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

Re: **THE APPLICATION OF BP**	)	**Area Injection Order No. 31**
EXPLORATION (ALASKA) INC.	)	
for an order authorizing underground	)	Prudhoe Bay Field
injection of fluids for enhanced oil	)	Prudhoe Bay Unit
recovery in the Raven Oil Pool of	)	Raven Oil Pool
the Prudhoe Bay Field.	)	August 9, 2006

IT APPEARING THAT:

1. By letter dated February 8, 2006, BP Exploration (Alaska), Inc. ("BPXA"), operator of the Prudhoe Bay Unit ("PBU"), requested an order from the Alaska Oil and Gas Conservation Commission ("Commission") to define the Raven Oil Pool ("ROP") within the PBU, and to prescribe rules for governing the development and operation of the pool. Concurrently, BPXA requested authorization for enhanced recovery operations in the proposed ROP

2. The Commission published notice of opportunity for public hearing in the Anchorage Daily News on February 14, 2006.

3. By e-mail correspondence dated February 13, 2006, the Commission requested additional information from BPXA in support of BPXA's application.

4. By correspondence dated March 3, 2006, and received by the Commission on March 6, 2006, Raymond C. Givens, attorney for the heirs of Andrew Oenga ("Oenga heirs"), notified the Commission that the Oenga heirs, as the owners of US BIA Allotment No. F-14632 and lessor of the land underlying the production facilities at Heald Point, requested the tentatively scheduled hearing be held March 30, 2006.

5. By correspondence dated March 9, 2006, and received by the Commission on March 13, 2006 the Inupiat Community of the Arctic Slope ("ICAS"), a Federally Recognized Regional Tribal Government, objected to the Raven project until the lease dispute between BPXA and the Oenga heirs is settled.

6. By correspondence dated March 15, 2006, the Commission advised the ICAS that the hearing regarding BPXA's application would be held on March 30 at 9:00 am.

7. On March 24, 2006, BPXA submitted through e-mail correspondence the additional technical information requested by the Commission and requested a modification of the pool rules area.

8. On March 29, 2006, Raymond C. Givens e-mailed a written statement from Tony Delia, an heir of Andrew Oenga. Tony Delia, on behalf of the Oenga heirs, objected to the establishment of pool rules and requested the Commission postpone adoption of the Raven Pool Rules until the lease dispute is resolved.

9. The Commission held a public hearing on March 30, 2006. The Commission held the record open until April 14, 2006.

10. By correspondence dated April 5, 2006 the Commission advised Raymond C. Givens that if the heirs of Andrew Oenga had additional information for the Commission to consider, it must be sent to the Commission by April 14, 2006.

11. By correspondence dated April 12, 2006 and received by the Commission on April 13, 2006, Raymond C. Givens responded to BPXA's written comments submitted at the March 30, 2006 hearing.

12. On April 18, 2006 Raymond C. Givens provided the Commission copies of the "Notice to Halt Trespass" addressed to companies with interest in the West Niakuk P.A., Prudhoe Bay, Alaska.

13. By letter dated April 18, 2006 and received by the Commission on April 24, 2006, Raymond C. Givens corrected a typographical error in his April 22, 2006 reply comments.

14. By correspondence dated April 19, 2006 the Commission advised BPXA that the record for the March 30 hearing would be left open until the close of business on April 28, 2006 for BPXA to respond to the April 12, 2006 letter from Mr. Givens

15. On April 28, 2006 BPXA delivered correspondence dated April 28, 2006 to the Commission titled "Supplemental response of BP Exploration (Alaska) Inc. to supplemental comments submitted by attorney Raymond C. Givens (counsel for heirs of Andrew Onega) in his letter dated April 12, 2006".

16. By E-mail dated May 26, 2006 and June 5, 2006, the Commission requested additional information from BPXA. BPXA responded to the request June 5, 2006.

17. On July 24, 2006, the Commission received BP's affidavit showing that they provided a copy of the application for injection to operators and surface owners within a one-quarter mile radius of the proposed injection area.

FINDINGS

1. Operator

   BPXA is the operator of the property for which injection is proposed.

