

HOUSE FINANCE COMMITTEE
January 17, 2024
1:35 p.m.

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CALL TO ORDER

Co-Chair Johnson called the House Finance Committee meeting to order at 1:35 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

John Boyle, Commissioner, Department of Natural Resources; Travis Peltier, Petroleum Reservoir Engineer, Division of Oil and Gas, Department of Natural Resources; Derek Nottingham, Director, Division of Oil and Gas, Department of Natural Resources; John Crowther, Deputy Commissioner, Department of Natural Resources.

SUMMARY

PRESENTATION: PRODUCTION FORECAST BY THE DEPARTMENT OF NATURAL RESOURCES

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Co-Chair Johnson welcomed committee members and staff. She discussed meeting protocol and decorum and introduced House Finance Committee staff. She thanked various members of the Legislative Finance Division staff and her staff.

^PRESENTATION: PRODUCTION FORECAST BY THE DEPARTMENT OF NATURAL RESOURCES

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JOHN BOYLE, COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, introduced himself and staff. The Department of Natural Resources (DNR) would present its fall 2023 oil production forecast. He relayed that DNR undertook the exercise semiannually to help inform decision makers on what the oil and gas production landscape looked like across the state. The department welcomed feedback on the ways it could improve the presentation of its data in a useful way. He shared that Alaska was on an exciting oil and gas production trajectory. The state was currently realizing a "major boom" in investment at the beginning of a new chapter on the North Slope.

Commissioner Boyle stated that for decades the major producers had controlled the fate of the North Slope. He explained that it was the beginning of a new era with new operators and explorers opening up new prospective areas on the North Slope. He detailed that different companies with different investment profiles that may prioritize investing in Alaska differently than other companies were infusing a new energy on the North Slope. He remarked that the state was starting to see a healthy mix of competition and investment dollars that would be a great benefit to the state in the long run. The situation was being driven by multiple projects and commitments and had been years in the making. He believed credit was due to the legislature for enabling an investment climate that bred confidence.

Commissioner Boyle pointed out that oil and gas developments did not happen overnight. He stated that companies could not merely acquire a lease and start producing oil six to twelve months later as they could in Texas and North Dakota. He clarified that the timeline for

new oil and gas developments in Alaska was 10 to 12 years. The projects took substantial time and effort; the time led to uncertainty and increased cost for companies. He noted that permitting and regulatory framework could be challenging, particularly if there was a federal nexus to the permitting. He stated it took a number of factors working together to create an environment incentivizing companies to invest. He reported that based on what DNR was seeing on the North Slope, it appeared that Alaska had its policy right. The state was seeing investment and activity and it would begin recognizing the fruits of the policy in the next several years in the form of increased production.

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Commissioner Boyle continued to provide opening remarks. The department projected that North Slope oil production would exceed 630,000 barrels per day by 2033. He argued that the estimate was relatively conservative. The number reflected DNR's confidence in seeing new projects, particularly Willow and Pikka, which had both received their final investment decisions (FID) and were in various stages of construction and development. He noted that current [North Slope] production was approximately 480,000 barrels per day. He expressed optimism about the projection for 630,000 barrels per day in the future.

Commissioner Boyle relayed that a large part of the state's oil production continued to come from legacy fields. While production decline was natural in legacy fields, the state continued to see operators make investments and infill work to stem and/or reverse the decline. He remarked that it was critical because the legacy fields maintained the [production] backbone and provided the opportunity to bridge new projects coming online, which would begin accounting for a larger component of Trans-Alaska Pipeline System (TAPS) throughput. He highlighted that data in the presentation showed that by 2033 legacy production from fields in Prudhoe Bay, Kuparuk, and the Colville River Unit (CRU) would represent the minority of the oil in TAPS, while new projects including Pikka, Willow, and expansions such as Quokka and Horseshoe would comprise the lion's share of production.

Commissioner Boyle highlighted there were promising opportunities on the exploratory work [the producer] Great Bear Pantheon was doing on its Talitha and Alkaid units

along the Dalton Highway. Additionally, [the company] Apache had partnered with Armstrong and had announced plans to drill three exploratory wells in the current winter located on the eastern North Slope to continue the Brookian play. The department was excited to see the results of the exploration, which could result in significant production in the future. He characterized the current production environment as a health ecosystem where companies were investing and targeting a multitude of different geologic formations.

