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AOGCC

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July 17, 2015

Via Hand Delivery

Cathy P. Foerster
Commission Chair
Alaska Oil and Gas Conservation Commission
333 West 7th Avenue, Suite 100
Anchorage, Alaska 99501

Re: Consolidated Application for Amendment of Prudhoe Oil Pool Rule 9 and Modification of Prudhoe Bay Unit Area Injection Orders AIO 3A and AIO 4F

Dear Chair Foerster:

BP Exploration (Alaska) Inc., as an individual working interest owner (*BPXA*) in the Prudhoe Bay Unit (*PBU*), and not as PBU operator, on behalf of itself and PBU working interest owner ExxonMobil Alaska Production Inc. (*EMAP*), submits this consolidated application to the Alaska Oil and Gas Conservation Commission (*AOGCC*) to obtain two related authorizations:

(i) Amendment of Rule 9 of Conservation Order (*CO*) 341D for the Prudhoe Oil Pool (*POP*) to authorize an increase in the maximum annual average gas off-take limit from 2.7 billion standard cubic feet per day (bscf/d) to 4.1 bscf/d.

(ii) Modification of AIO 3A and AIO 4F (collectively the *AIOs*) to authorize the injection of CO_2 for enhanced recovery and pressure maintenance from sources both inside, which is already authorized, and outside the Prudhoe Bay Unit.

As related procedural matters, BPXA respectfully requests that, to the full extent allowed by the applicable regulations, the AOGCC:

(i) consolidate proceedings pertaining to amendment of Rule 9 and modification of the AIOs because of their interrelated nature;

(ii) provide notice of a public hearing on this application tentatively scheduled for on or about August 31, 2015 in accordance with 20 AAC 25.520 and 20 AAC 25.540;

(iii) tentatively schedule a pre-hearing conference for on or about August 10, 2015 in accordance with 20 AAC 25.540(f); and

(iv) allow the submission of pre-filed written testimony in support of the application pursuant to 20 AAC 25.540(c)(12) with the submitting witness(es) to be present at the public hearing to provide sworn testimony and respond to questions of the AOGCC, if any.

Please note that the portion of this consolidated application contained in the Confidential Appendix is confidential, and BPXA requests that such information be held confidential pursuant to AS 31.05.035(d), 20 AAC 25.537(b), and AS 45.50.910 et seq. The Confidential Appendix is enclosed in a separate envelope and marked confidential.

BPXA respectfully requests that the AOGCC make a decision on the matters addressed in this consolidated application on or before October 15, 2015.

I. PRUDHOE OIL POOL RULE 9 AMENDMENT

A. POP Maximum Annual Average Gas Off-Take Rate

Rule 9, as adopted by the AOGCC in 1977, limits the maximum annual average gas off-take from the POP to 2.7 bscf/d. Approximately 0.6 bscf/d is currently used (and anticipated to continue to be used) for fuel, other field operations and minor local gas sales. Accordingly, under Rule 9, an annual average gas off-take of approximately 2.1 bscf/d would be available for major gas sales.

BPXA and the other PBU working interest owners (individually referred to as a *WIO* and collectively as *WIOs*) and the AOGCC have long contemplated a major gas sales project involving gas from Prudhoe Bay (*PBMGS*). In accordance with good oil field engineering practices, at various stages of field development, the PBU WIOs have evaluated the potential effects of a PBMGS on oil production and hydrocarbon recovery from the POP based upon then-existing information and models. Gas production from the POP has been used for extraction of miscible injectant, manufacture of natural gas liquids, pressure maintenance, and enhanced oil recovery. Partly as a result of this POP gas utilization, liquid recovery from the POP has increased from the estimated 9.6 billion barrels in 1977 to over 12.2 billion barrels to date.

The AOGCC held a public hearing in June 2007 and issued a report dated July 10, 2007 regarding possible amendment of Rule 9. The AOGCC concluded that no change was necessary to Rule 9 at that time.[1] The PBU WIOs have continued to prepare for a PBMGS and, because of progress by participants in the Alaska LNG Project (*AK LNG*) and related planning by the PBU

[1] Report of the Commission Inquiry Into Amending Rule 9 ("Pool Off-Take Rates"), CO 341D, For the Prudhoe Oil Pool, Prudhoe Bay Field.

