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

Re: THE APPLICATION OF BP)	Conservation Order No. 570
EXPLORATION (ALASKA) INC.)	
For an Order for Classification of a)	Prudhoe Bay Field
New Oil Pool and to Prescribe Pool)	Prudhoe Bay Unit
Rules for Development of the Raven)	Raven Oil Pool
Oil Pool within 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"), 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, 2006 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. **<u>Operator</u>**
   BPXA is the operator of the property in the area for development.

2. **Development Area**
The proposed ROP is located offshore of Alaska's North Slope and within the geographic limits of the Niakuk Oil Pool, in the PBU, Prudhoe Bay Field. The proposed ROP lies beneath the Niakuk Oil Pool (Kuparuk River Formation) and includes the stratigraphic interval from the top of the Sag River Formation to the base of the Ivishak Formation. The limits of the pool are defined by the structural closure. The legal description of the proposed pool area is;

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. **Owners and Landowners**
All lands within the development area are leased from the State of Alaska, lie within the PBU and have the same working interest ownership; 26.36 percent BPXA, 36.07 percent ConocoPhillips Alaska, Inc., 36.40 percent ExxonMobil Alaska Production Inc., 1.16 percent Chevron USA Inc., .02 percent Forest Oil Corporation. The affected landowner is the State of Alaska. The heirs of Andrew Oenga are the surface owners of US BIA Allotment No. F-14632 at Heald Pt. which is the site of the onshore, ROP surface facilities , and is external to the affected area of the pool.

4. **Delineation History**
There are twelve wells in, or near, the proposed ROP that have encountered the Sag River and/or Ivishak Formations. Eight of the wells are abandoned exploration or sidetracked well bores while four are currently active (2 ROP wells and 2 Niakuk Oil Pool wells). The NK-38A and NK-65A wells have open perforations in the proposed ROP (Ivishak Formation). The NK-43 and NK-19A wells are Niakuk Oil Pool producers, with plugged intervals in the Sag River and Ivishak Formations that could be utilized in the proposed ROP development.

In 2001, light gravity oil and gas flowed during a long-term test from the proposed ROP (Sag River Formation) in the NK-43 well. The well was converted solely to Niakuk Oil Pool production after several weeks of proposed ROP production. The NK-43 well is currently being evaluated to re-open the perforations in the proposed ROP and commingle production from the Niakuk Oil Pool and the proposed ROP.

In 2002, a wet ROP (Sag River and Ivishak Formations) section was logged and tested in the NK-19A well, confirming the down-dip limit of hydrocarbons in both formations.

A four-month production test was conducted within the Ivishak Formation interval of the proposed 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 and fingering from a larger Upper Ivishak Formation 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 proposed ROP was granted through an administratively approved modification to Area Injection Order 14A (14A.001) dated September 14, 2005.

Also in 2005, hydrocarbons were logged throughout the Sag River Formation in the NK- 38APB1 and NK-65A wellbores, but these wells were not tested.

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.

The NK-43 well tested from the Sag River Formation for two months in early 2001 after which it was recompleted to the Kuparuk River Formation. The Sag River Formation tested at 600 STBD (40 deg. API) and 14,000 scf/stb GOR at the end of the production period. Development plans for the Sag River are uncertain at this time.

5. <u>Pool Identification</u>
The proposed ROP is the accumulation of hydrocarbons common to and correlating with the interval between log measured depths 10,628 feet and 11,165 feet within Well NK-05 and includes the Sag River, Shublik, and Ivishak Formations.

6. <u>Stratigraphy/Reservoir/Fluid Properties</u>
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. 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.

Proposed 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.

Proposed 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.

7. **Structure**

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 don't appear separate at Sag River level but the South area is wet in the Ivishak. The North and South Fault Blocks are on the crest of the structure and account for the bulk of the proved reserves.

Detail

Wireline log, core, RFT (wireline deployed formation fluid and pressure sampler) pressure and production data from the NK-04, NK-65A and NK-38A wells consistently indicate a common light (32 api gravity) Ivishak Formation oil column and a GOC at 9780 true vertical feet below sea level (-9780' TVDss) in the North Fault Block.

