

MINUTES
SENATE FINANCE COMMITTEE
May 3, 2007
9:05 a.m.

CALL TO ORDER

Co-Chair Bert Stedman convened the meeting at approximately [9:05:36 AM](#).

PRESENT

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

Also Attending: DAVID KEANE, Vice President, Policy and Corporate Affairs, BG North America; DAN DICKINSON, Certified Public Accountant, Certified Management Accountant, and Legislative Consultant, Legislative Budget and Audit;

Attending via Teleconference: There were no teleconference participants.

SUMMARY INFORMATION

SB 104-NATURAL GAS PIPELINE PROJECT

The Committee heard from a representative from industry and a legislative consultant. The bill was held in Committee.

#sb104
[9:05:47 AM](#)

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 sixteenth hearing for this bill in the Senate Finance Committee.

[9:05:49 AM](#)

DAVID KEANE, Vice President, Policy and Corporate Affairs, BG North America introduced himself and informed that his presentation would be accompanied by a handout titled "BG North America, Legislative Hearings, David Keane, Juneau, 3-4 May 2007" [copy on file].

[9:07:33 AM](#)

Page 3

BG Group snapshot

- A world leader in natural gas
- A FTSE 20 company, listed on London and New York Stock Exchanges
- Market capitalisation over \$49 billion
- Production circa 70% gas; 30% oil
- Employs approx 4,766 staff; 64% outside UK, at year end 06

The integrated gas major

Mr. Keane overviewed this page, noting that BG was primarily focused on exploring for and developing natural gas reserves rather than oil.

[9:08:59 AM](#)

Page 4

Business model

[Pictorial illustrating BG's involvement in exploration and production of liquefied natural gas, transmission, distribution, and power.]

Resources - Enabling - Markets

A global natural gas business

Mr. Keane revealed that BG was the largest importer of liquefied natural gas (LNG) into the United States, transporting 49.8 percent of the imported LNG. The company also had a "strong presence" in South America as a natural gas distributor.

[9:09:53 AM](#)

Senator Huggins asked if BG was solely the transporter, or the owner-transporter, of the LNG imported to the U.S.

Mr. Keane responded that BG was involved in exploration and production of gas, and controlled 20 ships through ownership or long-term charters. BG did not own regasification facilities in the US, but leased 100 percent of entry capacity at the Lake Charles, Louisiana facility, as well as the majority of capacity at the Elba Island facility.

[9:10:47 AM](#)

Senator Huggins clarified that his question was if BG owned the gas that it imported to the US.

Mr. Keane affirmed that BG owned all the gas it transported.

[9:11:03 AM](#)

Page 5

Countries of current operation

[World map depicting the locations of BG operations in Canada, United States, Trinidad & Tobago, Bolivia, Brazil, Argentina, Uruguay, Italy, the UK, Norway, Tunisia, Algeria, Nigeria, Libya, Egypt, Madagascar, Israel/PA, Oman, Kazakhstan, India, Malaysia, Singapore, Thailand, China and the Philippines.]

Active in over 25 countries

Mr. Keane summarized this page.

[9:11:18 AM](#)

Page 6

Gas market focus

[World map with overlay indicating Developed Market, Developing Market, and Supplies.]

Connecting gas to markets

Mr. Keane reviewed this page, noting that BG's primary market was Europe and added that the company was expanding its business in North America.

[9:11:33 AM](#)

Page 7

Global gas trade - the recent past

[World map with overlay indicating Markets, LNG, and Pipe]

Industry evolution: from three main trade regions...

Mr. Keane recounted that until recently, natural gas generally remained in the region where it was discovered and produced.

[9:12:16 AM](#)

Page 8

Global gas trade - gradually evolving

[World map with overlay indicating Markets, LNG, and Pipe.]

...to a globalizing gas industry

Mr. Keane spoke to this page, and shared that current trends tended to favor global marketing to meet demands.

[9:13:16 AM](#)

Page 9

BG LNG supply projects

Atlantic LNG, Company of Trinidad and Tobago

- Train 1: 3.1 mtpa - 1999 (BG 26.0%)
- Train 2/3: 6.6 mtpa - 2002 (BG 32.5%)
- Train 4: 5.2 mtpa - 2005: (BG 28.9%)
- BG initiated project and was instrumental in Phillips design
- Single train start-up

Liquefied Natural Gas, Egyptian LNG

- Train 1: 3.6 mtpa - 2005 (BG 35.5%)
- Train 2: 3.6 mtpa - 2005 (BG 38.0%)
- Egypt's largest project financing to date
- Unique project commercial structure
- Utilized lessons learnt from ALNG

Atlantic LNG - total export capacity of 15 mtpa in just 7 years

Mr. Keane overviewed this page, noting that Atlantic LNG was one of the largest facilities in the world. Egyptian LNG was "up and running" within five years of the initial gas discovery in that region.

[9:13:58 AM](#)

Senator Dyson asked for a definition of "mtpa".

Mr. Keane defined mtpa as "million tons of LNG per annum".

[9:14:20 AM](#)

Page 10

US market summary

- Lake Charles import terminal
- Phase I expansion Q4 2005
 - 1.2 bcf/d sustainable send out
 - 1.5 bcf/d peak send out

- o 9.1 bcf total storage
- Phase II expansion Q2 2006
 - o 1.8 bcf/d sustainable send out
 - o 2.1 bcf/d peak send out
- Elba Island import terminal
 - o 0.45 bcf/d sustainable send out
 - o 0.67 bcf/d peak send out
 - o 4.0 bcf storage
 - o 1.17 bcf/d firm send out & 8.2 bcf storage after second expansion

Capacity in two of the four existing US onshore terminals

Mr. Keane reminded that BG held leases for 100 percent of the Lake Charles facility, and had assisted in significantly expanding that facility. A recently completed pipeline from Elba Island to northern Florida provided that state with access to natural gas from a source other than the Gulf of Mexico for the first time.

[9:15:34 AM](#)

Page 11

LNG imports - 2003 to present

Share of US LNG imports

[Bar graph depicting the percentage of US LNG imported by BG, Distrigas, BP, Shell, Statoil, and Other for the years 2003, 2004, 2005, and 2006, and listing the total mt for each year.]

BG - the largest US LNG importer in 2003, 2004, 2005 and 2006

Mr. Keane overviewed this page.

[9:15:47 AM](#)

Page 12

Alaska E&P

[Map of Alaska showing Alaska North Slope Gasline, Potential Spur Lines to Southcentral, Existing Gas Transmission Network, Potential Offtake Points, and Existing Commercial Natural Gas Users.]

