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

Re: THE APPLICATION OF UNION OIL COMPANY OF CALIFORNIA ("Unocal") for an order authorizing the underground storage of hydrocarbons in the Beluga and Sterling Formations in Pretty Creek Unit Well No. 4, Cook Inlet Area, Alaska.	)	**Storage Injection Order No. 4**
	)	
	)	**Pretty Creek Unit**
	)	**Pretty Creek Gas Storage Facility Pretty Creek Unit Well No. 4**
	)	
	)	**September 12, 2005**

IT APPEARING THAT:

1. By application dated May 10, 2005 and received by the Alaska Oil and Gas Conservation Commission ("Commission") on May 11, 2005, Union Oil Company of California ("Unocal") requested an order from the Commission authorizing the underground storage of hydrocarbons in the Beluga and Sterling Formations of the proposed Pretty Creek Gas Storage Facility ("PCGSF") using Pretty Creek Unit ("PCU") Well No. 4. Unocal proposes to inject gas into the PCU #4 well for storage during periods of excess gas supply and to produce the gas during periods of increased demand. This well is located in Section 33, Township 14 North, and Range 9 West, Seward Meridian ("SM").

2. Unocal submitted a revised application, dated June 20, 2005 and received June 22, 2005 that addressed errors and discrepancies in the original application.

3. Notice of opportunity for public hearing was published in the Anchorage Daily News Anchorage Daily News on June 24, 2005 in accordance with 20 AAC 25.540.

4. Cook Inlet Keeper submitted comments concerning Unocal's PCGSF Application on June 27, 2005; but did not request a public hearing.

5. On July 11, 2005 Trading Bay Oil & Gas, LLC ("TBO&G") requested the AOGCC hold a public hearing regarding Unocal's PCGSF proposal, citing correlative rights and potential encroachment on TBO&G leases to the North of PCU.

6. The Commission convened a public hearing on July 26, 2005. The hearing was continued to August 10, 2005 at the request of the Applicant and by consent of TBO&G.

7. On August 9, 2005 Unocal submitted an email and attached documents answering questions raised by AOGCC staff regarding the revised application

8. The public hearing was re-convened in conformance with 20 AAC 25.540 at the Commission's offices, 333 W. 7th Avenue, Suite 100, Anchorage, Alaska 99501 on August 10, 2005, at which time the Commission heard testimony concerning proposed storage of gas in and around well PCU #4. The hearing record was left open through August 17, 2005 to allow Unocal to provide exhibits and clarification to their hearing testimony.

9. On August 17, 2005 Unocal submitted an affidavit and 6 exhibits (Exhibits A, B, C, D, E, and F) to clarify testimony regarding the structure, stratigraphy and areal extent of the

Sterling 45-0 and Beluga 51-5 sands. Exhibits D and E were submitted under seal as proprietary and confidential information related to the proceedings.

10. The hearing record was closed at 4:30 p.m. ADT on August 17, 2005.

FINDINGS:

1. Operator:

Unocal is the operator of the PCU, which is located on the west side of Cook Inlet in Townships 13 North and 14 North, Range 9 West, SM.

2. Project Description:

Unocal proposes to use PCU #4 for storage purposes as well as a periodic peak demand producer in the proposed storage program. The gas storage project will inject a significant gas volume into the available reservoir(s) at a relatively high injection rate and withdraw the gas at a relatively high rate during peak demand periods. Unocal proposes to conduct dry gas storage injection within the PCU #4 well using the Beluga Formation 51-5 sandstone ("Beluga 51-5") as a primary target. The Sterling Formation 45-0 sandstone ("Sterling 45-0") may be used as a secondary target at some point in the future.

3. Storage Area:

The PCU #4 well is drilled and completed within State of Alaska Oil & Gas leases ADL 63048 and ADL 58813. The State of Alaska is the subsurface landowner within the area covered by the leases. There are no other operators within a one-quarter mile radius of the PCU #4 well. Unocal has given notice and copies of its application to the surface owners within a one-quarter mile radius of the PCU #4 well and to a surface and mineral rights owner whose land lies outside the storage area but within the current Pretty Creek Unit boundary.