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Commissioner Boyle stated that with some of the growth came some growing pains. He explained that workforce service capacity and infrastructure needed to support the new development was being stretched. There was close to \$18 billion coming into the state between Santos, ConocoPhillips, and other North Slope operators. He believed they were good challenges in some ways, but the state was keeping an eye on the situation. Despite all of the good things, the department was monitoring some potential challenges. He elaborated that the state was seeing movement out of the federal government, particularly with a proposed Natural Petroleum Reserve-Alaska (NPRA) rule making, which could have a significant impact on the efficacy of future permitting or development efforts in the NPRA.

Commissioner Boyle relayed that the state was seeing continued challenges with some operators in terms of the financial environment for oil and gas. He stated that the strong drive towards some of the environmental and social governance (ESG) principles seen in a number of financial institutions pre-pandemic had waned. He believed there was a greater realization in the investment community that the energy transition was taking a significant amount of time and that transitions had to be just and ensure people had access to reliable and affordable energy sources. He explained that while there continued to be some headwinds when it came to investment in the Arctic and Alaska, there were indications of some willingness to engage. The state would continue to engage in the effort to tell the story of how development was done in Alaska. He expounded that no one valued having clean air and water and a pristine tundra more than the residents of the area.

Commissioner Boyle summarized that the department's forecast was very optimistic. He stated that DNR had worked to provide robust data in the presentation as the committee thought through long-term planning for the state. He welcomed questions and input.

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TRAVIS PELTIER, PETROLEUM RESERVOIR ENGINEER, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, provided information on his educational and professional background. He provided a PowerPoint presentation titled "Fall 2023 Oil Production Forecast: House Finance Committee," dated January 17, 2024. He relayed that DNR had been performing the 10-year oil production forecast since 2016. He planned to share the oil production forecast result for FY 23 and the forecast for the next 10 years. The presentation also included information on how the forecast was generated. He noted the presentation appendix included a list of acronyms used in the presentation.

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Representative Hannan asked when the department's forecast data translated to the Department of Revenue (DOR). She asked if DOR used DNR's number as provided or reanalyzed it. She also wondered whether DOR participated in the forecast development.

Mr. Peltier answered that DOR did not change the [production] forecast number provided by DNR; however, he could not speak to how DOR parsed it out amongst the various state and federal leases. The forecast provided by DNR was the forecast used by DOR.

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Mr. Peltier turned to a chart titled "Fall 2023: North Slope Annualized Forecast" on slide 3. The y-axis of the chart reflected the fiscal year annual average daily oil production and barrels of oil per day (BOPD) showing a range from zero to 1 million BOPD. The x-axis showed fiscal years from 2024 through 2033. He noted that the forecast on the slide was reflected in the DOR Revenue Sources Book (RSB) released in the fall of 2023; the data was included in various parts of chapter 6 of the RSB. The dark blue line on the chart reflected the official DNR forecast,

which reflected the P50 value including existing fields and future production from future projects such as Pikka and Willow. He noted the forecast included risk and had been described by Commissioner Boyle as conservative. He stated that creating and meeting a single forecast every year was difficult; therefore, DNR generated a high and low production forecast as well. He highlighted that in FY 24 the range was about plus or minus 5 percent. He noted that because uncertainty grew over time, the number was closer to plus or minus 50 percent by FY 33.

Mr. Peltier continued to explain the chart on slide 3. The department had conducted in-person and written interviews with operators of existing fields to learn what they believed their assets on the North Slope and Cook Inlet would produce. The department summarized the information from operators and included it in the forecast [as shown by the black dotted line]. He pointed out that in FY 24 DNR and the operator expectations were very similar. He clarified that the operator data only reflected existing fields and did not include fields in development (e.g., Willow and Pikka), which accounted for the divergence between the operator and official forecast lines around FY 27.

Representative Stapp observed that operators seemed to anticipate production exceeding 500,000 barrels per day in FY 25 and FY 26. He did not believe oil production had exceeded 500,000 barrels per day in almost a decade. He asked for an explanation.

Mr. Peltier answered that he could not explain how the operators came up with their forecast.

Representative Stapp hoped the operators were right for the next two years and that DNR was right for the following years.