2.1 million acres in the Foothills of ANS and .2 million in the ENS

Mr. Keane summarized this page, and informed that BG was currently in partnership with Anadarko in exploration efforts in the Foothills area of the North Slope, as well as on the Eastern North Slope.

[9:16:11 AM](#)

Page 13

Alaska Gasline Inducements Act

- BG is investing in Alaska
 - Exploring along North Slope and ENS
- BG supports AGIA
 - The process is fair, open and inclusive
 - BG supports the mandatory provisions on access and rates
 - Will encourage new explorers to invest in Alaska
- AGIA provides:
 - Opportunities for input by all interested parties
 - Several opportunities for legislators to provide input:
 - Initial legislation
 - When pipeline applications are submitted
 - Legislative review of the winning application

AGIA will encourage development

Mr. Keane reviewed this page, and stressed the importance of the construction of a natural gas pipeline in Alaska.

[9:17:20 AM](#)

Alaska Gasline Inducements Act

- AGIA addresses BG's concerns by:
 - Providing a level playing field for all participants
 - Providing certainty that when we discover gas, we will have access to pipeline capacity
 - Providing a mechanism to ensure just and reasonable rates
- AGIA creates competition to build the pipeline and possibly an LNG export facility
- AGIA spells out what is required of any applicant
- Clearly identifies the State's "must haves"
- BG's "must haves" are:
 - Regulated pipeline
 - Open access provisions in the tariff
 - Just and reasonable rates

AGIA will encourage development

Mr. Keane spoke to this page, characterizing the Alaska Gasline Inducement Act (AGIA) as an "extremely fair process", regulated by either the Federal Energy Regulatory Commission (FERC) or by the Regulatory Commission of Alaska (RCA).

[9:18:45 AM](#)

Key messages

- AGIA is good for Alaska and for the natural gas industry
- AGIA will encourage the continued development of Alaska's untapped natural gas reserves
- AGIA's purpose:

- o "...to encourage expedited construction of a natural gas pipeline that
 - 1) Facilitates commercialization of North Slope gas resources of the state;
 - 2) promotes exploration and development of oil and gas resources on the North Slope;
 - 3) maximizes benefits to the people of the state from the development of oil and gas resources in the state; and
 - 4) encourages oil and gas lessees and other persons in the state to commit natural gas from the North Slope to a gas pipeline system for transportation to markets in this state or elsewhere."

Alaska must continue to encourage development

Mr. Keane summarized this page, and stressed that AGIA would "serve as a vehicle" for the expedited construction of a natural gas pipeline. He contended that the application process should commence prior to debate regarding specific aspects of pipeline construction and management.

[9:19:55 AM](#)

Co-Chair Stedman referred to page 14, and quoted BG's claim that AGIA would address concerns by "providing a level playing field for all participants." He asked for a definition of "all participants."

Mr. Keane understood AGIA to provide equality for new explorers, applicants who want to build Alaska's pipeline, the "big three" producers, and the Alaska State Legislature. All parties would have access to information and an opportunity to participate.

[9:20:55 AM](#)

Co-Chair Stedman asked regarding access to the pipeline, and inferred that BG regarded FERC as a "non-functioning entity" unable to ensure access to the pipeline via its regulatory authority.

Mr. Keane disagreed with that statement, and clarified that BG judged that regulation of the pipeline would be necessary, by FERC or another interstate regulatory body.

Co-Chair Stedman asked if an interstate pipeline could avoid FERC regulation.

Mr. Keane was not aware of a method to circumvent FERC regulation.

Co-Chair Stedman indicated that FERC would regulate the pipeline and determine the appropriate level of "openness and access".

Mr. Keane affirmed.

[9:22:18 AM](#)

Co-Chair Stedman asked if BG intended to participate in the first binding open season.

Mr. Keane explained that BG was "eager" to participate in AGIA, and would be drilling next winter in the foothills along the North Slope. He continued that BG could "conceivably" have adequate natural gas reserves within three to four years to commit to the pipeline in the form of a firm transportation (FT) agreement. If BG did not have sufficient reserves to commit to capacity during the first open season, the company anticipated doing so in the second open season.

[9:23:22 AM](#)

Co-Chair Stedman provided the following comments.

Binding commitments by showing up to the first open season, or the first binding open season, you would receive under AGIA is some fiscal stability. Currently in the bill it's ten years, the tax rate is 22.5 percent, and there's a couple little issues with progressivity we have to work on mechanically, but. So does your firm have any issues with not having any [fiscal] stability past the binding first open season?

Mr. Keane asserted that BG had concerns with the fiscal certainty provisions in the bill. He opined that companies actively exploring should be granted a measure of fiscal stability, whether reserves had been identified at the time of the first open season or not.

Co-Chair Stedman asked for recommended language changes from BG, as well as identification of provisions in the bill supported by the company.

[9:25:09 AM](#)

Senator Dyson was impressed with BG's presentation, and asked if the company was interested in building or partnering to build the Alaska natural gas pipeline.

Mr. Keane responded that BG was not currently considering building the pipeline.

Senator Dyson asked if BG was confident that FERC would provide access to all shippers regardless of who built and operated the pipeline.

Mr. Keane opined that the best interest of the State and explorers would be served if an independent third party built and operated the pipeline. If a major producer had an ownership interest in the pipeline, adherence to strict affiliate rules in term of access to information would be important.

[9:26:47 AM](#)

Senator Dyson asked for an explanation of "strict affiliate rules".

Mr. Keane clarified that strict affiliate rules would guarantee that a marketing affiliate would not have access to information which was not available to the rest of the industry.

[9:27:19 AM](#)

Co-Chair Stedman asked Mr. Keane to provide specific references in FERC regulations that appeared insufficient to protect pipeline access interests.

Mr. Keane would provide that information to the Committee.

[9:28:14 AM](#)

Senator Thomas relayed concern that was expressed in previous testimony that the shippers would bear the financial risk of the

pipeline project. He asked why BG did not appear concerned with the risk borne by the shippers.

Mr. Keane responded that the risk would be spread to all producers in the form of FT commitments, and that he expected shippers to be "extremely involved" in the regulatory process upon award of a license under AGIA.

[9:29:46 AM](#)

Senator Huggins asserted that FERC was a "federal body" that operated independent of the producers, pipeline investors, and the State of Alaska.

[9:30:23 AM](#)

Mr. Keane agreed. He stated that FERC would be involved if the pipeline served interstate commerce. Additionally, several of the parties that would likely be involved with the pipeline were currently embattled in legal matters challenging FERC decisions related to access. This was a concern to BG.

[9:31:17 AM](#)

Co-Chair Stedman asked if BG had argued a case before FERC.

Mr. Keane affirmed.

Co-Chair Stedman requested a list of cases BG had argued before FERC within the past ten years.

