UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101-3140

NOV 2 2 2017

OFFICE OF
COMPLIANCE AND ENFORCEMENT

Reply To: OCE-101

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Misty Alexa
WNS Operations Manager
ConocoPhillips Alaska, Inc.
PO Box 100360, ATO-1746
Anchorage, Alaska 99510

Re: Issuance of Underground Injection Control (UIC) Permit No. AK1I010-B
Colville River Unit, North Slope, Alaska

Dear Ms. Alexa,

The U. S. Environmental Protection Agency Region 10 (EPA) is issuing an Underground Injection Control permit (AK1I010-B, "the permit") for ConocoPhillips Alaska, Inc. at the Colville River Unit, North Slope, Alaska. The enclosed permit authorizes the permittee to inject non-hazardous industrial waste utilizing one Class I injection well at the Colville River Unit into the naturally saline intervals of the Sag River and Ivishak formations as described in the permit. EPA received no comments and no requests for a public hearing during the public comment period which occurred between October 5 and November 9, 2017.

This letter constitutes service of notice under 40 CFR 124.19(a). The permit will become effective on the date as indicated in the permit unless the Environmental Appeals Board receives a timely appeal meeting the requirements of 40 CFR 124.19. Information about the administrative appeal process may be obtained on-line at www.epa.gov/eab or by contacting the Clerk of the Environmental Appeals Board at (202) 233-0122.

Sincerely,

Edward J. Kowalski
Director

Enclosure
1. Permit AK1I010-B

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cc w/enc: Marc Bentley
ADEC Division of Water/Wastewater Discharge Permits

Chris Wallace
AOGCC

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ISSUANCE DATE AND SIGNATURE PAGE

U.S. ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS I
Permit Number **AK1I010-B**

In compliance with provisions of the Safe Drinking Water Act (SDWA), (42 USC §§ 300f–300j-27), and the Underground Injection Control (UIC) regulations promulgated by the U.S. Environmental Protection Agency (EPA) within Title 40 of the Code of Federal Regulations (CFR), ConocoPhillips Alaska, Inc. (CPAI) (Permittee) is authorized to inject non-hazardous industrial waste utilizing one Class I injection well within the Alpine Field at the Colville River Unit. CPAI is authorized to inject non-hazardous industrial waste into the Ivishak and Sag River Formations, in accordance with 40 CFR § 144.33 and the conditions of this permit. The Alpine Field is located approximately 250 miles above the Arctic Circle and lies approximately 45 miles west of Deadhorse, Alaska, approximately 8 miles north of the Village of Nuiqsut, and approximately 17 miles west of the Kuparuk River Unit. EPA has previously determined that there are no underground sources of drinking water (USDWs) below permafrost in the Alpine Field as documented in the fact sheet supporting the issuance of permit AK1I003-A in 1998. In 2007, EPA reaffirmed that aquifers in the Alpine Field below permafrost do not meet the criteria to be considered a USDW. EPA's determination was based on both water sampling results and borehole geophysical analyses that demonstrate the expected concentration of Total Dissolved Solids (TDS) in the injection zone aquifers and aquifers above the injection zones to be above the 10,000 mg/L threshold to be considered a USDW. Injection of hazardous waste as defined under the Resource Conservation and Recovery Act (RCRA) (42 USC §§ 6921-6939g) or radioactive wastes (other than naturally occurring radioactive material from pipe scale) are not authorized under this permit. All references to Title 40 of the Code of Federal Regulations are to the regulations in effect on the date this permit is issued. Figures and appendices are referenced to CPAI's UIC Permit Renewal Application Class I (Industrial), dated May 25, 2017.

This permit shall become effective on December 1, 2017, in accordance with 40 CFR § 124.15. This permit and the authorization to inject shall expire at midnight, November 30, 2027, unless otherwise terminated or revoked.

Signed this 21st day of November, 2017.

Edward J. Kowalski, Director
Office of Compliance and Enforcement
EPA Region 10 (OCE-101)
1200 Sixth Avenue Suite 900
Seattle, WA 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. Notwithstanding any other provisions of this permit, The Permittee shall not conduct any underground injection activity in a manner that allows the movement of fluid containing any contaminant into USDWs, 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. Any underground injection activity not specifically authorized in the permit application process is prohibited. Compliance with this permit during its term constitutes compliance for purposes of enforcement with Part C of the SDWA. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, or any other common or statutory law other than Part C of the SDWA.

