ISSUANCE DATE AND SIGNATURE PAGE

U.S. ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS I
Permit Number AK-1I011-B

In compliance with provisions of the Safe Drinking Water Act (SDWA), as amended, (42 U.S.C. 300f-300j-9), and attendant regulations incorporated by the U.S. Environmental Protection Agency (EPA) under Title 40 of the Code of Federal Regulations, Eni US Operating Co. Inc. (Eni) (Permittee) is authorized to inject non-hazardous industrial waste utilizing up to four (4) Class I injection wells at the Nikaitchuq Unit (located in State of Alaska tideland waters approximately 12 miles northeast of the mouth of the Colville River in the Beaufort Sea, North Slope of Alaska), into the Canning and Hue Shale Formations, in accordance with conditions set forth herein. The proposed disposal well(s) are in an area where there are no underground sources of drinking water (USDWs) below - 3500 feet TVDss (true vertical depth subsea) with the base of the permafrost at between approximately 1835 feet to 1912 feet TVDss at Spy Island and Oliktok Point respectively. A No Underground Sources of Drinking Water Ruling was issued by EPA on May 19, 2008. Injection of hazardous waste as defined under the Resource Conservation and Recovery Act (RCRA), as amended, (42 USC 6901) or radioactive wastes are not authorized under this permit. Injection shall not commence until the Permittee has received written authorization to inject from EPA Region 10 Director of the Office of Compliance and Enforcement (Director).

All references to Title 40 of the Code of Federal Regulations are to regulations that are in effect on the date that this permit is issued. Figures and appendices are referenced to the Nikaitchuq Development Area Underground Injection Control (UIC) Class I Permit Application dated August 8, 2008.

This permit shall become effective on September 16, 2008, in accordance with 40 C.F.R. 124.15. This permit and the authorization to inject shall expire at midnight, September 15, 2018, unless terminated.

Signed this 16th day of September, 2008. As modified this 16th day of April, 2013.

____________/s/______________________
Edward J. Kowalski, Director
Office of Compliance and Enforcement
U.S. Environmental Protection Agency
Region 10 (OCE-184)
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101

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PART I

GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The underground injection activity, otherwise authorized by this permit, shall not allow the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons or the environment. Compliance with this permit during its term constitutes compliance for purposes of enforcement with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, or any other law governing protection of public health or the environment from imminent and substantial endangerment to human health or the environment.

This permit may be modified, revoked and reissued, or terminated during its term for cause. Issuance of this permit does not convey property rights or mineral rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. This permit does not authorize any above ground generating, handling, storage, or treatment facilities.

This permit is based on the final permit application submitted by Eni on August 8, 2008, and supplemental material related to the “no USDW” ruling granted by EPA dated May 19, 2008.

B. PERMIT ACTIONS

1. <u>Modification, Reissuance, or Termination</u>

   This permit may be modified, revoked and reissued, or terminated for cause as specified in 40 CFR 144.39 and 144.40. In addition, the permit can undergo minor modifications for cause as specified in 40 CFR 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any permit condition.

2. <u>Transfer of Permits</u>

   This permit is not transferable to any person except after notice to the Director on APPLICATION TO TRANSFER PERMIT (EPA Form 7520-7) and in accordance with 40 CFR 144.38. The Director may require modification or revocation and reissuance of the permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission in the manner prescribed in 40 CFR 2.203 and on the application form or instructions, or, in the case of other submissions, by stamping the words "confidential" or "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 CFR Part 2 (Public Information).

Claims of confidentiality for the following information will be denied:

1. The name and address of the Permittee.
2. Information that deals with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply

   The Permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34.

2. Penalties for Violations of Permit Conditions

   Any person who violates a permit condition is subject to a civil penalty not to exceed $32,500 per day of such violation. Any person who willfully or negligently violates permit conditions is subject to a fine of not more than $32,500 per day of violation and/or being imprisoned for not more than three (3) years.

3. Duty to Reapply

   If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee must apply for and obtain a new permit. To be timely, a complete application for a new permit must be received at least 180 days before this permit expires.

