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

Andrea Rasey
andrea.rasey@kodares.com

Re: Draft Permit - UT22420-12015, RZA 14B1-34A

Dear Ms. Rasey:

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 EPA's website at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy.

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, will be published in the following newspapers(s):

Uintah Basin Standard
Vernal Express

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 Chris Brown at brown.christopher.t@epa.gov.

Sincerely,

12/22/2020

X Sarah Bahrman

Signed by: SARAH BAHRMAN

Sarah Bahrman, Chief
Safe Drinking Water Branch

Enclosures

cc:
Uintah & Ouray Business Committee

Luke Duncan, Chairman
Tony Small, Vice-Chairman
Kirby Arrive, Executive Director
Shaun Chapoose, Councilman
Edred Secakuku, Councilman
Ronald Wopsock, Councilman
Sal Wopsock, Councilman

Antonio Pingree, Acting Superintendent
BIA – Uintah & Ouray Indian Agency

Bruce Pargeets, Energy & Minerals Department Director
Ute Indian Tribe

Waylan Poowegup, Natural Resources Director
Ute Indian Tribe

Dayne Doucet, Oil and Gas Permitting Manager
Utah Division of Oil, Gas, and Mining

Jerry Kenczka, Assistant Field Manager for Lands & Minerals
BLM - Vernal Office

Landon Newell
Southern Utah Wilderness Alliance

Karl Biermann, Production Engineering Manager
Middle Fork Energy Uinta, LLC

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

DRAFT PERMIT

UT22420-12015

Class II Salt Water Disposal Well

RZA 14B1-34A
Uintah County, Utah

Issued To

Middle Fork Energy Uinta, LLC
1515 Wynkoop Street, Suite 650
Denver, Colorado 80202

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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),

Middle Fork Energy Uinta, LLC
1515 Wynkoop Street, Suite 650
Denver, Colorado 80202

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

RZA 14B1-34A
420' FEL & 2516' FSL, Section 33, Township 7S, Range 22E
Uintah County, Utah
43-047-56095

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, EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). EPA UIC permit conditions are based on authorities set forth in 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 Indian country injection wells in Utah are found in 40 CFR § 147.2253.

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 the operating life of the facility or until it expires under the terms of the Permit, unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41, and shall be reviewed at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

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.

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

1. 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 § 146.22. Remedial construction measures may be required if the well is unable to demonstrate mechanical integrity.

2. 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.

3. 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; and

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

4. Pre-Injection Logs and Tests

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

5. Postponement of Construction or Conversion to Injection Wells

(a) For wells to be newly drilled, the Permit shall expire if well construction has not begun within two years of the Effective Date of the Permit.

(b) The Permittee may request a one-time extension of the permit expiration date, not to exceed two additional years, which must be made prior to expiration of the Permit. Notification shall be in writing and state the reasons for the delay, provide an estimated completion date, and list additional wells within the area of review (AOR) that were not included in the initial permit application. For those newly completed AOR wells that penetrate the upper confining zone, a well construction diagram, cement records and cement bond logs are also required.

Once the Permit has 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.

(c) For wells that have begun construction or are conversions to an injection well, if authorization to inject has not been provided within two years of spud date or the Effective Date of the Permit, respectively, the Permittee is subject to the conditions found in Part II, Section E.5. *Wells Not Actively Injecting* or may elect to convert the well to a non-UIC well found in Part III, Section A.2 *Conversion to Non-UIC Well*.

Section B. WELL OPERATION

1. *Outermost Casing Injection Prohibition*

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

2. *Requirements Prior to Receiving Authorization to Inject*

Well injection may commence only after all well construction and pre-injection requirements have been met and a written authorization to commence injection has been obtained from the Director.

In order to obtain written authorization to inject, the following must be satisfied:

(a) The Permittee has:

(i). submitted to the Director a notice of completion of construction and a completed EPA Form 7520-18 and required attachments. If the well construction is different than the approved construction found in APPENDIX A, the Permittee shall also provide a revised well diagram and a description of the modification to the well construction;

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

(iii). satisfied requirements for corrective action in APPENDIX F, if applicable.

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

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

3. *Injection Zone and Fluid Movement*

Injection zone means “a geological formation, group of formations, or part of a formation receiving fluids through a well.”

Injection 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.4 *Injection Pressure Limitation* that may result in a change to the permitted MAIP.

4. Injection Pressure Limitation

(a) Injection pressure at the wellhead shall not initiate new fractures or propagate existing fractures in the confining zone. In no case shall injection pressure cause the movement of injectate or formation fluids into a USDW.

(b) Except during stimulation or other well tests approved by EPA, injection pressure shall not exceed the MAIP. The MAIP, as measured at the surface, shall equal the formation fracture pressure (FP**)** plus friction loss.

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.

The current permitted Maximum Allowable Injection Pressure (MAIP) is found in APPENDIX C. This MAIP is calculated using the equation above and data submitted with the permit application.

(c) To determine the MAIP, the Permittee shall submit prior to authorization to inject the following for review: step rate test results to determine the fracture gradient, fluid analysis from a representative sample of the injectate that provides specific gravity, and a revised well diagram (if construction is different than the approved construction found in APPENDIX A, that specifies the depth to top perforation.) The MAIP shall be calculated as described above. The Director will review the information and provide the MAIP in the written authorization to commence injection.

