

SENATE FINANCE COMMITTEE

March 2, 2022

9:01 a.m.

[9:01:02 AM](#)

CALL TO ORDER

Co-Chair Stedman called the Senate Finance Committee meeting to order at 9:01 a.m.

MEMBERS PRESENT

Senator Click Bishop, Co-Chair  
Senator Bert Stedman, Co-Chair  
Senator Donny Olson  
Senator Bill Wielechowski  
Senator David Wilson

MEMBERS ABSENT

Senator Lyman Hoffman  
Senator Natasha von Imhof

ALSO PRESENT

Dan Stickel, Chief Economist, Economic Research Group, Tax Division, Department of Revenue.

SUMMARY

^PRESENTATION: OIL & GAS SEVERANCE TAX - ORDER OF OPERATIONS

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Co-Chair Stedman explained that the committee would hear a presentation from the Department of Revenue (DOR) on oil and gas severance tax. The committee would consider the order of operations and how the state's oil and gas severance tax was structured. He emphasized that the state's oil tax structure was one of the most complex in the world. The committee would consider FY 22 and FY 23, and the following day would hear testimony from consultants regarding the state's competitive position of its oil basin compared to other basins in the world.

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DAN STICKEL, CHIEF ECONOMIST, ECONOMIC RESEARCH GROUP, TAX DIVISION, DEPARTMENT OF REVENUE, discussed the presentation "Order of Operations Presentation - Senate Finance Committee" (copy on file). He stated that the purpose of the presentation was to provide a high-level overview of how the oil and gas production tax worked for the North Slope.

Mr. Stickel showed slide 2, "Acronyms":

ANS - Alaska North Slope  
ANWR -Arctic National Wildlife Refuge  
Avg - Average  
Bbl - Barrel  
CBRF - Constitutional Budget Reserve Fund  
CIT - Corporate Income Tax  
DOR - Department of Revenue  
FY - Fiscal Year Acronyms  
GVPP - Gross Value at Point of Production  
GVR - Gross Value Reduction  
NPR-A - National Petroleum Reserve Alaska  
OCS - Outer Continental Shelf  
PTV - Production Tax Value  
SB21 - Senate Bill 21, passed in 2013  
TAPS - Trans Alaska Pipeline System  
Ths - Thousands

Co-Chair Stedman asked Mr. Stickel to try not to use acronyms as much as possible to ensure the public could easily understand what was being discussed.

Mr. Stickel agreed.

Mr. Stickel spoke to slide 3, "Agenda":

- Oil and Gas Revenue Sources
  - o How production tax fits in
  - o FY 2020 - FY 2024 oil and gas revenues
  
- Production Tax Calculation "Order of Operations"
  - o Detailed walk-through of each step of tax calculation
  - o Defining commonly used terms
  - o Focus on North Slope oil
  - o FY 2020 - FY 2024 comparison

Co-Chair Stedman thought the presentation was more of a mechanical discussion, while the discussion planned for the following day would address the merits of policy in detail.

[9:06:43 AM](#)

Mr. Stickel referenced slide 4, "Overview":

- Alaska's severance tax is one of the most complex in the world and portions are subject to interpretation and dispute.
- These numbers are rough approximations based on public data, as presented in the Fall 2021 Revenue Sources Book and other revenue forecasts.
- This presentation is solely for illustrative general purposes.
  - Not an official statement as to any particular tax liability, interpretation, or treatment.
  - Not tax advice or guidance.
- Some numbers may differ due to rounding.

Mr. Stickel cautioned that the presentation attempted to take a very complex tax system and break it in to understandable pieces. The data used aggregated numbers amongst all the companies doing business on the North Slope, while official revenue forecasts modeled on a company-specific basis. He noted he was an economist rather than an auditor and his comments were not an official tax interpretation.

Co-Chair Stedman asked Mr. Stickel to expand on the comment that the numbers used were in aggregate.

Mr. Stickel explained that there were multiple producers and companies doing business in the state, and there were a few major producers on the North Slope. He continued that when DOR did its official revenue forecast, it was modeling each individual producer's tax liability using confidential tax information. Due to the confidentiality provisions in state statute, the department was not allowed to release any information that would identify the particulars of any taxpayer, so when information was presented to the legislature or the public, all of the company's information was aggregated into a single set of numbers.

Co-Chair Stedman asked if the weekly, monthly, and daily data was rolled up into individual corporations and then consolidated into an annual figure. He thought that the information was what the legislature had in order to set policy.

Mr. Stickel agreed.

Co-Chair Stedman mentioned that it was a challenge that the data did not necessarily reflect any individual company, while in many circumstances the state had looked at changes to the structure that may affect companies in different ways. He commented on the challenge on setting consolidated policy for the basin or the state that all of the producers would be favorable to. He thought there were differences amongst the companies.

Mr. Stickel agreed that each company had a different portfolio of operations and a different cost structure, and the impacts of policies would vary between companies.

Co-Chair Stedman wanted to set to the stage as to why there was so much discussion on the topic over the years.

[9:10:11 AM](#)

Mr. Stickel turned to slide 5, "Oil and Gas Revenue Sources":

- Royalty - based on gross value of production
  - o Plus bonuses, rents, and interest
  - o Paid to Owner of the land: State, Federal, or Private
  - o Usually 12.5% or 16.67% in Alaska, but rates vary
- Corporate Income Tax - based on net income
  - o Paid to State (9.4% top rate)
  - o Paid to Federal (21% top rate)
  - o Only C-Corporations\* pay this tax
- Property Tax - based on value of oil & gas property
  - o Paid to State (2% of assessed value or "20 mills")
  - o Paid to Municipalities - credit offsets state tax paid
- Production Tax - based on "production tax value"
  - o Paid to State - calculation to follow

Oil and Gas Revenue Sources\* C-Corporation is a business term that is used to distinguish the type of business entity, as defined under subchapter C of the federal Internal Revenue Code.

