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September 8, 2015

Via Hand Delivery

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

Re: Docket Numbers: AIO 15-032, AIO 15-033 and CO 15-09, Prudhoe Oil Pool
BPXA Post-Hearing Written Response to Commission Requests
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. (BPXA) submits, on behalf of itself and ExxonMobil Production Inc., as applicants in the above referenced matter, the enclosed written response to Commission requests directed to BPXA during the hearing on August 27, 2015.

Please note that the portion of our response 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., as well as Section 11.4 of the Prudhoe Bay Unit Agreement. The Confidential Appendix is enclosed in a separate envelope and marked confidential.

Sincerely,

Dave Lachance

Dave P. Lachance
Vice President, Reservoir Development

Attachment

cc via email:

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INTRODUCTION

At the hearing on August 27, 2015, on the referenced application by BP Exploration (Alaska) Inc. (BPXA) to the Alaska Oil and Gas Conservation Commission (AOGCC or Commission), the Commission asked BPXA to submit, post-hearing, responses to Commission requests for the following:

1. Analysis of a full field model (FFM) run or runs depicting the optimal start-up time for Prudhoe Oil Pool (POP) major gas sales (MGS) that is indifferent to specific project considerations; and

2. Analysis of a FFM run depicting the point in time when the BTU value of fuel gas usage is greater than the BTU value of the oil it's producing. (BPXA interprets this request by the Commission as a request for a comparative analysis of incremental oil recovery and incremental fuel gas usage resulting from pushing back the start-up of major gas sales, expressed in barrels of oil equivalent.)

This submittal addresses each of these requests.

I. OPTIMAL MGS START-UP DATES INDIFFERENT TO SPECIFIC PROJECT CONSIDERATIONS

INTRODUCTION

The classic petroleum engineering text book approach to greater ultimate recovery of an oil field with an original gas cap is to first target the oil for development while re-injecting the produced gas to maintain reservoir pressure. In this text book approach to hydrocarbon recovery, it is only after oil production is no longer economically viable that the gas is produced from the reservoir and sold. The logic behind this text book approach to hydrocarbon recovery is that if gas is sold too early the reservoir will lose pressure before oil production is optimized, and as a result total hydrocarbon recovery will be less than otherwise. This is how development of the POP has proceeded for 38 years. The POP has recovered significantly more oil than it would have without gas re-injection.

However, the POP is entering a stage in which this simple text book approach to hydrocarbon recovery no longer reflects the complexities of POP development. That's because field development needs to consider several significant factors uniquely applicable to the POP: (1) availability of necessary infrastructure to support a gas export project; (2) fuel gas consumption; (3) facility life considerations; and (4) that the POP has acted similar to a gas field for more than two decades. For example, in a scenario in which a gas export project is available before oil development becomes un-economic, but would not be available at a later date, greater ultimate hydrocarbon recovery can only be achieved by proceeding with gas sales.

The Alaska LNG Project is moving forward on a timeline targeting gas production for major gas sales from the POP potentially in 2025. There are no other gas sales projects proposed for sales of POP gas sooner than that date or at a later date. Since oil production and gas re-injection consumes fuel gas that could otherwise be sold and contribute to hydrocarbon recovery, by adjusting for fuel gas consumption, if a major gas sales project moves forward in 2025 greater ultimate recovery will likely occur through gas sales prior to oil development becoming un-economic. POP operations currently consume ~400 MMSCFD, or approximately 25 million barrels oil equivalent (BOE) per year, of fuel gas to sustain oil production, whereas fuel gas requirements will be substantially reduced during major gas sales. As facilities age, equipment performance and reliability are factors that can impact production and ultimate hydrocarbon recovery. Oil production began from the POP in 1977 and with a MGS start-up in 2025 much of the Prudhoe Bay Unit production facilities will have been in operation for 50 years. Additionally, the landscape of existing supporting infrastructure and delivery systems is likely to change with time.