2. Proposed Injection Area

BPXA requested authorization to inject fluids for the purpose of enhanced recovery operations within the ROP in the following offshore area within the PBU

Umiat Meridian

Township/Range	Sections
12N-15E	S/2SW/4 Section 24
	E/2, NW/4, E/2SW/4 Section 25
	E/2NE/4 Section 26
	N/2NE/4 Section 36
12N-16E	S/2NW/4, N/2SW/4, SW/4SW/4Section 29
	All Section 30
	NW/4NW/4 Section 31

3. Operators/Surface Owners Notification

BPXA provided operators and surface owners within one quarter of a mile of the proposed offshore ROP injection area and within one quarter of a mile of ROP surface facilities, located in the adjacent to the South onshore at Heald Point, with a copy of the application for enhanced oil recovery injection. The only affected operator is BPXA, operator of the PBU. Surface owners are State of Alaska and Oenga heirs.

4. Geologic Information and Hydrocarbon Volumetrics

[DS1]The proposed ROP lies offshore in an area where permafrost thins rapidly from onshore to offshore, causing problems with processing and interpreting seismic data. The seismic data required sophisticated interpretation techniques in order to generate a valid correspondence between well and seismic data.

Basically, the limits of the proposed ROP are defined by structural closure at the top of the Sag River Formation on a low relief, densely faulted, east- west trending horst covering less than 5 square miles in area. The faulting interior to the proposed ROP has been sufficient to influence the Gas-Oil contacts ("GOC") between fault blocks and areas but the oil-water contact ("OWC") appears to be common across the field.

Four areas- the North and South Fault Blocks and the East and South Areas are defined. At the top of the Sag River, the North and South Fault Blocks are separated from the down-dip East Area by a faulted saddle and the down-dip South Area by a fault. The East and South areas appear to share a common hydrocarbon accumulation at Sag River level. Existing wells have not penetrated a Ivishak hydrocarbon accumulation in the East and South areas, but seismic mapping indicates the South and East areas may contain Ivishak Formation reserves. The North and South Fault Blocks are on the crest of the structure and account for the bulk of the proved reserves.

The Permo-Triassic proposed ROP reservoir is equivalent to the primary producing intervals, the Sag River and Ivishak Formations; and the intervening, low permeability Shublik Formation in the nearby Prudhoe Bay Field. The proposed ROP is defined by the correlative interval from 10,628 to 11,165 measured depth feet in the NK-05 well. Although the Shublik Formation is generally considered to be non-reservoir quality, it may include minor permeable zones that can be used for injection and/or production as development proceeds.

The proposed ROP is positioned between two major shales; the Kavik Shale (below) and the Kingak Shale (above).

Core data and well logs were used to estimate rock properties of the Ivishak and Sag River Formation sandstones. Cores were used to validate the petrophysical interpretations for Ivishak Formation porosity and Sag River Formation porosity and Net/Gross. The Ivishak Formation Net/Gross was determined by using a shale cutoff while a cutoff of 5 mD permeability (Kh) was used to calculate net sand in the Sag River Formation. The following table summarizes the rock properties used to determine in-place hydrocarbon volumes.

ROP Average Rock Property Summary

	POROSITY	NET/GROSS	Sw
Ivishak Formation	20 %	88 %	40 %
Sag River Formation	20 %	55 %	40 %

Fluid properties are estimated from surface fluid samples taken from the NK-38A and NK-43 wells combined with fluid property correlations. No reliable PVT data are available. Fluid properties used in the volumetric analysis are summarized below.

ROP Average Fluid Property Summary

	IVISHAK (Average)	IVISHAK (North Block)	IVISHAK (Other Areas)	SAG RIVER
Boi	1.903 rb/stb	1.960 rb/stb	1.833 rb/stb	1.960 rb/stb
Rsi	1515 scf/stb	1600 scf/stb	1412 scf/stb	1600 scf/stb
Bgi	0.64 rb/Mscf	0.62 rb/Mscf	0.66 rb/Mscf	0.62 rb/Mscf

Properties vary due to different pressures in various compartments as above. The black oil has a gravity of approximately 32 API and the condensate gravity is approximately 49 API.

Estimates of in-place hydrocarbons reflect the current stratigraphic and structural interpretation, plus the rock and fluid properties discussed above. The estimated in-place oil volumes are summarized below. The condensate volume is based on an estimated yield of 65 bbl/MMscf as determined from NK-43 production data.

