ConocoPhillips

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June 25, 2018

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

RE: 2018 Kuparuk River Unit Plans of Development

Dear Ms. Chantal Walsh,

Attached for your review are the 2018 updates to the Plans of Development for the Kuparuk, Meltwater, Tabasco, Tarn and West Sak Participating Areas (PA) within the Kuparuk River Unit. These updates are submitted pursuant to the requirements set forth in the "Decisions and Findings of the Commissioner" associated with the field participating area applications.

As always, these plans are subject to change based upon business conditions. ConocoPhillips Alaska, Inc. submits this update as Operator of the Kuparuk River Unit.

We look forward to hosting a presentation and review of the Plans on July 11th at ConocoPhillips' Anchorage offices (700 G Street).

Sincerely,

Erik Keskula

Erik Keskula
North Slope Development Manager

Attachments

CC: Mr. Kenneth Diemer, ADNR-DOG
Ms. Cathy Foerster, AOGCC
Mr. Sheldon Fisher, ADOR
Mr. John Dittrich, BPXA
Mr. Dave White, Chevron
Mr. Jamie Long, ExxonMobil

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UNIT PLAN OF DEVELOPMENT
KUPARUK PARTICIPATING AREA

AUGUST 1, 2018 – JULY 31, 2019

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LIST OF ATTACHMENTS

1.0 INTRODUCTION

This document is the annual update to the Kuparuk River Unit Plan of Development, submitted to the State of Alaska Department of Natural Resources (DNR) as required by Article 5, Section 5.1 of the Kuparuk River Unit Agreement and 11 AAC 83.343. The Department of Natural Resources, through a letter dated April 11, 1986, required the submittal of the annual updates to the Kuparuk River Unit Plan of Development by July 1 of each year for approval by August 1.

The effective plan period for this submittal is August 1, 2018, through July 31, 2019. This update to the Kuparuk River Unit (KRU) Plan of Development is submitted by ConocoPhillips Alaska, Inc. (“ConocoPhillips" or "CPAI"), the unit operator, on its own behalf and on behalf of the other KRU working interest owners BP Exploration (Alaska) Inc. (BP), Chevron U.S.A. Inc. (Chevron), and ExxonMobil Alaska Production Inc. (ExxonMobil), (all, collectively hereinafter referred to as "KRU WIOs").

This update covers development plans for the Kuparuk Participating Area (KPA). Assumptions that formed the basis for this plan are consistent with the current business climate. Changes in business conditions, applications of new technologies, new insights into reservoir performance or other changes may alter the timing, scope, or feasibility of one or more components of this plan. Working Interest Owners have proceeded with development of additional reservoirs (Meltwater, Tarn, Tabasco, and West Sak) within the Kuparuk River Unit. As required in the Special Supplemental Provisions approved for each reservoir, Plans of Development are submitted individually for each participating area.

2.0 FIELD STATUS

The following information describes the status of the field as of December 31, 2017, and forms the basis of the 2018 Unit Plan of Development. A map showing the development status of the field is included as Attachment 2.

- Major facilities in place are the same as in 2017.

- The Kuparuk field is developed from 45 drill sites (DS). Drill site 2T is shared with the Tabasco Field; drill sites 1B, 1C, 1D, 1E, 1J, 3K, 3R and 1H are shared with the West Sak Field; drill sites 2N and 2L are shared with the Tarn field; drill site 2P is shared with the Meltwater field.

- The Kuparuk field had 866 active* wells in 2017:
  - 471 producers
  - 395 injectors
    - Including 116 Water-Alternating-Gas (WAG) injectors**

- Drill site status at year-end 2017:
  - Water flood only at 17 Drill Sites
  - Immiscible WAG (IWAG) at 23 Drill Sites
  - Miscible WAG (MWAG) at 5 Drill Sites
  - Production only at 1 Drill Site***

- Cumulative oil production = 2.44 billion barrels

**Active is defined as having produced or injected fluid between January 1, 2017 and December 31, 2017.*
***WAG injectors are defined as those wells currently involved in the WAG scheduling process.*
****There are no future plans to inject at Drill Site 1J into the Kuparuk reservoir.*

3.0 SUMMARY OF 2017 ACTIVITIES

Summarized below are notable activites at Kuparuk over the preceding year (January 1, 2017 to January 1, 2018):

- 2017 KPA oil production averaged 84.1 MBOPD gross (with another 25.0 MBOPD gross from satellites.)

- Successful implementation of a 16 well Coiled Tubing Drilling (CTD) program generated a peak incremental oil rate of approximately 7.5 MBOPD gross. Forty-two laterals were drilled and completed in these wells.

- Completion of four grassroots rotary wells in Kuparuk Participating Area. Six West Sak wells were also drilled in 2017.

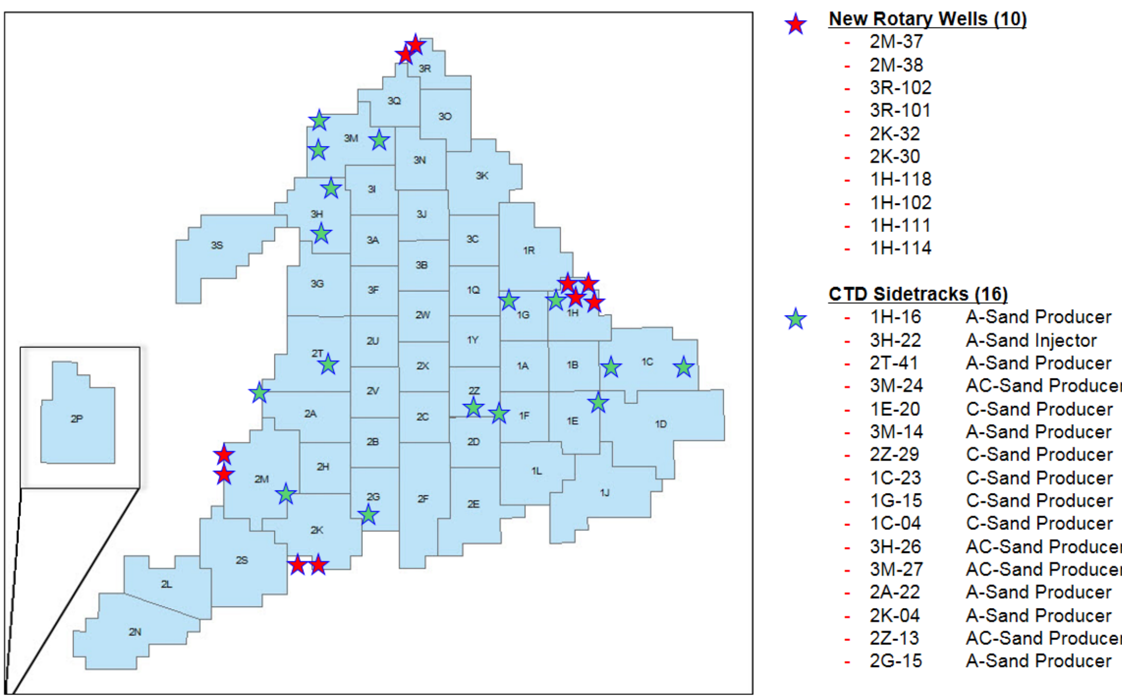


Figure 1: Location of 2017 CTD and rotary drilling projects

- Successful execution of a workover program that added approximately 2.0 MBOPD gross oil in 2017.

- Successful execution of non-rig wellwork activity that includes slickline, electric line, and service coiled tubing jobs that added approximately 8.0 MBOPD gross oil in 2017.

  Indigenous miscible injection continues with GKA indigenous NGL at drill sites 1B, 1C, 1D, 1E and 2C.

- The WI common line for drill sites 3A, 3H, 3I and 3M was repaired to allow continuous seawater injection.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state or national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing KRU infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for the Kuparuk River formation. Following is the annual update to the Unit Plan of Development.

4.1 OVERVIEW

The objective of the development plan is to identify strategies to maximize value through oil production and recovery from the Kuparuk Reservoir in a cost-effective, safe, and environmentally responsible manner.

The 2018 Plan assumes a continuation of the current business climate. There are many challenges to delivering on our proposed plan. Future investment decisions include evaluation of all factors affecting economic assessment including cost, production, technical, regulatory environment, and fiscal framework.

4.2 Reservoir Management

Kuparuk Base Reservoir Management is focused on simultaneously optimizing the life cycle of the sub-surface depletion processes of primary production, water flooding, miscible gas EOR, and immiscible gas flooding. This optimization requires prioritizing and staging the depletion mechanisms in order to load the existing pipeline and facilities infrastructure in the most cost efficient manner. Facility capacity utilization is maximized and constraints are modeled and mitigated through maintenance, repairs, and upgrades when economically feasible. The depletion options for Kuparuk are:

- Delineate and optimize development of remaining areas of competitive oil accumulation such as the peripheral areas.
- Evaluate and economically optimize water flood where incremental rate and recovery justify the process. An example is the A sand redevelopment accessing poorly swept A sand areas via CTD.
- Management of excess water volumes e.g. via water shut-offs, particularly in commingled A and C sand completions.
- Management of lean gas volumes in excess of fuel gas requirement.

4.3 Drilling Program

The development drilling strategy is to target high value locations and to apply the appropriate well construction and completion technologies in an effort to minimize development drilling costs.

Existing wells that are currently shut-in due to mechanical problems or low production rates may be sidetracked to new bottom-hole locations. As the field matures, horizontal, multi-lateral, and CTD sidetrack technologies will play an increasing role in Kuparuk in order to access incremental resources at reduced cost. Cost reductions and efficiencies will be essential to unlock the full value of Kuparuk resources.

To date, the 2005 Kuparuk West Sak (KWS) and 2011 Western Kuparuk (WK) 3D Seismic analysis has resulted in a significant number of leads for infill or sidetrack drilling. Candidate wells developed from these leads include a mix of coiled-tubing sidetracks, new wells, and rotary sidetracks, depending on the structural complexity of the area, expected oil recovery, and operational status of proximal wells.

For the Plan period, approximately 17 CTD sidetrack projects and 5 new Kuparuk rotary wells are planned.

4.4 FIELD EXTENSIONS – NEW DRILL SITE DEVELOPMENT

Additional drillsites to access Kuparuk A and C sands are not planned before July 2019.

4.5 ENHANCED RECOVERY

Miscible water-alternating gas was the main EOR process for the Kuparuk field through July 2014; 23 MWAG drillsites serviced the Kuparuk reservoir which included 115 available EOR patterns. Since July 2014, Miscible Injectant has been manufactured at two CPFs, by blending together produced lean gas and NGLs. NGLs currently originate only from the Kuparuk field itself (known as indigenous NGLs).

