State of Alaska
Department of Natural Resources
Division of Oil and Gas

Bill Walker, *Governor*
Andy Mack, *Commissioner*
Chantal Walsh, P.E., *Director*

Alaska's 10-Year Oil Production Outlook and Potential Future Developments

By

Islin Munisteri, P.E. and Pascal Umekwe

With Contributions from

John Burdick, Chirag Raisharma, Steve Moothart

Edited by

Paul Decker, Ph.D. and Ed King

February 2017

Alaska Division of Oil and Gas, 550 W. 7th Ave, Suite 1100
Anchorage, Alaska 99501-3560

THIS PAGE INTENTIONALLY LEFT BLANK.

State of Alaska
Department of Natural Resources
Division of Oil and Gas

Bill Walker, *Governor*
Andy Mack, *Commissioner*
Chantal Walsh, P.E., *Director*

Alaska's 10-Year Oil Production Outlook and Potential Future Developments

By

Islin Munisteri, P.E. and Pascal Umekwe

With Contributions from

John Burdick, Chirag Raisharma, Steve Moothart

Edited by

Paul Decker, Ph.D. and Ed King

February 2017

Alaska Division of Oil and Gas, 550 W. 7th Ave, Suite 1100
Anchorage, Alaska 99501-3560

Table of Contents

List of Figures

List of Tables

Abbreviations and Definitions

AOGCC	Alaska Oil and Gas Conservation Commission
Bootstrapping	A statistical process for describing a population that cannot be fully measured; involves repeated random sampling from a sub-population and calculating the distribution of each sample to infer the distribution of the full population
BOPD	Barrels of Oil per Day
Confidence Level	The probability that the value of a parameter falls within a specified range of values
Confidence Interval	The range of values defined such that there is a specified probability that the value of a parameter lies within that range.
CP	Volumes of oil from fields that were Currently Producing as of the data cutoff date (June 30, 2016) for the forecast
DCA	Decline Curve Analysis; projecting future production by determining the rate of decline from historical data
Deterministic	Single-point estimate or defined scenario of fixed inputs
Economic Limit	In financial terms, the economic limit of a field is defined as the time when the net revenue of the field is equal to the field production cost (Kaiser, M.J. and Y. Yu 2010)
MBOPD	Thousands of Barrels of Oil per Day
Mean value	The average value of a probabilistic distribution
Monte Carlo Analysis	A computerized mathematical technique to account for risk in quantitative analysis and decision making through simulation and random sampling
NGLs	Natural gas liquids; included in the oil production forecast. However, natural gas liquids are forecasted separately from the oil production forecast and later summed. NGL volumes depend on how much is manufactured in the plant, which depends on demand as well as the gas components produced from the reservoir
P10	High-side estimate in a probability distribution, corresponding to a 10% probability that the actual value will exceed that value
P50	The median estimate in a probability distribution, with 50% likelihood probability that the actual value may be either higher or lower
P90	Low-side estimate in a probability distribution, corresponding to 90% probability that the actual value will exceed that value

POD	Annual Plan of Development provided to the Alaska Department of Natural Resources by field operators outlining development and depletion plans for the next year
Pool	'"Pool" means an underground reservoir containing, or appearing to contain, a common accumulation of oil or gas; each zone of a general structure which is completely separated from any other zone in the structure is covered by the term "pool"' AS 31.05.170
Probability	The extent to which an event is likely to occur
Probabilistic	Multiple-point estimate of risk; calculated by incorporating randomness (e.g., probability distributions) for inputs
Production Profile	As used in this report, refers to actual oil production combined with predicted future oil production
Risk	The probability of an event occurring, and the potential impact of that occurrence (Caddy 1993)
Risked	As used in this report, refers to values calculated by multiplying the unrisked mean resource with a chance factor of success
Shut-in Well	A well that is currently not in production or injection service; not abandoned
Type curve	See Type Well
Type Well	Representative single-well production profile determined from geologically analogous fields; used to estimate production impacts of adding new wells
UD	Under Development. Volumes of oil from planned wells and projects that are Under Development, anticipated to yield first oil production in the first year of the forecast period
UE	Under Evaluation. Volumes of oil from proposed wells and projects that are Under Evaluation, anticipated to yield first oil production in the second through fifth years of the forecast period
Uncertainty	The extent to which the actual outcome cannot be determined. In this context, uncertainty is handled by replacing one or more input values with a distribution of possible values
Unrisked	As used in this report, refers to mean resource estimates that have no chance factor of success applied

Executive Summary

Crude oil production remains a key revenue generator for the State of Alaska, and production forecasting is an important part of the state's overall fiscal planning. Previous years of forecasting production have provided useful information to the public on this valuable state resource and guidance to decision makers within and outside the state. Lower oil prices make the task of planning for the state's future even more critical. In line with the State's current fiscal situation, this forecasting exercise was assigned to the State's oil and gas arm, the Division of Oil and Gas in the Department of Natural Resources.

Prior to engaging in a forecast effort, the Division of Oil and Gas (the Division) conducted an assessment of past production forecasts and observed a consistent tendency to predict production levels greater than actually achieved **(Figure ES-1.** It appeared that the divergence between forecast and actual production was mainly due to the inclusion of future projects that did not enter production as planned. This divergence tended to increase the further into the future the forecast was made. In order to correct this bias, some incorporation of the uncertainty surrounding future production was necessary. As a result, the Division embraced a probabilistic approach to forecasting production that accords more weight on currently producing fields and their governing reservoir engineering principles, and honors the higher level of uncertainty associated with future production.

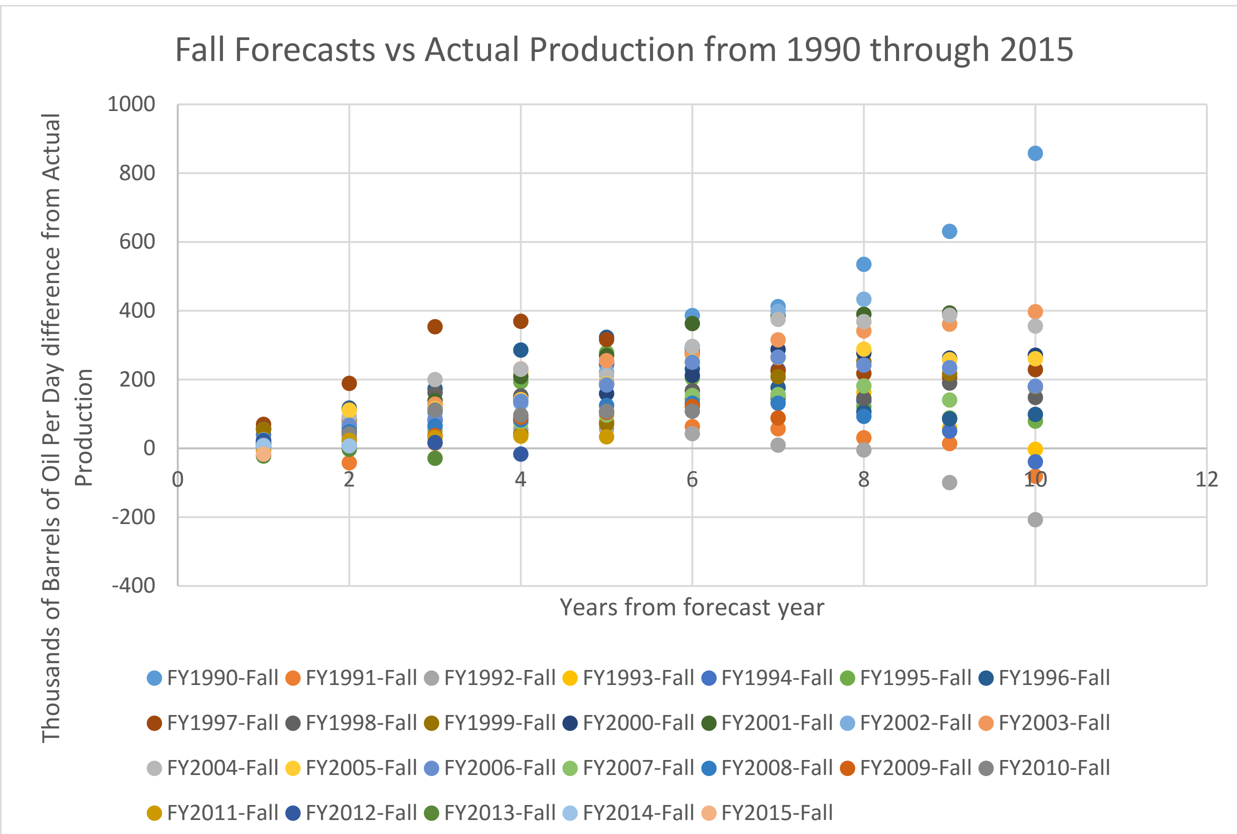

Figure ES-1. Revenue Sources Book forecasts' differences from actual oil production versus forecasted oil production, completed from 1990 to 2015.

In line with past forecasts, the Division maintained three production categories: a Currently Producing tranche, for wells and fields that are already producing; an Under Development tranche, for oil production from imminent new wells and projects; and an Under Evaluation tranche, for oil production expected from more distant projects. Consistent with industry best practice, probabilistic forecasts were generated for Currently Producing fields to show a range of possible production into the future. Production from wells and projects in the Under Development and Under Evaluation categories was estimated using type curves (representative production profiles) generated from analogous fields. See **Table ES-1** for a comparison of forecast methodologies from 1989 to the present Fall 2016 forecast.

	1989 - 2009	2009 – Spring 2016	Fall 2016 - present
Forecast Level	Field-Level Forecast	Well–Level Forecast	Pool-Level forecast
Approach towards Uncertainty	Deterministic (some scenarios)	Deterministic	Probabilistic
Risking	N/A	CP not Risked First UD/UE risking in 2013 Fall forecast	Probabilistic technical and non-technical risk
Type wells for future production	N/A	Single type well, by field	Pool-by-pool type wells
Oil Price Dependency for Risking	None	None	Dependence on oil price
Under Development Tranche (length of outlook to first oil)	10-year outlook	10-year outlook	1-year outlook
Under Evaluation Tranche (length of outlook to first oil)	10-year outlook	10-year outlook	5-year outlook

Table ES-1. Historical summary of production forecasting methodology from 1989 to present.

In the new methodology, the Division reduced the outlook on the less certain future projects from the 10-year window used previously to a five-year window to mitigate the tendency for over-prediction in the long-term.

The Division has provided a 10-year statewide production forecast for the purpose of fiscal planning, as seen in **Table ES-2**. The forecast results show that production for the near term will be impacted by the current oil price climate. In the past year, the level of drilling across the Alaska North Slope has dropped; fewer rigs now operate on the North Slope, some projects have been discontinued, and others have been deferred. Current capital expenditures go toward projects that were either far along in implementation before the oil price crash or projects that will not be on production in the near term.

	Official Forecast (mean) for Alaska North Slope Production (thousands of barrels per day)	Official Forecast (mean) for Cook Inlet Production (thousands of barrels per day)	Official Forecast (mean) for Total Alaska Production (thousands of barrels per day)
FY2017	490.3	15.5	505.8
FY2018	455.6	14.2	469.7
FY2019	442.1	15.7	457.8
FY2020	428.6	14.6	443.1
FY2021	413.5	13.0	426.5
FY2022	398.2	11.7	410.0
FY2023	380.4	10.6	391.0
FY2024	363.4	9.7	373.1
FY2025	345.9	8.9	354.7
FY2026	331.0	8.2	339.2

Table ES-2. Summary of official forecast (mean) for the Fall 2016 Revenue Sources Book.

It should be noted that the currently forecasted decline rate over the full 10-year forecast period is 4.2% for Alaska North Slope combined oil and NGL production, and is still optimistic compared to the 5.0 to 5.5% oil decline rates that can be computed for Alaska North Slope production since decline began in 1988. The average year-over-year decline since 1988 is 5%, whereas the 5.5% decline rate is based on an exponential regression of oil-only production (not including NGLs) on the North Slope since March 1988 (**Figure ES-2**), with an R-squared value of 0.97. A similar regression based on statewide combined oil and NGL production yields a decline rate of 5.3%.

