bp

BP Exploration (Alaska) Inc.
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September 29, 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: Prudhoe Bay Unit, Satellites Plans of Development

Dear Director Feige:

BP Exploration Alaska (BPXA), as Operator of the Prudhoe Bay Unit, submits with this letter five updates to the Plans of Development for Aurora, Borealis, Midnight Sun, Orion, and Polaris Participating Areas in 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. David White, Chevron USA
Mr. Dave Roby, Alaska Oil and Gas Conservation Commission

Aurora

PRUDHOE BAY UNIT
AURORA PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT (17TH)

JANUARY 1, 2017 – DECEMBER 31, 2017

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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 Aurora Participating Area (APA) 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 January 1, 2017, through December 31, 2017.

The objective of the APA POD is to identify strategies to maximize oil production and recovery from the Aurora reservoir in a cost-effective, safe and environmentally responsible manner. This update provides an overview of the projects and strategies that comprise the development program for the Aurora Participating Area. This update assumes a continuation of the current business climate and current understanding of the Aurora 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 & INJECTION

Development of the Aurora Reservoir has focused on phased drilling of production and injection wells from S-Pad. Initial drilling commenced July 2000 with production startup in November 2000. Water injection started in December 2001. Production is commingled with Prudhoe Bay production on S-Pad and processed at GC-2. Tertiary recovery, utilizing Prudhoe Bay miscible gas for WAG (Water-Alternating-Gas injection), was started in December 2003. All injectors at Aurora are designated as WAG injectors at the end of this reporting period.

Discussed below in this Section and in Section 2.2 is additional information describing the Aurora Field for the reporting period July 1, 2015 to June 30, 2016:

- 34 active wells at S-Pad
  - 19 oil producers
  - 15 injectors

Production volumes for July 1, 2015, through June 30, 2016, are indicated in Attachment 3. Average production rates for the reporting period are:

• Oil Production Rate:	6,303	BOPD
• Gas Production Rate:	14.1	MMSCFD
• Water Production Rate:	15,070	BWPD
• Water Injection Rate:	24,851	BWPD
• MI Injection Rate:	3.4	MMSCFD

Cumulative volumes, effective June 30, 2016 (end of reporting period)

• Cumulative Oil Production:	41.7	MMSTB
• Cumulative Gas Production:	127.4	BCF
• Cumulative Water Production:	48.6	MMSTB
• Cumulative Water Injection:	106.7	MMSTB
• Cumulative MI Injection:	45.7	BCF

2.2 DEVELOPMENT

Development activities have continued in accordance with the APA POD. Summarized below are the significant development activities over the reporting period.

A. ENHANCED RECOVERY

Enhanced recovery techniques such as water injection and water-alternating-gas injection (WAG) are employed to increase the recovery of Aurora hydrocarbons.

Aurora is undergoing a tertiary-recovery process involving alternating cycles of miscible-gas injection and water injection that maximizes rate and recovery from the reservoir. Miscible-gas injection started in December 2003 in injection wells S-104i and S-101i. The initial MI slug-size target is approximately 5-10% of the pattern hydrocarbon-pore volume with a nominal WAG ratio of 1.0. Cumulative MI injection is currently targeted 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.

Start-up of produced water injection booster pumps began in December 2005. Two Prince Creek aquifer water supply wells, S-400 and S-401 were drilled to supplement injection demand. Recurring problems with solids production and low deliverability despite sand control measures and acid jobs caused source water production to decline from a peak of 30 mbwd to less than 15 mbwd in 2008. Currently, produced water is the sole source of water used to meet injection demand.

Aurora Participating Area wells are shown in map view in Attachment 1 and listed in Attachment 2. An updated structure map is shown in confidential Attachment 4.

B. WELL ACTIVITY

Summarized below are significant activities at Aurora during the reporting period:

- S-42A: New producer replacing abandoned producer S-108 and targeting additional undrained volumes in an adjacent fault block was drilled in 3Q 2015 and was placed on production in 4Q 2015.
- S-44A: New producer to the North of S-101 injector was drilled in 3Q 2015 and was placed on production in 4Q 2015.
- S-112: Add lateral to support the toe of S-42A was spudded in 2Q 2016, but could not reach the target (West side of fault) due to wellbore stability; parent well and a portion of the add lateral (East side of fault) is currently on injection.
- S-135: A hydraulic fracture treatment was pumped in early January 2016 with the well being placed on production at the end of the month. The initial tested post-frac oil rate was 3,587 bopd at a formation gas-oil-ratio of 338 scf/stbo and watercut of 26%. The last tested pre-frac oil rate was 836 bopd.
- MI was injected into 2 water-alternating-gas injectors.
- In addition to the aforementioned activity, miscellaneous producer and injector wellwork was executed to minimize oil rate decline.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Aurora's reservoir management strategy is to utilize injection-to-withdrawal (I/W) ratios at a pattern level to maintain the reservoir pressure above minimum miscibility pressure for the miscible flood process. This is accomplished by setting optimum injection rates, additional drilling, workovers of existing wells, and cycling high GOR production wells as needed. For surveillance, each well is monitored for well-head pressure, injection flow rates, well-head temperature and production.

3.2 DRILLING AND OTHER WELL ACTIVITY

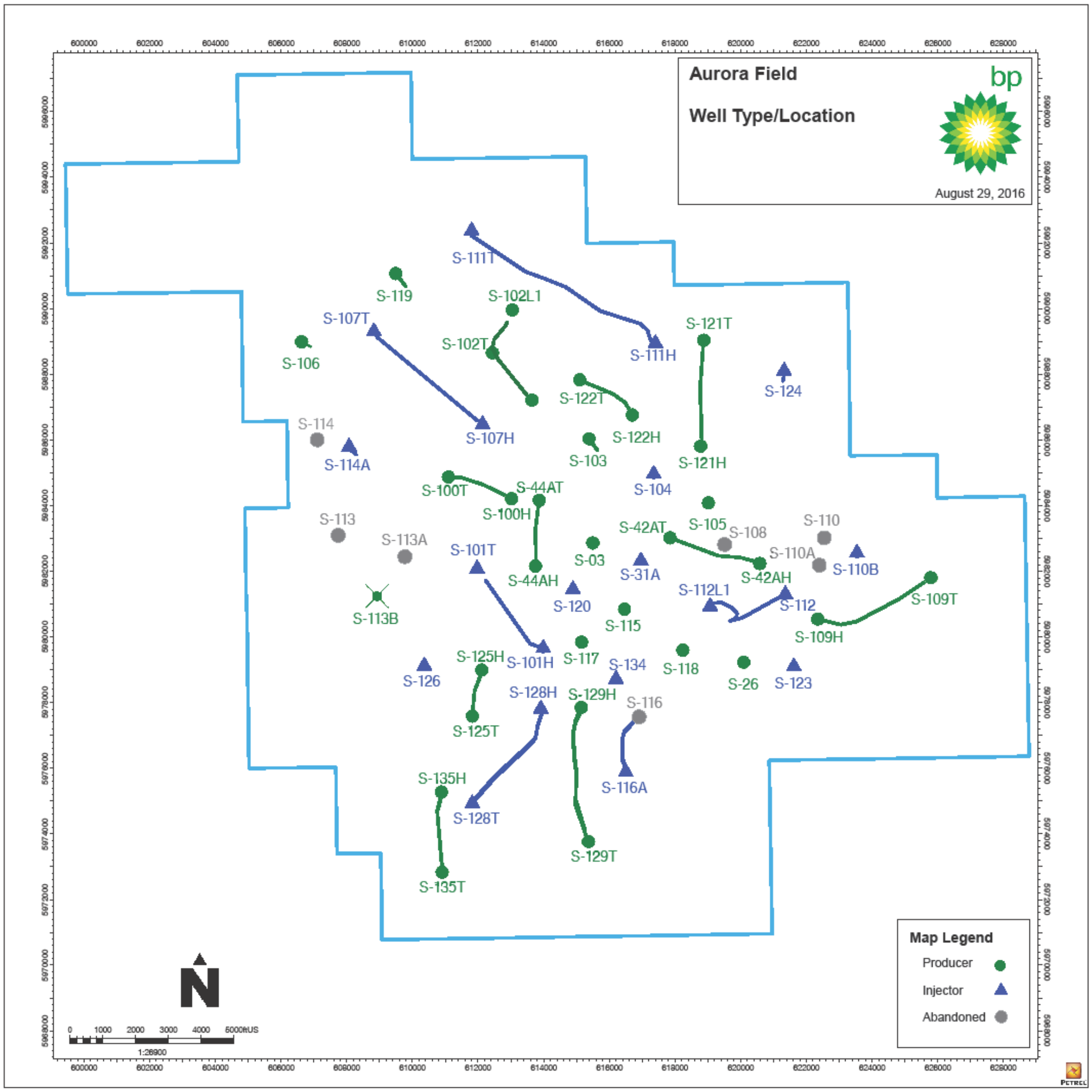
Current plans are for the wellwork program in support of the reservoir management goals above to continue and include jobs aimed to maintain production and mitigate decline. Workovers of existing wells and cycling of high GOR production wells will occur as needed.

Potential future infill targets have been identified using the geologic model and are being considered for future drilling. 2016 production performance will be evaluated to understand well performance and used to help improve current reservoir understanding.

3.3. PRODUCTION ALLOCATION

Aurora production allocation relies on performance curves to determine the daily theoretical production from each well. The GC-2 allocation factor is applied to adjust the total Aurora production. A minimum of one well test per month is used to check the performance curves and to verify system performance. No Natural Gas Liquids (NGLs) are allocated to Aurora.

Attachment 1 – Aurora Well Location Map with Aurora PA Outline



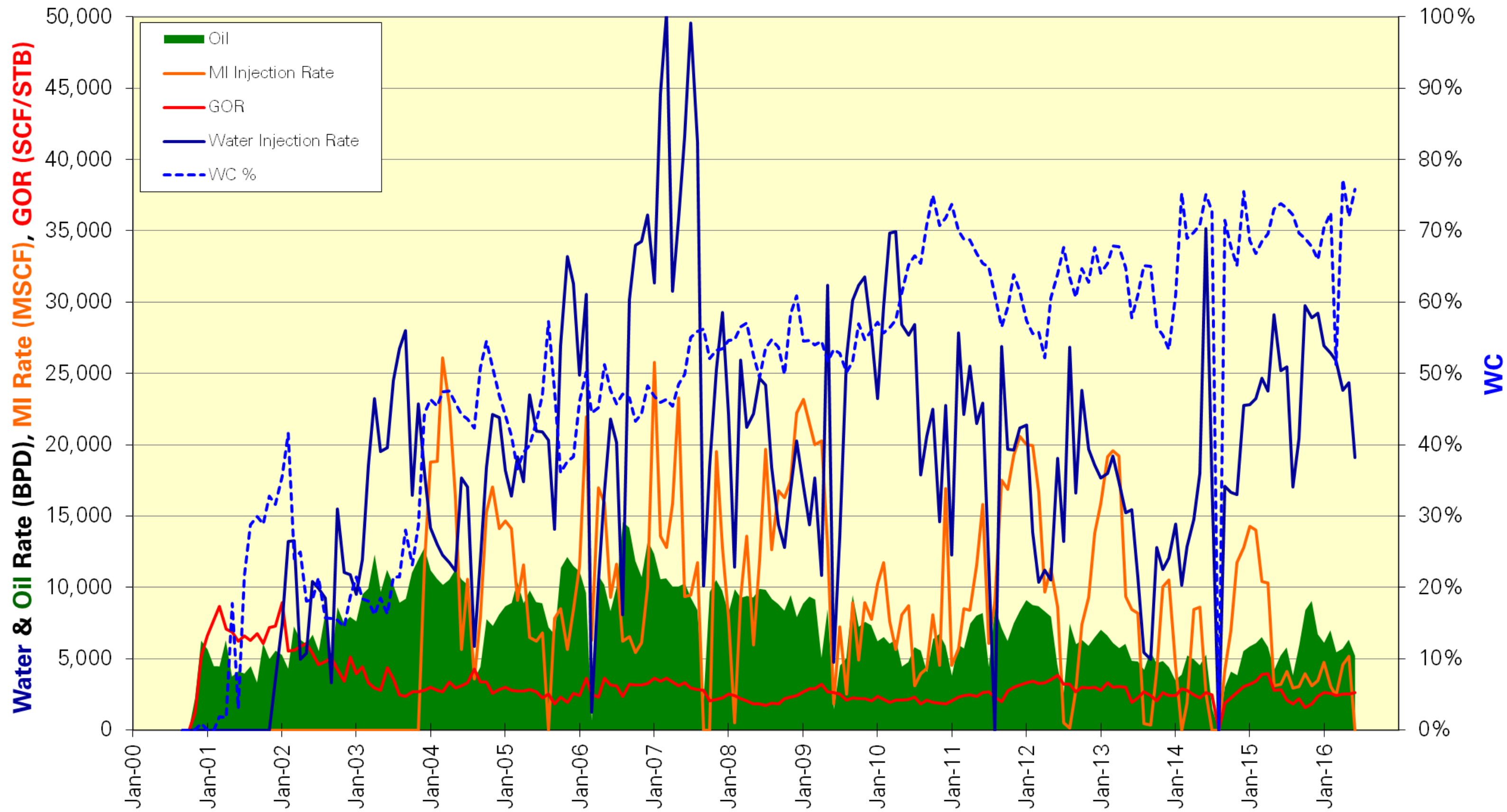
Attachment 2 – Aurora Participating Area Wells

