

ALASKA STATE LEGISLATURE
SENATE RESOURCES STANDING COMMITTEE

January 30, 2017

3:30 p.m.

MEMBERS PRESENT

Senator Cathy Giessel, Chair
Senator John Coghill, Vice Chair
Senator Natasha von Imhof
Senator Bert Stedman
Senator Shelley Hughes
Senator Kevin Meyer
Senator Bill Wielechowski

MEMBERS ABSENT

All members present

COMMITTEE CALENDAR

OIL PRODUCTION FORECAST METHODOLOGY OVERVIEW

- HEARD

SENATE BILL NO. 30

"An Act approving and ratifying the sale of royalty oil by the State of Alaska to Petro Star Inc.; and providing for an effective date."

- MOVED SB 30 OUT OF COMMITTEE

PREVIOUS COMMITTEE ACTION

BILL: SB 30

SHORT TITLE: APPROVAL: ROYALTY OIL SALE TO PETRO STAR

SPONSOR(S): RULES BY REQUEST OF THE GOVERNOR

01/20/17	(S)	READ THE FIRST TIME - REFERRALS
01/20/17	(S)	RES, FIN
01/30/17	(S)	RES AT 3:30 PM BUTROVICH 205

WITNESS REGISTER

JIM SHINE, Commercial Manager
Division of Oil and Gas

Department of Natural Resources (DNR)

Alaska Department of Natural Resources (DNR)

POSITION STATEMENT: Provided overview in support of SB 30.

ED KING, Special Assistant to the Commissioner

Alaska Department of Natural Resources (DNR)

POSITION STATEMENT: Commented supportively on SB 30 and helped provide an overview of the oil production forecast methodology.

DOUG CHAPADOS, President & CEO

Petro Star, Inc.

Anchorage, Alaska

POSITION STATEMENT: Supported SB 30.

DAN STICKEL, Chief Economist

Economic Research Group

Alaska Department of Revenue (DOR)

POSITION STATEMENT: Provided an overview of the oil production forecast methodology.

PAUL DECKER, Petroleum Geologist and Manager

Resource Evaluation Section

Division of Oil and Gas

Alaska Department of Natural Resources (DNR)

Anchorage, Alaska

POSITION STATEMENT: Provided an overview of the oil production forecast methodology.

ACTION NARRATIVE

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CHAIR CATHY GIESSEL called the Senate Resources Standing Committee meeting to order at 3:30 p.m. Present at the call to order were Senators Stedman, von Imhof, Hughes, Meyer, Wielechowski, and Chair Giessel.

SB 30-APPROVAL: ROYALTY OIL SALE TO PETRO STAR

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CHAIR GIESSEL announced SB 30 to be up for consideration. She said this bill cannot be amended since it is ratifying a contract for royalty oil between the Alaska Department of Natural Resources (DNR) and Petro Star. Last year this body considered and ratified the contract between the Alaska Department of Natural Resources and Tesoro. She explained that Alaska's Constitution mandates developing the resources for the maximum benefit of the people of Alaska and when the state takes

its royalty oil in kind (RIK) it needs to prove that it is getting more money than it otherwise would taking royalty in the traditional means of in value (RIV).

JIM SHINE, Commercial Manager, Division of Oil and Gas, Department of Natural Resources (DNR), Alaska Department of Natural Resources (DNR), said he would first provide a brief overview on the contract ratification process and then review the contract.

ED KING, Special Assistant to the Commissioner, Alaska Department of Natural Resources (DNR), introduced himself.

MR. SHINE noted that DNR Deputy Commissioner Mark Wiggin was available on line as well as other members of the Commercial Team who were involved in the negotiation with Petro Star.

He explained that when the state takes royalty it has a choice to receive it in kind (RIK) - physical possession - or in value (RIV). When it elects to receive its royalty in value, the producers ship, co-mingle, and sell the state's royalty share with theirs and remits the state's value to it by way of a check. When the state elects to receive RIK, the state assumes ownership over the actual oil and the DNR Commissioner disposes of it through sale procedures described in statute. The state has regularly sold RIK to in-state refiners dating back to 1979 with Mapco/Williams.

The contract that is before them in SB 30 for ratification has gone through a thorough public review; the preliminary best interest finding (BIF) was out for a 30-day public comment and no comments were received. A revised BIF was presented to the Royalty Oil and Gas Development Advisory Board (Royalty Board) in August and it considered the contract, the presentation, and the BIF and recommended unanimously that the legislature approve it.

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MR. SHINE clarified that there are two contracts, and the one that is currently in place is a one-year contract commencing on January 2017 for the sale of royalty oil to Petro Star, which does not require legislative approval. Following the termination of that contract starting in January 2018, the four-year contract in SB 30 would commence. The state will receive a combined benefit from the two contracts of \$29 - \$37 million more than if it had received the same barrels over those five years in value.

SENATOR COGHILL joined the committee.

CHAIR GIESSEL asked who is on the Royalty Board.