Mr. Stickel noted that there was an upcoming slide that described how the royalty provisions differed for all the different forms of land in the state. He explained that the production tax applied to any production within the state and within the three-mile limit regardless of land ownership.

Co-Chair Stedman asked Mr. Stickel to explain why there was a royalty and production tax, and to define the components.

Mr. Stickel explained that royalty was the payment to the landowner. The state leased land to companies that would make investments to develop the oil and gas on the land and would typically pay an upfront bonus bid for the initial right to do exploration and development. Additionally, the company would pay an ongoing rental for use of the land and would pay a royalty interest as production came out of the ground. He qualified that the royalty interest would be set at the time the leases were issued, and for most leases on state land the royalty was 12.5 percent. The production tax was a more general tax for the privilege of producing oil and gas in the state.

Co-Chair Stedman asked if the royalty was by contract.

Mr. Stickel answered affirmatively.

Co-Chair Stedman noted that the legislature did not change royalty rates but did have policy discussions and modifications of the production tax. He reminded that the state had royalty contracts that went back to the 1960s or perhaps even earlier. He thought the contracts were transferrable. He mentioned the oil company BP transferring its contract to a new operator.

Mr. Stickel thought Co-Chair Stedman was correct.

[9:14:00 AM](#)

Mr. Stickel considered slide 6, "Oil and Gas Revenue Sources: Five-Year Comparison of State Revenue," which showed a table of all the sources of state revenue from oil

and gas from FY 20 up through a forecast of FY 24. He noted that the property tax revenue shown was indicative of the state's share. Additionally, there was a much larger number in the \$400 million to \$500 million range that went to municipalities. The corporate tax applied only to C corporations. There were some temporary impacts for revenue in FY 20 and FY 21, which related to low oil prices and some federal tax changes related to the Covid-19 recovery act.

Mr. Stickel discussed royalty information, which included bonuses, rents and interest, the state's Unrestricted General Fund (UGF) share of royalties, and the constitutionally dedicated share of royalties that went to the Permanent Fund and the School Fund. He mentioned settlements to the Constitutional Budget Reserve (CBR) Fund, based on any assessments or disputes of prior years' production tax royalty or other oil and gas minerals taxes. The last category was shared revenue from the Natural Petroleum Reserve-Alaska (NPRA), which was the 50 percent share of any bonuses, rents, or royalties that the federal government received for production in the petroleum reserve. There were special restrictions as to how the funds could be used by the state, and the revenue source had been historically small. He expected the revenue source to be larger in the future as additional production came online.

Co-Chair Stedman asked if the NPRA royalties flowed through the state to the impacted local communities in the area.

Mr. Stickel affirmed that the state administered a grant program to direct the revenue to impacted communities on the North Slope.

Mr. Stickel noted that the revenue numbers in the presentation looked at current law and current year tax liabilities and fiscal impacts. He mentioned the issue of tax credits left over from prior tax regimes and available for state purchase. He cited that there was about \$565 million in outstanding tax credits available for state purchase as of January 1, 2022. He relayed that the presentation did not address the outstanding liability for past tax credits.

Co-Chair Stedman noted he had asked Mr. Stickel to delineate the topic so it was clear to see the flow of the

tax structure in any given year. There was accrued liabilities from the past that had to be considered. He thought the number Mr. Stickel provided was more accurate and explained the committee would discuss the matter during the work on the operating budget. He cautioned that if counting the tax credits against state revenue, the following year would be distorted if the amount was counted again. He considered that the amount of outstanding tax credits was sitting on the sidelines waiting for an appropriation but thought discussing the issues separately would minimize confusion.

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Senator Olson asked about the total of the tax credit liability.

Mr. Stickel stated that he had quoted \$565 million, which was submitted in a letter as of January 1, 2022. The number in the Fall Revenue Forecast had been \$587 million.

Senator Olson asked if the number included what was going to the Arctic Slope Regional Corporation (ASRC).

Mr. Stickel replied that the total included all outstanding credits available for state purchase.

Co-Chair Stedman asked Mr. Stickel to address how the tax credits worked. He thought the credits could be traded between companies. He thought there was some maneuvering and that the number changed from time to time.

Mr. Stickel explained that the outstanding tax credits, which were no longer available to be earned, could be certificated by the state. If a company had production and sufficient tax liability, it could use the credit to offset its tax liability. The company could request state purchase. He explained that prior to FY 16, the state purchased the whole outstanding balance of eligible tax credits each year, but since that time the state had purchased less than the full balance and companies would get on a list for credit purchase. A company could also transfer or assign the credits to a financial entity that could provide financing in exchange for the right to the tax credit certificate. The credits could also be sold to another company to apply against tax liability.

Senator Olson understood that the ASRC did not have the ability to trade or sell the tax credits, nor use them toward a tax liability. He asked if Mr. Stickel could confirm the information.

Mr. Stickel was not prepared to speak to the specifics of a particular taxpayer.

Senator Olson thought some tax credits were different.

Mr. Stickel noted that there had been various changes made to the tax credit provisions over the years.

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Co-Chair Stedman asked about tax credits being assigned to another entity and wondered if it meant that a bank or lending institution could pick up the tax credits.

Mr. Stickel explained that several of the companies had built the idea of monetizing the tax credits into ongoing plans for financing, considering that the state was purchasing the full balance of tax credits prior to FY 16. In the absence of the state purchasing the credits, companies had assigned the credits to a lending institution, which had allowed companies to get the needed financing to continue work, and then the credits were held by the lending institution. When the state ultimately purchased the tax credits, the money would flow through to the lending institution.

Mr. Stickel displayed slide 7, "Fiscal System: Overall Order of Operations":

- Royalties (State, Federal, or Private)
- Property Tax
- Production Tax
- State Corporate Income Tax
- Federal Corporate Income Tax

Mr. Stickel explained that the graphic showed the overall order in which the elements of the fiscal system were applied. He noted that royalties were taken before any taxes were taken. Downstream expenditures flowed through into the transportation cost for calculation of the production tax.

Co-Chair Stedman asked what "downstream" signified.

