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

Re: THE APPLICATION OF Aurora Gas LLC for disposal of Class II oil field wastes by underground injection in the Beluga Formation in the Aspen No. 1 Well, Section 33, T12N, R11W, S.M.	**Disposal Injection Order No. 32** **Beluga Formation** **Aspen No. 1 Well** **February 7, 2008**

IT APPEARING THAT:

1. By correspondence dated August 17, 2007 and received by the Alaska Oil and Gas Conservation Commission ("AOGCC" or "Commission") August 20, 2007, Aurora Gas, LLC ("Aurora") requested that the Commission issue an order authorizing underground disposal of Class II oil field waste fluids into the Beluga Formation through the Aspen No. 1 ("Aspen 1") well bore. The Aspen 1 well is located in Section 33, T12N, R11W, Seward Meridian ("S.M."), on the west side of Cook Inlet, Alaska.

2. Aurora originally submitted information to the Commission on May 15, 2007 concerning the proposed disposal injection. A letter sent to Aurora dated July 17, 2007 outlined additional information required before accepting for public notice and comment an application for the underground disposal of Class II oil field wastes. Aurora provided requested information to the Commission on July 18, August 10, and August 17, 2007.

3. Notice of opportunity for a public hearing was published in the ANCHORAGE DAILY NEWS on September 5, 2007 in accordance with 20 AAC 25.540.

4. The Commission did not receive any public comments, protests or a request for a public hearing.

5. A public hearing was held October 9, 2007. A brief project summary was provided by an Aurora representative. The Commission requested additional information concerning injected fluid confinement. The hearing was continued until October 16, 2007. Aurora submitted the requested information on October 11, 15 and 16, 2007.

6. The public hearing was reconvened on October 16, 2007. At the hearing, Commission senior staff confirmed that the additional information requested had been submitted.

7. Information submitted by Aurora and public well history records are the basis for this order. The Aspen 1 well history file, including well logs, was publicly released on October 6, 2007.

FINDINGS:

1. <u>Location of Adjacent Wells (20 AAC 25.252(c)(1))</u>

   There are no wells with surface or bottomhole locations within a one-quarter mile radius of the Aspen 1 well. The nearest known water well is a 50-foot deep domestic water well located about 3.5 miles to the northwest at the Chuit River Lodge.

2. <u>Notification of Operators/Surface Owners (20 AAC 25.252(c)(2) and 20 AAC 25.252(c)(3))</u>

   Aurora is the operator of the Aspen 1 well, which was drilled as a gas exploration well and suspended in 2005. The sole surface owner within a one-quarter mile radius of the Aspen 1 well is Tyonek Native Corporation ("TNC"). Cook Inlet Regional Incorporated ("CIRI") is the sole subsurface owner. Aurora submitted an affidavit showing that TNC and CIRI were provided a copy of the disposal application and thereby notified of the proposed waste disposal injection into the Beluga Formation using Aspen 1.

3. <u>Geologic Information on Disposal and Confining Zones (20 AAC 25.252(c)(4))</u>

   Aspen 1 encountered the Beluga Formation ("Beluga") from a depth of 722 feet measured depth ("MD") to the total depth of the well at 4,485 feet MD. In the Aspen 1 well, the Beluga is dominated by claystone and clay intervals that are interspersed with beds of coal (generally less than 5 feet thick, but occasionally from 6 feet to 12 feet thick) and thin beds (1 foot to 5 feet thick) of sand, sandstone, or siltstone. Sand and sandstone beds within the Beluga are discontinuous, and they are interpreted to have been deposited by shifting, shallow, braided streams (Hayes, J.B., Harms, J.C., and Wilson, T.W., 1976, in Miller, T.P., ed., Recent and Ancient Sedimentary Environments in Alaska, Alaska Geological Society Symposium Proceedings, p.J1-J27).

