STATE OF ALASKA
Alaska Oil and Gas Conservation Commission

Docket Numbers: AIO 15-032, AIO 15-033 and CO 15-09

Application for Amendment of Pool Rule 9
and
Modification of AIOs
Prudhoe Oil Pool, Prudhoe Bay Field

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Written Submittal of BP Exploration (Alaska), Inc.

Submitted August 25, 2015

Commissioners:

This submission and the accompanying appendices are a component of the application by BP (Exploration) Alaska, Inc. ("*BPXA*") as an individual working interest owner ("*WIO*") in the Prudhoe Bay Unit ("*PBU*") and not as PBU operator, on behalf of itself and PBU WIO ExxonMobil Alaska Production Inc. ("*EMAP*"), to the Alaska Oil and Gas Conservation Commission ("*AOGCC*" or "*Commission*"), for an amendment of Prudhoe Oil Pool ("*POP*") Rule 9 of Conservation Order ("*CO*") 341D and modification of PBU Area Injection Orders ("*AIOs*") 3A and 4F.

INTRODUCTION

The application requests that the Commission amend the maximum annual average gas offtake rate for the POP in CO 341D Rule 9, from 2.7 billion standard cubic feet per day ("*bscf/d*") to 4.1 bscf/d. As demonstrated in the application and this testimony, a maximum annual average gas offtake rate of 4.1 bscf/d is in accordance with good oil field engineering practices and should be approved by the Commission.

The application also requests that the Commission modify AIOs 3A and 4F to authorize the injection of CO_2 for enhanced hydrocarbon recovery and reservoir pressure maintenance, from sources both within and outside the PBU. As demonstrated in the application and this testimony, the requested modification of AIOs 3A and 4F is in accordance with good oil field engineering practices and should be approved by the Commission.

BPXA and EMAP are filing this application with the Commission so each PBU WIO has the ability to access the opportunity presented by the Alaska LNG Project (the "*AK LNG Project*") to progress major gas sales of Prudhoe Bay Unit natural gas ("*PBMGS*"). As the Commission knows, affiliates of the three largest PBU WIOs – BPXA, EMAP and ConocoPhillips Alaska, Inc. ("*CPAI*") are all working with the State of Alaska to develop the AK LNG Project. BPXA will provide a witness at the public hearing to testify further on the AK LNG Project from BPXA's perspective.

This application and the requested approvals are necessary at this time for several reasons:

(i) The requested approvals are needed so BPXA, EMAP and the other PBU WIOs have the ability to access the opportunity presented by the AK LNG Project for progressing PBMGS. The AK LNG Project participants have informed the PBU WIOs that the approvals requested in this application are necessary at this time to support progression of the project beyond pre-FEED engineering stage of development. The requested approvals are just one of many regulatory and facility planning activities on which the PBU WIOs have been diligently working to prepare for PBMGS.

(ii) The requested approvals support individual PBU WIO and State of Alaska internal preparations for major gas sales, including preparations for marketing each party's respective share of PBU gas. BPXA and EMAP collectively own 63 percent of the working interests in the oil and gas leases that comprise the PBU. The ability of each PBU WIO and the State of Alaska (assuming an election by the State to take gas royalty in kind) to market its gas is fundamental to the success of the PBMGS opportunity presented by the AK LNG Project. LNG buyers will demand certainty of gas supplies to the AK LNG Project system, and without the certainty provided by the requested approvals, BPXA and EMAP respective LNG marketing efforts to monetize their shares of PBU gas production would be impeded. The inability of each company to progress its individual gas marketing efforts would hinder progress of the AK LNG Project.

BPXA is submitting this sworn testimony in the form of this written narrative and associated exhibits. This testimony is provided by BPXA as an individual PBU WIO. BPXA has consulted and coordinated with PBU WIO EMAP in the preparation of this testimony, and has their support in the application. The assessments contained in this testimony have been discussed with the other PBU WIOs, CPAI and Chevron U.S.A. Inc. ("*CUSA*").

