UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region8

Ref: 8WD-SDU

SENT VIA EMAIL
DIGITAL READ RECEIPT REQUESTED

Ms. Kelley Montgomery
Regulatory Director
Kelley.montgomery@oxy.com

Re: Draft Permit - CO10044-00055, Garcia #1

Dear Ms. Montgomery:

Enclosed is a copy of the draft U.S. Environmental Protection Agency Region 8 Underground Injection Control (UIC) permit (Permit) for the above referenced well or project area. Also enclosed are copies of the statement of basis for the proposed action and the public notice provided on the EPA's website at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy.

The EPA regulations and procedures for issuing UIC permit decisions are found in Title 40 of the Code of Federal Regulations (40 CFR) part 124. These regulations and procedures require a public notice and the opportunity for the public to comment on this proposed Permit decision. The public comment period will run for at least 30 days and a courtesy announcement of the comment period, also enclosed, has been published in the following newspapers(s):

Durango Herald

A final decision will not be made until after the close of the comment period. All relevant comments will be taken into consideration. If any substantial comments are received, the effective date of the final Permit will be delayed for an additional 30 days, as required by 40 CFR § 124.15(b), to allow for any potential appeal of the final Permit decision.

If you have any questions or comments about the above action, please contact Linda Bowling at (303) 312-6254 or Bowling.Linda@epa.gov.

Sincerely,

12/18/2020

X Sarah Bahrman

Signed by: SARAH BAHRMAN

Sarah Bahrman, Chief
Safe Drinking Water Branch
Water Division

Enclosures

cc: Jim Annable
Bureau of Land Management
jannable@blm.gov

Dr. Holly Norton
State Archaeologist/Deputy SHPO – Archaeology/Director of the Office of Archaeology and Historic Preservation
holly.norton@state.co.us

U.S. Fish and Wildlife Service
Colorado Fish & Wildlife Conservation Office
Email: Pamela_sponholtz@fws

Grand Junction Fish and Wildlife Conservation Office
Email: dale_ryden@fws.gov

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

DRAFT PERMIT
Permit No. CO10044-00055

Class I Non-Hazardous Waste Disposal Well
Garcia No. 1 Well
Huerfano County, Colorado

Issued To

Oxy USA, Incorporated
P.O. Box 4294
Houston, Texas 77210-4294

TABLE OF CONTENTS

PART I. 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 in 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),

Oxy USA Inc.
P.O. Box 4294
Houston, Texas 77210-4294

hereinafter referred to as the "Permittee," is authorized to construct and to operate the following Class I well:

Garcia No. 1
Located 1900 feet FSL & 650 ft FEL in the NE SE
Section 35, Township 27 South, Range 70 West
Huerfano County, Colorado

This Permit is based on representations made by the applicant and on 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.

Where a state or tribe is not authorized to administer the UIC program under the SDWA, the EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). The EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. Regulations specific to Colorado injection wells are found at 40 CFR § 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 or by rule is prohibited.

Compliance with the terms of this Permit does not constitute a defense to any enforcement 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.

Issue Date: **DRAFT** Effective Date: **DRAFT**

DRAFT

Sarah Bahrman, Chief*
Safe Drinking Water Branch

* Throughout this Permit the term "Director" refers to the Safe Drinking Water Branch Chief or the Water Enforcement Branch Chief.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements specify the approved minimum construction standards for well casing and cement, injection tubing, and packer.

The EPA-approved well construction plan is incorporated into this Permit as APPENDIX A. Changes to the approved construction plan must be approved through permit modification by the Director, prior to being physically incorporated.

1. Well Siting

Under 40 CFR § 146.12(a), the wells shall be sited, such that injection occurs into a formation which is beneath the lowermost formation containing, within one quarter mile of the well bore, a USDW.

2. Casing and Cement

The well or wells shall be cased and cemented to prevent the movement of fluids into or between USDWs and shall be in accordance with 40 CFR § 146.12. Remedial construction measures may be required if the well is unable to demonstrate mechanical integrity.

3. Injection Tubing and Packer

Injection tubing is required and shall be run and set with a packer. The packer setting depth may be changed, provided the well construction requirements in APPENDIX A are met and the Permittee provides notice and obtains the Director's approval for the change.

4. Sampling and Monitoring Devices

The Permittee shall install and maintain in good operating condition:

(a) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) is reached at the wellhead;

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the MAIP described in Part II, Section B.4:

(i) on the injection tubing string(s);

(ii) on the tubing-casing annulus (TCA); and

(iii) on the surface casing-production casing (bradenhead) annulus;

(c) a sampling port such that samples shall be collected at a location that ensures they are representative of the injected fluid;

(d) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line; and

(e) continuous recording devices to monitor injection pressure, flow rate, volume, pressure on the annulus between the tubing and the long string of casing, and the bradenhead pressure.

Section B. WELL OPERATION

1. Outermost Casing Injection Prohibition

Injection between the outermost casing protecting USDWs and the well bore is prohibited.

2. 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 and perforations are permitted only within the approved injection zone specified in APPENDIX C. Injected fluids shall remain within the injection zone. If monitoring indicates the movement of fluids from the injection zone, the Permittee shall notify the Director within twenty-four (24) hours and submit a written report that documents circumstances that resulted in movement of fluids beyond the injection zone.

Additional individual injection perforations may be added, provided that they remain within the approved injection zone(s), fracture gradient data submitted is representative of the portion of the injection zone to be perforated, and the Permittee provides notice to the Director in accordance with Part II, Section B.8 for workovers. The Permittee shall also follow the requirements found in Part II Section B.3 *Injection Pressure Limitation* that may result in a change to the permitted MAIP.

3. Injection Pressure Limitation

(a) Except during stimulation, injection pressure at the wellhead shall not exceed the MAIP which shall be calculated to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.

(b) The MAIP, as measured at the surface, shall equal the formation fracture pressure (FP) plus friction loss, provided the pressure loss due to friction can be adequately documented through a direct measurement.

MAIP = **FP** + friction loss (if applicable)

The **FP** (measured at the surface) must be calculated using the following equation:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

The values used in the equation are defined as:

"FG" is the fracture gradient of the injection zone in pounds per square inch/feet (psi/ft). The **FG** value for each well shall be determined by conducting a valid step rate test, reviewed and approved by the Director. Alternative methods to the determine a representative **FG** may be used, if approved by the Director.

"SG" is the specific gravity of the injection fluid obtained from a representative fluid sample.

"D" is the true vertical depth in feet. The value for **D** is the depth of the top open perforation.

(c) During the life of the Permit, the fracture gradient, top perforation depth, and specific gravity may change. When new perforations are added to the injection zone, the Permittee shall demonstrate that the FG previously submitted is also appropriate for the new interval within the injection zone. It may be necessary to run a new step rate test to gather information from the new interval proposed for injection. Upon submission of monitoring reports, tests, or well workover records that indicate one of these parameters has changed, the MAIP calculation will be evaluated.

When the D or FG value changes, a new MAIP shall be recalculated. When a sample analysis is submitted, the newly submitted SG value will be compared to the SG used to calculate the MAIP. If the absolute difference is greater than 0.05, the MAIP will be recalculated using the newly submitted SG value.

To approve an increase to the MAIP, as a result of changes to the D or FG value, the Director may also require an external (Part II) mechanical integrity demonstration at the increased MAIP.

The Director will notify the Permittee in writing of the revised MAIP. A newly calculated MAIP shall not be implemented until written approval is received from the Director.

(d) Tests to demonstrate external (Part II) Mechanical Integrity (MI) shall be conducted at the most recently approved MAIP. However, if during testing, the Permittee is unable to achieve the MAIP, the MAIP will be readjusted and set to the highest pressure achieved during the successful external (Part II) Mechanical Integrity Test (MIT). The Permittee will be notified in writing from the Director of the new MAIP, based on the Part II MIT results.

4. *Injection Volume Limitation*

Injection volume is limited to the total volume specified in APPENDIX C.

5. *Injection Fluid Limitation*

Injected fluids are limited to non-hazardous industrial fluids. The permittee shall not inject any other chemical additives than those corrosion inhibitors listed below without the Director's approval:

(a) Chem Link C-144,
(b) Triethylene glycol,
(c) Produced fluid,
(d) Mutual Solvents such as Tretolite, and
(e) Dilute hydrochloric acid (HCL) used during well workovers.

The Permittee may inject fluids that meet the criteria above. However, prior to introduction of a new source (e.g. different production formation, well field, etc.) into the well, a fluid analysis shall be required, as listed in APPENDIX D under "WITHIN 30-DAYS OF AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE." The Permittee shall provide notification to the Director as well as provide a representative sample of the new injection fluid, as required in APPENDIX B. Results of the fluid analysis may affect the MAIP as described above in Part II, Section B.4 *Injection Pressure Limitation*.

6. *Tubing–Casing Annulus*

The tubing-casing annulus (TCA) shall be filled with a non-corrosive fluid or other fluid approved by the Director. The TCA valve shall remain closed during normal operations and the TCA pressure shall be maintained between 0 (zero) and the lesser of either 100 psi or 10 percent of the tubing pressure.