In 2018, import of NGLs from Prudhoe Bay is expected to recommence. Work is underway to gain regulatory approval and to align piping and equipment for 2018 NGL imports into GKA via the Oliktok pipeline. Drillsites 1B, 1C, 1D, 1E, and 2C are the current target drillsites for indigenous MI injection and will continue to have MI injection. However, the intent of NGL imports is to increase the availability of Miscible Injectant and focus EOR on the western half of CPF2, primarily at drillsite 2S and recent Tarn development wells.

In 2017, the MWAG program operated in full MI production mode for 5 MWAG drillsites. During 2017, the Greater Kuparuk Area produced an average of 9,950 BPD of indigenous NGLs. Indigenous NGLs are blended with available lean gas and generated an average of 64 MMSCFD of MI injected into the Kuparuk Field. The total estimated incremental oil+NGL sales for 2017 from the fieldwide Kuparuk MWAG project was 10.3 MBOPD.

Prior to July 2014 (during NGL imports) the priority for gas management at the Kuparuk field was to balance solvent injection between the A-Sand and C-Sand. This maximizes total EOR and returned NGL rates while avoiding excessive gas production rates, which would cause production impacts due to gas handling limitations. For the year 2017, the priority for gas management was to balance lean gas injection and MI injection to minimize gas production impacts. Total GKA annual average gas production rate in 2017 was 227 MMSCFD. The nominal average MI MMP was 3,107 psi during 2017. This is based on the average MI composition from 2017.

Historically, GKA has been long on solution gas production (i.e. solution gas production has exceeded fuel gas demand) and the surplus gas was re-injected as part of a gas storage, IWAG or MWAG operation. The gas balancing and management techniques discussed above were applied to minimize the impacts of system gas constraints while maximizing EOR production.

Alternative EOR opportunities for Kuparuk are explored, with laboratory investigation and field testing of promising methods to recover additional resource that is currently considered residual oil.

4.6 Lean Gas Chase

Produced gas that is not blended to generate Miscible Injectant is used for lean gas chase. Injection of lean gas into the Kuparuk reservoir after the ramp down of the EOR flood has two main benefits:

1) Recovery of a proportion of the NGLs trapped in the reservoir as part of the EOR process

2) Maintenance of liquid rates in high water cut producers by providing a formation lift benefit at the sand face as the gas cycles through the reservoir from the injectors to the producers. Kuparuk has a relatively low gas lift system pressure of around 1,400 psi due to production casing, pipeline and compressor limitations. As watercuts increase, FBHPs increase, resulting in increasingly inefficient gas lift characteristics as the gas lift “jumps” to a higher gas lift mandrel. Maintaining higher a Gas-Oil Ratio (GOR) in producers with continued gas injection is predicted to offset at least part of this impact.

4.7 Facilities

4.7.1 Gas Handling

Gas handling limits with the gas lift compressors will continue to constrain production from the Greater Kuparuk Area. Historically the summer months see greater impacts as turbine output is lower. Gas capacity debottlenecking continues to be studied as part of the facility management plan. Smaller projects with high added value will be emphasized, evaluated, and progressed in conjunction with larger projects to expand gas lift compression capacity. Currently planned is a re-wheel of the three CPF1 Gas Lift Compressors during 2018-2020 which will improve compressor effieciency and allow for improved gas handling at CPF1.

4.7.2 Water Handling

Water handling capacity has often been a constraint on oil production rate. This became more so in 2006 with the segregation of the produced water and seawater injection streams at CPF2 in order to reduce high corrosion rates in the water injection systems. This segregation often results in under-utilization of pump capacity as each Water Injection Pump (WIP) is dedicated to either produced water or seawater (SW), making them more difficult to optimize against system dynamics.

In addition to the WIP under-utilization issue, in 2010 turbine driver speeds continued to be restricted to prevent catastrophic blade failures. In 2014, upgraded blades began to be phased in during planned turbine overhauls. This will allow speed increases and subsequent water injection capacity increase. These constraints have resulted in localized areas of increased voidage within the reservoir.

To mitigate the impacts of the water injection constraints discussed above, the Operator is evaluating several facility projects to restore and enhance water injection capacity at each CPF to ensure the reservoir management guidelines will be met and recovery optimized.

The various issues and constraints at each CPF are discussed below along with the projects being evaluated. Each CPF has stand-alone water injection systems and so are addressed individually.

4.7.3 CPF1

Clean water injection in West Sak at drill sites 1C, 1D, 1E, 1H and 1J is a higher priority with studies in progress to evaluate means to improve injection water quality. These studies will look at the feasibility and economics of various options to provide cleaner water and higher injectivity to these drill sites. In May 2018, sea-water connection to drill site 1H was started-up, and achieved improved injectivity to the West Sak reservoir.

4.7.4 CPF2

Currently, injection at CPF2 is limited by pump capacity and, to a lesser extent, source water availability. Drill site 2S wells and satellite fields Tarn and Tabasco use the same facilities as Kuparuk at CPF2 and generally produce less water than is injected.

Satellite field Meltwater (DS2P) does not currently receive water injection following a 2009 pipeline de-rating. The GI line to DS2P has a suitable pressure rating for water injection service and will be re-purposed in late 2018 to supply the drillsite with water. A new jumper at DS2N will connect the water injection source at 2N to the line. The water will then be transferred to the original water injection header at DS2P for injection into the reservoir. In addition, a stream of water will be recycled directly from the injection line to the production line to keep the production line warm during winter months as production rates from Meltwater decline.

NGL imports and the shifting of MI injection to CPF2 is expected to increase the CPF2 I/W ratio and help to alleviate the shortage of water injection at CPF2 since a larger percentage of CPF2 patterns will be on gas injection. WI expansion projects include:

- Annual winter conversion of one produced water pump to seawater service (to maximize overall injection rate) continues. Also, the turbine driver speeds are increased but limited to mitigate the higher risk of blade failure. Upgraded blades are being phased in during planned turbine overhauls.
- Water injection pump capacity expansion at CPF2 continues to be evaluated, but due to high cost and low benefits a feasible project has yet to be identified.

4.7.5 CPF3

Injection at CPF3 is limited by injection well capacity. Current plans and issues include:

- Repairs to individual injection well lines are being undertaken as needed.

- Longer term, development of West Sak in the area of drill sites 3Q, 3O, and 3T may require modifications to the CPF3 water injection and production systems. As mentioned in section 4.7.3 above, clean water delivery to West Sak has been proven to be beneficial to fied recovery. Studies of the CPF3 issues and optimal solutions are underway and will be completed in due course. The timing of further West Sak developments at CPF3 is covered in the West Sak Unit Plan of Development.

- Seawater deliveries to the Oooguruk Unit (OU) have totaled 38 MMBBLs from 2009 through 2017. The OU Operator recently estimated that the OU demand for KRU seawater would increase through 2020 at about 20 thousand barrels of water per day (MBWPD) by 2020.

4.7.6 Seawater Treatment Plant

A multi-disciplinary team continues to address the inspection, mitigation and near/long term repair issues to manage the corrosion in the entire SW system.

4.7.7 Corrosion Monitoring and Mitigation

Kuparuk corrosion monitoring and mitigation programs are managed in accordance with the North Slope Operations and Development Corrosion Strategy Manual. Program enhancements such as improved corrosion inhibitors, maintenance pigging methods, new monitoring and inspection technologies, internal coating and sleeving, and data management software are continually being evaluated and incorporated into the program to ensure facility longevity. As discussed earlier, baseline ILI on water injection lines has resulted in the de-rating and subsequent repair or replacement of several lines, but has significantly improved estimation of remaining life and enhanced long term planning capability. A multi-disciplinary team is now in place and uses this information to optimize pipeline coating, replacements, repairs, repurposing and consolidations. A large project that brings ILI capability to 5 produced oil lines is currently being undertaken with a planned completion in 2018. The pipeline renewal program will be prioritized and the expenditure will be level loaded.

4.7.8 Artificial Lift

The most common artificial lift method for Kuparuk producers is gas lift. The injection pressure for the gas lift system is limited to 1,400 psi due to compressor, pipeline and production well casing limitations. With watercuts increasing to as high as 95% in some Kuparuk wells as the field matures, many wells cannot lift from the bottom due to the gas lift system pressure constraints.

To date, this has been mitigated to a large extent in the MWAG and IWAG areas by the returned MI and lean gas, which essentially provides an artificial lift benefit from the sand face. As additional water injection projects are progressed, the excess mobile gas in the reservoir will decrease, GORs will collapse and gas injection will cease. Studies are ongoing to improve the artificial lift system, as well as evaluate the lift benefits from large scale lean gas injection.

4.7.9 Other Facility Projects

With increased water and heavy oil production, vessel and tank modifications and upgrades will be evaluated as most vessels will require entry within the next five to ten years. The Turnarounds are also evaluated as opportunities to conduct repairs, overhauls, and upgrades on rotating equipment such as gas compressors to prevent and reduce production deferral.

Electronic equipment used at Kuparuk is becoming obsolete at an increasing rate as manufacturers introduce new equipment and no longer wish to support older equipment. As such, process control systems among other systems will continue to be upgraded and automated as current equipment becomes obsolete and no longer maintainable. The fire and gas systems have been upgraded at the CPFs and the seawater treatment plant.

Obsolescence of the turbines driving the water injection pumps and power generation equipment may require large capital expenditures. Transmission lines, substations, and other electrical equipment in the field are approaching their expected end of life and may need to be replaced to maintain current levels of reliability.

Much of the operations support infrastructure will be assessed for upgrade or replacement to target another 25 years of production from the KPA and the KRU satellite fields. Some of the larger infrastructure projects include upgrading the Kuparuk airstrip and upgrading and refurbishing portions of the Kuparuk camp and office space have been completed.

4.8 RECENT EXPLORATION / APPRAISAL ACTIVITY

At KRU the overlying Cretaceous Brookian Moraine interval is currently being tested to evaluate for productivity and waterflood performance. A two-well pilot (producer injector pair, 3S-613 and 3S-620) is providing reservoir performance data. A follow-up well pair is in 2019 to further de-risk waterflood performance. Coupled with results from special core analyses, this dynamic data will guide future plans for Moraine.

In December 2017, 17,920 acres adjacent to the Kuparuk River Unit drill-site 2S was awarded to ConocoPhillips; evaluation is ongoing.

The 1H-Ugnu-401 well was originally drilled and completed in 1998 to test the Ugnu B sands. The well has been produced intermittently for the last 12 years with the aid of diesel diluent. In 2013, a coiled-tubing deployed, mineral insulated electric heater was installed in the well to reduce in-situ viscosity of the oil in the producing lateral. The well produced in this manner through most of 2014 until it was shut in due to problems with the Electric Submersible Pump (ESP). ConocoPhillips continues to work through ESP troubleshooting in an effort to return 1H-401 to production with an upgraded pump to determine if higher oil production rates can be sustained.