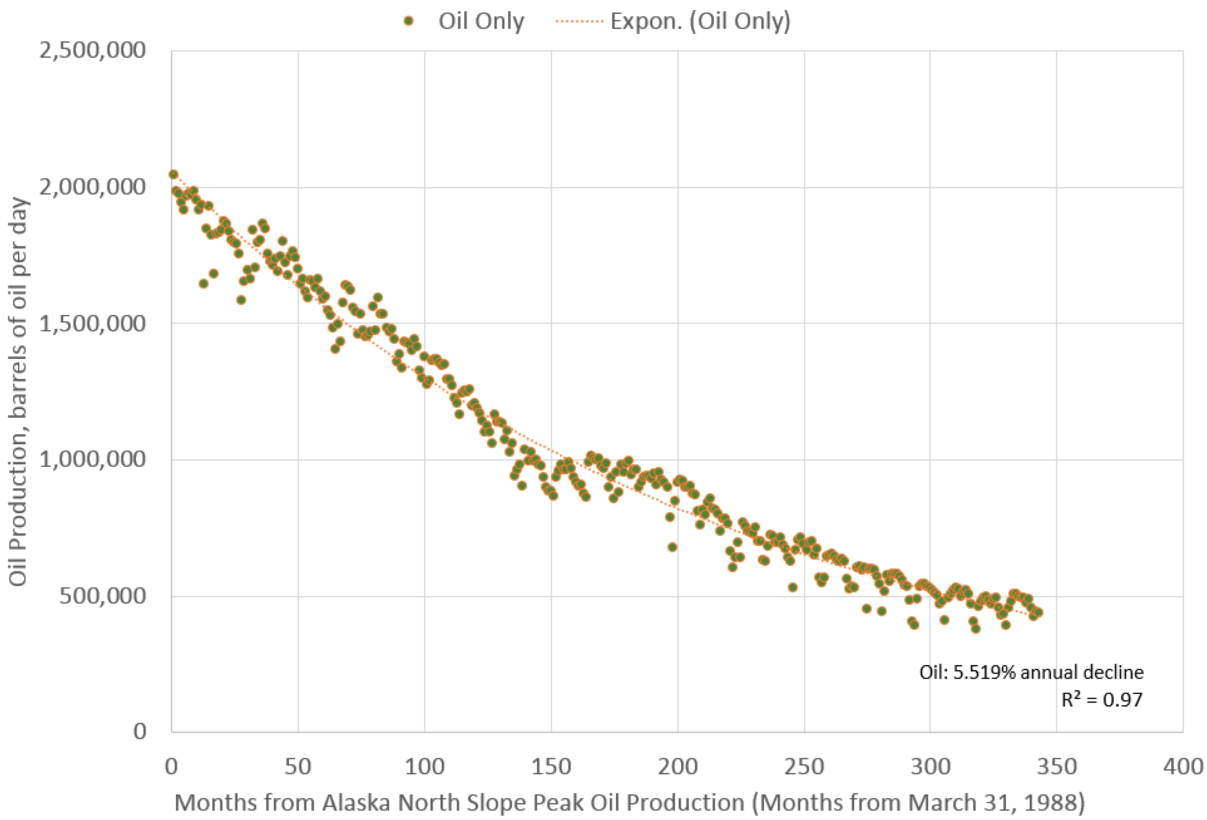

Figure ES-2. Average decline from Alaska North Slope peak oil production, since March 31, 1988 (oil only, not including NGLs).

Projects planned beyond five or more years out were excluded from the official forecast results. These potential future developments are examined separately in two highly speculative, longer-term outlooks informally referred to as "Pot of Gold" scenarios, which are not to be used for the State's fiscal planning.

The main purpose of the "Pot of Gold" scenarios is to contribute to the conversation on the state's future and the potential impacts of new production on the longevity of the state's main production artery, the Trans Alaska Pipeline System (TAPS). This analysis is provided simply for context and scale as public discussions and media outlets speak to these potential projects. The Division does not condone the use of these data for any other purpose and would vehemently object to basing long-term financial planning on these future projects until much more reliable information is available regarding startup timing, development pacing, and well productivity profiles.

Scenario A's unrisked oil production profile includes all eight speculative projects that may be developed, including Liberty, Tofkat, Ugnu, Placer, Smith Bay, Fiord West, Pikka, and Point Thomson Major Gas Sales (**Figure ES-3**). Scenario B shows an unrisked oil production profile that includes the oil production from the slightly less risky projects of Fiord West, Placer, Pikka, and Tofkat (**Figure ES-4**). [1]

[1] Neither of the two "Pot of Gold" scenarios include the Willow discovery, which was announced by ConocoPhillips as this report was being finalized. The operator estimates that development will yield 40,000 to 100,000 barrels of oil per day, depending on whether it produces through shared or standalone facilities.

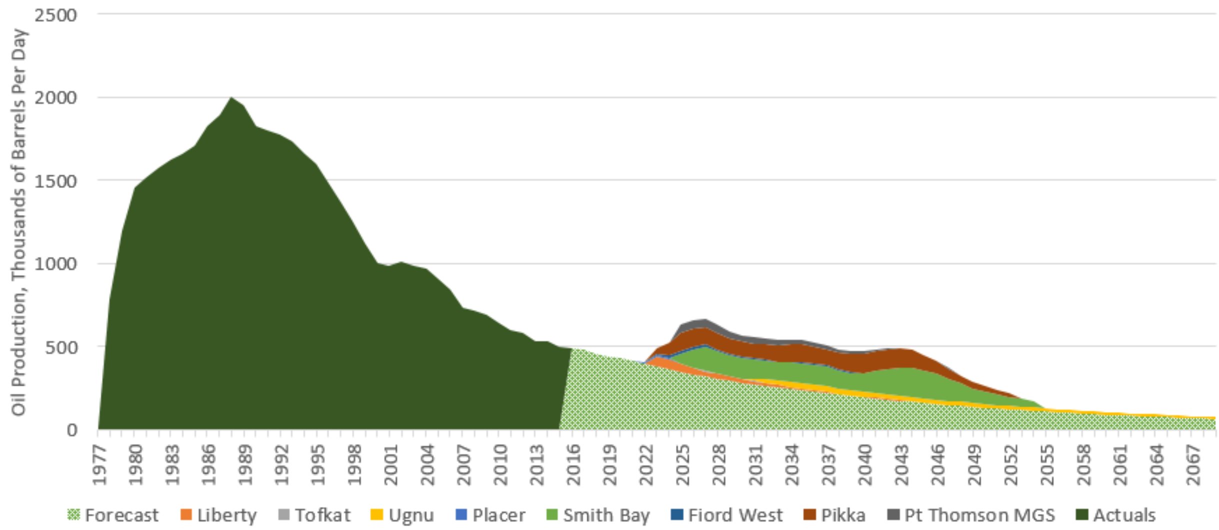

Figure ES-3. Scenario A of speculative, unrisked oil production forecast for all eight of the "Pot of Gold" projects.

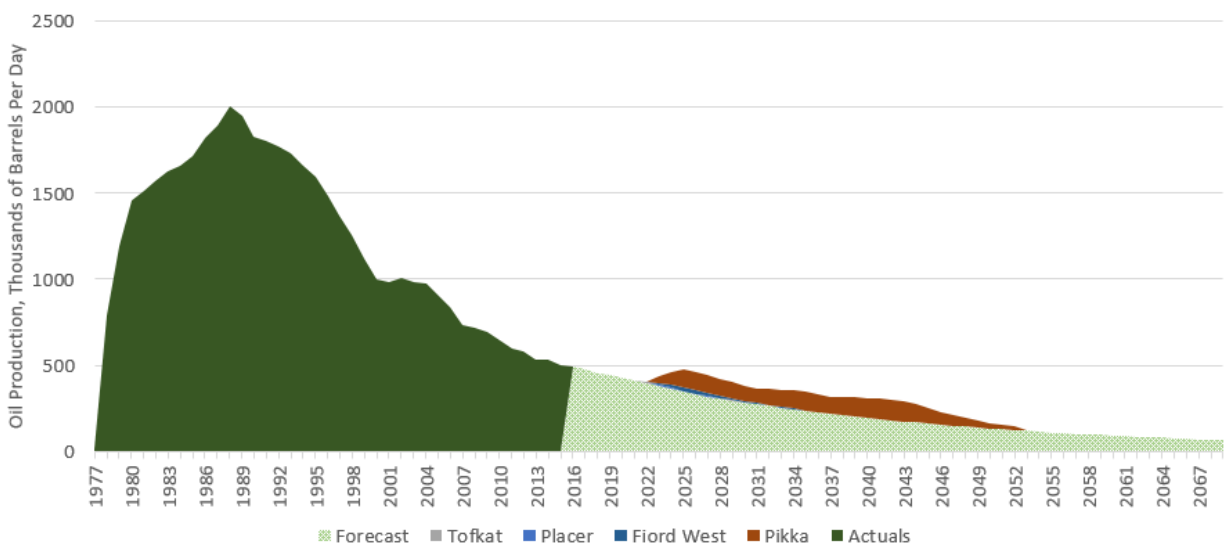

Figure ES-4. Scenario B of speculative, unrisked oil production forecast for the four most likely "Pot of Gold" projects.

Publicly reported estimates of TAPS minimum throughput range from 70,000 barrels of oil per day to 350,000 barrels of oil per day, based largely on technical factors. Economic factors are also important. As production declines, the cost of operating the pipeline is spread over fewer barrels of oil. This implies that if the value of oil is not sufficiently high, it will be more expensive to produce and ship the oil than it is worth. **Table ES-3** considers three different production scenarios (the official Fall 2016 Revenue Sources Book Production Forecast, Scenario B of lower risk projects, and Scenario A of all eight projects in the "Pot of Gold" outlook), and pairs them against two different estimates of the low-flow limit (a more conservative estimate of 300,000 barrels per day and a more optimistic estimate of 100,000 barrels per day). Using the data in this report, we can identify the point at which these hypothetical limits may be reached. While the Division of Oil and Gas makes no assertion as to when TAPS may become inoperable, and we acknowledge that the actual limit could fall outside that range, it is insightful to realize how these potential future oil projects move these thresholds.

Forecast / Scenario	TAPS Low-Flow Oil Rate Limit	Approximate Year of TAPS Shutdown
Fall 2016 Revenue Source Book Production Forecast	100,000 BOPD	2058
Scenario B (lower risk projects included, unrisked)	100,000 BOPD	2058
Scenario A (all 8 future projects included, unrisked)	100,000 BOPD	2061
Fall 2016 Revenue Source Book Production Forecast	300,000 BOPD	2029
Scenario B (lower risk projects included, unrisked)	300,000 BOPD	2042
Scenario A (all 8 future projects included, unrisked)	300,000 BOPD	2049

Table ES-3. Summary of possible TAPS low-flow oil rate limits and the corresponding year of TAPS inoperability given three different production profiles: the Fall 2016 Revenue Source Book Production Forecast, Scenario A, and Scenario B**.**

Introduction

Every December, the Governor is required under AS 37.07.020(b)(4) to provide a ten-year fiscal plan to the legislature. This plan "must set out significant assumptions used in the projections with sufficient detail to enable the legislature to rely on the fiscal plan in understanding, evaluating, and resolving issues of state budgeting". The Department of Revenue provides these assumptions to the Office of Management and Budget and to the public by way of its annual publication known as the *Revenue Sources Book.* This report augments that publication in order to ensure sufficient detail is available to the legislature as the Fall 2016 forecast provided by the Department of Revenue relies on the production outlook provided by the Division of Oil and Gas.

The production outlook is a critical component of the revenue forecast. The only parameter that drives more sensitivity in the unrestricted revenues forecast is the price of oil, which has proven to be very unpredictable and is outside the State's sphere of influence. From 2005 to 2014, Alaska relied on oil and gas revenues for 90 percent of the state's unrestricted budget (Hobson 2016). Hence, it is important to be able to understand the trends and projections of the oil production that underpins the state's unrestricted budget.

2016 is the first year in which the production forecast has been generated internally. Historically, the Department of Revenue has hired outside consultants to perform the technical work necessary to create a production profile from which to calculate expected tax and royalty revenues. As part of the budget reduction process that has occurred in recent years, the Department of Revenue eliminated funding for the petroleum engineering consultant and asked the Division of Oil and Gas to conduct this work with existing staff. The Division agreed and dedicated resources from the Resource Evaluation and Commercial sections to complete the project.

As the Division took on this task, we reviewed prior forecasting efforts and contemplated several methods that could be applied in production analysis or forecasting. In selecting between methods, appropriateness can be judged under three key criteria: the level of data required to conduct such analysis, the complexity of the method versus accuracy, and the time requirement. Decline Curve Analysis at a pool level rose to the top based on these criteria as the lowest cost, least complex, and adequately accurate over the forecast window.

Decline Curve Analysis is the preferred method across the petroleum industry for baseline projections because it can be conducted using readily available historical production data, provides acceptable levels of accuracy, and can be completed relatively quickly. It is an engineering approach that uses historical data to inform the expectation of the future. This method, like all others, could lead to errors if the analysis is not grounded in an understanding of the reservoirs' operational and performance history or if the future being projected is structurally different than the past.

The current forecast uses a statistical bootstrapping method in addition to traditional decline curve analysis to derive a quantifiable probabilistic range of outcomes, including low-side (P90), median (P50), and high-side (P10) cases. This effort does not attempt to make point estimate predictions of specific future events. A more complex model could be conceived that takes into account factors such as planned maintenance, facility constraints, or weather impacts, but would only have value if the model is well-informed. Attempting to include these factors without good data to correctly account for them in the historical data and to validate them in the future estimates will introduce more opportunity for error than improvement in forecast reliability.

The State of Alaska has nearly one hundred different oil pools and thousands of active oil wells. Conducting a statewide, fully probabilistic well-by-well forecast would require significant additional time and computing resources, and would not necessarily increase accuracy relative to a pool-level approach. Past forecasts for the State of Alaska have been conducted at both pool and well levels, although without applying a probabilistic approach. Forecasts using either method produced very similar results in the data-rich legacy fields that represent a vast majority of North Slope production. For this reason, the Division elected to apply probabilistic Decline Curve Analysis at a pool level.