4. Need to Halt or Reduce Activity Not a Defense

   It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. Duty to Mitigate

   The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. Proper Operation and Maintenance

   The Permittee shall, at all times, properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit. Decharacterized waste generated during remedial well workovers or well construction operations shall be appropriately disposed in a Class I non-hazardous well (refer to 40 CFR 148.4(d)).

7. Duty to Provide Information

   The Permittee shall provide to the Director, within a reasonable time, any information that the Director may request to determine whether cause exists for modifying, revoking and reissuing, terminating this permit, or to determine compliance with this permit. The Permittee shall also provide to the Director, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry

   The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law to:

a. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

d. Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by SDWA, any contaminants or parameters at any location.

9. Records

a. The Permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit and records of all data used to complete this permit application for a period of at least three years from the date of the sample, measurement, report or application. These periods may be extended by request of the Director at any time.

b. The Permittee shall retain records concerning the nature and composition of all injected fluids until three years after the completion of plugging and abandonment. At the conclusion of the retention period, if the Director so requests, the Permittee shall deliver the records to the Director. The Permittee shall continue to retain the records after the three-year retention period unless he delivers the records to the Director or obtains written approval from the Director to discard the records.

c. Records of monitoring information shall include:

(1) The date, exact place, and time of sampling or measurements;

(2) The name(s) of the individual(s) who performed the sampling or measurements;

(3) The date(s) analyses were performed;

(4) The name(s) of the individual(s) who performed the analyses;

(5) The analytical techniques or methods used; and

(6) The results of such analyses.

d. Monitoring of the nature of injected fluids shall comply with applicable analytical methods cited and described in Table I of 40 CFR 136.3, in appendix III of 40 CFR Part 261, or in certain circumstances by other methods that have been approved by the Administrator.

e. All environmental measurements required by the permit, including, but not limited to measurements of pressure, temperature, mechanical integrity, and chemical analyses shall be done in accordance with EPA's Quality Assurance Program Plan.

f. As part of the COMPLETION REPORT, the Permittee must submit a PLAN that describes the procedures to be carried out to obtain detailed chemical and physical analysis of representative samples of the waste including the quality assurance procedures used including the following:

(1) The parameters for which the waste will be analyzed and the rationale for the selection of these parameters;

(2) The test methods that will be used to test for these parameters; and

(3) The sampling method that will be used to obtain a representative sample of the waste to be analyzed.

g. Where applicable, the Waste Analysis Plan (WAP) from the permit application may be incorporated by reference.

h. The Permittee shall complete a written manifest for each batch load of waste received (for waste streams that are not hard piped and continuous). The Permittee shall require written manifests documenting all wastes received. The manifest shall contain a description of the nature and composition of all injected fluids, date of receipt, source of material received for disposal, name and address of the waste generator, a description of the monitoring performed and the results, a statement stating if the waste is exempt from regulation as hazardous waste as defined by 40 CFR 261.4, and any information on extraordinary occurrences.

For waste streams that are hard-piped continuously from the source to the wellhead, the Permittee shall provide for continuous, recorded measurement of the discharge rate and shall provide such sampling and testing as may be necessary to provide a description of the nature and composition of all injected fluids, and to support any statements that the waste is exempt from regulation as hazardous waste as defined by 40 CFR 261.4.

i. Dates of most recent calibration or maintenance of gauges and meters used for monitoring required by this permit shall be noted on the gauge or meter. Earlier records shall be available through a computerized maintenance history database.

10. <u>Reporting Requirements</u>

The Permittee shall give notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted facility or changes in type of injected fluid.

11. <u>Anticipated Noncompliance</u>

The Permittee shall give advance notice to the Director of any significant planned changes in the permitted facility or activity that may result in noncompliance with permit requirements.

12. <u>Twenty-Four Hour Reporting</u>

a. The Permittee shall report to the Director or an authorized representative any noncompliance that may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the Permittee becomes aware of the circumstances. The following shall be included as information that must be reported orally within 24 hours:

(1) Any monitoring or other information that indicates that any contaminant may cause an endangerment to an underground source of drinking water.

(2) Any noncompliance with a permit condition or malfunction of the injection system.

b. A written submission shall also be provided within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact date and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

13. Other Noncompliance

The Permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Permit Condition E.12.b.

