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

Re: THE APPLICATION OF Pioneer Natural Resources Alaska, Inc. for an order authorizing underground injection of fluids for enhanced recovery in the Oooguruk-Torok Oil Pool, within the Oooguruk Field, Oooguruk Unit, East Harrison Bay, Beaufort Sea, Alaska	)	Docket Number: AIO 12-10 Area Injection Order No. 37 Oooguruk Field Oooguruk Unit Oooguruk-Torok Oil Pool October 8, 2012

IT APPEARING THAT:

1. By application received on July 20, 2012, Pioneer Natural Resources Alaska, Inc. (Pioneer), as operator of the Oooguruk Unit (OU) and on behalf of Pioneer and Eni Petroleum US LLC (Eni), working interest owners, requested an order from the Alaska Oil and Gas Conservation Commission (AOGCC) authorizing the injection of fluids for enhanced recovery in the Oooguruk-Torok Oil Pool (OTOP).

2. A notice of public hearing scheduled was tentatively scheduled on September 6, 2012, was published on the State of Alaska Online Public Notice web site and on the AOGCC's web site on July 24, 2012. Publication of the notice in the ALASKA JOURNAL OF COMMERCE occurred on July 29, 2012.

3. The AOGCC convened a public hearing on the area injection order application on September 6, 2012. The public hearing was continued until September 10, 2012.

4. On September 10, 2012, testimony was received from the applicant and the record was closed. No protests or comments were received regarding the application.

FINDINGS:

1. Operator: Pioneer is the operator of the OU.

2. Owners: Pioneer (70%) and Eni (30%) are the working interest owners in the planned development area.

3. Landowner: The State of Alaska, Department of Natural Resources (State) is the landowner.

4. Surface Owners: The State and Jim and Teena Helmericks (Helmericks) are the only surface owners within ¼-mile of the Affected Area defined in paragraph 7 below.

5. Operators: Pioneer and ConocoPhillips Alaska, Inc. (CPAI) are the only operators within ¼-mile of the Affected Area.

6. Notification of Surface Owners and Operators: In accordance with 20 AAC 25.402(c)(3), Pioneer provided an affidavit with their application showing that copies of the Area Injection Order (AIO) application were sent by certified mail to the surface owners and operators on July 19, 2012. This affidavit was incorrectly dated as being executed on June 19, 2012. Upon discovering this error, a new affidavit was executed on September 20, 2012. Pioneer provided proof of certified mailing to the AOGCC.

7. Project Area and Interval Proposed for Enhanced Oil Recovery: Pioneer requests authorization to inject fluids for the purpose of enhanced oil recovery (EOR) operations for the OTOP, which is defined in Conservation Order No. 645. The Affected Area of the OTOP injection project is shown by the irregularly shaped green outline shown in Figure 1, below. The OTOP is defined vertically as the accumulation of hydrocarbons within the Affected Area common to, and correlating with, the interval between the measured depths (MD) of 4,991 and 5,272 feet on the resistivity log recorded in exploratory well Kalubik No. 1 (see Figure 2, below).

