ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
March 7, 2016
1:10 p.m.

MEMBERS PRESENT

Representative Benjamin Nageak, Co-Chair
Representative David Talerico, Co-Chair
Representative Bob Herron
Representative Craig Johnson
Representative Kurt Olson
Representative Paul Seaton
Representative Andy Josephson
Representative Geran Tarr

MEMBERS ABSENT

Representative Mike Hawker, Vice Chair

COMMITTEE CALENDAR

HOUSE BILL NO. 247
"An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the

limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

- HEARD AND HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 247
SHORT TITLE: TAX;CREDITS;INTEREST;REFUNDS;O & G
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

01/19/16	(H)	READ THE FIRST TIME - REFERRALS
01/19/16	(H)	RES, FIN
02/03/16	(H)	RES AT 1:00 PM BARNES 124
02/03/16	(H)	Heard & Held
02/03/16	(H)	MINUTE(RES)
02/05/16	(H)	RES AT 1:00 PM BARNES 124
02/05/16	(H)	Overviews Continued from 2/3/16 Meeting:
02/10/16	(H)	RES AT 1:00 PM BARNES 124
02/10/16	(H)	Heard & Held
02/10/16	(H)	MINUTE(RES)
02/12/16	(H)	RES AT 1:00 PM BARNES 124
02/12/16	(H)	Heard & Held
02/12/16	(H)	MINUTE(RES)
02/13/16	(H)	RES AT 1:00 PM BARNES 124
02/13/16	(H)	-- Public Testimony Postponed --
02/22/16	(H)	RES AT 1:00 PM BARNES 124
02/22/16	(H)	Heard & Held
02/22/16	(H)	MINUTE(RES)
02/24/16	(H)	RES AT 1:00 PM BARNES 124
02/24/16	(H)	Heard & Held
02/24/16	(H)	MINUTE(RES)
02/25/16	(H)	RES AT 8:30 AM BARNES 124
02/25/16	(H)	Heard & Held
02/25/16	(H)	MINUTE(RES)
02/25/16	(H)	RES AT 1:00 PM BARNES 124
02/25/16	(H)	Heard & Held
02/25/16	(H)	MINUTE(RES)
02/26/16	(H)	RES AT 1:00 PM BARNES 124

02/26/16	(H)	Heard & Held
02/26/16	(H)	MINUTE(RES)
02/27/16	(H)	RES AT 10:00 AM BARNES 124
02/27/16	(H)	Heard & Held
02/27/16	(H)	MINUTE(RES)
02/29/16	(H)	RES AT 1:00 PM BARNES 124
02/29/16	(H)	Heard & Held
02/29/16	(H)	MINUTE(RES)
02/29/16	(H)	RES AT 6:00 PM BARNES 124
02/29/16	(H)	Heard & Held
02/29/16	(H)	MINUTE(RES)
03/01/16	(H)	RES AT 1:00 PM BARNES 124
03/01/16	(H)	Heard & Held
03/01/16	(H)	MINUTE(RES)
03/02/16	(H)	RES AT 1:00 PM BARNES 124
03/02/16	(H)	Heard & Held
03/02/16	(H)	MINUTE(RES)
03/02/16	(H)	RES AT 6:00 PM BARNES 124
03/02/16	(H)	Heard & Held
03/02/16	(H)	MINUTE(RES)
03/07/16	(H)	RES AT 1:00 PM BARNES 124

WITNESS REGISTER

KEN ALPER, Director
Tax Division
Department of Revenue (DOR)
Juneau, Alaska
POSITION STATEMENT: During the hearing on HB 247, provided a PowerPoint presentation on behalf of the governor entitled, "Oil and Gas Tax Credit Reform- HB247, Additional Modeling and Scenario Analysis - Part 2a."

DAN STICKEL, Assistant Chief Economist
Tax Division
Department of Revenue (DOR)
Juneau, Alaska
POSITION STATEMENT: During the hearing on HB 247, answered questions on behalf of the governor.

CHERIE NIENHUIS, Commercial Analyst
Tax Division
Department of Revenue (DOR)
Anchorage, Alaska
POSITION STATEMENT: During the hearing on HB 247, answered questions on behalf of the governor.

ACTION NARRATIVE

1:10:12 PM

CO-CHAIR BENJAMIN NAGEAK called the House Resources Standing Committee meeting to order at [1:10] p.m. Representatives Olson, Seaton, Josephson, Johnson, Talerico, and Nageak were present at the call to order. Representatives Tarr and Herron arrived as the meeting was in progress.

HB 247-TAX;CREDITS;INTEREST;REFUNDS;O & G

1:11:08 PM

CO-CHAIR NAGEAK announced that the only order of business is HOUSE BILL NO. 247, "An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures

applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

1:11:26 PM

KEN ALPER, Director, Tax Division, Department of Revenue (DOR), on behalf of the governor, provided a PowerPoint presentation entitled, "Oil and Gas Tax Credit Reform- HB247, Additional Modeling and Scenario Analysis - Part 2a." Displaying slide 2, "What We'll Be Discussing," he said today's presentation is a continuation of the deeper details of the proposed provisions in HB 247. He said he will start by looking at how the proposed minimum tax in the bill would affect some of the economics of current production and then he will look at how the proposed credit changes would impact the analysis of a new field on the North Slope and in Cook Inlet.

MR. ALPER turned to slide 3, "North Slope Production Tax Snapshot With Impact of Minimum Tax Changes." He then turned to slide 4, "Assumptions," to outline the assumptions used in DOR's modeling. He said the department's model is called the Snapshot, a comingled map of all of the oil fields working together, and therefore it doesn't incorporate the specifics of any individual producer. He drew attention to DOR's assumptions shown in yellow from DOR's fall 2015 Revenue Sources Book, which forecasts for fiscal year (FY) 2017: average per barrel (bbl) transportation cost - $11.16; state royalty rate - 12.5 percent; average state corporate income tax (CIT) rate - 6.5 percent based on apportionment formula applied to the state's statutory 9.4 percent rate; federal CIT rate - 35 percent; total per barrel of [deductible] upstream capital expenditures ("capex") and operating expenditures ("opex") - [$31.62]; total FY 2017 production [at 1,000 barrels/day] - $504,900; and state's share of property tax per barrel produced - $1.25.

MR. ALPER explained that the chart on slide 5, "FY 2017 snapshot (legacy oil)," is the format used during DOR's presentations for Senate Bill 21 [passed in 2013, Twenty-Eighth Alaska State Legislature]. The chart shows the split of producer, state, and federal share of profit across a range of prices. The versions of the chart that were before the committee a few years ago didn't contemplate the lower prices being seen today. At an oil price of $50 a barrel state take is 98 percent and at $40 the state take is in excess of 100 percent because the companies are effectively losing money and because of the impact of the minimum tax. At $90 total state and federal government take is

60 percent; at $60 total government take is 70 percent; and at $70 total government take is 62 percent.

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REPRESENTATIVE JOSEPHSON, regarding the state taking in excess of 100 percent at a price of $40, inquired whether the credits have been subtracted.

MR. ALPER replied no, the calculation here is simply that the divisible profit is less than $0 because the companies are losing money on cash flow. So, any state take, in this case the minimum tax, is more than 100 percent of the divisible profit.

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MR. ALPER said the chart on slide 6, "FY 2017 snapshot (legacy oil) with 5 [percent] min. tax," is the same analysis if the minimum tax were increased from 4 percent to 5 percent. At a price of $80 a barrel total state and federal government take is 60 percent; [at $90 government take totals 60 percent and at $130 government take totals 66 percent]; at $70 total government take is 64 percent. At a price of $50 a 5 percent minimum state tax would take 102 percent of divisible profits. So, when in marginal places where there are no profits to divide, the increase to the minimum tax has the most impact.

MR. ALPER stated that the chart on slide 7, "FY 2017 snapshot (new oil)," provides the same analysis on new oil, oil that is eligible for the Gross Value Reduction (GVR). For new oil, government takes across the board are quite a bit lower at the higher prices, ranging from 57-58 percent. At $50 state take is 81 percent as opposed to 98 percent for legacy oil. The main reason for this difference is that new oil is not required to pay at the minimum tax level. Producers are able to use their per taxable barrel credits to reduce payments all the way down to $0 and therefore they are able to pay at the lower level, so the total state and federal government take is 88 percent.

MR. ALPER displayed slide 8, "FY 2017 snapshot (new oil) with 5 [percent] min. tax and hard floor," and pointed out that layering in the changes proposed in HB 247 would result in a dramatic change at, say, a price of $50 because in addition to having to pay the higher minimum tax of 5 percent the producers must pay a minimum tax. Under current law, new oil eligible for GVR benefits can go to zero, while the proposed changes would prevent that. Therefore, at the lower prices, the economics on

slide 8 are similar to the economics on slide 6 because the GVR becomes immaterial due to the imposition of the minimum tax.

