ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

333 West 7th Avenue, Suite 100

Anchorage Alaska 99501

Re:**THE APPLICATION OF BP**	)	**Conservation Order 341D**
EXPLORATION (ALASKA) INC.	)	
Prudhoe Oil Pool - Modification to	)	Prudhoe Oil Pool
pool rules - Conservation Order	)	Prudhoe Bay Field
341C, for injection of water into the	)	
Prudhoe Bay Gas Cap	)	
	)	November 30, 2001

IT APPEARING THAT:

1. By letter dated September 21, 2001, BP Exploration (Alaska), Inc. ("BPXA") on behalf of the Working Interest Owners ("WIOs") of the Initial Participating Areas of the Prudhoe Bay Unit ("PBU") has applied for a modification of certain rules of Conservation Order 341C ("CO 341C") in conjunction with a proposed project named the Gas Cap Water Injection Project ("GCWI").

2. The Commission published notice of opportunity for public hearing in the Anchorage Daily News on September 29, 2001.

3. The Commission held a public hearing October 30, 2001 at 9:00 am at the Alaska Oil and Gas Conservation Commission at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501.

4. The Commission received no protests to BPXA's application or to the public testimony.

5. Pre-filed testimony of representatives of BP Exploration (Alaska), Inc., Phillips Alaska, Inc. and ExxonMobil Production Company is included in the record (revised October 30, 2001). All additional information requested by the Commission at the hearing was received November 1, 2001 and November 6, 2001.

FINDINGS:

1. <u>Authority 20 AAC 25.520, 20 AAC 25.540</u>

Commission regulation 20 AAC 25.420 provides authority to issue orders prescribing rules to govern the proposed development and operation of a pool. The commission will, in its discretion, amend pool orders in accordance with procedures set forth in 20 AC 25.540.

2. Gas Cap Water Injection Project - Overview

Currently, reservoir pressure is declining at 25 to 35 psi/year. The WIOs have studied options to mitigate pressure decline and have annually reported the progress of these studies to the Commission, based upon rulings in CO 290 (2/21/92), which were incorporated into CO 341C, Rule 12(d). As a result of these studies, the WIOs sanctioned the Gas Cap Water Injection project in June 2001. This project represents a new element in the depletion strategy of the Prudhoe Bay Oil Pool with the dual goals to mitigate reservoir pressure decline and improve recovery.

3. Proposed Modifications to Conservation Order 341C

The most current rules governing Prudhoe Bay Field, Prudhoe Oil Pool are contained in CO 341C, dated June 12, 1997. CO 341C is a consolidation of all conservation orders in effect for the Prudhoe Bay Field, Prudhoe Oil Pool at that point in time. Specific to CO 341C, BPXA is requesting the following modifications:

a) Revoke paragraph (d) of Rule 12 that requires the Operator to continue to investigate options to mitigate pressure decline and to provide an annual report to the Commission. With the implementation of GCWI, BPXA claims pressure decline will be mitigated.

b) Modification of Paragraph (c) in Rule 12 which currently provides that the Operator maintain a pressure differential of at least 250 psi between the minimum miscibility pressure of the miscible injectant and the prevailing reservoir pressure. BPXA claims that as GCWI will mitigate pressure decline, a more appropriate pressure differential of 100 psi is appropriate and will allow BPXA to better optimize both the composition and volume of the miscible injectant.

c) Modification of Rule 11, which describes the Prudhoe Oil Pool surveillance report, to include the results of GCWI surveillance.

4. GCWI Project Overview

The project scope calls for ramping up to 650,000 barrels per day of seawater injection into the eastern portion of the gas cap from a new injection site located at the East Dock Staging Pad. Initial projected rates are 500,000 barrels per day. Water injection will increase over time with increased availability of seawater and decreased seawater demand in other projects, such as the Flow Station 2 and Point McIntyre waterfloods and Grind and Inject. Water injection is anticipated to continue for twenty years, with a final injected water volume of near four billion barrels. Increased hydrocarbon recovery of 150-200 million barrels is projected by BPXA.