Aurora Participating Area Wells, by Spud Date

Name	Api	Spud Date	Well Type
S-100	500292296200	7/9/2000	Oil Producer
S-101	500292296800	8/9/2000	WAG Injector
S-102	500292297200	9/14/2000	Oil Producer
S-105	500292297700	10/25/2000	Oil Producer
S-103	500292298100	11/6/2000	Oil Producer
S-104	500292298800	1/11/2001	WAG Injector
S-106	500292299900	5/5/2001	Oil Producer
S-108	500292302100	6/11/2001	Abandoned
S-107	500292302300	6/29/2001	WAG Injector
S-110	500292303000	8/13/2001	Plugged Back for Redrill
S-113	500292309400	6/17/2002	Plugged Back For Redrill
S-113A	500292309401	7/3/2002	Plugged Back For Redrill
S-113B	500292309402	7/8/2002	Oil Producer
S-112	500292309900	7/22/2002	WAG Injector
S-114	500292311600	9/4/2002	Plugged Back For Redrill
S-114A	500292311601	9/19/2002	WAG Injector
S-115	500292313000	12/20/2002	Oil Producer
S-109	500292313500	12/31/2002	Oil Producer
S-117	500292313700	2/17/2003	Oil Producer
S-102L1	500292297260	10/26/2003	Oil Producer – Plugged Back
S-116	500292318300	12/7/2003	Plugged Back for Redrill
S-116A	500292318301	12/01/2013	WAG Injector
S-120	500292318600	12/22/2003	WAG Injector
S-118	500292318800	1/3/2004	Oil Producer
S-123	500292321900	9/12/2004	WAG Injector
S-119	500292322200	9/27/2004	Oil Producer
S-111	500292325700	5/14/2005	WAG Injector
S-122	500292326500	7/30/2005	Oil Producer
S-03	500292069500	1/1/2006	Oil Producer
S-121	500292330400	5/9/2006	Oil Producer
S-124	500292332300	10/26/2006	WAG Injector
S-31A	500292210901	1/27/2007	WAG injection
S-125	500292336100	06/28/2007	Oil Producer
S-126	500292336300	10/19/2007	WAG Injector
S-26	500292204700	12/22/2007	Commingled Oil Producer
S-134	500292341300	9/15/2009	WAG Injector
S-129	500292343300	10/24/2010	Oil Producer
S-128	500292343600	11/20/2010	WAG Injector
S-110A	500292303001	12/31/2011	Plugged Back for Redrill
S-110B	500292303002	1/30/2014	WAG Injector
S-09	500292077100	07/05/1982	Plugged back. Non injecting in Aurora
S-135	500292350800	02/14/2014	Oil Producer
S-42A	500292266201	06/15/2015	Oil Producer

S-44A	500292273501	07/14/2015	Oil Producer
S-112L1	500292309960	04/23/2016	WAG Injector

Attachment 3 - Aurora Production and Injection History



The information provided in this Attachment by BP Exploration (Alaska) Inc., as PBU operator, is confidential, proprietary and trade secret information and is not subject to disclosure. It contains information or data that is required to be held confidential under AS 38.05.035, AS 45.50.910 et seq, Section 11.4 of the Prudhoe Bay Unit Agreement, and other applicable law.

Attachment 4 - Aurora Structure Map & PA– (Confidential)

Redacted. Marked CONFIDENTIAL by operator.

Borealis

PRUDHOE BAY UNIT
BOREALIS PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 PLAN OF DEVELOPMENT (16TH)

JANUARY 1, 2017 – DECEMBER 31, 2017

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Borealis Participating Area (BPA) 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 January 1, 2017, through December 31, 2017.

The objective of the BPA POD is to identify strategies to maximize oil production and recovery from the Borealis reservoir in a cost-effective, safe and environmentally responsible manner. This update provides an overview of the projects and strategies that comprise the development program for the Borealis Participating Area. This update assumes a continuation of the current business climate and current understanding of the Borealis 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 & INJECTION

Development of the Borealis Reservoir has focused on phased drilling of production and injection wells from L, V, and Z Pads. Initial drilling commenced July 2001 with production startup in November 2001. Water injection started in June 2002. Production is commingled with Initial Producing Area (IPA) and Orion production on L & V Pads, IPA production at Z-Pad and processed at GC-2. Tertiary recovery, utilizing Prudhoe Bay miscible injectant (MI) for Water-Alternating-Gas injection (WAG), was started in June 2004 as a pilot. The enhanced oil recovery pilot was completed and approval for fieldwide miscible gas injection was given by the AOGCC on April 22, 2005.

Discussed below in this Section and in Section 2.2 is additional information describing the Borealis Field for the reporting period July 1, 2015 to June 30, 2016:

- 24 active wells at L-Pad
  - 15 oil producers
  - 9 injectors
- 19 active wells at V-Pad
  - 11 oil producers
  - 8 injectors

- 8 active wells at Z-Pad
  - 4 oil producers
  - 4 injectors

Production volumes for July 1, 2015, through June 30, 2016, are indicated in Attachment 3. Average production rates for the reporting period are:

• Oil Production Rate:	8,517	BOPD
• Gas Production Rate:	16.2	MMSCFD
• Water Production Rate:	19,939	BWPD
• Water Injection Rate:	28,118	BWPD
• MI Injection Rate:	19.7	MMSCFD

Cumulative volumes, effective June 30, 2016 (end of reporting period.)

• Cumulative Oil Production:	80.9	MMSTB
• Cumulative Gas Production:	114.9	BCF
• Cumulative Water Production:	100.6	MMSTB
• Cumulative Water Injection:	181.5	MMSTB
• Cumulative Gas Injection:	86.2	BCF

Production and injection for V-Pad was shut-in, isolated, and brought to a safe state in June 2016 due to piping over stress findings from an engineering study. The study was commissioned to analyze subsidence and the potential for piping stress that was visually recognized across the pad, which was confirmed by the engineering model from the study. Therefore, in order to mitigate the potential for a loss of primary containment, the pad was shut in while a plan to safely return production/injection is developed. Currently, the piping is being brought back to a neutral stress state via piping modifications and support leveling. The plan is to have production/injection from the pad back online by the end of 2016. This will remain as a short term solution with periodic surveying of subsidence and preventative mitigations ongoing. The PBU operator is studying the cause of the subsidence, with the goal of developing a long term solution by early 2018.

2.2 DEVELOPMENT

Development activities have continued in accordance with the BPA POD. Summarized below are the significant development activities over the reporting period.

A. ENHANCED RECOVERY

Enhanced recovery techniques such as water injection and water-alternating-gas injection (WAG) are employed to increase the recovery of Borealis hydrocarbons.

Borealis is undergoing a tertiary-recovery process involving alternating cycles of miscible-gas injection and water injection that maximizes rate and recovery from the reservoir. Borealis began an MI pilot in the V-100 and L-105 patterns in June 2004. The initial MI slug size target is approximately 7% of the pattern hydrocarbon-pore volume with a nominal WAG ratio of 1.0. Cumulative MI injection is currently targeted 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.

Borealis Participating Area wells are shown in map view in Attachment 1 and listed in Attachment 2. An updated structure map is shown in confidential Attachment 4.

B. WELL ACTIVITY

Summarized below are significant activities at Borealis during the report period:

- L-123: A hydraulic fracture treatment was pumped in December 2015 with the well being placed on injection in February 2016. Prior to the treatment, the injector was offline due to poor injectivity (rock quality).
- L-124: A hydraulic fracture treatment was pumped in January 2016 with the well being placed on production in January 2016. The initial post-frac oil rate was 1,758 bopd at a formation gas-oil-ratio of 692 scf/stb and watercut of 5%. Production stabilized at a lower rate that was well in excess of the pre-frac oil rate of 83 bopd.
- Z-114: WAG injector was placed on MI injection in February 2016 for the first time.
- Z-504A: A booster pump has been repaired and is expected to be returned to service in 3Q 2016.

- Z-504B: B booster pump has been repaired and was returned to service in 2Q 2016.
- MI was injected into 12 water-alternating-gas injectors
- In addition to the aforementioned activity, miscellaneous producer and injector wellwork was executed to minimize oil rate decline.
- The static & dynamic models for the Borealis field have been updated, inclusive of history matching the dynamic model.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

The reservoir management strategy is to utilize injection-to-withdrawal (I/W) ratios at a pattern level to maintain the reservoir pressure above minimum miscibility pressure for the miscible flood process. This is accomplished by setting optimum injection rates, additional drilling, workovers of existing wells, and cycling high GOR production wells as needed. For surveillance, each well is monitored for well-head pressure, injection flow rates, well-head temperature and production.

3.2 DRILLING AND OTHER WELL ACTIVITY

Current plans are for the wellwork program in support of the reservoir management goals above to continue and include jobs aimed to maintain production and mitigate decline. Workovers of existing wells and cycling of high GOR production wells will occur as needed. The Borealis owners will continue to evaluate the optimal number of development wells and their locations throughout the life of the reservoir. The dynamic model for the Borealis field will be used to evaluate potential drilling targets.