   Aurora proposes to conduct disposal operations in the Aspen 1 well in the Beluga between 2,125 feet and 2,371 feet MD. This receiving zone consists of interbedded sand, claystone and coal. Well and mud log information indicate that the sand beds are up to 4 feet thick and composed of very fine-grained to coarse-grained sand partially cemented by calcite. The claystone beds are up to 5 feet thick. The coal beds are up to 6 feet thick and scattered throughout the injection interval.

Aurora proposes to utilize two perforated zones for the Class II disposal injection. The upper zone would be between 2,125 feet and 2,145 feet MD. This interval's effective porosity is about 25 percent, based on calculations using well log data. The lower perforated zone will also be 20 feet thick, with the top at 2,351 feet MD. This interval's effective porosity is about 22 percent.

Upper, lower and lateral confinement will result from interlayered claystone, clay, siltstone and coal beds as described in Finding 9 below.

4. Aspen 1 Logs (20 AAC 25.252(c)(5))

   The logs of the Aspen 1 well are on file at the AOGCC.

5. Aspen 1 Casing Description (20 AAC 25.252(c)(6)(A))

   There are three strings of casing as follows:

   - Conductor Casing: 13-3/8", 68 pounds per foot, J-55 casing driven to 77 feet true vertical depth ("TVD")[1];
   - Surface Casing: 9-5/8", 53.5 pounds per foot, L-80 casing, shoe depth 675 feet TVD, cemented to surface with 30 barrels of cement;
   - Production Casing: 5-½", 15.5 pounds per foot, J-55 casing, shoe depth 4,467 feet TVD, cemented to surface with 41 barrels of lead (13.5 pounds per gallon ("ppg")) and 136 barrels of tail (15.8 ppg) slurry.

6. Demonstration of Mechanical Integrity and Disposal Zone Isolation (20 AAC 25.252 (c)(6))

   Proposed workover operations were approved by the Commission on May 29, 2007 allowing Aurora to reconfigure Aspen 1 for Class II oil field waste disposal purposes. Sundry approval 307-172 authorizes Aurora to reenter Aspen 1 to confirm casing integrity, remove suspension plugs, install 2-7/8" injection tubing and packer in the well, and install the injection tree.

   A cement quality log is available for Aspen 1. It evidences the existence of adequate bonding across the upper and lower confining intervals to ensure disposed fluids are appropriately isolated. The top of the cement for the innermost casing is at 220 feet MD, which is approximately 470 feet above the surface casing shoe.

   Aspen 1 was perforated between 1,368 feet and 1,388 feet MD and flow tested as part of the exploration evaluation. Those perforations were abandoned with a balanced plug set from 1,265 feet to 1,373 feet MD prior to suspending the well. In the approved work plan, Aurora will drill out this plug and install 2-7/8" injection tubing and packer to isolate the uppermost perforations behind pipe.

[1] Aspen 1 is a vertical well; TVD equals MD.

Prior to initiating disposal operations, Aurora will perform a pressure test of the tubing by production casing annulus as required by 20 AAC 25.412(c). Aurora has also committed to a one-time temperature survey during the initial injection to demonstrate that the injected fluids are confined.

7. Disposal Fluid Type, Source, Volume and Compatibility with Disposal Zone (20 AAC 25.252(c)(7))

The wastes planned for disposal in Aspen 1 would consist of produced water, drilling, completion and workover fluids, rig wash, mud slurries and other Class II fluids and solids. The composition and constituents of the waste stream are heavily dependent on the type of activity (drilling, stimulation, production, maintenance, etc.). Fluids associated with production at the Three Mile Creek Unit ("TMCU") and Nicolai Creek Unit ("NCU") are currently stored in a nearby produced water impoundment. These fluids would be disposed of in Aspen 1.