Raven In-Place Oil Volume Summary (MMbo)

	OIL	CONDENSATE	TOTAL
Ivishak	6.9 to 11.4	2.3 to 3.8	9.2 to15.2
Sag River	3.5 to 5.8	1.3 to 2.2	4.8 to 8.0
Total	10.4 to 17.2	3.6 to 6.0	*14.0 to 23.2*

In-place gas volumes are summarized in the following table. The solution gas volumes are estimated from production data from the NK-38A well.

Raven In-Place Gas Volume Summary (bcf)

	FREE GAS	SOLUTION GAS	TOTAL
Ivishak	35.4 to 59.0	10.4 to 17.3	45.8 to 76.3
Sag River	20.4 to 33.9	5.3 to 8.8	25.7 to 42.7
Total	55.8 to 92.9	15.7 to 26.1	*71.5 to 119.0*

The ranges in OOIP and OGIP are due primarily to uncertainty in individual fault block oil-water contacts and gas-oil contacts where there is no well control, reservoir properties and fluid properties.

5. Well Logs

The logs of existing Prudhoe Bay Unit injection wells are on file with the commission.

6. Proposed Enhanced Recovery Injection Interval

Enhanced recovery injection is proposed for the ROP. The injection zone is correlative to the 10,628 to 11,165 measured depth feet interval in the NK-05 well and is comprised of the Sag River, Shublik and Ivishak Formations.

7. Previous Authorization for ROP Enhanced Recovery Pilot

A four month-production test was conducted within the Ivishak Formation interval of the ROP within Well NK-38A in 2005. During this time GOR increased to nearly 4000 mscf/stb. The increasing GOR is interpreted to be due to gas coning from larger Upper Ivishak gas cap along faults cutting through the 2A2 shale. Reservoir pressure decreased by about 700 psi during the production period. To ensure oil recovery was not compromised, the well was then shut-in to await waterflood. Subsequently, the NK-65A well was drilled and completed as a water injector to support the NK-38A producer. The NK-65A well began water injection on October 7, 2005. Authorization for the NK-65A well to inject water for the purpose of enhanced oil recovery from the ROP was granted through an administratively approved modification to Area Injection Order 14A (14A.001) dated September 14, 2005.

Cumulative production of NK-38A through February 2006 was 368 MSTB, 480 BW, and 1419 MMSCFD. Production rates currently are 1300 STBD at a GOR of about 5300 SCF/STB. Cumulative injection in NK-65A is 1,593 MBBL. Average rate of water injection is roughly 13 MBD.

8. Description of Operation

Only the North Fault Block is expected to have significant recovery from the Ivishak Formation with the two existing wells. Currently, there is a significant portion of the existing NK-38A wellbore in the South Fault Block that is not perforated. The current reservoir model predicts greater recovery efficiency if the two fault blocks are developed independently. Therefore, the current plan is to add South fault Block perforations once the North Fault Block has been depleted. The reservoir simulation model also suggests the potential for up to three sidetrack locations; one in the North Fault Block and two in the South Fault Block. Future development options will ultimately be determined by field performance and economic factors.

The operator plans to produce the Ivishak Formation from the NK-38A horizontal well in the North Fault Block and an average voidage replacement ratio of 1.0 will be maintained with water injection at NK-65A. The existing reservoir model will be history matched as production progresses and the model will be used to optimize production and injection rates. The model will also be used to evaluate additional drilling options and well placement. The model was built before the NK-38A and NK-65A wells were drilled and will be updated to better reflect the new well data.

The ROP Sag River Formation reservoir and well performance are less understood and the resource is small. Information from a planned NK-43 long-term test will be helpful in understanding the Sag River Formation development potential. Further development will be dependent upon field performance and economic factors.

Surveillance data will be collected on an ongoing basis to facilitate reservoir management and field development. These activities will include static bottom-hole pressure surveys, production logging, injection logging and production well testing.

In parallel with the Ivishak Formation development, the Sag River Formation production performance will be evaluated by re-opening the Sag River Formation in NK-43. The next development decisions will be based on the production information gained from the performance of these three wells (NK-38A, NK-65A, NK-43) in consideration of the many options described in the previous section.

Water injection is a key part of the Raven Reservoir management strategy. The initial injection will be in the NK-65A well located on the PBU DS NK Pad, which was built for Niakuk Oil Pool development. Water will be routed to the DS NK Pad manifold and then routed to the injection well where a flow meter will measure total fluid injected.

