ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
January 30, 2017
1:01 p.m.

MEMBERS PRESENT

Representative Andy Josephson, Co-Chair
Representative Geran Tarr, Co-Chair
Representative Dean Westlake, Vice Chair
Representative Harriet Drummond
Representative Justin Parish
Representative Chris Birch
Representative DeLena Johnson
Representative George Rauscher
Representative David Talerico

MEMBERS ABSENT

Representative Chris Tuck (alternate)

OTHER LEGISLATORS PRESENT

Representative Mike Chenault

COMMITTEE CALENDAR

PRESENTATION(S): TAX DIVISION UPDATE~ DEPARTMENT OF REVENUE

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

KEN ALPER, Director
Tax Division
Department of Revenue
Juneau, Alaska
POSITION STATEMENT: Provided a PowerPoint presentation entitled, "Alaska's Oil and Gas Taxation-Status Report," dated 1/30/17, and answered questions.

ACTION NARRATIVE

1:01:47 PM

CO-CHAIR GERAN TARR called the House Resources Standing Committee meeting to order at 1:01 p.m. Representatives Tarr, Birch, Drummond, Johnson, Parish, Talerico, Westlake, and Josephson were present at the call to order. Representative Rauscher arrived as the meeting was in progress. Also present was Representative Chenault.

CO-CHAIR TARR made opening remarks.

PRESENTATION(S): TAX DIVISION UPDATE, DEPARTMENT OF REVENUE

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CO-CHAIR TARR announced [that the only order of business would be a presentation by the Tax Division of the Department of Revenue.]

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KEN ALPER, Director, Tax Division, Department of Revenue (DOR), said DOR is responsible for collecting and administering most of the taxes for the state. He advised that oil and gas issues are complex and contentious and his presentation would provide "facts and figures." Oil and gas taxation is a collection of four major revenue items that fund most of Alaska's operations: property tax on oil and gas infrastructure and facilities raises approximately $0.1 billion per year, and approximately $0.4 of that is shared with local governments; royalty [landowner share] raised $1.2 billion in fiscal year 2016 (FY 16) and at least one-quarter of that is deposited into the Alaska Permanent Fund; production tax - which is a net profits tax - raised $0.2 billion in FY 16; corporate income tax is an apportionment share tied to global earning and is reduced to a negative for FY 16. Mr. Alper pointed out that in FY 12, the state collected a total of $9.7 billion in oil and gas taxes and royalty revenue, and in FY 16 the total was reduced to $1.5 billion (slide 3).

MR. ALPER returned to the topic of property tax, noting that property tax statutes are relatively unchanged since the 1970s, although property assessments, such as the Trans-Alaska Pipeline System (TAPS), are often litigated. Royalties are set by contract and the terms of the leases, and he described aspects of state land ownership and subsurface minerals rights on the North Slope and elsewhere (slide 4).

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REPRESENTATIVE TALERICO asked whether property tax assessments on infrastructure have held a constant value, in spite of the fluctuation in oil prices.

MR. ALPER said yes, and pointed out that the assessments may vary, but the underlying statutes have not changed much in 40 years.

REPRESENTATIVE TALERICO understood that Alaska cannot sell its subsurface mineral rights, but under the terms of the Alaska Statehood Act [passed in the 85th U.S. Congress], the state has the option of returning said rights to the federal government.

MR. ALPER agreed.

REPRESENTATIVE JOHNSON requested a comparison of Alaska's corporate income tax to that collected by other states.

MR. ALPER offered to provide specifics, and added that Alaska's corporate income tax rate statutes are similar to those of other states.

REPRESENTATIVE BIRCH questioned whether Alaska's Clear and Equitable Share (ACES) [passed in the 25th Alaska State Legislature] would generate less revenue today than Senate Bill 21 [passed in the 28th Alaska State Legislature].

MR. ALPER said he would provide a complete answer later in the presentation.

CO-CHAIR JOSEPHSON, referring to corporate income taxes, asked whether Alaska is in the minority of states that do not tax S corporations, limited liability companies (LLCs), or partnerships.

