MINUTES
SENATE FINANCE COMMITTEE
April 25, 2007
2:03 p.m.

CALL TO ORDER

Co-Chair Bert Stedman convened the meeting at approximately 2:03:21 PM.

PRESENT

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

Also Attending: MARCIA DAVIS, Deputy Commissioner, Department of Revenue; KEVIN BANKS, Director, Division of Oil and Gas, Department of Natural Resources; PAT GALVIN, Commissioner, Department of Revenue;

Attending via Teleconference: There were no teleconference participants.

SUMMARY INFORMATION

SB 104-NATURAL GAS PIPELINE PROJECT

The Committee heard from the Department of Revenue, and the Department of Natural Resources. The bill was held in Committee.

#sb104
2:03:31 PM

> 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 fifth hearing for this bill in the Senate Finance Committee.

2:03:48 PM

MARCIA DAVIS, Deputy Commissioner, Department of Revenue, testified that she would continue her sectional analysis of the Senate Judiciary Committee Substitute.

Section 43.90.320. Gas production tax exemption. (page 22, line 12)

Ms. Davis identified a "rolled-in" tariff rate provision on line 29 of subsection (c), which would disallow protest on the part of the resource owner when the pipeline licensee included expansion costs in the tariff.

Section 43.90.330. Inducement vouchers. (page 23, line 2)

Ms. Davis informed that this was a new section added during hearings in the Senate Judiciary Committee to allow buyers of gas to purchase the product at the North Slope, and then acquire capacity in the pipeline as a buyer. This section would allow those buyers of gas to serve as the shipper of the gas, and access the resource inducements offered to the resource owners.

2:05:12 PM

Ms. Davis explained that if the buyers of the gas had acquired capacity in the pipeline by participating in the first binding open season, those buyers could receive vouchers from the Department of Revenue and the Department of Natural Resources. The buyer could then transfer the benefit of the resource inducement in the form of a voucher to the producer as part of the gas purchase agreement.

2:06:06 PM

Co-Chair Stedman exampled a utility in the Midwest that needed a "substantial volume" of gas, and understood that this provision would allow that entity access to the inducement vouchers.

Ms. Davis explained that the entity would first acquire the capacity in the pipeline for the gas to be shipped, then present the voucher to the gas producer and negotiate the cost of the gas by leveraging the voucher's benefit associated with gas royalties and taxes.

Co-Chair Stedman concluded that a buyer of gas would turn their firm transportation (FT) commitment into a voucher, and then employ that voucher to negotiate a price with the resource owner.

Ms. Davis affirmed.

2:07:11 PM

Article 4. Miscellaneous Provisions.

Section 43.90.400. Alaska Gasline Inducement Act matching contribution fund; disbursements; audits. (page 23, line 21)

Ms. Davis stated that this section would establish a fund for the monies appropriated by the legislature to be disbursed as matching funds to the pipeline builder.

Section 43.90.410. Regulations. (page 24, line 10)

Ms. Davis reported that this bill was "unique" in that it involved commissioners of two different State departments, and this section provided for the two commissioners to jointly adopt regulations to implement the provisions of this chapter. Additionally, this section provided that the commissioner of the Department of Revenue may make changes to the existing regulations in AS 43, and the commissioner of the Department of Natural Resources may make necessary changes to the regulations of AS 38 to implement the provisions of this chapter.

2:08:21 PM

Section 43.90.420. Statute of limitations. (line 16)

Ms. Davis informed that this provision would accelerate any legal challenges to the Alaska Gasline Inducement Act, or AGIA, by establishing a 90 day time limit for such disputes to be brought in court.

Ms. Davis noted that the legislature's legal counsel strongly advised an amendment to the current version of the bill to ensure that challenges to AGIA be brought before a court in "this state".

2:09:21 PM

Co-Chair Stedman assumed that the Palin Administration would provide suggestions for "technical clean-ups" to the bill.

Ms. Davis affirmed.

2:09:40 PM

Section 43.90.430. Interest. (line 20)

Ms. Davis identified differences between the Senate Judiciary Committee version of the bill and its companion, HB 177, under consideration by the House of Representatives. The Senate version that was before the Committee contained a verbatim excerpt from the current statute while the version in the other body referenced the statute. Statutory reference was preferable due to the fact that if the statute was amended in the future, a reference to the statute would automatically "pick up" the changes while a verbatim excerpt would require further amendment. She indicated that the Administration would likely offer an amendment to that effect.

2:10:32 PM

Section 43.90.440. Licensed project assurances. (line 26)

Ms. Davis communicated that this "important" section would provide the State's commitment to the licensee that it would not offer preferential royalty or tax treatment or grants of State money to a competing natural gas pipeline. If the State did extend preferential treatment to a competing gasline before the licensee's gasline began operations, this provision would

provide the licensee payment equal to three times the amount of qualified expenditures incurred by the licensee.

