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

Re: THE APPLICATION OF Hilcorp Alaska, LLC. for disposal of Class II oil field wastes by underground injection in the Sterling Formation in well Beaver Creek Unit No. 3RD, (PTD 2030440) Section 34, T7N, R10W, S.M.	)	Disposal Injection Order No. 40 Sterling Formation, Undefined waste disposal pool Beaver Creek Unit No. 3RD Well Beaver Creek Unit March 2, 2015

IT APPEARING THAT:

1. Hilcorp Alaska, LLC (Hilcorp) requested authorization for underground disposal of Class II oil field waste fluids into well Beaver Creek Unit No. 3 Re-drill (BCU 3RD) (PTD 2030440). Hilcorp's Application for Disposal Injection Order was received by the Alaska Oil and Gas Conservation Commission (AOGCC) on October 29, 2014.

2. Pursuant to 20 AAC 25.540, the AOGCC scheduled a public hearing for January 6, 2015. On November 17, 2014, the AOGCC published notice of the opportunity for that hearing on the State of Alaska's Online Public Notice website and on the AOGCC's website and electronically transmitted the notice to all persons on the AOGCC's email distribution list. On November 18, 2014, the notice was published in the ALASKA DISPATCH NEWS.

3. At the January 6, 2015 hearing Hilcorp provided testimony and presented evidence in support of its Application. The hearing record was left open for two weeks to allow Hilcorp to provide additional information requested by the AOGCC.

FINDINGS:

The following are based upon the evidence submitted by Hilcorp, the testimony at the hearing, public records pertaining to Disposal Injection Order 4 (DIO 4), and Beaver Creek wells.

1. History of Wells BCU 3 and BCU 3RD

   During 1968, BCU 3 was drilled directionally to a measured depth (MD) of 6,387 feet and a true vertical depth (TVD) of 5,418 feet and completed as a development gas well in the Beaver Creek Unit Sterling Gas Pool. BCU 3 produced gas from September 1982 through October 1988. In December 1988, all perforations were squeezed with cement, and in November 1989 the well head was replaced with a dry-hole tree.

   On May 13, 1993, the AOGCC issued Disposal Injection Order No. 8 (DIO 8), which authorized disposal of Class II oil field fluids by underground injection in well BCU 3. In July 1994, the operator re-entered BCU 3, perforated the Sterling Formation B-1B sandstone from 5,910 to 5,940 feet MD (5,082 to 5,106 feet TVD), and re-completed the well as a Class II waste disposal injection well. BCU 3 was shut-in from July 1995 through May 2005; no injection volumes were reported for this well.

   During May 2003, the Sterling B-1B sand perforations in BCU 3 were plugged, the well was re-named BCU 3RD (PTD 2030440), re-entered, and deepened to 10,005 feet MD (8,713 feet TVD) to access gas reserves in the underlying Beluga Gas Pool. In June and July of 2003, BCU 3RD was perforated in several lower Beluga sandstone layers, fracture-stimulated, and completed as a development gas well.

   In April and May of 2005, a cast-iron bridge plug was set at 9,570' MD (7,969' TVD) to plug off the Beluga B28d sandstone, the suspected source of water, sand and coal production. Additional perforations were shot in the overlying B22 and B23 lower Beluga sandstones, and regular gas production began in June 2005. BCU 3RD was unable to sustain flow. The last reported regular gas production from BCU 3RD was during February 2006.

   BCU 3RD was shut-in in March 2006, with the single exception of 17,000 cubic feet of gas production reported in February 2013.

   Hilcorp proposes to convert BCU 3RD to a Class II disposal well by plugging back all Beluga perforations and perforating the shallower, Sterling Formation B1L and B2 sandstones between 5,804 and 5,945 feet MD (4,997 and 5,110 feet TVD).

2. Location of Wells BCU 3 and BCU 3RD

   BCU 3 and the redrill BCU 3RD have the same surface location, which is 1,227 feet from the north line and 1,501 feet from the west line of Section 34, Township 7 North, Range 10 West, Seward Meridian (SM). The top of the injection interval will lie about 700 feet from the south line and 1,700 feet from the west line of Section 27, Township 7 North, Range 10 West, SM.

   The proposed injection zone within BCU 3RD lies more than 1,850 horizontal feet from the nearest point on the Beaver Creek Unit boundary.