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Mr. ALPER next discussed the distribution of revenues for North Slope production with the proposed minimum tax changes [slide 9]. He explained that the two charts on slide 10, "Distribution of Revenues for Legacy Oil, $40," represent a barrel of oil that is divided. The charts take the value of a barrel oil and show what the cost is, what the state's share is, and what the different tax slices are of the value. At a price of $40 it is a money-losing proposition and therefore numbers go below the zero line. [Under current law of Senate Bill 21], at a price of $40 the producers have an estimated operating loss of $7.39 per barrel (blue bar) and the total government take is $5.86 (green bar). If HB 247 was passed as written, the main change at a price of $40 would be the 5 percent minimum tax, which would add about $.26 to the state's take and which is $.26 that would come out of the producers' piece.

MR. ALPER displayed slide 11, "Distribution of Revenues for Legacy Oil, $60," and continued the aforementioned discussion at a price of $60. At $60 the industry does see profits, he said, although relatively small ones compared to historic norms. [Under current law], at $60 the producer share of the divisible profit after all costs and all taxes would be $5.72. If HB 247 passed as written, there would be the reduction of $.26 that brings the producer share of the divisible profit down to $5.46. Government take would go up by the same $.26 to $13.01. These numbers line up to that roughly 70 percent government take calculation seen a few slides ago.

MR. ALPER showed slide 12, "Distribution of Revenues for Legacy Oil, $80," and continued the aforementioned discussion at an oil price of $80. He said this is the highest price that DOR looked at for the purpose of the analysis for this presentation. At $80 there is no change - the producer share is $15.56 under current law and would still be $15.56 if HB 247 were passed. This is because at a price of $80 the minimum tax is not part of the calculation; there is enough profit and enough value that the state is actually receiving the full 35 percent tax, less per taxable barrel credits, and therefore the change to the minimum tax doesn't have any impact. This would also be the case at any price above $80 a barrel.

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MR. ALPER pointed out that the next three slides are the same as the previous three, only rather than for legacy oil they are for new oil, oil that is eligible for the Gross Value Reduction (GVR). Moving to slide 13, "Distribution of Revenues for New Oil, $40," he said that [under current law] the producers are losing $6.39 per barrel. If HB 247 was passed, the producers would lose $7.65 per barrel, an increase of $1.25, and the government take would correspondingly increase by $1.25.

MR. ALPER displayed slide 14, "Distribution of Revenues for New Oil, $60," and noted that the producer share [under current law] is $6.76; if HB 247 was passed it would be $5.46, which is $1.30 less. [Government take would be raised to $13.01.] The after effects of HB [247] would make these numbers look identical to the non-GVR oil, essentially. By throwing in the minimum tax requirements of legacy oil at the lower prices there is no benefit to the Gross Value Reduction.

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REPRESENTATIVE JOSEPHSON posed a hypothetical scenario in which the GVR concept was in effect in 1967 when oil was discovered in Prudhoe Bay. He asked whether under the existing definition of GVR the Prudhoe Bay oil would still be treated as new oil today.

MR. ALPER replied that the definition of new oil in statute is a field that was unitized subsequent to 2003. Had a net profits tax regime with a new oil provision been passed back in the 1960s, yes, if Prudhoe were to fit under that definition then, there is no mechanism by which oil would graduate and go from being new oil to being old oil. Once something qualifies for new oil, the way Alaska statutes are currently written it remains new oil indefinitely.

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MR. ALPER addressed slide 15, "Distribution of Revenues for New Oil, $80." He reminded members that for legacy oil at a price of $80 there would be no impact from the changes contemplated by HB 247. However, he continued, for new oil there would be an increase of $.97 because of the GVR benefits. The cross over point, the place where a producer would switch over from paying at the minimum tax rate to paying at the full tax rate is actually a few dollars higher.

MR. ALPER next discussed DOR's field life cycle modeling for the North Slope [slide 16]. Turning to slide 17, "North Slope Life Cycle Modeling Assumptions," he explained that DOR modeled two field sizes on the North Slope, a small field of 50 million barrels of oil (MMbo) and a large field of 750 MMbo. The small field is analogous to some of the smaller fields that have come into production in the last few years as well as some that are under development, or under active exploration or delineation right now. The 750 million barrel field is a much larger type of field, something along the lines of the Alpine Field [also known as Colville River Unit]. Although it doesn't directly model the expectations of, say, the large Armstrong/Repsol development [Pikka Unit], it could in some ways be seen as a proxy for that.

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REPRESENTATIVE SEATON asked whether a 50 MMbo field is analogous to 15,000 barrels a day at peak production in the life cycle.

MR. ALPER responded yes, about 15,000 barrels a day.

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MR. ALPER continued his discussion of the assumptions outlined on slide 17, noting that in modeling the two field sizes, two types of producers were modeled - those producers eligible for cash refunds and that under HB 247 would be imposed a $25 million limit per company per year, and those new producers with worldwide revenue greater than $10 million that under HB 247 would not be eligible to receive any credit in cash and would have to roll it all forward until production occurs. The prices modeled were for $40, $60, and $80 held static, uninflated, through the life of the field as well as the fall 2015 forecast price, which is in the $50s now and moving up gradually into the $70s for the bulk of the study time. The fall 2015 forecast numbers will often split the difference of the $60 and $80 as far as the net result. The two tax systems modeled were the status quo system with new fields qualifying for the 20 percent GVR that would be in place throughout the life cycle of the field, and the system that would be put in place under HB 247. He said DOR is willing to do custom modeling per the committee's request. Today's modeling includes all the changes proposed in HB 247: an increase and hardening of the minimum tax; limit on the credits/refunds by the dollar amount, worldwide revenues, and the 10-year expiration of Net Operating Loss Credits; and

that the GVR cannot be used to increase the size of the net operating loss (NOL).

MR. ALPER displayed slide 18, "North Slope Life Cycle Modeling Assumptions, 50 mmbo field assumptions," and outlined the assumptions for this size field: field life cycle - 30 years; peak oil production - 15,000 barrels per day; transportation cost - $10 per barrel from wellhead to Pump Station 1 to the pipeline to marine transport; royalty rate - 12.5 percent; capital expenditure - $18 per barrel, generally frontloaded in the beginning of a project; operating expenditure - $15 per barrel, which is more back loaded, running alongside the production itself; property tax - $1.25 per barrel; [state corporate income tax (SCIT) rate - 6.5 percent of production tax value (PTV) after production tax; and federal corporate income tax rate - 35 percent of PTV after SCIT]. He noted that the production, and state and federal corporate income tax rates line up with the existing rates.

1:26:51 PM

MR. ALPER moved to slide 19, "North Slope Life Cycle Modeling, 50 mmbo Status Quo, $40/bbl," the first of four modeling slides for a 50 MMbo field under the status quo tax system. He said the series of three graphs on this slide will be seen on all of the slides related to life cycle modeling. The upper left graph is the state's cash flow from the production tax program itself. Any numbers below the line (red bars) are paying out credits, so are negative revenues. Any numbers above the line (blue bars) are positive payments under the production tax. At a price of $40 there is not much positive payment. The upper right graph is total state take, which is in many ways more important, and includes the royalty, the corporate income tax, [property tax, and production tax], with the production tax depicted in green. The lower left graph is the producer's cash flows. It represents the producer's spending money and getting some fraction of it back in credits. The lower right chart is an aggregate and summary of the data to come up with discounted numbers. He said DOR chose to use a net present value (NPV) discount rate of 6.15 percent. Elaborating, he said this type of analysis originated last year with some specific requests made to the Tax Division by Representative Seaton. The division did the modeling at that time based on what was then the Permanent Fund Corporation's expected 10-year return, so "we were saying the state's loss of money." The permanent fund subsequently revised that number upward to 6.9 percent, but the model still uses the 6.15 percent. The modeling uses the same

number for the producers as for the state. The hurdle rates used by the companies tend to be a little bit higher, he allowed, companies want to make a higher rate of return on their money than 6 percent. But, he explained, in the interest of equity and symmetry the same discounted cash flow was used for the investor as for the state.

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REPRESENTATIVE JOSEPHSON, regarding the modeling on slide 19, surmised that Company X was successful in finding a 15,000 barrel a day field and would do so for 30 years. Noting that a lot of companies haven't found anything yet, he surmised that these slides are portraying a success story.

MR. ALPER answered yes, the company has found a field and now is starting to develop it. What is seen in the graph in the lower left corner is all the spending that ramps up as the company starts building the oil field and bringing it into production.