The Commission's approval of BPXA's application in this matter is a necessary and critical step in trying to make POP major gas sales, through a large project such as the Alaska LNG Project it would support, successful.

SUMMARY AND CONCLUSIONS

Depending on the assumptions that are made, ultimate hydrocarbon recovery from the POP could potentially increase by up to 100 million BOE (MMBOE), less than 1% of ultimate hydrocarbon recovery, if a comparable MGS project were to commence operations in 2040 rather than 2025 in the reference case. This is premised on the assumption that a POP MGS project is available at that time and advances, and that all necessary facilities, infrastructure and delivery systems have the same remaining capability at project start-up as the 2025 MGS reference case. However, there are unknown factors that could significantly undercut these assumptions including that a MGS opportunity may not be available, which would reduce overall potential hydrocarbon recovery by approximately 3.6 billion BOE.

As mentioned, the Alaska LNG Project timeline targets potentially beginning operations in 2025 and if so then gas sales from the POP are estimated to total 22.4 TCF of gas, increasing ultimate hydrocarbon recovery from the POP by between 3.5 and 3.6 billion BOE. Even though there is a potential for slightly greater hydrocarbon recovery with a later MGS date, the complexity and significant financial commitments required to advance a MGS project of this magnitude and the risk of significantly lower ultimate recovery more than offset any potential gain.

A later MGS start-up also increases the uncertainty that the project can deliver a full 30-year project life due to declining oil production and revenues which underpin the project, and due to increasing project risk from aging facilities which could reduce project life and thus ultimate recovery, reducing the potential incremental recovery relative to a 2025 start-up.

A. BPXA'S FFM RUNS

1. ASSUMPTIONS AND RISKS

BPXA (as an individual working interest owner and not as operator) used its proprietary FFM tool (FFM Tool) to build FFM runs to assess the impact of starting MGS from the POP within a range of start-up dates: 2025, 2030, 2035 and 2040. BPXA used the following assumptions in running each case:

- **Assumption:** A project similar to the current AK LNG project is available to start-up at each of the different 5 year increments.
  Risk: A gas sales project is not available for POP major gas sales at a later date. Therefore, any additional recovery that may be assumed to be recovered by pushing back the start date for a project (<0.1 billion BOE), must be balanced against the risk of not recovering any of the gas (>3.5 billion BOE).

- **Assumption:** All PBU oil and gas process facilities and TAPS are fully available for oil transportation and gas production for the length of the total production period with a 30 year MGS project period in all cases.
  Risk: Facilities used to produce the oil and gas will age over time and typically operate outside optimum design basis parameters, reducing the ability to recover the oil and gas indicated in the profiles. While the FFM runs account for well breakage and repair, it does not account for impacts due to facility or pipeline availability or performance, including TAPS.[1] As the facilities age, it is more likely that major equipment performance and reliability will affect oil and gas production. Directionally, there will be an increasingly greater impact on the gas sales cases with later start-up dates. The production profiles provided are not adjusted for any performance reduction factors associated with later major gas sales dates.

2. Model Run Profiles

a. Gas Deliveries Profiles

The POP gas sales profiles (excluding CO_2) for the 2025 (Reference Case), 2030, 2035 and 2040 start-ups are shown in Figure 1 in the Confidential Appendix to this submittal. The shape of these gas delivery profiles are similar, however, as start-up dates are extended, the plateau length decreases, from 21.0 to 19.6 years. The cumulative amount of gas delivered for sales decreases with each increment of extended start-up, from 22.4 TCF (2025 Start-up) to 20.9 TCF (2040 start-up), due to increased fuel gas consumption (see Table 1).

b. Oil Production Profiles

The POP liquid hydrocarbons (oil + NGLs) profiles for the oil reference case, and the 2025 (gas reference case), 2030, 2035 and 2040 start-ups are shown in Figure 2 in the Confidential Appendix to this submittal. Due to the drop in reservoir pressure at the onset of gas sales, oil production profiles correspondingly decline at a faster rate at the onset of gas sales, followed by a period of slower rate of decline. Liquid hydrocarbon recovery for the various cases is detailed in Table 1 and Table 2.