Location of Adjacent Wells (20 AAC 25.252(c)(1)) Beaver Creek Unit No. 18 is the only well that penetrates the proposed injection zone within a ¼-mile radius of BCU 3RD.

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

   Hilcorp is the only operator within a ¼-mile radius of the proposed disposal well. Surface property owners within ¼-mile radius of BCU 3RD are U.S Bureau of Land Management (BLM) and U.S. Fish and Wildlife Service (FWS). Hilcorp has provided a copy of the AOGCC Application for Sundry Approval to BLM. This Disposal Injection Order does not exempt Hilcorp from obtaining additional permits or an approval required by law from other governmental agencies and does not authorize conducting disposal injection operations until all other required permits and approvals have been issued. In addition, the AOGCC reserves the right to withdraw the order in the event it was erroneously issued.

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

   The proposed disposal injection operations will affect strata that are assigned to the Pliocene-aged Sterling Formation. The Sterling Formation consists of massively bedded, predominately coarse-grained, moderate to well-sorted, fluvial sandstone with minor amounts of conglomerate. Hilcorp plans injection within the permeable Sterling Formation B1L and B2 sandstones, which have calculated porosities of approximately thirty percent. These two sandstones are present within BCU 3RD from approximately 5,804 to 5,945 feet MD (4,997 and 5,110 feet TVD).

   Upper confinement for the proposed injection interval consists of numerous, laterally continuous layers of claystone, siltstone, and coal that lie within the Sterling Formation between 2,132 and 5,649 feet MD (2,024 and 4,873 feet TVD). These confining layers, which range in thickness from 3 to 28 true vertical feet, have a combined true vertical thickness of about 235 feet, and will serve as effective barriers to prevent vertical migration of injected fluids.

   Lower confinement will be provided by numerous, laterally continuous layers of claystone, siltstone and coal within the Sterling Formation between 5,945 and 6,250 feet MD (4,997' and 5,353' TVD).

   Structure maps provided by Hilcorp do not display any faults within 4,000 horizontal feet of the planned injection interval.

5. Evaluation of Fluid Confinement (20 AAC 25.252(c)(9))

   The porous and permeable nature of the Sterling B1L and B2 sandstones allows injection of produced water at pressures that are lower than formation-fracture pressure. This has been observed in the existing BCU 2 Class II well, which has a cumulative injection total of 1.1 million barrels. Since prolonged injection of produced water will result in the accumulation of solids near the BCU 3RD wellbore, it will be occasionally necessary to fracture the injection interval to by-pass these solids by increasing injection pressure. Fracturing in this case is expected to remain within the injection interval.

   Disposal injection of produced water, drilling mud, slurried cuttings, and other Class II oil-field wastes will require pressure sufficient to fracture the Sterling Formation. Marathon Oil

Company (Marathon), the previous operator of the Beaver Creek Unit, planned to inject produced water and other Class II wastes into the same disposal interval. Marathon provided a three-dimensional hydraulic fracture model of the strata at Beaver Creek using lithology, stress variations, pore pressure, and rock elastic properties to simulate hydraulically induced fracture growth that will occur when drilling mud and slurried drill cuttings are injected above formation pressure. Under the "most likely" scenario, fracture growth height was limited to about 4,200 feet TVD within the middle Sterling which is about 2,550 true vertical feet below the top of the exempt aquifers (at 1,650 feet below ground surface). Under the "worst-case" scenario, fracture growth height extended to about 3,600 feet TVD, which is about 1,950 true vertical feet below the top of the exempt aquifers.

Future wells within 1/4-mile must be constructed to ensure they do not serve as a conduit for fluid migration from the disposal zone.

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

The portions of aquifers at depths greater than 1,650 feet below the ground surface, extending one-quarter mile beyond and lying directly below the Beaver Creek Field are exempted pursuant to 40 CFR 147.102(b)(1)(ii).

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

Log data from BCU 3 and BCU 3RD are on file with the AOGCC.

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

Thirteen and 3/8-inch surface casing was set at 533 feet MD, cemented to surface and tested to 1000 psi. Intermediate 9 5/8-inch casing was set at 1,569 feet MD, cemented to surface and tested to 1,000 psi. The 7-inch production casing was set at 6,380 feet MD, cemented to approximately 3,300 feet MD and tested to 1,000 psi.

Analysis of cement bond logs indicates casing strings have adequate cement behind casing to prevent vertical migration of disposal fluids.

