

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

March 23, 2012

1:22 p.m.

MEMBERS PRESENT

Representative Paul Seaton, Co-Chair
Representative Peggy Wilson, Vice Chair
Representative Alan Dick
Representative Neal Foster
Representative Bob Herron
Representative Cathy Engstrom Munoz
Representative Berta Gardner

MEMBERS ABSENT

Representative Eric Feige, Co-Chair
Representative Scott Kawasaki

COMMITTEE CALENDAR

CONTINUATION OF OVERVIEW(S): OIL & GAS TAXES & CREDITS

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

BRUCE TANGEMAN, Deputy Commissioner
Office of the Commissioner
Department of Revenue
Juneau, Alaska

POSITION STATEMENT: Provided a PowerPoint presentation entitled "Overview of Alaska's Oil & Gas Tax Structure."

LENNIE DEES, Audit Master
Production Audit Group
Tax Division
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Answered questions related to the overview of Alaska's oil and gas tax and credit structure.

CHERYL NIENHUIS, Acting Chief Economist, Commercial Analyst
Anchorage Office
Tax Division
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: Answered questions related to the overview of Alaska's oil and gas tax and credit structure.

ACTION NARRATIVE

[1:22:33 PM](#)

CO-CHAIR SEATON called the House Resources Standing Committee meeting to order at 1:22 p.m. Representatives Seaton, Dick, Foster, P. Wilson, and Gardner were present at the call to order. Representatives Munoz and Herron arrived as the meeting was in progress.

CONTINUATION OF OVERVIEW(S): Oil & Gas Taxes & Credits

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CO-CHAIR SEATON announced that the only order of business would be a continuation of the Overview on Alaska's Oil and Gas Taxes and Credits.

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BRUCE TANGEMAN, Deputy Commissioner, Office of the Commissioner, Department of Revenue, continued his PowerPoint presentation from March 21, beginning with slide 37 entitled, "Limitations under AS 43.55.011(e)," which deals with Cook Inlet gas and oil. He stated that Cook Inlet gas is discussed in AS 43.55.011(j)(1) and (2), and said that for any lease or property with commercial production prior to April 1, 2006, the tax is based on the rates in effect at that time. For any lease or property which began commercial production after March 31, 2006, the tax is \$.177/MCF [million cubic feet], and this rate is in effect until December 31, 2021.

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REPRESENTATIVE P. WILSON asked how much increased revenue the state has received as a result of the change in tax after March 31, 2006.

LENNIE DEES, Audit Master, Production Audit Group, Tax Division, Department of Revenue (DOR), replied the \$0.177/MCF was applied to any new commercial production properties coming on line after April 1, 2006, and said this rate was determined by taking the average rate of all properties in Cook Inlet for the prior year. He offered his belief that no new properties have actually come on to production since then, so there really is no difference. He said this tax limitation in Cook Inlet has resulted in almost no income for the state because of tax sales and taxpayer credits against the tax liability. While there is a small amount of revenue from the tax on private royalties and from a few producers that have enough production to pay some tax, the revenue from Cook Inlet is minute.

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REPRESENTATIVE P. WILSON inquired as to whether there would be any future tax profit to the state from Cook Inlet.

MR. TANGEMAN responded these tax rates do not expire until the end of 2021, but said the tax system has generated a lot of interest over the past couple of years and production is expected to be coming from those areas.

REPRESENTATIVE P. WILSON asked whether the state will make any money in Cook Inlet before 2021, given the tax credits.

MR. TANGEMAN answered he did not know and suggested that the Department of Natural Resources (DNR) could address the projected new production between now and 2021.

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CO-CHAIR SEATON reflected that this provision was added in 2006 because representatives from Anchorage had wanted to ensure there was not a consumer tax increase. He said the necessary costs and tax credits to develop a gas field would "probably eat up any tax," but pointed out that the state could still receive royalties. He stated that the total tax generated had been \$2-\$3 million when the petroleum production profits tax (PPT) came into effect, which was before establishment of the credits under Alaska's Clear and Equitable Share (ACES).