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MR. ALPER responded that the aforementioned entities are taxed through each state's personal income tax; it is hard to tax said entities through a corporate income tax because the earnings are not retained by the company, but are passed on to the owner's individual income, and Alaska does not have an individual income tax. He returned attention to royalties, and listed the factors affecting royalties. In most states royalties go to a private landowner, but as the owner of the resource, Alaska collects royalty in kind - meaning in oil - or as money. He cautioned that in the future, as oil not in the central North Slope is developed, royalties will pay a lower rate that is proportionate with the share of the federal royalty; for example, offshore three to six miles, the state collects 27 percent (slide 5).

CO-CHAIR JOSEPHSON surmised that from production offshore beyond six miles from the shoreline, the only benefits to the state would be applicable property and equipment taxes, and jobs.

MR. ALPER stated that a large discovery offshore would reduce the tariff on transportation through the pipeline, which would benefit the state, but there is no specific revenue tied to offshore oil development.

REPRESENTATIVE PARISH said he expects that the federal government would negotiate royalty rates within the Arctic National Wildlife Refuge (ANWR) and the National Petroleum Reserve Alaska (NPRA). He inquired as to whether the federal government could set the federal royalty rate at zero.

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MR. ALPER explained that the royalty set with the oil companies is on a case-by-case basis, usually at 12.5 percent. Certain statutory requirements are that a portion of the federal royalty goes to the state where the asset is located; regarding offshore oil development, he advised that there is pending congressional legislation that may benefit Alaska and other states that have offshore development off of their borders. In further response to Representative Parish, he said in the Gulf of Mexico, beyond six miles, producer states get a three-eighths share - 37.5 percent - and Alaska gets 27 percent [from three to six miles]. This is related to the state's connection to the outer continental shelf (OCS), where there is no longer active exploration underway.

MR. ALPER returned to the corporate income tax, which is an apportionment formula based on a company's worldwide earnings and Alaska's proportion of its income tied to sales, property, and barrels of oil produced. The focus of the following discussion will be directed to the production or severance tax, where there have been recent changes; however, he cautioned that often the numbers discussed are in the aggregate because information related to a specific taxpayer is confidential (slide 6). Mr. Alper identified the years between 1977 and 2005 as a stable period in the history of oil and gas taxes, during which there was a one percent gross tax on Cook Inlet production, and an additional gross tax based on the Economic Limit Factor (ELF) [passed in the 12th Alaska State Legislature] formula. He described the purpose and effects of ELF, as modified, on state revenue; for example, by 2005 most oil fields were paying less than one percent tax, and the legislature began efforts to reform oil and gas taxes (slide 7).

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CO-CHAIR JOSEPHSON assumed that currently, the state would collect more revenue from a 15 percent gross tax, but during a period with oil prices at $130 per barrel, the state would collect less from a 15 percent gross tax.

MR. ALPER explained that revenue from a net tax is less at low oil prices and more at high prices. In 2006, when the Petroleum Production Tax (PPT) [passed in the 24th Alaska State Legislature] began to tax net profits, the weighted average ELF tax on a barrel of oil produced on the North Slope was about 7 percent; now, most of the oil is taxed at the alternative minimum tax affected by Senate Bill 21: 4 percent. However, the ELF formula has not been modeled for the last ten years, thus the actual ELF tax is difficult to determine. Mr. Alper turned to the years between 2005 and 2017 - the volatile period of oil and gas taxes - as evidenced by the fact that the state has changed taxes six times over the last [eleven] years as follows (slide 8):

- 2005, ELF aggregation by executive order
- 2006, PPT
- 2007, ACES
- 2010, Cook Inlet Recovery Act [passed in the 26th Alaska State Legislature]
- 2013, Senate Bill 21
- 2016, House Bill 247 [passed in the 29th Alaska State Legislature]

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REPRESENTATIVE BIRCH asked if any of the foregoing changes were tax increases.

MR. ALPER answered that the [2005 aggregation] was an increase; PPT was neutral; ACES was an increase; Cook Inlet Recovery Act was a decrease; Senate Bill 21 was a tax cut, except at very low prices it is a small increase; House Bill 247 was a reduction in some benefits. In further response to Representative Birch, he acknowledged that Senate Bill 21 was a tax cut; although Senate Bill 21 has netted the state about $100 million, at the time of the legislation, the price of oil was about $100 per barrel and the fiscal notes described a [$500 million] to $700 million tax cut.