A casing mechanical integrity test will be performed in accordance with 20 AAC 25.412 prior to re-initiation of disposal operations. Hilcorp will perform mechanical integrity tests of the tubing and tubing-casing annulus (including packer) as part of the workover operations before injection recommences. Additional baseline assessments and subsequent evaluations may be necessary to confirm the well has the proper mechanical integrity for disposal injection as proposed.

The operator will monitor the 7-inch casing by 3 1/2-inch tubing annulus pressure daily and report the results on the Monthly Injection Report.

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

   Hilcorp requests approval to dispose of drilling, production, completion, workover wastes, and other associated wastes that are intrinsically derived from primary field operations. Hilcorp expects daily injection volumes of 1000 up to 7,200 barrels, with rates up to 6 barrels per minute, and slurry densities up to 10.5 pounds per gallon.

   Injected fluids are expected to be compatible with the lithology and resident water of the injection zone based on operating experience and performance (*e.g.*, pressures, rates, and volumes) of the BCU 3RD well during previous disposal operations. There have not been any reported compatibility issues associated with disposal injection into the Sterling or Beluga Formation at this or other fields in the Cook Inlet area.

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

    Hilcorp estimates that the average surface injection pressure will be between 1,600 psig for water disposal operations and 3,000 psig. The maximum surface injection pressure could reach 5,000 psig if sporadic plugging of perforations or fracture flow channels occurs, which is the maximum pressure rating of the casing head.

11. Mechanical Condition of Wells Penetrating the Disposal Zone Within a ¼-Mile Radius of Kenai Loop #3 (20 AAC 25.252(c)(12))

    BCU 18 is the only well to penetrate the proposed disposal injection zone within ¼-mile radius of BCU 3RD. Well construction records show that both the injection well and the BCU 18 are cased and cemented to prevent the movement of injected fluids beyond the well's confinement zones. Records documenting the drilling, casing, cementing, and testing of these wells are in the AOGCC's files.

CONCLUSIONS:

1. The requirements of 20 AAC 25.252 for approval of an underground disposal application are met.

2. BCU 3 was drilled in 1968 as a Sterling Formation gas production well. BCU 3 was converted to an authorized disposal well in May 1993. BCU 3 was deepened in 2003, re-named BCU 3RD, and produced gas from the Beluga Formation. Hilcorp will isolate the lower portion of BCU 3RD and convert the well to disposal injection in the Sterling Formation.

3. Hilcorp's planned injection interval in BCU 3RD consists of the Sterling B1L and B2 sands that lie between 5,804 and 5,945 feet MD (4,997 and 5,110 feet TVD), an interval that is about 113 true vertical feet thick.

4. Upper confinement will be provided by a combined 235 true vertical feet of laterally continuous claystone, siltstone, and coal layers within the Sterling Formation.

5. Lower confinement and fracture arrest will be provided by 356 true vertical feet of laterally continuous layers of Sterling Formation claystone, siltstone, and coal.
6. No significant faults are present that could be affected by the proposed injection operations.
7. The portions of aquifers at depths greater than 1,650 feet below the ground surface, extending one-quarter mile beyond and lying directly below the Beaver Creek Field are exempted by 40 CFR 147.102(b)(1)(ii).
8. No compatibility concerns relating to the injected fluids and in-situ formation fluids have been identified in connection with the injection of a similar waste fluid streams into the Sterling Formation at this site and other locations within the Cook Inlet Basin.
9. Fracture modeling indicates that disposed waste fluids will be contained within the receiving interval by confining lithologies, cement isolation of the well bore, and planned operating conditions. Modeling of the most extreme injection conditions predicts that fractures will not penetrate the upper confining zone, or breach the lower confining zone.
10. Supplemental mechanical integrity demonstrations and the surveillance of injection operations—including baseline and subsequent temperature surveys, monitoring of injection performance (*i.e.*, pressures and rates), and analyses of the data for indications of anomalous events—are appropriate to ensure that waste fluids remain within the disposal interval.
11. Actual performance information gained during injection and remedial well operations must be monitored during the life of the disposal project to ensure appropriate operation of the field. A requirement for formal review of the disposal injection performance every five years will ensure the findings, conclusions, and rules of this order remain valid.
12. Future wells within 1/4-mile of the injection interval in BCU 3RD must be constructed to ensure they do not serve as a conduit for fluid migration from the disposal zone.