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Mr. Peltier moved to slide 5 titled "FY2023 as Forecasted by DNR in Fall 2022: How did we do?" He looked at the chart on the right side of the slide showing the FY 23 North Slope forecast. The chart reflected the annual average daily oil production per day ranging from zero to 600,000 barrels of oil per day. He relayed that chapter 6 of the DOR RSB included a high and low forecast. He pointed to the

dark blue bar reflecting DNR's official forecast and noted that DNR considered the forecast to be a success as long as it fell within the range between the high and low scenarios. Actual production in FY 23 was 479,380 barrels per day, which was about 3 percent lower than DNR's official forecast at 491,700 barrels per day. The FY 23 operator forecast was 482,461 barrels per day, which was closer to the actual production, but still within DNR's forecast range.

Representative Ortiz asked what factors caused the actual FY 23 production to be a bit less than DNR's official forecast rather than a bit more.

Mr. Peltier responded there were three major things the department observed in FY 23. He elaborated that declines had resulted from challenges associated with the Badami Unit's primary well and Point Thomson's single producing well. The other two things had to do with existing or "infill" drilling. He explained that DNR forecasted the number of wells about right, but the expectation for the wells had not been met. Additionally, a new development in the NPRA had a significant production gap in the past year. He noted that the GMT Unit was highlighted on slide 6. He explained that DNR had forecasted a number based off of little data; the department had received more data the past year, but unfortunately the development did not meet its expectations.

Representative Ortiz assumed there were other areas that likely exceeded DNR's forecast expectations.

Mr. Peltier agreed.

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Mr. Peltier addressed factors currently shaping the forecast horizon on slide 5. He relayed that industry interest was expanding in Brookian age plays across the Nanushuk and North Slope. He detailed that Armstrong was partnering with Apache on a three-well exploration program on the eastern North Slope on state lands. He highlighted continued development on the Willow and Pikka projects on federal and state lands respectively. The projects were all located in Brookian age formations. He relayed that Great Bear Pantheon projects Talitha and Alkaid were also Brookian age plays that were of high interest to industry.

The department continued to see challenges associated with ESG influences, which continued to challenge capital allocation decisions in Alaska. He noted that companies and investors were adapting and trying to figure out how to get investment in Alaska. He added there had been some federal regulatory changes and leasing restrictions that had presented challenges, which was one of the reasons a couple of projects had been removed from DNR's list. He would address the issue on a later slide.

Representative Hannan asked for a definition of Brookian age plays.

Mr. Peltier responded that the term [Brookian age plays] had to do with the age of the sands. He detailed that it was after the age of the dinosaurs and before the current Holocene epoch. He explained that the rock was relatively new and not as deep as the Ivishak at Prudhoe Bay or the Kuparuk sands. He remarked that it was similar to Schrader Bluff sands. He noted the Brookian age plays were located below the permafrost but were not as old as the areas the traditional oil fields had been deposited.

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Mr. Peltier turned to slide 6 titled "FY2023 Summary: North Slope." He provided highlights comparing FY 22 and FY 23. He reported that DNR expected fields to naturally decline. He detailed that Prudhoe Bay and the Kuparuk River Unit (KRU) fields were some of the largest in North America and had been online for decades. He pointed to a chart on the top right of the slide showing North Slope daily production from FY 17 to FY 23. The chart showed a decline from 526,389 barrels of oil per day in FY 17 to 479,380 in FY 23; however, operators continued to invest capital to maintain the fields. He highlighted there had been a production increase in FY 23 compared to FY 22. In total, the North Slope produced about 2,890 barrels per day in FY 23 compared to FY 22.

Mr. Peltier addressed a waterfall chart on the lower left of slide 6 reflecting production changes across North Slope fields from FY 22 to FY 23. He explained that the chart began at zero with a waterfall from left to right, reflecting a cumulative difference that built on one or the other. He noted that the fields [shown on the x-axis] were organized alphabetically and he had input decreases first

followed by the increases. He pointed to Prudhoe Bay that ended at about 2,890 barrels of oil per day, which was the nature of how the waterfall chart worked. He reviewed the chart beginning with the Badami well, which had seen a decrease in FY 23 from FY 22 because its best producing well had been offline for a substantial part of the fiscal year. He noted the well had come back online in May 2023 and was still operating. There had been natural decline in the Colville River and Kuparuk River Units, which was offset by development drilling. He reported that drilling had been returning to the North Slope after the COVID-19 pandemic when there had been a drilling shutdown. He added that decline was being mitigated with continued investment. There was natural reservoir decline with the Endicott and Northstar fields. The Point Thomson field experienced decline because its single production well was suffering technical challenges continuing into FY 24.