2:11:57 PM

Co-Chair Stedman asked why 300 percent of expenditures was selected for repayment rather than a lower rate to reduce the State's potential obligation.

Ms. Davis acknowledged that the question was raised in other committees, and shared that 300 percent was the level determined by the Administration to be appropriate to prevent the State from "jumping onto" a competing project unless it was "extremely attractive." That rate would also signify to producers, especially independent producers, that the "playing field" was level. A repayment disbursement of 300 percent would have the stigma of a punitive damage award, whereas 200 percent might not be great enough to bring some of the more cautious parties into the bidding process.

2:15:24 PM

Co-Chair Stedman assumed that the tax rate, fiscal certainty, and incentives contained within the bill would afford the "attractiveness" necessary to bring applicants into the AGIA bidding process, and the repayment assurances were an "extra carrot".

Ms. Davis affirmed. The $500 million matching contribution was an important factor in the development of the project, as was the tax inducement. This provision specifically addressed the possibility that the licensee under AGIA could be met with competition to build a pipeline. If that occurred, this provision would ensure that the State stay "married" to the licensee despite poor market conditions created by a competing project. If, however, the competing project was more successful the State could opt to reimburse the licensee 300 percent of the qualified expenditures and back the alternate natural gas pipeline project.

2:18:12 PM

Ms. Davis advised that if the licensee was not successful at constructing the gasline after seven or eight years, there was a high likelihood that other major economic factors would be

contributing to the fruitless situation. Alternatively, if the licensee was being "highjacked" by the resource owners, the State may ultimately be more successful at developing its gas by supporting a different gasline project.

2:18:36 PM

Co-Chair Stedman asked if the Administration considered this a "must have" in advancing AGIA.

Ms. Davis replied that it was "critically important" for the State to signify its commitment to a project.

2:19:08 PM

Senator Huggins assumed that if the AGIA contract did not provide for compensation to the licensee of triple the qualified expenditures, the licensee could sue for an unspecified amount of damages.

Ms. Davis agreed that AGIA represented a license from the State to the licensee, and if the State breached that contract, it would be liable for damages.

Senator Huggins surmised that in the case of a breach of contract, the licensee would likely receive a court award.

Ms. Davis affirmed, adding that the award could be significant if based on lost profits.

2:20:12 PM

Senator Huggins asked if the specification of repayment of "three times" the qualified expenditures would protect the State from additional liabilities.

2:20:26 PM

Ms. Davis responded that the enumerated compensation was not designed to be a "cap".

2:20:47 PM

Senator Huggins asked if Ms. Davis had an estimate of the potential liability the State could face in the event of a breach of contract.

Ms. Davis reported that the "ballpark" range could be as little as $120 million if the transgression occurred early in the AGIA process. If the State elected to support an alternate project subsequent to the licensee receiving a certificate from the Federal Energy Regulatory Commission (FERC), the cost to the State could be as high as $1.5 billion.

2:21:49 PM

Senator Huggins projected that the breach could occur even later than the issuance of a FERC certificate.

Ms. Davis informed that most of the qualified costs would be incurred prior to obtaining the FERC certificate, and expenditures after that point would not be significant.

Co-Chair Stedman perceived the liability amount to be a "substantial sum of monies" that would potentially affect the State's operating budget, and asked if the Department of Revenue had fund source recommendations.

Ms. Davis qualified that it would be "foolhardy" of the State to support a competing project and immediately incur a liability of $1.5 billion if that money was not immediately recoverable. The provision was intended to be a "thinking period" to evaluate the project.

2:23:06 PM

Senator Thomas shared the same concern as Senator Huggins, commenting that if the "triple damages" provision would not preclude a party from seeking an additional award, he was unsure of the necessity of its inclusion.

2:23:44 PM

Ms. Davis set forth two solutions to that issue. One would be to characterize the provision as "liquidated damages", which was a frequent practice when a loss could be difficult to quantify or agree upon. Another option would be to exclude damage claims for consequential losses. This would provide for out-of-pocket

expenses, but not future lost profits, thus limiting the State's exposure.

2:24:57 PM

Senator Thomas opined that such a "waiver" of a party's right to recover damages should be considered.

2:25:12 PM

Senator Elton asked the Department to alert the Committee if proposed amendments had the effect of changing an inducement to an impediment for the potential licensee.

2:25:37 PM

Ms. Davis directed attention to Section 43.90.440.(1) on page 25, line 14 which reads as follows:

> (1) "competing natural gas pipeline project" means a project designed to accommodate throughput of more than 500,000,000 cubic feet a day of North Slope gas to market;

Ms. Davis clarified that the definition of a "competing natural gasline project" was designed to allow "spur" or "bullet" lines to operate, provided that they transported 500 million or less cubic feet of gas per day.

