UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
UNDERGROUND INJECTION CONTROL

DRAFT PERMIT

CO52432-12407

Class/Type: Class V Non-Hazardous Waste Disposal Well

Colowyo Mine County Road 17 INJ#1
Moffat County, Colorado

Issued To

Colowyo Coal Company, L.P.
(aka Tri-State Generation and Transmission Association, Inc.)
P.O. Box 33695
Denver Colorado 80233-0695

TABLE OF CONTENTS

AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act (SDWA) and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this permit (Permit),

Colowyo Coal Company, L.P.
(aka Tri-State Generation and Transmission Association, Inc.)
P.O. Box 33695
Denver, Colorado 80233-0695

hereinafter referred to as the "Permittee," is authorized to construct and, upon issuance of authorization to commence injection, to operate, the following Class V well(s):

Colowyo Mine County Road 17 INJ#1
NWNW S23, T4N, R93W
Latitude: 40.307500
Longitude: -107.800446
Moffat County, Colorado

This Permit is based on representations made by the Permittee and other information contained in the administrative record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit.

EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to Underground Sources of Drinking Water (USDWs). Under 40 CFR part 144, subparts D and E, certain conditions apply to all UIC permits and must be incorporated either expressly or by reference. Regulations specific to Colorado injection wells are found at 40 CFR part 147, subpart G. The Permittee is authorized to engage in underground injection in accordance with the conditions of this Permit. Any underground injection activity not authorized by this Permit into the above referenced well(s) is prohibited. Compliance with the terms of this Permit does not constitute a defense to any action brought under the provisions of Section 1431 of the SDWA or any other law governing protection of public health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

This Permit is issued for 10 (ten) years from the Effective Date, until it expires under the terms of the Permit, or unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41.

Effective Date **DRAFT**

DRAFT
Douglas Minter, Manager
Safe Drinking Water Branch

SECTION A. WELL CONSTRUCTION REQUIREMENTS

The EPA-approved well construction plan is given in ATTACHMENT I of this Permit. The Permittee must comply with ATTACHMENT I, as approved by the Director. Once construction has begun, the Permittee must notify EPA within 30 days of the start date. Changes in construction plans during construction may be approved by the Director as minor modifications under 40 CFR § 144.41. No such changes may be physically incorporated into construction of the well prior to approval of the modification by the Director in accordance with 40 CFR § 144.52(a)(1).

After initial well construction is complete, any subsequent changes in well construction will require a major modification of this Permit according to 40 CFR § 144.39 and § 124.5. All changes to well construction must be consistent with permit conditions. Changes to the approved well construction plan must not be implemented until after the Permittee has received a signed permit modification from the Director.

1. Casing and Cement

The well(s) must be cased and cemented to prevent the movement of fluids into or between USDWs, and in accordance with 40 CFR § 146.12. Additional federal, tribal, state or local laws or regulations may also apply.

The casing and cement used in the construction of each newly drilled well must be designed for the life expectancy of the well.

2. Injection Tubing and Packer

Injection must only take place through tubing with a packer set within or below the nearest cemented and impermeable confining system. Tubing and packer specifications must be as represented in ATTACHMENT I of this Permit. Any proposed changes must be submitted by the Permittee in accordance with Section B.8. *Alteration, Workover, and Well Stimulation* of this permit.

3. Sampling and Monitoring Devices

The Permittee must install and maintain in good operating condition any and all devices required to measure, monitor, and record the parameters required by this permit in ATTACHMENT III. Requirements for monitoring devices are found in ATTACHMENT I.

The Permittee must ensure that the devices and methods installed and used are sufficient to represent the activity being measured, monitored or recorded. Calculated flow data or periodic monitoring are not acceptable for required continuous monitoring except as a back-up system if the primary continuous monitoring devices malfunction or power outage occurs. The Permittee must ensure the well's construction and near-wellhead design is appropriate for collecting fluid samples and fulfilling all monitoring requirements. The Permittee must ensure all gauges used for monitoring and testing are calibrated as appropriate.

4. Pre-Injection Logs and Tests

Well logging and testing requirements prior to receiving initial authorization to commence injection are found in ATTACHMENT IV. Well logs and tests must be performed according to current EPA-approved procedures, or alternate procedures approved by the Director. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. Limited injection is permissible prior to receiving initial authorization to inject only for the purposes of conducting the initial well logs and tests required in ATTACHMENT IV.

5. Postponement of Construction or Conversion to Injection Wells

(a) If well construction has not commenced:

- (i) The permit expires two years from the “Effective Date” unless the Permittee requests and receives written approval for an extension from the Director. The Permittee is allowed a maximum of two extensions at the Director’s discretion not to exceed six (6) years after the “Effective Date” to construct the well. The Director may limit the number of and/or duration of extensions.
- (ii) A request for extension must be in writing and received prior to the applicable permit expiration date. The request must state the reasons for the delay, provide an estimated well completion date, and list any additional wells within the area of review (AOR) that have not been previously identified. The request must also include well construction diagrams, cement records, and cement bond logs for these wells within the AOR that penetrate the overlying confining zone. If no such wells exist, the Permittee must certify this in writing.
- (iii) For requests submitted in accordance with this section, the Permit remains in effect unless the Permittee receives written notice from the Director stating that the Permit has expired or is otherwise not extended.
- (iv) Once the Permit has expired, the Permittee must reapply for a UIC permit and restart the complete permit application process, including opportunity for public comment, if intending to use the well(s) for the purposes of this permit.

(b) If well construction has begun before the permit has expired in accordance with this section and the Permittee has not received authorization to commence injection, the Permittee is subject to the conditions found in Section E.5. *Wells Not Actively Injecting* or may elect to convert the well to a non-UIC well found in Section F.2. *Injection Well Conversion*.

SECTION B. WELL OPERATION

1. Annular Injection Prohibition

Injection into any annulus formed between casings serving as surface, intermediate or long string casing, or between any casing and the wellbore is prohibited.

2. Requirements Prior to Receiving Initial Authorization to Commence Injection

Well injection may commence only after the Permittee has received written authorization to inject from the Director and has met all well construction and pre-injection requirements, including the following:

(a) The Permittee has:

  (i) submitted to the Director a notice of completion of construction and a completed EPA Form 7520-18 and required attachments or its equivalent. If the well construction is different than the approved construction found in ATTACHMENT I, the Permittee must also provide a revised well diagram and a description of the previously approved modification to the well construction;

  (ii) conducted all applicable requirements found in ATTACHMENT IV and submitted required records to the Director. The logging and testing requirements include demonstration of mechanical integrity pursuant to 40 CFR § 146.8, in accordance with the conditions found in Section C of this permit;

  (iii) demonstrate monitoring required in ATTACHMENT III is able to be conducted as specified; and

  (iv) satisfied requirements for corrective action in ATTACHMENT VI, if applicable.

(b) The Director has received and reviewed the documentation associated with the requirements in Paragraph 2(a) of this section and finds it is in compliance with the conditions of the Permit.

(c) The Director has inspected the injection well and finds it is in compliance with the conditions of the Permit. Such inspection is waived if the Permittee has not received notice from the Director of intent to inspect the injection well within 13 days of the date of the notice provided in Paragraph 2(a)(i) above.

3. Injection Zone and Fluid Movement

Injection zone means "a geological formation, group of formations, or part of a formation receiving fluids through a well." Injection may only occur within the approved injection zone specified in ATTACHMENT II. All perforations must be made within the approved injection zone and injected fluids must remain within the injection zone. If monitoring indicates the movement of fluids from the injection zone, the Permittee must notify the Director within twenty-four (24) hours (Section I.11) and submit a written report that documents circumstances that resulted in movement of fluids beyond the injection zone.