Whether they applied well-by-well or pool level methods, previous forecasts were deterministic, i.e., only considered success case additions, which were either included in or excluded from the forecast based on the subjective assessment of the forecaster. When these projects did not follow the forecast plan, the actual production always fell below the forecast. When aggregated across the North Slope, the net forecast represented a highly unlikely scenario in which all of the projects entered production on time and at the projected rate. This resulted in a consistent bias toward over-projecting future production, which increased as the forecast looked further into the future. As a result, a change in methodology was adapted to build on the strengths of previous methods while reducing the errors observed in the forecast.

The probabilistic method adopted by the Division does not promise a single, exact answer. On the contrary, it delivers a quantified range of potential outcomes, and ensures that forecast errors are minimized over time by accounting for the fact that it is far more likely that at least one future project will be delayed or will underperform than it is that every project will meet expectations. Uncertainty is inherent in forecasting future oil production, especially from fields that do not have a history of production and that are vulnerable to a changing commercial climate. It is an industry best practice to acknowledge and account for this uncertainty.

This report discusses the production forecast in two segments. Part 1 is the official 10-year outlook of production for the State, provided to the Department of Revenue for revenue forecasting purposes. The forecast predicts that production for the near term will be impacted by the current low oil price climate, in keeping with the recent reduction of drilling activity, especially on the North Slope. As fewer rigs now operate on the North Slope, some projects have been discontinued and others deferred. Capital expenditures still being deployed go towards projects that were either far along in implementation before the oil price crash or projects that will not be on production in the very near term. This results in a more "pessimistic" view of the near term than previous forecasts.

Projects not planned to enter production within the next five years were deemed to have too much uncertainty to be included in this 10-year outlook; such projects would be expected to enter future forecasts as they cross minimum certainty thresholds.

Part 2 of this report describes a related but separate effort. It addresses potential future development projects, but should not be used for prudent fiscal planning. It is intended to provide a more comprehensive picture of the potential production increases associated newer discoveries and prospects that have entered the public conversation. The purpose of discussing these scenarios is to acknowledge the attention given to these potential resources and to stress the importance of transforming them into producing oil volumes. Collectively referred to as the "Pot of Gold", these new projects will be important to the state's future, in terms of their monetary value and in terms of the benefit of new production in prolonging the life of the state's main production artery, the Trans Alaska Pipeline System. As important and exciting as these potential resources are, the Division reiterates that the scenarios in Part 2 of this report should not be used for revenue projections until there is a much better understanding of these projects and a much higher degree of confidence of when they will enter production. Twenty-five years of history in forecasting North Slope future activities demonstrates that there are many reasons that these projects may not follow the plan as we see it today and that over-optimism is likely to lead to disappointment.

1 Part 1: Production Forecast

Production forecasts provide insight to the State's revenue outlook. Over the years, different methods have been applied in generating this forecast. All the past forecasts provided to the Department of Revenue have applied the Decline Curve Analysis (DCA) technique in some form. This is a petroleum reservoir engineering technique that incorporates the historical production of a well or reservoir with an understanding of the reservoir to establish a decline rate from which a production profile can be generated and expected future production can be forecasted. Some forecasts have applied DCA at a well level and others, including the current forecast, have applied it at the pool or field level, but this is not the primary difference. Likewise, discussions surrounding exponential versus hyperbolic decline would likely be a point of discussion among engineers evaluating this forecast. However, those differences are not as significant as restricting the outlook to a 10-year window.

The most significant changes in methodology are related to the treatment of future production from wells and pools that are not currently producing. Treatment of this potential production has varied over the years. At times, forecasters have included all plans reported by an operator or in newspaper articles as though they were assured of meeting those timelines and production rates. In other forecasts, the forecaster has added production based solely on speculation that future resources would be discovered and developed. But in all past forecasts, the individual constructing the forecasts has used discretion and subjective opinions as to whether or not to include a potential future source of production into the forecast.

As a result, nearly all past forecasts have been overly optimistic with regard to this category of production from not-yet-producing wells and projects. In recent years, the Department of Revenue has attempted to reduce this bias toward over-prediction, adopting changes in methodology to reduce the difference observed between forecast and actual production. The following sections will discuss the history of the methods used, the new method being introduced by the Division of Oil and Gas, and the reasons for a change in methodology.

1.1 Previous Forecast Methodologies and Results

1.1.1 Production Forecasting Methodology prior to 2008

The first *Revenue Sources Book (RSB)* by the Department of Revenue available on their website is from 1970, following the first North Slope lease sale. Although there was no published production forecast, the projection of declining royalties indicates that some forecast was used. The large projected jump in royalties and taxes in 1975 indicates an expectation of North Slope production. This appears to be the first official instance of over-forecasting anticipated future production, since production did not occur until 1978.

Following a change in the oil tax law in 1974, the revenue forecaster commented on how the projected tax revenues were calculated. While the associated production forecast was not published, the report did provide insight into the method used:

> "Royalty and tax income estimates from oil and gas operation have been made after considering the past and future production performance of each pool in the State."

That report goes on to warn the reader that "…the estimates are subject to fluctuations, even within a lease."

The responsibility of publishing the *RSB* was transferred to the Department of Revenue in 1975 from the Department of Administration. Upon assuming this responsibility, they concluded that rather than projecting 5 years into the future as had been done in the past, they would not attempt to forecast beyond the budget year "due to the uncertainties resulting from the impact of pipeline construction and the fluctuation of oil prices."

Once oil began to flow from the North Slope in 1978, the Department of Revenue constructed a "marketing and production simulation model which projects severance tax and royalties on a company-by-company, field-by-field basis."

Beginning in the September 1984 quarterly update, the Department of Revenue added a "Long-Range Revenue Projection" using an updated model they had constructed. Upon introduction of this new portion of their forecast, they warned the reader that "those numbers in the near future can be regarded with greater confidence than those further out."

As production decline began in 1988, the Department of Revenue hired internationally renowned oil economist Dr. John C. Gault of the International Energy Development Corporation to review the forecasting method and provide advice. Dr. Gault gave two major recommendations in his report: first, pay attention to international markets to better understand price expectations; second, consider a variety of potential future scenarios rather than just one. Heeding that advice, the Department published three price scenarios including a production response to the different economic conditions, warning decision makers that "debates over forecasts are not a substitute for debates over higher spending, budget cuts, borrowing, holding reserves, or adding to long-term savings in the Permanent Fund."

This three scenario forecasts continued until 1996, when the Department of Revenue switched to one "reference case" developed at the field level. Additionally, they broke the forecast into two parts, a short-term outlook for the next two years and a long-term outlook out to 2010. Then, in the Fall 1999 *RSB*, the Department first referenced an outside consultant and began a process of adding production from possible new resources. This added production was layered on top of the reference case.

Over the next several years, the additional production layer from possible new sources was slowly adopted into the "official forecast" and a hypothetical production profile was added to illustrate that a more pleasant future was possible than the bleak realities of the present. These profiles were based on USGS estimates of undiscovered resources, calling this an "Active Exploration" layer on top of the forecast.

The Spring 2004 Forecast formally adopted these categories of future production as three layers still in use today: Currently Producing (CP), Under Development (UD), and Under Evaluation (UE). Over the next few years, the Department of Revenue adjusted the definition of these categories and acknowledged that the forecast associated with each layer was increasingly speculative. In the 2006 *RSB*, the Department suggested that the Under Development category had a "subjective confidence" of 80-85% and the Under Evaluation category was "in the 70-75% range." While they noted that "all production from this category is subject to delays and scope changes that might impact reserves or production rates," the forecasters used these thresholds to decide whether or not to include the project rather than risk-weighting the project within the forecast.

1.1.2 Production Forecasting Methodology from 2009 to Spring 2016

In 2008, the forecasters began to pull back on what they were willing to include in the forecast. They specifically identified several sources of potential future production that they were not willing to include "in order to avoid speculation and to reduce the uncertainty typically associated with the commercialization, timing, and magnitude of resource development." As such, the "under evaluation" layer of the forecast was considerably reduced and they described their forecast as "conservative."

At the same time, there was also a change in methodology to what the *RSB* described as a "bottom-up, well-by-well evaluation on each of the individual fields" (Alaska Department of Revenue 2008). They further described the new method, saying "the engineering consultant employs decline curve analysis, augmented by generally accepted engineering principals, discussions with field operators, and public and private information…" (Alaska Department of Revenue 2008).

This method used the production trends of individual wells and aggregated those forecasts to the pool level to create the Currently Producing tranche. One advantage of this method is that it considered each well as a unique contributor to production within its specific completion and reservoir segment limitations. However, in a field or several fields with thousands of wells, this method is resource intensive. There is little assurance that expending the additional resources needed to conduct well-by-well forecasts ultimately yields a more accurate statewide production forecast.

The Under Development and Under Evaluation tranches applied to forecasts during this time frame were based on data provided by the operators for a period extending 10 years into the future. The reservoir engineering consultant hired by Alaska Department of Revenue created average type wells by analyzing the production data within a certain time window (Molli, personal communication, July 21, 2016). Using the drilling schedule provided by the operator, the consultant estimated the UD and UE tranches for the production forecast by aggregating each average well based on when the operator said that well would be on production. Additionally, wells that had been shut-in for three months were assumed to be put back on production, unless the water cut was 95% or if the GOR was too high. In other cases, the oil production forecast for the UD or UE tranche was provided by the operators and included unrisked in the forecast if the engineer felt that the project was likely to be developed.

A 40-year oil production profile combining all three tranches was the product provided to the Alaska Department of Revenue for the Revenue Sources Book during this time frame (Molli, personal communication, July 21, 2016). No economic limits were applied—each well's production forecast was only limited by the 40-year forecasting period.

Legislative direction in 2011 from Representative Costello in the House Finance Committee provided the following observation:

> "I'm looking at a graph, from your department [Department of Revenue], that shows the forecast, starting in 2001 to 2010, and it seems that the trend is that the department is optimistic in its forecast of the production."

In response, the Department of Revenue and Division of Oil and Gas personnel analyzed past forecasts and compared them to actual production, ultimately developing a range of "confidence bands" and risk factors (Tangeman and Barron 2013) that were applied to subsequent forecasts by the Alaska Department of Revenue in an effort to reduce the over-prediction observed in previous years. In the Fall 2012 *RSB*, the Department of Revenue continued to pull back on their method noting a significant change in approach to production forecasting. “Ideally, actual values would be close to the projected values; however, because that is unlikely, the goal should be to have any differences between actual production and forecasted production offset one another, resulting in an average error close to zero over time” (Alaska Department of Revenue 2012). This terminology indicates that the Department was departing from a deterministic approach to predict exactly what would happen in the future, and toward an effort to provide some central tendency around which production would occur. Within the methodology section, the author explained that the more speculative sources of future production were reduced (risk-weighted) to account for the uncertainty around their production rates and timing. The author went on to explain that the reduction was greater further into the future, and that the UE category was discounted greater than the UD category.

1.1.3 Results from Previous Methodologies

We observe that past forecasts generally overestimated actual production. A possible reason for this is that the pace of development typically reduces as a field matures. As fields age, new wells drilled are mainly infill wells within existing reservoirs, and fewer exploration targets exist within the unit. When additional production from UD and UE projects within a pool are added to a deterministic pool-level production forecast, overall production could easily be grossly overestimated. This is because the pool-level forecast of the Currently Producing tranche is based on data that already includes ongoing background field development activities, such as new wells drilled, and other base management or rate-adding activities done on a year-to-year basis to stem the pool’s natural production decline. Adding additional planned drilling or other projects into the forecast that are akin to historic background development levels amounts to double-counting the rate from that activity.

Forecasts performed prior to 2012 did not account for any uncertainty. Projects in the Under Development and Under Evaluation tranches were entered at their full target rate and at the target time if they were included at all. In reality, some planned projects are never executed, or are delayed, or contribute less production than planned. As an example, production from the Liberty oil discovery was included in numerous forecasts since 1997, projecting first oil in 2001, but more than 15 years later, the field still remains undeveloped. These factors account for how previous forecasts’ deterministic methodology has tended to overestimate actual future production, when combining the Currently Producing, Under Development, and Under Evaluation tranches.

Even as past production forecasts provided guidance in the state of Alaska’s planning and budgeting, it was observed that these forecasts were significantly different from actual production. A look at the forecasted and actual production data showed that there was a consistent overestimation of oil production in outer years (**Figure 1**).