If TCA pressure cannot be achieved, the Permittee shall report to EPA the actions taken to determine the cause of the excessive pressure and the proposed remedy. If a loss of MI has been determined, the Permittee shall comply with the *Loss of Mechanical Integrity* requirements found in Part II, Section C.5.

7. *Alteration, Workover, and Well Stimulation*

Alterations, workovers, and well stimulations shall meet all conditions of the Permit. Alteration, workover, and well stimulation include any activity that physically changes the well construction (casing, tubing, packer) or injection formation.

Prior to beginning any addition or physical alteration to an injection well's construction or injection formation, the Permittee shall give advance notice to the Director. Additionally, the Director's written approval must be obtained if the addition or physical alteration to the injection well modifies the approved well construction. Substantial alterations or additions may be cause for modification to the permit and may include additional testing or monitoring requirements.

The Permittee shall record all alterations, workovers, and well stimulations on a Well Rework Record (EPA Form 7520-19) and submit a revised well construction diagram, when the well construction has been modified. The Permittee shall provide this and any other record of well workover, logging, or test data to EPA within thirty (30) days of completion of the activity.

The Permittee shall complete any activity which affects the tubing, packer, or casing and provide demonstration of internal (Part I) MI within ninety (90) days of beginning the activity. If the Permittee is unable to complete work within the specified time period, the Permittee shall propose an alternative schedule and obtain Director's written approval. Injection operations shall 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.

8. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

9. Annual Pressure Falloff Test

The Permittee must perform a pressure falloff test at least once every twelve months (40 CFR § 146.13(d)(1)). The pressure falloff test is required for Class I operations 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* shall 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.

10. Well Injection and Seismicity

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service which reports real-time earthquake events for any area specified by the user. The Permittee is required to subscribe to this service, known as the Earthquake Notification Service (ENS) to monitor seismic activity within 50 miles from the area permit boundary. Details for the ENS can be found at: https://earthquake.usgs.gov/ens/.

For any seismic event reported within two miles of the permit boundary, the Permittee shall immediately cease injection and report to EPA within twenty-four (24) hours according to Part III, Section E.11. Injection shall not resume until the Permittee has obtained approval to recommence injection from EPA. For any seismic event occurring between two and fifty miles of the permit boundary, that event will be recorded and reported to EPA on a quarterly basis.

Section C. MECHANICAL INTEGRITY

1. Requirement to Maintain Mechanical Integrity

The Permittee is required to ensure the injection well maintains MI at all times. Injecting into a well that lacks MI is prohibited.

An injection well has MI if:

(a) there is no significant leak in the casing, tubing, or packer (internal Part I); and

(b) there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (external Part II).

2. Demonstration of Mechanical Integrity

The conditions under which the Permittee shall conduct the MI testing are as follows and detailed in APPENDIX B:

(a) An authorization to resume injection and periodically thereafter as specified in APPENDIX B, the Permittee shall demonstrate both internal Part I and external Part II MI. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are specified in APPENDIX B.

(b) After any rework that compromises the MI of the well and after a loss of MI.

Other than during periods of well workover (maintenance) in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the Permittee shall monitor injection tubing pressure, rate, and volume, pressure on the annulus between tubing and casing, and bradenhead pressure, as specified in APPENDIX D.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from the injection activity.

Results of any MIT results required by this Permit shall be submitted to the Director as soon as possible but no later than thirty (30) calendar days after the test is complete.

3. Mechanical Integrity Test Methods and Criteria

EPA approved methods shall be used to demonstrate MI. These methods may be found in documents available from the EPA at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance:

- *“Ground Water Section Guidance No. 34: Cement Bond Logging Techniques and Interpretation"*
- *“Ground Water Section Guidance No. 39: Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity"*
- *“Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations”*
- *“Temperature Logging for Mechanical Integrity”*

Current versions of these documents will also be available from the EPA upon request. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

4. Notification Prior to Testing

The Permittee shall notify the Director at least thirty (30) calendar days prior to any MIT. The Director may allow a shorter notification period if it would be sufficient to enable the EPA to witness the MIT or the EPA declines to witness the test. Notification may be in the form of a yearly or quarterly schedule of planned MITs, or it may be on an individual basis.

5. *Loss of Mechanical Integrity*

If the well fails to demonstrate MI during a test or a loss of MI becomes evident during operation (such as presence of pressure in the tubing-casing annulus, water flowing at the surface, etc.), the Permittee shall notify the Director within twenty-four (24) hours (see Part III, Section E.11(e) of this Permit), cease injection and shut-in the well within forty-eight (48) hours unless the Director requires immediate shut-in.

Within five (5) calendar days, the Permittee shall submit a follow-up written report that documents circumstances that resulted in the MI loss and how it was addressed. If the MI loss has not been resolved, the Permittee shall provide a report with the proposed plan and schedule to reestablish MI. A demonstration of MI shall be reestablished within ninety (90) calendar days of any loss of MI unless written approval of an alternate time period has been given by the Director.

Injection operations shall not resume until after the MI loss has been resolved, the well has demonstrated MI pursuant to 40 CFR § 146.8, and the Director has provided written approval to resume injection.

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. *Monitoring Parameters and Frequency*

Monitoring parameters are specified in APPENDIX D. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D, 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. Sampling data shall be submitted if the well has injected any time during the reporting period.

Records of monitoring information shall include:

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

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

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

(d) the analytical technique or method used; and

(e) the results of such analyses.

2. *Monitoring Methods*

Observations, measurements, and samples taken for the purpose of monitoring shall be representative of the monitored activity and include:

(a) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in 40 CFR § 136.3 or by other methods that have been approved in writing by the Director.

(b) Injection tubing, TCA annulus, and bradenhead pressures, injection rate, injected volume, and cumulative injected volume shall be observed and recorded at the wellhead. All parameters shall be observed simultaneously to provide a clear depiction of well operation. Annulus pressure applied during standard annulus pressure tests performed during mechanical integrity tests should not be included in the annual monitoring report.

(c) Pressures are to be measured in pounds per square inch (psi).

(d) Fluid volumes are to be measured in standard oil field barrels (bbl) or thousands of cubic feet (MCF).

(e) Injection rates are to be measured in barrels per day (bbl/day) or thousands of cubic feet per day (MCF/day).

3. *Records Retention*

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

(a) Calibration and maintenance records and all original recordings for continuous monitoring instrumentation, copies of all reports required by this Permit, and records of all data used to complete the application for this Permit, for a period of at least (3) years from the date of the sample, measurement, report, or application. This period may be extended any time prior to its expiration by request of the Director.

(b) Nature and composition of all injected fluids until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR § 144.52(a)(6). The Permittee shall continue to retain the records after the three-year (3) 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.

4. Quarterly Reports

Regardless of whether or not the well is operating, the Permittee shall submit Quarterly Reports to the Director that:

(a) summarizes the results of the monitoring required in Part II, Section D and APPENDIX D;

(b) includes a summary of any major changes in characteristics or sources of injected fluid. The report of fluids injected during the year must identify each new fluid source by well name and location, and the field name or facility name; and

(c) includes any additional wells within the AOR that have not previously been submitted. For those wells that penetrate the injection zone, a well construction diagram, cement records and cement bond log are also required.

The Quarterly Report shall cover the period from January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31. Quarterly Reports shall be submitted by the fifteenth day of the month following the end of the data collection period. EPA Form 7520-8 may be used or adapted to submit the Quarterly Report. An electronic form may also be obtained from the EPA to satisfy reporting requirements.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment

The Permittee shall notify the Director in writing at least thirty (30) days prior to plugging and abandoning an injection well. The notification shall include any anticipated changes to the plugging and abandonment plan (P&A Plan), which will be incorporated into the Permit as a modification.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids into or between USDWs, in accordance with 40 CFR § 146.10. Additional federal, state or local laws or regulations may also apply.

3. Approved Plugging and Abandonment Plan

The approved P&A Plan and required tests are incorporated into this Permit as APPENDIX E. Changes to the approved P&A Plan will be incorporated into the Permit as a modification prior to beginning plugging operations and shall be submitted using EPA Form 7520-19. The Director also may require revision of the approved P&A Plan at any time prior to plugging the well.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-19) to the Regional Administrator or his/her authorized representative. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall 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 APPENDIX E, an updated version of the plan, specifying the differences.

5. Wells Not Actively Injecting

After any period of two (2) years during which there is no injection, or two (2) years from the spud date of a newly drilled well or the permit effective date of a well to be converted to an injector, the Permittee shall plug and abandon the well in accordance with Part II, Section E.2 and APPENDIX E of this Permit unless the Permittee:

(a) provides written notice to the Regional Administrator or his/her authorized representative, prior to the two-year (2) 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. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells, 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 Permittee of a well that has been temporarily abandoned shall notify the Director prior to resuming operation of the well.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. 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. Conversion to Non-UIC Well

The Director may allow conversion of the well to a non-UIC well. Conversion may not proceed until the Permittee receives written approval from the Director, at which time this permit will expire due to the end of operating life of the facility. Once expired under this part, the Permittee will need to reapply for a UIC permit and restart the complete permit process, including opportunity for public comment, before injection can occur.

