bp

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June 30, 2016

HAND-DELIVERED

Ms. Corri Feige, 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 Feige:

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. Jon Schultz, ConocoPhillips Alaska, Inc.
Mr.Gilbert Wong, ExxonMobil Alaska, Production Inc.
Mr. Phil Ayer, Chevron USA
Mr. Dave Roby, Alaska Oil and Gas Conservation Commission

Lisburne

PRUDHOE BAY UNIT
LISBURNE PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2016 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, 2016, through September 30, 2017.

The objective of the LPA POD is to identify strategies to maximize oil production and recovery from the Lisburne reservoir in a cost-effective, safe and environmentally responsible manner. The 2016 update to the LPA POD assumes a continuation of the current business climate and 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 5.8 MB/D for the reporting period. A total of 2.1 MMB of Lisburne oil and NGL was delivered to the Trans-Alaska Pipeline System (TAPS) during the reporting period ending March 31, 2016.

B. PRODUCED GAS

Lisburne gas production totaled 42.9 BSCF for the reporting period with 45 BSCF re-injected into the Lisburne Gas Cap to provide pressure support. 4.0 BSCF was consumed as fuel or flare gas. For the report period, Lisburne gas production averaged 117.3 MMSCF/D yielding an average GOR of 20,071 SCF/STBO. Lisburne NGL separation averaged 0.74 MB/D with a total of 0.27 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 1.8 MMB, yielding an average water production rate of 5.1 MB/D and average water cut of 46%. 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 24 MMB (including Pt McIntyre, Niakuk and FS1 produced water) yielding an average water disposal injection rate of 66.45 MB/D for both wells.

2.2 Development

Development activities have continued in accordance with the LPA POD. Summarized below are the significant development activities over the past year. More details regarding these activities can be found in Section 3.

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 injection continued into 04-350 (peripheral Wahoo), NK-25 (Alapah) and L5-13 & L5-15 (mid-field Wahoo). The L5-29 Gas Cap Water Injection (GCWI) pilot project also continued.

On July 14th 2008, the Lisburne Gas Cap Water Injection (GCWI) Pilot commenced injecting into the L5-29 well, as approved under CO 207A.001 and AIO 4E.029. A total of 1.32 MMB of seawater was injected during the reporting period, for an annual average rate of 3.61 MB/D. Water breakthrough has reached wells L5-28, L5-33 and L5-36. Breakthrough indications include rise in watercut, GOR suppression, as well as water sample analysis for seawater trace minerals.

Peripheral Lisburne Wahoo seawater injector 04-350 commenced injection in May 2012. A total of 1.014 MMB of seawater was injected during the reporting period, for an annual average rate of 2777 bbl/day. Seawater production has been observed in offset L3-22 during the reporting period.

Mid-field Lisburne Wahoo seawater injectors L5-13 and L5-15 commenced injection in March 2013. A total of 2.672 MMB of seawater was injected in both wells during the reporting period, for an average rate of 3660 bbl/day per well. No seawater breakthrough to offset producers has been detected.

Lisburne Alapah seawater injector NK-25 commenced injection in March 2013. A total of 1.681 MMB of seawater was injected during the reporting period, for an average rate of 4607 bbl/day. Seawater breakthrough to the offset producer NK-26 has been confirmed during the reporting period.

B. Well Activity

Three wells: L1-23, L3-03 and L3-10, were drilled and completed into the Lisburne Formation during the reporting period. Twenty six additional Lisburne wells had a total of thirty one rate-adding non-rig interventions performed during the reporting period. These rate-adding interventions included perforations, acid stimulations, hydraulic fracture stimulations, gas-lift work, profile modifications, tubing patches, casing repairs and surface component repairs.

3.0 UPDATE OF PLAN OF DEVELOPMENT

BPXA is committed to safe, compliant and reliable operation, in accordance with good engineering and production practices, and the time-proven practices of prudent operators. The LPA POD makes maximum use of existing LPA and other PBU infrastructure. This minimizes environmental impacts while maximizing recovery from the LPA reservoir. Following is the annual update to the LPA POD.

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 L5-13 & L5-15. 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 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 characterization.