MR. ALPER provided further details related to the executive order by former Governor Frank Murkowski that aggregated Prudhoe Bay satellite fields into a higher ELF multiplier (slide 9). In 2006, PPT was passed, and he provided details leading up to the PPT legislation and the aftermath thereof (slide 10).

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REPRESENTATIVE PARISH asked for further details and costs related to the legal challenge of former Governor Murkowski's executive order that aggregated Prudhoe Bay fields for tax purposes.

MR. ALPER said that the Department of Law represented the state and he would provide information regarding the cost of the litigation.

CO-CHAIR JOSEPHSON recalled that the tax credits provided by PPT in 2006 were an outlay of $56 million.

MR. ALPER responded:

> The key portion of the capital credit was not anything we might have spent ... the capital credit was embedded as a component of the PPT tax for the major taxpayers, so if a, if a major producer might have, let's call it a billion dollars in taxable profit, they would then multiply it by the tax rate and then from that, subtract their capital credit. It would come off the top before they paid the tax, and the great bulk of this capital credit was ... revenue foregone, rather than any outlay of the state.

CO-CHAIR JOSEPHSON questioned whether 11 years ago the commitment was under $100 million, and in the last fiscal year it was over $700 million.

MR. ALPER said, "... yes, there was a ramping up of our obligation for cash tax credits." He explained that after the passage of the Cook Inlet Recovery Act the amount for Cook Inlet grew, and the current year's obligation is estimated to be about $700 million. However, after the actions taken by the governor and the legislature, the state spent $498 million [for credits] in FY 16. Mr. Alper directed attention to the ACES tax system, and provided details on the ensuing debate that was focused on progressivity and on the windfalls from high oil prices that resulted in large budget surpluses, savings accounts, and a large capital budget. The Act also created the tax credit repurchase fund and the formula for annual appropriations (slide 11). In 2010, the Cook Inlet Recovery Act did not change the ACES tax, but was targeted at Cook Inlet and expanded to other areas, and created a tax credit to build a gas storage facility in Kenai. He provided details surrounding the intent and the effects of this legislation, noting that by FY 14, more than one-half of repurchased credits were outside the North Slope (slide 12).

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MR. ALPER continued to the current tax regime, Senate Bill 21, legislation that intended to increase investment in new production on the North Slope. He provided details, most notably that most of the revenue impact is at high prices, which will be explained later in the presentation (slide 13).

REPRESENTATIVE BIRCH asked for confirmation that if ACES had been restored, "the delta there is about $100 million a year today."

MR. ALPER agreed. He then directed attention to the most recent tax change - by House Bill 247 - that represented the governor's intent to slow the rate of the growth of the state's obligations and liabilities. He provided details of the changes in the final bill that "left the fundamental tax calculations intact ... we weren't changing SB 21 per se ...." (slide 14).

CO-CHAIR JOSEPHSON referred to transparency and expressed his understanding that only officials of the Department of Natural Resources (DNR) perhaps the Department of Revenue (DOR) know which North Slope fields earned credits for a certain company.

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MR. ALPER responded that for tax purposes, a company files one tax return for all its operations on the North Slope, which explains why tax credits impact a new company differently than they impact an existing producer; House Bill 247 requires the state to report the name of each company and the amount of cash received for tax credits per year. Said reporting does not include the use of the money, or which company has credits but did not receive payment.

CO-CHAIR JOSEPHSON surmised that House Bill 247 reduced the annual cap to approximately $60 million.

MR. ALPER said there was not previously a limit, and House Bill 247 established a $70 million limit in statute - and that is further affected by the "hair cut" provision - thus a company taking cash to the cap would receive $61.25 million per year. In further response to Co-Chair Josephson's question about whether cash credits are subject to appropriation, he remarked:

> ... there's no requirement to appropriate anything at all. The [$]70 million company cap is obviously moot in a year where there's only $30 million in the fund, so that we haven't actually used that provision for anything yet. Had it been in place five years ago it would have been quite material.