14. Reporting Corrections

When the Permittee becomes aware that he/she failed to submit any relevant facts in the permit application or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information.

15. Signatory Requirements

a. All permit applications, reports required by this permit and other information requested by the Director shall be signed by a principal executive officer of at least the level of vice-president, or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(1) The authorization is made in writing by a principal executive of at least the level of vice-president.

(2) The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position.

(3) The written authorization is submitted to the Director.

b. If an authorization under paragraph a. of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph a. of this section must be submitted to the Director prior to or together with any reports, information, or applications to be signed by an authorized representative.

c. Any person signing a document under paragraph a. of this section shall make the following certification:

"I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment."

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

The Permittee shall notify the Director no later than 45 days before conversion or abandonment of the well.

2. Plugging and Abandonment Report

The Permittee shall plug and abandon the well as provided in the Plugging and Abandonment portion (Attachment Q) of the August 8, 2008 permit application, which is hereby incorporated as a part of this permit.

Within 60 days after plugging any well the Permittee shall submit a report to the Director in accordance with 40 CFR 144.51(p). EPA reserves the right to change the manner in which the well will be plugged if the well is not proven to be consistent with EPA requirements for construction and mechanical integrity. The Director may ask the Permittee to update the estimated plugging cost periodically.

3. Cessation Limitation

After a cessation of operations of two years, the Permittee shall plug and abandon the well in accordance with the plan unless he/she:

a. Provides notice to the Director;
b. Demonstrates that the well will be used in the future; or
c. Describes actions or procedures, satisfactory to the Director that the Permittee will take to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells unless waived by the Director.

4. Cost Estimate for Plugging and Abandonment

a. The Permittee estimates the 2008 cost of plugging and abandonment of the permitted Class I well(s) to be approximately $ 2.8 million ($ 700,000/well). Please refer to Attachment Q and Appendix A of the August 8, 2008 permit application.
b. The Permittee must submit financial assurance and a revised estimate in April of each year. The estimate shall be made in accord with 40 CFR 144.62.
c. The Permittee must keep at the facility or at the Permittee central files in Anchorage during the operating life of the facility the latest plugging and abandonment cost estimate.
d. When the cost estimate changes, the documentation submitted under 40 CFR 144.63(f) shall be amended as well to ensure that appropriate financial assurance for plugging and abandonment is maintained continuously.
e. The Permittee must notify the Director by registered mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 business days after the commencement of the proceeding.

G. FINANCIAL RESPONSIBILITY

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well. If the financial test and corporate guarantee provided under 40 CFR 144.63(f) should change, the Permittee shall immediately notify the Director. The Permittee shall not substitute an alternative demonstration of financial responsibility for that which the Director has approved, unless it has previously submitted evidence of that alternative demonstration to the Director and the Director notifies him that the alternative demonstration of financial responsibility is acceptable.

PART II

WELL SPECIFIC CONDITIONS

A. CONSTRUCTION

1. Casing and Cementing

The Permittee shall case and cement the well(s) to prevent the movement of fluids into strata other than the authorized injection interval (see II.C.3, below). Casing and cement shall be installed in accordance with a casing and cement program approved by the Director and in accordance with EPA Class I well construction practices (40 CFR 146.12) and the State of Alaska/AOGCC Regulations (20 AAC 25.412 and 20 AAC 25.252).

The proposed well design includes one of the two wells at each site (Oliktok Point and Spy Island) being a vertical hole with the other well being deviated (with maximum anticipated deviation of 50 degrees at OP26-DSP02 and 26 degrees at SI-DSP02 respectively). The wells will be drilled to the base of DCI # 3, then cased (long string) and cemented. The actual injection intervals to be perforated will be selected based on log results of each individual well.

The Permittee shall provide not less than ten days advance notice to the Director of all cementing operations. The 10-3/4 inch surface casing in each well will be cemented back to surface. If primary cement returns to surface are not observed for the 10 ¾ inch surface casing cementing procedure, then additional sacks of Permafrost L cement as required may need to be pumped as a Top Job. The 7 5/8 inch injection casing shall be cemented from 7 5/8 inch casing shoe to 200 feet above the upper confining shale #2, which will be determined by geologic evaluation (Reference is Nikaitchuq # 1 Type Log).