WIOs for a PBMGS, it is now appropriate for the AOGCC to amend Rule 9 to allow a greater gas off-take rate from the POP.[2]

B. Gas Off-Take for PBMGS

The participants in AK LNG are progressing plans for an integrated LNG project, currently anticipated to start-up in 2025, consisting of a liquefaction facility and associated LNG storage and marine terminal facilities located in the Cook Inlet area, a large diameter gas pipeline approximately 800-miles in length (with gas off-take interconnection points to allow for in-state deliveries) connecting the liquefaction facility to a Gas Treatment Plant (*GTP*) on the North Slope, transmission lines between the GTP and producing fields, and various other associated facilities and infrastructure.[3] On May 28, 2015 the U.S. Department of Energy conditionally granted authorization to AK LNG to export LNG to non-free trade agreement nations.[4]

The GTP is being designed by AK LNG to receive, treat, and ship gas to the Liquefaction Plant, and to send to the PBU a GTP by-product stream primarily consisting of carbon dioxide (CO_2).[5] The design of the AK LNG facilities is premised on maintaining an annual average gas supply rate of 3.5 bscf/d to the GTP.[6] BPXA and EMAP plan to deliver part of the gas supply into the GTP from PBU (from the POP).

C. Request to Increase POP Maximum Annual Average Off-take Rate

There are several reasons why an amendment of Rule 9 to increase the maximum annual average gas off-take rate is being requested.

Under expected normal operations of the GTP, approximately 75 percent of the gas supply (2.7 bscf/d) will be from the POP with approximately 25 percent of the gas (0.8 bscf/d) supplied from

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[2] BPXA participated in PBMGS preparations in its capacity as a PBU WIO and facilitated discussions in its capacity as PBU operator.

[3] *See* AK LNG Preliminary Resource Report No. 1 at § 1.1, Docket No. PF14-21-000 (doc. Number: USAKE-PT-SRREG-00-0001) (hereafter referred to as "Resource Report No. 1"), available at: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14300991. The AK LNG project is currently undergoing pre-filing review before the Federal Energy Regulatory Commission (*FERC*) at Docket No. PF14-21-000. The applicants before FERC for the AK LNG project are the Alaska Gasline Development Corporation, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LP.

[4] *See* DOE/FE Order No. 3643 (FE Docket No. 14-96-LNG), available at: http://www.energy.gov/fe/downloads/order-3643-alaska-lng-project-llc.

[5] *See* Resource Report No. 1 at p.15.

[6] According to the current design, the GTP will have an annual average inlet gas treating capacity of up to 3.7 bscf/d, excluding planned/unplanned downtime. *Id.* Assuming 95% operating efficiency, the annual average gas supply requirement for the GTP is 3.5 bscf/d.

other sources. Under normal operations, total POP gas off-take would occur at an annual average rate of approximately 3.3 bscf/d (2.7 bscf/d to the GTP plus 0.6 bscf/d for existing fuel use and minor local gas sales)[7]. The current Rule 9 off-take rate of 2.7 bscf/d is not sufficient to meet the annual average gas off-take from the POP under those circumstances. The Commission has long acknowledged that a change to the gas off-take rate from the POP would be needed to facilitate a major gas sale.

In addition to POP gas supply under normal operating conditions, if the supply of gas from other sources is not delivered as expected (or during startup of, or after gas production begins to decline from, other fields), it is possible the POP would need to be the source for up to 100 percent of the gas BPXA and other parties will each need to supply to the GTP to cover gas supply commitments. In such circumstances, the total gas off-take from the POP could be up to 4.1 bscf/d (3.5 bscf/d to the GTP adjusted for the higher CO_2 content of POP feed gas in comparison to the expected blended feed stream plus 0.6 bscf/d for existing fuel use and minor local sales). This application to amend Rule 9 requests an increase in the annual average off-take rate to 4.1 bscf/d to accommodate the maximum potential gas off-take from the POP in circumstances when non-POP gas supply to the GTP is not delivered as expected.

