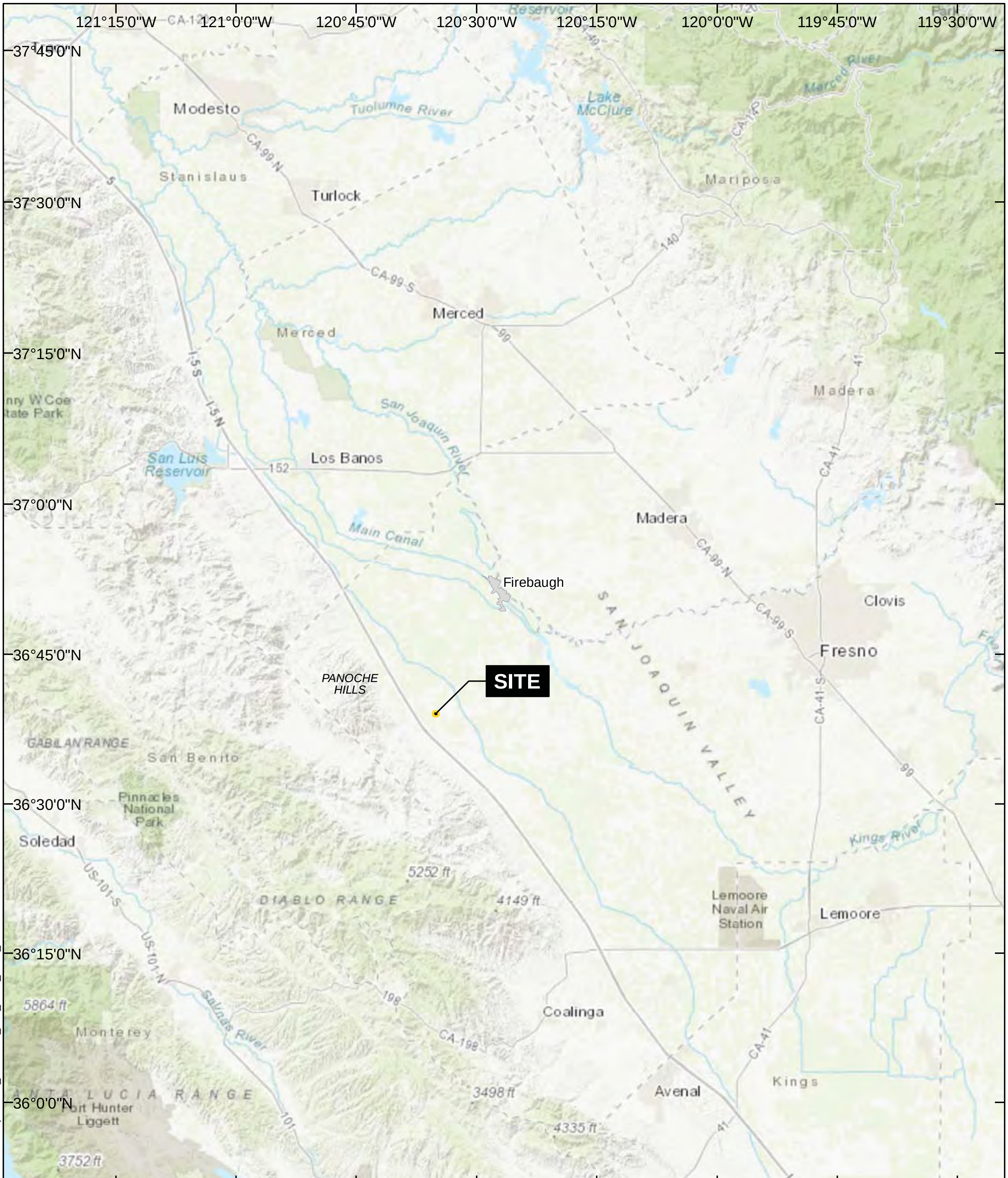
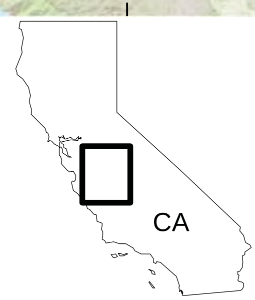
Appendix A