A cement bond log (ultrasonic imaging log (USIT) or equivalent) will need to be run in the 7 5/8 inch injection casing (from 7 5/8 inch shoe to top of cement (TOC)) and 10 ¾ inch surface casing (from 10 3/4 inch shoe up to 500 feet) to evaluate the quality of the primary cement jobs. The integrity of both the surface casing and the injection casing will need to be verified by pressure testing (leak off test – LOT/formation integrity test - FIT). Should a change(s) be required to the design casing and cementing program (due to unanticipated conditions), the Director or authorized representative shall be notified as to the nature of the change(s), so that approval is obtained from the Director or authorized representative in a timely manner enabling the well to be drilled and completed in a safe and successful manner.

The casing, cementing and well construction data will be in compliance with the procedures outlined in Attachment L – Construction Procedures (including integrity criteria) and the well schematics (Exhibits 26, 28, 30 and 32) of the August 8, 2008 permit application.

2. Tubing and Packer Specifications

The well shall inject fluids through tubing with a packer. Tubing and packer shall be installed in accordance with Attachment L of the permit application, with the packer set not more than 200 feet measured depth above the top of the selected injection zone/interval (based on well testing and reservoir/log analysis) and confirmed by tubing tally. In the event that the packer needs to be re-set at a higher depth at a later date, the Permittee will submit the necessary data and obtain authorization from EPA, prior to resumption of continued injection activities. For additional details on Eni’s proposed injection scenarios, please refer to Part II.C.5. of this permit and to well schematics (Exhibits 26, 28, 30 and 32) as shown in the permit application.

The proposed wellhead assembly is shown in Exhibit 38 of the permit application, with a wellhead rating of at least 5000 psi.

3. New Wells in the Area of Review

New wells within the Area of Review (AOR) shall be constructed in accordance with the Alaska Oil and Gas Conservation Commission Regulations Title 20 - Chapter 25. Further, all wells that penetrate the injection intervals within the area of review shall have casing cemented to the formation throughout the entire section from 200 feet TVD below the Canning and Hue Shale injection zone to 200 feet TVD above the injection zone (reference is Exhibit 2 Type Log Nikaitchuq-01 of the permit application).

B. CORRECTIVE ACTION

The applicant has identified no wells within the 1/4 mile radius of the planned disposal wells at the Spy Island site and two wells within the 1/4 mile radius of the planned disposal wells at the Oliktok Point site. Wells OPI-1 and OPI-2 are approximately 420 feet northeast of the planned Oliktok Point disposal well locations. Neither of the two existing wells penetrated the injection zones.

Also, there are no transmissive faults, open well bores, un-cemented wells or other conduits within 1/4 mile at both the offshore Spy Island and Oliktok Point sites that require corrective action in order to prevent fluids from moving above the confining zone. If the applicant later discovers that a well or wells within the AOR require(s) corrective action to prevent fluid movement, then the applicant shall inform EPA upon such discovery and provide a corrective action plan for EPA Director or authorized representative review and approval. If EPA or the Permittee discovers that fluids have moved above the upper confining zone along a wellbore within the AOR, then injection shall cease until the fluid movement problem can be diagnosed and corrected**.**

C. WELL OPERATION

1. Prior to Commencing Injection

Injection operations pursuant to this permit may not commence until:

a. Construction is complete and the Permittee has submitted two copies of COMPLETION FORM FOR INJECTION WELLS (EPA Form 7520-9), see APPENDIX A; and

   (1) The Director or authorized representative has inspected or otherwise reviewed the new, existing, sidetrack or replacement injection well(s) and finds it is in compliance with the conditions of the permit; or

   (2) The Permittee has not received notice from the Director or authorized representative of intent to inspect or otherwise review the new, sidetrack or replacement injection well(s) within thirteen (13) days of receiving the COMPLETION REPORT in which case prior inspection or review is waived and the Permittee may commence injection.

b. The Permittee demonstrates that the well has mechanical integrity as described in Part II.C.3. below and the Permittee have received notice from the Director or authorized representative that such a demonstration is satisfactory. The Permittee shall notify EPA at least two weeks prior to conducting this initial test so that an EPA representative may be present.

c. The Permittee has conducted a step-rate injection test and submitted a preliminary report to EPA that summarizes the results.