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CO-CHAIR SEATON, in response to Representative P. Wilson, agreed that balancing provisions have been made for the various areas of the state.

REPRESENTATIVE P. WILSON clarified that she wants to balance provisions for the northern and western parts of the state, given there have been hydropower projects in Southeast Alaska.

CO-CHAIR SEATON noted the committee does not want to ask DOR to advocate or suggest a certain policy, but that today's discussion was for committee members to better understand the current tax system.

MR. TANGEMAN agreed that today's goal was to discuss current statutes.

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MR. TANGEMAN continued his discussion of the laws governing Cook Inlet, noting that [AS 43.55.011(k)(1) and (2)] address Cook Inlet oil [slide 38]. He stated the tax rate is zero for a lease or property that had commercial production prior to April 1, 2006. For a lease or property entering commercial production after March 31, 2006, the rate is zero based on ELF [economic limit factor] tax rates during the period April 1, 2005, through March 31, 2006. He related that these rates would remain in effect until December 31, 2021.

REPRESENTATIVE FOSTER asked how many leases were prior to 2006.

MR. DEES replied that only a few leases have come on line since April 1, 2006, therefore about 80-90 percent of the leases were producing before April 1, 2006.

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MR. TANGEMAN, moving to slide 39, pointed out that gas used in state under AS 43.55.011(o) has the same ceiling as gas subject to [AS 43.55.011(j)(2)], which is the Cook Inlet gas at \$.177 per MCF.

MR. TANGEMAN, responding to Representative P. Wilson, stated that 68 degrees latitude defined the North Slope versus south of the North Slope. In further response, he said gas used in state covers the entire state, with no differentiation between north and south of 68 degrees.

MR. TANGEMAN, responding to Co-Chair Seaton, confirmed that the definition for gas used in state is any gas used commercially, residentially, for power generation, or for conversion into something such as gas-to-liquids, but not conversion into liquefied natural gas (LNG) for shipment out of state.

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CO-CHAIR SEATON understood that in 2006 Cook Inlet was ring fenced for its expenses, but since then changes have been made so that the current tax lets credits be applied against North Slope or other production.

MR. DEES replied the referenced change was passed two years ago and was made to AS 43.55.011(m); it allows for tax credits from Cook Inlet to be used on the North Slope and elsewhere in the state. He pointed out that not many taxpayers operate in both Cook Inlet and other areas, including the North Slope, but the change allows these taxpayers the opportunity to apply the credits elsewhere in the state without having to apply them against the full tax liability in Cook Inlet. He added that this law did not change the treatment of excess lease expenditures, so lease expenditures are still ring fenced a bit in Cook Inlet. These excess lease expenditures can be converted to a net operating loss carry forward credit, but it is necessary to use them as if there is no ceiling in Cook Inlet before any excess can be converted to that credit.

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MR. TANGEMAN, resuming his presentation, pointed out that slide 40 depicts AS 43.55.011(j) and (k), the statute language for Cook Inlet gas and oil, and gas used in state.

CO-CHAIR SEATON understood that the tax credits are computed as a net operating loss at the base rate and not at the higher corporate rate off the North Slope so that they get converted at ACES net operating loss base rate to be applied elsewhere.

MR. DEES confirmed the aforementioned is correct, to the extent a company has excess lease expenditures, which are defined as the amount of operating and capital lease expenditures that exceed the amount of revenue from a specific property or lease. He explained that those excess lease expenditures can be converted at the base rate, 25 percent, and that 25 percent credit can be used anywhere in the state as an offset to a tax

liability. He concurred that it is capped at the base rate, not the nominal rate.

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CO-CHAIR SEATON noted that under the current situation [the state provides] a very preferential, low tax rate in Cook Inlet which needed to be balanced in its capacity for write off. Therefore, it was set at the net operating carry forward.