There is a significant pressure difference between the Ivishak Formation pressure in well NK-38A of 4973 psi in the North Fault Block and the Ivishak Formation pressure in well NK-38APB1 of 4464 psi of the South Fault Block. This difference of over 500 psi indicates a probable sealing fault, despite an Ivishak-to-Ivishak fault juxtaposition. In addition, the GOC in the south fault block is approximately 70' deeper than in the North Fault block; -9780' TVDss in the North Fault Block vs. -9850' TVDss in the South Fault Block. The deeper GOC in the South Fault Block is best explained by compartmentalization that existed when the structure was originally filled.

The NK38APBl well drilled entirely within the South Fault Block has the most complete data set defining proposed ROP fluid and pressure characteristics. MDT (wireline deployed formation fluid and pressure sampler) pressure data and log curves appear to identify four fluids in the well (Sag River Formation gas, Ivishak Formation gas, Ivishak Formation oil, and Ivishak Formation water) and three slightly different pressure gradients (Sag River Formation, Upper Ivishak Formation, Lower Ivishak Formation). This complexity implies the need to manage the reservoir for effective sweeping by the injected EOR fluid.

a. The Sag River Formation exhibits a pressure gradient of 0.17 psi/ft.

b. The Upper Ivishak Formation contains a gas column with a more typical gas gradient of 0.12 psi/ft.

c. The Upper Ivishak Formation also contains an oil column (0.31 psi/ft gradient) with oil down to the top of a locally significant shale. This gradient is consistent with the 32 API gravity oil tested in the North Fault Block from NK-38A. The upper Ivishak Formation oil and gas gradients intersect at -9850' TVDss at the interpreted GOC in the NK-38APB1 well.

d. The Upper and Lower Ivishak Formation is locally separated by a shale. There is a water gradient (0.43 psi/ft) in the entire lower Ivishak Formation. There is oil down to -9889' TVDss and water up to -9910' TVDss. Therefore, the oil/water contact is interpreted to be midway at approximately -9900' TVDss.

No hydrocarbons appear to be trapped in the Lower Ivishak Formation in the down-dip South and East Areas. As currently interpreted a column of hydrocarbons in the Sag River Formation is common between the two areas as evidenced by wells NK-05 and NK-43. Mapping indicates a separate Upper Ivishak Formation oil accumulation up dip from the NK-19 well may be present in the South Area. Similarly a separate Upper

Ivishak Formation accumulation may be updip from the NK-43 well in the East Area. A lack of well control imposes a degree of uncertainty in mapping these areas. Similarly a continuous hydrocarbon column may exist in the Sag River Formation interval through the South Fault Block and the East Area, but the Ivishak Formation in the South Fault Block is expected to be separate from an Ivishak Formation in the East Area due to a structural "saddle" between the NK-38APB1 and NK-43-wells. Seismic depth conversion uncertainty makes it impossible to determine if these areas are separate, or connected, at the Ivishak Formation level. The interpreted faults could compartmentalize the two areas, as observed in the North and South Fault Blocks. The NK-43 log through the Sag River and Ivishak Formations indicates the Sag River Formation is hydrocarbon bearing and the Ivishak Formation is wet. The top Ivishak Formation depth -9900' TVDss is coincident with the estimated OWC in the South Fault Block, this well suggests that the East Area does not have a separate, deeper contact.

The NK-43 well is currently producing from the Kuparuk River Formation, and the Sag River Formation was produced for several weeks after the well was initially drilled in 2001. The Sag River Formation produced a high GOR condensate (49 API), in combination with a small percentage of oil (estimated at 10% of the liquid volume). This suggests that the Sag River Formation is straddling a GOC and is producing both from a gas cap and an oil leg. The GOC seen in the South Fault Block -9850' TVDss would place the GOC below the Sag River Formation in NK-43, but the North Fault Block GOC -9780' TVDss would be in the middle of the Sag River at NK-43 and could produce the results seen in the test (condensate and oil).

The NK-43 well shows gas/condensate, and possible oil in the Sag River Formation. Down-dip, the NK-05 well is clearly in the oil column with 32 API oil tested in the Sag River Formation. Further down-dip, the NK-19A well tested water in the Sag River Formation, thus giving a lower limit to the OWC.

A drill stem test (DST) in the 1985 NK-05 exploration well in the Sag River Formation produced 32 API oil. The Sag River Formation DST indicates the GOC is above -9800' TVDss (consistent with the NK-43 data), and the OWC is at, or below -9850' TVDss. The pressure differences between NK-04 (North Fault Block) and NK-05 (South Area) clearly demonstrate these wells are in different pressure segments of the proposed ROP.