2. During Injection

The Nikaitchuq Unit is an oil discovery located on the North Slope of Alaska. The unit is in State of Alaska tidelands 12 miles northeast of the Colville River Delta. Eni is operator and 100% working interest owner of the field. As stated earlier, two of the four proposed Class I disposal wells will be drilled at the offshore Spy Island Drillsite (SID), while the remaining two wells will be drilled at the onshore Oliktok Production Pad (OPP).

The SID is located approximately 3 miles offshore from Oliktok Point in approximately 6 feet of water and will have minimal production equipment.

The OPP is onshore and includes besides the drillsite, crude oil processing, power supply for the field, and a waste handling and injection facility. Finally, the Nikaitchuq Operations center (NOC) located onshore will include a camp, helipad and storage facilities. Additional project-related details are available in EPA's Fact Sheet and Public Notice on the Nikaitchuq Class I UIC Permit No. AK-1I011-A. After the initial drilling phase, which is expected to be the first approximately seven years of operations, and during the production phase, the SID will basically be unmanned except when the rig is intermittently active, monitoring/inspection activities are underway, or maintenance is going on.

Recording and non-recording injection pressure gauges, inner and outer annulus (IA and OA) gauges, injection rate gauges, and temperature gauges will be installed. Out-of-limit Alarms and shut-off systems will be installed and a manning plan (if dedicated manning) or operator control room (facility operating personnel) plan if monitored by Control room operators will be developed and implemented. Visual and automatic monitoring of the IA and tubing pressures will occur routinely with pre-set, out-of-limit alarms to inform supervisory personnel.

The wellhead, controls, and monitoring instrumentation will be enclosed in an insulated and heated structure.

3. Mechanical Integrity

a. Standards

The injection well(s) must have and maintain mechanical integrity pursuant to 40 CFR 146.8.

b. Prohibition without Demonstration of Mechanical Integrity

Injection operations are prohibited after the effective date of this permit unless the Permittee has conducted the following tests and submitted the results to the Director:

(1) In order to demonstrate there is no significant leak in the casing, tubing or packer, the tubing/casing annulus must be pressure tested to at least 3,500 pounds per square inch gauge (psig) for not less than thirty minutes. Pressure shall show a stabilizing tendency. That is, the pressure may not decline more than 10 percent during the 30-minute test period and shall experience less than one-third of its total loss in the last half of the test period. If the total loss exceeds 5 percent or if the loss during the second 15-minute period is equal to or greater than one-half the loss during the first 15 minutes, the Permittee may extend the test period for an additional 30 minutes to demonstrate stabilization. An initial pressure test (standard annulus pressure test - SAPT) will be required upon completion of the well and prior to the well first being placed on injection. After acquiring this baseline pressure test data, the SAPT will be required annually until expiration of the ten (10) year permit period. Since the SID facility may normally be unmanned, the annual SAPT due dates have been granted a six month grace period for operational and cost efficiency (so that the well can be tested when the well is active or people are on this island). At the discretion of the Director, and depending on the results of the baseline data, the frequency for demonstrating internal mechanical integrity (no leaks in the tubing-casing annulus or in the tubing-packer assembly) may be revised (either increase or decrease in frequency) as specified and approved by the Director.

(2) To detect movement of fluids in vertical channels adjacent to the well bore and to determine that the confining zone is not fractured, a temperature survey, oxygen activation/water flow log or other equivalent fluid movement/confinement logs shall be conducted at an injection pressure at least equal to the maximum continuous injection pressure observed in the previous six months. Approved fluid movement tests include, but are not limited to tracer surveys, temperature logs, noise logs, oxygen activation/water flow logs (WFL), borax pulse neutron logs (PNL), or other equivalent logs. Fluid movement tests not previously used to satisfy this requirement must be submitted 30 days in advance and are subject to prior approval by the Director or authorized representative. Copies of all logs shall be accompanied by a descriptive and interpretive report. Fluid movement/confinement logs will be run <u>initially</u> upon completion of the well and prior to initiation of injection at start-up. After acquiring this baseline data, the fluid movement/confinement logs will be required every two (2) years until expiration of the ten (10) year permit period. Again, since the SID facility will normally be unmanned, a six month grace period is being granted to the test due dates to allow for operational and cost efficiency. At the discretion of the Director, and depending on the results of the baseline data, the frequency for demonstrating external mechanical integrity (no flow behind pipe and isolation above injection interval) and utilizing alternative diagnostic techniques, may be revised (either increase or decrease in frequency) as specified and approved by the Director or authorized representative.