Conditions of such conversion shall include approval of the proposed well rework, demonstration of mechanical integrity, and documentation that the well is authorized by another regulatory agency.

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)), 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 thirty (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, or modify, the transfer is effective on the date specified in the written agreement. A modification under this paragraph may also be a minor modification under 40 CFR § 144.41.

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 thirty (30) days.

Section B. CONTINUATION OF EXPIRING PERMITS

1. 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 submit a complete application for a new permit at least 180 days before this Permit expires.

2. Permit Extensions

The conditions of an expired permit continue in force in accordance with 5 U.S.C. 558(c) until the effective date of a new permit, if:

(a) The Permittee has submitted a timely application, which is a complete application for a new permit; and

(b) The Regional Administrator or his/her authorized representative, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

3. Enforcement

When the Permittee is not in compliance with the conditions of the expiring or expired permit, the Regional Administrator or his/her authorized representative may choose to do any or all of the following:

(a) Initiate enforcement action based upon the permit which has been continued.

(b) Issue a notice of intent to deny the new permit. If the permit is denied, the owner or operator would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit.

(c) Issue a new permit under 40 CFR part 124 with appropriate conditions.

(d) Take other actions authorized by these regulations.

4. State or Tribal Continuation

An EPA issued permit does not continue in force beyond its expiration date under Federal law if at that time a State or Tribe has primary enforcement authority. A State or Tribe authorized to administer the UIC program may continue the EPA issued permits until the effective date of the new permits, if State or Tribal law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State or Tribal-issued new permit.

Section 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. Additionally, in a permit modification, only those conditions to be modified shall be reopened. All other aspects of the existing permit shall remain in effect for the duration of the permit.

Section D. CONFIDENTIALITY

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to the 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, the 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:

- the name and address of the Permittee; and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. ADDITIONAL PERMIT REQUIREMENTS

1. Prohibition on Movement of Fluid Into a USDW

The Permittee shall 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, except as authorized by 40 CFR part 146.

2. 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; 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 penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

3. Need to Halt or Reduce Activity Not a Defense

The Permittee shall not use as a defense 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 shall 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 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.

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 federal, state or local law or regulations.

8. Duty to Provide Information

The Permittee shall furnish to the Director, within a 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 shall also furnish to the Director, upon request, copies of records required to be kept by this Permit.

9. Inspection and Entry

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

(a) enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records 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 Requirements

All applications, reports or other information submitted to the Regional Administrator or his/her authorized representative shall be signed and certified according to 40 CFR § 144.32. This section explains the requirements for persons duly authorized to sign documents and provides wording for required certification.

11. Reporting Requirements

Copies of all reports and notifications required by this Permit shall be signed and certified in accordance with the requirements under Part III, D.10 of this Permit and shall be submitted to the EPA:

UIC Enforcement, Mail Code: 8ENF-WSD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

All correspondence should reference the well name and location and include the EPA Permit number.

(a) *Monitoring Reports.* Monitoring results shall be reported at the intervals specified elsewhere in this Permit.

(b) *Planned changes.* The Permittee shall 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 shall 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 shall be submitted no later than thirty (30) calendar days following each schedule date.

(e) *Twenty-four hour reporting.* The Permittee shall report to the Director any noncompliance 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; or

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

Information shall 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 the EPA Region 8 Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) calendar 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 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 of the noncompliance.

(f) *Other Noncompliance.* The Permittee shall report all instances of noncompliance not reported under Paragraphs 11(a), 11(b), 11(d), or 11(e) of this Section at the time the monitoring reports are submitted. The reports shall 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 shall submit such facts or information to the Director within thirty (30) days of discovery of failure.

(h) _Oil Spill and Chemical Release Reporting._ The Permittee shall 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 F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

The Permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§144.51(o) and 146.10, and the Permittee has submitted a plugging and abandonment report pursuant to 40 CFR §144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR §144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new Permittee, has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director 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 to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Types of Adequate Financial Responsibility.

Adequate financial responsibility to properly plug and abandon injection wells under the Federal UIC requirements must include completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,

(b) a letter of credit with a standby trust agreement,

(c) a fully funded trust agreement, or

(d) a financial test and corporate guarantee.

A standby trust agreement acceptable to the Director shall contain wording identical to model language provided to the Permittee by the EPA and must accompany any surety bond or letter of credit. Annual reports from the financial institution managing the standby trust account shall be submitted to the Director showing the available account balance.

A surety bond acceptable to the Director shall contain wording identical to model language provided to the Permittee by the EPA and shall be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://fiscal.treasury.gov/surety-bonds/circular-570.html.

A letter of credit acceptable to the Director shall contain wording identical to model language provided to the Permittee by the EPA and be issued by a bank or other institution whose operations are regulated and examined by a state or federal agency.

A fully funded trust agreement acceptable to the Director shall contain wording identical to model language provided to the Permittee by the EPA. Annual reports from the financial institution managing the trust account shall be submitted to the Director showing the available account balance.

An independently audited financial test with a corporate guarantee acceptable to the Director shall contain wording identical to model language provided to the Permittee by the EPA and shall demonstrate that the Permittee meets or exceeds certain financial ratios. The Permittee must meet the EPA's requirements including, but not limited to, total net worth to be able to use this method. If this financial instrument is used, it must be resubmitted annually, within ninety (90) calendar days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year. If at any time the Permittee does not meet the financial ratios, notice to the EPA must be provided within 90 days and a new demonstration of financial responsibility must be submitted within 120 days.

The Permittee shall submit a completed, originally-signed financial responsibility demonstration to:

UIC Financial Responsibility Coordinator
Mail Code: 8ENF-WSD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

3. Determining How Much Coverage is Needed

The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, may be required to adjust the given cost for inflation or pursue a new cost estimate as prescribed by the Director.

4. Insolvency

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism;

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) calendar days after any event specified in (a), (b), or (c) above.

The Permittee must also 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 the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The well shall be cased and cemented to prevent the movement of fluids into or between USDWs, and in accordance with 40 CFR § 146.22 and other applicable federal, state or local laws and regulations. General requirements include:

Packer must be set within 130 feet of the top of the injection zone at 4,023 feet.

WELL CONSTRUCTION:

Garcia No. 1 well, API No. 05-055-06012
Non-Hazardous Water Disposal Well
1900 feet (ft) FSL 650 ft FEL
NESE Section 35, Township 27 South, Range 70 West, 6th PM
Sheep Mountain Field
Huerfano County, Colorado

Completed on 9/25/1985

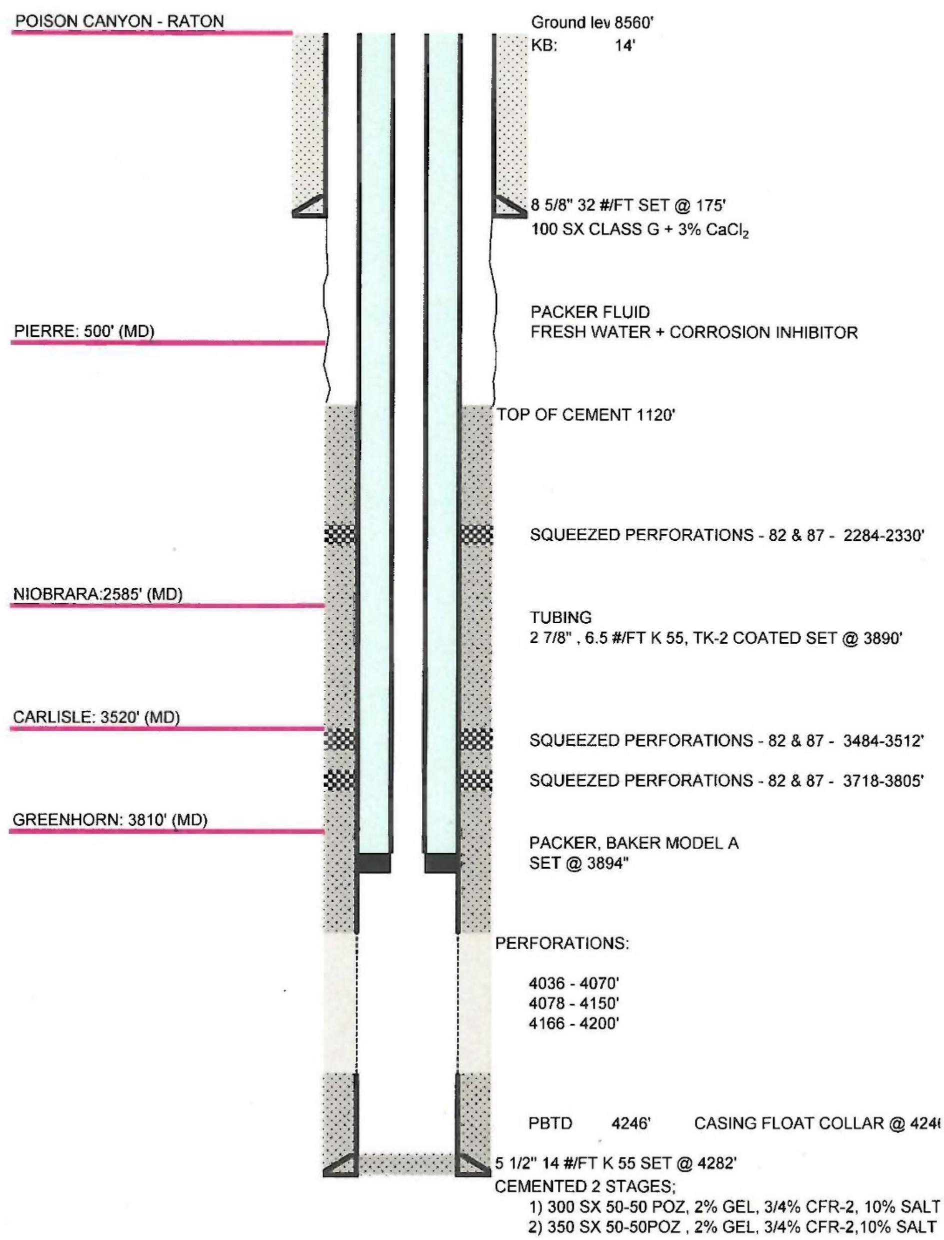
Operator Name: Oxy USA Incorporated
Elevation: 8560 ft
Measured TD: 4282 ft
Measured PBTD: 4246 ft
Top of Cement: 1120 ft or less