a) Facilities Requirements

Facility construction is planned for this winter, followed by start-up of injection in mid 2002. To implement the Gas Cap Water Injection project, a new seawater pipeline from Flow Station 2 to the East Dock Staging Pad will be constructed. The new line will have a 32" diameter and a total length of approximately 18,000 feet. It will tie-in to the existing 32"seawater line running from the Eastern Seawater Injection Plant to Flow Station 2. A heated pig receiver/manifold module and well houses will be installed at the East Dock Staging Pad to accommodate five to seven new injection wells.

b) GCWI Well Locations

Current plans for the GCWI include drilling of up to seven water injection wells into the eastern portion of the PBU, Ivishak formation gas cap. BPXA indicates the well locations were strategically chosen to allow for sufficient Ivishak pay at the bottom hole locations of the injectors, while maintaining sufficient distance from the gas injection and oil producing areas.

c) GCWI Well Completion

Each gas cap water injector will be completed with 13 3/8" surface casing cemented to surface, 9 5/8" intermediate casing with cement brought to 1000' above the shoe, and a fully cemented 7" injection liner. The tubing will be 7 5/8" and will include a 7" subsurface safety valve and two 7" profiles. The tubing is large to accommodate the high volume of water to be injected. The tubing will also be plastic coated to help minimize the friction losses. Average surface pressure for these new injection wells will be approximately 2700 psi. Maximum injection pressure is expected to be approximately 3100 psi.

5. Project Benefits

a) Reservoir Pressure

Average reservoir pressure in the Prudhoe Bay field is declining at a rate of 25-35 psi/year. The declining pressure reduces efficiency of every recovery mechanism operating in the field. The GCWI project is designed to arrest pressure decline and maintain the reservoir pressure until water injection ends in 2022. Current average reservoir pressure is approximately 3450 psi (@ 8800' ss datum).

b) Reservoir Simulation of Recovery

The GCWI incremental oil recovery was predicted using BPXA's Full Field Compositional Reservoir Model, comprised of a sixty (60) acre areal grid of the Prudhoe Bay field. It includes the oil that initially was in the gas cap and is immobile. The recovery calculated by the full field model was validated using mechanistic studies of GCWI using fully compositional 1D, 2D, strip, and pattern models. The increased pressure resulting from GCWI improves every recovery mechanism operating in the field. The benefits are characterized for three regions of the field; Gas Cap, Gravity Drainage, and Waterflood/EOR.

The incremental net additional recovery from GCWI is approximately 200 MMB in the full field model. The total reflects a reduction of 20 MMB in the Gas Cap region with increases of 200 MMB in the Gravity Drainage region, and 20 MMB in the waterflood/EOR region.

(1) Gas Cap Area

In total, there is a net reserves reduction of about 20 MMB in the Gas Cap region. In the original gas cap, not invaded by water, BPXA projects 30 MMB additional reserves from vaporization of residual oil and retrograde condensate. In the water invaded area, some hydrocarbon liquids will be trapped and remain immobile to injected water, preventing vaporization by injected gas, which reduces liquid recovery by approximately 50 MMB.

(2) Gravity Drainage Area

BPXA projects improved vaporization and gravity drainage processes will yield about 200 MMB of incremental recovery from the Gravity Drainage region. Vaporization of residual oil and retrograde condensate by the injected gas is more efficient at higher pressure. Higher reservoir pressure reduces oil shrinkage and oil viscosity. Both of these effects increase oil mobility and result in more efficient gravity drainage.

(3) Waterflood and EOR Area

The waterflood/EOR benefits are approximately 20 MMB. The projected benefits result from: 1) higher reservoir pressure increasing well production capacity; 2) lowered oil shrinkage; and 3) the higher reservoir pressure allowing leaner miscible injectant, thus greater supply, leading to more EOR recovery.

6. Water Movement

The potential for water to interfere with the various recovery mechanisms has been extensively studied by the WIOs. In particular, the potential for water to finger through the gas cap, and interfere with the gravity drainage area was a prime concern. WIO studies showed that because gas is 100 times more mobile than the water that displaces it, a piston-like displacement is anticipated. Water saturations in simulation of water displacing oil were compared to simulation of water displacing gas in a reservoir containing a high permeability (5 Darcy) thief zone. In the case of water displacing oil, water fingered through the high perm streak to the producer. In the case of water displacing gas, a piston-like displacement occurred.