Ms. Davis furthered her explanation, referencing Sec. 43.90.440.(2) on page 25, line 17 which reads as follows:

> (2) "preferential royalty or tax treatment" does not include
>
> (A) the state's exercise of its right to resolve disputes involving royalties and taxes;
>
> (B) the state's exercise of its right to modify royalties as authorized by law in effect on the effective date of this section; or
>
> (C) the benefits of a large project permit coordinator authorized by law in effect on the effective date of this section.

Ms. Davis informed that the definitions in paragraphs (A) (B) and (C) were designed to allow the State and the Department of Natural Resources to continue with "business as usual" under

existing laws, without those actions constituting "preferential treatment".

2:29:50 PM

Senator Huggins asked if the "large project permit coordinator" in subparagraph (C) was a reference to the pipeline coordinator position.

Ms. Davis understood it to reference an existing Department of Natural Resources statute under Title 38 and not AGIA.

Senator Huggins asked for a comparison of the capabilities of the Department of Natural Resources coordinator and the AGIA pipeline coordinator.

Ms. Davis would bring forth that information.

2:30:37 PM

Senator Thomas suggested the inclusion of language allowing "any normal permitting process" under subparagraph (C) for clarity.

Ms. Davis agreed. The consequence of specific references was that legal activities not explicitly permitted could be challenged in court.

2:31:52 PM

Section 43.90.450. Assignments (page 25, line 24)

Ms. Davis stated that this section was intended to clearly address how transfers could occur of the license, the resources inducements possessed by the resource owners, and the voucher possessed by the shipper. In all instances, a transfer would be allowable but subject to conditions.

Ms. Davis continued that it was "fully expected" through the course of the project development that the license would be transferred, and that transfer would be allowed as long as it met the conditions of subparagraphs (1) and (2) of subsection (a).

2:33:38 PM

Ms. Davis pointed out that language had been added in subsection (a) during previous committee hearings to stipulate that the transfer of the license would be subject to the same hearing and approval process as the initial license. This would include publishing notice of the transfer, providing notice to the legislature, and allowing for a 30 day public comment period.

2:34:15 PM

Ms. Davis testified regarding the transfer of the royalty inducement as follows.

> The transfer of a royalty inducement is of some concern to the Department, because again, this process has to be administered. We have to track which leases have incorporated the royalty changes. We have to track, as far as the tax inducements, which tax payer has the benefit of a tax, a different tax treatment than would be the norm if the tax laws have changed. And we have to be able to administer this cleanly and have it handled and processed through the audit. So what we determined made the most sense was to allow the transfer of the resource inducement only in connection with the transfer by that tax payer or royalty owner of their entire North Slope portfolio, or in connection with the sale of that company out right. So we've limited the transfer of the resource inducement because what we can envision is people starting to slice and dice their capacity and spreading it out amongst multiple parties and it would soon become an administrative nightmare to try to track it.

Ms. Davis continued that the transfer of the voucher was similarly limited. A utility or other buyer that had received a voucher after acquiring capacity in the pipeline could transfer that voucher, but only in connection with the transfer of the entire pipeline capacity.

2:35:51 PM

Senator Huggins quoted language on page 26, line 3 that referenced the transfer of "all or part of a license". He asked what the "parts" of the license included.

Ms. Davis surmised that the parts of a license referred to a fractional share of the license in the event that the license

was granted to a multi-party group. If an association of multiple entities was granted the license and one of those entities decided to transfer its interest in the license, that transfer would be considered a "part" of the license. The license would not, however, be divided into discreet portions; only the license in its entirety could be transferred to another party.

2:37:21 PM

Section 43.90.460. Conflicting laws. (page 26, line 18)

Ms. Davis characterized this section as a "boiler plate" assurance that nothing in the chapter was intended to modify or conflict with existing State or federal law.

2:37:38 PM

Section 43.90.470. State pipeline employment development. (line 21)

Ms. Davis informed that this section spoke to the commissioner of the Department of Labor and Workforce Development's commitment to develop a job training program to prepare Alaskans to perform the jobs associated with the construction of a natural gas pipeline.

2:37:57 PM

Article 5. General Provisions.
Section 43.90.900. Definitions. (line 26)

Ms. Davis called attention to paragraph (3) on page 27 line 2, which reads as follows.

(3) "commencement of commercial operations" means the first flow of gas in the project that generates revenue to the owners;

Ms. Davis reported that this was an important "timing benchmark" in AGIA.

Ms. Davis also told that "project" as defined in paragraph (14) on page 28, line 1 would be used throughout the bill to

reference a natural gas pipeline project authorized under this chapter.

Ms. Davis summarized the definition of "sanction" as set forth in paragraph (16) on page 28, line 8 which reads as follows.

> (16) "sanction" means financial commitments to go forward with the project as evidenced by entering into financial commitments of at least $1,000,000,000 with third parties;

2:39:10 PM

Section 43.90.990. Short title. (page 28, line 15)

Ms. Davis acknowledged that this chapter's short title was the Alaska Gasline Inducement Act.

