate a pre-feasibility study and would move to a FEED stage in 1.5 to 2 years. The slide indicated significant change that could occur between the FEED stage and project completion. He noted the project in the example was not online yet.

Co-Chair Austerman asked for an explanation of the FEED acronym.

Mr. Tsafos replied that FEED stood for Front End Engineering and Design. He explained that the FEED stage was a project's most extensive study that was conducted to determine whether a project was viable. The final stage called the Final Investment Decision (FID) occurred once a project had been deemed viable by the companies involved. He detailed that when the Queensland Curtis LNG project had entered the FEED stage it had been conceived as a "one train" unit of volume of 3 million to 4 million tons (with the potential to expand to 12 million tons). The upstream was owned by a British company BG and by Queensland Gas Company (QGC). The liquefaction ownership was 70 percent BG and 30 percent QGC. The off-take of the gas was 100 percent BG. When the project had reached FID two years later the project size had expanded to 8.5 million tons. Upstream ownership had shifted primarily to BG with the China National Offshore Oil Corporation (CNOOC) and Tokyo Gas acquiring a small portion.

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Mr. Tsafos continued to discuss slide 4. The liquefaction had also shifted to 90 percent BG ownership and 10 percent CNOOC ownership in the first train and 97.5 percent BG ownership and 2.5 percent Tokyo Gas ownership in the second train. Additionally, the CNOOC and Tokyo Gas had been added as buyers.

Representative Gara asked about the acronym mmtpa. Mr. Tsafos replied that the report included a unit section. He relayed that 7.8 mmtpa [million metric tonne per annum] was equal to 1 billion cubic feet (bcf) per day. The project shown on slide 4 was slightly over 1 bcf per day.

Representative Gara surmised that it was about one-third or one-quarter the size of the proposed Alaska LNG project.

Mr. Tsafos replied that the Alaska LNG project was slightly over 2 bcf per day (the project shown on slide 4 was about half the size of the AK LNG project). He continued to address slide 4. In January 2014, the Queensland Curtis LNG project had remained the same size, but CNOOC had taken a larger percentage of the upstream. The liquefaction ownership had changed to 50/50 for train 1 and CNOOC had

acquired an option for a possible third train if an expansion took place. The project off-take had increased beyond the project's capacity with the idea that BG would supplement sales from its other projects. Financing had been secured from the Japan Bank for International Cooperation and \$1.8 billion had been secured from the U.S. Export and Import Bank. The slide's purpose was to demonstrate how things changed; it was useful to think about where the project was at present, but many changes would take place before the project came online. He elaborated that new partners may join the project, some partners may leave, and buyers were yet to be determined. He noted that financing had not been secured until the after the FID stage for the Queensland Curtis LNG project.

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Mr. Tsafos turned to slide 5. The slide depicted a timeline for Alaska LNG and addressed what may be expected to occur at different development stages. Subject to the passing of enabling legislation the project would begin in the pre-FEED stage, which provided a "first pass" to determine project viability. The project seemed to make sense; however, whether it would cost \$45 billion or \$65 billion was unknown. Due to the broad spectrum of potential costs it was necessary to narrow the estimate down in order to make a decision. There may be some preliminary marketing agreements; related documents included the Memorandum of Understanding (MOU), the Heads of Agreement (HOA), and a State of Alaska (SOA) plan. It was possible to move through the entire pre-FEED stage without securing any definitive gas sales plans. Preliminary work may include travel to Asia to determine whether the market was amenable to purchasing gas from Alaska. The state would need to reach out to private and sovereign financial institutions to determine whether investors were interested in the project. Defining the initial structure would cost between \$400 million to \$500 million; whereas the state's investment would be between \$50 million and \$120 million. He relayed that the range depended on the total cost and whether TransCanada partnered in the project.

Mr. Tsafos continued to discuss slide 5. The project would advance to the FEED stage if the pre-FEED results were positive. The transition went from the concept stage to the detailed blueprint stage. The finalization of marketing and financing plans began in the FEED stage including how much

the state could borrow, the rate, and implications. The FEED stage could cost between \$1.5 billion to \$2 billion with the state's cost ranging from \$200 million to \$500 million. At any point during the FEED stage new partners may sign on and ownership may be refined.

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Mr. Tsafos continued to discuss slide 5. Once it was determined that the project would move forward the FID stage began; construction took place and the majority of the cash was spent. Additional partners and financing could still be secured during the FID stage. He relayed that it would be 4 or 5 years before the state would know whether it wanted to authorize spending to move into the FID stage. He discussed the challenge was that more information was wanted for the state to make an informed decision, but gaining more information required going through the process. The process had to be taken step by step. The point of the slide was to address where the project was in the process at present and what would need to happen before it came online.

Mr. Mayer addressed slide 6. He highlighted two agreements the legislature had to consider including the HOA that it would sign with the producers and TransCanada and the MOU that it would sign only with TransCanada. He discussed that currently the state was a taxing and regulating authority; it drove value from its oil and gas assets through leases to private sector participants. Production tax and royalties were currently determined by the value of the commodity at the point of production (i.e. the North Slope wellheads). As a result the state had no direct stake in the upstream assets and under the status quo it would not have a stake in the rest of the project; it would be a recipient of value (net of all transportation costs) based on a percentage of tax and royalty at the wellhead. The HOA was a nonbinding document that laid out a vision for an alternative; instead of taking value at the wellhead the state would be a participant in the project and would receive its share of project value in-kind in the form of gas at the point of production. The state would not participate in the upstream, but it would have a share of the gas and a corresponding share of gas treatment facilities, pipeline, and liquefaction project. The HOA posited a state share somewhere between 20 and 25 percent; the figure was more likely to be 25 percent (as reflected

on slide 6). The state would have 25 percent of the gas and 25 percent of the infrastructure facilities required to eventually sell the gas as LNG to Asian buyers. The MOU contemplated what may happen with the state's share of the gas treatment plant (GTP) and the pipeline.

