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

Re: THE APPLICATION OF BP EXPLORATION (ALASKA) INC. for an order allowing underground injection of fluids for enhanced oil recovery in the Niakuk Oil Pool, Prudhoe Bay Field	**Area Injection Order No. 14A** **Prudhoe Bay Field** **Niakuk Oil Pool** **December 31, 2001**

IT APPEARING THAT:

1. By letter dated March 26, 2001, and received by the Commission March 27, 2001, BP Exploration (Alaska) Inc. ("BP") requested that the Alaska Oil and Gas Conservation Commission ("Commission") revise Area Injection Order No. 14 ("AIO 14") for expansion of injection operations in Niakuk Oil Pool ("NOP"). The expansion area requested included sections 15, 22 and 27 of T12N, R15E UM.
2. The Commission published the first notice of opportunity for public hearing (June 12, 2001 hearing date) on April 21, 2001.
3. The Commission published the second notice of opportunity for public hearing (July 24, 2001 hearing date) in the Anchorage Daily News on May 29, 2001.
4. The Commission did not receive a protest or written request for public hearing.
5. BP provided supplemental application materials in support of the amendment to AIO 14 on July 23, 2001.
6. On August 20, 2001, the Commission approved Administrative Order 14.001 allowing water injection into well NK-28 until November 1, 2001 to gather information to support expansion of AIO 14.
7. By letter dated October 19, 2001, and received by the Commission on October 26, 2001, BP submitted a revised application for the expanded Niakuk Area Injection Order.
8. On November 14, 2001, the Commission approved Administrative Order 14.002 allowing continued injection of water into well NK-28 until February 1, 2002.
9. Additional information pertaining to the application was received December 3, 2001.

FINDINGS:

1. Authority 20 AAC 25.460

   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. Summary of Injection Projects

   AIO 14, originally issued March 22, 1995, authorized enhanced recovery injection operations within the NOP. Conservation Order 329A (June 3, 1996) and Administrative Order 329.005 (January 12, 1998) designate pool rules for the affected area. Conservation Order 329A approved expansion of the pool to include additional acreage in the western area of the field.

   The proposed revision to AIO 14 is to expand water injection operations into the Western portion of the Niakuk Oil Pool. Specifically, expansion of the Area Injection Order was proposed for conversion of well NK-28 from production to water injection service to provide pressure support for well NK-08A.

3. Injection Area (20 AAC 25.402(c)(1)), Pool Description (Pool Information (20 AAC 25.402(c)(5))

   a) Niakuk Injection Area ("NIA"): BP has requested the expansion of injection operations to include sections 15, 22 and 27 of T12N, R15E UM. With inclusion of the proposed expansion, following area is included in the NIA:

      T12N, R15E UM, Sections 13-15 (all); 22-27 (all); and 36 (NE/4)

      T12N, R16E UM, Sections 28 (W/2, NE/4, W/2 of SE/4, SE/4 of SE/4);

      29-30 (all); 31 (N/2); and 32 (N/2)

   b) Niakuk Oil Pool: The NIA includes the Niakuk Oil Pool ("NOP") in the Kuparuk River Formation ("Kuparuk"). The Kuparuk is defined in the pool rules as the stratum that is common to and correlates with the accumulation found in the Niakuk 6 well between the measured depths ("MD") of 12,318 and 12,942 feet.

4. Operators/Surface Owners (20 AAC 25.402(c)(2) and 20 AAC 25.403(c)(3))

   BP has provided all designated operators and surface owners within one-quarter mile radius of the NIA with a copy of the application for amendment of AIO 14. Those surface owners and operators are: BP, Mr. Leroy Oenga, Ms. Georgene Shugluk, BIA / Heirs of Jenny Oenga, Mr. Michael M. Delia, Mr. Wallace Oenga and the State of Alaska, Department of Natural Resources.

5. Description of Operation (20 AAC 25.402(c)(4)).

The NOP has been developed from two drill sites, Heald Point and Lisburne DS L-5. There are 13 producers and 7 water injectors currently active on Heald Point and one producer on DS L-5. Produced water for re-injection is transported from the Lisburne Production Center through an 8" pipeline. Prior to year 2000, seawater injection was used to provide pressure support within the NOP. Current injection capacity is approximately 60,000 BWPD. Future injection requirements may require the use of one or more booster pumps at the drill site in order to provide sufficient water for injection. BP indicates there is potential to return to seawater injection at a future date.