Additional injection perforations may be added if (1) they are made within the approved injection zone(s), (2) fracture gradient data is submitted and representative of the portion of the injection zone to be perforated, and (3) the Permittee provides notice and reports to the Director in accordance with Section B.8. *Alteration, Workover, and Well Stimulation*. The Permittee must also follow the requirements found in Section B.4 *Injection Pressure Limitation* that may result in a change to the permitted Maximum Allowable Injection Pressure (MAIP).

4. Injection Pressure Limitation

(a) Injection pressure at the wellhead must not initiate new fractures or propagate existing fractures in the injection zone and must not cause the movement of injectate or formation fluids into a USDW.

(b) Except during stimulation or other well tests approved by EPA, injection pressure must not exceed the MAIP.

(c) The **MAIP** is calculated using the equation below. The MAIP and data parameters used in calculating the MAIP are found in ATTACHMENT II. The MAIP as measured at the surface must equal the formation fracture pressure (FFP**)** plus friction loss, if applicable. Friction loss may be applied at the Director's discretion.

MAIP = **FFP** + **Friction Loss** (if applicable)

Friction Loss (psi) is pressure loss between the wellhead and the injection zone as a result of injection.

The **FFP** (measured at the surface) will be calculated using the following equation:

FFP = [***Fracture Gradient*** - (0.433 * (***Specific Gravity*** + ***SG Fluctuation Factor***))] * ***Depth***

Fracture Gradient (psi/ft) is the fracture gradient of the injection zone.

Specific Gravity (SG, unitless) is the specific gravity of the injection fluid obtained from a representative fluid sample. The specific gravity is a ratio of the density of the injection fluid to the density of water at 4 degrees Celsius.

SG Fluctuation Factor (**SGFF,** unitless) is added to the Specific Gravity to account for potential variations of the actual injected fluid specific gravity.

Depth (ft) is the measured depth in the well. See ATTACHMENT II for additional details.

(d) MAIP Changes

(i) After initial construction of the well, the MAIP may be recalculated based upon the completion report data.

(ii) Any time the injectate specific gravity value is greater than SG + SGFF used to calculate the current MAIP, a new MAIP must be calculated according to the new value. Other data that may support a MAIP calculation include information about the injection zone fracture gradient, friction loss, and/or depth.

(iii) The recalculated MAIP per this section of the Permit must replace the MAIP value given in ATTACHMENT II of the Permit and will become effective and enforceable upon the written correspondence from the Director. The Director may also determine that a permit modification is needed to implement the change.

(iv) The Permittee may request a change to the MAIP. The Permittee must submit documentation needed to reevaluate the MAIP to the Director for approval.

(v) The Director may determine that a lower MAIP is appropriate for the protection of USDWs.

5. Injection Volume Limitation

Injection volume is limited to the total volume specified in ATTACHMENT II.

6. Injection Fluid Limitation

Injected fluids are limited to those fluids described in ATTACHMENT II.

7. Tubing–Casing Annulus

The tubing-casing annulus (TCA), or the inner most annulus in the well, must be filled with a non-corrosive fluid or other fluid approved by the Director. Any wellhead TCA valve, if present, must remain closed during normal operations. The pressure at which the TCA must be maintained is found in ATTACHMENT II.

If wellhead TCA pressure cannot be maintained at the pressure found in ATTACHMENT II, the Permittee must report to EPA the actions taken to determine the cause and the proposed remedy. If a loss of MI has been determined, the Permittee must comply with the Loss of Mechanical Integrity requirements found in Section C.5.

8. Alteration, Workover, and Well Stimulation

Alterations, workovers, and well stimulations must meet all conditions of the Permit. Alterations, workovers and well stimulations include any activity that physically changes the well construction (casing, tubing, packer) or injection formation. These actions are collectively called, “alterations” for the remainder of this section.

The Permittee must give advance notice to the Director prior to beginning an alteration to an injection well or the injection formation. This notice must be provided 30 days prior to the date of the planned alteration. At the Director’s discretion, a shorter notification period may be allowed. Additionally, the Director's prior written approval must be obtained if the alteration modifies the approved well construction. Alterations that fall outside the construction requirements in ATTACHMENT I require permit modification, and/or may require additional testing or monitoring requirements.

The Permittee must record all alterations, workovers, and well stimulations on a Well Rework Record (EPA Form 7520-19) and submit a revised well schematic and plugging and abandonment (P&A) plan (if necessary) when the well construction has been modified. The Permittee must submit these documents and other records of well workover, logging, or test data to the Director within 30 days of completion of the activity.

The Permittee must complete any activity which affects the tubing, packer, or casing and provide demonstration of Internal MI within 90 days of beginning the activity. If the Permittee is unable to complete work within the specified time period, the Permittee must propose an alternative schedule. Injection operations must not resume until the well has successfully demonstrated mechanical integrity. If the well lost mechanical integrity, the Permittee must receive written approval from the Director to recommence injection in accordance with Section C.5 of this permit.

9. Well Logging and Testing Requirements

Well logging and testing requirements are found in ATTACHMENT IV. The Permittee must ensure the logging and test requirements are performed within the time frames specified in ATTACHMENT IV. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. The Permittee must provide the well logging and testing procedure prior to conducting any well log or test. It is the responsibility of the Permittee to conduct all well logging and testing requirements according to EPA approved procedures.

10. Area of Review and Corrective Action

The AOR for this Permit is found in Attachment II and associated corrective action required within the AOR is found in Attachment VI. The Permittee has an on-going obligation as described in Attachment III to identify and report any additional wells not previously reported within the AOR.

For any wells, that penetrate the confining zone within the AOR, which are improperly sealed, completed, or plugged and abandoned, the Director may require corrective action as is necessary to prevent movement of fluid out of the injection zone into USDWs.

SECTION C. MECHANICAL INTEGRITY

1. Requirement to Maintain Mechanical Integrity

The Permittee is required to ensure the injection well always maintains Mechanical Integrity (MI). Injection into a well that lacks MI is prohibited. An injection well must satisfy two parts of MI:

> **Internal MI -** There is no significant leak in the casing, tubing, or packer; and
>
> **External MI** - There is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

2. Demonstration of Mechanical Integrity

The Permittee must demonstrate that the injection well(s) has established MI as defined in Section C.1. The Permittee must demonstrate MI on the following occasions:

(a) Prior to receiving authorization to commence injection in accordance with Section B.2 and Attachment IV and periodically, thereafter as specified in ATTACHMENT III.

(b) After any alteration that compromises the MI of the well or after a loss or suspected loss of MI in accordance with Section C.5 *Loss of Mechanical Integrity*.

(c) As part of the plugging and abandonment of the well, in accordance with Section E and ATTACHMENT V, to ensure there will be no movement of fluids into or between USDWs.

(d) As part of the conversion of the well to another type in accordance with Section F.2.

(e) Upon request of the Director.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate mechanical integrity.

The Permittee must ensure that all gauges used in MI demonstrations are properly calibrated within one year prior to the test date. Use of a new gauge with proof of purchase will meet this requirement.

Results of any MI test required by this Permit and any additional documents required by the Director to support the test results, must be submitted to the Director as soon as possible but no later than 30 calendar days after the test is complete.

3. Mechanical Integrity Test Methods and Criteria

EPA approved methods must be used to demonstrate MI. EPA MI testing guidance can be found at: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance. Subsequent to MI testing, the maximum injection pressure will be limited to the pressure used during the test.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. The Permittee must follow the prescribed test method or receive approval for an alternative method, before conducting the test.