Areal water saturation maps from BPXA's full field model were presented, showing the movement of water over time. The water is projected to move in a relatively radial to oblong shaped front. At the end of GCWI injection in 2022, water is projected to reach the waterflood area in the eastern part of the field, and the northern oil producers in the gravity drainage area. However, the western portion of the gas cap, and the major portion of the gravity drainage area are not expected to be invaded with water. Shut-down of GCWI is expected in 2022. Review of model projections through 2031 indicates little lateral movement of the water, again due to the low mobility of the water to the gas in the area.

7. GCWI - Major Gas sale Relationship

The WIOs addressed the interaction of the GCWI project with potential major gas sales and how gas sales would impact the estimated benefits of the GCWI project and how gas cap water injection is expected to impact ultimate gas recovery.

a) Major Gas Sale Effect on GCWI Recovery

A gas sale will reduce the incremental oil recovery from gas cap water injection. While the rate and timing have not been determined for major gas sales, a case to demonstrate the effect was shown. Assuming a 4 BCF/D gas sales rate beginning in 2008, the incremental production derived from GCWI is reduced from about 200 MMB to about 135 MMB. The reduction in the recovery results from three mechanisms:

* With a major gas sale the volume of gas available for injection is reduced in order to meet the gas sale demand. This reduces vaporization recovery for gas cap water injection;

* The ability of the injected gas to vaporize the oil it contacts diminishes as reservoir pressure decreases.

* Gas sale will lower reservoir pressure, making the oil more viscous, which decreases efficiency of oil production and reduces oil produced by gravity drainage.

b) <u>Effect of GCWI on Gas Recovery of Major Gas Sales</u>

The WIOs state that ultimate gas recovery should not be reduced by GCWI. Major Gas Sales off-take will require a large water free area from which to produce the gas. The simulation projections presented for the GCWI project suggest that the water will be localized and a significant portion of the gas cap will be free from water to allow blow-down of the gas reserves.

Without GCWI, gas recovery is expected to exceed 80% of the original gas cap gas in place when the pressure is reduced from the original 4400 psi to about 850 psi. With GCWI, gas is expected to be trapped at a saturation of 25% within the area of water injection. When reservoir pressure is subsequently reduced during "blow down", the trapped gas expands and once again becomes mobile. In the example shown by the WIOs, at a reservoir pressure of 1500 psi the gas recovery was projected at 90% with GCWI, while by pressure depletion alone the pressure has to be blown down to 500 psi to achieve the same recovery.

8. <u>Surveillance</u> BPXA presented plans to monitor injection well conformance, water movement and reservoir pressure. The major components of the GCWI surveillance plan are:

* Injection wells will be monitored in a manner similar to other water injection wells within the Prudhoe Bay pool.

* Pulsed Neutron Logs (PNLs) in existing wells will provide downhole and regional data on the water movement.

* 4-D gravity will provide a general view of water movement.

* Reservoir pressure monitoring will be done according to current Prudhoe Bay pool rules.

a) <u>Injection Well Monitoring</u>

Injection well monitoring will be conducted to ensure that the water injection is contained in the desired reservoir interval. The injection wells will be monitored with surface measured temperature, pressure and injection rate. These measurements will be similar to other injection wells within the Prudhoe Bay pool. With these measurements it is possible to monitor injection characteristics, particularly changes in the injectivity indices. The injectivity indices provide direct evidence of changes in well performance. Downhole measurements will provide confirmation of the surface measurements and will also help describe reservoir properties and hydraulic performance. Downhole temperature logs will provide verification of injection conformance and confirm that fracture height growth is confined within the Ivishak. Downhole pressure measurements will be used to determine tubular pressure drops and hydraulic performance. Pressure falloff tests will be undertaken to determine reservoir properties and wellbore skin.

b) Water Movement Surveillance with Pulsed Neutron Logs:

The leading edge of the waterflood will be detected primarily with pulsed neutron logs. BPXA identified more than nine wells surrounding the injection areas in which pulsed neutron logs can be run to monitor the movement of water. These wells are primarily Lisburne producing wells. BPXA indicated that there are no known cement problems that would prevent confinement of injection to the Ivishak. Pulsed neutron logs, specifically the RST logs, were chosen because they can be run in Lisburne wells completed with 2 7/8 inch tubing. Also, they can be run in two modes to collect data for discerning a major change in fluids (sigma & Carbon/Oxygen). The RSTs will help locate the leading edge of the waterflood, by detecting the change in saturation as water invades the Ivishak gas cap interval at the wellbore. It will also provide data in determining the regional waterflood coverage. BPXA indicated that the statistical variations seen in the RST log measurements should not substantially affect the ability to detect movement of water into the gas zones.

c) 4D Gravity Technique

The 4D Gravity technique utilizes very sensitive surface gravity measurements taken periodically. The method measures small changes in gravity as the low-density gas is replaced with the higher density water. Baseline measurements will be taken prior to water injection. Subsequent measurements will be made at discrete time intervals and compared to the baseline measurements. An increase in the density of the fluids in the gas cap indicates the presence of water. BPXA anticipates the 4D Gravity technique will allow them to map general water movement, determine an average waterflood front, and provide a means to perform a mass balance of the injected water. The major limitations of the 4D gravity technique are that it cannot detect small horizontal or vertical flood fronts and it cannot provide any downhole zonal information. Gravity measurements coupled with material balance and PNL measurements can aid validation of simulation predictions and fine tune history match calculations.

9. Proposed change to Rule 12(c)

BPXA requested in the rules for GCWI that the requirements for minimum miscibility pressure stipulated in Rule 12(c) should be modified. Currently this rule stipulated that the Operator maintain a pressure differential of at least 250 psi between the minimum miscibility pressure of the miscible injectant and the prevailing reservoir pressure. The 250 psi differential had been initially proposed by the WIOs in testimony provided 10/9/91, and approved in CO 290 dated February 21, 1992. This differential was based upon the assumption that the reservoir pressure will decline 100-150 psi during the time in which a cycle of MI is in the reservoir. A safety factor of 100 psi in addition was added to this. With GCWI pressure will be maintained in the injection patterns. As such 100 psi differential is sufficient until such time that the reservoir pressure is stabilized. This change will allow some additional flexibility of the Operator to increase overall MI volumes, and disperse MI to other areas of the field, leading to better optimization of MI throughout the field. This will not have a negative impact upon overall recovery.

10. Mitigation of Risks

Studies indicate that not implementing or further delaying GCWI will result in less recovery over the remaining life of the field. The studies and analysis appear thorough and technically sound. Though outweighed by the expected benefits to overall hydrocarbon recovery, there remain some risks that must be managed through ongoing surveillance. Oil reserves are potentially at risk if the injected water moves too far, too fast and enters the sensitive Gravity Drainage area of the field. Numerous reservoir simulation and studies show a likely tendency for the injected water to be concentrated in the eastern portion of the gas cap where it is more likely to improve oil recovery from up dip oil zone waterfloods already in progress or planned. In addition, model studies have consistently shown that water will move in a piston-like way through the gas cap, regardless of heterogeneities. Therefore, sweep efficiency of the process will be high and the water should move downdip slowly. GCWI is a recovery technique, which, though well studied, is untried at Prudhoe Bay. Despite the lack of precedents, risks to hydrocarbon reserves can be controlled. The WIOs have designed a process and outlined overall surveillance plans that should minimize losses and ensure greater ultimate hydrocarbon recovery.

11. Blowout Prevention Equipment and Practice

The provisions of Rule 4 of CO 341C are obsolete and inconsistent with current Commission regulations as stated in 20AAC 25 and current North Slope operator practice.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.520 have been met.

2. The GCWI project is expected to significantly increase overall hydrocarbon recovery from the Prudhoe Bay Oil Pool.

3. The GCWI project will mitigate pressure decline within the Prudhoe Bay Oil Pool.

4. With the planned implementation of GCWI, further investigation of options to mitigate pressure decline and annual report of these investigations is no longer necessary.

5. Further implementation of paragraph (d) of Rule 12, is unnecessary so long as the GCWI project is in operation.

6. Decreasing the minimum pressure differential requirement of Paragraph (c) of Rule 12 from 250 psi between the minimum miscibility pressure and the average reservoir pressure in the EOR injection areas will allow the Operator flexibility to provide more MI volume, and will not negatively impact recovery. Potential for increased rate and recovery exists through optimization of the MI injectant.