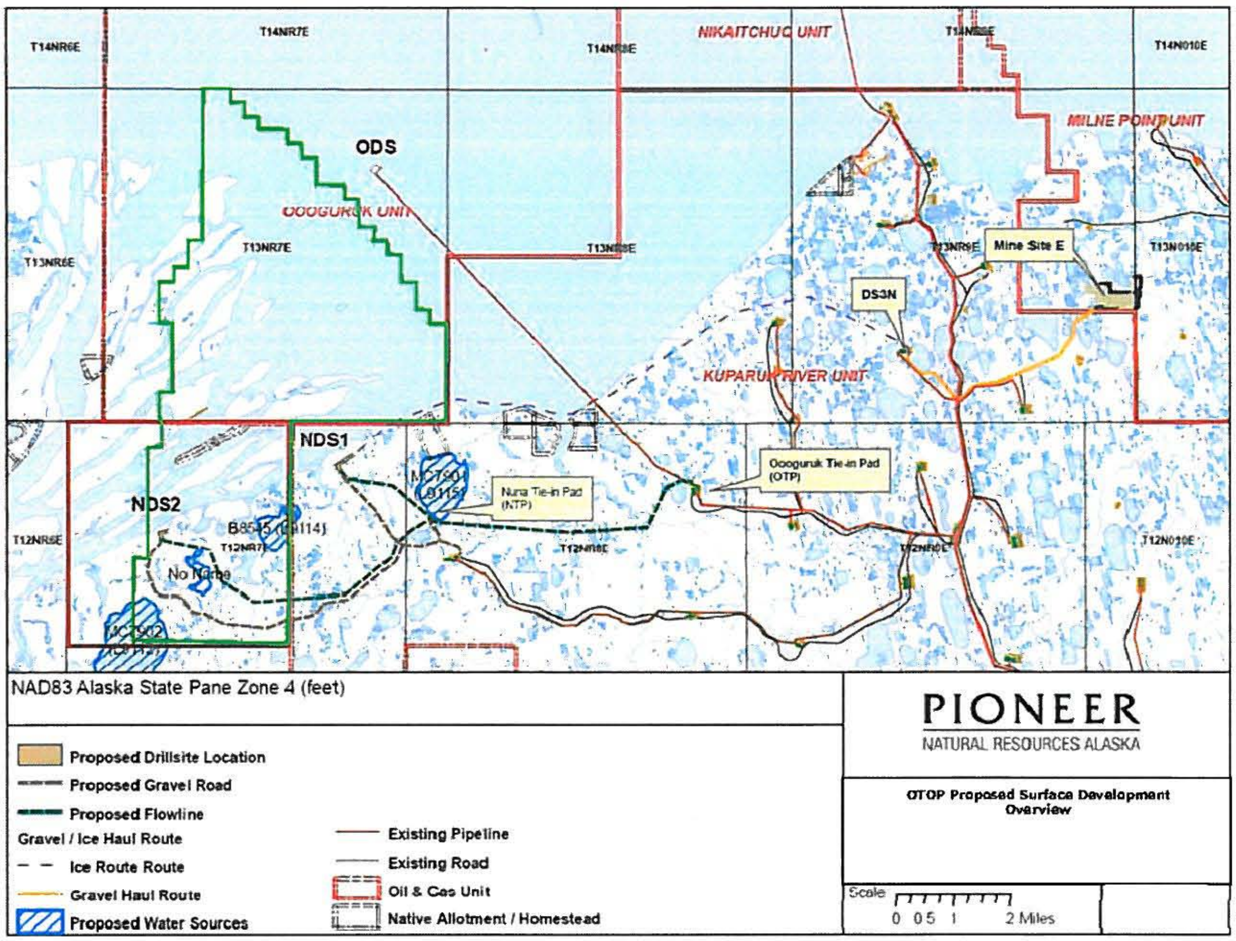

Figure 1. Affected Area for the Proposed Oooguruk-Torok Oil Pool Enhanced Oil Recovery Injection Project (enclosed by green-colored line) and Surface Facilities Locations