(d) 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 values, 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.

(e) 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.

5. Injection Volume Limitation

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

6. Injection Fluid Limitation

Injected fluids are limited to those identified in 40 CFR § 144.6(b) as fluids: (1) which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, (2) used for enhanced recovery of oil or natural gas, and (3) used for storage of hydrocarbons which are liquid at standard temperature and pressure. Non-exempt wastes, including, but not limited to, unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are not approved for injection. This well is not approved for commercial brine injection or other fluid disposal operations.

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*.

7. 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.

8. 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.

9. 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.

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) Prior to receiving authorization to inject 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 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 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 EPA to witness the MIT or 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 D.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, for a period of at least (3) years from the date of the sample, measurement, or report. 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. Annual Reports

Regardless of whether or not the well is operating, the Permittee shall submit an Annual Report 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 first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. 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 the EPA form indicates otherwise. An electronic form may also be obtained from 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.

Section F. MEASURES FOR PROTECTION OF ENDANGERED SPECIES

The EPA is proposing a no effect finding as a result of issuing this UIC Permit. However, mitigation measures were undertaken for the subject well pad during the construction phase that included the RZA 14B1-34A and RZA 15A1-33A production wells. During the well's conversion to a UIC Class II well, Middle Fork Uinta will follow these mitigation measures as documented in the following Environmental Assessment (EA):

DOI-BLM-UT-G010-2019-0005-EA
February 2019
Vernal Field Office
170 South 500 East
Vernal, Utah 84078

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. 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 C. CONFIDENTIALITY

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 CFR part 2 (Public Information). Claims of confidentiality for the following information will be denied:

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

Section D. 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 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 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 E. 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 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 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 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 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 EPA and shall demonstrate that the Permittee meets or exceeds certain financial ratios. The Permittee must meet 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 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:

- Cemented casing shall be cemented from the casing shoe to the surface and care shall be taken to maximize cement fill and bond in the annulus behind the casing.
- The casing and cement used in the construction of the well shall be designed for the life expectancy of the well, including the natural and applied pressures expected during the life of the well.
- When drilling the surface hole, unless waived by the Director, air or mud made with water containing no additives and no more than 3,000 mg/L TDS shall be used. At no time shall the permittee conduct any activity that endangers any USDW, as prohibited by 40 CFR § 144.12.
- The well shall be completed with injection tubing set on at least one packer.
- The uppermost packer must be set within 100 feet of the uppermost open perforation.

WELL CONSTRUCTION:

Conductor casing: 16-inch (") diameter, Grade H-40, 65 pounds per foot (lbs/ft), depth from 0 to 150 feet-below ground surface (ft-bgs), cemented from 150 ft-KB to surface.

Production casing: 9-5/8" diameter, Grade L-80, 40 lbs/ft, depth from 0 to 4,229 feet-measured depth (ft-MD), cemented from 4,229 ft-MD to surface.

Injection tubing: 3-1/2" diameter, Grade L-80 EUE, 9.3 lbs/ft, internally plastic, coated tubing, depth from 0 to 3,580 ft-MD, Arrowset nickel coated injection packer set at approximately 3,580 ft-MD.

Perforations: Limited to the injection zone described in Appendix C. The final perforated interval shall be reported with information submitted as part of information submitted to fulfill the requirements list in Part II, Section B.2.

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*.

INJECTION WELL CONSTRUCTION DIAGRAM

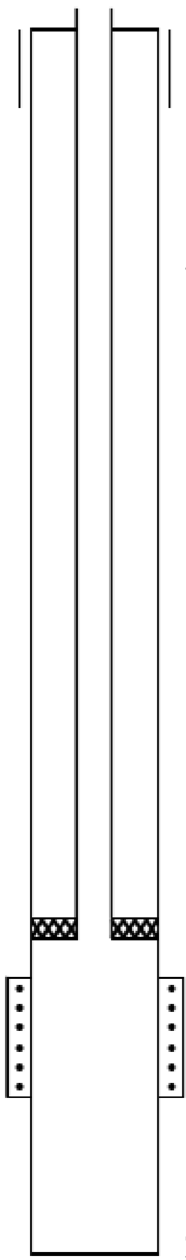
FIELD: **Red Wash Unit**	GL: 5,361 ' KB: 5,392 '	Spud Date: 05/24/2019 Date of last work: N/A
Well: **RZA 14B1-34A**	TD: 4,253 ' PBTD: 4,091' WLM	Current Well Status: Permitting

Location - surface: (420' FEL-2,516' FSL) NESE of Sec. 33, T7S-R22E
Location - bottom hole: (389' FWL-1,850' FSL) NWSW of Sec. 34, T7S-R22E
API#: 43-047-56095 Uintah County, Utah

Reason for Pull/Workover: Convert to disposal well.

Deviation: Deviated; KOP at 200' MD; Max inclination of 20.4° at 4,106' MD.