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 to the eastern boundary of the LPA. There are six cycle producers, four full time producers, one Alapah seawater injector (NK-25), two mid-field seawater injectors (L5-13 and L5-15) and one gas cap seawater injector (L5-29) in this area. The gas cap water injection pilot project is approved by the AOGCC through July 1, 2016. L5-29 has been shut in since July 2015 due to well integrity concerns but plans are actively underway to repair it. The operator plans to evaluate putting L5-29 on permanent injection During the reporting period, the East Lisburne work effort included managing and monitoring of the Lisburne GCWI pilot with seawater injection into L5-29 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) pilot project. Conversion of mid-field Wahoo producer wells L5-13 and L5-15 to seawater injection was completed in March 2013 (see section 3.4 Projects).

Conversion of Alapah producer NK-25 to seawater injection was successfully completed in March 2013. Monitoring of this flood will continue via the injector NK-25 and the offset Alapah producer NK-26 (see section 3.4 Projects). Newly acquired seismic and recent well integrity problems in the producer NK-26 will factor into the future plans for this area.

<u>West Lisburne</u>

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 two full time and seven cycle producers, and three gas injectors in this area. Additional work on L1 pad included obtaining reservoir pressure measurements.

<u>Central Lisburne</u>

The Central Lisburne Area includes pads L2, L3, and L4. There are ten full time and eight 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 Development Drilling and Other Well Activity

Development drilling of wells L1-23, L3-03 and L3-10 were completed during the 2015-2016 reporting period. Current plans include drilling an additional two wells, L1-13 and L5-12A, during the 2016-2017 reporting period. These wells are depicted in Attachment 1. Several Lisburne drilling locations are being considered for possible future drilling. Additional drilling is contingent on the performance and evaluation of the 2015-2016 drilling program.

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. 22.1 MMB of seawater has been injected in L5-29 since the start-up of the pilot. The peripheral Wahoo seawater injection pilot commenced injection in May 2012. 3.48 MMB of seawater has been injected in 04-350. The mid-field Wahoo seawater injection pilot commenced in March 2013 with the conversion to injection of wells L5-13 and L5-15. A combined total of 5.6 MMB of seawater has been injected in L5-13 & L5-15. The Alapah seawater injection pilot commenced injection in March 2013 into converted producer NK-25 and injected 4.2 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.