Mr. Stickel explained that upstream and downstream delineated activity on the lease versus off the lease. In the oil field where production was taking place, it was considered "upstream" of production, while "midstream" referenced the transportation structure, and "downstream" was the end result of the oil going into a refinery and to distribution.

Co-Chair Stedman asked if upstream was a wellhead.

Mr. Stickel explained that when he used the term "upstream," it denoted upstream of the point of production on the lease.

Mr. Stickel continued that production tax was calculated after royalties and did allow for property tax as a deduction. State corporate income tax used worldwide income as part of the tax base, which excluded the property tax, production tax, and royalties in its calculation. He explained that all state taxes, including the state corporate income tax, were deductible in calculating the federal corporate income tax.

[9:26:47 AM](#)

Mr. Stickel highlighted slide 8, "Production Tax "Order of Operations": FY 2023," which showed a table. He explained that he would address the table in a series of slides. The numbers were based on the income statement presentation, which was an illustration of the production tax calculation for 2023 in particular. The information was included in Appendix E of the 2021 Revenue Sources Book (RSB). He addressed the fall revenue forecast, which showed an average oil price of \$71/bbl and a production forecast of 500,200 barrels per day of daily production, which calculated out to an annual number of barrels of just over 182 million barrels of oil with a value of about \$13 billion. The next several slides would focus on how the \$13 billion was split and taxed. He reminded that the slides represented an aggregation of the tax calculation, and the actual taxes were based on monthly filings and calendar year returns for all the different producers.

Mr. Stickel looked at slide 9, "Production Tax "Order of Operations": FY 2023," which showed a table that

represented royalty and taxable barrels. Step 1 was calculating the taxable barrels, which were subject to the production tax. Any royalty barrels were subtracted regardless of the owner of the barrels. The typical rates were 12.5 percent or 16.67 percent, but the rates varied. In addition to the state royalty, any federal and private land royalty barrels were also subtracted in calculating the taxable barrels.

Mr. Stickel added that also any barrels not subject to taxation would be subtracted including a small portion of production beyond the state's 3-mile limit. He cited that currently there was a small portion of production at the North Star field that fell into the category, as well as potential future developments such as the Liberty field. He continued that after subtracting the royalty barrels, there was about 160 million taxable barrels for FY 23 with a total value of \$11.4 billion.

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Mr. Stickel addressed slide 10, "Production Tax "Order of Operations": FY 2023," which showed information on gross value at point of production (GVPP), which was also called "well-head value." He noted that transportation costs (known as net-back costs) were subtracted from the total taxable value, to arrive at the GVPP. He described starting with the oil sale, which in the forecast was \$71/bbl on the West Coast. All the transportation costs were deducted, including marine transportation, the Trans-Alaska Pipeline System (TAPS) tariffs, and any feeder pipelines to get to TAPS. Subtracting the transportation costs got to an average wellhead value of \$61.91/bbl for FY 23, with a total value of about \$9.9 billion.

Co-Chair Stedman asked for more detail on downstream costs. He commented that "not all oil is equal" due to different severance tax or royalty issues. He asked Mr. Stickel to discuss the \$9.09 of tariff to move the oil down the pipeline and over the ocean.

Mr. Stickel explained that he endeavored to understand the value of the oil when it left the lease on the North Slope. There was not a posted price for the value, and the value within the tax calculation was called a "net back." He continued that the net back calculation started with the sale value (typically on the West Coast), and then netted

back all the different costs to get to an assumed value at the lease. He noted that there was a public assessment of the end value. The cost for the pipelines and the tankers was deducted.

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Co-Chair Bishop asked if the downstream cost would go down if the state was producing 800,000 barrels a day.

Mr. Stickel answered "yes." He explained that some of the costs were fairly constant on a per barrel basis, while there were some downstream costs (such as the operation of TAPS) that were fixed and therefore the average per-barrel cost would be lower if there were more barrels of oil going down the pipeline. He cited that in recent years production had stabilized and so had transportation costs.

Senator Wielechowski knew that the argument had been made when the More Alaskan Production Act was passed. He recalled that the state had been told it would get one million barrels of oil per day and it would lower downstream tariffs, and the state would make more money. He reflected that unfortunately the state was getting only half of what was promised. He asked what percentage of the \$9.09 downstream transportation costs was the cost for pipelines in Alaska. He asked about ownership of the pipelines.

Mr. Stickel detailed that the \$9.09 broke down into: \$3.47/bbl in marine costs, \$4.98/bbl forecasted tariffs for TAPS, \$.56/bbl for feeder pipeline tariffs, \$.07/bbl adjustment for quality bank adjustments, and \$.15 in "other adjustments" which was primarily pipeline and tanker gains and losses. He cited that the information was from page B1 in the RSB.

Co-Chair Stedman asked who owned the tankers and TAPS.

Mr. Stickel explained that TAPS was operated by an independent third party, in which the major operators shared ownership.

Co-Chair Stedman asked if the tankers were also owned by the same entity.

Mr. Stickel stated that some producers owned tankers, while others chartered tankers.

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Senator Wielechowski asked if there was a regulated return on the downstream costs.

Mr. Stickel relayed that there were all sorts of regulations surrounding the transportation costs. He did not have the rate of return at hand.

Co-Chair Stedman asked Mr. Stickel to get back to the committee with the information. He noted that the state had had disagreements with some of the tariff structures and had had court cases and settlements numerous times.

Senator Wielechowski understood that there was a 10 percent to 14 percent regulated return. He asked about the rationale for deduction of transportation costs. He noted that the companies were making a profit on the transportation.

Mr. Stickel thought the approach was typical worldwide. The state was not taxing the oil when it was sold in California when it was sold, but rather was attempting to tax the value of the oil that came out of the ground on the North Slope. Absent a market price for oil coming out of the ground on the North Slope, the state needed a method for valuation, and the net-back approach was the way the state had chosen to arrive at the calculation.

Co-Chair Stedman asked if the calculation was by contract.