Section I of this submission identifies the witness who is submitting this written testimony on behalf of BPXA. Section II provides a brief summary of this testimony. Section III contains the substance of the testimony in support of an amendment to CO 341D Rule 9. Section IV contains the substance of testimony in support of modification of AIOs 3A and 4F. Section V, which is being separately submitted to the Commission as a Confidential Appendix to preserve confidentiality, contains confidential information and figures referenced in this testimony that BPXA requests be held confidential by the Commission pursuant to AS 31.05.035(d), 20 AAC 25.537(b) and AS 45.50.910 et seq.

SECTION I
BPXA WITNESS

This narrative submission is the testimony of Mr. Bruce Laughlin. His business address is 900 E. Benson Blvd., Anchorage, Alaska 99508. Mr. Laughlin received a Bachelor of Science Degree from Pennsylvania State University and a Masters of Science degree from Texas A&M University. Mr. Laughlin's current title at BPXA is Reservoir Management Team Leader. In his present position, Mr. Laughlin supervises BPXA and contract staff focused on delivering long term oil and gas production opportunities for BPXA's PBU assets, including the POP. His team comprises reservoir engineers, geologists and geophysicists. Mr. Laughlin has the training, experience and knowledge relevant and necessary to provide the opinions included in this testimony; in particular as to analytical and dynamic simulation of field depletion mechanisms.

Mr. Laughlin has previously testified before the AOGCC as an expert in January 2014 in relation to the "Inquiry Into Gas Liquids Disposition." BPXA respectfully requests that the Commission qualify Mr. Laughlin as an expert in these proceedings in accordance with 20 AAC 25.540(c)(5).

Mr. Laughlin will be present, and made available to the Commissioners for questions, at the public hearing on this application to amend POP Rule 9.

As noted above, BPXA will provide at least one non-expert witness at the public hearing to testify on the AK LNG Project from BPXA's perspective. That testimony is not included in this filing.

SECTION II
SUMMARY OF SUBMITTAL

A. The Requested Amendment Will Support Progress On The AK LNG Project

BPXA and EMAP consider this request to amend the gas offtake rate in Rule 9 of CO 341D as a significant step for PBU development. The PBU WIOs and the AOGCC have long contemplated a major gas sale project. The participants in the AK LNG Project (which include the State of Alaska and affiliates of BPXA, EMAP and CPAI) have publicly stated that they are progressing plans for an integrated LNG project with a scheduled start-up in 2025. The requested amendment of CO 341D Rule 9 to increase the maximum annual average gas offtake rate from 2.7 bscf/d to 4.1 bscf/d facilitates that opportunity by providing the flexibility to supply both expected normal and full sustained gas feed rates to the AK LNG Project Gas Treatment Plant ("*GTP*") from the POP.

The AK LNG Project participants have informed the PBU WIOs that the GTP is being designed for sustained receipt of feed gas at the GTP at an annual average rate of 3.5 bscf/d. (The filings by the AK LNG Project with FERC state that the GTP will have an initial gas treating capacity of up to 4.3 bscf/d of feed gas.) BPXA expects that under normal operating circumstances, after a one-year operations ramp-up period beginning in 2025, approximately three-fourths of the gas delivered to the GTP is anticipated to be from the POP (2.7 bscf/d) and one-fourth is anticipated to be from Point Thomson or other sources (0.8 bscf/d). (Please refer to AK LNG project draft Resource Reports filed with FERC, cited in the application).

To support this level of gas delivery to the GTP from the POP, a minimum annual average gas offtake rate of 3.3 bscf/d from the POP would be required (2.7 bscf/d to the GTP and additional gas offtake of approximately 0.6 bscf/d annual average used for fuel, field operations and minor local gas sales). However, because the GTP is being designed for sustained receipt of feed gas at an average annual rate of 3.5 bscf/d, if the supply of gas to the GTP from the Point Thomson Unit or other sources does not occur as expected or is interrupted, up to 100 percent of the gas supply to the GTP from the POP would be required to maintain uninterrupted gas deliveries to the AK LNG Project. To allow the flexibility for the POP to be the source for up to 100 percent of the feed gas supplied to the GTP in those circumstances, and to avoid disruptions to GTP operations and resulting disruptions to PBU operations that could result from interruptions in a sustained stable supply of gas to the GTP, BPXA and EMAP are requesting AOGCC authorization for a maximum annual average gas off-take of 4.1 bscf/d (3.6 bscf/d to the inlet of the GTP plus 0.5 bscf/d for fuel, field operations and minor local gas sales). Note that in the 100 percent POP case, the feed gas inlet to the GTP must be slightly greater than 3.5 bscf/d to yield an equivalent hydrocarbon gas delivery to the downstream gas offtake points and the LNG liquefaction facility because the CO2 percentage of the POP feed gas stream is greater than in the Point Thomson feed gas stream. The POP fuel gas requirements in the 100 percent POP case drops slightly from 0.6 bscf/d to 0.5 bscf/d since less POP gas is re-injected into the Prudhoe reservoir. A 4.1 bscf/d offtake rate for the POP also would accommodate improved facility performance and allow operational flexibility.