Mr. Peltier addressed the increases in North Slope production between FY 22 and FY 23 on slide 6. The Greater Mooses Tooth Unit (GMT2) had a new pad put in development, which had resulted in new oil beginning in November 2021. There was more drilling needed over the years and continued activity played out in FY 23 resulting in a relatively large increase due to new resources. Production growth on the Milne Point, Nikaitchuq and Ooguruk Units pertained to infill drilling targets and rig workover efforts. Prudhoe Bay had seen production growth from improved facility reliability and increased gas throughput in the winter. He explained that the operator Hilcorp was able to keep the facilities online and running for a good part of the year, which led to a year-over-year production increase.

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Mr. Peltier turned to slide 7 titled "Status Update of Key Future Projects: North Slope." He noted that the project list was not exhaustive and included five projects DNR saw as material to the North Slope's production future. He highlighted that Pikka and Willow were large new fields with combined capital investment exceeding \$10 billion. Additionally, there were new pads under development or pads under expansion for additional production within existing fields. He cited examples including Narwhal CD8 in the Colvill River Unit (CRU), Raven Pad (R Pad) within the Milne Point Unit (MPU), and the Nuna-Torok Pad within the Kuparuk River Unit.

Mr. Peltier addressed the current status and expected production rates of the five projects shown on slide 7. He would review the status in January 2023, the current status as of January 2024, and the production rate estimates for each of the projects. He began with Pikka, which was operated by Santos and located on state land. In 2023, FID had been approved for Pikka Phase 1 and first oil was anticipated in 2026. As of January 2024, project construction and drilling activities were ongoing and project first oil was anticipated in the second quarter of 2026. The peak design capacity and rate remained at 80,000 barrels per day.

Mr. Peltier moved to the Willow project on slide 7. Willow was operated by ConocoPhillips and located on federal lands. In January 2023, the project had been awaiting a record of decision (ROD) from the Bureau of Land Management (BLM) on a supplemental environmental impact statement (EIS). He relayed that ConocoPhillips had stated that the FID could not be made prior to the completion of the ROD and if first oil happened, it would be six years after FID. He reported that the BLM issued the ROD on the supplemental EIS in 2023 and ConocoPhillips started construction activity in April 2023. Throughout the year there had been some legal uncertainties, which had been largely resolved by November 2023 and Conoco had announced FID in December 2023. The timeline remained at six years after FID and first oil was expected in 2029. The peak rate for the project was expected to be 180,000 barrels per day.

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Mr. Peltier discussed the CRU Narwhal CD8 (CD8) project on slide 7. He relayed that in January 2023, CD8 was expected to start production in early 2028 pending alignment with external and internal stakeholders. He noted the date came out of the 23rd plan of development (POD) submitted in 2021. As of January 2024, CD8 was expected to have its first oil in 2030 according to the 25th CRU POD. The project was still awaiting stakeholder alignment, permitting, and internal studies and alignment. The peak estimate for the project was around 32,000 barrels per day.

Mr. Peltier reviewed the status of the MPU Raven Pad (R Pad). In January 2023, Hilcorp had recently applied for approval to construct the R Pad project. Over the past 12

months DNR granted approval for R Pad construction to begin in February 2023 and construction activities were ongoing. He reported the pad was expected to be online within the next two years. The DNR peak production estimate was 10,000 barrels per day. He noted that the operator, Milne Point, had developed the M Pad or Moose Pad in 2018. He detailed that the R Pad and M Pad resource base was very similar, and the production expectations were the same for the two projects.

Mr. Peltier addressed the KRU Nuna-Torok project located on state lands (last project on slide 7). In January 2023, ConocoPhillips had still been doing testing with an additional injector/producer pair planned. In 2023, the operator saw enough to approve the funding for a 3T pad expansion. Production from the project was expected in 2025 and peak production was expected to be 20,000 barrels per day.