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Mr. Mayer addressed alignment and why the state may have an interest in the concept. He stressed the importance of long-term stability for large scale LNG projects. First, LNG projects tended to involve enormous upfront capital expenditures (\$45 billion to \$60 billion for the Alaska LNG project) with relatively low levels of operating expenditure and a long and steady cash flow year after year. From the perspective of private sector investors the purpose of investment was to make one large upfront investment, which was followed by years of steady and predictable cash flow. He detailed that the predictable cash flow was necessary because in order to finance the upfront capital the overwhelming bulk of LNG produced was sold under long-term contracts; typically 20-year take-or-pay contracts. He explained that under take-or-pay contracts a buyer signs up to take a volume of LNG and agrees to pay even if they are not able to receive it for some reason. The security of the long-term contracts enabled projects to move forward; it was important for investors to understand what economics looked like in the future after committing significant capital. He elaborated that a significant number of items would be locked over a 20-year period; therefore, it was important to understand what revenues and costs would be over time. He mentioned the possibility of disputes related to costs and what investors were entitled to; the potential for a dispute was scary from the perspective of investors, particularly when investing \$45 billion to \$65 billion.

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Mr. Mayer continued to address stability over time and why alignment may be in the state's and producers' interest (slide 7). He listed items to consider including how oil differed from gas and lessons that could be learned from the past related to North Slope oil production and the Trans-Alaska Pipeline System (TAPS) pipeline. Calculations on slide 7 had been used from the Department of Revenue (DOR), Revenue Sources Book projections related to royalty

and production tax. He pointed to the DOR FY 15 projected price of \$105.06 per barrel of oil at the top of the slide. To reach the gross value at the point of production, transportation costs of approximately \$10 per barrel were subtracted (\$3.50 for marine transportation, \$6.18 for TAPS tariff, and other); the state's royalty value was calculated from this figure. Additionally, after lease expenditures (\$45.99 in FY 15) were subtracted the state could levy production tax on the remaining amount (\$48.64 projected in FY 15). He noted that credits would be applied later.

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Mr. Mayer turned to slide 8 and addressed alignment and oil versus gas prices. Determining gas revenue would be different from oil. He explained that oil prices were published daily; whereas, there was no global market or quoted price for gas. The price of gas depended on the cargo of LNG and under the contract it had been delivered. Gas was priced differently in Asia than in Europe or the U.S. and could vary between contracts. The highest price of LNG going into Korea over the past year was almost double the price of the lowest priced LNG going into Korea during the same time. He detailed that the LNG going into Korea had been sold under long-term contracts based on indexation to oil; however, the indexation varied widely between contracts. Subsequently, some cargo may have been delivered from \$8 to \$10 per million btu (mmbtu) under some contracts or for \$15 per mmbtu or more under others. He stated that the actual gas price was variable based on location and was far from transparent; the price would likely be linked at a discount to the Japan Customs Cleared (JCC) price of crude oil. Gas was sold on the basis of thermal equivalency; however, the same price based on heat content would not be received for LNG compared to oil. Currently a typical gas contract may bring in around \$80 when oil was \$100. He spoke about a regression formula.

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Mr. Mayer addressed the tariff on slide 9. He relayed that the tariff for gas would be much higher than it was for oil (gas tariff shown on slide 10). He elaborated that there may be different scenarios determining how a pipeline tariff was set. He shared that the liquefaction project was within the jurisdiction of the Federal Energy Regulatory

Commission (FERC); only FERC could regulate a tariff, but currently the agency did not regulate tariffs on LNG export projects. He described the liquefaction component as a "black box" with scope for substantial changes in capital structure without significant state insight. He elaborated that the tariff was sensitive to debt, equity, and allowable returns.

Mr. Mayer directed attention to slide 10. The slide showed an average LNG price of \$81.00 per barrel with a tariff price of \$66.00. The slide included minimal operating and capital expenditures totaling \$6.00 per barrel. With the subtractions the production tax value would equal \$8.82 under the current tax structure.

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He moved to slide 11 related to the midstream. He communicated that fair market price was critical in establishing a solid top line and that the overwhelming bulk of the value was likely to reside in the midstream; upstream was secondary to midstream and often the wellhead value was insufficient to drive value to the state (particularly when prices were low). He discussed LNG production at different price levels using the price of a barrel of oil equivalent. Slide 12 included a bar chart showing prices ranging from \$110 down to \$70 per barrel of oil equivalent or \$18.33 per mmbtu down to \$12.08 per mmbtu. The slide depicted a scenario in which the state was a taxing regulating authority at the wellhead where it generated everything based on value at the point of production. He pointed to large deductions that were the first claims on the cash coming from selling the LNG including tariff, transportation, shipping, liquefaction, pipeline, and gas treatment; all the items could be deducted prior to the assessment of value at the gross point of production. He explained that a deduction of \$66 from a price of \$110 still meant substantial value was remaining; however, it did not take a large drop in price to reach a point where there was no value to the state remaining. He elaborated when oil was \$70 per barrel and gas was at \$12.08 per mmbtu there would be no value left for the state to take in the form of royalty or production tax. He explained that the return on capital for the significant investment in the midstream was guaranteed to companies making the investment; the wellhead price was the shock absorber that took the price risk.

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Mr. Mayer relayed intent to show what value for the state looked like across a range of possible scenarios specifically when prices were high or low. He pointed to slide 13 related to equity methodology. There were two basic cash flows that would come to the state if it were an active investor and participant in the project (as envisioned under the HOA). The state would earn revenues from selling LNG to Asia (the volume of LNG sold multiplied by price). There were also a number of expenditures that would need to be removed to reach the net cash flow to the state including initial capital expenditures, operations and maintenance expenses, debt service (principal and interest), and tariff paid to a partner (i.e. TransCanada). The state would also receive cash flows from sovereign functions including state corporate income tax and property tax from the state as a whole.

