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

Re: THE APPLICATION OF ConocoPhillips Alaska Inc. for disposal of Class II oil field wastes by underground injection in the Sterling Formation in the North Cook Inlet Unit Well B-01A, Section 6, T11N, R9W, S.M.	**Disposal Injection Order No. 33** **Sterling Formation** **North Cook Inlet Unit Well B-01A** **November 5, 2008**

IT APPEARING THAT:

1. By correspondence received by the Alaska Oil and Gas Conservation Commission (AOGCC or Commission) July 14, 2008, ConocoPhillips Alaska Inc. (CPAI) requested that the Commission issue an order authorizing underground disposal of Class II oil field waste fluids into the Sterling Formation through the North Cook Inlet Unit (NCIU) B-01A wellbore. The NCIU B-01A well is located on the Tyonek Platform offshore Cook Inlet, Alaska.

2. The Commission requested additional information on July 15, 2008. CPAI clarified several points by electronic mail on July 15, 2008 and met with the Commission on July 21, 2008 to give an overview of the project and discuss specifics relating to the well.

3. Notice of opportunity for a public hearing was published in the ANCHORAGE DAILY NEWS on July 17, 2008, in the PENINSULA CLARION on July 20, 2008, on the State of Alaska Online Notices on July 17, 2008, and on the AOGCC website on July 17, 2008 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 August 26, 2008 and recessed until September 17, 2008. The record was left open at CPAI's request to allow additional time to provide Commission-requested information.

6. Additional clarification and information in support of the application was received from CPAI on September 11, 2008. The Commission closed the hearing record on September 17, 2008, without reconvening the hearing based on a review of the information provided by CPAI.

7. Information submitted by CPAI and public well history records are the basis for this order.

FINDINGS:

1. Location of Adjacent Wells (20 AAC 25.252(c)(1))

   NCIU B-01A is an existing gas development well located 1249 feet from the north line and 980 feet from the west line of Section 6, Township 11N, Range 9W, Seward Meridian. The surface location is on the CPAI-operated Tyonek Platform in 110 feet of water approximately 5 miles due east of Tyonek, Alaska and 40 miles west-southwest of Anchorage, Alaska. Five wells penetrate the disposal zone within a ¼-mile radius of NCIU B-01A.

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

   CPAI is the only operator within a ¼-mile radius of the proposed disposal well. The sole surface owner within a ¼-mile radius of NCIU B-01A is the State of Alaska.

3. Geological Information on Disposal and Confining Zones (20 AAC 25.252(c)(4))

   The proposed disposal injection interval in NCIU B-01A lies within the Sterling Formation, and it consists of a series of coarse-grained sand beds interspersed with relatively thin layers of carbonaceous mudstone. This interval, which lies between 3295 feet true vertical depth (TVD) and 3387 feet TVD, was previously perforated and used in NCIU B-01A to dispose approximately 135,000 barrels of slurried Class II drilling waste during 1997-98. This same interval is also currently used for disposal injection in offset well NCIU A-12.

   Upper confinement is provided by a stacked sequence of siltstones, mudstones, and coals interbedded with scattered sands. This sequence extends from approximately 3110 feet TVD to 3295 feet TVD, and it contains an aggregate thickness of about 125 true vertical feet of mudstone. Lower confinement is provided by a sequence of interlaminated mudstone, claystone, coal and siltstone interbedded with occasional sand intervals. This sequence extends from 3387 feet TVD to 3549 feet TVD, and it contains an aggregate thickness of at least 55 true vertical feet of mudstone.

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

   CPAI states the effectiveness of the confining and arresting intervals – both upper and lower – is demonstrated by the past injection in the proposed disposal zone in NCIU A-12 and B-01A. Structure maps and cross sections provided with the application indicate the confining zones are laterally continuous.

5. Standard Laboratory Water Analysis of the Formation (20 AAC 25.252(c)(10)); Aquifer Exemption (20 AAC 25.252(c)(11))

   Aquifer Exemption Order (AEO) 4 dated September 29, 1998, exempts those portions of aquifers within the NCIU that are common to and correlate with the interval below 2900 feet TVD[1] in NCIU A-12. Wireline analytical techniques compliant with EPA recommended methods coupled with laboratory analysis of water samples in wells offsetting NCIU B-01A were used to characterize formation water salinities. The Commission concluded in AEO 4 that freshwater aquifers underlying NCIU do not serve as a source of drinking water. Further, the Commission concluded that freshwater exists at a depth and location that makes its recovery for drinking purposes economically impractical. The closest drinking water well to the NCIU is onshore approximately 8 miles to the northwest, in the Beluga River Unit.