1:30:31 PM

MR. ALPER returned to his discussion of slide 19 and noted that no matter how big or small the field and no matter the tax structure of status quo or under HB 247, no field makes any money at a price of $40 a barrel. By the time positive cash flow is reached for a field of 15,000 barrels a day at a price of $40 the state will have cashed out $221 million in production tax credits. Very little tax will ever actually be paid because of the continued low prices. Referring to the bottom right chart, he reported that the effective discounted loss to the state through the production tax system is negative $153 million. Things are better for the state when the royalty and other state revenues are included, but still the state's overall cash flow loss is $24 million. When the time value of money is included (the discounted cost) the state loses $58 million and the producers themselves will have spent $365 million and gained $384 million, so the producers are barely cash flow positive. However, because of the time value of money, the producers show a substantial loss of $99 million.

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REPRESENTATIVE OLSON inquired whether any credits are available after 50,000 barrels a day.

MR. ALPER replied yes, but pointed out that the peak for this model is 15,000 barrels a day. If a producer drills and produces more than 50,000 barrels a day, the producer gets its credits but cannot turn them into cash - the credits must be rolled forward and used against the producer's tax liability.

REPRESENTATIVE OLSON remarked that the producer can get the credits but cannot use them.

MR. ALPER responded not exactly and explained that the producer can use the credits to reduce its production tax payments. So long as the price is high enough to support a tax payment, a producer could offset that all the way down to $0 or the minimum tax depending on the credit. A producer can use the credits to reduce its tax payments, but cannot use them to get cashed out by the state. Responding further to Representative Olson, Mr. Alper said he will address the cap of 50,000 barrels a day when he gets to the analysis for large fields. Even if a new company builds a giant field, that new company would put itself in that 50,000 category under the status quo analysis pretty quickly.

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REPRESENTATIVE SEATON asked whether the basic presumption for including the production tax net present value (NPV) of 6.15 percent in the analysis is so a look doesn't need to be taken at alternative investment of that money. In other words, he surmised, the state is paying out cash and if that cash had been left in the permanent fund the state would have expected a 6.15 percent 10-year average of return.

MR. ALPER answered yes, exactly right. The state does have time value to its money. Traditionally and historically the state has not really contemplated that because it sort of operates the government on a cash basis. But now suddenly the state is using savings and there is opportunity cost to using those savings. A similar conversation was had in this committee during the interest rate conversation. The provisions of the bill that would change the interest rates are also designed to compensate the state for the money it would have earned had that money stayed in savings. The companies themselves use the term "hurdle rate," which relates to their opportunity for investment options around the world and the companies will invest money with the expectation of earning a cash flow profit on it as well as a discounted rate of return on that profit. The 6.15 percent is used here with the understanding that quite likely the typical company operating in Alaska is going to expect a larger

number than 6.15 percent, which would reduce those discounted value numbers. "The higher the interest rate that you're charging yourself on your future money," he explained, "the less money a dollar in the future is worth today."

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MR. ALPER resumed his presentation and addressed slide 20, "North Slope Life Cycle Modeling, 50 mmbo Status Quo, $60 bbl." Referring to the upper left graph, he noted that much more [positive cash flow] (blue bars) is seen at a price of $60. At a price of $60 the companies will be paying production tax by the fifth or sixth year when they get towards peak production. That production tax adds up to $183 million against the $162 million that the state pays out in credits. However, while there is a bit of positive production tax, applying the discount rate results in a production tax net present value to the state of negative $37 million. Regarding total state take (upper right graph), he noted that green represents the production tax, blue is royalty, purple is state corporate income tax, and red is state property tax. The state receives $380 million in positive cash flow out of this field at a price of $60 in the status quo, with a net present value of about $136 million. Referring to the lower left graph, he explained that the cash flow for the producer is negative (red bars) while the field is under construction, but after construction the cash flow turns to profits after taxes (green bars). The producer receives about $400 million in positive cash flow and a discounted value of $112 million.

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REPRESENTATIVE SEATON inquired whether the production tax net present value of negative $37 million can be translated to mean that the state is advancing credits early in a project and over the life of the project the state is not going to recover that money by approximately $37 million.

MR. ALPER provided a reply by assuming two scenarios - one the status quo and the other a field that never happened and so the money remained in the permanent fund for the duration. Had that money stayed in the permanent fund earning a 6.15 percent return over the multiple years, the state would have had $37 million more at the end of the day than if the state had paid it out in tax credits and received it in production tax with that field invested. He pointed out that this is purely on the production tax and does not include the other state revenue.

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REPRESENTATIVE JOSEPHSON noted that in the aforementioned example the money was kept in the permanent fund, but posited it would be more likely that the money would not be kept in the permanent fund. In this case there would then be assorted arguments about what the state did do with the money and who benefitted from it.

MR. ALPER responded that that is why the state hasn't historically discounted its cash flows - the state has more or less operated on a cash basis. More likely in the recent past and an era of short-term or expected short-term deficits, the money would be in the Constitutional Budget Reserve (CBR), not the permanent fund. The CBR itself now has the great bulk of its money in very liquid cash-type investments that earn less than that. Until about a year ago the bulk of the CBR was in the "sub-account," which was invested diversely out in the financial markets and earned a comparable rate of return to the permanent fund itself. The limitations on the CBR's sub-account were that there needed to be five years' worth of money. Once prices fell as catastrophically as they did as quickly as they did, almost immediately the state no longer had five years' worth of money in the CBR and the decision was made last spring to liquidate CBR's securities portfolio and turn it into cash.

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MR. ALPER continued his presentation, moving to slide 21, "North Slope Life Cycle Modeling, 50 mmbo Status Quo, $80/bbl." He explained that at higher prices more taxes and more royalties are seen. At an oil price of $80 there is a positive production tax value to the state of $110 million in discounted cash flow, and $364 million in total cash flow. To the owner and producer of the field, a price of $80 over the life cycle of the project creates $287 million in value.

MR. ALPER brought attention to slide 22, "North Slope Life Cycle Modeling, 50 mmbo Status Quo, Fall 2015 FC Prices." He said the fall 2015 forecast price is somewhere in between $60 and $80. In this scenario the state's production tax net present value is a positive $40 million and total state take is $255 million in value. The producer is at $203 million in net present value.

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MR. ALPER explained that slides 23-26 look at the same four price scenarios under the changes proposed by HB 247. He compared slide 23, "North Slope Life Cycle Modeling, 50 mmbo HB 247, $40 / bbl," to the status quo on slide 19, and noted that the state's cash flow in the status quo is a payout of $50-$60 million a year in credits during the peak construction years. Under HB 247, however, the credits paid out by the state would never be more than $25 million a year due to the proposed cap of $25 million per company per year. Larger numbers would also be seen a couple of years in the future because the company would be rolling its tax credits forward and getting them against its taxes in the years after the company is under production. For example, in the sixth or seventh year the state's cash flow would be nearly negative $20 million because the company would have about $7-8 million in tax liability that would be offset by the $25 million of carried forward credit and then the company would get the remaining $18 million in actual credits. Under the status quo at a price of $40 (slide 19) the state is out-of-pocket $221 million, while under the proposed changes of HB 247 the state would be out-of-pocket $150 million. Under the status quo the state's net present value is negative $153 million, while under the proposed changes of HB 247 it would be negative $95 million. Under the status quo the producer's net present value is negative $99 million, while under the bill's proposed changes it would be negative $155 million.

1:42:50 PM

MR. ALPER compared slide 24, "North Slope Life Cycle Modeling, 80 mmbo HB 247, $60 / bbl," to the status quo on slide 20. He pointed out that a price of $60 a barrel is something like a break-even model for the state. The state's net present value under the status quo is negative $37 million, while under the proposed changes of HB 247 it would be negative $10 million. Under the status quo a producer's net present value would be a profit of $112 million, while under the proposed changes of HB 247 it would be $93 million, an erosion of less than 20 percent to the producer and an improvement to the state's cash flow of about $60 million over the life of the project. Under the status quo the state's net cash flow gain is $380 million and net present value [is $136 million], while under the proposed changes of HB 247 the state's net cash flow gain would be $412 million and net present value [would be $163 million]. So, at a price of $60 there would be a small impact on the project itself but not an impact that DOR considers catastrophic.

1:44:19 PM

REPRESENTATIVE SEATON understood that the red bars in the upper left graph on slide 24 represent the investment by the state, or money out from the state. He further understood that the lower left graph on slide 24 shows the negative for a producer but that there are two or three years of net gain for a producer while the state is still seeing a net outflow.

MR. ALPER answered that it is actually two years because there is actually a zero bar all the way on the left of all these scenarios for the state because no one starts claiming credits until after the first year of work. In the upper left chart for the state there are six red/negative bars but the last negative bar is actually year seven; however, by years six and seven a producer is in a positive place. So there are two years where a producer is having positive cash flow while the state is still repaying credits. Referring to the upper right chart, Mr. Alper noted that the state's positive cash flow under the provisions of HB 247 would start in year six because once a producer is in production the state starts receiving a royalty. In year five the state would receive about $13 million in primarily royalty revenue and would pay out $20 million in continuing tax credits, so the state would be negative $7 million. In year six the state would receive about $28 million in revenue (blue bar) and would pay out about $15 million [green bar], so the state would now start being in a positive cash flow.