Mr. Stickel relayed that the net-back calculation was laid out in statute. He thought for production tax was specified in contract, and there was a similar approach used in royalty calculation.

Co-Chair Bishop asked about the .07 cent adjustment for the quality bank mentioned by Mr. Stickel.

Mr. Stickel described that a quality bank was a financial accounting done for pipelines. The issue was that each field on the North Slope had a different quality of oil, and when the oil was mixed in TAPS the end product was different than what producers put into the pipeline. He

continued that the quality bank was a financial mechanism that allowed a producer to pay or be compensated according to the differences of the oil put into the pipeline versus what came out of the pipeline.

Mr. Stickel continued that also along TAPS there were refineries, and if a refinery took oil out of the pipeline, it produced higher value end products, and the net oil at the end was of a slightly lower quality. The refineries also paid into the quality bank. The .07 cents per barrel was the forecasted increase of the value that accrues to producers due to the refinery impact.

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Mr. Stickel advanced to slide 11, "Production Tax "Order of Operations": FY 2023," and addressed lease expenditures. He noted that the production tax was essentially a modified net profit tax, and the state allowed companies to deduct expenses in calculating their tax value. For capital expenditures, they were usually defined using guidelines from the Internal Revenue Service (IRS) to define what was a capital expense. There was no depreciation required for a capital expense in the production tax. He explained that operating expenditures were any allowable expenses that were not a capital expense, and were typically the ongoing cost of operations and labor.

Mr. Stickel discussed the terms "allowable" and "deductible" lease expenditures. He defined that allowable lease expenditures signified any cost in the unit that was directly associated with producing the oil. Not all costs were allowable. He gave examples of costs that were not allowable in the production tax calculation: any financing costs, lease acquisition costs, costs of dispute resolution, and dismantlement, removal, and restorations costs. He noted that DOR had created the term "deductible lease expenditures," which was not used in any statute or regulation and referred to that portion of allowable lease expenditures that were applied to the tax calculation in a given year. Non-deductible lease expenditures were any allowable expenses beyond a company's gross value that were not deducted against the tax calculation in a given year.

Mr. Stickel explained that the non-deductible lease expenditures were translated into carry-forward losses. He directed attention to the bottom of the table which showed

a forecast of about \$681 million of lease expenditures that would be made in FY 23 and not deducted in the tax calculation. The amount would turn into carry-forward.

Co-Chair Stedman asked if the forecasted amount came from smaller companies, or companies with no production that were most likely not one of the largest three companies. He assumed that the expenditures that were incurred with no revenue, and the companies were allowed to carry forward the expenditures to deduct when production of oil was underway.

Mr. Stickel affirmed that Co-Chair Stedman's description was accurate. He explained that the carry-forward lease expenditures benefit would be available to any company. Given the current and expected price forecast, the benefit would primarily be for not existing producers that were making significant investments in exploration and development of future production.

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Co-Chair Stedman asked if companies could carry forward the expenditures forever or trade the deductions to other companies. He asked for more detail on how the \$681 million in forecast lease expenditures would be handled.

Mr. Stickel explained that the carry-forward lease expenditures could not be transferred to another company and were held by the company that earned them until production, at which time the expenditures could be applied against a future tax liability. The carry-forward lease expenditures belonged to a specific year earned and beginning with the eighth or eleventh year would reduce in value 10 percent annually if not used.

Co-Chair Stedman considered that the carry forward expenditures had a trigger and then then reduced in value towards zero.

Mr. Stickel explained that the ten percent reduction was called a "downlift," and was based on the prior year's ending value, so the value of the lease expenditures would never disappear. Rather, the value would reduce by 10 percent of the prior year in perpetuity if not used.

Co-Chair Stedman wondered if the state could face up to as much as \$1 million in carry forwards if there was expansion on the North Slope.

Mr. Stickel agreed that to the extent that there were significant investments made in future production by new entrants, there would be a significant outstanding value of the carry-forward lease expenditures. He cited that Table 8-4 in the RSB included a projection of the tax value of the future lease expenditures with a value that would exceed \$1 billion.

Co-Chair Stedman asked if the carry forwards were a standard practice and why Alaska participated in the practice. He asked about the effect if the state did not allow for carry forwards.

Mr. Stickel explained that allowing companies to recoup costs was very much a standard practice in oil and gas fiscal systems around the world. He continued that if the state did not allow for lease expenditures to be carried forward and only allowed the expenditures to be deducted by companies with current revenue, the incentive would be for a lot less investment by new entrants and would concentrate investment in existing companies.

[9:48:16 AM](#)

Co-Chair Stedman discussed the timing of cash flow and pondered a company sinking a significant amount of funds over four to five years before production and revenue return. He pondered that if the state did now allow for deductibility of expenditures, it would significantly alter company's cash flow models and time value of money calculations to the negative. He thought a lack of carry-forward of lease expenditures would make it difficult to have a project that was economic. He referenced the amount of time the legislature spent in making changes to adjusting cash flow timing to encourage investment in the state's oil and gas. He asked what the investment losses could be counted against geographically.

Mr. Stickel discussed the carry forward loss provision, which was currently available for the North Slope and Middle Earth. The department was not forecasting significant investment in Middle Earth.

Co-Chair Stedman asked Mr. Stickel to discuss Middle Earth.

Mr. Stickel explained that there were two primary oil and gas basins in the state, the North Slope and Cook Inlet. There was a separate tax regime for everything outside the North Slope and Cook Inlet, and colloquially it was referred to as "Middle Earth." He continued that for any carry-forward lease expenditures on the North Slope could only be applied against North Slope production. There was a provision that required a company to come into production in order to utilize the carry-forward of lease expenditures.

[9:52:30 AM](#)

Senator Wielechowski referenced Mr. Stickel's remark that allowing carry forwards was common around the world. He asked how many other states allowed for the carry forward of the expenses.

Mr. Stickel thought most states in the United States had a less sophisticated tax regime than Alaska and instead were based on taxing the gross value on a lower tax rate. He stated that Alaska's tax regime was more comparable to other countries in the world.