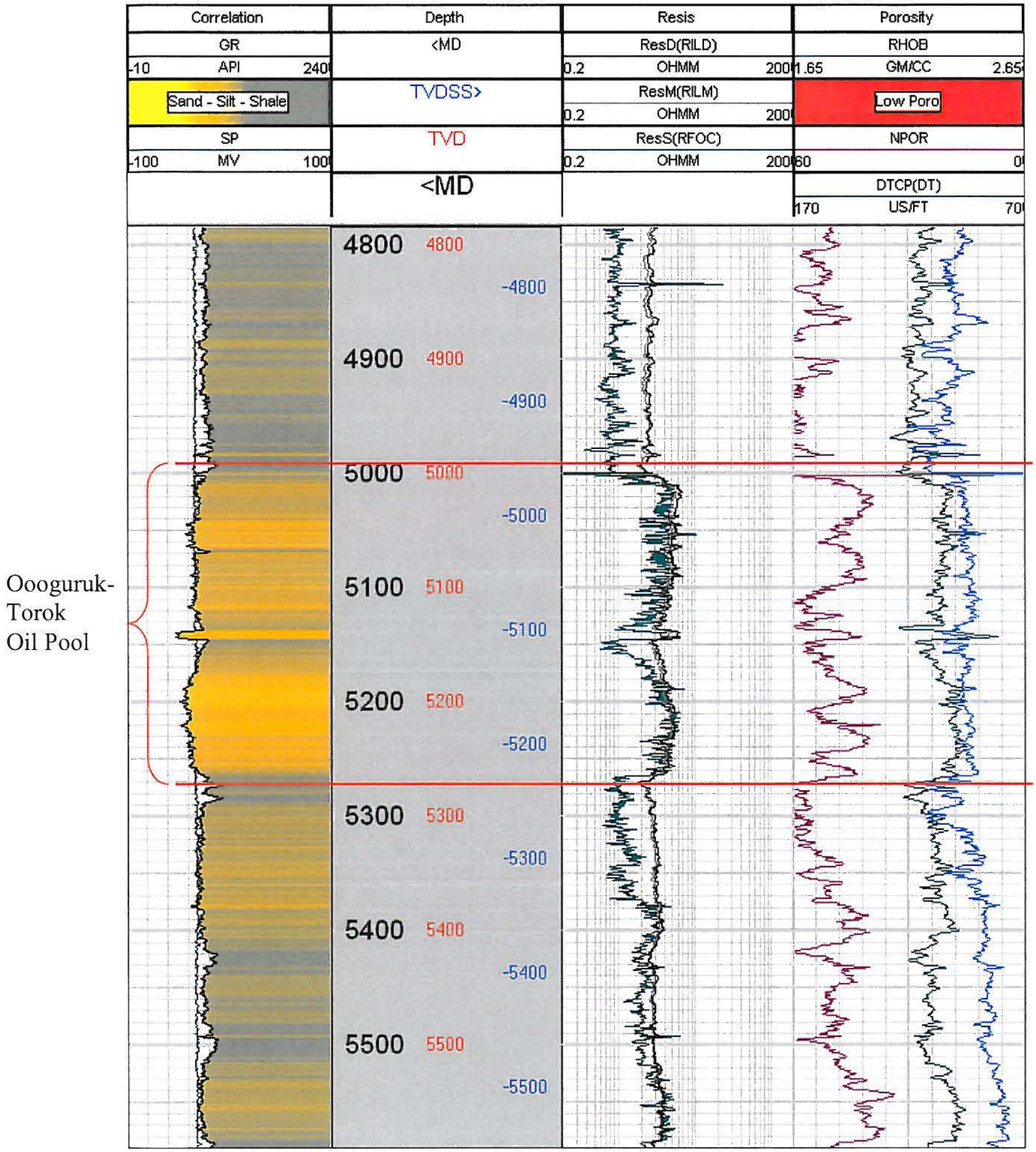

Figure 2. Kalubik No. 1 – Type Well Log for Oooguruk-Torok Oil Pool[1]

[1] Figure 2 is for illustration purposes only. Refer to the well log measurements recorded in exploratory well Kalubik No. 1 for the precise representation of the proposed Oooguruk-Torok Oil Pool. The horizontal grid lines in this figure represent increments of ten feet measured depth. The acronym TVDSS refers to true vertical depth subsea (true vertical depth below sea level).

8. Description of Operations: The OTOP will be developed initially from the existing offshore Ooogurük Drill Site (ODS), which connects to the onshore Oooguruk Tie-in Pad (OTP), and then to the Kuparuk River Unit (KRU) processing facilities. Upon successful development of the proposed pool from the ODS, additional development may occur from two new onshore drill sites, named Nuna Drill Site 1 and Nuna Drill Site 2, located on the eastern side of the Colville River Delta. The Nuna Drill Sites would connect to the OTP via the proposed Nuna Tie-in Pad. Current plans are to develop the OTOP in discrete phases with 26 horizontal wells split evenly between producers and injectors. Most wells will trend northwest and range in length from 3,000 to 8,000 feet within the reservoir. Wells will be arranged end-to-end to form alternating rows of producers and injectors in a line-drive flood pattern. These rows will be spaced about 1,500 feet apart. All wells will be fracture stimulated. The number of wells and their design and placement may change based on initial drilling results and additional studies.

Pioneer proposes to develop the OTOP as an immiscible-water-alternating-gas-injection (IWAG) EOR project. Production and injection will be managed to maintain reservoir pressure near the original measured pressure. Injection water will consist of seawater, with the future potential of injecting produced water. Injection gas will be sourced from OTP or KRU processing facilities. Although the future availability of gas for injection purposes cannot be predicted, some form of IWAG will occur on one or more injection patterns.

9. Hydrocarbon Recovery: Pioneer estimates that primary recovery will recover approximately 5% of the original oil-in-place (OOIP) and that the IWAG will recover an additional 15% of OOIP, with a low of 5% and a high of 25% incremental recovery. Recovery (in units of millions of stock tank barrels, or MMSTB) within the OTOP development area are:

Development Phase	OOIP	Primary Recovery (5% of OOIP)	Incremental IWAG Recovery (Low/Median/High – 5%/15 %/25% of OOIP)	Combined Recovery (Low/Median/High – 10%/20%/30% of OOIP)
ODS	50	2.5	2.5/7.5/12.5	5/10/15
Onshore Core Area	290	14.5	14.5/43.5/72.5	29/58/87
Onshore Expansion Area	350	17.5	17.5/52.5/87.5	35/70/105
OTOP Total	690	34.5	34.5/103.5/172.5	69/138/207

The OTOP has been producing since March 2010. Injection is expected to begin in October 2012. Over the 20 to 30 year life of the project the OTOP is expected to average between 4,000 and 9,000 stock tank barrels of oil per day (STBOPD) and peak between 7,000 and 15,000 STBOPD. Injection is expected to average between 5,000 and 12,000 barrels of water per day.