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Mr. Mayer addressed four cash flow scenarios on slide 13. The initial analysis was more about taking the state's value of a taxing regulating authority versus taking it as a project participant. The presentation would address what the economics looked like under four cash flow scenarios (slide 13):

- No debt and no TransCanada partnership
- No TransCanada partnership but the state finances 70% of its share with debt
- TransCanada is a partner and the state exercises its buyback option
- TransCanada is a partner and the state does not exercise its buyback option

Mr. Mayer relayed that the presentation would address total cash flows to the state and whether it would be useful to subtract out the 25 percent royalty that went to the Permanent Fund Dividend (PFD) and property tax that went to municipalities. He communicated that it was important to keep in mind that the project still needed to go through the pre-FEED and FEED stages. He stated that currently

there was not a project to conduct a cash flow analysis on. Any numbers presented to the legislature currently were based on educated guesses on potential costs, a range of structures, and revenues. He acknowledged that the information could be very useful for directional analysis. The goal behind running numbers presently was not to predict that the state would receive \$3 billion to \$4 billion in annual revenue into the future and what would need to be spent. The items all came with significant caveats because much was unknown. The basic idea was to predict what the items would look like given a range of assumptions if the state took value at the point of production as a taxing regulating authority or a participant, what it could look like over a range of prices, and how the variables interacted. He stated that clearly there was not currently enough information to determine whether the project should move forward; if the information was known the state would not need to spend hundreds of millions of dollars on feasibility work and analysis to nail down the numbers.

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Mr. Mayer turned to slide 14 titled "SOA Equity Leads to Higher Government Take on Average." He remarked that the committee had received a different but similar analysis from Black and Veatch. He believed the models that made different assumptions and ran different numbers were directionally similar in their conclusions related to value to the state. The left chart showed a status quo scenario where the state would remain a taxing regulating authority taking its value by receiving a royalty in value at the wellhead and levying a 35 percent production tax. The green bars represented the overall share of the total project value for the state. The other charts showed what the state's value would look like if it had a share of the gas and a corresponding equity stake in the project (20 percent in the middle chart and 25 percent in the right chart). The slide showed that the state would receive good value for a project in a status quo scenario (with the state as a taxing regulating authority) if current LNG prices of \$15 to \$18 mmbtu could hold for a long duration; value could be better than what the state may receive if it went with equity in-kind. However, when prices decreased, the state's value fell much faster if it was only a taxing regulating authority at the wellhead. He explained that when all of the value came at the point of production, after everyone

invested in infrastructure to transport the gas from the North Slope into Asian markets had been paid a fixed and guaranteed rate of return on their investment, the state was the variable source bearing the price risk. The state's value remained steadier in the middle and right charts (the state received the highest share at low prices). Under a scenario where the producers and the state each had a 25 percent share the state would receive a larger percentage of the value if the state's sovereign functions were removed; the reason was due to the difference between a private sector participant and a sovereign participant in the project. The state had sources of cash flow from sovereign functions (state corporate income and property tax) and from producers. As long as the structure was correct the state should not be liable for federal corporate income tax; whereas, producers were (as shown in blue on slide 14).

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Mr. Mayer addressed slide 15. When prices began high and decreased the value to the state in the "in value" world was very susceptible to movements in price and could quickly disappear. The slide looked at total cumulative cash flows over the life of the project. The previous slides looked at a share of value to the state that added to 100 percent at both low and high prices. He noted that the total value was much smaller than in a high price world. Data shown on slide 15 used pure, undiscounted cumulative cash flows over the lifetime of the project and indicated how value was distributed between involved participants. In a high price world there was substantial value to the state as a taxing regulating authority (shown in the left chart). He reiterated that as prices declined, value to the state decreased quickly; the state would receive more value if it were an in-kind participant with a corresponding equity share. He added that the bigger the state's share the more value it would receive; under the scenario the state's value was subject to its total capital commitment to the project and the amount producers were willing to share. He communicated that going in-kind with equity counterintuitively provided more downside protection to the state when prices were low; whereas, the in-value status quo structure provided less value to producers when LNG prices were high, but protected them better from the downside. Under the in-kind with equity structure producers were more exposed than the state.

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Mr. Mayer relayed that the information summarized analytica's high level perspective on the HOA and on the state going from a taxing regulating authority to an entity taking a share of the gas and facilities. He asked members to think about what alignment was like when there was a \$10 tariff on \$100 of value. He asked them to think about the past couple of decades of litigation related to what the real tariff was or should be and what the value to the state was or should be. He spoke to the creation of uncertainty on future project value. He then asked members to think about a tariff of \$66 on an \$80 per barrel of oil equivalent (delivered to Asian markets) and all of the incentives it created. He highlighted the concept of spending \$45 billion to \$65 billion of capital to the project based on 20-year contractual commitments. He stated that alignment was fundamental to the project and the reasoning behind the proposed structure because the tariff essentially went away and all parties had a share of the infrastructure and gas. Additionally, under the structure, all parties would make their money by selling LNG to Asia (transportation costs were subtracted); whether the value happened at the wellhead, through the pipeline, or at the liquefaction plant was no longer an issue or a source of dispute and arbitration. He believed that combined with the mitigation of price risk to the state, the structure was an attractive option to consider provided that it had a sufficient share of the project to generate value (i.e. 25 percent) and that a range of items were negotiated (e.g. disposition of the state's share of LNG).

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Mr. Mayer continued to discuss slide 16. He addressed the MOU agreement between the state and TransCanada related to the gas treatment and the pipeline. The slide showed the HOA with 25 percent state ownership in the GTP and pipeline. The MOU gave the 25 percent to TransCanada in return for TransCanada using its capital to build the GTP and pipeline facilities; TransCanada would recuperate the capital in the form of a tariff. He noted that TransCanada would not have a share in the LNG. The slide showed a second MOU option where the state would have no direct equity in the GTP and pipeline, but it would have 25 percent ownership of LNG. The MOU also contained an equity

buyback option where the state could buy back up to 40 percent of its initial 25 percent investment (up to 10 percent of the total) in the GTP and pipeline before the end of 2015. He elaborated that a TransCanada subsidiary vehicle would hold the overall 25 percent share and the state would own 10 percent of the total as a limited partner. The state would be liable for a tariff to TransCanada, but the upfront capital required would be much less.