Ms. Davis communicated that Section 2 of the bill would amend AS 36.30.850(b) by adding a list of contracts that would be exempt from the procurement code. The exemption would include contracts for the arbitration panel, contracts to develop the Request for Applications (RFAs) for the license, and contracts to acquire the technical and expert assistance needed to evaluate the contracts.

2:39:49 PM

Ms. Davis spoke to Section 4 of the bill which began on page 28, line 24 and would amend AS 40.25.120(a). This section listed the public records that would not be available for inspection by the public. Records relating to AGIA were specifically listed in subsection (12) on page 30, line 17 as follows:

> (12) records that are
> (A) proprietary or a trade secret in accordance with AS 43.90.150;
> (B) applications that are received under AS 43.90 until notice is published under AS 43.90.160.

Ms. Davis noted that subparagraph (B) provided that applications under AGIA would not be available for review until all applications had been submitted and a determination had been made regarding which applications were complete.

Co-Chair Stedman asked if only complete applications would be available for public review or if all submitted applications would be reviewable.

2:41:20 PM

Ms. Davis was unsure, but would research whether incomplete applications would be made public.

Co-Chair Stedman assumed an application would be considered incomplete if it was missing a "must have".

Ms. Davis affirmed. She directed Members to Section 43.90.160. on page 11 of the bill, lines 1 through 3. She understood this language to restrict the public review and comment process to only those applications deemed complete, but allowed that different interpretations may be plausible. An amendment to the existing language could clarify the intent of the Committee.

2:42:26 PM

Co-Chair Stedman declared the Committee would strive for "openness and clarity".

Ms. Davis informed that Section 5 of the bill on page 30, line 22 would add a new section in uncodified law. An earlier version of the AGIA bill contained a "hard deadline" for the commissioners to publish the RFAs within 90 days of the passage of the bill. This section would modify the absolute deadline of the earlier version to instead express that it was the intent of the legislature that the RFAs be published within 90 days, which would allow for delays due to unforeseen circumstances.

2:43:23 PM

Ms. Davis stated that Section 6 of the bill on page 30, line 28 was language added by the Senate Judiciary Committee. She classified it as an "aspirational statement" requesting that the courts of the State expedite any cases that arose in relation to this chapter.

Ms. Davis told that the severability clause was outlined in Section 7 of the bill on page 31, line 5. This provision would provide that if any portion of AGIA was held invalid, the remainder of the bill would remain intact and enforceable.

AT EASE 2:44:27 PM/2:49:37 PM

KEVIN BANKS, Director, Division of Oil and Gas, Department of Natural Resources introduced himself as the Acting Director of the Division.

2:50:51 PM

Mr. Banks presented a "catalog" of the tax royalty incentives available to developers and explorers in Alaska utilizing a handout titled "Oil and Gas Incentives" [copy on file]. The exploration credits offered to the oil and gas industry to stimulate exploration and development were incorporated in AGIA. Those credits would be available to any entity that entered the market. AGIA contained "upstream" benefits, and awarded them in a manner that further "leveled the playing field". The exploration and tax incentives he would speak of were available to all parties, and therefore provided no advantage to any particular company or entity.

2:53:13 PM

Mr. Banks informed that the credits offered thus far were focused on oil development prospects with an expectation that gas would likely be discovered with oil. While physical access to the pipeline was not currently an issue of concern, access to facilities may prove to be. He reminded that the oil "net-back" value used to evaluate prospects considered as a part of its calculation a deduction for the cost of transportation, which was much less for oil than for gas.

Mr. Banks offered an example of the "net-back" calculation. In calculating the net-back for oil, approximately $4 to $6 in marine transportation costs and the Trans Alaska Pipeline System (TAPS) tariff would be deducted, and would amount to approximately $6 to $7. A tariff deduction of $2 for gas would be equivalent to a $14 deduction for a barrel of oil. Thus, gas required nearly twice the amount of energy to transport to market than does oil. Due to the significance of the transportation deduction AGIA would attempt to "moderate" the impact on explorers by widening the incentives relating to gas.

2:55:35 PM

Mr. Banks referred to pages 2 and 3 of the handout. This consisted of a spreadsheet titled "Incentive Grid" dated 1-24-07.xls. and provided the following information.

[Exploration Incentive Credits (EIC)

Current Incentives: AS 38.05.180(j)
Conventional Leases: up to 50% of drilling costs
Unleased State Land: up to 50% of seismic costs
Licensed Land: N/A
SNG Leases: up to 50% of drilling costs
Federal & Private Land: N/A

Current Incentives: AS 41.09.010 -- expires 7-1-2007
Conventional Leases: N/A
Unleased State Land: up to 50% of drilling & seismic costs
Licensed Land: up to 50% of drilling & seismic costs
SNG Leases: N/A
Federal & Private Land: up to 25% of drilling & seismic costs