c. Fuel Gas Usage Profiles

Fuel gas is mainly consumed in the POP to generate electricity, heat fluids and facilities, pump fluids, and most significantly, compress the dry residue gas for reinjection. When gas sales begin from the POP, fuel usage will decrease as less compression is needed to send gas to the GTP rather than to re-inject the gas. As reservoir pressure declines and active well counts decrease over time, less fluid will be heated, pumped and compressed, and fuel usage will decrease further. These effects are accounted for in the FFM run forecasts of fuel gas usage shown in Figure 3 in the Confidential

[1] The FFM Tool is capable of performing this analysis, but BPXA has not run such cases.

Appendix to this submittal. The figure shows that a later start of gas sales results in higher total fuel usage. Once gas is used for fuel it is no longer available for gas sales; therefore, later start of major gas sales results in lower gas sales volumes.

Total Hydrocarbon Profiles

Figure 4 in the Confidential Appendix to this submittal shows oil and gas sales profiles combined into total hydrocarbon BOE profiles, assuming 1 barrel of oil is equivalent to 5.8 thousand standard cubic feet (MSCF) of gas. The POP BOE rate profiles in Figure 4 are the same as the oil reference case until the start of major gas sales, when total BOE production increases dramatically. Although gas sales rates are on plateau for approximately 20 years, total BOE delivery declines over that period due to declining oil production rates. At the end of the major gas sales plateau period, total BOE delivery rates drop more rapidly as both oil and gas sales rates are declining.

B. Assessment of Ultimate Recovery

1. End of Field Life

Two methods to evaluate the end of field life (EOFL) were used in this study to evaluate ultimate hydrocarbon recovery:

1. Common gas sales project length
2. Common minimum total hydrocarbon production rate

Ultimate hydrocarbon recovery for the suite of MGS start-up dates sensitivities are evaluated against each of the EOFL methodologies.

2. Full Field Model Precision

The resolution of the model is ~+/- 10 Million barrels of oil recovery, and ~+/- 30 Million BOE on gas sales, and ~+/- 40 Million BOE of hydrocarbon recovery. FFM model precision was determined by running a series of simulation runs that were identical, except for a small perturbation to the inputs. The model precision quoted was determined from the range of this series of results. If simulation results from model runs of different scenarios are within these ranges of recovery, the impact of the sensitivity is not discernible from the uncertainty, and should not be used to inform decisions or rank scenarios.

3. Unaccounted For Risks to Ultimate Recovery

The following analysis does not account for two significant risks. These risks have a greater probability of occurrence as a MGS project start-up extends beyond 2025.

1. A major gas sales project may not be available to ship gas from POP at a later date. Therefore, any additional recovery that may be assumed to be recovered by a later project (<0.1 billion BOE), must be balanced against the risk of not recovering and selling any of the gas (>3.5 billion BOE).
2. Facilities used to produce the oil and gas will age and operate outside of the maximum efficiency range which could affect performance and reliability over time, reducing the ability to recover both the oil and gas indicated in the profiles. Infrastructure and delivery systems

could also impact oil and gas deliverability later in POP field life. While the FFM Tool and the cases run by BPXA account for well breakage and repair, they do not account for impacts due to facility or pipeline availability or performance, including TAPS.[2] Directionally, however, it is safe to say that there will be a disproportionately greater impact on the gas sales cases with later start-up dates.

C. Ultimate Recovery Comparison

1. Recovery at a Common Project Length

Table 1 shows the recovery of oil and gas, fuel usage, and total hydrocarbon recovery assuming a 30-year MGS project life; for example, the 2025 start-up case has an EOFL in 2055 and the 2040 start-up case has an EOFL in 2070. The EOFL of the Oil reference case is 2055.