[9:31:31 AM](#)

Senator Huggins asked for evidence to support the claim on page 15 that AGIA would "encourage expedited construction" of the gasline.

Mr. Keane answered that AGIA would advance the project. The proposed contract offered by former Governor Murkowski to the Legislature the previous year was not inclusive and had other faults. AGIA set forth specific timelines and real measures of progress for the construction of a natural gas pipeline.

[9:33:29 AM](#)

Senator Huggins retorted that some elements of AGIA "do the opposite" of expediting a pipeline, such as the allowance of five years to acquire financing for the project.

[9:34:13 AM](#)

Senator Elton understood Mr. Keane's testimony to indicate that BG's preference would be that a pipeline company would build the gasline. Producers had expressed a desire to be involved in the construction process to exercise cost control and prevent an overly burdensome tariff as the result of construction cost overruns. He asked if BG shared similar concerns.

Mr. Keane informed that BG, as a company that would participate in the open seasons, would monitor and intervene during the construction process to contain tariffs and costs.

[9:35:33 AM](#)

Co-Chair Stedman relayed that TransCanada and Enbridge had testified they had the capability to build the gasline, but preferred that it be constructed by a consortium. He asked if BG would be financially able and interested in participating in a pipeline consortium if adequate reserves were identified.

Mr. Keane replied that BG would not be interested in building the pipeline, and expected that a consortium of pipeline companies would ultimately construct the project.

[9:36:50 AM](#)

Co-Chair Hoffman asked why Alaska was not included in the "Gas market focus" map on page 6 of the presentation, and also asked what role China had as a developed market.

Mr. Keane responded that Alaska was considered part of North America, and therefore included in the North America category. Currently volumes of gas were moved from Alaska to Japan.

Co-Chair Hoffman clarified that his question referred to supplies and developing markets. The map did not show Alaska as a major market supply.

Mr. Keane directed attention to page 8 which depicted the evolving global gas trade. Alaska was shown as a supplier of LNG to the continental U.S.

Co-Chair Hoffman understood the "evolution" of the gas market, and reiterated that Alaska was not shown as a developing market or a supply of gas on the chart on page 6.

[9:39:04 AM](#)

Mr. Keane explained that the map on page 6 illustrated the company's market focus, not the global distribution of gas.

[9:39:26 AM](#)

Senator Thomas asked regarding the anticipated "consortium" that would build the pipeline, and whether Mr. Keane was familiar with the experience of the Alliance pipeline project. In that instance, producers were initially involved but had entirely sold out their interests by completion of the project. He asked if it would be reasonable to expect a similar outcome from the anticipated Alaska gas pipeline consortium.

Mr. Keane answered that BG would not be concerned if a producer held an interest in the pipeline company, as the gasline would be a major undertaking which would likely require the "pooling" of resources.

[9:40:57 AM](#)

Senator Thomas asked regarding BG's presence in Canada.

Mr. Keane informed that BG had exploration business in the Western Canadian Sedimentary Basin and in the Northwest Territories.

Senator Thomas asked if BG was producing in those areas.

Mr. Keane replied that BG had sold most of the small producing areas, and was focused on developing larger resources.

[9:41:35 AM](#)

Senator Huggins informed that TransCanada and Mid-America had indicated interest in participating in the construction of the

gasline, and asked for a prediction of what entity would build the Alaska gas pipeline.

[9:42:14 AM](#)

Mr. Keane could not speculate on who would build the gasline.

Senator Huggins asked if Mr. Keane was aware of any other parties qualified to take part in the AGIA process.

Mr. Keane was unable to provide that information.

[9:42:32 AM](#)

Senator Huggins understood that the FT commitments made during the first binding open season would provide a "key piece" to ensure financing for the construction of the natural gas pipeline.

Mr. Keane affirmed.

Senator Huggins furthered that the FT commitments carried obligation and debt burden.

Mr. Keane agreed.

[9:43:13 AM](#)

Co-Chair Stedman described the two most important issues to BG as guaranteed access to the pipeline and a fair tariff rate.

Mr. Keane affirmed. BG's primary concerns were securing access to a pipeline to transport gas to market, and fair tariff rates in the form of rolled-in rates. The guarantee that the initial shippers' rate would not exceed 15 percent of the preliminary rate was sufficient protection.

Co-Chair Stedman asked BG's experience with tariff rate structures world-wide, and whether negotiated, incremental or rolled-in rates were most common.

[9:44:56 AM](#)

Mr. Keane replied that the rate structure depended on the condition of the market. The U.S. exhibited competing pipelines

while other countries had no competition for gas transportation, thus the tariffs in these areas differed greatly.

[9:45:21 AM](#)

Co-Chair Hoffman referred to the bar graph on page 11, and asked how the gas was imported to the United States and if the imported gas depicted on that page was utilized primarily to supply the East Coast market. He furthered, asking how BG would address the gas needs of the United States in the absence of an Alaska natural gas pipeline.

Mr. Keane answered that the LNG imported into the U.S. arrived via tanker ships and was delivered into the terminals at Elba Island and Lake Charles where BG had leased space. Those facilities were connected by pipeline to deliver gas to U.S. markets in the Midwest and East Coast.

[9:47:03 AM](#)

Co-Chair Hoffman asked if BG would increase its tanker fleet to import more LNG to meet U.S. demands if the Alaska natural gas pipeline did not reach fruition.

Mr. Keane responded that BG currently owned seven ships and would receive two more within the year. Two additional ships would be delivered by 2010, and BG also had long-term charters of nine other vessels, for a total of approximately 20 tanker ships world-wide. He continued to express the desirability of a natural gas pipeline to transport North Slope gas to American markets.

[9:48:14 AM](#)

Co-Chair Hoffman asked if BG would prefer a pipeline that transported gas to Alberta to tie into existing pipeline infrastructure, or a pipeline that transported gas to Valdez to be shipped by ocean going tanker.

Mr. Keane informed that a pipeline to Alberta would produce greater "net backs" than carrying the gas by tanker from Valdez to the West Coast of the U.S.

[9:48:46 AM](#)

Co-Chair Stedman asked Mr. Keane to repeat his remark.

Mr. Keane reiterated that a pipeline into the Continental U.S. would produce greater revenues than would transporting the gas by tanker.

Co-Chair Stedman concluded that the reference to "net back" indicated the returns to the company and the State.

[9:49:18 AM](#)

Mr. Keane agreed that the net back would be greater on gas shipped via pipeline, provided that the gas was destined for the U.S. If the gas was to be shipped to the "Far East," the two modes of transportation would be comparable.

