

HOUSE FINANCE COMMITTEE
January 23, 2023
1:32 p.m.

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CALL TO ORDER

Co-Chair Johnson called the House Finance Committee meeting to order at 1:32 p.m.

MEMBERS PRESENT

Representative Bryce Edgmon, Co-Chair
Representative Neal Foster, Co-Chair
Representative DeLena Johnson, Co-Chair
Representative Julie Coulombe
Representative Mike Cronk
Representative Alyse Galvin
Representative Sara Hannan
Representative Andy Josephson
Representative Dan Ortiz
Representative Will Stapp
Representative Frank Tomaszewski

MEMBERS ABSENT

None

ALSO PRESENT

Helen Phillips, Staff, House Finance Committee, Legislative Finance Division; John Boyle, Commissioner Designee, Department of Natural Resources; Travis Peltier, Petroleum Engineer, Division of Oil and Gas, Department of Natural Resources; Representative Craig Johnson; Representative Tom McKay.

SUMMARY

PRODUCTION FORECAST: DEPARTMENT OF NATURAL RESOURCES

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Co-Chair Foster introduced himself and relayed he would be in charge of legislation for the committee.

Co-Chair Edgmon introduced himself and welcomed returning and new finance members. He would be in charge of the capital budget.

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Co-Chair Johnson introduced herself and expected to get more information about operating budget subcommittees in the near future. She discussed meeting protocol.

HELEN PHILLIPS, STAFF, HOUSE FINANCE COMMITTEE, LEGISLATIVE FINANCE DIVISION, introduced herself and staff. She welcomed the committee.

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Co-Chair Johnson reviewed the meeting agenda.

^PRODUCTION FORECAST: DEPARTMENT OF NATURAL RESOURCES

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JOHN BOYLE, COMMISSIONER DESIGNEE, DEPARTMENT OF NATURAL RESOURCES, provided opening remarks. He discussed that the Department of Natural Resources (DNR) produced the production forecast in an effort to assist the legislature better understand the outlook for the coming years in order to make budgeting decisions for the state. He believed the particular presentation should be cause for optimism. The department was forecasting fairly flat production for the next five years with a gradual increase as projects came online. He stated the forecast was a bit of a departure from previous years as many people had become accustomed to seeing steady decline from Alaska's oil fields.

Commissioner Boyle explained that the current legacy field operators were putting in the time and investment in order to keep production relatively stable. He stated it was a significant accomplishment to keep aging fields at steady production when each additional molecule produced required additional energy. The legacy backbones comprising North Slope production (Prudhoe Bay, Kuparuk, Alpine) enabled DNR to forecast the steady trend of continuing production. Additionally, there was reason for optimism related to new projects such as Pikka and Willow. He elaborated that the type of project had the potential to significantly increase

state production. He explained that the department's forecasting methodologies showed a relatively smooth production gradient rather than a stairstep approach.

Commissioner Boyle highlighted the forecast for steady production with legacy fields and new production coming online. He stated new production was underpinned by the Nanushuk formation. He elaborated that the discovery and delineation of the particular geologic formation highlighted Alaska as an exciting place for companies to invest. He reported there was much reason to believe there would be ongoing activity on the North Slope. He thought there was much reason for optimism surrounding the production front and the price of oil remained to be seen. There was reason to continue to be mindful of the need for continued good policies as the resources were managed, but he believed the state would continue to see strong investment and activity in the coming years.

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TRAVIS PELTIER, PETROLEUM ENGINEER, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, provided information about his educational and work background. He introduced a PowerPoint presentation titled "Fall 2022 Production Forecast," dated January 23, 2023 (copy on file). The presentation focused on the forecast for the next decade. He relayed that DNR had been performing the analysis since 2016. He noted the presentation would include methodology and background on how the forecast was generated.

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Mr. Peltier covered the agenda for the presentation on slide 2. The presentation would look at the FY 22 year in review and the DNR production forecasting approach. He would discuss the fall 2022 forecast results and a summary. He noted each slide included a list of acronyms.