1:46:26 PM

REPRESENTATIVE JOSEPHSON requested clarification on which of the graphs on slide 24 were being compared.

MR. ALPER replied that Representative Seaton's original question was comparing the state's cash flow [upper left graph] with the producer's cash flow [lower left graph]. Representative Seaton was making the observation that the producer gets into a positive cash flow while the state is still paying out credits. Mr. Alper agreed that that is true for one or two years.

1:47:06 PM

MR. ALPER resumed his presentation. He stated that slide 25, "North Slope Life Cycle Modeling, 50 mmbo HB 247, $80 / bbl," is the "after" comparison to the status quo or "before" depicted on slide 21 for an oil price of $80 a barrel. Referring to the upper left graph he said the credits that would be paid out by the state would be restricted by [the proposed $25 million cap].

Mr. Alper pointed out that the scale on the three graphs keeps changing throughout the different slides. When there is more money the scale needs to be extended because if the scale were to be kept constant the numbers would be nearly invisible for a large portion of it. The state's positives from the production tax at $80 oil reach as much as almost $60 million a year. The state's total take at the peak of that is close to $100 million a year. A discounted total state take cash flow of about $380 million is seen with the changes envisioned in the bill. The comparable number [for the status quo at $80 on slide 21] was $364 million. The state would gain about $16 million in value over the life cycle of the project, while the producers would go from $289 million to $277 million, a loss of $12 million. As prices get higher the changes envisioned in HB 247 become much less material. Most provisions of the bill are protecting the state's interest at low price. Although the impact is higher at a price of $60, the impact is less at $80.

MR. ALPER displayed slide 26, "North Slope Life Cycle Modeling, 50 mmbo HB 247, Fall 2015 FC Prices," stating that the fall 2015 forecast price is somewhere in between. In this scenario the state would have a positive production tax net present value of $60 million, while under the status quo it is $40 million. [Under the proposed changes in HB 247] the state's net present value would be $274 million, while under the status quo it is $255 million. Under HB 247 the producer's cash net present value would be $189 million, while under the status quo it is $203 million. So, about $14 million of the producer's value would be taken by the changes envisioned in HB 247.

1:49:38 PM

REPRESENTATIVE SEATON asked about the fall 2015 forecast price.

MR. ALPER responded that the price for the current fiscal year is $50 and the FY 2017 price is $56. He deferred to Mr. Dan Stickel to provide further details.

DAN STICKEL, Assistant Chief Economist, Tax Division, Department of Revenue (DOR), answered that the fall forecast has a few years of price increases and prices end up leveling out in the $70 real range. For instance, looking out through 2024 the price is $84.53 in nominal terms, which is $70-$71 real range.

MR. ALPER added that DOR is using uninflated numbers throughout the life cycle here. So, when $60 is seen or $50 million is seen, those are current-year dollars; DOR did not build in any

sort of inflation. The department has a forecasted oil price that is going up slightly. The last year of DOR's forecast is in 2025 and that 2025 number is then held flat for the rest of the life cycle of these fields - in that $70-ish range. That is why these forecast numbers come out splitting the difference nicely between the $60 and $80 because for the bulk of the time period it is a $70 forecast.

1:51:13 PM

MR. ALPER next discussed the large field model. He turned to slide 27, "North Slope Life Cycle Modeling Assumptions, 750 mmbo field assumptions," the first of four modeling slides for a 750 MMbo field under the status quo tax system. He said the assumption for the life of a field this size is 40 years and the assumption for peak oil production is 120,000 barrels a day. The capital cost is assumed to be $13 a barrel, which is less than the cost of $18 for a smaller field due to economies of scale from drilling pads and processing facilities. However, $13 multiplied by 750 million barrels is close to $10 billion; $10 billion is what it would cost the producer that develops and builds such a field. The department must contemplate what that means in its tax credit modeling when someone comes up and spends $10 billion on the North Slope.

1:52:18 PM

REPRESENTATIVE JOSEPHSON understood that a 750 MMbo field is comparable in size to Alpine, Alaska's third largest field. He inquired whether Alpine received credits when it was started.

MR. ALPER answered that Alpine began operating in 2004 and peak production was 124,000 barrels a day in 2007. Alpine went into production under the Economic Limit Factor (ELF) system, a gross production tax, and therefore there were not credits associated with that field's buildout or construction. Unitization of that field was prior to 2003 so it does not enjoy the Gross Value Reduction (GVR). For all intents and purposes Alpine is legacy oil. When the switch was made in 2006 to the production profits tax (PPT) [Twenty-Fourth Alaska State Legislature, House Bill 488], people talked about the weighted average of the tax rates among the different fields that were in production on the North Slope and attention was brought to the fact that many of the smaller fields were below a 1 percent effective tax rate. The Kuparuk River Unit had fallen to a very low tax rate. All of the taxes were coming, really, from Prudhoe Bay and Alpine; Prudhoe Bay because it was so large and its wells still very

productive and Alpine simply because it was so new it was in its peak productivity per well and there was a relatively high multiplier that was paying a 10 percent or higher gross tax rate in 2006 when the switchover was made from ELF to PPT.

1:54:16 PM

MR. ALPER returned to his presentation. He brought attention to slide 28, "North Slope Life Cycle Modeling, 750 mmbo Status Quo, $40/bbl," the first of four modeling slides for a 750 MMbo field under the status quo tax system. He noted that the numbers are bigger for this field size and correspondingly the scales on each of the slide's three graphs are bigger. In this scenario, the state's share through the tax credit program is just less than $3 billion; that is what the state would be paying out in cash to get this field up and running. Given the low price, the value the state gets from that is relatively small, so the discounted loss [the production tax net present value] to the state is about negative $2 billion. When royalty and corporate tax are included, the state ends up with just over $3 billion in total revenues over the life of the project against a negative $2.8 billion in cash flow. Thus, the total gain is $367 million, but the discounted value of the state's gain is negative $1.016 billion. The producer is also losing a large amount of money under the status quo, with a [producer cash net present value] of negative $1.768 billion. Continuing with the thesis that was begun earlier, no one is going to make any large investments in Alaska going forward if it is thought that the price of oil is going to stay at $40 indefinitely.

1:56:05 PM

REPRESENTATIVE JOSEPHSON asked whether slide 28 is depicting GVR oil or legacy oil.

MR. ALPER replied that DOR's assumption for the modeling of any new fields on the North Slope is that they will be eligible for the GVR. So, there are two primary assumptions for this new oil. First, should a field be profitable, the production tax is going to be reduced by the multiplier that takes a fraction of the gross and subtracts it from the production tax value; so, this new oil will enjoy a lower tax rate. Second, at lower prices this oil would receive the $5 Per-Barrel Credit rather than the sliding-scale Per-Barrel Credit. The $5 Per-Barrel Credit can reduce the producer's production tax liability to $0 because there is no minimum tax in a GVR field.

1:57:09 PM

MR. ALPER continued his presentation, moving to slide 29, "North Slope Life Cycle Modeling, 750 mmbo Status Quo, $60/bbl." He noted that at a price of $60 under the status quo the credits are still very large during the early years of construction, approaching $2.9 billion. In about 10 years the state starts seeing positive production tax cash flow; prior to that the Per-Barrel Credit is enough to wipe the tax down to $0. Referring to the upper left graph, he drew attention to the years where it appears that nothing is happening and explained that in the early years of production from this field there is some production tax liability, but it is wiped out to $0 by the Per-Barrel Credit, which is why a gap of nothing is seen. The state does start getting royalties as soon as production begins and the state gets positive cash flow in about year eight, but by the time the state gets to that place it is negative cash flow somewhere between $2.5 and $3 billion. The producer, meanwhile, at the 6.15 percent discount rate, is in a mildly profitable circumstance of $312 million. The producer has a lot of cash flow at $7.4 billion, but because of how frontloaded a project like this is it is quite likely that a decision would not be made to invest in a large, expensive project like this if the expected oil price was in the $60 range. He offered his presumption that producers would not make this kind of investment unless they expected the price of oil to be higher than $60 for the next 40 years.

1:58:43 PM

MR. ALPER addressed slide 30, "North Slope Life Cycle Modeling, 750 mmbo Status Quo, $80/bbl." He said the upfront cost to the state at this price under the status quo is still in the range of $2.8 billion being spent in credits. The difference is that the state gets to positive cash flow a bit quicker and gets to really good cash flow somewhere down the line. In the eighth to tenth year of production, during the peak years where those 120,000 barrels a day are flowing, the state is going to get $1 billion a year in revenue. He recalled testimony by Mr. Bill Armstrong [President, Armstrong Oil & Gas Inc.] that the state will get $1 billion a year in revenue. However, Mr. Alper pointed out, that $1 billion comes on the heels of several years where the state is paying multiple hundreds of millions of dollars per year during the construction and development phase of the project. The producer's cash flow in this scenario is much more robust - a discounted cash flow of $2.2 billion and a discounted cash flow to the state of $3.5 billion. So, this

scenario is great except for the part about the state not having the money to pay for the upfront costs, leading to the conversation about what to do about that.