The table shows that hydrocarbon recovery is fundamentally maximized by achieving an MGS project, as the remaining hydrocarbon recovery from 2025 forward increases by more than four-fold for all MGS scenarios relative to the Oil Reference case. Among the MGS scenarios, the table shows that oil recovery increases, with greater fuel gas consumption and less gas sales, with a later MGS project. In addition to greater oil recovery prior to start of major gas sales, additional oil recovery is achieved on the tail of the profile due to possible field life extension. This additional oil recovery is balanced against the additional fuel consumed during the oil production period and on the tail. These results assume that wells and facilities will last for the duration of production in each scenario.

These un-risked recovery profiles show that the increase in ultimate total hydrocarbon recovery with later start-up of major gas sales from 2025 to 2030 is about 0.05 B BOE or 50 MMBOE. Extending the start of major gas sales from 2025 to 2040 increases total hydrocarbon recovery by approximately 0.1 B BOE or 100 MMBOE. A volume of 100 MMBOE is only about 0.5% of the total expected hydrocarbon recovery.

TABLE 1: UNRISKED RECOVERY OF OIL, GAS, FUEL AND TOTAL HYDROCARBONS FROM THE POP FROM 2025 TO 30 YEARS AFTER THE MGS START-UP, SENSTIVITIES TO PBU MGS START-UP DATES.

Unrisked Recovery from 2025 to 30 years after MGS Start-Up				
Case	**Oil (Billion STB)**	**Gas Sales (TCF)**	**Fuel Gas (TCF)**	**Total Hydrocarbons (Billion BOE)**
Oil Reference	1.07	-	3.68	1.07
Gas Reference - 2025 MGS	0.79	22.43	2.40	4.65
2030 MGS	0.93	21.92	3.08	4.71
2035 MGS	1.05	21.35	3.61	4.73
2040 MGS	1.14	20.96	4.15	4.75

2. Recovery at a Common Total Hydrocarbon Rate

Assessment of EOFL at a common total hydrocarbon production rate is often used to estimate the economic life of a project. The ultimate hydrocarbon recovery is determined by assessing the

[2] As noted earlier, the FFM Tool is capable of performing this analysis, but BPXA has not run such cases.

cumulative hydrocarbon recovered at the same total hydrocarbon rate for each case, instead of a fixed date. The cut-off rate assumed for this evaluation is 100 MBOE/D, and does not represent BPXA's view of the actual field economic limit which will depend on oil and gas prices and other future economic conditions which cannot be accurately predicted now. This total hydrocarbon rate is consistent with the rate limit used in the 2007 Blaskovich report commissioned by the AOGCC.

Figure 5 in the Confidential Appendix to this submittal shows the total hydrocarbon production rate as a function of the total cumulative hydrocarbon recovery. The optimal recovery case is the one achieving the highest cumulative recovery at a given cut-off rate. However, Figure 5 indicates that after the field comes off plateau, the recovery curves lie on top of each other. This means that after gas plateau ends, the cases have similar ultimate hydrocarbon recovery for almost any common hydrocarbon production rate cut-off.

Table 2 shows the recovery of oil and gas, fuel usage, and total hydrocarbon recovery assuming a common hydrocarbon rate cut-off of 100 MBOE/D. The data indicates that oil production is greater with MGS than the oil reference case by about 60 million barrels (MMbbls) using the common rate cut-off, rather than -280 MMbbls with a common end date, due to a significant extension of field life. The data in Table 2 also shows that the maximum difference in ultimate hydrocarbon recovery between the 2025 start-up case and other cases is 70 MMBOE, which approaches the resolution of the model for total hydrocarbon recovery (~+/- 40 MMBOE), without making any adjustments for facility life and project availability risks. According to the common total hydrocarbon rate EOFL metric, there is little discernible difference in total hydrocarbon recovery between the different MGS start dates cases, within the resolution of the FFM runs.

TABLE 2: UNRISKED RECOVERY OF OIL, GAS, FUEL AND TOTAL HYDROCARBONS FROM THE POP FROM 2025 TO 100 MBOE, SENSTIVITIES TO PBU MGS START-UP DATES.

