bp

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June 27, 2018

HAND-DELIVERED

Ms. Chantal Walsh, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 1100
Anchorage, AK 99501-3560

Re: Greater Point McIntyre Area Plans of Development

Dear Director Walsh:

BP Exploration Alaska (BPXA), as Operator of the Prudhoe Bay Unit, submits with this letter six updates to the Plans of Development for Lisburne, Combined Niakuk, Point McIntyre, Raven, North Prudhoe Bay and West Beach Participating Areas in the Greater Point McIntyre area of the Prudhoe Bay Unit.

The updates to the Plans of Development may contain geological, geophysical, or engineering data that is labeled 'confidential.' Data labeled 'confidential' is a confidential and valuable trade secret of BPXA and the Prudhoe Bay Unit working interest owners, and BPXA requests that the data be kept confidential as provided in the Prudhoe Bay Unit Agreement and AS 38.05.035(a)(8), 11 AAC 82.810 and other applicable law; and note that such data is protected from misuse and disclosure by the Alaska Uniform Trade Secrets Act (AS 45.50.910 et seq.).

Any questions can be directed to Bill Bredar at 564-5348 or through email to William.Bredar@bp.com.

Respectfully,

Katrina Garner

Katrina Garner
Fieldwide Manager
Alaska Reservoir Development Team
BP Exploration (Alaska) Inc.

cc: Mr. Eric Reinbold, ConocoPhillips Alaska, Inc.
Mr. Hank Jamieson, ExxonMobil Alaska Production Inc.
Mr. Jefferey Farr, ExxonMobil Alaska Production Inc.
Mr. Dave White, Chevron USA
Mr. Carl Lundgren, BPXA
Mr. Dave Roby, Alaska Oil and Gas Conservation Commission

PRUDHOE BAY UNIT
LISBURNE PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2018 UPDATE OF PLAN OF DEVELOPMENT

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Lisburne Participating Area (LPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2018, through September 30, 2019.

The objective of the LPA POD is to identify strategies to maximize commercial oil production from the Lisburne reservoir in a cost-effective, safe and environmentally responsible manner. The 2018 update to the LPA POD assumes a continuation of the current business climate and reflects the current understanding of the Lisburne reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE, CONDENSATE AND NGLS

Crude, condensate and NGL rates for the Lisburne Field averaged 13.8 MB/D for the reporting period April 1, 2017 to March 31, 2018. A total of 5.1 MMB of Lisburne oil and NGL was delivered to the Trans-Alaska Pipeline System (TAPS) during the reporting period.

B. Produced Gas

Lisburne gas production totaled 83.0 BSCF for the reporting period with 54.5 BSCF re-injected into the Lisburne Gas Cap to provide pressure support. 7.5 BSCF was consumed as fuel or flare gas. For the report period, Lisburne gas production averaged 226.7 MMSCF/D yielding an average GOR of 16,401 SCF/STBO. Lisburne NGL separation averaged 1.67 MB/D with a total of 0.61 MMB delivered and shipped with crude oil production through TAPS during the reporting period.

C. Produced Water

Lisburne water production for the reporting period was 4.3 MMB, yielding an average water production rate of 11.8 MB/D and average water cut of 46%. Lisburne Production Center (LPC) produced water not used for water injection in the Pt. McIntyre reservoir is injected into the LPC-01 and LPC-02 Cretaceous interval disposal wells. Water injection into the two Cretaceous disposal wells totaled 16.2 MMB (including Pt McIntyre, Niakuk and FS1 produced water) yielding an average water disposal injection rate of 44 MB/D for both wells.

2.2 Development And Production Activity

Development and production activities have continued in accordance with the LPA POD. Summarized below are the significant development activities over the past year.

A. Enhanced Recovery - Injected Water

Seawater injection into the Lisburne reservoir gas cap continues to be used to supplement the benefits of gas injection for oil recovery.

Seawater injector L5-29i only injected for 11 days in the reporting period due to integrity issues encountered with the injector, Seawater injection continued into 04-350i (peripheral Wahoo) and L5-15i (mid-field Wahoo). NK-25i (Alapah) injected for part of the reporting period but was shut-in since there was no longer off-take in its injection block and reservoir pressure had achieved desired levels. L5-13i (Wahoo) injector was P&A'd after it developed an integrity issue during a pressure test in early 2017.

On July 14th 2008, the Lisburne Gas Cap Water Injection (GCWI) Pilot commenced injecting into the L5-29i well, as approved under CO 207A.001 and AIO 4E.029. During the prior reporting period the GCWI Pilot was approved for permanent injection under AOGCC Conservation Order 207B.16. The injector remained shut in throughout most of the reporting period awaiting repair. As of March 31st, 2018, the L5-29i gas cap water injector has injected 22.2 MMB of water. Repair is planned during the current POD plan year. Water breakthrough has reached wells L5-28A, L5-32, L5-33 and L5-36. Breakthrough indications include rise in watercut, GOR suppression, as well as water sample analysis for seawater trace minerals. With GCWI resulting in GOR suppression, several previously uncompetitive wells have begun to be brought back online at L5 Pad (pending gas lift installs). Some gas re-influx has begun to be seen in well L5-28A in the absence of GCWI while the integrity repair is completed.

Peripheral Lisburne Wahoo seawater injector 04-350i commenced injection in May 2012. A total of 1.282 MMB of seawater was injected during the reporting period, for an annual average rate of 3500 bbl/day. Seawater production has been observed in offset L3-22.

Mid-field Lisburne Wahoo seawater injectors L5-13i and L5-15i commenced injection in March 2013. A total of 0.51 MMB of seawater was injected in both wells during the reporting period, for an average rate of 1500 bbl/day. Seawater breakthrough to offset producer L5-16A has been detected. L5-13 developed integrity issues at the beginning of the reporting period and has since been plugged and abandoned.

Lisburne Alapah seawater injector NK-25i commenced injection in March 2013. During the reporting period, it was only injecting for 12 days for a total of volume of 0.05 MMB of seawater. Seawater breakthrough to the offset producer NK-26 has been confirmed. NK-26 had been shut in during the last reporting period due to integrity issues encountered with the well, and a sidetrack well was identified.