Mr. Peltier moved to slide 4 and discussed the FY 22 summary for the North Slope. The slide referred to production areas, which was different than past years. He explained that DNR and the Department of Revenue (DOR) were striving for consistent terminology. He noted the DOR Revenue Sources Book used the term production areas. He reported that DNR expected to see a year-on-year decline across all production areas. He expounded that oil fields

naturally declined over time. He shared that North Slope production in FY 22 decreased by approximately 2 percent or approximately 9,570 barrels per day from FY 21.

Mr. Peltier pointed to the top chart on slide 4 showing North Slope daily production. The y-axis showed the fiscal year annual average daily oil production in barrels of oil per day and the x-axis showed the fiscal year from FY 16 through FY 22. He relayed the peak oil production rate in FY 17 was just over 526,000 barrels of oil per day and had declined until about FY 20, which was expected with natural decline. He added that FY 20 was the start of the COVID-19 pandemic and several oil fields had been shut in for economic reasons resulting in an artificially high decline. The issue resolved in FY 21 when oil prices rebounded after COVID era lows. The normal decline rate resumed in FY 22. He reported that FY 22 gross North Slope production averaged about 476,490 barrels of oil per day.

Mr. Peltier addressed production changes from FY 21 to FY 22 in the lower chart on slide 4. The blue color denoted a production increase, and the orange denoted a decrease. The chart began at a zero line. He highlighted Prudhoe Bay as an example and stated there was a slight production increase to 787 barrels of oil per day. The Prudhoe Bay Unit (PDU) satellites produced 6,120 barrels per day, but in total the top of the blue line was around 6,800 barrels per day. He explained that the chart flowed with the most recent cumulative sum of change.

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Mr. Peltier continued to review slide 4. He began with Prudhoe Bay on the left of the lower chart. The forecast showed a year-on-year production increase for PDU and PDU satellites from FY 21 to FY 22. He noted that DOR included the Milne Point Unit was included in PDU satellites; therefore, a large percentage of the Milne Point development was reflected in the PDU increase. He highlighted there had been a change in operator from BP in 2020 to Hilcorp. He explained that investment from the new operator in the PDU and PDU satellites led to the production increase. He relayed that GPMA field operated by Hilcorp within PDU showed a decrease reflecting natural reservoir decline. He highlighted a decrease in Kuparuk and Kuparuk satellites of around 10,000 barrels per day from FY 21 to FY 22. He elaborated there was natural decline due to

the cessation of natural gas liquid (NGL) imports, which were used for enhanced oil recovery (EOR) within the Kuparuk reservoir unit. The NGL imports and EOR had ceased because of the need to convert the Oliktok pipeline (running from PDU to the Kuparuk River Unit) to fuel gas in order to maintain the base production from the Kuparuk River Unit.

Mr. Peltier briefly noted that the decline in the Endicott field was natural. The Alpine field saw a decline of just under 11,000 barrels of oil per day reflecting natural decline after returning to flush production from an extended shut-in. He expounded that in 2021 and 2022 there had been limited development drilling compared to historical norms.

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Mr. Peltier continued to discuss slide 4. He stated the next decrease was in the Offshore areas at approximately 2,400 barrels per day due to natural reservoir decline. There had been a large production increase for the Natural Petroleum Reserve-Alaska (NPRA).

Representative Ortiz referred to the term development drilling and its impact on overall production. He asked for an explanation.

Mr. Peltier explained the term development drilling with an example. He detailed that existing oil fields such as Prudhoe Bay continued to invest capital to drill in-fill or in-field wells.

Representative Ortiz surmised it was a way to keep production levels up by doing more drilling in an already established area.

Mr. Peltier agreed.

Co-Chair Foster asked for an explanation of the phrase "flush production after extended shut-ins" pertaining to the Alpine field.

Mr. Peltier replied that reservoirs on the North Slope recharged a little around the wellbore. He elaborated there was pressure decline around producing wells, which healed or recharged during a shut-in period. Flush production

reflected a high production rate as the pressure transient progressed through the reservoir before returning to a steady flow rate.