Mr. Peltier summarized slide 7. He explained that the top two projects [Pikka and Willow] would bring significant investment to Alaska in the medium and far-term, while the last two [Raven Pad and Nuna-Torok] would bring significant oil production benefit in the near-term.

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Representative Stapp remarked that the peak production for the Willow project was expected to be 180,000 barrels per day despite the fact that three pads were approved instead of five. He asked for verification that the number of pads had not changed the production projections.

Mr. Peltier responded that the supplemental EIS included a table of production rates. He noted that the absence of the fourth pad decreased the total volume for the project; however, the peak rate was estimated to be the same.

Representative Stapp observed that in 2022 the peak rate for the Nuna-Torok project was projected at 25,000 barrels per day. He remarked on the reduction to 20,000 barrels per day. He asked what had caused the change.

Mr. Peltier answered that the Nuna-Torok project included an expansion on 3T pad. He explained that the Nuna-Torok formation was also accessible from the 3S pad on the Kuparuk River Unit. He elaborated that because some of the rate [of production] was accessible from an existing pad, DNR had removed a portion from the part of the project highlighted on slide 7. The change had naturally reduced the [projected production] rate.

Representative Hannan referenced the Pikka project and the [anticipation for first oil in the] second quarter of 2026. She noted a litigation issue related to access for development. She asked if the first oil anticipation changed depending on how the litigation played out. She asked if the information shown on slide 7 accounted for the possibility of having to build a new road.

Commissioner Boyle answered that the outcome of the litigation was not a factor in the anticipated first oil date for Pikka. The project was anticipated to use the roads it was using currently during the development of the fields. More impactful for the timing of the development of the Pikka field was the ability to build out the pipeline structure within the next two winter seasons. He stated if there was long tundra travel and winter season in the current year and if more of the pipeline work was completed, the start date may move up.

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Representative Josephson asked for verification that because of net operating losses and carried forward lease expenditures, the Willow and Pikka projects would be a boon to the state treasury later in the current decade because the credits would offset revenue the state would otherwise have.

Commissioner Boyle prefaced his answer by noting that DNR was not the Department of Revenue. He stated his understanding that revenues coming to the state from Pikka occurred nearly immediately because Santos was not a current operator and was not currently paying production tax to the state. As soon as Pikka began production there would be royalty payments accruing to the state treasury. He relayed that the Willow project was located on federal land within NPRA and the royalty rates were split with 50 percent accruing to the federal government and the other 50

percent was dedicated to the North Slope Impact Grant Fund administered by the Department of Commerce, Community and Economic Development. He explained that the money was earmarked for the five villages within the NPRA most impacted by the development. The state did not receive a direct royalty share. He added that the current operator/producer ConocoPhillips would have the opportunity to offset some of its construction costs with its existing production taxes, which would have an impact on cashflow timing for the state in the earlier years. He noted that in later years it would still provide a net overall revenue benefit to the state.

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Representative Galvin asked if the department had heard from companies on any unique development challenges in the particular fields that may result in increased development costs. She highlighted road access and difficult rocks as examples.

Commissioner Boyle replied that the Pikka and Willow projects were the first developments of the Nanushuk formation. He believed the companies had been working to get as efficient recovery as possible out of the reservoirs. He noted that he was not a geologist or petroleum engineer. He stated his understanding as a layperson that the formation was different from Prudhoe Bay and Kuparuk and required more enhanced oil recovery techniques such as gas or water injection to help stimulate the reservoirs and sweep the rock to get as much oil and gas molecules as possible. He explained that it added an element of cost and complexity to understand how the geologic systems would react to the techniques. He elaborated that Pikka was advantaged by its location near existing roads and infrastructure. Willow was well attenuated from the central facilities, pipelines, and infrastructure on the North Slope, which resulted in increased cost and complexity logistically (i.e., the need to build a pipeline to transport its oil).

Mr. Peltier advanced to slide 8 titled "FY2023 Summary: Cook Inlet." He relayed that Cook Inlet had been online since 1958 and due to its age, fields were expected to broadly decline year-on-year. He pointed to a chart on the top right of the slide reflecting Cook Inlet daily oil production. The chart showed fiscal year average daily

production ranging from zero to 20,000 barrels per day for FY 17 to FY 23. He highlighted the peak rate at 15,653 barrels per day in FY 18, which had declined through FY 23 to 9,033. The decrease from FY 22 to FY 23 was roughly 4 percent or 370 barrels per day. He highlighted that oil from the Cook Inlet basin was critical to supplying instate refineries. Fuel generated from instate refineries was used for various purposes including aviation fuels for the State of Alaska.

