

**United States Environmental Protection Agency
Underground Injection Control Program**

FINAL PERMIT

Class I Non-hazardous Waste Injection Well

Permit No. R9UIC-CA1-FY17-3 (the Permit)

Well Name: McKittrick WD-1

Issued to:

**McKittrick Limited (McKittrick)
4905 Reward Road
McKittrick, CA 93251**

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PART I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control (UIC) regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (CFR) Parts 124, 144, 145, 146, 147, and 148,

McKittrick Limited (McKittrick or the Permittee)
4905 Reward Road
McKittrick, CA 93251

is hereby authorized, as owner and operator, and contingent upon Permit conditions, to operate an existing injection well facility. Since 1991, the facility has been permitted by California Division of Oil, Gas, and Geothermal Resources (CDOGGR) as a UIC Class II well facility because it provided a byproduct of steam to assist nearby oil producers in the recovery of heavy oil. However, steam sharing with oil recovery operations has decreased and is expected to cease in the future. Given this transition of operations, EPA and CDOGGR agreed that the existing McKittrick injection well would be more appropriately regulated by EPA through a UIC Class I non-hazardous injection permit instead of the existing CDOGGR UIC Class II injection permit. Pursuant to this Permit, the facility will now be classified by EPA as a UIC Class I non-hazardous waste injection well facility, with one (1) injection well, known as Well McKittrick WD-1 (API# 029-87661). CDOGGR has indicated that once EPA makes a final permit determination, CDOGGR will revoke McKittrick's existing Class II permit.

The facility is located at Section 13, Township 30 South, Range 21 East, Northeast ¼ Sec; Latitude 35 Deg, 19 Min, 11.7 Sec; and Longitude -119 Deg, 39 Min, 41.6 Sec in the McKittrick Oil Field, approximately 2.4 miles northwest of the Town of McKittrick, California.

EPA authorizes the Permittee to operate the now-classified UIC Class I well conditional upon the Permittee meeting the Financial Assurance requirements set forth in Section II.G of this Permit. Injection operation of the permitted well will be limited to the maximum volume and pressure as determined by conducting a Step-Rate Test, in accordance with terms and conditions in this Permit.

The Permittee will be limited to injecting into Well McKittrick WD-1 fluids that consist of waste waters generated from the McKittrick power plant and from any of seven (7) additional power plants, all owned by Western Generation Partners – Redwood Holdings, LLC (WGP) in the Central Valley of California, listed in the Table under Section II.D.5.e. The waste waters approved for injection are limited to the following four waste streams: (1) boiler blow down, (2) cooling tower blow down, (3) boiler feed water conditioning waste waters, and (4) raw water filter backwash. All the WGP sources shall provide characterization of their waste waters as required in Section II.D.1.b. and other Sections within this Permit such as providing EPA with manifests, periodic testing, and reporting to obtain and maintain authorization to inject into Well McKittrick WD-1.

This Permit authorizes injection by Well McKittrick WD-1, for disposal of specific types of waste waters from power plant operations, into the Stevens Sand within the McKittrick

Oil Field at depths ranging between 3,455 and 3,573 feet below ground surface. The Stevens Sand at Well McKittrick WD-1 has greater than 10,000 mg/L total dissolved solids and is confined above by the approximately 350-foot thick shale of the Antelope Member of the Monterey Formation and below by the approximately 200-foot thick shale of the McDonald Member of the Monterey Formation.

All conditions set forth herein are based on Title 40 of the CFR Parts 124, 144, 145, 146, 147 and 148, and are regulations that are in effect on the date that this Permit is effective.

This Permit consists of thirty-two (32) pages plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by McKittrick and on other information contained in the administrative record. It is the responsibility of the Permittee to read, understand, and comply with all terms and conditions of this Permit.

This Permit is issued for a period of ten (10) years unless the Permit is terminated under the conditions set forth in Section III.B.1 or administratively extended under the conditions set forth in Section III.E.12 of this Permit.

This permit is issued on December 18, 2019 and becomes effective on December 18, 2019.

_____/Signed by/_____
Tomás Torres, Director
Water Division, EPA Region 9

PART II. SPECIFIC PERMIT CONDITIONS

A. REQUIREMENTS PRIOR TO DRILLING, TESTING, CONSTRUCTING, OR OPERATING

1. Financial Assurance

The Permittee's plugging and abandonment cost estimate and chosen financial assurance mechanism for Well McKittrick WD-1 meet the requirements of 40 CFR § 144.52(a)(7).

2. Field Demonstration Submittal, Notification, and Reporting for Existing Well

- a. Prior to each field demonstration required by and described in the following Sections II.B.4.a. and 4.b., and Sections II.D.1.a., 2.a., and 2.b., the Permittee shall submit plans for procedures and specifications to the EPA Region 9 Groundwater Protection Section for approval at a minimum of sixty (60) days prior to the planned demonstration. Submittals shall be made in accordance with Section III.E.9. No demonstration in these Sections may proceed without prior written approval from EPA.
- b. After receipt of approval of the Permittee's proposed field demonstrations in writing from EPA, the Permittee must provide notice at least thirty (30) days prior to performing any required field demonstrations.
- c. Unless otherwise specified elsewhere in this Permit, the Permittee shall submit results of each such field demonstration required by Sections II.B. through D. to EPA within sixty (60) days of completion, unless otherwise directed by EPA.

B. CONDITIONS FOR EXISTING WELL AND FUTURE WELL CONSTRUCTION

1. Surface Location

Only Well McKittrick WD-1 is authorized for UIC Class I non-hazardous injection activities under this Permit. Well McKittrick WD-1 is located at Section 13, Township 30 South, Range 21 East, Northeast ¼ Sec; Latitude 35 Deg, 19 Min, 11.7 Sec; and Longitude -119 Deg, 39 Min, 41.6 Sec within the administrative boundaries of the McKittrick Oil Field, approximately 2.4 miles northwest of the Town of McKittrick, California.

2. Existing Well Construction Details

Well Schematic for Well McKittrick WD-1 is contained in Appendix B of this Permit. The Permittee shall at all times maintain Well McKittrick WD-1 consistent with the Well Schematic.

3. Future Well Authorization and Construction

Prior to drilling any new injection wells not already covered by this Permit, the Permittee must submit to EPA for review and approval, a permit application with detailed construction plans and procedures, including proposed field coordinates (Section, Township, Range, with latitude/longitude) for the surface and bottom hole locations of the proposed well(s). The Permittee shall also provide the drilling program details, and the distance between all wells, and any justification for the proposed separation distance between the wells, both at the surface and at the true vertical depth of the top of the injection interval.

Construction on any such new injection wells may only commence after the Permittee receives a modified or new permit, consistent with 40 CFR § 144.52(a)(1), that covers the construction and operation of the new injection well. All drilling, work-over, and plugging procedures must also comply with CDOGGR's "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Sections 1722-1723. Additional requirements may be applied upon EPA's review and issuance of a modified or a new permit.

4. Injection Formation Testing

a. Step-Rate Test (SRT)

- i. Within one hundred eighty (180) days after the effective date of the Permit, the Permittee shall conduct a SRT on Well McKittrick WD-1 to establish the maximum allowable injection pressure in accordance with Section II.D.3.a. The report shall be submitted to EPA within sixty (60) days of test completion.

The Permittee shall submit to EPA for review and approval a detailed plan for conducting the SRT. Once EPA approves in writing the test plan, the Permittee may schedule the SRT, providing EPA at least thirty (30) days' notice before the SRT is conducted. The final SRT report shall be submitted to EPA within sixty (60) days of test completion.

- ii. Refer to Appendix F – Step Rate Test Procedure Guidelines. Refer also to Society of Petroleum Engineering (SPE) Paper #16798 for test design and analysis guidance.
- iii. Injection as proposed in the approved SRT procedure, which includes injecting above fracture pressure, will be temporarily authorized until such time that EPA approves final injection requirements pursuant to Section II.D.3.

b. Pressure Fall Off Test (FOT)

- i. Within one hundred eighty (180) days after EPA approves the completed SRT and establishes a maximum allowable injection pressure pursuant to Section II.D.3., the Permittee shall conduct an initial FOT to determine and monitor formation characteristics. The Permittee shall conduct the FOT after a radial flow regime has been established at an injection rate which is representative of the wastewater contribution to Well McKittrick WD-1. The Permittee shall conduct the FOT in accordance with EPA Region 9 guidance found in Appendix E, and as follows.
- ii. The Permittee shall submit to EPA for review and approval a detailed plan for the FOT that is developed in accordance with EPA Region 9 guidance in Appendix E. Once EPA approves in writing the test plan, the Permittee may schedule the FOT, providing EPA at least thirty (30) days' notice before the test is conducted. The final FOT report shall be submitted to EPA within sixty (60) days of test completion.
- iii. The Permittee shall use the test results to recalculate the Zone of Endangering Influence (ZEI), consistent with procedures set forth at 40 CFR § 146.6, and to evaluate whether any additional corrective action will be required (refer to Section II.C.). The Permittee shall include a summary of the ZEI recalculation with the FOT report.
- iv. After the initial FOT, the Permittee shall conduct a FOT annually thereafter following the same procedures described in Sections II.B.4.b.i. and ii., above. The Permittee may conduct the annual FOT in conjunction with the annual External Mechanical Integrity Test (MIT) demonstration, as required by Section II.D.2.a.iii.
- v. The Permittee shall create a plot/graph of the latest static reservoir pressure of the injection zone and its cumulative behavior over time, starting with the FOT conducted after the initial FOT; the plot shall be included with the annual FOT report each year.

5. Injection Interval

Well McKittrick WD-1 is currently injecting into the Stevens Sand within the McKittrick Oil Field. The Stevens Sand at Well McKittrick WD-1 has greater than 10,000 mg/L total dissolved solids. Injection by Well McKittrick WD-1 is only permitted into the Stevens Sand, within the depth range as depicted in the well schematic in Appendix B (i.e., at depths ranging between 3,455 and 3,573 feet below ground surface).

6. Monitoring Devices

The Permittee shall install and maintain in good operating condition at all times during operation of Well McKittrick WD-1 the following monitoring devices:

- a. A tap on the discharge line between the injection pump and the wellhead or an alternative location proposed in a detailed written request by the Permittee and approved in writing by EPA for the purpose of obtaining representative samples of injection fluid; and
- b. Devices to continuously measure and record injection pressure, annulus pressure, flow rate, and injection volume, subject to the following:
 - i. Pressure gauges shall be of a design to provide:
 - (a) A full pressure range of at least fifty (50) percent greater than the anticipated operating pressure; and
 - (b) A certified deviation accuracy of five (5) percent or less throughout the operating pressure range.
 - ii. Flow meters shall measure cumulative volumes and be certified for a deviation accuracy of five (5) percent or less throughout the range of injection rates allowed by the Permit.

7. Proposed Changes and Workovers

- a. The Permittee shall give advance notice to EPA, as soon as possible, pursuant to and in accordance with 40 CFR § 144.51(I), of any planned physical alterations or additions to Well McKittrick WD-1, including sidetracking and deepening or perforating additional intervals. Any changes in well construction, including changes in casing, tubing, packers, and/or perforations other than minor changes, require prior written approval by EPA and may require a permit modification application under the requirements of 40 CFR § 144.39 or 144.41. Modifications that are considered routine in well construction details, such as tubing dimensions and strengths, packer models, types and setting depths, and perforation interval changes within the permitted injection zone, may be processed by EPA as minor permit modifications, consistent with 40 CFR § 144.41 and Section III.B.1.
- b. For Well McKittrick WD-1, the Permittee shall provide all records of well workovers, logging, or other subsequent test data to EPA within sixty (60) days of completion of the activity.
- c. The Permittee shall submit all reports required by this Permit using the appropriate reporting forms contained in Appendix C.

- d. For Well McKittrick WD-1, the Permittee shall perform a MIT, using the procedures set forth in Sections II.D.1.a. and II.D.2., within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Section II.D.1. The Permittee shall provide results of the MIT to EPA within sixty (60) days of completion.

C. CORRECTIVE ACTION

The Permittee is not required to conduct any corrective action, in accordance with 40 CFR §§ 144.55 and 146.7, prior to EPA granting initial authorization to inject under this Permit.

1. Annual Zone of Endangering Influence Review

Annually, beginning with January 2021, the Permittee shall review the ZEI calculation based on any new data obtained from the FOT and static reservoir pressure observations required by Section II.B.4.b. The Permittee shall provide to EPA a copy of the modified ZEI calculations, along with all associated assumptions and justifications, with the Quarterly Report due annually in January, as required by Section II.E.5.c.

2. Implementation of Corrective Actions

- a. If any wells requiring corrective action, in accordance with 40 CFR §§ 144.55 and 146.7, are found within the modified ZEI referenced above, a list of the wells along with their locations and construction data shall be provided to EPA within thirty (30) days of their identification.
- b. The Permittee shall submit a plan for approval by EPA to re-enter, plug, and abandon the wells listed in Section II.C.2.a., above, in a way that prevents the migration of fluids into an underground source of drinking water (USDW). The Permittee may submit an alternative plan to address the potential for fluid migration in any of these wells to EPA.
- c. The Permittee may not commence corrective action activities without prior written approval from EPA.

D. WELL OPERATION

1. Required Demonstrations

- a. Mechanical Integrity

- i. Within ninety (90) days of the effective date of this Permit, the Permittee shall conduct a MIT to demonstrate that Well McKittrick WD-1 has mechanical integrity consistent with 40 CFR § 146.8 and

with Section II.D.1.a. The Permittee shall demonstrate that there are not significant leaks in the casing and tubing (internal mechanical integrity) and that there is not significant fluid movement into or between USDWs through the casing wellbore annulus or vertical channels adjacent to the injection wellbore (external mechanical integrity).

b. Injectate Hazardous Waste Determination

- i. Within sixty (60) days of the effective date of this Permit, the Permittee shall perform an Injectate Hazardous Waste Determination of each unique waste stream source injected into Well McKittrick WD-1, as listed in Section II.D.5.a. from the McKittrick power plant, in accordance with 40 CFR § 262.11. The results of the analyses shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR § 261. A letter with the results of the analyses shall be submitted to EPA within sixty (60) days of the “Hazardous Waste Determination” completion.
- ii. Within sixty (60) days of the effective date of this Permit and prior to any injection of wastewater from other power plants into Well McKittrick WD-1, the Permittee shall perform an Injectate Hazardous Waste Determination of each unique waste stream source listed in Section II.D.5.a. from the other power plants listed in Section II.D.5.e. in accordance with 40 CFR § 262.11. The results of the analyses shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR § 261. A letter with the results of the analyses shall be submitted to EPA within sixty (60) days of the “Hazardous Waste Determination” completion.
- iii. Whenever there is a process change or a change in fluid chemical constituents or characteristics of the injectate at the McKittrick power plant, the Permittee shall perform an additional “Hazardous Waste Determination” for each unique waste stream source listed in Section II.D.5.a. The Permittee should also refer to injectate testing requirements set forth in Section II.E.1., below. A letter with the results of the analyses shall be submitted to EPA within sixty (60) days of the “Hazardous Waste Determination” completion.
- iv. Whenever there is a process change or a change in fluid chemical constituents or characteristics of the injectate at the other power plants listed in Section II.D.5.e., the Permittee shall perform an additional “Hazardous Waste Determination” for each unique waste stream source listed in Section II.D.5.a. from these power plants. The Permittee should also refer to injectate testing requirements set forth in Section II.E.1., below. A letter with the results of the analyses shall be

submitted to EPA within sixty (60) days of the “Hazardous Waste Determination” completion.

2. Mechanical Integrity

a. Mechanical Integrity Tests

Mechanical integrity testing shall conform to the following requirements throughout the life of Well McKittrick WD-1 and in accordance with the requirements set forth at 40 CFR §§ 144.51(q) and 146.8:

i. Casing/Tubing Annular Pressure (Internal MIT)

In accordance with the timing requirements defined in Section II.D.2.b., below, the Permittee shall perform a pressure test on the annular space between the tubing and long string casing to demonstrate the absence of significant leaks in the casing, tubing and/or liner. This test shall be for a minimum of thirty (30) minutes at a pressure equal to or greater than the maximum allowable surface injection pressure. A well passes the MIT if there is less than a five (5) percent change in pressure over the thirty (30) minute period. A pressure differential of at least three hundred and fifty (350) pounds per square inch (psig) between the tubing and annular pressures shall be maintained throughout the MIT. This test shall be performed on Well McKittrick WD-1 initially as described in Section II. D.1.a. and once every five (5) years thereafter.