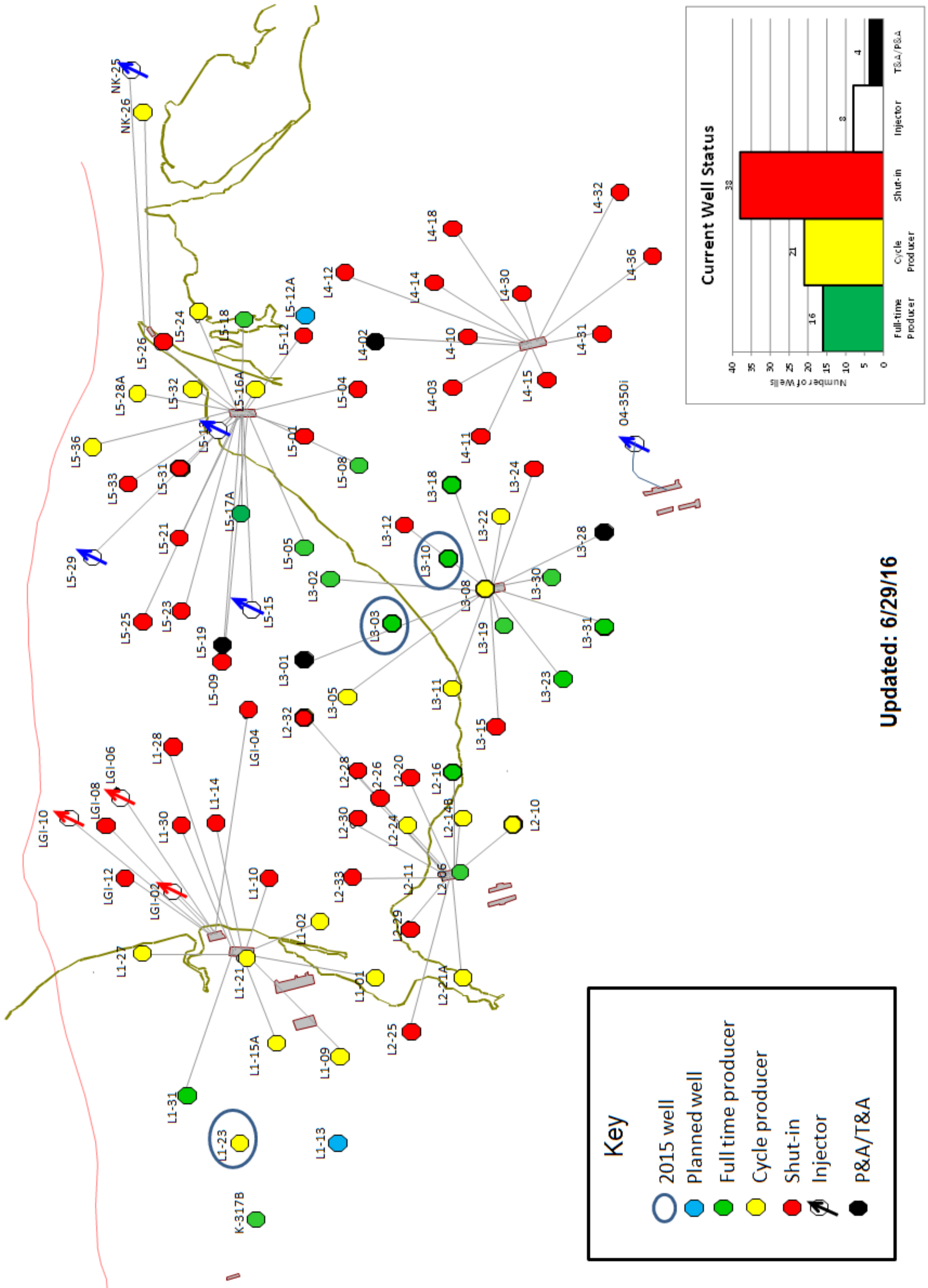
In 2014 the L4 pad export line was shut-in due to line wall loss concerns. Evaluation of future opportunity and line repair options for L4 are being considered as a potential future project.

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.

<u>ATTACHMENT 1</u> LISBURNE DEVELOPMENT WELL STATUS

Current as of May 2016



N Prudhoe

PRUDHOE BAY UNIT
NORTH PRUDHOE BAY PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2016 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, 2016, through September 30, 2017.

The objective of the NPBPA POD is to identify strategies to maximize oil production and recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2016 update to the NPBPA POD assumes a continuation of the current business climate and 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 occurs from a single well completed in 1993 (WB-03). 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 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 risk could be reduced by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015. Processing of these data is expected to take one to two years. Interpretation of the data will focus on improving the structure map over the field and understanding of subsurface areas of interest.

Niakuk

PRUDHOE BAY UNIT
COMBINED NIAKUK PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2016 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 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, 2016, through September 30, 2017.

The objective of the CNPA POD is to identify strategies to maximize oil production and recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2016 update to the CNPA POD assumes a continuation of the current business climate and 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 AND CONDENSATE

Niakuk crude, condensate and NGL rates averaged 1.11 MB/D. 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 .405 MMB was delivered to the Trans-Alaska Pipeline System (TAPS) from April 1, 2015 to March 31, 2016.

B. Produced Gas

Niakuk gas production totaled .8 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 Fields. A total of 75.86 MMCF of produced gas was consumed as fuel or flared. NGL separation averaged 31.5 B/D with a total of 0.425 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 7.0 MMB, yielding an average water production rate of 19.1 MB/D. Produced water is processed at the LPC and injected into the Pt. McIntyre Field.

2.2 Development

Development activities have continued in accordance with the CNPA POD. Summarized below are the significant activities at Niakuk over the past year. More details regarding these activities can be found in Section 3.

A. Enhanced Recovery - Injected Water

Waterflood operations are conducted to maintain field pressure and optimize conformance. During the reporting period four water injection wells, NK-10i, NK-13i, NK-23i, and NK-28i were in operation. NK-15i is shut-in and a diagnostic design is in progress. NK-18i is shut-in due to its offset producer, NK-21, being offline with high watercut. NK-16i remains shut in due to a thief zone connection to NK-21. The total water injected into the field during the period was 9.2 MMB, averaging 25.1.0 MB/D.