(3) Tubing inspection logs (pipe analysis logs, caliper logs, or other equivalent logs) shall be run once every two years, or at the Director or authorized representative's discretion, to monitor condition, thickness and integrity of the downhole tubing. Copies of the logs shall be accompanied by a descriptive and interpretive report.

c. Terms and Reporting

(1) Two (2) copies of the log(s) and two (2) copies of a descriptive and interpretive report of the mechanical integrity tests identified in 3.b (2) shall be submitted within 45 days of completion of the logging.

(2) Mechanical integrity shall also be demonstrated by the pressure test in 2.b. (1) any time the tubing is removed from the well or if a loss of mechanical integrity becomes evident during operation. The Permittee shall report the results of such tests within 45 days of completion of the tests.

(3) After the <u>initial</u> mechanical integrity demonstration, the Permittee shall notify the Director of intent to demonstrate mechanical integrity at least 30 days prior to subsequent demonstrations.

(4) The Director will notify the Permittee of the acceptability of the mechanical integrity demonstration within 13 days of receipt of the results of the mechanical integrity tests. Injection operations may continue during this 13-day review period. If the Director does not respond within 13 days, injection may continue.

(5) In the event that the well fails to demonstrate mechanical integrity during a test or a loss of mechanical integrity occurs during operation, the Permittee shall halt operation immediately and shall not resume operation until the Director gives approval to resume injection.

(6) The Director may, by written notice, require the Permittee to demonstrate mechanical integrity at any time.

4. <u>Injection Zone</u>

Injection shall be limited to the Canning and Hue Shale Formations. These formations are located below the Ugnu/Schrader oil bearing formations and above the Kuparuk/Ivishak formations.

On May 19, 2008 EPA issued a No Underground Sources of Drinking Water (No USDW) ruling in the Nikaitchuq Development Area for the Canning and Hue Shale formations (Exhibit 1 of the permit application). The three proposed injection intervals (Drill Cuttings Intervals #s 1, 2 and 3) are shown in Exhibit 2 of the permit application. The Permittee intends to complete the well at the bottom of deepest permitted injection interval (DCI # 3 within the Hue Shale – Torok Sand equivalent). The Torok formation, as identified in the Pioneer Oooguruk project area, is expected to be present in the Oliktok Point area, but is believed to shale out offshore – See EPA UIC Class I Permit # AK 1I009-A issued to Pioneer's Oooguruk project. The Permittee will open up additional intervals uphole (DCI #s 2 and 1 if needed, for additional capacity), based on injectivity testing and log evaluation. Because the disposal intervals and confining zones structurally dip down to the northeast across the project area, the approved injection intervals will apply to the Canning (upper) and Hue Shale (lower intervals) as defined on the Nikaitchuq #1 Type Log (Exhibit 2 of the permit application). Estimated injection interval depths are: DCI # 3 depths are at approximately - 6800 to – 7000 feet TVDss; DCI # 2 depths are from – 5480 to – 6600 feet TVDss; and DCI # 1 depths are from –4360 to 5200 feet TVDss (from Nikaitchuq #1 Type Log. It should be noted that the subsea depths of the formation tops and bottoms vary considerably across the project area. The tops and bases of the injection zones and confining zones will be determined from open hole e-line logs and measurement-while-drilling (MWD) logs during the drilling of each well. Each of the selected DCI intervals has overlying and underlying shale layers that should provide adequate confinement of the injected fluids. The Permittee has submitted a detailed fracture simulation report for the various injection scenarios with solids injection and fracture growth and geometry results for the projected volumes, rates and injection pressures for this project (See Appendix C – Report prepared by Advantek for Eni and Appendix D – Report prepared by ASRC Energy Services for Pioneer Natural Resources – Oooguruk Unit in Eni's August 8, 2008 permit application).