Detailed plans for conducting the Internal MIT must be submitted to EPA for review and approval. Once approved, the Permittee may schedule the Internal MIT, providing EPA at least thirty (30) days’ notice before the Internal MIT is conducted. The final test report shall be submitted to EPA within sixty (60) days of test completion.

ii. Continuous Pressure Monitoring

The Permittee shall continuously monitor and record the tubing/casing annulus pressure and injection pressure by a digital instrument with a resolution of one tenth (0.1) psig. The average, maximum, and minimum monthly results shall be included in the next Quarterly Report submitted to EPA pursuant to Section II.E.5.b., along with any additional records or data requested by EPA regarding the continuous monitoring data described in this Section.

iii. Injection Profile Survey (External MIT)

In conjunction with and consistent with the deadlines for the initial FOT required in Section II.B.4.b., the Permittee shall conduct a demonstration that the injectate is confined to the proper zone and submit the results of the demonstration to EPA for approval.

This demonstration shall consist of a radioactive tracer survey and a temperature log (as specified in Appendix D) or other diagnostic tool or procedure as approved by EPA.

Detailed plans for conducting the External MIT must be submitted to EPA for review and approval. Once approved, the Permittee may schedule the External MIT, providing EPA at least thirty (30) days' notice before the External MIT is conducted. The final test report shall be submitted to EPA within sixty (60) days of test completion.

b. Schedule for MITs

EPA may require that an Internal and/or External MIT be conducted within thirty (30) days of a written request from EPA during the permitted life of Well McKittrick WD-1. The Permittee shall also arrange and conduct MITs according to the following requirements and schedule:

- i. Within thirty (30) days from completion of any work-over operation where well integrity is compromised, an Internal MIT shall be conducted and submitted to EPA for approval to verify that the well has mechanical integrity. Prior to this field demonstration, the Permittee shall submit testing plans to EPA, as described in Section II.A.2.
- ii. At least annually, an injection profile survey External MIT shall be conducted in accordance with 40 CFR § 146.8 and Section II.D.2.a.iii., above.
- iii. At least once every five (5) years, an Internal MIT shall be conducted in accordance with 40 CFR § 146.8 and Section II.D.2.a.i., above.
- iv. At least once every five (5) years, a casing evaluation log in Well McKittrick WD-1 shall be conducted, and a copy provided to EPA within sixty (60) days, in accordance with 40 CFR § 146.8 and Section II.D.2.a.iii., above.

c. Loss of Mechanical Integrity

Within twenty-four (24) hours from the time the Permittee becomes aware of any loss of mechanical integrity of Well McKittrick WD-1, the Permittee shall notify EPA of the situation and specify which of the following circumstances apply:

- i. The well fails to demonstrate mechanical integrity during a test; or
- ii. A loss of mechanical integrity becomes evident during operation; or
- iii. A significant change in the annulus or injection pressure occurs during normal operating conditions. See Section II.D.6.b.

In the event of a loss of mechanical integrity, the Permittee shall immediately suspend injection activities in Well McKittrick WD-1 and shall not resume operation until it has taken necessary actions to restore and confirm mechanical integrity of Well McKittrick WD-1, and EPA has provided written approval to recommence injection into Well McKittrick WD-1.

The Permittee may not recommence injection after a workover which has compromised well integrity (such as unseating the packer, etc.) until it has received written approval from EPA that the demonstration of mechanical integrity is satisfactory.

3. Injection Pressure Limitation

For Well McKittrick WD-1:

- a. Maximum allowable injection pressure (MAIP) will be set at 80% of the calculated fracture pressure at the surface without consideration of friction losses, or the maximum safe operating pressure of the injection equipment, whichever is less. The applicable fracture gradient will be based on results of the SRT conducted in Well McKittrick WD-1 in the Stevens Sand injection zone pursuant to Section II.B.4.a. EPA will provide the Permittee written notification of the MAIP once it has been calculated pursuant to the above restrictions, which will become the enforceable MAIP pursuant to this Permit. Once established, the approved MAIP will be added to this Permit as an attachment. The Permittee shall limit injection pressure to the lesser of MAIP or the safe operating pressure, as described in Appendix H of this Permit, until the SRT is conducted and evaluated by EPA.
- b. The Permittee may request a change in the maximum injection pressure allowed under Section II.D.3.a. Any such request shall be made in writing and

justified to EPA with the results of a SRT conducted as described in Section II.B.4.a.

- c. In no case shall the Permittee inject at pressures that (i) initiate new fractures or propagate existing fractures in the injection zone or the confining zone, (ii) cause the movement of injection or formation fluids into or between USDWs, or (iii) allow injection fluids to migrate to oilfield production wells.

4. Injection Volume (Rate) Limitation

For Well McKittrick WD-1:

- a. An injection rate limit shall be determined along with EPA's establishment of a maximum allowable injection pressure, based on a SRT(s) and an annual ZEI re-calculation. Once the injection rate limit is established based on the testing requirements outlined in this Permit, the Permittee shall not inject at a rate above the limit. This rate will be subject to an annual review based on the annual ZEI determinations performed as described in Paragraph II.C.1. The current injection rate, as described in Appendix H, may continue until the SRT is conducted and evaluated by EPA.
- b. The Permittee may request an increase in the maximum rate allowed in Section II.D.4.a., above. Any such request shall be made in writing, along with a justification for the proposed increase, to EPA for its review and approval.
- c. Should any increase in injection rate be requested, the Permittee shall demonstrate to the satisfaction of EPA that the proposed increase will not interfere with the operation of the facility, its ability to meet conditions described in this Permit, change its well classification, or cause migration of injectate or pressure buildup to occur beyond the Area of Review.
- d. The injection rate shall not cause an exceedance of the injection pressure limitation established pursuant to Section II.D.3.a.

5. Injection Fluid Limitation

- a. This Permit authorizes the following injection fluids into Well McKittrick WD-1, which consist of waste waters generated from the McKittrick power plant and from any of seven (7) additional power plants, all owned by Western Generation Partners – Redwood Holdings, LLC (WGP) in the Central Valley of California, listed in the Table under Section II.D.5.e., below: (1) boiler blow down, (2) cooling tower blow down, (3) boiler feed water conditioning waste waters, and (4) raw water filter backwash.

- b. The Permittee shall not inject any hazardous waste, as defined by 40 CFR § 261, at any time. See also Section II.D.1.b.
- c. Injection fluids shall be limited to those authorized by this Permit, which includes those fluids produced by the Permittee as described in Section II.D.5.a., above, and the same category of fluids from power plant facilities of the WGP listed in the Table of Section II.D.5.e., below. At no time shall the injection of fluids from the identified pre-approved WGP facilities and the McKittrick facility into Well McKittrick WD-1 exceed the limitations as described in Sections II.D.3. and II.D.4. of this Permit. All fluids that are authorized for injection by this Permit from other WGP facilities shall be manifested per load delivery and copies of these manifests shall be included in the Quarterly Reports submitted pursuant to Section II.E.5. (see Appendix I for manifest requirements). Likewise, in the event the McKittrick facility provides fluid deliveries to other authorized, permitted facilities for injection, these deliveries shall be manifested per load and copies of the manifests shall be provided with the Quarterly Reports.
- d. Particulate Filters may be used upstream of Well McKittrick WD-1, at the discretion of the Permittee, to prevent formation plugging or damage from particulate matter. The Permittee shall include any filter specifications in the Quarterly Report due annually in January as required in Section II.E.5.b., including proposed particle size removal with any associated justification for the selected size. For any particulate filters used, the Permittee shall follow appropriate waste analysis and disposal practices consistent with local, state, and federal law, and provide documentation to EPA.
- e. List of WGP Facilities

<u>Plant Name</u>	<u>Location</u>	<u>Size (MW)</u>	<u>Raw Water Source</u>	<u>Boiler Feed Water Treatment System</u>
Double C	Kern Front Oil Field	Two 24 MW Turbines	Double C's and Badger Creek's Water Wells	Sodium Zeolite Water Softeners and/or Reverse Osmosis
High Sierra	Kern Front Oil Field	Two 24 MW Turbines	Double C's and Badger Creek's Water Wells	Sodium Zeolite Water Softeners and/or Reverse Osmosis
Kern Front	Kern Front Oil Field	Two 24 MW Turbines	Double C's and Badger Creek's Water Wells	Sodium Zeolite Water Softeners and/or Reverse Osmosis
Badger Creek	Kern Front Oil Field	One 48.5 MW Turbine	Well Water	Dual train demineralizer

Bear Mountain	Kern Bluff Oil Field	One 48 MW Turbine	City of Bakersfield	Dual train demineralizer
Live Oak	Kern River Oil Field	One 48 MW Turbine	Well Water	Dual train demineralizer
McKittrick	McKittrick Oil Field	One 48 MW Turbine	West Kern Water District	Reverse Osmosis followed by Dual train demineralizer
Chalk Cliff	Midway-Sunset Oil Field	One 49 MW Turbine	West Kern Water District	Reverse Osmosis followed by Dual train demineralizer

If WGP sells or dismantles any of these plants, it shall notify EPA in writing within thirty (30) days. If WGP purchases or builds a new plant, it can request that EPA add it to the above list, provided new waste streams are similar to those at the listed power plants.

- f. Any well stimulation or treatment procedure (such as acidizing, etc.) performed at the discretion of the Permittee shall be proposed and submitted to EPA for approval. After approval is granted, notification to EPA is required at least thirty (30) days prior to performing the approved procedure. This requirement may be modified if the Permittee submits a standard operating procedure for well stimulation or treatment for EPA approval after the effective date of this Permit. If the standard operating procedure plan is approved by EPA in writing, the Permittee may notify EPA within fifteen (15) days of the proposed well stimulation or treatment procedure, provided the procedure does not deviate in any way from the EPA-approved plan.

6. Tubing/Casing Annulus Requirements

For Well McKittrick WD-1:

- a. The Permittee shall use and maintain corrosion-inhibiting annular fluid during well operation. See Appendix H for a complete, generic description and characterization of the annular fluid.
- b. The Permittee shall maintain a minimum pressure of one hundred (100) psig at shut-in conditions on the tubing/casing annulus.
- c. If the historic cyclic range of annular pressure fluctuation is not already known, then within the first ninety (90) days of normal injection operations after the effective date of this Permit, the Permittee shall monitor and record to determine that range. This pressure range shall be submitted with the first Quarterly Report due after the effective date of the Permit.
- d. Any annular pressure measured outside of the established normal pressure range, regardless of whether it otherwise meets the requirements of this

Permit, shall be reported orally to EPA within twenty-four (24) hours, followed by a written submission within five (5) days, as a potential loss of mechanical integrity. In the submission, the Permittee must describe the event and include details, such as, associated injection pressures and temperatures. The Permittee shall provide any additional information regarding the reported annular pressure event requested by EPA within sixty (60) days of receipt of a written request from EPA, or such other time frame established by EPA.

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Fluid Monitoring Program

On a quarterly basis for the first four (4) quarters after the effective date of this Permit, the Permittee shall sample and analyze injection fluids from each WGP facility to yield representative data on their physical, chemical, and other relevant characteristics. Test results from each WGP facility shall be submitted by the Permittee to EPA on a quarterly basis (see Section II.E.5., below). Thereafter, the Permittee shall sample and analyze the fluid generated from the combination of the McKittrick power plant operations and the operations of all other WGP facilities that are being injected into Well McKittrick WD-1, prior to injection. Test results of the fluid shall be submitted by the Permittee to EPA on a quarterly basis. EPA may at any time require the Permittee to sample and analyze injection fluids from any WGP facilities.

Samples and measurements shall be representative of the monitored activity. The Permittee shall utilize applicable analytical methods described in Table I of 40 CFR § 136.3 or in EPA Publication SW-846, “Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,” and as described below, unless other methods have been approved by EPA or additional approved methods or updates to the methods listed below become available.

a. Summary of Acceptable Analytic Methods

- i. Inorganic Constituents – USEPA Method 300.0, Part A for Major Anions and USEPA Method 200.8 for Cations and Trace Metals.
- ii. Solids – Standard Methods 2540C and 2540D for Total Dissolved Solids (TDS) and Total Suspended Solids (TSS).
- iii. General and Physical Parameters – appropriate USEPA methods for Temperature, Turbidity, pH, Conductivity, Hardness, Specific Gravity, Alkalinity, and Biological Oxygen Demand (BOD); and Density and Viscosity (see EPA Bulletin 712-C-96-032) under standard conditions.

iv. Volatile Organic Compounds (VOCs) – USEPA Method 8260D.

v. Semi-Volatile Organic Compounds (SVOCs) – USEPA Method 8270E.

b. Analysis of Injection Fluids

Within thirty (30) days after the effective date of this Permit, and whenever there is a change in injection fluids such as whenever the injection fluid is no longer representative of previous samples and measurements that have been submitted and approved, the Permittee shall perform injectate sampling and analyses as outlined in Section II.E.1.a., above.

2. Monitoring Information

The Permittee shall maintain records of monitoring activity required under this Permit, including the following information and data:

- a. Date, exact location, and time of sampling or measurements;
- b. Name(s) of individual(s) who performed sampling or measuring;
- c. Exact sampling method(s) used;
- d. Date(s) laboratory analyses were performed;
- e. Name(s) of individual(s) who performed laboratory analyses;
- f. Types of analyses; and
- g. Results of analyses.

3. Monitoring Devices

a. Continuous Monitoring Devices

During all periods of operation of Well McKittrick WD-1, the Permittee shall measure the following wellhead parameters: (i) injectate rate/volume, (ii) injectate temperature, (iii) annular pressure, and (iv) injection pressure. All measurements must be recorded at minimum to a resolution of one tenth (0.1) of the unit of measure (e.g. injection rate and volume must be recorded to a resolution of one tenth (0.1) of a gallon; pressure must be recorded to a resolution of one tenth (0.1) of a psig; injection fluid temperature must be recorded to a resolution of one tenth (0.1) of a degree Fahrenheit). Exact dates and times of measurements, when taken, must be recorded and submitted. The well shall have a dedicated flow meter, installed so it records all injection

flow. To meet the requirements of this Section, the Permittee shall monitor the following parameters, at the prescribed frequency, and record the measurements at this required frequency, using the prescribed instruments (continuous monitoring requires a minimum frequency of at least one (1) data point every thirty (30) seconds):

Monitoring Parameter	Frequency	Instrument
Injection Rate (gallons per minute)	Continuous	Digital recorder
Daily Injection Volume (gallons)	Daily	Digital totalizer
Total Cumulative Volume (gallons)	Continuous	Digital totalizer
Well Head Injection Pressure (psig)	Continuous	Digital recorder
Annular Pressure (psig)	Continuous	Digital recorder
Injection Fluid Temperature (degrees Fahrenheit)	Continuous	Digital recorder

The Permittee must adhere to the required format below for reporting injection rate and well head injection pressure. An example of the required electronic data format:

<u>DATE</u>	<u>TIME</u>	<u>INJ. PRESS (PSIG)</u>	<u>INJ. RATE (GPM)</u>
mm/dd/yy	hh:mm:ss	XXXX.X	XXXX.X

Each data line shall include four (4) values separated by a consistent combination of spaces or tabs. The first value contains the date measurement in the format of mm/dd/yy or mm/dd/yyyy, where mm is the number of the month, dd is the number of the day and yy or yyyy is the number of the year. The second value is the time measurement, in the format of hh:mm:ss, where hh is the hour, mm are the minutes and ss are the seconds. Hours should be calculated on a twenty-four (24)-hour basis, i.e. 6 PM is entered as 18:00:00. Seconds are optional. The third value is the well head injection pressure in psig. The fourth column is injection rate in gallons per minute (gpm).

b. Calibration and Maintenance of Equipment

The Permittee shall calibrate and maintain on a regular basis all monitoring and recording equipment to ensure proper working order of all equipment.