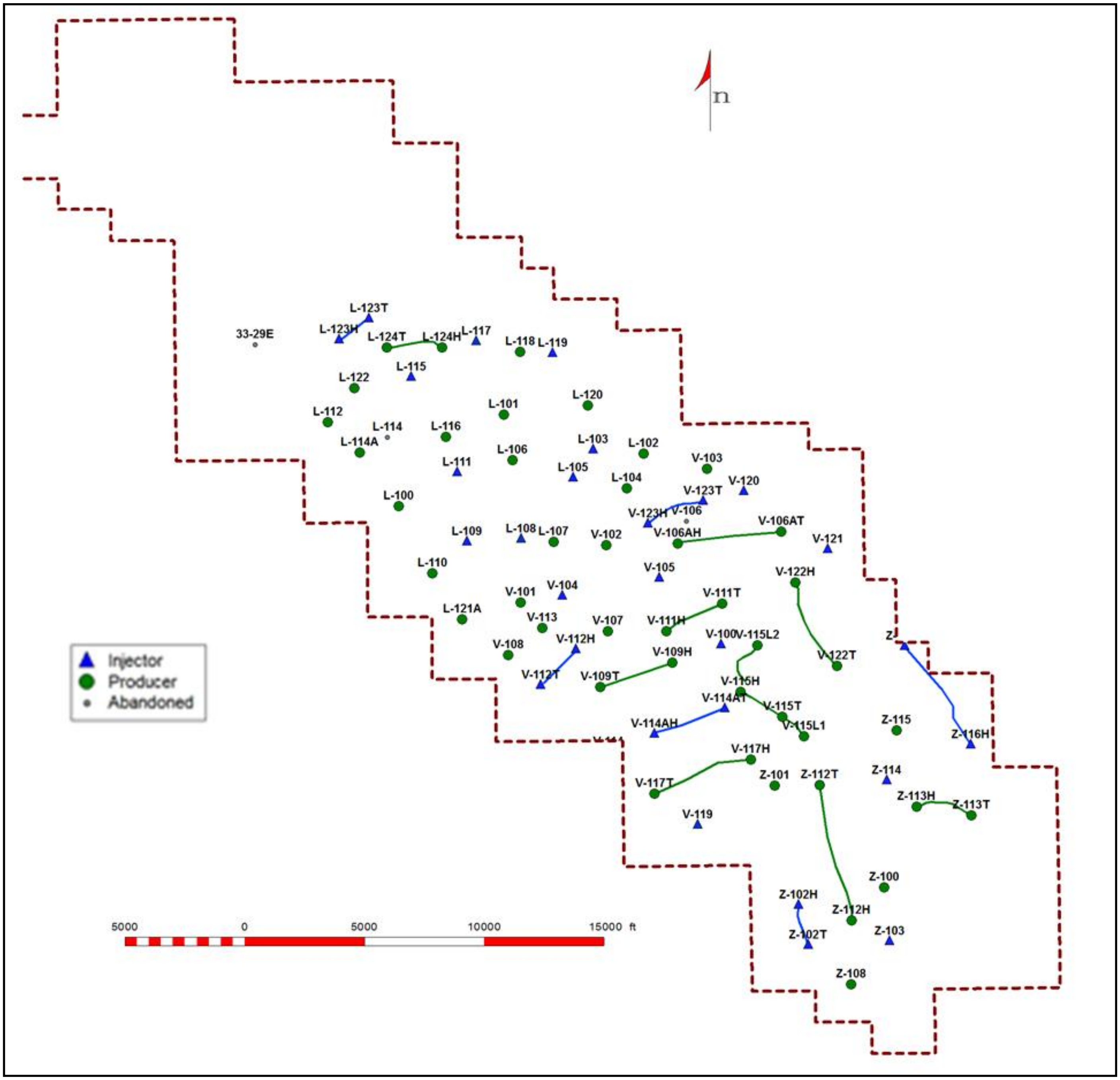
3.3 PROJECTS

Development options for Northwest Borealis are being integrated into the overall development plan for Northwest PBU. The Northwest Borealis accumulation, in the I-Pad project area, lies beneath the Northwest Orion PA accumulation. Evaluation of the reprocessed seismic, existing well data, and Northern L-Pad performance is ongoing to better understand the Northwest Borealis accumulation.

3.4 PRODUCTION ALLOCATION

Borealis production allocation relies on performance curves to determine the daily theoretical production from each well. The GC-2 allocation factor is applied to adjust the total Borealis production. A minimum of one well test per month is used to check the performance curves and to verify system performance. No Natural Gas Liquids (NGLs) are allocated to Borealis.

Attachment 1: Borealis Participating Area and Well Location Map



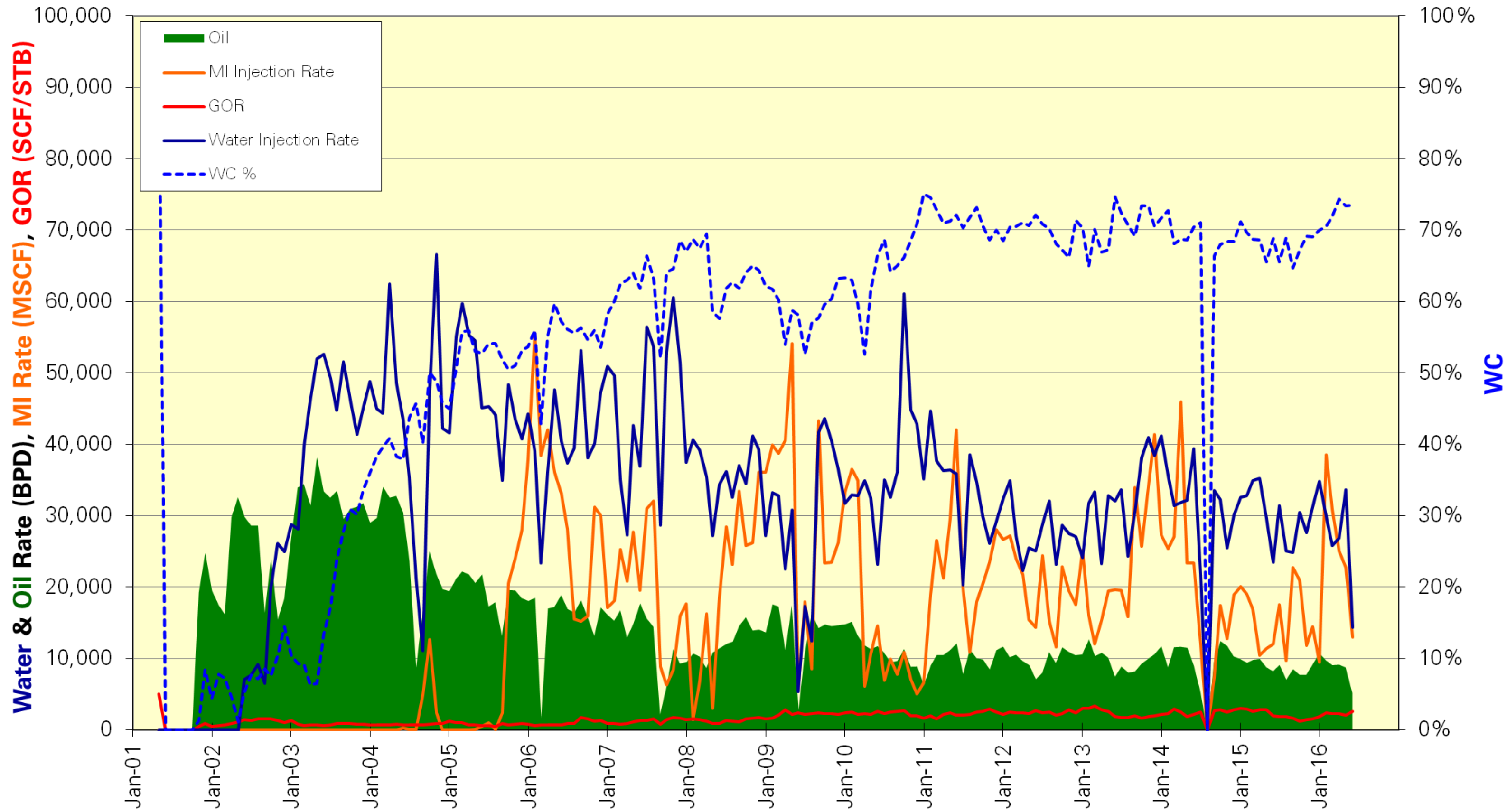
Attachment 2: Borealis Participating Area Wells

POD Table 1: Borealis Participating Area Wells, by Spud Date

Name	Api	Spud Date	Well Type
L-101	500292286500	03/09/1998	Oil Producer
L-100	500292285801	04/01/1998	Oil Producer
Z-101	500292297800	12/15/2000	Tract Well-Shut-In
V-100	500292300800	04/29/2001	WAG Injection
L-116	500292302500	07/02/2001	Oil Producer
L-110	500292302800	07/16/2001	Oil Producer
L-114	500292303200	08/04/2001	Plugged back for Redrill
L-107	500292303600	08/18/2001	Oil Producer
L-117	500292303900	09/13/2001	WAG Injection
L-115	500292303500	10/07/2001	WAG Injection
L-106	500292305500	01/03/2002	Oil Producer
L-104	500292306000	01/17/2002	Oil Producer
L-120	500292306400	01/31/2002	Oil Producer
L-111	500292306900	02/21/2002	WAG Injection
L-102	500292307100	03/07/2002	Oil Producer
L-119	500292307700	03/27/2002	WAG Injection
V-101	500292307400	04/17/2002	Oil Producer – Shut-In
V-106	500292308300	05/01/2002	Plugged back for Redrill
V-102	500292307000	05/14/2002	Oil Producer
L-109	500292304600	05/30/2002	WAG Injection
L-108	500292309000	06/18/2002	WAG Injection
L-105	500292307500	07/05/2002	WAG Injection
L-103	500292310100	07/26/2002	WAG Injection
V-104	500292310300	08/14/2002	WAG Injection
V-105	500292309700	08/27/2002	WAG Injection
V-108	500292311200	09/11/2002	Oil Producer
V-103	500292311700	09/23/2002	Oil Producer
V-107	500292310800	10/08/2002	Oil Producer
V-109	500292312000	10/16/2002	Oil Producer
V-113	500292312500	12/08/2002	Oil Producer
L-112	500292312900	01/01/2003	Oil Producer
L-121A	500292313801	03/14/2003	Oil Producer
L-118	500292304300	03/22/2003	Oil Producer
L-122	500292314700	05/19/2003	Oil Producer
V-117	500292315600	05/30/2003	Oil Producer

V-111	500292316100	07/02/2003	Oil Producer
V-114A	500292317801	10/21/2003	PW Injection Only
Z-100	500292318200	11/24/2003	Oil Producer
V-115	500292319500	03/15/2004	Oil Producer
V-119	500292320100	04/04/2004	WAG Injection
V-120	500292622500	09/18/2004	WAG Injection
V-106A	500292308301	10/01/2004	Oil Producer
Z-103	500292323570	01/31/2005	WAG Injection
L-124	500292325500	04/25/2005	Oil Producer
L-114A	500292303201	08/12/2005	Oil Producer
L-123	500292329000	12/14/2005	WAG Injection
Z-108	500292329200	1/30/2006	Oil Producer
V-112	500292330000	2/17/2006	WAG Injection
I-100	500292324500	3/20/2006	Delineation Well-Not Yet Completed
V-122	500292332800	12/5/2006	Oil Producer
V-121	500292334800	3/16/2007	WAG Injection
Z-102	500292335300	4/29/2007	WAG Injection
Z-112	500292338000	1/19/2008	Oil Producer
V-115L1	500292319560	8/6/2008	Oil Producer
V-115L2	500292319561	8/13/2008	Oil Producer
V-123	500292342200	12/20/2009	WAG Injector
Z-113	500292345000	8/9/2011	Oil Producer
Z-116	500292345500	10/23/2011	WAG Injector
Z-115	500292346800	6/6/2012	Oil Producer
Z-114	500292349000	7/6/2013	WAG Injector

Attachment 3: Borealis Production and Injection History



The information provided in this Attachment by BP Exploration (Alaska) Inc., as PBU operator, is confidential, proprietary and trade secret information and is not subject to disclosure. It contains information or data that is required to be held confidential under AS 38.05.035, AS 45.50.910 et seq, Section 11.4 of the Prudhoe Bay Unit Agreement, and other applicable law.