B. Well Activity

Niakuk has an active non-rig wellwork program and scale inhibition program. During the reporting period:

- NK-28 had a successful tubing patch to repair a TxIA communication and is back on injection.
- An extended coil campaign for milling scale was conducted on NK-08A, NK-09, NK-29, and L5-34.
- NK-07A had a successful installation of a QCLL (quick connect liner latch). It is awaiting installation of a new gas lift choke before it can be returned to production.
- NK-20A had a successful packer squeeze; it is awaiting a milling job before it can be returned to production.

During the reporting period one oil sample was taken from NK-43 for geochemical analysis to confirm production allocation splits between the Sag River and Kuparuk reservoirs. Production allocation splits from the previous geochemical analysis were used for allocation. This analysis shows that 100% of oil production in NK-43 is from the Kuparuk.

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. 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 rate and recovery 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 DEVELOPMENT DRILLING AND OTHER WELL ACTIVITY

As part of the ongoing reservoir management strategy, Niakuk development well targets are continually being evaluated and technical work to assess potential infill and peripheral drilling locations continued during the report period. These evaluations could be improved by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015. Processing of these data is expected to take one to two years. Interpretation of the new data will focus on improving the structure map over the field and understanding of original oil in place and remaining subsurface areas of interest.

On December 19, 2013, BP Exploration (Alaska) Inc. (BPXA) submitted a request to the Alaska Department of Natural Resources, Division of Oil and Gas (Division) to extend the Prudhoe Bay Unit (PBU) Expansion Area Number 3 contraction date. As per the conditional approval of this request by the Division of Oil and Gas on February 5, 2014, since the North Prudhoe 3D offshore seismic program was completed by December 31, 2014, contraction of Expansion Area #3 was automatically delayed until September 1, 2018.