Co-Chair Stedman asked Mr. Stickel to speak to how Alaska was different than other states, in a way beyond just geography. He mentioned the subsurface.

Mr. Stickel explained that in Alaska the state owned the subsurface rights to most of the oil and gas production, while in most other states private landowners owned a significant share. He continued that Prudhoe Bay was a world-class oil field and the state had a world-class oil basin, which was very different than the type of production that was dominating in other states where there was shale-oil production. He thought the state's consultants would indicate that the most direct comparison for the state's production tax and competitiveness were other oil-producing countries and other world-class oil basins around the world.

Co-Chair Stedman reminded that in most other states, farmers or ranchers owned the subsurface rates and there were higher royalties. He mentioned Alberta, Canada. He thought it was important to remember that Alaska was

different and cautioned against comparing it to other states. He thought the finer points of Senator Wielechowski's question would be addressed the following day at the meeting with the state's oil and gas consultants.

[9:55:47 AM](#)

Senator Wielechowski asked if it was correct that no states in the United States allowed carry forwards.

Co-Chair Stedman asked to leave the question until the following day. He emphasized that Alaska was the only state in the union that owned the subsurface rights. He mentioned additional components including property tax, royalties, corporate income tax, and severance tax. He thought that Alaska was the only state that had a production-sharing contract structure.

Senator Wielechowski recalled that Mr. Stickel had discussed differences and called Alaska a "world class basin." He asked why the state was not receiving the same amount of royalties and taxes as in Texas and North Dakota. He asked if Alaska should be producing more than half of what the other states were producing.

Mr. Stickel thought Senator Wielechowski had posed policy questions, while his presentation was intended to address the nuts and bolts of how the tax system worked.

Co-Chair Stedman thought Senator Wielechowski's question would be addressed the following day, as well as comparisons. He mentioned transferability of royalty contracts and commented that the royalty contracts had been signed decades previously and were very valuable due to significant changes in the structure. He thought there was concern amongst members, as cited by Senator Wielechowski, whether the sharing relationship was fair relative to other basins. He reiterated that the meeting the following day would address the concerns expressed.

[9:59:02 AM](#)

Senator Wielechowski understood that the topic would be addressed later and understood the presenter was an economist. He thought Mr. Stickel was "wading into policy areas" and had made a portrayal that was not completely

accurate. He thought Alaska could be compared to other states or other profit-sharing countries. He used the example of Norway, which allowed for 100 percent recoupment like Alaska but taxed at 78 percent. He continued that Iraq allowed for 100 percent recoupment but taxed at 99 percent. He pondered that Alaska allowed 100 percent recoupment yet had a gross tax of \$4.63 on \$71/bbl oil which equated to 6.5 percent. He thought Alaska had the lowest tax rate in the world. He thought it was important to have the information presented in an objective way without the information being slanted to make the tax structure seem as if it was good for the state. He thought the policy had been horrific and terrible for the state.

Co-Chair Stedman thought all the comparisons would be discussed. He discussed the size of the state's oil basin and cited that the North Slope was the largest conventional oil field in North America. He emphasized that the state would not run out of oil or gas in the near future and thought there was little to no chance of the field being shut down in the future. He emphasized the value of the oil field.

Senator Olson wanted to summarize the state's net take after the formula was enacted. He wondered if the state received more or less than it would if it had a less complex system.

Mr. Stickel thought Senator Olson had asked a nuanced question.

Senator Olson questioned what way would result in more net-back to the state.

Co-Chair Stedman thought Senator Olson's questions were policy-related and asked to focus on the structure.

Senator Olson wanted a simple answer.

Co-Chair Stedman reiterated that the committee would address the topic of lease expenditures the following day, as well as the subject of ring fencing.

[10:03:42 AM](#)

Senator Wielechowski asked if any of the lease expenditure deductions were allowed for fields from which the state

would receive no royalties or very little taxes in the future.

Mr. Stickel relayed that lease expenditures were allowed to be deducted for any activity within the area in which the state levied the production tax, which was any activity on state land or within the state's three-mile limit.

Co-Chair Stedman stated that the last slide would address the topic, which was a point of concern. He thought it was a question that the incentives offered were offered on lands where revenue could be received. He thought that was the point of Senator Wielechowski's question.

Senator Wielechowski reiterated the question of whether the state was allowing the industry to write off expenses on fields for which the state would not receive royalties.

Mr. Sickel affirmed that the state received some tax or royalty benefit for all production on state land and within the three-mile limit. The exact nature of the benefit and amount of royalty received was dependent on the landowner.

Co-Chair Stedman reiterated that the topic would be addressed later in the presentation and would also be discussed with the consultant the following day. He thought the order of magnitude was a concern as the state went forward and developed other areas outside state ownership.

Mr. Stickel looked at slide 12, "Production Tax "Order of Operations": FY 2023," and addressed production tax value (PTV), which was the gross value at point of production less the deductible lease expenditures. The PTV was the net profit proxy or tax base that the state used for levying the production tax. He explained that each company calculated its PTV based on all of its North Slope activity, including all fields and developments including new developments.

[10:06:39 AM](#)

Mr. Stickel showed slide 13, "Production Tax "Order of Operations": FY 2023," which addressed gross minimum tax floor. He explained that there were two primary calculations done in the production tax calculation, the net tax levy and a gross minimum tax floor. The minimum tax floor was four percent of gross value when annual oil

prices were greater than \$25/bbl. There were lower percentages for the floor if the annual oil price were to be less than \$25/bbl. For FY 23, the minimum tax floor of four percent multiplied by the gross value at point of production of \$9.9 billion got to a minimum tax floor of \$396.7 million.

Co-Chair Stedman thought the calculation was confusing. He considered the tax rates applied to gross tax and net tax. He asked Mr. Stickel to discuss how to switch between the two.

Mr. Stickel noted that a following slide would discuss the calculation of the tax.

