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

Re: **THE APPLICATION OF PHILLIPS ALASKA, INC.** for an order allowing 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. 21** Kuparuk River Field Meltwater Oil Pool August 1, 2001

IT APPEARING THAT:

1. By letter and application dated March 12, 2001, Phillips Alaska, Inc. ("PHILLIPS") requested an order authorizing the injection of fluids for enhanced oil recovery in the Meltwater Oil Pool ("MOP"). PHILLIPS provided draft written testimony for Meltwater Pool rules to the Commission on February 14 and March 12, 2001 and supplemental information on March 22, June 6, June 19, and July 18, 2001.
2. Notice of opportunity for public hearing was published in the Anchorage Daily News on March 23, 2001. A second public hearing notice changing the date of public hearing was published in the Anchorage Daily News on April 5, 2001
3. The Commission did not receive a protest.
4. A hearing concerning PHILLIPS request was convened in conformance with 20 AAC 25.540 at the Commission's offices, 333 W. 7th Avenue, suite 100, Anchorage, Alaska 99501 on May 7, 2001. Concurrently, the Commission heard testimony to define the MOP and establish rules for its development.

FINDINGS:

1. Commission regulation 20 AAC 25.460 provides authority to issue an order governing underground injection of fluids on an area basis for all wells within the same field, facility site, reservoir, project, or similar area.
2. The proposed MOP is located in the western portion of Township 8 North and Range 7 East, Umiat Meridian, on Alaska State Leases ADL-373111, ADL-373112, ADL-389058 and ADL-389059. The MOP is located within and adjacent to the current boundaries of the Kuparuk River Unit ("KRU"), North Slope, Alaska.

3. PHILLIPS is the operator of the MOP. PHILLIPS, BP Exploration (Alaska) Inc., Unocal Corporation, ExxonMobil Corporation, and Chevron U.S.A. Inc are working interest owners. The State of Alaska is the surface owner.

4. PHILLIPS has applied to the Alaska Department of Natural Resources to expand the existing Kuparuk River Unit to encompass the southern half of the proposed MOP and approve a Meltwater Participating Area ("MPA").

5. PHILLIPS drilled three exploratory wells, Meltwater North 1, 2 and 2A, into the proposed MOP. Well and 3-D seismic data have been used to characterize the hydrocarbon accumulation within the proposed MOP.

6. The proposed MOP is defined as an accumulation of hydrocarbons that is common to, and correlates with, the interval between 6411' and 6974' measured depth ("MD") in the Meltwater North #2A well.

7. The proposed MOP is a sequence of very fine to fine-grained sandstones and associated mudstones that are late Cretaceous-aged (Cenomanian-Turonian) and lie within the Seabee Formation. The MOP proposed by PHILIPS is informally divided into two stratigraphic units that are named, in ascending order, the Bermuda Interval and the Cairn Interval.

8. The Bermuda Interval is interpreted as a channel fill and lobate sandstone turbidite fan accumulation, deposited in a slope-apron environment below an incised Cenomanian-age shelf. This interval lies between 6785' and 6974' MD in the Meltwater North #2A well, and is the only demonstrated productive interval within the proposed MOP.

9. The top of the Bermuda Interval dips approximately 2 to 3 degrees to the east-southeast. Complex faulting occurs along the western (updip) margin of the MOP. Shale filled channel complexes and stratigraphic pinch-outs act as lateral boundaries for the MOP.

10. Hydrocarbons are stratigraphically trapped in the Bermuda Interval, and their distribution is controlled by the distribution of sand. No gas cap or water has been encountered in Bermuda Interval within the MOP.

11. The MOP Bermuda interval is the stratigraphic equivalent and has similar lithology to the Tarn accumulation to the north. Drilling at Tarn has shown these deposits to be compartmentalized, primarily due to discontinuous sandstone distribution.

12. Petrophysical log, conventional core, sidewall core and cased-hole test data have been used to determine Bermuda Interval reservoir properties.

13. The Bermuda Interval sands are fine to very fine-grained, lithic-rich, and have common mudstone laminations and interbeds. X-ray diffraction analyses indicate clay content ranges from 15 to 25%, but the clay minerals occur dominantly as framework grains rather than as matrix.

14. Sandstone cores from the Bermuda Interval average 20% porosity and 12 millidarcies air permeability. Facies dependent water saturation values calculated from well logs range from 32% to 45%.

15. Initial reservoir pressure is approximately 2,400 pounds per square inch (“psi”) and reservoir temperature is 135° F at datum level 5400 feet TVDss.

16. Bermuda Interval crude oil gravity is 37° API, formation volume factor at reservoir pressure is about 1.33 reservoir barrels per stock tank barrel, solution gas-oil ratio is about 620 SCF/B, and the viscosity of the oil is 0.76 cps.

17. The Bermuda Interval original oil in place (“OOIP”) is estimated to be 125 million stock tank barrels of oil (“MMSTB”), with an additional possible 7 MMSTB OOIP within the Cairn Interval (see Cairn Interval description below)

18. Approximately 3,000 feet of impermeable shale separate the top of the Cairn Interval from the Tabasco Sandstone equivalent, the first overlying potential reservoir zone. About 500 feet of shale separate the base of the MOP from the underlying Kuparuk Formation.

19. Recovery estimates range from 18% of OOIP by primary depletion to 29% with a waterflood (11% incremental recovery).

20. Model studies of alternating cycles of water and miscible gas injection (MWAG) are estimated to increase recovery 20 % over primary depletion and 9% over waterflood. These model studies assumed a 20% hydrocarbon pore volume slug, which is approximately 46 BCF. Total recovery with an MWAG process is estimated to be 38% OOIP.