6. Well Logs (20 AAC 25.252(c)(5))

   Log data from NCIU B-01A and offsetting wells are on file with the Commission. CPAI provided a type log section of NCIU B-01A and a cross section through NCIU wells A-11, A-12, B-01A and B-02 identifying the confining and disposal zones.

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

   NCIU B-01A is an existing gas development well directionally drilled south to a depth of 12988 feet TVD. The well was drilled originally as an oil exploration well and subsequently plugged back and sidetracked to a Sterling-Beluga Formation gas producing objective. The well is constructed with 30-inch structural pipe set at 407 feet TVD, 20-inch conductor casing set at 2571 feet TVD, 13-3/8-inch surface casing set at 3514 feet TVD, 9-5/8-inch intermediate casing set at 8840 feet TVD, and 5-inch production liner set from 8598 feet to 12896 feet TVD. Well B-01A is completed with a single 5-1/2-inch production tubing string and produces gas through Sterling and Beluga perforations between 3307 feet and 5943 feet. The annulus space between surface casing and conductor casing is cemented from shoe depth to the surface; well records indicate cement was circulated to surface and a passing positive pressure test was performed.

   Well construction for NCIU B-01A incorporates a cuttings injection system consisting of two 2-3/8-inch injection strings (*i.e.*, annulus injection tubings) strapped to the surface casing and cemented to surface. These annulus injection tubings were installed to a depth of 3437 feet TVD. The cuttings injection system was designed to inject oil-based muds and cuttings within a confined interval in the upper Sterling Formation. Inability to run perforating equipment into the annulus injection tubings resulted in installing the intermediate casing in stages – the lower section run as a liner and cemented to the liner top packer at 3268 feet TVD. Prior to running the remainder of the intermediate casing (upper section), the intermediate casing and annulus injection tubings were perforated from 3280 feet to 3314

[1] 2900 feet TVD is 2900 feet MD as referenced in AEO 4.

feet TVD, providing access to the Sterling disposal zone. The upper section of the intermediate casing was run into the well, connected to the lower section and tested. The remainder of the well was constructed as planned.

A Cement Bond Log run during well construction over the surface casing interval provides inconclusive results regarding the quality of the cement in the surface casing annulus. CPAI states this is due to the existence of the two annulus injection tubings. Interpreted results from CPAI indicate a cement top in the surface casing annulus at 2530 feet TVD. The Commission authorized the injection of approximately 135,000 barrels of drilling waste down the annulus injection tubings during 1997-98 in conjunction with development drilling activities on the Tyonek Platform. Injection occurred without incident.

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

NCIU B-01A will be the second waste disposal well for non-hazardous Class II oil field wastes generated on the Tyonek Platform. Waste disposal injection will consist of the same fluids currently being injected into A-12, including drilling mud, drill cuttings, reserve pit fluids, rig wash fluids, formation material, completion fluids, produced water, stimulation fluids and other fluids eligible for injection into a Class II disposal well. The total estimated volume of Class II wastes to be injected into B-01A for disposal over the life of the project is 1,200,000 barrels. Disposal injection is expected to be made in small batches and at rates similar to NCIU A-12 (*i.e.*, approximately 1000 barrels every other day). CPAI states that performance data and extensive operational experience involving similar waste materials, the same formation and depths, and similar volumes and rates in NCIU A-12 provide an adequate analogy for the proposed NCIU B-01A disposal injection.

Fracture modeling submitted with the application for DIO 17 (NCIU A-12) used well B-01A as the basis for simulating fracture propagation. A third party fracture model was used to update the DIO 17 results by simulating 3 cases:

- 150,000 barrels of 7.4 pounds of solids to each gallon of slurry at 3000 barrels per day (*i.e.*, a volume representing the approved, historical cutting-slurry disposal injection that occurred during 1997-98);
- 1,000,000 barrels of produced water at rates of 1 barrel per minute (*i.e.*, modeling the maximum water handling rate capability on the Tyonek Platform);
- 60,000 barrels of 7.4 pounds of solids to each gallon of slurry at 2.4 barrels per minute (*i.e.*, modeling the proposed cuttings disposal injection).

All fracture model simulations were run with performance assumptions (*i.e.*, rates, volumes, pressures, and continuous injection) that CPAI states exceed the planned injection. Rock properties and wellbore hydraulic data replicate actual conditions. Modeling indicates single wing fracture lengths up to nearly 400 feet horizontally. The total vertical fracture growth (true vertical thickness) is predicted to be 125 feet.

9. Estimated Injection Pressures (20 AAC 25.252(c)(8))

   CPAI estimates that the maximum surface injection pressure will be 2500 psig. CPAI modeling indicates the average surface injection pressure will be approximately 1030 psi. A step-rate injectivity test was performed in July 2008 with injection rates up to 2 barrels per minute and injection pressures up to 2116 psi.