Issuance of this permit does not 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 the Permittee on May 25, 2017. This permit is a reissuance of Permit AK1I010-A.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination

This permit may be modified, revoked and reissued, or terminated, as specified in 40 CFR §§ 144.39 and 144.40. In addition, the permit can undergo minor modifications 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. Transfer of Permits

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 and 40 CFR § 144.5, 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 validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information).

Claims of confidentiality for the following information will be denied:

a. The name and address of the Permittee.

b. Information which deals with the existence, absence, or level of contaminants in drinking water.

c. Information already in the public domain.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply

The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. Discharges authorized under an emergency permit, issued under 40 CFR § 144.34, do not need to meet the conditions of this permit, limited to the extent and duration authorized under the emergency permit

2. Penalties for Violations of Permit Conditions

Any person who violates a permit requirement is subject to civil penalties and other enforcement action under the SDWA. Any person who willfully violates permit requirements may be subject to criminal prosecution.

3. Continuation of Expiring Permits

a. 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.

b. Permit Extensions: The requirements of an expired permit continue in force and effect, in accordance with 5 USC § 558(c), until the effective date of a new permit, if:

i. The Permittee has submitted a timely and complete application for a new permit; and

ii. EPA, through no fault of Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

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.

7. Property Rights

This permit does not convey any property rights or mineral rights of any sort, or any exclusive privilege.

8. Duty to Provide Information

The Permittee shall provide to the Director 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, that are retained under the conditions of this permit.

9. Inspection and Entry

The Permittee shall allow the Director or authorized EPA 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 (including logging data) that are retained under the conditions of this permit;

c. Inspect and photograph, 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 substances or parameters at any location.

10. 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. Records may be retained in hard copy or electronic format to satisfy this requirement.

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. Records may be retained in hard copy or electronic format to satisfy this requirement.

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 40 CFR § 136.3, in Appendix I of 40 CFR Part 261, or, in certain circumstances, by other methods that have been approved by the Director.

e. The permittee shall make all environmental measurements required by the permit, including, but not limited to, measurements of pressure, temperature, mechanical integrity, and chemical analyses in accordance with any applicable EPA Quality Assurance Plans.

f. As part of the Completion Report, the Permittee must submit a Waste Analysis Plan (WAP) 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.

The WAP submitted with the permit application may be incorporated by reference to satisfy the WAP submittal requirement.

g. The Permittee shall require a written manifest for each batch load of waste received for waste streams that are not hard piped and continuous. 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 retain:

(1) Continuous measurement of the discharge rate,

(2) A description of the nature and composition of all injected fluids, and

(3) A hazardous waste determination as defined by 40 CFR § 261.4.

h. The Permittee shall note dates of most recent calibration or maintenance of gauges and meters used for monitoring required by this permit on the gauge or meter. Earlier records of calibration and maintenance shall be available through a computerized maintenance history database.

11. <u>Reporting Requirements</u>

a. Planned Changes: 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.

b. Anticipated Noncompliance: 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.

c. Compliance Schedules: Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit must be submitted to the Director no later than 30 days following each schedule date.

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

a. The Permittee shall report to the Director or authorized EPA 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 which indicates that any contaminant may cause an endangerment to a USDW or may otherwise adversely affect the health of persons.

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

b. The Permittee shall provide a written submission (in electronic format for release to the public within five 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. The Permittee shall provide email notice to affected stakeholders, such as Tribal Governments, if warranted as determined by an authorized EPA representative.

13. <u>Other Noncompliance</u>

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 Part I E.12.b.

14. <u>Reporting Corrections</u>

When the Permittee becomes aware that it 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 in accordance with 40 CFR § 144.32. 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 record is retained on-site and an electronic scan copy is submitted to the Director. Upon request, the original is submitted to the Director or an authorized EPA representative.

b. Changes to authorization: If an authorization under paragraph 15.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 15.a. of this section must be submitted to the Director. The Permittee may submit this authorization with any reports, information, or applications to be signed by an authorized representative.

c. Certification: Any person signing a document under paragraph 15.a. of this section shall make the following certification:

d. “I certify under the penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.”