4. Recordkeeping

- a. The Permittee shall retain the following records and shall have them available at the facility at all times for inspection by EPA or other authorized personnel, in accordance with the following:

- i. All monitoring information, including required observations, calibration and maintenance records, recordings for continuous monitoring instrumentation, copies of all reports required by this Permit, and records of all data used to complete the permit application;
 - ii. Information on the physical nature and chemical composition of all injected fluids;
 - iii. Results of the injectate “Hazardous Waste Determination” according to 40 CFR § 262.11 (see Section II.D.1.b.). Results shall demonstrate that the injectate does not meet the definition of hazardous waste as defined in 40 CFR § 261; and
 - iv. Records and results of MITs, FOTs, and any other tests and logs required by EPA, and any well work and workovers completed.
- b. The Permittee shall maintain copies (or originals) of all records described in Sections II.E.4.a.i. through iv., above, during the operating life of Well McKittrick WD-1 and shall make such records available at all times for inspection at the facility. The Permittee shall only discard the records described in Sections II.E.4.a.i. through iv., if:
- i. The records are delivered to the EPA Region 9 Groundwater Protection Section; or
 - ii. Written approval from EPA to discard the records is obtained.

5. Quarterly Reports

- a. The Permittee shall submit to EPA Quarterly Reports containing, at minimum, the following information gathered during the Reporting Period identified in Section II.E.5.b.:
- i. Injection fluid characteristics for parameters specified in Section II.E.1.a.;
 - ii. When appropriate, Injectate Hazardous Waste Determination according to Section II.D.1.b.;
 - iii. The results of any additional MITs, FOTs, logging or other tests, as required by EPA;
 - iv. Any pressure tests, as required by Section II.D.2.a.i.;

- v. Shut-in static reservoir pressure cumulative behavior plot of the injection zone, as required by Section II.B.4.b.v.;
 - vi. Hourly and daily values, submitted in electronic format, for the continuously monitored parameters specified for the injection wells in Section II.E.3.a.; and
 - vii. Monthly cumulative total volumes, as well as monthly average, minimum, and maximum values for the continuously monitored rate, pressure, and temperature parameters specified for the injection wells in Section II.E.3.a., unless more detailed records are requested by EPA.
 - viii. A copy of the Safety Data Sheet (SDS) for any new processes or water treatment chemicals used at any WGP facilities.
- b. Quarterly Reports, with the applicable Appendix C forms, shall be submitted for the reporting periods by the respective due dates as listed below:

<u>Reporting Period</u>	<u>Report Due</u>
Jan, Feb, Mar	Apr 28
Apr, May, June	July 28
July, Aug, Sept	Oct 28
Oct, Nov, Dec	Jan 28

- c. For the January Quarterly Report, the Permittee shall also include in that Report the following information collected during the prior year covering January through December:
- i. Annual reporting summary (7520-11 in Appendix C);
 - ii. Annual injection profile survey results as required in Section II.D.2.a.iii.;
 - iii. Annual ZEI recalculation as required in Section II.C.1.; and
 - iv. A narrative description of all non-compliance that occurred during the past year.
- d. In addition to meeting the submittal requirements of Section III.E.9., digital e-copies of all Quarterly Reports shall also be provided to the following:

California Division of Oil, Gas and Geothermal Resources
 Inland District
 Attention: District Engineer

4800 Stockdale Hwy., Suite 100
Bakersfield, CA 93309-0279

Central Valley Regional Water Quality Control Board
Attention: Permit Section
1685 E Street
Fresno, CA 93706-2007

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

The Permittee shall notify EPA no less than sixty (60) days before abandonment of Well McKittrick WD-1 and shall not perform the plugging and abandonment activities until the Permittee receives written notice of approval by EPA.

2. Plugging and Abandonment Plans

The Permittee shall plug and abandon the well(s) as provided by the Plugging and Abandonment Plan submitted by the Permittee (see Appendix G) and approved by EPA, consistent with CDOGGR's "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Sections 1722-1723 and 40 CFR § 146.10. Upon written notice to the Permittee, EPA may change the manner in which a well will be plugged, based upon but not limited to the following reasons: (a) if the well is modified during its permitted life, (b) if the proposed Plugging and Abandonment Plan for the well is not consistent with EPA requirements for construction or mechanical integrity, or (c) otherwise at EPA's discretion. Upon written notice, EPA may periodically require the Permittee to update the estimated plugging cost. To determine the appropriate level of financial assurance for the Plugging and Abandonment Plan, the Permittee shall obtain a cost estimate from an independent third-party firm in the business of plugging wells. The estimate shall include the costs of all the materials and activities necessary to pay an independent third-party contractor to completely plug and abandon the well as established in the Plugging and Abandonment Plan.

3. Cessation of Injection Activities

After a cessation of injection operations for two (2) years for any wells authorized by this Permit, a well is considered inactive. In this case, the Permittee shall plug and abandon the inactive well in accordance with the approved Plugging and Abandonment Plans for Well McKittrick WD-1, contained in Appendix G, unless the Permittee:

- a. Provides notice to EPA of an intent to re-activate the well;
- b. Has demonstrated that the well(s) will be used in the future;
- c. Has described actions or procedures, satisfactory to EPA and approved in writing by EPA, which will be taken to ensure that the well(s) will not endanger USDWs during the period of inactivity, including annually demonstrating external mechanical integrity of the well(s); and
- d. Conducts an initial, Internal MIT and every two (2) years thereafter while the well remains inactive, demonstrating no loss of mechanical integrity. Note that the Permittee must restore mechanical integrity of the inactive well if the well fails the MIT.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging Well McKittrick WD-1, or at the time of the next Quarterly Report (whichever is less), the Permittee shall submit a report on Form 7520-19, provided in Appendix C, as well as the detailed procedural activity of engineer's log and daily rig log to EPA. The report shall be certified as accurate by the person who performed the plugging operation and shall consist of either:

- a. A statement that the well was plugged in accordance with the approved Plugging and Abandonment Plan contained in Appendix G; or
- b. Where actual plugging differed from the Plugging and Abandonment Plan contained in Appendix G, a statement specifying and justifying the different procedures followed.

G. FINANCIAL ASSURANCE REQUIREMENTS

1. Demonstration of Financial Assurance

The Permittee is required to demonstrate and maintain financial assurance and resources sufficient to close, plug, and abandon any authorized underground injection operations by this Permit, as provided in the Plugging and Abandonment Plan contained in Appendix G and consistent with 40 CFR § 144 Subpart D.

In addition, the Permittee shall meet the following specific financial assurance requirements:

- a. The Permittee established financial assurance for the plugging and abandonment of Well McKittrick WD-1 in the amount of \$59,200 by demonstrating that it passed the financial test as specified in 40 CFR § 144.63(f)(1)(i). The Permittee submitted a letter signed by the chief financial officer of Harbert Power Fund V, LLC (the "Fund") along with a copy of the

Deloitte & Touche, LLP report on examination of the Fund's financial statement ended December 31, 2018, to support its use of the financial test to demonstrate financial assurance. The plugging and abandonment amount has been factored in the cost for an independent third party to plug and abandon Well McKittrick WD-1.

- b. The financial assurance mechanism shall be reviewed and updated annually, and a description of that review and any updates, such as the firm's latest year-end financial statements, shall be set forth in the Quarterly Report due on January 28 of each year. At its discretion, and upon written request, EPA may require the Permittee to change to an alternate method of financial assurance. Any such change must be approved in writing by EPA prior to the change.
- c. EPA may periodically require the Permittee to update the estimated Plugging and Abandonment Plan (see Appendix G) and/or the cost associated with it, and the Permittee shall make such an adjustment within sixty (60) days of notice from EPA. Alternately, EPA may independently adjust the required financial assurance amount, as warranted.

2. Failure of Financial Assurance

The Permittee must notify EPA of the insolvency of a financial institution supporting the financial assurance as soon as possible, but no later than ten (10) days after the Permittee becomes aware of the insolvency. The Permittee shall submit to EPA a revised and/or new instrument of financial assurance, consistent with the terms of this Permit, within sixty (60) days after any of the following events occur:

- a. The institution issuing the bond or other financial instrument files for bankruptcy;
- b. The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked; or
- c. The institution issuing the financial instrument lets it lapse or decides not to extend it.

Failure to submit an acceptable financial assurance may result in the termination of this Permit pursuant to 40 CFR § 144.40(a)(1).

3. Insolvency of Owner or Operator

An owner or operator must notify EPA by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days after such an event occurs. A guarantor of a corporate guarantee must make such a notification if he/she is named as debtor, as required under the terms of the guarantee.

H. DURATION OF PERMIT

This Permit and the authorization to inject are issued for a period of ten (10) years unless terminated under the conditions set forth in Section III.B.1 or administratively extended under the conditions set forth in Section III.E.12.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection well construction and operation in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any injection activity not otherwise allowed by this permit, as such activities may allow the movement of fluid containing any contaminant into USDWs (as defined by 40 CFR §§ 144.3 and 146.3).

No injection fluids are allowed to migrate to any nearby oilfield production wells. Further, this permit requires systematic and predictive documentation over the facility's operational life to ensure that no injection fluids, either presently or in the future, will migrate to oilfield operation or geothermal production wells.

Any underground injection activity not specifically authorized in this Permit is prohibited. 40 CFR § 144.11. The Permittee must comply with all applicable provisions of the Safe Drinking Water Act (SDWA) and 40 CFR Parts 124, 144, 145, and 146. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, 42 U.S.C. § 300(i), or any other common law, statute, or regulation other than Part C of the SDWA. Issuance of 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 State or local law or regulations. Nothing in this Permit shall be construed to relieve the Permittee of any duties under all applicable, including future, laws or regulations.

B. PERMIT ACTIONS

1. Modification, Revocation and Reissuance, or Termination

EPA may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.51(f). The Permit is also subject to minor modifications for cause as specified in 40 CFR § 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated non-compliance by the Permittee, does not stay the applicability or enforceability of any permit condition. EPA may also modify, revoke and reissue, or terminate this Permit in accordance with any amendments to the SDWA if the amendments have applicability to this Permit.

2. Transfers

This Permit is not transferable to any person unless notice is first provided to EPA and the Permittee complies with requirements of 40 CFR § 144.38. *See also* 40 CFR § 144.51(l)(3). EPA may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

C. SEVERABILITY

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

D. CONFIDENTIALITY

In accordance with 40 CFR §§ 2 and 144.5, any information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission 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 validity of the claim will be assessed in accordance with the procedures contained in 40 CFR § 2 (Public Information). Claims of confidentiality for the following information will be denied:

1. Name and address of the Permittee; or
2. Information dealing with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

The provisions of 40 CFR § 144.51 are incorporated by reference into this permit, except as modified by specific provisions in this permit. In addition, the following general duties and requirements apply to this permit and the Permittee.

1. Duty to Comply

The Permittee shall comply with all applicable UIC Program regulations and all conditions of this Permit, except to the extent and for the duration such non-compliance is authorized by an emergency permit issued in accordance with 40 CFR § 144.34. Any permit non-compliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, or modification, or denial of a permit renewal application. Such non-compliance may

also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions

Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may also be subject to enforcement actions pursuant to RCRA or other actionable authorities. Any person who willfully violates a permit condition may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity Not a Defense

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

4. Duty to Mitigate

The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from non-compliance 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. Property Rights

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

7. Duty to Provide Information

The Permittee shall furnish to EPA, within a time specified, any information which EPA 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 EPA, upon request, copies of records required to be kept by this Permit.

8. Inspection and Entry

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

- a. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this Permit;
- b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this Permit;
- c. Inspect and photograph, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and
- d. Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

9. Submittal Requirements

The Permittee shall follow the procedures set forth below for all submittals made to EPA under this Permit, including all notices and reports:

- a. All submittals to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative consistent with the requirements of 40 CFR §§ 122.22, 144.32, and 144.51(k).
- b. Unless otherwise required by this Permit or rule, all submissions (including correspondence, reports, records and notifications) required under this Permit shall be in writing and mailed first class mail to the following address:

U.S. Environmental Protection Agency, Region 9
Water Division
UIC Program
Groundwater Protection Section (WTR-4-2)
75 Hawthorne St.
San Francisco, CA 94105-3901

- c. The compliance date for submittal of a report is the day it is mailed.

10. Additional Reporting Requirements

a. Planned Changes

The Permittee shall give notice to EPA as soon as possible of any planned physical alterations or additions to the permitted facility.

b. Anticipated Non-compliance

The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in non-compliance with permit requirements.

c. Compliance Schedules

Reports of compliance or non-compliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted to EPA no later than thirty (30) days following each schedule date.

d. Monitoring Reports

Monitoring results shall be reported at the intervals specified elsewhere in this Permit.

e. Twenty-four Hour Reporting

i. The Permittee shall report to EPA any non-compliance which may endanger health or the environment, including:

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

(b) Any non-compliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs.

ii. Any information shall be provided orally within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances. A written submission of all non-compliance as described in Section III.E.10.e.i., above, shall also be provided to EPA within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain: a description of the non-compliance and its cause; the period of non-compliance, including exact dates and times; if the non-compliance has not been

corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the non-compliance.

f. Other Non-compliance

At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of non-compliance not otherwise reported pursuant to other reporting requirements outlined in this Permit. The Permittee shall submit the information listed in Section III.E.10.d.

g. Other Information

If the Permittee becomes aware that it failed to submit all relevant facts in the permit application, or submitted incorrect information in the permit application or in any report to EPA, the Permittee shall submit such facts or information within two (2) weeks of the time such facts or information becomes known.

11. Requirements Prior to Commencing Injection, Plugging and Abandonment Report, Duty to Establish and Maintain Mechanical Integrity

The Permittee shall comply with all applicable requirements set forth at 40 CFR §§ 144.51(m)-(q) and as outlined throughout this Permit.

12. Continuation of Expiring Permit

a. Duty to Re-apply

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, the Permittee must submit a complete application to EPA for a new permit at least one hundred and eighty (180) days before this Permit expires.

b. Permit Extensions

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

- i. The Permittee has submitted a timely and complete application for a new permit; and
- ii. EPA, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

13. Records of Permit Application

The Permittee shall maintain records of all data required to complete the permit application and any supplemental information submitted with the permit application.

14. Availability of Reports

All reports prepared in accordance with the conditions of this Permit shall be available for public inspection at appropriate offices of the EPA. Permit applications, permits, and well operation data shall not be considered confidential.

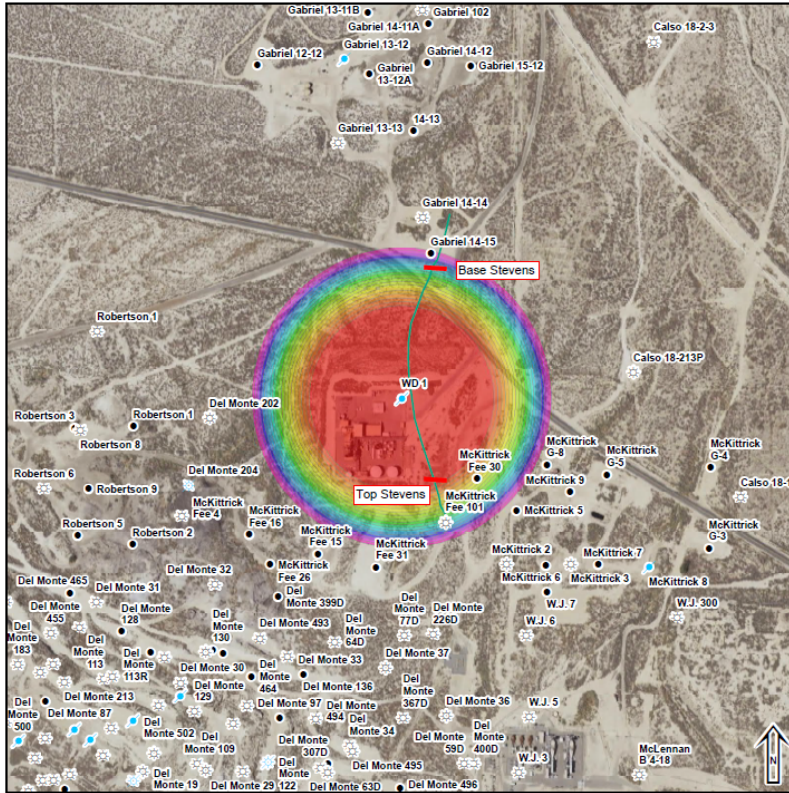
Appendix A

Project Maps

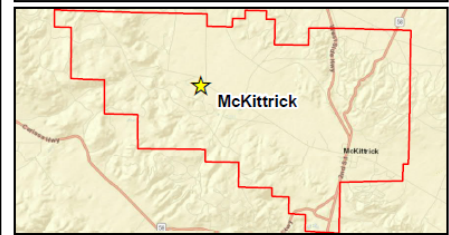
UIC Permit R9UIC-CA1-FY17-3



Overview map with insert showing plant location with respect to the Town of McKittrick