[9:49:38 AM](#)

Senator Thomas asked regarding the map on page 8, which appeared to illustrate the flow of gas from Australia and Southeast Asia to the West Coast of the United States. He asked if BG anticipated the construction of receiving facilities on the West Coast in the near future.

Mr. Keane replied that shipping gas to the West Coast was a long range goal.

Senator Thomas asked if BG expected the need for energy to have an impact on development in that area.

[9:51:03 AM](#)

Mr. Keane did not expect energy pressures to have an immediate impact on the construction of new natural gas receiving facilities on the West Coast.

[9:51:23 AM](#)

Senator Olson referred to page 11 of the presentation and asked for an estimate of the anticipated LNG imports for 2007, taking into consideration North Slope production.

Mr. Keane was unsure regarding North Slope production, but anticipated an increase in LNG imports to the U.S. due to lower prices in Eastern Asia, Europe and Japan. A mild U.S. winter and

colder winters in Europe and Asia caused LNG that was originally bound for the U.S. to be diverted to other markets with higher demand.

Senator Olson asked regarding fiscal certainty. He referenced the Baku-Tbilisi-Ceyhan (BTC) pipeline project's 60 year tax agreement, but pointed to political instability that could negate that fiscal certainty. He asked how these circumstances, as well as the recent nationalization of Trinidad and Tobago petroleum, could affect investments internationally.

[9:54:01 AM](#)

Mr. Keane corrected that Trinidad and Tobago were politically very safe and reliable. He assumed that Senator Olson was referring to Venezuela, which had witnessed seizure of petroleum assets.

Senator Olson surmised that BG did not anticipate any problems with foreign investment.

Mr. Keane stated that the production in Trinidad and Tobago as well as Egypt was stable.

Senator Olson commented that in the area he represented, Venezuelan President Hugo Chavez had "been a major factor in heating the homes", referring to the provision of subsidized heating oil offered by Chavez.

Co-Chair Stedman directed, "We're not going to go down that road here."

[9:55:00 AM](#)

Senator Elton asked if BG placed greater value on tax stability or political stability.

Mr. Keane responded that both political and fiscal stability were extremely important.

[9:55:53 AM](#)

Senator Thomas observed the prolific use of nuclear power in Europe, and asked if BG viewed that as a realistic future energy source.

Mr. Keane opined that nuclear power was important, providing approximately 93 percent of generation capacity in France, and contributing to power sources in the UK. The issue was national and would have to be decided in the future.

AT EASE [9:57:41 AM/10:05:26 AM](#)

DAN DICKINSON, Certified Public Accountant, Certified Management Accountant, and Legislative Consultant, Legislative Budget and Audit, communicated that he would provide a presentation to address four key questions posed by legislators. His presentation would be accompanied by a handout titled "Presentation to the Alaska Legislature, Senate Finance Committee, May 3, 2007, Dan E. Dickinson, CPA, CMA" [copy on file].

[10:06:45 AM](#)

Page 2

Question 1:

- How is gas generally taxed under the PPT? What are the PPT credit implications of gasline work?
- Same as oil (almost) - on net value
- Investment downstream of point of production not eligible for credits

Mr. Dickinson reminded that the State collected revenues from petroleum operations in Alaska in four ways: royalties, production taxes, special income taxes and special property taxes. He would focus on production taxes and credits. Credits were available only for costs incurred upstream of the point of production. The costs associated with the construction of the natural gas pipeline would be considered downstream costs and would not be eligible for credits under the Petroleum Profits Tax (PPT) enacted by the prior Legislature.

[10:08:26 AM](#)

Page 3

How is gas taxed under the PPT

- 43.55.011
- (e) 22.5% of net value
- (f) North Slope floor triggered by oil price
- (g)&(h) Progressivity triggered by single taxpayer net value
- Private royalty 1.67% for gas - 1/3 of oil
- (j) Cook Inlet Ceiling

Mr. Dickinson summarized the five manners in which gas was taxed under PPT, and would address each tax individually.

[10:09:12 AM](#)

Page 4

AS 43.55.011(e) 22.% of net value

- Total upstream costs are deducted from the revenue streams from oil and gas sales.
- Gas Revenue Exclusion (GRE) mechanism discussed in 2006 is an administratively simple way of adjusting the effective rate without changing the nominal rate or making lots of allocations.

Mr. Dickinson corrected that the page should reflect "22.5% of net value". It was not possible to separate the volumes of oil from the volumes of gas at the wellhead, and he therefore recommended a Gas Revenue Exclusion (GRE) provision, which would make differentiation between gas and oils costs less complex. This method would tax a percentage of the value generated from the sale of gas, and was the recommended mechanism for providing a lower tax to distance gas.

[10:11:12 AM](#)

Page 5

43.55.011(f) North Slope floor triggered by oil price

- Alternative floor just applicable to North Slope Oil and Gas is triggered by oil price.

- o Consider future if Prudhoe Bay is producing 250,000 bbls oil and 3 bcf of gas.
- o If the heating value is 1,000,000 btu per mcf, that translates to the equivalent of 500,000 bbls a day - so 1/3 of the field's production will be used to set the trigger.

Mr. Dickinson reminded that tax reforms under PPT changed the tax base from a gross to a net value, and established a "floor" on gross oil prices. He summarized the examples on the page as illustrative of the fact that if gas production was higher than oil, oil prices would still determine the floor. In a situation of high oil prices and low gas prices, the floor would not be "triggered", regardless of the quantities produced of each product. He suggested that the Committee may reconsider that aspect of the PPT.

[10:13:31 AM](#)

Page 6

Also insert Question 3 here:

- Question 3. How does PPT Progressivity work on gas and what is it's link to oil?

Mr. Dickinson read this page.

[10:13:42 AM](#)

Page 7

AS 43.55.011(g)&(h) Progressivity triggered by single taxpayer net value

- Progressivity is determined for each taxpayer on its mix of oil and gas and all upstream costs
- Calculated on a monthly basis - monthly upstream costs are 1/12 of the total annual costs
- Example - Next slide
 - o Prices April 27 2007,
 - o 1,000 btu per mcf,
 - o Equal mix of boe gas and oil

Mr. Dickinson corrected that the example on the following page should read "1,000 btu per cubic foot", which would equal one million btu per thousand cubic feet.