B. Well Activity and Rate Adding Surface Projects

One well, L3-25, was drilled and completed and another, was in the process of being completed into the Lisburne Formation during the reporting period (L3-25 into the Wahoo and NK-26A into the Alapah). Twenty five additional Lisburne wells had a total of thirty rate-adding interventions and repairs performed during the reporting period. These rate-adding interventions included perforations, hydrate & paraffin removal, acid stimulations, gas-lift work, profile modifications, fill cleanouts, well integrity repairs and surface component repairs. The Lisburne Gas Cap Water Injection Project achieved permanent status via Conservation Order 207B.16 on January 26, 2017. Reservoir pressure measurements were obtained from wells on L1 pad.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

The Lisburne Participating Area is divided into three areas for depletion planning purposes. The East Lisburne area includes the L5 pad area and areas east of the L5 pad to the boundary of the LPA. It includes both Wahoo and Alapah production. West Lisburne includes L1 pad and the Lisburne Gas Injection (LGI) pad west to the boundary of the LPA. The West Lisburne area has Wahoo only production. The Central Lisburne area also has LPA Wahoo only production from the remaining L2, L3, and L4 pads. L2 pad has some IPA production associated with the L2 re-route project.

Oil recovery from the East and West areas of the Lisburne Wahoo reservoir continues through a combination of solution gas drive, gas cap expansion supported by gas injection at LGI pad, gas cap water injection in L5-29 and mid-field water injection from L5-15 (and formerly L5-13 before it was P&A'd). Solution gas drive is the primary recovery mechanism in the Central area supplemented by weak aquifer influx in addition to peripheral water injection from 04-350.

The current Lisburne development plan is focused in five key areas: (1) maximizing commercial oil production through optimization of field gas offtake; (2) remedial wellwork; (3) optimizing voidage replacement; (4) evaluation of reservoir pressure maintenance options; and (5) reservoir play-type characterization for optimizing competitive development with future drilling.

A map of the Lisburne Field showing current fulltime production, cycle production, injection, shut-in, plugged and abandoned/temporarily abandoned wells and sidetracked wells is included as Attachment 1.

East Lisburne

The East Lisburne area includes wells drilled from both L5 pad and Heald Point (NK Pad) to the eastern boundary of the LPA. There are three cycle producers, ten full time producers, one Alapah seawater injector (NK-25), one remaining mid-field seawater injector (L5-15) (L5-13 was P&A'd during reporting period), and one gas cap seawater injector (L5-29) in this area. L5-29 has been shut in since July 2015 for all but 11 days, but plans are underway to repair it. During the reporting period, the East Lisburne work effort included managing and monitoring of the Lisburne GCWI pilot through fluid sampling L5 offset producers. Reservoir surveillance activities such as static reservoir pressure measurements were completed as part of surveillance for the gas cap water injection (GCWI) project. Conversion of mid-field Wahoo producer wells L5-13 and L5-15 to seawater injection was completed in March 2013.

Conversion of Alapah producer NK-25 to seawater injection was successfully completed in March 2013. With no offtake in the Alapah in this area and the pending sidetrack of NK-26 during the reporting period, injection into NK-25 was put on hold. Pressures will be taken in NK-25 once the new sidetrack NK-26A begins producing from the Alapah in the fault block north of injector. Monitoring of this pressure will help determine if injection via NK-25 should be continued to provide pressure support to NK-26A.

West Lisburne

West Lisburne, including L1, K and Lisburne Gas Injection (LGI) pads and extending to the western boundary of the LPA, includes wells completed in the Wahoo. There are seven full time wells, two cycle wells, and three gas injectors in this area. Mixed success in the recent drilling on L1 pad

(L1-13 in 2016 and L1-23 in 2015) is still being evaluated to inform future drilling in the area.

Central Lisburne

The Central Lisburne Area includes pads L2, L3, and L4. There are thirteen full time and five cycle producers in this area. Activities in this area included continued operation of peripheral water injector 04-350i between L3 and L4 pads and obtaining reservoir pressure measurements.

3.2 Production Management

The LPC continues to be gas constrained. Due to the high GOR nature of Lisburne wells, oil production rates are influenced by seasonal ambient temperature cycles and corresponding compressor efficiencies that in turn drive oil offtake rates.

Certain wells in the field exhibit a GOR behavior that responds positively to a shut-in period compared to continuous production. Appropriate wells are rotated through a cycle of several days of production followed by days or weeks of shut-in. When production is resumed, the GOR is generally reduced resulting in increased oil production.

3.3 Drilling and Other Well Activity

This area was covered by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing completed September 2016. Interpretation has been focusing on improving structure mapping. Current plans include potentially drilling 3 additional wells, L3-22A, L5-03, and L5-25A, during the POD plan period. These wells are depicted in Attachment 1. Several additional Lisburne drilling locations are being considered for possible future drilling. Additional drilling is contingent on the continued performance of the 2015-2017 drilling program as well as the performance of new wells that may be potentially drilled.

3.4 Projects

The L5 GCWI pilot project commenced injection in July of 2008. The initial injection rate was 2 MB/D, and over time has been gradually increased to an injection rate of about 15 MB/D. 22.2 MMB of seawater has been injected in L5-29 since the start-up. Water injection is expected to continue during the permanent phase. The peripheral Wahoo seawater injection pilot commenced injection in May 2012. 5.6 MMB of seawater has been injected in 04-350i. The mid-field Wahoo seawater injection pilot commenced in March 2013 with the conversion to injection of wells L5-13i and L5-15i. A combined total of 7.8 MMB of seawater has been injected in L5-13i & L5-15i. The Alapah seawater injection pilot commenced injection in March 2013 into converted producer NK-25i and injected 5.9 MMB of seawater. A full report of the multiple projects' surveillance can be found in the Lisburne Annual Reservoir Surveillance Report.