MR. ALPER brought attention to slide 31, "North Slope Life Cycle Modeling, 750 mmbo Status Quo, Fall 2015 FC Prices," and said this scenario falls somewhere between and is the forecasted FY fall 2015 Revenue Sources Book prices. In this case the state has about $2.5 billion in value and the producer about $1.4 billion. Once again, however, there are very large credits in the early years of the development phase, peaking out at just over $800 million of state cash liability to that producer in about the fifth year of the project, which is peak construction.

2:00:38 PM

MR. ALPER discussed slide 32, "North Slope Life Cycle Modeling, 750 mmbo HB247, $40 / bbl," the first of four modeling slides for a 750 MMbo field under the changes proposed by HB 247. He said this is a very dramatic change, with two things happening. One is the state is only paying out $25 million a year. Comparing slide 32 with slide 28, he noted that under the status quo for this same scenario the production tax credits cashed was just less than $3 billion. However, under HB 247, the state would only spend $134 million, a tremendous decrease in the state's credit liability. The reason for this decrease is the proposed cap of $25 million per company per year. Under HB 247 the state would have something of a positive because the producer would be paying an actual minimum tax at the rate of 5 percent during the life cycle of the project. The producer's cash flow at $40 is worse under the proposed changes of HB 247 [negative $3.744 billion] than under the status quo [$1.768 billion]. Therefore, Mr. Alper said, he would rather have this conversation around the oil prices of $60 and $80 where such a project would be more likely to happen than at a price of $40 where the math is almost ludicrous - it is technically correct but such a project isn't going to happen.

2:02:02 PM

REPRESENTATIVE JOSEPHSON noted he is undecided on HB 247 and said he thinks he just heard Mr. Alper, in effect, make the oil industry's argument. He further asked whether the life cycle is 30 years or 40 years.

MR. ALPER responded it is a 40-year life cycle. He said he is uncomfortable with the scenario of a price of $40 because it is

so implausible for all of this to happen at a price of $40. About $2 billion in value is shifted from the producer to the state in this modeling over the 40 years. The all-in present value to the state under the status quo on slide 28 is negative $1 billion, while under the proposed changes of HB 247 on slide 32 it is about positive $1 billion, which is the $2 billion shift. He urged that this conversation be had at a more reasonable oil price and therefore turned to a price of $60.

2:03:10 PM

MR. ALPER drew attention to slide 33, "North Slope Life Cycle Modeling, 750 mmbo HB247, $60 / bbl," and said that under the proposed changes of HB 247 the state's credit liability would be capped at $25 million for the producer. He pointed out that a project like this is unlikely to have only one partner and the way the bill is written the cap would be $25 million per company per year. So, if there were four companies involved in such a project, the allowable amount of credits would be quadrupled and that would dramatically change a lot of these numbers. But the modeling had to start somewhere and so DOR started with the bill and the modeling as DOR literally interprets it. He said DOR would be happy to look at split fields to come up with different scenarios if the committee wishes. Continuing, Mr. Alper noted that the state's cash flow in the before/status quo scenario depicted on slide 29 was close to $3 billion out the door. Part of the reason the administration is before the committee is that the state does not have $3 billion, the state does not have the ability to participate in a new oil field development with $3 billion in cash. So, the administration is looking at mechanisms to limit that and the changes proposed in HB 247 would greatly limit that amount of cashed credits to only $116 million in a one partner, $25 million modeling.

2:04:46 PM

REPRESENTATIVE JOSEPHSON understood Mr. Alper to be saying that when looking at a large, new, Alpine-sized development, the unaffordability of these credits becomes extremely magnified and under existing statutes creates some real risks of insolvency because the state does not have $3 billion.

MR. ALPER answered he would say that the State of Alaska's credit regime was designed to try to get new players on the North Slope, generally presumed to be smaller. But, if someone finds something that is big, the law is silent on the size of the field. He recalled that a year ago he and Mr. Stickel sat

before the committee and discussed theoretical long-term cash flows for the Arctic National Wildlife Refuge (ANWR). The chair had asked DOR to look at what would happen if the refuge was developed and 20 different fields were layered on and there was a great river of money and a great river of oil in the later years. However, DOR saw billions of dollars in negative credit cash flow in the early years of it because people would be spending $5-$6 billion a year to get the refuge developed. If it were to fall into the literal interpretation of the state's current law, it would be unaffordable for the state in the short term and the state would have to find a way to afford that. That is part of why the administration is before the committee now - to recognize that these projects are very much wanted to happen, but as the law is currently written the state does not have the money to afford the obligations that it has taken on for these larger projects.

2:06:39 PM

REPRESENTATIVE OLSON posed a scenario in which Mr. Alper owns an oil company and is thinking about doing business in Alaska under the terms proposed in HB 247. He asked where Mr. Alper would seriously start thinking about price.

MR. ALPER replied he does not have an oil company and so it is hard to imagine. He related that he found Mr. Armstrong refreshing in a lot of ways when he was before the committee, but Mr. Armstrong is bullish and thinks the price of oil is going to be high and is prepared to make very large investments and borrow a lot of money. However, Mr. Alper continued, some of his anxiety is that the state cannot be as bullish as is Mr. Armstrong, the state has obligations to its citizens that it cannot be on the hook for a 35 percent partner based upon Mr. Armstrong's optimism. If he were a very wealthy person and investing in oil projects in Alaska, he would probably want to know that prices are going to be in the range of $80 or better.

REPRESENTATIVE OLSON remarked that $80 is the range he was thinking of as well.

2:07:55 PM

REPRESENTATIVE HERRON commented that changes to HB 247 probably have to be sensitive to $40, $50, and $60 over 40 years, not the reverse. In a nutshell, the biggest reserve in the world, the Saudi's, does not want to become irrelevant. Therefore, it is important to concentrate on tweaks to HB 247 that are down in

the price ranges of $40 and $50. As was just said by Mr. Alper, the state cannot afford to play with the big boys; a far more conservative approach to this must be taken.

REPRESENTATIVE SEATON understood Mr. Alper's point to be that regardless of whether the price is $40, $60, or $80, under current law the state does not have the money to invest in this size field because that investment would be $3 billion over the next seven years. He inquired whether Mr. Alper's message is that even if the expected price is $80, the state does not have the $3 billion to put into the field as cash credits to go forward with the project under the current statute.

MR. ALPER responded yes, and he would go further to say that at a price of $80, although the fields might pencil out better, it is not like the state's budget woes are solved. The budget presented by the governor this year balances at an oil price of about $103. The administration is expecting additional cuts and revenue measures and the like, and if something structural is done with how the state treats its savings that number will be able to be dropped dramatically. The state is far away from seeing the kind of surpluses that will enable the state to afford these multi-hundred million dollar per year investments in a single new project.

2:10:32 PM

REPRESENTATIVE TARR observed that slide 32 includes the cap of $25 million on the production tax credits cashed, while on slide 28 the credits cashed reach almost $600 million in the third or fourth year and then go above $800 million. Given that the gap between these two examples is so great, she asked whether anything in between was looked at during the drafting of HB 247. She also asked how $25 million was selected as the right limit.

MR. ALPER answered that the modeling done earlier by DOR was based on smaller fields. As seen in this presentation, the impact was far less dramatic when the credits in play were a lot smaller, the $25 million limit. The department didn't model the very large fields until embarking on this project right here. The number of $25 million comes from historic statute. When the state first got into the business of paying cash for credits in 2006 with the passage of the PPT bill, there was a specific $25 million per company per year cap on repurchases. It was not initially intended to be an open-ended benefit. Credits in most places in the world are not cashable, credits in places that offer them are generally used against taxes. Other Alaska

statutes offer credits that can be used against taxes, the Education Tax Credit being an example. Alaska's credits for oil and gas development are unique that way. The state is paying cash into the industry, the state is becoming indirectly an investor. So, $25 million was an historic number and was chosen for HB 247 because it had legislative history. One could easily say that that could be inflation-proofed. However, that number was only a limit for real for 15 months - between the effective date of PPT and the effective date of Alaska's Clear and Equitable Share (ACES) [House Bill 2001, passed in 2007, Twenty-Fifth Alaska State Legislature], which eliminated the cap.

2:13:06 PM

REPRESENTATIVE OLSON recalled that Mr. Alper was around during consideration of the PPT.

MR. ALPER replied yes, at that time he was working for Representative Eric Croft.

REPRESENTATIVE OLSON recalled that a round table was held toward the end of PPT hearings, to which the three major producers and a number of the explorers were invited and asked questions. He recounted that the companies were asked how far forward do they look for the development of assets and reserves that they already have. Only one company answered the question and that company's answer was in excess of 60 years. He asked how the state can compete with that.