10. Geology:

a. Stratigraphy:

Within the OTOP area, early Cretaceous-aged reservoir turbidite sandstones comprising the proposed OTOP are typically very fine sand-sized to coarse silt-sized and rich in quartz (20% to 50%), feldspar (15% to 25%), and clay (5% to 40%), with metamorphic rock fragments and minor amounts of carbonate. These sandstones are sheet-like in form, and they were deposited in a lower slope-to-basin floor environment. Within the proposed development area, the reservoir interval is 200 to 250 feet thick, but thins to the east, toward the paleo-basin, and pinches out to the west against the paleo-shelf slope. Net-to-gross sand thickness is typically 45% to 50%. Porosity ranges from 12% to 26%, averaging 19%. Permeability ranges from 0.1 to 100 millidarcies and averages 4 millidarcies. Water saturation estimates for the reservoir sandstones range from 40% to 55%, with an average of about 50%.

b. Structure: Within the development area, the structure of the proposed OTOP forms broad, east-plunging anticlinal nose cut by several, northwest- and north-trending, normal faults with vertical displacements ranging up to 40 feet. The top of the OTOP lies between about -4,800 feet TVDSS[2] and -5,500 feet TVDSS.

c. Faults: The vertical displacement of faults observed within the Torok interval ranges up to 40 feet. Because of the thinly bedded nature of this reservoir, some faults may act as internal barriers.

d. Trap Configuration and Seals: Well log and seismic information indicate that the OTOP accumulation is trapped by both structural and stratigraphic elements. The OTOP sandstones thin toward the west, and pinch out as they lap onto the toe of the paleo-slope. To the south and southwest, the depositional limit of the fan defines the pool boundary. To the north and east, structural dip, diminishing sand content in the sediments, and a southeast-trending, down-to-the-east fault appear to define the northeastern limit of the oil accumulation. The top seal for the OTOP is formed by more than 1,000 true vertical feet of shale and siltstone assigned to the undifferentiated Seabee Formation / Hue Shale.

e. Confining Intervals: The OTOP lies within the thick and laterally extensive marine deposited Hue shale. The Hue Shale provides a 650- to 1,000-foot thick upper confining interval. The Hue Shale and the underlying HRZ Shale provide a 300- to 800-foot thick lower confining interval (see Figure 3 & Figure 4, below).

f. Reservoir Compartmentalization: At present, limited well test results suggest the reservoir sands are laterally continuous at the scale of the spacing of the planned development wells (1,000 to 2,000 feet apart).

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[2] To avoid confusion, when depths presented represent true vertical depth subsea, the footage will be preceded by a minus sign and followed by the acronym TVDSS (e.g., 3,000 feet true vertical subsea will be depicted as -3,000 feet TVDSS).

g. Permafrost Base: The base of permafrost is interpreted to lie between about -1,400 and -1,600 feet TVDSS.