Wellbore Schematic



Conductor Casing:
Size: 16"
Weight: 65.0 #/ft
Grade: H-40
Set @ 150'
Cmtd w/ Surface
Hole size: 20"

Uinta @ Surface

TOC @ Surface (circulated)

Green River Top @ 3,075'

Packer @ ± 3,580'

Bird's Nest Top at 3,619' MD

Production Casing:
Size: 9-5/8"
Weight: 40 #/ft
Grade: L-80
Bottom @ 4,229' MD
Cmtd w/ 1,432 sx
Hole size: 13.50"
Circ cmt to surface (223 bbls).

PBTD: 4,091' WLM (CBL)
9-5/8" Shoe @ 4,229' MD
TD: 4,253' MD

Tubing Landing Detail:

Description	Size	Footage	Depth
KB		30.00	30.00
3-1/2", 9.3 #/ft L-80 EUE 8rd	3.50"	3,540.00	3,570.00
3-1/2" x 4" Crossover	3.50"	3.00	3,573.00
Arrow Set Injection Packer	9-5/8"	7.00	3,580.00
Injection Packer / EOT @		±	3,580.00

Tubing Information:
Condition:
New: X Used: Rerun:
Grade: L-80
Weight (#/ft): 9.3 #/ft

SUMMARY
Injection will occur thru perforations in the Birds Nest Fm.

Top of Bird's Nest interval is at 3,619' MD.

Exact perforation interval to be determined based on Cased Hole Neutron / GR log.

Perforation density will be 2 JSPF.

3-1/2" Injection Tubing to be internally plastic coated.

9-5/8" Injection packer will be nickel coated.

Wellhead will be standard carbon steel trim.

Prepared By: Andrea Rasey / OLP Date: July 23, 2020

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

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

Well logs and test results shall be submitted to the Director within sixty (60) 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 (EDIT AS NECESSARY – MAKE SURE THIS LIST MATCHES EXCEL UPLOAD)

TYPE OF LOG OR TEST	DATE DUE
Well logs and test results shall be submitted to the Director within sixty (60) 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. Within 30 days after Authorization to Inject 2. Annually 3. Prior to the introduction of a new source
Injection Zone Water Sample A representative water sample from each discrete injection zone shall be analyzed. The list of constituents for analysis shall be submitted for approval prior to collection of the injection zone water sample. After purging a minimum of three successive wellbore volumes, a representative sample shall be determined by stabilized specific conductivity. A log recording data (e.g. initial fluid level, volume purged with each swab run, fluid level in between swab runs, specific conductivity after each swab run, etc.) gathered throughout well purging activities shall be recorded and reported with the water sample results. The sampling procedure should follow immediately after perforating an interval in order to prevent wellbore fluids from contaminating the naturally occurring injection formation water.	Prior to receiving Authorization to Inject
Injection Formation Fluid Pressure	Prior to receiving Authorization to Inject
Logging While Drilling Any logs obtained while drilling the well and not submitted with the permit application.	Prior to receiving Authorization to Inject
Surface and Production Casing and Cemented Liner **Cement Evaluation Logs (CBL or CET)** The log shall cover the area of the cementing to verify the adequacy and location of the cement placement.	1. Prior to receiving Authorization to Inject 2. Shall be performed within sixty (60) days after the completion of any workover involving remedial cementing. Not required for surface casing.

Cement Records	Prior to receiving Authorization to Inject
Step Rate Test (SRT) The SRT shall be performed following current EPA guidance. The SRT shall be conducted with both surface and bottom-hole pressure gauges. This requirement may be waived with a written approval from the Director.	Prior to receiving Authorization to Inject
Standard Annulus Pressure (internal Part I MI) If the well has not received authorization to inject and does not have tubing installed, in lieu of the Standard Annulus Pressure test, a Casing Pressure Test can be performed.	1. Prior to receiving Authorization to Inject or within two (2) years of the permit effective date. 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.
Radioactive Tracer Survey (RTS) If the Director's review of the cement bond log does not show 80% bond index, an RTS is required.	1.Prior to receiving Authorization to Inject 2. 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) If the Director's review of the cement bond log does not show 80% bond index, a temperature log is required.	1. Baseline temperature log required prior to receiving Authorization to Inject. 2. Initial temperature log will be conducted between 6 to 12 months after Authorization to Inject. 3. Subsequent logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.

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.) *
Birds Nest	3,501	3,901

*estimated top and bottom depths of formations in ft-True Vertical Depth (TVD)

MAXIMUM ALLOWABLE INJECTION PRESSURE:

The parameters below are the estimated values used to calculate the initial, temporary MAIP issued with this Permit. A step rate test is required in Appendix B prior to receiving authorization to inject, and the permitted MAIP will be recalculated with the information submitted to obtain the authorization to commence injection. 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)**
0.58	1.062	3501	N/A	420	^

*From the MAIP equation in Part II, Section B.4(b), 1.012+0.05 or 1.062
^ Dependent upon Step Rate Test results

MAXIMUM INJECTION VOLUME:

There is no limitation on the fluid volume permitted to be injected into this well. However, the AOR shall be expanded to one-half (1/2) mile once the cumulative injection volume in the well reaches 12,673,347 barrels. This one-half (1/2) mile AOR expansion shall extend from the surface to the base of the injection zone in the deviated well. The results of the expanded AOR shall be submitted with the annual report and include the information required in Part II, D.4 for EPA review, comment, and approval. If determined necessary by the Director, an updated corrective action plan shall be appended to Appendix F. The Director may subsequently request that the AOR be reevaluated and expanded further if necessary, using the criteria in 40 CFR 146.6 to ensure that fluids will remain within the injection zone.