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 Plan (7520-6 Attachment Q) of UIC Class I Permit Application submitted by the Permittee, 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 well is considered to be in temporary abandoned status. The Permittee shall plug and abandon the well in accordance with the approved plan and 40 CFR § 144.52(a)(6) unless the Permittee:

a. Provides notice to the Director within 30 days of the end of the two years of temporary abandonment, and
b. Provides information that, to the Director's satisfaction, demonstrates the Permittee's intent to use the well in the future; or
c. Describes actions or procedures, satisfactory to the Director, which the Permittee will take to ensure that the well will not endanger USDWs 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 is required in the permit application (see 7520-6 attachment R) to estimate the cost of plugging and abandonment all permitted Class I UIC wells. Please refer to the permit application (7520-6 attachment R) for the plugging and abandonment cost estimates(s) per well for the year the application is submitted. Such estimates must be based upon costs that a third party would incur to plug the wells.
b. The Permittee shall submit financial assurance and a revised estimate prior to April 30 of each year. The estimate shall be made in accordance with 40 CFR § 144.62. The Director or an authorized EPA representative may approve electronic submittal of this requirement provided the Permittee retains the original and submits the original upon request.
c. The Permittee shall keep at the facility or at the Permittee central files in Alaska during the operating life of the facility the latest plugging and abandonment cost estimate.
d. When the cost estimate changes, the Permittee shall amend the documentation submitted under 40 CFR § 144.63(f) and ensure that appropriate financial assurance for plugging and abandonment is maintained continuously.

G. FINANCIAL RESPONSIBILITY

The Permittee is required to demonstrate and continuously maintain financial responsibility and resources sufficient to close, plug, and abandon the underground injection operation as provided in the Plugging and Abandonment Plans and consistent with 40 CFR § 144 Subpart D, which the Director has chosen to apply. 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 the Permittee that the alternative demonstration of financial responsibility is acceptable.

If the Permittee chooses to rely upon a financial test and corporate guarantee provided under 40 CFR § 144.63(f), the Permittee shall immediately notify the Director of any change that would result in non-compliance with 40 CFR § 144 Subpart D.

Consistent with 40 CFR § 144.63 and regarding incapacity of owners or operators, guarantors, or financial institutions, 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 ten business days after the commencement of the proceeding. Furthermore, an owner or operator must notify the Regional Administrator by certified 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. A guarantor of a corporate guarantee as specified in 40 CFR § 144.63(f) must make such a notification if he is named as debtor, as required under the terms of the guarantee (See 40 CFR § 144.70(f)).

PART II
WELL SPECIFIC CONDITIONS

A. CONSTRUCTION

1. Casing and Cementing

The Permittee shall case and cement the well in a manner that ensures injection occurs into the approved injection interval (see II.C.4, 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 UIC well construction practices (40 CFR § 146.12) and the State of Alaska/AOGCC Regulations (20 AAC §§ 25.412 and 25.252). For any Class I well to be drilled at this location (including replacement/sidetracks), in addition to the above requirements, the Permittee shall provide not less than 30 days advance notice to the Director or authorized EPA representative to witness all cementing operations. The 30 days advance notice requirement may be revised (either increased or decreased) by the Director or authorized EPA representative. If primary cement returns to surface are not observed for the (20 inch or other) surface casing cementing procedure, the Director or authorized EPA representative is to be notified as to the nature of the augmented testing proposed to ensure the integrity of the cement bond and adequacy of any Top Job procedure. The top of the intermediate casing cement shall be at least 100 feet measured depth above the top of the injection zone and no more than 500 feet measured depth below the surface casing shoe.

For any future well constructions, Cement Bond/Ultrasonic Imaging (USIT or other) logs and pressure tests (leak off test and/or formation integrity test) will be run for both the surface and injection casings to confirm zonal isolation and verify casing integrity. The Permittee shall provide all data requested by the Director or authorized EPA representative, including but not limited to field copies of all logging data.

Should a change(s) be required to the design casing and cementing program due to unanticipated conditions, the Permittee shall notify the Director or authorized EPA representative as to the nature of the change(s). The Permittee may not construct the proposed change without approval from the Director or authorized EPA representative.