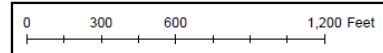


McKittrick Limited

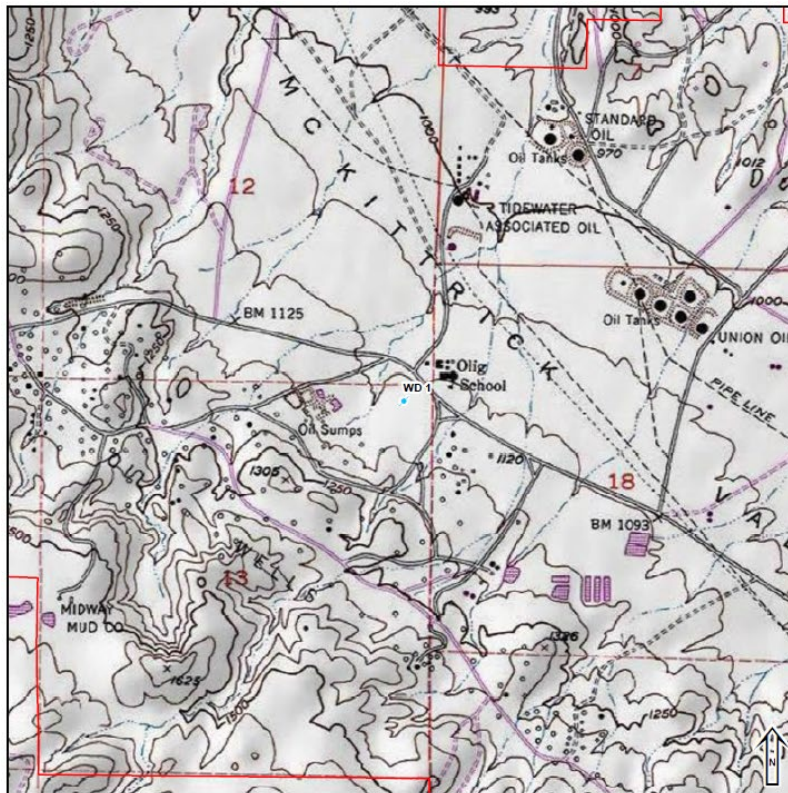


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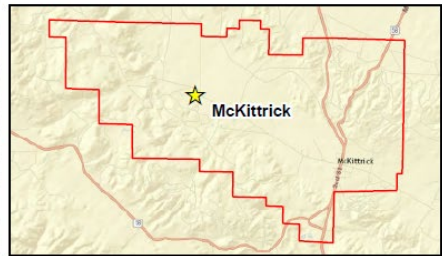
DOGGR Wells	Time Interval (Years)
● Active Oil & Gas	1
● Active Injectors	2
● Plugged Oil & Gas	3
● Plugged Injectors	4
● 101 Wormtrack Dir Survey	5
● McKittrick Oil Field	6
	7
	8
	9
	10
	11
	12
	13
	14
	15
	16
	17
	18
	19
	20 (604 ft)



Prepared By:	TITLE:	Waste Front Map
EnviroTech Consultants, Inc.	OIL FIELD:	McKittrick
	COUNTY:	Kern
Section/Township/Range	DRN BY:	Jennifer Prosser
Section 13 - T305/R21E MDB&M	DATE:	July 2, 2018
	SCALE:	1 inch = 300 feet

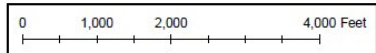


McKittrick Limited



Legend

- ★ McKittrickUIC
- ▭ McKittrick Oil Field



Prepared By:	EnviroTech Consultants, Inc.	TITLE:	Topographic Map
		OIL FIELD:	McKittrick
		COUNTY:	Kem
Section/Township/Range		DRN BY:	Ashley Bylow
Section 13 - T30S/R21E MDB&M		DATE:	March 31, 2017
		SCALE:	1 inch = 1,000 feet

Appendix B

Well Schematic

UIC Permit R9UIC-CA1-FY17-3

McKittrick Limited

WD1; API # 029-87661

Section 13, T30S, R21E M.D.B.&M.

ELEVATION:

KB 1123.5'

DATUM:

KB 10' above ground surface

TD:

OH: 3944'

PBTD:

3922'

BFW:

No USDW

SPUD DATE:

06/03/1991

COMPLETION DATE:

06/16/1991

WELL STATUS:

Active

DIRECTIONALLY DRILLED:

No

JUNK:

None

PLUGS:

3922' - 3944'

CASING:

10.75" csg @ 511' w/290 sx cmt, cmt to surface

7" csg @ 3943' w/1038 sx cmt, cmt to surface

TUBULARS:

2 7/8" O-3356'

Packer @ 3356'

PERFORATIONS:

3458' - 3490', 3501' - 3636', 3671' - 3686', 3689' - 3795', 3801' - 3829', 3832' - 3861', 3864' - 3873'

HOLE SIZE:

0' - 511': 14.75"

511' - 3944': 9-7/8"

MARKERS:

Alluvium: 0'

Tulare: 260'

San Joaquin: 765'

Top Olig: 1022'

Base Olig: 1696'

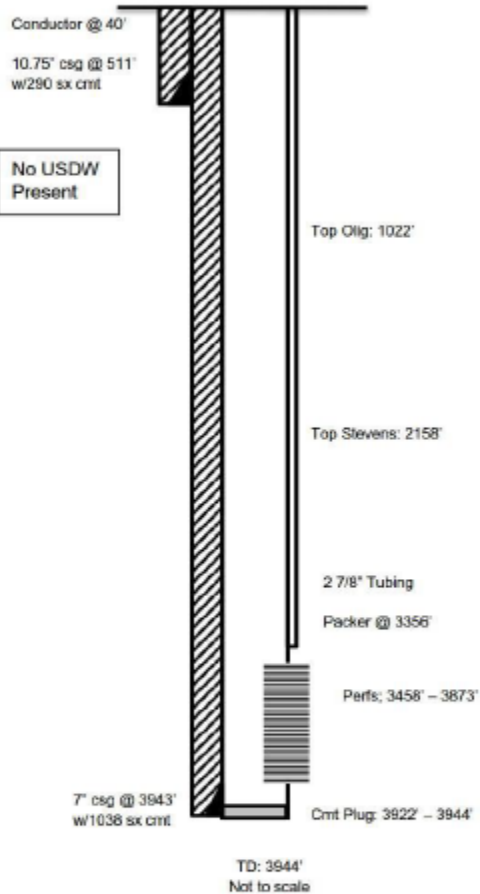
Top Stevens: 2158'

Base Stevens: 3876'

EnviroTech
Consultants, Inc.

INITIAL & DATE:

JBR - 03/09/2017



* A 20-inch conductor was proposed to be set at 40 ft. before drilling was initiated and cemented to surface and is listed as being completed in the Report of Operations (November 5, 1991).

Appendix C

EPA Reporting Forms

UIC Permit R9UIC-CA1-FY17-3

EPA Reporting Forms List

Form 7520-7: Application to Transfer Permit

Form 7520-8: Quarterly Injection Well Monitoring Report

Form 7520-19: Well Rework Record, Plugging and Abandonment Plan, or Plugging and Abandonment Affidavit

These forms are available for downloading at:

<https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators>

Appendix D

Logging Requirements

UIC Permit R9UIC-CA1-FY17-3

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 9

RADIOACTIVE TRACER SURVEY (RTS) GUIDELINES

Introduction:

The intent of this guideline document is to provide general guidance to owners and operators of Class I non-hazardous underground injection wells for performing radioactive tracer surveys (RTS) used as a means of testing and measuring the external mechanical integrity of these wells as defined in 40 CFR Part 146.8(a)(2). These guidelines are general in nature and individual well conditions may require deviations from these procedures. All proposed plans and any deviations from these guidelines to conduct radioactive tracer surveys must be approved in advance by the EPA Region 9 Drinking Water Protection Section.

Basic Guidelines:

Prior to commencing performance of the RTS, the operator must have available onsite the following:

- EPA approved plan for conducting the RTS
- Reference Gamma Ray (GR) or Open Hole logs and complete well construction details

The logging company must provide a drawing of their tool configuration with tool diameter, tool length, spacing between detectors, ejector location, casing collar log (CCL), a sketch of the well to be tested construction details and equipment details as part of the logging record.

Tool must include dual GR detectors spaced below the ejector port, centralized with a bow spring centralizer (or motorized centralizer) and be run in conjunction with a CCL.

GR logs are usually run at approximately 60 ft /min. at a time constant of 1 second or 30 ft/min. at a time constant of 2 seconds. Indicate the logging speed and time constant on the logging record. The log scale should preferably correspond with that of the Reference lithology logs that are made available for onsite correlation.

The radioisotope typically utilized for tracer surveys in injection wells is sodium iodine 131 with a half-life of 8.05 days. It is important that the isotope be completely soluble with the injectate fluid.

Example Procedure:

Indicate the beginning and ending clock times on each log pass. Indicate the volume of water injected between log passes. Indicate the volume and concentration of each slug of tracer material and the depth and location of each slug. Where possible, the tracer survey should be conducted utilizing the facility's permitted injectate. If that is not possible, the injected water should have a specific gravity equivalent to that of the facility wastewater and be compatible with the formation and previously injected wastewater. A hydraulically actuated packoff (lubricator) should be utilized even when high well pressures are not expected.

Install the RTS tool with an upper and lower detector and CCL. The RTS tool should be configured to run a standard RTS and to conduct velocity shots. Place the RTS tool in the lubricator and mount lubricator onto the injection wellhead. Open the master valve and slowly start pumping into the well until the desired flow rate is reached.

Radioactive Baseline Survey

1. Run a Correlation GR log with a CCL for 200 to 400 feet at or near the injection interval, provided lithology changes are sufficient for correlation purposes. This will allow equipment to be set on proper depths with the Reference Open Hole or GR logs for the well. The CCL should be run through the packer setting depth and preferably past a short casing joint to collect reference depth information.
2. Run a Base GR log from total depth to approximately 400 feet above the packer setting depth. The log sensitivity should be set such that the slug trace response will take up the entire horizontal log scale in API units. The Base log need not be sensitive enough to show lithology. Record the Total Depth for this initial Base log.
3. Record the injection rate and pressure on the well log record for each log pass. The test should be conducted at the rate corresponding to the Maximum Authorized Injection Pressure (MAIP); however, where the well has been operating at a pressure and rate that are lower than the MAIP, the operator may request approval in advance that the RTS should be run at those operating pressures and rates in which the well normally operates (lower than the MAIP).

Radioactive Tracer Depth Drive Survey

4. Initiate the first slug/ejection with the ejector situated approximately 200 feet above the packer. Record the depth and time, verify ejection of the slug, then drop below the slug and record the time, logging speed, time constant, flow rate, etc. Proceed to make the first logging run up through the slug to above where the slug was initially ejected. Note the time when logging terminated, then again drop past the slug and repeat the logging procedure, each time overlapping the previous log and up to a point where the log returns to baseline. Repeat the

logging sequence until all tracer material has exited the wellbore or has diminished substantial amounts.

Radioactive Tracer Time Drive Survey

5. Initiate a second ejection with the tool set 2 to 5 feet above the injection interval and on time drive. Wait for the pre-calculated Wait-Time to observe whether any vertical migration is occurring. Increase the pump rate to the anticipated operating injection rate and leave on time drive for another 10 to 15 minutes. Note times, flow rates, pressures, and slug depth.

Radioactive Tracer Vertical Migration Survey

6. Initiate a third ejection approximately 200 feet above the packer, then follow the slug to the injection zone using multiple log passes as with the first slug/ejection to check for leakage around the packer.

Radioactive Tracer Velocity Survey

7. These can be performed at this juncture of the testing. First, run a velocity profile over the injection horizon noting injection rate. Make velocity shots of tracer material at recorded intervals while injection is occurring at less than normal or peak pumping rates. Run the gamma ray tool through the injection zone and record injectate across the intervals injected. Increase the well injection rate to maximum or normal pumping rate and repeat velocity shots of tracer material at recorded intervals. Run the GR tool through the injection zone and record injectate across the intervals injected at the higher well pumping rate. The information gathered from the two passes made at different pumping rates will allow flow distribution to be compared at the different rates.

Radioactive Post Tracer Survey

8. After sufficient testing has been done to determine the exit point of the tracer material and for indications of vertical migration, drop to and record this second total depth and run a final Base GR log from total depth to approximately 400 feet above the packer at the same logging speed and sensitivity as with initial base log. These two logs should overlay each other with all the "hot spots" being explainable.

Post Survey Requirements

9. Interpretation of the log must be provided by the logging company on the log itself. The well log heading should be completely filled out with all essential information provided such as well name and number, coordinates, well owner/operator, reference logs, and elevations, etc. documented. The log should

be depicted in a manner that fully describes the operations conducted with explanations inserted to minimize the possibility of misinterpretation. Three copies of the final prints must be forwarded to the EPA Region 9 Groundwater Office within 30 days of the survey. The electronic copy may be provided via mailed storage disk, email or a web accessed site. Courtesy field copies provided to the onsite EPA Inspector are not official records.

10. The operator provides an analytical interpretation of the logging results performed by a qualified analyst. This must include a written description of the procedure, the methodology used to calculate the Wait-Time and conclusions drawn from the test. The submittal must also include a fluid loss profile across the injection interval.

NOTE: The above referenced method for performing a Radioactive Tracer Survey (RTS) is not necessarily prescriptive of how all tests are to be conducted. Each underground injection well presents unique subsurface geological, pressure and injection rate situations which must be properly accounted for when designing specific RTS plans and procedures and approved in advance.

References and Additional Information:

Refer to the following EPA publications for additional information and guidance on running and interpreting radioactive tracer and temperature logs for evaluation of injection well integrity:

- Dr. R. M. McKinley's publication EPA/600/R-94/124, *Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity*. It is out of print, but can be downloaded (searched as "600R94124") from the National Service Center for Environmental Publications (NSCEP) site:
<https://www.epa.gov/nscep>
- EPA Region 8 UIC Program Staff Guidance Document at:
<http://www2.epa.gov/sites/production/files/documents/INFO-RATS.pdf>

*Special acknowledgments for additional consultation with:
Texas World Operations, Inc.
Dr. R.M. McKinley*

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION 9

TEMPERATURE LOGGING GUIDELINES

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid MIT as specified by 40 CFR §146.8(c)(1). Variances to these requirements are expected for certain circumstances, but they must be approved prior to running the log. As a general rule, the well shall inject for approximately six (6) months prior to running a temperature decay progression sequence of logs.

1. With the printed log, also provide raw data for both logging runs (at least one data reading per foot depth) unless the logging truck is equipped with an analog panel as the processing device.
2. The heading on the log must be complete and include all the pertinent information, such as correct well name, location, elevations, etc.
3. The total shut-in times must be clearly shown in the heading. Minimum shut-in time for active injectors is twelve (12) hours for running the initial temperature log, followed by a second log, a minimum of four (4) hours later. These two log runs will be superimposed on the same track for final presentation.
4. The logging speed must be kept between twenty (20) and fifty (50) feet per minute (30 ft/min optimum) for both logs. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).
5. The vertical depth scale of the log should be one (1) or two (2) inches per one-hundred (100) feet to match lithology logs (see 7(b)). The horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.
6. The right hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.
7. The left hand tracks must contain (unless impractical, but EPA must pre-approve any deviations):
 - (a) a collar locator log,
 - (b) a lithology log which includes either:
 - (i) an historic Gamma Ray that is "readable", i.e. one that demonstrates lithologic changes without either excessive activity by the needle or severely dampened responses;
or
 - (ii) a copy of an original spontaneous potential (SP) curve from either the subject well or from a representative, nearby well.
 - (c) A clear identification on the log showing the base of the lowermost Underground Source of Drinking Water (USDW). A USDW is basically a formation that contains less than ten thousand (10,000) parts per million (ppm) Total Dissolved Solids (TDS) and is further defined in 40 CFR §144.3.