Attachment 4: Borealis Structure Map – TKC4 Depth Map, CI = 50 feet PA Outline (Confidential)

Redacted. Marked CONFIDENTIAL by operator.

Midnight Sun

PRUDHOE BAY UNIT
MIDNIGHT SUN PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 PLAN OF DEVELOPMENT (18TH)

JANUARY 1, 2017 – DECEMBER 31, 2017

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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 Midnight Sun Participating Area (MNSPA) 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 January 1, 2017, through December 31, 2017.

The objective of the MNSPA POD is to identify strategies to maximize oil production and recovery from the Midnight Sun reservoir in a cost-effective, safe and environmentally responsible manner. This update provides an overview of the projects and operations that comprise the development program for the Midnight Sun Participating Area. This update assumes a continuation of the current business climate and current understanding of the Midnight Sun 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

Figure 1 is a structural contour map on the Top Kuparuk (the Midnight Sun reservoir), showing the location of all production and injection wells. An east-west cross-section (indicated as A-A’ on Figure 1) is shown in Figure 2.

Development of the field commenced in 1997. A total of six Midnight Sun wells have been drilled, with the most recent well drilled in early 2015. There are two producing wells (E-101 and E-102) and four water injection wells (E-100, E-103, E-104, and P1-122i) in the Midnight Sun Field. Water injection started in October 2000. Production is commingled with IPA production on E-Pad and is processed at GC-1.

2.1 PRODUCTION

Production volumes for July 1, 2015, through June 30, 2016, are indicated in Figure 3. Average production rates for the reporting period (July 1, 2015 – June 30, 2016) are:

- Oil Production Rate: 1,134 BOPD
- Gas Production Rate: 2.1 MMSCFD
- Water Production Rate: 11,561 BWPD
- Water Injection Rate: 14,143 BWPD

Listed below are cumulative production volumes for the Midnight Sun field as of June 30, 2016:

- Cumulative Oil Production: 20.8 MMSTBO
- Cumulative Gas Production: 65.9 BSCF
- Cumulative Water Production: 44.3 MMSTB
- Cumulative Water Injection: 98.0 MMSTB

2.2 DEVELOPMENT

Development activities have continued in accordance with the Midnight Sun POD. Summarized below are significant activities at Midnight Sun Field during the reporting period (July 1, 2015 – June 30, 2016).

A. ENHANCED RECOVERY

Produced water injection into the Midnight Sun reservoir commenced in October, 2000, and continues to provide pressure support. An upgrade to the GC-1 produced water injection pump in 2001 increased injection pressures and maximum injection rates to 20-25,000 bwpd.

The objective of water injection is to increase reservoir pressure, reduce gas oil ratios (GORs) to enable wells to be produced at their full capacity, and maximize areal sweep efficiency. A plot of reservoir pressure versus time is attached as Figure 4. Static bottomhole pressure surveys (SBHPS) will continue to be taken at a rate of at least one per year. More surveys will be conducted if production sheltering opportunities arise.

B. WELL ACTIVITY

The new injection well, P1-122i, drilled in 1Q 2015 to the Midnight Sun Kuparuk reservoir from PM1 pad, was not placed on injection due to integrity issues. Remedial actions to repair it occurred in 2Q 2016, restoring both integrity and zonal isolation, allowing implementing enhanced oil recovery using Miscible Injectant (MI) in a Water-Alternating-Gas (WAG) injection process. The location of this well is shown in Figure 1.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

The reservoir management strategy is to target a field-wide injection-to-withdrawal ratio of 1.0 to 1.3 to maintain reservoir pressure while minimizing resaturation of oil into the gas cap. During the period July 1, 2015 – June 30, 2016, an average VRR of 1.00 was achieved. The average VRR target for 2017 is 1.2.

Ongoing reservoir surveillance will be carried out to evaluate waterflood performance, fluid movement, well integrity, and the opportunity for wellwork.

3.2 DEVELOPMENT DRILLING AND OTHER WELL ACTIVITY

As the waterflood continues to mature, sidetracking the producers within the pool to maximize oil recovery will be evaluated after the benefits from WAG injection are realized. No additional injectors or producers are planned at this time.

3.3 Production Allocation

Midnight Sun production is processed through the GC-1 facility. Midnight Sun production allocation relies on performance curves to determine the daily theoretical production from each well. The GC-1 allocation factor is applied to adjust the production. At least one well test per month is used to check the performance curves and to verify system performance.

ATTACHMENT 1:

FIGURE 1 MIDNIGHT SUN TOP KUPARUK RESERVOIR STRUCTURE MAP

The information provided in this Attachment by BP Exploration (Alaska) Inc., as PBU operator, is confidential, proprietary and trade secret information and is not subject to disclosure. It contains information or data that is required to be held confidential under AS 38.05.035, AS 45.50.910 et seq, Section 11.4 of the Prudhoe Bay Unit Agreement, and other applicable law.

Redacted. Marked CONFIDENTIAL by operator.

FIGURE 2: MIDNIGHT SUN CROSS-SECTION

The information provided in this Attachment by BP Exploration (Alaska) Inc., as PBU operator, is confidential, proprietary and trade secret information and is not subject to disclosure. It contains information or data that is required to be held confidential under AS 38.05.035, AS 45.50.910 et seq, Section 11.4 of the Prudhoe Bay Unit Agreement, and other applicable law.

Redacted. Marked CONFIDENTIAL by operator.

FIGURE 3: Midnight Sun Production and Injection History

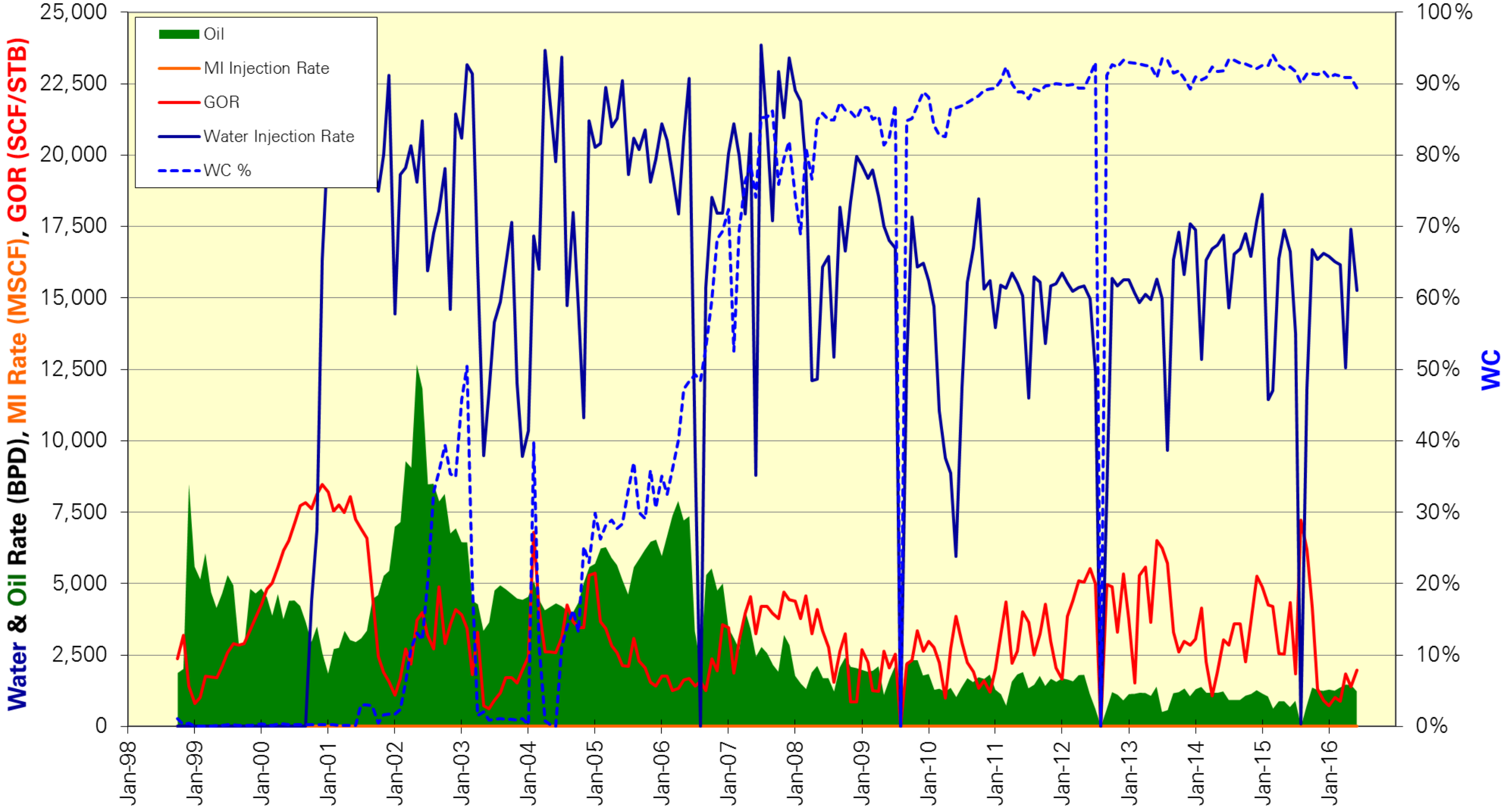
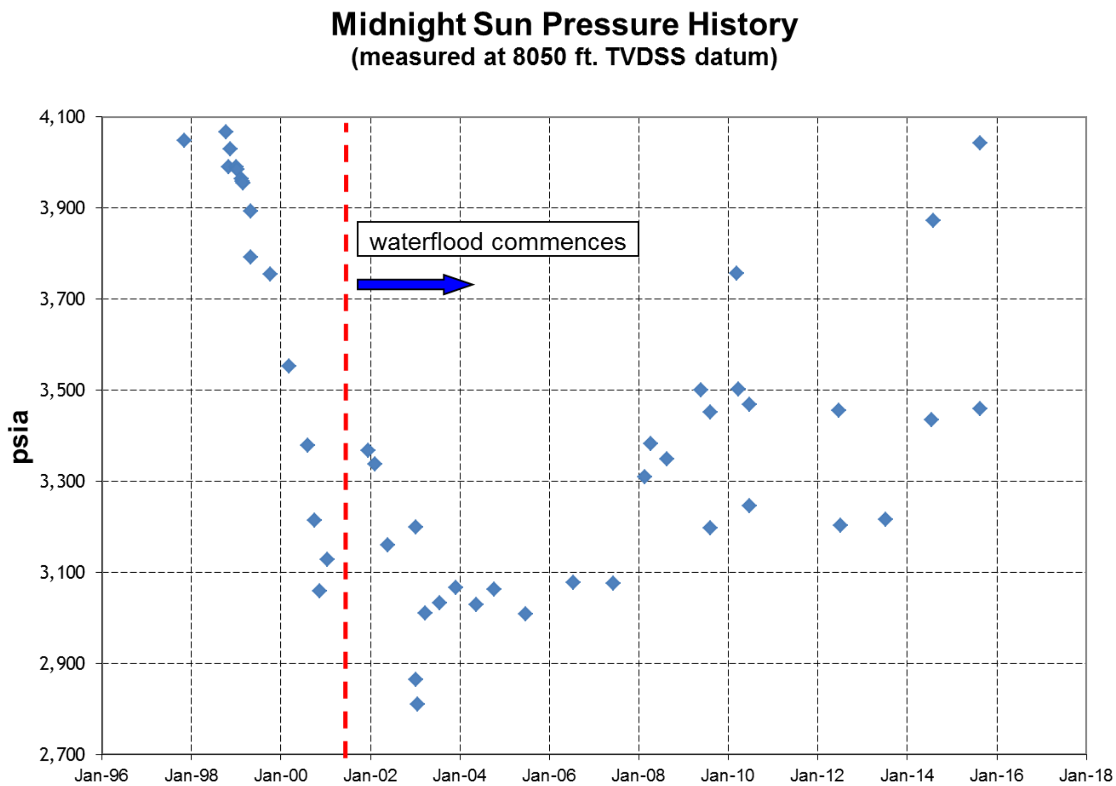


FIGURE 4: Midnight Sun Well Reservoir Pressure (measured at 8050 TVDSS Datum)



PRUDHOE BAY UNIT
ORION PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT (13TH)

JANUARY 1, 2017 – DECEMBER 31, 2017

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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 Orion Participating Area (OPA) 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 January 1, 2017, through December 31, 2017.