MR. ALPER began to explain how oil has funded the state; since FY 78, Alaska has received $141 billion in total petroleum revenue, which he described as 27 percent of the oil's market value and 35 percent of the oil's wellhead value. He provided further details on past unrestricted general fund (UGF) revenue and the FY 17 oil revenue forecast (slides 15 and 16). In response to Co-Chair Tarr, he clarified that the oil revenue that makes up over 90 percent of UGF is the non-Alaska Permanent Fund portion of royalties; about 30 percent of royalties do not go through the budget, but go directly into the Alaska Permanent Fund. Mr. Alper directed attention to a graph that depicted the state's share of the market value of petroleum revenue from 1978 through 2016 (slide 17). He pointed out that the revenue was lower in the earlier years because there was less production and a high tariff on TAPS; however, the wellhead value in the earlier years is higher (slide 18). The wellhead value is known in tax law as the gross value at the point of production (GVPP). Slide 19 was an annotated version of slide 18 and illustrated that beginning in 1978 revenue hovered around 32 percent, with the exception of 1994, during which there was a large payment of royalty settlement money to the Constitutional Budget Reserve Fund (CBRF). As more wells were drilled, ELF rates for the larger fields declined, thus revenue started to decline from 1998 to 2005; after the change to a net profits system - which collects high revenues when prices are high - during the period from 2007 to 2013 revenues averaged 41 percent. When oil prices fell, from 2014 to 2016, revenue also fell to approximately 26 percent (slides 18 and 19).

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REPRESENTATIVE PARISH asked how much revenue was lost to the state due to companies' business decisions "of drilling additional wells to drive down the, the rate in a given field."

MR. ALPER was unsure; however, [the decline beginning in 1998] was due to a natural occurrence in that more wells were being drilled, which was changing the [ELF] multiplier, and there was an emphasis on the Prudhoe Bay satellite fields that were aggregated in 2005. He offered to research this question.

MR. ALPER turned to the present and discussed the meaning of percent of value (POV). Currently, production of approximately 185 million total barrels at $50 per barrel is worth $9.25 billion on the market, and each 1 percent of total market value is about $90 million to the state treasury; the wellhead value is about $7.4 billion, and each 1 percent of wellhead value is about $75 million. He further described the impacts of adding tax, or reducing credits, to the value of taxable and royalty barrels of oil, concluding that additional revenue of about $450 million reaches a revenue percentage of 32 (slide 20). During the ACES tax regime, the state earned high revenue because oil prices were high and costs were low; however, because prices were high, the oil industry searched for and developed challenging fields where the cost to produce oil costs $40 per barrel. He directed attention to a graph that illustrated the increase in lease expenditures for producing fields from 2007 to 2016. Noting the decrease of total cost in 2016, he explained that companies deduct costs against taxable barrels, which increases [taxable] total cost by 10-15 percent (slide 22). The steps of Senate Bill 21 tax calculations for legacy oil were illustrated on slide 23. Mr. Alper clarified that transportation costs are about $10 per barrel, including the TAPS tariff and transportation to a refinery, and production tax value is also referred to as PTV or net profits before tax. He observed, "You could get a sense that SB 21 was written around higher prices; at any price below [$]90, that was considered very low, so oil is receiving a credit at the maximum level, $8 per barrel" (slide 23). Slide 24 illustrated Senate Bill 21 tax calculation for a range of oil prices from $40 to $140 per barrel, as per the DOR Revenue Sources Book (RSB)

Spring 2016. Transportation and lease expenditures are constant, but as the PTV (net) goes higher, he estimated that the "crossover [from the minimum tax to $7.12 calculated level] is maybe [$]65, $68 a barrel." He stressed that in a net profits tax, price impacts are magnified through the tax system, whereas a gross tax has a more linear relationship of price to tax.

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CO-CHAIR TARR compared the costs illustrated on slide 22 to those of slide 24, and pointed out that under a net profit tax system, transportation costs and lease expenditures are deducted from the production tax; for example, at $40 per barrel, the PTV is negative in value. She advised that in a low-price environment under a net system, there are deductions that protect the industry, but do not protect state.

MR. ALPER restated that the minimum tax is 4 percent of GVPP.

CO-CHAIR JOSEPHSON questioned whether at less than $60 per barrel, the state's share is larger than that of the industry.

MR. ALPER, referring to information gleaned from industry tax returns, said that the breakeven price of an average barrel of oil produced on the North Slope last year was $45, and for the current year is $41, due to cost containment measures taken by the industry. In further response to Co-Chair Josephson, he agreed that the industry is in an unfavorable position and is suffering from low oil prices around the world.