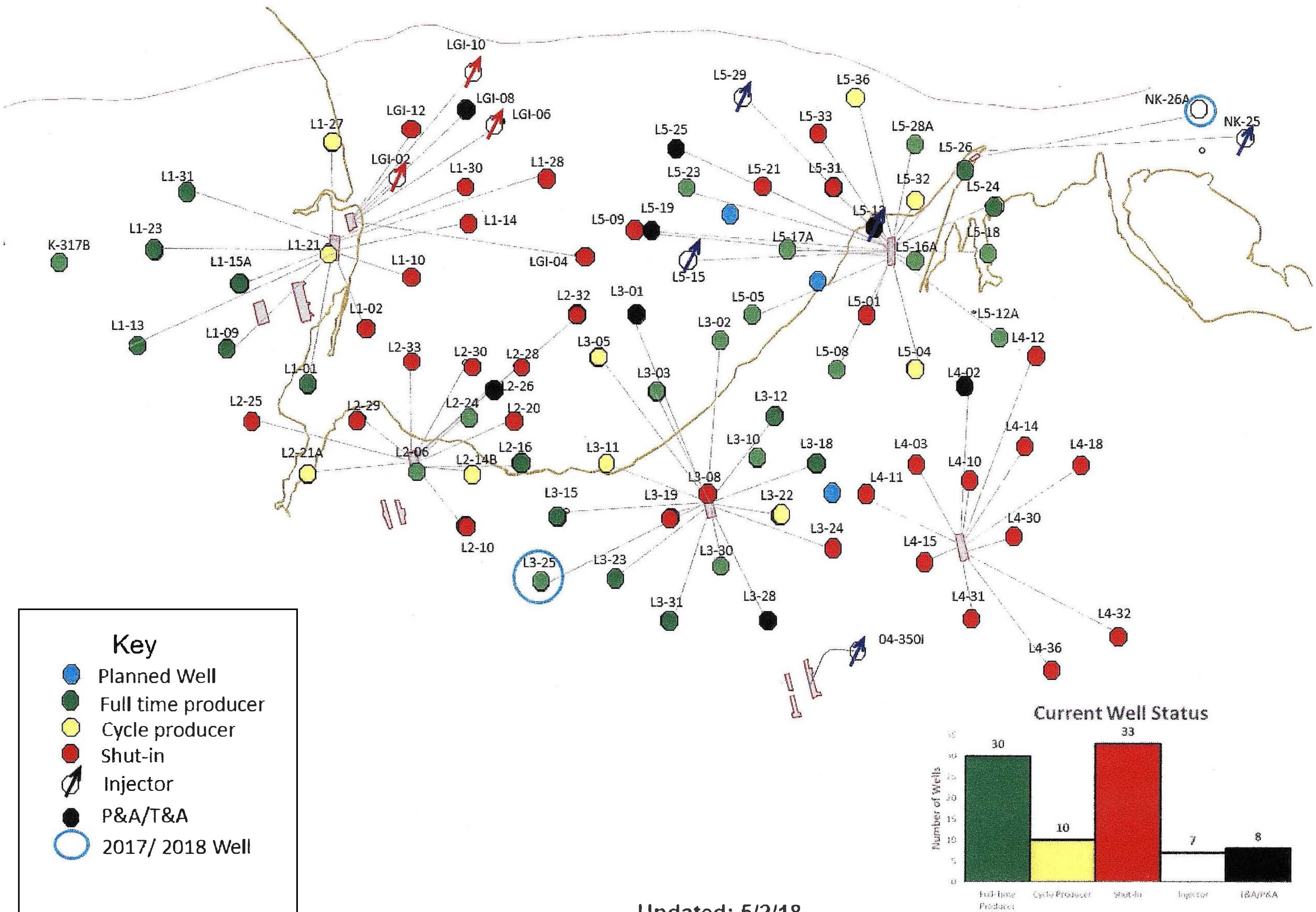
Currently, re-injection of the Lisburne produced gas is occurring for pressure support of the Wahoo. Additional support in the Wahoo reservoir through the use of water injection continues. This effort is currently focused on the L5 pad and Drill Site #4 which both have available seawater supply.

In 2014 the L4 pad export line was shut-in due to line wall loss concerns. Evaluation of future opportunity and line repair options for L4 are being considered as a potential future project pending line inspections scheduled for summer 2018.

3.5 PRODUCTION ALLOCATION

Production of oil and gas will continue to be allocated to the Lisburne Participating Area in accordance with conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There are test separators at Lisburne Drill Sites L1, L2, L3, L4, L5, K-pad, and Niakuk that are utilized to satisfy those conditions.

Lisburne Well Status



Updated: 5/2/18

ATTACHMENT 1 LISBURNE FIELD WELL STATUS MAP

Current as of May 2018

PRUDHOE BAY UNIT
NORTH PRUDHOE BAY PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2018 UPDATE OF PLAN OF DEVELOPMENT

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the North Prudhoe Bay Participating Area (NPBPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2018, through September 30, 2019.

The objective of the NPBPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2018 update to the NPBPA POD assumes a continuation of the current business climate and reflects the current understanding of the North Prudhoe Bay reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT - SUMMARY OF DEVELOPMENT ACTIVITIES AND STATUS

Production from North Prudhoe Bay occurred from a single well completed in 1993 (WB-03) to West Beach Pad. Previous reports have set forth the recompletion and testing activities that have been undertaken on WB-03. The well was shut-in February 2000 due to safety concerns arising from continued proppant production from an earlier fracture stimulation of the Sag River Formation. Attempts to eliminate flowback of proppant were made. Due to safety and environmental considerations production testing was suspended.

Production is currently shut-in due to integrity concerns. To date, total crude and condensate production totals 2.1 MMB.

3.0 DEVELOPMENT PLANS

BP as North Prudhoe Bay Unit Operator has reviewed the condition and history for WB-03, and concludes that the well is not currently in condition to bring on line and flow. Significant challenges also remain for development of the Ivishak and Sag River intervals due to structural complexity, reservoir compartmentalization, and fluid contact uncertainty. This area was covered by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing was completed September 2016. Interpretation of the data has been recently completed in January 2018. The interpretation focused on improving the structure mapping over the entire area and now detailed analysis of substructures will begin for prospect identification into 2019.