MR. TANGEMAN concurred that the Cook Inlet area is the most confusing part of the state's tax structure because of how it is calculated for Cook Inlet as well as how it affects other parts of the state when a company has production or expenditures in other parts of the state. He directed attention to the two handouts, "Table of Tax Credits..." and "Summary of Tax Credits under AS 43.55," which he characterized as concise explanations for a working knowledge of the various tax credits.

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REPRESENTATIVE P. WILSON, referring to the three areas which did not have any tax regulations, shared that she received a call from DOR explaining that there is not yet any need for regulations in those areas.

MR. TANGEMAN clarified that DOR used the term "not yet" when it would have been more accurate to state "not required".

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MR. TANGEMAN, returning to his presentation, stated that slide 41 is the explanation of the Cook Inlet credits in three bullet points, which are as follows:

- In 2010 AS 43.55.011(m) was amended to allow that credits no longer had to be recalculated and applied as if there were no tax ceilings for Cook Inlet oil & gas and for gas used in-state
- In other words, beginning in 2011 any tax credits remaining after application against the tax ceilings of AS 43.55.011(j), (k), & (o) could be applied against any tax obligation in the state
- However, for the period 2007 - 2012, the tax credits must first be applied as if no ceilings existed before any 'excess tax credits' can be determined

MR. TANGEMAN stated that slide 42 is a reading chart on AS 43.55.011(m), which is what Mr. Dees referred to in how lease expenditures are handled after January 1, 2011.

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MR. TANGEMAN next reviewed the payment of tax [slide 43], explaining that a producer subject to tax under AS 43.55.011 "must make a monthly estimated payment of tax." He said "any under or overpayment amount of an installment payment bears interest at the rate provided under the federal Internal Revenue Code", which is compounded daily. In response to Co-Chair Seaton, he said this is corporate-wide/state-wide. In response to Representative P. Wilson, he said it is in the best interest of the taxpayer to make the monthly payment as close to correct as possible. Payments will vary between a little over and a little under, so they balance out in the end. The interest rate is severe, so it is in the best interest of the company to get it correct and it is in the state's best interest to make sure it is correct because in the case of an overpayment the state would owe interest to the taxpayer. He said the true-up for the previous year occurs on March 31.

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CO-CHAIR SEATON asked when the overpayment interest would be reimbursed.

MR. DEES replied the March 31 true-up must occur because it is only at the end of the year that the real numbers are known. Alaska law requires that the estimated monthly tax payment be calculated at one-twelfth of the annual lease payment, so the numbers are actualized on March 31 to determine whether there was an over- or underpayment for the year. He said the rate was about 3 percent for an underpayment and about 1.5 percent for an overpayment. When the true-up is submitted on March 31, the taxpayer includes either the additional tax and interest or a request for a refund of an overpayment. The department has 90 days to pay a refund to the taxpayer at no interest, but after that 90-day period the interest rate turns to 11 percent compounded quarterly.

MR. TANGEMAN summarized that the monthly payments are estimates based on one-twelfth of the annual lease expenditures; March 31 is the first true-up; DOR has 90 days to do a desk audit; and DOR can take up to six years to do the full-blown audit that verifies these numbers.

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MR. TANGEMAN said slides 44-46 spell out the statutory language about the payment of tax to the state.

MR. TANGEMAN, responding to Representative P. Wilson, said the companies have until March 31 to present their final tax filings and the state has 90 days from then to confirm the filings, which is the interest-free time period. Therefore, the companies basically have until March 31 of interest-free time period to finalize their tax returns.

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MR. TANGEMAN moved to slide 47 to continue his presentation, explaining that under AS 43.55.150 the gross value at the point of production (GVPP) "is determined at the point where the oil or gas first enters into the transportation system and does not include any cost upstream of the point of production (lifting and processing costs)." For example, this would be Pump Station 1 for Prudhoe Bay and for Kuparuk this would be entry into the Kuparuk Pipeline. He said that "generally the first point of entry into a common carrier pipeline is considered to be the point of production." Responding to Co-Chair Seaton, he confirmed that all of the upstream costs are subtracted from the value and that is the gross value at the point of production.