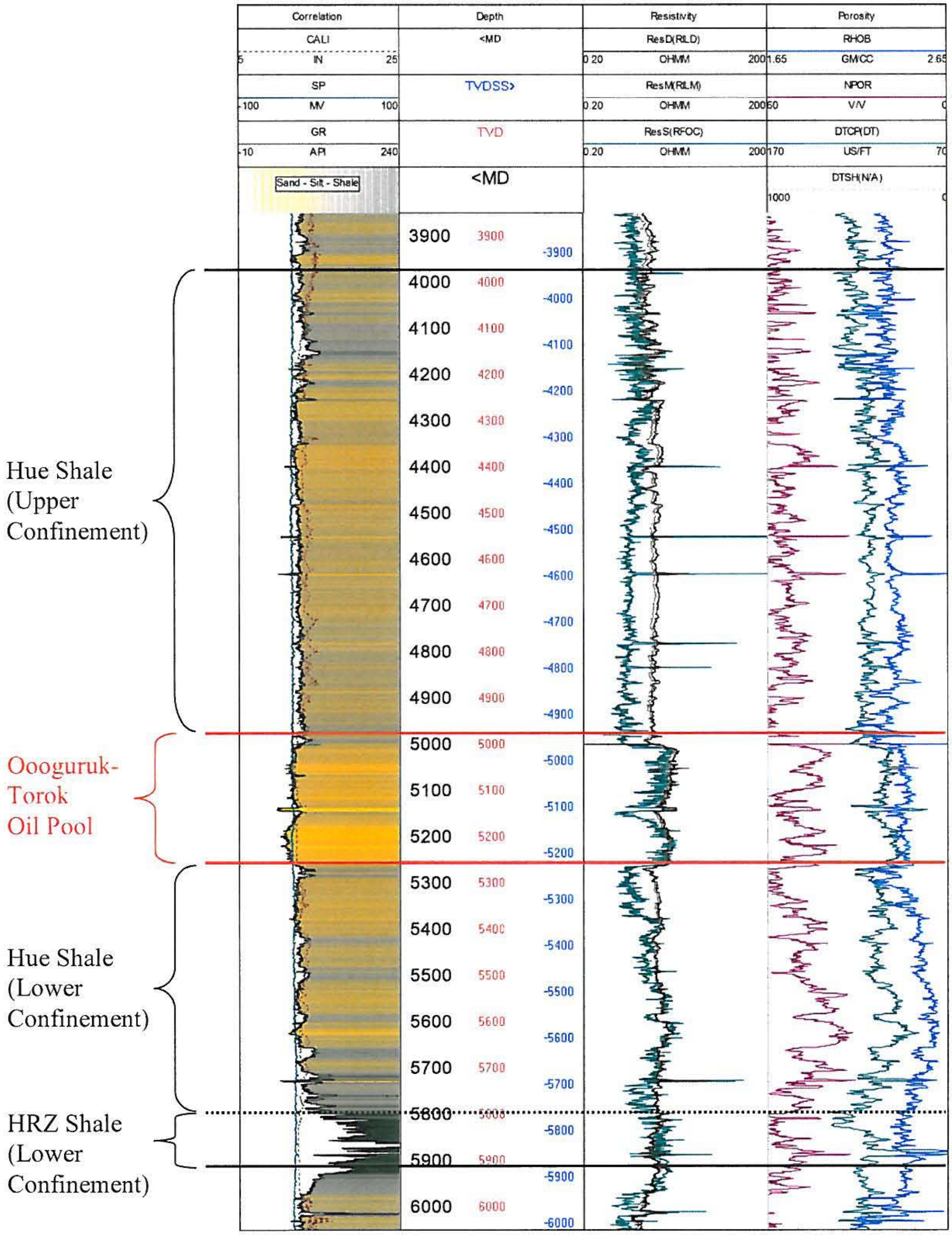

Figure 3. Kalubik No. 1 – Type Well Log for Oooguruk-Torok Oil Pool Showing Upper and Lower Confining Zones

11. Reservoir Fluid Contacts: The Colville Delta No. 3 exploratory well tested oil down to -5,150 feet TVDSS; the OTOP outline is based on this depth. The highest known water for the pool is established by MDT measurements in the Ivik No. 1 exploratory well at -5,212 feet TVDSS.
12. Reservoir Fluid Properties: The API gravity of Torok oil measures 24°, and viscosity ranges from about 2 to 4 centipoise. The solution gas-oil ratio (GOR) is estimated to be 250 to 550 standard cubic feet per stock tank barrel, and the bubble point pressure is estimated between 1,000 psig to 2,200 psig. Initial reservoir pressure is 2,250 psi at a depth of -5,000 feet TVDSS. Reservoir temperature is about 135° F. The oil formation volume factor is estimated from 1.15 to 1.30 reservoir barrels per stock tank barrel of oil, and the gas formation volume factor is estimated at 1.234 reservoir barrels per thousand standard cubic feet of gas.[3] Free gas has not been encountered with the Torok interval.