MR. SHINE replied that the Royalty Board consists of eight members: three commissioners from the Department of Natural Resources (DNR) who is a non-voting member, the Department of Revenue (DOR), and the Department of Commerce, Community and Economic Development (DCCED), as well as five public members: Bruce Anders (Chair), Dana Pruhs, Kathryn Dodge, Lawrence Gaffaney, and Steve Selvaggio.

SENATOR WIELECHOWSKI asked if the lower tariffs are factored into the \$29 - 37 million in savings from the increased production in the pipeline that would result in more revenue to the state.

MR. SHINE replied the \$27 - \$37 million figure is spelled out in the BIF. The real benefit is the difference between the marine transportation deduction, which is present in the RIV net back formula versus RIK net back, which is an in-state location differential, which he would describe later.

SENATOR WIELECHOWSKI asked again if that savings figure takes into account the lower tariff that would result in slightly higher taxes to the state.

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MR. SHINE answered that both RIK and RIV formulas have a tariff reduction as part of the net back formula. If the royalty volumes are coming from Prudhoe Bay, the tariff is from Pump Station 1 to the Valdez Marine Terminal. Tariffs from any fields upstream of Prudhoe Bay would include transportation to that point.

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However, before taking RIK the commissioner must find it is in the state's best interest. The state can dispose of its RIK through a competitive bid process or a non-competitive, negotiated sale process. The DNR issued a solicitation of interest in January 2015 to five refineries - Petro Star, Tesoro, Flint Hills, BP, and ConocoPhillips - within the state to determine market interest in purchasing the state's royalty barrels. The two responses it received were from Tesoro and Petro Star, and last year the Tesoro negotiated sale contract

was ratified. This year the Petro Star negotiated sale contract is before them.

Based on the responses, it was determined that there was not enough competition for a competitive sale, Mr. Shine said, and while Tesoro agreed immediately to the price terms in the solicitation, Petro Star was seeking a different pricing mechanism that is not as advantageous to the state. At that point the DNR commissioner determined that a competitive bid sale was not in the state's interest and entered into separate negotiated sales.

The first contract in effect right now is less than one year in length to relieve market conditions and allow Petro Star to secure its feed stock for refineries in Valdez and North Pole in the near term while also negotiating a long term contract to provide a secure source of supply for the refineries over the next four years.

He explained the reason for having both contracts terminate near the same time in 2021 is because at that point the department will have a better sense of what royalty volumes are available. Historically, the state has been able to enter into 10-year RIK sale contracts, but with declining throughput and uncertainty of what volumes would be available, it's been determined that five year contracts are more accurate at this point.

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MR. SHINE said AS 38.05.183(e) states that the commissioner must sell the state's royalty oil to the buyer who offers "maximum benefits to the citizens of the state," and in making this determination, the commissioner must consider:

1. The cash value offered,
2. The projected effects of the sale on the economy of the state,
3. The projected benefits of refining or processing the oil in state,
4. The ability of the prospective buyer to provide refined products for distribution and sale in the state with price or supply benefits to the citizens of the state, and
5. The eight criteria listed in AS 38.06.070(a), as reviewed by the Royalty Board.

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For approval of an RIK sale the DNR must make a Best Interest Finding (BIF) in support of the sale. In this case, the

preliminary BIF was issued in July 2016 and the final was issued in September 2016. DNR presented the proposed sale to the Royalty Board on August 31, 2016, and it unanimously voted in Resolution 2016-2 that the proposed disposition of ANS royalty oil to Petro Star meets the requirements of AS 38.06.070. Prior to finalizing the RIK contract, the legislature must pass a bill ratifying the contract with Petro Star (HB 70; SB 30).

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The Royalty Board's decision criteria was listed on slide 6. Slide 7 had the actual contract terms:

1-year contract:

from 18,800 bpd to 23,500 bpd for Jan. 2017 -Dec. 2017

4-year contract:

from 16,400 bpd to 20,500 bpd for Jan. 2018 -Dec. 2018

from 13,200 bpd to 16,500 bpd for Jan. 2019 -Dec. 2019

from 10,800 bpd to 13,500 bpd for Jan. 2020 -Dec. 2020

from 8,400 bpd to 10,500 bpd for Jan. 2021 -Dec. 2021

MR. SHINE explained that the range is a minimum nomination per day and the high number would be the maximum. The numbers decline over the next five years, whereas the Tesoro contract last year had a static number of 20,000-25,000 barrels per day.

The Petro Star contract is meant to give them as much royalty volume as the state can project to not exceed in the next four years. Typically they don't nominate more than 95 percent of expected royalty volumes and so the Tesoro contract combined with the Petro Star contract is about 95 percent of expected royalty volumes under contract to local refiners within the state.

The net back formula provides a higher revenue to the state over RIV that uses a marine transportation deduction, which is basically the price to ship a barrel of oil from Valdez to its destination on the West Coast. The in-state location differential is a deduction in the net back formula meant to represent the cost of a barrel of oil within the state.