During the winter of 2010, the 6” test line between the West Beach Pad and LPC had a preliminary external inspection. There was no evidence found of structural problems. However, production through the West Beach production line will not be restarted until an internal pipeline integrity inspection has been completed. Engineering studies of the pad are underway and assessment of the current conditions of the pipeline and surface kit are expected to be complete in 2019. At such time, additional prospects will be evaluated for development in the North Prudhoe Bay PA.

PRUDHOE BAY UNIT
COMBINED NIAKUK PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Combined Niakuk Participating Area (CNPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2018, through September 30, 2019.

The objective of the CNPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2018 update to the CNPA POD assumes a continuation of the current business climate and reflects the current understanding of the Niakuk reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE, CONDENSATE AND NGLS

Niakuk crude, condensate and NGL rates averaged 1.2 MB/D for the reporting period April 1, 2017 to March 31, 2018. This rate, combined with production from the other GPMA fields, fully utilized available Lisburne Production Center (LPC) capacity, within reservoir management constraints. A total of 0.436 MMB was delivered to the Trans-Alaska Pipeline System (TAPS).

B. PRODUCED GAS

Niakuk gas production totaled 0.7 BCF for the reporting period, of which none was re-injected into the Niakuk reservoir. The produced gas is processed at the LPC and injected into the Lisburne and Pt. McIntyre reservoirs. A total of 59.5 MMCF of produced gas was consumed as fuel or flared. NGL separation averaged 30.48 B/D with a total of 0.011 MMB delivered and shipped with crude oil production through TAPS during the reporting period.

C. PRODUCED WATER

Niakuk water production for the reporting period was 7.9 MMB, yielding an average water production rate of 22 MB/D. Produced water is processed at the LPC and injected into the Pt. McIntyre reservoir.

2.2 DEVELOPMENT AND PRODUCTION ACTIVITY

Development and production activities have continued in accordance with the CNPA POD. Summarized below are the significant activities at Niakuk over the past year.

A. ENHANCED RECOVERY - INJECTED WATER

Waterflood operations are conducted to maintain field pressure and optimize conformance. During the reporting period three water injection wells, NK-10i, NK-13i, NK-18i were in operation. NK-15i was side tracked as the Raven optimized-location injector and is discussed in the Raven Participating Area POD. NK-23i is shut in because the surface line is not in service, however is estimated to be back on injection 2-3Q 2018. NK-28i is shut back in after additional tubing by inner annulus (TxIA) communication was found. NK-16i remains shut in due to a thief zone connection to NK-21. The total water injected into the reservoir during the reporting period was 6.0 MMB, averaging 16 MB/D.

B. Well Activity

Niakuk has wellwork and scale inhibition programs. During the reporting period:

NK-27 had a repair job following a leak detect log that allowed for a return to production .

Two oil samples were taken from NK-43 (5/17 and 10/17) for geochemical analysis to confirm production allocation splits between the Sag River and Kuparuk reservoirs. The analyses showed that ~95% of oil production in NK-43 is from the Kuparuk.

Technical work to assess potential infill and peripheral drilling locations continued during the April 1, 2017 to March 31, 2018 reporting period. An updated integrated subsurface description project has been underway during this year and has been utilizing the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing completed September 2016. A new interpretation of the data was utilized for an update to the reservoir description of the Niakuk field.

3.0 PLAN OF DEVELOPMENT

3.1 Reservoir Management

The structural and stratigraphic complexity of the Niakuk reservoir precludes positioning injectors and producers in a uniform pattern (Attachment 1). Emphasis is given to a dynamic reservoir management strategy to maximize commercial production and total recovery from the reservoir. Elements of this strategy include selective perforation and profile modification to isolate water-bearing zones in production wells and to open un-swept zones in injection wells. Production profiles are obtained, as needed, to better understand which zones are receiving pressure support and which zones are isolated. Pressure surveys are taken to monitor the performance of offtake and injection strategies. These data help determine the continuity of individual reservoir zones and the communication characteristics between wells. Analysis of this information is used for material balance calculations.

3.2 Production Management

Reservoir management and waterflood strategies are designed to optimize oil production from the Niakuk reservoir. Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts.