The NK-05 and NK-19A wells establish a Sag River Formation OWC between -9850' TVDss and -9890' TVDss.

The existing well data indicate that the Sag River Formation may have an OWC of -9850' TVDss (or as deep as -9890' TVDss) and a GOC of -9780' TVDss. The Ivishak Formation fluid contacts are better established; especially across the main field area which includes the North and South Fault Blocks. A field-wide OWC of -9900' TVDss is consistent with all existing well data. A GOC of -9780' TVDss is used in the North Fault Block, while a GOC of -9850' TVDss is assumed in all other parts of the field.

There is a level of uncertainty for these contacts, additional data collected as the proposed ROP development matures may better define the proposed ROP fluid distribution and pool limits.

8. In-Place Hydrocarbons

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 are no well control, reservoir properties and fluid properties.

9. Development Plans

Only the North Fault Block is expected to have significant recovery from the Ivishak Formation utilizing the two existing wells and perforations. Currently, there is a significant portion of the existing NK-38A wellbore in the South Fault Block that is not perforated. Greater recovery efficiency is predicted if the two fault blocks are developed independently. The current plan is to add these perforations once the North Fault Block has been depleted. The simulation model also suggests the potential for up to three sidetrack locations; one in the North Fault Block and 2 in the South Fault Block.

In parallel with the Ivishak development, the Sag River Formation production performance will be evaluated by re-opening the Sag River Formation in the NK-43 wellbore.

Future development options will ultimately be determined by field performance and economic factors.

The proposed ROP will be developed from the Niakuk Heald Point Drill Site. Production will be processed within the Lisburne Production Center (LPC). No additional facilities will be required, as the proposed ROP will utilize infrastructure of the Lisburne and Prudhoe Oil Pools.

To allow for close proximity of wells in separate fault blocks, BPXA has requested well spacing of a minimum of 20 acres.

10. **Reservoir Management**
Water injection is planned to maintain a voidage replacement ratio of 1.0. Ivishak Formation reservoir modeling indicates primary recovery of 10-20% and an incremental recovery of waterflooding relative to primary depletion to be approximately 10 - 20% of the original oil in place.

11. **Reservoir Surveillance Plans**
Surveillance data will be collected on an ongoing basis including static bottomhole pressure surveys, production and injection logs and production well testing. Wells will be tested a minimum of two times per month. Production will be commingled on the surface with other pools located in the Prudhoe Bay Unit. All the proposed ROP wells will use the Lisburne Production Center well allocation factor for oil gas and water.

12. **Automatic Shut in Equipment**
A series of conservation orders culminating with CO 363 generally eliminated the SSSV requirement wells in the Prudhoe Bay Oil Pool. Existing NOP wells within the Prudhoe Bay field require SSSVs unless a no flow test demonstrates the well is incapable of unassisted flow to surface (CO 329A, Rule 5; 20 AAC 25.265(b)). The commission concluded that requiring the use of SSSV's was appropriate because of the proximity of the Heald Point Drill Site to the Beaufort Sea. The proposed ROP will be developed from the same Niakuk Heald Point Drill Site. Similar rules governing automatic shut in equipment, specifically the SSSV requirement, are appropriate for the proposed ROP development.

13. **Sustained Casing Pressure**
The Commission has adopted a series of orders addressing sustained casing pressures for certain active wells in Alaska. The wells in the proposed ROP will be operated under similar conditions and similar rules are appropriate for the development.

14. **Consistency of Operating Rules**
To ease administrative burdens and to prevent confusion, the Commission seeks to establish, when appropriate, consistent operating rules for similar reservoirs within the same field. The reservoir characteristics, fluid properties and development plans for the proposed ROP are sufficiently similar to those of other pools within the Prudhoe Bay Field to warrant consistent operating rules.

15. Protest

Both the Oenga heirs and the ICAS Realty Department requested the Commission postpone adoption of Raven Pool Rules until the lease dispute between BPXA and the Oenga heirs is resolved.

Neither the Oenga heirs nor BPXA is asking the Commission to adjudicate the lease dispute.