The objective of the OPA POD is to identify strategies to maximize oil production and recovery from the Orion reservoir in a cost-effective, safe and environmentally responsible manner. This update to the Orion PA POD provides an overview of the projects and operations that comprise the current OPA development program. This update assumes a continuation of the current business climate and current understanding of the Orion 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 & INJECTION

Development of the Orion Reservoir has included phased drilling of 48 producers and injectors from L-, V- and Z-Pads and numerous additional appraisal wells. Initial development drilling commenced in December 2001, with production startup in April 2002. Orion production is commingled with IPA and Borealis production and flows to Gathering Center #2 (GC-2) for processing. Water injection started in December 2003. The waterflood is designed to increase recovery and provide pressure support in the Orion reservoir. Tertiary recovery, utilizing Prudhoe Bay MI (Miscible Injectant) for WAG (Water-Alternating-Gas injection), was initiated in October 2006.

Central and southern areas of Orion are being developed using existing and expanded infrastructure at L-Pad, V-Pad, and Z-Pad. Currently, the Orion reservoir is being produced from seven Schrader Bluff sands (Nb, OA, OBa, OBb, OBc, OBd, & OBe).

Discussed below in this section and in Section 2.2 and 2.3 is additional information describing activity in the Orion Field for the reporting period July 1, 2015 to June 30, 2016:

- 10 active wells at L-Pad
  - 3 oil producers
  - 7 injectors
- 20 active wells at V-Pad
  - 5 oil producers
  - 15 injectors

Average production rates for the reporting period are:

• Oil Production Rate:	4,747	BOPD
• Gas Oil Ratio	1,045	SCF/STB
• Water Production Rate	4,217	BWPD
• Water Injection Rate:	8,275	BWPD
• Gas Injection Rate:	9.4	MMSCFD

As of June 30, 2016 the cumulative totals are:

• Cumulative Oil Production:	33.8	MMSTBO
• Cumulative Gas Production:	32.0	BSCF
• Cumulative Water Production:	11.0	MMSTB
• Cumulative Water Injection:	42.3	MMSTB
• Cumulative Gas Injection	23.1	BCF

Production and injection for V-Pad was shut-in, isolated, and brought to a safe state in June 2016 due to piping over stress findings from an engineering study. The study was commissioned to analyze subsidence and the potential for piping stress that was visually recognized across the pad, which was confirmed by the engineering model from the study. Therefore, in order to mitigate the potential for a loss of primary containment, the pad was shut in while a plan to safely return production/injection is developed. Currently, the piping is being brought back to a neutral stress state via piping modifications and support leveling. The plan is to have production/injection from the pad back online by the end of 2016. This will remain as a short term solution with periodic surveying of subsidence and preventative mitigations ongoing. The PBU operator is studying the cause of the subsidence, with the goal of developing a long term solution by early 2018.

Attachment 4 shows Orion production and injection data since field inception.

2.2 DEVELOPMENT

Development activities have continued in accordance with the OPA POD. Summarized below are the significant development activities over the reporting period.

A. ENHANCED RECOVERY

Orion is managed as a WAG flood, with injectors alternating between produced water and MI.

During this reporting period, MI was injected into 13 Orion wells.

No new matrix bypass events were confirmed during the reporting period. However, two previously reported matrix bypass events in injectors V-211 and V-224 were remediated.

B. WELL ACTIVITY

Waterflood regulating valve changeouts were performed on 15 injection wells. Regulating valve changeouts are significant operations requiring several pieces of equipment for several days. They are performed to adjust injection profiles and/or ensure correct regulator function.

During the reporting period, two injection logs were run. Injection logs are used to quality check waterflood regulating valve performance while in water service or to determine the distribution of miscible injectant between zones. In May 2016, injection logs were run in V-211 and V-224 to identify if any valves (dummy valve or waterflood regulating valve) were no longer seated in the well's gas lift mandrels; troubleshooting increased injectivity.

Prior production logs have frequently been adversely affected by well slugging, and as a result no production logs were run during the reporting period. Future production logging candidates will be evaluated on a case by case basis.

Installation of sand-face pressure gauges for each injection zone in new injectors started in January 2007. This technology has enabled identification of Matrix Bypass Events (MBEs). Monitoring of sand-face pressure gauges is an integral part of the base management process and has also helped identify problematic waterflood regulating valves. OPA wells are shown in map view in Attachment 1, and listed in Attachments 2 and 3. An updated structure map is shown in confidential Attachment 5.

2.3 Projects

Processing Capability. Orion production is processed at GC-2, a facility that was originally built to handle light oil. Sand-laden viscous oil production requires a substantially enhanced solids handling capability. The current volumes of viscous oil production entering GC-2 have led to operational difficulties and increased wear on plant components.

To mitigate problems at GC-2 and enable further viscous production, the PBU owners executed work at GC-2 in 2012 and 2013 to upgrade its solids handling capabilities. The work was designed to deliver improvements in GC-2's solids handling capability. An accumulator was installed and improvements were made in sand jetting procedures and dehydrator sand jetting. The equipment was commissioned in late 2Q 2013. Although the project has had some improvement in sand handling capability, the project has not yielded the desired level of improvements. Additional engineering work is ongoing to evaluate designs for improvements.

Reducing Subsurface Uncertainties. Subsurface uncertainties impact potential rates and recoveries of viscous development projects, as well as the optimal design and placement of wells. To better understand these subsurface uncertainties, work continued with the development and history matching of the Orion dynamic models.

Viscous Well Downtime. Viscous wells in the Northwestern most portion of the Orion PA, adjacent to the potential I-Pad development, have experienced downtime that reached fifty percent in recent years due to sand production, matrix bypass events, and downhole equipment failures. Understanding the causes of well downtime, as well as increasing the time Orion wells are online, would have a sizable impact on the certainty of being able to deliver projected rate streams for future Orion development projects. Causal analysis performed on viscous wells having high downtime, along with subsurface studies, indicates alternative junction technology and sand control technology as a possible means to reduce downtime in future developments.

During the reporting period, work was initiated on possible sidetrack options for two long term shut-in producers at L Pad; L-200 and L-205. Both L-200 and L-205 are multi-lateral producers that have failed top junctions with significant sand production. In their current states, both wells have little to no remaining value. A plan to re-drill both multi-lateral producers as vertical wells with frac-pack completions is being evaluated. This approach eliminates junctions as a potential failure mechanism and adds positive sand control as a means to eliminate sand production and as a result prevent matrix bypass events from occurring. If progressed, these wells will be the first vertical, frac-pack completions in the Orion PA.

I-Pad. As discussed in the 2016 POD submittal, potential I-Pad viscous oil development is contingent upon the results of sand control technology deployed in the Schrader Bluff Formation and the business environment. The sand control trial at Z Pad is deferred due to the current business climate. In the reporting period, PBU owners continued to evaluate learnings from other ongoing technology trials (e.g. standalone screens).

During the reporting period, work continued on the dynamic models to improve the subsurface description in the I-Pad area.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Orion is being developed with primary depletion and enhanced recovery via water injection to displace oil and maintain reservoir energy. Further recovery is achieved by alternating Prudhoe Bay miscible gas with the water injection (WAG).

All injectors drilled since 2006 utilize a viscous oil injector completion basis of design that incorporates a multi-packer completion and use of downhole waterflood regulator valves to control the injection rate into each of the sands. New injection wells incorporate check valves in the waterflood regulators to eliminate crossflow during shut-in periods and improve reliability of the regulator valves. Downhole pressure gauges are installed to provide real-time sand-face pressure data in each zone. Experience with the Schrader development shows that this control is needed because of significant differences in rock and oil quality between sands. Individual well target water injection rates range from ~500 to 2,300 bwpd. The waterflood regulating valves also reduce the chance of MBEs and limit the flood rate if an MBE occurs.

Because of the variability in sand and oil quality between zones, reservoir surveillance work has been undertaken to develop a better understanding of the reservoir performance by zone and design a development program to maximize recovery. For producers, production allocation efforts focus on using geochemical fingerprinting analysis on produced oil. This technique is in use world-wide and has proven useful in the Schrader Bluff fields on the North Slope of Alaska. The complex nature of multilateral designs makes conventional production logging for zonal contribution difficult. For injectors, efforts include injection logging and zonal control using flow regulators. Work is ongoing to balance waterflood pattern voidage and provide proper pressure support.

3.2 DRILLING AND OTHER WELL ACTIVITY

Potential future sidetrack targets have been identified and are being considered for future drilling. Current plans are for the wellwork program to continue and include jobs necessary with a goal of maintaining production and mitigating decline. Jobs such as more waterflood regulating valve changeouts and running injection logs to quality check waterflood regulating valve performance while in water service or to determine the distribution of miscible injectant between zones are projected.

Future production logging candidates will be evaluated on a case by case basis.

The Orion structure map is shown in confidential Attachment 5.

3.3 PROJECTS

PBU working interest owners have experienced technical challenges during the development of the Orion Field. Development plans for remaining opportunities within the Orion PA focus on reducing risks and costs as highlighted below.

Processing Capability. Orion production is processed at GC-2, a facility that was originally built to handle light oil. The current volumes of sand laden viscous oil production entering GC-2 have led to operational difficulties and increased wear on plant components. Additional Orion and Polaris viscous production is dependent upon upgrades to GC-2 that will increase its ability to process sand-laden viscous oil. As discussed in section 2.3, the recent work to improve sand handling capability has indicated a need for further engineering and modifications to achieve the desired improvements. Work is ongoing to optimize the separation system efficiency to improve how GC-2 processes the large volume of solids being produced.

Reducing Subsurface Uncertainties. The PBU working interest owners plan on performing a subsurface work program during the 2017 POD period that includes:

- Incorporating learnings from the geomechanical study for Prudhoe Bay Schrader Bluff into field management, well design and future developments.
- Utilizing the updated structural framework and subsurface models to evaluate development scenarios.

Viscous Well Downtime. During the 2017 POD period, BPXA will continue to gather data from the current wells. Work will continue on evaluating options for alternative completion designs and technologies that are intended to improve junction reliability and control sand production.