MR. ALPER responded he does not know the state would compete with that; the state is not really competing with that. The state has a co-dependent, or a co-mingled, relationship with industry. The state is a sovereign, it owns things, it runs a state, it has a school system and they are an oil company that is trying to plan its strategy to develop a field and then the next field with the cash flow from the first one. The two are very different business models. It is easier to be a passive sovereign, it is easier to let them come to Alaska and let them do their investments and then pay the taxes when they produce something. A conscious choice was made 10 years ago for the state to participate with cash. That changed everything. It has caused a lot of positives for the state, especially in the years where prices were high and the state had tremendous surpluses and was able to save large amounts of money. Today the state is experiencing the flip side of that, with tremendous negatives and liabilities to the state being seen. In some ways they are the mirror image of each other. On the other hand, if

these kinds of lower prices are being expected for years into the future, the state needs to contemplate how to react to it.

REPRESENTATIVE OLSON remarked that industry has one advantage that the state does not and that is time. Industry can wait until it feels it has a chance to make a profit, which is not a dirty word because industry is not nonprofits. If the state has to do something now it can only do it a few years out and that gives industry a distinct advantage in how things are done and he is thinking the state is seeing that again right now.

2:15:45 PM

REPRESENTATIVE SEATON, regarding the proposed $25 million cap per company, inquired whether there are any sideboards on the percentage of ownership. He posed a scenario in which a company has six 1 percent partners and inquired whether each partner as well as the main company would get the $25 million cap under the current language of HB 274.

MR. ALPER said the easy answer is yes, with the caveat that it is not tied to the project. It is tied to the company's entire North Slope operations; every taxpayer can get up to $25 million. Things have been done in both statute and regulation. For example, the Small Producer Credit has a per-company fixed dollar cap. Because of conversations like this the final version of the language was written so that a company cannot artificially split itself in two to try to double dip on the Small Producer Credit. [The department] would try to provide some sort of protections whereas a legitimate number of companies if they were truly partners would be able to benefit from something, but there wouldn't be any intentional workaround to try to increase a company's ability to claim credits.

2:17:17 PM

REPRESENTATIVE SEATON said he has some concern if what is trying to be done in HB 247 is to lower the state's liability so it is not hundreds of millions of dollars per year for seven years as this model of a larger field goes. He posited that without sideboards in statute the state's exposure to paying large upfront cash credits into a project would not be limited. He requested that consideration be given to that limitation in order to make it a real limitation and not something that could be gone around and that this be brought back to the committee.

MR. ALPER replied two things happen. He posed a scenario in which there are four partners and they are getting $100 million a year. Not only does it change the cash flow model and the state is out four times as much money, but also seen especially at lower prices is the sunset of the credits themselves after 10 years. What was seen in the low price, large field modeling was expiring credits where people were not actually able to enjoy the full benefit of their credits because after five years they were literally falling off the table. If that was bumped to a larger number with multiple partners, both of those problems would go away for the producers. On the other hand, the state would be paying four times as much money per year in the upfront.

2:19:09 PM

REPRESENTATIVE SEATON noted that this is being talked about and thought about as a project, but the credit limitation is per company. He asked whether there is anything that keeps additional companies from coming into the project later and having that same $25 million and therefore extending the credits out for longer than 10 years.

MR. ALPER responded he hadn't contemplated a technical name change, but the credit itself is a certificate. The company earns the credit in year one. If, for example, a company earned $500 million but is only able to use $25 million a year of it, if the company doesn't ever have any tax liability after 10 years the company is going to lose a certain portion of it. Even if the tax credit certificate is transferred or sold or a company changes name, the certificate is what would be expired. Typically after a few years the expectation is that there is going to be tax liability and the company will be using the bulk of that certificate not to get $25 million a year but to offset a tax bill. If the prices are high enough the tax bill is enough to use it up more quickly. When talking about bringing new partners into a project it is important to remember that the current refund language in this proposed new $25 million cap is in Alaska Statute (AS) 43.55.028, which is about the tax credit fund. It is about the spending of money to purchase certificates and not anywhere in the language that talks about how a company earns a certificate. It is very much tied to the taxpayer, it is tied to per company of limit and that is why the legislature's consultant, Mr. Janak Mayer, testified that it would be likely that companies might get nothing. Mr. Mayer was building a scenario that said the developer of a new field might already be doing something in Alaska and therefore already

getting its full $25 million from another project and contemplating the possibility that even in the smaller fields a company might not get cash. The department did not model the smaller fields with that set of assumptions, the smaller fields were modeled with the assumption that a company would enjoy the full $25 million.

2:21:19 PM

REPRESENTATIVE JOSEPHSON presumed that when Mr. Alper stated Alaska has great benefits from its credit systems that he meant Alaska is either optimistic that more production will come on line or that the industry's argument is correct that it has stemmed the decline, particularly over the last three years; that the decline curve would be worse had it not been for these credits. He said he is playing a mystery game where he doesn't know what the world would look like without the credits.

MR. ALPER answered, "Neither do we, we can't know what would have happened." He explained that when he said the state has benefitted, he primarily meant the state benefitted from the net profits tax regime that brought in very high rates and very high revenues at high prices. The credits in many ways were a built-in offset to that, the flip side of it. When ELF replaced PPT there was a crossover. At low prices the state makes more money in a gross tax; at high prices the state makes more money in a net tax. North Dakota does much better than Alaska at low prices, whereas Norway does better than Alaska at high prices. North Dakota is not getting as much as it could because it has a flat gross tax. On the other hand, at these low prices North Dakota is doing very well because it is getting at least a limited amount of revenue with the caveat being that people aren't drilling wells anymore because their type of development isn't profitable at prices of $30 or $40.

2:23:11 PM

MR. ALPER resumed his presentation, turning to slide 34, "North Slope Life Cycle Modeling, 750 mmbo HB 247, $80 / bbl." He commented that this is the more ambitious price, but as recently as three years ago it would have been the low side. At a price of $80 a barrel under the proposed changes of HB 247 the state's cash flow out would be only $109 million, whereas under the status quo (slide 31) it is $2.8 billion in credit spend. The expected value of the state's production tax under the proposed changes would be $1.7 billion, as compared to about $900 million under the status quo. The overall state take under HB 247 would

be $4.4 billion, while under the status quo it is $3.5 billion. The amount that would be removed from the producer's side of the ledger to the state's is far less than it was at the lower prices - [under HB 247 the producer cash net present value] would be $1.4 billion, while under the status quo it is $2.2 billion, a migration of about $800 million in present value through the tax credit reform contemplated in the bill.

MR. ALPER displayed slide 35, "North Slope Life Cycle Modeling, 750 mmbo HB 247, Fall 2015 FC Prices," and said it again splits the difference. Similar amounts of increase in state value of about $900 million and a similar decrease in company value of about $900 million, and there would be the tremendous changes to the state's cash flow between the big credit cost and the $25 million a year cap.

2:24:53 PM

MR. ALPER explained that slides 36-39 in many ways parallel slides 32-35, only now what is being contemplated is that the developer/producer in question would be a large international or domestic company with $10 billion in revenue. [Under HB 247] a company with $10 billion in global revenue would no longer be able to get cash from the state, meaning the company would have to use all of its credits and hold them against future liability. Therefore, on slides 36-39, the upper left graph no longer has any red bars below the line because the state isn't paying any credits at all. The presumption is that a producer of this size has enough money on its balance sheet to simply build the project and pay the taxes and accept the credits when it is done, much like Alpine, Kuparuk, and every other older large legacy field in Alaska that was built without any credits or state cash participation on the frontend. So, that is what the modeling here is contemplating as well.

MR. ALPER addressed slide 36, "North Slope Life Cycle Modeling, 750 mmbo HB 247, $40/bbl, Co. w/ > $10 billion revenue." He noted that at an oil price of $40 the state would have positive value because it has no years with negatives; there would be no less-than-zeroes dragging down a present value. The state's total production taxes received would be just less than $1 billion and the discounted value of that would be $337 million. The total state take would be $3.86 billion with a discounted cash flow of $1.3 billion. The producer would have a big loss of $3.8 billion, but under the status quo that number was a very large negative as well. No one is going to make this investment [at a price of $40].

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MR. ALPER moved to slide 37, "North Slope Life Cycle Modeling, 750 mmbo HB 247, $60/bbl, Co. w/ > $10 billion revenue," and said that the models for the proposed zero credits barely moved the needle as compared to the models for the proposed cap of $25 million. The numbers at stake here are so large that whatever value the state is taking from these companies was done by the time of cutting it down to the proposed $25 million and taking that last $25 million and reducing the state's cash flow to $0 was a fairly insignificant change. For example, comparing slide 37 to slide 33 the cash flow to the producer [under the proposed cap of $25 million] would be a non-economic negative $870 million, [while for a company with over $10 billion in revenue it would be negative $974 million], a relatively small change compared to the quite dramatic change that went from paying open-ended tax credits to paying only $25 million a year.