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. 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 other participants in the AK LNG Project to progress the project to the front-end engineering and design (FEED) development stage. As more specifically addressed below, modifications of the AIOs are based upon the AK LNG Project design plan for injection of the GTP CO_2 by-product into the POP.

B. There Is A High Degree Of Confidence In The Current Full Field Model Results

The PBU Full Field Model ("*FFM*") consists of three parts: (i) historical PBU operational data; (ii) a set of reasoned assumptions about future PBU activities; (items (i) and (ii) are collectively referred to as the "*FFM Inputs*"); and (iii) a BPXA proprietary and trade secret process consisting of software code and algorithms owned by or licensed to BPXA (the "*FFM Tool*"). Full Field Model runs (sometimes referred to as model scenarios) are generated by inputting the FFM Inputs into the FFM Tool ("*FFM Runs*").

FFM Runs are meant to be predictive of future circumstances or consequences that could occur, depending on the FFM Inputs. Because of the proprietary and trade secret processes that BPXA employs in the use of the FFM Tool, it is not possible to derive the details of PBU operational or technical data (e.g., specific geological data) from FFM Runs. BPXA uses the FFM Tool to generate FFM Runs for both itself and, upon request, for the PBU WIOs. All references in this submission to the FFM are a reference to FFM Inputs plus the FFM Tool. References to and discussions of FFM modeling, scenarios, runs and similar statements are references to FFM Runs.

The AOGCC and the PBU WIOs have evaluated and reviewed the potential effects of a PBMGS project on oil production and hydrocarbon recovery from the POP at various stages of field development, most recently in 2007[1]. The PBU WIOs informed and discussed with AOGCC staff, in a series of workshops held earlier this year, upgrades that BPXA has made to the FFM since 2006. Over the past several years the underlying geologic and dynamic data have been extensively reviewed and agreed by the WIOs with the State of Alaska to determine the historic and predictive behavior. The upgrades that have been made by BPXA to the FFM include: increased model resolution; improved and updated well breakage and repair assumptions and data; segregation of drilling by type and area to align assumptions and predictions with potential drilling schedules; use of an improved fuel gas usage algorithm; and improved and updated satellite field flow assumptions and data. Moreover, with substantial updated production and flow history, the FFM history match has been updated to 2014 and improved to include gas cap water injection ("*GCWI*") impacts on reservoir pressure projections.

The updated and recalibrated FFM provides a higher degree of confidence in its predictive capabilities.

C. The PBMGS Gas Reference Case

The FFM was used to generate an FFM Run of the estimated increase in ultimate hydrocarbon recovery from the POP for a PBMGS case beginning in 2025 and assumed to end in 2055, with a total annual average gas offtake rate of 3.3 bscf/d including all uses, (the "*gas reference case*"), as well as the estimated ultimate hydrocarbon recovery from the POP.

BPXA's assessment of the gas reference case is that hydrocarbon recovery is increased by approximately 3.8 billion barrels of oil equivalent ("*BOE*") or 22 trillion standard cubic feet of gas ("*tscf*"). Combined with oil, condensate and NGLs production, BPXA's

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[1] The Commission has long understood that the gas off-take rate in Rule 9 of CO 341D would have to be revised for major gas sales. *See* the July 10, 2007 Report Of The Commission Inquiry Into Amending Rule 9 and December 5, 2005 Report On Commission Inquiry Into Potential Revision of Gas Offtake Limit.

assessment is that total hydrocarbon recovery from the POP under the gas reference case is approximately 17.7 billion BOE; a net increase of 3.6 billion BOE from the current oil reference case. The details of BPXA's assessment of the gas reference case are discussed in Section V (the Confidential Appendix).