6. Geologic Information (20 AAC 25.402(c)(5)

The following is a summary of the geologic information for the NOP.

a) Introduction: Three structurally defined areas are present in the NIA. Two east-west oriented grabens separated by a paleohigh that lacks Kuparuk sediments are present in the southern portion of the area. In the Northwestern portion of the NIA is a platform with numerous, west-northwest trending normal faults.

b) Reservoir Interval: The NIA includes the NOP in the Kuparuk. The Kuparuk is defined in the pool rules as strata that are common to and correlate with the accumulation found in the Niakuk 6 well between 12,318 and 12,942 feet MD.

c) Stratigraphy: The NOP consists of the Kuparuk that was deposited in an Early Cretaceous age marine environment. Within the expanded NIA, the Kuparuk consists of a stratigraphically complex accumulation of shale, siltstone and sandstone. These sediments are characterized by rapid changes in thickness, sedimentary facies, and cementation. Within the NIA, predominately fine grained Kuparuk basin fill initially accumulated north of the Niakuk Field Fault in the West Niakuk Graben (designated by BP as "Segment 1") and East Niakuk Graben (designated by BP as "Segment 2"), to a gross thickness exceeding 500 feet. The basin fill sediments are generally below the oil water contact in both grabens.

   A period of non-deposition or erosion separates the basin fill sequence from a thick (100's of feet) series of predominately fine grained, aggradational, shoreface sandstones with a high net to gross ratio. The shoreface sands are present throughout the NIA and contain the majority of the oil in place.

d) Structure Overview: The West Niakuk and East Niakuk Grabens (Segments 1 and 2) are fault-bounded depocenters cut by faults that are en echelon to the Niakuk Field Fault. The West Niakuk Platform (designated by BP as "Segment

3/5") consists of a system of horsts, grabens and half-grabens created by a series of high angle, principally normal faults that lie parallel with, and en echelon to, the Niakuk Field Fault. The top of the Kuparuk ranges from a high of –8800 feet True Vertical Depth sub-sea ("TVDss") in West Niakuk and dips to a low of –9800 feet TVDss in the eastern portion of East Niakuk. Most of the accommodation related to faulting in the NIA occurred during Kuparuk deposition, with significant fault displacement at the base of the interval and much smaller fault offsets at the top.

e) Confining Intervals: The Kuparuk is bounded below by the Jurassic age Kingak Formation over most of the NIA. The Kingak Formation is a highly impermeable, low resistivity (2 – 3 ohm-meters) shale with a thickness varying from 400 to 800 feet. In the extreme SE corner of the Injection Area, the Kingak Formation has been interpreted as absent on seismic. In this small area, confinement of injected fluids will be provided by Lower Kuparuk siltstones and shales. The Kuparuk is overlain by the Lower Cretaceous age Highly Radioactive Zone ("HRZ") interval over the entire Injection Area. It is comprised of a 200 foot thick, black, organic rich, impermeable shale.

f) Oil and Rock Properties: Oil gravity averages about 25 degrees API, with observations between 20-30 degrees API. Initial reservoir pressure was approximately 4500 pounds per square inch ("psi") at a datum of 8900' TVDss and the initial temperature ranged from 171 to 182 degrees F. The bubble point pressure is approximately 4200 psi, with solution gas/oil ratios of 600-700 Standard Cubic Feet per Stock Tank Barrel ("SCF/STB"), and oil formation volume factor of approximately 1.3 Reservoir Barrel per Stock Tank Barrel ("RVB/STB"). Initial solution gas/oil ratios are approximately 300 SCF/BBL. Pay averages about 16-21% porosity and 100-300 millidarcies ("md") permeability. Net sand to gross sand ratios vary from .20 to .9.

g) Compartmentalization: Within the NIA, the Kuparuk reservoir is compartmentalized. Three separate oil-water contacts have been identified within the injection area: West Niakuk Graben (Segment 1) at 9240 feet TVDss, the West Niakuk Platform (Segment 3/5) at 9285 feet TVDss, and at 9535 feet TVDss in the East Niakuk Graben (Segment 2).

h) Original Oil in Place: Estimated total original oil in place ("OOIP") in the NOP is approximately 310 MMSTB. Cumulative production to date is 59 MMSTB. East Niakuk Graben (Segment 2) OOIP is estimated at 120 MMBO. West Niakuk Graben (Segment 1) OOIP is estimated at about 85 MMBO. West Niakuk Platform (Segment 3/5) is estimated at about 105 MMBO.