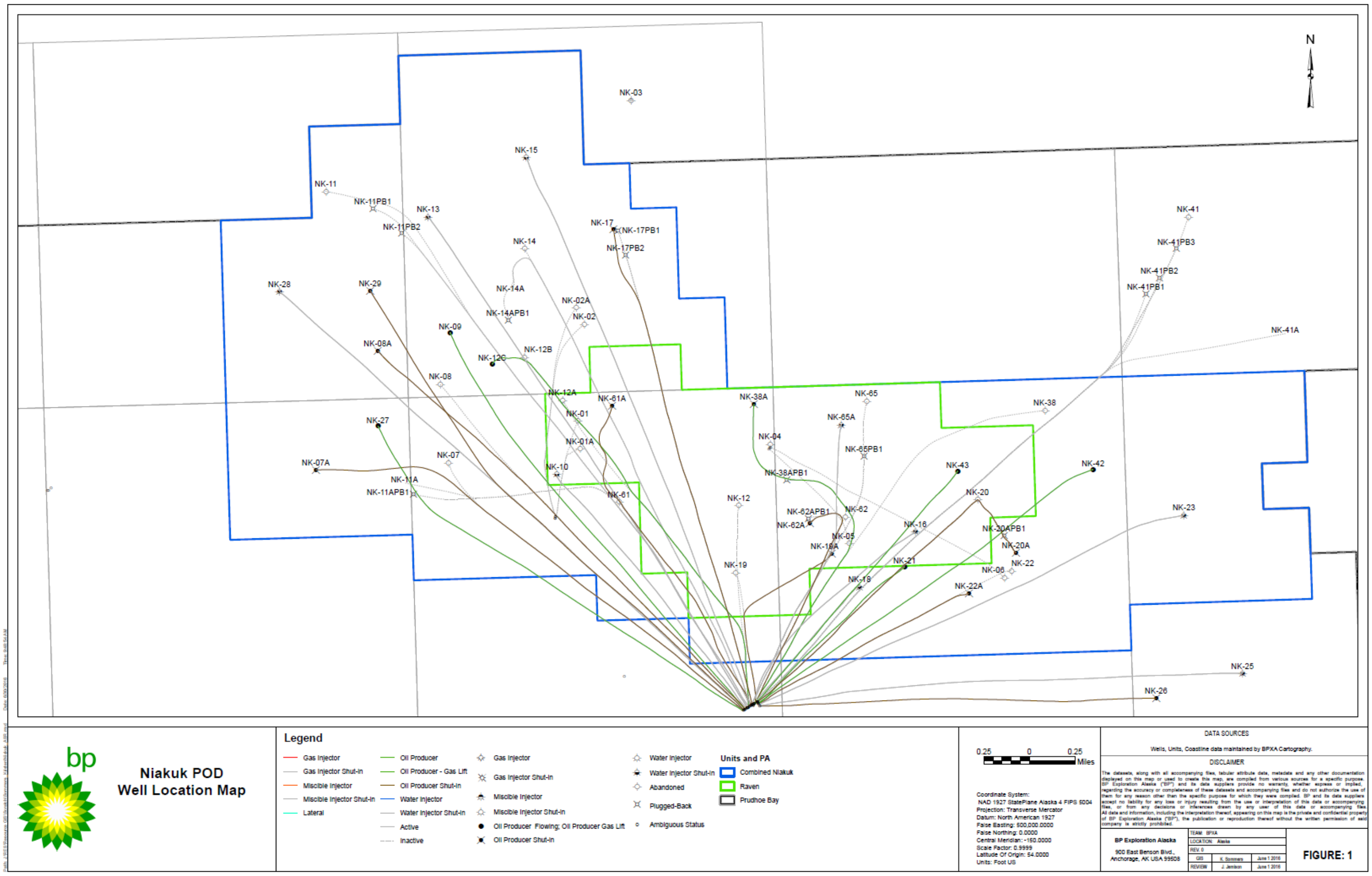
3.4 Projects

No new facility or reservoir projects were executed during the 2015/2016 reporting season.

3.5 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



Pt. McIntyre

PRUDHOE BAY UNIT
POINT MCINTYRE PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
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ATTACHMENT 1: PA expansion acreage around Point McIntyre

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, 2016, through September 30, 2017.

The objective of the PMPA POD is to identify strategies to maximize oil production and recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2016 update to the PMPA POD assumes a continuation of the current business climate and 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 AND CONDENSATE

Crude, condensate and NGL rates averaged 15.41 mb/d. Field offtake was managed to maximize production within the available pipeline and facility constraints, while maintaining close to full voidage replacement. A total of 5.64 MMB was delivered to the Trans-Alaska Pipeline System (TAPS) during the year ending March 31, 2016. Pt. McIntyre wells produce to the Lisburne Processing Center (LPC).

B. PRODUCED GAS

Pt. McIntyre total gas production (including MI breakthrough in EOR patterns) totaled 62.5 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 51.9 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 5.5 BCF of Pt. McIntyre gas produced was consumed as fuel or flared. The fuel and flared gas was consumed for normal LPC and GPMA drillsite operations.

NGL separation averaged 1.12 MB/D with a total of 0.411 MMB delivered and shipped with crude oil production through TAPS during the reporting period. This NGL volume is the allocated Pt. McIntyre NGL production to the LPC.

C. PRODUCED WATER

Pt. McIntyre water production for the reporting period was 34.3 MMB, yielding an average water production rate of 93.9 MB/D.

2.2 DEVELOPMENT

Development activities have continued in accordance with the PMPA POD. Summarized below are the activities at Pt. McIntyre over the past year. More details regarding these activities can be found in Section 3.

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, 16 waterflood patterns were in operation. Produced water from the Pt. McIntyre Field is normally used for re-injection. Additional produced water is provided from the Prudhoe Bay Unit IPA and is pumped to the LPC from Flow Station 1. Water injection totaled 37 MMB for the report period. This volume is equivalent to a daily rate of 101.3 MBWPD.

B. Enhanced Recovery - Miscible Gas

The Pt. McIntyre miscible gas (MI) enhanced oil recovery project continued operation with injection of a total of 17.5 BCF of MI during the report period (48.0 MMSCFD). All MI gas was supplied from the Prudhoe CGF facility for the reporting period.

C. WELL ACTIVITY

Point McIntyre has an active non-rig wellwork program and scale inhibition program. During the reporting period P1-14 had a successful rig work-over to repair a production casing leak and was restored to injection in March 2016.

3.0 PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Point McIntyre is undergoing a tertiary recovery process involving alternating cycles of miscible gas injection and water injection (WAG) that maximizes rate and recovery from the reservoir. Miscible gas injection (MI) started up 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 258 BCF of MI gas has been injected into the reservoir to date.