7. Adequate surveillance of the GCWI project is required to determine that water movement within the reservoir is confined as intended and does not negatively impact overall hydrocarbon recovery, and to determine if the project is successful in stabilizing reservoir pressure.

8. The Commission needs to be apprised of surveillance plans and results on a yearly basis.

9. The conclusions in CO 341C and the amendments thereto are incorporated herein to the extent not inconsistent with this order.

10. Rule 4 of CO 341C is no longer current and has been superseded by 20 AAC 25.035, 25.036, 25.037, 25.285, 25.286, 25.287, and 25.288.

NOW, THEREFORE, IT IS ORDERED THAT

(1) Conservation Order 341D supersedes Conservation Order 341C dated June 12, 1997;
(2) Rule 4 of Conservation Order No. 341C is revoked, Rules 11,12, and 16 are amended, and new Rule 17 is added; and
(3) In addition to statewide requirements under 20AAC 25 (to the extent not superseding these rules), the following rules now apply to the Prudhoe Oil Pool within the following described area (referred to in this order as the affected area):

UMIAT MERIDIAN

Township	Range	Section
T. 10N.,	R. 12E.,	1, 2, 3, 4, 10, 11, 12
T. 10N.,	R. 13E.,	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 24
T. 10N.,	R. 14E.,	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17,
		18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 36
T. 10N.,	R. 15E.,	all
T. 10N.,	R. 16E.,	5, 6, 7, 8, 17, 18, 19, 20, 29, 30, 31
T. 11N.,	R. 11E.,	1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 24, 25
T. 11N.,	R. 12E.,	all
T. 11N.,	R. 13E.,	all
T. 11N.,	R. 14E.,	all
T. 11N.,	R. 15E.,	all
T. 11N.,	R.	17, 18, 19, 30, 31, 32

	16E.,	
T. 12N.,	R. 10E.,	13, 24,
T. 12N.,	R. 11E.,	15, 16, 17, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29, 30,
		32, 33, 34, 35, 36
T. 12N.,	R. 12E.,	23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 13E.,	19, 20, 21, 22, 23, 26, 27, 28, 29, 30, 31, 32, 33, 34,
		35, 36
T. 12N.,	R. 14E.,	25, 26, 27, 28, 29, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 15E.,	25, 26, 27, 28, 29, 30 ,31 ,32, 33, 34, 35, 36

(Source: C. O. 145, page 7, expansions/contractions of initial participating area based on November 20, 1987 letter, Wade and Nelson to Eason, Re: Prudhoe Bay Unit Exhibits, Exhibit C, Part I Oil Rim Participating Area and Part II Gas Cap Participating Area.)

<u>**Rule 1 Pool Definition and Changing the Affected Area**</u> (ref. C.O. 145)

(a) The Prudhoe Oil Pool is defined as the accumulations of oil that are common to and which correlate with the accumulations found in the Atlantic Richfield - Humble Prudhoe Bay State No. 1 well between the depths of 8,110 feet and 8,680 feet. (Source: C.O. 145, Rule 1)

(b) The Commission may adjust the description of the affected area to conform to future changes in the initial participating area by administrative approval. (Source: C. O. 145, Rule 12)

<u>**Rule 2 Well Spacing**</u> (ref. C.O. 145, 174)

There shall be no restrictions as to well spacing except that no pay shall be opened in a well closer than 500 feet to the boundary of the affected area. (Source: C.O. 174, Rule 2)

<u>**Rule 3 Casing and Cementing Requirements**</u> (ref. C.O. 145, 238)

(a) Conductor casing shall be set at least 75 feet below the surface and sufficient cement shall be used to fill the annulus behind the pipe to the surface. Rigid high-density polyurethane foam may be used as an alternate to cement, upon approval by the Commission. The Commission may also administratively approve other sealing materials upon application and presentation of data which show the alternate is appropriate based on accepted engineering principles. (Source: C.O. 238, Rule 3a)