4. Storage Reservoirs Description & Properties:

Unocal describes the Beluga 51-5 as lying between 5144 and 5173 feet measured depth ("MD") and the Sterling 45-0 lies between 4503 and 4518 feet MD in the PCU #4 well.

The Sterling Formation is comprised of interbedded sandstone, siltstone, mudstone and coal. This formation was likely deposited in a high energy meandering to braided stream environment. The Sterling 45-0 is confined by 36 feet of coal above and 33 feet of coal below. The coal is commonly called Beluga Coal and is laterally extensive and correlates across gas fields to the north and east. The Beluga Coals are described in Unocal's application as barriers between permeable sands above and below the Sterling 45-0 sandstone.

The Beluga Formation lies below the Sterling and is characterized as stream sediments deposited in a low energy environment. Beluga sandstones are commonly lenticular and often discontinuous over interwell distances. The Beluga section is approximately 900 feet thick in the Pretty Creek Unit.

The Beluga 51-5 is bounded above by 10 feet of impermeable interbedded siltstone, clay-rich siltstone and mudstone. Underlying the Beluga 51-5 are 21 feet of shale and shaly coal which grade to 10 feet of coal (informally termed the PC4 Beluga Coal in the PCU #4 well), which is laterally extensive and seals the overlying sand from potential permeable sands below.

Initial reservoir pressure estimated in PCU #4 Beluga 51-5 was 1674 psia at 3686 feet true vertical depth ("TVD"), assuming a normal 0.45 psi/foot gradient. Reservoir pressure in the PCU #4 well Beluga 51-5 has depleted to about 669 psi between December 2001 and February 2005.

5. Production & Material Balance:

Production from the Sterling 45-0 and Beluga 51-5 and an underlying sandstone termed Beluga 55-6 has been commingled on occasion and has totaled 2.6 BCF. The Operator suspects the Beluga 55-6 is non-productive or depleted and did not contribute any gas during appraisal tests or attempts to produce.

Unocal estimates the Beluga 51-5 originally held 2.07 Bcf gas-in-place ("GIP") based on a P/Z material balance analysis. The pressure used in the analysis was from the Beluga 51-5 when isolated from the Sterling 45-0 and the Beluga 55-6. Material balance analysis of historical production supports the contention that the Beluga 51-5 and Sterling 45-0 intervals proposed for gas storage each drain a limited area, are isolated from other strata and from each other. The Operator believes the Sterling 45-0 has watered out based on production history and performance.

Gas storage in a water-saturated sand may cause production problems by increasing formation back pressure as water is produced thereby decreasing gas flow rate and increasing water handling problems at the surface. Formation water may potentially trap gas when injection displaces it and then resaturates during production operations.

Unocal stated that gas was likely trapped in the Sterling 45-0 as it depleted and water encroached. The last pressure measured in the Sterling 45-0 was 687 psi during April 2004. This indicates energy remains within the reservoir. As water production from this zone increased, the amount of produced water became too great to lift from the perforations to the surface.

Gas storage in the Sterling 45-0 may or may not cause additional gas to be trapped. Unocal acknowledged the Sterling 45-0 would have slightly more risk of gas loss because of elevated water saturation.

6. Mechanical Condition:

The Operator will demonstrate the mechanical integrity of the PCU #4 well according to the provisions of 20 AAC 25.252(d) before initiating gas injection and storage operations.

Well records indicate the Beluga 51-5 and Sterling 45-0 in the PCU #4 well are adequately protected by casing and cement. The Beluga 51-5 and Sterling 45-0 in the PCU #4 well are covered by 7 inch production casing, which was cemented with 106 barrels of 12 pound per gallon cement. The cement evaluation log (Ultrasonic Imager Cement Bond Log dated 11/04/01) indicated good bond from 6918-5900 feet MD. A formation leak off test at 6941 feet MD indicated leak off at 1465 psi and a 0.82 fracture gradient indicating the cement at the shoe of the 7" casing was sealing.

A remedial circulation squeeze cement job was performed on the 7" casing through perforations from 5594 to 5596 feet MD. Drilling mud was circulated from the 7" by open hole and the 7" by 9-5/8" casing annuli. The remedial cement job consisted of 230 barrels of cement pumped through the perforations and circulated to surface with 12 barrels returned. The evaluation of the cementing operation indicated formation isolation. Further evidence of formation isolation is predicated on the volumetric depletion and pressure drop in each sandstone and lack of behind-pipe water movement.