MR. ALPER displayed slide 38, "North Slope Life Cycle Modeling, 750 mmbo HB 247, $80/bbl, Co. w/ > $10 billion revenue," and noted that the field at a price of $80 would be quite profitable to the producer at $1.3 billion even with all the changes contemplated in the bill. Pointing to the spike in the graphs that would happen to the state in about year 11, he explained that the spike is the 10-year sunset of some of the earlier tax credits that are rolled forward and used to offset tax liability. When these credits suddenly go away a much larger production tax starts to be paid beginning in year 11 or 13. Some of the earlier tax credits have been overwhelmed by the ability to use them against tax liability because the tax liability only goes so high.

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MR. ALPER brought attention to slide 39, "North Slope Life Cycle Modeling, 750 mmbo HB 247, Fall 2015 FC price, > $10 billion rev." He said the fall forecast price is somewhere in between $60 and $80, is mildly profitable for the producer and reasonably profitable for the state, and has no negative cash flow to the state at the frontend of the project.

REPRESENTATIVE SEATON inquired how this project would play out if there were six companies, one them a company with revenue of over $10 billion.

MR. ALPER replied by assuming that each of the partners would own one-sixth of the project and spending one-sixth of the money up front. Five of the companies would be eligible for the $25 million a year, so the state would be paying out about $125 million in total. The sixth company [with over $10 billion in revenue] would be a smaller version of the modeling [on slides 36-39]. The $10 billion [revenue] cap is not tied to the amount of oil the company produces, it is tied to the overall size of the company. He said he would like to model some scenarios that look at multiple partners, and his guess is that the economics and impact of the bill would split the difference somewhere between the status quo and the HB 247 slides. He advised that as HB 247 evolves, it is important to create some language to ensure that any doubling up is authentic and not an artificial workaround trying to maximize the credit value, but being several different legitimate companies that happen to be partners in a North Slope project.

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REPRESENTATIVE TARR referred to slides 22 and 23 and asked how DOR evaluated the status quo versus HB 247 in regard to the $25 million cap and the potential for companies to stretch out the activity to keep spending around the cap versus accelerated activity that would happen with more generous credits.

MR. ALPER responded that Mr. Mayer did a good job of talking about that scenario when he was discussing a Cook Inlet field that was market constrained. Mr. Mayer said that if companies have to spend all of this money, but cannot produce enough gas to pay for it because they cannot find a place to sell their gas, that is where their economics were the most challenged. But, if they could sell all the gas they produce and drill all the wells they wanted, then the companies were fine without tax credits. Mr. Alper said he thinks the same thing happens here. The company is concerned about the time value of its money. If the company stretched out the project for 10 years so as to stay within the tax credit cap artificially, the company is also delaying the payback that it will get for selling oil by the number of years and the company has its own discount rates to worry about.

REPRESENTATIVE TARR inquired whether DOR could see a scenario where there would be behavior adjustments for one to three years rather than ten years as a way to stretch it out.

MR. STICKEL answered that this was discussed internally when DOR was doing the modeling. Certainly, if there is a $25 million limit on refunded credits, companies would be expected to take that into account when planning how to make their capital expenditures. For purposes of today's modeling, DOR has assumed the same spend profile on all of the different scenarios. So, DOR is not assuming that the companies are making any changes to the timing of their spending.

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MR. ALPER showed slide 4, "Field Life Cycle Modeling: Cook Inlet," and stated that he has concluded the North Slope portion of modeling and will now switch to the Cook Inlet modeling.

The committee took an at-ease from 2:34 p.m. to 2:44 p.m.

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MR. ALPER began the next portion of his presentation with slide 41, Cook Inlet Life Cycle Modeling Assumptions." He explained that the same structure of modeling was used for the Cook Inlet as was used for the North Slope. A giant field was not envisioned for Cook Inlet, he said, so the modeling was only done for a field size of 50 MMbo in place. He further explained that in the Cook Inlet a new producer would be eligible for cash refunds. [The modeling also applies for an incumbent producer not eligible for cash refunds that can apply credits to other North Slope fields.] Modeling was for the four price scenarios of $40, $60, $80, and fall 2015 forecasted price [held static though life of field and in real uninflated dollars]. The modeling compares the status quo tax system to the changes proposed in HB 247. Mr. Alper pointed out that under HB 247: the minimum tax does not apply in Cook Inlet because it is a North Slope only law, AS 43.55.011(f); the $25 million per company per year limit is included; the repeal of the Qualified Capital Expenditure Credit and the Well Lease Expenditure Credit is included; and the 10-year limit on the carry-forward of Net Operating Loss (NOL) Credits is included.

MR. ALPER further pointed out that it is unknown what the taxes are going to look like for the Cook Inlet beginning in the year 2022. Under current law is a tax cap that has been in place since the PPT bill in 2006, which severely limits the amount of production tax that can be paid on both oil and gas produced throughout Cook Inlet, whether old or new fields. This tax cap sunsets in 2022. He recounted that in the first hearing he

discussed the underlying tax regime being very high and a little bit unstable. The modeling here for Cook Inlet was done for two tax regimes: one where the caps would continue indefinitely and keep production taxes at effectively $0 for forever; and one where the tax caps go away completely, which is a 35 percent tax without any Per-Barrel Credit or any new oil Gross Value Reduction (GVR) benefit. So, he explained, the status quo modeling is for both too high and too low a tax regime. At some point, he noted, the Alaska State Legislature will need to come up with a future tax regime for Cook Inlet after the year 2022

MR. ALPER drew attention to an error on slide 41 in the fourth major bullet, first sub-bullet, which states there is a GVR in Cook Inlet. He said that is incorrect - there is no GVR in Cook Inlet. The GVR is a benefit from Senate Bill 21 that is specific to the North Slope.

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REPRESENTATIVE JOSEPHSON asked whether the modeling uses a price per barrel equivalent given there are only 16,000 barrels of oil, which in the world of oil is a very small amount. He recalled that the idea behind not taxing the oil was to incentivize gas production.

MR. ALPER replied that to be fair to the Cook Inlet it did once produce 200,000 barrels of oil a day. The reason for such small numbers now is that no new oil fields have come on in a long time. The recent increases in production have primarily been from workovers to improve the operation of mature oil fields.

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MR. ALPER discussed slide 42, "Cook Inlet Life Cycle Modeling Assumptions, 50 mmbo field assumptions." He noted that the peak oil production modeled was for 17,000 barrels a day, which is what would be expected from a field of 50 Mmbo. The closest analog to this is BlueCrest Energy, Inc.'s, Cosmopolitan Unit in the Homer area. Development drilling is about to begin in that unit and will begin in the oil field first because that is BlueCrest's first priority. BlueCrest has said it is going to have a similar dollar and number profile to what is presented on slide 42, which is peaking out at 15,000-17,000 barrels a day and capital expenditures of $12 a barrel. Mr. Alper elaborated that the capital costs are a bit lower in the Cook Inlet than on the North Slope primarily because the logistics are easier. The tax caps were put in place to incentivize gas, but in many ways

they were there as a hold harmless. In 2005 the tax rate in Cook Inlet really was zero - the ELF multipliers had eroded to the point where all the then-existing oil fields in Cook Inlet were paying a production tax of zero; all existing gas production in Cook Inlet was paying around $.17 per thousand cubic feet [Mcf], it varied from field to field. "So," he continued, "what the ELF caps did was codify and lock in place for 15 years that which already was at the moment of transition to PPT and hold them harmless from what was primarily a tax increase on the North Slope."

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MR. ALPER turned to slide [43], "Cook Inlet Life Cycle Modeling, 50 mmbo Status Quo, 2022 Tax Caps expire, $40/bbl." He explained that because the tax caps would expire [in 2022] the state would get a production tax and it would be reasonably high at 35 percent of production tax value/net value. Referring to the upper left graph, he said that at a price of $40 there is not a lot of net value, so the state would pay out about $350 million in tax credits to get the field in this scenario produced. A total of $172 million in production taxes would be generated over the life of the field, with a cash flow on just the net production tax of about negative $177 million. The discounted value, or net present value, to the state would be negative $192 million. Referring to the upper right graph for total state take, he noted that even with a royalty of 12.5 percent [and property and corporate income tax] in addition to the production tax there would still be a negative present value to the state [negative $59]. There would be positive cash flow for many years and $99 million more would be coming in than going out, but because of the time value of money the state would lose $59 million in value. Referring to the lower right graph, Mr. Alper said that under the status quo the producer would get a large amount of tax credits in the early years, with $90 million or more a year for a couple years of peak construction. Once the producer begins selling oil it would have a positive cash flow and the producer's cash net present value would be $3 million. He pointed out that $3 million is within the rounding error and so this would be a breakeven or worse field for the producer and therefore not likely to happen at a price of $40.