7. Injection Fluids (20 AAC 25.402(c)(9)). Injection will utilize either produced or source water. The wells are currently configured to allow 60,000 Barrels of Water per Day ("BWPD") total, with a maximum injection of up to 70,000 BWPD. The produced water will be a mix of Pt. McIntyre, West Beach, North Prudhoe Bay,

Lisburne and Niakuk produced water separated through the Lisburne Production Center ("LPC"), with the majority coming from Pt. McIntyre. Seawater has been injected as well. SEM, XRD and ERD analyses conducted on Niakuk core indicate very low clay content in reservoir intervals. As a result no significant problems with formation plugging or clay swelling due to fluid incompatibilities is expected. Produced water may contain trace amounts of scale inhibitor, corrosion inhibitor, emulsion breakers, and other products used in the production process.

8. Well Logs (20 AAC 25.402(c)(7)): The logs of existing injection wells are on file with the Commission. Specific to this application, the bond logs of NK-28 have been reviewed, and sufficient cement exists above the Kuparuk interval.

9. Mechanical Integrity (20 AAC 25.402(c)(8)): NK-28 is the only well currently planned to be converted to an injector. A Segmented Bond Tool was run in the well in July 1995. The tool shows good bond above and below the perforations. A mechanical integrity test was performed on the well on 8/12/01, which showed good mechanical isolation. All wells used for injection will be cased and cemented in accordance with 20 AAC 25.412. In drilling all NOP injection wells, the casing is pressure tested in accordance with 20 AAC 25.030. The NOP injection wells are designed to comply with the requirements specified in 20 AAC 25.412.

10. Injection Pressures (20 AAC 25.402(c)(10)): The estimated average and maximum wellhead injection pressure for the NOP water injection project is as follows:

	Surface Operating Pressure, pounds per square inch, gauge ("psig")	
Service	Maximum	Average
Water Injection	2850	2450

11. Fracture Information (20 AAC 25.402(c)(11)): Injection in the Kuparuk at pressures above fracture parting pressure may be necessary to allow for additional recovery of oil. Water injection at the pressures proposed by BP should not initiate or propagate fractures through the confining strata. There are no freshwater strata in the area of issue.

    No fracture gradient has been obtained in the Kuparuk interval at Niakuk; however it is expected that the fracture gradient will be similar to that of the Kuparuk interval of Pt. McIntyre and West Beach Pools, or .60-.63 psi/ft.

    The Kuparuk Formation is overlain by the HRZ shale. Leakoff test data for NK-05 and NK-06 indicate a fracture gradient of over .82 psi/ft. Surface injection pressures in excess of 3200 psi would be required to initiate a fracture into the HRZ.

12. Water Analysis (20 AAC 25.402(c)(12)): Produced water analysis from the NOP indicates 25,000 parts per million ("ppm") total dissolved solids (TDS). Calculation of TDS from wireline logs indicates NaCl equivalents of greater than 10,000 ppm in the formations above the Kuparuk Formation. Therefore, aquifer exemption is not required.

13. Hydrocarbon Recovery (20 AAC 25.402(c)(14)): BP projects waterflood overall recoveries of approximately 35-38% in the Segments 1 and 3/5 of the western Niakuk, (67 to 72 MMSTBO), and 24-27% Segment 2 of the eastern Niakuk region (or 29-33 MMSTBO). Recovery by primary depletion alone is estimated at about 13%. Waterflood has been ongoing in Niakuk since 1994. These recovery figures include wells drilled and completed to date, including the NK-28 conversion, but not future development. Incremental recovery of 1.2 MMBO is projected as a result of conversion of NK-28 to water injection.

    a) Water Management Areas: The Niakuk accumulation is managed as three main pools – Segment 1, Segment 3/5, and Segment 2.

    b) Reservoir Surveillance Results: Initial reservoir pressure is estimated at 4500 psi. Production prior to 1996 dropped reservoir pressures in some areas. After injection started in 1995, pressures stabilized at approximately 4000 psi in the Segments 1 and 3/5 in the western Niakuk. Segment 2 in the eastern Niakuk has shown mixed results from water injection because there is structural and stratigraphic compartmentalization that is not as evident in the western Niakuk.

Segment 1 (West Niakuk Graben): Production in the Segment 1 began in April 1994. Injection began approximately one year later with the conversion of NK-10. Production has been sustained via pressure maintenance from this single injector. Aquifer support to the west may also be present, but has not been verified. Recent increases in oil production are attributed to redrilled well NK-07A. Although injection is currently adequate in this area, future conversions may be considered.