Conservation Order ~~569~~ 570 and Area Injection Order 31 prescribe rules for the development and operation of the proposed ROP. Neither Conservation Order ~~569~~ 570 nor Area Injection Order 31 purports to address any claims that arise from the lease between the Oenga heirs and BPXA.

CONCLUSIONS:

1. Pool Rules for the development of the proposed ROP within the Prudhoe Bay Field in the PBU are appropriate at this time.

2. The proposed ROP is located in a structurally complex area; additional development drilling will provide better definition of fault related pressure compartmentalization and fluid contacts.

3. Monitoring reservoir performance will ensure optimal management of the pool. Annual reports and technical review meetings will keep the Commission apprised of reservoir performance and will ensure that future development plans promote greater ultimate recovery.

4. Proper annular pressure management is necessary to prevent failure of well integrity, uncontrolled release of fluid or pressure, or threat to human safety.

5. Eliminating spacing restrictions on wellbores interior to the affected area will allow the operator greater flexibility for placement of wells as the pool is developed, and it will not affect recovery from the reservoir, promote waste, jeopardize correlative rights, or result in an increased risk of fluid movement into freshwater. Correlative rights will be protected by a 500-foot set back from external property lines where ownership or landownership changes.

6. Water injection is necessary to maintain reservoir pressure and to maximize hydrocarbon recovery.

7. The Commission does not have the authority to resolve the lease dispute between the Oenga heirs and BPXA.

8. It is not necessary to have the lease dispute resolved between the Oenga heirs and BPXA before prescribing rules for the development and operation of the proposed ROP.

NOW, THEREFORE, IT IS ORDERED:

The development and operation of the ROP, within the affected area, is 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/4Section 29
	All Section 30
	NW/4NW/4 Section 31

Rule 1: Field and Pool Name
The field is the Prudhoe Bay Field. Hydrocarbons underlying the affected area and within the herein defined interval of the Ivishak, Shublik and Sag River Formations constitute the ROP.

Rule 2: Pool Definition
The ROP is defined as the accumulation of hydrocarbons common to and correlating with the interval between log-measured depths 10,628 feet and 11,165 feet within Well NK-05.

Rule 3: Well Spacing
To allow for close proximity of wells in separate fault blocks, spacing within the pool will be a minimum of 20 acres. The ROP shall not be opened in any well closer than 500 feet to the external boundary of the affected area.

Rule 4: Casing and Cementing Practices
In addition to the requirements of 20 AAC 25.030, the conductor casing must be set at least 75' TVD below the surface.
In addition to the requirements of 20 AAC 25.030, the surface casing must be set at least 500' TVD below the base of the permafrost.

Rule 5: Automatic Shut-in Equipment

a. Upon completion each well shall be equipped with:

    1. A fail-safe automatic surface safety valve (SSV) capable of preventing uncontrolled flow.

2. A fail-safe automatic surface controlled subsurface safety valve (SSSV), installed in the tubing string below the base of the permafrost and capable of preventing uncontrolled flow, unless other types of subsurface valve are approved by the Commission.

b. A well that is not capable of unassisted flow of hydrocarbons, as determined by a "no flow" performance test witnessed by a Commission representative, is not required to have fail-safe automatic SSSV's.

c. Safety valves may be temporarily removed for not more than 15 days as part of routine well operations or repair without specific notice to, or authorization by the Commission. The SSV and SSSV may not be simultaneously out of service without specific authorization from the Commission.

   1. Wells with SSV's or SSSV's removed shall be identified by a sign on the wellhead stating that the valve has been removed and the date of removal.

   2. A list of wells with SSV's or SSSVs removed, removal dates, reasons for removal, and estimated re-installation dates must be maintained current and available for Commission inspection on request.

d. The Low Pressure Sensor (LPS) systems shall not be deactivated except during repairs to the LPS, while engaged in active well work or if the pad is manned. If the LPS cannot be returned to service within 24 hours, the well must be shut-in at the wellhead and at the manifold building.

   1. Wells with a deactivated LPS shall be identified by a sign on the wellhead stating that the LPS has been deactivated and the date it was deactivated.

   2. A list of wells with the LPS deactivated, the dates and reasons for deactivating, and the estimated re-activation dates must be maintained current and available for Commission inspection on request.