CASING or OTHER EQUIPMENT TYPE	HOLE SIZE, ft	CASING SIZE, ft	CASING LENGTH, ft	CEMENTED INTERVAL ft
Surface	12.25	8.625	0 - 175	0 - 175
Longstring	7.875	5.5	0 - 4282	1120 - 4282
Squeezed Perforations Depths, ft	2284 – 2330; 3484 – 3512; 3718 – 3805			
Open Perforations Depths	4036 – 4070 4078 – 4150 4186 - 4200			
Packer	Set at 3894 feet			

No well stimulation program is proposed during well completion. In the event the Permittee wishes to conduct well stimulation, the Permittee shall follow the requirements in Part II, Section B.8. *Alteration, Workover, and Well Stimulation*.

Garcia No. 1 Well
located in the NE SE,
1900 feet from the south line & 650 feet from the east line
Section 35, Township 27 South, Range 70 West
Huerfano County, Colorado

API No. 05-055-06012



APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Well logging and tests shall be performed according to the 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#guidance.

Well logs and test results shall be submitted to the Director within thirty (30) calendar days of completion of the logging or testing activity and shall include a report describing the methods used during logging or testing and an interpretation of the log or test results. When applicable, the report shall 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) a USDW and the confining zone adjacent to it, and (2) the injection zone and adjacent formations.

LOGS AND TESTS

TYPE OF LOG OR TEST	DATE DUE
Well logs and test results shall be submitted to the Director within thirty (30) calendar days of completion of the logging or testing activity.	
Injectate Water Analysis A representative water sample of the injectate shall be analyzed for the constituents found in APPENDIX D.	1. Quarterly 2. Prior to the introduction of a new source
Production Casing **Cement Evaluation Logs (CBL, RAL, USIT)**	Shall be performed within sixty (60) days of the permit effective date. The Permittee shall run a new cement bond log (with a gamma ray, travel time curve, casing locator, amplitude curve, variable density log, and ultrasonic imager tool) that covers the area of the cementing to verify the adequacy of the cement placement. The bond long shall be run from the surface to the plug back total depth of the well.
Standard Annulus Pressure (internal Part I MI) If the well has not received authorization to continue to inject and does not have tubing installed, in lieu of the Standard Annulus Pressure test, a Casing Pressure Test can be performed.	1. Within ninety (90) days following the completion of construction requirements identified in Part II. Section A.1 of this permit. 2. Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well or a loss of MI. 3. At least once every five (5) years after the last successful demonstration of internal (Part I) Mechanical Integrity.
Step Rate Test At a minimum, the step rate test should conform to the EPA Region 8 step rate test procedure found at https://www.epa.gov/uic/underground-injection-control-	Within one hundred eighty (180) days following the completion of construction requirements identified in Part II. Section A.1 of this permit.

epa-region-8-co-mt-nd-sd-ut-and-wy#guidance. Additionally, the step rate test shall be conducted with a minimum of six (6) steps with pressures that range from near 0 psi to a maximum surface pressure approved by the Director (e.g., 2350 psi) and include recording of the pressure fall-off curve following the test.	
Radioactive Tracer Survey (RTS) If the Director's review of the cement bond log does not show 80% bond index, an RTS is required	If an RTS is required, subsequent logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.
Temperature Log (external Part II MI)	Subsequent logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.
Pressure Fall-Off Test It is important that the initial and subsequent tests follow the same or similar test procedure, including pressure build up value and fall-off duration, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. 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. The report shall also compare the test results with previous years test data, unless it is the first test performed at that well. A fall-off test that fails to adhere to these requirements may be subject to retest. Refer to Part II.10 Annual Pressure Fall-off Test for additional requirements.	At least once every twelve (12) months. Subsequent tests shall be conducted at least once every year following the last successful Pressure Fall-Off Test.

APPENDIX C

OPERATING REQUIREMENTS

INJECTION ZONE:
Injection is permitted only within the approved injection zone listed below.

APPROVED INJECTION ZONE (GL, ft.)

FORMATION NAME or STRATIGRAPHIC UNIT	TOP (ft.) *	BOTTOM (ft.) *
Dakota	4023	4200

*estimated top and bottom depths of formations

MAXIMUM ALLOWABLE INJECTION PRESSURE:

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 well, pursuant to the conditions and formula at Part II.B.4 of this Permit. Documentation to support a change shall be provided and approved by the Director prior to recalculation of the MAIP.

MAIP Parameters

fracture gradient	specific gravity*	depth (ft)	friction loss (PSI)	Calculated MAIP (PSI)	**Authorized MAIP (PSI)**
1.04	1.002	4023	4.57	2350	2350

MAXIMUM INJECTION VOLUME:

There is no limitation on the fluid volume permitted to be injected into this well. In no case shall injection pressure exceed the MAIP.

APPENDIX D

MONITORING, AND REPORTING PARAMETERS

MONITORING, AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the Part II, Section D of the Permit, for detailed requirements for observing, recording, and reporting of these parameters.

EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise. An electronic form may also be obtained from the EPA to satisfy reporting requirements.

RECORD CONTINUOUSLY	
RECORD	Injection Tubing Pressure (psi)
	Bradenhead Pressure (psi)
	Annulus Pressure (psi)
	Injection Rate (bbl/day)
	Injected Volume (bbl)
	Cumulative Fluid Volume Injected (since injection began) (bbls)

PRIOR TO INTRODUCTION OF A NEW SOURCE AND QUARTERLY (if injection occurred during reporting period) Analytical methods used must comply with the methods cited in Table 1 of 40 CFR 136.3, Appendix II of 40 CFR 261, or those methods listed below.	
ANALYZE	Analyze a sample of injection fluids for the following constituents: • 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 • Corrosivity Index (Langelier Saturation Index) • Nitrate (as N) (mg/L) • Nitrite (as N) (mg/L) • Cations: Na, Fe, Mg, Ca (mg/L) • Anions: Cl and SO_4 (mg/L) • Strontium (mg/L) • Gross Alpha and Beta Radiation (pCi/L) via Method 900.0 • Uranium-234 and Uranium-238 (pCi/L) via Method 907.0 • Radium-226 (pCi/L) via Method 903.0 • Radium-228 (pCi/L) via Method 904.0 • Potassium-40 (pCi/L) via Method 901.1 • Barium • Chromium • Nitrite + Nitrate (as N) (mg/L) • Total Alkalinity

	• Additional Metals: Arsenic, Cadmium, Lead, Selenium, Mercury and Silver • Triethylene Glycol • Oil and Grease

QUARTERLY	
REPORT	Each month's minimum, maximum and average injection tubing pressures (psi)
	Each month's minimum, maximum and average annulus pressures (psi)
	Each month's minimum, maximum and average bradenhead pressures (psi)
	Each month's minimum, maximum and average injection rate (bbl/day)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year, including any wellfield and formation, noting any major changes in characteristics of injected fluid.
	Summary of monthly reviews of seismic event(s), within a fifty (50) mile radius of the area permit boundary, gathered from the USGS Earthquake Hazard Program website or personal communication.

In addition to these items, additional logging and testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B – LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT (P&A) REQUIREMENTS

All wells shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids either into or between USDWs in accordance with 40 CFR § 146.10. Additional federal, state or local law or regulations may also apply. General requirements applicable to all wells include:

- Prior to plugging a well, mechanical integrity must be established unless the P&A plan will address the mechanical integrity issue. Injection tubing shall be pulled.
- Cement plugs shall have sufficient compressive strength to maintain adequate plugging effectiveness.
- 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.
- 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.
- If there is more than 2,000 mg/liter difference of TDS between individual exposed USDWs, they must be isolated from each other.

