STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue, Suite 100
Anchorage Alaska 99501

Re: **THE APPLICATION OF CONOCOPHILLIPSALASKA, INC.** for an amendment to the order authorizing underground injection of fluids for enhanced oil recovery in the Meltwater Oil Pool, in the Meltwater Participating Area, Kuparuk River Field, North Slope, Alaska	)	Area Injection Order No. 21A Kuparuk River Field Kuparuk River Unit Meltwater Oil Pool (Amended Upon Reconsideration) May 16, 2013

IT APPEARING THAT:

1. The Alaska Oil and Gas Conservation Commission (AOGCC) issued Area Injection Order (AIO) 21 for the Kuparuk River Unit (KRU) Meltwater Oil Pool (MOP) on August 1, 2001, authorizing the underground injection of fluids for enhanced oil recovery.

2. Information presented by ConocoPhillips Alaska, Inc. (CPAI) to the AOGCC on August 8 and August 22, 2012 summarized ongoing efforts to diagnose outer annulus pressures in numerous MOP wells. Recent geologic and production data analyses indicate AIO 21 does not accurately describe the MOP and confinement of injected fluids.

3. By application received on October 2, 2012 CPAI, in its capacity as Operator of the Kuparuk River Unit, requested approval of three amendments to existing AIO 21 rules and the addition of three new rules. CPAI also requested AOGCC amend one rule in Conservation Order (CO) 456A related to enhanced oil recovery operations in the MOP.

4. A notice of a public hearing was published on the State of Alaska Online Public Notice web site and on the AOGCC web site on October 2, 2012. On October 3, 2012, the notice was published in the Anchorage Daily News. The hearing was scheduled for November 8, 2012.

5. The AOGCC received no comments or requests for a public hearing.

6. On November 8, 2012, the public hearing was convened and continued until November 14, 2012 to accommodate the availability of Commissioners.

7. Based on review of the materials submitted in support of CPAI's application and public testimony offered by CPAI on November 14, 2012, the AOGCC requested additional information. CPAI submitted the information on November 29, 2012.

8. The AOGCC issued AIO 21A on January 29, 2013.

9. On February 13, 2013, CPAI applied for and was granted an extension of time to March 8, 2013 in which to file an application for reconsideration of the Commission's Order.
10. CPAI filed an application for reconsideration on March 8, 2013. On March 18, 2013, the AOGCC granted CPAI's request.
11. A notice of a public hearing was published on the State of Alaska Online Public Notice web site and on the AOGCC web site on April 4, 2013 and sent to the AOGCC electronic distribution email list. The hearing was scheduled for April 17, 2013.
12. The AOGCC received no comments or requests for a public hearing.
13. On April 17, 2013, the public hearing was convened, and the record was left open until May 8, 2013. On May 8, 2013, CPAI provided additional information responsive to questions and issues raised by the AOGCC during the reconsideration hearing.

FINDINGS:

1. The Environmental Protection Agency exempted all aquifers within the existing KRU. 40 CFR 147.102.
2. CO 456A defines the MOP as strata equivalent to those between 6,785 and 6,974 feet measured depth (MD) in well Meltwater North #2A.
3. Regular production from the MOP commenced in November 2001. Miscible gas injection began in January 2002, and water injection commenced in May 2003. Producing wells use miscible injectant (MI) for artificial lift.
4. The initial reservoir pressure for the MOP was approximately 2,400 psi. Injection activity increased reservoir pressure near injection wells to over 4,000 psi; reservoir pressure near shut-in producers reached nearly 3,000 psi.
5. CPAI encountered elevated gas pressures while drilling MOP well KRU 2P-441 in March 2002.
6. Beginning in April 2002, CPAI noted elevated outer annulus pressures in MOP development wells. Gas samples taken from outer annuli had chemical signatures consistent with MI. At the time, CPAI believed that MI gas used for artificial lift appears to be migrating into the outer annuli, possibly through leaking, threaded casing connections.
7. After identifying elevated outer annulus pressures in MOP wells, CPAI initiated an annulus-monitoring program and attempted periodic annulus pressure bleeds. Since 2003, CPAI has provided periodic updates of monitoring and diagnostic efforts to AOGCC.
8. Water injection into the MOP ceased in October 2009 due to water supply line corrosion concerns. CPAI converted existing MOP water-injection wells to MI injection or shut them in. CPAI has no plans for restoring water injection.