5.0 HISTORICAL EXPLORATION / APPRAISAL RECAP

2017-18:

- Ongoing performance monitoring of 3S-613 and 620 well pair.
- December 2017: 17,920 acres adjacent to the Kuparuk River Unit drill-site 2S was awarded to ConocoPhillips

2014-2016:

- CPAI drilled two wells under Tract Operations to further evaluate the Moraine formation.
- The 3S-620 is a multi-stage hydraulically fractured horizontal producer. This well serves as the producing lateral for a horizontal producer/injector well pair with horizontal injector well 3S-613. The primary objectives of the well pair are to evaluate commerciality and flood performance.

2013-2014:

- Analyses for the 3S-19 well tests results to appraise the Moraine interval.

2012-13:

- A perforation and hydraulic fracture pilot test in existing well DS 3S-19 was performed in 2012/13 to evaluate the overlying Cretaceous Brookian Moraine interval.

2011-12:

- On January 18, 2012, the Shark Tooth #1 well was spud on Tract 90, ADL 25603. The surface and productive horizon location was 1792' FNL, 1025' FEL, Sec. 20, T10N, R8E, UM. The primary objective was the Kuparuk interval, both Kuparuk C and A sands were encountered.
- WK 3D Seismic Survey: In 2011-12 the KRU WIOs acquired and processed 220 surface sq. miles of seismic data within the KRU.

2010-11:

- None

2009-10:

- None

2008-09:

- The Tarn South well, 2N-342 was drilled in 2007 to the Tarn/Bermuda interval., The well was converted to jet pump in 2009 due to lift problems caused by the low flowing temperature of the produced fluids. This area now resides inside the Tarn Participating Area (PA).
- The 2N-310 Cairn test occurred in 2008. The Cairn interval was tested while drilling a Tarn reservoir development well (an injector). Both gas and oil was discovered in the Cairn interval, and additional appraisal will be required to determine the Cairn development potential in this area.
- 3K-103 and 3K-108, offset injectors to 3K-102, were drilled in 2008 from drillsite 3K to the West Sak interval within Sections 35 and 36, T13N, R09E, UM, within KRU Tract 004, ADL 25519 outside of the existing West Sak PA. On December 16, 2008 an application for the formation of the NEWS PA was filed with DNR. This application was approved by DNR on May 29, 2009 retroactive to March 1, 2008.

2007-08:

- The Tarn South well, 2N-342 was drilled in 2007 to the Tarn/Bermuda interval, outside of the existing Tarn PA.
- 3K-102 was successfully drilled in 2008 from drill site 3K to the West Sak interval within Sections 35 and 36, T13N, R09E, UM, within KRU Tract 4, ADL 25519 outside of the existing West Sak PA.

2006-07:

- 1J-109 well completed as a producer in the West Sak B sand within ADL 390705 within Section 6, T10N, R11E, UM.
- 1J-180 pre-produced and completed as an injector in the West Sak D and B sands within ADL 385172 within Section 5, T10N, R10E, UM.
- 1J-182 completed as a producer in the West Sak D and B sands within ADL 380058 within Section 4, T10N, R10E, UM.
- 1J-184 pre-produced and completed as an injector in the West Sak D and B sands within ADL 380058 within Section 4, T10N, R10E, UM.

- 1J-136 pre-produced and completed as an injector in the West Sak D and B sands within ADL 380058 within Section 4, T10N, R10E, UM.
- West Sak PA Expansion Application submitted on or before April 9, 2007.
- Continued evaluation of potential 3K Development.
- Continued evaluation of potential 1H Development.
- Reference is made to the drilling commitments for Area 4 contained in the 8th KRU expansion decision as amended. KRU WIOs met these drilling commitments by drilling two wells within Expansion Area 4 in 2006/07.

2005-06:

- The 1Q-101 well was drilled in 4Q 2005 to evaluate the West Sak Formation in ADL 25634, KRU Tract 21 to a bottom hole location within Sec. 24, T12N, R09E, UM.
- The 3J-101 well was drilled in 4Q 2005 to evaluate the West Sak Formation in ADL 25630, KRU Tract 13 to a bottom hole location within Sec. 3, T12N, R09E, UM.
- The 1H-North well was drilled in 2Q 2006 to evaluate the West Sak Formation in ADL 25636, KRU Tract 19 to a bottom hole location within Sec. 15, T12N, R10E, UM.
- The 1R-East well was drilled in 2Q 2006 to evaluate the West Sak Formation in ADL 25636, KRU Tract 19 to a bottom hole location within Sec. 3, T16N, R09E, UM.
- The 1H-South well was drilled in 2Q 2006 to evaluate the West Sak Formation in ADL 25637, KRU Tract 18 to a bottom hole location within Sec. 23, T16N, R10E, UM.
- 2005 KWS 3D Seismic Survey. In 2005-06 the KRU WIOs processed 221 surface and 190 full fold sq. miles of seismic data within the KRU.
- Antigua #1 Well. In 2Q 2006 ConocoPhillips and co-owners Pioneer Natural Resources Alaska, Inc., Union Oil Company of California and ExxonMobil Alaska Production Inc. ("Antigua Owners") drilled the

Antigua #1 Well in Section 35, T10N, R10E, UM within ADL 390484. ADL 390484 lies immediately adjacent to the KRU south of 1J Pad.

2004-05:

- 1D-30-L1 well -- Kuparuk
- 1D-32-L1 well -- Kuparuk
- 10th Expansion of the KPA to include the W2 of Section 30 and the NE4 of Section 31, T. 11 N., R. 11 E., UM.
- 1H-105 -- West Sak appraisal well
- 2005 KWS seismic survey acquired 190 full fold sq. miles of seismic data within the KRU.
- ADL 355024 farm out (portions) enabled drilling of Kigun #1 well by Kerr-McGee Oil & Gas Corporation and Armstrong Alaska, Inc.

2003-04:

- The Winstar joiner agreement enabled drilling of the Winstar Oliktok State #1.
- Placer #1 and Placer #2 wells were drilled in early 2004 after completion of a joiner agreement with the Arctic Slope Regional Corporation in 2003.
- Techniques for high-frequency (HFVS) 3D seismic data acquisition were tested for possible future application in the KRU.

2002-03:

- 2L-03 (Serac)
- 2G-17 (Cayman)
- Cirque #3

2001-02:

- Palm #1– Kuparuk
- Palm #1A (3S-26)- Kuparuk
- 2P-415
- Silvertip #1 (1J-14) – Kuparuk/West Sak
- 2K-27 – Jurassic exploratory tail
- Resolution 3D Seismic Survey – 363 mi^2
- Eastern Bounded Area 3D Seismic Survey – 55 mi^2

2000

- Meltwater North #1 - Bermuda
- Meltwater North #2 - Bermuda
- Meltwater North #2A – Bermuda
- SE Delta 3D Seismic Survey – 153 mi^2

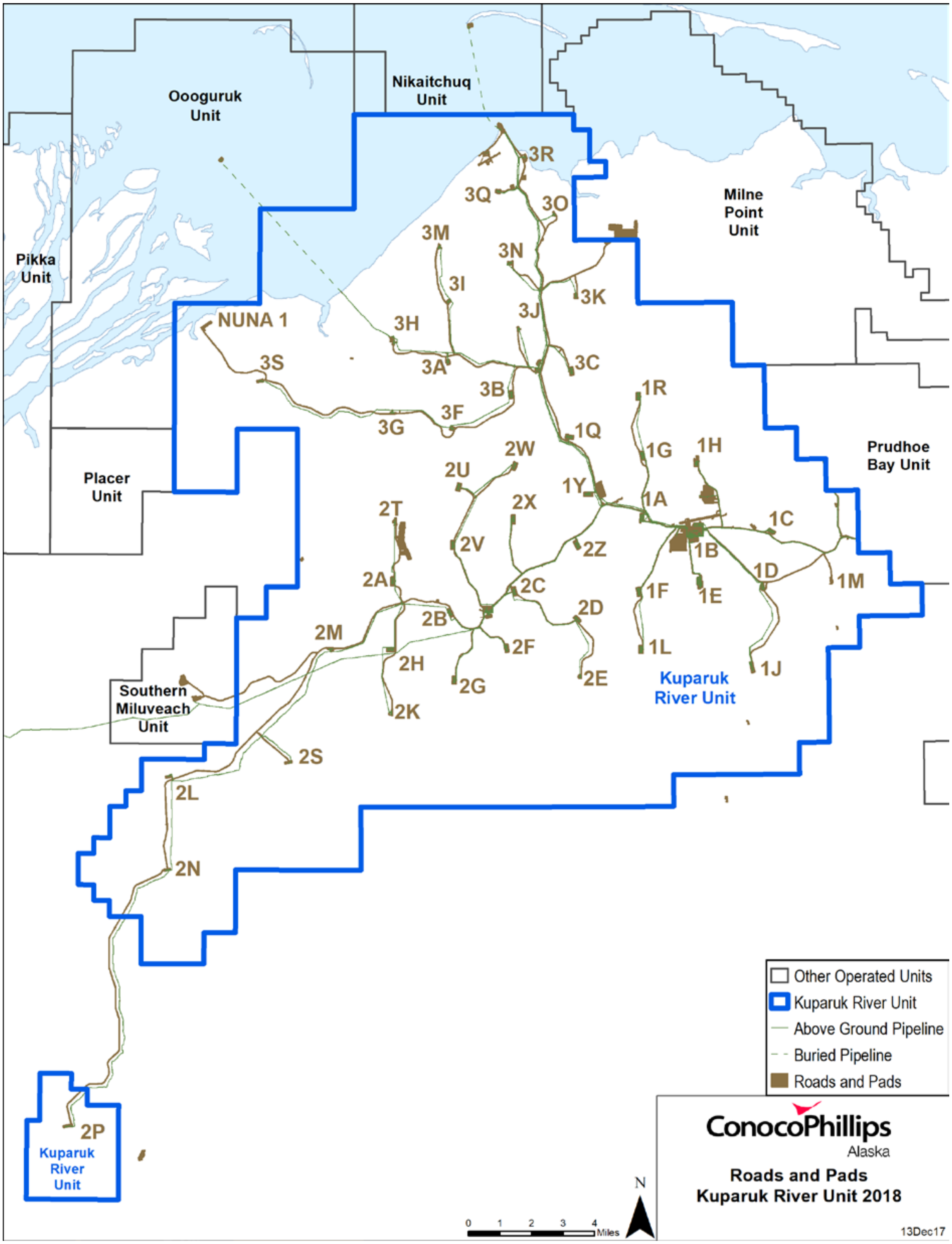
1999

- Meltwater South #1 - Bermuda

1998

- Kalubik #2 - Moraine
- Kalubik #3 – Kuparuk/Moraine/Jurassic
- 2L-329 - Arete
- 2L-305 – Iceberg
- Meltwater 3D Seismic Survey – 138 mi^2
- Kuparuk 4D Seismic Test Survey – ~5 mi^2

Attachment 2: Kuparuk River Unit Roads and Drill sites



UNIT PLAN OF DEVELOPMENT
MELTWATER PARTICIPATING AREA

AUGUST 1, 2018 – JULY 31, 2019

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1.0 INTRODUCTION

Exploration drilling in early 2000 discovered an oil accumulation approximately nine miles south of the existing Tarn Oil Pool. The exploration program consisted of three successful penetrations (Meltwater North #1, Meltwater North #2 and Meltwater North #2A) in what is now known as the Meltwater Oil Pool. Development of the Meltwater Field began in 2001 and was completed in 2004 after 2 phases of development drilling.