If an aquifer exemption is required and approved for this Permit, then a volume limit will be set based on the conditions of the aquifer exemption, through the modification process.

APPENDIX D

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. An electronic form may also be obtained from EPA to satisfy reporting requirements.

OBSERVE WEEKLY AND RECORD MONTHLY	
OBSERVE AND 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)

WITHIN 30 DAYS AFTER AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE ***AND*** **ANNUALLY (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 Alternative analysis methods may be used, if pre-approved.

ANNUALLY	
REPORT	Each month's maximum and average injection tubing pressures (psi)
	Each month's maximum and minimum annulus pressures (psi)
	Each month's maximum and minimum bradenhead pressures (psi)
	Each month's 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.

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 and packer shall be pulled.
- Cement plugs shall have sufficient compressive strength to maintain adequate plugging effectiveness.
- 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.
- 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/L 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 ~9.2 pound per gallon (ppg) plugging fluid.
   PLUG 1: Squeeze the entire perforated interval of the injection zone with a sufficient volume of cement, including any excess, to cover the injection zone. Set a cast iron bridge plug (CIBP) within the innermost casing string within 50 feet above the top perforations.

   PLUG 2: Place a minimum of 50 sacks of Class "G" cement plug on the top of the CIBP.

2. **Isolate Shallow USDWs from the Injection Zone**:
   PLUG 3: Set a minimum 200-foot cement plug approximately 50 feet above the contact between the Uinta Formation and top of the Green River Formation to 150 feet below the contact between the Uinta Formation and top of the Green River Formation.

3. **Isolate Surface Fluid Migration Paths**:
   PLUG 4: Set a cement plug inside the innermost casing string from 240 feet to the surface.

INJECTION WELL P&A DIAGRAM

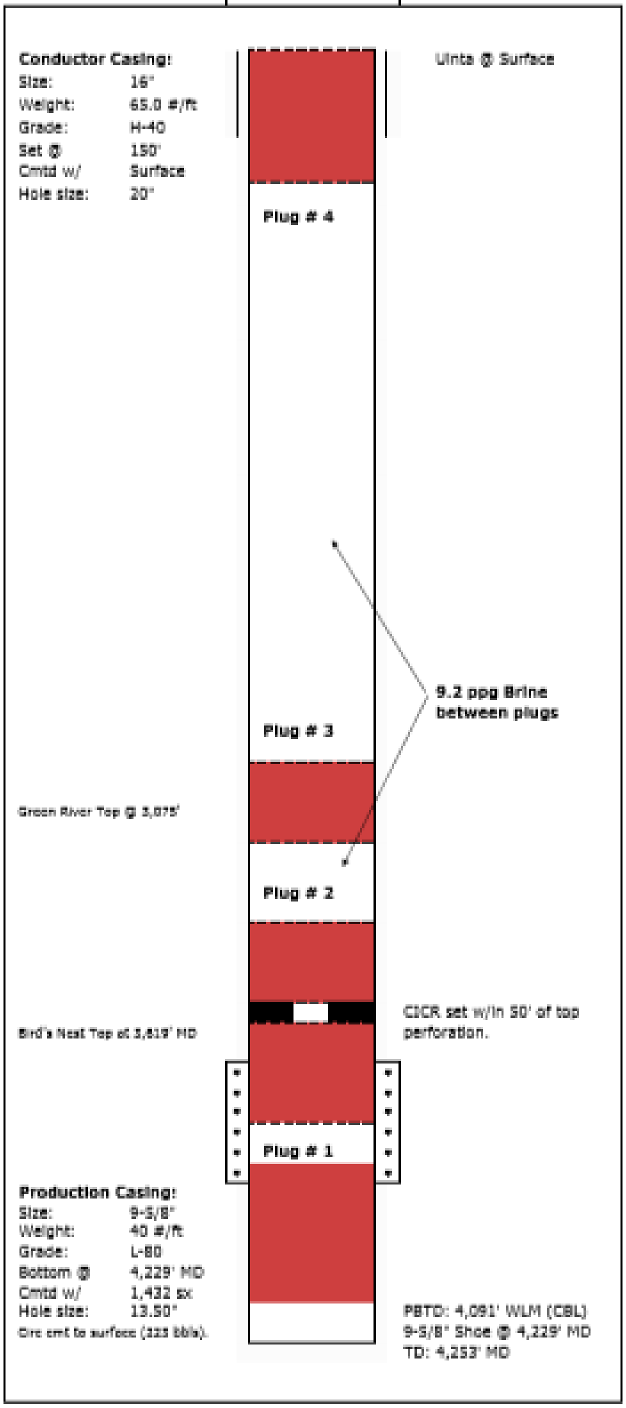
FIELD: **Red Wash Unit**	GL: 5,361 ' KB: 5,392 '	Spud Date: 05/24/2019 Date of last work: N/A
Well: **RZA 14B1-34A**	TD: 4,253 ' PBTD: 4,091' WLM	Current Well Status: Permitting

Location - surface: (420' FEL-2,516' FSL) NESE of Sec. 33, T7S-R22E
Location - bottom hole: (389' FWL-1,850' FSL) NWSW of Sec. 34, T7S-R22E
API#: 43-047-56095 Uintah County, Utah

Reason for Pull/Workover: Plug & abandonment plans for wellbore.