4. Notification Prior to Testing

The Permittee must notify the Director at least 30 calendar days prior to conducting any tests required by this Permit. The Director may allow a shorter notification period if it would be sufficient to enable EPA or a designated representative to witness the test, or EPA declines to witness the test. Notification may be in the form of a yearly or quarterly schedule of planned MI tests, or it may be on an individual basis.

5. Loss of Mechanical Integrity

Loss of MI may include any malfunction of the injection well including but not limited to a failed MI test, fluids flowing at the surface, wellhead malfunctions, loss of fluids during annulus fill-ups, or a significant change in the annulus or injection pressure during normal operating conditions that may be indicative of a loss of MI. Any well rework/workover that has the potential to compromise MI will constitute a loss of MI. This will include but is not limited to any time the tubing or packer is removed from the well, moved within the well, or reset or replaced.

The Permittee must cease injection immediately upon becoming aware that the well(s) lacks or is suspected of lacking MI. Within 24 hours of the event, the Permittee must notify the Director of the circumstances surrounding the event in accordance with Section I.11(e). The Permittee must also cease injection immediately upon receiving notification from the Director that the well(s) lacks or is suspected of lacking MI and restore mechanical integrity within the timeframe established by the Director.

The Director may allow plugging of the well(s) pursuant to 40 CFR § 146.10, or require the Permittee to perform such additional construction, operation, monitoring, reporting or corrective action as necessary to prevent the movement of fluid into or between USDWs.

The Permittee must notify the Director at least 30 calendar days prior to conducting well repair and the MI demonstration. The Director may allow a shorter timeframe if it allows EPA sufficient time to review and comment on the proposed repair and arrange on-site inspections. The well(s) must remain shut-in until the Permittee receives written approval from the Director to resume injection.

SECTION D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency

Monitoring parameters are specified in ATTACHMENT III. The listed parameters are to be monitored, recorded, and reported at the frequency indicated in ATTACHMENT III, even when the well is not operating. In the event the well has not injected or is no longer injecting, the monitoring report will reflect its status. Required sampling data must be submitted if the well has injected any time during the reporting period.

Records of monitoring information must include:

(a) the date, exact place, and time of the observation, sampling, or measurements; and

(b) the individual(s) who performed the observation, sampling, or measurements

Records for sampling analysis must include:

(a) the date(s) of analyses and individuals who performed the analyses;

(b) a description of both sampling methodology and the handling of samples;

(c) the analytical technique or method used; and

(d) the results of such analyses.

2. Monitoring Methods

Observations, measurements, and samples taken for the purpose of monitoring must be representative of the monitored activity. Sampling methods used to monitor the characteristics of the injected fluids must comply with analytical methods cited in ATTACHMENT III or by other methods that have been approved in writing by the Director.

Pressure monitoring (e.g., injection tubing, tubing-casing annulus, bradenhead annulus), injection rate, injected volume, and cumulative injected volume must be observed and recorded at the wellhead. All parameters must be observed simultaneously to provide a clear depiction of well operation. For all annuli monitored, annulus pressures must be recorded prior to bleed-off. Annulus pressure applied during internal MI tests should not be included in the monitoring report.

3. Seismic Monitoring

(a) The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service known as the Earthquake Notification Service (ENS), which reports real-time earthquake events for any area specified by the user. Details for the ENS can be found at: https://earthquake.usgs.gov/ens/. The Permittee must subscribe to this service and check daily for notification emails from the service.

(b) The Permittee must notify the Director within twenty-four (24) hours of any seismic event measuring 4.5 magnitude (MMI scale) or greater reported within two miles of the permit boundary.

(c) If any seismic event of magnitude 4.5 (MMI scale) or greater is reported within two miles of the permit boundary, the Permittee must immediately cease injection.

(d) The Director will determine if any structural testing of the facility infrastructure is required before injection resumes.

(e) Injection must not resume until the Permittee has obtained approval to recommence injection from EPA.

(f) The Permittee must record any seismic event measuring 2.0 magnitude (MMI scale) or greater occurring within fifty miles of the permit boundary and report such events to EPA on a quarterly basis.

4. Records Retention

The Permittee must retain records of all monitoring information, including the following:

(a) Calibration and maintenance records;

(b) All original strip charts or other recordings for continuous monitoring instrumentation;

(c) Copies of all records required by this Permit;

(d) Records and results of MITs and any other tests or logs required by the Director;

(e) Records of all data used to complete the application for this Permit; and

(f) Other records related to the construction, operation, and closure of a well

These records must be retained for a period of at least three (3) years from the date of the sample, measurement, report, or application. This period may be extended by request of the Director at any time.

The Permittee must retain records of the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures in accordance with ATTACHMENT V of this Permit. The Permittee must continue to retain the records after the three-year retention period unless the Permittee delivers the records to the Regional Administrator, or his/her authorized representative, or obtains written approval from the Regional Administrator, or his/her authorized representative, to discard the records.

5. Submission of Sampling and Monitoring Reports

The Permittee must submit sampling and monitoring reports to the Director at the frequency required in ATTACHMENTS III and IV and in accordance with Section I.11 of this permit. EPA Form 7520-8 or 7520-11 or their equivalents may be used or adapted to submit the reports along with any additional information required in ATTACHMENTS III and IV. The Permittee must submit the report to the Director as required in ATTACHMENTS III and IV. Reporting requirement begins once the permit becomes effective and is required whether or not injection activity has occurred during that period.

SECTION E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment

The Permittee must notify the Director in writing at least 30 days prior to plugging and abandoning of an injection well. If the Permittee intends on deviating from the previously approved P&A plan, EPA must be notified of the intended deviation no less than 45 days prior to the start of the plugging work.

2. Approved Plugging and Abandonment Plan

The approved P&A Plan and required tests are incorporated into this Permit as ATTACHMENT V. Changes to the approved P&A Plan must be submitted using EPA Form 7520-19 at least 45 days prior to plugging or a shorter time period if approved by the Director. Modifications to the approved plan must be incorporated into the Permit as a permit modification prior to beginning plugging operations. The Director also may require revision of the approved P&A Plan at any time prior to plugging the well. If the Permittee requests a revised P&A Plan, plugging work cannot commence without first receiving approval from the Director. Upon approval, the Permittee must comply with such changes, and such changes constitute enforceable requirements of this permit.

3. Well Plugging Requirements

(a) Prior to abandonment, the well(s) must be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids into or between USDWs. Plugging and abandonment must be made in accordance with 40 CFR § 146.10 and follow the procedures outlined in the approved P&A Plan incorporated in ATTACHMENT V. Additional federal, tribal, state or local laws or regulations may also apply.

(b) Unless converted to a non-UIC well, the well(s) must be plugged and abandoned in accordance with all requirements in this Section prior to expiration or termination of this Permit.

4. Plugging and Abandonment Report

Within 60 days after plugging a well, the Permittee must submit a completed EPA Form 7520-19 to the Regional Administrator or his/her authorized representative. The plugging report must be certified as accurate by the person who performed the plugging operation. Such report must consist of either:

(a) a statement that the well was plugged in accordance with the approved P&A Plan; or

(b) where actual plugging differed from the approved P&A Plan found in ATTACHMENT V, an updated version of the plan, specifying the differences.