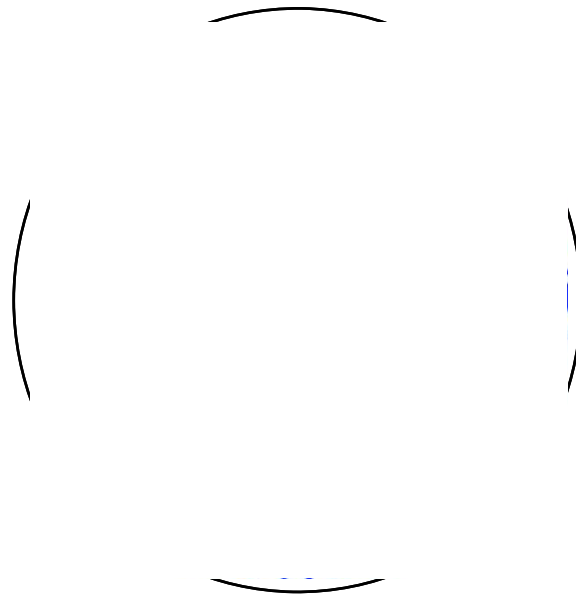
Appendix E

EPA Region 9 UIC Pressure Falloff Requirements

UIC Permit R9UIC-CA1-FY17-3

**EPA Region 9
UIC PRESSURE FALLOFF
REQUIREMENTS**

**Condensed version of the
EPA Region 6
UIC PRESSURE FALLOFF
TESTING GUIDELINE
Third Revision**



August 8, 2002

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- 1.0 Background
- 2.0 Purpose of Guideline
- 3.0 Timing of Falloff Tests and Report Submission
- 4.0 Falloff Test Report Requirements
- 5.0 Planning
 - General Operational Concerns
 - Site Specific Pretest Planning
- 6.0 Conducting the Falloff Test
- 7.0 Evaluation of the Falloff Test
 - 1. Cartesian Plot
 - 2. Log-log Plot
 - 3. Semilog Plot
 - 4. Anomalous Results
- 8.0 Technical References

APPENDIX

Pressure Gauge Usage and Selection

- Usage
- Selection

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- General Operational Considerations
- Wellbore and Reservoir Data Needed to Simulate or Analyze the Falloff Test
- Design Calculations
- Considerations for Offset Wells Completed in the Same Interval

Falloff Test Analysis

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- Log-log Diagnostic Plot
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- Characteristics of Individual Test Flow Regimes
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 - Radial Flow
 - Spherical Flow
 - Linear Flow
 - Hydraulically Fractured Well
 - Naturally Fractured Rock
 - Layered Reservoir

Semilog Plot Determination of the Appropriate Time Function for the Semilog Plot
Parameter Calculations and Considerations
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Radius of Investigation
Effective Wellbore Radius
Reservoir Injection Pressure Corrected for Skin Effects
Determination of the Appropriate Fluid Viscosity
Reservoir Thickness
Use of Computer Software
Common Sense Check

REQUIREMENTS

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision

August 8, 2002

1.0 Background

Region 9 has adopted the Region 6 UIC Pressure Falloff Testing Guideline requirements for monitoring Class 1 Non Hazardous waste disposal wells. Under 40 CFR 146.13(d)(1), operators are required annually to monitor the pressure buildup in the injection zone, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

All of the following parameters (Test, Period, Analysis) are critical for evaluation of technical adequacy of UIC permits:

A falloff **test** is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff **period** is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing **analysis** provides transmissibility, skin factor, and well flowing and static pressures.

2.0 Purpose of Guideline

This guideline has been adopted by the Region 9 office of the Environmental Protection Agency (EPA) to assist operators in **planning and conducting** the falloff test and preparing the **annual monitoring report**.

Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well. Both the reservoir parameters and pressure data are necessary for UIC permit demonstrations. Additionally, a valid falloff test is a monitoring requirement under 40 CFR Part 146 for all Class I injection wells.

The ultimate responsibility of conducting a valid falloff test is the task of the operator. Operators should QA/QC the pressure data and test results to confirm that the results “make sense” prior to submission of the report to the EPA for review.

3.0 Timing of Falloff Tests and Report Submission

Falloff **tests** must be conducted annually. The time **interval** for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals.

The falloff testing **report** should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

4.0 Falloff Test Report Requirements

In general, the **report** to EPA should provide:

- (1) general information and an overview of the falloff test,
- (2) an analysis of the pressure data obtained during the test,
- (3) a summary of the test results, and
- (4) a comparison of those results with previously used parameters.

Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The **falloff test report** should include the following information:

1. **Company name and address**
2. **Test well name and location**
3. The name and phone number of **the facility contact person**. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. **A photocopy of an openhole log** (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. **Well schematic** showing the current wellbore configuration and completion information:
 - X Wellbore radius
 - X Completed interval depths
 - X Type of completion (perforated, screen and gravel packed, openhole)
6. **Depth of fill depth and date tagged.**
7. **Offset well information:**
 - X Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
 - X Simple illustration of locations of the injection and offset wells
8. **Chronological listing of daily testing activities.**
9. **Electronic submission of the raw data (time, pressure, and temperature)** from all pressure gauges utilized on CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any

- edited data used in the analysis can be submitted as an additional file.
10. **Tabular summary of the injection rate or rates preceding the falloff test.** At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
 11. **Rate information from any offset wells completed in the same interval.** At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
 12. **Hard copy of the time and pressure data** analyzed in the report.
 13. **Pressure gauge information:** (See Appendix, page A-1 for more information on pressure gauges)
 - X List all the gauges utilized to test the well
 - X Depth of each gauge
 - X Manufacturer and type of gauge. Include the full range of the gauge.
 - X Resolution and accuracy of the gauge as a % of full range.
 - X Calibration certificate and manufacturer's recommended frequency of calibration
 14. **General test information:**
 - X Date of the test
 - X Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
 - X Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
 15. **Reservoir parameters (determination):**
 - X Formation fluid viscosity, μ_f cp (direct measurement or correlation)
 - X Porosity, ϕ fraction (well log correlation or core data)
 - X Total compressibility, c_t psi⁻¹ (correlations, core measurement, or well test)
 - X Formation volume factor, r_{vb}/stb (correlations, usually assumed 1 for water)
 - X Initial formation reservoir pressure - See Appendix, page A-1
 - X Date reservoir pressure was last stabilized (injection history)
 - X Justified interval thickness, h ft - See Appendix, page A-15
 16. **Waste plume:**
 - X Cumulative injection volume into the completed interval
 - X Calculated radial distance to the waste front, r_{waste} ft
 - X Average historical waste fluid viscosity, if used in the analysis, μ_{waste} cp

17. **Injection period:**
 - X Time of injection period
 - X Type of test fluid
 - X Type of pump used for the test (e.g., plant or pump truck)
 - X Type of rate meter used
 - X Final injection pressure and temperature
18. **Falloff period:**
 - X Total shut-in time, expressed in real time and Δt , elapsed time
 - X Final shut-in pressure and temperature
 - X Time well went on vacuum, if applicable
19. **Pressure gradient:**
 - X Gradient stops - for depth correction
20. **Calculated test data:** include all equations used and the parameter values assigned for each variable within the report
 - X Radius of investigation, r_i ft
 - X Slope or slopes from the semilog plot
 - X Transmissibility, kh/μ md-ft/cp
 - X Permeability (range based on values of h)
 - X Calculation of skin, s
 - X Calculation of skin pressure drop, ΔP_{skin}
 - X Discussion and justification of any reservoir or outer boundary models used to simulate the test
 - X Explanation for any pressure or temperature anomaly if observed
21. **Graphs:**
 - X Cartesian plot: pressure and temperature vs. time
 - X Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
 - X Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
 - X Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. **A copy of the latest radioactive tracer run** and a brief discussion of the results.

5.0 Planning

The **radial flow portion** of the test is the basis for all pressure transient calculations. Therefore the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns

- X Adequate storage for the waste should be ensured for the duration of the test

- X Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- X Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- X The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- X The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- X Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- X Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- X Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- X If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be **analyzed as an interference test** to obtain interwell reservoir parameters.

Site Specific Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
 - X Review previous welltests, if available
 - X Simulate the test using measured or estimated reservoir and well completion parameters
 - X Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
 - X Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.
2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to

produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/μ) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are required. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)
4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

6.0 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well
2. Simplify the pressure transients in the reservoir
 - X Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
 - X Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
 - X Do not shut-in two wells simultaneously or change the rate in an offset well during the test.
3. The test well should be shut-in at the wellhead in order to minimize wellbore storage and afterflow. (See Appendix, page A-3 for additional information.)
4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.
5. Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.

7.0 Evaluation of the Falloff Test

1. Prepare a **Cartesian plot** of the pressure and temperature versus real time or elapsed time.
 - X Confirm pressure stabilization prior to shut-in of the test well
 - X Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution
2. Prepare a **log-log diagnostic plot** of the pressure and semilog derivative. Identify the

flow regimes present in the welltest. (See Appendix, page A-6 for additional information.)

- X Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff (See Appendix, page A-10 for details on time functions.)
 - X **Mark the various flow regimes** - particularly the radial flow period
 - X Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
 - X If there is no radial flow period, attempt to type curve match the data
3. Prepare a **semilog plot**.
- X Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
 - X Draw the semilog straight line through the radial flow portion of the plot and obtain the slope of the line
 - X Calculate the transmissibility, kh/μ
 - X Calculate the skin factor, s , and skin pressure drop, ΔP_{skin}
 - X Calculate the radius of investigation, r_i
4. Explain any anomalous results.

8.0 Technical References

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APPENDIX

Pressure Gauge Usage and Selection

Usage

- X EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- X **Downhole pressure measurements** are less noisy and are required.
- X A bottomhole surface readout gauge (SRO) allows tracking of pressures in real time. Analysis of this data can be performed in the field to confirm that the well has reached radial flow prior to ending the test.
- X The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.
- X Mechanical gauges should be **calibrated** before and after each test using a dead weight tester.
- X Electronic gauges should also be **calibrated** according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

Selection

- X The pressures must remain within the range of the pressure gauge. The larger percent of the gauge range utilized in the test, the better. Typical pressure gauge limits are 2000, 5000, and 10000 psi. Note that gauge accuracy and resolution are typically a function of percent of the full gauge range.
- X Electronic downhole gauges generally offer much better resolution and sensitivity than a mechanical gauge but cost more. Additionally, the electronic gauge can generally run for a longer period of time, be programmed to measure pressure more frequently at various intervals for improved data density, and store data in digital form.
- X Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.

Test Design

General Operational Considerations

- X The injection period controls what is seen on the falloff since the falloff is replay of the injection period. Therefore, the injection period must reach radial flow prior to shut-in of the well in order for the falloff test to reach radial flow
- X Ideally to determine the optimal lengths of the injection and falloff periods, the test should be simulated using measured or estimated reservoir parameters. Alternatively, injection and falloff period lengths can be estimated from empirical equations using assumed reservoir and well parameters.

- X The injection rate dictates the pressure buildup at the injection well. The pressure buildup from injection must be sufficient so that the pressure change during radial flow, usually occurring toward the end of the test, is large enough to measure with the pressure gauge selected.

- X Waste storage and other operational issues require preplanning and need to be addressed prior to the test date. If brine must be brought in for the injection portion of the test, operators should insure that the fluid injected has a consistent viscosity and that there is adequate fluid available to obtain a valid falloff test. The use of the wastestream as the injection fluid affords several distinct advantages:
 1. Brine does not have to be purchased or stored prior to use.
 2. Onsite waste storage tanks may be used.
 3. Plant wastestreams are generally consistent, i.e., no viscosity variations

- X Rate changes cause pressure transients in the reservoir. **Constant rate injection in the test well and any offset wells completed in the same reservoir are critical to simplify the pressure transients in the reservoir.** Any significant injection rate fluctuations at the test well or offsets must be recorded and accounted for in the analysis using superposition.

- X Unless an injectivity test is to be conducted, shutting in the well for an extend period of time prior to conducting the falloff test reduces the pressure buildup in the reservoir and is not recommended.

- X Prior to conducting a test, a crown valve should be installed on the wellhead to allow the pressure gauge to be installed and lowered into the well without any interruption of the injection rate.

- X The wellbore schematic should be reviewed for possible obstructions located in the well that may prevent the use or affect the setting depth of a downhole pressure gauge. The fill depth in the well should also be reported. The fill depth may not only impact the depth of the gauge, but usually prolongs the wellbore storage period and depending on the type of fill, may limit the interval thickness by isolating some of the injection intervals. A wellbore cleanout or stimulation may be needed prior to conducting the test for the test to reach radial flow and obtain valid results.

- X The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period.

- X The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

Wellbore and Reservoir Data Needed to Simulate or Analyze the Falloff Test

- X Wellbore radius, r_w - from wellbore schematic

- X Net thickness, h - See Appendix, page A-15
- X Porosity, ϕ - log or core data
- X Viscosity of formation fluid, μ_f - direct measurement or correlations
- X Viscosity of waste, μ_{waste} - direct measurement or correlations
- X Total system compressibility, c_t - correlations, core measurement, or well test
- X Permeability, k - previous welltests or core data
- X Specific gravity of injection fluid, s.g. - direct measurement
- X Injection rate, q - direct measurement

Design Calculations

When simulation software is unavailable the test periods can be estimated from empirical equations. The following are set of steps to calculate the time to reach radial flow from empirically-derived equations:

1. Estimate the wellbore storage coefficient, C (bbl/psi). There are two equations to calculate the wellbore storage coefficient depending on if the well remains fluid filled (positive surface pressure) or if the well goes on a vacuum (falling fluid level in the well):

- a. Well remains fluid filled:

$$C = V_w \cdot c_{waste} \text{ where, } V_w \text{ is the total wellbore volume, bbls}$$

$$c_{waste} \text{ is the compressibility of the injectate, } \text{psi}^{-1}$$

- b. Well goes on a vacuum:

$$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot g_c}} \text{ where, } V_u \text{ is the wellbore volume per unit length, bbls/ft}$$

$$\rho \text{ is the injectate density, psi/ft}$$

$$g \text{ and } g_c \text{ are gravitational constants}$$

2. Calculate the time to reach radial flow for both the injection and falloff periods. Two different empirically-derived equations are used to calculate the time to reach radial flow, $t_{radial\ flow}$, for the injectivity and falloff periods:

- a. Injectivity period:

$$t_{radial\ flow} > \frac{(200000 + 12000s) \cdot C}{\frac{k \cdot h}{\mu}} \text{ hours}$$

- b. Falloff period:

$$t_{radial\ flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \text{ hours}$$

The wellbore storage coefficient is assumed to be the same for both the injectivity and falloff periods. The skin factor, s, influences the falloff more than the injection period. Use these equations with caution, as they tend to fall apart for a well with a large

permeability or a high skin factor. Also remember, the welltest should not only reach radial flow, but also sustain radial flow for a timeframe sufficient for analysis of the radial flow period. As a rule of thumb, a timeframe sufficient for analysis is 3 to 5 times the time needed to reach radial flow.

3. As an alternative to steps 1 and 2, to look a specific distance “L” into the reservoir and possibly confirm the absence or existence of a boundary, the following equation can be used to estimate the time to reach that distance:

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_i \cdot L_{boundary}}{k} \text{ hours}$$

where, $L_{boundary}$ = feet to boundary

$t_{boundary}$ = time to boundary, hrs

Again, this is the time to reach a distance “L” in the reservoir. Additional test time is required to observe a fully developed boundary past the time needed to just reach the boundary. As a rule of thumb, to see a fully developed boundary on a log-log plot, allow at least 5 times the time to reach it. Additionally, for a boundary to show up on the falloff, it must first be encountered during the injection period.

4. Calculate the expected slope of the semilog plot during radial flow to see if gauge resolution will be adequate using the following equation:

$$m_{semilog} = \frac{162.6 \cdot q \cdot B}{k \cdot h \cdot \mu}$$

where, q = the injection rate preceding the falloff test, bpd

B = formation volume factor for water, rvb/stb (usually assumed to be 1)

Considerations for Offset Wells Completed in the Same Interval

Rate fluctuations in offset wells create additional pressure transients in the reservoir and complicate the analysis. Always try to simplify the pressure transients in the reservoir. Do not simultaneously shut-in an offset well and the test well. The following items are key considerations in dealing with the impact of offset wells on a falloff test:

- X Shut-in all offset wells prior to the test
- X If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
- X Obtain accurate injection records of offset injection prior to and during the test
- X At least one of the real time points corresponding to an injection rate in an offset well should be synchronized to a specific time relating to the test well
- X **Following the falloff test in the test well, send at least two pulses from the offset well to the test well by fluctuating the rate in the offset well.** The pressure pulses can confirm communication between the wells and can be simulated in the analysis if observed at the test well. The pulses can also be analyzed as an interference test using an Ei type curve.