Exploration Tax Credit

Current Incentives: AS 43.55.025_ (03.185)
Conventional Leases: As much as 40% of drilling costs, or
Unleased State Land: As much as 40% of drilling costs, or
Licensed Land: As much as 40% of drilling costs, or
SNG Leases: As much as 40% of drilling costs, or
Federal & Private Land: As much as 40% of drilling costs, or

Current Incentives: Expires 7-1-2007 for NS (05-286)
Conventional Leases: As much as 40% of seismic costs
Unleased State Land: As much as 40% of seismic costs
Licensed Land: As much as 40% of seismic costs
SNG Leases: As much as 40% of seismic costs
Federal & Private Land: As much as 40% of seismic costs

Current Incentives: Expires 7-1-2010 for non-NS
Conventional Leases:
Unleased State Land:
Licensed Land:
SNG Leases:
Federal & Private Land:

Current Incentives: AS 43.20.043 -- expires 1-1-2013
(03.61)
Conventional Leases: 10% of capital investment
Unleased State Land: 10% of capital investment
Licensed Land: 10% of capital investment
SNG Leases: 10% of capital investment
Federal & Private Land: 10% of capital investment

Current Incentives: for below 68^{o} latitude***(see note)
Conventional Leases: 10% of annual cost
Unleased State Land: 10% of annual cost
Licensed Land: 10% of annual cost
SNG Leases: 10% of annual cost
Federal & Private Land: 10% of annual cost

Royalty Reduction

Current Incentives: AS 38.05.180(j) (03.28)
Conventional Leases: as low as 5% if new production
Unleased State Land: N/A
Licensed Land: (Applies after conversion to Lease)
SNG Leases: as low as 5% if new production
Federal & Private Land: N/A

Current Incentives:
Conventional Leases: as low as 3% if producing or shut-in
Unleased State Land:
Licensed Land: (Applies after conversion to lease)
SNG Leases: as low as 3% if producing or shut-in
Federal & Private Land:

Current Incentives: AS 38.05.180(f)(6) (03.185)
Conventional Leases: As low as 5% for oil production from CI platforms if production falls below specified levels
Unleased State Land: N/A
Licensed Land: N/A
SNG Leases: N/A
Federal & Private Land: N/A

Discovery Royalty

Current Incentives: AS 38.05.180(f)(4) for Cook Inlet only
Conventional Leases: 5% royalty for 10 yrs
Unleased State Land: N/A

Licensed Land: (In limited area after conversion: T18N)
SNG Leases: (Applies to limited area: T18N)
Federal & Private Land: N/A

Current Incentives: Pre-1969 leases only, statewide
Conventional Leases: 5% royalty for 10 yrs
Unleased State Land: N/A
Licensed Land: N/A
SNG Leases: N/A
Federal & Private Land: N/A

Current Incentives: AS 38.05.180(f)(5) for the following fields only: Falls Creek, Nicolai Creek, Starichkof, North Fork, Redoubt Shoals, & West Foreland field must be in production by 1-1-2004
Conventional Leases: 5% on 1st 25 MM bbls for 10 yrs
5% on 1st 35 BCF for 10 yrs
Unleased State Land: N/A
Licensed Land: N/A
SNG Leases: N/A
Federal & Private Land: N/A

Current Incentives: Economic Limit Factor based Ceiling--AS 43.55.011(j)(k)
Conventional Leases: Yes
Unleased State Land: N/A
Licensed Land: (Applies after conversion to Lease)
SNG Leases: Yes
Federal & Private Land: Yes

Current Incentives: Contract Gas Price with a Utility vs Royalty Value -- AS 38.05.180(aa)
Conventional Leases: Value of state's royalty share equals gas contract price
Unleased State Land: N/A
Licensed Land: (Applies after conversion to Lease)
SNG Leases: Value of state's royalty share equals gas contract price
Federal & Private Land: Value of state's royalty share equals gas contract price

Current Incentives: Value of state's royalty gas used for ag products -- AS 38.05.180(ee)
Conventional Leases: Negotiated Value
Unleased State Land: N/A

Licensed Land: (Applies after conversion to Lease)
SNG Leases: Negotiated Value
Federal & Private Land: Negotiated Value

***If requesting this credit, not eligible for any other tax credits or royalty modifications]

Mr. Banks testified that he would review the information in the table while "glossing over" issues relating specifically to Cook Inlet, but commented that Cook Inlet gas could contribute to a major gas pipeline sometime in the future under the right market conditions.

Mr. Banks stated that the Exploration Incentive Credits (EIC) under AS 38.05.180(i) related to credits incorporated into a lease at the time the lease was sold. This was an incentive credit the commissioner could offer in addition to royalty rates or work commitments at the time a lease was sold. These credits could also be offered for geophysical work on State land, but were limited to 50 percent of the costs.

Mr. Banks remarked that AS 41.09.010 provided for a similar incentive program designed to compliment the State's licensing program and was also applied to non-state land. This program allowed the State to pay up to 50 percent of drilling and seismic costs in the form of royalty or tax credits, as determined by the commissioner.