Meltwater Working Interest Owners approved the Meltwater Special Supplemental Provisions in 2001 which include a requirement for an Annual Development Plan.

This document provides an overview of the projects and strategies that comprise the development program for the Meltwater Participating Area. The effective plan period for this submittal is August 1, 2018 through July 31, 2019. Assumptions that form the basis for this development plan are consistent with the current business climate and the current understanding of the Meltwater reservoir. Changes in business conditions and/or new insights into the reservoir may alter the feasibility of these plans.

2.0 FIELD STATUS

The Meltwater field began production in November 2001. Injection of miscible injectant (MI) was initiated in January 2002 and the miscible water-alternating-gas (MWAG) process was implemented in May 2003. The field currently operates with continuous lean gas injection after the water injection (WI) line was taken out of service in October 2009 due to corrosion damage, and miscible injection was discontinued after the importation of Prudhoe Bay natural gas liquid (NGL) was stopped in July of 2014. Nineteen development wells have been drilled to date. Lean gas is also currently used for gas lift at 2P since a separate lean gas line was not installed to this drill site.

The status of the Meltwater field as of December 31, 2017 is summarized below:

- 19 wells drilled at DS 2P.
  - 11 producers
  - 8 gas injectors
- 15 active* wells at DS 2P.
  - 9 producers
  - 6 injectors

* Active is defined as having injection or production between January 1, 2017 and December 31, 2017

Meltwater 2017 Annual Average Production and Injection Rates

- Oil Production Rate: 947 BOPD
- Gas Production Rate: 11,766 MSCFD
- Water Production Rate: 47 BWPD
- MI Injection Rate: 0 MSCFD
- LG Injection Rate: 13,760 MSCFD
- Water Injection Rate: 119 BWPD

Meltwater Cumulative Production and Injection as of Dec. 31, 2017

- Cumulative Oil Production: 19,724 MSTBO
- Cumulative Gas Production: 60,499 MMSCF
- Cumulative Water Production: 3,676 MSTBW
- Cumulative MI Injection: 56,673 MMSCF
- Cumulative LG Injection: 28,740 MMSCF
- Cumulative Water Injection: 25,180 MSTBW

3.0 SUMMARY OF 2017 ACTIVITIES

Summarized below are notable activities at Meltwater over the preceding year (January 1, 2017 through January 1, 2018):

- In June of 2017 Meltwater drillsite was shut in for three weeks in a scheduled test. The purpose of the test was to determine how much back pressure, and therefore how much oil was being backed out of the common production line due to Meltwater producing 13 MMSCF/D of gas. After the test, the backout was estimated at 900 BOPD.

- On August 22nd a water injection test was conducted at Meltwater in injector 2P-429. Water was trucked to the drillsite and injected continuously for two weeks at a rate of 3,300 BWPD. At the end of the period, a step-rate injectivity test was performed.

- Maintenance pigging of the DS 2P produced oil line (2PPO) is scheduled for 6 to 12 month intervals. Two pigging operations were completed in 2017. The maintenance pigging program and inhibition programs appear to be adequately controlling corrosion rates.

- Gathered static bottomhole pressures (SBHP) on producers 2P-422A and 2P-415A and injectors 2P-438, 2P-434 and 2P-429.

- Routine paraffin scrapes and hot diesel flushes were conducted throughout 2017 on many Meltwater wells to maintain production.

- In late 2004, the cumulative injection-withdrawal ratio (I/W) went over 1.0 and increased steadily through 2009. Changing voidage strategy has enabled better management of the cumulative I/W. For 2017, the cumulative year-end I/W ratio was 1.2, the same for end of year 2016.

- Sand face injection pressure set at 3,400 psi to maintain injection into the Bermuda formation only.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state or national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing Kuparuk River Unit infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the Meltwater and the Kuparuk River formations. Following is the annual update to the Unit Plan of Development.

4.1 Reservoir Management

Until October 2009, Meltwater was undergoing a tertiary recovery process involving alternating cycles of MWAG designed to maximize recovery from the reservoir. The WI line was taken out of service in October 2009 due to corrosion concerns. Comparing the estimated performance of Meltwater on depletion and gas injection, it is more efficient to inject gas at Meltwater than other fields in the Greater Kuparuk Area. In addition, gas injection appears to provide more efficient support because of its higher mobility.

However, a gas-only flood leads to increasing gas/oil ratios. The GOR at Meltwater has been rising and will soon cause the wells to be uneconomic to produce. Therefore, ConocoPhillips plans to convert the flood at Meltwater to water in late 2018 or early 2019. Pattern level I/W ratios will target 1.0; however the primary control of water injection rate will be the 3,400 psi injection pressure limit.

4.2 Meltwater Reservoir Containment and Well Integrity

Meltwater has experienced anomalies in the overburden and reservoir since its initial development. These problems began as encountering unexpected shallow pressure while drilling Phase 1 development wells and continued in the form of rapid breakthrough of injection fluids at certain production wells. As a result of an internal study in 2012, ConocoPhillips identified migration of injection fluids out of the Bermuda interval. The specific mechanism(s) is not conclusively known.

This discovery prompted ConocoPhillips to adopt a new reservoir management strategy in 2012 for Meltwater. A sand face injection pressure limit of 3,400 psi was imposed. This pressure limit will maintain the bottomhole pressure at a pressure less than the formation integrity test and leak-off test data from development wells with casing set at the top of the Bermuda formation. This will further ensure that fluids injected into the Meltwater reservoir will remain in the Meltwater reservoir.

4.3 Drill Site 2P Pipeline Status/Outlook

The DS 2P water injection line (2PWI) has been out of service since 2009, after extensive pitting damage was discovered throughout the line by in line inspection (ILI) tools. Detailed analysis of ILI and physical inspection data confirms that this line is suitable for produced oil (PO) service. The current DS 2P produced oil line has a low average velocity and is monitored closely via several physical inspection locations. The 2PWI line will serve as a backup in the event the current PO line is taken out of service.

The gas injection (GI) pipeline has a suitable pressure rating for WI service and will therefore be used to supply the drillsite with water, expected to be ready for service in late 2018. A new jumper at DS2N will connect the water injection source at 2N to the line. The water will then be transferred to the original water injection header at DS2P for injection into the reservoir. In addition, a stream of water will be recycled directly from the injection line to the production line to keep the production line warm during winter months as the production rates from Meltwater decline.

4.4 Development Drilling

Further development opportunities are being analyzed through re-evaluation of the 2008 seismic data, recent surveillance findings, water injection supply, and business climate. Opportunities could include coiled-tubing drilling sidetracks or producer to injector conversions.

4.5 Artificial Lift

Meltwater completions include downhole “jewelry” that allow the application of multiple artificial lift options, such as hydraulic jet pumps, hydraulic piston pumps, lift gas, or plunger lift systems. Artificial lift selection is a well-by-well decision based on individual well properties and facility optimization.

Currently all producing wells utilize lift gas for artificial lift due to the loss of WI service to Meltwater. When the drillsite is converted to water injection it is anticipated that the producers will be switched to jet pump when the wells are unable to lift without aid.

Jet pumps will allow the warm injection water (~120°F) used for power fluid to keep the temperature in the tubing string above the cloud point and thus prevents wellbore paraffin deposition.

4.6 Shallow Gas Monitoring

Wells 2P-406, 2P-417, 2P-431, 2P-432, 2P-434, 2P-438, 2P-441, 2P-447, 2P-448A and 2P-451 had a history of elevated outer annulus (OA) pressures. Based upon the information gathered and technical analyses completed to date, it is likely the initial migration of injected fluids out of the Bermuda interval was a result of a large pressure differential between injectors and producers. This pressure differential was exacerbated by low permeability and stratigraphic and/or structural discontinuities within the Bermuda interval.

The Operator continues to monitor OA pressures daily, take OA fluid levels quarterly, and sample OA gas composition twice per year. There are currently no indications that injection occurred out of the Bermuda interval in 2017. Gas sampling will be discontinued once water injection is implemented as it will no longer indicate a loss of containment.

In addition, the extended bleed of the outer annulus of well 2P-431 is continuously monitored in an effort to deplete the source charging the outer annulus.

4.7 Exploration/Delineation

No further exploration/delineation is planned in the Cairn or Bermuda sand intervals at this time.

UNIT PLAN OF DEVELOPMENT
TABASCO PARTICIPATING AREA

AUGUST 1, 2018 – JULY 31, 2019

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1.0 INTRODUCTION

The Tabasco accumulation was discovered in 1985 during development drilling of Kuparuk wells at drill site (DS) 2T. In 1995, the 2T-201 test well was drilled and yielded 400 BOPD of 16.5° API gravity oil. In 1997, the Greater Kuparuk Area (GKA) Alignment Agreement was completed, which aligned interests among the Tabasco owners and set the facility sharing terms and conditions for GKA reservoirs located outside the Kuparuk Participating Area. Development of the Tabasco reservoir started in March of 1998 with the drilling of the 2T-202 well.

Tabasco is a high net to gross canyon fill reservoir composed of conglomerate and pebbly/porous/cemented sands located at depths between 2,900-3,400' SSTVD. The oil within the reservoir is 16.5° API gravity with a viscosity of 251 cP at its bubblepoint pressure of approximately 1,512 psi and reservoir temperature of 71° F. The initial reservoir pressure was slightly below bubble point pressure since there was initially a small gas cap of less than 100 MMSCF.

Tabasco Phase 1 Development originally planned for up to 19 conventionally deviated wells drilled from drill site 2T on approximately forty (40) acre well spacing using waterflood as the recovery mechanism. Only nine wells were drilled (7 producers, 2 injectors) due to observed water slumping caused by gravity segregation shown in temperature logs in various offset Kuparuk wells that penetrate the Tabasco formation.