2. Tubing and Packer Specifications

The well shall inject fluids through tubing with a packer. Tubing and packer shall be installed in accordance with the procedures in the permit application. In the event that a packer needs to be set or re-set at a revised depth at a later date, the Permittee will perform a mechanical integrity test, submit the necessary data, and obtain authorization from EPA prior to resuming injection. The packer will be set no more than 100 feet measured depth (MD) from the top of the injection zone unless a greater spacing from the packer to the top of the injection zone is specified and authorized by the Director or an authorized EPA representative.

3. New Wells in the Area of Review (AoR)

EPA has set a one-quarter mile radius as the AoR for this Class I UIC permit application. New Class I permitted UIC wells shall be constructed 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 will also follow the State of Alaska/AOGCC Regulations (20 AAC §§ 25.412 – 25.252). If any development or service wells are drilled in the future that penetrate the injection intervals within the AoR, these wells shall have casing cemented to the formation throughout the entire section from the base of the lower confining zone [at the base of the Kavik Formation Marker] to at least 100 feet MD above the top of the permitted secondary Sag River injection zone.

B. CORRECTIVE ACTION

The applicant has identified no wells in the AoR which 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 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

Unless the well has previously (within the last 180 days) fulfilled the requirements of Part II C.1., prior to commencing injection into new, converted, sidetrack, and/or replacement wells, the following requirements must be fulfilled:

a. Construction is complete and the Permittee has submitted two copies of COMPLETION FORM FOR INJECTION WELLS (with logging data) (EPA Form 7520-9, see Attachments to be submitted with the Completion Report); and

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

(2) The Permittee has not received notice from the Director of intent to inspect or otherwise review the new, converted, sidetrack or replacement injection well within 13 days of receipt of 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. Mechanical Integrity, and the Permittee has received notice from the Director or authorized EPA 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 authorized EPA representative may be present.

c. The permittee has conducted a step-rate injection test (SRT) and submitted a preliminary report to EPA that summarizes the results. Upon approval by the Director or an authorized EPA representative, submitting the results of a previously conducted SRT satisfies this requirement.

2. During Injection

The Permittee shall ensure that the well authorized by this permit is monitored 24 hours per day by trained and qualified personnel while injection is occurring. During injection, the Permittee shall monitor the well injection pressure, tubing-casing inner annulus pressure, and injection rate on a continuous basis. The Permittee shall install automatic alarms and shut-off systems to take effect in notifying staff in the event injection conditions deviate from expected procedures and operations. De-characterized waste may be appropriately disposed in a Class I non-hazardous well [refer to 40 CFR § 148.1(d)].

3. Mechanical Integrity

a. Standards

The injection well 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) The Permittee shall pressure test the tubing/casing annulus in order to demonstrate there is no significant leak in the casing, tubing or packer by conducting a mechanical integrity test of the inner annulus (MITIA). The annulus between the casing and the tubing shall be pressure tested to the maximum allowable injection pressure (4,200 psi) but not to exceed 70% of the minimum yield strength of the casing, as determined by the operator before the test.

To demonstrate that there is no significant leak in the casing, tubing, or packer, the well must be tested for 30 minutes and satisfy either (i) or (ii) below:

i. The pressure does not decline more than 10% during the test period and the loss in the second half of the test period is less than one half of the loss in the first half of the test period, or

ii. The pressure does not decline more than 2% of the initial test pressure during the test period and the loss in the second half of the test period is less than the loss in the first half of the test period.

If the well fails to satisfy (i) or (ii) during the first 30-minute test period, the test may be extended by an additional 30 minutes to demonstrate stabilization.

The Permittee shall conduct an MITIA prior to the well being used for injection authorized under this permit. After the initial test, the Permittee shall conduct an MITIA annually if the well is active and once every two years if the well is inactive. The due date for the MITIA may be extended by up to one month to accommodate for personnel constraints related to operating injection in a remote environment upon approval by the Director or an authorized EPA representative. Also, the Director or authorized EPA representative may revise (either increase or decrease) the frequency with which the Permittee must conduct the MITIA.