2:57:48 PM

Senator Huggins noticed an expiration date attached to the aforementioned incentive credits. He asked if that was of concern to the Department.

Mr. Banks responded that no applications had been made for those credits, which he assumed was due to the requirement in the statute that information provided to the Department of Natural Resources in the course of the application be made public after a lease sale occurred. He opined that the "potential exposure" acted as a disincentive for the use of the credit.

Senator Huggins concluded the credit was "dysfunctional".

Mr. Banks agreed. He went on to note the importance for the State to acquire the information, and expressed that some other

mechanism should be designed to facilitate the sharing of information. He stated: "It is in sharing information in this business that, actually, some of the best incentives can occur for new players."

2:59:25 PM

Senator Thomas asked regarding the commencement date of the AS 38.05.180(i) tax credit.

Mr. Banks shared that the credit had been available throughout his employment with the State.

Senator Thomas asked if the witness would estimate the credit existed prior to the development of the Prudhoe Bay oil fields.

Mr. Banks told that the statutes effecting the Department of Natural Resources were changed drastically in 1979 and speculated that the statute in question was modified at that time. He would research that issue.

Senator Thomas asked the establishment dates of all the credits.

3:00:19 PM

Mr. Banks spoke to the Exploration Tax Credits offered by the Department of Revenue. He referred to AS 43.55.025 as the "20/20 exploration tax credit", and told that the amount of the credit depended on the distance between the producer and existing infrastructure. Exploration taking place between July 1, 2003 and July 1, 2016 would be eligible for credit for drilling or other seismic geophysical work provided that the exploration occurred outside of units in existence on May 13, 2003. A 20 percent credit could be granted by the commissioner of revenue for exploration more than three miles away from an established well. An additional 20 percent credit could be granted if the drilling occurred more than 25 miles away from an existing unit on the North Slope, or ten miles in Cook Inlet.

3:02:47 PM

Mr. Banks noted that AS 43.20.043 applied to Cook Inlet or other areas south of the 68^{o} latitude, and represented a capital credit of up to ten percent of qualified capital expenditures and ten percent of annual costs. That credit became available in June,

2003 and could not exceed 50 percent of the tax liability. "Carry forwards" were allowed under this provision, and transfers were prohibited unless in connection with the sale of the property.

3:03:51 PM

Senator Elton asked how AS 43.55.025 related to the Petroleum Profits Tax (PPT) legislation passed by the previous legislature.

3:04:05 PM

Mr. Banks replied that it was "additive", as companies could benefit from both credits.

Senator Elton asked for confirmation of whether credits could be "stacked".

3:04:52 PM

Mr. Banks pointed out that under AS 43.20.043, a producer could not take any additional credits.

Mr. Banks reported that AS 38.05.180(j) related to the royalty modification offered by the Department of Natural Resources for three types of projects. This change in the royalty rate was available for new fields that were "sufficiently delineated" to demonstrate that they had not been previously produced and would not otherwise be economically feasible; to extend a field's life at a time when revenues were less than the operating costs of maintaining the field; and for fields that were currently "shut-in" but could resume production.

Mr. Banks admitted this was "one of the longest provisions in our oil and gas statutes" and that eligibility for this credit required clear proof that the project needed royalty relief. A "sliding scale" royalty would replace the fixed royalty, and would be adjusted by price and other factors, but could not be less than five percent. The benefit was not assignable to another lessee without permission from the commissioner. It also required a public finding that the royalty relief was in the State's best interest, and that provided for public comment. In the past 18 months the State had reviewed applications and awarded a royalty modification to Pioneer for activities

conducted at the Oooguruk unit, and denied a requested modification to another company at a different location.

3:08:47 PM

Co-Chair Stedman asked Mr. Banks to "jump" to the second page of the table where PPT credits were addressed.

Mr. Banks agreed.

3:09:35 PM

Mr. Banks directed Members to the second page of the spreadsheet, which contained the following information.

Current Incentives: Qualified CapEx Credits (PPT) -- AS 43.55.023(a)
transferrable credit against PPT
Conventional Leases: up to 20% of capital expenditures
Unleased State Land: N/A
Licensed Land: up to 20% of capital expenditures
SNG leases: up to 20% of capital expenditures
Federal & Private Land: up to 20% of capital expenditures

Current Incentives: Loss Carry-Forward Credits (PPT) -- AS 43.55.023(b)
transferrable credit against PPT
Conventional Leases: up to 20% of capital expenditures
Unleased State Land: N/A
Licensed Land: up to 20% of capital expenditures
SNG leases: up to 20% of capital expenditures
Federal & Private Land: up to 20% of capital expenditures

Current Incentives: Transition Investment Expenditure Credits (PPT) -- AS 43.55.023(i)
non-transferrable credit against PPT
Expires at the end of 2013
Conventional Leases: up to 20% of 2001-2006 capital expenditures
Unleased State Land: N/A
Licensed Land: up to 20% of 2001-2006 capital expenditures
SNG leases: up to 20% of 2001-2006 capital expenditures
Federal & Private Land: up to 20% of 2001-2006 capital expenditures