The PCU #4 well has been completed to isolate the Sterling 45-0, Beluga 51-5 and Beluga 55-6 to prevent cross flow in the tubing. There are packers above and below the upper sandstones and sliding sleeves across from each interval to facilitate isolation. Unocal described water cross flow from the Sterling 45-0 to the Beluga 51-5 when the well was shut-in for mechanical problems.

7. Reservoir Fluids, Gas and Storage Gas Properties:

The gas proposed for storage is predominantly methane produced from Middle Kenai Gas Pool in the McArthur River Field. The composition of this gas is 97.8% methane, 1.5% carbon dioxide 0.3% nitrogen and 0.4% other gaseous hydrocarbons (ethane, propane, butanes and C6+). The gas from the Pretty Creek undefined pool has 98.8% methane, 0.5% CO_2, 0.6% N_2 and 0.1% miscellaneous hydrocarbons (ethane, C6+). Specific gravity of the injected gas is expected to be 0.57 (air = 1.0). Gas from other fields on the West side of Cook Inlet may also be stored in the PCGSF.

Produced water from the Sterling 45-0 has approximately 22,500 parts per million Total Dissolved Solids ("TDS"). Water from the Beluga 51-5 has approximately 9,900 parts per million TDS. TDS are based on samples the Operator gathered and had analyzed. Both reservoir intervals are classified as hydrocarbon bearing and are not sources of drinking water.

Unocal does not expect gas adsorption in adjacent coal beds to cause a significant problem for the PCGSF in the Sterling 45-0. Gas adsorption and desorption will occur according to the pressure being exerted by injection or the pressure differential exerted by depletion caused by production.

8. Injection Rate, Pressure and Fracture Gradients:

Formation fracture gradients measured in shallower and deeper formations range from 0.99 psi to 0.82 psi per foot based on leak off tests performed at 2398 and 6954 feet MD respectively. Neither the Beluga nor Sterling Formations have had direct fracture gradient determinations. Calculated fracture gradients based on electric log-derived properties were 0.68 and 0.72 psi/ft for the Sterling 45-0 and between 0.77 and 0.79 psi/ft in the Beluga 51-5.

Estimated maximum injection rate is 20 MMSCF/D, and expected average wellhead injection pressure is 1550 psig. The Operator proposes to limit the maximum pressure gradient while injecting gas to 0.65 psi/ft. This will limit maximum injection pressure to 2400 psi at the mid-point of Beluga 51-5 at 3686 feet TVD. The proposed maximum pressure and gradient are less than calculated fracture gradients of the Beluga 51-5 and Sterling 45-0.

9. Reservoir Surveillance:

Unocal plans to monitor the reservoirs with material balance based on measured net gas in and out of the reservoir and reservoir pressure. Hysteresis effects between injection and production material balance data may alter straight-line P/Z analysis, but the technique is expected to verify volumetric balance within the storage reservoirs. Material balance surveillance of the Beluga 51-5 and Sterling 45-0 will enable the Operator to account for gas in and out of the reservoirs, monitor mechanical integrity, monitor confinement of the gas and provide a means to prevent waste.

10. Lateral Reservoir Confinement:

TBO&G holds five leases immediately to the north and east of Pretty Creek Unit. TBO&G stated their support for gas storage projects in the Cook Inlet Area. TBO&G is concerned that operation of the PCGSF could impact their leases if gas were to migrate from the storage reservoir onto their leases and potentially create correlative rights and safety issues.

Maps provided by Unocal indicate the Beluga 51-5 and Sterling 45-0 reservoirs are confined within a small area of the PCU by the structure and stratigraphic features. This interpretation is based on data derived from drilling, electric logs, pressure tests, material balance, and production performance.

CONCLUSIONS:

1. The project as described and proposed meets the requirements of 20 AAC 25.252.

2. Mechanical integrity of the PCU #4 well will be demonstrated according to the requirements of 20 AAC 25.252(d) prior to initiating gas injection and storage operations.

