

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 Porcupine Drive
Anchorage, Alaska 99501-3192

Re: The **REQUEST OF BP**) Area Injection Order No. 14
EXPLORATION (ALASKA) INC. to)
inject fluids for enhanced recovery into the) Prudhoe Bay Field
Niakuk Oil Pool.) Niakuk Oil Pool

March 22, 1995

IT APPEARING THAT:

1. BP Exploration (Alaska) Inc., by correspondence dated November 16, 1994 made application to the Commission for authorization to inject fluids for enhanced recovery into the Niakuk oil pool.
2. Notice of an opportunity for public hearing was published in the Anchorage Daily News on November 22, 1994.
3. No protest was filed.

FINDINGS:

1. Commission regulation, 20 AAC 25.460, provides authority to issue an order governing underground injection operations on an area basis for all wells within the same field, facility site, reservoir, project or similar area.
2. BP Exploration (Alaska) Inc (BP) is operator and 100% working interest owner of the area proposed for enhanced oil recovery operations in the subject application.
3. Conservation Order No. 329 defines the Niakuk oil pool in the Prudhoe Bay Field as strata common to the 12,318 to 12,942 foot measured depth interval in the Niakuk 6 well.
4. The area proposed for enhanced oil recovery operations in the subject application includes the Niakuk Pool Rules Area and BP-operated acreage which is outside the currently defined Niakuk Pool Rules Area.
5. Development plans for the Niakuk oil pool include approximately ten development wells producing through primary depletion for a period of one year. The primary production phase will end about April, 1995 when four or five of the original producers will be converted to water injectors.

6. The exact number, type, and location of wells ultimately drilled into the pool will depend on an analysis of well performance data obtained during the production life of the pool.
7. Production from the Niakuk oil pool will be commingled with that from other Greater Point McIntyre Area pools at the surface and processed at the Lisburne Production Center (LPC).
8. Produced gas from the Niakuk oil pool will be injected into other Greater Point McIntyre Area reservoirs.
9. No injection wells currently exist in the Niakuk oil pool. BP's application includes proposed locations and mechanical configurations for currently envisioned injectors, and the locations of all existing and abandoned wells within the pool area.
10. All operators and surface owners within one-quarter mile of the currently planned injectors have been notified as required by 20 AAC 25.402 (c) (2).
11. Performance data may indicate optimal injection well locations other than those proposed in the application.
12. Specific approvals to convert or drill injection wells will be obtained pursuant to 20 AAC 25.507 or 20 AAC 25.005.
13. Estimated maximum and average surface pressures for Niakuk oil pool water injection wells are 2,850 and 2,450 psig respectively.
14. Data from sandstone intervals analogous to the Niakuk oil pool reservoir indicate parting pressure gradient is in the range of .6 to .63 psi/ft.
15. The Kuparuk River Formation is overlain by the HRZ shale. The HRZ is a thick sequence which behaves as a plastic medium, and can be expected to contain significantly higher pressures than the underlying Kuparuk River Formation sandstones.
16. Injection into the Kuparuk River Formation at pressures above the formation parting pressure will be necessary in order to maximize oil recovery.
17. Pressure tests indicate the HRZ shale has a leak off gradient of .82 psi/ft at Niakuk 5 and a fracture gradient estimated at .86 psi/ft at Niakuk 6.
18. Injection induced fractures within the Kuparuk River Formation are not expected to propagate through the overlying HRZ shale interval.
19. Analysis of water samples and open hole wireline log data indicate no freshwater aquifers, or water bearing sandstones with a total dissolved solids (TDS) concentration of less than 10,000 ppm (USDWs), are present in the proposed project area.
20. Injection water for the Niakuk oil pool will be 1) water from the Prudhoe Bay Unit Seawater Treatment Plant, 2) a mix of Pt. McIntyre, West Beach, North Prudhoe Bay,

Niakuk, and Lisburne pool produced water separated through the LPC, or 3) formation waters from Upper Cretaceous to Tertiary aged sandstones within the project area.