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MR. ALPER reviewed slide 44, "Cook Inlet Life Cycle Modeling, 50 mmbo Status Quo, 2022 Tax Caps expire, $60/bbl." He noted that

this scenario is the same field of 50 MMbo but at a price of $60, and with the expectation that the tax caps would expire so that production tax would begin to be paid in 2022. The state would pay out $337 million in production tax credits against $465 million in production tax paid, so a positive net production tax of $128 million but with the time value of money it turns into a negative $50 million. However, the state is positive on total take. There is enough money from the state's royalties to make up for the loss of money from the production tax. The net state gain is $579 million with a discounted value of $167 million at the 6.15 percent discounted rate. The producer, even though paying a 35 percent tax rate, would see a positive net present value of over $200 million over the life cycle of this field in Cook Inlet.

MR. ALPER addressed slide 45, "Cook Inlet Life Cycle Modeling, 50 mmbo Status Quo, 2022 Tax Caps expire, $80/bbl." He said it is again the same field with the same assumptions but at an oil price of $80. In this scenario the state makes enough money from the production tax to more than make up for the negatives of the credits. The positive cash flow to the state from the production tax is $92 million. Adding in the royalties the state would have almost $400 million in value. The actual positive cash flow to the state would be about $1 billion, meaning the state spent $300 million and received $1.3 billion back, but some of that comes many years later. The producer would see a positive cash flow of over $150 million in the peak year and a decline with the decline of the field. The producer's total cash flow would be $915 million, which is a discounted cash flow of just less than $400 million.

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REPRESENTATIVE JOSEPHSON, regarding slide 45, understood that in 2022 the Qualified Capital Expenditure (QCE) Credit and the Well Lease Expenditure (WLE) Credit are gone. He inquired whether this would be a laissez faire do-what-you-will economy or would the state be incentivizing.

MR. ALPER responded no, this is the status quo scenario. The QCE Credit and the WLE Credit do not have sunsets in existing statute. Thus, the relatively high credit spend for the state (red bars in the upper left graph) are the QCE, WLE, and Net Operating Loss credits. The tax caps will expire in the status quo/do-nothing scenario, so slide 45 is the do-nothing scenario.

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MR. ALPER moved to slide 46, "Cook Inlet Life Cycle Modeling, 50 mmbo Status Quo, 2022 Tax Caps expire, Fall 2015 FC Price." He said the forecast price is a number somewhere in between $60 and $80. The production tax credits to help develop the field would be [$335] million. To put that [$335] million in perspective, he noted that the assumption for this 50 MMbo field is a capital expenditure of $12 [per barrel], so the total company capital spend is about $600 million to build this field. Thus, the company is spending $600 million and getting back $335 million [in credits], which is a bit more than half, and that roughly lines up with the expectation that there is an operating loss credit and a drilling credit that are generally stackable against each other. Today the state is paying in the range of 50-60 percent on new field construction in Cook Inlet, so that is assumed to continue with the sunset of the tax caps.

MR. ALPER addressed slide 47, "Cook Inlet Life Cycle Modeling, 50 mmbo Status Quo, Tax Caps extended, $40/bbl." He pointed out that this slide is the same as slide 43 in that it is the status quo, but on slide 43 the producer is paying tax because the tax cap expires. In the scenario on slide 47 the production tax received by the state is $0 because it is an oil field and the production tax rate for the Cook Inlet tax caps is zero. That number is not offset by credits, it is a flat zero. Thus, the state pays $357 million in credits and that is the total negative cash flow, there is no positive cash flow on the production tax side. For total state take, however, there is the royalty, but the royalty doesn't adequately offset the negative cash flow for the credits at a price of $40 so the state would lose $137 million. Regarding the producer, he specified that this is one scenario where the producer is actually profitable at an oil price of $40 simply because the producer is enjoying the high credits on the upfront side and then not paying any production taxes over the life of the field. Thus, the producer's discounted cash flow is $54 million.

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MR. ALPER turned to slide 48, "Cook Inlet Life Cycle Modeling, 50 mmbo Status Quo, Tax Caps extended, $60/bbl." He said this slide is comparable to slide 44 except slide 48 is without the production tax. The credits are the same, roughly $100 million a year at peak. Even with the royalty coming in, at a price of $60 the state is still in a negative cash flow/negative value situation [negative $37 million], while the producer has a positive discounted cash flow of $335 million.

MR. ALPER showed slide 49, "Cook Inlet Life Cycle Modeling, 50 mmbo Status Quo, Tax Caps extended, $80/bbl," relating that per the tax caps the production tax is zero. The credit spend is offset by primarily the royalty revenue, so total state take is $63 million in discounted cash flow. The producer sees the great bulk of the value here with a $612 million benefit versus the $63 million received by the state. Mr. Alper clarified that DOR doesn't consider these to be realistic scenarios. He said he doesn't think it is likely that the decision will be made to extend the production tax caps forward indefinitely while keeping the credit system intact as it is, but the modeling had to start somewhere. The department is looking at reality as coming in somewhere between slide 49 and slide 45.

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REPRESENTATIVE JOSEPHSON asked why Mr. Alper does not foresee an extension of the tax caps in 2022.

MR. ALPER answered that he has no particular reason; it is because the state held producers harmless for 15 years with the changes on the North Slope. He said he doesn't know where that number came from, why the decision was made for 2022. But, as seen on these slides, having a production tax of zero while still paying large credits doesn't work very well for the state. It might get certain work done, but part of the whole argument for having a robust tax credit system that might in some ways wipe out the state's production tax revenue is that at least the state gets the royalty, a fully legitimate and reasonable argument to make. But, if the royalty doesn't even make up for the amount of the production tax, it seems that there is a little inherent instability in the system. That was mentioned by Mr. Mayer - industry sees a big unknown looming in 2022.

REPRESENTATIVE JOSEPHSON inquired why the administration would not have entertained reform of the tax structure in Cook Inlet, given the administration did not intend to amend Senate Bill 21 and this is not a Senate Bill 21 item.

MR. ALPER replied it is not imminent. Realistically, the tax reform in Cook Inlet has to happen between now and the 2021 legislative session. There are more pressing concerns related to the cash flow of the tax credit regime; that is what HB 247 was written to do. The administration did internally discuss ways to do it and the most straight forward way, which was actually modeled by Mr. Mayer, is to take Senate Bill 21 and

extend it statewide. That is as plausible and realistic a scenario as any other and DOR could bring the committee modeling to that effect. The choice was made to leave the Cook Inlet taxes in place cleanly and not mess with that in the five-year gap between now and their expected sunset, but it could be done. It is a whole different set of things to propose and deserves a robust process to even think about what the Cook Inlet tax should be in the future.

3:01:58 PM

REPRESENTATIVE OLSON asked whether the committee will be getting the Cook Inlet gas modeling tonight.

MR. ALPER responded that DOR did not model a gas field from scratch from Cook Inlet for this presentation. It gets a lot more complicated because of cost issues. He requested Ms. Cherie Nienhuis to speak to why the department was unable in the short term to come up with Cook Inlet gas field modeling.

CHERIE NIENHUIS, Commercial Analyst, Tax Division, Department of Revenue (DOR), answered that modeling could be done. However, part of the issue is the same thing that Mr. Mayer talked about in that the situation in Cook Inlet for gas is constrained by the market and part of the difficulty in modeling that is knowing exactly how much gas can be produced over a lifetime and what some of the costs are for that gas. She said she would assume that depending on where the gas is located could make a very large difference in terms of what the cost is to bring that gas to market. It is not that DOR cannot do it, DOR could try, but some of those difficulties presented themselves when DOR was first doing this modeling.

REPRESENTATIVE OLSON inquired whether that is something that is needed for making an educated decision on HB 247.

MR. ALPER replied that Mr. Mayer's scenarios of one, two, and three were very compelling to him, and what he took from them was that the gas price in Cook Inlet is somewhat regulated and relatively high compared to the oil price right now. Under the expected prices under normal circumstances a development is profitable today. Where the producer's constraint comes from is the inability to sell it because it is not a liquid market like oil. For oil, no matter how much oil is produced someone will be found to buy it. Gas is stranded within the Cook Inlet Basin. The assumption to be made is whether a producer can drill all the wells that are needed to develop this field. If a

$400 million platform must be built and then the developer is not able to drill the few wells a year that it will take to make the gas come at a worthy pace to justify spending that $400 million, then it is going to be a very difficult project. The educated guess is whether there is going to be a market for Cook Inlet gas. If an investment is made to develop that much gas, there is the second-order question of whether there is a place to sell it and that is a question that DOR cannot easily answer, although there is other legislation in this building trying to answer that.

REPRESENTATIVE OLSON requested that there be follow-up on this at the committee's hearing tonight.

[Mr. Alper continued his presentation at the committee's 6:00 p.m. meeting on this same day.]

[HB 247 was held over.]

3:05:20 PM

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 3:05 p.m.