Representative Hannan asked for the full name of the GPMA field.

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Mr. Peltier responded that GPMA stood for Greater Point McIntyre Area.

Representative Hannan asked where the GPMA field was located.

Mr. Peltier answered that the GPMA field was directly north of PDU and southeast of the North Star Unit.

Representative Hannan asked if the GPMA field was located entirely on state lands.

Mr. Peltier believed the field was all on state land. He noted it was not on federal land, but he did not know about Native land holdings.

Mr. Peltier continued to address slide 4. He explained that ConocoPhillips had brought the new pad GMT2 online in 2022 in the NPRA area. The new pad had only been online for a number of months but had been meeting expectations and resulting in a production increase of just over 7,000 barrels of oil per day. The last field on the chart was the Point Thomson Unit, which had been developed by ExxonMobil and come online in 2016. He stated it was a technically challenged reservoir and had facility up time issues for a number of years. Hilcorp was the current operator and had continued the trend. The chart showed a total Alaska North Slope change of about 9,570 barrels of oil per day.

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Mr. Peltier turned to slide 5 titled "FY 2022 As Forecasted by DNR in Fall 2021: How did We Do?" He relayed that production had come in within DNR's forecasted rates in FY 21. He expounded that the DNR mean forecast was about 2 percent higher than the actual FY 22 production. The goal was to hit the mean forecast; however, it was very challenging to do so. He explained that DNR provided a high

and low forecast and an official forecast that fell within the range. He pointed to the chart on the right of the slide showing the FY 22 North Slope forecast. The y-axis showed the FY annual average daily oil production ranging from zero to 600,000 barrels. The first bar reflected the DOR Revenue Sources Book forecast for a high of 524,170 barrels and the fourth bar showed DOR's low forecast of just under 450,000 barrels per day. The second bar showed DNR's official forecast for FY 22 of 486,730 barrels per day. The actual FY 22 production was 476,490 barrels of oil per day. The actuals came within DNR's range of expectation. The department also asked operators for their own individual forecasts, which were confidential individually, but could be provided in an amalgamated form.

Representative Galvin asked if the operator forecasts included projects on the horizon (e.g., Willow).

Mr. Peltier answered that the future projects were not included in the number.

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Representative Stapp asked about the purpose of including the high projection range.

Mr. Peltier answered that production forecasting was difficult. He explained that the high and low forecast put out a range showing what DNR believed would happen in the next 12 months. The high and low range provided median barriers that production would stay within. He stated that the operators provided a forecast to deliver to their business. He referenced a quote: "A P50 forecast is a forecast they hit 90 percent of the time." He stated it was very hard to do.

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Representative Hannan asked if it was normal for the operator forecasts to be slightly more optimistic than the DNR forecast.

Mr. Peltier responded that he would have to look at the historical information to answer the question.

Representative Hannan replied that she did not need the department to take the time to compile the information.

Mr. Peltier replied that when he had worked in private industry, the operators did not look at the state's production forecast for the PDU satellites; however, the midstream asset did look at production throughput of the Trans-Alaska Pipeline System (TAPS), which had been important for market consistency engineers.

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Mr. Peltier continued to address slide 5. He discussed factors to watch for that currently shaped the forecast horizon. He stated that environmental social governance (ESG) influences continued to challenge capital allocation decisions in the Arctic, especially for early-stage oil projects under development and evaluation. He relayed the department often heard it was hard to get money for projects on the North Slope. On the other hand, DNR also heard about continued interest in the Nanushuk development. He elaborated that leases on state and federal land continued to draw interest due to their high resource potential.

Representative Josephson stated he had heard corporate interests using the term ESG favorably more and more. He asked if the industry (e.g., ExxonMobil) was allowing/welcoming the influence of ESG and thereby inviting the problem.