Mr. Stickel referenced slide 14, "Gross Value Reduction":

- Gross Value Reduction (GVR) is an incentive program for new fields.
- Available for the first seven years of production and ends early if ANS prices average over \$70 per barrel for any three years.
- Allows companies to exclude 20% or 30% of the gross value from the net production tax calculation.
- In lieu of sliding scale Non-GVR Per-Taxable Barrel Credit, qualifying production receives a flat \$5 GVR Per-Taxable-Barrel Credit.
- The \$5 GVR Per-Taxable-Barrel Credit can be applied to reduce tax liability below the minimum tax floor, assuming that the producer does not apply any sliding scale Non-GVR Per-Taxable Barrel Credits.

Mr. Stickel explained that the GVR had been part of SB 21, oil and gas tax reform legislation passed in 2013. The GVR provided a temporary benefit used to reduce the value of oil subject to tax for new fields. He cited that the GVR was available exclusively for fields that were including only state-issued leases with greater than 12.5 percent royalty.

Co-Chair Stedman thought Mr. Stickel indicated that GVR was available only for newer leases.

Mr. Stickel answered affirmatively. To qualify for the GVR, a field must be comprised exclusively of state-issued leases with greater than 12.5 percent royalty. He addressed

the last bullet on the slide. He thought a future slide would address the taxable per-barrel credits.

Co-Chair Stedman asked if the floor was "leaky."

Mr. Stickel expanded that as an added benefit for GVR, the new fields with \$5 per-barrel tax credit could reduce liability below the floor.

[10:11:08 AM](#)

Mr. Stickel turned to slide 15, "Production Tax "Order of Operations": FY 2023," and spoke to the net tax calculation and GVR. The net tax was a 35 percent statutory tax rate applied against the production tax value. For companies with qualifying new production, they were able to reduce production tax value by the value of the gross value reduction. He cited that for FY 23 there was an estimated \$5.7 billion of production tax value (after the gross value reduction) multiplied by the statutory 35 percent tax rate, to give a tax before credits of about \$2 billion. He reminded that the amount signified the tax before any tax credits.

Co-Chair Stedman asked about the effective tax rate.

Mr. Stickel stated that the effective tax rate would be a little less. He explained that typically the way an effective tax rate was shown, the department looked at the total tax paid to the state divided by the production tax value.

Co-Chair Stedman asked Mr. Stickel to provide the committee with more information. He thought the effective tax rate was significantly different than 35 percent.

Mr. Stickel estimated that the amount was somewhere between 10 percent and 20 percent.

Co-Chair Stedman asked Mr. Stickel to get back to the committee with more information, using the table on the slide. He asked about the per-barrel deduction.

Mr. Stickel considered slide 16, "Production Tax "Order of Operations": FY 2023," which addressed tax credits against liability. He explained that the two major tax credits were the per-taxable-barrel credits, and there was one for GVR-

eligible oil and one for all other oil. He noted that currently the vast majority of oil was non-GVR-eligible oil, which could change as future fields came online. For most production, the oil was not GVR-eligible and there was a sliding scale credit that ranged from zero to \$8 per taxable barrel. The zero sliding scale credit applied when the wellhead value of oil was greater than \$150/bbl. For each \$10 of oil, there was a change in the value of credit. The \$8 per barrel credit applied when the wellhead value was less than \$80 per taxable barrel of oil.

Mr. Stickel continued to address slide 16. He explained that the sliding scale per taxable barrel credit could not be used to reduce the tax below the minimum tax floor. He noted that companies claiming the credit could not pay below the minimum tax floor under any circumstances. For GVR-eligible production there was a flat \$5 per barrel credit per barrel of taxable production, and the credit could be used to reduce tax below the minimum floor, providing the company did not apply any sliding scale credits. He noted that any per taxable barrel credits not used in the year earned were forfeited, and could not be re-purchased, transferred, or carried forward.

Mr. Stickel informed that given the current pricing at \$71/bbl oil, the department was forecasting that companies would be able to utilize nearly all of the credits generated. For FY 23, there was a forecast for \$1.25 billion of per taxable barrel credits generated, nearly all of which would be deducted in the tax calculation. There were some other tax credits against liability, but they had relatively minor fiscal impact.

[10:16:22 AM](#)

Senator Wielechowski asked about the non-GVR-eligible tax credits and asked why the figures were not even numbers.

Mr. Stickel responded that at \$71/bbl oil, companies would generate \$8 per taxable barrel tax credits, and the credits could only be used to reduce tax liability to the gross minimum tax floor. He explained that while the vast majority of the credits were applied in the tax calculation, there were some companies that could not utilize the \$8 per barrel, resulting in the weighted average of \$7.45 per taxable barrel.

Co-Chair Stedman referenced the 35 percent tax rate mentioned earlier but estimated that the state's effective tax rate was around 13 percent. He thought the deductions were significant. He knew there was some concern about the statutory rate of 35 percent and the per barrel sliding rate of \$5 to \$8. He thought at \$8 per barrel the total would equate to almost \$1.2 billion in deductions and acknowledged there was some concern that the calculation led to significant distortions over different price ranges and holding the state to the minimum tax for longer than anticipated. He thought the matter would be addressed in the meeting with consultants the following day. He thought the state should not be afraid of using the statutory rate of 35 percent and using the effective rate to observe the impact on the numbers. He thought the top rate for the deduction was \$8.

Mr. Stickel agreed.

Co-Chair Stedman asked if Senator Wielechowski's question was answered regarding the effective tax rate.

Senator Wielechowski discussed the per barrel tax credits and wondered if certain amounts were combined.

Mr. Stickel referenced Table 8-4 of the 2021 RSB and explained that on line 11 the two per-taxable-barrel credits were combined.