[10:14:33 AM](#)

Page 8

AS 43.55.011(g)&(h) Progressivity triggered by single taxpayer net value

Dest Price

Oil: 63.76

Gas: 7.32

Downstream Adj

Oil: (5.00)

Gas: (3.00)

Gross Value

Oil: 58.76

Gas: 4.32

6.00

Gas BOE: 25.92

Upstream Adj

Oil: (7.00)

Gas BOE: (7.00)

Net Value:

Oil: 57.76

Gas BOE: 18.92

Taxpyr Ave: 35.34

.011(h) limit

Oil: (40.00)

Gas BOE: (40.00)

Taxpyr Ave: (40.00)

Price Index

Oil: 11.76

Gas BOE: N/a

Taxpyr Ave: N/a

.011(g) factor

Oil: 0.0025
Gas BOE: 0.0025
Taxpyr Ave: 0.0025

Progressivity %
Oil: 2.940%
Gas BOE: N/a
Taxpyr Ave: N/a

Mr. Dickinson testified as follows.

The destination price, I pulled it out of the newspaper, was \$63.76. Let's assume for a minute that TAPS and the tankering costs are \$5.00. I'm using all sort of round numbers here. And that would leave you a gross value of \$58.76. Let's assume that upstream costs ...I'm assuming a number \$7.00 worth of per barrel costs, and that brings us out to a net value of \$51.76. The law says that we compare that to \$40.00, and so what the law calls the price index, we're \$11.76 over that. What you stipulated was that for every dollar over the base price, over the price index, you would add a quarter of a percentage point of progressivity, and so the net result is there's about 2.94 percent, and just so I can sort of do this in my head, if we call that three percent, you take three percent of 51, and so what you would see at today's prices folks are paying about 1.50 in every barrel on a progressivity charge. So they pay a 22.5 percent charge, and on top of that they pay another \$1.50.

[10:15:54 AM](#)

Mr. Dickinson continued his testimony as follows.

Let's go over to the next column. I again went to the newspaper, \$7.32 for a thousand cubic feet of gas. Who knows what the tariff is going to be, I used \$3.00 and that leaves ya \$4.32. At my assumption of how many btus there are per mcf, we end up saying a gas barrel of equi, a barrel of equivalent of gas will now be worth \$25.92. It's significantly lower. We said, my assumption that oil and gas are split fifty-fifty, so I'm gonna use that same \$7 charge, and we come out to \$18.92 in net value. That's way below the \$40 in limit. So the gas, if the gas were standing alone, would not pay any progressivity and if you

average the two numbers together they don't pay any progressivity. So what's really happening is, because the charge, the tariff, the cost of getting the gas to market is such a significant percentage of its destination value, when you look at the well head a barrel equivalent, a gas barrel equivalent will contribute a whole lot less than an actual barrel of oil. Again, as you can see, \$5 is, you know, seven or eight percent of the destination price of 63, but a three dollar tariff is between a third and half of the gas price. So, the point I want to make here is on the kind of prices we see today, and let's assume that's not typical or average but it's what we might expect in that range, generally a producer who has a lot of gas, that will lower their progressivity payments. And in fact in the example I gave here, I think most of us, maybe it's just those of us who've been around a while consider \$63.76 an extraordinarily high oil price, and yet if we were in a situation where we were producing half gas and half oil, it would not be sufficient to generate a progressivity charge.

[10:18:04 AM](#)

Mr. Dickinson noted that other versions of AGIA had contained progressivity provisions that would speak to gas prices without considering the upstream calculations. The tariff for gas would represent a much larger percentage of the "final realization" price, thus reducing progressivity rates.

[10:18:44 AM](#)

Page 9

Dollar/bbl Progressivity Charge at various Destination values and net deductions

Per barrel Progressivity Charge

Per Barrel Costs: 5

Monthly Average Destination Value per bbl in Dollars

50: 0.56

55: 1.25

60: 2.06

65: 3.00

70: 4.06

75: 5.25

80: 6.56

Per Barrel Costs: 6

Monthly Average Destination Value per bbl in Dollars

50: 0.44

55: 1.10

60: 1.89

65: 2.80

70: 3.84

75: 5.00

80: 6.29

Per Barrel Costs: 7

Monthly Average Destination Value per bbl in Dollars

50: 0.32

55: 0.96

60: 1.72

65: 2.61

70: 3.62

75: 4.76

80: 6.02

Per Barrel Costs: 8

Monthly Average Destination Value per bbl in Dollars

50: 0.21

55: 0.82

60: 1.56

65: 2.42

70: 3.41

75: 4.52

80: 5.76

Per Barrel Costs: 9

Monthly Average Destination Value per bbl in Dollars

50: 0.10

55: 0.69

60: 1.40

65: 2.24

70: 3.20

75: 4.29

80: 5.50

Per Barrel Costs: 10

Monthly Average Destination Value per bbl in Dollars

50: n/a

55: 0.56
60: 1.25
65: 2.06
70: 3.00
75: 4.06
80: 5.25

Per Barrel Costs: 11

Monthly Average Destination Value per bbl in Dollars

50: n/a
55: 0.44
60: 1.10
65: 1.89
70: 2.80
75: 3.84
80: 5.00

Per Barrel Costs: 12

Monthly Average Destination Value per bbl in Dollars

50: n/a
55: 0.32
60: 0.96
65: 1.72
70: 2.61
75: 3.62
80: 4.76

Per Barrel Costs: 13

Monthly Average Destination Value per bbl in Dollars

50: n/a
55: 0.21
60: 0.82
65: 1.56
70: 2.42
75: 3.41
80: 4.52

Per Barrel Costs: 14

Monthly Average Destination Value per bbl in Dollars

50: n/a
55: 0.10
60: 0.69
65: 1.40
70: 2.24
75: 3.20

80: 4.29

Per Barrel Costs: 15

Monthly Average Destination Value per bbl in Dollars

50: n/a

55: n/a

60: 0.56

65: 1.25

70: 2.06

75: 3.00

80: 4.06

Per Barrel Costs: 16

Monthly Average Destination Value per bbl in Dollars

50: n/a

55: n/a

60: 0.44

65: 1.10

70: 1.89

75: 2.80

80: 3.84

Per Barrel Costs: 17

Monthly Average Destination Value per bbl in Dollars

50: n/a

55: n/a

60: 0.32

65: 0.96

70: 1.72

75: 2.61

80: 3.62

Per Barrel Costs: 18

Monthly Average Destination Value per bbl in Dollars

50: n/a

55: n/a

60: 0.21

65: 0.82

70: 1.56

75: 2.42

80: 3.41

Per Barrel Costs: 19

Monthly Average Destination Value per bbl in Dollars

50: n/a

55: n/a
60: 0.10
65: 0.69
70: 1.40
75: 2.24
80: 3.20

Per Barrel Costs: 20

Monthly Average Destination Value per bbl in Dollars

50: n/a
55: n/a
60: n/a
65: 0.56
70: 1.25
75: 2.06
80: 3.00

Mr. Dickinson summarized this table, and pointed out that at current oil prices of approximately \$65 per barrel, the producers would pay approximately \$1.50 to \$2.00 per barrel in progressivity charges.