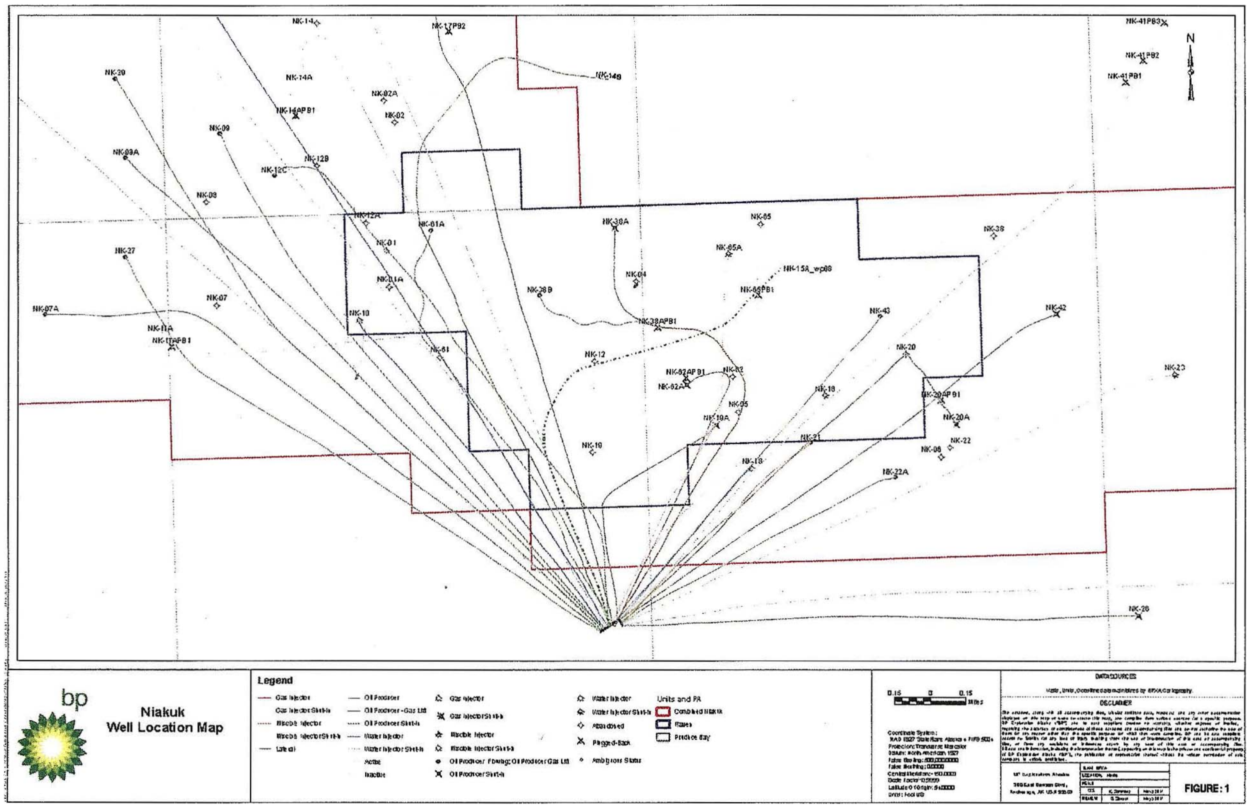
3.3 Drilling and other well activity

The North Prudhoe Seismic survey is currently being used for a better understanding of subsurface areas of interest. As part of the ongoing reservoir management strategy, Niakuk development well targets are under technical and commercial evaluation.

3.4 Production Allocation

The production of oil and gas will continue to be allocated to the Combined Niakuk Participating Area in accordance with the conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There is a test separator at Heald Point.

ATTACHMENT 1 – NIAKUK WELL LOCATION MAP



PRUDHOE BAY UNIT

PT. MCINTYRE PARTICIPATING AREA

ANNUAL PROGRESS REPORT AND

2018 UPDATE OF PLAN OF DEVELOPMENT

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ATTACHMENT 1: MAP OF PT. MCINTYRE PARTICIPATING AREA

1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Pt. McIntyre Participating Area (PMPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2018, through September 30, 2019.

The objective of the PMPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2018 update to the PMPA POD assumes a continuation of the current business climate and reflects the current understanding of the Pt. McIntyre reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE, NGL AND CONDENSATE

Crude, condensate and NGL rates averaged 14.8 mb/d during the reporting period April 1, 2017 to March 31, 2018. Field offtake was managed to maximize production within the available pipeline and facility constraints, while maintaining close to full voidage replacement. A total of 5.40 MMB was delivered to the Trans-Alaska Pipeline System (TAPS) during the reporting period. All Pt. McIntyre production until October, 2016 went to the Lisburne Production Center (LPC). The completion of the STP-36 Project in October, 2016 enabled all PM-2 production to go to Gathering Center 1 for the entire plan year.

B. PRODUCED GAS

Pt. McIntyre total gas production (including MI breakthrough in EOR patterns) totaled 54.8 BCF for the reporting period. Produced gas supplied from the LPC is injected into the Pt. McIntyre gas cap to provide pressure support and promote recovery in the up-structure area. A total of 64.2 BCF was injected into the Pt. McIntyre gas cap/gravity drainage area during the reporting period. Lean gas supplied from the LPC for Pt. McIntyre gas cap re-injection is a mixture of gas from Pt. McIntyre, Lisburne and Niakuk production.

A total of 3.34 BCF of Pt. McIntyre gas produced was consumed as fuel or flared in the reporting period. The fuel and flared gas was consumed for normal LPC and GPMA drillsite operations.

NGL separation averaged 1.05 MB/D with a total of 0.385 MMB delivered and shipped with crude oil production through TAPS during the reporting period. This NGL volume is the allocated Pt. McIntyre NGL production in the LPC.

C. PRODUCED WATER

Pt. McIntyre water production for the reporting period was 33.3 MMB, yielding an average water production rate of 91.1 MB/D.

2.2 DEVELOPMENT AND PRODUCTION ACTIVITY

Development and production activities have continued in accordance with the PMPA POD Summarized below are the activities at Pt McIntyre over the past year

A. ENHANCED RECOVERY - INJECTED WATER

Waterflood and WAG operations are conducted to help maintain field pressure and improve reservoir recovery efficiency. During the reporting period, 15 waterflood patterns were in operation P2-34i has not been on injection for the majority of the reporting period due to wellbore operability and BP is working to restore injection. Produced water from the Pt McIntyre Field is normally used for re-injection. Additional produced water is provided from the PBU IPA and is pumped to the LPC from Flow Statıon 1. Water injection totaled 30.1 MMB for the report period. This volume is equivalent to a daily rate of 82.2 MBWPD.

B. ENHANCED RECOVERY - MISCIBLE GAS

The Pt. McIntyre miscible gas (MI) enhanced oil recovery project continued operation with injection of a total of 22.4 BCF of MI during the report period (61.3 MMSCFD). All MI gas was supplied from the PBU CGF facility.

A project that expanded the volume of MI to PM-2 completed in the previous plan year P2-15Ai injected its first slug of MI during this reporting period, and offset EOR benefits have been observed.

C. Well Activity

Pt. McIntyre has an active wellwork and scale inhibition programs. P1-09 was recently re-completed to access the Ivishak formation and is on production with a recent production log to assess entry splits. Surface casing excavation work and welding was completed on well P1-18 successfully restoring integrity of the OA anulus and prepared for POP in April, 2018. A rig workover was completed on P1-04 in October 2017 to repair a tubing and production casing leak and restored the well to cycle production at LPC. Two fracs were executed on low productivity producers at PM1: P1-23 and P1-20.

D. RATE ADDING SURFACE PROJECTS

The STP 36-inch pipeline had been used to send some production from PM-2 to GC1, but was taken out of service in November 2011. About 1.8 miles of the STP-36 line cannot be used due to problems encountered with cathodic protection. The remaining ~8 miles of the ~10 mile line was smart pigged in 2014 to evaluate returning the line to service. The option to use an existing common line and then jumper into the useable portion of the STP 36" line requires that all PM-2 production go to GC1, rather than splitting PM-2 production between LPC and GC1. Benefits of this added flow into GC1 were evaluated, and restoration of the STP-36 line to service was completed October 2016, resulting in increased production at LPC. The plan year was the first full year with the restored STP 36 line in service.