At a minimum, the following plugs are required:

1. **Isolate the Injection Zone**: Remove down hole apparatus from the well and perform necessary clean out; displace well fluid with plugging gel.

   PLUG 1: Squeeze injection zone perforations (4036 ft – 4200 ft). Set a cement retainer (CR) within the innermost casing string no more than 50 feet above the top perforations with a minimum 20-foot cement plug on the top of the CR. A cement plug should also be placed within the 5.5 inch casing at the base of the cement retainer to a depth of 4200 ft.

2. **Isolation of the Upper Confining Zone**
   PLUG 2: Set a 100 ft cement plug inside the 5.5 inch casing from 3785 to 3885

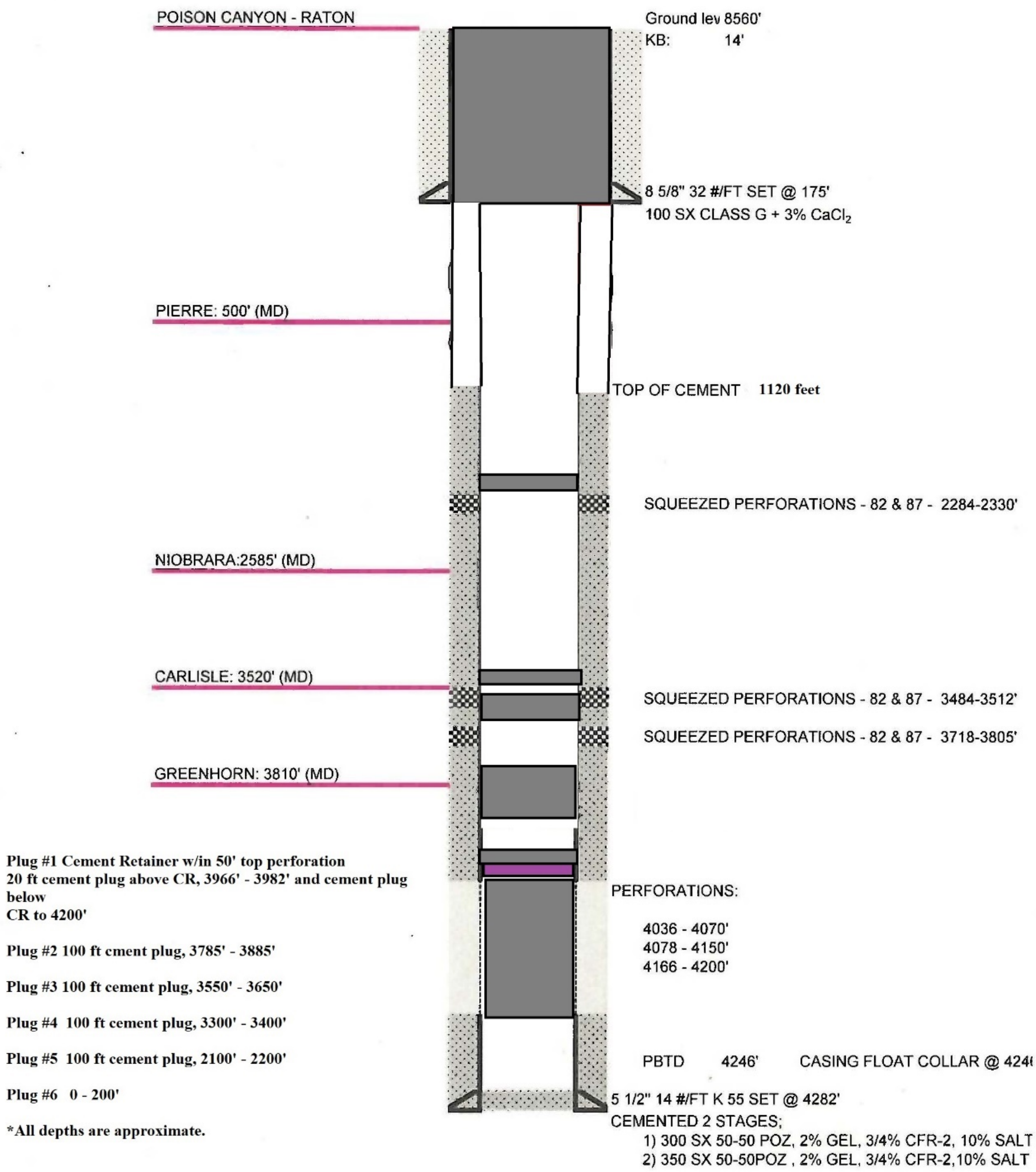
3. **Isolation of Squeezed Perforation**
   PLUG 3: Set a 100 ft cement plug inside the 5.5 inch casing from 3550 to 3650 ft
   PLUG 4: Set a 100 ft cement plug inside the 5.5 inch casing from 3300 to 3400 ft.
   PLUG 5: Set a 100 ft cement plug inside the 5.5 inch casing from 2100 to 2200 ft.

4. **Isolate Surface Fluid Migration Paths**:
   PLUG 6: Set a cement plug outside and inside the innermost casing string from 200 feet to the surface.

INJECTION WELL P & A DIAGRAM

Garcia No. 1 Well
located in the NE SE,
1900 feet from the south line & 650 feet from the east line
Section 35, Township 27 South, Range 70 West
Huerfano County, Colorado

API No. 05-055-06012



APPENDIX F

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.

STATEMENT OF BASIS

Garcia No. 1 Well
Sheep Mountain CO_2 Unit
Huerfano, Colorado

OPERATOR: Oxy USA, Incorporated

EPA PERMIT NO. CO10044-00055
Class I – Nonhazardous Industrial Waste Disposal Well

CONTACT: Linda Bowling
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (303) 312-6254 or (800) 227-8917, extension 312-6254
Email: bowling.linda@epa.gov

This Statement of Basis gives the derivation of site-specific Underground Injection Control (UIC) permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in Garcia No. 1 Well, Permit No. CO10044-00055.

EPA Class I UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water (USDWs) nor initiate or propagate fractures in the injection zone during normal operations. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions in 40 CFR parts 2, 124, 144, 146 and 147, and address potential impacts to USDWs.

In accordance with 40 CFR § 144.35, issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR § 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR parts 144, 146 and 147) are not discussed in this document. Regulations specific to Colorado injection wells are found at 40 CFR 147 Subpart G.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection well or wells as needed so that the injection does not endanger USDWs. 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.

Project Description

Oxy USA, Incorporated is involved in the extraction of carbon dioxide (CO_2) from the Entrada and Dakota Sandstone subsurface reservoirs. The produced water stream which contains some triethylene glycol is trucked to the Garcia No. 1 for disposal into the Dakota Formation. The wastewater may also contain some corrosion inhibitor which is recovered from the CO_2 production wells immediately after they are periodically treated.

The Sheep Mountain Garcia No. 1 injection well began operating under Rule Authorization June 25, 1984, for disposal of a combination of

- waste fluid as described above which has been treated with corrosion inhibitor, oxygen scavenger, and biocide; and
- small amounts of mutual solvents, such as Tretolite to remove emulsion buildup on perforations.
- The operator states that the volume of injection will not exceed 400 barrels of fluid per day (BFPD). As of July 2000, the operator stated that injection averages approximately 100 BFPD.

The EPA Permit for the disposal of the above fluids into the Garcia No. 1 was first issued June 13, 1989. The Permit states that it became effective July 13, 1989. However, operator comments, and EPA responses, delayed the issuance of an effective Permit until June 18, 1990.

PART I. General Information and Description of Project

Oxy USA, Incorporated
P.O. Box 4294
Houston, Texas 77210-4294

hereinafter referred to as the "Permittee," submitted an application for a UIC Program permit for the following injection well or wells:

Garcia No. 1
located in the NE SE, 1900 feet FSL & 650 ft FEL
Section 35, Township 27 South, Range 70 West
Huerfano County, Colorado

The application, including the required information and data necessary to issue or modify a UIC permit in accordance with 40 CFR parts 2, 124, 144, 146 and 147, was reviewed and determined by EPA to be complete.

PART II. Permit Considerations (40 CFR § 146.14)

Hydrogeologic Setting

The Sheep Mountain CO_2 Field is located in the Sangre de Cristo Mountains of the Southern Rocky Mountains physiographic sub-province, which is within the Rocky Mountains physiographic province.

The structural geology of the CO_2 field area is dominated by igneous intrusions and folding, and faulting associated with the building of the Sangre de Cristo Mountains. These structural entities have produced bedrock dips ranging from vertical near the igneous intrusions and faults to nearly horizontal away from these structures. The structure of the Sheep Mountain reservoir is very complex. Tectonic activity, which occurred from Late Cretaceous through the Eocene periods created several thrust faults through the Paleozoic, Mesozoic, and Tertiary sections, along with two (2) thrust plates which contain the CO_2. Associated with the tectonics was significant igneous activity. Several igneous dikes and sills are present throughout the Sheep Mountain Field, with most of them occurring above the CO_2 productive horizons. Some metamorphosed altered sections within the Dakota and Entrada have been observed, with one (1) well having the Entrada section totally replaced with an igneous intrusion.