D. The PBMGS Full GTP Inlet Supply Case (The Application Request)

The FFM was also used to generate an FFM Run evaluating a scenario where the requested total annual average gas offtake rate from the POP of 4.1 bscf/d was applied for an assumed AK LNG Project life of 30 years (i.e., assuming no gas delivery to the GTP from other fields) (the "*full GTP inlet supply case*"). This case has been compared to the gas reference case.

BPXA's assessment of the full GTP inlet supply case is that slightly more BOEs are recovered than in the gas reference case (17.8 billion instead of 17.7 billion BOEs) due to higher gas recovery that offsets additional impacts on oil production. The details of BPXA's assessment of the full GTP inlet supply case are discussed in Section V (the Confidential Appendix).

E. Reference Case Sensitivities

The FFM also was used to test the sensitivity of reference case predicted oil and gas recovery to a robust set of alternative assumptions and development scenarios. This type of analysis is often undertaken by BPXA, using its FFM Tool, in conjunction with BPXA and the other PBU WIOs development of specific development plans.

Apart from in-place volumes, the most sensitive parameters identified are CO_2 injection location (for enhanced hydrocarbon and pressure maintenance), and well breakage. BPXA's assessment of the results of these analyses is that the sensitivity of liquid and total hydrocarbon recovery is negligible (less than 1 percent). The details of BPXA's analysis are discussed in Section V (the Confidential Appendix)

F. CO2 Injection into the POP

The AK LNG Project participants have indicated that the GTP is being designed to deliver 350 to 450 mmscf/d of CO2 byproduct to PBU for injection. Greater than 90 percent of the total CO2 volume will originate from gas delivered to the GTP from PBU. The additional hydrocarbon recovery associated with PBMGS is 3.8 billion BOE. This additional hydrocarbon recovery is dependent upon CO2 being received at PBU from the GTP. Reservoir studies have been conducted to look at several possible injection locations for enhanced hydrocarbon recovery and pressure maintenance, and initially the Eileen West End ("*EWE*") area has been identified as the most promising, but the specific location in the POP has not been determined. BPXA and EMAP will continue to work with the PBU WIOs, the Commission and the Alaska Department of Natural Resources to determine one or more locations for injection of CO2 for enhanced hydrocarbon recovery and pressure maintenance.

G. Conclusion

The POP is the most robust resource on the North Slope, with more than 35 years of production history and operations. BPXA and EMAP are seeking a maximum annual average gas off-take rate of 4.1 bscf/d to allow for the full inlet gas delivery to the GTP and related LNG facilities to be supplied from the POP. This off-take rate will provide BPXA and EMAP, the other PBU WIOs (CPAI and CUSA) and the State of Alaska with flexibility, and allow use of POP gas to cover any gas supply disruptions to the GTP that may occur from other gas supply fields. BPXA and EMAP are also seeking a modification of AIOs 3A and 4F to authorize the injection of CO_2 into the POP for enhanced hydrocarbon recovery and reservoir pressure maintenance purposes, from sources both within and outside the PBU.

BPXA is confident in the results of the updated and enhanced FFM.

BPXA's assessment of the studies and the FFM Runs that have been performed using the FFM is that:

(i) total BOE hydrocarbon recovery for the POP is substantially increased with a PBMGS project by approximately 3.8 billion BOE or 22 tscf of gas. Combined with oil, condensate and NGLs production, total hydrocarbon recovery from the POP under the gas reference case is approximately 17.7 billion BOE, a net increase of 3.6 billion BOE from the current oil reference case;
(ii) the total BOE hydrocarbon recovery from the POP at the requested full GTP inlet supply case off-take rate (17.8 billion BOE) is comparable to the gas reference case off-take rate (17.7 billion BOE), a difference of less than 1 percent;
(iii) ultimate hydrocarbon recovery is relatively insensitive to alternative assumptions and scenarios (less than 1 percent); and
(iv) EWE is initially the most promising location for injecting CO_2 for enhanced hydrocarbon recovery and pressure maintenance.