In 2003, the 2T-218 horizontal production well was drilled at the top of the structure. Performance was sufficient to justify two more horizontal production wells at the top of structure, 2T-203 and 2T-208, which were drilled in late 2005 and early 2006, respectively. Well 2T-217A was converted to injection in late 2007. Currently, the 2T Tabasco development consists of six deviated producers, three horizontal producers, and three water injectors. Presently, three of the deviated producers are shut in: two due to high water cut and one due to a stuck plug from a packer leak repair job. In 2013, one additional deviated producer was plugged and abandoned (P&A'd) due to low productivity. One of the three water injectors was shut in after less than 1 year of injection due to completion issues.

Work will continue in 2018 to determine if a more optimum drive mechanism and additional development wells could be implemented to produce incremental oil.

This document provides an overview of the projects and strategies that comprise the development program for the Tabasco satellite field within the boundaries of the Kuparuk River Unit. The effective plan period for this submittal is August 1, 2018, through July 31, 2019. Assumptions that formed the basis for this development plan are consistent with the current business climate. Changes in business conditions, current state and national regulations, application of improved technology, and/or new insights into the reservoir may alter the feasibility of these plans.

2.0 FIELD STATUS

The Tabasco field began production during May 1998. Water injection was initiated in June 1998. Twelve development wells have been drilled to date. Listed below is additional information describing the Tabasco field (as of December 31, 2017).

- 12 wells drilled at DS 2T
  - 6 deviated producers (1 P&A'd)
  - 3 horizontal producers
  - 3 injectors

- Well Status as of end of 2017
  - 4 producers on line
  - 2 producers offline due to high water cut
  - 1 producer offline due to a stuck plug from a packer leak repair job
  - 1 producer offline due to ESP motor failure
  - 1 producer P&A'd due to low productivity
  - 2 injectors online
  - 1 injector shut in due to completion issues

Tabasco 2017 Annual Average Production and Injection Rates

- Oil Production Rate: 1,380 BOPD
- Gas Production Rate: 215 MSCFD
- Water Production Rate: 10,644 BWPD
- Water Injection Rate: 9,893 BWPD

Tabasco Cumulative Production and Injection Volumes (YE 2017)

- Cumulative Oil Production: 20,153 MSTBO
- Cumulative Gas Production: 3,346 MMSCF
- Cumulative Water Production: 99,553 MSTB
- Cumulative Water Injection: 109,426 MSTB

3.0 SUMMARY OF 2017 ACTIVITIES

Summarized below are notable activities at Tabasco over the preceding year (January 1, 2017 through January 1, 2018):

- Tabasco produced 504 MBO, 79 MMSCF of gas and 3.9 MMBW during 2017. Water injection was 3.6 MMBW.

- The cumulative year-end 2017 injection-withdrawal ratio (I/W) is estimated at 0.90 based on current formation volume factors.

- The pool average water-oil ratio (WOR) was 7.6 for the 2017 calendar year, compared with 7.7 for 2016, which is a result of improved reservoir management.

- In 2013, a plug was stuck in 2T-202 from a packer leak repair job. In 2014, a polymer agent in the inner annulus was placed on top of the packer, which successfully sealed the slow leak. However, while pulling the plug out of the wellbore, the coiled tubing unit was unable to jar free and subsequently had to cut its coil string. Hence the well remained shut-in during 2017. The well is currently being evaluated for future utility and means of remediation.

- Sampling of active producers continued in 2017 in support of the chemical tracer study initiated in 2014. Current sweep appears to be in the periphery of the field.

- The 2T-209 producer watered out and was suspended with a plug in 2012. In 2017 the process of converting the well into an injector began, and will complete in 2018. This conversion is premised to provide more pressure support and improve the sweep efficiency from the periphery area, in addition to 2T-201 and 2T-217A.

- The 2T-203 ESP producer was shut-in following a motor failure in December 2016. While a long-term solution was worked, a sundry was submitted and approved to place the well on temporary gas lift. The well was successfully gas lifted from January to July 2017 at which point a RWO was executed to return the well to production on ESP. In December 2017 the well failed again with was suspected to be another motor failure. A sundry was again submitted and approved to temporarily produce the well utilizing gas lift while a RWO project is being worked.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state and national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing Kuparuk River Unit infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the Tabasco and the Kuparuk River formations. Following is the annual update to the Unit Plan of Development which is subject to change based on new information and market conditions.

4.1 RESERVOIR MANAGEMENT

Currently, the major recovery mechanism at Tabasco is waterflood. The cumulative I/W ratio is estimated at 0.90 at the end of year 2017. As a result, the reservoir pressure has recently been maintained near 1,300 psi, compared to initial reservoir pressure of 1,500 psi. Tabasco's I/W ratios will be monitored continuously to maintain an instantaneous value of approximately 1. Adjustments to injection and/or production rates will be made to achieve this goal in order to provide pressure support close to initial reservoir pressure, obtain better pattern displacement and keep gas in solution.

Reservoir management optimization by shutting in the central canyon producers to increase the pressure support on the peripheral wells has shown positive results on total oil production and stabilization of water production. Tabasco WOR has been reduced from 11.5 in 2014 to 7.6 in 2017. Study of waterflood optimization strategies in order to maintain or improve the current field performance is our target in the next year, as well as long term.

4.2 TRACER STUDY

In November 2014, chemical tracers were injected into the two online injectors, 2T-201 and 2T-217A. From 2015 to 2017 all active producers were sampled on at least a quarterly basis for the presence of these tracers. The concentration and duration of the chemical tracer breakthrough was used to evaluate heterogeneities within the Tabasco reservoir and found the majority of current sweep to be taking place in the periphery of the field, within close proximity of the two active injectors. This finding was key to the proposal to convert the 2T-209 from production to injection.

4.3 WATERFLOOD SWEEP OPTIMIZATION

2T-209 is a high watercut producer that has been shut in since 2012. It is located in the central canyon area of Tabasco. Currently water injection is only available from either the NE or SW edge of the field. Conversion of 2T-209 to water injection service will be completed in 2018. 2T-209 will continue to support and improve sweep from the center of the field towards the producers on the periphery. This is expected to create new streamlines and could increase ultimate oil recovery.

4.4 EXPLORATION/DELINEATION

No further exploration/delineation is planned during this plan period.

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UNIT PLAN OF DEVELOPMENT
TARN PARTICIPATING AREA

AUGUST 1, 2018 TO JULY 31, 2019

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1.0 INTRODUCTION

Exploration drilling in early 1997 confirmed a commercial oil accumulation to the southwest of the existing Kuparuk River Unit (KRU). Development of this accumulation, now known as the Tarn Oil Pool, commenced in 1997 and continued into 2001. A further development drilling campaign was completed in 2014-15.

This document provides an overview of the projects and strategies that comprise the development program for the Tarn Participating Area. The effective plan period for this submittal is August 1, 2018 through July 31, 2019. Assumptions that form the basis for this development plan are consistent with the current business climate and the current understanding of the Tarn reservoir performance. Changes in business conditions, current state and national regulations, application of improved technology, and/or new insights into the reservoir may alter the feasibility of these plans.

2.0 FIELD STATUS

The Tarn field was brought on-line in July 1998; a continuous miscible injectant (MI) flood began in November 1998. A 12" water injection line was put in service in July 2001, and a continuous Miscible Water-Alternating-Gas (MWAG) flood began at the same time. The 12" water injection line allowed Tarn to utilize hydraulic jet pumps for artificial lift as an alternative to gas lift.

Following the cessation of imported natural gas liquids from the Prudhoe Bay Field Central Gas Facility at the end of July 2014, immiscible water-alternating gas utilizing lean gas (LG) has been applied to the Tarn reservoir. Seventy-seven development wells have been drilled at Tarn as of December 31, 2017.

Following is additional information describing the Tarn status as of December 31, 2017:

- 77 development wells drilled at two drill sites (DS) 2L and 2N.
  - 55 producers
  - 22 MWAG injectors
- 63 active* wells
  - 39 producers
  - 24 injectors

*Active is defined as having injection or production between January 1, 2017 and December 31, 2017

Tarn 2017 Annual Average Production and Injection Rates

- Oil production rate: 7.8 MBOPD
- Gas production rate: 14.8 MMSCFD
- Water production rate: 22.7 MBWPD
- MI injection rate: 0.0 MMSCFD
- LG injection rate: 7.5 MMSCFD
- Water injection rate: 32.4 MBWPD

Tarn Cumulative Production and Injection Volumes

- Cumulative oil production: 121.6 MMSTBO
- Cumulative gas production: 196.3 BSCF
- Cumulative water production: 96.5 MMSTB
- Cumulative MI injection: 188.6 BSCF
- Cumulative LG injection: 31.0 BSCF
- Cumulative water injection: 226.9 MMSTB

3.0 SUMMARY OF 2017 ACTIVITIES

Drilling:

Development wells were not added at Tarn in 2017.

Workover:

A rig workover was executed on producer 2L-315 to replace tubing and isolate a production casing leak. This work was completed in January 2017 and successfully restored production.

Well conversion:

There were no wells that were converted to injection in 2017.

Facility:

No significant facility changes were made in 2017.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state and national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing KRU infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the Tarn and the Kuparuk River formations.

4.1 DEVELOPMENT DRILLING

No wells are planned to be drilled at Tarn before July 31 2019.

4.2 RESERVOIR MANAGEMENT

The original Tarn development plan specified continuous injection of MI into the Tarn reservoir for pressure maintenance and enhanced recovery. The use of MWAG injection was not initially recommended due to the lower permeability seen in the exploration wells and signs of water damage in laboratory tests of the exploration well core.

Discovery of higher quality reservoir during development drilling from the 2N and 2L pads reopened the potential of using an MWAG recovery process. MWAG, as compared to continuous MI injection, is expected to yield higher recoveries than the original straight gas injection approach due to improved mobility control. Short term field tests completed in the summer of 1999, and repeated in 2000, showed no loss of injectivity or other indications of formation damage as a result of water injection. Based upon these results, full field MWAG operations were recommended, approved by co-owners, and implemented in the field.

Field performance data showed good response in the production wells from the MWAG injection program. MWAG slug sizes and WAG ratios were optimized through use of a full field simulation model of the Tarn accumulation.

Through July 2014, the Tarn MWAG process used Kuparuk spec MI injected above the minimum miscibility pressure. Following the cessation of imported natural gas liquids from the Prudhoe Bay Field Central Gas Facility at the end of July 2014, immiscible water-alternating gas utilizing lean gas has been applied to the Tarn reservoir.NGL import resumption is currently expected in 2018, at which time the Tarn flood will return to an MWAG process. The primary MI targets at Tarn will consist of patterns that were developed after the previous NGL imports ceased, thus having received no MI to date.