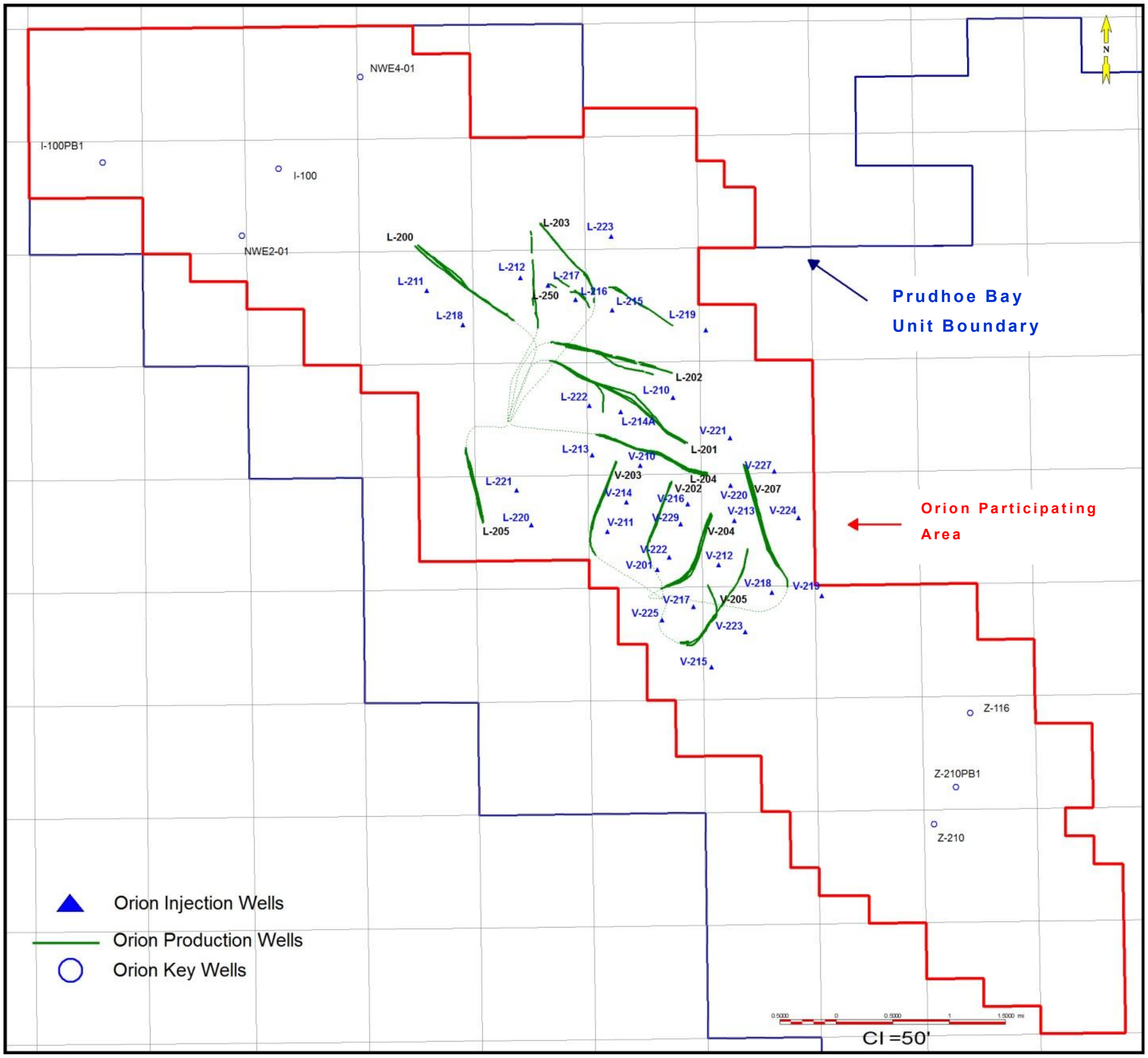
I-Pad.

During the 2017 POD period, the PBU working interest owners plan to continue to work on the dynamic model in the I-Pad area to improve the subsurface description and evaluate development scenarios. Also, an alternative sand control technology will be tested in a potential rotary sidetrack and the learnings will be factored into I Pad development planning.

3.4 PRODUCTION ALLOCATION

Orion production allocation relies on performance curves to determine the daily theoretical production from each well. The GC-2 allocation factor is applied to adjust the total Orion production. At least one well test per month is used to check the performance curves and to verify system performance. No Natural Gas Liquids (NGLs) are allocated to Orion.

ATTACHMENT 1- ORION WELL LOCATION MAP



Attachment 2 - Orion Participating Area Wells

Orion Participating Area Wells, By Spud Date			
Well Name	**API No.**	**Spud Date**	**Well Type**
V-201	500292305400	12/25/2001	Suspended
V-202	500292315300	5/4/2003	Horizontal Oil Producer
V-202L1	500292315360	11/26/2003	Horizontal Oil Producer
V-202L2	500292315361	12/3/2003	Horizontal Oil Producer
L-210	500292318700	12/31/2003	Vertical Water Injector
L-200	500292319100	1/18/2004	Horizontal Oil Producer
L-200L1	500292319160	2/6/2004	Horizontal Oil Producer
L-200L2	500292319161	2/14/2004	Horizontal Oil Producer
L-211	500292319700	2/24/2004	Vertical Water Injector
L-201	500292320200	3/17/2004	Horizontal Oil Producer
L-201L1	500292320260	4/6/2004	Horizontal Oil Producer
L-201L2	500292320261	4/14/2004	Horizontal Oil Producer
L-201L3	500292320262	4/23/2004	Horizontal Oil Producer
L-216	500292320600	5/2/2004	Vertical Water Injector
V-213	500292321300	7/12/2004	Vertical Water Injector
V-204	500292321700	7/29/2004	Horizontal Oil Producer
V-204L1	500292321760	8/13/2004	Horizontal Oil Producer
V-204L2	500292321761	8/19/2004	Horizontal Oil Producer
V-204L3	500292321762	8/27/2004	Horizontal Oil Producer
V-216	500292321600	9/2/2004	Vertical Water Injector
Z-210	500292322600	10/10/2004	Vertical Water Injector
V-210	500292323100	10/31/2004	Vertical Wag Injector
V-211	500292323200	11/12/2004	Vertical Wag Injector
V-221	500292324600	2/22/2005	Vertical Water Injector
L-212	500292325200	3/23/2005	Vertical Water Injector
L-214	500292325800	5/16/2005	Vertical Water Injector
L-202	500292322900	6/5/2005	Horizontal Oil Producer
L-202L1	500292322960	6/20/2005	Horizontal Oil Producer
L-202L2	500292322961	6/27/2005	Horizontal Oil Producer
L-202L3	500292322962	7/3/2005	Horizontal Oil Producer
L-218	500292327200	8/24/2005	Vertical Water Injector
L-215	50029232744	9/8/2005	Vertical Water Injector
L-250	500292328100	10/24/2005	Horizontal Oil Producer
L-250L1	500292328160	11/12/2005	Horizontal Oil Producer
L-250L2	500292628161	11/21/2005	Horizontal Oil Producer
V-214	500292327500	10/29/2005	Vertical Wag Injector
V-212	500292327900	12/2/2005	Vertical Wag Injector
V-203	500292328500	1/8/2006	Horizontal Oil Producer
V-203L1	500292328560	1/8/2006	Horizontal Oil Producer
V-203L2	500292328561	1/8/2006	Horizontal Oil Producer
V-203L3	500292328562	1/8/2006	Horizontal Oil Producer
V-203L4	500292328563	1/8/2006	Horizontal Oil Producer

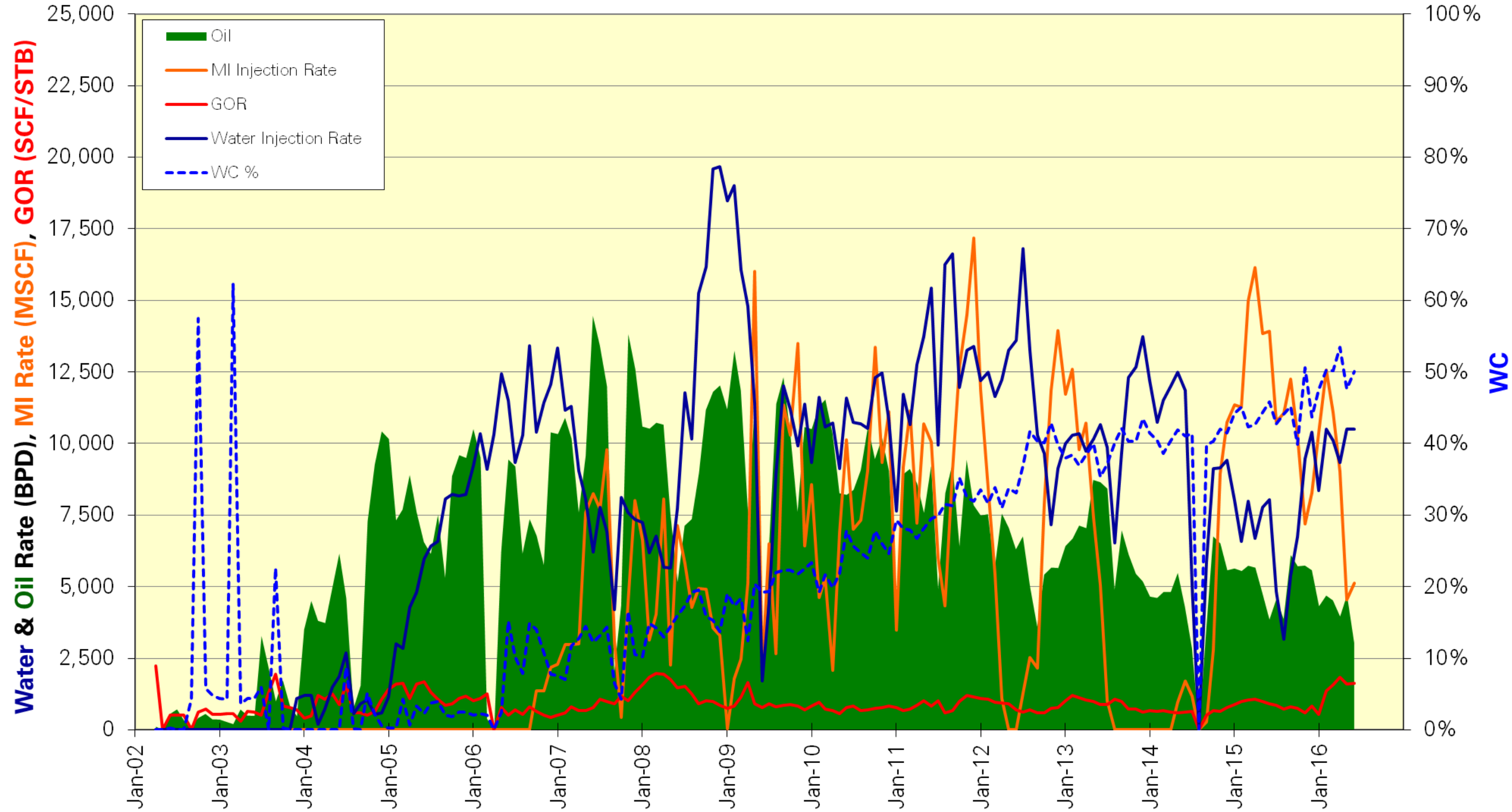
Attachment 2 (cont'd) - Orion Participating Area Wells