CO-CHAIR JOSEPHSON remarked:

> On the other hand, the minimum tax is, is not a minimum tax because - depending on the facts of each field - because of a number of features can that drive the tax rate beneath the 4 percent floor. Is that correct?

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MR. ALPER responded that new oil - gross value reduction eligible oil - is not subject to the minimum tax, and can pay a zero rate; in addition, credits can be used to bring tax payments below the minimum, which led to debate related to "hardening the floor, making it so that certain taxes can't be used so as to protect the minimum tax for the state." He stressed there are other taxes in addition to production tax - such as royalty and corporate income tax - and production tax is a severance tax to pay the state for removing a non-renewable resource that cannot be replaced; in fact, there is thought that a severance tax should be paid under any conditions, which is the intent of the minimum tax.

CO-CHAIR TARR returned attention to slide 24, and stated that changes to operating expenditures (OPEX} and capital expenditures (CAPEX) such as layoffs and scaled-back drilling, would lag behind price changes, albeit depressing PTV.

MR. ALPER agreed that as companies cut their costs and reduce their breakeven price, the state benefits somewhat, except for job losses. The information on slide 24 is complicated and he summarized the important points as follows (slide 25):

- the price of oil fell by 50 percent
- the wellhead value declined by 54 percent
- the taxable net declined by 75 percent
- production taxes paid declined by 92 percent
- due to the impact of the variable per barrel credit - the tax paid at $120 per barrel was $26.32 and the tax paid at $60 was $2.03 per barrel - there was a reduction from $4 billion to $325 million per year in production taxes

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REPRESENTATIVE BIRCH questioned whether the state "bought into this ... as far as the volatility goes ...."

MR. ALPER acknowledged that the state chose taxing on net, which is known to be higher at high prices and lower at low prices. He turned attention to the types of credits and provided a history and the economics of the system of exploration, capital expenditure, and carried forward annual loss credits (slide 27). Not shown on slide 27 is the exception to the expired exploration credits related to Middle Earth that will remain in effect until 2022. In response to Co-Chair Tarr, he said Cook Inlet is defined in statute as the Cook Inlet Sedimentary Basin, water and land; the land north of latitude 68 degrees north is considered the North Slope; everything else is Middle Earth. Returning to credits, he clarified that carry forward annual loss credits are generally known as net operating loss (NOL) credits, and pay a company for a percentage of its losses that are not tied to a specific project. He characterized the aforementioned credit as "the main thing, when we look at our future credit burden .... What we're going to be paying in the future is this 35 percent North Slope NOL if anything big happens ...." Returning to a previous question, he said "stackability" is in effect when a company has both an NOL and a capital, well, or exploration credit, and he gave an example.

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CO-CHAIR JOSEPHSON inquired as to whether a company in production could have an NOL if the price of oil were $100 per barrel, because the company would be making a profit.

MR. ALPER said the price of oil does not matter. If a company is developing, and is not in production, its spending is effectively a loss. In further response to Co-Chair Josephson, Mr. Alper explained that an NOL affects producers and non-producers differently. He remarked:

> Conoco recently announced their Willow major find ... [that is expected] to produce a hundred thousand barrels of oil a day, [located] twenty or so miles west of existing infrastructure. ... Conoco is also a partner in Prudhoe Bay and Kuparuk, and the existing producing fields on the North Slope. They will be able to take that spend on a month-to-month basis and subtract it from their profits from their producing fields, and reduce their tax liability, more or less, in real time. They will reap the benefits of a 35 percent write-off, from month to month. If say Armstrong ... found a similarly sized field ... and spent several billion dollars ... they have no recourse other than a cashable tax credit system to get paid back, to get any sort of short-term benefit from the state on that. ... [This credit] creates some form of equity in tax treatment between the producer and the non-producer.

REPRESENTATIVE BIRCH inquired as to how and when the state will pay the tax credits it has offered and has an obligation to pay.