9. Using proprietary 4D seismic evaluation, CPAI recently identified that injected fluids have migrated from the MOP and entered shallower strata.

10. During April 2012, CPAI reduced the injection-to-withdrawal ratio to ensure confinement of injected fluids to the MOP. Outer annuli pressures subsequently declined. In August 2012, CPAI restricted MI injection pressure to ensure that sand-face injection pressure remains less than 3,400 psi.

11. On October 4, 2012, AOGCC issued Administrative Approval AIO 21.001 allowing continued MI injection into the MOP subject to several conditions, including: daily recording of well pressures, monthly reporting of all MOP wells, and pressure restrictions on the outer annuli of all wells.

12. CPAI requests AOGCC issue a revised AIO 21 to address numerous changes needed because injected MI is no longer confined to the MOP as required by AOGCC regulations and AIO 21.

13. CPAI proposes changing Rule 1 of AIO 21, Authorized Injection Strata for Enhanced Recovery, to expand the authorized injection interval to encompass strata that are common to, and correlate with, the interval between 2,503 to 6,974 feet MD in well Meltwater North #2A. CPAI requests this expansion to clarify that continued injection for enhanced oil recovery complies with governing regulations and orders.

14. CPAI proposes changing Rule 3 of AIO 21, Monitoring the Tubing-Casing Annulus Pressure Variations, to allow exceptions to the requirement for weekly monitoring in the event of extreme weather conditions, emergency situations, or similar unavoidable circumstances.

15. CPAI testified that MOP wells are connected to a supervisory-controlled data acquisition system allowing the ability to monitor well pressures continuously.

16. CPAI proposes changing Rule 4 of AIO 21, Demonstration of Tubing-Casing Annulus Mechanical Integrity, to align that rule with other AIOs that apply within the Kuparuk River Field.

17. CPAI requests a new rule addressing well integrity and confinement of injected fluids.

18. CPAI requests a new rule that specifies a maximum sand-face injection pressure of 3,400 psi. CPAI states that "this sand face injection pressure corresponds to a pressure below the FIT/LOT data from wells where production casing was set at the top of the Bermuda Interval."

19. CPAI requests a new rule that authorizes specific fluids for injection.

20. CPAI's request to amend AIO 21 and CO 456A states: "The long-term benefit of MI injection compared to water injection is uncertain."

21. CPAI testified during the November 14, 2012 hearing that it is undertaking an overburden characterization study that will take about 18 to 24 months to complete. The purpose of the study is to understand confinement for injected fluids.

22. During the November 14, 2012 hearing, CPAI offered information it claimed was confidential. At the conclusion of the hearing, AOGCC requested CPAI to provide

written justification as to why that information should be held confidential. CPAI submitted its justification on November 29, 2012. Based on CPAI's November 29, 2012 submission, the AOGCC determined the information was not confidential. At the April 17, 2013 hearing on reconsideration, CPAI presented additional testimony and evidence in support of its claim the information presented at the November 14, 2012 hearing is confidential.

CONCLUSIONS:

1. AIO 21 and associated administrative actions should be revoked and replaced with a time-limited injection order tailored to the circumstances at MOP.
2. There are no potential underground sources of drinking water (USDW) in the MOP.
3. Injection activities at the MOP resulted in loss of confinement allowing injected fluids to migrate into shallower strata, enter uncemented portions of offset wells, and elevate pressure in the outer annuli of numerous MOP wells. Injection well reservoir pressures exceeded 4,000 psi (Finding 4), exceeding the fracture initiation pressure of the Bermuda and confining strata (Finding 18) therefore establishing migration pathways.
4. No additional drilling and no production-to-injection well conversions should occur in the MOP until existing confinement and well integrity issues have been resolved.
5. CPAI has implemented reservoir management practices including reducing the injection-to-withdrawal ratio and restricting the MI injection pressure in response to the migration of MI out of the approved injection zone. However, more data is needed to assess the effectiveness of these mitigating practices.
6. Rule 1 of AIO 21, Authorized Injection Strata for Enhanced Recovery, will not be modified. CPAI's proposed changes violate AOGCC well construction regulations by allowing open casing annuli within the authorized injection interval and by allowing injection packers to be set at improper depths.
7. Rule 3 of AIO 21, Monitoring the Tubing-Casing Annulus Pressure Variations, will not be modified. Any inability to monitor pressures during extreme weather conditions, emergency situations, or similar unavoidable circumstances is required to be immediately communicated to AOGCC.
8. The daily monitoring, monthly reporting, and outer annuli operating pressure requirements of Administrative Approval AIO 21.001 should be integrated into a new injection order.
9. Rule 4 of AIO 21, Demonstration of Tubing-Casing Annulus Mechanical Integrity, should be modified consistent with the AOGCC's recent orders and practices.
10. A new rule addressing well integrity and confinement of injected fluids is necessary.
11. A new rule that specifies a maximum sand-face injection pressure is necessary.
12. The list of fluids proposed for enhanced oil recovery injection includes categories that are too broad in scope. Adding a new rule that specifically lists approved fluids

is necessary.

13. Because CPAI does not plan to restore water injection capability, a comparison of the benefits of MI injection to water injection is not possible.

14. CPAI acknowledges that additional information is needed to determine the best development options for the MOP. CPAI's overburden characterization study is critical for understanding MOP injection confinement, MOP boundaries, injection interval limits and the impact of an expanded injection interval upon well construction requirements.

15. Based upon the additional evidence presented by CPAI, the information for which CPAI claimed confidentiality will be held confidential.

NOW, THEREFORE, IT IS ORDERED THAT AIO 21 and all associated administrative approvals are hereby revoked and replaced by this order. All information related to AIO 21 is hereby incorporated by reference into the record for this order. The following rules, in addition to statewide requirements under 20 AAC 25 (to the extent not superseded by these rules), govern Class II enhanced oil recovery injection operations in the affected area described below:

Umiat Meridian

Township	Range	Section
T8N	**R7E**	**Sections 1 through 36: All State Lands**

Rule 1 Authorized Injection Strata for Enhanced Recovery.

Within the affected area, fluids appropriate for enhanced recovery may be injected for purposes of pressure maintenance and enhanced recovery into strata that are common to, and correlate with, the interval between 6,785' and 6,974' MD in well Meltwater North #2A.

Rule 2 Fluid Injection Wells.

New wells and production-to-injection conversions are prohibited in the MOP.

Rule 3 Monitoring the Tubing-Casing Annulus Pressure Variations.

The tubing-casing annulus pressure and injection rate of each injection well must be checked at least weekly to confirm continued mechanical integrity. The Operator shall record wellhead pressures and injection rates daily. The Operator shall limit the outer annulus pressure to 1000 psig.

Rule 4 Demonstration of Tubing-Casing Annulus Mechanical Integrity.

The mechanical integrity of an injection well must be demonstrated before injection begins, and before returning a well to service following a workover affecting mechanical integrity. An AOGCC-witnessed mechanical integrity test must be performed after injection is commenced for the first time in a well, to be scheduled when injection conditions (temperature, pressure, and rate) have stabilized and every 2 years thereafter. Mechanical integrity tests must be conducted in accordance with AOGCC Industry Guidance Bulletin No. 10-02 – "Mechanical Integrity Testing" and done to a test pressure equal to the maximum anticipated surface injection pressure. The AOGCC must be notified, following the procedures in AOGCC Industry Guidance Bulletin No. 10-01A – "Test Witness Notification", at least 48 hours in advance to enable a representative to witness mechanical integrity tests. Mechanical integrity test report (AOGCC Form 10-426) must be provided to AOGCC within 5 days after completing the test. Test results must be readily available for AOGCC inspection upon request.

Rule 5 Notification of Improper Class II Injection.

In addition to the requirements of any other State or Federal agency, regulation or statute, the Operator must immediately notify the AOGCC if it learns of any improper Class II injection.

Rule 6 Well Integrity and Confinement.