The Sheep Mountain CO_2 reservoir consists of two (2) distinct carbon dioxide bearing zones within two (2) different thrust plates. The Sheep Mountain Plate underlies the Sheep Mountain Unit, while the Abeyta Creek Plate underlies the nearby Kike Mountain Unit. The upper horizon within the Sheep Mountain Plate, the Dakota Formation, is divided into two (2) Members, the Lower Member being made up of medium grained and pebble conglomerates (typical of a beach or near-shore environment). The Dakota Formation is 177 feet thick at the Garcia No. 1 well. Permeability ranges from 20 to 4000 millidarcies.

The Entrada Sandstone is separated from the Dakota by the Morrison Formation. The Entrada Formation is made up of fine to medium grained sand. The depositional environment of the Entrada is assumed to be fluvial. It ranges in thickness from 60 feet to 90 feet in the Sheep Mountain Field, and permeability ranges from 10 millidarcies to 250 millidarcies. Cement in both sandstones tend to be siliceous, with much lesser amounts of carbonate and clay cements.

Lithology and zone type information presented in Table 2.1 were obtained from the permit application for the Garcia No. 1 well. Formation depths were obtained from a completion report obtained from the Colorado Oil and Gas Commission database. Water quality data was obtained from both the well permit application and the United States Geological Survey (USGS) database. Depths for the Morrison and Entrada Formations are estimated based upon formation thickness data included in EPA records for the site.

TABLE 2.1
Geologic Setting

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft.	BOTTOM DEPTH, ft.	TDS mg/l	ZONE TYPE
Poison Canyon – Raton	Impermeable low porosity limestone	0	500	<10,000	USDW
Pierre Shale	Sandstones, Shale and limestone	500	2085	Unknown	Unknown
Niobrara	Shale and limestone	2585	3421	N/A	Confinement
Fort Hays	Impermeable, low porosity limestone	3421	3480	N/A	Confinement
Codell	Low porosity, sandstone	3480	3520	N/A	Confinement
Carlile	Tight Shales	3520	3810	N/A	Confinement
Greenhorn	Impermeable limestone	3810	3916	N/A	Confinement
Graneros	Tight shale and bentonite	3916	4023	N/A	Confinement
Dakota	fine to medium grained sandstone	4023	4200	20,000	Injection
Morrison	Fairly impermeable siltstone, mudstone, and claystone underlain by interbedded sandstone, siltstone, and mudstone	4200	~4600	N/A	Confining
Entrada	fine to medium grained sand	~4600	~ 4660 -4690	>10,000	Non-USDW

Note: “mg/l” indicates milligrams per liter
“TDS” indicates Total Dissolved Solids

Injection Zone
An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zone(s) are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review (AOR).

The Dakota Sandstone is perforated: 4036 – 4070 feet (ft); 4076 – 4150 ft; and 4166 – 4200 ft. Hydrogeologic parameters for this interval are:

- Permeability is 20 to 4000 millidarcies
- Fracture Pressure is 4330 psi

TABLE 2.2
INJECTION ZONE

Formation Name	Top (ft.)	Thickness (ft.)	TDS (mg/l)	Fracture Gradient (psi/ft.)	Porosity	Exempted?
Dakota	4023	177	20,000	1.04	16 to 21%	Not required

* depths are approximate values at the wellbore

Confining Zones
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone. The confining zone or zones are listed in TABLE 2.3.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the AOR.

TABLE 2.3
CONFINING ZONES

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft.	BOTTOM DEPTH, ft.	ZONE TYPE
Greenhorn/Graneros	Impermeable limestone (Greenhorn Limestone) underlain by tite shales (Graneros Shale)	3810	4023	Upper Confining
Morrison	Fairly impermeable siltstone, mudstone, and claystone underlain by interbedded sandstone, siltstone, and mudstone	4200	~4600	Lower Confining

* depths are approximate values at the wellbore

Other low permeability units between the lowermost USDW are the Carlile Shale and the Niobrara Shale. The Carlile is 264 feet thick and the Niobrara is 968 feet thick.

Underground Sources of Drinking Water (USDWs)
Aquifers or the portions thereof which 1) currently supply any public water system or 2) contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contain fewer than 10,000 mg/l TDS, are considered to be USDWs. Most water wells in the region are over four (4) miles distant from the Garcia No. 1 well. There are small capacity water wells, domestic stock wells, completed in the Poison Canyon or the Pierre or younger formations in the area ranging in depth from 60 to 300 ft.

There are no wells in the one-quarter (¼) mile AOR. Most water wells in the region are over four (4) miles away. These are small capacity domestic – stock wells completed in the Poison Canyon. Due to a lack of data, the presence and quality of water in the Pierre Shale is unknown. Water wells in the older formations probably occur in an outcrop area, but a detailed study would be required to identify them because of the lack of public records. The aforementioned outcrop area does not occur in the one quarter (¼) mile AOR.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft.	BOTTOM DEPTH, ft.	TDS	ZONE TYPE
Poison Canyon - Raton	Impermeable low porosity limestone	0	500	< 10,000 mg/l	USDW

* depths are approximate values at the wellbore

PART III. Well Construction (40 CFR § 146.12)

The approved well construction plan, incorporated into the Permit as APPENDIX A, will be binding on the Permittee. Modification of the approved plan during construction is allowed under 40 CFR §144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cement
The permittee has installed cement in the surface casing from the surface to 175 feet. The top of cement in the long string casing occurs at a depth of 1120 feet. This well construction information was obtained from the Colorado Oil and Gas Commissions database and information submitted in the application.

The well construction plan was evaluated and determined to comply with standard practices and guidelines that ensure well injection does not result in the movement of fluid containing any contaminant into USDWs. The well construction plan for the injection well(s) is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of external (Part II) mechanical integrity.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS

Casing Type	Hole Size (in.)	Casing Size (in.)	Cased Interval (ft.)	Cemented Interval (ft.)
Surface	12.25	8.625	0 - 175	0 - 175
Longstring	7.875	5.5	0 - 4282	1120- 4282

Injection Tubing and Packer
The tubing and packer are designed to prevent injection fluid from coming into contact with USDWs. Specifically, 40 CFR 146.12(c) requires that all Class I wells, except those municipal wells injecting non-corrosive wastes, inject fluids through tubing with a packer set immediately above the injection zone.

The permit requires that injection tubing be installed from a packer up to the surface inside the well casing and allows the packer to remain at 3,894 feet in the existing well construction. The top of the injection zone is 4,023 feet, and the packer placement is 29 feet higher than the typical allowance for placement of a packer within 100 feet of the injection zone. The Permittee requested that the packer remain in its existing configuration due to concerns that movement of the packer may result in damage to the well because of the length of time it has been secured at its existing location.

As described in Part II above, the base of the lowermost known USDW occurs at a depth of 500 feet and there are multiple formations with confining characteristics separating the injection zone from this USDW and any unknown USDW occuring within the Pierre Shale between 500 and 2,085 feet. The existing packer placement is located within the upper confining zone, well below the base of the lowermost known USDW and the Pierre Shale, and does not allow injected fluid to directly contact the portion of the casing adjacent to these intervals. As a result, the existing packer placement is reasonably consistent with the construction requirement contained in 40 CFR 146.12(c) and is protective of USDWs. In addition, testing requirements contained in Appendix B of the permit will ensure that the well maintains Part I and II Mechanical Integrity (MI), as defined in Part V below.

Tubing-Casing Annulus

The tubing-casing annulus (TCA) allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity and will allow for detection of leaks. The TCA will be filled with non-corrosive fluid or other fluid approved by the Director.

Sampling and Monitoring Device

To fulfill permit monitoring requirements and provide access for EPA inspections, sampling and monitoring equipment will need to be installed and maintained. Required equipment includes but is not limited to: 1) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) is reached at the wellhead; 2) fittings or pressure gauges attached to the injection tubing(s), TCA, and surface casing-production casing (bradenhead) annulus; 3) a fluid sampling point between the pump house or storage tanks and the injection well, isolated by shut-off valves, for sampling the injected fluid; 4) a flow meter capable of recording instantaneous flowrate and cumulative volume attached to the injection line; and 5) a continuous recording device(s) to monitor injection pressure, flow rate, volume, pressure on the annulus between the tubing and the long string of casing, and the bradenhead pressure.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR § 144.55)

Area of Review (AOR)

Permit permittees are required to identify the location of all known wells within the AOR which penetrate the lowermost confining zone, which is intended to inhibit injection fluids from the injection zone. Under 40 CFR § 146.6 the AOR may be a fixed radius of not less than one quarter (¼) mile or a calculated zone of endangering influence. For area permits, a fixed width of not less than one quarter (¼) mile for the circumscribing area may be used.

The ¼ mile radius used for the area of review is considered to be adequate. There are no wells within the ¼ mile area of review. No additional facilities including surface water bodies, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults were identified within a ¼ mile radius.