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.

3.2 PRODUCTION MANAGEMENT

Reservoir management and EOR strategies are designed to optimize oil rate and recovery 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 DEVELOPMENT DRILLING AND OTHER WELL ACTIVITY

Technical assessment of the subsurface is ongoing. This assessment could be improved by the 2014/2015 North Prudhoe Seismic survey. The offshore portion of the survey was completed by December 31, 2014 and the onshore portion in April 2015. Processing of these data is expected to take one to two years. Interpretation of the new data will focus on improving the structure map over the field and understanding of subsurface areas of interest.

3.4 Miscible Gas Enhanced Oil Recovery

Miscible gas injection will continue to be an integral part of the Pt. McIntyre reservoir management plan during 2016. Three injectors at P1 and seven injectors at P2 have been equipped for MI injection and it is anticipated that the remaining waterflood patterns will receive MI over the life of the project. Ten patterns have now received at least one cycle of MI, and MI response has been detected in multiple wells and patterns.

3.5 Projects

The STP36-inch pipeline previously sent production from P2 to GC1, but was taken out of service in November 2011 because of concerns about external corrosion. The STP 36" line which had been used for 3-phase production from P2 to GC1 has about 1.8 miles that cannot be used due to cathodic protection issues. The rest 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 ~8 mile portion of the STP 36" line which potentially can be used would require that all of the P2 production go to GC1, rather than the previous split of P2 production between LPC and GC1. Production benefits of this added flow into GC1 were evaluated.

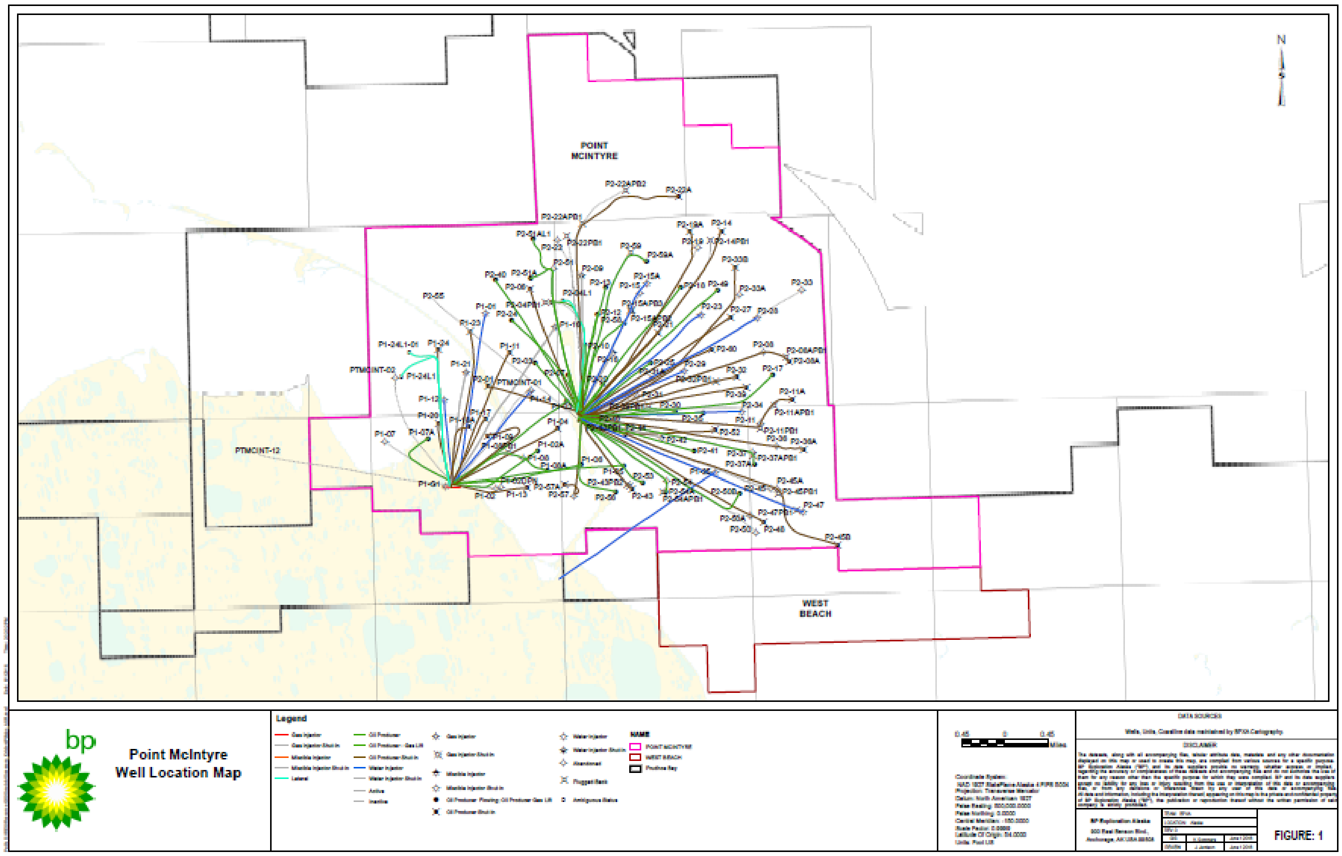
Restoration of the STP-36 line to service and installation of permanent pigging facilities so that the line can be regularly maintained is underway.