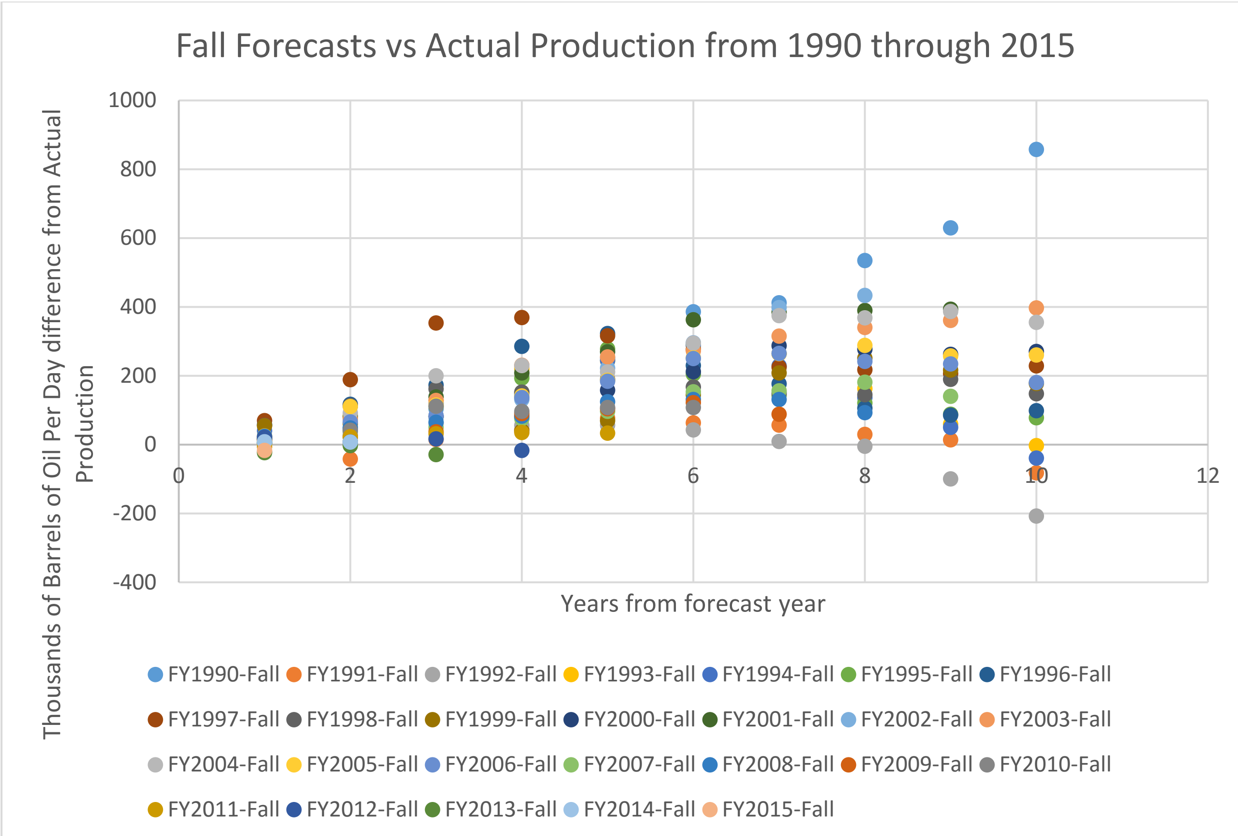

Figure 1. Revenue Sources Book forecasts' differences from actual oil production versus forecasted oil production, completed from 1990 to 2015.

There is also the challenge in predicting the timing of first oil from future projects. Forecasts done in the past show evidence of production peaks that came in earlier than actual production typically due to the challenge in forecasting project delays or cancellations.

In addition to challenges in timing projects, two other observations were evident from analysis of historical forecasts. First, the errors in forecasts were smaller for the first 5 years of forecast than for the entire 10-year forecast period (**Figure 2**). This implies that, in forecasting oil from future projects, a shorter forecast horizon could improve the overall accuracy of state production forecasts. Second, there is evidence that historically, the UD and UE tranches of the production forecast were the largest contributors to over-prediction of actual production (**Figure 3**). However, excluding these tranches of the forecast and using just the CP tranche would have led to under-prediction. This implies that although new projects clearly deliver additional production, some of the proposed projects are either deferred, cancelled, or deliver less rate than anticipated. This evidence points to the need for a new weighting/risking strategy that would honor more of the uncertainty in future production.

In conclusion, a new production forecast methodology is necessary to account for the following:

- A better way to decrease the difference between actual production and forecasted production for the entirety of the production forecast, including the CP, UD, and UE tranches,
- A better risking methodology for the UD and UE tranches, to decrease the difference between actual production and forecasted production, and

- A shorter forecast period to decrease the error between actual production and forecasted production. Previous forecast periods were up to 40 years in length.

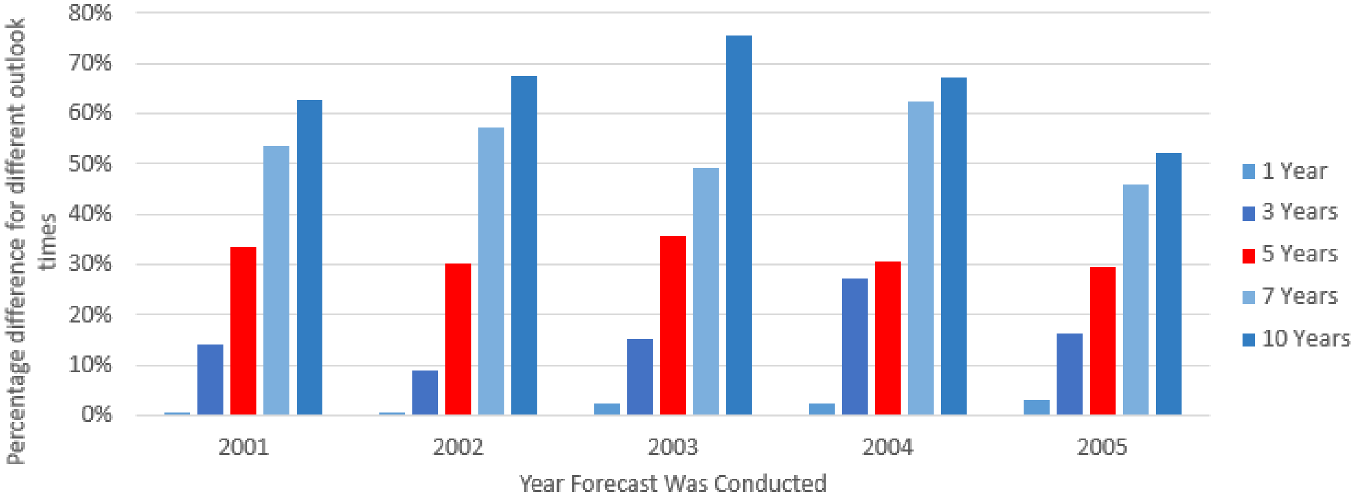

Figure 2. Historical forecast error increases with the length of the outlook into the future. 2001 to 2005 timeframe shown allows for analysis of 10-year prediction versus actual.

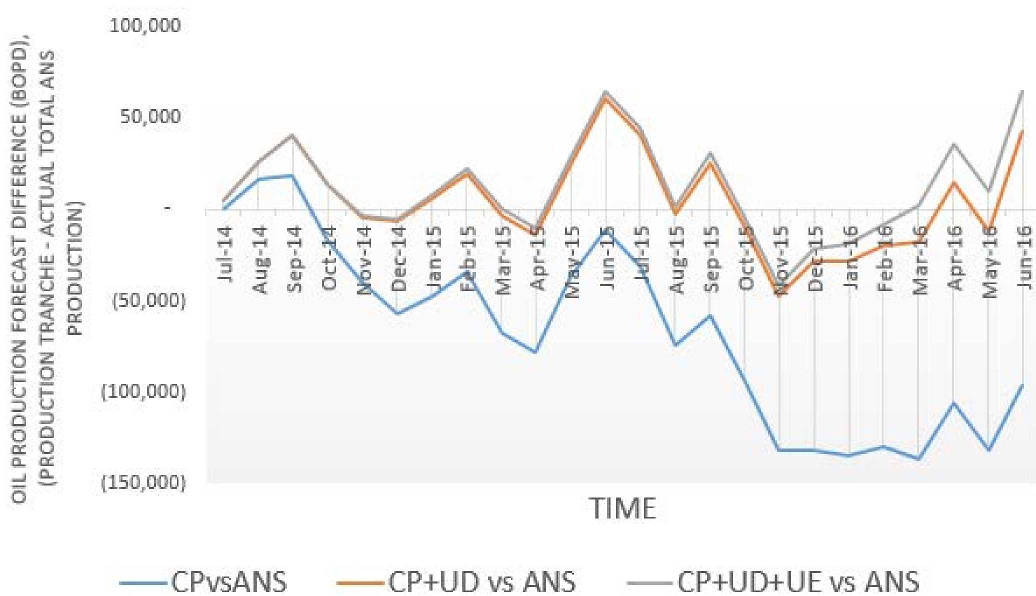

Figure 3. Errors in production forecasting introduced by different forecast tranches in the 2014 Fall Forecast. The blue line shows the difference between the Currently Producing tranche versus actual Alaska North Slope production. The orange line shows the difference between the Currently Producing and Under Development versus actual Alaska North Slope production. The gray line shows the difference between the Currently Producing, Under Development and Under Evaluation tranches versus actual Alaska North Slope production.

1.2 Fall 2016 Production Forecasting Methodology

"Bear in mind that successful forecasting using a distribution would expect to be outside the P90-P10 forecast range 20% of the time" (Spencer and Morgan, 1998).

The production forecast method adopted for the Fall 2016 Revenue Sources Book integrates production forecasting within a more inter-disciplinary framework, which includes geologists, petroleum reservoir engineers, petroleum economists, and commercial analysts. It is a joint effort by the Resource Evaluation and Commercial Sections of the Division of Oil and Gas within the Department of Natural Resources in consultation with the Department of Revenue. All the production data used was obtained from monthly production data published by the Alaska Oil and Gas Conservation Commission (AOGCC).

The 2016 forecasting methodology applies best practice reservoir engineering principles of production forecasting and risk and uncertainty analysis techniques to honor the different levels of risk and uncertainty associated with the different tranches that make up total production. A key component of this method is in the handling of the CP tranche, which makes up approximately 90% of the total expected oil and NGLs production in the current forecast.

The five main features to this approach are summarized as follows:

- A probabilistic Decline Curve Analysis forecast of the expected possible production range for the CP tranche
- Reducing project outlook for new oil projects from 10 years to one year until first oil for the UD tranche
- Reducing project outlook for new oil projects from 10 years to 5 years until first oil for the UE tranche
- Generation and application of probabilistic type wells for each pool and well category, and
- Application of technical and commercial risks to production in the UD and UE tranches.

Differences between previous production forecasting methodologies and the current forecasting methodologies are summarized in **Table 1**.

1.2.1 Currently Producing Tranche

Forecasts of CP pools and type curves were derived using the commercially available Schlumberger Oil Field Manager (OFM) software package. Using different periods of historical production in any given forecast exercise will yield different results. The strength of the probabilistic methodology is that it produces hundreds of profiles or realizations from which statistically valid P10, P50, and P90 profiles are determined. Further details of how the probabilistic ranges of CP pool level forecasts were established is discussed in section 1.2.3.1 below. Results from OFM were exported to Microsoft Excel where uncertainty analysis was conducted using the Palisade @Risk software package.

With pool-level forecasting, the observed historical decline rate reflects not just the reservoir's natural decline rate, as wells deplete the reserves within their respective drainage areas, but also reflects the rate-bolstering effects of maintaining well stock and drilling additional wells in the pool. This "background" drilling rate is a key part of base production management and is inherently reflected in the annual decline profile of pools. Thus, our forecasts of P10, P50 and P90 forecast profiles of the Currently Producing pools include background drilling activity – an important consideration when it comes to defining the Under Development tranche (below).

	1989 - 2009	2009 – Spring 2016	Fall 2016 - present
Forecast Level	Field-Level Forecast	Well–Level Forecast	Pool-Level forecast
Approach towards Uncertainty	Deterministic (some scenarios)	Deterministic	Probabilistic
Risking	N/A	CP not Risked First UD/UE risking in 2013 Fall forecast	Probabilistic technical and non-technical risk
Type wells for future production	N/A	Single type well, by field, deterministic	Pool-by-pool type wells, probabilistic profiles
Oil Price Dependency for Risking	None	None	Dependence on oil price
Under Development Tranche (length of outlook to first oil)	10-year outlook	10-year outlook	1-year outlook
Under Evaluation Tranche (length of outlook to first oil)	10-year outlook	10-year outlook	5-year outlook

Table 1. Historical summary of production forecasting methodologies from 1989 to present.

Actual downtime is also included within the pool level production data. By trending a long enough portion of historical data, which includes periods across winter and summer months and is representative of field development plans in the outlook window, the forecast range produced accounts for the impact of facilities shutdowns, seasonal impacts and, well work projects. For forecasting purposes, Cook Inlet oil was treated as a single pool.

1.2.2 Under Development and Under Evaluation Tranches

These categories consist of production from new projects that are expected to yield first oil within a 5-year window. Individual infill wells in mature fields and other production from future major multi-well projects all fall within this segment. This category is split into production from projects under development (UD) and under evaluation (UE). In the 2016 forecast, the UD category is defined as production from future wells and projects that are expected to produce first oil within the first year of the forecast (i.e., 12 months following the forecast start date), and are incremental above the historic level of background drilling and development, since the background activity is implicitly accounted for in decline analysis of the CP tranche. The UE category consists of production from future wells and projects expected to produce first oil in the second through fifth year of the forecast (i.e., more than one year and up to five years following the forecast start date).