The formation evaluation and testing program will obtain data on fluid pressure, temperature, fracture gradient, and other physical, chemical and radiological parameters of the injection zone as stated in Attachment I of the permit application. Given the consistent regional subsurface geology and fluid types and that injection has been successful into the Torok Sand at the nearby Oooguruk Unit and the success of past injection of millions of barrels of similar fluids into both deeper and shallower formations at other nearby facilities on the North Slope, EPA is waiving the requirements of 40 CFR 146.12(e) and 40 CFR 146.14(a) to sample and characterize formation fluids and rock matrix of the injection zone.

EPA waives the requirement in (40 CFR 146.13 (b) to monitor the strata overlying the confining zone for fluid movement since the aquifers at the Nikaitchuq Unit are too naturally saline to qualify as USDWs (meet "No USDW" criteria).

5. <u>Injection Scenarios</u>

Eni plans to have a grind and inject facility at OPP and SID. Each of those facilities will inject waste into a single well. An additional well is being permitted at each location as a contingency.

Eni proposes to inject at pressures above the fracture gradient. Based on Advantek's recommendation for a batch injection scenario (with a shut-in period for the fracture to heal), and at an injection rate of 5 barrels/minute, the maximum growth of the fracture is 670 feet in a vertical direction and 420 feet in a horizontal direction and is fully contained within the arresting and confining layers and within the limits of the ¼ mile AOR. EPA waives the prohibition (in 40 CFR 146.13 (a)) from injecting at pressures that would initiate new fractures or propagate existing fractures within the injection zone, and would instead allow hydraulic fracturing so long as new fractures are not initiated nor existing ones propagated within the upper confining zone. Injection will be limited to the Canning and Hue Shale formations injection intervals at approximate depths of between approximately 4300 to 6800 feet TVDss in the Nikaitchuq Unit.

Eni intends to first perforate wells in the approved injection interval DCI # 2 or # 3 near the base of each interval and start injecting into DCI # 2 or # 3. Should the lower injection interval in the future fail to take injected fluids in sufficient volumes then as needed the injection well could be perforated higher up hole in DCI # 2 and then, if needed, in the lower DCI # 1 interval near the base of the interval with injection then commencing into the DCI # 1. Exact perforated intervals will be picked once the disposal wells have been drilled and the well logs analyzed. The exact perforated intervals may or may not correlate exactly with the Type Log of Nikaitchuq # 1. Estimated porosities in the disposal intervals are in the 15 % to 35 % range with permeabilities expected to be poor to moderate (10 md or less). The fracture gradient in the disposal intervals is expected to be between 0.65 to 0.70 psi/ft.

6. Injection Pressure Limitation

Injection pressures shall not initiate new fractures or propagate existing fractures in the upper confining zone as that stratigraphic interval is described in the Nikaitchuq #1 Type Log (Exhibit 2 of the permit application). Neither shall the maximum injection pressure, measured at the wellhead, exceed 4,000 pounds per square inch (psig), except as follows:

a. On occasions, the maximum pressure may be exceeded due to minor plugging from entrained solids accumulating in and around the wellbore; whereupon the well would need to be surged with clear fluid, and in an extreme case a well stimulation may be required.

b. In the event of a plant shutdown or outage, there may be instances where injection pressures exceed 4,000 psi (unrelated to fluid injection activities). In such instances, the Permittee shall notify the Director or an authorized representative by telephone or electronic mail within twenty-four (24) hours of the initial exceedance of the 4,000-psig limitation and shall submit a written incident report not later than ten (10) days thereafter.

However, in all cases including the above, the well-head rating of 5000 psi should not be exceeded.

7. Annulus Pressure

The annulus between the tubing and the long string casing shall be filled with a corrosion inhibited non-freezing solution. To accommodate swings in wellbore temperatures and tubing thermal expansion, a positive surface pressure up to 1500 psig is authorized for the inner annulus (tubing x long string injection casing).

Since the tubing-casing annulus volume will vary due to temperature changes, the high-low annulus pressure limits can be adjusted, if necessary and upon approval by the Director or authorized representative, at the end of the first year of performance (to include both the summer and winter ambient temperature swings).