Segment 3/5 (West Niakuk Platform): Production in Segment 3/5 began in January 1995. Injection began approximately two years later at NK-15. Production has been sustained via pressure maintenance from this one injector, although injection has also been attempted at NK-17 with poor injectivity caused by poor rock quality. Injection in the Segment 3/5 is currently not balanced with voidage, in part due to production from recently redrilled well NK-08A. Another reason is the reduction in injectivity at NK-15 since its conversion from seawater to produced water injection roughly one year ago. BP anticipates conversion of NK-28 to injection service will alleviate this situation and optimize recovery from NK-08A. NK-28, which has produced over 2 MMBO, has watered out, and was recently converted to injection. While injection has not fully matched production, the segment has shown low decline relative to the to the other segments. BP indicates that additional aquifer support to the west may be present, but has not been verified.

Segment 2 (East Niakuk Graben): Segment 2 is more complex relative to the West Niakuk Graben and West Niakuk Platform. Production in Segment 2 began in April 1994. Injection began approximately one year later when NK-16, NK-23, and NK-38 were put into injection service. NK-65 was later put on injection in mid-1998. Production has been maintained to varying degrees via pressure maintenance from these injectors. NK-19 is an exception to this because it is completed in a relatively small isolated block that receives no pressure support. This well produced less than half a million barrels of oil before gassing out and dying due to low reservoir pressure and lack of injection support. NK-18 has had similar performance, but is not located in a completely isolated fault block. NK-18 was recently converted to injection in anticipation of production from the redrill of NK-19A. Because of the greater complexity and reservoir compartmentalization, BP states that well configuration and recovery performance in East Niakuk may differ substantially from what is seen in the west.

c. Reservoir Simulation: BP has developed two reservoir models in the evaluation of the waterflood, infill drilling, water conversion candidates and future development options. Both models were built using a deterministic methodology.

Kuparuk tops and bottoms were defined by seismic data, along with internal stratification where it could be seen. Well control was honored in defining the structure. Geologic descriptions from core, coupled with log data, were used to interpret internal stratigraphy, and formed the basis for an internal zonation scheme and the final simulation grid.

Porosity in both models was derived from core data where available and an interpreted log model elsewhere. Porosity/permeability crossplots were derived from the cored intervals. The log model incorporates density, sonic, and neutron measurements along with adjustments for shale volumes, heavy minerals, and cementation, which are zone-specific in some cases. Initial water saturations are assigned by functions developed from core that incorporate porosity, height above the water column, saturation exponents (Archie model), and Waxman-Smits parameters. Relative permeability experiments have not been conducted with Niakuk rock samples. Accordingly, scalable relative permeability curves developed from Prudhoe Bay samples have been employed and are assigned based on initial water saturation. The lithologic description used in the current reservoir simulation contains 32 layers for Segment 2 in eastern Niakuk and 13 layers for Segments 1 and 3/5 in the western Niakuk. Simulation grids that averaged less than 15% porosity or 10 md permeability were zeroed out. BP provided results of the history matches obtained in the West and East Niakuk models. BP indicated some adjustments to description were required to obtain the match, particularly with respect to fault locations.

14. Mechanical Condition of Adjacent Wells (20 AAC 25.402(c)(15)). BP is utilizing injection wells previously covered by AIO 14. To the best of BP's knowledge, the wells within the Niakuk and Western Niakuk Participating Areas were constructed, and where applicable, have been abandoned to prevent the movement of fluids into freshwater sources. Information regarding wells that penetrate the injection zone within ¼ mile radius of injection wells has been filed with the Commission.