Corrective Action Plan (CAP)

For wells in the AOR which are improperly sealed, completed, or abandoned, the permittee will develop a CAP consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

TABLE 4.1 lists the wells in the AOR and shows the well type, operating status, depth, top of casing cement (TOC) and CAP is required for the well. The CAP will be incorporated into the Permit as APPENDIX F and becomes binding on the Permittee.

TABLE 4.1
CAP TABLE

Well Name	Well Type	Operating Status	Total Depth (ft.)	Top of Cement (ft.)	Corrective Action
None	N/A	N/A	N/A	N/A	N/A

There are no wells located within a ¼ mile area of review.

PART V. Well Operation Requirements (40 CFR § 146.13)

Mechanical Integrity (40 CFR § 146.8)
An injection well has mechanical integrity (MI) if:

1. Internal (Part I) MI: there is no significant leak in the casing, tubing, or packer; and
2. External (Part II) MI: there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

The Permit requires MI to be maintained at all times. The Permittee must demonstrate MI prior to injection and periodically thereafter, as required in APPENDIX B Logging and Testing Requirements. A demonstration of well MI includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating internal (Part I) and external (Part II) MI are dependent upon well conditions and are subject to change. Should well conditions change during the operating life of the well, additional requirements may be specified and will be incorporated as minor modifications to the Permit.

A successful internal Part I Mechanical Integrity Test (MIT) is required no less than five years after the last successful MIT. A demonstration of internal MI is also required following any workover operation that affects the tubing, packer, or casing or after a loss of MI. In such cases, the Permittee must complete work and restore MI within 90 days following the workover or within the timeframe of the approved alternative schedule. After the well has lost mechanical integrity, injection may not recommence until after internal MI has been demonstrated and the Director has provided written approval.

Internal (Part I) MI is demonstrated by using the maximum permitted injection pressure or 1,000 psi, whichever is less, with a ten percent or less pressure loss over thirty minutes. Additional guidance for Internal (Part I) MI can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Demonstration of External (Part II) MI is required and will be repeated no less than five years after the last successful MIT. The External MIT will be demonstrated by using the results of a temperature log. A baseline temperature log will be required prior to authorization to recommence injection as needed, a temperature log will be run within six to twelve months after injection has re-commenced, and subsequent temperature logs will be run at least once every five (5) years after the last successful demonstration of Part II MI.

In addition to the required temperature log discussed above, should the analysis of a cement bond log related to remedial cementing show inadequate cement behind pipe to prevent significant movement of fluid out of the approved injection zone of the annulus cement, i.e. less than 80% bond index cement bond across the confining zone, a Radioactive Tracer Survey (RTS) will be required prior to authorization to inject along with additional tests as required by the Director.

The following monitoring and mechanical integrity test have been submitted for the Garcia No. 1 well:

- Temperature Log dated 11/2/2015
- Monitoring Report dated 10/10/2018
- Part I (Internal) MIT or Annulus Test dated 8/14/2019
- Cement Bond Log dated 9/26/1971 was used to estimate the current top of cement. A requirement to perform a new CBL test with current technology is included in APPENDIX B of the Permit. The previous CBL was performed with older technology and has data that is more difficult to determine the quality of cement throughout the well.
- Pressure Fall Off Test dated 8/16/2017

Injection Fluid Limitation
Injected fluids are limited to non-hazardous industrial and municipal fluids.

The approved injection fluid is limited to

1. Chem Link C-144
2. Triethylene glycol
3. Produced fluid
4. Mutual solvents, such as Tretolite, and
5. Dilute hydrochloric acid (HCL) used during well workovers.

Prior to adding a new source, a fluid analysis sample must be provided for any new source that was not previously characterized. A new source may include fluids from a new formation, a new portion of the field, non-commercial fluids from another operator, or that are chemically dissimilar from fluids that are already injected into the well. The list of analytes is found in APPENDIX D of the Permit "WITHIN 30-DAYS OF AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE". As a result of the new sample analysis, the MAIP may need to be recalculated.

Volume Limitation
Injection volume is limited to the total volume specified in APPENDIX C of the Permit.

There is no limitation on the fluid volume permitted to be injected into this well. In no case shall injection pressure exceed the MAIP.

Injection Pressure Limitation
40 CFR § 146.13(a)(1) requires that the injection pressure at the wellhead must not exceed a maximum calculated to ensure that the pressure during injection does not initiate new fractures or propagate existing fractures in the injection zone.

The calculated MAIP described below is the pressure that will initiate fractures in the injection zone and that the Director has determined satisfies the above condition. Except during stimulation, the injection pressure must not exceed the MAIP. Furthermore, under no circumstances shall injection pressure cause the movement of injection or formation fluids into a USDW.

The temporary **MAIP** allowed under the permit, as measured at the surface, will be 2350 psig. The initial formation testing program was conducted by ARCO in 1982 when several injectivity tests were conducted and a fracture gradient of 1.0 to 1.10 psi/ft was documented. On December 13, 1995, a new step rate test was conducted, showing a parting pressure corresponding to a surface pressure just above 2350 psi. The Permittee shall perform a step rate test in accordance with the conditions in APPENDIX B of the Permit with an initial pressure near 0 psig and then increase the pressure to slightly above the requested or needed MAIP (e.g., 2352 psig). The maximum and average operating injection pressures for the Garcia no. 1 well are 1700 psi and 1550 psi, respectively.

The Permit itself does not contain a specific MAIP value but instead requires that a MAIP be calculated using the equations below. The Permit also specifies the derivation of the input values. The Permittee must submit for review the necessary information to calculate the new MAIP. After review of the submitted documents, the Director will notify the Permittee of the MAIP in the written re-authorization to commence injection.

The formation fracture pressure (**FP**) is the pressure above which injection of fluids will cause the injection formation to fracture. This equation, as measured at the surface, is defined as:

FP = [**FG** - (0.433 * (**SG** + 0.05))] * **D**

Where, FG is the fracture gradient in psi/ft
SG is the specific gravity
D is the depth of the top perforation in feet

The **FG** value for each well will be determined by conducting a step rate test. The results of the test will be reviewed and approved by the Director. As appropriate, the FG may be determined by one of these other following methods:

- Representative **FG** values determined previously from valid tests in nearby wells.
- Established **FG** values found in reliable sources approved by the Director. These could include journal articles, scientific studies, etc.
- An alternative method approved by the Director.

The value for **SG** must be obtained from the fluid analysis of a representative sample of the injection fluid.

The value for **D** is the depth of the top perforation of the as-built well.

When a step rate test is conducted, bottom-hole and surface gauges are required. This requirement may be waived by the Director but may result in a final MAIP that does not include adjustment for friction loss.

The MAIP can also be adjusted for friction loss if the friction loss can be adequately demonstrated. To account for friction loss, the **MAIP** is equal to **FP** adjusted for friction loss, or:

MAIP = **FP** + friction loss (if applicable)

An acceptable method to determine friction loss is to measure it directly. Friction can be calculated when surface and bottom-hole pressures are known. When conducting a step rate test, a surface and bottom-hole gauge at depth **D** are necessary to calculate friction loss.

During the operational life of the well, the depth to the top perforation, fracture gradient, and specific gravity may change. When well workover records, tests, or monitoring reports indicate one of the variables in the FP equation has changed, the MAIP calculation will be reviewed. The EPA is incorporating the MAIP equations into this Permit instead of identifying a specific MAIP value because it will result in a more efficient application of the true MAIP, as these changes occur over the life of the well to provide greater protection for nearby USDWs.

When additional perforations to the injection zone are added, the Permittee must provide the appropriate workover records and also demonstrate that the fracture gradient value to be used is representative of the portion of the injection interval proposed for perforation. It may be necessary to run a step rate test to provide representative data, such as when a new formation (within the approved injection zone) or a geologically distinct interval (based on core data or well logs) in the same formation is proposed for injection.

When the fracture gradient or depth to top perforation changes, the formation fracture pressure will be recalculated. The Permittee will also submit fluid analysis that reports SG annually. In the above, a factor of 0.05 has been added to the SG. This adjustment factor allows for the MAIP to be recalculated only if the newly submitted SG is greater than 0.05 from the previous year's SG, without exceeding the fracture pressure of the formation. A MAIP due to the SG change will only be recalculated if the absolute difference of the newly submitted SG and that of the previous year is greater than 0.05.

The new permitted MAIP will become effective when the Director has provided written notification. The Permittee may also request a change to the MAIP by submitting the necessary documentation to support a recalculation of the MAIP.

As discussed above, the formation fracture pressure calculation sets the MAIP to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the injection zone(s). However, it may be that the condition of the well may also limit the permitted MAIP. When external (Part II) MIT demonstrations (such as a temperature survey or radioactive tracer test) are required, the tests required to make this demonstration must be conducted at the permitted MAIP based on the calculations described above. If during testing, the Permittee is unable to achieve the pressure at the permitted MAIP, the new permitted MAIP will be set at the highest pressure achieved during a successful external (Part II) MIT and not the calculated MAIP.

TABLE 5.1 provides an estimated formation fracture pressure based on the information submitted with the application. The permitted MAIP will be recalculated with the information submitted to obtain the re-authorization to commence injection.