Probabilistic type well profiles were developed by engineers within the Division of Oil and Gas to represent production for each pool and for distinct well types within the pools. The P10, P50, and P90 type curves were generated from a population of representative wells in the respective pools, intending to characterize the behavior of future wells drilled in the pools. The appropriate type curves were equally applied to all future wells in both the UD and UE tranches. **Figure 4** shows a breakdown of the production segments.

The North Slope Under Development tranche was examined pool-by-pool, based on a study of Plans of Developments submitted by the operators from the previous year. In general, recent PODs have shown a reduction in drilling following the oil price crash. Wells that were drilled in the previous year reflect investment decisions made earlier, often with the expectation of higher oil prices. BP reduced its rig count from six rigs to two in 2016, and "production from Prudhoe Bay and its satellites is expected to go down" (Cashman 2016). Other non-drilling field wide optimizations were also considered.

The reservoir engineers in the Resource Evaluation team of the Division of Oil and Gas conducted a three-year review to determine which wells are part of the background drilling level reflected in the CP forecast. Any additional drilling above this background level during the period from July 1, 2016 to June 31, 2017 was considered as UD. After the review, only two CD5 wells were deemed to fall in the North Slope UD category.

The current Cook Inlet UD category includes four sidetrack wells at McArthur River Field and one new well at Cosmopolitan. Wells in this category have facilities in place and rigs contracted for their development, and in most cases, funding is already allotted.

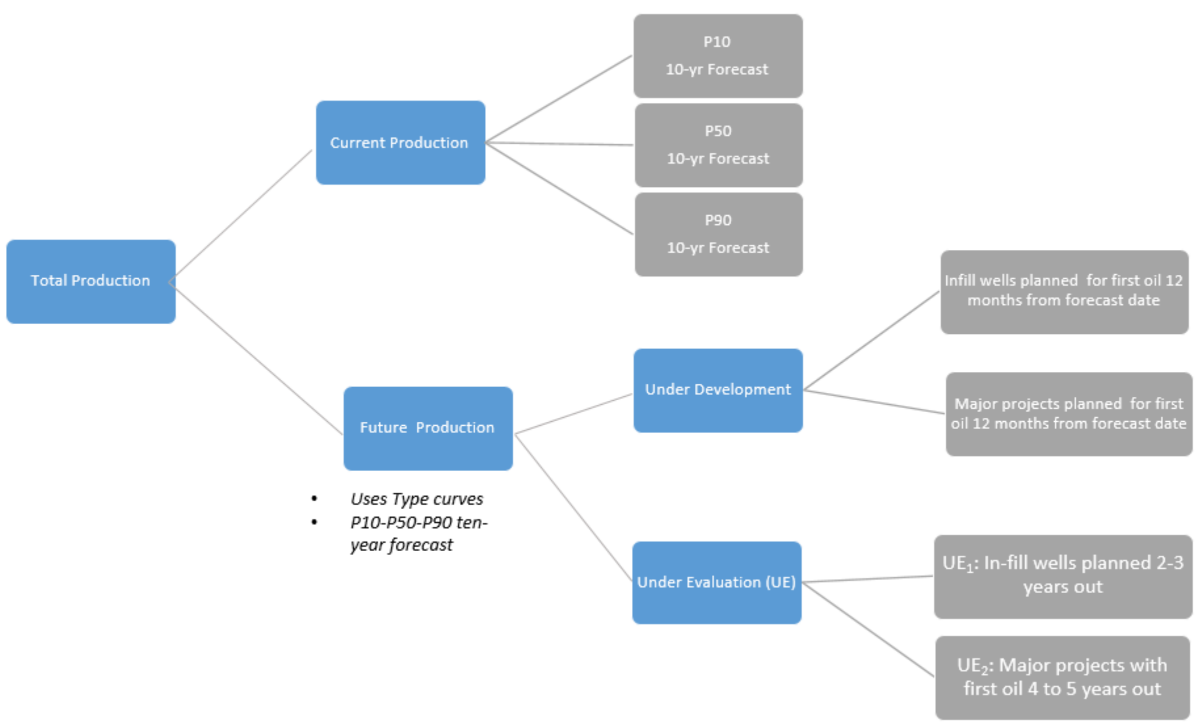

Figure 4. How total production is segmented into Current Production (CP), Under Development (UD), and Under Evaluation (UE) tranches.

The UE tranche includes all incremental production from single wells and major projects expected between 1 and 5 years from the forecast year. For example, the UE tranche includes both well-level and field-level projects. The UE tranche includes continued drilling at Cosmopolitan and three Trading Bay wells in the Cook Inlet, as well as additional wells at Colville River Unit CD5. The UE tranche on a field level includes GMT1, Oooguruk Nuna, Oooguruk Nuiqsut expansion, Nikaitchuq, Moose Pad at Milne Point, Moraine at Kuparuk River Unit, 1H NEWS at Kuparuk River Unit, and GMT 2.

1.2.3 Application of Risk and Uncertainty to the Currently Producing, Under Development, and Under Evaluation Volumes

Before 2012, minimal risking was applied to the production forecast. Between 2012 and Spring 2016, "DOR applied a uniform risk factor to [the] final consultant forecast for UD/UE production" (Alaska Department of Revenue 2016). The application of risk is different in the Fall 2016 production forecast.

1.2.3.1 Modified Bootstrapping Method

The modified bootstrapping method is the main feature in a software plug-in developed by Schlumberger in support of this project as a new part of their OFM probabilistic production forecasting suite. This plug-in was used to derive quantitative P10, P50, and P90 DCA forecasts for each of the pools in the CP tranche.

The modified bootstrapping method uses repeated random sampling of various portions of the historical production data to create sub-populations, calculates the distribution of each sample population, and applies that information to quantify the 80% confidence interval (P10-P90 range) of the probabilistic DCA forecasts that flow from them. The modified bootstrapping method works by including the residuals into the sampling process in a manner that honors the trends in the data, and through a backward analysis scheme uses several sub-segments of selected historical data to generate P10, P50, and P90 results over a wider range of outcomes (Wang 2006).

The modification permits generation of decline-based forecasts that fall between the generated P10 and P90 forecasts approximately 80% of the time (Wang, 2006). This is an improvement over conventional bootstrapping techniques, which Huffman and Thompson (1994), Hefner and Thompson (1996), and Wang (2006) showed have a 20% to 60% reliability of falling between the P10 and P90 forecasts. Application of the modified bootstrapping technique for probabilistic DCA is consistent with the best practice principle that successful forecasting would expect to be outside the P10-P90 range 20% of the time (Spencer and Morgan 1998).

1.2.3.2 Technical Risks and Uncertainty

In line with the new forecasting methodology, the following reservoir and commercial risks and uncertainty are considered.

Reservoir risks are considered primarily within the Oil Field Manager Software (OFM). The range of CP production derived using the OFM Software alongside the probabilistic plug-in produces not a single profile estimate of future production, but a probabilistic range that honors the uncertainty in the historical production trend. To aggregate this range of production with UD and UE production across different fields, it was necessary to use a Microsoft Excel model equipped with a probabilistic add-in, Palisade @Risk. The forecasted production range for CP pools determined using OFM was imported into the Microsoft Excel model. Type curves, generated from analogue historical wells of different performance levels within a given pool, were also imported into the Excel model. The range of production from currently producing pools and future production from type curves were used to develop expected production profiles for each pool, which were aggregated stochastically across different pools. The resulting P90-mean-P10 production profiles represent the possible range of future production.

The model also considers financial risks. This risking method uses a price trigger for each future project depending on how the development and operating costs for future production within each pool compares with the State's official price forecast. This risking is binary (that is, 0 or 1) and over several iterations, within a breakeven price range and cumulative production range for each type of project, this trigger determines whether individual projects go forward or not.

A more complex technique for financial risking of additional production might have considered a separate cash flow model for every pool to determine viability of rate-adding projects, amidst the fiscal system and separate division of interests for every pool. However, this approach was rejected as too time- and resource-intensive, and incorporating another layer of uncertain input with no assurance of producing more accurate output.

1.2.3.3 Non-Technical Risks

A pool performance index was considered in forecasting future production. This index accounts for other factors that have affected operators' performance in the past. This includes factors that are difficult to measure ranging from operator internal project approval strategy to field management strategies and geologic uncertainties. On a well level, this was derived from looking back at past PODs and comparing between wells promised by operators and those actually drilled, irrespective of the reasons provided for the change in plans. A review of the history of each pool shows varying levels of this risk and a 90% chance was used for every proposed well.

The risk of cancelling entire projects was considered but not included in the forecast because of the challenge in quantifying such risk. Rather, the forecast methodology applied a date cutoff of 5 years and included all projects that were estimated to achieve first oil within this time period.

1.3 Results

A 10-year production forecast was provided by the Department of Natural Resources to the Department of Revenue for incorporation in the Fall 2016 Revenue Sources Book (**Figure 5**).

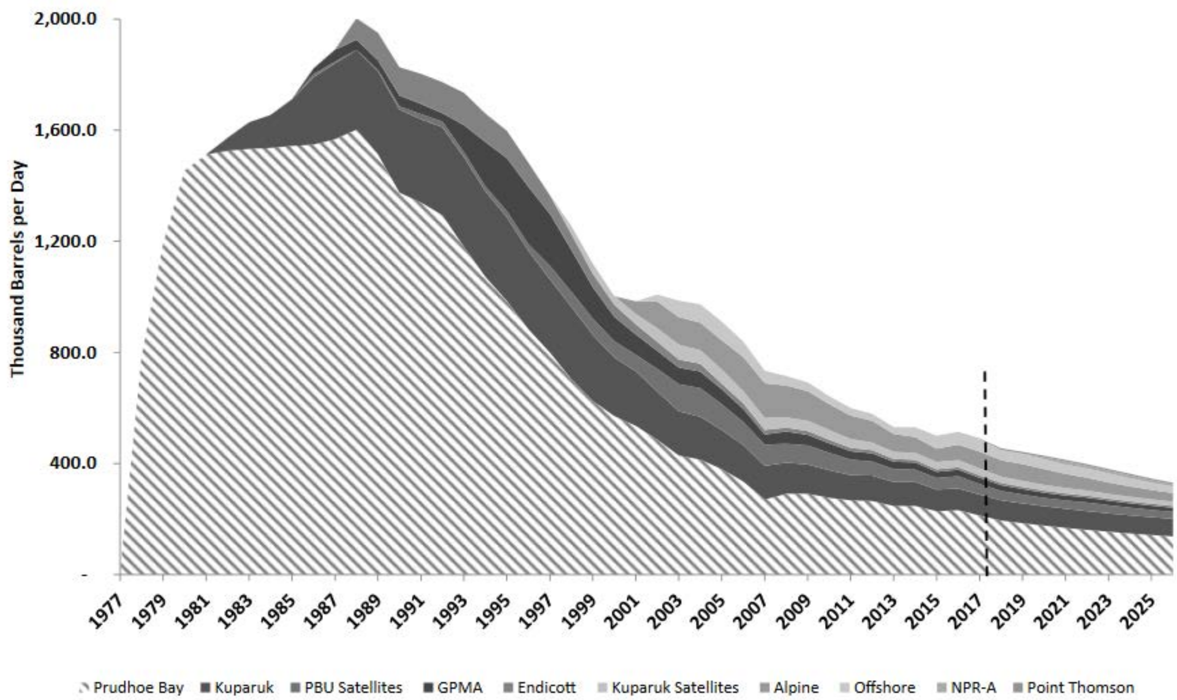

Figure 5. Alaska North Slope Production by production area, FY 1977 to FY2026, from the Fall 2016 Revenue Sources Book (Department of Revenue 2016).

Table 2 summarizes the official mean forecast for Alaska North Slope, Cook Inlet, and statewide total future oil production. The State fiscal year runs from July 1 of the preceding calendar year through June 30 of the calendar year.

The following regression analyses are meant to compare historical decline of Alaska North Slope oil, Alaska North Slope NGLs, and DNR's 10-year production forecast decline. The regression of **Figure 6**, based on oil production only (no NGLs) since production peaked in 1988, shows the overall historic decline rate on the Alaska North Slope has been approximately 5.5%. The regression of **Figure 7**, based on monthly NGL manufacture since peak in 1997, is 4.8%. When Alaska North Slope oil production and NGL production are combined, the decline rate since 1988 peak oil is 5.3%. The combination of oil and NGL is for discussion purposes, but is not considered best practice in decline-based production forecasting.

Note that NGLs are manufactured by chilling produced gas within the facilities process. Since NGLs are blended with the oil production stream for sale through TAPS, the volume of NGL produced depends to a large extent on existing TAPS vapor pressure limits. NGLs can also be used to blend miscible injectant for enhanced oil recovery purposes. For example, at the Duck Island Unit, NGLs not sold to TAPS are blended to create a miscible injectant that is used in water-alternating-gas enhanced oil recovery from the Endicott Field (Petrotechnical Resources of Alaska 2004). The Prudhoe Bay Unit is the largest NGL producer.