- X If time permits, conduct an interference test to allow evaluation of the reservoir without the wellbore effects observed during a falloff test.

Falloff Test Analysis

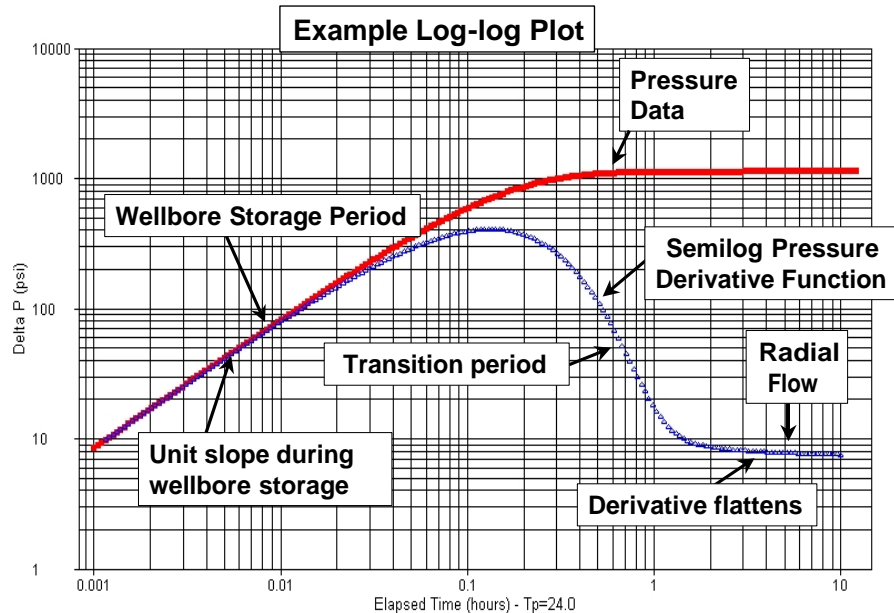
In performing a falloff test analysis, a series of plots and calculations should be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. Individual plots, flow regime signatures, and calculations are discussed in the following sections.

Cartesian Plot

- X The pressure data prior to shut-in of the well should be reviewed on a Cartesian plot to confirm pressure stabilization prior to the test. A well that has reached radial flow during the injectivity portion of the test should have a consistent injection pressure.
- X A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to the pressure gauges used to confirm adequate gauge resolution existed throughout the test. If the gauge resolution limit was reached, this timeframe should be identified to determine if radial flow was reached prior to reaching the resolution of the pressure gauge. Pressure data obtained after reaching the resolution of the gauge should be treated as suspect and may need to be discounted in the analysis.
- X **Falloff tests conducted in highly transmissive reservoirs** may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for by the pressure gauge, resulting in erroneous pressure data and an incorrect analysis. For this reason, the Cartesian plot of the temperature data should be reviewed. **Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.**
- X Include the injection rate(s) of the test well 48 hours prior to shut-in on the Cartesian plot to illustrate the consistency of the injection rate prior to shut-in and to determine the appropriate time function to use on the log-log and semilog plots. (See Appendix, page A10 for time function selection)

Log-log Diagnostic Plot

- X Plot the pressure and semilog derivative versus time on a log-log diagnostic plot. Use the appropriate time function based on the rate history of the injection period preceding the falloff. (See Appendix, page A-10 for time function selection) The log-log plot is used to identify regimes in the welltest. An example plot is shown below:



Identification of Test Flow Regimes

- X Flow regimes are mathematical relationships between pressure, rate, and time. Flow regimes provide a visualization of what goes on in the reservoir. Individual flow regimes have characteristic slopes and a sequencing order on the log-log plot.
- X Various flow regimes will be present during the falloff test, however, not all flow regimes are observed on every falloff test. The late time responses correlate to distances further from the test well. **The critical flow regime is radial flow from which all analysis calculations are performed.** During radial flow, the pressure responses recorded are representative of the reservoir, not the wellbore.
- X The derivative function amplifies reservoir signatures by calculating a running slope of a designated plot. The derivative plot allows a more accurate determination of the radial flow portion of the test, in comparison with the old method of simply proceeding 1½ log cycles from the end of the unit slope line of the pressure curve.
- X The derivative is usually based on the semilog plot, but it can also be calculated based on other plots such as a Cartesian plot, a square root of time plot, a quarter root of time plot, and the 1/square root of time plot. Each of these plots are used to identify specific flow regimes. If the flow regime characterized by a specialized plot is present then when the derivative calculated from that plot is displayed on the log-log plot, it will appear as a

“flat spot” during the portion of the falloff corresponding to the flow regime.

X **Typical flow regimes observed on the log-log plot** and their semilog derivative patterns are listed below:

<u>Flow Regime</u>	<u>Semilog Derivative Pattern</u>
Wellbore Storage	Unit slope
Radial Flow	Flat plateau
Linear Flow	Half slope
Bilinear Flow	Quarter slope
Partial Penetration	Negative half slope
Layering	Derivative trough
Dual Porosity	Derivative trough
Boundaries	Upswing followed by plateau
Constant Pressure	Sharp derivative plunge

Characteristics of Individual Test Flow Regimes

X **Wellbore Storage:**

1. Occurs during the early portion of the test and is caused by the well being shut-in at the surface instead of the sandface
2. Measured pressure responses are governed by well conditions and are not representative of reservoir behavior and are characterized by both the pressure and semilog derivative curves overlying a unit slope on the log-log plot
3. Wellbore skin or a low permeability reservoir results in a slower transfer of fluid from the well to the formation, extending the duration of the wellbore storage period
4. A wellbore storage dominated test is unanalyzable

X **Radial Flow:**

1. The pressure responses are from the reservoir, not the wellbore
2. The critical flow regime from which key reservoir parameters and completion conditions calculations are performed
3. Characterized by a flattening of the semilog plot derivative curve on the log-log plot and a straight line on the semilog plot

X **Spherical Flow:**

1. Identifies partial penetration of the injection interval at the wellbore
2. Characterized by the semilog derivative trending along a negative half slope on the log-log plot and a straight line on the 1/square root of time plot
3. The log-log plot derivative of the pressure vs 1/square root of time plot is flat

X **Linear Flow:**

1. May result from flow in a channel, parallel faults, or a highly conductive fracture
2. Characterized by a half slope on both the log-log plot pressure and semilog derivative curves with the derivative curve approximately 1/3 of a log cycle lower than the pressure curve and a straight line on the square root of time plot. 3.
The log-log plot derivative of the pressure vs square root of time plot is flat

X **Hydraulically Fractured Well:**

1. Multiple flow regimes present including wellbore storage, fracture linear flow, bilinear flow, pseudo-linear flow, formation linear flow, and pseudo-radial flow
2. Fracture linear flow is usually hidden by wellbore storage
3. Bilinear flow results from simultaneous linear flows in the fracture and from the formation into the fracture, occurs in low conductivity fractures, and is characterized by a quarter slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus quarter root of time plot
4. Formation linear flow is identified by a half slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus square root of time plot
5. Pseudo-radial flow is analogous to radial flow in an unfractured well and is characterized by flattening of semilog derivative curve on the log-log plot and a straight line on a semilog pressure plot

X **Naturally Fractured Rock:**

1. The fracture system will be observed first on the falloff test followed by the total system consisting of the fractures and matrix.
2. The falloff analysis is complex. The characteristics of the semilog derivative trough on the log-log plot indicate the level of communication between the fractures and the matrix rock.

X **Layered Reservoir:**

1. Analysis of a layered system is complex because of the different flow regimes, skin factors or boundaries that may be present in each layer.
2. The falloff test objective is to get a total transmissibility from the **whole reservoir system**.
3. Typically described as commingled (2 intervals with vertical separation) or crossflow (2 intervals with hydraulic vertical communication)

Semilog Plot

- X The semilog plot is a plot of the pressure versus the log of time. There are typically four different semilog plots used in pressure transient and falloff testing analysis. After plotting the appropriate semilog plot, a straight line should be drawn through the points located within the equivalent radial flow portion of the plot identified from the log-log

plot.

- X Each plot uses a different time function depending on the length and variation of the injection rate preceding the falloff. These plots can give different results for the same test, so it is important that the appropriate plot with the correct time function is used for the analysis. Determination of the appropriate time function is discussed below.
- X The slope of the semilog straight line is then used to calculate the reservoir transmissibility - kh/μ , the completion condition of the well via the skin factor - s , and also the radius of investigation - r_i of the test.

Determination of the Appropriate Time Function for the Semilog Plot

The following four different semilog plots are used in pressure transient analysis:

1. Miller Dyes Hutchinson (MDH) Plot
2. Horner Plot
3. Agarwal Equivalent Time Plot
4. Superposition Time Plot

These plots can give different results for the same test. Use of the appropriate plot with the correct time function is critical for the analysis.

- X The **MDH plot** is a semilog plot of pressure versus Δt , where Δt is the elapsed shut-in time of the falloff.
 1. The MDH plot only applies to wells that reach psuedo-steady state during injection. Psuedo-steady state means the pressure response from the well has encountered all the boundaries around the well.
 2. The MDH plot is only applicable to injection wells with a *very* long injection period at a constant rate. This plot is not recommended for use by EPA Region 6.
- X The **Horner plot** is a semilog plot of pressure versus $(t_p+\Delta t)/\Delta t$. The Horner plot is only used for a falloff preceded by a single constant rate injection period.
 1. The injection time, $t_p=V_p/q$ in hours, where V_p =injection volume since the last pressure equalization and q is the injection rate prior to shut-in for the falloff test. The injection volume is often taken as the cumulative injection since completion.
 2. The Horner plot can result in significant analysis error if the injection rate varies prior to the falloff.
- X The **Agarwal equivalent time plot** is a semilog plot of the pressure versus Agarwal equivalent time, Δt_e .
 1. The Agarwal equivalent time function is similar to the Horner plot, but scales the falloff to make it look like an injectivity test.
 2. It is used when the injection period is a short, constant rate compared to the length of the falloff period.
 3. The Agarwal equivalent time is defined as: $\Delta t_e=\log(t_p \Delta t)/(t_p+\Delta t)$, where t_p is calculated the same as with the Horner plot.

- X The **superposition time function** accounts for variable rate conditions preceding the falloff.
1. It is the most rigorous of all the time functions and is usually calculated using welltest software.
 2. The use of the superposition time function requires the operator to accurately track the rate history. As a rule of thumb, at a minimum, the rate history for twice the length of the falloff test should be included in the analysis.

The determination of which time function is appropriate for the plotting the welltest on semilog and log-log plots depends on available rate information, injection period length, and software:

1. If there is not a rate history other than a single rate and cumulative injection, use a Horner time function
2. If the injection period is shorter than the falloff test and only a single rate is available, use the Agarwal equivalent time function
3. If you have a variable rate history use superposition when possible. As an alternative to superposition, use Agarwal equivalent time on the log-log plot to identify radial flow. The semilog plot can be plotted in either Horner or Agarwal time if radial flow is observed on the log-log plot.

Parameter Calculations and Considerations

- X Transmissibility - The slope of the semilog straight line, m , is used to determine the transmissibility (kh/μ) parameter group from the following equation:

$$\frac{k \cdot h}{\mu} = \frac{162.6 \cdot q \cdot B}{m}$$

where, q = injection rate, bpd (negative for injection)

B = formation volume factor, rvb/stb (Assumed to be 1 for formation fluid)

m = slope of the semilog straight line through the radial flow portion of the plot in psi/log cycle

k = permeability, md

h = thickness, ft (See Appendix, page A-15)

μ = viscosity, cp

- X The viscosity, μ , is usually that of the formation fluid. However, if the waste plume size is massive, the radial flow portion of the test may remain within the waste plume. (See Appendix, page A-14)
1. The waste and formation fluid viscosity values usually are similar, however, if the wastestream has a significant viscosity difference, the size of the waste plume and distance to the radial flow period should be calculated.
 2. The mobility, k/μ , differences between the fluids may be observed on the derivative curve.

- X The permeability, k , can be obtained from the calculated transmissibility (kh/μ) by substituting the appropriate thickness, h , and viscosity, μ , values.

Skin Factor

- X In theory, wellbore skin is treated as an infinitesimally thin sheath surrounding the wellbore, through which a pressure drop occurs due to either damage or stimulation. Industrial injection wells deal with a variety of waste streams that alter the near wellbore environment due to precipitation, fines migration, ion exchange, bacteriological processes, and other mechanisms. It is reasonable to expect that this alteration often exists as a zone surrounding the wellbore and not a skin. Therefore, at least in the case of industrial injection wells, the assumption that skin exists as a thin sheath is not always valid. This does not pose a serious problem to the correct interpretation of falloff testing except in the case of a large zone of alteration, or in the calculation of the flowing bottomhole pressure. Region 6 has seen instances in which large zones of alteration were suspected of being present.
- X The skin factor is the measurement of the completion condition of the well. The skin factor is quantified by a positive value indicating a damaged completion and a negative value indicating a stimulated completion.
1. The magnitude of the positive value indicating a damaged completion is dictated by the transmissibility of the formation.
 2. A negative value of -4 to -6 generally indicates a hydraulically fractured completion, whereas a negative value of -1 to -3 is typical of an acid stimulation in a sandstone reservoir.
 3. The skin factor can be used to calculate the effective wellbore radius, r_{wa} also referred to the apparent wellbore radius. (See Appendix, page A-13)
 4. The skin factor can also be used to correct the injection pressure for the effects of wellbore damage to get the actual reservoir pressure from the measured pressure.
- X The skin factor is calculated from the following equation:

$$s = 1.1513 \left[\frac{P_{1hr} - P_{wff}}{m} - \log \left(\frac{k \cdot t_p}{(t_p + 1) \cdot \phi \cdot \mu \cdot c_t \cdot r_w^2} \right) + 3.23 \right]$$

where, s = skin factor, dimensionless

P_{1hr} = pressure intercept along the semilog straight line at a shut-in time of 1 hour, psi

P_{wff} = measured injection pressure prior to shut-in, psi

μ = appropriate viscosity at reservoir conditions, cp (See Appendix, page A-14)

m = slope of the semilog straight line, psi/cycle

k = permeability, md

ϕ = porosity, fraction

c_t = total compressibility, psi^{-1}

r_w = wellbore radius, feet

t_p = injection time, hours

Note that the term $t_p/(t_p + \Delta t)$, where $\Delta t = 1$ hr, appears in the log term. This term is usually assumed to result in a negligible contribution and typically is taken as 1 for large t . However, for relatively short injection periods, as in the case of a drill stem test (DST), this term can be significant.

Radius of Investigation

- X The radius of investigation, r_i , is the distance the pressure transient has moved into a formation following a rate change in a well.
- X There are several equations that exist to calculate the radius of investigation. All the equations are square root equations based on cylindrical geometry, but each has its own coefficient that results in slightly different results, (See Oil and Gas Journal, Van Poolen, 1964).
- X Use of the appropriate time is necessary to obtain a useful value of r_i . For a falloff time shorter than the injection period, use Agarwal equivalent time function, Δt_e , at the end of the falloff as the length of the injection period preceding the shut-in to calculate r_i .
- X The following two equivalent equations for calculating r_i were taken from SPE Monograph 1, (Equation 11.2) and Well Testing by Lee (Equation 1.47), respectively:

$$r_i = \sqrt{0.00105 \frac{k \cdot t}{\phi \cdot \mu \cdot c_t}} \equiv \sqrt{\frac{k \cdot t}{948 \cdot \phi \cdot \mu \cdot c_t}}$$

Effective Wellbore Radius

- X The effective wellbore radius relates the wellbore radius and skin factor to show the effects of skin on wellbore size and consequently, injectivity.
- X The effective wellbore radius is calculated from the following:

$$r_{wa} = r_w e^{-s}$$

- X A negative skin will result in a larger effective wellbore radius and therefore a lower injection pressure.

Reservoir Injection Pressure Corrected for Skin Effects

- X The pressure correction for wellbore skin effects, ΔP_{skin} , is calculated by the following:

$$\Delta P_{skin} = 0.868 \cdot m \cdot s$$

where, m = slope of the semilog straight line, psi/cycle
 s = wellbore skin, dimensionless

- X The adjusted injection pressure, P_{wfa} is calculated by subtracting the ΔP_{skin} from the measured injection pressure prior to shut-in, P_{wf} . This adjusted pressure is the calculated reservoir pressure prior to shutting in the well, $\Delta t=0$, and is determined by the following:

$$P_{wfa} = P_{wf} - \Delta P_{skin}$$

- X From the previous equations, it can be seen that the adjusted bottomhole pressure is directly dependent on a single point, the last injection pressure recorded prior to shut-in. Therefore, an accurate recording of this pressure prior to shut-in is important. Anything that impacts the pressure response, e.g., rate change, near the shut-in of the well should be avoided.