TABLE 5.1
Injection Zone Fracture Pressure

Formation Name or Stratigraphic Unit	Depth (ft.)	Specific Gravity	Fracture Gradient (psi/ft.)	Friction Loss (psi)	Estimated Formation FP (psi)
None	4023	1.002	1.04	4.57	2350

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Annual Pressure Falloff Test (40 CFR § 146.13(d)(1))

The pressure falloff test is required for Class I operations and must be performed at least once every twelve months for the purposes of monitoring pressure buildup in the injection zone, to monitor reservoir parameters, to identify any fracturing, and to identify any boundaries within the injection formations.

Annual monitoring of the pressure buildup in the injection zone includes a shutdown of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

Injection Well Monitoring Program

Continuous monitoring of injection pressure, injection flow rate, injection volume, cumulative fluid volume, bradenhead and TCA pressures shall be at the wellhead. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. If the continuous monitoring is carried out with a continuous chart recorder: 1) to monitor the injection, annulus, and bradenhead pressures, the chart shall be of a scale that allows changes in pressure of 5 psi to be detected and 2) to monitor the injection volume and injection rate the chart shall be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected. Monthly averaged, maximum, and minimum values for injection pressure, flow rate and volume, and bradenhead and annular pressure is required to be reported as part of the Quarterly Report to the Director.

Reporting Requirements
Quarterly, the Permittee must analyze a sample of the injected fluid for parameters specified in APPENDIX D of the Permit. This analysis must be reported to EPA as part of the Quarterly Report to the Director. Any time a new source is added, a fluid analysis must be provided of the injection fluid that includes the new source as discussed above, in PART V Injection Fluid Limitation.

PART VII. Plugging and Abandonment Requirements (40 CFR § 146.10)

Plugging and Abandonment Plan
Prior to abandonment, the well must be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable federal, state or local law or regulation. Tubing, packer and other downhole apparatus must be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement must be verified by tagging. A minimum 50 ft surface plug must be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface.

Within thirty (30) days after plugging the owner or operator must submit Plugging Record (EPA Form 7520-14) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in APPENDIX E of the Permit.

PART VIII. Financial Responsibility (40 CFR § 144.52(a)(7))

Demonstration of Financial Responsibility
The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The Permittee will show evidence of such financial responsibility to the Director by the submission of completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,
(b) a letter of credit with a standby trust agreement,
(c) a fully funded trust agreement, OR
(d) an independently audited financial statement with a Chief Financial Officer's letter.

The Director may, on a periodic basis, require the holder of a ten year (10) permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility, if necessary. The Permittee, may also upon written request provide an alternative demonstration of financial responsibility.

If a financial statement is provided, evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Other Federal Law (40 CFR § 144.4)

The EPA will ensure that issuance of this Permit is in compliance with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act (NHPA), the Endangered Species Act (ESA), and Executive Order 12989 (Environmental Justice), before a final permit decision is made.

EPA has determined that issuance of Permit Number CO10044-00055 for the Garcia No. 1 Injection Well is in compliance with the laws, regulations, and orders described at 40 C.F.R. § 144.4, including the NHPA and ESA.

National Historic Preservation Act (NHPA)
Section 106 of the National Historic Preservation Act, 54 U.S.C. § 306108, requires federal agencies to consider the effects on historic properties of actions they authorize, fund or carry out. The EPA has determined that a decision to issue a Class I injection well permit for authorization of injection into the Garcia No. 1 well constitutes an undertaking subject to the NHPA and its implementing regulations at 36 CFR part 800.

Huerfano County and several participating jurisdictions prepared the local hazard mitigation plan to guide hazard mitigation planning in order to better protect the people and property within the county from the effects of hazardous events. Thirteen historical properties were identified in the plan. The county identified rules and procedures for safeguarding historical properties and artifacts in the Huerfano Plan.

TABLE 9.1
ARTIFACTS AND HISTORICAL ARCHITECTURE

HUERFANO COUNTY HISTORIC PROPERTIES/DISTRICTS IN STATE AND NATIONAL REGISTERS		
Property Name	**City**	**Location**
Montoya Ranch	Farisita	Address Restricted
La Veta Pass Narrow Gauge Railroad Depot	La Veta	Off U.S. 160
Lamme Hospital	La Veta	314 S. Main Street
Veta Pass	La Veta	3652, 3665, 3688 Cty. Rd. 443
La Veta Masonic Hall	La Veta	210 S. Main Street
Francisco Plaza	La Veta	312 S. Main Street
Huerfano County Courthouse and Jail	Walsenburg	400 Main Street
Maitland Arroyo Bridge	Walsenburg	CO 69 at Milepost 3.0
Huerfano County High School	Walsenburg	415 Walsen Ave
Fox Theater	Walsenburg	715 Main Street
Huerfano County High School	Walsenburg	401 Main Street
Roof & Dick Building	Walsenburg	600 Main Street/109 E. 6th Street
St. Mary School, Convent, Rectory & Church	Walsenburg	121 and 201 E. 7th Street and 726 Russel Street

This project has been in operation since the 1980's. No surface disturbance will occur as a result of the permit reissuance as this project has the necessary existing infrastructure. Furthermore, the historical properties are located several miles from the Garcia well and all production and injection activities. The surrounding cities with artifacts are located outside of the ¼ mile AOR according to information pulled from Google Earth database: Farisita (approximately 8.5 miles away); La Veta (approximately 19 miles away); and Walsenburg (approximately 25 miles away). Therefore, reissuance of Permit No. CO10044-00055 to allow continued injection into the Garcia No. 1 well will not affect any documented artifacts or historical properties in Huerfano County, Colorado.

Endangered Species Act (ESA)
Section 7(a)(2) of the Endangered Species Act, 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. The EPA has determined that a decision to reissue a Class I permit for authorization of injection into the Garcia No. 1 well would constitute an action that is subject to the ESA and its implementing regulations (50 CFR part 402). Accordingly, EPA's determination (noted below) will be documented as part of the administrative record supporting this decision.

A species list has been prepared by the Colorado Ecological Services Field Office for the AOR. This information was obtained from the IPAC database. There is a total of four (4) threatened, endangered or candidate species on the species list.

TABLE 9.2
THREATENED AND ENDANGERED SPECIES LIST

SPECIES TYPE	SPECIES NAME	STATUS
Mammal	Canada Lynx (Lynx canadensis)	Threatened
Mammal	North American Wolverine Gulo (gulo luscus)	Proposed Threatened
Bird	Mexican Spotted Owl (Strix occidentalis lucida)	Threatened
Fish	Greenback Cutthroat Trout (Oncorhynchus clarkii stomias)	Threatened

Existing field activities are not expected to harm the threatened species in the area. There are no critical habitats within the project area for the species identified above.

Continued injection into the Garcia No. 1 well is not expected to endanger any threatened or endangered species and proposed species in the area. Twenty-seven Entrada and Dakota formation wells produce fluids which are treated at five treatment facilities. Production fluids are collected from five treatment facilities which are located within the Sheep Mountain Field. These fluids are transported by the operator's trucks on established roads within the Sheep Mountain Field, located on the operator's property, and also travels for a short period on Highway 562. Fluids are transferred from the trucks to a settling and feed tank prior being disposed through the Garcia No.1 injection pad. Hose lines attach to a connection point which introduces the fluid into the injection system. Injection Pumps are located in an enclosed building. The Garcia No. 1 injection well, pump house and two tanks are located on a pad which has containment. All of the infrastructure is complete and has in place since the 1980's. The only feature near the disposal well site is a creek, where runoff water from two man made ponds is collected during most of the year. Within the ¼ mile radius AOR there are no wells that penetrate the Dakota sandstone formation. Trucks transport the fluid approximately two (2) to three (3) loads per week.

Huerfano county has specific rules that operators must follow to protect endangered and proposed species. The project has the necessary existing infrastructure. Trucking of fluids and subsurface injection timeframes are restricted to protect species in the area. The project will allow fluids to be disposed into the Dakota Formation which is a non-USDW and exists below the surface at a depth of 4030 ft. The surface and longstring casing will be cemented behind pipe at the depths of the shallow aquifers and injection will occur below the confining zone to restrict fluid disposal activities to the Dakota Formation and protect USDWs.

Therefore, reissuance of Permit No. CO10044-00055 to allow continued injection into the Garcia No. 1 well will have no effects on any federally-listed endangered or threatened species or their designated critical habitat.

Executive Order 12898

On February 11, 1994, the President issued Executive Order 12898, entitled “Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations.”

The EPA’s UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. The EPA has concluded that the specific conditions of UIC Permit CO10044-00055, Garcia No. 1 well will prevent contamination to USDWs, including USDWs which either are or could be used in the future by communities of EJ concern. The UIC program will be conducting enhanced public outreach to EJ communities by publishing a public notice announcement in local newspapers and holding a public hearing, if requested, or if public interest in the proposed permit is high. Furthermore, no surface-disturbing activities are associated with a lease sale and; therefore, impacts from the lease sale would not disproportionately adversely affect environmental justice populations.