Mr. Peltier reviewed a waterfall chart showing average yearly production changes (in barrels of oil per day) across Cook Inlet assets on the lower left of slide 8. He explained that the chart was alphabetically ordered on decreases and alphabetically ordered on increases. Overall, the Cook Inlet basin was experiencing natural decline. He highlighted Beaver Creek, Granite Point, Hansen, McArthur River, and Swanson River units were all experiencing natural decline. He remarked that the year-on-year declines were expected from a mature basin. He noted that the Redoubt Shoal unit experienced natural decline, which was partially offset by some rate adding well work. Additionally, well work had been done at the West McArthur River unit, which resulted in an increased rate year-on-year.

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Mr. Peltier turned to slide 10 titled "DNR Forecast Process: Projects/Pools Included in Forecast." He pointed out that the previous year DNR had made its capital drilling program more explicit in its forecasting methodology approach. He noted there was no changes from the methodology between the fall 2023 forecast and the present day.

Co-Chair Johnson remarked that daily production was down significantly less than she expected. She was trying to recall DNR's production forecast from the prior year.

Mr. Peltier replied that slide 15 showed the spring 2023 forecast. He asked to address the question at that point in the presentation.

Mr. Peltier addressed the DNR production forecast process on slide 10. The process began with the various pools and projects. He explained that DNR did an annual bottoms-up

decline curve forecast for all producing pools (everything publicly available in the Alaska Oil and Gas Conservation Commission (AOGCC) database as of June 30). There were 39 pools in the current forecast across the North Slope and Cook Inlet. The forecast included one additional pool over the previous year because ConocoPhillips had a new pool - the Coyote formation in the Kuparuk River Unit - the previous year that had not been included in the forecast. He noted that DNR treated the Cook Inlet basin as one pool in the data it provided DOR. The Division of Oil and Gas refined the forecast after conducting in-person and in-writing interviews with operators arranged through DOR. Operators provided information on development plans over the next ten years including activity levels and major projects they intended to invest in.

Mr. Peltier continued to review the forecast process on slide 10. The information provided by operators enabled the department to find 15 additional under development/under evaluation projects to finish building the forecast. The forecasts used confidential information from operators, which could not be shared. He explained that major projects were not necessarily in existing fields with existing pools and a track record of production history; therefore, it was necessary to adjust them for scope and chance of occurrence with a range of start dates. He used Pikka as an example and explained that DNR used a start date range from 2025 to 2027.

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Mr. Peltier turned to slide 11 titled "Categories of Production: Ongoing/Current vs Future Production." The first category was current production (CP), which included ongoing production from existing fields. He detailed that any wells producing on or before June 30, 2023, were part of the current production category. The current production forecast considered expected well and facility uptime. Additionally, DNR verified that operators would continue to maintain base production and that reservoir management practices would be consistent through the forecast period to avoid major surprises in the current production forecasts.

Mr. Peltier reviewed the projects under development (UD) and projects under evaluation (UE) category on the bottom of slide 11. The category pertained to new production

projects requiring new investment including new wells on existing fields or new projects. He noted there was always uncertainty around how future wells would perform and about how many wells may get drilled (including both infill drilling and future projects) when looking at a 10-year timeframe. He explained that anything occurring within the next 12 months was considered under development and anything beyond that timeframe was under evaluation. For example, in January 2026 the Pikka project would move to the under development category, assuming the field was not already online and producing. He noted there was significant timing uncertainty associated with project timing. He highlighted economic and regulatory risks and remarked that some projects were canceled or continued to get deferred; therefore, DNR built in a risk profile for each individual project. The forecast included the summation of all projects and how it worked out materially.

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Mr. Peltier turned to slide 12 titled "Major Projects Under Evaluation (UE) Considered in Fall 2023 Forecast." The slide included a map of the project locations across the North Slope. He noted the slide included the large projects incorporated into the fall 2023 forecast. He highlighted that none of the projects were online by June 30, 2023, and none were expected to be online until at least 2025. He added that the projects on the slide had a higher risk factor than currently producing pools and a higher risk factor than for infill drilling. Additionally, the projects were known discoveries with identifiable operators that required major investments to bring online.