SECTION III
AMENDMENT OF CO 341D RULE 9 TO INCREASE THE MAXIMUM GAS OFF-TAKE TO 4.1 bscf/d IS PRUDENT, APPROPRIATE AND NECESSARY TO PROGRESS THE AK LNG PROJECT

A. POP Rule 9 Gas Off-Take Rate

CO 341D Rule 9 limits the maximum annual average gas offtake from the POP to 2.7 bscf/d. Currently, approximately 0.6 bscf/d from the POP is used for fuel, field operations and minor local gas sales. This level of other gas usage is anticipated to remain stable. Accordingly, under Rule 9, an annual average gas off-take of approximately 2.1 bscf/d would be available for gas pipeline delivery for major gas sales. This offtake level is not adequate to allow sufficient gas delivery from the POP to the AK LNG GTP for PBMGS. (Please note that unless otherwise indicated, references to AK LNG public statements in this submission are to the draft Resource Reports filed with FERC as referenced in the application.)

1. AK LNG Project

The participants in the AK LNG Project, including the affiliates of both BPXA and EMAP and the State of Alaska, have informed the PBU WIOs that the design of the AK LNG facilities is premised on a sustained annual average gas supply rate of 3.5 bscf/d to the GTP. (AK LNG Project participants have publicly stated that the GTP will have an initial gas treating capacity of up to 4.3 bscf/d of feed gas.) The AK LNG Project participants have also publicly stated that the GTP is being designed to receive, treat, and ship gas to the Liquefaction Plant, and to return for reinjection into the POP the by-product primarily consisting of CO2.

2. POP Gas Supply to AK LNG

The AK LNG Project participants have publicly stated that under normal operating circumstances, they anticipate that ~3/4 of the feed gas to the GTP (2.7 bscf/d) will be from the POP, and the remaining 1/4 of the feed gas (0.8 bscf/d) will be from Point Thomson or other sources. BPXA and EMAP together will provide approximately 69 percent of the total hydrocarbon resources from these fields to the AK LNG Project. BPXA and EMAP's assessment is that the POP will be able to deliver gas to the GTP for 30 years under this scenario.

3. Amendment of Rule 9

CO 341D Rule 9 limits the maximum annual average gas off-take from the POP to 2.7 bscf/d. Currently, approximately 0.6 bscf/d of gas from the POP is used for fuel, field operations and minor local gas sales. This level of other gas usage is anticipated to remain stable in the future. Therefore, the current 2.7 bscf/d off-take limit is insufficient to meet the gas delivery inlet capacity of the AK LNG GTP under even normal operating conditions, which assume delivery of 0.8 bscf/d from Point Thomson or other sources (current POP offtake limit of 2.7 bscf/d minus 0.6 bscf/d gas for fuel, field operations and minor local sales only allows 2.1 bscf/d to the GTP, which combined with 0.8 bscf/d from Point Thomson or other sources does not meet AK LNG Project design for a sustained annual average gas supply rate of 3.5 bscf/d of feed gas to the GTP).

Under the circumstance where gas delivery to the GTP from Point Thomson and other sources does not occur as expected or suffers a supply interruption, a total gas offtake of 4.1 bscf/d would be required from the POP (3.6 bscf/d to the GTP + 0.5 bscf/d for fuel, field operations and minor local sales) to allow the full supply of inlet gas supply to the

GTP.

B. Full Field Model And Data Improvements

BPXA has made many updates to the FFM since the AOGCC last considered analyses of a PBMGS in 2007. The following is a high level summary of those updates. Section V of the Confidential Appendix contains a comprehensive and more detailed discussion of these confidential FFM improvements.

BPXA has continuously updated the FFM since its original development. Over many years of historical production and development updates, the model continues to narrow the assumptions and improvement needs. The physical constraints associated with facility limits, pipeline networks, drilling and well work activity all contribute to better understanding of the shape of the model and the property distribution. With improved computer processors, refinements to the grid resolution have given better understanding to the flow characteristics between wells. The FFM has been used internally by BPXA to inform its analysis, from a PBU WIO perspective, of drilling projects, the gas cap water injection project, surface facility debottlenecking projects, as well as previous PBMGS analyses. BPXA has also provided FFM Runs to the PBU WIOs to inform their analysis of similar projects.