(b) Surface casing to provide proper anchorage for equipment, to prevent uncontrolled flow, to withstand anticipated internal pressure, and to protect the well from the effects of permafrost thaw-subsidence or freeze-back loading shall be set at least 500 feet, measured depth, below the base of the permafrost but not below 5000 feet true vertical depth. Sufficient cement shall be used to fill the annulus behind the casing to the surface. The surface casing shall have minimum axial strain properties of 0.5% in tension and 0.7% in compression. (Source: C.O. 238, Rule 3b)

(c) Alternate casing programs may be administratively approved by the Commission upon application and presentation of data, which show the alternatives, are appropriate, based upon accepted engineering principles. (Source: C.O. 238, Rule 3c)

Rule 4 Blowout Prevention Equipment and Practice (revoked C.O. 341D).

Rule 5 Automatic Shut-in Equipment (ref. C.O. 145, 333, 363)

(a) Each well shall be equipped with a Commission approved fail-safe automatic surface safety valve system (SVS) capable of preventing uncontrolled flow by shutting off flow at the wellhead and shutting down any artificial lift system where an over pressure of equipment may occur.

(b) The safety valve system (SVS) shall not be deactivated except during repairs, while engaged in active well work, or if the pad is manned. If the SVS cannot be returned to service within 24 hours, the well must be shut in at the well head and at the manifold building.

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

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

(c) A representative of the Commission will witness operation and performance tests at intervals and times as prescribed by the Commission to confirm that the SVS is in proper working condition.

(d) The SVS must be maintained in working condition at all times unless the well is shut in and secured, or the well is being operated in conformance with other sections of this rule.

(e) Upon proper application or its own motion, the Commission may administratively waive or amend the requirements of this rule as long as the change does not promote waste, jeopardize correlative rights or compromise ultimate recovery, and is based on sound engineering principles.

(f) Nothing in this rule precludes the installation of a SSSV in wells designated by the operator. If a SSSV is installed, it must be maintained in working order and is subject to performance testing as part of the SVS.

Rule 6 Pressure Surveys (ref. C.O. 145, 165, 192, 208, 213, 220, AA 220.1, 341B)

(a) Prior to regular production, a static bottom hole or transient pressure survey shall be taken on at least one in three wells drilled from a common drilling site. (Source: C.O. 220, Rule 1, C.O. 341B)

(b) An annual pressure surveillance plan shall be submitted to the Commission in conjunction with the Annual Prudhoe Pool Reservoir Surveillance Report by April 1, each year. The plan will contain the number of pressure surveys anticipated for the next calendar year and be subject to approval by the Commission by May 1. These surveys are needed to effectively monitor reservoir pressure in the Prudhoe Oil Pool. The surveys required in (a) of this rule may be used to fulfill the minimum requirements. (Source: C.O. 220, Rule 6, C.O. 341B)

(c) Data from the surveys required in (a) and (b) of this rule shall be submitted with the Annual Prudhoe Oil Pool Reservoir Surveillance Report by April 1 each year. Data submitted shall include rate, pressure, time depths, temperature, and any well condition necessary for the complete analysis of each survey. The datum for the pressure surveys is 8800 feet subsea. Transient pressure surveys obtained by a shut in buildup test, an injection well pressure fall-off test, a multi rate test or an interference test are acceptable. Other quantitative methods may be administratively approved by the Commission. (Source: C.O. 220, Rule 7, C. O. 341C.001)

(d) Results and data from any special reservoir pressure monitoring techniques, tests, or surveys shall also be submitted as prescribed in (c) of this rule. (Source: C.O. 220, Rule 8)

(e) By administrative approval the Commission may grant time extensions and waive requirements of this rule, and by administrative order the Commission may require additional pressure surveys in (b) of this rule. (Source: C.O. 220, Rule 5)

Rule 7 Gas-Oil Contact Monitoring (ref. C.O. 145, 165, 192, 208, 213, AA 213.39)

(a) Prior to initial sustained production, a cased or open hole neutron log shall be run in each well. (Source: C.O. 165, Rule 9a) This requirement is waived for waterflood/EOR areas encompassed by the expanded Prudhoe Bay Miscible Gas Project outlined in C.O. 290, and for those areas not expected to have significant GOC movement or gas encroachment from the gravity drainage area defined by the Commission through Administrative Approval. (Source: AA 213.39, excerpts from paragraph 1)