Current Incentives: Frontier Basin Production Credit -- AS 43.55.023(a)
non-transferrable credit against PPT
(for production south of 68 latitude and outside Cook Inlet basin)
Expires at the end of 2016
Conventional Leases: up to $6MM
Unleased State Land: N/A
Licensed Land: (Applies after conversion to Lease)
SNG leases: up to $6MM
Federal & Private Land: up to $6MM

Current Incentives: Small Producer Credit -- AS 43.55.023(c)
non-transferrable credit against PPT
($12 MM for production <50,000 BOE/day, declining on a sliding scale to $0 for production >100,000 BOE/day)
Conventional Leases: up to $12MM
Unleased State Land: N/A
Licensed Land: (Applies after conversion to Lease)
SNG leases: up to $12MM
Federal & Private Land: up to $12MM

Incentives as Part of a Program: Exploration Licensing AS 38.05.132
Conventional Leases: N/A
Unleased State Land: N/A
Licensed Land: Up to 500,000 acres per license
One-time $1/acre license fee
No bonus bid
No annual rental
Sole right to O & G leases
SNG Leases: N/A
Federal & Private Land: N/A

Incentives as Part of a Program: Nonconventional Gas Incentive-- AS 38.05.180(n)(2) (04.531)
Conventional Leases: reduced rental
6.25% royalty if no competition with 12.5% leasee
Unleased State Land: N/A
Licensed Land: (Applies after conversion to Lease)
SNG Leases: N/A
Federal & Private Land:

Mr. Banks informed that the PPT offered capital expenditure credits of up to 20 percent, and "carry forward" credits of up to 20 percent, both of which were transferable. Transitional Investment Expenditures, or TIE, credits were also applicable for up to 20 percent of qualified capital expenses for the years of 2001-2006, but were not transferable. The Frontier Basin Credits were not applicable to the Cook Inlet or North Slope areas, but provided an additional deduction in some circumstances. He remarked that the sum of these available credits was "sizeable".

3:11:29 PM

Mr. Banks set forth that the "small producer credits" were available under AS 43.55.023(c) for fields that produced less than 100,000 barrels of oil per day. The credit ranged from $6 million to $12 million and diminished as the amount of production increased. The credit was applied to the company producing the oil, not specifically to a project.

3:12:52 PM

Mr. Banks referred to the final type of incentives as "programmatic credits". These credits included exploration licensing and the Nonconventional Gas Incentive under AS 38.05.180(n)(2). The exploration licensing credit was beneficial to explorers in that it allowed leases without the "bonus bidding" that occurred in traditional practices. The Nonconventional Gas Incentive was available for leases in areas that did not compete with existing producing leases, and provided for a reduced royalty rate of 6.25 percent rather than the standard 12.5 percent.

3:14:25 PM

Mr. Banks shared that he had been asked to speak to Outer Continental Shelf (OCS) and National Petroleum Reserve-Alaska (NPR-A) incentives that may be available to producers operating in those areas. On April 18, 2007 the U.S. Minerals Management Service (MMS) held a sale of lease tracks in the Beaufort Sea. The sale resulted in the collection of $42 million in bonus bids and the sale of 92 lease tracks. The area was divided into two regions: one that was close to infrastructure, zone A, and one that was not, zone B. The zone A leases that were near the shore and existing facilities were offered at a 12.5 percent royalty

and approximately a $5 per acre minimum bid, as well as a royalty suspension program. Under that program, the first volume of gas produced would be royalty free, depending on the size and location of the lease.

3:16:15 PM

Mr. Banks continued by providing an example of a zone A lease totaling less than 2,000 acres, in which the first 10 million barrels of oil would be free of royalty. A lease of equal size in zone B, farther from existing infrastructure, would enjoy royalty-free production on the first 15 million barrels of oil. He noted that tracts larger than approximately 3,800 acres also received increased royalty suspension benefits.

Mr. Banks qualified that the royalty relief applied only to oil production, and if the price exceeded $41.50 per barrel, standard royalty rates applied with any production counted against the royalty suspension volume. The lease agreement also included a "floor" for the price of oil, with all royalties deferred if the price per barrel of oil fell below $21. Production in that instance would not be calculated towards the suspension volume.

3:18:14 PM

Mr. Banks characterized the lease agreements offered by the MMS as "aggressive", but pointed out that the reward was earned by the leaseholder after production had occurred. He stated that the State's incentives differ in that they assumed some of the exploration risk, and could result in no net gain if oil or gas was not identified. The NPR-A incentive credits were not as "aggressive" as the OCS program. The State PPT credits would apply and the federal Bureau of Land Management (BLM) offered slightly lower royalty rates for leases in the more "prospective" areas, as well as somewhat lower minimum bids on those lands.