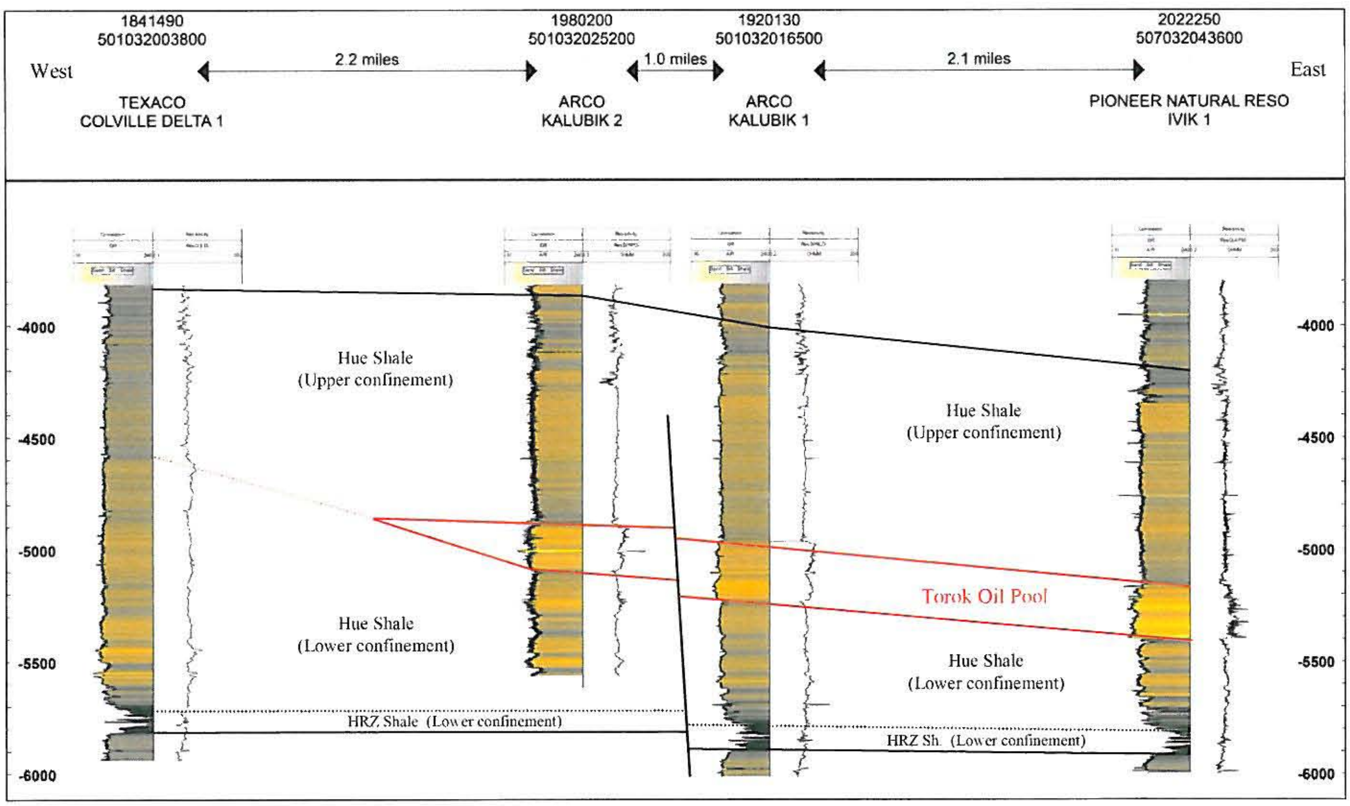

Figure 4. West-to-East Structural Cross Section from Colville Delta 1 to Ivik 1

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[3] Reservoir and reservoir fluid properties are based on samples and measurements collected from well ODST-45A. At present, this well utilizes gas for artificial lift, so the initial GOR of the reservoir is not known at this time. The ranges for associated oil properties are based on PVT studies conducted by Intertek for Pioneer.

13. Well Logs: Logs of injection wells will be filed with the AOGCC according to the requirements of 20 AAC 25.

14. Mechanical Integrity and Design of Injection Wells: Drilling and completion operations will be performed in accordance with 20 AAC 25. In accordance with 20 AAC 25.412(d), cement quality logs, or other data approved by the AOGCC, will be provided for all injection wells to demonstrate isolation of the injected fluids to the approved interval. Mechanical integrity tests will be performed in accordance with 20 AAC 25.412(c). To facilitate wireline access to the deeper portions of highly deviated wellbores, Pioneer requests an exception to 20 AAC 25.412(b) to allow packers in injection wells to be located more than 200 feet measured depth above the top of the injection zone; however, packers will not be located above the confining interval.

15. Types and Source of Fluids: Fluids requested for injection are:
    a. Source water from the Kuparuk or Prudhoe seawater treatment plants;
    b. Produced water provided by the Kuparuk River Field;
    c. Produced water from the Oooguruk-Kuparuk, Oooguruk-Nuiqsut, and Oooguruk-Torok Oil Pools;
    d. Tracer survey liquid to monitor reservoir performance;
    e. Biocide-treated and oxygen-scavenged sea water extracted from Harrison Bay, adjacent to the ODS;
    f. Biocide-treated and oxygen-scavenged water from the ODS shallow water source wells;
    g. Biocide-treated and oxygen-scavenged effluent from the ODS reverse osmosis unit;
    h. Mixtures of the fluids described in (e), (f), and (g) above;
    i. Diesel associated with freeze protection;
    j. Non-hazardous glycol and water mixtures; and
    k. Natural gas.

16. Fluid Compatibility: Analysis of formation water samples collected from the ODST-45A well indicate the potential for moderate scaling during production and when the formation water mixes with sea water. Scaling mitigation measures include placement of aqueous and solid phase scale inhibitors in fracture treatments, conventional squeeze treatments, and chemical injection in the wells and at the surface. Pioneer has not conducted specific formation compatibility tests, but petrographic descriptions and field injectivity data from analogous fine-grained turbidite reservoirs (Tarn and Meltwater in the Kuparuk River Field and Nanuq in the Colville River Field) suggest limited permeability degradation will occur with properly treated injection fluids. Additionally, injection into the ODST-46 well will provide the opportunity to evaluate injection performance prior to expanding the injection project to the entire Affected Area.

    Although the OTOP has high clay content, the majority of the clay occurs in laminar sheets within the reservoir sands where EOR fluids will be injected. The interbedded reservoir sandstone layers are relatively clay poor, so the possibility of permeability loss due to clay swelling is low.

17. Injection Rates and Pressures: Pioneer proposes to develop the OTOP using an IWAG EOR project. Injection well rates will be managed to replace offset production voidage and will be controlled by surface chokes. The maximum injection well rate is expected to be 5,000 barrels of water per day (BWPD) or 6 million standard cubic feet of gas per day (MMSCFPD). The average injection well rate is expected to be 1,500 BWPD or 2 MMSCFPD. Surface facility constraints will limit injection pressure. Water injection pressure is limited to 2,800 psi, which is the delivery pressure from the Kuparuk River Field. Water injection pressure is expected to range from 2,500 to 2,800 psi. Gas injection pressure is limited to 4,500 PSI by the compression at the OTP. Gas injection pressure is expected to range from 4,000 to 4,400 psi.

18. Fracture Information: Disposal Injection Order No. 31 (DIO 31) authorized disposal injection into the Torok Formation down dip of the OTOP. Fracture modeling done for the DIO was provided with Pioneer's application for the AIO. This modeling demonstrated that at the sand face pressures that would occur during disposal activities, which are much higher than the pressures that will occur during EOR injection activities, fractures will not propagate through the confining intervals above and below the OTOP.