(b) A minimum of 40 repeat cased hole neutron log surveys shall be run annually. (Source: C.O. 208, Rule 4)

(c) The neutron logs run on any well and those required in (a) and (b) of this rule shall be filed with the Commission by the last day of the month following the month in which the logs were run. (Source: C.O. 165, Rule 9d)

(d) By administrative approval, the Commission may delay, modify or waive the logging requirements of this rule or may require additional wells to be logged. (Source: C.O. 213, Rule 3)

Rule 8 Productivity Profiles (ref. C.O. 145, 165, 192, 208, 213, AA 213.40)

(a) A spinner flow meter or tracer survey shall be run in each well during the first six months the well is on production. (Source: C.O. 165, Rule 11a) This requirement is waived for wells completed with a single perforated interval, or with perforations in a single reservoir zone including highly deviated (greater than 65 degrees) and horizontal wells. (Source: AA 213.40

paragraph 3)

(b) Follow-up surveys shall be performed on a rotating basis so that a new production profile is obtained on each well periodically. Nonscheduled surveys shall be run in wells which experience an abrupt change in water cut, gas-oil ratio, or productivity. (Source: C.O. 165, Rule 11b)

(c) The complete spinner flow meter or tracer data and results shall be recorded and filed with the Commission by the last day of the month following the month in which each survey is taken. (Source: C.O. 165, Rule 11c)

(d) The Commission may administratively approve alternate methods and time periods in the enforcement of this rule provided that the data obtained is appropriate for monitoring the Prudhoe Oil Pool or may waive the requirements of (a), (b) and (c). By administrative order the Commission may specify additional surveys other than the surveys submitted under (a), (b) and (c) of this rule. (Sources: C.O. 208, Rule 8 and C.O. 213, Rule 2)

Rule 9 Pool Off-Take Rates (ref. C.O. 145, 214)

The maximum annual average oil offtake rate is 1.5 million barrels per day plus condensate production. The maximum annual average gas offtake rate is 2.7 billion standard cubic feet per day, which contemplates an annual average gas pipeline delivery sales rate of 2.0 billion standard cubic feet per day of pipeline quality gas when treating and transportation facilities are available. Daily offtake rates in excess of these amounts are permitted only as required to sustain these annual average rates. The annual average offtake rates as specified shall not be exceeded without the prior written approval of the Commission.

Annual average offtake rates mean the daily average rate calculated by dividing the total volume produced in a calendar year by the number of days in the year. However, in the first calendar year that large gas offtake rates are initiated, following the completion of a large gas sales pipeline, the annual average offtake rate for gas shall be determined by dividing the total volume of gas produced in the calendar year by the number of days remaining in the year following initial delivery to the large gas sales pipeline.

Rule 10 Facility Gas Flaring revoked (ref. C. O. 341C)

Rule 11 Annual Surveillance Reporting (ref. C.O. 165, 186, 195, 208, 223, 224, 279, AA 279.1)

(a) An annual Prudhoe Oil Pool surveillance report will be required by April 1 of each year. The report shall include but is not limited to the following:

1. Progress of enhanced recovery project(s) implementation and reservoir management summary including engineering and geotechnical parameters.

2. Voidage balance by month of produced fluids, oil, water and gas, and injected fluids, gas, water, low molecular weight hydrocarbons, and any other injected substances (which can be filed in lieu of monthly Forms 10-413 for each EOR project). (Source C.O. 279, Rule 7 and AA 279.1 excerpt from paragraph 3)

3. Analysis of reservoir pressure surveys within the field.

4. Results and where appropriate, analysis of production logging surveys, tracer surveys and observation well surveys.

5. Results of gas movement and gas-oil contact surveillance efforts including a summary of wells surveyed and analysis of gas movement within the reservoir. The analysis shall include map(s) and/or tables showing the locations of various documented gas movement mechanisms as appropriate. (Source: C.O. 279, Rule 7)

6. Progress of the Gas Cap Water Injection project with surveillance observations including;

(a) volume of water injected,
(b) reservoir pressure results, maps, and analysis (in conjunction with (a) 3 of this rule),
(c) water movement and zonal conformance maps derived from surveillance (such as Pulsed Neutron Logs and 4-D gravity surveys)
(d) results of reservoir evaluations of performance (such as material balance and reservoir simulation studies),
(e) surveillance plans for the upcoming year, and
(f) any plans for change in project operation.