10. Mechanical Condition of Wells Penetrating the Disposal Zone Within ¼-Mile of NICU B-01A (20 AAC 25.252(c)(12))

    Five wells[2] penetrate the Sterling within a ¼-mile radius of NCIU B-01A. Within this area of review, the lateral distance from B-01A to the offsetting penetrations ranges from 440 feet to approximately 1000 feet. Construction information for each well, including cement tops for casing set across the Sterling is summarized in the injection order application. Detailed well construction information is in Commission well files; this information includes cementing records that indicate cement has been circulated to surface in the surface casing annulus for each of the five wells. In addition, CPAI has summarized the results of Cement Bond Logs run for four of the five wells (no bond log was run in NCIU B-03). Recent wellhead pressures (*i.e.*, tubing, inner annulus, and outer annulus pressures) have also been summarized for the five wells penetrating the ¼-mile area of review.

11. Operating Intent

    CPAI intends to simultaneously operate NCIU B-01A as a waste disposal injection well and a gas production well. NCIU A-12 is similarly operated.

CONCLUSIONS:

1. The application requirements and conditions for approval of an underground disposal application in 20 AAC 25.252 have been met.

2. Aquifers below 2900 feet TVD are exempt under 20 AAC 25.440 by AEO 4.

3. Proposed injection sands and confining layers are laterally continuous over the field. Stacked confining zones totaling approximately 185 feet true vertical thickness above and approximately 160 feet true vertical thickness below the injection zone will provide confinement of injected wastes.

4. Injection in NCIU A-12 (which is the same sand interval as proposed for B-01A) and results from historical injection in B-01A (1997-98) confirm that injected fluids will remain confined to the intended interval.

[2] The five wells are NCIU A-04, A-06, A-07, A-12, and B-03.

5. Based on the modeled injection rates, volumes, fluid densities, and pressures, which exceed expected operating conditions, and the historical injection in the proposed disposal zone common to NCIU B-01A and NCIU A-12, reasonable grounds exist to conclude that waste fluids should be contained within the receiving intervals by the confining lithologies within the Sterling. Cement isolation of the injection zone in the well bore and operating conditions further support the Commission's conclusion about confinement. Modeling worst case conditions (*i.e.*, continuous injection) predicts a zone of influence (waste plume area) for injected materials to occupy a fracture domain extending approximately 400 feet laterally from the well and vertically 125 feet, all within the identified geologic confinement. Batch injection will likely result in a radial-type disposal domain, reducing the predicted lateral and vertical propagation of the fractures that result from the slurry injection.

6. A ¼-mile area of review is appropriate given the fracture modeling results.

7. Disposal injection operations in NCIU B-01A will be conducted at rates and pressures below those estimated to fracture through the confining zones. Therefore, oil field wastes injected into B-01A will be confined to the isolated Sterling disposal injection zone. Successful disposal of 135,000 barrels of slurried Class II drilling waste during 1997-98 in the identified zone confirms injected fluids will be confined. Also, a step-rate injectivity test performed in July 2008 confirms injection is into a confined system.

8. Fluid compatibility in the Sterling disposal zone is not an issue. Operating experience and data from disposal injection—(i) involving similar materials and performance parameters (*i.e.*, pressures, rates, and volumes), (ii) including the historical injection of 135,000 barrels of Class II drilling waste, and (iii) involving the same injection zone in nearby NCIU A-12—provide a suitable analogy for underground disposal using annulus injection tubings in NCIU B-01A.

9. The mechanical integrity of the five offset wells within the ¼-mile area of review has been demonstrated by cementing records, bond logs (where available) and annuli pressures.

10. Unique well construction involving two small diameter annulus injection tubings and casing perforations mandate procedures other than pressure testing for demonstrating ongoing mechanical integrity of NCIU B-01A.

11. Supplemental mechanical integrity demonstrations and the surveillance of injection operations—including temperature surveys, monitoring of injection performance (*i.e.*, pressures and rates), and analysis of the data for indications of anomalous events—are appropriate to ensure that waste fluids remain within the disposal interval.

12. NCIU B-01A may simultaneously operate as a completed gas production well (producing up the 5-1/2-inch tubing) and a Class II disposal well (injecting down the two 2-3/8-inch annulus injection tubings installed in the surface casing by conductor casing annulus).