Deviation: Deviated; KOP at 200' MD; Max inclination of 20.4° at 4,108' MD.

Wellbore Schematic



Plugging Procedure:

1. MIRU WO rig. ND WH. NU & test BOPE.
2. TOOH & LD injection tubing & packer.
3. TIH with 8-3/4" bit and 9-5/8" casing scraper & 2-7/8" work string.
4. Clean well out to a minimum depth of 100' below top perforation.
5. TIH with CICR and set within 30' of top perforation.
6. Spot 180 sx. of Class "G" Neat Cement (486 ft of coverage). Plug # 1.
7. Pull out of CICR; spot 50 sx of Class "G" Neat on top of CICR. Plug # 2. Spot a 30 bbl pill of 9.2 ppg brine on top of Plug # 2.
8. TOOH and spot a balanced 50 sx plug of Class "G" Neat across the Green River Formation (~3,100'). Plug # 3.
9. Spot a 207 bbl pill of 9.2 ppg brine on top of Plug # 3.
10. Plug # 4 is to seal the surface. Will set a 90 sx Class "G" Neat plug (240 ft plug).
11. Dig down and cut off wellhead. Weld on flat plate with weep hole. Plate to be not less than 1/4" thick with Operator Name; Lease Serial #, Well #, Section, Township, Range & Qtr-Qtr.
12. Location reclamation to commence after P&A acceptance by State & Federal regulatory agencies.

NOTE: All cement will be Class "G" Neat cement; 15.80 ppg, 5.0 gallons/sx of water; 1.15ft^3/sx yield. 9-5/8" 40 #/ft casing = 0.4257 ft^3/ft capacity.

Prepared By: Andrea Rasey / OLP Date: October 21, 2020

APPENDIX F

CORRECTIVE ACTION PLAN

No corrective action is required at this time as EPA's evaluation did not identify migration pathways within the one quarter (1/4) mile AOR; however, corrective action requirements may be appended to this section following expansion of the AOR and subsequent analysis required in Appendix C.

STATEMENT OF BASIS

Middle Fork Energy Uinta, LLC
RZA 14B1-34A
Uintah County, Utah

Class II Salt Water Disposal Well
UT22420-12015

CONTACT: Christopher Brown
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (303) 312-6669
Email: Brown.Christopher.T@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 UT22420-12015 (Permit).

U. S. Environmental Protection Agency (EPA) UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water (USDWs). EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 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 Indian country injection wells in Utah are found at 40 CFR § 147.2253.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of the injection well or wells so that the injection does not endanger USDWs. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR § 144.40 and can be modified or revoked and reissued under 40 CFR § 144.39 or § 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to an approved state or tribal program, unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a tribal or state permit.

PART I. General Information and Description of Project

Middle Fork Energy Uinta, LLC
1515 Wynkoop Street, Suite 650
Denver, Colorado 80202

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

RZA 14B1-34A
420' FEL & 2516' FSL, Section 33, T7S, R22E
Uintah County, Utah

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.

Project Description

The Permittee is proposing to convert the existing RZA 14B1-34A well to a Class II Salt Water Disposal (SWD) well. The well was spudded on May 24, 2019 and was completed as a deviated well to a total depth of 3,901 feet-True Vertical Depth (ft-TVD). The well has not yet been perforated. The Permittee has proposed a maximum daily injection rate of 15,000 barrels per day (bbl/d) and average daily injection rate of 7,500 bbl/d with an expected well life of 20 years. The estimated cumulative injection volume during the expected well life is 54,787,500 bbl of Class II fluids described in the fluid limitation section below.

PART II. Permit Considerations (40 CFR § 146.24)

Hydrogeologic Setting

The Uinta Basin is located in the northeastern corner of Utah and is comprised of more than 18,000 ft of sedimentary rocks at its deepest. It is bounded to the north by the Uinta Mountains, to the east by the Douglas Creek Arch, to the south by the Tavaputs Plateau, and to the west by the Wasatch Mountains. The RZA 14B1-34A well is located in the central eastern portion of the basin.

The RZA 14B1-34A well proposes injection within the Birds Nest Zone of the upper Green River Formation. The Eocene Green River Formation contains sediment deposited from an interior lake basin system (Lake Uinta) that covered a significant area of northeastern Utah, western Colorado, and southwestern Wyoming. The upper Green River Formation represents a transition to a shrinking lake basin and the formation of the saline mineral Nahcolite in deep lake sediments. After deposition, fracture zones present within Nahcolite rich intervals of the upper Green River Formation were filled with the saline mineral Shortite.

The Birds Nest Zone is a fracture rock aquifer created by the dissolution of saline minerals from groundwater flow within a predominantly impermeable oil shale matrix. The lower Green River Formation is comprised of deltaic sands interbedded with organic rich muds of lacustrine origin. Table 2.1 provides a summary of information regarding known or estimated TDS concentrations above, below, and within the proposed injection zone.