Laboratory analyses of the produced fluids from TMCU 1, TMCU 2, and NCU 9 and the fluids temporarily stored in the produced water impoundment were provided to the Commission. Calculations to determine the scaling tendencies of the produced waters were also provided. Produced water from the Beluga Formation within the TMCU 1 and TMCU 2 wells may cause calcium carbonate scale or precipitates to form when injected into Aspen 1. None of the other Aspen 1 proposed waste stream fluids are likely to form scale or precipitates.

8. Estimated Injection Pressure (20 AAC 25.252(c)(8))

A 4-point step rate test (which is a test designed to validate the injection rate and pressures used in fracture modeling) would be performed prior to any disposal injection operations using water from the produced water impoundment. The test would be designed to establish the actual injection rate and pressure characteristics of the Beluga Formation. Aurora's fracture modeling predicts injection pressures between 1,200 psi and 1,600 psi at disposal rates of 1 barrel per minute and fluid densities ranging from 8.4 pounds per gallon to 9.7 pounds per gallon.

9. Evaluation of Confining Zones (20 AAC 25.252(c)(9))

Disposed wastes will be prevented from migrating upward by interlayered claystone, clay, siltstone and coal occurring from 1,400 to 2,125 feet MD in Aspen 1. This upper confining interval totals 725 feet gross thickness, of which 40% is clay, claystone or coal. Downward migration will be prevented by claystone, clay, siltstone and coal occurring between 2,372 and 3,480 feet MD in the well. This lower confining interval totals 1,108 feet of gross thickness, of which 60 percent is clay, claystone or coal. Beluga sand and sandstone beds are thin and discontinuous. Encapsulating clay, claystone and coal will prevent significant lateral migration of injected fluids.

Low injection pressures, low injection rates, and the limited amount of disposed fluids ensure that fractures will not propagate through the confining intervals. Aurora's computer modeling study indicates that, under the proposed operating conditions, fractures created by fluid injection may extend upward about 30 feet MD above the receiving interval and downward about 40 feet MD below the receiving interval[2].

10. Standard Laboratory Water Analysis of the Disposal Zone (20 AAC 25.252(c)(10))

A formation water salinity determination was provided with the disposal injection application. Aurora calculated a salinity range of 10,000 to 29,000 parts per million ("ppm") for the Beluga Formation within the injection interval. Aurora's salinity calculations were confirmed by the Commission using wireline log data and methods compatible with the R_{wa} method endorsed in the U.S. Environmental Protection Agency.[3]

11. Freshwater Exemption (20 AAC 25.252(c)(11))

A freshwater aquifer exemption issued under 20 AAC 25.440 is not required because the total dissolved solids of the formation water exceed 10,000 ppm in the target injection zone.

12. Mechanical Condition of Wells Penetrating the Disposal Zone Within ¼ Mile of Aspen 1 (20 AAC 25.252(c)(12))

There are no wells within a one-quarter mile radius of the Aspen 1 well.

CONCLUSIONS:

1. The requirements of 20 AAC 25.252(b) and (c) are met.

2. A freshwater aquifer exemption is not required. The total dissolved solids of the receiving zones' waters are greater than 10,000 ppm.

3. Waste fluids will be contained within the receiving interval—and, therefore, will not contaminate freshwater, oil, or gas sources—by the confining lithologies, Aspen 1 well's construction (*i.e.*, casing and cement), and the proposed disposal injection operating conditions.

4. Disposal injection operations in the Aspen 1 well will be conducted at rates and pressures below those that would fracture through the confining zone.

5. Evaluation of surveillance and operational performance data will reasonably assure there is no fracturing through the confining zone.

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[2] *See* Bruce Webb letter to Commission, received on Oct. 15, 2007, at 2.

[3] *See* U.S. EPA, "Survey of Methods to Determine Total Dissolved Solids Concentration" (KEDA Project No. 30-956).

6. Disposal operations may result in the formation of calcium carbonate scale or precipitates.

7. Surveillance of disposal volumes, daily monitoring of operational parameters, and demonstration of mechanical integrity will reasonably assure the continued mechanical integrity of the well and that waste fluids are contained within the disposal interval.