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MR. SHINE explained that the flexibility of quantity provides for a three-month consecutive turnaround clause in which either refinery may nominate below its minimum range for planned service interruptions for factory upgrades, de-bottlenecking, and efficiencies, which is customary in the refining and the upstream oil and gas industry. The reason the state doesn't want

to keep 5 percent of expected royalty oil is to keep markers on what the marine transportation deductions are and what the net back formulas look like to ensure the department is meeting its statutory mandate to meet or exceed royalty in value when the it elects to sell the state's royalty in kind. If more royalty is available than projected, additional volumes will be offered to both Petro Star and Tesoro on equal terms consistent with the pricing mechanisms in each contract.

He said that Petro Star has filed a \$46 million surety bond with the state as provided in the one-year contract in the event an in-state refiner or royalty purchaser defaults (or denominates) on its obligations to pay the state for royalty already delivered. Both contracts encourage commercially reasonable efforts to manufacture refined products within the state and promote local hire of Alaska residents and contractors. All communications with Petro Star have indicated that they have no intent to do anything but refine the products within the state for local use as jet fuel, home heating fuel, and ultra-low sulphur diesel, to name a few.

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MR. SHINE said the RIK net back formula is: ANS Spot Price - \$1.95 -Tariff Allowance +/-Quality Bank Adjustments -Line Loss.

He explained that the ANS spot price is a monthly average of the daily average of the two reporting agencies, Platts and Reuters. The in-state location differential is deducted from that \$1.95 as well as the TAPS and upstream tariffs to Pump Station 1. Then there are Quality Bank adjustments and a small percentage of line loss. Line loss is a .09 percent, industry-standard deduction from net back formulas that is meant to represent small differences in measurement between meters upstream and downstream as well as any loss in product due to evaporation, friction, ice build-up, or paraffin as is the case in the TransAlaska Pipeline System (TAPS).

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SENATOR WIELECHOWSKI said if you take 20,000 barrels out of TAPS he understands that the tariff will go up slightly for everyone else who put oil in the pipeline. Then that in turn is able to be deducted from the production taxes that are paid to the State of Alaska, which ultimately causes a small loss for the state. He asked if that is factored into this.

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ED KING, Special Assistant, Alaska Department of Natural Resources (DNR) answered that the oil that is being delivered to Tesoro is presumed to have already been produced and shipped through TAPS through the Petro Star refinery, so it would already be calculated into the tariff calculation. If the state weren't selling oil to Tesoro the assumption is that they would be purchasing the same volumes of oil from someone else and it wouldn't have any net effect.

SENATOR WIELECHOWSKI said that didn't answer his question, but they could discuss it afterwards.

SENATOR COGHILL asked who puts the calculation together and what value that adjustment means at the end of the line.

MR. SHINE answered that the Quality Bank administrator makes those determinations, which is meant to measure the difference in value of the oil streams into the co-mingle point and the stream of oil coming out in Valdez. So, adjustments are made to those entities who are contributing a lower quality of oil that result in a benefit to the upstream producer who has a higher quality product. Those adjustments can be made as far back as eight years in this contract when the Quality Bank administrator or FERC makes a determination.

SENATOR COGHILL said that is interesting, because this contract has a huge variable.

MR. SHINE said that is the reason for the eight-year tail in the contract. Even though it is a five-year contract having that tail move out eight years provides the state with a little bit more certainty that if adjustments were made that they would benefit the state, too.

MR. KING noted that the Quality Bank adjustment is also in existence if they were to take RIV as well as RIK. So this contract has no actual effect on the value in that regard.

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MR. SHINE continued that the contract will yield \$29 - \$37 million in additional revenue to the state over what it would have received taking the same barrels in value. The real benefit between RIV and RIK is really realized in the in-state location differential and the RIK net back formula as opposed to the marine transportation deduction, which is present in the RIV net back formula. The marine transportation deduction for FY17 is somewhere in the \$3.30-\$3.40/barrel range and is expected to

move up by about 10 cents per year until 2021 when it will be about \$3.70/barrel. The static \$1.95 RIK differential in the current contract as well as the Tesoro contract is where the state is getting the most benefit from the sale of royalty over RIV.

The value realized by the different contracts is:

1-year contract (Jan. -Dec. 2017): from \$7.6 to \$9.5 million

4-year contract (Jan. 2018 -Dec. 2021): from \$22.3 to \$27.9 million

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He explained that some of the criteria that the commissioner and the Royalty Board consider are the impacts to local economies and local hire; and Petro Star provides benefits to the state in terms of employment, its in-state refining capabilities, as well as providing ultra-low sulphur diesel, jet fuel, and asphalt to local economies. He presented a comparison of the volumes of the two contracts on slide 10 and said he was available to answer questions.

CHAIR GIESSEL asked if he had any objections to this contract.

MR. SHINE answered no and no public comments were received; no adverse comments were presented at the Royalty Board.