D. Analysis of Increase in Gas Off-Take

Upgrades to the PBU Full Field Model (*FFM*) have been made since the AOGCC last considered POP gas off-take rates in 2007. In addition, model inputs incorporate updated production, drilling, well breakage data, and updated fuel gas algorithms. As a result of increased model resolution, other model refinements, and updated data, a greater degree of confidence in model results has been achieved regarding recovery mechanisms, well productivity, facility processing and compositional detail of oil and gas production.

Analyses of the upgraded FFM were performed and presented by the PBU WIOs to AOGCC staff in workshops during April and May of this year. BPXA's assessment of the results is set forth in the Confidential Appendix to this application.

BPXA believes that amendment of Rule 9 to allow a maximum annual average gas off-take rate of 4.1 bscf/d for the POP is consistent with good oilfield engineering practices, and appropriate action for the Commission to take.

E. Timing for AOGCC Decision

Amendment of Rule 9 is being requested at this time in consideration of current actions by the State of Alaska and the AK LNG parties, including BPXA's affiliate BP Alaska LNG LLC and EMAP's affiliate ExxonMobil Alaska LNG LLC, to progress the AK LNG project to the front-end engineering and design (*FEED*) development stage (which effort involves the expenditure of billions of dollars). To move to the FEED stage of project activity, a number of project-enabling

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[7] Resource Report No. 1 at 16, 18-19.Current GTP design contemplates that 25% of the supply into the facility will be gas delivered from the Point Thomson Unit.

actions have been identified.[8] Amendment of Rule 9 to allow the flexibility to supply both ordinary and full feed gas rates to the GTP from PBU supports those activities. BPXA is requesting that the AOGCC render a decision by October 15, 2015 to facilitate those project-enabling actions.

II. MODIFICATION OF AIOS

A. Introduction

As addressed in Sections I.A-.B above (incorporated into this request by reference), the GTP is being designed to receive, treat and ship gas to the liquefaction facility, and to return CO_2 by-product to the PBU for injection. Gas will be received from multiple fields, including the POP at PBU.

Similar to the requested amendment of Rule 9 addressed above, the requested modifications to the AIOs are being requested at this time to support the joint efforts of the State of Alaska and the AK LNG parties to progress the Alaska LNG Project to FEED development stage. As more specifically addressed below, modifications of the AIOs are based upon the Alaska LNG project design plan for re-injection of the GTP CO_2 by-product into the POP.

B. Request to Authorize Injection of CO_2

1. Injection of CO_2 by-product

After treatment of feed gas at the GTP, the Alaska LNG Project design is to return CO_2 by-product, which is greater than 99% dry CO_2, to the Prudhoe Bay Unit for injection.[9] BPXA's assessment is that PBMGS will enable an additional hydrocarbon recovery benefit of approximately 3.8 billion barrels of oil equivalent from the PBU, of which the injection of CO_2 in the POP is a key step.

BPXA's analysis and assumptions regarding CO_2 injection is set forth in the Confidential Appendix to this application.

Please refer to the Confidential Appendix for information provided to the Commission in support this application, pursuant to 20 AAC 25.402.

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[8] *See* Heads of Agreement for the Alaska LNG Project (Jan. 14, 2014).

[9] Resource Report No. 1.

2. Modification of AIOs to authorize injection of GTP CO_2 by-product will not allow or increase the risk of movement of fluids into sources of freshwater or underground drinking water

Within the PBU, there are no subsurface sources of freshwater. Aquifer Exemption Order 1 states that all portions of aquifers lying directly below the Western Operating and K Pad areas of the Prudhoe Bay Unit are exempted for Class II injection activities. Based on data submitted to AOGCC, Finding 5 of AIO 4 covering the Eastern Operating Area states that "injection into, though, or above a fresh water aquifer or underground source of drinking water will not occur."

The AIOs only authorize injection into an authorized injection strata. The orders contain requirements for periodic mechanical integrity testing and monitoring injection wells. Should a lack of injection zone isolation be indicated, the operator must notify the AOGCC and submit a plan of corrective action. The well must be shut-in if freshwater were threatened.