The reservoir management strategy of maintaining I/W ratios, on a pattern level, at or above 1.0, to achieve targeted pressures, will continue. This will be accomplished through setting optimum injection well rates and cycling high formation GOR and water-oil ratio production wells as needed.

4.3 Artificial Lift

Tarn was originally designed to utilize the MI from the injection header as a means of gas lifting the production wells which were not able to flow under existing reservoir energy. However, Tarn oil is prone to paraffin deposition when production fluids fall below the cloud point temperature of 92° F. Production fluids cool as they flow from the reservoir and paraffin begins to deposit in the tubing across the permafrost interval. Gas lifting the wells with MI further cools the produced fluid due to Joule-Thomson related cooling effects. Utilizing jet pump power fluid (produced water) with a high heat capacity increases the temperature of the produced fluids and virtually eliminates paraffin deposition in the down-hole tubulars. Jet pumps as an alternative means of artificial lift at Tarn were proven to increase production rates during the 1999 and 2000 water injection field tests.

Thirteen of the artificially lifted wells at Tarn were converted to hydraulic jet pumps in October 2001. As watercut increases flowing temperatures increase, reducing the potential for paraffin deposition, and wells can be switched back to a gas lift mechanism.

Untreated saline produced water injected down the inner annuli as pump power fluid in 2006 accelerated tubing and casing corrosion which led to well integrity issues. As a result, eight wells were secured and shut-in for workover or sidetrack.

Tarn wells with jet pumps installed are being considered for conversion to gas lift, where well design allows. As of December 31, 2017, there are only five remaining wells at Tarn on jet pump: 2L-311, 2L-321, 2L-330, 2N-304, and 2N-342.

The southern peripheral well 2N-342 was converted from gas lift to jet pump in 2009 since the well could not be produced on gas lift due to freezing issues associated with low flow rates. The tubing size limitation has made it necessary to continue using jet pumps in 2L-321 and 2N-304 for artificial lift despite having a workover. Well 2L-311 has seen no integrity issues so far to warrant artificial lift conversion to gas lift. Well 2L-315 was shut in for annular communication in 2016. Since 2L-315 was converted to gas lift in 2008, it is uncertain if the annular communication issue was related to the jet pump history from 2001-2008.

4.4 Producer to Injector Conversion

At this time eight wells have been converted to MWAG injection service: 2L-301, 2L-305, 2L-319, 2N-309, 2N-326, 2N-335, 2L-310, and 2N-308.

Other future conversions will be considered as part of the Tarn redevelopment strategy to mitigate pattern inefficiencies such as early water or gas breakthrough. The aforementioned well conversions have created a line drive pattern with injectors aligned in a north-northwest to south-southeast direction. This has improved sweep efficiency and helped to optimize recovery from the Tarn field. With this line drive, the risk of future short circuits between injectors and producers has been greatly reduced.

4.5 Exploration / Delineation

Several reservoir characterization efforts were completed in the Tarn area during 2017:

1) A new thin-bed petrophysical model was developed for the Tarn-Meltwater area, incorporating all historical log and core data.

2) Re-mapping of the field, including an update to the stratigraphic description of the pre-Bermuda T2 section (Purple, Orange, and Chartreuse) and interval isochores for the entire Tarn Field.

3) Construction of a new geocellular model, including the revised isochores, recent 2014-15 Tarn drilling campaign wells, new drill-site 2S penetrations, and new petrophysical model results. The goal of this work was to lay the foundation for evaluation of the remaining development potential of the field. This analysis will be undertaken in 2018.

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UNIT PLAN OF DEVELOPMENT
WEST SAK AND NEWS PARTICIPATING AREAS

AUGUST 1, 2018 – JULY 31, 2019

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1.0 INTRODUCTION

As required by the December 18, 1997 Decision and Findings of the State of Alaska Department of Natural Resources Commissioner concerning the West Sak Participating Area in the Kuparuk River Unit, and 11 AAC 83.343, ConocoPhillips Alaska, Inc. hereby submits the Annual Update to the West Sak Development Plan.

On May 29, 2009, the Alaska Department of Natural Resources Commissioner approved the formation of the North East West Sak (NEWS) Participating Area (PA) within the boundaries of the Kuparuk River Unit, retroactive to March 1, 2008. This report also covers the Annual Update to the NEWS Development Plan.

This plan provides an overview of the projects and strategies that comprise the development program for the West Sak and NEWS PAs within the Kuparuk River Unit (KRU). The effective plan period for this submittal is August 1, 2018 through July 31, 2019. Assumptions that form the basis for this development plan are consistent with the current business climate and the current understanding of the West Sak reservoir performance. Changes in business conditions and/or new insights into reservoir performance may alter the timing, scope, or feasibility of these plans

2.0 FIELD STATUS

The following information describes the status of development in the West Sak Oil Pool as of December 31, 2017. Maps showing the development status of the West Sak PA and NEWS PA are included as Attachments 1 and 2, respectively.

During 2017, there were 119 active wells at drill sites (DS) 1B, 1C, 1D, 1E, 1H, 1J, 3K and 3R. An active well is defined as having produced or injected fluid between January 1, 2017 and December 31, 2017.

- 60 producers
- 57 water injectors
- 2 water-alternating-gas (WAG) injectors
- 10 wells were shut in (3 producers | 7 water injectors)

2017 Average Rates

- Oil production rate: 13,818 BOPD
- Water production rate: 12,444 BWPD
- Gas production rate: 11,683 MCFPD
- Water injection rate: 29,086 BWPD
- Gas injection rate: 1,243 MCFPD

Cumulative Production

- Cumulative oil production: 88,626 MSTBO
- Cumulative water production: 34,071 MSTBW
- Cumulative gas production: 52,970 MMSCF
- Cumulative water injection: 125.946 MBW
- Cumulative gas injection: 8,332 MMSCF

3.0 SUMMARY OF 2017 FIELD ACTIVITIES

Summarized below are notable activities at West Sak over the preceding year (January 1, 2017 to December 31, 2017).

- Attachment 1 illustrates the updated extents of the recently expanded West Sak PA, approved in December 2015. The approved PA boundary accommodates DS1H which began production in 2017 with additional wells planned for 2018.

- During 2017, 2 new producers (3R-101, 1H-102) and 5 injectors (3R-102, 1H-118,1H-114,1H-111) were drilled and completed.

- Waterflooding continues as the primary method for pressure maintenance and enhanced recovery in the West Sak Oil Pool. Produced water was the primary source of injection fluid for the Core Area in 2017. In late 2016 DS1D and DS1J were converted to seawater injection. Preliminary results indicate injectivity on seawater is twice that of produced water. At December 31 2017, DS1D, DS1J, and DS3K receive seawater. Evaluation continues to determine whether expansion to other West Sak drill sites is feasible given facility constraints (see Section 4.4: DS1H began sea-water injection in May 2018).

- Matrix Bypass Events (MBEs) continue to challenge sweep in several patterns. During 2017, two new MBEs developed at 1C-135 and 1E-126. Seven MBE remediation treatments were attempted in injectors 1J-105, 1E-105, 1J-119, 1E-112, 1C-190, 1E-114 & 1J-136 to reestablish water injection support and pattern sweep. Two of the seven treatments failed before the end of 2017. A review of these failures is underway as well as an evaluation of alternative treatment methodologies.

- Injectors 1C-150, 1C-152, 1C-154 and 1J-122 received VRWAG injection during 2017. Early results of VRWAG suggest positive benefits with ongoing pattern-level surveillance efforts. Additional injectors will be converted to VRWAG service following monitoring of the improved injectivity due to seawater at DS1J.

- Field trials of through-tubing conveyed ESP motor and pump systems (Rigless ESP) continue. In 2017, Rigless ESPs were installed in 3 additional wells (1J-120, 1J-137, 1C-104). The reliability of early Rigless ESP systems was challenged by electrical and mechanical issues. Key design changes addressed these challenges. The six systems continue to run demonstrating the increasing potential of this technology to improve overall uptime with improved drawdown of West Sak producers. Surveillance and reliability monitoring of these field trials will continue in 2018. Assuming continued success with Rigless ESP field trials, additional systems may be considered for future wells.

- Ultra-fine OHSAS completions were installed in four producing wells in 2014 and 2015 (1C-151, 1C-153, 1C-155, and 1D-145). Surveillance activities including periodic sand shakeouts suggest little to no sand production with low productivity impairment relative to slotted-liner completions. Monitoring activities will continue in 2018 and beyond to establish long-term performance. Additional consideration is being given to this technology in future new developments at West Sak, should the ultra-fine OHSAS completion type prove to be a value adding investment enabling a higher inter-well gradient and reduction in MBE frequency.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state and national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing KRU infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the West Sak and the Kuparuk River formations. Following is the annual update to the Unit Plan of Development.

4.1 HISTORICAL SUMMARY

Consistent with the original 1997 Plan of Development, Phase 1 development of the West Sak reservoir was initiated at Kuparuk DS1C and DS1D. As proposed, Phase 1 was to consist of 50 wells (31 producers and 19 injectors). A producer-bounded five-spot pattern configuration on forty (40) acre well spacing was envisioned with water flood as the drive mechanism.

Phase 1 drilling at DS1D was divided into two drilling periods, the first of which commenced in 1997 (Phase 1A). The second drilling period (Phase 1B) commenced in 1998. Phase 1A consisted of nine producers and five injectors. Phase 1B consisted of ten producers and six injectors for a total of 19 producers and 11 injectors. First production was achieved in December 1997 with production ramping up into 1999. Phase 1 producers are completed in the West Sak D, B and A sands with a mix of multiple stage fracturing/gravel packing operations or fracturing for sand control using an epoxy resin. Electric submersible pumps and electrical submersible progressing cavity pumps were originally employed as the artificial lift mechanism.

Phase 1 drilling at DS1C (originally referred to as Phase 1C) was to commence in early 1999, but a decision was made to defer additional drilling pending further evaluation of reservoir and well performance.

Engineering assessments of Phase 1B indicated that drilling costs were near the optimum and that only minor savings could be expected through further optimization of the current completions (fracturing). Additionally, it was believed that the 30 wells drilled to date provided an adequate number of penetrations to assess costs and performance associated with the conventional cased and fractured completions being pursued. Conceptual studies initiated in 1999 indicated that horizontal multi-lateral wells held significant promise in reducing overall development costs while significantly increasing reservoir performance and recovery. Thus, in an effort to develop a "step change" reduction in West Sak development costs and improve low price environment margins, a detailed engineering evaluation of horizontal multi-lateral well designs was initiated.

Beginning in 2000, three multi-lateral producers were drilled with six support injectors at DS1D. These wells were completed in the B and D intervals only. A completion design having an A sand "tag" originating in the lower lateral was determined to be overly expensive and uneconomic at that time.