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DOUG CHAPADOS, President & CEO, Petro Star, Inc., Anchorage, Alaska, thanked the DNR Division of Oil and Gas for their efforts and past and present commissioners for the work they had done in getting this contract in place. These are critically important contracts for their company, because without oil they are out of business. With the decline of TAPS throughput they have found it more and more difficult to source crude oil from producers on the North Slope. Being a consistent source of crude in the future, the state has brought Petro Star back and they look forward to refining this oil and making products for Alaska consumers.

SENATOR COGHILL commented that the investment Petro Star had made was immediately beneficial to the North Pole area and he is very grateful.

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SENATOR MEYER asked if it matters to him or the refinery if the oil is heavy or light, or what the gravity or sulphur rate is.

MR. CHAPADOS said they like to see higher quality crude oil and Petro Star refineries are designed to process a barrel of crude in a very simple way. They like to see lots of middle distillate materials in the crude: kerosene, jet fuel, and diesel fuels. That allows them to retain more from each barrel they process. Typically they retain 25-30 percent of each barrel that they process and the balance is returned back to the pipeline. That is where this Quality Bank liability is generated, because the oil they return is considered to be of lower quality than the balance of the oil that is being shipped through TAPS. Crude from the Alpine Field is an example of a lighter crude oil that has a high concentration of jet fuel range material in it.

SENATOR MEYER asked if he gets to choose which oil he gets.

MR. CHAPADOS answered he wished he could, but they are subject to whatever is being shipped through TAPS, which is a co-mingled stream from all the fields. Over time the quality of the oil increases and decreases; it's at a good point now between those that are coming on line and those that are declining.

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SENATOR MEYER said he had heard that pipeline oil is becoming heavier, so it is encouraging to hear that CD-5 and the Willow discovery have high gravity rates.

MR. CHAPADOS responded that he believes that the new fields are of reasonably good quality.

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MR. CHAPADOS said Senator Wielechowski questioned whether or not the sale of this royalty oil to Petro Star would increase the tariff rates for the remaining barrels that are being shipped through TAPS, and the very quick and simple answer is no. He explained that prior to the state royalty oil contracts, Petro Star was buying oil from another North Slope producer. Those barrels were being shipped through TAPS just as these barrels will be. So, at the end of the day, it's really a zero net gain in terms of how many barrels are being shipped through TAPS and where it's being shipped to.

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CHAIR GIESSEL opened public testimony, and finding none, closed it.

SENATOR COGHILL moved to report SB 30, labeled 30-GS1873\A, from committee with individual recommendations and attached fiscal note(s). There were no objections and it was so ordered.

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At ease

Oil Production Forecast Methodology Overview

[4:05:32 PM](#)

CHAIR GIESSEL called the meeting back to order and announced an overview of the oil production forecast methodology. Before them is the fall forecast and explained that the Revenue Sources Book is like a paper version of the state's accounts and check book telling them how much money is coming in to pay for government. For petroleum the state forecasts the price of oil and the production each year. These two inputs form a calculation upon which the budget is based. It is a forecast and some would say a guess, but it is based on a scientific method, but it's not infallible. Over the last 10 years this calculation methodology has changed in an effort to more accurately predict the trends of the state's oil field activities, and it is in the interest of the members of this committee and the legislature to understand this methodology, its terms and the changes made to it. She invited Mr. Stickel who will explain how it works in the context of the Revenue Sources Book.

DAN STICKEL, Chief Economist, Economic Research Group, Alaska Department of Revenue (DOR), said he would talk about how the production forecast is used, some of the recent history of the production forecasting process, and what the roles of the Department of Revenue (DOR) and Department of Natural Resources (DNR) were in this year's production forecast. He would also present the forecast overview and then hand it over to DNR for more of the technical discussion.

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MR. STICKEL said the production forecast is one of the key inputs into the revenue forecast along with oil price and cost of production - into the production tax and royalty forecast, in particular, but also to a lesser extent to the property tax and corporate income tax forecast. This is important because petroleum revenue provided 72 percent of unrestricted state revenue in FY16 and is forecast to provide about 70 percent of unrestricted revenue over the next decade. The production forecast is also a key source of information the department provides to policy makers, industry, and the public.

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MR. STICKEL said for the last 30 years the DOR has hired an outside consultant to produce its production forecast, and that was the case through 2016. However, realizing that DOR forecasts were being over-optimistic a risk factor was added in the fall 2012 that basically included only a portion of expected production from new fields. So, a lot of the work the DNR has done this year built on adding uncertainty to the forecast. In fall 2016, the over \$100,000/year consultant contract had expired and the department decided not to renew it and to use in-house expertise instead.

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In hopes of providing better information to policy makers, the department began applying risk factors in 2012 to new oil and new fields that only incorporated a portion of that expected production into the revenue forecast. And from fall 2012 to 2015 the actual production came in a lot closer to their forecast.