[10:19:23 AM](#)

Co-Chair Stedman acknowledged that the PPT legislation was drafted with the assumption that the State would take its gas payments "in kind". He understood that the current Administration had proposed modifications that effectively caused progressivity to "act as a dilution" to State revenues.

Mr. Dickinson agreed. The general understanding of the 24th Alaska State Legislature was that the PPT should stand alone with or without a gasline contract. He shared that Cook Inlet currently produced approximately 100,000 barrels of gas per day, and the companies that had both Cook Inlet and North Slope production were enjoying the "degradation" of the PPT progressivity taxes.

[10:20:55 AM](#)

Page 10

AS 55.43.011(i) Private Royalty 1.67% of gross for gas

- This is one third the rate for oil which is 5% of gross.

Mr. Dickinson reviewed this page.

[10:21:52 AM](#)

Page 11

AS 43.55.011(j) Cook Inlet Ceiling

- No direct effect on North Slope gas
- Expires in 2022
- If gas line is built from North Slope to Cook Inlet may want to consider effect of differential rates of taxation
- Ceiling potentially different for each producer:
 - Average (15 AAC 55.440) 4.947% of \$3.585 per mcf.

Mr. Dickinson commented that the tax structure for Cook Inlet gas would be very different than the taxes levied on North Slope gas.

[10:22:42 AM](#)

Page 12

Question 2:

- Are PPT gas credits applicable to the GTP in the AGIA bill?
- Under PPT - the GTP is not eligible for credits.

Mr. Dickinson informed that under current law gas treatment plants were not eligible for the PPT tax credits. The definitions in AGIA would "confuse" that issue, and he would offer a very specific recommendation to clarify the matter.

Co-Chair Stedman asked the "rough magnitude" of the credit dollars involved.

Mr. Dickinson responded that a gas treatment plant could constitute an expense of approximately two to three billion dollars, thus a 20 percent credit could amount to \$600 million.

Co-Chair Stedman explained that a tax credit would have the effect of reducing the revenues received by the State.

[10:24:06 AM](#)

Mr. Dickinson specified that the PPT tax credit was designed to encourage upstream activity and exploration and was not related to the construction of a gas pipeline.

Co-Chair Stedman surmised that the legislature must be precise in drafting language in AGIA relating to the PPT tax credits to avoid conflicting legal interpretations.

[10:24:50 AM](#)

Mr. Dickinson affirmed that no ambiguity should exist, and that the gas treatment plant (GTP) was defined under the PPT legislation as a downstream facility that would not qualify for the tax credit.

[10:25:20 AM](#)

Page 13

Only Upstream Costs Qualify as Credits

- AS 43.55.023(a) "...may take a tax credit for a qualified capital expenditure...in the amount of 20 percent of the expenditure;"
- AS 43.55.023(k) "'qualified capital expenditure'...means...an expenditure that is a lease expenditure under AS 43.55.165 and is...treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code)

Mr. Dickinson summarized this page.

[10:26:04 AM](#)

Page 14

Only Upstream Costs Qualify as Credits

- AS 43.55.165(a) "...a producer's lease expenditures for a calendar year are the ordinary and necessary costs upstream of the point of production of oil and gas...and that are the direct costs of exploring for developing, or producing oil or gas...

Mr. Dickinson noted that this statute clearly specified that the tax credit applied only to costs upstream of the point of production.

[10:26:31 AM](#)

Senator Dyson asked for the definition of "point of production".

Mr. Dickinson answered that the next pages would address that question.

[10:26:41 AM](#)

Page 15

Where is the point of Production?

- In AS 43.55.900
- (21) gas processing
- (23) gas treatment
- (27) point of production
- Are defined so that gas processing is upstream of the point of production and gas treatment is downstream of the point of production.

Mr. Dickinson revealed that gas processing is defined in statute as upstream of the point of production, and gas treatment is downstream from the point of production.

[10:27:11 AM](#)

Page 16

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (A) for oil...

- (B) for gas, other than gas described in (c) of this paragraph that is
- (i) not subjected to or recovered by mechanical separation or run through a gas processing plant, the first point where the gas is accurately metered;
- (ii) subjected to or recovered by mechanical separation but not run through a gas processing plant, the first point where the gas is accurately metered after completion of mechanical separation;

Page 17

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (B) for gas...
- (iii)run through a gas processing plant, the first point where the gas is accurately metered downstream of the plant
- (C)for gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the first point where the gas processing is completed of where gas treatment begins, whichever is further upstream.

Mr. Dickinson stressed that subparagraph (B)(iii) of AS 43.55.011(27) identified the point of production of gas processed through a gas processing plant as "the first point where the gas is accurately metered downstream of the plant". Subparagraph (C) established the point of production for gas that had been run through an integrated gas processing plant.

Mr. Dickinson relayed that he had been asked how the point of production would be affected if the gas treatment plant was placed upstream from the gas processing facility. In that instance, although the gas would be treated prior to its entry into a processing facility, the definition still stipulated that the point of production was located at the first point that gas treatment began. Therefore, the point of production would "move" upstream, and the treatment and processing costs would remain ineligible for the PPT tax credits.

[10:29:02 AM](#)

Page 18

PPT Definitions: Gas Processing

- AS 43.55.011(21) "gas processing"
- (A) means processing a gaseous mixture of hydrocarbons
- (i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation; and
- (ii) for the purpose of extracting and recovering liquid hydrocarbons [producing ngl's/oil];
- (B) does not include gas treatment

Mr. Dickinson overviewed this page.

[10:29:50 AM](#)

Page 19

PPT Definitions: Gas Treatment

- AS 43.55.011(23) "gas treatment"
- (A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system.
- (B) includes incidentally removing liquid hydrocarbons from the gas

Mr. Dickinson spoke to this page.

[10:30:23 AM](#)

Page 20

PPT Definitions: Gas Treatment

- AS 43.55.011(23) "gas treatment" (cont.)
- (C) does not include

- o (i) dehydration required to facilitate the movement of gas from the well to the point where gas processing takes place;
- o (ii) the scrubbing of liquids from gas to facilitate gas processing.

Mr. Dickinson reviewed this page.

[10:30:33 AM](#)

Page 21

Under Current law:

- Gas Processing
- Starts with gaseous mixture of hydrocarbons, and produces natural gas liquids and gas by removing the hydrocarbon liquids.
- Gas Treatment
- Starts with produced gas and removes nonhydrocarbons (including incidental hydrocarbons) to prepare the gas for tender to the pipeline. Nothing is produced.

Mr. Dickinson summarized this page.