Commissioner Designee Boyle replied that ESG could mean different things to different people in different contexts. He relayed there were still a number of lending institutions domestically and internationally that had generalized blanket policies they couched as part of their ESG principles that prohibit investing in new hydrocarbon development in areas such as Alaska. He elaborated that companies needing to look for outside sources of financing in order to develop a project were running into the roadblocks. He stated that a number of oil companies in Alaska including ExxonMobil, Santos, and ConocoPhillips had set targets to become net zero. The department was not seeing policies from the industry side as a factor playing into a lack of investment in Alaska. He noted there were some global companies that had announced a reticence to further Arctic investment. Generally, the point on slide 5 pertained to lending institutions that has a blanket

prohibition on Arctic investment and how it influenced the availability of capital.

Representative Josephson recalled a recent Alaska Oil and Gas Association (AOGA) meeting where most everyone was using ESG. He considered perhaps they had been using it in a different way or the term was being borrowed.

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Co-Chair Johnson recognized Representative Craig Johnson in the room.

Mr. Peltier turned to slide 6 showing an FY 22 summary for Cook Inlet. He noted the slide reflected oil production only and did not include gas. He stated that due to natural reservoir decline, the department typically expected to see all fields decline year-on-year. He reported that Cook Inlet production increased by about 11 percent or 1,200 barrels per day from FY 21 to FY 22. He relayed that oil from the Cook Inlet basin was critical for instate refineries. He looked at the Cook Inlet daily oil production in a chart on the upper right side of the slide. The y-axis showed the fiscal year annual average daily oil production with a range from zero to 20,000 barrels per day. The high point on the chart was in 2016 at 16,585 barrels per day. The chart showed production mostly declining over time with a bump in 2017. He highlighted a reduction from 10,600 barrels per day in FY 21 to about 9,400 barrels of oil per day in FY 22. He noted there were many oil producing fields in the Cook Inlet area; however, the forecast showed the Cook Inlet basin lumped into a single oil production basin.

Mr. Peltier reviewed the chart on the bottom of slide 6 showing average yearly production changes across Cook Inlet assets. The majority of the fields in Cook Inlet saw natural reservoir decline from FY 21 to FY 22. He pointed to a decrease of about 930 barrels of oil per day in the Middle Ground Shoal field was a result of the field being taken offline in April 2021 due to a fuel gas pipeline leak. He stated that production from the specific field was currently suspended. He reviewed the three increases beginning with the Beaver Creek Unit, which increased by 490 barrels per day from FY 21 to FY 22 due to successful rate adding well work. Additionally, the Redoubt Shoal and West McArthur River fields had been brought back online in

September and October 2021 respectively after being offline since May 2020 due to COVID-19 pandemic reasons.

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Representative Hannan referenced the Middle Ground Shoal field that Mr. Peltier had referred to as offline. She asked for the difference in the terms offline and shut in.

Mr. Peltier answered that shut in meant the field was turned off; the field was still capable of producing oil, but it was not being operated due to a leak in the fuel gas pipeline. He explained that if the integrity issue was resolved, the field could be brought back online.

Representative Hannan asked if the terms had been used interchangeably in the current context.

Mr. Peltier answered affirmatively.

Co-Chair Johnson acknowledged Representative Tom McKay in the room.

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Mr. Peltier turned to slide 7 and discussed a status update of five key future projects on the North Slope. He highlighted Pikka and Willow as new fields scheduled to come online during the next ten years, while the Colville River Unit (CRU) Narwhal CD8, Milne Point Unit (MPU) Raven Pad, and the Kuparuk River Unit (KRU) Nuna-Torok were new pads within existing fields. He elaborated that CD8 and the Raven Pad would be brand new, while Nuna-Torok would be a pad expansion. He relayed that each of the projects represented a large capital investment for operators.