NOW, THEREFORE, IT IS ORDERED THAT disposal injection is authorized into the Sterling Formation within North Cook Inlet Unit B-01A subject to each of the following requirements:

RULE 1: Injection Strata for Disposal

The underground disposal of Class II oil field waste fluids is permitted into the Sterling within NCIU B-01A in the interval between 3295 feet and 3387 feet TVD. The Commission may immediately suspend, revoke, or modify this authorization if injected fluids fail to be confined. Injection shall only occur down the 2-3/8-inch tubings installed in the 13-3/8-inch surface casing by 20-inch conductor casing annulus.

RULE 2: Fluids

This authorization is limited to Class II oil field waste fluids generated during drilling, production and workover operations. Included are drilling mud, drill cuttings, reserve pit fluids, rig wash fluids, formation material, completion fluids, produced water, stimulation fluids and other fluids eligible for injection into a Class II disposal well.

RULE 3: Injection Rate and Pressure

Disposal injection is authorized at (a) rates that do not exceed 2.4 barrels per minute and (b) surface pressures that do not exceed 2500 psig.

RULE 4: Demonstration of Mechanical Integrity

The mechanical integrity of NCIU B-01A must be demonstrated before injection begins and before returning the well to service following a workover affecting mechanical integrity. A pump-in differential temperature log shall be run in the 5-1/2-inch production tubing every 2 years to evaluate injected fluid isolation. The anniversary date for the temperature log is the effective date of this order. after the date of entry of this order Ongoing mechanical integrity of the well shall be demonstrated by injection performance monitoring of the surface pressure at static conditions in the 2-3/8-inch annulus injection tubings and open 13-3/8-inch by 9-5/8-inch casing annulus with a known fluid.

The results of all mechanical integrity demonstrations and CPAI's interpretation of those results shall be provided to the Commission and be readily available on the Tyonek Platform for Commission inspection.

RULE 5: Well Integrity Failure and Confinement

Whenever any pressure communication between the production tubing and the casing-tubing annulus is identified, 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 threaten contamination of freshwater, or if so directed by the Commission. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the Commission for all injection wells indicating well integrity failure or lack of injection zone isolation.

RULE 6: Surveillance

The operator shall run a baseline differential temperature log in the 5-1/2-inch tubing 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. Results of daily wellhead pressure observations in NCIU B-01A must be documented and available to the Commission upon request. Subsequent temperature surveys or other surveillance logging (*e.g.*, water flow; 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, including, among other information, the following: surface pressures (daily average, maximum and minimum); fluid volumes injected (including disposal and clean fluid sweeps); injection rates; an assessment of fracture geometry; a description of any anomalous injection results; and a calculated zone of influence for the injection fluids.

RULE 7: Notification of Improper Class II Injection

The operator must immediately notify the Commission if it learns of any improper Class II injection. 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 outside of the authorized injection zone.

RULE 9: Compliance

Operations must be conducted in accordance with the requirements of this order, AS 31.05, and (unless specifically superseded by Commission order) 20 AAC 25. Noncompliance may result in the suspension, revocation, or modification of this authorization.

DONE at Anchorage, Alaska, and dated November 5, 2008.

Daniel T. Seamount, Jr., Chair

Cathy P. Foerster, Commissioner

John K. Norman, Commissioner

RECONSIDERATION AND APPEAL NOTICE

As provided in AS 31.05.080(a), within **20** days after written notice of the entry of this order or decision, or such further time as the Commission grants for good cause shown, a person affected by it may file with the Commission an application for reconsideration of the matter determined by it. If the notice was mailed, then the period of time shall be **23** days. An application for reconsideration must set out the respect in which the order or decision is believed to be erroneous.

The Commission shall grant or refuse the application for reconsideration in whole or in part within 10 days after it is filed. Failure to act on it within 10-days is a denial of reconsideration. If the Commission denies reconsideration, upon denial, this order or decision and the denial of reconsideration are **FINAL** and may be appealed to superior court. The appeal **MUST** be filed within **33** days after the date on which the Commission mails, **OR 30** days if the Commission otherwise distributes, the order or decision denying reconsideration, **UNLESS** the denial is by inaction, in which case the appeal **MUST** be filed within **40** days after the date on which the application for reconsideration was filed.

If the Commission grants an application for reconsideration, this order or decision does not become final. Rather, the order or decision on reconsideration will be the **FINAL** order or decision of the Commission, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the Commission mails, **OR 30** days if the Commission otherwise distributes, the order or decision on reconsideration. As provided in AS 31.05.080(b), "[t]he questions reviewed on appeal are limited to the questions presented to the Commission by the application for reconsideration."

In computing a period of time above, the date of the event or default after which the designated period begins to run is not included in the period; the last day of the period is included, unless it falls on a weekend or state holiday, in which event the period runs until 5:00 p.m. on the next day that does not fall on a weekend or state holiday.