3. The proposed injection of natural gas into the PCU #4 well for the purpose of storage will not cause movement of hydrocarbons into sources of freshwater.

4. The proposed storage of natural gas in the reservoir beneath the PCU #4 well will not cause fluids to move behind casing beyond the approved storage zone.

5. The proposed storage of natural gas in well PCU #4 will not propagate fractures through the confining zones.

6. The proposed injection of natural gas into the PCU #4 well for the purpose of storage will not cause waste, jeopardize correlative rights, endanger freshwater, or impair ultimate recovery.

7. Surveillance of operating parameters on the storage well and offset wells will aid in preventing stored gas from moving out of the formation where it is intended to be stored.

8. Surveillance of reservoir pressure and volumes injected and produced will ensure conservation of natural gas, prevent waste and protect correlative rights.

NOW, THEREFORE, IT IS ORDERED that the following rules, in addition to statewide requirements under 20 AAC 25, apply to the underground storage of hydrocarbons by injection in the PCU #4 well.

<u>RULE 1: STORAGE INJECTION</u>

The Commission approves the injection for storage of natural gas into the Beluga Formation 51-5 sandstone. After one year of injection storage and retrieval operations have been completed, the operator shall provide a written summary report and meet with the Commission to present its findings. At that time, the Commission will render a decision concerning storage injection operations in the Sterling Formation 45-0 sandstone within the PCU #4 well bore. The Operator shall report disposition of production and injection as required by 20 AAC 25.228, 20 AAC 25.230, and 20 AAC 25.235.

<u>RULE 2: ACQUISITION OF A GAS STORAGE LEASE</u>

The Commission's approval in Rule 1 is conditioned on the issuance and maintenance of a Gas Storage Lease from the Alaska Department of Natural Resources, Division of Oil and Gas, in accordance with AS 38.05 prior to beginning and throughout the duration of storage operations.

<u>RULE 3: DEMONSTRATION OF MECHANICAL INTEGRITY</u>

The mechanical integrity of the 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 the 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 shall 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 4: WELL INTEGRITY FAILURE AND CONFINEMENT

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by injection rates, operating pressure observations, tests, surveys, logs, 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 and offsets within 1/2 mile indicating well integrity failure or lack of injection zone isolation.

RULE 5: MAXIMUM INJECTION PRESSURE

Maximum wellhead injection pressure shall be limited to 1900 psi or 20% over initial reservoir pressure or 2000 psi at 3686 feet TVD and a formation pressure gradient of 0.55 psi per foot. Upon satisfactory demonstration of confinement of the storage gas at elevated pressure by P/Z material balance, the Operator may apply to the Commission to increase the reservoir pressure for storage purposes.

RULE 6: ANNUAL PERFORMANCE REPORT

An annual report evaluating the performance of the storage injection operation must be provided to the Commission no later than 60 days after the beginning of each calendar year. The report shall include material balance calculations of the gas production and injection volumes to provide assurance of continued reservoir confinement of the gas storage volumes.

RULE 7: EXPIRATION OF APPROVAL`

As provided in 20 AAC 25.252(j), if storage operations are not begun within 24 months after the date of this Order, the injection approval shall expire unless an application for extension has been approved by the Commission.

RULE 8: ADMINISTRATIVE ACTIONS

Unless notice and public hearing is 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 September 12, 2005.

John K. Norman Chairman	Daniel T. Seamount, Jr. Commissioner	Cathy P. Foerster Commissioner

AS 31.05.080 provides that within 20 days after receipt of written notice of the entry of an order, a person affected by it may file with the Commission an application for rehearing. A request for rehearing must be received by 4:30 PM on the 23rd day following the date of the order, or next working day if a holiday or weekend, to be timely filed. The Commission shall grant or refuse the application in whole or in part within 10 days. The Commission can refuse an application by not acting on it within the 10-day period. An affected person has 30 days from the date the Commission refuses the application or mails (or otherwise distributes) an order upon rehearing, both being the final order of the Commission, to appeal the decision to Superior Court. Where a request for rehearing is denied by nonaction of the Commission, the 30-day period for appeal to Superior Court runs from the date on which the request is deemed denied (i.e., 10th day after the application for rehearing was filed).