(2) The Permittee shall conduct an approved fluid movement test to detect fluid migration outside of the permitted injection intervals at an injection pressure at least equal to the average continuous injection pressure observed at the well in the previous six months. Approved fluid movement test methods include, but are not limited to: tracer surveys, temperature survey logs (conducted after a 12-hour shut-in unless otherwise authorized by the authorized EPA representative), noise logs, oxygen activation/water flow logs, borax pulse neutron logs, or other equivalent logs. The Permittee shall notify the Director or an authorized EPA representative 30 days prior to commencement of the fluid movement test along with a description of the testing procedures, if the test method has not previously been used to satisfy this requirement. The Permittee shall conduct a fluid movement test and submit logs of this test upon completion of a new, sidetrack, converted, or replacement well prior to injection. After the initial test, the Permittee shall conduct a fluid movement test and submit results every year while the well is active until expiration of the permit. The Director or authorized EPA representative may extend the due date for the fluid movement tests up to one month to accommodate for operating injection in a remote arctic location. Also, the Director or authorized EPA representative may revise (either increase or decrease) the frequency with which the Permittee must conduct a fluid movement test.

(3) The Permittee shall conduct tubing inspection tests (pipe analysis logs, caliper logs, or other equivalent logs approved by the Director or an authorized EPA

representative) to monitor condition, thickness, and integrity of the downhole tubing every year until expiration of the permit. The Permittee shall notify the Director or an authorized EPA representative 30 days prior to commencement of the tubing inspection test and include a description of the testing procedures, if the test method has not previously been used to satisfy this requirement. Unless waived by the authorized EPA representative, the Permittee shall conduct an inspection of any exposed section of the injection casing if tubing is removed from the wellbore. This requirement may be waived with approval from the Director or an authorized EPA representative. The Director or authorized EPA representative may extend the due date for the fluid movement tests up to one month to accommodate for operating injection in a remote arctic location. Also, the Director or authorized EPA representative may revise (either increase or decrease) the frequency with which the Permittee must conduct the tubing inspection.

c. Terms and Reporting

(1) The Permittee shall submit one copy of the log(s) and one copy of a descriptive and interpretive report of the mechanical integrity tests identified in 3.b (2) and 3.b (3) to EPA within 45 days of completion in hard copy or electronic format, unless waived by an authorized EPA representative. The Permittee shall submit two field copies of any log(s) upon request by an authorized EPA representative to the representative immediately upon completion of the field logging event. This includes all logging associated with well construction events.

(2) The Permittee shall demonstrate mechanical integrity by the MITIA in 3.b.(1) prior to resuming injection if at any time the tubing is removed from the well or 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 initial mechanical integrity demonstration, the Permittee shall notify the Director or an authorized EPA representative of intent to demonstrate mechanical integrity at least 30 days prior to conducting a test.

(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 or an authorized EPA representative gives approval to resume injection.

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

4. Injection Zone

Injection shall be limited to the Ivishak and Sag River Formations, below the top of the Sag River CD1-01A Stratigraphy log and Depth Structure map, Exhibits 3-1 and 3-3 of the permit application, respectively.

5. Waivers to UIC Program requirements

Due to the absence of USDWs at the proposed location(s), EPA grants three (3) waivers of UIC regulatory program requirements:

(1) Compatibility of Formation and Injectate (40 CFR §§ 146.12(e)(4)-(5) and 146.14(a)(8):
Based upon the applicability of past injectability studies, injection history at the North Slope of Alaska, and performance of CD1-01A since inception, EPA intends to waive the requirement to sample and characterize formation fluids and the rock matrix in order to determine whether or not they are compatible with the approved injectate stream.

(2) Injection Zone Fracturing (40 CFR § 146.13(a)(1)):
The prohibition against injecting at pressures that would initiate new fractures or propagate existing fractures within the injection zone is waived. Hydraulic fracturing of the injection and arresting zones is allowed so long as fractures are not propagated within the upper confining zone. Injection is limited to approved sections of the Sag River and Ivishak formations and external mechanical integrity demonstrations are required to verify that all injected fluids are exiting in the injection interval and that there is no flow behind pipe due to channeling or other conduits. [See Part II C.3.b (2)]

(3) Ambient Monitoring Above the Confining Zone (40 CFR § 146.13(b)(1) and (4) and 40 CFR § 146.13(d)):
The requirement to monitor the strata overlying the confining zone for fluid movement is waived since the aquifers at the Alpine Field are too naturally saline to qualify as USDWs (meet "No USDW" criteria).