Mr. Peltier provided an update on the Pikka project. He detailed that when the project had been discussed with the legislature the previous year, it had been in the front end engineering and design (FEED) stage. He elaborated that the start of production and phase 1 was expected to be online in 2025, the phase 2 final investment decision (FID) had been expected shortly thereafter. He explained there had been a Santos and Oil Search merger completed as well. He relayed that the project had been granted FID for phase 1 in August 2022 and first oil was expected in 2026 from Santos. The peak design rate for phase 1 of the project was

80,000 barrels per day per public information released by Santos.

Mr. Peltier reviewed the Willow project on slide 7. He detailed the project had been remanded from the Alaska District Court in 2022 to target a new Bureau of Land Management (BLM) decision. He explained that construction had been anticipated to start in the first quarter of 2023 with first oil in 2025 or 2026. Currently the project was awaiting a BLM record of decision (ROD) on its supplemental environmental impact statement (EIS), which was released in July of 2022. ConocoPhillips was the operator and it could not make the FID until the ROD was released. If approved, first oil was expected six years after FID. The peak rate, as published in the supplemental EIS, was 180,000 barrels of oil per day.

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Representative Ortiz asked for a high level overview of factors that went into companies' FID decisions.

Commissioner Designee Boyle replied that companies looked at a number of factors including the level of confidence a geologist and reservoir engineers had that the underlying resource would produce at anticipated rates. Second, there were commercial and financial considerations such as the cost of supply and transportation, the expected rate of return, severance tax, royalties, and any pending policy issues that could lend to increased risk. Generally, many companies had global portfolios or a multitude of assets spread across a region.

Commissioner Designee Boyle explained that when a board of directors was making a final investment decision, an Alaska project may have to compete with a project in Papua New Guinea, Surinam, Texas, or elsewhere. He elaborated that boards had to look at all of the potential projects and determine which could move quicker, be successful, and offer a competitive rate of return. He furthered that once a company had received approval for FID, it indicated the company had successfully made the case to its board and shareholders that the project would add value to the company.

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Mr. Peltier continued with slide 7 and discussed the CRU Narwhal CD8 project. He relayed that DNR had given a presentation to the legislature that the project had first oil in December of 2021. He explained that typically, the department would categorize such a project as currently producing; however, the CD8 project was a large capital investment. He expounded that DNR opted to categorize CD8 as an uncertain project, while moving some of what was historically Narwhal into the currently producing category. According to the ConocoPhillips plan of development, CD8 could commence as early as 2028, pending stakeholder alignment, permitting, and internal studies and alignment. The DNR peak estimate was around 32,000 barrels of oil per day.

Mr. Peltier discussed the MPU Raven Pad on slide 7. He explained that in 2022, the plan of development discussed future drilling opportunities in undeveloped acreage in the northwest of the unit. Hilcorp had formally applied for approval to construct a new drilling and production pad, also known as R Pad, on ADL 025509 within MPU. He detailed it was analogous to the previously developed Moose Pad or M Pad within MPU. The estimated peak rate for the pad was around 10,000 barrels of oil per day.

Mr. Peltier reviewed the KRU Nuna-Torok development on slide 7. The 2021 plan of development was for two appraisal wells and additional seismic data processing. In 2022, the plan of development included rotary drilling in the third quarter of 2022 with an additional injector/producer pair for additional Torok reservoir appraisal to inform future development. Assuming ConocoPhillips moved forward with the pad, DNR projected a peak rate of 25,000 barrels of oil per day.

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Representative Josephson asked for verification there should not be an assumption the Willow project would be generating 700,000 barrels per day in 2029.

Mr. Peltier agreed. He added there was a lot of uncertainty about when the projects would come online and the production they would generate. He would expound on the answer over the next several slides.

Mr. Peltier turned to slide 8 and discussed the DNR fall 2022 production forecasting approach. The department worked to be consistent with its forecasting and worked to make improvements to provide a better forecast. He reviewed a couple of minor changes in methodology from the prior year's forecast. First, in past years under the current production category, DNR had included capital and development drilling, which reflected a future expense baked into current production. He clarified that current production should only be what was in place at the end of the last fiscal year; therefore, all future capital spend for future drilling was captured in the under development or under evaluation categories. He elaborated that the DOR Revenue Sources Book defined the three categories; therefore, DNR changed its methodology to be more in line with DOR's definition. Second, previously there had been a slight variation in the first few months of the forecast period between the DNR and DOR forecasts. He explained that the updated forecasting approach included aligning the two forecasts to show the same numbers.