Determination of the Appropriate Fluid Viscosity

- X If the wastestream and formation fluid have similar viscosities, this process is not necessary.
- X This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/\mu)_w$, and formation fluid, $(k/\mu)_f$. Depending on when the test reaches radial flow, these cases with extreme mobility differences could cause the derivative curve to change and level to another value. Eliminating alternative geologic causes, such as a sealing fault, multiple layers, dual porosity, etc., leads to the interpretation that this change may represent the boundary of the two fluid banks.
- X First assume that the pressure transients were propagating through the formation fluid during the radial flow portion of the test, and then verify if this assumption is correct. This is generally a good strategy except for a few facilities with exceptionally long injection histories, and consequently, large waste plumes. The time for the pressure transient to exit the waste front is calculated. This time is then identified on both the log-log and semilog plots. The radial flow period is then compared to this time.
- X The radial distance to the waste front can then be estimated volumetrically using the following equation:

$$r_{\text{waste plume}} = \sqrt{\frac{0.13368 \cdot V_{\text{waste injected}}}{\pi \cdot h \cdot \phi}}$$

where, $V_{\text{waste injected}}$ = cumulative waste injected into the completed interval, gal

$r_{\text{waste plume}}$ = estimated distance to waste front, ft

h = interval thickness, ft

ϕ = porosity, fraction

X The time necessary for a pressure transient to exit the waste front can be calculated using the following equation:

$$t_w = \frac{126.73 \cdot \mu_w \cdot c_t \cdot V_{\text{waste injected}}}{\pi \cdot k \cdot h}$$

where, t_w = time to exit waste front, hrs

$V_{\text{waste injected}}$ = cumulative waste injected into the completed interval, gal

h = interval thickness, ft

k = permeability, md

μ_w = viscosity of the historic waste plume at reservoir conditions, cp

c_t = total system compressibility, psi^{-1}

X The **time should be plotted on both the log-log and semilog plots** to see if this time corresponds to any changes in the derivative curve or semilog pressure plot. If the time estimated to exit the waste front occurs before the start of radial flow, the assumption that the pressure transients were propagating through the reservoir fluid during the radial flow period was correct. Therefore, the viscosity of the reservoir fluid is the appropriate viscosity to use in analyzing the well test. If not, the viscosity of the historic waste plume should be used in the calculations. If the mobility ratio is extreme between the wastestream and formation fluid, adequate information should be included in the report to verify the appropriate fluid viscosity was utilized in the analysis.

Reservoir Thickness

X The thickness used for determination of the permeability should be justified by the operator. The net thickness of the defined injection interval is not always appropriate.

X The permeability value is necessary for plume modeling, but the transmissibility value, kh/μ , can be used to calculate the pressure buildup in the reservoir without specifying values for each parameter value of k , h , and μ .

X Selecting an interval thickness is dependent on several factors such as whether or not the injection interval is composed of hydraulically isolated units or a single massive unit and wellbore conditions such as the depth to wellbore fill. When hydraulically isolated sands

are present, it may be helpful to define the amount of injection entering each interval by conducting a flow profile survey. Temperature logs can also be reviewed to evaluate the intervals receiving fluid. Cross-sections may provide a quick look at the continuity of the injection interval around the injection well.

- X A copy of a SP/Gamma Ray well log over the injection interval, the depth to any fill, and the log and interpretation of available flow profile surveys run should be submitted with the falloff test to verify the reservoir thickness value assumed for the permeability calculation.

Use of Computer Software

- X To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.
- X All data should be submitted on a CD-ROM with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the CD, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

- X After analyzing any test, always look at the results to see if they “make sense” based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.
- X If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.
- X Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data

acquisition hardware such as a faulty gauge. An anomalous response can often be traced to a brief, but significant rate change in either the test well or an offset well.

- X Anomalous data trends have also been caused by such things as ambient temperature changes in surface gauges or a faulty pressure gauge. Explanations for data trends may be facilitated through an examination of the backup pressure gauge data, or the temperature data. It is often helpful to qualitatively examine the pressure and/or temperature channels from both gauges. The pressure data should overlay during the falloff after being corrected for the difference in gauge depths. On occasion, abrupt temperature changes can be seen to correspond to trends in the pressure data. Although the source of the temperature changes may remain unexplainable, the apparent correlation of the temperature anomaly to the pressure anomaly can be sufficient reason to question the validity of the test and eliminate it from further analysis.
- X The data that is obtained from pressure transient testing should be compared to permit parameters. Test derived transmissibilities and static pressures can confirm compliance with non-endangerment (Area Of Review) conditions.

APPENDIX F

EPA Region 9 Step Rate Test Procedure Guidelines

UIC Permit R9UIC-CA1-FY17-3

Refer also to:

Society of Petroleum Engineers (SPE) Paper #16798, Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure

(This paper can be ordered from the SPE website.)

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
DRINKING WATER PROTECTION
75 HAWTHORNE STREET
SAN FRANCISCO, CA 94105**

STEP-RATE TEST PROCEDURE GUIDELINES

PURPOSE:

The purpose of the document is to provide guidelines for performing a Step-Rate Test (SRT). Test results shall be used by the EPA Region 9 (EPA) Underground Injection Control (UIC) offices to determine a Maximum Allowable Injection Pressure (MAIP) at the wellhead that will provide for the protection of underground sources of drinking water (USDW) at injections wells.

A detailed work plan proposal must be submitted to EPA for review and approval prior to the SRT being performed. The work plan must include detailed plans, supporting justifications and associated calculations for conducting the SRT. Refer to the Society of Petroleum Engineers (“SPE”) paper 16798 for supporting test design and analysis guidance (1987, Society of Petroleum Engineers).

Dialogue is expected and encouraged during the actual development of the work plan. EPA will review the work plan proposal and will send written communications either to request clarification or changes to the proposed work, or grant approval of the proposed work. Once the SRT plan is approved, we require at least 30 days’ notice in advance of SRT operations so we may schedule an EPA representative to witness the SRT.

Test results will be used by Region 9’s Underground Injection Control permitting program to determine a Maximum Allowable Injection Pressure (MAIP) which is the surface pressure that correlates to (a) 80 percent of the bottom hole pressure (BHP) that represents the Formation Parting Pressure (FPP) of the permitted injection zone, or, (b) 80 percent of the maximum pressure applied during SRTs in which the FPP was not achieved. This determination serves to provide for the protection of the Underground Sources of Drinking Water (USDWs) as required by the regulations at 40 CFR §§ 146.12(e)(3) (fracture pressure) and 146.14(b)(3) (the anticipated maximum pressure and flow rate at which the permittee will operate).

SRT results must be documented and the test should be witnessed by an EPA inspector who can assist in approving real-time modifications.

RECOMMENDED TEST PROCEDURES:

- 1) The well should be shut in long enough prior to testing such that the BHP approximates static formation pressures.
- 2) It is important to use equipment that will be capable of accurately controlled pumping rates at varying amounts and exceeding the estimated Formation Parting Pressure (FPP) or alternately,

equipment that will exceed the operator's equipment limitations by 120%. Operator must also ensure that sufficient water will be available onsite to complete the SRT. The water used for the SRT may be the operator's permitted wastewater or other water with known specific gravity.

3) Measure and record test pressures with both down-hole and surface pressure recorders. Observe, record, and synchronize surface and BHP pressures, times, dates, and injection rates for each increment (step) of the test. The BHP behavior will be the basis for the determination of FPP. Surface pressures will also be observed to monitor pressure versus rate behavior during the SRT and to determine pressure losses due to friction and other factors that affect the MAIP.

4) The step intervals must be of equal duration and their duration must be of no less than the minimum 30 minutes. Engineering based justification of the planned duration for the steps is required. Steps must be sufficiently long to overcome well bore storage effects and achieve or clearly demonstrate a stabilized pressure (radial flow) at the end of each timed step.

5) The SRT should proceed continuously and uninterrupted, with minimally delayed transition between steps. The SRT must be planned to provide at least 3 to 5 steps before reaching the expected FPP and at least 3 additional steps after exceeding the FPP. Alternatively, the SRT must exceed the BHP that occurs at the operator's maximum equipment surface pressure limitation by at least 120 percent of that corresponding BHP.

6) Because a surface readout of the BHP is employed, the duration of the planned injection rate increments may be modified during the initial part of the test. This will allow, for instance, an initial determination whether modification of the subsequent rate increments may be necessary to obtain at least three BHP data points above the FPP or to adequately exceed the proposed operator's maximum equipment limitation before concluding the test. The well operator shall consult and receive approval from the onsite EPA inspector before any modifications to the plan are implemented during ongoing SRT operations.

7) After pumping stops, observe and record (a) the instantaneous shut-in pressure (ISIP) and (b) the injection zone's pressure fall-off decline for a sufficient time to allow a pressure transient analysis which shall be included in the operator's report. The length of time for pressure fall-off observation will be determined in consultation with EPA prior to conducting the SRT, but may be modified by EPA depending on the actual BHP fall-off behavior observed at the conclusion of the test.

APPENDIX G

Plugging and Abandonment Plan

UIC Permit R9UIC-CA1-FY17-3

ATTACHMENT Q – PLUGGING AND ABANDONMENT PLAN

In the event McKittrick Limited WD 1 becomes unfit for injection or is no longer economic to operate, a thorough plugging and abandonment (P&A) program will be performed to EPA and DOGGR standards. The tubing and packer will be pulled from the hole. The abandonment will consist of a wellbore clean-out down to 3,943 feet, followed by cement plug abandonment from total depth to surface. The cement intended to be used for abandonment is Class G Abandonment cement. The abandoned well will be marked with a steel plate welded on top of the casing. The well name will be welded onto the steel plate. The cellar will be dug out at five feet below ground level and covered with fill dirt. The packer will be redressed to be used elsewhere, if appropriate. See Table 5 for details on the workover procedures. A detailed P&A program with cost estimate is provided in Exhibit Q-1. A completed EPA form 7520-19 has been prepared for McKittrick Limited WD 1 and is included in Exhibit Q-2.

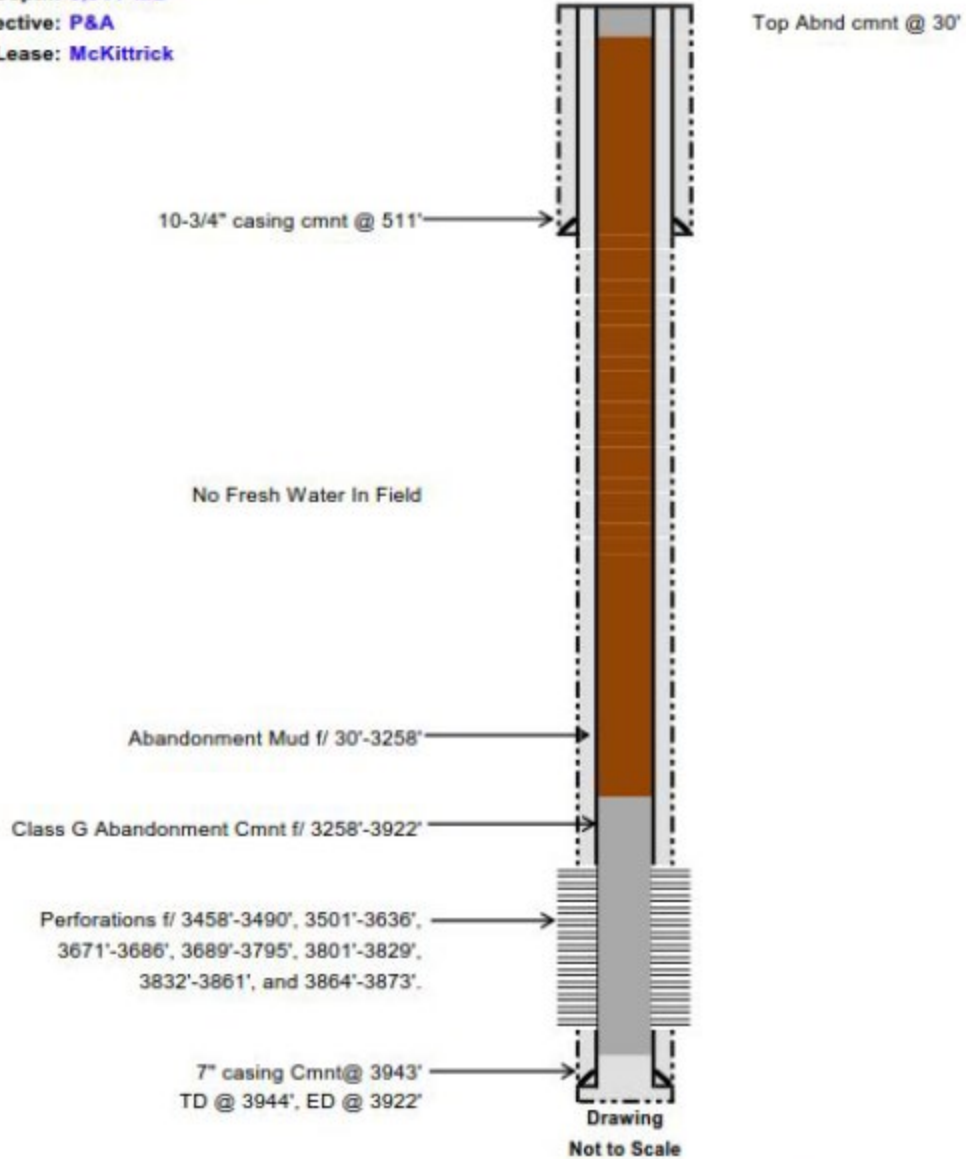
Table 5: McKittrick Limited WD 1 workover rig steps to abandon the Stevens Sand.

Revised
 1/18/2017
 2:04 PM

ACTIVITY CODE	OPERATION DESCRIPTION	MD ft	MW ppg	EXPECTED hrs	CUM TIME days
ABND	MIRU Production Rig, PDOH/LD tubing, RDMO production rig, SDON.	3,922'	9.7	24	1.0
ABND	Move in CTU. RIH to 3922, CO any fill. Pump abnd cmnt f/ 3922'-3258". WOC Tag cmnt. SDON.	3,258'	9.7	24	2.0
ABND	Displace fluid w/ abandonment mud f/ 3258'-30'. Pump abnd cmnt f/ 30'-Surface.	0'	9.7	16	2.7
ABND	WOC Tag cmnt. SDON.	0'	9.7	8	3.0
ABND	Dig out cellar. Cut casing 5' below GL. Cover with fill dirt. Well Abandoned.	0'	9.7	24	4.0

WD-1
Kern County, CA Sec 13-T30S-R21E MDB&M
Wellbore Diagram

Well Design: Casing: 10-3/4" x 7"
Planned Depth: 3,944' MD
Objective: P&A
Lease: McKittrick