5. Wells Not Actively Injecting

After a cessation of operations of two years, the Permittee must plug and abandon the well in accordance with Section E.2 and ATTACHMENT V of this Permit unless the Permittee:

(a) Provides written notice to the Regional Administrator or his/her authorized representative, of the period of temporary abandonment prior to the end of the two-year period;

(b) Describes actions or procedures, satisfactory to the Regional Administrator or his/her authorized representative, that the Permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. This must include an Internal MI demonstration conducted no more than one year prior to the two-year period and may include additional actions or procedures deemed necessary by the Director to protect USDWs. Compliance with the technical requirements applicable to active injection wells must be continuously maintained, unless waived by the Regional Administrator or his/her authorized representative; and

(c) Receives written notice by the Regional Administrator or his/her authorized representative to temporarily waive plugging and abandonment requirements.

The above request must be made every two (2) years the well remains temporarily abandoned. The Permittee of a well that has been temporarily abandoned must notify the Director within 30 days after resuming operation of the well.

After a period of ten (10) consecutive years during which there is no injection, the well must be plugged and abandoned in accordance with Section E.1 through E.4 or converted to a non-UIC well in accordance with Section F.2. *Injection Well Conversion*.

SECTION F. CHANGES TO PERMIT CONDITIONS

1. Modification, Revocation and Reissuance, or Termination

The Director may, for cause, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.41. The filing of a request for modification, revocation and reissuance, 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 condition of this Permit.

2. Injection Well Conversion

The Permittee must provide a 30-day notice prior to planned well conversion to another type of UIC or non-UIC well. The notification must include the following:

(a) The type of well to which the authorized well will be converted, and

(b) A completed 7520-19 form or its equivalent.

The Permittee must receive prior written approval from the Director to proceed with conversion. After conversion work has been completed, the Permittee must provide to the Director:

(a) Demonstration of Internal (conducted no more than one year prior to conversion) and External MI (in accordance with Section C of this Permit), and

(b) Documentation that another agency has regulatory authority over the proposed type of well.

The Permittee must convert the well(s) in a manner which will not allow the movement of fluids into or between USDWs. The Permittee must also ensure that the conversion meets all applicable federal, tribal, state, and local requirements. The Permittee must continue to meet all permit requirements until the Permittee receives written confirmation of permit expiration from the Director.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit may be transferred by the Permittee to a new owner or operator only if:

(a) the Permit has been modified or revoked and reissued (under 40 CFR § 144.39(b)(2)), or a minor modification made (under 40 CFR § 144.41(d) and requiring submission to the Director of a written agreement containing a specific date for transfer of Permit responsibility, coverage, and liability between the current and new permittees), to identify the new Permittee and incorporate such other requirements as may be necessary under the SDWA, or

(b) the Permittee provides written notification (EPA Form 7520-7) to the Director at least 30 days in advance of the proposed transfer date and submits a written agreement between the existing and proposed new permittees containing a specific date for transfer or permit responsibility, coverage, and liability between them, and demonstrates that the financial responsibility requirements of 40 CFR § 144.52(a)(7) have been met by the proposed new permittee. If the Director does not notify the Permittee and the proposed new permittee of his or her intent to modify or revoke and reissue, the transfer is effective on the date specified in the written agreement.

Until and unless either of these requirements are met, the transferor remains liable for all Permit compliance and the transferee has no authority to operate or control any well pursuant to this Permit.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

SECTION G. 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 will not be affected thereby. Additionally, in a permit modification, only those conditions to be modified will be reopened. All other aspects of the existing permit modification will remain in effect for the duration of the permit.

SECTION H. CONFIDENTIALITY

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "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:

(a) the name and address of the Permittee; and

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

SECTION I. CONDITIONS APPLICABLE TO ALL PERMITS

1. Prohibition on Movement of Fluid Into a USDW

The Permittee must not construct, operate, maintain, convert, plug, abandon or conduct any other injection activity in a manner that allows the movement of a fluid containing any contaminant into USDWs. If any water quality monitoring of a USDW indicates the movement of any contaminant into the USDW, except as authorized under part 146, the Permittee may be subject to additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection well) as are necessary to prevent such movement as mandated by the Director.

2. Duty to Comply

The Permittee must comply with all conditions of this Permit and its Attachments. 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; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration as such noncompliance is authorized in an emergency permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to enforcement for compliance, civil penalties, and/or criminal prosecution as specified in Section 1423 of the SDWA.

3. Need to Halt or Reduce Activity Not a Defense

It will 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.

4. Duty to Mitigate

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

5. Proper Operation and Maintenance

The Permittee must 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 include 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.

6. Permit Actions

This Permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property and Private Rights; Other Laws

This Permit does not convey property 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 any other applicable federal, tribal, state or local law or regulations.

8. Duty to Provide Information

The Permittee must furnish to the Director, within the time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this Permit, or to determine compliance with this Permit. The Permittee must also furnish to the Director, upon request, copies of records required to be kept by this Permit.

9. Inspection and Entry

The Permittee must 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 must be kept under the conditions of this Permit;

(b) have access to and copy, at reasonable times, any records that must be 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 the SDWA, any substances or parameters at any location.

10. Signatory and Certification Requirements

All applications, reports or other information submitted to the Regional Administrator, or his/her authorized representative, must be signed and certified according to 40 CFR § 144.32. This regulation explains the requirements for persons duly authorized to sign documents and provides the required certification statement below that must accompany every submitted report:

I certify under 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 submitted 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.

This certification statement is required, unless an EPA approved 7520 form is used.

11. Reporting Requirements

Copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Section D.10. *Signatory and Certification Requirements* of this Permit and submitted in a manner approved by EPA. All correspondence must reference the well name and location and include the EPA Permit number.

Reports and notifications required by this Permit should follow the Procedures for Submitting Required Reports and Notifications found at: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#contact.

(a) *Sampling and Monitoring Reports.* Sampling and monitoring results must be reported at the intervals specified in ATTACHMENTS III and IV.

(b) *Planned changes.* The Permittee must give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted well, and prior to commencing such changes.

(c) *Anticipated noncompliance.* The Permittee must give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

(d) *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 no later than 30 calendar days following each schedule date.

(e) *Twenty-four hour reporting.* The Permittee must report to the Director any circumstance which may endanger human health or the environment, including:

  (i) any monitoring or other information, which indicates that any contaminant may cause an endangerment to a USDW, including any loss or suspected loss of MI; or

  (ii) any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information must be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region 8 UIC Program SDWA Enforcement Supervisor, or by contacting EPA Region 8 Emergency Operations Center at (303) 293-1788

In addition, a follow up written report must be provided to the Director within five calendar days of the time the Permittee becomes aware of the circumstances. The written submission must contain a description of the event and its cause, the period of the event including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence.

(f) *Other Noncompliance.* The Permittee must report all instances of noncompliance not reported under paragraphs 11(a), 11(d), or 11(e) of this section at the time the monitoring reports are submitted. The reports must contain the information listed in paragraph 11(e) of this section.

(g) *Other information.* Where the Permittee becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in a permit application or in any report to the Director, the Permittee must submit such facts or information to the Director within 30 days of discovery of failure.

(h) *Oil Spill and Chemical Release Reporting.* The Permittee must comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802 or NRC@uscg.mil.

SECTION J. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

The Permittee must demonstrate and maintain financial responsibility (FR) and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

(a) The well(s) has been plugged and abandoned in accordance with the approved plugging and abandonment plan in ATTACHMENT V, and the Permittee has submitted a plugging and abandonment report according to Section E.4.; or

(b) The well(s) has been converted in compliance with the requirements of Section F.2.; or

(c) The Permittee has received notice from the Director that the Permit has been successfully transferred to a new owner or operator, which includes financial responsibility demonstration.

No substitution of a demonstration of financial responsibility will become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable.

When Financial Statement Coverage is used as the financial mechanism, this coverage must be updated on an annual basis.