Unrisked Recovery from 2025 to 100 MBOE/D Cut-Off				
Case	**Oil (Billion STB)**	**Gas Sales (TCF)**	**Fuel Gas (TCF)**	**Total Hydrocarbons (Billion BOE)**
Oil Reference	0.72	-	1.91	0.72
Gas Reference - 2025 MGS	0.78	22.16	2.35	4.60
2030 MGS	0.93	21.72	3.04	4.67
2035 MGS	1.05	21.03	3.55	4.68
2040 MGS	1.13	20.35	4.03	4.64

II. OIL RECOVERY VERSUS FUEL GAS USAGE

Using the data in Table 1, the comparative incremental oil recovery and incremental fuel gas burned by pushing back the start-up of MGS, can be approximated. Figure 6 shows that the incremental oil recovered by a later start of MGS from 2025 to 2030 is ~140 MMBOE, and the corresponding additional fuel burned is about ~120 MMBOE. If POP MGS start-up occurs from 2035 to 2040 the BOE increase in fuel gas consumption surpasses the additional oil recovery.

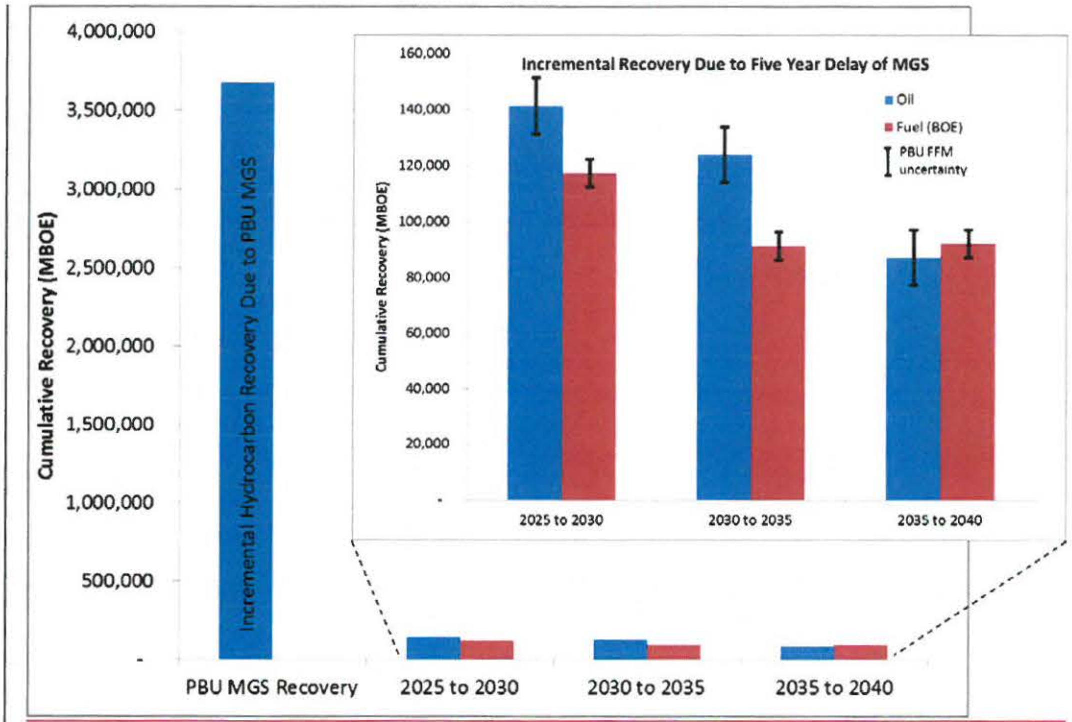

FIGURE 1: INCREMENTAL OIL RECOVERY AND FUEL GAS BURNED BY EXTENDING THE START OF MGS FOR FIVE YEAR PERIODS. ERROR BARS REPRESENT PRECISION OF FFM RUN PREDICTIONS FOR ULTIMATE RECOVERY.