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The chart on slide 7 adds the fall 2016 forecast to the previous two charts. For the next several years the fall 2016 forecast is in the range of where the production forecast has been recently but slightly higher in the out years, which has to do with a change in the risking methodology (moving from a single risk factor to evaluating risk on a project-specific basis).

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The chart on slide 8 addresses what the roles of DOR and DNR are in the forecast process. DNR has done everything that the consultant previously did for the DOR. They review the production surveys and plans of development that come in from the companies and create the forecasting model. And they deliver to DOR a forecast of barrels of oil per day pool-by-pool. One key difference this year is that that forecast was done probabilistically, which allows them to look at a range of possible production levels and outcomes for each field as opposed to the previous consultant's forecast that just delivered a one-point estimate for oil production.

The DOR actually publishes the forecast and creates a revenue forecast out of it. They conduct the surveys and interviews with the oil companies and find out what their plans are and update the DOR tax database system that goes back to DNR as one of their inputs for their forecast. A high level view of the production forecast is in the fall 2016 Revenue Sources Book.

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CHAIR GIESSEL asked if the consultant was one person.

MR. STICKEL answered yes; he was Frank Molly, an engineer out of Colorado, who had developed proprietary production forecasting software.

CHAIR GIESSEL asked what kinds of things his software took into account that differ from DOR's.

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MR. STICKEL replied that his forecasting methodology had several differences that a DNR slide compared side-by-side. He explained that the first slide was the familiar production mountain chart showing North Slope peak production in 1988 at about 2 million barrels a day. Since then with a couple small exceptions, the first being the start of Alpine in the early 2000s and the second being last year, production has been on a downward trend. Last week it averaged about 560,000 barrels per day. Their forecast anticipates modest 4 percent declines through the next decade with the majority of oil still coming from the major fields of Prudhoe Bay, Kuparuk and Coleville River Units.

In putting the production forecast together, Mr. Stickel explained that the DOR looks at production in four different categories: currently producing (CP) (including an assumption for some background drilling work), volumes under development (UD) (any new fields expected to come on line within the next year as well as any work in the existing fields above and beyond the baseline level of development). An example in the current forecast category is the continued build out of CD-5 in the Coleville River Unit. Then there is the under evaluation (UE) category (new fields expected to produce within 2 - 5 years); some examples are additional developments at Oooguruk and Kuparuk, Mustang, and Greater Moose's Tooth Unit in the NPR-A). Anything that doesn't fall into those three categories falls within the fourth category (oil with an expected start date of five years or greater or with different types of uncertainty regarding financing, permitting, economics or resource definition); some examples are Pikka, Smith Bay, and Willow. The official forecast is the sum of those categories. However 90 percent is in the currently producing category, a few are under development (about 5,000 barrels a day in 2018), and about 30,000 barrels a day are under evaluation oil.

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In developing the fall 2016 forecast model, Mr. Stickel said DNR used a "probabilistic analysis," which allows them to examine a range of possible values. In addition to giving DOR a baseline official forecast they also give them a high case (P-10), which means they believe based on the given activity set in the forecast there is a 10 percent chance that oil production will come in at that level or higher. They also give them a low-case (P-90) forecast, which means there's a 90 percent chance that oil production will come in at that level or higher. These cases are based on those fields included in the forecast and don't include the new fields.

[4:19:11 PM](#)

Another chart shows what the official, low, and high case look like for the fall forecast. The official one has oil production declining to about 331,000 barrels per day by 2026; the P-10 and P-90 range is plus or minus 40,000 barrels a day.

Slide 15 is the same information in table format and comes from page 37 of the Revenue Sources Book. In addition to providing the raw numbers behind that chart, it also provides an estimate of that production that qualifies for the gross value reduction (GVR), which is an incentive under the production tax law for qualifying new oil. He noticed that the GVR-eligible oil goes to zero by the end of the forecast as it changed from the previous book, the reason being HB 247 passed in the last legislature and it implemented phasing-out oil qualifying for that provision.

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The chart on slide 16 was a comparison of the fall 2016 forecast to the previous spring 2016 forecast, the last forecast produced by the previous consultant, reduces production a little bit for the next several years. The reasons are reduced drilling in the company plans of development, as well as reduction in company spending. Getting into the long-term 2024 and beyond, the production forecast is actually a little bit higher than the previous forecast.

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On a final note, DOR made a seasonal adjustment to the current year production forecast from information DNR provided. The department's revenue models are on a monthly basis. So, they created a seasonally adjusted forecast by taking the total DNR production forecasted for FY17 and allocated that out among the months in the fiscal year based on what seasonality has looked like for the last several years. When that was done there was no change to the total numbers in their forecast. In addition, when

they put their revenue forecast together in September and October they actually had two more months of actual data, which brought the forecast up a little bit.

CHAIR GIESSEL asked if the consultant would have taken the Willow and Pikka discoveries into account.