2. Types of Adequate Financial Responsibility.

The permittee must show evidence of financial responsibility to the Director through the submission of a surety bond, letter of credit, trust fund, financial test, or other adequate assurance, such as a financial statement or other materials acceptable to the Director. For more information regarding adequate types of financial assurance, contact your EPA Regional Office.

3. Determining How Much Coverage is Needed

The owner or operator must revise the plugging and abandonment cost estimate whenever a change in the plugging and abandonment plan(s) increases the cost of plugging and abandonment and provide a revised demonstration of financial responsibility.

Additionally, the Regional Administrator, or his/her authorized representative, may on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well(s) to adjust for inflation and a revised demonstration of financial responsibility.

4. Bankruptcy and/or Insolvency of the Permittee

The Permittee must notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after commencement of the proceeding. A guarantor of a corporate guarantee must make such a notification if he is named as debtor, as required under the terms of the guarantee. See 40 CFR §§ 144.28(d)(5) & 144.64(a).

5. Bankruptcy, Insolvency, Suspension, or Loss of Authority of an Issuing Financial Institution

In the event of insolvency or bankruptcy of the trustee or issuing institution of the financial mechanism; the suspension or revocation of the authority of the trustee institution to act as trustee; or the issuing institution's losing its authority to issue such an instrument, the Permittee must notify the Director, within ten (10) business days of the Permittee's receiving notice of such event by certified mail. See 40 CFR §§ 144.28(d)(5) & 144.64(a).

An owner or operator who obtains a type of instrument such as letter of credit, surety bond or insurance policy will be deemed to be without the required FR or liability coverage in the event of bankruptcy, insolvency, or a suspension or revocation of the license or charter of the issuing institution. The owner or operator must establish other FR or liability coverage acceptable to the Director, within 60 calendar days after such an event. See 40 CFR §§ 144.28(d)(6) & 144.64(b).

ATTACHMENT I - WELL CONSTRUCTION REQUIREMENTS

1. Construction Requirements

The well construction plan must comply with the minimum requirements listed below. Should a Permittee need to modify the approved plan, the following standards, at a minimum, must be satisfied in any plan submitted in accordance with Section A. *Well Construction Requirements*.

Applicable to Newly Constructed Well(s)

- Casing and cement used in the construction of the well must be designed for the life expectancy of the well, including the natural and applied pressures expected during the life of the well.
- Well(s) must be completed with at least two (2) cemented casing strings set within a drilled hole, in addition to any conductor pipe.
- Casing strings must be cemented as follows:
  - Surface casing is cemented from the casing shoe to the surface, and
  - All USDWs must be isolated by placing cement between the outermost casing and the well bore.
- When drilling the surface hole, unless waived by the Director, air or mud made with water containing no additives and no more than 3,000 mg/L Total Dissolved Solids (TDS) must be used. At no time will the Permittee conduct any activity that endangers any USDW, as prohibited by 40 CFR § 144.12.

Applicable to all wells:

- The well must be completed with injection tubing set on at least one packer.
- The uppermost packer must be set within 100 feet of the uppermost open perforation.
- Perforations must be made within the approved injection zone.

2. Required Monitoring Devices

The following sampling and monitoring devices are required:

- Transducers for measuring injection pressure and annulus pressure;
- A pressure actuated device attached to the injection flow line set to prevent MAIP from being reached at the wellhead;
- At least one female pipe fittings for attachment to a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the MAIP. The fittings must be isolated by shut-off valves and conveniently accessible near the wellhead. Fittings must be present at these locations:
  - on the injection tubing string(s);
  - on the tubing-casing annulus (TCA);
  - on the surface casing-production casing (bradenhead) annulus; and
  - on any other annulus space required to be monitored in the Permit;
- A sampling port such that samples can be collected at a location that ensures they are representative of the injected fluid; and
- A flow meter capable of recording instantaneous flow rate, instantaneous volume and cumulative volume attached to the injection line.

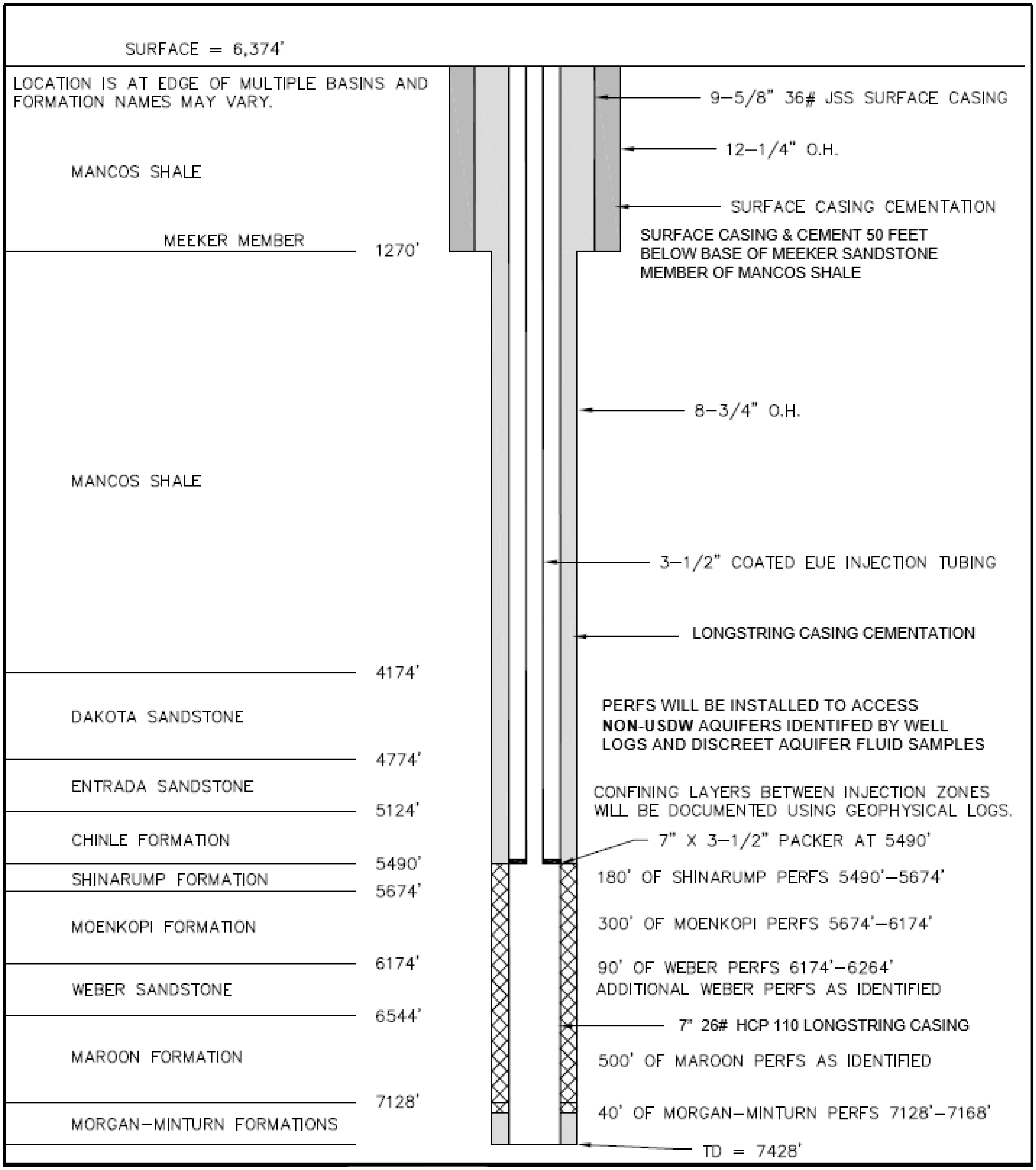
3. *Well Schematic* **(The diagram below depicts a well construction plan submitted by the permit applicant that meets the minimum performance standards in Attachment I)**

Well construction information:

- 9-5/8” 36 lbs./ft. surface casing set in a 12-1/4” hole to a depth of 50 feet below the base of the Meeker Sandstone and cemented to surface.
- 7” 26 lbs./ft. longstring casing set in an 8-3/4” hole to a depth of 7428 feet (below ground level) and cemented to surface.