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Mr. Mayer highlighted potential financial and non-financial benefits and drawbacks of the MOU on slide 17. The first financial benefit was that the state would not be obligated to meet a substantial portion of the capital cost upfront. He estimated that \$22 billion to \$25 billion of the \$45 billion to \$65 billion project would be for the GTP and pipeline; the state's share would be 25 percent. He relayed that the state would not be required to meet the obligation upfront if it faced capital constraints. He noted that the state would ultimately reimburse TransCanada in-full through a tariff and would enter into a firm transportation services agreement over time. The state-owed debt could be in the form of a bond, loan, or tariff, which were equivalent in some ways. He believed further analysis on the fundamental difference between the debt reimbursement options was necessary in terms of understanding the state's debt service capacity, borrowing costs, and how ratings agencies thought about the items. He questioned whether the capital cost would be fundamentally shifted from the state's books or whether the result would be less clear.

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Mr. Mayer continued to highlight MOU benefits on slide 17. Data indicated that the MOU held attractive tariff terms relative to market norms. Additionally, the MOU would allow the state to exit from potential Alaska Gasline Inducement Act (AGIA) liabilities. He spoke to financial costs occurring under the MOU. Tariff costs would be higher than the cost of capital the state would have if it were able to finance the project on its own. Also, the state would be required to reimburse TransCanada in full with 7.1 percent interest in all circumstances (even if TransCanada decided to terminate). He discussed that the agreement could be terminated by the state if the project was determined

uneconomic or if TransCanada could not get adequate financing.

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Mr. Mayer discussed the non-financial benefits of TransCanada's involvement. TransCanada would be an expansion-oriented partner, which would be important to drive future expansion development to the remainder of the North Slope and into Arctic waters. Unlike producers that made money selling the gas to market, TransCanada would make money transporting gas through the infrastructure; having a partner that cared about expansion was important. A presence at the negotiation table and a partner with expansion execution capabilities were clear benefits to the state. Additionally, the state would benefit from the continuity and momentum to move forward without setbacks. One non-financial drawback was that the state would bear most of the risk under the MOU; TransCanada would be "made good" in most circumstances. There was some financing risk to TransCanada; the company bore the risk of not receiving the same 12 percent return on equity (ROE) outlined in the MOU if it could not raise sufficient capital; however, the company had the right to terminate if financing was not available. He questioned how much the return could deteriorate before TransCanada decided to exercise its termination agreement or to renegotiate with the state. The state would also be a limited partner under the MOU and therefore it would give up significant control (the general partner would make the majority of the decisions).

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Mr. Mayer summarized slide 17. He stated that there were clearly many things to like about the proposed MOU (e.g. transitioning from AGIA and the involvement of an expansion-oriented partner); however, there were costs to assess as well. He turned to slide 18 related to the tariff benchmark. The slide included 2012 capital and debt structure information for all FERC regulated pipeline companies. The left chart debt reported to FERC ranged from zero to 34.7, 40.2, 46.7, to 68.1 percent. He detailed that 25 percent of the companies reported a level of debt between zero and 34.7 percent; the next 25 percent reported debt below 40.2 percent. He noted the median was 40.2 percent. The next quartile reported debt between 40.2 and 46.7 percent; the remaining 25 percent reported debt

between 46.7 and 68.1 percent. He applied the information to the MOU where there would be a 75/25 debt-to-equity structure for the initial phase of the pipeline.

Mr. Mayer explained that the MOU debt-to-equity structure was quite aggressive based on the other figures; the median debt-to-equity for companies reporting to FERC was 60 /40. Rate making capital structures were ideally established based on a correlation to the capital structure underpinning the pipeline; it was a set number that determines the eventual rate of return allowed to the company in setting a tariff; the rate was determined on both the debt and equity components. The higher the debt used to set the rate, the cheaper the eventual weighted average cost of capital used in the rate would be. The proposed debt to equity was attractive because the lower cost of debt combined with the greater component of debt reduced the tariff to the state. He pointed to the average cost of debt between 2.5 percent and 9.8 percent (right chart), with a median around 6 percent. The chart showed the average cost of equity between 9 percent and 18.5 percent, with a median around 12.5 percent. The project's proposed cost of debt was 5 percent and equity was 12 percent; both figures were well within market norms. The project's weighted cost of capital was 6.75 percent compared to the 6.5 percent to 14 percent range for companies reporting to FERC.

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Mr. Mayer turned to a chart on slide 19 and relayed that historically FERC ROE had been higher than returns in Canada. He addressed how FERC returns historically compared with the Canadian National Energy Board (NEB). The black line represented NEB ROE rates over time and the dots represented FERC approved litigated cases and approved settlements. The chart indicated that overall there was a lower allowed return on equity under the NEB formula. The FERC numbers tended to be around the 12 percent to 14 percent range; whereas NEB numbers had started out at that range and had dropped to 8 percent and 9 percent in the past decade. He detailed that many companies had sought higher returns from NEB through litigation. He referred to a recent TransCanada report citing two to three cases of successful settlements with NEB where rates had gone from the 8 percent level to the 12 percent level (based on the 60/40 percent debt to equity split). He communicated that

based on a 75/25 percent debt to equity with a cost of equity around 8 percent or 9 percent the weighted average cost of capital would be around 6 percent. He relayed that based on the figures the proposed structure looked like a good deal.