Currently, the only water used for injection at the Niakuk drill site is taken from the Beaufort Sea and processed at the Sea Water Treatment Plant ("STP"). It is possible that produced water could be injected at some time in the future. Produced water is water that is produced with Lisburne, Pt. McIntyre, West Beach, North Prudhoe Bay State and Niakuk oil, and is separated from the oil and gas at the Lisburne Production Center ("LPC"). Produced water may contain trace amounts of scale inhibitor, corrosion inhibitor, emulsion breakers, and other products used in the production process. BPXA requests authorization to injection seawater from the STP, produced water from the LPC and fluids injected for purposes of stimulation.

Currently there is no gas injection line to the Niakuk pads. The possibility of implementing EOR in the Raven reservoir will be evaluated in the future.

9. Freshwater Aquifer Exemption

The Commission found in the Niakuk Oil Pool ("NOP") that produced water from the NOP contained 25,000 parts per million ("ppm") total dissolved solids ("TDS"). Through calculations of TDS from wireline data logs the Commission also found NaCl equivalents of greater that 10,000-ppm in the formations above the Kuparuk Formation (AIO 14A). The ROP directly underlies and is largely coincident with the NOP. The absence of freshwater determination made in AIO 14A is valid also for the ROP..

10. Mechanical Condition of Adjacent Wells

NK-43, a gas lifted producer, exhibits sustained inner annulus pressure as a result of a tubing leak, and is currently shut in awaiting installation of a tubing patch. NK-38A is currently naturally flowing and is waivered by the operator for inner annulus by outer annulus pressure communication.

11. Injection Rates and Pressures, Fracture Information

The maximum injection rate of 15,000 bwpd will be the initial target rate. This is being done in order to make up voidage from production prior to the initiation of water injection. The injection rate is expected to decline to approximately 6,000 bwpd and the maximum injection pressure will be 2,500 psi. The NK-65A wellhead injection pressure will be determined by the Niakuk Oil Pool requirements, but the average wellhead injection pressure is expected to be about 1,500 psi. Surface injection pressures of 1500 psi would yield less than the average expected Ivishak Formation parting pressure of .66 psi/ft.

12. Mechanical Integrity and Well Design of Injection wells

The NK-65A casing program was permitted and the well completed in accordance with 20 AAC 25.030. NK-65A well bore geometry and relative well target position necessitated issuance of a packer depth variance pursuant to 20 AAC 25.412 (b). NK-65A well bore integrity is ensured by use of premium (Hydril 521) liner connections, placement of high compressive strength cement over the entire liner length, and placement of an XN nipple profile in the liner just above perforation depth.

13. Type of Fluid / Source

Fluids requested for injection are:
a. Seawater from the STP
b. Produced water from the LPC (possible in the future)
c. Fluids injected for purposes of stimulation (possible in the future)

14. Water Composition and Compatibility with Formation

Water compatibility problems are not expected because of the successful history of both sea water and produced water injection into the Prudhoe Bay Reservoir. No clay swelling problems have been seen in the Ivishak Formation in the Ivishak Participating Area of the PBU (IPA) with either source water injection or produced water injection. When present, scaling in the Ivishak Formation in the IPA has been limited to calcium carbonate deposition, which has been eliminated with acid treatments and controlled with the use of inhibitors. Minimal problems with formation plugging or clay swelling due to fluid incompatibilities are anticipated.

15. Hydrocarbon Recovery

Ivishak reservoir modeling indicates an incremental recovery from water-flooding to be approximately 10 - 20% of the original oil in place, relative to primary depletion. Water is the principal fluid that will be injected into the Raven Pool.

Conclusions

1. The application requirements of 20 AAC 25.402 have been met.
2. Water injection will significantly improve recovery.
3. There are no known sources of fresh water in the area proposed for the development of the ROP.
4. 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.
5. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbore and appropriate operating conditions.
6. Reservoir and well surveillance, coupled with regularly scheduled mechanical integrity tests will demonstrate appropriate performance of the enhanced oil recovery project or disclose possible abnormalities.

NOW, THEREFORE, IT IS ORDERED that:
The underground injection of fluids for pressure maintenance and enhanced oil recovery is authorized in the ROP within the affected area, subject to the following rules and the statewide requirements under 20 AAC 25 (to the extent not superseded by these rules).