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 P1 and two test separators at Drill Site P2.

Revisions to the existing allocation procedures covering three phase P2 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: PA expansion acreage around Point McIntyre



PRUDHOE BAY UNIT

RAVEN PARTICIPATING AREA

ANNUAL PROGRESS REPORT AND

2016 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 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, 2016, through September 30, 2017.

The objective of the RPA POD is to identify strategies to maximize oil production and recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2016 update to the RPA POD assumes a continuation of the current business climate and current understanding of the Raven 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 and Condensate

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 0.13 MB/D for the reporting period. A total of 0.06 MMB from the Raven PA was delivered to the Trans-Alaska Pipeline System (TAPS) from April 1, 2015 to March 31, 2016.

B. Produced Gas

Raven gas production totaled 0.73 BCF from April 1, 2015 to March 31, 2016. Produced gas from Raven is processed at the LPC and injected into the Lisburne and Pt. McIntyre Fields. A total of 66 MMCF of produced gas was consumed as fuel or flared. NGL separation averaged 7.7 B/D with a total of 2.8 MB delivered and shipped with crude oil production through TAPS.

C. Produced Water

Raven water production for the reporting period was 0.86 MMB, yielding an average water production rate of 2.4 MB/D. Produced water is processed at the LPC and injected into the Pt. McIntyre Field.

2.2 Development

Development activities have continued in accordance with the RPA POD. Summarized below are the activities at Raven over the past year. More details regarding these activities can be found in Section 3.

A. Enhanced Recovery - Injected Water

Waterflood operations are conducted in order to maintain field pressure and optimize conformance. During the reporting period the NK-65A water injection well provided injection support to the major oil producer in the field, NK-38A. The total water injected into the field during the reporting period is 1.01 MMB, averaging nearly 2.8 MB/D.

B. Well Activity

Surveillance in the NK-38-A and pre-rig integrity screening in both NK-38A and NK-65A were conducted during the reporting period. Rig and non-rig well work continue to be options under consideration.

3.0 PLAN OF DEVELOPMENT

3.1 Reservoir Management

Production from the Raven Ivishak reservoir continues to be limited to a rate that allows voidage replacement by the water injector. Oil production rate in NK-38A has been declining since water broke through in February 2007.

Commingled production from NK-43 from the Sag (Raven PA) has gone from 4.5% to 0% consistent with the increase seen in water production. A comprehensive logging program was completed in 2014. Based on this data, the team is evaluating wellwork options.

3.2 Production Management

Reservoir management and waterflood strategies are designed to optimize oil rate and recovery from the Raven 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 Development Drilling and other well activity

Technical evaluations of drilling options in Raven will be done using the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015. Interpretation of the processed data will focus on improving the structure map over the field and understanding of subsurface areas of interest.