As a result of these FFM refinements and updated data, BPXA's assessment of the FFM is that the current history match predicts each fluid phase within 1 percent of actual field data. Therefore, BPXA considers the current FFM to be highly reliable.

C. FFM Assumptions And Analyses

In order to assess hydrocarbon recovery for a PBMGS development scenario compared to an oil production scenario, a reference case set of assumptions was developed and incorporated in the FFM to reflect both sound engineering principles and a development program that recognizes economic considerations. The following is a high level summary of those assumptions. Section V of the Confidential Appendix contains a comprehensive discussion and details of these assumptions.

In order to perform a valid analysis of the benefits for PBMGS, the model requires assumptions about both oil-focused operations and a PBMGS. In this analysis, the following assumptions were made for the oil reference case and the gas reference case.

1. <u>The Oil Reference Case</u>

The oil reference case assumed the following activities will continue. Among these assumptions are activities that have been implemented with the view toward PBMGS.

- Active development drilling program
- Rig workovers to maintain healthy well stock

- Continued Gas Cap Water Injection
- Normal Turnaround activities for facility maintenance

2. <u>The PBMGS Gas Reference Case</u>

The gas reference case includes many of the same activities assumed for the oil reference case. The reason for these assumption sets to be the same is to give a more valid consideration of the benefits on a like-for-like comparison. There are certain additions to the assumptions that must be incorporated to manage a gas analysis. The following are the assumptions associated with the gas reference case.

- Same development drilling program as the oil reference case
- January 2025 gas sales startup date with a 1 year ramp to full delivery
- Annual average gas supply to the GTP ~2.7 bscf/d
- Normal annual turnaround maintenance events
- GTP by-product CO_2 injected into the Eileen West End of the POP
- Conversion of the apex gas injectors to gas producers late in project life
- Rig workovers to keep healthy well stock until the end of the project
- Perforations to add gas production to the project
- 30 year total project life

As noted earlier, the gas reference case shows PBMGS will increase ultimate hydrocarbon recovery from the POP by approximately 22 tscf or 3.8 BOE.

3. <u>The PBMGS Full GTP Inlet Supply Case Comparison</u>

The full GTP inlet supply case incorporates one change. The annual average gas supply to the GTP is increased from ~2.7 bscf/d to a rate of 3.6 bscf/d. (3.6 bscf/d is used because the gross inlet volume of gas will be slightly higher in this modeled case due to the higher CO_2 content in POP gas compared to the blended gas stream expected from other gas fields.)

As noted earlier, the full GTP inlet supply case recovers slightly more BOEs than the gas reference case (17.8 instead of 17.7 billion BOEs) due to higher gas recovery that offsets additional impacts on oil production.

4. <u>Impacts of Sensitivities</u>

The impacts of the sensitivities on gas sales, oil recovery and BOE recovery were evaluated. Apart from in-place volumes, the most sensitive parameters identified are CO_2 injection location (for enhanced hydrocarbon and pressure maintenance), and well breakage. All of the other sensitivities have less than a 5 percent impact on total BOE recovery, with most sensitivities having a negligible impact (less than 1 percent impact). The impacts on gas production from the sensitivities tested have a greater effect on ultimate BOE recovery than the nominal positive impacts to oil recovery. These results are discussed in Section V (the Confidential Appendix).

SECTION IV
MODIFICATION OF AIOS 3A AND 4F
INJECTION OF CO2 FROM SOURCES WITHIN OR OUTSIDE OF PBU FOR ENHANCED HYDROCARBON RECOVERY AND PRESSURE MAINTENANCE

A. AK LNG CO_2 Byproduct Return

The AK LNG Project participants (including affiliates of BPXA, EMAP and CPAI, and the State of Alaska) have informed BPXA that gas shipped through the AK LNG system pipelines to the liquefaction facility will need to be treated in the GTP to a CO_2 specification of 50 ppm or less. AK LNG Project participants have publicly stated that the GTP is being designed on the basis that the byproduct from gas treated at the GTP, which BPXA expects will be dry and approximately greater than 99 percent CO_2, will be transported to the PBU for further handling. See Figure 1 below for a conceptual depiction of a CO_2 distribution system.