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MR. ALPER responded that tax credits are used generally to offset future taxes, which was the intent of the tax credits as written; in fact, the tax credit certificates issued by the state can be used for that purpose. The state also agreed to buy them back at face value subject to available funds, which was unique. He said that the credits submitted for purchase will have funds appropriated as necessary; however, the statute that created the tax credit fund gives a formula based on a percentage of revenue. In the most recent budget the governor used the statutory formula, reasoning that the credits do not lose value, can be used to offset future taxes, and can be sold. Last year the original version of House Bill 247, as part of the governor's fiscal package, had a fiscal note to pay all of the tax credits from CBRF. The governor was expecting the bill and other revenue measures to pass. The measures did not pass, and the fiscal note was not funded either, which left the tax credit balance as an obligation. As to the question of when the tax credits will be paid, Mr. Alper opined the legislature and the governor will address that as soon as the underlying fiscal problem is resolved.

REPRESENTATIVE WESTLAKE, as an aside, suggested latitude 68 degrees north includes offshore.

REPRESENTATIVE PARISH asked whether the state pays credits immediately rather than, for example, in the instance where a customer buys $100 worth of goods, and receives a store coupon worth $25 off their future purchase.

MR. ALPER said yes. In further response to Representative Parish, he recalled that this practice was established because the state had a policy to diversify the North Slope and encourage new companies to invest. Also, at that time, Alaska could afford the credit obligations, but as revenue has reduced, the credit obligations have not.

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REPRESENTATIVE PARISH asked what proportion of NOL credits have gone to small producers.

MR. ALPER estimated that about two-thirds of the NOL credits the state has issued have gone to the major producers, but not in cash; major producers must use the credits to offset or reduce their tax payments. About one-third has been in checks written to smaller companies that produce less than 50,000 barrels per day or are not producing at all.

MR. ALPER, in response to Representative Rauscher, said the split of new [companies] versus old was relatively stable until affected by the recent economy and activities in Cook Inlet. In further response to Representative Rauscher, he elaborated that the last couple of years have been "an aberration."

MR. ALPER returned to the presentation and described small producer credits, per-taxable barrel credits, and credits against corporate income taxes. He stressed that to qualify for cash, a company must produce less than 50,000 barrels per day; companies larger than that must "carry forward" to use against future year's taxes (slide 28). In response to Co-Chair Tarr, he clarified that the cash credits are considered a repurchase, not a refund. Mr. Alper returned to the history of tax credits and said that from FY 2007 through the end of 2016, about $8 billion in state credit money has been spent or foregone, of which $4.4 billion are credits against tax liability and $2.3 billion have been paid to repurchase credits on the North Slope. Outside the North Slope, there are $0.1 billion credits against tax liability and $1.2 billion have been paid to repurchase credits (slide 29). Slides 30, 31, and 32 provided further details on the distribution of the nearly $3.5 billion in state repurchased credits through FY 16, described by location and project. Slide 30 was corrected to read: $0.9 billion and $0.3 billion.

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CO-CHAIR JOSEPHSON expressed his concern that the state made a $1.5 billion investment for the equivalent of five months of oil production.

MR. ALPER stated this is incremental production from generally smaller and more challenged fields. An issue facing the credit system is that if a larger project is developed using the tax credit system, both volumes and liabilities will increase dramatically. He provided a production tax graph that illustrated the historical and forecast costs of statewide tax credits and production tax by three colored bars for each year: production taxes without any credits are shown on the left as a pink bar; production taxes paid after credits are used to offset tax liability are shown in the middle bar; the net effect after cash credits are paid is shown on the right as a red bar. At the outset and through the early years, tax credits truly were a reinvestment of surplus revenue to build for the future (slide 33). In regard to FY 15, FY 16, and FY 17, he remarked:

> If the credits were being paid at the rate at which they are being earned, we would actually be spending

substantially more on tax credits then we would be receiving in the production taxes that support them.

MR. ALPER provided a similar graph that illustrated statewide tax credits and all unrestricted petroleum revenue except for the "permanent fund piece" (slide 34). In regard to FY 17, he said the forecast assumes $700 million in credits is paid, as opposed to the actual amount of $30 million that was spent, and that the blue line on the graph is also out of date. Regarding forthcoming legislation with the intent to "harden the floor" he cautioned that the issue is this: A company with a carry forward loss could reduce its payments below the minimum tax and possibly to zero. In response to Co-Chair Tarr, he confirmed that the minimum tax is 4 percent for legacy oil and less for new oil.