- The Permittee intends to perforate the well casing to access non-USDW aquifers between the approximate depths of 5,490 and 7,168' TD as determined by well logs and discreet water samples collected from each injection zone aquifer.

Proposed Well Construction Diagram



Note: Depths shown in diagram are estimated from formation tops identified in nearby wells. Actual depths will be based on well logs. Packer must be set within 100 feet above the uppermost open perforation.

ATTACHMENT II - OPERATING REQUIREMENTS

1. Area of Review

The area of review for this permit is a 2.25-mile fixed radius from the injection well. The fixed radius is based on a zone of endangering influence (ZEI) calculation incorporating hydrogeologic factors.

2. Injection Zone

The formation(s) and/or stratigraphic unit(s) listed in the table, below, comprise the allowable injection zone(s):

Injection Zone Table

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*
Non-USDW Triassic-Jurassic Aquifers: Entrada Sandstone Kayenta Formation Wingate Sandstone	4774	5124
Shinarump	5,490	5,674
Moenkopi	5,674	6,174
Weber Sandstone	6,174	6,544
Maroon-Morgan-Minturn	6,544	7,428

* Depths shown in diagram are estimated from formation tops identified in nearby wells. Actual depths will be based on well logs.

3. Maximum Allowable Injection Pressure (MAIP)

The parameters below are the values used to calculate the initial authorized MAIP issued with this Permit. These parameters may be updated throughout the life of the well, pursuant to the conditions and formula at Section B.4 of this Permit. The recalculated MAIP becomes effective and enforceable upon the written approval from the Director. The Director may also determine that a permit modification is needed to implement the change.

The table below provides the initial values used to calculate the initial MAIP at the top of the Shinarump:

Fracture Gradient	Specific Gravity	SG Fluctuation Factor	Depth (ft)	Friction Loss (psi)	Calculated MAIP (psi)	Authorized MAIP (psi)
0.60	1.05	TBD	5,490	165	963	TBD

Fracture Gradient must be determined by conducting a valid step rate test, reviewed and approved by the Director. Alternative methods to determine a representative fracture gradient may be used, if approved by the Director.

Specific Gravity must be derived from the results of the analytical sample required in ATTACHMENT III.

Depth is the true vertical depth to the top of the uppermost perforation.

4. Step Rate Test Data to Submit to EPA

Conduct the Step Rate Test according to the Guideline Document available on the EPA Region 8 UIC webpage under *Regional Guidance Documents*. Submit to EPA a spreadsheet containing columns for time measurements at one-minute intervals, flow rate (barrels per day), corresponding pressure readings (psi) from the surface pressure gauge and the downhole pressure bomb. Also provide the specific gravity of the test injection fluid, the specific gravity of the proposed injectate, the depth (feet) to the downhole pressure bomb and the depth (feet) to the top perforation.

5. Tubing-Casing Annulus Pressure

The TCA valve shall remain closed during normal operations and the TCA pressure shall be less than 100 psi.

6. Maximum Injection Volume Limitation

There is no maximum injection volume limit associated with this permit. In no case will injection pressure exceed the MAIP.

7. *Injection Fluid Limitation*

This Permit authorizes the injection of only the non-hazardous fluids naturally flowing from the East Taylor Spring.

8. Injectate Sampling Equipment

A fitting and valve assembly must be installed for sampling of the injection fluid before the injection wellhead.

9. *Annual Pressure Falloff Test*

The Permittee must perform a pressure falloff test at least once every twelve months. The pressure falloff test is required to monitor pressure buildup in the injection zone, to monitor reservoir parameters, to identify any fracturing, and to identify any boundaries within the injection formations.

The Permittee is required to prepare a plan for running the falloff test. *EPA Region 6 UIC Pressure Falloff Testing Guideline* should be used by the Permittee when developing a site-specific plan. This document can be found at: https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf.

The test plan shall be submitted to EPA for review at least 30 days prior to conducting the initial annual pressure falloff test. Subsequent test plan is required only if it is not identical to the previous year's plan. It is important that the initial and subsequent tests follow the same or similar test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made.

The report shall also compare the test results with previous years test data, unless it is the first test performed at that well. A falloff test that fails to adhere to these requirements may be subject to retest.

The Permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. The report shall be prepared by a knowledgeable analyst, comparing the test results with previous years test data, unless it is the first test performed for the well.

ATTACHMENT III – MONITORING AND REPORTING REQUIREMENTS

Monitoring requirements, units for reporting, permit limitations (if applicable), and monitoring, recording, and reporting frequencies are listed below.

- All parameters must be observed simultaneously to provide a clear depiction of well operation.
- Tubing-casing annulus pressure must be recorded prior to bleed-off.
- Annulus pressure applied during standard annulus pressure tests performed during MI tests should not be included in the annual monitoring report.

Monitoring and Reporting Requirement	Report Parameter	Permit Limit	Monitor Frequency	Minimum Recording Frequency	Minimum Reporting Frequency
Surface Injection Pressure (psi)	maximum minimum average	Max#: TBD	Continuous	Monthly	Semiannually
TCA Annulus Pressure (psi)	maximum minimum average	Max#: 100	Continuous	Monthly	Semiannually
Bradenhead Pressure (psi)	maximum minimum average		Continuous	Monthly	Semiannually
Injection Rate (bbl/day)	maximum minimum average		Continuous	Monthly	Semiannually
Injected Volume (bbl)			Continuous	Monthly	Semiannually
Cumulative Fluid Volume Injected (since injection began) (bbls)			Continuous	Monthly	Semiannually
MIT Results			As required in Attachment VI		In next semiannual report following test.
Seismic monitoring			As required in Section D.3		Semiannually
Laboratory report of injected fluid analysis for: • Total Dissolved Solids (mg/L) via Method 2540 C-97 • pH via Method 4500-H+ B-00 • Specific gravity via Method SM 2710 F • Conductivity/Specific Conductance (S/m) via Method 2510 B-97					Semiannually
Identify any new well in the AOR that penetrates an injection zone and analyze new AOR well construction to determine if corrective action is needed.					Semiannually

Injectate samples must be collected near the end of January to capture East Taylor Springs low flow conditions and September to capture East Taylor Spring high flow conditions.

Semiannual reports are due to EPA on the following dates each year:

- March 15
- November 15

Injectate Sample Collection Date	Report includes data within this date range	Report due to the EPA
End of January	Oct 1 – Jan 31	March 15
End of September	Feb 1 – Sept 30	November 15

ATTACHMENT IV – LOGGING AND TESTING REQUIREMENTS

Well logs and tests must be performed according to EPA approved procedures. It is the responsibility of the Permittee to obtain and use these procedures prior to conducting any well logging or test required as a condition of this Permit. These procedures can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy. Well logging and testing procedure must be submitted to the Director prior to conducting any well log or test.