NOW, THEREFORE, IT IS ORDERED THAT disposal injection is authorized into the Sterling Formation within well Beaver Creek Unit No. 3RD subject to each of the following requirements:

<u>RULE 1: Injection Strata for Disposal</u>

The underground disposal of Class II oil field waste fluids is permitted into the Sterling Formation within BCU 3RD in the interval from 5,804 feet to 5,945 feet MD (4,997 feet to 5,110 feet TVD).

<u>RULE 2: Authorized Fluids</u>

This authorization is limited to Class II oil field waste fluids generated during drilling, production, workover, or abandonment operations, specifically:

> Drilling fluids; drill cuttings; well workover fluids; stimulation fluids and solids; produced water; rig wash water; formation materials; naturally occurring radioactive materials; scale; tracer materials; glycol dehydration; reserve pit fluids; chemicals used in the well or for production processing at the surface (in direct contact with produced fluids); and precipitation accumulating in drilling and production impoundment areas.

AOGCC approval is required prior to initiating commercial Class II disposal injection in BCU 3RD.

RULE 3: Injection Rate and Pressure

Injection pressures must be maintained such that the injected fluids do not fracture the confining intervals or migrate out of the approved injection stratum. Disposal injection is authorized at (a) rates that do not exceed 6 barrels per minute and (b) wellhead injection pressures that do not exceed 5,000 psig.

RULE 4: Demonstration of Mechanical Integrity

The mechanical integrity of BCU 3RD must be demonstrated before injection begins and before returning the well to service following a workover affecting mechanical integrity. An AOGCC-witnessed mechanical integrity test must be performed after injection is commenced for the first time in BCU 3RD, 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 after the date of the first AOGCC-witnessed test if the well injects solids laden slurries, and at least once every four years if the well only injects solids-free fluids. Mechanical integrity tests must be conducted in accordance with AOGCC Industry Guidance Bulletin No. 10-02A, "Mechanical Integrity Testing". The AOGCC must be notified at least 24 hours in advance of each such test to enable a representative to witness the test. The results of all mechanical integrity demonstrations and Hilcorp's interpretation of those results shall be provided to the AOGCC no later than the 5th calendar day of the month following the testing.

RULE 5: Well Integrity Failure and Confinement

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by injection rate, operating pressure observation, test, survey, log, or any other evidence, the Operator shall notify the AOGCC within 24 hours and submit a plan of corrective action on a Form 10-403 for AOGCC 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 AOGCC. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the AOGCC for BCU 3RD if the well indicates any well integrity failure or 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 anomalous conditions. Results of daily wellhead pressure observations in BCU 3RD must be documented and available to the AOGCC upon request. The conduct of 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 AOGCC by April 1 of each year covering injection operations during the previous calendar year. The report shall include data sufficient to characterize the disposal operation, including, among other information, the following: injection and annuli pressures (*i.e.*, daily average, maximum, and minimum pressures); fluid volumes injected (*i.e.*, in disposal and clean fluid sweeps); injection rates; an assessment of the fracture geometry; a description of any anomalous injection results; and a calculated zone of influence for the injected fluids. An assessment of the applicability of the injection order findings, conclusions, and rules based on actual performance shall be included with the annual performance report.

RULE 7: Notification of Improper Class II Injection

Injection of fluids other than those listed in Rule 2 without prior authorization is considered improper Class II injection. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and propose actions to prevent recurrence. Additionally, notification requirements of any other State or Federal agency remain the operator's responsibility.

If fluids are found to be fracturing through a confining interval or migrating out of the approved injection stratum, the operator must immediately shut in the well. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and propose actions to prevent recurrence. Injection may not be restarted unless approved by the AOGCC.

RULE 8: Administrative Action

Upon proper application, or its own motion, and unless notice and public hearing are otherwise required, the AOGCC may administratively waive the requirements of any rule stated herein or administratively amend this order as long as the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in an increased risk of fluid movement into freshwater or 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 AOGCC order) 20 AAC 25. Noncompliance may result in the suspension, revocation, or modification of this authorization and other penalties.

RULE 10: Reauthorization

The Operator must apply to reauthorize disposal injection at intervals not exceeding five years from the effective date of this Order. The application shall include an assessment of the Order findings, conclusions, and rules taking into account actual injection performance.

DONE at Anchorage, Alaska, and dated March 2, 2015.

ALASKA OIL AND GAS CONSERVATION COMMISSION

Cathy P. Foerster
Chair, Commissioner

Daniel T. Seamount, Jr.
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.