3.0 PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Pt. McIntyre is undergoing a tertiary recovery process involving alternating cycles of miscible gas injection and water injection (WAG) to maximize commercial production and total recovery from the reservoir.

The reservoir management strategy is to utilize injection-to-withdrawal (I/W) ratios at a pattern level to maintain the reservoir pressure above that required for miscibility (minimum miscibility pressure) during the MWAG process and to stabilize the gravity drainage waterflood interaction area of the field. This is accomplished by setting optimum injection rates, managing pattern offtake, and cycling high Formation GOR (FGOR) production wells as needed.

Miscible gas injection (MI) started in October 2000 with injection into well P2-23. The target cumulative MI injection is currently estimated at 35% of the hydrocarbon pore volume. After the cumulative target slug size of MI has been injected into the formation, pressure support will be maintained with water injection. A total of 293 BCF of MI gas has been injected into the reservoir to date.

3.2 PRODUCTION MANAGEMENT

Reservoir management and EOR strategies are designed to optimize oil production from the Pt. McIntyre reservoir. Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts and gas-oil ratios.

3.3 Drilling and other well activity

Technical assessment of the subsurface is ongoing. This area was covered by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing completed September 2016. Interpretation of the data is currently being prioritized across the Prudhoe Bay Unit. Interpretation has been focusing on improving structure mapping over the field and understanding of the subsurface areas of interest (Kuparuk, Sag, Ivishak, Lisburne, and Alapah intervals). The seismic has resulted in a better understanding of flank opportunities, and coil sidetracks are currently being evaluated.

3.4 Miscible Gas Enhanced Oil Recovery

Miscible gas injection will continue to be an integral part of the Pt. McIntyre reservoir management plan. Three injectors at PM-1 and ten injectors at PM-2 have been equipped for MI injection and it is anticipated that the remaining waterflood patterns will receive MI over the life of the project. Twelve patterns have now received at least one cycle of MI, and MI response has been detected in multiple wells and patterns.

3.5 Projects

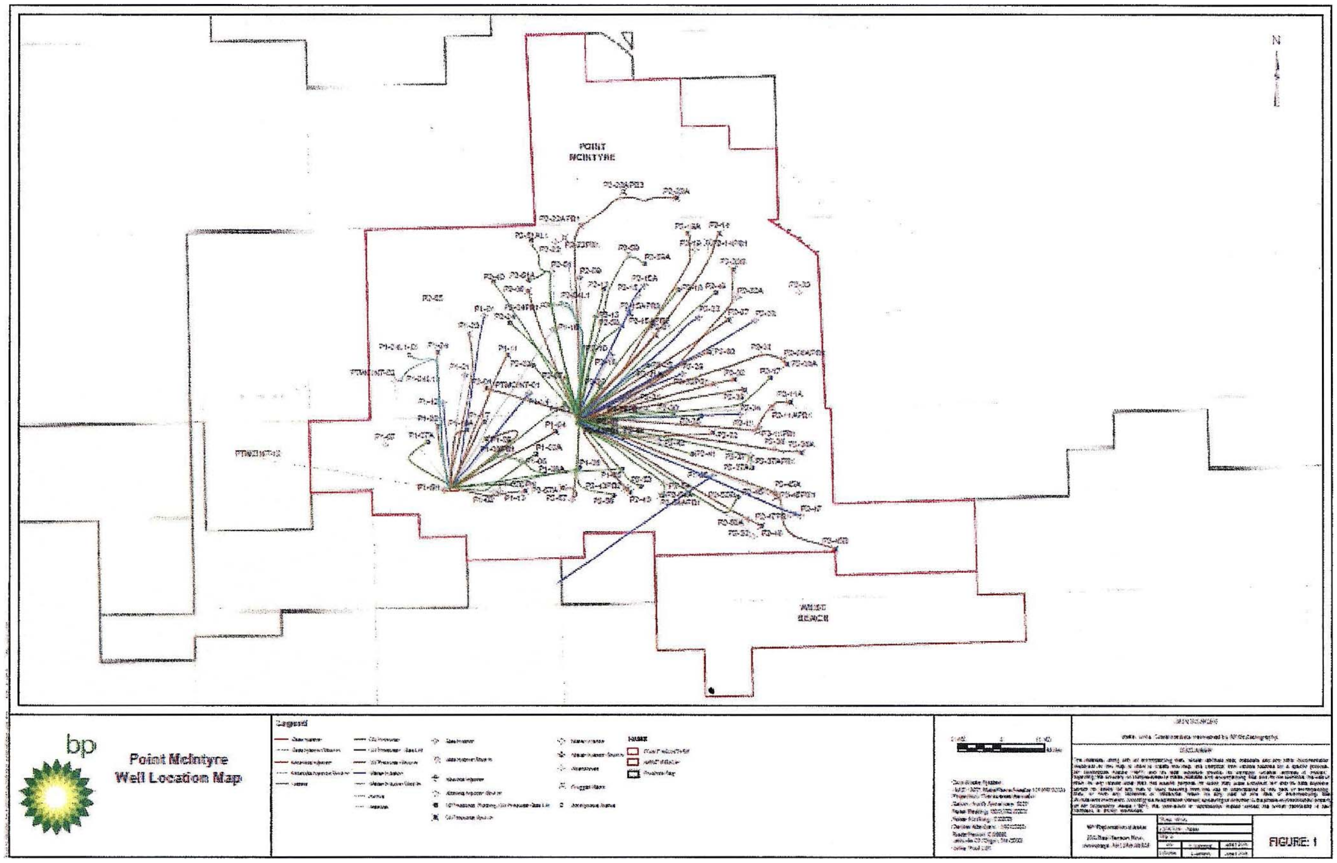
A project that will expand the volume of MI to PM-1 pad is planned for 2018. This is similar to the project that expanded the volume of MI to PM-2 completed in the previous plan year. P2-47 is currently injecting its first bulb and we are monitoring offset wells for interactions.