MR. STICKEL replied that they would have left them out, because the Willow announcement came out after the forecast was completed. Pikka was left out of the spring forecast because at the time it didn't meet the level of certainty needed to be included in the forecast yet. Both will be evaluated for the next forecast.

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SENATOR MEYER said one of the frustrations they must have in trying to predict future production is the permitting process that could take many years, especially at the federal level, and asked if that is why they have a high and a low case scenario. He gave the ConocoPhillips CD-5 project as an example.

MR. STICKEL said he would let DNR speak to how that uncertainty is incorporated into the forecast, but permitting has contributed to some of the over-forecasting in years past with CD-5 being a great example.

SENATOR MEYER remarked that President Trump has indicated that he hopes to expedite permits and eliminate some regulations, so maybe it will get better.

CHAIR GIESSEL thanked them and invited the next presenters to come forward.

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PAUL DECKER, Petroleum Geologist and Manager, Resource Evaluation Section, Division of Oil and Gas, Alaska Department of Natural Resources (DNR), said several members of his section worked alongside Jim Shine and his section to generate the forecast.

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ED KING, Special Assistant to the Commissioner, Alaska Department of Natural Resources (DNR), said prior to this job he worked with the commercial group in the Division of Oil and Gas. Prior to that in 2012/13 he was a petroleum economist with the DOR; his primary task was to work on the production forecast.

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MR. KING said DNR took over the production forecasting assignment this year and that he kept his DOR relationship very close. Now production forecasts are done in-house by DNR independent of all prior forecasts. This is the first time it has been done exclusively by the department. They didn't take last year's forecast and make adjustments to it; they actually took data and generated a new independent forecast, the goal being to make the most accurate forecast that they could. In reviewing some of the historical forecasts that had been made and his experience with the process, he made a couple of adjustments. They also wanted to make sure that their methodology is scientifically rigorous as it could be - data driven, empirical, and defensible. They do not believe the forecast is conservative and there was no intent to be; it is realistic and it is based in real data.

4:28:06 PM

MR. KING acknowledged that there is a difference between their forecast and the last one. There is lower production once the available information was put in. A lot of the lower production level is being driven by the producers' reduced plans of operations (a change in behavior as opposed to methodology). They also acknowledge a cross-over point that is a by-product of the change in methodology. Whereas the previous method used increasing and escalating decline rates to get rid of new production, he used a probabilistic approach, which spreads the barrels out instead of removing them from the forecast. So, in future years one sees less of a penalty on the risking method that was previously adopted.

CHAIR GIESSEL said in 2016 there were over 500,000 barrels of production a day and asked why he is starting FY18 so precipitously below that.

MR. KING answered to begin with, FY18 will begin in this coming summer, but they do have six months of production for FY17, which isn't quite on this graph, but on the next one which gets to her point that current production is actually higher than the forecast. And while the department is really excited about that, it doesn't want to be overly optimistic because of the fact that turnarounds still have to happen in the summertime, maintenance is going to take production off-line, and the last year or two have had less investment after the price of oil fell. They do expect that oil production is going to decrease and that the flattening will not continue.

He also pointed out that the production forecast is due to the DOR by October, which means DNR instigated the production forecasting process in August and the last data they had for it was from June. The data that was used to develop the 2017 forecast didn't use any data after June of 2016. This was because data needs to be static in order to do the production forecast, and if they were continuing to update the forecast, it would be like starting over every month. June 30, 2016, was the data cutoff and then the forecast was released. They now have seven more months of data, and it does look promising.

SENATOR STEDMAN asked what the final date was for actual figures used in the spring forecast.

MR. KING answered that they are currently in discussions with the DOR on how the spring forecast is going to look, but historically the consultant has not instituted another forecast well-by-well using new data. He replaced the forecast data from June through March with actual data and that is the process DNR will probably use this spring. The next fall forecast will take into account the new data that does exist as well as the new discoveries that have recently been announced.

He also pointed out that the 10,000-or-so barrels in excess of the 2017 forecast amount to \$20-30 million more to the state.

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MR. KING hit the highlights again saying they developed a new forecast methodology that is an improvement over the change in methodology that happened in 2012 when the risk concept was introduced. It uses probabilistic approaches, which honor the uncertainty, as well, that result in a range of future scenarios rather than just one. He also pointed out that the 10-year forecast is about a 4 percent decline and historically the decline on the North Slope has been about 5.5 percent. It's not conservative. Rather by employing this probabilistic approach, the DOR can run different scenarios through its model and generate different revenue scenarios to get a range of possible outcomes in terms of revenue rather than just a one-point estimate.

Finally, the price dependency in the forecast is very important as an improvement to the process as the distribution around the forecast can be used to inform DNR's model of how production will respond to the price environment it is projecting. That has never been done in the past.

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In 2012, Mr. King said, when he was at the DOR, one of his first tasks in doing production forecasting was looking at the history of how things had been done in the past. The chart on slide 8 caught his eye as something that needed to be fixed. Said the production forecasts back in the early 2000s were overly optimistic as the decline rates are really flat, but year after year as production forecasts were updated the laws of physics took precedence over that optimism. That is not the way super giant oil fields produce; they tend to decline.