	Official Forecast (mean) for Alaska North Slope Production (thousands of barrels per day)	Official Forecast (mean) for Cook Inlet Production (thousands of barrels per day)	Official Forecast (mean) for Total Alaska Production (thousands of barrels per day)
FY2017	490.3	15.5	505.8
FY2018	455.6	14.2	469.7
FY2019	442.1	15.7	457.8
FY2020	428.6	14.6	443.1
FY2021	413.5	13.0	426.5
FY2022	398.2	11.7	410.0
FY2023	380.4	10.6	391.0
FY2024	363.4	9.7	373.1
FY2025	345.9	8.9	354.7
FY2026	331.0	8.2	339.2

Table 2. Summary of official oil plus NGL forecast (mean) for the Fall 2016 Revenue Sources Book.

When examining statewide the oil plus NGL decline rate for the Fall 2016 Revenue Sources Book forecast, the mean decline rate over the 10-year forecast period is 4.2%, somewhat optimistic relative to the 5.3% average historic decline rate for oil plus NGL since production peaked in 1988. The Alaska North Slope oil plus NGL forecast has a P90 decline rate of 3.0% and a P10 decline rate of 5.5% over the 10-year forecast period. The statewide oil plus NGL forecast has a slightly narrower distribution, with a P90 decline rate of 3.2% and P10 decline rate of 5.6%.[2]

[2] Note that in the context of decline rates, the P90 (low-side) decline value leads to more optimistic estimates of future production, and the P10 (high side) decline value leads to more conservative estimates.

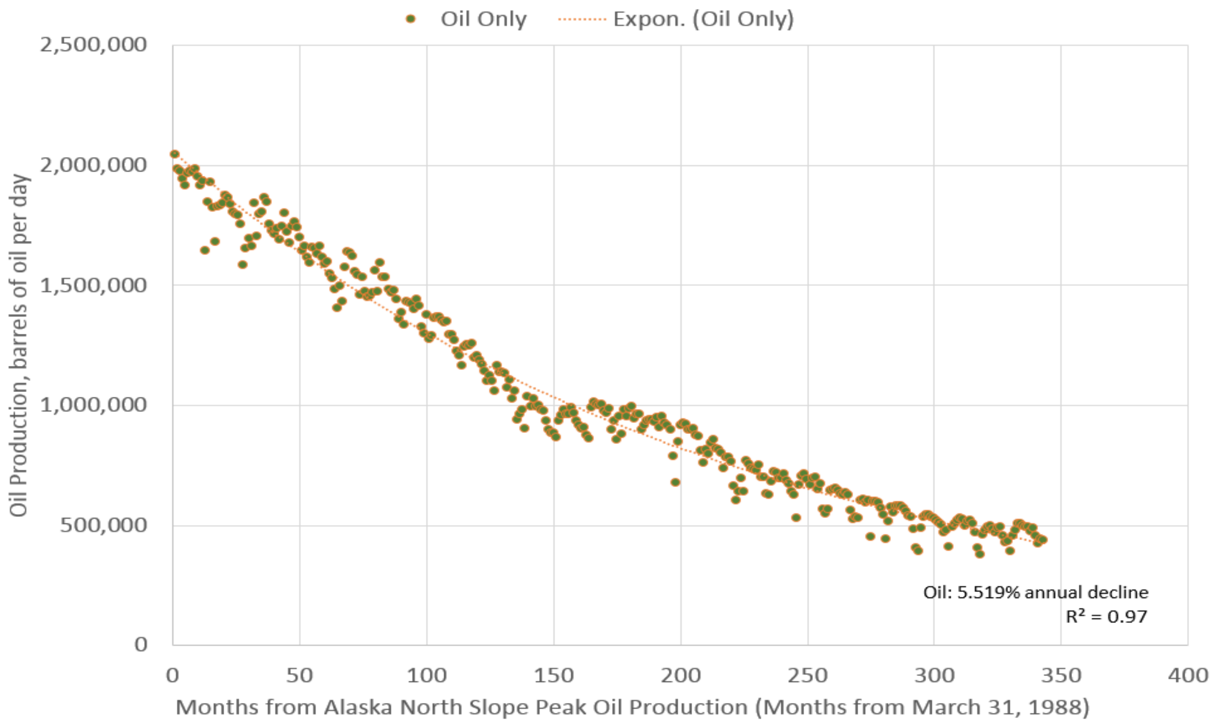

Figure 6. Average decline from Alaska North Slope peak oil production, since March 31, 1988 (oil only, not including NGLs).

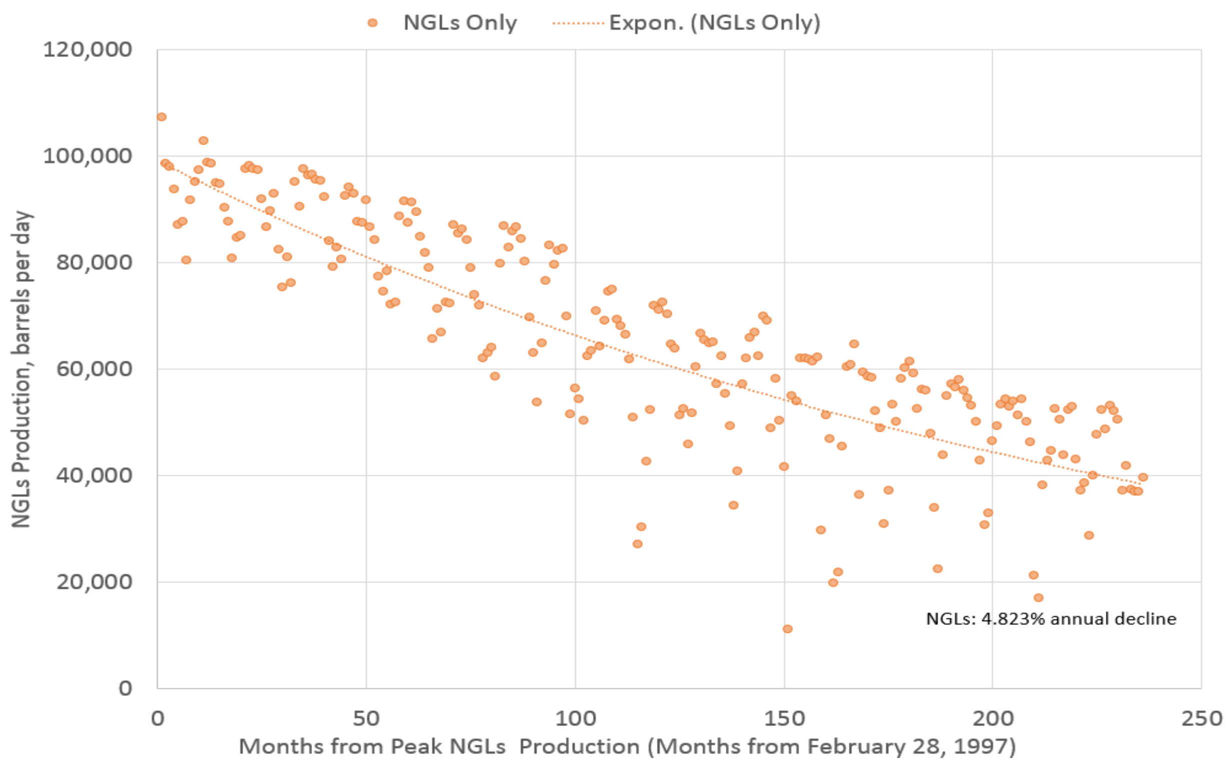

Figure 7. Average decline from Alaska North Slope peak NGL production, since February 28, 1997 for NGL production.

2 Part 2: Potential Future Projects

2.1 Disclaimer

Part 2 of this report discusses production scenarios associated with potential future development projects. These outlooks are informally referred to as “Pot of Gold” scenarios to differentiate them from the actual forecast, and because they reflect a very optimistic (unrisked) view of how the long-term future might play out. They are completely independent of the official forecast provided by the Division of Oil and Gas to the Department of Revenue for fiscal planning purposes. Because of the highly uncertain nature of many of these projects, this part of the report should not be construed as an actual forecast, a reserves report, or an economic validation of future projects. The hypothetical oil production profiles were calculated in order to show, for illustrative purposes only, the identifiable future possibilities that are outside of the 5-year window until anticipated first oil production for the UD and UE tranches considered in the official state forecast. These speculative oil production profiles are useful to frame a discussion around the impact new production might have on the longevity of the Trans Alaska Pipeline.

The following discussion does not conform to Security and Exchange Commission Oil and Gas rules, nor is it based on the definitions and disclosure guidelines contained in the Petroleum Resources Management System adopted by the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists, and Society of Petroleum Evaluation Engineers.

The ”Pot of Gold” oil production profiles shown below were compiled using unrisked type well production profiles, estimated timing to first oil, and estimated ultimate recoveries. That is, no technical, economic, or political risks have been applied to the production rate profiles. Applying such risks would predictably reduce the oil production rate profile.

2.2 Methodology

The rate impacts of potential future projects are estimated based on analogue type wells from similar North Slope reservoirs, or other methods using engineering judgement. The projects in this analysis are listed below in terms of increasing risk in delivering their respective oil production profiles by the estimated first oil date. To illustrate, the Fiord West project is considered the most likely to meet the estimated first oil date because of an agreement between the State of Alaska and ConocoPhillips (Bailey 2016). The following projects were considered:[3]

1. Fiord West Project
2. Placer Project
3. Pikka Project
4. Tofkat Kuparuk C Project
5. Liberty Project
6. Point Thomson Major Gas Sales Project
7. Smith Bay Project
8. Ugnu Project

[3] Neither of the two “Pot of Gold” scenarios include the Willow discovery, which was announced by ConocoPhillips as this report was being finalized. The operator estimates that if developed, Willow will yield 40,000 to 100,000 barrels of oil per day, depending on whether it produces through shared or standalone facilities.

2.2.1 Analogue Type Wells

Analogue type well oil production rates were developed based on North Slope reservoirs of similar geological age and reservoir characteristics. “Several geologic and reservoir parameters influence well-productivity in oil fields. Geologic factors include formation, age, depth, depositional style, lithology, net pay, and heterogeneity of the primary producing interval of each field. Reservoir factors are porosity, permeability, pore-pressure gradient, and crude gravity” (Sandrea and Goddard 2016). Additional reservoir factors include the reservoir recovery mechanism, such as water-alternating-gas, waterflood, or primary depletion.

Taking into account both geological parameters and reservoir conditions, P50 type wells were statistically calculated for the following fields on a pool or reservoir level:

- **Fiord West Project:** analogue type wells for this project’s Kuparuk C and Nechelik reservoirs were developed from Fiord-Kuparuk and Fiord-Nechelik reservoirs at the Colville River Unit;
- **Pikka Project:** analogue type wells were developed for the Nanushuk, Alpine C, and Alpine A reservoirs from their Colville River Unit counterparts, and for the Kuparuk C and Nuiqsut reservoirs based on their equivalents at the Oooguruk Unit. The full development includes proposed Drill Sites 1, 2, 3, 4, and 5, though the current EIS only applies for permits Drill Sites 1, 2, and 3;
- **Placer Project:** analogue type wells were developed for this Kuparuk C reservoir from its equivalent at the Oooguruk Unit;
- **Smith Bay Project:** analogue type wells for this Torok Formation prospect were developed based on the Torok Nanuq-Nanuq reservoir at the Colville River Unit;
- **Tofkat Project:** analogue type wells for the Kuparuk C prospect on former Tofkat Unit leases were developed from the Kuparuk C reservoir at the Oooguruk Unit.

2.2.2 Other Methods

Alternative methods included researching Environmental Impact Statements, public meeting slide decks, periodicals, and retrieving public data from other sources.

Below are the fields for which alternative sources of information were used to determine the oil production profile. It is important to note these methods are based on the most recent data publicly available.

- **Liberty Project:** The Liberty Development Project Development and Production Plan, Revision 1, provided a production profile integrating most recent known exploration and appraisal data into a reservoir simulation of the most likely outcome (Hilcorp 2015).
- **Point Thomson Major Gas Sales (MGS) Project:** A single project production profile was developed based on condensate yields from public AOGCC well files and expected gas offtake.
- **Ugnu Heavy Oil Project:** A single project production profile was developed based on a BP presentation given at the Alaska Oil and Gas Association (Pospisil 2011).

2.3 Results

It is important to reiterate that the “Pot of Gold” exercise described here should not be construed as an actual forecast, a reserves report, or an economic validation of future projects. Scenario A contains the oil production that would result from all eight projects if they were to occur as timed, whereas Scenario B contains only the first four higher chance projects: Fiord West, Placer, Pikka, and Tofkat.

Though the Department of Natural Resources provided only a 10-year forecast for the official 2016 Fall Revenue Source Book from the Department of Revenue, the forecast was further extended out to 2069 using the 10-year decline rate of 4% to depict the impacts of Scenarios A and B. This does not represent a long-term forecast for use in any public purpose, including but not limited to property tax assessment, fiscal planning, or any other regulatory or legislative action.

This analysis is provided simply for context and scale as public discussions and media outlets speak to these potential projects. The division does not condone the use of these data for any other purpose and would vehemently object to the inclusion of these future projects for the purpose of long-term financial planning until much more information is available.