Rule 6: Common Production Facilities and Surface Commingling

a. Production from the ROP may be commingled with production from other oil pools located in the PBU in surface facilities prior to custody transfer.

b. Production allocation is to be performed in accordance with the PBU Western Operating Metering Plan, described in the letter dated April 23, 2002 subject to ongoing review. All Raven wells must use the LPC well allocation factor for oil, gas and water.

c. All wells must be tested a minimum of twice per month. The Commission may require more frequent or longer tests if the allocation quality deteriorates.

d. The operator shall submit a monthly report and file(s) containing daily allocation data and daily test data for agency surveillance and evaluation.

Rule 7: Reservoir Pressure Monitoring

a. Prior to regular production or injection, an initial pressure survey must be taken in each well.

b. A minimum of one pressure survey will be taken annually in each of the ROP reservoir compartments where production wells exist.

c. The reservoir pressure datum will be 9,850' feet true vertical depth subsea.

d. Pressure surveys may consist of stabilized static pressure measurements (bottom-hole or extrapolated from surface), pressure fall-off tests, pressure build-up tests, multirate tests, drill stem tests, and open-hole formation tests.

e. Data and results from pressure surveys shall be submitted with the annual reservoir surveillance report. All data necessary for analysis of each survey need not be submitted with the report but must be available to the Commission upon request.

f. Results and data from special reservoir pressure monitoring tests shall also be submitted in accordance with part (e) of this rule.

Rule 8: Gas-Oil Ratio Exemption

Wells producing under secondary depletion from the ROP are exempt from the gas-oil ratio limits of 20 AAC 25.240(a) so long as requirements of 20 AAC 25.240(b) are met.

Rule 9: Pressure Maintenance Project

Waterflood operations are approved for the ROP. Average reservoir pressure will be maintained and/or adjusted to maximize ultimate recovery.
Commission approval is required prior to commencement of all other enhanced recovery operations.

Rule 10: Annual Reservoir Surveillance Report

An annual reservoir surveillance report must be filed by June 15 of each year. The report must include future development plans, reservoir depletion plans, and surveillance information for the prior calendar year, including:

a. Voidage balance by month of produced fluids and injected fluids and cumulative status for each producing interval.

b. Reservoir pressure map at datum, summary and analysis of reservoir pressure surveys within the pool.

c. Results and, where appropriate, analysis of production and injection log surveys, tracer surveys, observation well surveys, and any other special monitoring.

d. Review of pool production allocation factors and issues over the prior year.

e. Progress of enhanced recovery project implementation and reservoir management summary including results of reservoir simulation studies.

f. By August 1 of each year, the Operator shall schedule and conduct a technical review meeting with the Commission to discuss the report contents and to review items that may require action within the coming year by the Commission. The Commission may conduct audits of technical data and analyses used in support of the surveillance conclusions and reservoir depletion plans.

Rule 11 Waiver of "Application for Sundry Approval" Requirement for Workover Operations (ref. C.O. 556)

a. Except as provided in (d) and (e) of this rule, the requirement to submit an Application for Sundry Approvals (Form 10-403) and supporting documentation for workover activities described in 20 AAC 25.280(a) (1), (2), (3) and (5) is waived or modified for development wells as provided in the Commission document entitled "Well Work Operations and Sundry Notice/Reporting Requirements for Pools Subject to Sundry Waiver Rules," dated July 15, 2005 (referred to below as "Sundry Matrix"). This waiver and modification do not affect the operator's responsibility to submit a Report of Sundry Well Operations (Form 10-404) within 30 days following the completion of a workover operation.

b. Except as provided in (d) and (e) of this rule, the requirement to submit an Application for Sundry Approvals (Form 10-403) and supporting documentation for workover activities described in 20 AAC 25.280(a) (1) and (5) is modified for service wells as provided in the Sundry Matrix. This modification does not affect the operator's responsibility to submit a Report of Sundry Well Operations (Form 10-404) within 30 days following the completion of a workover operation.

c. The Sundry Matrix summarizes the sundry approval and reporting requirements that apply to various categories of operations in the specific well types under Commission regulations as modified by these rules.

d. The waivers provided under (a) of this rule do not apply to wells that are required to be reported to the Commission under the provisions of Rule 12.

e. The Commission reserves the discretion to require that an operator submit an Application for Sundry Approvals for a particular well or for a particular operation on any well.