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Using a shooting analogy on slide 9 he explained the first column on the left represents all of the forecasts one year into the future and the "shot group" or the cluster of data is pretty good, which means there is not a lot of volatility or deviation; it's also fairly close to target. Moving to the right one sees years forward or a farther-out target, and when you're shooting at a farther target it's a lot harder to get consistency. Part of that is because more variables are involved (price of oil changes and permitting issues), but it also might be an opportunity to improve the technique (breathing technique in shooting, continuing the analogy). Their goal was to both to make the aim more accurate and to fix their technique.

SENATOR GIESSEL said that was a pretty logical conclusion, but she still questioned his December forecast that used actual data up to June 2016 that is pretty far-off already.

MR. KING replied even though it appears to be a fairly sizeable deviation, in reality it is only about 2 percentage points off, which is pretty good for forecasting. They used all of the available data and tried not to use any subjectivity.

MR. DECKER pointed out that their forecast did not attempt to quantify seasonality effects. The cause of the deviation on slide 5 is because of the production increases in the winter months.

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CHAIR GIESSEL said she appreciated those variables.

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MR. KING explained that a lot of what they are seeing over the last year and into the beginning of this fiscal year is the result of investment that happened in 2013/14 in Shark Tooth, Kuparuk, and CD-5, and Point Thompson came on line. Also,

maintenance issues happened in Prudhoe Bay the prior year that didn't have to happen this summer, and those fixes actually were very productive. What is being seen now is the result of investment that occurred before the price of oil fell by half. Since then, investment level has not kept on par, and in the next coming months and years reduced production will be the result of this lack of investment. It might happen as soon as this summer. He said their 2017 forecast was based on the full fiscal year of 2016 without using any actual production months of fiscal year 2017. Moving forward through the rest of this fiscal year, the expected annual average of 550,000 barrels probably won't be met.

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CHAIR GIESSEL said the previous methodology included a gathering of experts and producers who provided them information on investments being made. She asked how much of that was confidential and included in this forecast and to what extent that process was followed this year.

MR. KING replied that DOR was allowed to continue their past process by which they met with the producers and asked them specific questions about their investments. They then shared what they could of that information that wasn't confidential with DNR. Their forecast used as much publicly available data as possible including the plans of development provided by the operators and Alaska Oil and Gas Conservation Commission (AOGCC)'s data for actual production rates, very similar to the way DOR's consultant had done in the past (using his own subjective assessments). After talking to Mr. Molly, the consultant, DOR would talk to the producers and ask clarifying questions. That introduced a degree of subjectivity which the state wanted to remove. So, the operator's information was definitely considered, but they didn't rely on it.

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He said the very glaring reality is that looking into the future of a development that is meant to come into production five or more years into the future almost always resulted in some form of delay. For example, in 1997 Liberty was supposed to come on line in 2002, but that production still has not occurred, and that field has entered into and out of the forecast many times over the last 20 or 30 years. For that reason, because so many things can change, they elected not to include anything that wasn't anticipated to come into production within the five-year window. It is considered imprudent to include that kind of

development into the revenue forecast right now until it's more certain.

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In 2012, the DOR started introducing some risk factors, thus reducing some production from future developments, and if a development was forecast to come into production five years from now at 100,000 barrels, the DNR would hit it with a risk factor and then only include a portion of those barrels in the forecast. This was an improvement over prior methods that didn't use any risking whatsoever.

MR. KING said he uses this technique because it is quick, but it is not considered the best practice in risk management and the department wants to move to a Monte Carlo simulation stochastic approach this year. That method will continue to evolve as they forecast method gets back-tested.

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MR. DECKER continued the presentation (slide 15) and started with the 2016 method that had three tranches of production: currently producing, under development, and under evaluation. The important take-away being that this new forecasting methodology adjusted the time frame and the criteria for inclusion or exclusion in the various categories, in particular in the under development and the under evaluation categories.

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He said slide 16 was a table comparing the current methodology to some of the previous consultants' methodologies. The two most impactful things are at the top of the chart:

- limiting the inclusion to the first oil window from 10 years to 1 year;
- shortening the under evaluation tranche from 10 years to the 5-year outlook (anything expected beyond five years out has been excluded).

There is uncertainty throughout the process and a probabilistic method was developed so that Monte Carlo simulations based on the ranges of many of the variables could be used. That is a big change, because things in the past were deterministic: basically scenarios or single-point estimates. Oil price dependency was also incorporated, so as the model is run projects are weighed against the break-even price versus the DOR's price forecast. If a project was under water, then it wouldn't be brought into the forecast.