This multi-lateral design (Figure 1) greatly influenced the 2001-02 development drilling at West Sak and replaced the previously planned Phase 1C development using conventional wells. Similarly, the Horizontal Undulating Injection well designs (Figure 2), as well as the D sand horizontal injection wells were incorporated into the development plans for Phase 1C.

West Sak development continued in 2003 with an eight well development program. This program included two multilateral producers, two D sand only producers, two horizontal undulating injectors, one D sand only injector and an undulating A sand producer. The lateral lengths averaged approximately 6,000 feet. The producers used jet pumps for artificial lift and had slotted liner completions.

In 2004, West Sak development moved to DS1E. Nine wells were drilled, including the first tri-lateral wells, which had laterals in the D, B and A2 sands. In total, 13 wells were drilled at DS1E. Two principal changes that were included in the 1E development were the use of oil based mud to reduce drilling damage as well as extended reach drilling to increase the area that could be developed from a single pad.

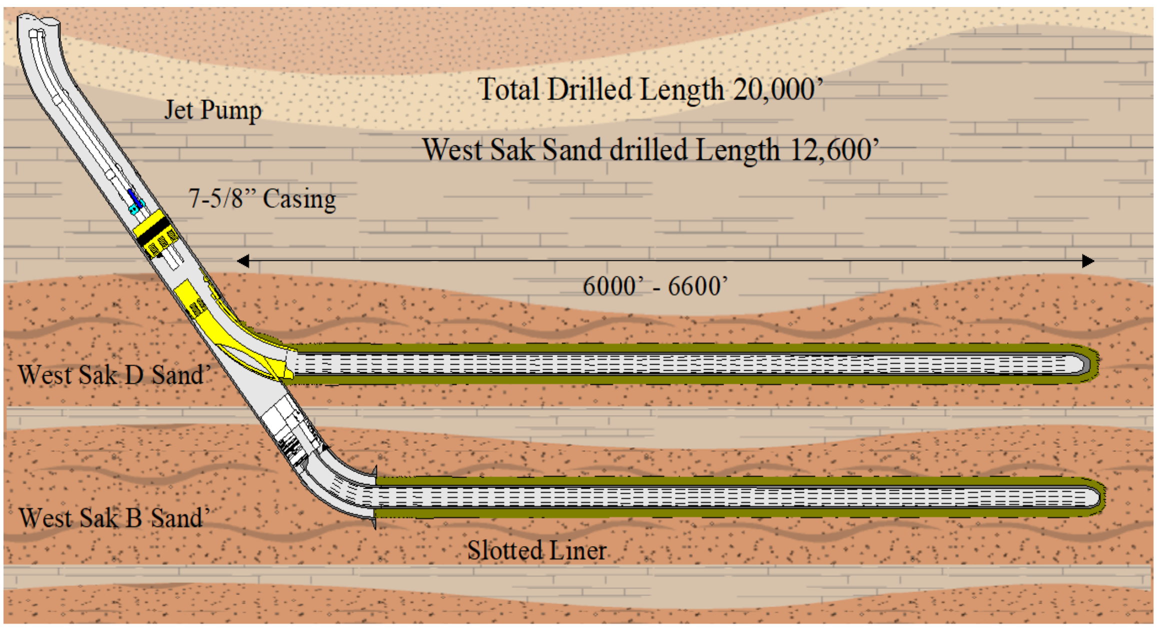

Figure 1: Schematic of a Multi-Lateral Well in the West Sak B and D Sands

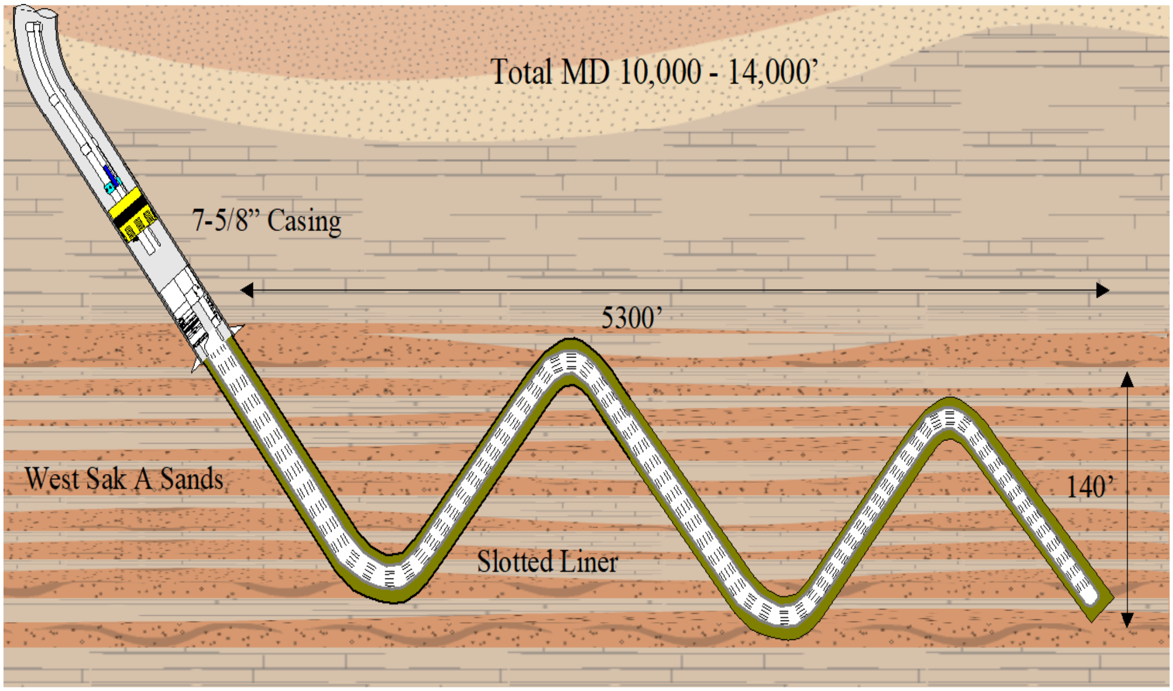

Figure 2: Schematic of a West Sak Undulating well

In 2005, DS1E development was completed and drilling commenced on DS1J. In total, 31 horizontal multi-lateral wells were drilled (17 producers and 14 injectors) and the development was completed in 2007. This represents a reduction in the number of wells premised during project sanction, which was dictated by higher than anticipated oil-water contacts on the eastern flank of the accumulation defined during the drilling phase of project execution. The well design was based on the DS1E design but incorporated a few enhancements. After the first four wells, the strategy of undulating between the upper and lower lobes of the A2 sand was changed such that the A2 laterals for the remaining wells focused only on the upper A2 sand (Figure 3). The utility of the horizontal undulating well design was subsequently re-evaluated due to experienced drilling and performance inefficiencies (loss of net pay exposure while drilling through intervening shales) and operability challenges (impact of MBEs and waterflood conformance). Therefore, as stated above, early in the 1J drilling program it was decided to abandon this design and target individual reservoir sands with dedicated laterals.

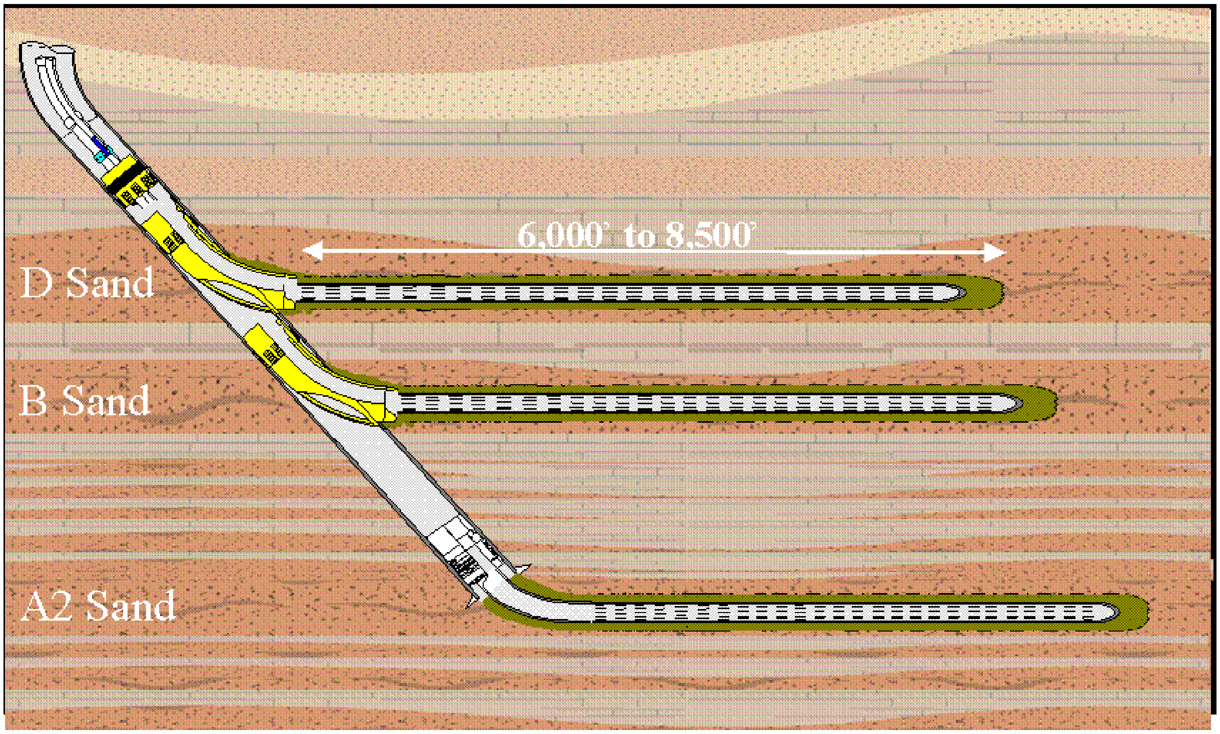

Figure 3: Tri-lateral Well Design

Included in the DS1J program was early drilling of two wells to develop tracts due to contract out of the West Sak PA. These areas are developed with multi-lateral injectors and producers in a direct line-drive pattern configuration. The wells target and D, B and A2 sands and have lateral lengths between 6,000 and 8,000 feet.

Additional delineation drilling was done in the NEWS area starting in 2004 with well 1H-05A (see Attachment 2). Additional wells were drilled from DS3J and 1Q to determine oil quality and oil water contacts. West Sak 3J-101 and 1Q-101 were drilled to the West Sak and suspended at surface casing for future developments in these areas. In early 2006, three exploration wells were drilled from an ice pad to evaluate the 1R east, 1H north and 1H south areas. As a result of this drilling activity the resources in the NEWS area have been high graded and future developments concentrate on the areas with the best oil quality.