MR. TANGEMAN explained that for "netback" purposes determination of the GVPP begins with the destination value at the sales point of the oil or gas [slide 48]. The determination allows for the actual cost of transportation except when: the shipper is affiliated with the transportation carrier; the contract for transportation is not an arms-length transaction; or the method of transportation is "not reasonable" in view of existing alternatives.

MR. DEES, responding to Representative Gardner, said "not reasonable" would be a situation such as a pipeline being available to ship the oil but instead the oil was loaded onto a car and driven to Valdez. He said that to his knowledge something unreasonable has not happened.

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MR. DEES, responding to Representative Dick, defined an arms-length transaction as being two unaffiliated people executing an

exchange where the agreed-to price of that exchange is what a reasonable buyer or seller would do that transaction for, as opposed to dealing with an affiliate where one or the other [could influence the price or the cost].

MR. TANGEMAN added that if it does not appear to be a market-price transaction, it would not be arms-length.

CO-CHAIR SEATON explained the concept using a real estate example: a willing buyer and a willing seller would be the market value, while selling to one's daughter at half price would not be an arms-length transaction.

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MR. DEES, responding to Representative Seaton, said the point of production is defined in AS 43.55.900. For oil, the point of production is before the inlet of the pipeline connecting to a particular field; the oil must go through an automatic custody transfer meter, called a lack meter, and that meter is the point of production. Under rules mandated by the Alaska Oil and Gas Conservation Commission (AOGCC), each field must have a lack meter to measure the oil before it leaves the field.

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MR. TANGEMAN, continuing his presentation, noted that slide 49 spells out the actual statutory language for AS 43.55.150.

MR. TANGEMAN next reviewed the determination of production tax value of oil and gas [slide 50], explaining that lease expenditures under AS 43.55.165 "must be upstream of the point of production; must be ordinary and necessary costs of exploring for, developing, or producing oil or gas;" and "must be direct costs of exploring for, developing, or producing oil or gas." He said they are adjusted by reimbursements or similar payments under AS 43.55.170, and also noted that under AS 43.55.160(b) "a production tax value calculated under this section may not be less than zero."

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CO-CHAIR SEATON requested Mr. Tangeman to distinguish between gross value at the point of production and production tax value.

MR. TANGEMAN directed attention to the income statement on slide 10 and explained that the gross value at the point of production

is the value after transportation costs are subtracted; from this value the lease expenditures are deducted to arrive at the production tax value.

REPRESENTATIVE DICK asked how closely the state monitors the cost numbers [that are provided by the companies].

MR. TANGEMAN responded that the monthly tax payments are an estimate but in March the company trues up the entire [previous] 12-month year. The state then spends 90 days confirming the numbers, after which the state conducts a full-blown audit reviewing the details. Hanging over this for the entire time is the interest payment clause, so there is incentive to be as accurate as possible through each stage.

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MR. TANGEMAN, responding to Co-Chair Seaton, confirmed that the gross value at the point of production is not shown on a specific line on slide 10, but pointed out that it would be right after the line for total transportation costs and before the line for lease expenditures.

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MR. TANGEMAN resumed his presentation, moving to slide 51 and explaining that lease expenditures are direct costs "allowed by the department by regulation". Regulation 15 AAC 55.250, standards for lease expenditures other than overhead, defines the types of activities for which direct charges will be allowed. Responding to Co-Chair Seaton, he confirmed that these would be all the lease expenditures. Regulation 15 AAC 55.260, direct charges, defines the allowed expenses for activities in 15 AAC 55.250.

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CO-CHAIR SEATON surmised this standard for lease expenditures does not have anything to do with the limitation that was in place for the first three years on the allowable expenditures.

MR. DEES answered the aforementioned reference is to a standard deduction that was placed on the legacy fields based on their actual lease expenditures in 2006. These regulations were not in place in 2006 so they were not really addressing what was allowable as part of that calculation. However, DOR audited those years and found expenditures it did not think allowable.