Lonnie A. Kerley, Consultant						
Detail Workover Cost Estimate						
					AFE No.:	
Well Name:		McKittrick WD 1			Date: September 25, 2018	
Project Name:		Plug & Abandonment cost est			rig days = 4	
					# of	2 Prod hoist, 2 CT unit
Description	Charge Codes	Cost	Units	Units	Sub-Total	Comments
Supervision - Company	2410 1195	\$1,300	/ day	4	\$5,200	well site Supervision
Engineer	2410 1195	\$150	/ hr	10	\$1,500	Prog. permits
Transportation - Intangible, vac trucks/mud, etc.	2410 2105	\$250	/ day	4	\$1,000	vac trucks, misc equ
Rig Cost - Workover and Completion	2410 2320	\$5,125	/ day	4	\$20,500	2 Prod hoist, 2 CT unit
Rig Cost - Production	2410 2305	\$150	/ hr	0	\$0	
Rig Cost - Drilling	2410 2310	\$305	/ hr	0	\$0	
Rig Mob, Demob	2410 2325	\$3,000	/ well	0	\$0	
Mud & Chemicals - including foaming chemicals	2410 2331	\$2,500	/ well	0	\$0	
Cement & Cementing Services	2410 2355	\$7,500	/ well	4	\$17,000	cmt from ED to surf
Wireline Services - CASED HOLE-perf	2410 2370	\$3,600	/ well	0	\$0	
Wireline Services - slick line for P-bomb	2410 2370	\$1,000	/ well	0	\$0	
Wireline Services - pressure bomb	2410 2370	\$8,300	/ well	0	\$0	
Roads & Location - Construction	2410 2375	\$1,200	/ well	0	\$0	
Roads & Location - Misc other work	2410 2375	\$200	/ well	0	\$0	
Roads & Location - Sump Abandonment	2410 2375	\$1,600	/ well	0	\$0	
Equipment Rental - workover BHA	2410 2380	\$1,000	/ well	0	\$0	
Equipment Rental - Trailer / Office	2410 2380	\$50	/ day	0	\$0	
Equipment Rental - BOPE	2410 2380	\$500	/ day	2	\$1,000	estimate
Equipment Rental - Baker Tank	2410 2380	\$25	/ day	4	\$100	estimate
Baker tank delivery	2410 2380	\$250	/trip	2	\$500	estimate
Equipment Rental - Power Swivel	2410 2380	\$1,000	/ day	0	\$0	
Contract Labor	2410 2505	\$2,500	/ well	1	\$2,500	Welder, Backhoe, misc
Special Services - Directional Drillers	2410 2720	\$9,000	/ well	0	\$0	
Mud Loggers	2410 2725	\$0	/ day	0	\$0	
Logging / Formation Evaluation	2410 2730	\$5,750	/ well	0	\$0	
Core - Core Evaluation	2410 2735	\$0	/ well	0	\$0	
Conductor	2410 3515	\$1,600	/ well	0	\$0	
Drill Bits	2410 3705	\$2,000	/ well	0	\$0	
Survey Permits & Right of Way	2410 4240	\$500	/ well	0	\$0	
Miscellaneous Materials - Subsurface	2410 2390	\$250	/ well	0	\$0	
CONTINGENCY		20%	/ well	1	\$9,900	
				Intangible=	\$59,200	
Contract Labor - Pumping Unit Installation	2420 2525	\$800	/ well	0	\$0	
Lift equipment - Pumping Unit & base	2420 3105	\$1,000	/ well	0	\$0	
Contract Labor - Welder- csg work, well heads	2420 2520	\$1,000	/ well	0	\$0	
Contract Labor, Construction - Flowline	2420 2505	\$7,500	/ well	0	\$0	
Line Pipe & Pipeline Material	2420 3305	\$2,600	/ well	0	\$0	
Insulation Material	2420 3360	\$2,600	/ well	0	\$0	
Gathering/Distribution - Manifold	2420 3310	\$0	/ well	0	\$0	
Lift equipment - Prime Mover	2420 3335	\$1,000	/ well	0	\$0	
Electric Labor	2420 2515	\$3,600	/ well	0	\$0	
Electrical Materials	2420 3340	\$3,500	/ well	0	\$0	
Intrmd & Surf Csg	2420 3505	\$0	/ well	0	\$0	
Casing Installation - Tong Service	2420 2365	\$2,000	/ well	0	\$0	
Production Casing - 7" 23# K-55 LT&C	2420 3510	\$7.00	/ well	0	\$0	
Production Casing Hardware	2420 3510	\$1,000	/ well	0	\$0	
Liner - 5-1/2", 17#, K-55, LT&C	2420 3520	\$5.00	/ ft	0	\$0	
Liner - Slotting - 26R, 40Mx2"MUCS,6"C	2420 3520	\$5.00	/ ft	0	\$0	
Liner Hardware	2420 3520	\$1,750	/ well	0	\$0	
Wellhead / Tree - valves, etc.	2420 3525	\$800	/ well	0	\$0	
Tubing - 2-7/8" 6.5# K55 EUE	2420 3530	\$6	/ ft	0	\$0	
Lift Equipment - Pump	2420 3535	\$800	/ well	0	\$0	
CONTINGENCY		20%	/ well	0	\$0	
				Tangible=	\$0	
		TOTAL AFE COST=			\$59,200	

United States Environmental Protection Agency



**WELL REWORK RECORD, PLUGGING AND ABANDONMENT PLAN,
OR PLUGGING AND ABANDONMENT AFFIDAVIT**

Name and Address, Phone Number and/or Email of Permittee
 MCKITTRICK LIMITED
 4905 REWARD ROAD
 MCKITTRICK, CA 93251
 (661) 387-7828

Permit or EPA ID Number	API Number 029-87661	Full Well Name McKittrick Limited WD-1
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State California	County Kern
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Locate well in two directions from nearest lines of quarter section and drilling unit
 Latitude 35.319927
 Surface Location
 NE 1/4 of NE 1/4 of Section 13 Township 30S Range 21E Longitude -119.661573
 203 ft. from (N/S) N Line of quarter section
 410 ft. from (E/W) E Line of quarter section.

Well Class	Timing of Action (pick one)	Type of Action (pick one)
<input checked="" type="checkbox"/> Class I <input type="checkbox"/> Class II <input type="checkbox"/> Class III <input type="checkbox"/> Class V	<input type="checkbox"/> Notice Prior to Work Date Expected to Commence _____ <input type="checkbox"/> Report After Work Date Work Ended _____	<input type="checkbox"/> Well Rework <input checked="" type="checkbox"/> Plugging and Abandonment <input type="checkbox"/> Conversion to a Non-Injection Well

Provide a narrative description of the work planned to be performed, or that was performed. Use additional pages as necessary. See instructions.

Timing of action above is not applicable to the P&A plan submitted with the permit. In the event that McKittrick WD 1 becomes unfit for injection or is no longer economic to operate, the following P&A program will be performed.

The tubing and packer will be pulled from the hole. The abandonment will consist of a wellbore clean-out down to 3,943 feet, followed by cement plug abandonment from total depth to surface. The cement intended to be used for abandonment is Class G Abandonment cement. The abandoned well will be marked with a steel plate welded on top of the casing. The well name will be welded onto the steel plate. The cellar will be dug out at five feet below ground level and covered with fill dirt. The packer will be redressed to be used elsewhere, if appropriate.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)

Name and Official Title (Please type or print) Edward Capehart, Plant Manager	Signature 	Date Signed 10/25/19
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APPENDIX H

Operating Data

UIC Permit R9UIC-CA1-FY17-3

2,140 ft. had permeability less than 1 md and a porosity of 46.9%. Both samples are described by the laboratory as shaley mudstone. The sample at 2,140 ft. is described as having fractures.

The upper confining shale is of sufficient competency to create the seal to trap the hydrocarbon of both oil and gas. The reservoir was also under pressure as observed by the initial production found in DOGGR completion reports. Well Del Monte 84-A had a production of 1,040 MCFPD at a 19/64-inch beam and a tubing pressure of 460 lbs., casing pressure of 550 lbs. (page 40, DOGGR history).

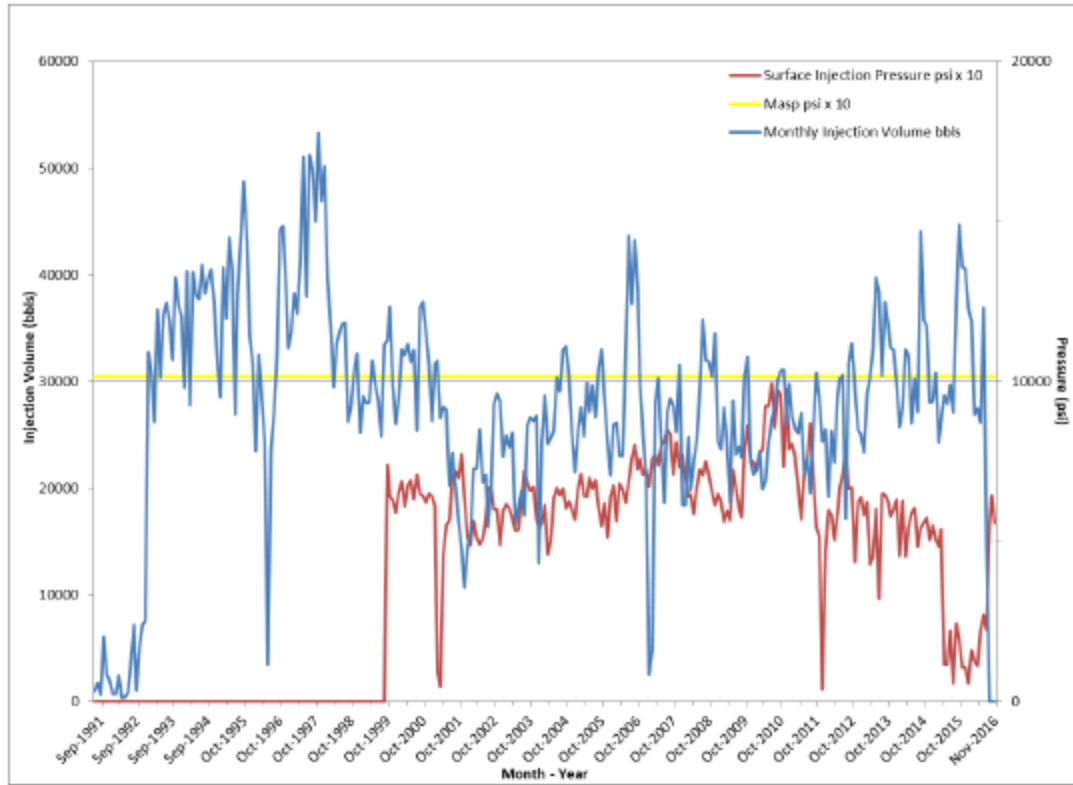
The lower confining shale was not sampled by sidewall cores due to lack of operator interest. The neutron porosity log was ran through the base of the Stevens sand into the underlying shale. The neutron curve shows a porosity of 24%. A mudlog accompanied the drilling of the McKittrick Limited WD 1 well. The lower confining shale is described as a siliceous shale with interbedded sandstone stringers. The shale is brittle and cherty, a typical description for the McDonald Shale. Drill rates through the shale became very slow to 10 ft. per hour, where it was drilling through the Stevens sand immediately above the McDonald at a 20 ft. to 40 ft. per hour drill rate. The mudlog notes that the Stevens carried oil shows from 2,420 ft. to 2,495 ft., 2,915 ft. to 2,930 ft., and 3,130 ft. to 3,185 ft.

ATTACHMENT H – OPERATING DATA

H.1 Average and Maximum Daily Rate and Volume of the Fluids to be Injected

The maximum proposed daily water injection volume is 2,500 barrels of water per day with an estimated average injection rate of 500 barrels of water per day. This average may vary due to the episodic nature of McKittrick and other WGP plant operations but will not exceed the maximum proposed daily injection volume. A plot of the injection volume since initial operation in 1991 is shown in Figure 3 below. The historic injection rate and surface injection pressure for well WD 1 is provided in Exhibit H-3.

Figure 3: Monthly Volume and Surface Pressure



H.2 Average and Maximum Injection Pressure – Stevens Sand

The Maximum Allowable Surface Pressure (MASP) is limited to below the pressure required to induce a hydraulic fracture of the receiving zone. The pressure value required to initiate a hydraulic fracture that was permitted by the California DOGGR is based on a fracture pressure gradient of 0.8 psi/ft. Based on an injection water gradient of 0.433 psi/ft the MASP is 1,015 psi. A safety factor of 80% has been applied to the MASP calculation, as follows:

$$\text{MASP: } [80\% \times (0.80 \text{ psi/ft} - 0.433 \text{ psi/ft}) \times 3,458 \text{ ft}] = 1,015 \text{ psi}$$

This is a conservative estimate since historical reservoir testing indicates that the fracture pressure gradient is 0.904 psi/foot (Attachment I, Exhibit I-1). A step-rate test will be performed upon final approval and issuance of a UIC Class I Permit by the EPA to determine the final MASP value.

H.3 Safe Operating Pressures for Injection Equipment

The injection equipment is engineered so that the surface and subsurface equipment safe operating pressures are below the anticipated MASP. The pressure rating for the surface piping and flanges is 2,200 psig (Pounds per Square Inch Gauge) at 100 degrees Fahrenheit and the pressure rating for the annulus pressure vessel is 1,750 psig at 250 degrees Fahrenheit.

The anticipated MASP for McKittrick Limited WD1 is 1,015 psi. The injection pumps are set to shut off when the anticipated MASP is reached. In addition, pressure relief devices on individual pieces of equipment will be set such that safe operating pressures are not exceeded.

H.4 Nature of Annulus Fluid

Fluids are contained in the casing-tubing-packer annulus as a safety precaution as well as to enable continuous monitoring of the annular pressure and volume. The casing-tubing-packer annulus will remain completely filled with fluid. A positive pressure of 100 psig will be applied by adding nitrogen to the annular fluid volume and this pressure will be continuously monitored and recorded. The fluid will typically have a specific gravity of ~ 1.0 and is comprised of water with the following additives:

- 2% potassium chloride (KCL)
- Corrosion inhibitor
- Oxygen scavenger (sodium sulfite, hydrazine)
- Biocide (sodium chromate, mercuric chloride, silver nitrate, coco primary amine acetate, coco trimethylene diamine, alkyl trimethyl quaternary ammonium chlorite, 1-phynyl-4, 4-dimethyl imidazoline, sodium tetrachlorophenate, acrolein, peracetic acid).

These treating fluids are available through various commercial chemical suppliers and are often proprietary. The typical chemical composition of the annulus fluid is:

Material	% Concentration
Potassium chloride (KCL)	1.0 to 3.0
Methanol	0.2 to 0.4
Alkylpyridine salts	0.02 to 0.06
Fatty quaternary NH4Cl	0.005 to 0.03

H.5 Source and Characteristics of the Injection Fluid

The waste stream sent to the injection well for disposal is the treated effluent of the power plant operation including RO reject water, boiler blowdown, cooling tower blowdown, and demineralization brine. Attachment K contains a description of the plant water processing steps. The facility receives municipal water from the Western Kern Water District.

A representative sample of wastewater was collected in October 2015. The wastewater sample was taken at the injection well McKittrick Limited WD 1 (Exhibit H-1). The sample was decanted into appropriate sampling containers and cooled with ice for storage and transportation under standard chain of custody procedures. The sample was delivered to a state and federal certified laboratory.

APPENDIX I

Manifest Requirements

UIC Permit R9UIC-CA1-FY17-3

Manifest System for Disposal Water

This Permit prohibits the injection of hazardous waste as defined in 40 CFR § 261 and limits the injection fluids to those as described in Paragraph II.D.5.a. of this Permit. It is the responsibility of the Permittee to ensure that prohibited fluids are not injected into Well McKittrick WD-1. Therefore, the Permittee is required to do the following to ensure that prohibited fluids are not injected for every disposal load received.

1. For each disposal load, the Permittee shall establish and maintain a three-party custody record between the Generator (responsible party from where the fluids were generated), Transporter, and Disposal Facility (Permittee). Each disposal load custody record shall include the following information:
 - a. Generator: facility name, facility address, facility telephone number, date, composition (i.e., boiler blow down, cooling tower blow down, boiler feed water conditioning waste waters, and raw water filter backwash) and total volume of fluids generated at the Generator;
 - b. Transporter: company name, company address, company telephone number, truck driver name, truck identification number, location, date, and time of disposal load pick up from the Generator;
 - c. Disposal Facility: facility name, facility address, facility telephone number, composition and volume of fluids unloaded at the Disposal Facility, date and time of unloading.
2. These records shall be kept for a minimum of five (5) years after date of disposal at the facility and shall be made available for inspection upon request.
3. For each disposal load, the Permittee shall provide the following certification:

I certify under penalty of law that the waste fluids that are injected into Well McKittrick WD-1 (API# 029-87661) have not been mixed with, or otherwise co-injected with hazardous waste at the Underground Injection Control Class I Non-hazardous permitted facility, and that injection of the waste fluids is in compliance with the applicable requirements contained in this Permit.

4. For each disposal load, the Permittee must obtain certification from the Transporter that states:

I certify under penalty of law that the waste fluids that I am transporting have not been mixed with hazardous wastes, and I have transported the waste fluids in compliance with Department of Transportation requirements for injection into a well subject to the requirements for the Class I Non-hazardous Underground Injection Control Program of the Safe Drinking Water Act.

5. The Permittee shall submit a report to EPA describing any discrepancies in the composition, transported volumes or place of origin of the injected fluids. These discrepancies may be identified based upon personal observations or information contained on the three-party custody record. A report of discrepancy shall be submitted with the Quarterly Reports as described in Paragraph II.D.5.a. of this Permit.