Orion Participating Area Wells, By Spud Date			
Well Name	**API No.**	**Spud Date**	**Well Type**
L-214A	500292325801	3/13/2006	Vertical Water Injector
I-100PB1	500292324570	3/20/2006	Appraisal plug-back
L-213	500292330800	4/19/2006	Vertical Wag Injector
L-217	500292331200	7/3/2006	Vertical Water Injector
L-204	500292331400	7/16/2006	Horizontal Oil Producer
L-204L1	500292331460	8/3/2006	Horizontal Oil Producer
L-204L2	500292331461	8/9/2006	Horizontal Oil Producer
L-204L3	500292331462	8/16/2006	Horizontal Oil Producer
L-204L4	500292331463	8/25/2006	Horizontal Oil Producer
V-217	500292333400	1/8/2007	Vertical Water Injector
V-205	500292333800	1/19/2007	Horizontal Oil Producer
V-205L1	500292333860	2/1/2007	Horizontal Oil Producer
V-205L2	500292333861	2/10/2007	Horizontal Oil Producer
V-218	500292335000	4/1/2007	Vertical Wag Injector
V-215	500292335100	4/16/2007	Vertical Wag Injector
V-222	500292335700	6/4/2007	Vertical Water Injector
L-219	500292337600	12/12/2007	Vertical Water Injector
V-220	500292338300	2/24/2008	Vertical Water Injector
V-223	500292338400	2/24/2008	Vertical Water Injector
L-221	500292338500	3/28/2008	Vertical Water Injector
L-220	500292338700	4/10/2008	Vertical Water Injector
L-205	500292338800	4/15/2008	Horizontal Oil Producer
L-205L1	500292338860	6/7/2008	Horizontal Oil Producer
L-205L2	500292338864	6/11/2008	Horizontal Oil Producer
L-205L3	500292338861	6/18/2008	Horizontal Oil Producer
L-205L4	500292338862	6/24/2008	Horizontal Oil Producer
L-205L5	500292338863	6/30/2008	Horizontal Oil Producer
V-207	500292339000	7/10/2008	Horizontal Oil Producer
V-207L1	500292339060	8/3/2008	Horizontal Oil Producer
V-207L2	500292339061	8/12/2008	Horizontal Oil Producer
V-207L3	500292339062	8/23/2008	Horizontal Oil Producer
V-207L4	500292339063	9/1/2008	Horizontal Oil Producer
V-219	500292339700	11/8/2008	Vertical Water Injector
L-223	500292341500	10/1/2009	Vertical Water Injector
L-222	500292342000	10/29/2009	Vertical Water Injector
V-227	500292341700	11/1/2009	Vertical Water Injector
V-224	500292340000	11/26/2009	Vertical Water Injector
L-203	500292341600	4/10/2010	Horizontal Oil Producer
L-203L1	500292341660	5/5/2010	Horizontal Oil Producer
L-203L2	500292341661	5/13/2010	Horizontal Oil Producer
L-203L2-01	500292341662	5/21/2010	Horizontal Oil Producer
L-203L3	500292341663	6/1/2010	Horizontal Oil Producer
L-203L4	500292341664	6/11/2010	Horizontal Oil Producer
V-225	500292341900	6/23/2010	Vertical Water Injector
V-229	500292346400	4/22/2012	Vertical Water Injector

Attachment 3 - Orion Participating Area Wells Commingled Orion / Borealis Injection

Orion Participating Area Wells, By Spud Date			
Well Name	**API No.**	**Spud Date**	**Well Type**
L-117	500292303900	9/13/2001	Vertical Water Injector
L-103	500292310100	7/26/2002	Vertical Water Injector
V-105	500292309700	8/27/2002	Vertical Water Injector

Attachment 4 – Orion Production and Injection History



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Attachment 5 - Orion Top OA Depth Structure Map (Confidential

Redacted. Marked CONFIDENTIAL by operator.

PRUDHOE BAY UNIT
POLARIS PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT (16TH)

JANUARY 1, 2017 – DECEMBER 31, 2017

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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 Polaris Participating Area (PPA) 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 January 1, 2017, through December 31, 2017.

The objective of the PPA POD is to identify strategies to maximize oil production and recovery from the Polaris reservoir in a cost-effective, safe and environmentally responsible manner. This update to the PPA POD provides an overview of the projects and operations that comprise the current PPA development program. This update assumes a continuation of the current business climate and current understanding of the Polaris 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 & INJECTION

Development of the Polaris Reservoir has entailed phased drilling of 28 production and injection wells from S and W Pads. Initial drilling commenced in November 1997, and production startup began in November 1999. Production is commingled with IPA and Aurora Pool production on S-Pad, and with IPA production on W-Pad, and is then processed at Gathering Center #2 (GC-2). Water injection began in May 2003. W-215i injected miscible injectant (MI) for a short time in 2006, but the offset producer was subsequently shut-in, so the water-alternating-gas (WAG or MWAG) cycle was curtailed. MI injection in Polaris resumed in November 2009 with implementation in well S-215i, eventually including other wells.

Discussed below in this section and in Sections 2.2 and 2.3 is additional information describing activity in the Polaris Field for the reporting period July 1, 2015 to June 30, 2016:

- 4 active wells at S-Pad

  - 1 oil producer
  - 3 injectors
- 19 active wells at W-Pad
  - 7 oil producers
  - 12 injectors

Average production rates for the reporting period are:

• Oil Production Rate:	4,306	BOPD
• Gas Oil Ratio:	832	SCF/STB
• Water Production Rate:	6,095	BWPD
• Water Injection Rate:	6,049	BWPD
• Gas Injection Rate:	4.1	MMSCFD

As of June 30, 2016 the field cumulative totals are:

• Cumulative Oil Production:	20.3	MMSTBO
• Cumulative Gas Production:	18.2	BSCF
• Cumulative Water Production:	9.7	MMSTB
• Cumulative Water Injection:	24.0	MMSTB
• Cumulative MI Injection:	5.6	BSCF

Attachment 3 shows Polaris production and injection data since field inception.

2.2 DEVELOPMENT

Development activities have continued in accordance with the PPA POD. Summarized below are the significant development activities over the reporting period.

A. ENHANCED RECOVERY

Polaris is managed as a WAG flood, with injectors alternating between produced water and MI.

During this reporting period, MI was injected into 7 Polaris wells.

No new matrix bypass events were confirmed during the reporting period.

B. WELL ACTIVITY

During the reporting period, two injection logs were run. In December 2015, an injection log was run in W-212 to determine if the well needed to be re-perforated after the remediation of the matrix bypass event. In March 2016, an injection log was run in W-216 to identify which zone was cycling MI as quick breakthrough was observed in offset producer W-204. Injection logs are typically run to quality check waterflood regulating valve performance while in water service or to determine the distribution of miscible injectant between zones.

Waterflood regulating valve changeouts were performed on 8 injection wells. Regulating valve changeouts are significant operations requiring several pieces of equipment for several days. They are performed to adjust injection profiles and/or ensure correct regulator function.

During the reporting period, a production log was run in August 2015 in W-202. The primary goal of the logging job was to identify the location of the matrix bypass event in the OBa lateral. The logging job was successful and played a key role in designing the wellwork job to remediate the matrix bypass event. Prior production logs have frequently been adversely affected by well slugging. Future production logging candidates will be evaluated on a case by case basis.

Installation of sand-face pressure gauges for each injection zone in new injectors started in January 2007. This technology has enabled identification of matrix bypass events (MBEs). Monitoring of sand-face pressure gauges is an integral part of the base management process and has also helped identify problematic waterflood regulating valves.

Three previously reported matrix bypass events in injectors S-215 and W-212, and W-202 were remediated.

No development wells were drilled or completed during this reporting period.

Polaris Participating Area wells are shown in map view in Attachment 1, and listed in Attachment 2. A structure map, incorporating all base wells, is shown in confidential Attachment 4.

2.3 PROJECTS

Processing Capability. Polaris production is processed at GC-2, a facility that was originally built to handle light oil. Sand-laden viscous oil production requires a substantially enhanced solids handling capability. The current volumes of viscous oil production entering GC-2 have led to operational difficulties and increased wear on plant components.

To mitigate problems at GC-2 and enable further viscous production, the PBU owners executed work at GC-2 in 2012 and 2013 to upgrade its solids handling capabilities. The work was designed to deliver improvements in GC-2's solids handling capability. An accumulator was installed and improvements were made in sand jetting procedures and dehydrator sand jetting. The equipment was commissioned in late 2Q 2013. Although the project has had some improvement in sand handling capability, the project has not yielded the desired level of improvements. Additional engineering work is ongoing to evaluate designs for improvements.

Reducing Subsurface Uncertainties. Subsurface uncertainties impact potential rates and recoveries of viscous development projects, as well as the optimal design and placement of wells. To better understand these subsurface uncertainties, work continued with the development and history matching of the Polaris dynamic models.

Viscous Well Downtime. As discussed in sections 2.0 and 3.3, well downtime and production deferrals in the Polaris PA are the result of matrix bypass events. Previous reporting periods have also seen significant downtime and cost due to the need for fill cleanouts. Understanding the causes of well downtime, as well as increasing the time Polaris wells are online, would have a sizable impact on the certainty of being able to deliver projected rate streams for future Polaris development projects. Causal analysis performed on viscous wells having high downtime, along with subsurface studies, indicates alternative junction technology and sand control technology as a means to possibly reduce downtime in future developments.

M&S Pad Development. As discussed in the 2016 POD submittal, potential M&S Pad viscous oil development is contingent upon the results of sand control technology deployed in the Schrader Bluff Formation. The sand control trial at Z Pad (Orion PA) is deferred due to the current business climate. In the near term, PBU owners will continue to evaluate learnings from other ongoing technology trials (e.g. standalone screens).

During the reporting period, work continued on the dynamic models to improve the subsurface description in the M&S Pad area.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Polaris is being developed with primary depletion and enhanced recovery via water injection to displace oil and maintain reservoir energy. Further recovery is achieved by alternating Prudhoe Bay miscible gas with the water injection (WAG).

All injectors drilled since 2006 utilize a viscous oil injector completion basis of design that incorporates a multi-packer completion and use of downhole waterflood regulator valves to accurately control the injection rate into each sand. Downhole pressure gauges are installed to provide real-time sand-face pressure data from each zone. In 2009, the downhole waterflood flow regulator design was updated to incorporate check valves to eliminate between zone cross-flows during shut-in periods and improve reliability of the regulator valves. Experience with the Schrader development shows that this control is needed because of significant differences in rock and oil quality between sands. Individual well target water injection rates typically range from 500 to 1,400 bwpd. The waterflood regulating valves also reduce the chance of MBEs and limit the flood rate if an MBE occurs.

Because of the variability in sand and oil quality between zones, reservoir surveillance work has been undertaken to develop a better understanding of the reservoir performance by zone and design a development program to maximize recovery. For producers, production allocation efforts focus on using geochemical fingerprinting analysis on produced oil. This technique is in use world-wide and has proven useful in the Schrader Bluff fields on the North Slope of Alaska. The complex nature of multilateral designs makes conventional production logging for zonal contribution difficult. For injectors, efforts include injection logging and zonal control using flow regulators. Work is ongoing to balance waterflood pattern voidage and provide proper pressure support.

3.2 DRILLING AND OTHER WELL ACTIVITY

Current plans are for the wellwork program to continue and include jobs aimed to maintain production and mitigate decline. Activities such as more waterflood regulating valve changeouts and running injection logs to quality check waterflood regulating valve performance while in water service or to determine the distribution of miscible injectant between zones are projected. Future production logging candidates will be evaluated on a case by case basis.

Opportunistic logs are being considered for Aurora and IPA new drills that cross the Schrader Bluff horizon in the next year, to gather additional reservoir information.

The Polaris structure map is shown in confidential Attachment 4.

3.3 PROJECTS

Development plans for remaining opportunities within Polaris focus on reducing risks and costs as highlighted below.

Processing Capability. Polaris production is processed at GC-2, a facility that was originally built to handle light oil. The current volumes of sand laden viscous oil production entering GC-2 have led to operational difficulties and increased wear on plant components. Additional Orion and Polaris viscous production is dependent upon upgrades to GC-2 that will increase its ability to process sand-laden viscous oil. As discussed in section 2.3, the recent work to improve sand handling capability has indicated a need for further engineering and modifications to achieve the desired improvements. Work is ongoing to optimize the separation system efficiency to improve how GC-2 processes the large volume of solids being produced.

Reducing Subsurface Uncertainties. The PBU working interest owners plan on performing a subsurface work program during the 2017 POD period that includes:

- Incorporating learnings from the geomechanical study for Prudhoe Bay Schrader Bluff into field management, well design and future developments.