Because 2006 was a nine-month year, statute allowed for those particular legacy fields a deductible lease expenditure of 1.37 times the number that was reached for 2006. The number for 2008 was 1.03. So, the number grew by an inflation amount of 3 percent each year until 2009, which was the last year of the standard deduction. In further response, he said the standards in 15 AAC 55.250 do apply eventually to what those expenses were because DOR did not allow any activities that were not within the parameters of those standards. These regulations were not in place at the time that those audits were done, so in a way these standards would have been what DOR would have used to determine what those numbers were for those years.

MR. TANGEMAN interjected that Sections 250 and 260 are actual and extensive listings of items that are allowed and they are post that timeframe.

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CO-CHAIR SEATON inquired whether the combined direct costs on the North Slope are all the lease expenditures. He further asked how much those direct costs are; for example, how much were those costs for last year. He understood that 4.5 percent of direct costs are allowed for overhead given that overhead is not an allowed deduction.

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MR. TANGEMAN believed that was part of the capital expenditures shown in DOR's Revenue Sources Book. He deferred to Ms. Nienhuis for answering the question further.

CHERYL NIENHUIS, Acting Chief Economist, Commercial Analyst, Anchorage Office, Tax Division, Department of Revenue (DOR), replied DOR would probably take a percentage of the operating expenditures because the overhead is the 4.5 percent of operating and capital expenditures. She said she would get this information for the committee.

MR. TANGEMAN, responding to Co-Chair Seaton, agreed to have DOR go back for three years of this information.

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MR. TANGEMAN, continuing his review of lease expenditures, explained that direct costs include charges for both capital and operating expenses [slide 52]. He said AS 43.55.023(o) defines

"qualified capital expenditures" as an expenditure that is a lease expenditure under AS 43.55.165 and that it is a capitalized expenditure under the Internal Revenue Code. Because DOR relies on the federal codes there is no other objective or defining criteria to be a "qualified capital expenditure". Moving to slide 53, he noted that exclusions from lease expenditures are provided for under AS 43.55.165(e).

MR. TANGEMAN, responding to Co-Chair Seaton, confirmed that a capitalized expenditure under the Internal Revenue Code [slide 52] is not capitalized in the state's system and that the state allows full write off. He said [AS 43.55.023(o)] establishes what is allowable.

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MR. TANGEMAN returned to slide 53 and related that lease expenditures include an exclusion for "that portion of expenditures that would otherwise be qualified capital expenditures" and reduces the deduction for capital expenditures by \$.30 times the total taxable production for each lease or property in British Thermal Unit (BTU) equivalent barrels.

MR. DEES, responding to Co-Chair Seaton, confirmed that the \$.30 is applicable to all areas of the state. He said it reduces what otherwise would be qualified capital expenditures by \$.30 times the total production in BTU equivalent barrels; so even in an area that produces gas, the taxpayer will have to convert the gas to a BTU equivalent barrel and multiply it by \$.30 and that figure will be deducted from the total capital expenditures. While the reason for this exclusion depends on the person being talked to, some suggest it was done to allow for a deduction for deferred maintenance in the field, recognizing that some of the expenditures a company has could be for maintenance items.

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MR. TANGEMAN resumed his definition of lease expenditures, stating that in Cook Inlet each lease or property (LOP) is a segment [slide 54] and on the North Slope all leases or properties are segments. "Both statute and regulation require that costs are ring fenced to each segment. A single production tax value must be calculated for each segment within the state. The provision of [AS] 43.55.160(b) that a production tax value may not be less than zero applies to each production tax value calculated for each segment," he explained.

MR. DEES, responding to Co-Chair Seaton, explained that each lease or property and each product on a particular lease or property is a segment. For example, a lease or property within Cook Inlet that produces both oil and gas would have two segments, so the cost would have to be allocated to each of those products on the basis of BTU equivalent barrels and then a production tax value would be calculated for each of those segments. For a particular taxpayer the overall excess lease expenditures are determined on a Cook Inlet-wide basis, so the ring fence in Cook Inlet is on a Cook Inlet-wide basis. To determine whether a taxpayer with 10 different properties in Cook Inlet had excess lease expenditures, all 10 of those leases or properties would be considered. Responding to Mr. Tangeman, he confirmed that in this example there would be 20 calculations - one for gas and one for oil for each of the 10 segments - and then these calculations would be taken as a whole for the lease expenditures.