(b) Upon its own motion or upon written request, the Commission may administratively amend this rule so long as the change does not promote waste nor jeopardize correlative rights and is based on sound engineering principles. (Source: C.O. 279, Rule 8)

<u>**Rule 12 Prudhoe Bay Miscible Gas Project (PBMGP)**</u> (ref. C.O. 195, 290)

(a) Expansion of the PBMGP and infill expansion of miscible gas injection in the NWFB is approved for the 59,740 acre portion of the Prudhoe Oil Pool defined in the record. (Source: C.O. 290, Rule 1, AA 290.1)

(b) An annual report must be submitted to the Commission detailing performance of the PBMGP and outlining compositional information for the current miscible injectant (MI) necessary to maintain miscibility under anticipated reservoir conditions. (Source: C.O. 290, Rule 2)

(c) The minimum miscibility pressure (MMP) of the Miscible Injectant must be maintained at least 100 psi below the average reservoir pressure in the Prudhoe Bay Miscible Project area. When the Operator demonstrates that the reservoir pressure is no longer declining within the Prudhoe Bay Miscible Project Area (as evidenced by reservoir pressure measurements), the MMP may be maintained at or below the average reservoir pressure in the Prudhoe Bay Miscible Project area. (Source: C.O. 290, Rule 4; amended C.O. 341D)

(d) Revoked (C.O. 341D).

(e) Upon its own motion or upon written request, the Commission may amend this rule by administrative action if the change does not promote waste, violate correlative rights, nor jeopardize ultimate recovery, and is based on sound engineering principles. (Source: C.O. 290, Rule 6)

Rule 13 Waiver of GOR Limitation (ref. 8/22/86 letter)

The Commission waives the requirements of 20 AAC 25.240(b) for all oil wells in the Prudhoe Oil Pool of the Prudhoe Bay Field so long as the gas from the wells is being returned to the pool, or so long as the additional recovery project is in operation. (Source: Letter 8/22/86, L. Smith to Heinze/Nelson, paragraph 3)

Rule 14 Waiver of "Application for Sundry Approval" Requirement for Workover Operations (ref. C.O. 258)

The requirements of 20 AAC 25.280(a) are waived for development wells in the Prudhoe Oil Pool of the Prudhoe Bay Field. (Source: C.O. 258)

Rule 15 Waterflooding (ref. 3/20/81 letter Hamilton to Nelson/Norgaard)

The commission approves the December 1980 additional recovery application for water-flooding in the Prudhoe Oil Pool subject to the requirements listed in Rule 11 above.

Any proposed changes must be submitted to the Commission for approval. (Source: Letter 3/20/81, Hamilton to Nelson/Norgaard)

Rule 16 Orders Revoked

The following Conservation Orders and associated Administrative Approvals and letter approvals are hereby revoked. Conservation orders 78, 83B, 85, 87, 88, 96, 97, 98B, 117, 117A, 118, 130, 137, 138, 139, 140, 141, 143, 145, 145A, 148, 155, 160, 164, 165, 166, 167, 169, 174, 178, 180, 181, 183, 184, 185, 186, 188, 189, 192, 194, 195, 195.1, 195.2, 195.4, 197, 199, 200, 204, 208, 213, 214, 219, 220, 223, 224, 238, 258, 259, 279, 290 and 333, 341, 341A, 341B, 341C, and March 20, 1981 and August 22, 1986 letter approvals.

The hearing records of these orders are made part of the record for this order.

Rule 17 Gas Cap Water Injections

The Gas Cap Water Injection Project as described in the operator's application and testimony is approved. Ongoing reservoir surveillance is required to determine that water movement within the reservoir is confined as intended and does not negatively impact overall hydrocarbon recovery, and to determine that the project has resulted in stabilization of reservoir pressure.

DONE at Anchorage, Alaska and dated November 30, 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, Commissioner
Alaska Oil and Gas Conservation Commission

Conservation Order Index