Well logs and test results must be submitted to the Director within 60 calendar days of completion of the logging or testing activity and must include a report describing the methods used during logging or testing and an interpretation of the log or test results. **The report must also identify confining zones above and below any USDWs identified above or below an injection zone.** When applicable, the report must include a descriptive report prepared by a knowledgeable log analyst, interpreting the results of that portion of those logs and tests which specifically relate to: (1) USDWs and the confining zone adjacent to it, and (2) the injection zone and adjacent formations.

Test/Log Requirement	Date Due
MIT 1-Standard Annulus Pressure	Prior to Authorization to Inject and at least once every 5 Year(s) after the last successful test.
Cement Records	Prior to Authorization to Inject
Step Rate Test	Prior to Authorization to Inject
Longstring casing: Cement Log (CBL, RAL, USIT)	Prior to Authorization to Inject
MIT 2 Radioactive Tracer Survey	Prior to Authorization to Inject
MIT 2-Temperature Log	1. Baseline temperature log required prior to receiving Authorization to Inject. 2. Initial temperature log will be conducted between 6 to 12 months after Authorization to Inject. 3. Subsequent logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.
Pressure Falloff Test: A report shall be provided with appropriate narrative interpretation, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. Refer to Attachment II.9 Annual Pressure Falloff Test for additional requirements.	First test shall be run 6 to 12 months after Authorization to Inject. Subsequent tests shall be conducted at least once every year thereafter. The initial and subsequent years' test plans, if different than the previous year's plan, shall be submitted for review at least 30 days prior to conducting the annual pressure fall-off test.
Injection Formation Fluid Pressure	Prior to Authorization to Inject
Mud Logging Records	Prior to Authorization to Inject

Caliper, Resistivity, Spontaneous Potential, and Gamma Ray and a combination of logs (as opposed to a single log) to provide formation porosity. The logs shall provide information from ground level to total depth.	Prior to Authorization to Inject
Deviation Checks	Prior to Authorization to Inject
Spring water analysis for parameters listed in Attachment IV.1(f) and Tables IV-1 and IV-2.	Prior to Authorization to Inject
Aquifer Fluid Sampling and Analysis: A discreet, representative water sample must be collected from each aquifer intersected by the well below the Mancos Shale: • Dakota (TDS and major cations/anions only) • Curtis (if present) • Entrada • Kayenta • Wingate • Shinarump Member of the Chinle • Moenkopi • Weber • Maroon • Morgan-Minturn	Prior to Authorization to Inject
Each aquifer sample must be collected and analyzed as described below	Prior to Authorization to Inject

1. Protocol for Groundwater Sample Collection from Intersected Aquifers below the Mancos Shale.

(a) The Permittee must collect a discrete fluid sample by isolating each aquifer below the Mancos Shale intersected by the well. Each aquifer must be isolated in the open hole interval using packers and pumping to purge any fluids introduced while drilling and ensure a representative sample of the aquifer.

(b) A minimum of three volumes of the isolated interval should be pumped before the sample is collected.

(c) To ensure the water sample collected is representative of each aquifer, after pumping a minimum of three isolated interval volumes and once field measurements for pH, specific conductivity, temperature, and turbidity measurements meet the stabilization criteria in Table IV-1, a sample may be collected for analysis.

(d) If stabilization does not occur after stabilization parameters have been measured for three additional interval volumes, then the sample may be collected after specific conductivity has stabilized.

(e) If specific conductivity has not stabilized after a total of five additional interval volumes have been measured, the permittee may collect a sample.

(f) Collect three samples for laboratory analysis of **Total Dissolved Solids** and major cations/anions listed in Table IV-2 (calcium, magnesium, sodium, potassium, bicarbonate, bromide, carbonate, chloride, sulfate).

(g) The Permittee must include stabilization information in the sampling and analysis report submitted to the Director.

Table IV-1. Field Parameters to be Monitored and Stabilization Criteria to Meet before Sample Collection

Parameter	**Stabilization Criteria**
pH	$\pm$ 0.1pH units
Specific conductance	$\pm$ 3% mmhos/cm at 25°C
Temperature	$\pm$ 0.5°C
Turbidity	$\pm$ 10%

2. *Fluid Analysis for Potential Injection Zone Aquifers*

If the Permittee wishes to use an aquifer that is a USDW as an injection zone in the future, the aquifer fluid should be analyzed for total and dissolved metals, fluoride, and adjusted gross alpha listed in Table IV-3. The purpose for analyzing these additional parameters is to determine permit limits for a potential USDW injection zone. For analysis of metals, either EPA-NERL 200.7 or 200.8 must be used. Fluoride must be analyzed using EPA-NERL 340.2. Equivalent methods may be used after written approval by the Director. An equivalent method has detection limits no higher than the maximum detection limits for each respective analyte listed in the Table IV-3 below. ***Note that a major modification of this permit is required for injection into a USDW.***

3. *Aquifer Sampling and Analysis Report*

The Permittee must submit a report to the Director with analytical results from all sampled aquifers overlying the injection zone and injection zone aquifers. The report must include a description of sample collection activities and the laboratory analytical report. The laboratory report must include quality assurance procedures for the analytical methods used.

4. *Requirements if an aquifer is a USDW.*

(a) If an aquifer fluid has a TDS concentration below 10,000 mg/l, the aquifer is a USDW.

(b) For USDWs overlying the injection zone: If TDS values differ more than 2,000 mg/L in two adjacent aquifers, the Plugging & Abandonment plan in Attachment V must include a cement plug separating the two aquifers.

(c) No injection into a USDW is authorized under this permit; therefore, the well must not be perforated to access any USDW.

Table IV-2. TDS Analyte List

Dissolved Major Anions and Cations (mg/L)
Bicarbonate
Bromide
Calcium
Carbonate
Chloride
Magnesium
Potassium
Sodium
Sulfate
Total Dissolved Solids

Table IV-2. Analyte List, Analytical Methods, and Maximum Detection Limit for Analytical Method.

Parameter Name*	Required Analytical Methods	Maximum Detection Limit (mg/L)
Antimony	EPA-NERL 200.7 or 200.8	0.003
Arsenic	EPA-NERL 200.7 or 200.8	0.005
Barium	EPA-NERL 200.7 or 200.8	1
Beryllium	EPA-NERL 200.7 or 200.8	0.002
Boron	EPA-NERL 200.7	3
Cadmium	EPA-NERL 200.7 or 200.8	0.001
Chromium(total)	EPA-NERL 200.7 or 200.8	0.05
Cobalt	EPA-NERL 200.7 or 200.8	0.001
Copper	EPA-NERL 200.7 or 200.8	0.6
Fluoride	EPA-NERL 340.2	2
Gross Alpha	EPA-NERL 900.0	7 pCi/L
Iron	EPA-NERL 200.7	2.5
Lead	EPA-NERL 200.7 or 200.8	0.007
Lithium	EPA-NERL 200.7	0.005
Manganese	EPA-NERL 200.7 or 200.8	0.15
Mercury (inorganic)	EPA-NERL 200.7 or 200.8	0.001
Molybdenum	EPA-NERL 200.7 or 200.8	0.02
Nickel	EPA-NERL 200.7 or 200.8	0.05
Selenium	EPA-NERL 200.7 or 200.8	0.025
Silver	EPA-NERL 200.7 or 200.8	0.05
Strontium	EPA-NERL 200.7	2
Thallium	EPA-NERL 200.7 or 200.8	0.001
Uranium	EPA-NERL 200.8	0.015
Zinc	EPA-NERL 200.7 or 200.8	1

Note: *Total and dissolved concentrations (not applicable to gross alpha)

ATTACHMENT V - PLUGGING AND ABANDONMENT REQUIREMENTS

The plugging and abandonment plan must prevent vertical fluid movement into and between USDWs and meet the requirements below. Should a Permittee need to modify the approved plan, the following standards, at a minimum, must be satisfied in any submitted plans in accordance with Section E. *Plugging and Abandonment*.