Mr. Mayer looked at three charts showing total value titled "TC's Share of Cash is Highest at Low Prices" (slide 20). The left chart showed a scenario of value for the state and partners without TransCanada. The middle and right charts included TransCanada with no buyback option and with a buyback option respectively. He emphasized that TransCanada would only receive 25 percent of the infrastructure return, which did not include a share of the gas; the company would take value from the state, but the amount was not enormous. He explained that ultimately value would come from moving gas through infrastructures and selling it to buyers in Asia. The value to TransCanada was highest when prices were low; it was a fixed claim on the state's cash. He elaborated that under a no-buyback scenario with the lowest prices TransCanada may receive 7 percent of the total cash; however, with high prices and a buyback provision, the total cash to TransCanada may only be 1 percent of the total.

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Mr. Mayer turned to slide 21 titled "Limited Value Foregone Under TransCanada W/ Buyback Option." He explained that cash outlays under a 25 percent equity share with TransCanada and a buyback option were comparable to a 20 percent share without TransCanada. The slide showed cumulative cash flows over the life of the project (left chart) and net present value to the state (right chart). Overall the value to the state (particularly when a discount was factored in for the time value of money and TransCanada's footing of upfront costs) looked relatively closer to the 25 percent share as opposed the 20 percent share. Under a scenario where the state could not do the project on its own, the MOU and transportation services agreement could make the project affordable for the state; however, much remained unknown at present regarding the state's ability to finance the project.

Mr. Mayer addressed key questions related to the midstream on slide 22:

- Should the state reimburse TransCanada's expenses under all scenarios; even if the project is a no-go?
- What does this imply for risk/reward split and appropriate locus of control?
- How firm is 'off ramp' if state must offer TransCanada participation if it continues with project within 5 years?
- Should non-participants in an expansion benefit from lower costs if they share no risks of higher costs?

Mr. Mayer elaborated on slide 22. He asked whether the all the risk should be on the state if TransCanada decided to not make the final investment decision. He referred to the third question and added that the cost of debt and equity would be negotiated at the time based on conditions at the time. He believed it was important to ask what it would mean if the state decided it could finance the project on its own. Under the scenario, he asked whether the state could communicate its cost of capital and ask TransCanada if it could compete on the cost of capital and debt or whether it was more complicated.

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Mr. Tsafos addressed risks associated with the project on slide 23. The largest risk was that the project would not get built. The slide included a world map comparing Alaska to other locations looking to develop LNG. Other locations included Western Canada, the Lower 48, Brazil, eastern Mediterranean, Qatar, Russia, Africa, Australia, and Southeast Asia. He referred to the high expense of the Alaska LNG project. He communicated that it was possible for the state to compete, but it was not a given. He moved to a map representing the mid/late 2000s on slide 24 to demonstrate the point. The map showed where analysts had predicted that new LNG would come from at the time. He listed various world locations where projects had been proposed that had not happened including Alaska, Venezuela, Trinidad, Norway, Russia, Algeria, Libya, Egypt, Nigeria, Equatorial Guinea, Qatar, Iran, Myanmar, Brunei, Tangguh, and Papua New Guinea. In the past it was not the cheapest gas or most attractive project that came to fruition; the

project that got built was the project that could get built. He elaborated that many locations were cheap, but politics, technology, or other things got in the way. He relayed that just because the Alaska LNG project was expensive, did not mean it could not happen.

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Mr. Tsafos turned to slide 25 related to various financing options open to LNG projects. He discussed specifics associated with balance sheet finance:

- Project sponsors provide funds
- Funds can combine debt and cash flow
- Guaranteed by project sponsor (recourse)
- Rate depends on sponsor's balance sheet
- Easier if all parties have strong balance sheets

Mr. Tsafos discussed project finance, the second form of financing (slide 25):

- Third parties lend to project directly, not to sponsors
- Sponsors put up some equity (e.g. 30 percent)
- Guaranteed by projected revenues (non-recourse)
- Rate depends on project risk
- Easier to accommodate riskier options

Mr. Tsafos explained that because money was lent to the project, what it earned was important; earnings would be driven by gas contracts. Ultimately, the project itself mattered when thinking about the rate (e.g. whether the project could happen, were contracts worthwhile, etc.). He elaborated that project finance was attractive, especially when there were riskier sponsors. For example, if a company was trying to do an LNG project in Qatar in the mid-1990s and the state of Qatar had declared bankruptcy, the company may want to think about project finance as an option. He

continued that under project finance because money was not lent to the sponsor, the debt did not show up on the sponsor's balance sheet. Whether or not the State of Alaska wanted to recognize the debt would be something to determine. He relayed that it was useful to remember that different financing options existed; the options had different implications for the state's balance sheet. He addressed various questions including the right mix of debt and equity, debt to the project or the sponsors, whether equity would come from reoccurring revenues or other money, and other. He explained that the different answers to the questions would provide very different impacts in terms of the state's ability to borrow and finances to the state.

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Mr. Tsafos continued to discuss project finance on slide 26. He noted that it may be tempting to think that project finance sounded like a great option because it would be off the balance sheet and that debt would be guaranteed through project revenues, while wondering who would lend money to such a large project. He pointed to recent examples of LNG projects and relayed that large amounts of capital existed for big LNG projects. The Ichthys project in Australia had secured \$20 billion in project finance and a Papua New Guinea project secured \$14 billion from ExxonMobil and others. He detailed that frequently the capital came from official sponsors. For example, the mission of the Japan Bank of International Cooperation was to support Japanese companies investing overseas with the goal of importing natural resources into Japan; the company was willing to provide interest rates significantly below market. He concluded that once the state began working through financial options, aspects, and rates, it may discover that the underlying burden was much different; it was not yet known and was something to study over the next few years. He summarized that it was not worth getting sticker shock up front because the picture would change over time.