- Utilizing the updated structural framework and subsurface model to evaluate development scenarios.

Viscous Well Downtime. During the 2017 POD period, BPXA will continue to gather data from the current wells. Work will continue on evaluating options for alternative completion designs and technologies that are intended to improve junction reliability and control sand production.

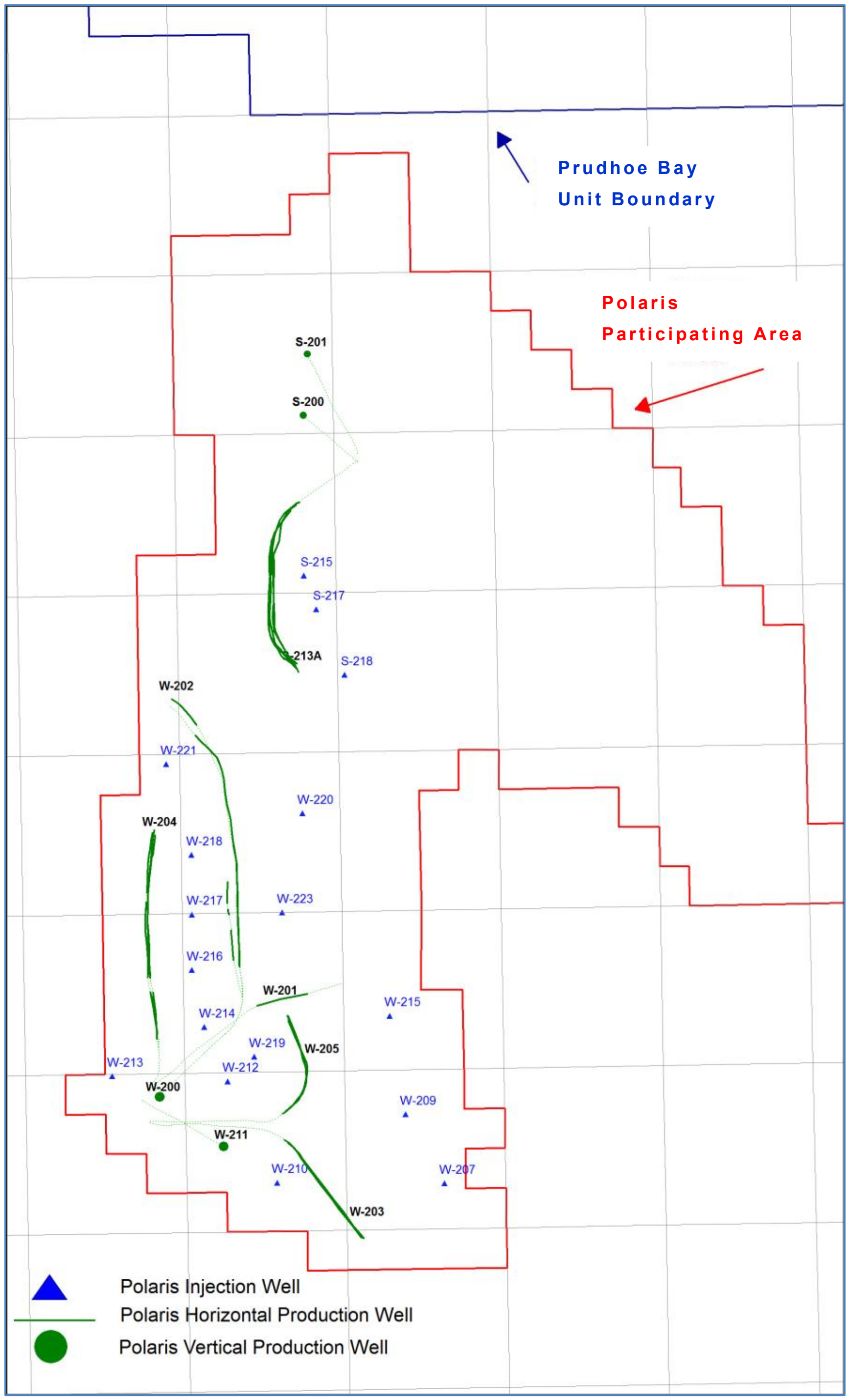
M&S Pad Development.

During the 2017 POD period, the PBU working interest owners plan to continue to work on the dynamic models in the M&S Pad area to improve the subsurface description and evaluate development scenarios. Also, an alternative sand control technology will be tested in a planned rotary sidetrack and learnings will be factored into I Pad development planning.

3.4 PRODUCTION ALLOCATION

Polaris production allocation relies on performance curves to determine the daily theoretical production from each well. The GC-2 allocation factor is applied to adjust the total Polaris production. At least one well test per month is used to check the performance curves and to verify system performance. No NGLs are allocated to Polaris.

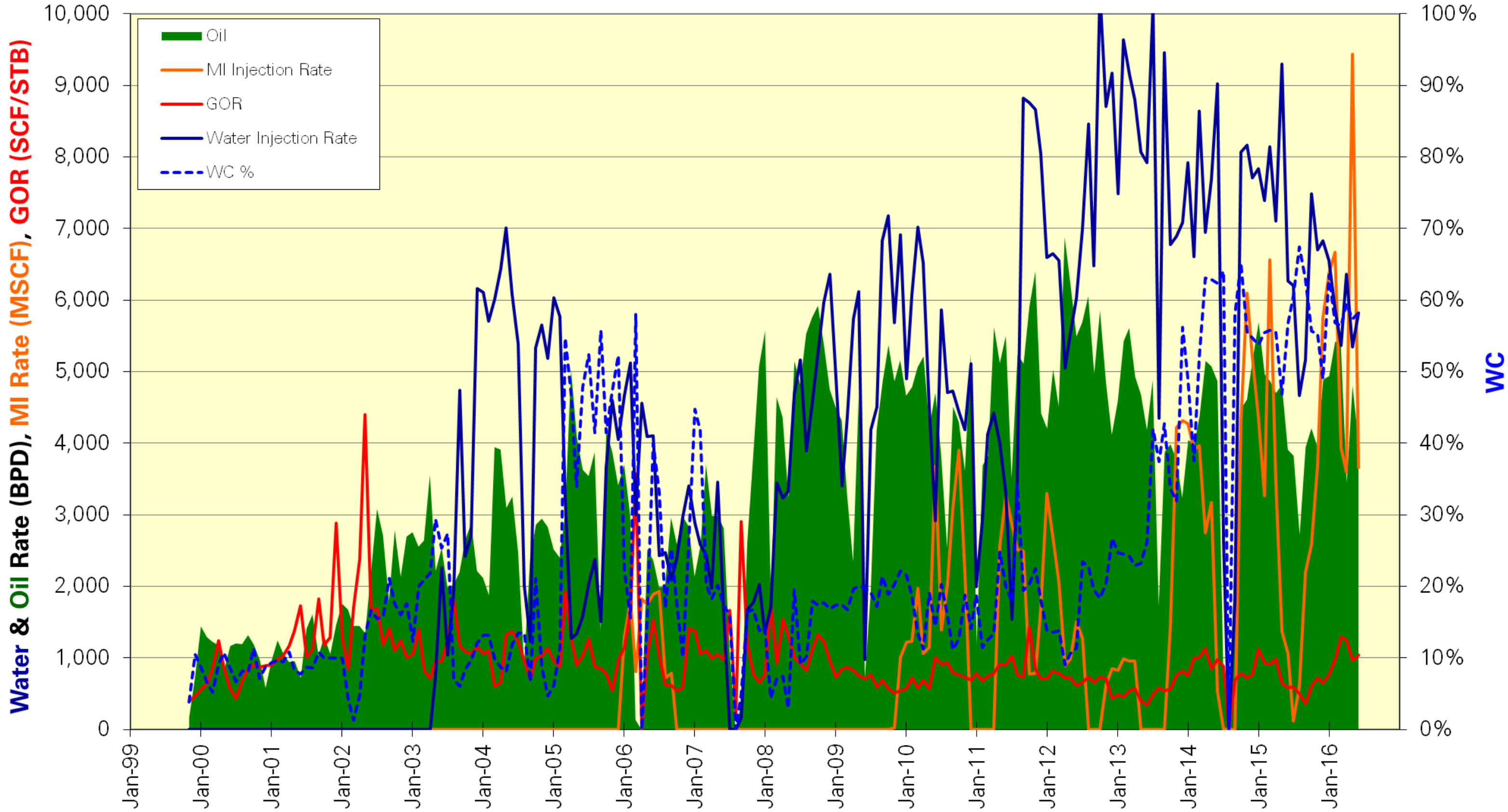
Attachment 1- Polaris Well Location Map



Attachment 2 – Polaris Participating Area Wells

Polaris Participating Area Wells, By Spud Date			
Well Name	**API No.**	**Spud Date**	**Well Type**
W-200	500292283100	11/25/1997	Vertical Oil Producer
S-200	500292284600	12/17/1997	Vertical Oil Producer
S-201	500292298700	11/22/2000	Vertical Oil Producer
S-216	500292298900	12/9/2000	Converted to Water Injection
W-201	500292300700	5/22/2001	Horizontal Oil Producer
W-212	500292307800	4/4/2002	Water Injector
W-211	500292308000	4/14/2002	Vertical Oil Producer
W-203	500292308700	5/24/2002	Horizontal Oil Producer
W-203L1	500292308760	6/7/2002	Horizontal Oil Producer
W-203L2	500292308761	6/11/2002	Horizontal Oil Producer
S-215	500292310700	8/8/2002	Water Injector
W-207	500292314500	4/2/2003	Water Injector
W-205	500292316500	8/23/2003	Horizontal Oil Producer
W-215	500292317200	9/10/2003	WAG Injector
W-209	500292317000	9/23/2003	WAG Injector
W-205L1	500292316560	12/14/2003	Horizontal Oil Producer
W-205L2	500292316561	12/22/2003	Horizontal Oil Producer
S-213A	500292299301	11/25/2004	Horizontal Oil Producer
S-213AL1	500292299361	12/15/2004	Horizontal Oil Producer
S-213AL1-01	500292299360	12/23/2004	Horizontal Oil Producer
S-213AL2	500292299362	11/25/2004	Horizontal Oil Producer
S-213AL3	500292299363	11/25/2004	Horizontal Oil Producer
W-204	500292333300	1/4/2007	Horizontal Oil Producer
W-204PB1	500292333370	1/4/2007	Appraisal Plug-Back
W-204L1	500292333360	2/4/2007	Horizontal Oil Producer
W-204L2	500292333361	2/16/2007	Horizontal Oil Producer
W-210	500292333900	2/20/2007	Vertical Injector
W-213	500292335400	5/20/2007	Vertical Injector
S-217	500292336200	10/1/2007	Vertical Injector
W-214	500292337300	11/5/2007	Vertical Injector
W-216	500292337900	12/27/2007	Vertical Injector
W-218	500292340300	11/25/2008	Vertical Injector
S-218	500292341400	10/2/2009	Vertical Injector
W-217	500292341800	11/11/2009	Vertical Injector
W-219	500292342900	10/31/2010	Vertical Injector
W-220	500292343200	11/25/2010	Vertical Injector
W-202	500292343400	1/5/2011	Horizontal Oil Producer
W-202L1	500292343460	2/12/2011	Horizontal Oil Producer
W-202L2	500292343461	3/6/2011	Horizontal Oil Producer
W-223	500292344000	4/27/2011	Vertical Injector
W-221	500292344400	5/23/2011	Vertical Injector

Attachment 3 - Polaris Production and Injection History



Attachment 4 - Polaris Top OA Structure Map (Confidential)

Redacted. Marked CONFIDENTIAL by operator.