f. Each week the operator shall provide the Commission with a report of workover operations performed the previous week that did not require submission of a Form 10-403. (These operations are listed in Column 2 of the Sundry Matrix.) The report must include the date, well, permit to drill number, nominal operation completed, and a brief description of that operation including depths of perforations, perforations, and stimulated zones.

g. Nothing in this rule precludes an operator from filing an Application for Sundry Approvals (Form 10-403) in advance of any well work or from including Sundry authorized operations (listed in column 3 of the Sundry Matrix in the weekly report required by (f) of this rule).

h. Unless notice and public hearing are otherwise required, the Commission may administratively waive the requirements of any provision of this rule or administratively amend any provision including the Sundry Matrix, 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 12 Annular Pressures

a. At the time of installation or replacement, the operator shall conduct and document a pressure test of tubulars and completion equipment in each development well that is sufficient to demonstrate that planned well operations will not result in failure of well integrity, uncontrolled release of fluid or pressure, or threat to human safety.

b. The operator shall monitor each development well daily to check for sustained pressure, except if prevented by extreme weather conditions, emergency situations, or similar unavoidable circumstances. Monitoring results shall be made available for Commission inspection.

c. The operator shall notify the Commission within three working days after the operator identifies a well as having (1) sustained inner annulus pressure that exceeds 2500 psig for wells processed through the Lisburne Processing Center and 2000 psig for all other development wells, or (2) sustained outer annulus pressure that exceeds 1000 psig.

d. The Commission may require the operator to submit in an Application for Sundry Approvals (Form 10-403) a proposal for corrective action or increased surveillance for any development well having sustained pressure that exceeds a limit set out in paragraph (c) of this rule. The Commission may approve the operator's proposal or may require other corrective action or surveillance. The Commission may require that corrective action be verified by mechanical integrity testing or other Commission approved diagnostic tests. The operator shall give the Commission sufficient notice of the testing schedule to allow the Commission to witness the tests.

e. If the operator identifies sustained pressure in the inner annulus of a development well that exceeds 45% of the burst pressure rating of the well's production casing for inner annulus pressure, or sustained pressure in the outer annulus that exceeds 45% of the burst pressure rating of the well's surface casing for outer annulus pressure, the operator shall notify the Commission within three working days and take corrective action. Unless well conditions require the operator to take emergency corrective action before Commission approval can be obtained, the operator shall submit in an Application for Sundry Approvals (Form 10-403) a proposal for corrective action. The Commission may approve the operator's proposal or may require other corrective action. The Commission may also require that corrective action be verified by mechanical integrity testing or other Commission approved diagnostic tests. The operator shall give the Commission sufficient notice of the testing schedule to allow the Commission to witness the tests.

f. Except as otherwise approved by the Commission under (d) or (e) of this rule, before a shut-in well is placed in service, any annulus pressure must be relieved to a sufficient degree (1) that the inner annulus pressure at operating temperature will be below 2000 psig, and (2) that the outer annulus pressure at operating temperature will be below 1000 psig. However, a well that is subject to (c) but not (e) of this rule may reach an annulus pressure at operating temperature that is described in the operator's notification to the Commission under (c) of this rule, unless the Commission prescribes a different limit.

g. For purposes of this rule,
   1. "inner annulus" means the space in a well between tubing and production casing;
   2. "outer annulus" means the space in a well between production casing and surface 5
   3. "sustained pressure" means pressure that (A) is measurable at the casing head of an annulus, (B) is not caused solely by temperature fluctuations, and (C) is not pressure that has been applied intentionally.

Rule 13 Use of Multiphase Flowmeters in Well Testing

For purposes of satisfying well test measurement requirements of 20 AAC 25.230, the use of multiphase meters will be approved only in accordance with the provisions of the Commission's document, "Guidelines for Qualification of Multiphase Meters for Well Testing" dated November 30, 2004. The Commission may administratively waive a requirement of these Guidelines or administratively amend the Guidelines as long as the change does not promote waste or jeopardize correlative rights, and is based on sound engineering and geoscience principles. This rule shall expire on December 31, 2007.

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Rule 14 Administrative Action

Unless notice and public hearing are otherwise required, the Commission may administratively waive the requirements of any rule stated above or administratively amend any rule, including the "Sundry Matrix" referred to in Rule 11, 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 August 9, 2006.

ALASKA OIL AND GAS CONSERVATION COMMISSION

Daniel T. Seamount, Jr., 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 Month 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 non-action 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).