[10:30:57 AM](#)

Page 22

AGIA Definitions: Gas Processing

- AS 43.55.900(7) "gas processing" means the treatment of gas downstream of the point of production to extract natural gas liquids. CSHB 177(RES)
- AS 43.55.900(7) "gas processing" means post-production treatment of gas to extract natural gas liquids. CSSB 104(JUD)

Mr. Dickinson corrected that the reference to AS 43.55.900 should have been a reference to subparagraph (7) of Section 43.90.900. Definitions., in SB 104, the AGIA legislation. It defined gas processing as "the treatment" of gas, while PPT differentiated between gas treatment and processing.

[10:32:37 AM](#)

Page 23

AGIA Definitions: Gas Processing

- Suggested Definition
- AS 43.55.900(7) "gas processing" has the same meaning as "gas processing" in AS 43.55.900(21)

Mr. Dickinson provided his suggested definition to achieve continuity between the proposed AGIA bill and the PPT statute.

[10:33:01 AM](#)

Page 24

PPT Point of Production for Gas

[Flow chart summarizing the following four pages.]

Mr. Dickinson informed that the following pages would expound on this page.

[10:33:10 AM](#)

Page 25

Gas Point of Production

[Illustration indicating that the point of production of gas that is not run through a gas processing point or subject to mechanical separation is the first point at which gas is accurately metered.]

Mr. Dickinson noted that this was the simplest form of gas production, and the least common.

[10:33:37 AM](#)

Page 26

Gas Point of Production

[Illustration indicating that the point of production after mechanical separation for gas not run through a gas processing plant but subject to mechanical separation is at the first point at which gas is accurately metered after separation is complete.]

Mr. Dickinson spoke to the page.

[10:34:01 AM](#)

Page 27

Gas Point of Production

[Illustration indicating that the point of production after gas processing for gas not run through an integrated gas processing plant and a gas treatment plant is at the first point at which the gas is accurately metered downstream of the plant.]

Mr. Dickinson explained this page.

[10:34:27 AM](#)

Page 28

Gas Point of Production

[Illustration indicating that the point of production for gas run through an integrated gas processing plant and gas treatment plant is the furthest upstream point in which treatment begins or processing ends.]

Mr. Dickinson summarized this page.

[10:34:46 AM](#)

Page 29

Prudhoe Bay: Point of Production under the PPT

[Flow chart summarizing the point of production for gas and oil on the North Slope.]

Mr. Dickinson described this page as follows.

What happens on the North Slope now? You have well fluids coming out in the lower left had corner coming out of wells. They go into six separation facilities that are called usually the gathering centers or the flow stations. What happens there is you have water and sediment. You pull that out, you have liquid hydrocarbons which get delivered to PS1 (pump station 1) of TAPS, which is where they become oil. That's the point of production for oil, and you have a gaseous mixture of hydrocarbons that get pulled off the top of each of those facilities. Those all get routed together and sent to something called the Central Gas Facility. Central Gas Facility uses a much more sophisticated set of processes, so they qualify as gas processing. It gets down to very, very low temperatures, and it separates out some more hydrocarbon liquids that get delivered to the TAPS and, off the top we pull off a bunch of gas. Some of it gets used for sale, some of it gets used for use, and of course the one thing that we all regret is eight billion cubic feet a day of that gets reinjected back down into the ground. That's the situation we're trying to remedy.

[10:36:04 AM](#)

Senator Elton had understood that the point of production came "after fuel use", and asked if this was a "new interpretation".

Mr. Dickinson replied that page 31 would address that question.

Page 31

North Slope Central Gas Facility

- On the Alaska North Slope the Central Gas Facility is a gas processing plant,
- AS 43.55.020(e) "...gas used in the operation of a lease or property in the state in drilling for or producing oil or gas or for repressuring...is not considered...as...gas produced from a lease or property."

Mr. Dickinson agreed that the gas Senator Elton identified was not considered to be produced at the point of production.

[10:36:56 AM](#)

Page 32

Answer to the Question:

- If CGF remains a separate plant and sends gas to a Gas Treatment Plant (GTP), gas would be produced as it is metered out of plant. The GTP would be downstream of the point of production for the gas and thus associated operating and capital costs would not qualify as lease expenditures under AS 43.55.165 (a) nor would capital costs qualify for credit treatment under AS 43.55023(a).

Mr. Dickinson overviewed this page.

[10:37:30 AM](#)

Page 33

Prudhoe Bay: Point of Production under the PPT with a GTP

[Flow chart depicted on Page 29 with the addition of a Gas Treatment Plant and an Export Gasline.]

Mr. Dickinson pointed out that the addition of a gas treatment plant would not change any of the prior established points of production. Therefore, the definitions that existed under the PPT would sufficiently delineate the point of production for the purposes of the AGIA legislation, and could be imported from existing statute.

[10:38:13 AM](#)

Page 34

Answer to the Question:

- If CGF becomes integrated into a Gas Treatment Plant (GTP) (produced gas is not metered), then the gas would be produced within that integrated facility, at the furthest point upstream of the beginning of gas treatment of the end of gas processing. If plants are integrated, the risk is that some gas processing will move downstream of the point of production, not that

gas treatment will move upstream of the point of production.

Mr. Dickinson summarized this page, noting that gas treatment could not be moved upstream to become eligible for the PPT credits.

[10:38:51 AM](#)

Page 35

Prudhoe Bay: Point of Production under the PPT w/integrated GTP

[Flow chart depicted on Page 33 with the Gas Treatment Plant integrated into the Central Gas Facility.]

Mr. Dickinson declared that the point of production would always be the furthest point upstream that gas treatment occurred. Any process that could be identified as removing nonhydrocarbons for the purpose of preparing the gas for transport would be defined as gas treatment and considered the point of production.

[10:40:00 AM](#)

Senator Thomas asked the likelihood that the gas treatment plant and the central gas facility would be attached.

Mr. Dickinson understood that the most common assumption was that the gas treatment plant would be located approximately 50 yards downstream from the central gas facility. The possibility also existed that facets of the central compression plant could be incorporated into the gas treatment plant, with the central gas facility standing independently.

[10:41:31 AM](#)

Page 36

Question 4:

- We are trying to determine how attractive an investment this pipeline is. Antony Scott, Commercial Analyst, DNR, Oil and Gas, in his April 11, 2007 presentation shows that using the IRR metric this

project can have very high rates of return, particularly with a third party line. However we believe he does not include the cost of shippers' firm transportation commitments in his numbers when comparing an independent pipeline with a producer owned pipeline. How might this affect his results?

Mr. Dickinson articulated the question on this page.