8. Disposal injection of Class II wastes into Aspen 1 will not cause waste, jeopardize correlative rights, impair ultimate recovery, or contaminate freshwater.

NOW, THEREFORE, IT IS ORDERED THAT disposal injection is authorized into Aspen 1 subject to each of the following conditions:

RULE 1: Injection Strata for Disposal

The underground disposal of Class II well oil field waste fluids is permitted into the Beluga Formation within Aspen 1 in the interval between 2,125 feet and 2,371 feet MD. The Commission may immediately suspend, revoke, or modify this authorization if injected fluids fail to be confined within this interval.

RULE 2: Fluids

This authorization is limited to Class II waste fluids generated during drilling, production and workover operations. The operator shall treat the injected waste fluids to minimize the formation of scale or precipitates.

RULE 3: Injection Rate and Pressure

Disposal injection is authorized at (a) rates that do not exceed 1 barrel per minute and (b) surface pressures that do not exceed 1,500 psi.

RULE 4: Demonstration of Mechanical Integrity

The mechanical integrity of Aspen 1 must be demonstrated before injection begins and before returning the 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 Aspen 1, to be scheduled when injection conditions (temperature, pressure, rate, etc.) have stabilized. Subsequent mechanical integrity tests must be performed at least once every two years. The Commission must be notified at least 48 hours in advance of each such test to enable a representative to witness the test. 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 1,500 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. A written record of the results of all mechanical integrity tests must be provided to the Commission within 7 days of test completion.

RULE 5: Well Integrity Failure and Confinement

Whenever any pressure communication, leakage in any casing, tubing, or packer, or lack of injection zone isolation is indicated by the injection rate, an operating pressure observation, a test, a survey, a log, or any other evidence, the operator shall notify the Commission by the next business day and submit a plan of corrective action on Form 10-403 for Commission approval. The operator shall immediately shut in the well if continued operation would be unsafe or would threaten contamination of freshwater, or if so directed by the Commission. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the Commission for all injection wells indicating well integrity failure or the lack of injection zone isolation.

RULE 6: Surveillance

The operator shall run a baseline temperature log and perform a baseline step rate test prior to initial injection. A subsequent temperature log must be run one month after injection begins, to delineate the receiving zone of the injected fluids. Surface pressures and rates must be monitored continuously during injection for any indications of fracture height growth. The results of daily wellhead pressure observations in Aspen 1 must be documented and available to the Commission upon request. Subsequent temperature surveys or other surveillance logging (e.g., oxygen activation and acoustic) will be based on the results of the initial and follow-up temperature surveys and injection performance monitoring data.

A report evaluating the performance of the disposal operation must be submitted to the Commission by July 1 of each year. The report shall include data sufficient to characterize the disposal operation and include, for example: pressures (daily average, maximum and minimum); fluid volumes injected (disposal and clean fluid sweeps); injection rates; an assessment of fracture geometry; a description of any anomalous injection results; a calculated zone of influence for the injection fluids; and the assessment of treatments to remediate scale and precipitates.

RULE 7: Notification of Improper Injection

The operator must immediately notify the Commission if it learns of any improper injection. The notification requirements of any other state or federal agency remain the operator's responsibility.

RULE 8: Administrative Action

Unless notice and public hearing are otherwise required, the Commission may administratively waive or amend any rule stated above as long as the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in fluid movement beyond the authorized injection zone.

RULE 9: Conditions

It is a condition of this authorization that operations be conducted in accordance with the rules set out in this order, AS 31.05, and (unless specifically superseded by Commission order) 20 AAC 25. Failure to comply with an applicable provision of AS 31.05, 20 AAC 25, or these rules may result in the suspension or revocation of this authorization.

DONE at Anchorage, Alaska, and dated February 7, 2008.

ALASKA OIL AND GAS CONSERVATION COMMISSION

John K. Norman, Commissioner

Cathy P. Foerster, Commissioner

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