Affected Area:

Umiat Meridian

Township/Range	Sections
12N-15E	S/2SW/4 Section 24
	E/2, NW/4, E/2SW/4 Section 25
	E/2NE/4 Section 26
	N/2NE/4 Section 36
12N-16E	S/2NW/4, N/2SW/4, SW/4SW/4 Section 29
	All Section 30
	NW/4NW/4 Section 31

Rule 1 Authorized Injection Strata for Enhanced Recovery
Authorized fluids may be injected for purposes of pressure maintenance and enhanced recovery within the ROP into strata that are common to, and correlate with, the interval between the measured depths 10,628 feet and 11,165 feet within Well NK-05.

Rule 2: Fluid Injection Wells
The underground injection of fluids must be through a well that has been 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 and 20 AAC 25.412 (e).

Rule 3: Authorized Fluids for Enhanced Recovery
Fluids authorized for injection include:

a. Produced water from Raven or PBU production facilities for the purposes of pressure maintenance and enhanced recovery;
b. Tracer survey fluid to monitor reservoir performance;
c. Fluids injected for purposes of stimulation per 20 AAC 25.280(a)(2);
d. Source water from the Seawater Treatment Plant;
e. Non-hazardous water collected from well house cellars and standing ponds.

Rule 4: Authorized Injection Pressure for Enhanced Recovery
a. Normal injection pressures must be maintained below the parting pressure of the Sag River and Ivishak Sandstones of the ROP.
b. Injection pressures must be maintained so that injected fluids do not fracture the confining zone or migrate out of the approved injection stratum.

c. If fluids are found to be fracturing the confining zone or migrating out of the approved injection stratum, the Operator must immediately shut in the injection wells. Injection may not be restarted unless approved by the Commission.

Rule 5: Monitoring Tubing-Casing Annulus Pressure
The tubing and casing annuli pressures of each injection well must be monitored at least daily, except if prevented by extreme weather condition, emergency situations, or similar unavoidable circumstances. Monitoring results shall be documented and made available for Commission inspection.

Rule 6: 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. A Commission-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, rate, etc.) have stabilized. Subsequent tests must be performed at least once every four years thereafter (except at least once every two years in the case of a slurry injection well). The Commission must be notified at least 24 hours in advance to enable a representative to witness mechanical integrity tests. Unless an alternate means is approved by the Commission, mechanical integrity must be demonstrated by a tubing/casing annulus pressure test using a surface pressure of 1500 psi or 0.25 psi/ft multiplied by the vertical depth of the packer, whichever is greater, that shows stabilizing pressure and does not change more than 10 percent during a 30-minute period. Results of mechanical integrity tests must be readily available for Commission inspection.

Rule 7: Multiple Completion of Water Injection Wells
a. Water injectors may be completed to allow for injection in multiple pools within the same wellbore so long as mechanical isolation between pools is demonstrated and approved by the Commission.
b. Prior to initiation of commingled injection, the Commission must approve methods for allocation of injection to the separate pools.
c. Results of logs or surveys used for determining the allocation of water injection between pools, if applicable, must be supplied in the annual reservoir surveillance report.
d. An approved injection order is required prior to commencement of injection in each pool.

Rule 8: Well Integrity Failure 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 notify the Commission by the next business day and submit a plan of corrective action on a Form 10-403 for Commission approval. The Operator shall immediately shut in the well if continued operation would be unsafe or would threaten contamination of freshwater, or if so directed by the Commission. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the Commission for all injection wells indicating well integrity failure or lack of injection zone isolation.

Rule 9: Notification of Improper Class II Injection
Injection of fluids other than those listed in Rule 3 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 10: Plugging and Abandonment of Fluid Injection Wells
An injection well located within the affected area must not be plugged or abandoned unless approved by the Commission in accordance with 20 AAC 25.

Rule 11: Other conditions
It is a condition of this authorization that the operator complies with all applicable Commission regulations.
The Commission may suspend, revoke, or modify this authorization if injected fluids fail to be confined within the designated injection strata.

Rule 12: Administrative Actions
Unless notice and public hearing are otherwise required, the Commission may administratively waive or amend any rule stated above 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 fluid movement outside of the authorized injection zone.

DONE at Anchorage, Alaska and dated August 9, 2006.

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

Cathy P. Foerster, Commissioner
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).