Mr. Tsafos spoke to three additional aspects of risk on slide 27 titled "Project Finance well Established in LNG." He highlighted that price risk associated with oil involved price fluctuations in ANS West Coast pricing; whereas LNG would most likely sell at a price linked to oil. He elaborated that a formula specifying that if the price of oil was \$100, the price of gas would be \$14 per mmbtu. He stressed that when a contract was signed the relationship

was locked; therefore, risk was associated with the price of oil. The chart showed three long-term LNG supply contracts for Taiwan with Indonesia, Malaysia, and Qatar. He detailed that the price paid by Taiwan was linked to oil; however, that did not mean it would be the same price under different contracts. For example, at an oil price of \$120 the price of LNG was \$6 or \$7 with Qatar, but at the same price of oil the price of LNG was over \$20 with Indonesia. The most important factor was what had been negotiated in the finalized contract; knowing the numbers before investing in the project was beneficial. He pointed to an original contract with Malaysia (red) and a renegotiated contract (blue); the contract had been renegotiated after Malaysia determined it was not receiving a fair deal out of the price. Due to their long-term nature every contract allowed for price review and renegotiation, which could be defined in the contract. He discussed that the state may hear something like the Lower 48 was offering gas to Asia that was not linked to oil. He stressed that if the state had a contract that was linked to oil in a specific formula, it really did not matter what another seller did later because the state's relationship would be locked; the price could only be revisited per the contract agreement.

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Mr. Tsafos addressed slide 28 that outlined options to reduce exposure. The chart on the left titled "No S-Curve" showed a scenario where the price of LNG rose with the price of oil. There were ways of hedging against the volatility of oil price as shown in the middle and right charts. The middle chart titled "S-Curve" showed a scenario where the price of gas did not drop as fast as the price of oil; usually this option could be negotiated by foregoing some of the upside. The chart on the right titled "Floor/Ceiling" depicted a scenario where LNG would not drop below \$12, but would not increase beyond \$17 to \$19. He concluded that there were ways to contractually reduce some of the state's exposure as contracts were negotiated in order to fit a comfortable revenue profile. He relayed that several more expensive projects had utilized the floor/ceiling method. Project sponsors did not want to invest only to realize later that they were out of the money; therefore a floor/ceiling option could make sense if they were willing to give up some of the upside.

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Mr. Tsafos addressed risk associated with cost overruns on slide 29. He communicated that cost overruns were a fact of life in large-scale projects. The slide included 16 LNG projects worldwide and illustrated two types of risk that could occur once investment had been made. Delay was the first risk shown in red in the center of the slide. He detailed that projects coming online on time or early did happen, though not frequently. Cost overruns for projects shown on slide 29 ranged from zero to 120 percent, with an average of 25 percent (the presentation used a 25 percent cost overrun example later on).

Mr. Tsafos looked at cash-in/cash-out on slide 30. He emphasized the importance of the slide that worked to bring together all components the presentation had addressed thus far. The slide depicted four scenarios: 1) No TransCanada and no debt (green); 2) No TransCanada with a 70/30 debt to equity split (yellow); 3) TransCanada with a buyback option and a 70/30 debt to equity split (red); and 4) TransCanada with 100 percent GTP and pipeline ownership and a 70/30 debt to equity split (blue). The slide illustrated how cash-out and cash-in changed between scenarios in the pre-FEED stage (would be authorized with legislation); the FEED stage (detailed study); the construction period; and once the project went online (this section was shown as an annual figure). He relayed that the state would be responsible for \$55 million to \$100 million if it entered into the pre-FEED stage. He encouraged members to refrain from getting too caught up in the estimates. The cost to the state depended on whether it or TransCanada paid for the study related to the GTP and pipeline. The state could choose to abandon the project if the pre-FEED study was not promising; the state would be responsible for paying TransCanada what it had fronted plus interest. The state could also decide to sell down some of its equity at any time during the process.

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Mr. Tsafos continued to address slide 30. Depending on the state's arrangement with TransCanada, the FEED stage could cost it between \$250 million to \$500 million. The state would need to pay TransCanada anywhere from \$150 million to \$400 million if it decided to disband the agreement. He added that the state could always adjust its equity if it

decided that 25 percent was too much. The state could also decide to move forward at the FEED study to the FID stage. The state could potentially spend somewhere between \$300 million to \$600 million before it decided to move forward with the project. He reminded the committee that the figures corresponded to 25 percent of the project; the partners would spend 75 percent. He pointed to the construction phase and relayed that the state would be on the hook for \$11.8 billion to \$12 billion if it elected to move forward on the project without TransCanada and with no debt. The figure may reduce to approximately \$5 billion if the state elected to take on debt. He stressed that once the construction phase had begun it would be too late to abandon the project due to the large financial investment. Once the project came online the state may see revenues between \$2.9 billion to \$4 billion. The chart's purpose was to illustrate the impact of different choices; what the state was giving up in terms of revenues later on versus what the state gained upfront for spending less money. Choosing between the yellow and red option (no TransCanada versus with TransCanada) may allow the state to spend \$1 billion or less in construction, but annually the state may earn \$300 million less.

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Mr. Tsafos turned to slide 31 titled "LNG Income Includes Restricted Revenue." The chart on the left included the same State of Alaska cash flow information shown on the right of the previous slide. The middle chart subtracted the PFD from the numbers and the right chart subtracted the PFD and property tax for municipalities (the slide included a hypothetical assumption that 80 percent of the property taxes went to municipalities). He detailed that the state may earn \$4 billion, but the figure could be reduced to something like \$3.4 billion.