Mr. Peltier highlighted projects on the map moving west to east. He began with the Willow project operated by ConocoPhillips and located on federal land. Next was the Colville River Unit CD8 pad located on state land. Followed by a number of Santos operated projects targeting the Nanushuk Brookian age plays including Horseshoe Stirrup, Pikka, Pikka Phase 2, and Quokka/Mitquq. Adjacent to the Santos projects was the Mustang project, acquired by Finnex from Alaska Industrial Development and Export Authority (AIDEA) in December 2023. Next were the Nuna-Torok and MPU Raven Pad projects. Just south of Prudhoe Bay was the Theta West, Talitha, and Alkaid projects operated by Great Bear Pantheon. Next was the Liberty unit located on federal coastal land operated by Hilcorp. The two most eastern

projects were the Point Thomson expansion operated by Hilcorp and the Sourdough project operated by Jade Energy, both located in the Point Thomson Unit. He noted there were two projects included on the map the previous year that were not included on the present slide: Smith Bay and Umiat. He detailed that Smith Bay would have been far to the west and north offshore (the leases were highlighted in blue on the map on slide 12). The project would have required the developer to go through substantial federal acreage in some sensitive areas and DNR did not see a realistic option for getting the project online within a 10-year timeframe. The project continued to be on DNR's watchlist. Additionally, DNR had removed the Umiat project (indicated on the map by a green box just off of federal acreage on the south) from its forecast because it did not see a realistic way to get the project online within the next 10 years.

Representative Tomaszewski referenced Pikka Phase 1 that was projected to generate 80,000 barrels per day. He asked if Phase 2 was also projected to generate 80,000 barrels per day. He asked for verification that there were four phases. He asked about a timeframe on the second phase.

Mr. Peltier responded that he could not recall whether Pikka Phase 2 was projected to generate 40,000 or 80,000 barrels per day. He confirmed there were a number of phases. He deferred to a colleague for additional information.

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DEREK NOTTINGHAM, DIRECTOR, DIVISION OF OIL AND GAS, DEPARTMENT OF NATURAL RESOURCES, replied that the department could follow up with the information. He believed that the maximum volume from Pikka and its additional phases was roughly 120,000 barrels per day. The additional phases would come in and fill the facility capacity over time.

Representative Tomaszewski asked for verification that Mr. Nottingham thought the expected production was 120,000 barrels per day.

Mr. Nottingham confirmed he believed the number was around 120,000 barrels per day.

Mr. Peltier turned to slide 14 titled "Fall 2023: North Slope Annualized Forecast." He highlighted that DNR forecast FY 24 average annualized daily statewide production at 478,000 barrels of oil per day. The production forecast for the North Slope was 470,000 for FY 24. The low range was 422,000 barrels per day and the high range was 519,000 barrels per day. He explained that DNR's long-term forecast reliability was gauged by a general comparison between the DNR and operators' forecasts. He added that DNR built its forecasts from the bottom up and did not use the operators' forecasts. He elaborated that DNR finalized its forecast prior to looking at the operators' forecast. He remarked it was good to see relative consistency in FY 24 even with a blind approach on forecast development.

Mr. Peltier continued to review slide 14. He noted that DNR's forecast included projects [operators' forecasts did not], which accounted for the projected growth over time. The DNR forecast for North Slope production climbed towards 630,000 barrels of oil per day by year 10. He pointed out that DNR's forecast assumed that operators' plans and other project drivers remain unchanged. He explained that if there was a major change in investment on the North Slope - positive or negative - it could yield a dramatically different forecast.

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Mr. Peltier turned to slide 15 titled "Fall 2023: AK Statewide Annualized Forecast (Expected Case with Production Categories)." The chart on the left showed the fall 2023 production forecast for all production categories. The blue portion of the chart reflected currently producing wells as of June 30, 2023. The orange portion of the chart reflected the next 12 months of expected infill drilling and showed the benefit within existing fields including Prudhoe Bay, KRU, and CRU. He noted the substantial development within the existing fields. The grey portion of the slide reflected projects under evaluation: any capital in the 13+ month timeframe over the next 10 years.