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 Exhibit 3-3 of the permit application. Never shall the maximum injection pressure, measured at the wellhead, exceed 4,200 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. 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 4,200 psig (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 4,200-psig limitation and shall submit a written incident report not later than ten (10) days thereafter. Upon request, electronic mail submittal of the incident report may be approved by an authorized EPA representative.

In all cases, including the above, the well-head rating of 5,000 psig shall not be exceeded.

7. Annulus Pressure Limitation

The annulus between the tubing and the long string casing shall be filled with a corrosion inhibited, non-freezing solution. A positive surface pressure up to 2,000 psig is authorized for the inner annulus (tubing x long string injection casing).

Since the tubing-casing annulus pressure will vary due to temperature changes, the pressure limits may be adjusted upon approval by the Director or an authorized EPA representative.

> NOTE: The authorization of up to 2,000 psig on the inner annulus 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 if pressure communication arises between the inner and/or outer annuli. In the event of a loss of mechanical integrity, 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. De-characterized waste may be appropriately disposed in a Class I non-hazardous well (refer to 40 CFR § 148.1(d)). 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. Hazardous waste as defined in 40 CFR Part 261 and radioactive wastes, other than naturally occurring radioactive material (NORM) from pipe scale and/or radioactive tracer beads, shall not be injected for disposal. In the event that third party wastes are accepted, the third party shall certify the fluids are eligible for injection.

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

The Permittee shall install, maintain, and use continuous monitoring devices 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 casing. Calculated flow data or periodic monitoring are not acceptable except as a back-up system if the primary continuous injection rate device malfunctions or a power outage occurs.

3. Monitoring Direct Waste Injection

The Permittee shall continuously man and visually monitor direct waste injection pumping operations at the well site. During these pumping operations, the Permittee shall maintain a chronological record of the time of day, a description of the waste pumped, injection rate and pressure, and well annulus pressure observations. The person in charge of the pumping operations shall be identified on the pumping record.

4. Alarms and Operational Modifications

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 including, but not limited to, the control room. The Permittee shall install and maintain an emergency shutdown system to respond to losses of internal mechanical integrity as evidenced by deviations in the annular fluid pressures.

The Permittee shall submit plans and specifications for the alarms to the Director or authorized EPA representative prior to the initiation of injection.

E. REPORTING REQUIREMENTS

1. Semi-annual Reports

The Permittee shall submit a semi-annual report 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). Upon request of an authorized EPA representative, the Permittee shall submit the report electronically.
b. Graphical plots of continuous injection pressure and rate monitoring.
c. Daily 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 “practice” tests.
g. Results of any other tests required by the Director.

2. Annual Reports

The Permittee shall submit to the Director two copies of an annual performance report for the reporting period of April 1 through March 31. This report shall be submitted by May 31 of each year. *(For example, injection data from April 1, 2017 through March 31, 2018 should be reported by May 31, 2018)*. The annual performance report shall include, but not be limited to, rate and pressure performance, surveillance logging and results, fill depth, disposal storage volume, estimated fracture growth (if any) in the event that solids injection takes place, and updates of operational plans. Surveillance logging, fill depth, and survey results may not be conducted every year so the annual report may not always contain that information. In addition, a report for fracture growth is required only when fracture slurry injection has taken place during the reporting period. The Permittee may substitute an annual performance report required by an AOGCC Disposal Injection Order, provided it includes the above-mentioned minimum requirements.

3. Report Certification

All reports and notifications required by this permit shall be signed and certified in accordance with Part I.E.15; electronically stored and maintained at the Permittee’s facility or company headquarters; electronically submitted to the Director or an authorized EPA representative; and, upon request by the Director or an authorized EPA representative, submitted as a hard copy to the following address:

UIC Manager, Ground Water Unit (OCE-101)
U.S. Environmental Protection Agency Region 10
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101

APPENDIX A: REPORTING FORMS

PDF copies of following forms are available on 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/7520-8_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