Mr. Tsafos moved to slide 32 titled "Stress Testing SOA's Cash Calls and Revenues." The slide created a "near perfect storm" of three things that could go wrong for the state. First, capital expenditures that were 25 percent higher (the average cost overrun shown on slide 29). Second, the potential for an LNG sales price of \$7 per mmbtu versus \$15 per mmbtu. He noted that the prior year there was almost no LNG in Asia that went for \$7; there were a few bilateral trades trading at \$7 in legacy agreements from 12 or 13 years earlier. He added that Henry Hub gas in the Lower 48

at \$3 would be closer to \$9 or \$10 in Asia. At a price of \$7 most of the proposed LNG projects would be uneconomical; the price was not very sustainable. Third, the average utilization was 80 percent rather than 100 percent. He elaborated that average LNG utilization worldwide was in the high 80s, which was due to some older projects that had run out of gas. For example, Kenai had been included in the calculation when the project had been active. The slide used the same charts shown on slides 30 and 31, with an additional chart titled "Stress Case Online (2023+) Annually." He explained that the base case construction figures were all 25 percent higher in the stress case scenario, which meant the state may be on the hook for up to \$15 billion. Under the stress case scenario annual revenues could be between \$480 million to \$1.6 billion instead of \$2.9 billion to \$4 billion. He stressed that even in the worst case scenario presented on slide 32, the state's revenue did not turn negative. The beauty of LNG projects was that once a project was built, it produced a steady stream of cash for a long period of time without needing significant attention.

Mr. Nikos Tsafos turned slide 33 titled "Stress Test: Restricted vs. Unrestricted Revenues." The first of three charts reflected State of Alaska total stress case revenues of \$500 million to \$1.6 billion. The second and third charts subtracted the PFD and property tax and indicated that revenues would turn negative in the most extreme cases.

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Mr. Tsafos addressed slide 34. The slide illustrated cash flows to the state and included three stress case factors of price, capital expenditures, and utilization (left to right respectively). He relayed that other committees had asked which of the three factors was the most important. He discussed that hopefully a perfect storm would not occur and only one of the factors would happen. He reiterated that the cases included no TransCanada, TransCanada with a buyback option, or TransCanada with no buyback. The charts showed that price was the most important factor by far. He relayed that capital expenditures were much less important for the overall project economics. He pointed to the table showing cost overruns (slide 29) and addressed why anyone would build the projects with all of the overruns. He relayed that even with cost overruns it was possible to

recoup an investment. He communicated that the importance of utilization fell in between price and capital expenditures.

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Co-Chair Austerman communicated that the current meeting was the first time the full committee had taken a look at the issue from the perspective presented by enalytica. He anticipated hearing from enalytica again in the future.

Representative Costello referred to the importance of price. She relayed that the legislature had been told that Exxon, ConocoPhillips, or BP would help the state market the gas; however, it was not addressed in the HOA. She opined that if the clause was not included in the agreement, the state would be competing against the companies to sell gas in Asia. She remarked that the state did not have experience marketing gas to Asia. She wondered if the issue could be included in the HOA.

Mr. Tsafos replied that it could be done. He detailed that the oil companies understood that selling the gas the largest headache for the state. He surmised that if the state did not receive a good answer to the question, the project would not move forward. He believed the state should keep some of its options open. He elaborated that the HOA specified that the state may decide to have the three partners sell gas on its behalf, but it could also locate other partners that were willing to market the state's LNG. He asked members to think about whether the headache was large enough to lock down at present or whether a better deal may come along later in the process. He pointed out that the state could ask for bids from various companies beyond the three major partners. It was possible to define it up front, but was also possible that the state could drive a harder bargain if it kept the option open. He thought the state may receive significant interest beyond the three partners. He opined that if the HOA locked in the option to the three partners, it may unnecessarily narrow the competition. He agreed that competition with the three companies was an issue, but it was not a significant as one could think. He relayed that a number of LNG projects had different players marketing gas individually. He used the Gorgon project as an example where Shell, Chevron, and ExxonMobil each marketed their share of the gas; the entities were competing with each

other and had the theoretical potential to bid down the price. He reiterated that the state may receive a better deal by opening the field to a broader range of participants.

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Representative Costello wondered what role treble damages played and if that was the reason the state was only considering TransCanada. She elaborated that Black and Veatch had deferred the question to the Department of Natural Resources; whereas Mr. Mayer had relayed that lawyers should be addressing the issue.

Mr. Mayer addressed several fundamental questions related to the MOU including whether the state needed a partner, whether it was best off going with TransCanada through the MOU, or whether a broader and more competitive process would be preferable. He relayed that much was not yet known about the state's financial capacity to carry the project on its own. Additionally, he believed there was a significant amount to consider around future expansions and whether a third party was desirable and would offset the additional capital structure costs. He addressed whether going with TransCanada was the best approach to take if the state determined it needed a partner. He added that the true answer would never be known because going down one path precluded the other. He noted that someone could look at the MOU and find many sensible terms (e.g. a competitive cost of capital) and could look at terms of allocation for risk and reward and the five-year offer to TransCanada to participate even after termination. He spoke about negotiating leverage (which probably came through AGIA) and what it would take to get out of the agreement amicably. He surmised that people could look at the issues differently and draw conclusions about how the costs and benefits stacked up. He believed a further legal analysis would be necessary to gain a grounded and educated understanding of the costs and benefits including the potential liability through AGIA (whether the cost was in the millions or billions of dollars). He did not know the liability related to AGIA because it would require rigorous legal analysis.

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Representative Costello thought it appeared that the state had an obligation to address the opportunity costs of

approving an MOU during the current legislative session. She wondered if it would be valuable for the legislature to take the time to consider different financing options. Alternatively, she asked if there was no chance to make changes until the legislature found out later on that it would pay damages and perhaps others.

Mr. Mayer replied that if he was a legislator his answer would depend on his interpretation of the off-ramp provisions. He referred to a comment he had received from a legislator that off-ramps appeared to always lead to an on-ramp. He pointed to the state's numerous rights to terminate the contract, but if it wanted to proceed with the project or a similar project, it would need to offer the right to TransCanada to participate on similar terms (with the exception of the cost of debt and equity negotiated based on conditions at the time). He would want a good understanding of the situation; if the state wanted to "go it alone" at some point in the future for a better deal it could communicate its cost of capital and its openness to offers that were competitive. He would feel more comfortable locking down the partnership at present if there was a possibility of exiting the contract in the future. He added that he would feel increased anxiety about committing to the agreement at present (before the state's financing capabilities and other items were known) if he thought there would be potential for dispute in the future.