Note: The authorization of up to 1500 psi on the inner annulus is to enable shut-down and alarm systems to be set at appropriate pressure limits, so as not to shut-down the facility from unintended causes not related to direct injection activities, and is not intended to allow the Permittee to continue to maintain the well on injection, in the event of a loss of mechanical integrity or when there is pressure build-up either in the tubing x inner annulus or between the injection casing and surface casing (between the IA x OA), resulting in a potential sustained casing pressure (SCP) scenario. In the event of a loss of mechanical integrity, then the Permittee has to meet the requirements as outlined in Part II.C.3.c.5 of this permit.

8. Injection Fluid Limitation

This permit only authorizes the injection of those fluids identified in the permit documentation. In the event that third party wastes are accepted, the third party must certify that fluids for injection are not hazardous waste or radioactive wastes.

Fluids generated from Class I injection well construction and well workover, and fluids generated from the operation and maintenance of Class I injection wells and associated injection well piping, may be disposed in a Class I non-hazardous injection well.

> **NOTE:** Neither hazardous waste as defined in 40 CFR 261 nor radioactive wastes other than naturally occurring radioactive material (NORM) from pipe scale shall be injected for disposal.

D. MONITORING

1. Monitoring Requirements

Samples and measurements collected for the purpose of monitoring shall be representative of the monitored activity.

2. Continuous Monitoring Devices

Continuous monitoring devices shall be installed, maintained, and used to monitor injection pressure and rate for those streams that are hard-piped and continuous, and to monitor the pressure of non-freezing solution in the annulus between the tubing and the long string casing. Calculated flow data are not acceptable except as a back-up system if the primary continuous injection rate device malfunctions.

3. Monitoring Direct Waste Injection

Direct waste injection pumping operations at the well site shall be continuously manned and visually monitored. During these pumping operations, a chronological record of the time of day, a description of the waste pumped, injection rate and pressure, and well annulus pressure observations shall be maintained. The pumping record must be signed by the person in charge.

4. Alarms and Operational Modifications

a. The Permittee shall install, continuously operate, and maintain alarms to detect excess injection pressures and significant changes in annular fluid pressure. These alarms must be of sufficient placement and urgency to alert operators in all operating spaces.

b. Plans and specifications for the alarms shall be submitted to the Director or authorized representative prior to the initiation of injection.

E. REPORTING REQUIREMENTS

1. Quarterly Reports

The Permittee shall submit quarterly reports to the Director containing the following information:

a. Monthly average, maximum, and minimum values for injection pressure, rate, and volume shall be reported on INJECTION WELL MONITORING REPORT (EPA Form 7520-8).

b. Graphical plots of continuous injection pressure and rate monitoring.

c. Raw monitoring data in an electronic format.

d. Physical, chemical, and other relevant characteristics of the injected fluid.

e. Any well workover or other significant maintenance of downhole or injection-related surface components.

f. Results of all mechanical integrity tests performed since the previous report including any maintenance-related tests and any “practice” tests.

g. Any other tests required by the Director.

2. Annual Reports

   An annual performance report covering the period October 1 of the previous year through September 30 of the report year shall be submitted on or before November 30. The report shall include rate and pressure performance, surveillance logging, fill depth, survey results and volumetric analysis of the disposal storage volume. In the event that fracture slurry injection takes place, then an estimate of the fracture growth shall also be included in the report.

3. Report Certification

   All reporting and notification required by this permit shall be signed and certified in accordance with Part I.E.15., and submitted to the following address:

   UIC Manager, Ground Water Protection Unit
   U.S. Environmental Protection Agency (OCE-127)
   1200 Sixth Avenue Suite 900
   Seattle, Washington 98101

APPENDIX A. REPORTING FORMS

The following forms are available on the EPA's web site

7520-7 APPLICATION TO TRANSFER PERMIT
https://www.epa.gov/sites/production/files/2016-01/documents/7520-7_508c_0.pdf

7520-8 INJECTION WELL MONITORING REPORT
https://www.epa.gov/sites/production/files/2016-01/documents/7520-9_508c_0.pdf

7520-9 COMPLETION FORM FOR INJECTION WELLS
https://www.epa.gov/sites/production/files/2016-01/documents/7520-9_508c_0.pdf