[10:42:30 AM](#)

Page 37

Firm Transportation

- Shipper makes a Firm Transportation commitment (FT) to pay the capital portion of the tariff whether it uses the pipeline or not.
- It is that financial commitment that underwrites the pipeline:
 - Required by FERC before approving a project
 - Required by lenders before lending money to a project.

Mr. Dickinson reviewed this page.

[10:43:08 AM](#)

Page 38(9)

Producers' returns as both shippers + pipeline owners

\$3.50

NPV: 3.0

IRR: 12.6%

P/I: 1.3

NPV per BOE: \$0.37

\$4.00

NPV: 5.0

IRR: 14.0%

P/I: 1.4

NPV per BOE: \$0.60

\$4.50

NPV: 6.9
IRR: 15.4%
P/I: 1.6
NPV per BOE: \$0.83

\$5.00
NPV: 8.7
IRR: 16.7%
P/I: 1.7
NPV per BOE: \$1.06

\$5.50
NPV: 10.6
IRR: 17.9%
P/I: 1.9
NPV per BOE: \$1.28

\$6.00
NPV: 12.4
IRR: 19.0%
P/I: 2.0
NPV per BOE: \$1.50

\$6.50
NPV: 14.2
IRR: 20.1%
P/I: 2.2
NPV per BOE: \$1.72

\$7.00
NPV: 16.0
IRR: 21.1%
P/I: 2.3
NPV per BOE: \$1.93

\$7.50
NPV: 17.7
IRR: 22.1%
P/I: 2.5
NPV per BOE: \$2.14

\$8.00
NPV: 19.3
IRR: 23.0%
P/I: 2.6

NPV per BOE: \$2.33

\$8.50

NPV: 20.8

IRR: 23.9%

P/I: 2.7

NPV per BOE: \$2.51

Mr. Dickinson informed that the information depicted on pages 38 and 39 of his presentation was garnered from presentation material provided by Antony Scott, Commercial Analyst, Division of Oil and Gas, Department of Natural Resources on April 11, 2007. This page examined the expected internal rate of return (IRR) for a producer-owned pipeline for which the producers were also shippers.

[10:44:04 AM](#)

Page 39(7)

Producer Upstream Returns Base case cost = \$20.5B

\$3.50

NPV: 4.1

IRR: 29.8%

P/I: 3.2

NPV per BOE: \$0.49

\$4.00

NPV: 6.1

IRR: 39.7%

P/I: 4.3

NPV per BOE: \$0.74

\$4.50

NPV: 8.1

IRR: 48.7%

P/I: 5.3

NPV per BOE: \$0.98

\$5.00

NPV: 10.1

IRR: 56.3%

P/I: 6.4

NPV per BOE: \$1.22

\$5.50
NPV: 12.1
IRR: 62.9%
P/I: 7.5
NPV per BOE: \$1.46

\$6.00
NPV: 14.0
IRR: 68.9%
P/I: 8.5
NPV per BOE: \$1.70

\$6.50
NPV: 16.0
IRR: 74.2%
P/I: 9.5
NPV per BOE: \$1.93

\$7.00
NPV: 17.8
IRR: 79.2%
P/I: 10.5
NPV per BOE: \$2.15

\$7.50
NPV: 19.6
IRR: 83.9%
P/I: 11.5
NPV per BOE: \$2.37

\$8.00
NPV: 21.3
IRR: 90.4%
P/I: 12.4
NPV per BOE: \$2.57

\$8.50
NPV: 22.9
IRR: 95.6%
P/I: 13.2
NPV per BOE: \$2.76

Mr. Dickinson commented that this page provided the anticipated IRR if the producers were not pipeline owners, but merely

shippers on the line. At current gas prices, the rate of return on the pipeline would be approximately 80 percent. He allowed that the analysis could be incorrect, as the project had not been undertaken and costs not studied for several years.

[10:44:54 AM](#)

Co-Chair Stedman asked for a definition of the terms "net present value", "internal rate of return", and "profitability index".

Mr. Dickinson defined the net present value, or NPV, as "how much better off" a firm would be after making "this investment". It was a "measure of net gain" for participating in a project after expenses were paid.

Co-Chair Stedman understood NPV to compare all future income from a project in a lump sum, effectively "moving money and time back to today" for the purpose of comparison.

Mr. Dickinson affirmed, adding that the future cash flows would be adjusted or discounted to take into account the time those dollars were invested.

[10:46:58 AM](#)

Mr. Dickinson explained the profitability index (PI) as a ratio of the "out flows" to the "in flows". It examined income as the result of an investment in comparison to the initial investment. A PI ratio higher than "one" was desirable, as that would demonstrate profit.

[10:47:43 AM](#)

Page 40

Calculated IRR at various price levels

[line graph depicting the internal rates of return for a shipper-owner and a shipper at various gas prices from \$3.50 to \$8.50]

Mr. Dickinson was concerned that this graph indicated that the IRR for a shipper-owner at gas prices of \$8.50 was less than the IRR for a shipper without an ownership interest at gas prices of

\$3.50. He opined that the rates of return demanded further analysis.

[10:49:05 AM](#)

Co-Chair Stedman referred to the \$7.00 gas price listed on page 39 and asked the following question.

If we look at seven, which is the seven dollar price, regardless of what entity you're investing in, just the mechanics of the internal rate of return, if this is over a 25-year horizon or whatever time horizon it's calculated under, am I interpreting this correctly to make that seven 79.2 whatever number on the bottom, you'd have to reinvest every year's cash flow into a project that would return that 79.2 first cash flow for 20 years, second cash flow for 19 years, and isn't that rather challenging?

Mr. Dickinson responded that Co-Chair Stedman had identified the "reinvestment problem", which was one reason that IRR was not used to evaluate potential investments. It implied that other opportunities would be just as "fruitful", without taking into consideration reinvestment challenges.

[10:50:49 AM](#)

Senator Huggins was "alarmed" by the figures presented, and asked if Mr. Scott had questioned the validity of the model.

Mr. Dickinson shared that Mr. Scott would acknowledge that IRR was a limited calculation that was not applicable to all circumstances. He opined that Mr. Scott would warn against reaching a firm conclusion based on that analysis.

[10:51:55 AM](#)

Senator Elton reported that he had been told that Mr. Scott's analysis and use of numbers closely reflected the information in Conoco-Phillips' most recent "10K" filing. He asked if Mr. Dickinson had knowledge of that, and how Conoco-Phillips' analysis differed from Mr. Scott's.

[10:52:37 AM](#)

Mr. Dickinson would review that with the Committee. He referred to the 2003 annual reports of BP, Conoco, and Exxon, and would address those issues.

#

ADJOURNMENT

Co-Chair Bert Stedman adjourned the meeting at [10:54:23 AM](#)