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CO-CHAIR SEATON inquired whether this is a holdover from the economic limit factor (ELF) where the less the volume from a segment or a property the less the tax, so a taxpayer holding a lot of segments did not pay any taxes.

MR. DEES offered his belief that this is the case. He said that under ELF there were separate economic limit factors for each product; thus there was an ELF for oil and an ELF for gas. To keep Cook Inlet from having a tax increase under the new net tax, the integrity of those segments was maintained to determine the tax ceilings and to prevent the tax increase.

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CO-CHAIR SEATON stated that the economic limit factor was a factor based on the total production in a field and the average production per well in that field; so, the smaller the production in a field the less tax paid and the more wells in the field the lower the tax on that field. Given the tax rates in Cook Inlet, he asked whether there really is any tax effect of having these segments since the inlet is ring fenced. He also asked whether this complicated tax system is currently serving a purpose.

MR. TANGEMAN replied that things were locked in when the state went to this system. Either existing production was locked in

based on the previous 12 months or new production was locked in based on the calculation with \$.177.

MR. DEES verified that for Cook Inlet all these calculations must be done to determine that basically the taxpayer owes no tax. All the calculations must be done for all the segments to determine whether there are excess lease expenditures or excess tax credits that could be used in another area of the state. He concurred there is a lot of complexity in Cook Inlet that could be simplified.

CO-CHAIR SEATON commented that this complexity may be something to look at since the result is zero tax, making all the calculations useless.

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MR. TANGEMAN returned to his overview of lease expenditures, noting that segments would be identified under 15 AAC 55.206(c) [slide 55]. Moving to slide 56 he pointed out that in addition to the oil and gas production tax under AS 43.55.011(e), a producer must also pay the following surcharges: \$.01 per taxable barrel of oil from each lease or property in the state [AS 43.55.201] and \$.04 per taxable barrel of oil from each lease or property in the state [AS 43.55.300]. He noted that "the legislature may appropriate these funds to the response account in the oil and gas hazardous substance release prevention and response fund established by AS 46.08.010."

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REPRESENTATIVE GARDNER asked what the current balance is of the aforementioned fund and whether that balance is adequate for a possible need.

MR. TANGEMAN offered to get back to the committee with this figure.

MR. TANGEMAN, responding to Representative P. Wilson, said the two surcharges apply to taxable barrels after the royalty barrels are taken out; thus, the total surcharge per taxable barrel is \$.05.

MS. NIENHUIS, responding to Co-Chair Seaton, related that according to DOR's Revenue Sources Book the AS 43.55.201 surcharge of \$.01 is called the "response surcharge" and the [AS 43.55.300] surcharge of \$.04 is the "prevention surcharge". She

said the \$.01 per barrel surcharge is suspended when the state's response account equals or exceeds \$50 million and since the account's current balance is about \$48 million the state is still collecting the entire \$.05. In further response, Ms. Nienhuis reported that the response account is administered by the Department of Environmental Conservation (DEC).

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CO-CHAIR SEATON concurred with Representative Herron that the committee will probably want to look at whether \$50 million is adequate for oil spill prevention and response, given inflation over the years. In further response, Co-Chair Seaton stated that DEC will be asked to address the committee about the fund. He surmised that DOR's responsibility is only to make the calculations and to put the money into the fund.

MS. NIENHUIS confirmed that DOR's responsibility is to track the fund balance. She said DOR receives notification of the fund balance so the department knows when to suspend or resume charging that penny per barrel. She added that the penny per barrel only went into place again in 2007. While DOR monitors the fund's balance and has occasional conversations with DEC about the fund, she said DOR has little influence over that money.