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Representative Wilson asked what the state should do. She remarked on gaining understanding about what the state's relationship had to be with TransCanada and limits that would be put on the state. Mr. Mayer asked for clarification on the question. Representative Wilson asked what the state should do related to the entire project.

Co-Chair Austerman interjected and pointed to the noted broad nature of the question and the limited meeting time. He planned to have analytica address the committee again. Black and Veatch would also be available if the committee wished to hear from them again. He relayed that tax consultant Roger Marks would also present to the committee. He noted that the committee did not currently have a bill before it. He asked members to submit questions to his office; his office would submit them to the consultants. He

relayed that DNR and DOL would also have an opportunity to weigh in.

Representative Gara followed up on Representative Costello's question related to selling the state's LNG. He stressed that the issue was a big concern because the larger oil companies were experienced at marketing gas. He was not comforted to hear that the companies knew the issue was a big concern to the state and that they would deal with it. He stated that the companies would do what was best for them. He understood the point that the state may not want to commit because a better option may come along; however, he wondered what would be wrong with including the option for the large three to sell its gas in legislation. He relayed that the concept was not foreign; currently the companies were selling the state's oil. He asked the consultants if they could help with an amendment to legislation.

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Mr. Mayer replied that the HOA contemplated the option. He believed the question related to how much the state wanted to lock in at present versus later. Part of the issue related to how much was known about the project structure and other possibilities. He referred to joint venture projects worldwide where the joint venture collectively marketed LNG and participants each take the proceeds respectively. Under the joint venture structure the participants did not compete against one another and the project marketed the gas. There were other projects that included a joint venture where LNG sales were competitive between each company with their own off-take entitlement and obligation to sell their own share. The HOA outlined that the parties would negotiate to have the three producers market the state's gas if a satisfactory agreement could be arranged. He observed that the issue was clearly the biggest sensitivity for the state. He believed the state should only proceed with taking equity and with gas in-kind if it could satisfactorily resolve the issue. He reiterated that the HOA did not commit the state, but stipulated that the state would satisfactorily resolve the issues if it could. He relayed that it was the start of a long negotiating process; there were many things that could be worked in and that would be better understood once the project was better understood. He noted that the state could include more restrictive language in the legislation,

but there were also a range of possibilities where it would be in the state's best interest to remain open.

Mr. Tsafos added that it would be necessary to know the terms if legislation included an option specifying that Exxon, BP, and Conoco had to sell the state's gas. He detailed that unless the state determined what the companies would charge to sell the gas it would not have resolved as much of the problem as it may like. He addressed whether the agreed upon deal was good or not. He stated that the world of marketing LNG was bizarre and nontransparent. He pointed to Australia and noted that price discovery basically consisted of gossip. He stated that the bottom line was that what the market was and the price that was accessible became extremely obvious when marketing gas. He added that it was not very difficult to assess whether a contract was in line with market norms; the gas price transaction world was small. However, it was not possible to predict whether in hindsight a deal would turn out to be bad; the involvement of oil companies was no guarantee of a good deal. He relayed that oil companies had signed long-term LNG deals that they regretted at present. He communicated that as the state went through the process it would realize that judging whether it had a good deal may not be as much of a concern.

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Mr. Mayer added that as the state went through the process it would gain a better understanding about what constituted a reasonable commercial relationship with companies. He relayed that it was possible to firm up the sale of the state's share of gas in current legislation, but it would be done with much less knowledge about the project, the market, and a whole range of conditions, which may not be in the state's interest.

Co-Chair Austerman wanted to come back to the discussion.

Vice-Chair Neuman referred to earlier testimony that the best way to reduce the state's risk prior to FID related to the ability to change the financial agreements. He wondered how the state would implement the advice in the current gasline legislation (SB 138).

Mr. Mayer answered that the legislation under consideration by the legislature would establish a tax structure that

would enable a discussion of in-kind versus equity and would authorize a negotiation process with producers to establish the details. The legislation also created a process where legislators would be briefed in executive sessions on negotiations as they occurred (there would be an extended period where the administration was in negotiations with producers and TransCanada). Once the negotiation process had concluded (in over two years' time) the terms would come before the legislature for approval. He surmised that once the terms had come back to the legislature for approval there would be relatively little ability to influence the precise details. He noted that it was crucial what happened in the negotiation process and how the executive session briefings worked, how frequent meetings would occur, how much detail legislators would have access to, and how much ability there would be to make it clear if the state did not like certain aspects.

Vice-Chair Neuman wondered if the consultants had seen a financial agreement where the state or sovereign owner of gas was paid in royalty and in production tax in an in-kind form.

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Mr. Tsafos replied that in the majority of countries with LNG, the sovereign was a participant with access to and marketing of the gas. There were a few places in the world where the sovereign acted purely as a tax and royalty authority (e.g. the Lower 48 and Australia); however, in the vast majority of countries with LNG projects the sovereign participated as an investor and took ownership of the gas. In some countries the sovereign was very active as an investor and marketed the gas (e.g. Qatar owned ships and regasification terminals and was active in marketing the gas). Other sovereigns were more passive and let international oil companies market the gas on their behalf.

Mr. Mayer added that there was one aspect that was unusual, which related to the specifics of turning royalty and tax into a gas share. He characterized it as a hybrid approach compared to the more traditional North American tax and royalty regime. A structure where the state was an investor and participant was not a typical arrangement; however, its goal of state participation in the project was common.

Vice-Chair Neuman surmised that the answer was no.

Mr. Tsafos replied that typically the state would own 25 percent of the upstream rather than turning royalty and tax into a 25 percent share.

Co-Chair Austerman thanked the consultants for their time. He addressed the paradigm shift in the state from pocketing tax to moving to a profit base by converting tax into a sellable product. He believed the public would need to weigh in with its preference at some point over the next year and a half. He reiterated his request for committee members to provide questions to his office.

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ADJOURNMENT

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The meeting was adjourned at 4:02 p.m.