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Mr. Peltier turned to slide 9 and reviewed the projects and pools included in the DNR forecast. The Resource Evaluation Section within the Division of Oil and Gas looked at all of the pools on the North Slope and Cook Inlet and generated a decline curve analysis for all producing pools. The information was generated from public data from the Alaska Oil and Gas Conservation Commission (AOGCC). He noted that pools had to be in production by June 30, 2022 to be part of the category. The division also engaged with operators through DOR in in-person and written interviews to gain information about current fields and future projects. He detailed that 17 projects under development/under evaluation were included in the current production forecast. He relayed that projects used confidential information from the operators; therefore, the information was presented as a single aggregated number. The projects were adjusted for scope of contribution, chance of occurrence, and start date.

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Mr. Peltier discussed categories of production on slide 10 including ongoing/current production and future production. He began with ongoing/current production, which encompassed

production up to June 30, 2022. The category included the Prudhoe Bay Unit, PBU satellites, Kuparuk River Unit, and Alpine Units and evaluated well and facility uptime within the units to provide an appropriate decline curve analysis. The department talked with operators to ensure they were maintaining their base production by appropriately spending and investing in their fields. Additionally, the department looked at reservoir management practices and evaluated whether there were any changes that would impact trends in the future.

Mr. Peltier discussed future production on the bottom portion of slide 10. He noted that future production was much more uncertain [than ongoing/current production]. He added that many of the currently producing fields had been operating for around 50 years. He stated that Prudhoe Bay had started in 1977; therefore, five decades of production history provided a lot of credence on how to decline the field. Many of the projects under evaluation/under development were brand new fields in reservoirs with short production histories on the North Slope. The department considered rate contribution including uncertainty in future well performance and in project scope. He noted the range could be quite large resulting in a large uncertainty band. Project occurrence and timing was also important.

Mr. Peltier discussed that some future projects were cancelled over time. He highlighted the Nikaitchuq North offshore development as an example and explained the project had never occurred and the leases had been relinquished; therefore, the project was not included in the fall 2022 production forecast. Additionally, DNR evaluated commercial risk based off of expected future prices of oil.

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Mr. Peltier moved to a map on slide 11 showing major projects under evaluation/development considered in the fall 2022 forecast. He reviewed general characteristics of the projects. First, the projects were not online at the end of the data cutoff period of June 30, 2022. Second, the projects had higher risk factors than currently producing fields. Third, the projects were known discoveries with identifiable operators, and fourth, the projects required major investments. He reviewed projects from west to east on the map on slide 11. He began with the Smith Bay

development shown in top left corner of the map. He pointed to the Willow and Umiat projects and noted a red square on the map indicated the developments were located on federal lands. The CRU Narwhal CD8 project was to the east of the Willow development. He listed the remaining projects and their locations on the map including Pikka, Quokka/Mitquq, Mustang, Nuna-Torok, Ugnu (located across PDU, KRU, and MPU), MPU Raven Pad, Theta West, Talitha, Alkaid, Liberty, PTU expansion, and Sourdough project.

Co-Chair Johnson asked if the Ugnu formation was drilled at a different depth.

Mr. Peltier answered that the Ugnu formation was shallower than most of the producing fields; the depth was just below the permafrost and above the Schrader Bluff Formation.

Co-Chair Johnson observed that the Smith Bay development was located off the coast of NPRA. She asked for verification the location was a state lease.

Mr. Peltier confirmed Smith Bay was a state lease.

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Mr. Peltier continued to review the list of major North Slope projects on slide 11 including MPU Raven Pad, Theta West, Talitha, Alkaid, Liberty, Point Thomson Unit (PTU) expansion, and Sourdough project.