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REPRESENTATIVE TALERICO recalled previous testimony that companies have cut their expenses, impacting net operating losses and reducing the cost to produce a barrel of oil. He asked whether assumptions related to factors impacting net operating losses are "figured in."

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MR. ALPER advised that slides 33 and 34 have not been updated; however, in the RSB and other DOR official forecasts, the assumption of companies' profits and losses, and the impact to future tax revenue, has been fully incorporated. He stressed that slides 33 and 34 illustrate that when the state had more revenue, the credits "meant something very different than they do in the current context." He offered to provide updated slides to the committee. Mr. Alper directed attention to the aforementioned credit appropriation formula AS 43.55.028(b) and (c), and described the use of and possible uses of the formula (slide 35). He added that in FY 18, DOR anticipates about $490 million in production tax; 15 percent of $490 million is $74 million, which was in the governor's budget proposal, and the same formula was used to determine the related governor's veto of $30 million in FY 17. Continuing details of tax credit history were presented on slide 36.

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CO-CHAIR JOSEPHSON suggested that with $3 billion to $3.5 billion in CBRF, even with a cut to the budget of $0.5 billion, the state [budget] would almost drain CBRF, thus funding the aforementioned without a fiscal plan is "absurd."

MR. ALPER recalled that one year ago it was expected that the CBRF balance would be $6 billion or $7 billion, and appropriating $1 billion to clear a major state liability made more sense. He cautioned that CBRF money is needed for a crisis such as a geological disaster. Returning to the presentation, he provided further details on tax credit certificates that have been paid, transferred, are ineligible, and are awaiting repurchase (slide 37).

REPRESENTATIVE TALERICO asked whether the aforementioned credits were all acquired in FY 17, or if some were from previous fiscal years.

MR. ALPER responded that most were expenditures during the calendar year 2015; as NOL credits require an annual profit and loss statement, applications are submitted at the end of March and that is the start of a 120-day processing time. Therefore, NOL credits are generally issued in July and August. In further response to Representative Talerico, he offered to provide additional information on the state's current liability on an annual basis, and directed attention to a graph from the RSB Fall 2016, which illustrated how the credit liability will grow over the next few years, based on certain assumptions (slide 38).

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REPRESENTATIVE BIRCH opined that postponing the payment of tax credits for ten years will not provide the benefits that were intended.

MR. ALPER agreed, and restated that the state is only obligated to pay under the credit appropriation statutory formula and that tax credits were designed to offset future taxes. He continued with details on the options for companies holding credit certificates (slide 39). He further explained that the option to sell certificates to a company with a tax liability - generally one of the three major producers - is rarely taken because the state buys certificates for 100 percent [of their value] and a third-party buyer would negotiate a purchase at a discount; however, under present circumstances, "we're seeing credits change hands." Furthermore, there are restrictions on how many credits a company can buy to the amount it can offset from the taxes that it owes; in addition, NOL credits can only offset 20 percent per year. Conversely, exploration credits do not have that restriction thus a company can offset all of its taxes with exploration credits, and he anticipated that exploration credits will be found in the secondary market.

MR. ALPER turned to the major provisions and regional impacts of House Bill 247, the tax credit reform bill, and provided details (slide 40). He noted that a qualified capital expenditure is known as QCE and a well lease expenditure is known as WLE. Regarding a statewide impact, the bill changed the interest rate charged on delinquent production taxes, carved out the production tax, and increased the interest rate for three years and then dropped it to zero which, he opined, will cause tax disputes in future years.

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CO-CHAIR TARR recalled that the intent of the surety bond is to protect local Alaska businesses if companies go out of business and local vendors are not paid.

CO-CHAIR JOSEPHSON questioned whether the intent of the increase in interest rates is to ensure audits are completed in a timely manner.

MR. ALPER said the provision is related to audits and the statute of limitations. He acknowledged, "It's unfortunate that we have been pushing the six-year limit and especially when interest rates were higher. ... Eleven percent compounded for six years kind of doubles your cost, and companies were finding that quite onerous, and deservedly so." The provision also eliminated compound interest, and then after three years interest goes to zero. He cautioned that the problem with this part of the provision is that if an audit assessment ends up in litigation for five more years after the audit, no interest will accrue, and thus there is no incentive for a company to ever settle a tax issue.

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ADJOURNMENT

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