15. Incorporation of AIO 14 Findings: The findings of fact in AIO 14 and amendments thereto are incorporated herein to the extent not inconsistent with this order.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.402 have been met.
2. An order permitting the underground injection of fluids on an area basis, rather than for each injection well individually, provides for efficiencies in the administration and surveillance of underground fluid injection operations.
3. The waters are currently injected under prior Commission approval of AIO 14. Core tests indicate minimal plugging problems with injected water. No problems with compatibility of the fluids have been observed.
4. Revision of AIO 14 to expand the effected area is appropriate in accordance with 20 AAC 25.450 and 20 AAC 25.460.
5. NK-28 is the only existing well planned for water injection conversion in the expansion area.
6. Injection of water in NK-28 is needed to maintain pressure and improve recovery in the Western region of the Niakuk.
7. All injection wells are designed to comply with the mechanical integrity requirements specified in 20 AAC 25.412. Mechanical integrity of NK-28 has been demonstrated by mechanical integrity test.
8. An order for temporary water injection into NK-28 was approved by the Commission on August 20, 2001, and extended by order dated November 14, 2001.
9. Fluids injected for enhanced recovery will consist of a mix of either produced waters processed in the Lisburne Production Facilities, or water from the Prudhoe Bay Unit Seawater Treatment Plant. Produced water may contain trace amounts of scale inhibitor, corrosion inhibitor, emulsion breakers, and other products used in the production process.
10. The proposed injection operations will be conducted in permeable strata that can

reasonably be expected to accept injected fluids at pressures less than the fracture pressure of the confining strata.

11. There are no USDW's within the project area.
12. Injection of water will significantly increase hydrocarbon ultimate recovery above primary production.
13. Reservoir surveillance, operating parameter surveillance and mechanical integrity tests will demonstrate appropriate performance of the water injection project or disclose possible abnormalities.
14. The conclusions in AIO 14 and the amendments thereto are incorporated herein to the extent not inconsistent with this order.

NOW, THEREFORE, IT IS ORDERED;

1. Except as otherwise provided herein, this order supersedes Area Injection Order No. 14 and previous revisions.
2. The following rules, in addition to statewide requirements under 20 AAC 25 (to the extent not superseded by these rules), govern enhanced oil recovery injection operations in the NOP in the affected area defined below.

Umiat Meridian

Township	Range	Sections
T12N	R15E	13-15 (all); 22-27 (all); 36 (NE/4)
T12N	R16E	28 (W/2, NE/4, W/2 of SE/4, SE/4 of SE/4); 29-30 (all); 31 (N/2); 32 (N/2)

Rule 1 Authorized Injection Strata for Enhanced Recovery and Authorized Injection Fluids

Enhanced recovery operations as described in the operator's applications are approved for the NOP within the Prudhoe Bay Field subject to these rules.

1) **Authorized Injection Strata:**
Within the affected area, fluids may be injected for purposes of pressure maintenance and enhanced recovery into strata defined as those that

correlate with and are common to the formations found in BP Niakuk No. 6 between the measured depths of 12,318 - 12942 feet.

2) **<u>Authorized Injection Fluids:</u>**
Fluids authorized for injection for the NOP:
   a. Produced water from LPC operations;
   b. Beaufort seawater;
   c. Trace amounts of scale inhibitor, corrosion inhibitor, emulsion breakers, and other products used in the production process; and
   d. Fluids injected for the purposes of stimulation per 20AAC24.280(2).

<u>Rule 2 Fluid Injection Wells</u>

The injection of fluids must be conducted 1) through a new well that has been permitted for drilling as a service well for injection in conformance with 20 AAC 25.005; or 2) through an existing well that has been approved for conversion to a service well for injection in conformance with 20 AAC 25.280.

<u>Rule 3 Monitoring the Tubing-Casing Annulus Pressure Variations</u>

The tubing-casing annulus pressure and injection rate of each injection well must be checked at least weekly to confirm continued mechanical integrity.

<u>Rule 4 Demonstration of Tubing-Casing Annulus Mechanical Integrity</u>

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.

<u>Rule 5 Notification of Well Integrity Failure</u>

Whenever injection rates or operating pressure observations or pressure tests indicate pressure communication or leakage of any casing, tubing or packer, the operator must notify the Commission by the first working day following the observation, and submit a plan of corrective action on Form 10-403 for Commission approval. Additionally, notification requirements of any other State or Federal agency remain the operator's responsibility.

<u>Rule 6 Notification of Improper Class II Injection</u>

Injection of fluids other than those listed in Rule 1, above, without prior authorization is considered improper Class II injection. Upon discovery of such an event, the operator must immediately notify the Commission, provide details of the operation, and propose actions to prevent recurrence. Additionally, notification requirements of any other State or Federal agency remain the operator’s responsibility.

Rule 7 Other Conditions

a. It is a condition of this authorization that the operator complies with all applicable Commission regulations.

b. The Commission may suspend, revoke, or modify this authorization if injected fluids fail to be confined within the designated injection strata.

Rule 8 Administrative Action

Unless notice and public hearing is otherwise required, 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 freshwater.

DONE at Anchorage, Alaska and dated December 31, 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).