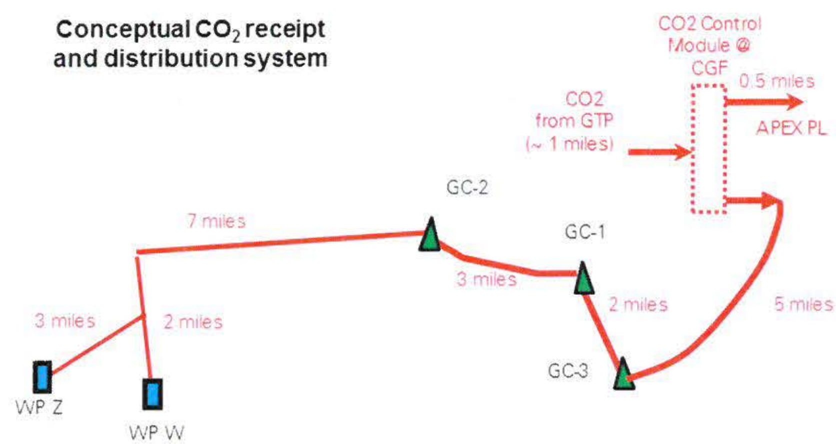

Figure 1 CO2 Distribution System

B. Amendment of AIOs

The AK LNG Project participants inform us that the GTP may deliver an annual average of 350 to 450 mmscf/d of CO_2 byproduct to PBU for injection. Greater than 90 percent of the total CO_2 volume will originate from gas delivered from PBU. AIOs 3A and 4F, however, currently only permit injection of gas (which includes the CO_2 entrained in the gas) that is sourced from PBU gas processing facilities.

The additional hydrocarbon recovery associated with PBMGS is 3.8 billion BOE. This additional hydrocarbon recovery is dependent upon the ability of PBU to receive CO_2 from the GTP. Although the specific location for injection is still being evaluated, analysis of CO_2 injection in POP shows there will be enhanced hydrocarbon recovery and pressure maintenance benefits.

BPXA is therefore seeking a modification of AIOs 3A and 4F to authorize the injection of CO_2 into the POP for enhanced hydrocarbon recovery and reservoir pressure maintenance purposes, from sources both within and outside the PBU.

Similar to the requested amendment of Rule 9 addressed above, the requested modifications to the AIOs are requested at this time to support the joint efforts of the State of Alaska and the other AK LNG Project participants to progress the AK LNG Project to the front-end engineering and design (FEED) development stage.

Amendment of the AIOs at this time will also allow the PBU WIOs to pursue related PBU activities supporting this injection of GTP CO_2.

C. Assessment of CO2 Injection

Various locations within the POP were evaluated to determine the hydrocarbon recovery associated with injection of CO_2. These areas included the Gas Cap, Flow Station 2 area and Eileen West End.

In past evaluations of PBMGS, the gas cap was considered as an option. Lower CO_2 handling limits into the GTP and the rapid increase in CO_2 from the POP that would occur demonstrates that this location is a less viable option given the impact on hydrocarbon recovery. The Flow Station 2 area was also evaluated and this area remains a potential location due to the availability of the miscible injection distribution system. Compared to the more promising Eileen West End location, the FS2 area was also determined to have higher returned CO2 concentrations and lower hydrocarbon recovery. Eileen West End provided the highest benefit from a hydrocarbon recovery perspective when compared to the other injection locations.

Due to the large volume of CO_2 that is currently injected into the POP through day to day operations as part of the overall gas reinjection stream (about 800 mscf/d), the volume of CO_2 injected during PBMGS is essentially the same. The benefits of this injection are associated with increased pressure to the reservoir, thus improving oil recovery throughout the field and recovery of Miscible Injectant ("*MI*") currently trapped in the EWE area of the field. This MI can be utilized for additional EOR benefits.

OATH

BPXA requests that the Commission authorize and recognize this submission as pre-filed written public testimony in support of its application. Based upon my expertise, knowledge, information and belief formed after reasonable inquiry, I certify and swear that the statements and information in Sections II through V of this submittal, including in the Confidential Appendix to this submittal, are true and accurate.

Bruce Laughlin

Bruce Laughlin
BP Exploration (Alaska), Inc.