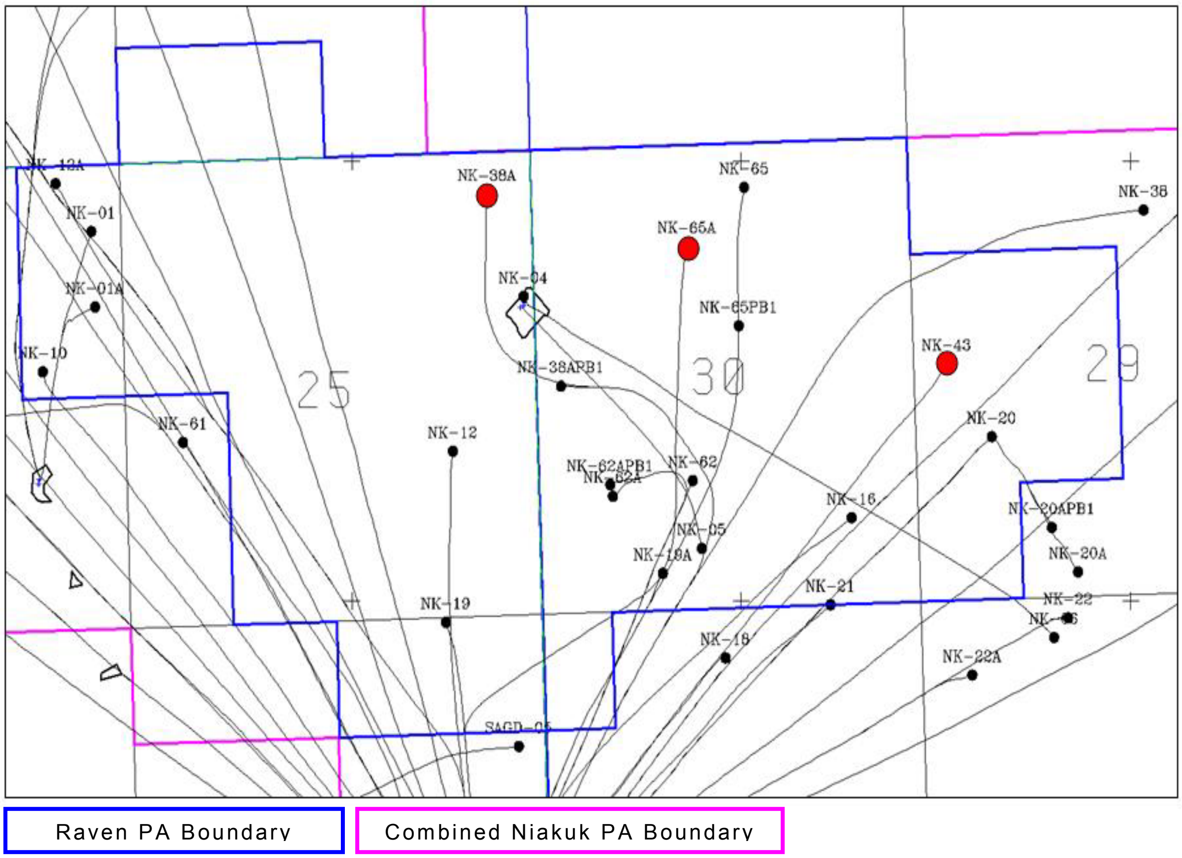
3.4 Projects

No new projects are anticipated in the Raven PA.

3.5 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



West Beach

PRUDHOE BAY UNIT
WEST BEACH PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2016 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, 2016, through September 30, 2017.

The objective of the WBPA POD is to identify strategies to maximize oil production and recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2016 update to the WBPA POD assumes a continuation of the current business climate and 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 - 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 January 2001 and continued through August 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-06 is 6.8 MMBW.

Since the suspension of production in 2001, field wide reservoir pressure has increased. Pressure surveys in WB-04, WB-05B, and WB-06 from 2002 through 2009 show that reservoir pressure has remained at about 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 bbls/day. 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 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. Equipment was ordered for an ILI (In Line Inspection) “smart” pig run to assess pipeline integrity. Current plans are to pig these lines ahead of any new development from the West Beach drillsite, pending further technical assessment. These assessments could be improved by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015. Processing of these data is expected to take one to two years. Interpretation of the processed data will focus on improving the structure map over the field and understanding of subsurface areas of interest. West Beach production line pigging and any new development plans are subject to prioritization with other projects across the Prudhoe Bay Unit.