Mr. Peltier turned to slide 13 and discussed the fall 2022 North Slope annualized forecast. The y-axis of the chart showed the fiscal year annual average daily oil production barrels per day with a range of zero to 1 million barrels. The chart included the DOR Revenue Sources Book high forecast reflected as a blue line and its low forecast reflected in gray. The DOR official forecast was shown in dark blue along the middle of the chart. The summation of the operator forecasts was included as a dotted line. He added that operator forecasts only included currently producing fields; however, the DOR official forecast included future projects.

Representative Galvin looked at the highs and lows on slide 13 and observed the extremes were much broader than on a prior slide. She asked for detail.

Mr. Peltier answered that the high and low cases diverged through time based on uncertainty of how projects would play out in the future. He explained that over time some of the projects expected to come online added a potentially higher rate than the forecast. He elaborated that as projects continued to be added, the forecast continued to diverge on the high side, whereas the low end reflected a scenario where projects did not come online.

Representative Galvin remarked that results for FY 22 generated in the fall of 2021 showed a very small difference between the high and low scenarios compared to the chart on slide 13. She asked if it was not out of the ordinary based on Mr. Peltier's previous response.

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Mr. Peltier answered that the uncertainty was hard to gauge. He explained that every year the uncertainty band continued to increase through time. He elaborated that in the next five months, plus or minus 5 percent may be something reasonable to expect and beyond that time period the range may be plus or minus 10 percent. He clarified that the contribution from future uncertain projects was the reason the band increased.

Representative Galvin saw there was a difference of about plus or minus 75,000 barrels in the near-term and a difference that was closer to 200,000 barrels per day in the future. She believed Mr. Peltier was explaining the difference was within the norm. She thought it was a much greater range.

Mr. Peltier answered that the uncertainty band was the nature of the way the analysis was done year-on-year. He explained that when looking at the forecast from the previous year the same was true.

Representative Josephson referenced the Smith Bay project shown on the map on slide 11. He recalled there had been constant discussion with the legislature between 2013 and 2015 about the field's potential including meetings with the oil company Caelus. He referenced the industry's desire at the time for continuing cash credits that had been suspended by the state in the middle of the past decade. He clarified he was not saying Smith Bay would not happen, but he observed that the excitement about the field had gone

away. He asked how to know when a project would come to fruition. He asked if it was FID and the lack of litigation.

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Mr. Peltier responded that when the department looked at all 17 projects individually, every project had uncertainty around start date and chance of occurrence. He explained there was a group of 24 people in the room who all got one vote. He detailed that projects like Smith Bay may be considered higher risk by some people than something like a pad expansion off an existing field. He used Smith Bay compared to the MPU Raven Pad as an example. The department had a higher risk associated with possibility the Smith Bay project would come online. The department did not want its forecast to pick on any one project; therefore, it relied on the broad perspective of the group to determine how to aggregate Smith Bay's production forecast. In comparison, the group within the department would likely consider the Raven Pad project as lower risk because it was an existing pad within an existing field with no subsurface risk.

Mr. Peltier clarified the department did not want to pick winners and losers in the forecast; it worked to aggregate the projects using the same method. He explained that the department added all of the project risk components using a Monte Carlo analysis. He stated that while some of the group may think Smith Bay had a high chance of coming online and others may think it had a low chance of coming online; the department used all of the results to aggregate a forecast.

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Representative Josephson stated he was not spending a significant amount of time thinking about Smith Bay, but he recalled the incredible amount of excitement about the field in the past. He had not heard anything about the project in recent years and it made him watchful and a little skeptical sometimes.

Representative Stapp looked at the fall 2022 North Slope annualized forecast on slide 13. He stated his understanding that Willow was awaiting the record of decision by the BLM, FID would come next, and first oil would be projected six years from the FID. He calculated

oil could be expected as early as 2029; however, he did not see any associated projected increase in the official forecast. He asked how to reconcile the two things.