TABLE 2.1
Hydrogeologic Setting

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Uinta	0	3,075	Conservatively assumed <10,000 at a transition zone occuring within this interval$_1$	Calcareous shale, mudstone and sandstone; some limestone and alluvial deposits; shallow sands may be fresh-water bearing, deeper sands likely to have higher TDS with variable hydrologic continuity.
Upper Green River	3,075	3,501	>10,000$_2$	Limestone, shale, sandstone. Characteristically comprised of mixed lithologies due to fluctuating lake bottom and lake-margin depositional conditions; carbonate mudstone deposition in standing water of Lake Uinta especially during evaporative conditions, including basin scale reservoir in dissolution zones of "Birds Nest" interval; kerogen rich intervals ("oil shale" of Mahogany zone); locally extensive high-TDS water bearing sands in middle Green River; local oil-bearing sandstone and ostracodal dolomitic limestone reservoirs present in lower third of the formation. The Green River formation interfingers both the overlying Uinta and underlying Wasatch formations.
Birds Nest Zone (Injection Zone)	3,501	3,901	11,296 - 21,095	Limestone, shale, dolomite. The Birds Nest zone consists almost entirely of porous and permeable sandstones interbedded with lower permeability siltstones, marlstones, and minor shale breaks. Nodular Nahcolite, approximately 0.5 to 1.5 feet in diameter, is common throughout the Birds Nest aquifer. The dissolution of

				the Nahcolite nodules creates the extensive porosity and permeability needed for significant groundwater storage and flow within the Birds Nest aquifer.
Lower Green River	3,901	4,800	>10,000[2]	See above description for Upper Green River Formation.
	4,800	6,457	<10,000[1]	

* depths are approximate values at the wellbore

[1] Additional discussion included in the Underground Sources of Drinking Water Section below.

[2] Based on a limited review of sample results within the corresponding interval in the general vicinity and identified in the United States Geologic Survey Produced Water Database v2.3.

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 is listed in TABLE 2.2. The injection zone is approximately 400 ft. thick with a total estimated porosity thickness of 160 to 200 ft.

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.

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	Estimated Porosity	Exemption Status
Birds Nest Zone	3,501	3,901	2.5-10.5%	TBD[1]

* depths are approximate values at the wellbore in ft-TVD.

[1] Exemption status to be determined (TBD) following collection of a formation water quality sample.

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.

Both the upper and lower confining zones occur within the Green River Formation. The upper confining zone is 466 feet thick and occurs above the Birds Nest Zone to the base of the Uinta Formation occuring at 3,075 ft-TVD. This interval was estimated by the Permittee to be comprised of 69% shale with a permeability less than 0.001 millidarcies. The lower confining zone is 101 feet thick and occurs from the base of the Birds Nest Zone to the top of the Mahogany Zone. This interval was estimated by the Permittee to be comprised of 90% shale with a permeability less than 0.001 millidarcies. There are reportedly no known geologic features such as faults, fractures, or Gilsonite veins that cross-cut the upper or lower confining zones.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)	Lithology
Green River (Upper Confining Zone)	3,075	3,501	Limestone, shale, sandstone.
Green River (Lower Confining Zone)	3,901	3,990	Shale, sandstone.

* depths are approximate values at the wellbore in ft-TVD.

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 total dissolved solids (TDS), are considered to be USDWs.

The Permittee reported that there are no known USDWs above the Birds Nest Zone but indicated that shallow sands of the Uinta Formation may contain fresh water. A review of the Utah Division of Water Rights online database did not reveal any permitted shallow groundwater rights located within the AOR. Additionally, a review of geophysical logs available in the Utah Division of Oil, Gas and Mining online data explorer did not reveal any open-hole logs within the AOR logged high enough to evaluate whether shallow sands of the Uinta Formation contain fresh water. An estimate of the TDS concentration (Na-Cl equivalent) from open-hole resistivity and density porosity logs available for the OU GB 5W-17-8-22 well located approximately 3.5 miles southwest of the RZA 14B1-34A well supported that estimated TDS concentrations below 2,220 feet are greater than 10,000 mg/L. Conversely, a review of the United States Geologic Survey (USGS) Produced Water Database v2.3 revealed one (1) sample exhibiting a TDS concentrations of 2,372 mg/L collected from the Uinta Formation between 2,624 and 2,651 ft. at the Red Wash Unit No. 39 well located approximately 2.8 miles northeast of the RZA 14B1-34A well. As a result, the presence of a USDW above the injection zone within the AOR could not be confirmed; however, a transition zone to TDS concentrations less than 10,000 mg/L has been identified within the Uinta Formation in other portions of the basin and is likely present at the location of the RZA 14B1-34A well. Future Class II permitting actions for new wells in central eastern portion of the Uinta basin should require open hole resistivity and density porosity logs run to surface in order to identify and delineate such a transition zone.