2.3.1 Scenario A

Scenario A shows the Fall 2016 Revenue Sources Book Forecast from the Alaska Department of Revenue, hypothetically extrapolated to 2069, using the official forecast's average 10-year decline rate of 4% percent, with all eight of the projects included. The forecasted oil production profile shown is not risked. Actual (historical) production is from previous Revenue Sources Books, and only includes Alaska North Slope production. **Figure 8** shows the results from the oil production forecast for all eight projects without the application of any risk factors. Depending on timing and other performance assumptions, all these projects combined could potentially increase production by 250,000 to 350,000 BOPD compared to the underlying official forecast over a period of 20 years or more.

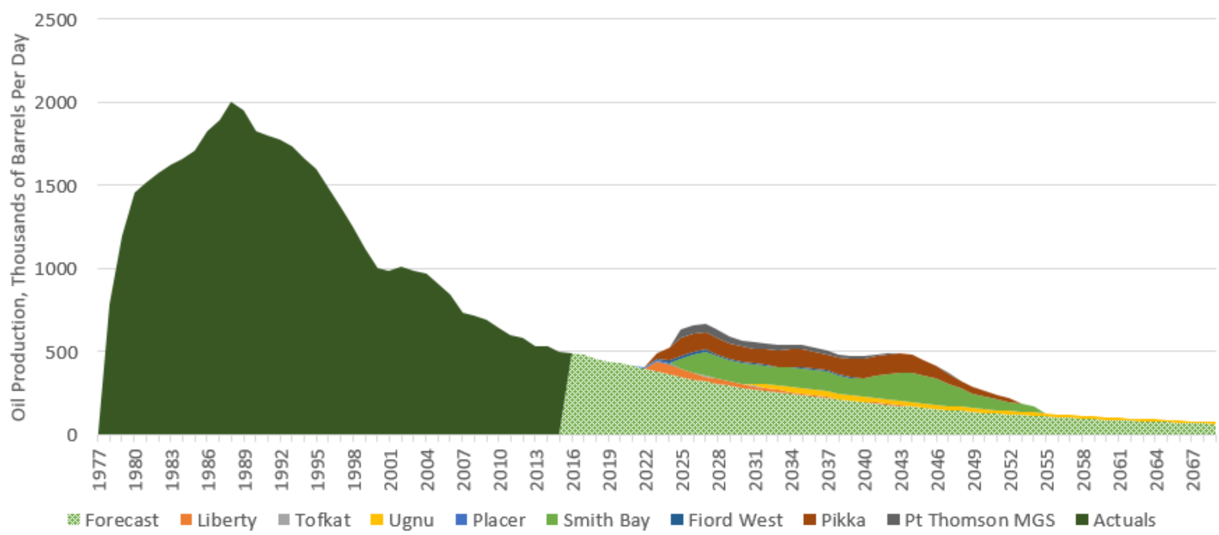

Figure 8. Scenario A, speculative, unrisked oil production forecast for all eight projects.

2.3.2 Scenario B

The profile of Scenario B includes only the four most likely projects (Fiord West, Placer, Pikka, and Tofkat) layered onto the Fall 2016 Revenue Sources Book Forecast from the Alaska Department of Revenue, hypothetically extrapolated to 2069, using the official forecast's average 10-year decline rate of four percent.

The forecasted oil production profile shown is not risked. Actual production is from previous Revenue Sources Books, and only includes Alaska North Slope production. **Figure 9** shows the results from the oil production forecast for the lower risk projects of Fiord West, Placer, Pikka, and Tofkat without the application of any risk factors. As in Scenario A, this scenario's production profile is unrisked. Actual production is from previous Revenue Sources Books, and only includes Alaska North Slope production. This scenario is considerably more conservative, with the potential for boosting production by 100,000 BOPD or more compared to the underlying official production forecast for approximately 20 years.

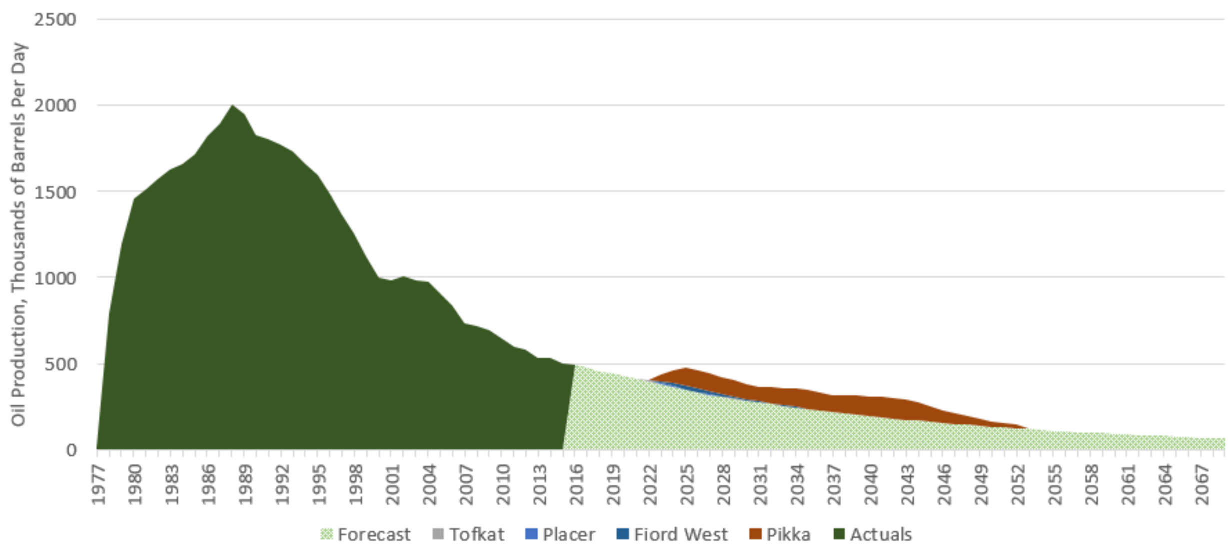

Figure 9. Scenario B, speculative, unrisked oil production forecast for the lower risk projects of Fiord West, Placer, Pikka and Tofkat.

3 Summary

This report summarizes the approach and method used to produce two separate and distinct products. The first is a statewide 10-year production forecast for oil and NGLs for the Department of Revenue's Fall 2016 Revenue Sources Book. The second product is unrisked scenarios of potential future production associated with more speculative projects that are not expected to yield first oil within the next five years. Only the official state forecast, presented in the Revenue Sources Book, should be used for planning and budgeting purposes.

The State's official forecast, discussed in Part 1 of this report, includes CP, UD, and UE production categories. The CP forecast category considers decline-based estimates of production from existing fields and wells. The UD category consists of new wells and projects where first oil is expected within the first year from the forecast date of July 1, 2016. The UE category includes projects where first oil is expected to occur within five years from July 1, 2016. It is important to note that over 90% of the forecasted oil production belongs to the CP category.

Part 2 of this report shows additional analysis undertaken to examine other potential development projects being discussed within Alaska's oil industry. Given the uncertain nature of this second group of projects, and their anticipated first oil dates more than five years into the future, they are not included in the state's forecast for budgeting and planning. However, as these projects progress they will be reevaluated and potentially added into the official state forecasts in the future. In their current states, these uncertain projects contribute to the larger discussion of the future of oil development within the state and are illustrative in discussing the service life of the Trans Alaska Pipeline.

3.1 Impact on Trans Alaska Pipeline Service Life

There exists some minimum amount of oil that can flow through the Trans Alaska Pipeline System (TAPS) to keep it technically and economically operational. If the volume of oil produced on the North Slope does not exceed that minimum amount, it can be expected that all production on the North Slope will cease. The exact amount of that minimum threshold is a hot topic of debate. Public reports on TAPS minimum throughput range between 70,000 barrels of oil per day to 350,000 barrels of oil per day, largely based on technical factors. Economic factors are also important. As production declines, the cost of operating the pipeline is spread over fewer barrels of oil. This implies that if the value of oil is not sufficiently high, it will be more expensive to produce and ship the oil than it is worth. **Table 3** provides a summary of the ranges provided by different sources for the TAPS low-flow rate.

In the face of such widely ranging estimates, the Division of Oil and Gas does not take a position on the actual low-flow limit. However, we do find it useful to show examples of how different forecast scenarios and low-flow estimates interact to provide a range of estimates for when TAPS might end operations. For example, **Table 4** considers three possible production scenarios, paired against two different estimates of the low-flow limit. The production scenarios are the mean Fall 2016 Revenue Sources Book forecast (Part 1 of this report) and the two more speculative scenarios A and B of additional future projects (Part 2 of this report). We examine a conservative estimate of 300,000 BOPD and a more optimistic estimate of 100,000 BOPD, though we acknowledge the actual low-flow limit could be outside that range.

Using the data in this report, we can identify the point at which these theoretical limits are reached. While the Division of Oil and Gas makes no assertion as to when TAPS may become inoperable, it is insightful to realize how these potential future oil projects move these thresholds.

Low-Flow Rate of Oil	Source
350,000 BOPD	Alyeska Pipeline Co. Report 2011
300,000 – 350,000 BOPD	TAPS owner companies interpretation of Alyeska Pipeline Co. Report 2011
300,000 BOPD	BP low flow rate for booking SEC reserves, until 2004
135,000 BOPD	BP / JTG Technology and Information Services Inc. 2005
100,000 BOPD	Judge Gleason conclusion on low-flow rate, 2011 (BP Pipelines, et al. v. State, et al., 2011)
70,000 BOPD – 100,000 BOPD	BP / Phil Carpenter, BP low flow rate for booking SEC reserves, 2010
45,000 BOPD, assuming new pipeline, 20-inch inner diameter, from Prudhoe Bay to Fairbanks	BP / JTG Technology and Information Services Inc. 2005

Table 3. Summary of TAPS low-flow rates from BP Pipelines, et al. v. State, et al. 2011

Forecast / Scenario	TAPS Low-Flow Oil Rate Limit	Approximate Year of TAPS Shutdown
Fall 2016 Revenue Source Book Production Forecast	100,000 BOPD	2058
Scenario B (lower risk projects included, unrisked)	100,000 BOPD	2058
Scenario A (all 8 future projects included, unrisked)	100,000 BOPD	2061
Fall 2016 Revenue Source Book Production Forecast	300,000 BOPD	2029
Scenario B (lower risk projects included, unrisked)	300,000 BOPD	2042
Scenario A (all 8 future projects included, unrisked)	300,000 BOPD	2049

Table 4. Summary of possible TAPS low-flow oil rate limits and the corresponding year of TAPS inoperability assuming three different production profiles: the Fall 2016 Revenue Source Book Production Forecast, Scenario A, and Scenario B.

Figures 10 through 12 below show an illustrative range of low-flow rate and the three different production scenarios, and yield estimates of approximate year that TAPS may become inoperable. **Figure 10** shows that taking the Fall 2016 Revenue Sources Book production forecast as the base scenario, the low-flow rate of 300,000 BOPD will be reached in approximately 2029. If the 100,000 BOPD scenario is assumed for the Fall 2016 Revenue Source Book production forecast, that low-flow rate will be reached in approximately 2058.

Figure 11 shows that under Scenario A, if all eight unrisked projects achieve their estimated first oil dates and sustain their production rates, and given a 300,000 BOPD low-flow rate, the approximate year of TAPS inoperability can be deferred from 2029 to 2049. Given Scenario A and a more optimistic low-flow limit of 100,000 BOPD, TAPS could continue to operate until 2061.

Figure 12 shows that under Scenario B, if only the four most likely unrisked projects achieve their estimated first oil and sustain their production rates, and given a 300,000 BOPD low-flow rate, the approximate year of TAPS inoperability can be deferred from 2029 to 2042. Because Scenario B projects are assumed to be exhausted by about 2053, a low-flow limit of 100,000 BOPD could be reached in 2058, the same time as without these projects.

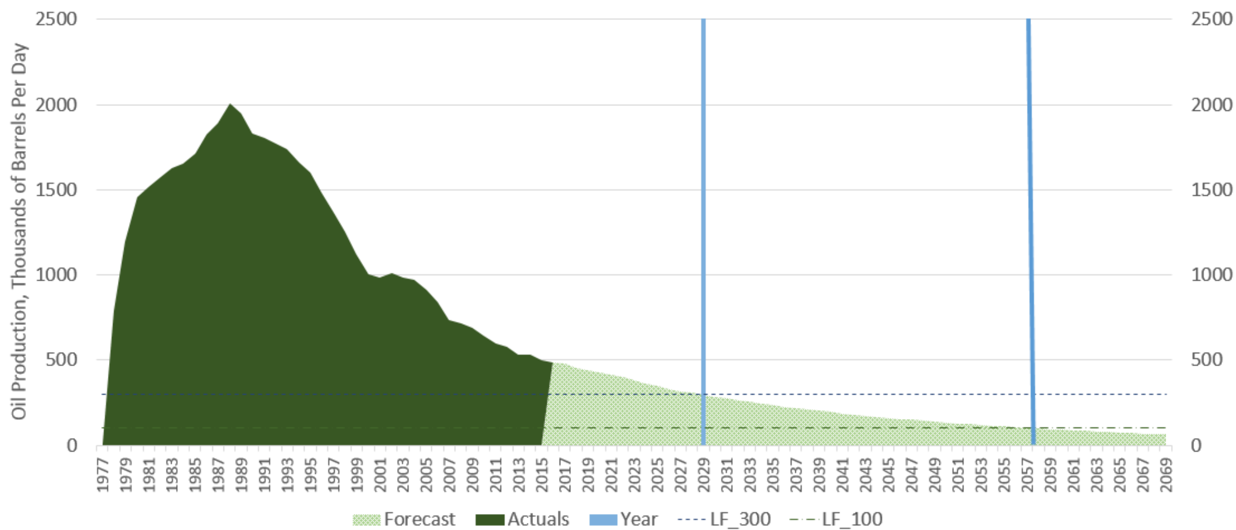

Figure 10. Alaska North Slope actual production and official forecast for Fall 2016 Revenue Source Book. An illustrative range of low-flow rates is shown with approximate year of shutdown. For the 300,000 BOPD low-flow rate, the approximate year of TAPS shutdown could be 2029. For the 100,000 BOPD low-flow rate, the approximate year of TAPS shutdown could be 2058.