Mr. Peltier answered that he would more fully address the question on a subsequent slide. He explained the forecast accounted for the various uncertainties including start date, amount of production, and FID approval and spread out the potential production increase over time. He clarified the forecast would not show a dramatic increase in the production rate; the increase would be reflected as a gradual wedge over time. He noted the phenomenon was illustrated on slide 14.

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Representative Ortiz looked at the variance between the high and low projections. He thought it was understandable the variance increased over time. He asked if forecasts included variables like changes in technology and potential successes in alternative energy that may make oil less advantageous.

Mr. Peltier replied that the department's forecast did not include the impact of substantial changes to future oil demands. The department included technology changes operators were already using, but it did not include changes in technology that may come in the future.

Mr. Peltier provided a recap of the difference between the DOR and DNR forecasts. He explained that the DNR official forecast included future projects. The operator forecast came from currently producing operators and excluded future projects. He clarified that the Willow and Pikka projects were not included in the operator forecast, which was one of the reasons the official forecast and operator forecast began to diverge in FY 27 [slide 13]. He highlighted that in the short-term (FY 23), the DNR forecast for the average daily statewide production was just over 500,000 barrels of oil per day. He clarified that the acronym MBOPD stood for thousand barrels of oil per day, whereas MMBOPD stood for million barrels of oil per day. The DNR forecast included FY 23 production at 492,000 with a range of 448,000 and 535,000 barrels per day. In the long-term, the department anticipated the 500,000 barrels per day to continue for the next five or so years.

Mr. Peltier explained the forecast had to include many assumptions that operators would continue to inject and manage reservoirs as they had in the past. He elaborated that the forecast was updated when operators changed their activity set or business information. He noted the process occurred in the fall and spring.

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Mr. Peltier advanced to slide 14 showing the fall 2022 expected case and categories of production. The chart on the left of the slide showed the fiscal year average daily oil production ranging from zero to 700,000 barrels of oil per day. The blue showed current producing fields declining over time, the orange showed development drilling within producing fields, and the gray section reflected a combination of in-field drilling and the 17 major projects under exploration (growing over time through FY 32). The chart on the right of the slide reflected projects under exploration only. He pointed out that in-field development drilling and project aggregation were major contributors to the oil production forecast over the next ten years.

Mr. Peltier turned to slide 15 and discussed the fall 2022 production forecast summary:

- DNR Forecast continues to use the best information available to DNR/DOR, to generate production outlook for oil fields within the state, with a focus on generating accurate near term, and realistic long term, forecasts.
- Fall 2022 Forecast is a static view on production; DNR's outlook is updated annually (Fall and Spring) to incorporate latest operator plans and the state's official updated price outlook.
- DNR's Fall 2022 outlook shows mean annual production of approximately 500 MBOPD across much of the outlook period, based on the current snapshot of operators' plans.
- Production from projects under evaluation reflects uncertainty in operators' plans towards return to pre pandemic activity levels, specific project uncertainties, as well as project scope and timing risks.

[2:57:25 PM](#)

Mr. Peltier thanked the committee for inviting the department to present the production forecast team. He listed members of the production forecast team within the department.

Co-Chair Foster pointed to slide 5 showing the FY 22 forecast. He looked at the difference between the forecast of 486,730 and the actual of 476,490, which was a difference of about 10,000 barrels per day. He looked at slide 13 showing the DNR forecast for FY 23 North Slope production at 492,000 barrels per day. He observed the forecast for FY 23 was up from the actual FY 22 production by about 15,500 barrels per day. He asked if his statements were accurate.

Mr. Peltier responded affirmatively. He confirmed the numbers listed by Co-Chair Foster were accurate and there was an increase projected in the coming year.

Co-Chair Johnson thanked the presenters. She informed committee members they would receive emails about subcommittee assignments. She reviewed the agenda for the following meeting on Wednesday. She introduced her operating budget staff Remond Henderson.

#

ADJOURNMENT

[3:00:46 PM](#)

The meeting was adjourned at 3:00 p.m.