19. Water Quality in the Injection Interval: Laboratory analysis of an OTOP formation water sample collected from well ODST-45A measured total dissolved solids of 16,980 mg/l, which is above the 10,000 mg/l cut off for freshwater. Pioneer also calculated the salinity of Torok Formation water in ten nearby wells, and found a salinity range from approximately 17,000 to 24,000 mg/l NaCl. Based on this information, the U.S. Environmental Protection Agency confirmed Pioneer's conclusion that the Torok Formation in the area of the disposal wells authorized by DIO 31 is not an underground source of drinking water.

20. Mechanical Condition of Adjacent Wells: There are ten penetrations of the OTOP within the affected area. Three of these penetrations (ODST-39, 45A, and 46) are existing OTOP producers, a fourth well ODST-47 is currently being drilled as an OTOP producer. ODST-46 will be converted to an injector upon approval of this AIO. Three are exploratory wells (Colville Delta 2, Colville Delta 3, and Kalubik 2) that have been permanently plugged and abandoned after drilling and testing was completed. One is the Nuna 1 OTOP appraisal well which was drilled in 2012 and is currently suspended. One is the ODSN-23 Oooguruk-Nuiqsut Oil Pool (ONOP) producer. The final well is the failed ONOP injector, the ODSN-45i, which was plugged and sidetracked to become the ODST-45A OTOP producer. All of the aforementioned wells are either properly constructed, or were properly plugged and abandoned so that they provide sufficient mechanical isolation to confine injected fluids to the target interval.

CONCLUSIONS:

1. The requirements of 20 AAC 25.402 have been met.
2. Operation of an enhanced oil recovery injection project in the Oooguruk-Torok Oil Pool will significantly improve recovery from the pool.
3. The injection interval does not contain freshwater and is not a potential underground source of drinking water.

4. Review of analogous injection projects indicates that the fluids proposed for injection, when properly treated, will be compatible with the Oooguruk-Torok Oil Pool formation and formation water. Scale formation will be controlled using standard oilfield practices.
5. The proposed injection activities will be conducted in permeable and hydraulically fractured strata. These strata can be reasonably expected to accept injected fluids at pressures that are lower than those required to fracture through the surrounding confining intervals.
6. Injected fluids will be confined within the receiving interval by thick and laterally extensive impermeable confining layers, cement isolation of the wellbores, and appropriate operating conditions.
7. Regular well surveillance and reservoir monitoring will demonstrate appropriate performance of the enhanced oil recovery project and disclose possible abnormalities. An annual report of injection performance is warranted, and it must include an assessment of fracture propagation into adjacent confining intervals.
8. Setting the packers in the injection wells more than 200 feet MD above the injection interval to facilitate wireline access will not increase the potential of an injection fluid confinement failure, provided that the packer is set at least 300 feet MD below the top of the production casing cement and is not above the confining interval. The location of production casing cement will be established through cement bond logging or alternate methods deemed acceptable by the AOGCC. Any alternative methods must be approved in advance by the AOGCC. MITs will ensure integrity of injection wells.
9. Reservoir voidage will be maintained at a replacement ratio of about 1:1.
10. Sufficient information has been provided to authorize injection of fluids into the Oooguruk-Torok Oil Pool for the purposes of pressure maintenance and enhanced oil recovery, subject to monitoring as described in the rules below.

NOW THEREFORE IT IS ORDERED:

The underground injection of fluids for pressure maintenance and enhanced oil recovery is authorized in the following area, subject to the following rules and 20 AAC 25, to the extent not superseded by these rules.

<u>Affected Area: Umiat Meridian</u>

Township, Range	Description
T13N, R07E	Section 3: SW ¼ SW ¼
	Section 4: SE ¼ SE ¼, W ½ SE ¼, SW ¼, SE ¼ NW ¼, W ½ NW 1/4
	Section 5: E ½ E ½
	Section 8: E ½ E ½
	Section 9: All
	Section 10: SW ¼ NE ¼, SE ¼ SE ¼, W ½ SE ¼, W ½

Township, Range	Description
	Section 11: SW ¼ SW ¼
	Section 14: SE ¼ SE ¼, W ½ SE ¼, W ½
	Section 15: All
	Section 16: All
	Section 17: E ½ E ½, SW¼ SE ¼
	Section 20: E ½, SW ¼, SE ¼ NW ¼
	Section 21: All
	Section 22: All
	Section 23: All
	Section 24: SW ¼, W ½ NW ¼
	Section 25: SE¼ NE ¼, W ½ NE ¼, SE ¼, W ½
	Section 26: All
	Section 27: All
	Section 28: All
	Section 29: E ½, E ½ W ½, NW ¼ NW ¼
	Section 32: E ½, E ½ W ½, W ½ SW ¼
	Section 33: All
	Section 34: All
	Section 35: All
	Section 36: All
T12N, R07E	Section 3: All
	Section 4: All
	Section 5: E ½ NE ¼, SE ¼
	Section 8: E ½
	Section 9: All
	Section 10: All
	Section 15: All
	Section 16: All
	Section 17: E ½, E ½ SW ¼
	Section 20: E ½, E ½ W ½
	Section 21: All
	Section 22: All

Rule 1 Authorized Injection Strata for Enhanced Recovery.