As noted earlier in this Application, injection of PBU CO_2 into the POP (as part of authorized PBU gas cycling operations) is already allowed by the Commission, and this request simply requests authorization for the injection of incremental CO_2 from gas supplied to the GTP from other reservoirs.

B. Requested modifications to AIOs

BPXA requests, pursuant to 20 AAC 25.410(h), that the Commission approve the following modifications to the referenced Rule in each of the AIOs (**requested modifications in bold and underlined text**):

1. AREA INJECTION ORDER 3A (PRUDHOE OIL POOL)

Rule 1. Authorized Injection Strata and Fluids for Enhanced Recovery

Within the affected area and in the strata defined as those strata which correlate with the strata found in ARCO Alaska Inc. (Atlantic-Richfield-Humble) Prudhoe Bay State Well No. 1 between the measured depths of 8110 feet and 8680 feet the following fluids may be injected for purposes of pressure maintenance and enhanced oil recovery:

a) Produced water and gas from Prudhoe Bay Unit processing facilities;
b) **CO_2 and other GTP effluent gases from sources within or outside the Prudhoe Bay Unit;**
~~b~~**c)** Enriched hydrocarbon gas;
~~c~~**d)** Non-hazardous water and water based fluids - (specifically seawater, source water, freshwater, domestic wastewater, equipment washwater, sump fluids, hydrotest fluids, firewater, and water with trace chemicals, and other water based fluids with a pH greater than 2 and less than 12.5 and flashpoint greater than 140 degrees F);

~~d~~**e**) Fluids introduced to production facilities for the purpose of oil production, plant operations, plant/piping integrity or well maintenance that become entrained in the produced water stream after oil, gas, and water separation in the facility. Specifically:
   i. Freeze protection fluids;
   ii. Fluids in mixtures of oil sent for hydrocarbon recycle;
   iii. Corrosion/scale inhibitor fluids;
   iv. Anti-foams/emulsion breakers;
   v. Glycols;
   vi. Radioactive tracer survey fluids

~~e~~**f**) Non-hazardous glycols and glycol mixtures;

~~f~~**g**) Fluids that are used for their intended purpose within the oil production process.

Specifically:
   i. Scavengers;
   ii. Biocides

~~g~~**h**) Fluids to monitor or enhance reservoir performance. Specifically:
   i. Tracer survey fluids;
   ii. Well stimulation fluids;
   iii. Reservoir profile modification fluids.

2. AREA INJECTION ORDER 4F (PRUDHOE OIL POOL, PUT RIVER OIL POOL, LISBURNE OIL POOL. PT. MCINTYRE OIL POOL, WEST BEACH OIL POOL, AND STUMP ISLAND OIL POOL)

Rule 1 Authorized Injection Strata and Fluids for Enhanced Recovery

Within the affected area and the following strata:

The Prudhoe Oil Pool strata defined as (i) the accumulations of oil that are common to and that correlate with the accumulations found in the Atlantic Richfield -Humble Prudhoe Bay State No. 1 well between the depths of 8,110 feet and 8,680 feet, and (ii) the accumulation of oil that is common to and correlates with the interval from 9,638 to 9,719 measured feet on the Borehole Compensated Sonic Log, Run 2, dated September 28, 1975, in the Atlantic Richfield-Exxon NGI No. 1 well, and that is in hydraulic communication with the gas cap of the former accumulations in the Sag River Formation. The latter accumulation is found within the following area:

Umiat Meridian.
T11N R14E: Sections: 1, 2, 11(N/2 and SE/4), 12, 13, 14(E/2), 23(NE/4), 24, 25(N/2); T11N R15E: Sections: 6, 7, 8, 17, 18, 19, 20, 29(N/2), 30(N/2);
T12N R14E: Sections 35, 36

The Put River Oil Pool strata are defined as the sandstone reservoirs within the Southern, Central and Western lobes of the Put River Sandstone Member (PRS) of the Kalubik Formation that correlate with the interval 9,638 to 9,719 measured feet on the Borehole Compensated Sonic Log, Run 2--dated September 28, 1975--in the Atlantic Richfield-Exxon NGI No. I well, but excluding the PRS Northern Lobe reservoirs that are in pressure communication with the Prudhoe Oil Pool gas cap in the Sag River Formation. The Put River Oil Pool is found within the following area:

> Umiat Meridian.
> T11N R14E Sections: 3, 4, 9, 10, 11(SW/4), 14(W/2), 15, 16, 21, 22, 23(W/2 and SE/4), 25(S/2), 26, 27, 28, 33, 34, 35, 36; T11N RI5E Sections: 29(S/2), 30(S/2), 31, 32;
> T10N R14E Sections: 1, 2, 3, 11, 12, 13, 14;
> T10N R15E Sections: 5, 6, 7, 8, 17, 18

The Lisburne Oil Pool strata correlate with and are common to the formations found in the ARCO Prudhoe Bay State No. 1 well between the measured depths of 8, 790-10,440.

The Pt. Mcintyre Oil Pool strata correlate with and are common to the formations found in the Pt. Mcintyre No. 11 well between the measured depths of 9,908-10,665 feet.

The West Beach Oil Pool strata correlate with and are common to the formations found in the West Beach No.4 well between the measured depths of 14,458-14,781 feet.

The Stump Island Oil Pool enhanced recovery plans will be evaluated on a well-by-well basis in conjunction with Pt. Mcintyre Oil Pool development.

The following fluids may be injected for pressure maintenance and enhanced recovery purposes:

a) Produced water and gas from PBU processing facilities;
b) **CO_2 and other GTP effluent gases from sources within or outside the Prudhoe Bay Unit;**
~~b~~c) Enriched hydrocarbon gas;
~~c~~d) Non-hazardous water and water based fluids -(specifically seawater, source water, freshwater, domestic wastewater, equipment washwater, sump fluids, hydrotest fluids, firewater, and water with trace chemicals, and other water based fluids with a pH greater than 2 and less than 12.5 and flashpoint greater than 140 degrees F);
~~d~~e) Fluids introduced to production facilities for the purpose of oil production, plant operations, plant/piping integrity or well maintenance that become entrained in the produced water stream after oil, gas, and water separation in the facility. Specifically:
   i. Freeze protection fluids;
   ii. Fluids in mixtures of oil sent for hydrocarbon recycle;
   iii. Corrosion/scale inhibitor fluids;
   iv. Anti-foams/emulsion breakers;
   v. Glycols

- **ef)** Non-hazardous glycols and glycol mixtures;
- **fg)** Fluids that are used for their intended purpose within the oil production process. Specifically:
  - i. Scavengers;
  - ii. Biocides
- **gh)** Fluids to monitor or enhance reservoir performance. Specifically:
  - i. Tracer survey fluids;
  - ii. Well stimulation fluids;
  - iii. Reservoir profile modification fluids.

III. SUPPORTING INFORMATION

This application provides comprehensive information and support for approval of the requested amendment of Rule 9 maximum annual average gas off-take rate for the POP to 4.1 bscf/d, as well as modification of the AIOs. Mr. Bruce Laughlin, as testifying witness, will be present at, and made available to, the AOGCC for questions at the public hearing with respect to this application. Depending upon the testimony, if any, presented by others at the public hearing, BPXA reserves the right to present additional testimony at the public hearing, or by post-hearing submission if so authorized by the Commission.

IV. CONCLUSION

Based upon this application, BPXA requests that the AOGCC: (i) amend Rule 9 of CO 341D to establish a maximum annual average gas off-take rate of 4.1 bscf/d for the POP; and (ii) modify AIO 3A.002 and AIO 4F to authorize injection of CO_2 from the PBU and other sources for the purposes of enhanced oil and gas recovery, and pressure maintenance.

Please contact John Dittrich at 907-564-5075 if the Commissioners or AOGCC staff have any questions or clarification regarding this application. BPXA is represented in this matter by George Lyle of Guess & Rudd, 510 L Street, Suite 700, Anchorage, AK 99501, 907-793-2222. Please direct communications regarding procedural matters, including the pre-hearing and public hearing, to Mr. Lyle.

We sincerely appreciate the time and attention of the Commissioners and the AOGCC staff to this application.

Sincerely,

Dave P. Lachance
Vice President, Reservoir Development

Attachment

cc: George Lyle