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In general, Mr. Decker said, they have tried to apply probabilistic risking throughout even to the currently producing tranche, so the decline-based analysis has a probabilistic range associated with it rather than a single slope of decline. They also applied probabilistic pool-by-pool type wells to represent new production that can be added in as they come in, making sure that the well's type was appropriate to that pool, and also gave them a range. Finally, the forecast level uses mostly the currently producing/decline analysis and that was done on a pool-by-pool level as opposed to a well-by-well level, another distinction, although not the most impactful one.

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He recapped that the currently producing category constitutes more than 90 percent of the total forecast. They looked at 34 individual North Slope pools and for Cook Inlet, because those fields are very mature and only a few produce significant amounts of oil they were aggregated into a single pool, with the exception of the Cosmopolitan Field which is still brand new and has a different development style. So, it has its own characteristics in the decline curve analysis. This is based on public Alaska Oil and Gas Conservation Commission (AOGCC) data that has a two-month lag in availability. Therefore, they chose the date of cutoff as the end of last fiscal year.

MR. DECKER also pointed out that the decline curve analysis forecasting, when done at the pool level, inherently includes and accounts for the background ongoing investments being made to keep well stock alive and keep projects moving. That actually shaves some out of the under development category and accounts for it in the decline of the currently producing category.

He explained that a decline curve analysis looks at historical data for trends of decline while asking what part best predicts the future. Because they are making an effort to do everything possible to be probabilistic, they worked with Schlumberger to develop a software plug-in for oil field manager software (OFM) that actually helps quantify various decline rates in terms of the distribution of possible declines.

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An example of a probabilistic decline curve analysis is for the Tarn Pool (slide 19) in the Kuparuk River Field. If one were to just look at the historical points, some general trends can be seen, but things vary greatly from those as well. The software plug-in for this project helps quantify what would be a

reasonable low-side decline and a high-side decline. This was done for all the pools.

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The time frame for the under development tranche was restricted to first oil by the end of the current fiscal year, next June 30th. This includes incremental wells added in producing fields that are in excess of the background level. New fields would be included that are intended to start up within that time frame, but there aren't any this year.

MR. DECKER said they also applied a 90 percent chance of occurrence for each of the under development and under evaluation wells based on a look-back at plans of development: if they said they were going to drill 10 wells, typically 9 would be drilled.

The price dependency economic risks are applied to both the under development and the under evaluation categories. The under evaluation is for first production expected between June 1, 2017, and the end of the 2021 fiscal year, years 2-5 of the forecast. Some of the criteria they would apply to make sure the production is in this category would be having detailed development plans in place, significant sunk costs or at least sources of funding in place, maybe inside or outside capital committed and secure, facilities or facility sharing agreements developing, and the National Environmental Policy Act (NEPA) analysis and Environmental Impact Statements (EIS) would be in progress or completed. The same chances of occurrence in price dependency are used in the under development category. Examples in the under evaluation category are Oooguruk Unit, the Nuna Pool, the Greater Mooses Tooth-1 Development (GMT-1) in NPR-A, the Mustang, the Kuparuk Field Moraine Development, the 1-H News in the West Sak at Kuparuk, the Oooguruk Nuiqsut Expansion, and the Greater Mooses Tooth-2 Development (a separate reservoir in the Greater Mooses Tooth Unit from GMT-1).

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The category excluded from the forecast because it just didn't meet those criteria were projects that are just a little bit less defined than those that were squeezed into a five-year window. Yes, the environmental and permitting challenges are one of the key variables and that is recognized here. Examples here would be the Pikka, Ugnu, Placer, Tofkat, the major gas sales from Point Thomson, Liberty, the Fjord West, and Smith Bay, Willow, and ANWR - in some cases, just looking at prospects.

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The results were on slide 25 in which the North Slope makes up most of the production mountain. Slide 26 showed statewide production trends. Basically one could argue from this slide that if you just look back at the last 10 years and put an exponential fit to the data, you would get an average decline of about 5.3 percent and pretty close to what the actual production was.

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MR. DECKER said slide 27 compared that history to the production forecast and that showed up in a range of dots moving into the future. The mean decline over 10 years is a 4 percent decline - the historic decline is around 5.3 percent - so, a little more optimistic overall than past history since 1988.

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He said some "pot of gold" scenarios were looked at: what things were not well enough known to include them into the forecast being prepared for revenue generation purposes. A total of eight projects were looked at including Smith Bay, Pikka, Willow, Liberty, etc. and excluded from the forecast. If four or five of the most likely of those projects are brought on, a healthy bump in production would be seen, but Alaska will never go back up that production mountain to "the Glory Days of a couple of decades ago." It's just not likely to happen with the excluded projects. This will be addressed in a report that will come out from the Division of Oil and Gas as soon as it can be thoroughly vetted.

MR. KING added that slide 26 is a classic example of why it's important not to make overly complex models. In fact, the efforts that were made by consultants to include everything to make the model look more like reality actually injured the ability to forecast and using a simpler approach relying on data over the last decade would have provided much better results.

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CHAIR GIESSEL thanked everyone and finding no further business to come before the Senate Resources Committee she adjourned the meeting at 5:01 p.m.