3:20:18 PM

Senator Olson asked if significant differences existed in the exploration incentive credits offered for onshore and offshore leases. As a representative of the area with offshore potential, he informed that his constituents had expressed "hostility" towards the prospect of offshore drilling.

3:21:26 PM

Mr. Banks responded that all the incentives offered by the State applied equally to onshore leases and offshore leases within three miles of the coast. Leases farther than three miles offshore were under federal jurisdiction.

3:22:06 PM

Senator Elton voiced interest in the "stack" provisions, and how the PPT credits could be employed in conjunction with other incentive credits.

3:22:32 PM

Mr. Banks referred to the Oooguruk project as an example in which royalty relief was awarded to the lessee by the State, resulting in the "transformation" of the area, with construction and drilling currently underway. The PPT provisions applied to that lessee interacted with the royalty modifications in two ways. First, the State's royalty was reduced from 12.5 percent to five percent, which had the effect of increasing the revenues for the resource owner. That revenue would be included in the calculation of the production tax owed to the State. The credits offered by the Department of Natural Resources for up to 50 percent of capital expenditures related to drilling costs would reduce capital expenditures that would qualify for PPT, thus reducing costs that would be available for tax deductions. He summarized that no "double dipping" occurred, as the Department of Natural Resources' incentives operated in accord with the PPT tax credits.

3:25:11 PM

Co-Chair Stedman asked that the commissioner of the Department of Revenue speak to fiscal implications.

3:25:38 PM

Senator Huggins deduced that "some of the tools at the disposal of the Department are much more robust than PPT," and asked if Mr. Banks would agree with that statement.

Mr. Banks replied that the Department of Natural Resources had only the ability to reduce royalties from approximately 12 percent to five percent. He observed that fluctuations in the price of oil had a greater influence on the value of a project. The 50 percent exploration credits applied only to the first well drilled in exploration, and only to the geophysical efforts. He opined that the 20 percent capital expense credits under PPT had "a lot more horsepower" than the incentives offered by the Department of Natural Resources.

Senator Huggins clarified that he was referring to the 40 percent exploration tax credit.

Mr. Banks informed that the Department of Natural Resources did not automatically offer that credit.

3:28:00 PM

Co-Chair Stedman asked that Commissioner Pat Galvin provide information to the Committee regarding the relationship between the PPT credits and a gas treatment plant (GTP).

PAT GALVIN, Commissioner, Department of Revenue, responded that no such credit was associated with the PPT.

Co-Chair Stedman corrected that he was referring to "AGIA" as the gasline, and asked how the credit could and could not be applied.

3:28:54 PM

Mr. Galvin set forth that under PPT, capital expense deductions were allowed for a "lease hold expense", which was defined as any expense upstream of the point of production. The point of production was where the product changed custody at the first metering station. It was the Department's expectation that gas would pass through the first metering station before entering the GTP. Thus, the GTP would be downstream from the point of production and not eligible for the capital expense deduction under PPT.

3:30:08 PM

Mr. Galvin explained that PPT would allow upstream expenses related to an exploration well to be deducted from a company's

profits at a value of 22.5 percent. An additional capital credit of 20 percent would be available, and for next seven years that exploration well could be used to "pull in" expenditures that preceded the enactment of the PPT legislation, resulting in an further 10 percent reduction.

3:30:49 PM

Mr. Galvin estimated the total deductions in the aforementioned scenario would range from 42.5 percent to 52.5 percent, depending on the time the exploration occurred. In comparison to the exploration tax credit available through the Department of Natural Resources, the PPT structure was preferable to the producer. Seismic operations would likely not be included in PPT deductions, thus the 40 percent credit under the Department of Natural Resources incentives would be preferable.

3:31:51 PM

Mr. Banks spoke of the Oooguruk project as an example of the use of the credits under consideration. The project was examined with the existing lease royalties, excluding the PPT credits, and then compared the calculation to the employment of royalty relief. The result was that at a mean price of $33 per barrel, the use of the PPT provisions increased the producer's net present value (NPV) by approximately $21 million, and added 1.3 percent to the rates of return. He summarized the findings as indicative that royalty modifications improved the economic situation of the producer. When PPT was compared to the prior tax structure referred to as the Economic Limit Factor, or ELF, without the inclusion of royalty relief provisions, the producer's NPV increased $89 million at a price of $33 per barrel, with an additional rate of return of approximately 6.5 percent.

3:33:51 PM

Co-Chair Stedman stated:

> More on point to what we're dealing with with AGIA is PPT relationship to the GTP plant, the gasline, feeder lines, how all that interexchange, and then also offshore gas coming onshore and the impact on rolled-in rates and volume and is it going to squeeze out and impact exploration on land with the huge volumes offshore and some limited

capacity of the size of whatever line is gonna be built. More in that direction than heading down into the whole PPT comparisons.

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ADJOURNMENT

Co-Chair Bert Stedman adjourned the meeting at 3:37:21 PM