3.6 Production Allocation

The production of oil and gas will continue to be allocated to the Pt. McIntyre Participating Area in accordance with conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There is a test separator at Drill Site PM-1 and two test separators at Drill Site PM-2.

Revisions to the existing allocation procedures covering three phase PM-2 production processed through GC-1 were previously reviewed with the Alaska Department of Natural Resources and the Alaska Oil and Gas Conservation Commission.

Attachment 1: Point McIntyre Participating Area



PRUDHOE BAY UNIT

RAVEN PARTICIPATING AREA

ANNUAL PROGRESS REPORT AND

2018 UPDATE OF PLAN OF DEVELOPMENT

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LIST OF ATTACHMENTS

1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Raven Participating Area (RPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2018, through September 30, 2019.

The objective of the RPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2018 update to the RPA POD assumes a continuation of the current business climate and reflects the current understanding of the Raven reservoirs. Changes in the business climate, new insights into the reservoirs, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE, CONDENSATE AND NGLS

Production from Raven, combined with production from the other GPMA fields, fully utilized available Lisburne Production Center (LPC) capacity, within reservoir management constraints. Raven crude, condensate and NGL rates averaged 1.05 MB/D for the reporting period April 1, 2017 to March 31, 2018. A total of 0.39 MMB from the Raven PA was delivered to the Trans-Alaska Pipeline System (TAPS) during the reporting period.

B. Produced Gas

Raven gas production totaled 2.33 BCF from April 1, 2017 to March 31, 2018. Produced gas from Raven is processed at the LPC and injected into the Lisburne and Pt. McIntyre Fields. A total of 204 MMCF of produced gas was consumed as fuel or flared. NGL separation averaged 73.4 B/D with a total of 26.90 MB delivered and shipped with crude oil production through TAPS.

C. Produced Water

Raven water production for the reporting period was 1.38 MMB, yielding an average water production rate of 3.8 MB/D. Produced water is processed at the LPC and injected into the Pt. McIntyre Field.

2.2 Development and production activity

Development and production activities have continued in accordance with the RPA POD. Summarized below are the activities at Raven over the reporting period.

A. Enhanced Recovery - Injected Water

NK-38A was sidetracked in August 2016 to the current NK-38B location, where it was observed early on that the new well had aquifer support. NK-65A was kept off injection in the latter part of 2016 to understand the NK-38B natural decline to help improve the future performance and reservoir management for the Raven Pool. NK-65A was put back on injection in early 2017 as NK-15A was planned for drilling an optimized injector location. NK-65A injected water throughout the reporting period. The total water injected into the field during the reporting period is 0.51 MMB, averaging nearly 1.4 MB/D.

B. Well Activity

NK-14B was spudded in March 2017 and is an extension well delineating the extent of the Raven Oil Pool. NK-14B is being produced on a Tract Operation basis as information that will guide future Raven Oil development is gathered. NK-14B is a horizontal well completed in the Sag River formation but developed a casing leak 3 months after completion. The well was shut-in from September 2017 – March 2018 due to operations trying to determine failure and repair options. NK-14B has since been restored to production. No other Raven wellwork was performed during this period.

NK-15Ai was spudded in February of 2018 and was completed as an injector at a new location in the Raven Pool.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Production from the Raven reservoirs continues to be managed and monitored to maximize commercial production and total recovery from the reservoir. Future drilling locations are being evaluated and are expected to be moved forward for increased production and recovery in the Raven reservoirs.

NK-43 produces comingled fluids from the Sag (Raven PA) and the Kuparuk (Combined Niakuk PA). The Sag portion decreased from 10% to 5% with an increased water oil ratio.

3.2 PRODUCTION MANAGEMENT

Reservoir management and waterflood strategies are designed to optimize oil rate and recovery from the Raven reservoirs. Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts and gas-oil ratios. In the developed part of Raven, the long-term depletion plan is to optimize hydrocarbon production in the Raven reservoirs through voidage replacement from injection to supplement aquifer influx in order to keep reservoir pressure at levels that will optimize oil recovery. This depletion plan is being evaluated for the expanded part of the pool.

3.3 Drilling and other well activity

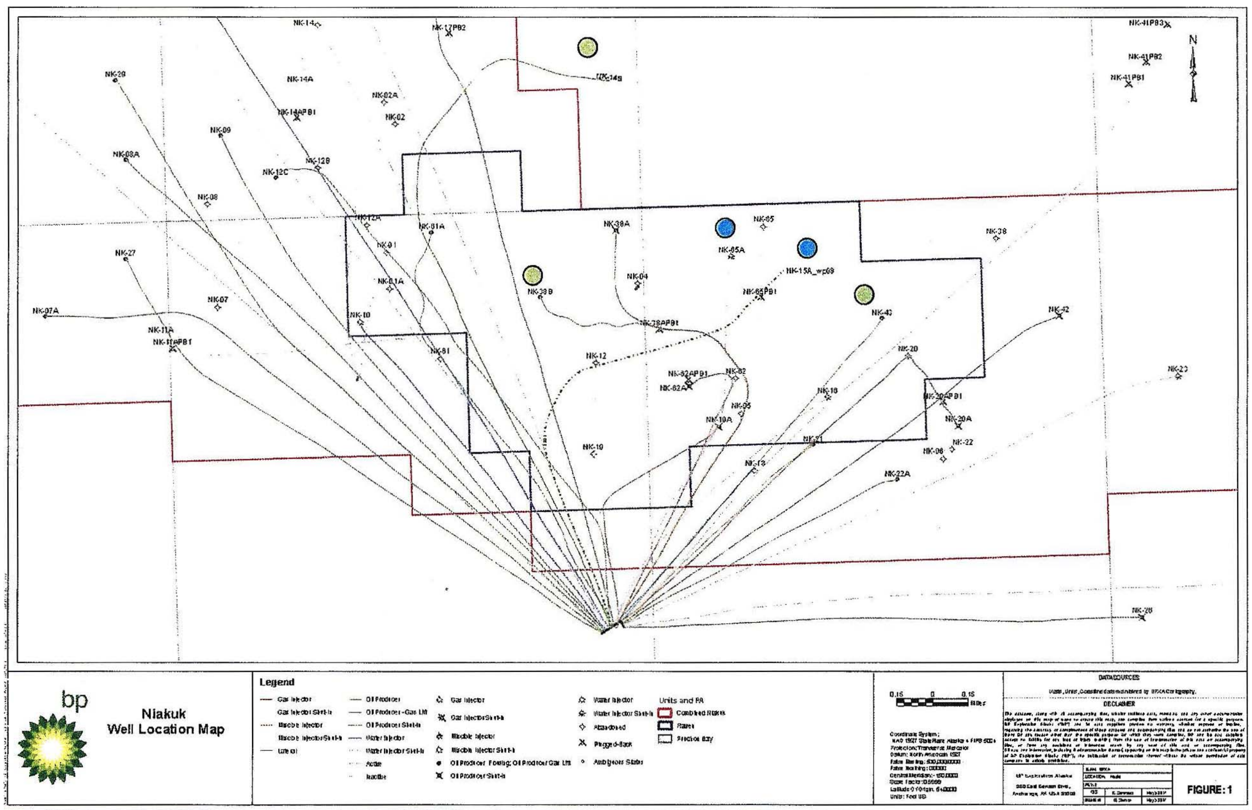
Injection is expected to begin in the newly drilled NK 15Ai. It will provide additional support to the NK-38B along with the natural aquifer support it already receives. Once NK-15Ai is on established injection, plans are to convert NK-65Ai to a producer.