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by injection rate, operating pressure observation, test, survey, log, or other evidence, the Operator shall immediately notify the AOGCC and obtain permission for continued operation of the well. A corrective action plan shall be provided for AOGCC review and approval prior to further action being taken. The Operator will also consult with the AOGCC about the need to-shut in all wells in the MOP.

Rule 7 Authorized Injection Pressure.

Surface injection pressures shall be limited to 2600 psig. Injection pressures must be maintained at or below 3,400 psig at the reservoir sand-face.

Rule 8 Authorized Fluids for Injection.

Fluids authorized for injection are:

a. Miscible injectant;

b. Dry gas provided by the Kuparuk River Unit;

c. Tracer survey fluid to monitor reservoir performance;

d. Fluids injected for stimulation purposes per 20 AAC 25.280(a)(2);

e. Glycol from hydro-tests and freeze protection;

f. Methanol used for freeze protection; and

g. Standard oilfield chemicals (corrosion and scale inhibitors, defoamers, emulsion breakers, etc.)

All fluids injected must be compatible with the injection zone. Any other fluids shall be approved in advance by separate administrative action based upon proof of compatibility with the reservoir and formation fluids. Water provided by the Kuparuk River Unit water injection system is currently not available and not planned for injection. The water is not authorized for injection and shall be approved by a separate administrative action.

Rule 9 Performance Reporting.

The Operator shall submit to AOGCC a monthly report detailing the daily monitoring of all Meltwater Oil Pool wells. Included in the monthly report, the Operator shall submit OA fluid levels, well pressures, injection and/or production rates, and pressure bleeds for all annuli. Trends shall be evaluated and detailed. In addition to the conditions listed in the above rules the Operator shall provide by April 1st of each year an interim progress report that provides an update on the status of the overburden characterization study, a synopsis of the monitoring data collected during the previous year, and a detailed analysis of the effects on ultimate recovery of switching from an MWAG project, as authorized by AIO 21, to the current MI injection only project.

Rule 10 Administrative Action.

Upon proper application, or its own motion, and unless notice and public hearing are otherwise required, the AOGCC may administratively waive the requirements of any rule stated herein or administratively amend this order as long as the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in an increased risk of fluid movement into freshwater.

Rule 11 Expiration Date.

This order shall expire 24 months after the effective date shown below.

Done at Anchorage, Alaska and dated May 16, 2013.

Cathy P. Foerster
Chair, Commissioner

John K. Norman
Commissioner

ALASKA OIL AND GAS CONSERVATION COMMISSION

RECONSIDERATION AND APPEAL NOTICE

As provided in AS 31.05.080(a), within **20** days after written notice of the entry of this order or decision, or such further time as the AOGCC grants for good cause shown, a person affected by it may file with the AOGCC an application for reconsideration of the matter determined by it. If the notice was mailed, then the period of time shall be **23** days. An application for reconsideration must set out the respect in which the order or decision is believed to be erroneous.

The AOGCC shall grant or refuse the application for reconsideration in whole or in part within 10 days after it is filed. Failure to act on it within 10-days is a denial of reconsideration. If the AOGCC denies reconsideration, upon denial, this order or decision and the denial of reconsideration are **FINAL** and may be appealed to superior court. The appeal **MUST** be filed within **33** days after the date on which the AOGCC mails, **OR 30** days if the AOGCC otherwise distributes, the order or decision denying reconsideration, **UNLESS** the denial is by inaction, in which case the appeal **MUST** be filed within **40** days after the date on which the application for reconsideration was filed.

If the AOGCC grants an application for reconsideration, this order or decision does not become final. Rather, the order or decision on reconsideration will be the **FINAL** order or decision of the AOGCC, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the AOGCC mails, **OR 30** days if the AOGCC otherwise distributes, the order or decision on reconsideration. As provided in AS 31.05.080(b), "[t]he questions reviewed on appeal are limited to the questions presented to the AOGCC by the application for reconsideration."

In computing a period of time above, the date of the event or default after which the designated period begins to run is not included in the period; the last day of the period is included, unless it falls on a weekend or state holiday, in which event the period runs until 5:00 p.m. on the next day that does not fall on a weekend or state holiday.