[10:20:17 AM](#)

Mr. Stickel displayed slide 17, "Production Tax "Order of Operations": FY 2023," which addressed adjustments and total tax paid. He explained that there were some other items that were added to the total production tax revenue received by the state. He listed prior year tax payments or refunds, a tax on private landowner royalties, tax on gas produced on the North Slope, any net tax liability from Cook Inlet and other areas, any some company-specific adjustments. The numbers had been aggregated on the chart. He cited that for FY 23, the \$741.2 million represented the total cash expected into the General Fund from the production tax. There was an additional \$681 million in non-deductible lease expenditures expected to be incurred in FY 23 and carried forward, which could potentially be applied against a future year tax liability. He noted that the bottom line showed the General Fund impact, which did

not include about \$8 million in hazardous release surcharge, which was a \$.05 tax on non-royalty barrels and was considered designated revenue.

Co-Chair Stedman noted that over the years the legislature had asked the department to provide the gross revenue for the oil field. He recounted that almost twenty years previously there had been reluctance to provide the information. The slide showed \$12.9 billion in gross stock. He recounted working with the department, which showed the flow of deductions to get to the net figure for budgeting purposes. He thanked the department for always keeping the numbers clear.

Co-Chair Stedman continued his remarks. He suggested that if oil averaged \$100/bbl for FY 23, the state would end up with about \$18 billion in gross stock. He commented that the numbers could significantly change.

[10:24:13 AM](#)

Senator Wielechowski referenced Table 8-4, where the production revenue forecast showed \$785 million in carry-forward credits. He was curious about the discrepancy with the \$681 million in carry-forward lease expenditures shown on the slide.

Mr. Stickel looked at line 22 on Table 8-4 of the Fall 2021 RSB, which showed a calculation that estimated the net tax impact of all outstanding carry-forward lease expenditures, as well as any carry-forward credits held by producers. The \$785 million in FY 23 would take all of the tax credits and lease expenditures that had been carried forward through the end of FY 23 (for all prior years) assuming they were offsetting the 35 percent statutory tax rate, would get to the estimated \$785 million tax impact. He directed attention to the bottom line of slide 17, which showed \$681 million, which was the total amount of lease expenditures estimated to be incurred just for FY 23 and carried forward. He explained that the \$681 million, multiplied times the 35 percent statutory tax rate, was embedded in the \$785 million in Table 8-4 of the RSB.

Senator Wielechowski looked at Table 8-4 of the RSB, which showed the number grew to over \$1 billion in FY 24, then grew to \$1.3 billion within a few years. He asked about the

impact of a net operating loss of \$1 on the state production tax of \$741 million.

Mr. Stickel explained that carry forward annual losses that a company may choose to apply to its tax liability and may not reduce its tax liability below the minimum tax floor using the carry-forward lease expenditures. In a hypothetical situation in which all companies had very large amounts of carry-forward annual losses, he expected the tax to be reduced to the minimum.

Senator Wielechowski estimated that in FY 23, the minimum tax would have been about \$396 million.

Mr. Stickel stated that Senator Wielechowski was correct.

Senator Wielechowski asked if there were any net loss carry forwards calculated into the forecast.

Mr. Stickel explained that the forecast assumed very minimal impact of prior year carry forward losses. He continued he vast majority of carry forward losses being earned were being earned with companies without significant current tax liability, which were those making the large investments in exploration and development of future production.

Co-Chair Stedman thought Senator Wielechowski was concerned that carry forwards would overwhelm future revenue or carry-forwards coming against the state from areas where the state had significantly less revenue potential. He reiterated that the committee would be asking the consultant the following day about how other regimes dealt with the issue, and whether there were limits on deductibility to ensure that the sovereign always had cash flow.

[10:29:05 AM](#)

Senator Wielechowski asked if the department had included the future use of net operating loss carry forwards in the ten-year production forecast.

Mr. Stickel relayed that the department's ten-year revenue forecast modelled each company's projected tax liability, including the expected use of the carry forwards.

Senator Wielechowski referenced hearing from the DOR Deputy Commissioner that the administration had done some analysis on lowering the per-barrel taxable credits. He asked if Mr. Stickel was a part of the analysis.

Mr. Stickel noted that the department's economic research group supported all sorts of analysis and thought the deputy commissioner was available for questions.

Co-Chair Stedman relayed that when working on oil tax structure, the Senate had passed a fixed \$5 per-barrel credit, and the House had added a sliding component well as the 35 percent tax (which he thought had been 25 percent in the Senate). The Senate had concurred with the action and adjourned. He recounted that there had always been concern in the Senate that the change was not a good of a policy call as hoped. He recalled having support from the industry for a 25 percent tax and a \$5 credit. He asked Mr. Stickel to address the hypothetical tax structure that had been supported by the Senate.

Mr. Stickel recounted that back in 2013, Governor Parnell had introduced the original version of SB 21, which had a 25 percent net profit tax rate and no per-taxable-barrel credit. The version of SB 21 that passed the Senate had included a 35 percent net profits tax rate and a \$5 per-taxable-barrel credit for all production.

Co-Chair Stedman stood corrected.

Mr. Stickel recalled there had been multiple iterations of the legislation.

Co-Chair Stedman asked Mr. Stickel to discuss the results if there were a 35 percent tax rate with a capped \$5 credit.

Mr. Stickel estimated that holding all else equal for investment and production with a \$5 per-taxable-barrel credit for all production, the state would receive about \$443 million of additional revenue in FY 23 with the forecast oil price. He noted that the calculation came from the state fiscal model on the DOR website, and reducing the taxable barrel credit schedule was one of the options included in the model. He thoguht the model could be the analysis that the deputy commissioner had referenced.

10:33:40 AM

Co-Chair Stedman asked if the \$443 million included severance tax or any other tax issues.

Mr. Stickel affirmed that the calculation did not incorporate any potential impacts on company decision-making as a result of the tax increase.

Co-Chair Stedman asked about other taxes, which he thought stayed the same in the calculation.

Mr. Stickel answered affirmatively.

Co-Chair Stedman thought the committee could go into further detail with the consultants regarding the competitiveness. He wondered if Senator Wielechowski recalled testimony on the topic.