Water quality analysis collected from other wells completed in the Birds Nest Zone submitted by the Permittee suggests that the proposed injection zone is not a USDW. However, the permit requires the collection of a representative formation sample from the injection zone prior to receiving authorization to inject to verify the TDS concentration of the Birds Nest Zone. An aquifer exemption may be necessary if the formation sample collected from the proposed injection zone exhibits a TDS concentration less than 10,000 mg/L and this portion of the formation is determined to not be part of a pre-existing area aquifer exemption.

The Utah Geologic Survey approximated the depth to the base of moderately saline groundwater at 4,800 feet at the location of the RZA 14B1-34A well in Special Study No. 144. Moderately saline groundwater, as defined in the report, includes groundwater with TDS concentrations between 3,000 and 10,000 mg/L. There is limited available water quality sample data below the proposed injection zone in the vicinity of the RZA 14B1-34A well. However, a sample collected at the RW 32-33A well located northwest and just outside of the AOR exhibited a TDS concentration of 8,626 mg/L; the sample was reportedly collected from a depth of 5,746 feet in the Lower (relative to the proposed injection zone) Green River Formation. This sample result is consistent with the interpretation of moderately saline groundwater occurring below ~4,800 feet made by the Utah Geologic Survey. However, EPA aquifer exemption records indicate that this portion of the lower Green River Formation beneath the proposed well in the Red Wash Field was exempted as part of the State of Utah Class II primacy application.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Uinta	0	3,075	Conservatively assumed <10,000 at a transition zone occuring within this interval	Shale, mudstone, sandstone.

* depths are approximate values at the wellbore

PART III. Well Construction (40 CFR § 146.22)

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 well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluid containing any contaminant into USDWs. Well construction details for the injection well(s) are 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)*
Production	13.5	9.675	0-4,229	0-4,229
Conductor	20	16	0-150	0-150
Tubing	9.675	3.5	0-3,580	N/A

* depths are approximate values at the deviated wellbore in ft-MD.

Injection Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set within 100 feet above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the production casing.

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) pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the

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; and 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line.

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 applicants 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 (1/4) mile or a calculated zone of endangering influence. For area permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Since the existing well is deviated, the AOR encompasses a one quarter (1/4) mile buffer from the well surface location extending to the horizontal distance corresponding to the base of the injection zone at the bottom of the well. The well surface location is 420 ft. from the east line, 2,516 ft. from the south line of the NESE quarter-quarter in Section 33, Township 7 South, Range 22 East. The well bottom hole location at the base of the injection zone is 389 ft. from the east line, 1,850 ft. from the south line of the NWSW quarter-quarter in Section 34, Township 7 South, Range 22 East.

The permit includes a provision in Appendix C that the AOR shall be expanded to one-half (1/2) mile once a cumulative volume of 12,673,347 barrels has been injected into the well. This volume corresponds to an area of emplaced waste with a radius of one-quarter (1/4) mile. The area of emplaced waste was calculated using a simple radius-of volumetric fill-up equation using information supplied with the permit application. Additionally, this volume also corresponds to the approximate point at which the area of emplaced waste from the 14B1-34A will begin overlapping with the identical area of emplaced waste calculated for and included in the draft permit for the 14A1-33A well, which is co-located on the same well pad. The permit provides that additional corrective action may be required and appended to Appendix F if analysis of the expanded half-mile (1/2) AOR reveals additional wells, which as determined by the Director, require corrective action. The Director may subsequently request that the AOR be reevaluated and expanded further if necessary, using the criteria in 40 CFR 146.6 to ensure that fluids will remain within the injection zone.

Corrective Action Plan (CAP)
For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant will develop a CAP consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs. In addition, Part II, Section B.3 of the permit states that injection is only permitted within the approved injection zone and injected fluids must remain within the injection zone. As a result, corrective action may also be necessary to ensure injected fluids remain within the approved injection zone.

No corrective action is required at this time as EPA’s evaluation did not identify migration pathways within the one quarter mile AOR; however, corrective action requirements may be appended to this section following expansion of the AOR and subsequent analysis required in Appendix C of the permit. Specifically, two (2) wells (RW 34-33A and RW 32-33A) located to the northwest and outside of the current one quarter (1/4) mile AOR may necessitate corrective action upon expansion of the AOR to one half (1/2) mile.

TABLE 4.1 lists the wells in the AOR and shows the well type, operating status, depth, uncemented interval from well records and CAP required for the well. The CAP is incorporated into the Permit as APPENDIX F and becomes binding on the Permittee.

TABLE 4.1
CAP TABLE

AOR Well Name	Well Type	Operating Status	Total Depth (ft)*	Uncemented Interval (ft)*	Corrective Action
N/A					

PART V. Well Operation Requirements (40 CFR § 146.23)

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 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 prior to receiving authorization to inject and repeated 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.

External (Part II) MIT may be demonstrated by evaluation of the cement bond log to show that adequate cement exists to prevent significant movement of fluid out of the approved injection zone through the casing annular cement (i.e., 80% bond index cement bond across the confining zone.) Guidance on the logging and interpretation of the cement bond log (CBL) can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Should the CBL analysis show inadequate external Part II MI, additional periodic tests will be required at a frequency no less than every five years after the last successful test. These requirements are found in APPENDIX B Logging and Testing Requirements of the Permit.