Technical evaluations of drilling options in Raven are currently using the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015. Interpretation of the processed data has been focused on improving the structure map over the field areas and understanding of subsurface areas of interest. These evaluations combined with drilling results will form the basis for potentially expanding the Raven PA.

3.4 Production Allocation

The production of oil and gas will continue to be allocated to the Raven Participating Area in accordance with conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There is a test separator at the Niakuk drill site.

ATTACHMENT 1: RAVEN WELL LOCATION MAP



Raven PA Boundary

Combined Niakuk PA Boundary

PRUDHOE BAY UNIT
WEST BEACH PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2018 Update of PLAN OF DEVELOPMENT

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the West Beach Participating Area (WBPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2018, through September 30, 2019.

The objective of the WBPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2018 update to the WBPA POD assumes a continuation of the current business climate and reflects the current understanding of the West Beach reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT - SUMMARY OF ACTIVITIES AND STATUS

West Beach startup occurred in April 1993. The field has been delineated by eleven penetrations consisting of seven wells and four sidetracks. The field has produced a total of 3.37 MMB of crude oil, with approximately 92% coming from the original WB-04 well. Oil production was suspended in 2Q 2001 due to increasing GOR and declining reservoir pressure.

Water injection commenced at WB-06 in December 2000 and continued through September 2003, when the injector was shut-in due to an annular communication leak (IA by OA). Two attempts to cement squeeze the well failed, and the injector remains shut-in. Cumulative injection into WB-06i is 6.8 MMBW.

WB-04 producer showed a breakthrough in water in less than 4 months from injection start-up, and was shut-in in 2Q of 2001. The well was brought back on in 3Q 2002 with high water cut and was produced intermittently through 2005 with continuing increasing water production. WB-06i continued to inject until September 2003, which resulted in increasing reservoir pressure. Pressure surveys in WB-04, WB-05B, and WB-06 from 2003 through 2009 show that reservoir pressure has stabilized at approximately 3550 psi.

WB-04 had 165 feet of perforations added in June 2008 and was brought online during June and November 2008 in an attempt to demonstrate productive capability. Two production tests were obtained before the well was shut in and freeze protected due to the risk of forming hydrates in the tubing and flowline. The oil rate ranged between 140 to 280 BOPD with high watercut and cold wellhead temperature. Cumulative production for WB-04 at that time was 3.1 MMBO.

In October of 2008, an attempt was made to pull the IBP in WB-05B which had been set at 15,765' on 8/03/05. Coil was unable to pull the IBP and an attempt was made to push it to bottom. This effort resulted in not being able to get the plug deeper than 15,710'. 40 ft. of perforations were added on 10/30/08. The well was tested with gas lift, and the oil rate ranged between 260 and 360 BOPD with high watercut and cold wellhead temperature. WB-05B was shut in and freeze protected due to the risk of forming hydrates in the tubing and flowline.

During the summer of 2009, both WB-04 and WB-05B were extensively production tested for two months. WB-04 produced at an oil rate of 70-110

BOPD. Water cut was 92% and the well head temperature was 62 degrees F. The well produced 5,588 bbls oil and 52,723 bbls of water during the 66 days it was on line. WB-05B tested at 177-256 bopd. Water cut was 61%. Well head temperature was 57 degrees F. This well produced 4,409 bbls of oil and 6,647 bbls of water during the 23 days it was on line. A SBHP survey was run in WB-05B. The pressure at a datum depth of 8800 ft subsea was 3517 psi. Although methanol was slip streamed into WB-05B IA there were still problems with hydrates in this well. The K valve was pulled, and operations continued with a 24 hour man watch. Both of these wells were flowed simultaneously to the LPC #1 pad. These wells were manifolded though a line heater during the testing, so warm fluids were sent downstream of the pad. Modeling of the 12" production line indicated at these low rates and cool well head temperatures this line might become inoperative due to hydrates.

During the winter of 2010, the 6" test line between West Beach Pad and LPC # 1 pad had an external inspection. There was no evidence found of structural problems.

3.0 DEVELOPMENT PLANS

Production through the West Beach production lines will not be restarted until an internal pipeline integrity inspection is made. Engineering studies of the Pad are underway and assessment of the current conditions of the pipeline and surface kit are expected to be complete in 2019.

This area was covered by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing was completed September 2016. Interpretation of the data was completed in January 2018. The interpretation focused on improving the structure mapping over the entire area and now detailed analysis of substructures will begin for prospect identification into 2019.