21. The MWAG project is scheduled to commence within six months of production start-up. Existing Kuparuk River Field facilities will be used to supply Miscible Injectant (MI). An 8-inch MI injection line will be constructed from KRU Drill Site 2N to the Meltwater Drill Site 2P.

22. MI and water will be injected to provide reservoir pressure support and to maximize recovery. As development matures, lean gas will be injected to maximize recovery of light hydrocarbon liquids injected as part of the MI stream. Produced water from the KRU and Meltwater will be the source of injection water. KRU facilities will be the major source of produced water, MI and lean gas. Produced water from Meltwater may provide an additional source of injection water.

23. MI and water well head injection pressures are expected to range from 2,600 to 3,600 psi and 1,600 to 2,600 psi, respectively.

24. PHILLIPS’ modeling indicates that the maximum injection pressure is not likely to initiate or propagate fractures through the confining strata.

25. The chloride content in water derived from Meltwater cores is estimated to be 35,000 to 45,000 parts per million (“ppm”) NaCl. Average salinity estimates from core plugs obtained in the Bermuda Interval within the Tarn Oil Pool, located 8 miles to the north, is 30,000 ppm NaCl.

26. Wireline log analytical techniques, which comply with EPA recommended methods as described in “Survey of Methods to Determine Total Dissolved Solids Concentrations”, (KEDA Project No. 30-956), were used to characterize formation water total dissolved solids content in the Meltwater Oil Pool vicinity.

27. Analysis of potential underground sources of drinking water also included dipole sonic and mud log data. These data demonstrate that apparent aquifers in the Meltwater pool area contain significant hydrocarbon saturations related to either hydrates or free gas.

28. PHILLIPS interprets the Cairn Interval within the proposed MOP as a marine, contourite-like, channel fill sand deposit that formed in a base of slope setting. This interval lies between 6411' and 6785' MD in the Meltwater North #2A well, and is a potential source of hydrocarbons.

29. Exploration targets within the Cairn Interval are offset along the eastern margin of the Bermuda hydrocarbon accumulation and are down dip from the western portion of the field.

30. Reservoir quality sandstones have not been encountered within Cairn Interval, but may be present near the center of the proposed MOP area. This interval is expected to be a stratigraphic trap.

31. Phillips will attempt to evaluate the productivity of the Cairn interval early in the development of the Bermuda interval.

32. Communication between the Bermuda and Cairn Intervals is uncertain at present. It is uncertain if underground injection of fluids into the Bermuda reservoir will have any effect on potential Cairn reservoirs.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.402 have been met.

2. An Area Injection Order is appropriate for the project area in accordance with 20 AAC 25.460

3. The U.S. Environmental Protection Agency has exempted all aquifers in the existing KRU (40 CFR Subpart C 147.102).

4. There are no potential underground sources of drinking water in the Meltwater pool area.

5. The proposed injection operations will be conducted in permeable strata, which can reasonably be expected to accept injected fluids at pressures less than the fracture pressure of the confining strata.

6. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.

7. Implementation of an enhanced recovery operation involving injection of alternating cycles of water and miscible gas, MWAG, will preserve reservoir pressure/energy and enhance ultimate recovery.

8. The proposed MOP water injection project will result in 20 percent (about 25 million barrels) increased recovery over primary production alone.

9. Reservoir surveillance, operating parameter surveillance and mechanical integrity tests will demonstrate appropriate performance of the enhanced oil recovery project or disclose possible abnormalities.
10. An Area Injection Order enabling enhanced oil recovery activity will not cause waste nor jeopardize correlative rights.

NOW, THEREFORE, IT IS ORDERED THAT 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 the Meltwater North #2A well.

Rule 2 Fluid Injection Wells

The underground injection of fluids must be through a well permitted for drilling as a service well for injection in conformance with 20 AAC 25.005, or through a well approved for conversion to a service well for injection in conformance with 20 AAC 25.280.

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.

Rule 4 Demonstration of Tubing-Casing Annulus Mechanical Integrity

A schedule must be developed and coordinated with the Commission that ensures that the tubing-casing annulus for each injection well is pressure tested prior to initiating injection, following well workovers affecting mechanical integrity, and at least once every four years thereafter.

Rule 5 Notification of Improper Class II Injection

The operator must notify the Commission if it learns of any improper Class II injection. Additionally, notification requirements of any other State or Federal agency remain the operators' responsibility.

Rule 6 Administrative Action

Upon proper application, the Commission may administratively waive the requirements of any rule stated above or administratively amend any rule 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 a USDW.

DONE at Anchorage, Alaska and dated August 1, 2001.

Cammy Oechsli Taylor, Chair
Alaska Oil and Gas Conservation Commission

Daniel T. Seamount, Jr., Commissioner
Alaska Oil and Gas Conservation Commission

Julie M. Heusser, Commissionner
Alaska Oil and Gas Conservation Commission

AS 31.05.080 provides that within 20 days after receipt of written notice of the entry of an order, a person affected by it may file with the Commission an application for rehearing. A request for rehearing must be received by 4:30 PM on the 23rd day following the date of the order, or next working day if a holiday or weekend, to be timely filed. The Commission shall grant or refuse the application in whole or in part within 10 days. The Commission can refuse an application by not acting on it within the 10-day period. An affected person has 30 days from the date the Commission refuses the application or mails (or otherwise distributes) an order upon rehearing, both being the final order of the Commission, to appeal the decision to Superior Court. Where a request for rehearing is denied by nonaction of the Commission, the 30 day period for appeal to Superior Court runs from the date on which the request is deemed denied (i.e., 10th day after the application for rehearing was filed).