Senator Wielechowski stated there was a legal obligation for a company to produce when the industry could make a reasonable profit. He thought there was a tendency for people in the building to compare the state with other states and nations and asserted that the state's attorneys analyzed things differently. He noted that multiple times over the years the analysis had focused on whether companies could make a reasonable profit and had looked at internal rates of return. He emphasized that the state was not competing against other states or nations.

10:35:59 AM

Mr. Stickel highlighted slide 18, "Order of Operations: Five Year Comparison," which showed a table with a similar analysis as previous slides and a five-year spread including two years of history, the current year, as well as two years of forecast. He pointed out that FY 20 was a minimum tax floor year, when most companies were paying the minimum tax. Some companies paid above the minimum tax floor in FY 21. For the current year and all future years, the current revenue forecast showed the state expecting to receive revenue above and beyond the minimum tax floor.

Co-Chair Stedman asked for Mr. Stickel to discuss where the "trigger point" was.

Mr. Stickel extrapolated that for the major companies for FY 23, the price at which the companies paid above the minimum tax floor was in the \$50/bbl to \$70/bbl range. The point at which the state received greater than the minimum tax floor was around the \$50/bbl range. He reminded that each company had a different relationship between the minimum tax floor and its net tax depending on the fields and investments it was making.

Co-Chair Stedman wondered about the consolidation of the policy and what the price per barrel would be.

Mr. Stickel estimated that with an aggregate calculation, it would be about \$50/bbl.

Co-Chair Stedman thought the number would change if there was a flat \$5 credit rather than a sliding credit.

Mr. Stickel did not have an estimation.

Co-Chair Stedman looked at the bottom of the table which showed net new lease expenditures earned and carried forward. He asked if the line reflected the aggregate liability for any given year, or if there should be another line to show accumulation.

Mr. Stickel explained that the net new lease expenditures were those expenditures that would become carry-forward annual losses in that given fiscal year.

Co-Chair Stedman asked about the line that showed the accumulation of liability to the state. He thought the accumulation was important to track and consider the pros and cons. He mentioned the issue of the effective rate.

[10:40:12 AM](#)

Mr. Stickel looked at slide 19, "Illustration Assuming a Single North Slope Taxpayer: FY 2023," which contemplated how non-GVR credits "reduce" net tax to the gross minimum tax floor. He explained that with a single taxpayer, he expected get about \$50 million more in revenue. He reminded that there were some companies paying less than the minimum tax floor, primarily those companies operating the GVR-eligible fields and were using the \$5 flat per-barrel credit rather than the sliding scale. He relayed that the point of the slide was to illustrate that each company had

a different set of economics and a different portfolio of operations and investments, which he suggested to keep in mind when looking at data.

Co-Chair Stedman expressed that he had asked Mr. Stickel to create the slide. He thought it was hard to understand the minutiae of the impact of deductions and incentives when looking at aggregate numbers versus looking at the impact of the numbers as a single taxpayer. He thought the difference might be \$50 million.

Mr. Stickel noted that the initial forecast estimated \$741.2 million in General Fund Production Tax revenue, and the estimation of a single payer was \$794.5 million.

Co-Chair Stedman thought the last slide would be relevant to the discussion regarding revenue sources and incentives.

[10:43:24 AM](#)

Mr. Stickel addressed slide 20, "State Petroleum Revenue by Land Type," which showed a table of land lease status and revenue components. He reiterated that the basic concept was that not all oil was the same, and the revenue from oil production was dependent upon where the oil came from. He cited that for any oil produced in federal waters that were more than six miles offshore, the state would not receive any revenue, and noted that there was currently not any production on the North Slope that fell into the category.

Mr. Stickel continued that for any oil produced within three to six miles offshore, the state received 27 percent of the federal royalty, but taxes did not apply to the oil. There was a small amount of production that fell into the category, primarily the portion of the North Star Oilfield that extended beyond the state's three-mile limit. For anything on state land and up to three miles offshore, all taxes applied regardless of the landownership, including the production tax, state corporate income tax, and property tax.

Mr. Stickel continued to address slide 20, and relayed that royalties had a lot of variation, depending upon the landowner. He explained that royalties applied to any state land and anything within the three-mile limit. If the state was the landowner, it collected a direct royalty. He cited that most production was at the 12.5 percent royalty rate.

Federal royalty applied For federally owned land in the NPRRA, and 50 percent was shared back to the state, which must be used to benefit impacted communities on the North Slope. For federally owned land in the Alaska National Wildlife Refuge (were it to come into production), federal royalty would apply, and 50 percent would be shared back to the state. There were currently no restrictions on how the 50 percent could be used.

Mr. Stickel informed that for other federal land, the federal royalty applied, with 90 percent going back to the state without spending restrictions. For private land (primarily Native corporation owned land), there was a private negotiated royalty that applied, and the state did tax the private royalty value as part of the production tax.

Co-Chair Stedman asked about Point Thomson on the North Slope.

Mr. Stickel shared that the Point Thomson development was state-owned leases, which would be on the third category under "Land Lease Type" shown on the table on slide 20.

Co-Chair Stedman asked to have the slide available for the following day, as he expected questions pertaining to deductibility versus ownership.

Mr. Stickel showed slide 21, "Thank You," which showed contact information.

[10:46:55 AM](#)

Senator Wielechowski asked for copies of the analysis of cutting the oil tax credits.

Mr. Stickel explained that the analysis was incorporated into the department's fiscal model, which was on the DOR website. He relayed that he was happy to break out the information and include it in his response to the committee.

Co-Chair Stedman asked Mr. Stickel to provide the information by 9 o'clock in the morning the following day, so that members would have access to the information.

Mr. Stickel agreed.

Senator Wilson thanked Mr. Stickel for the chart on new production.

Mr. Stickel pointed out that the majority of the analysis was done by the Department of Natural Resources.

Co-Chair Stedman thanked Mr. Stickel for his testimony.

Co-Chair Stedman discussed the agenda for the following day.

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ADJOURNMENT

10:49:13 AM

The meeting was adjourned at 10:49 a.m.