[2:37:49 PM](#)

REPRESENTATIVE MUNOZ thanked the Department of Revenue for providing graphs depicting the scenarios of profit splits under HB 110 and SB 192 [8 slides produced in response to the committee's request to reproduce slide number's 22 and 23 from DOR's 3/21/12 presentation to reflect absolute profit split and share of profit under HB 110 and CSSB 192]. She asked why the federal tax increases in the scenarios when the state tax decreases.

MR. TANGEMAN responded that as the producer share increases the producer is keeping more of the revenue, so the producer is responsible to pay [federal tax].

REPRESENTATIVE MUNOZ asked whether all of the scenarios in the aforementioned graphs take into account the credits provided to the producers by the state.

MS. NIENHUIS answered the graphs take into account the lease expenditures and the oil that is being produced and therefore

the credits that are taken against tax liability. Credits generated by companies that are not applying those credits to the tax liability are handled through the budget cycle, so those credits are not included in the graphs.

MR. TANGEMAN clarified that not included in the graphs are the explorers that do not yet have a tax liability.

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MR. TANGEMAN, responding to Co-Chair Seaton, confirmed that the graphs for HB 110 are calculated on old, not new, oil. He said they are based on the fall forecast, both production and price, so DOR is not assuming any hypothetical new production based on any bill passing.

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REPRESENTATIVE P. WILSON, requested Mr. Tangeman to expound on the difference between absolute profit split and the share of profit.

MR. TANGEMAN explained that DOR had originally used slide 7 as looking at just the percentage split, but then received questions about what the dollar split would look like. So slide 4 [of the 8 slides] is purely the dollar impact as the price progresses upward. Slides 6 and 7 depict a percentage split, so it is just two different ways to look at it.

CO-CHAIR SEATON observed from the graphs that the producers are always making more money as the price rises. While slide 7 shows that the producers' percentage may go down, they are still making more money in absolute terms. He pointed out that when Alaska's share increases, that amount is deductible from federal taxes; when the state's share is reduced, 35 percent of that reduction goes to the federal government because that is then profit to the producer. The state only taxes profits, so when \$100 million is shifted from the state, \$35 million of that goes to the federal government.

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MS. NIENHUIS, responding to Co-Chair Seaton, confirmed that the graphs on these 8 slides include royalty, corporate income tax, and property tax - so they include all the state revenues.

CO-CHAIR SEATON requested the graphs be redone without the royalty because in other states the royalty is private and private royalties are not computed into the government share, which makes it hard to do comparisons between Alaska and other states.

MR. TANGEMAN said this could be done, but advised that it would skew the producers' share because a producer in another state is paying a royalty. Whether that royalty goes to the state or a private landowner, it is still a payment that a producer is making.

CO-CHAIR SEATON pointed out that what is being compared is government take, so it does not matter whether the royalty is being paid to the State of Alaska or someone else. So when the 12.5 Alaska royalty is included in the graphs it does not depict the same tax consequences seen in another state where the royalties are not included because they are paid to private entities. He would like to be able to compare Alaska's tax system with another state's tax system.

MR. TANGEMAN believed DOR has produced charts that break out the state's four revenue streams and said he will provide the committee with them.

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REPRESENTATIVE GARDNER added that most informative would be charts comparing Alaska to other regimes with the royalty added to that - but not as government take - so committee members could see how industry take in Alaska compares to industry take elsewhere, given that royalty in other states can be twice as much as it is in Alaska.

REPRESENTATIVE P. WILSON commented it is unknown what the private royalty take is because it is a private contract.

CO-CHAIR SEATON concurred, but said it is known from some landowners that those landowners are receiving 25-30 percent royalty. He allowed that this amount varies; for example, in Kansas certain landowners are receiving 16 percent.

MR. TANGEMAN pointed out that today's presentation was based on current statutes, so DOR will need some direction from the co-chairs on what the committee would like for additional graphs when there is another bill.

CO-CHAIR SEATON said the committee is currently asking for charts that DOR has already prepared now.

[2:51:58 PM](#)

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 2:52 p.m.