Mr. Peltier answered an earlier question by Co-Chair Johnson about the [production] difference in 2024. He stated that the spring 2023 forecast included 10 years of data beginning in FY 23 and the chart naturally cut off in

FY 32, which was the reason for the difference. He elaborated that in FY 24, the difference was about 20,000 barrels of oil per day. He highlighted that one of the big differences was that last year, the NPRA production area forecast had a difference of about 15,000 barrels of oil per day in 2024. He explained that the difference came from DNR's expectations of how the NPRA would produce versus how it did produce. He expounded that it was a relatively new field with new formations being targeted; therefore, DNR did not necessarily have a good track record on how the areas would perform. He noted that unfortunately production had come in significantly below DNR's expectations. He noted the gap was reflected in the difference between the prior year's forecast and the forecast for the current year.

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Co-Chair Johnson looked at FY 25 and FY 26 and observed there continued to be a gap.

Mr. Peltier agreed and explained it was cumulative.

Co-Chair Johnson asked if it was a similar situation.

Mr. Peltier agreed. He elaborated that the production in question pertained to the NPRA area. He stated that it had not met expectations for the current year and would not start meeting expectations in future years.

Co-Chair Johnson remarked that 20,000 barrels per day did not seem that substantial, but when talking about the budget, it was substantial over time.

Mr. Peltier pointed out that there was a higher chance of occurrence for a number of projects. He detailed that there was more confidence around Willow because legal uncertainties had been diminished. Additionally, there was more confidence associated with the Pikka Phase 2 and Quokka projects operated by Santos. He highlighted that at the end of the forecast period there was increased production in total even compared to the spring of 2023. The last datapoint for the spring 2023 forecast had about 543,000 barrels of oil per day, whereas the current forecast for the same datapoint was 609,000 (a difference of about 66,000 barrels per day). He noted that the

forecast built to the 633,000 barrels of oil per day expectation in FY 33.

Mr. Peltier pointed to the chart on the right of slide 15 showing the importance of the new capital coming into the state. The chart ranged from zero to 700,000 barrels of oil per day and showed how material the new production was from the various 15 projects highlighted on previous slides to the State of Alaska and the North Slope.

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Mr. Peltier provided a fall 2023 production forecast summary on slide 16. He relayed that DNR did the best it could to forecast using the best information available to DNR and DOR. The department generated the production outlooks twice a year - in the fall and spring - and did its best to get the most up to date information from operators. The department used the State of Alaska's official updated price outlook at the time it made the forecast. The goal was to generate an accurate near-term and realistic long-term forecast. The department's fall 2023 outlook showed near-term production at around 480,000 to 500,000 barrels of oil per day in the first few years, increasing towards 630,000 barrels of oil per day towards the end of the 10-year outlook. He relayed that production estimates from projects under evaluation accounted for several technical and commercial factors and project execution risks to account for uncertainty on individual project production delivery.

Mr. Peltier relayed that the DNR team worked hard every year to deliver a robust production forecast. On behalf of the team, he expressed gratitude for the opportunity to present the forecast to the committee.

Representative Ortiz asked whether the department had looked back to 2013 to see what its forecast had been for 2023. He wondered whether the department had been able to determine whether its forecasting was improving or remaining static. He asked if there were too many variables to make a valuable comparison.

[2:51:00 PM](#)

Mr. Peltier could not tell the committee about 2013 specifically because his team had taken over the process in

2016. He relayed that the forecast had been within the plus or minus 5 percent every year since then. He deferred to a colleague for additional information.

JOHN CROWTHER, DEPUTY COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, replied that in the 2016 timeframe, DNR brought the function in-house for efficiency to save money and apply some processes DNR believed to be more conservative and appropriate. The department would be happy to do a comparison chart of what the 2013 forecast showed compared to the present. He thought it was illustrative about some of the new developments and how they had progressed over the past 10 years. He added that DNR was trying to learn from its past efforts and at times mistakes.

Representative Ortiz asked if the production forecast was conducted by DOR or another party prior to 2016.

Mr. Peltier replied he was under the impression it was a private contractor.

Co-Chair Johnson thanked the presenters and reviewed the schedule for the following day.

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ADJOURNMENT

2:53:25 PM

The meeting was adjourned at 2:53 p.m.