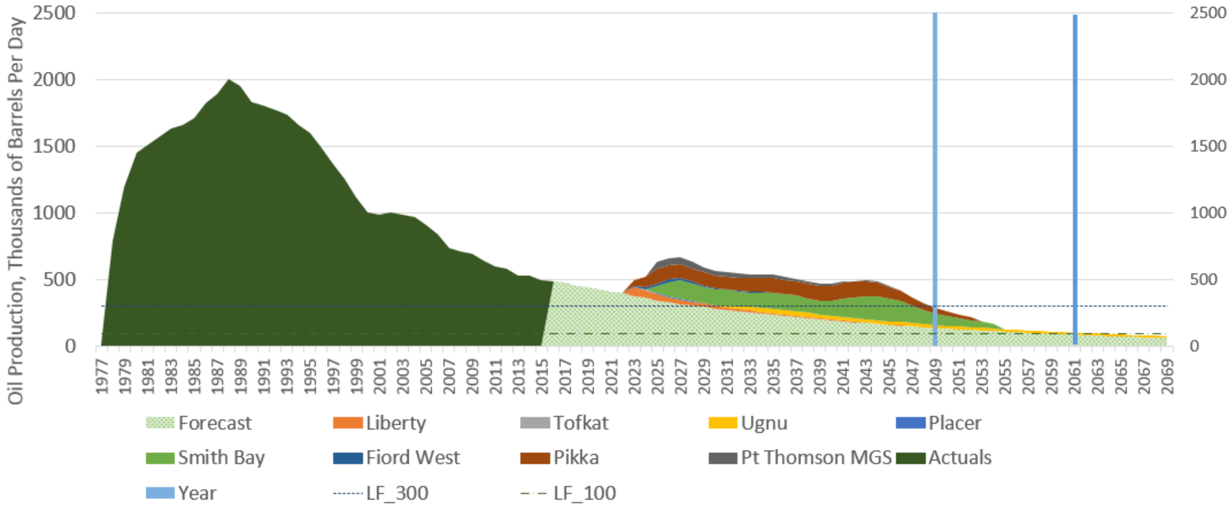

Figure 11. Alaska North Slope actual production and Scenario A, showing all eight unrisked potential future North Slope projects coming online. An illustrative range of low-flow rates is shown with approximate year of shutdown. For the 300,000 BOPD low-flow rate, the approximate year of TAPS shutdown could be 2049. For the 100,000 BOPD low-flow rate, the approximate year of TAPS shutdown could be 2061.

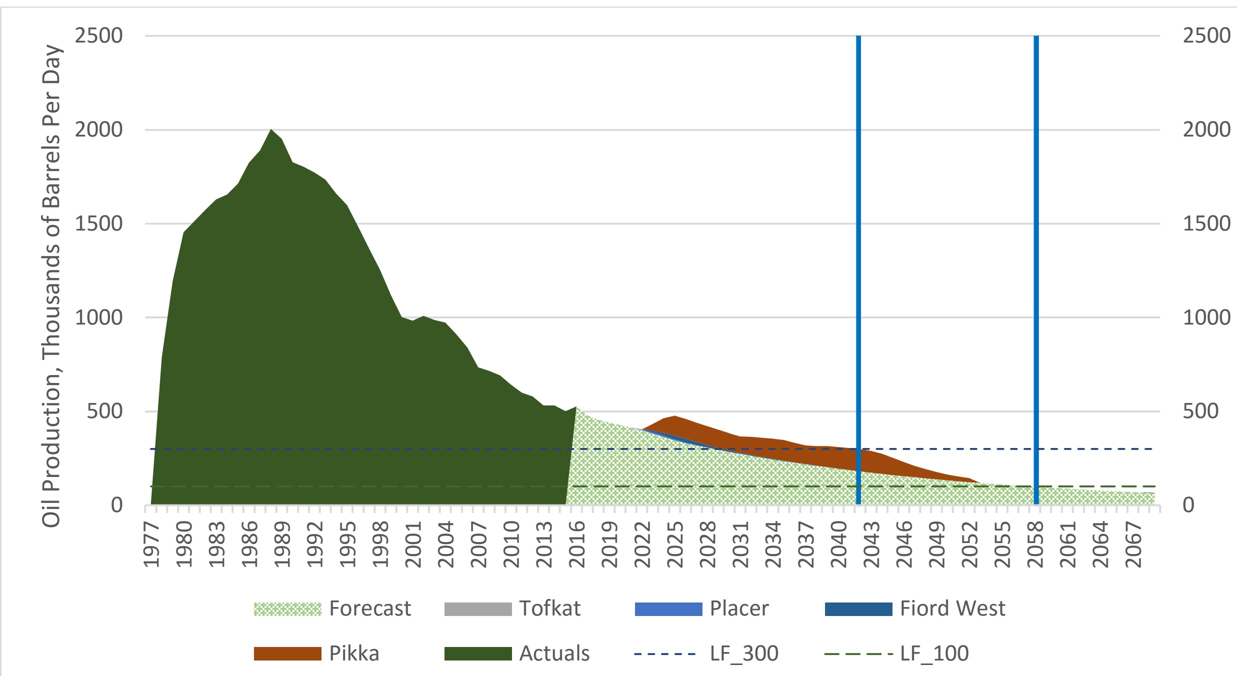

Figure 12. Alaska North Slope actual production and Scenario B, showing four lower risk North Slope projects coming online, including Tofkat, Placer, Fiord West, and Pikka. An illustrative range of low-flow rates is shown with approximate year of inoperability. For the 300,000 BOPD low-flow rate, the approximate year of TAPS shutdown could be 2042. For the 100,000 BOPD low-flow rate, the approximate year of TAPS shutdown could be 2058.

4 Works Cited

Alaska Department of Revenue. (1970). *Revenue Sources Book.* Juneau, AK.

Alaska Department of Revenue. (1975). *Revenue Sources Book.* Juneau, AK.

Alaska Department of Revenue. (1984, September). *Revenue Sources Book September 1984.* Juneau, AK.

Alaska Department of Revenue. (1988). *Revenue Sources Book Fall 1988.* Juneau, AK.

Alaska Department of Revenue. (1996). *Revenue Sources Book Fall 1996.* Juneau, AK.

Alaska Department of Revenue. (1999). *Revenue Sources Book Fall 1999.* Juneau, AK.

Alaska Department of Revenue. (2004). *Revenue Sources Book Spring 2004.* Juneau, AK.

Alaska Department of Revenue. (2006). *Revenue Sources Book Fall 2006.* Juneau, AK.

Alaska Department of Revenue. (2012). *Revenue Sources Book Fall 2012.* Juneau, AK.

Alaska Department of Revenue. (2016). *Revenue Sources Book Fall 2016.* Juneau, AK.

Bailey, Alan. (2012, January). A TAPS bottom line: Operation economics as much as technology will determine pipeline future. *Petroleum News.* Retrieved December 1, 2016 from http://www.petroleumnews.com/pntruncate/225019711.shtml

Bailey, Alan. (2016, October). A major new ERD rig: ConocoPhlilips has commissioned drilling unit for Fiord West development. *Petroleum News.* Retrieved December 1, 2016 from http://www.petroleumnews.com/pntruncate/748220773.shtml.

BP Pipelines, et al. vs. State, et al., Decision Following Trial de Novo – 2007, 2008, 2009 Assessed Valuations (Alaska 2011).

Capen, E. C. (1976, August 1). The Difficulty of Assessing Uncertainty (includes associated papers 6422 and 6423 and 6424 and 6425). Society of Petroleum Engineers. doi:10.2118/5579-PA

Caddy, D. G. (1993, January 1). Cost Control and Risk Mitigation of Major Projects. Society of Petroleum Engineers. doi:10.2118/25310-MS

Cashman, Kay. Six rigs to two: Operator BP shutting down drilling rigs in Prudhoe Bay and satellites. *Petroleum News.* Retrieved December 27, 2016 from http://www.petroleumnews.com/pntruncate/471154696.shtml.

Hefner, J.M. and Thompson, R.S.: "A Comparison of Probabilistic and Deterministic Reserve Estimates: A Case Study," SPERE (Feb. 1996) 43.

Hilcorp Alaska LLC. (2015, September). Liberty Development Project Development and Production Plan Revision 1. Retrieved December 19, 2016 from http://libertyprojectak.com/wp-content/uploads/2015/07/2015-09-18-LibertyDPP.pdf

Hobson, M.K. Economist explains bleak economic realities of oil crash. *E&E News*. Retrieved December 22, 2016 from http://www.eenews.net/stories/1060036804

Huffman, C.H. and Thompson, R.S.: "Probabilistic Ranges for Reserve Estimates from Decline Curve Analysis," paper SPE 28333 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, 25-28 September.

Kaiser, M.J. and Y. Yu. (2010, June). Gulf Coast Economic Limits—1: Economic limits estimated for US gulf coastal field. *Oil and Gas Journal.* Retrieved from http://www.ogj.com/articles/print/volume-108/issue-20/exploration-__development/gulf-coast-economic.html

Low Flow Study Project Team at the Request of Alyeska Pipeline Service Company. (2011, June 15). Low Flow Impact Study Final Report. Retrieved December 1, 2016 from http://www.alyeska-pipe.com/assets/uploads/pagestructure/TAPS_Operations_LowFlow/editor_uploads/LoFIS_Summary_Report_P6%2027_FullReport.pdf

McVay, D. (2015, February 1). Industry Needs Re-Education in Uncertainty Assessment. Society of Petroleum Engineers. doi:10.2118/0215-0072-JPT

Molli, F. Historical context and technical interview with Alaska Division of Oil and Gas (personal communication, July 21, 2016).

Monte Carlo Simulation. Retrieved from http://www.palisade.com/risk/monte_carlo_simulation.asp

Murtha, J.A. and S.K. Peterson. "Chapter 10 – Risk and Decision Analysis." *Petroleum Engineering Handbook Volume VI – Emerging and Peripheral Technologies*, edited by H.R. Warner Jr. and Larry W. Lake, Society of Petroleum Engineers, 2007.

Nelson, K. (2007, November 18). Alaska Oil forecast shaky: Production interruptions, infrastructure renewal, slowed heavy oil pace the cause. *Petroleum News.* Retrieved November 18, 2016 from http://www.petroleumnews.com/pntruncate/463243474.shtml

Petrotechnical Resources of Alaska for Division of Oil and Gas, Alaska Department of Natural Resources. (2004). *North Slope of Alaska Facilities Sharing Study*. Anchorage, AK: B. Kaltenbach, C. Walsh, C. Foerster, T. Walsh, J. McDonald, P. Stokes, C. Livesey, and W. Nebesky.

Pospisil, Gordon (2011, January). Heavy Oil Challenges & Opportunities North Slope Alaska. Retrieved December 1, 2016 from http://www.aoga.org/wp-content/uploads/2011/01/8.-Pospisil-Heavy-Viscous-Oil.pdf [PowerPoint slides].

Rajvanshi, A. K., Gmelig Meyling, R., & Ten Haaf, D. (2012, January 1). Instilling Realism in Production Forecasts: Dos and Don'ts. Society of Petroleum Engineers. doi:10.2118/155443-MS

Sandrea, R. and D. A. Goddard. (2016, December). New reservoir-quality index forecasts field well-productivity worldwide. *Oil and Gas Journal.* Retrieved December 19, 2016 from http://www.ogj.com/articles/print/volume-114/issue-12/drilling-production/new-reservoir-quality-index-forecasts-field-well-productivity-worldwide.html

Singleton, I. (1995, January 1). A Pragmatic Approach to Risked Production Forecasting. Society of Petroleum Engineers. doi:10.2118/29672-MS

Spencer, J. A., & Morgan, D. T. K. (1998, January 1). Application of Forecasting and Uncertainty Methods to Production. Society of Petroleum Engineers. doi:10.2118/49092-MS

Tangeman, B. & W.C. Barron. (2013, January 24). *Oil Production Forecast.* [PowerPoint slides].

Wang, Y. (2006) *Determination of Uncertainty in Reserves Estimate from Analysis of Production Decline Data* (Masters of Science dissertation). Retrieved from Texas A&M OAKTrust database.

Acknowledgements

The authors thank Jhonny Meza, Mike Redlinger, Greg Bidwell, Alex Nouvakhov, and Jim Shine for their support in this project.