- Part I mechanical integrity demonstration must be conducted no more than one year prior to plugging. If required, Part II mechanical integrity demonstration must be in compliance with permit schedule.
    - Prior to plugging a well, mechanical integrity must be established unless the P&A plan will address a loss of mechanical integrity.
- Injection tubing must be removed.
- Cement plugs must have sufficient compressive strength to maintain adequate plugging effectiveness.
- The well to be abandoned must be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director, prior to the placement of the cement plug(s).
- Each plug placement, unless above a retainer or bridge plug, must be verified by tagging the top of the plug after the cement has had adequate time to set.
- All USDWs must be isolated by placing cement between the outermost casing and the well bore.
- A minimum 50 feet surface plug is required inside and, if necessary, outside of the surface casing, to seal pathways for fluid migration into the subsurface.

At a minimum, the following plugs are required.

1. **PLUG 1 - Isolation of the Perforations, Injection Zone, and Upper Confining Zone**:

   The injection tubing and down hole apparatus must be removed from the well and any necessary clean out conducted. The injection zone must be isolated by using a cement retainer, a Cast Iron Bridge Plug (CIBP), or by setting a balanced plug.

   Cement Retainer: A cement retainer must be set 50-100 feet above the injection perforations and cement squeezed below the retainer. The amount of cement used must be adequate to fill the casing between the retainer and the perforations and should allow for some extra cement to be squeezed into the perforations. At least 20 feet of cement also should be left on top of the retainer.

   CIBP: A CIBP must be set 50-100 feet above the top injection perforation. At least 20 feet of cement must also be left on top of the bridge plug.

   Balanced Plug. The balanced plug method involves pumping cement slurry through drill pipe, coiled tubing, work string, or production tubing until the level of cement outside is equal to that inside the drill pipe/tubing string. The pipe then is pulled slowly from the slurry, leaving behind the cement plug. To minimize cement contamination by wellbore fluids, fluid spacers should be used both ahead of and behind the slurry, especially if the wellbore fluid is incompatible with the cement slurry. Plug placement must be verified by tagging the top of the plug after the cement has had adequate time to set. If a bridge plug is used at the base of the balanced plug, tagging the top of the plug is not necessary.

2. **PLUGS ABOVE INJECTION ZONE - Isolate USDWs from the Injection Zone and each other if there is more than 2,000 mg/liter difference in TDS between individual exposed USDWs**.

   Cement plugs must extend at least 50 feet above and below each zone being isolated.

3. **PLUG 3 - Isolate Surface Fluid Migration Paths**:

   Set a cement plug inside the innermost casing string a minimum 50 feet to the surface.

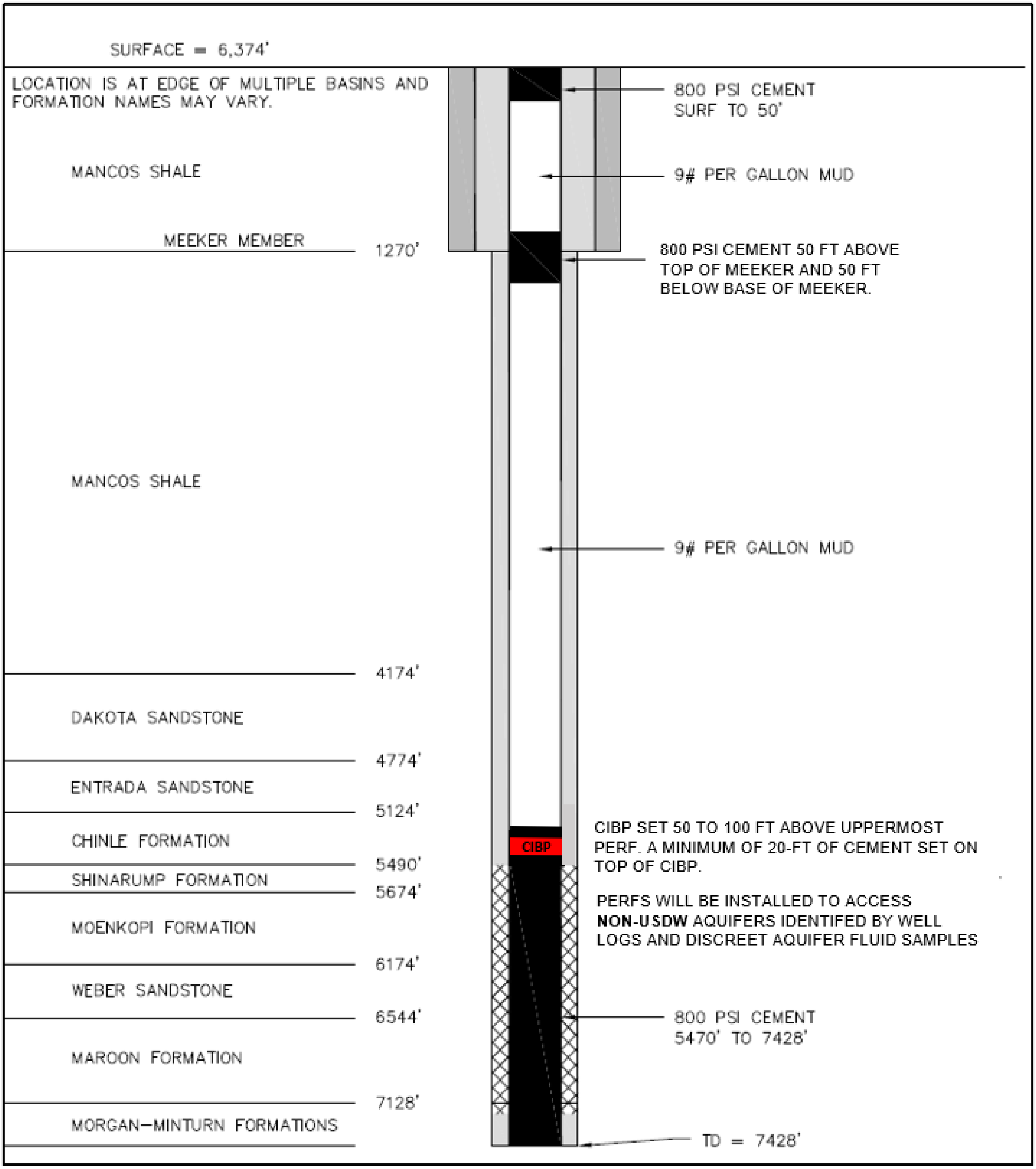
(The following diagram depicts a well plugging plan submitted by the permit applicant that meets the minimum performance standards in Attachment V)

For Plug 1: The injection tubing and down hole apparatus will be removed from the well and any necessary clean out conducted. The well fluid will be displaced with plugging gel. A CIBP will be set within the longstring casing no less than 50 ft above the top perforation and a minimum 20-ft cement plug will be set on top of the CIBP.

For Plug 2: The cement plug will be set 50 feet below the base to 50 feet above the top of Meeker Sandstone Member of the Mancos Shale.

For Plug 3: The cement plug will be set at 50 feet to surface.

Proposed Plugging Abandonment Well Bore Schematic



Note: Depths shown in diagram are estimated from formation tops identified in nearby wells. Actual depths will be based on well logs.

ATTACHMENT VI - CORRECTIVE ACTION PLAN

No corrective action is required at this time as EPA's evaluation did not identify migration pathways within the area of review.