21. Laboratory analysis and computer modeling of the chemical compatibility between the Upper Cretaceous/Tertiary formation water, Niakuk formation water, and Beaufort seawater have shown that mixing of these fluids will cause precipitation of moderate volumes of calcite and barite scale.
22. Scaling due to mixing of injection waters will be controlled through the appropriate use of scale inhibitors.
23. The salinity of injection water from the Prudhoe Bay Unit Seawater Treatment Plant will periodically be less than that of the Kuparuk River formation water in the project area because of seasonal salinity changes.
24. Detailed clay mineralogy investigations have determined reservoir intervals in the project area contain minor volumes of clay. Clay types identified are only moderately susceptible to swelling.
25. The estimated maximum daily injection rate in the project area is 50,000 barrels of water per day.
26. Waterflooding the currently defined Niakuk oil pool is expected to result in an incremental recovery of 49 million stock tank barrels of oil beyond primary depletion.
27. The operator proposes to monitor tubing-casing annulus pressures of all injection wells at least weekly to ensure there is no leakage and that casing pressure remains less than 70% of minimum yield strength of the casing.
28. All existing wells drilled within the project area have been constructed in accordance with 20 AAC 25.030. All wells abandoned in the project area have been abandoned in accordance with 20 AAC 25.105

CONCLUSIONS:

1. 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.
2. The area authorized for injection operations under an area injection order has no inherent relationship to, nor affect on, the area of participation formed by the mineral interest owners and approved by the state for pool development.
3. An area injection order is appropriate for the project area in accordance with 20 AAC 25.450 and 20 AAC 25.460.

4. An area injection order covering the project area will neither cause waste nor jeopardize correlative rights.
5. Specific approvals to convert or drill injection wells will be required.
6. 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.
7. Injection of Class II fluids at proposed pressures will not propagate fractures through the confining zone.
8. There are no USDWs within the project area.
9. Fluids injected for enhanced recovery will consist of Class II fluids.
10. Proposed injection fluids are compatible with formation fluids.
11. Well mechanical integrity must be demonstrated in accordance with 20 AAC 25.412 prior to initiation of injection or disposal operations and at reasonable intervals thereafter.
12. Tubing-casing annulus pressures, injection rates and pressures, and operational parameters will be monitored weekly.
13. The cumulative effects of drilling and operating proposed injection wells in the project area are consistent with proven engineering practice and are acceptable to the Commission.

NOW, THEREFORE, IT IS ORDERED THAT Area Injection Order No. 14 is issued with the following rules to govern Class II injection operations in the following affected area:

UMIAT MERIDIAN

T12N	R15E	Sections 13, 14, 23, 24, 25, 26, and Section 36 N 1/2.
T12N	R16E	Sections 28, 29, 30, Section 31 N 1/2, and Section 32 N 1/2.

Rule 1 Authorized Injection Strata for Enhanced Recovery

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.

Rule 2 Fluid Injection Wells

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. Pumping of excess non-hazardous fluids that are developed solely from well operations, or necessary to control the fluid level of reserve pits, into surface-production casing annuli is exempted from the above requirements.

Rule 3 Reporting the Tubing-Casing Annulus Pressure Variations

The tubing casing annulus pressure of each injection well must be checked at least weekly to ensure there is no leakage and that it does not exceed a pressure that will subject the casing to a hoop stress greater than 70% of the casing's minimum yield strength.

Rule 4 Demonstration of Tubing-Casing Annulus Mechanical Integrity

A schedule must be developed and coordinated with the Commission which ensures that the tubing-casing annulus for each injection well is pressure tested prior to initiating injection, and at least once every four years thereafter. A test surface pressure of 1500 psi or 0.25 psi/ft. multiplied by the vertical depth of the packer, whichever is greater, but not to exceed a hoop stress greater than 70% of the casing's minimum yield strength, must be held for at least a thirty-minute period with decline less than or equal to 10% of test pressure. The Commission must be notified at least twenty-four (24) hours in advance to enable a representative to witness pressure tests.

Rule 5 Well Integrity Failure

Whenever operating pressure observations or pressure tests indicate pressure communication or leakage of any casing, tubing or packer, the operator must notify the Commission on the first working day following the observation, obtain Commission approval of a plan for corrective action, and obtain Commission approval to continue injection.

Rule 6 Administrative Action

Upon request, the Commission may administratively amend any rule stated above as long as the operator demonstrates to the Commission's satisfaction that sound engineering practices are maintained and the amendment will not result in an increased risk of fluid movement into a USDW.

DONE at Anchorage, Alaska and dated March 22, 1995.

David W. Johnston, Chairman

Russell A. Douglass, Commissioner

Tuckerman Babcock, Commissioner

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).