Injection Fluid Limitation
Injected fluids are limited to those identified in 40 CFR § 144.6(b) as fluids (1) which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, (2) used for enhanced recovery of oil or natural gas, and (3) used for storage of

hydrocarbons which are liquid at standard temperature and pressure. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are not approved for injection. This well is not approved for commercial brine injection or other fluid disposal operations.

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 injecting 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

There is no limitation on the fluid volume permitted to be injected into this well. However, the AOR shall be expanded to one half (1/2) mile once the cumulative injection volume reaches 12,673,347 barrels. The results of the expanded AOR shall be submitted with the annual report and include the information required in Part II, D.4, and if determined necessary, an updated corrective action plan shall be appended to Appendix F. In no case shall injection pressure exceed the MAIP.

If an aquifer exemption is required and approved for this Permit, then a volume limit will be set based on the conditions of the aquifer exemption, through the permit modification process.

Injection Pressure Limitation

40 CFR § 146.23(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 confining zone adjacent to the USDWs. In lieu of testing the fracture pressure of the confining zone, which may be impractical, the pressure in the injection formation provides a conservative surrogate.

The calculated Maximum Allowable Injection Pressure (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 **MAIP** allowed under the permit, as measured at the surface, will be calculated according to the equations below. The Permit itself does not contain a specific MAIP value but instead requires that a MAIP be calculated using these equations. The Permit also specifies where the input values are derived from. Prior to authorization to commence injection, the Permittee must submit for review the necessary information to calculate the MAIP. After review of the submitted documents, the Director will notify the Permittee of the MAIP in the written authorization to commence injection.

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

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

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. 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 are added to the injection zone, 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 confining zones adjacent to USDWs. 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. A step rate test is required in Appendix B of the permit prior to receiving authorization to inject, the permitted MAIP will be recalculated with the information submitted to obtain the 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)
Birds Nest Zone	3,501	1.062	0.58	N/A	420

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
At least once a year 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 annually as part of the Annual 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.

Instantaneous injection pressure, injection flow rate, injection volume, cumulative fluid volume, bradenhead and TCA pressures must be observed on a weekly basis. A recording, at least monthly, must be made of that month's injected volume and cumulative fluid volume to date, the maximum and average value for injection tubing pressure and rate, maximum and minimum annulus and bradenhead pressures. This information is required to be reported annually as part of the Annual Report to the Director.

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. 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 and packer shall be pulled.
- Cement plugs shall have sufficient compressive strength to maintain adequate plugging effectiveness.
- 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.
- 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.

Within thirty (30) days after plugging the owner or operator must submit Plugging Record (EPA Form 7520-19) 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) a financial test and corporate guarantee.

The Director may, on a periodic basis, require the holder of a lifetime 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 test 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)

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

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. EPA has determined that a decision to issue a Class II injection well permit for authorization of injection into the RZA 14B1-34A well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800.

Prior to construction, Aros Archaeology, L.L.C. completed a literature review and Class III cultural resource survey of the Red Wash 33-7-22 Well Pad, Access Road, Powerline and Pipeline Corridors on Deadman Bench associated with the 14B1-34A and 15A1-33A wells in Uintah County, Utah. A total of 39.8 acres were examined on land administered by the Vernal Field Office Bureau of Land Management. No previously recorded sites were revisited or new cultural resource sites were recorded within the project's Area of Potential Effects (APE). A total of eight isolated artifacts were observed. The isolated artifacts are not significant. No further work or adjustment to well or infrastructure location is recommended for this project. A finding of No Historic Properties Affected was recommended pre-construction, and EPA correspondingly finds that no historic properties will be affected during the well conversions.

Based on this information, EPA is proposing to find that no historic properties will be affected as a result of issuing this UIC Permit.

Endangered Species Act (ESA)

Section 7(a)(2) of the Endangered Species Act (ESA), 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. EPA has determined that a decision to issue a Class II permit for authorization of injection into the RZA 14B1-34A well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402). Accordingly, EPA will comply with these regulations by determining what, if any, effects this action will have on any federally-listed endangered or threatened species or their designated critical habitat and by following any required ESA procedures. EPA's determination will be documented as part of the administrative record supporting this decision.

Mitigation measures were undertaken for the subject well pad during the construction phase that included the RZA 14B1-34A and RZA 15A1-33A wells. During the well's conversion to a UIC Class II well, the Permittee will follow the mitigation measures as documented in the following Environmental Assessment (EA):

DOI-BLM-UT-G010-2019-0005-EA
February 2019
Vernal Field Office
170 South 500 East
Vernal, Utah 84078

Based on this information, EPA is proposing a no effect finding as a result of issuing this UIC Permit.

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." EPA has concluded that there may be potential EJ communities proximate to the Authorized Permit Area. The primary potential human health or environmental effects to these communities associated with injection well operations would be to local aquifers that are currently being used or may be used in the future as USDWs. EPA's UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. EPA has concluded that the specific conditions of UIC Permit UT22420-12015 will prevent contamination to USDWs, including USDWs which either are or will be used in the future by communities of EJ concern. These USDWs could include the aquifer within the proposed injection zone in which case injection would only commence if the aquifer is exempted and thereby no longer protected under the SDWA. 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.