In 2008, the first phase of the NEWS development was drilled at DS3K. The 2008 program consisted of drilling one horizontal multilateral producer and two horizontal multilateral water injectors. The injector wells utilized new technology to allow hydraulic isolation of the B and D sands; as well as improving injection conformance along the laterals. The injectors utilized the first TAML (Technology Advancement of Multilaterals) level 5 junctions installed in the West Sak, and should allow more control over future matrix bypass events as well as improve sweep efficiency (Figure 4).

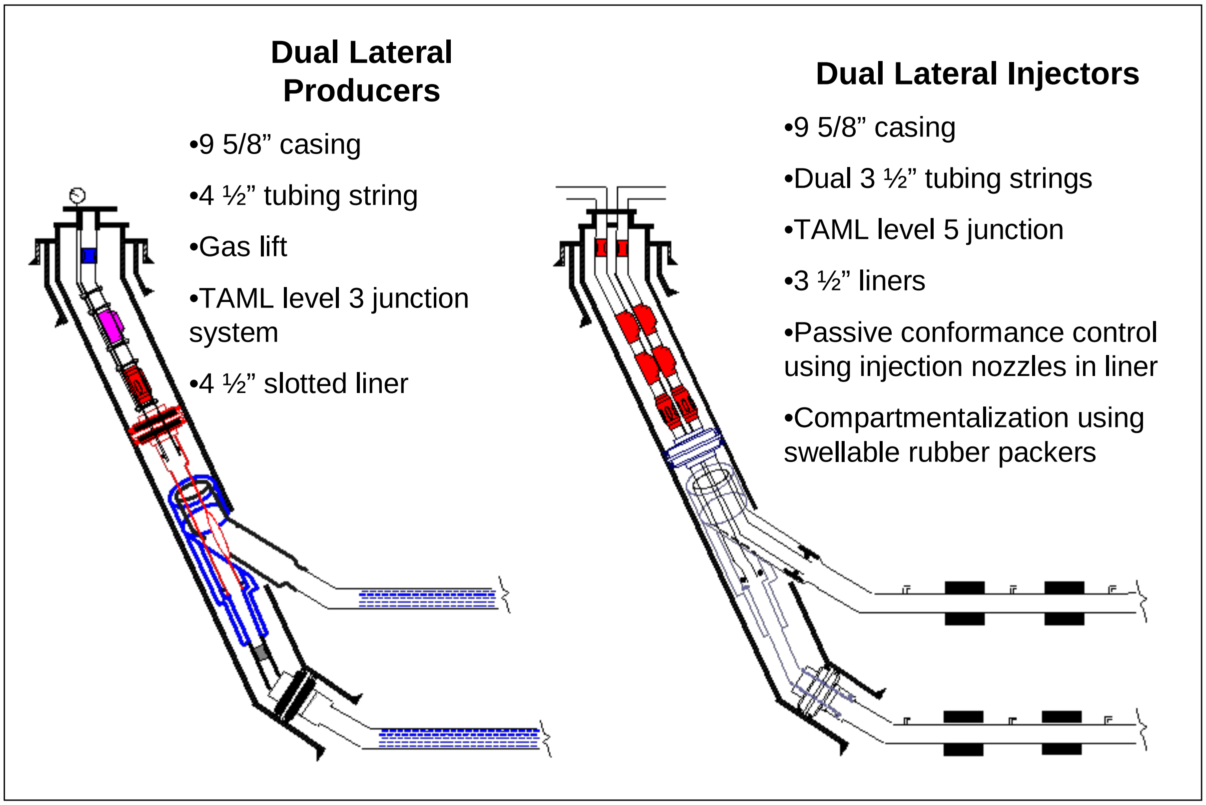

Figure 4: NEWS 3K Well Design

In December 2012, drilling commenced on 3K-105, a second horizontal multilateral producer at DS3K, with a drilling and completion design similar to the 3K-102.

Significant development activity occurred in 2014 and 2015 in the Core Area. Ten new wells were added in the DS1C and DS1D areas during this time period. These wells focus on adding low-cost, high-rate resource from existing infrastructure while trialing new technologies to improve long-term recovery.

4.2 Well Completions and Artificial Lift

West Sak well completions have evolved from vertical sand controlled producers offset to vertical injectors to a mix of horizontal wells both with and without sand control. Completion designs continue to evolve with technology and operational experience. Competitive completion technology is anticipated to deliver reliable sand control in multi-lateral producers.

Artificial lift, like well completions, continues to evolve at West Sak. Individual well behavior is the primary consideration when determining the “best” artificial lift method. TTC-ESPs are the primary lift mechanism for lower rate sand-controlled wells at DS1D. A small subset of wells continues to employ jet pumps as the primary artificial lift method; however, well testing, power fluid backout, and pump longevity continue to be challenges. The higher rate, slotted liner wells at DS1E and DS1J were originally completed with TTC-ESPs, but uptime challenges including plugging due to excessive sand production led to a widespread conversion to gas lift service. This change facilitates well intervention in the laterals to remediate production impairments caused by sand production.

4.3 FUTURE DRILLING

During 2018, West Sak operations are focused on delivery of the 1H NEWS program, while studying and planning the future development opportunities described below.

4.3.1 DS1H Development

The 1H NEWS 2017-18 drilling program comprises 4 horizontal multi-lateral producers and 15 vertical injectors. Surface work to expand the existing DS1H gravel pad and facilities to accommodate the new wells was completed between 2015 and early 2017. Drilling activities began in August 2017 and are expected to complete in 2018.

The next phase of viscous development is expected to begin in 2019, from existing drill-site 3R.

Further viscous opportunities will continue to be evaluated during 2018-19, including drilling from existing drill-sites (see Attachment 3):

- DS3K and DS3N
- 1H NEWS Phase 2 at DS1H
- Core Area re-development at DS1C and 1D
- Eastern NEWS

The 4D seismic response observed in the West Sak reservoirs appears to be leveraging for understanding some of the dynamic changes in these reservoirs. To date, one dedicated 4D seismic shoot (KWS-WK) has occurred over a 60 square mile pilot overlap area. This pilot area includes most of the West Sak core area. The time period between these two seismic surveys is from 2005(KWS) to 2011(WK). The 4D processing applied to these two surveys demonstrated reservoir changes and fault compartmentalization in and around the existing developments. These results are being incorporated into surveillance activities and development planning.

The West Sak reservoirs appear to be conducive to 4D technology. Efforts are underway to understand the appropriate areas and timing for additional application and acquisition.

4.4 Facilities

Drill sites 1B, 1C, 1D, 1E, 1H, 1J, 3K and 3R currently have West Sak/NEWS production. New developments at existing drill sites in the West Sak/NEWS area may require facilities upgrades such as the addition of heaters, electrical upgrades, and pipelines. These additional facility requirements add to the economic challenge of further West Sak/NEWS development in the current business environment.

Corrosion integrity concerns affected water injection at DS3K and DS1E in 2015. Major repairs on the injection facilities at both drill sites restored them to full injection in 2016.

In May 2018, 1H NEWS was connected to the seawater system and seawater injection commenced. Preliminary results indicate improved injectivity using seawater.

4.5 Enhanced Recovery Pilot Evaluation

During 2003, ConocoPhillips Alaska, Inc. received approval to commence a West Sak small scale enhanced oil recovery (SSEOR) Pilot Project using Kuparuk MI in a WAG pilot. The SSEOR Pilot Project consisted of three phases in two permitted areas:

Phase I : WAG wellbore completion integrity test;
Phase II : WAG injectivity test; and
Phase III : WAG breakthrough test.

Phase I of the Pilot Project was initiated in September 2003 with injection of Kuparuk MI into well 1C-135. Injection was continued for approximately two months. Well 1C-135 was returned to long-term production in April 2004. Production from the well indicated that slotted liner wells are suitable for gas production.

Phase II of the Pilot Project was initiated in March 2004 with injection into deviated conventional injectors 1C-119 and 1C-121. Well 1C-119 received one month of gas injection and the well was returned to water injection. Water injectivity after gas injection was initially lower, but recovered over about two weeks to the pre-gas injection levels. The 1C-121 injector received five months of gas injection, was shut-in for several weeks and then returned to water injection. This well also recovered to the pre-gas injection levels. Due to surface casing leaks found in both wells 1C-119 and 1C-121, no additional WAG cycles have been completed. Repairs have been made and the wells have been returned to water service only (2006 for 1C-121 and 2007 for 1C-119).

Phase III of the Pilot Project was also initiated in 2004 with gas injection into well 1C-121. Well 1C-121 was on continuous gas injection for five months and resulted in an increase in the gas-oil ratio (GOR) of offset producer 1C-102. Once well 1C-121 was switched to water injection, the

GOR in well 1C-102 dropped back to its pre-gas injection level. No additional gas breakthrough was noted in well 1C-102, as subsequent WAG cycles in wells 1C-119 and 1C-121 were suspended due to failed surface casing, which was detected in both injectors during 2005. In 2005, the first WAG cycle in horizontal undulating injector well 1C-174 was completed. This first cycle was just over a month in duration and pre-gas injection water rates were established within a few days of returning to water injection. No gas breakthrough for this first cycle was observed in offset producers 1C-178 and 1C-170. The second WAG cycle in 2006 lasted just over a month but no definitive GOR response was observed in offset producers 1C-178 and 1C-170. The West Sak SSEOR Pilot Project has been completed.

A VRWAG pilot project was approved by the AOGCC in 2009, and first gas injection began in November 2009. The pilot injection wells include 1E-102, 1E-117, 1J-122 and 1J-170. Well 1E-102 experienced a matrix bypass event and is now excluded from the pilot. The pilot was authorized for 36 months after the commencement of gas injection. In 2012, an extension was granted to continue the VRWAG pilot into 2013. Another extension was granted in 2013 to allow for continued pilot operations to the end of the year. Surveillance shows some enhancement of production in offset producers, and an analysis of the data with a final report detailing pilot conclusions was submitted to the AOGCC in 2013. The West Sak team requested an amendment to Area Injection Order 2B to allow for Viscosity Reducing Water Alternating Gas in the West Sak Oil Pool. The request was granted on June 19, 2014 when the AOGCC issued Area Injection Order 2C. Wells 1E-117, 1E-119, 1J-122, 1J-164, and 1J-170 injected gas during 2014. Additional wells will be converted to gas injection when the appropriate well integrity criteria are met.

Lean gas injection, i.e. no solvent was blended with the blend gas, was briefly attempted in late-2014 to early-2015 following the cessation of NGL imports and downtime from indigenous NGL production equipment.

Unexpected challenges arising from lean gas injection included faster breakthrough times and additional sand production. These challenges resulted in significant well downtime. Operational best practices were developed from these lessons-learned and implemented.