Fluids authorized under Rule 3, below, may be injected for purposes of pressure maintenance and enhanced oil recovery within the Affected Area in to strata that are common to, and correlate with, the interval between 4,991 and 5,272 feet MD on the resistivity log recorded in exploratory well Kalubik No. 1.

Rule 2 Well Construction.

To facilitate wireline access, packers in injection wells may be located more than 200' MD above the top of the Oooguruk-Torok Oil Pool; however, packers shall not be located above the top of the confining interval. Production casing cement volume must be sufficient to place cement a minimum of 300' MD above the planned packer depth. Production casings must be cemented to a minimum of 500' MD above the Oooguruk-Torok Oil Pool.

Rule 3 Authorized Fluids.

Fluids authorized for injection are:

a. Source water from the Kuparuk or Prudhoe seawater treatment plants;
b. Produced water provided by the Kuparuk River Field;
c. Produced water from the Oooguruk-Kuparuk, Oooguruk-Nuiqsut, and Oooguruk-Torok Oil Pools;
d. Tracer survey liquid to monitor reservoir performance;
e. Biocide-treated and oxygen-scavenged seawater extracted from Harrison Bay, adjacent to the ODS;
f. Biocide-treated and oxygen-scavenged water from the ODS shallow water source wells;
g. Biocide-treated and oxygen-scavenged effluent from the ODS reverse osmosis unit;
h. Mixtures of the fluids described in (e), (f), and (g) above;
i. Diesel associated with freeze protection;
j. Non-hazardous glycol and water mixtures; and
k. Natural gas.

Injection fluids shall be properly treated to mitigate the potential for scaling and permeability degradation in the Oooguruk-Torok Oil Pool. The injection of any other fluids, or mixtures of the above fluids, shall be approved by separate administrative action.

Rule 4 Authorized Injection pressure for Enhanced Recovery

Injection pressures must be maintained such that the injected fluids do not fracture the confining intervals or migrate out of the approved injection stratum. Wellhead injection pressure shall not exceed 4,500 psi during gas injection or 2,800 psi during water injection.

Rule 5 Monitoring Tubing-Casing Annulus Pressure

The tubing and casing annuli pressures of each injection well must be monitored at least daily, except if prevented by extreme weather conditions, emergency situations, or similar unavoidable circumstances. Monitoring results shall be documented and made available for AOGCC inspection.

Rule 6 Demonstration of Tubing/Casing Annulus Mechanical Integrity

The mechanical integrity of an injection well must be demonstrated before injection begins, and before returning a 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 a well, to be scheduled when injection conditions (temperature, pressure, rate, etc.) have stabilized. Mechanical integrity tests must be conducted in accordance with AOGCC Industry Guidance Bulletin No. 10-02 – Mechanical Integrity Testing and done to a test pressure equal to the maximum anticipated surface injection pressure. The AOGCC must be notified, following the procedures in AOGCC Industry Guidance Bulletin No. 10-01 – Test Witness Notification, at least 48 hours in advance to enable a representative to witness mechanical integrity tests. Results of mechanical integrity tests must be readily available for AOGCC inspection.

Rule 7 Well Integrity 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 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 would 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 all injection wells indicating well integrity failure or lack of injection zone isolation.

Rule 8 Notification of Improper Class II Injection

Injection of fluids other than those listed in Rule 3 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 injection wells. 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 9 Annual Surveillance Report

A report evaluating the performance of the enhanced recovery injection must be submitted to the AOGCC by April 1st of each year covering injection operations during the previous calendar year. The report shall include data sufficient to characterize the injection operation, including, among other information, the following: injection and annuli pressures (*i.e.*, daily average, maximum, and minimum pressures); fluid volumes injected; injection rates; mechanical condition of the injection wells; and integrity of confining layers. 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 10 Other Conditions

The AOGCC may suspend, revoke or modify this authorization if injected fluids fail to be confined within the designated injection strata.

Rule 11 Administrative Action

Upon proper application, or its own motion, and unless notice and public hearing is 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.

DONE at Anchorage, Alaska and dated October 8, 2012.

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

ALASKA OIL AND GAS CONSERVATION COMMISSION

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 AOGCC grants for good cause shown, a person affected by it may file with the AOGCC 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 AOGCC 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 AOGCC 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 AOGCC mails, **OR 30** days if the AOGCC 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 AOGCC 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 AOGCC, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the AOGCC mails, **OR 30** days if the AOGCC 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 AOGCC 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.