Project Maps

UIC Permit R9UIC-CA1-FY17-2R





0 10 20
SCALE IN MILES

MAP SOURCE: ESRI
SITE COORDINATES: 36°39'3"N, 120°35'4"W

HALEY ALDRICH

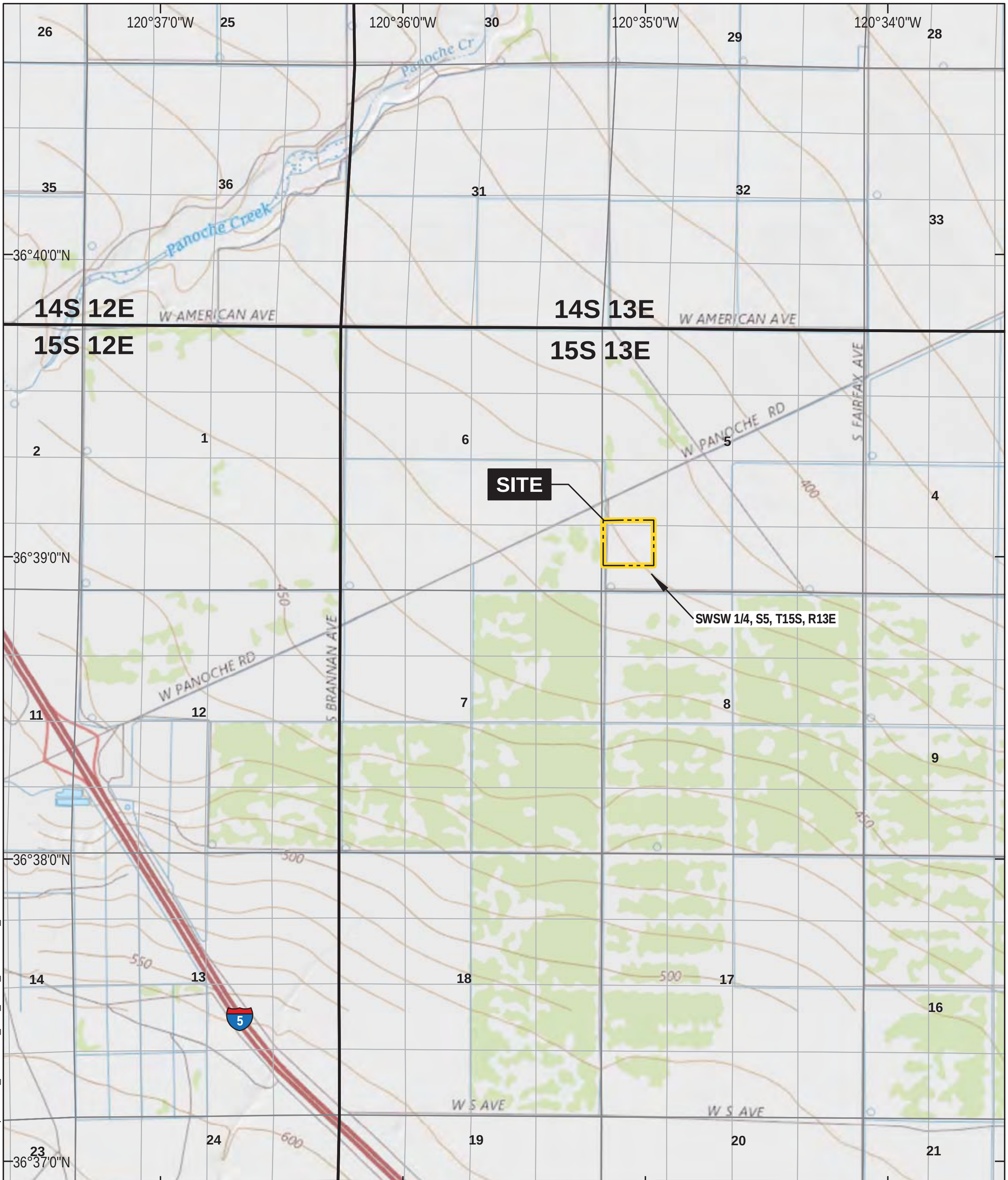
PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

SITE VICINITY

APPROXIMATE SCALE: 1 IN = 20 MI
OCTOBER 2017

FIGURE 1

GIS FILE PATH: G:\39073_Panoche_Compliance\GIS\Maps\2017_08\39073_007_0001_SITE_VICINITY.mxd — USER: ibruce — LAST SAVED: 10/17/2017 5:12:17 PM



N

0 0.5 1

SCALE IN MILES

MAP SOURCE: ESRI
SITE COORDINATES: 36°39'5"N, 120°35'7"W

HALEY ALDRICH

PANOCHE ENERGY CENTER
43833 WEST PANOCHE ROAD
FIREBAUGH, CALIFORNIA

PROJECT LOCUS

APPROXIMATE SCALE: 1 IN = 1 MI
SEPTEMBER 2017

FIGURE 2

GIS FILE PATH: G:\39073_Panoche_Compliance\GIS\Maps\2017_08\39073_007_0002_PROJECT_LOCUS.mxd — USER: ibruce — LAST SAVED: 9/1/2017 12:05:00 PM

Appendix B

Well Schematics

UIC Permit R9UIC-CA1-FY17-2R

Panoche Energy Center
Well IW1

FIGURE M-1

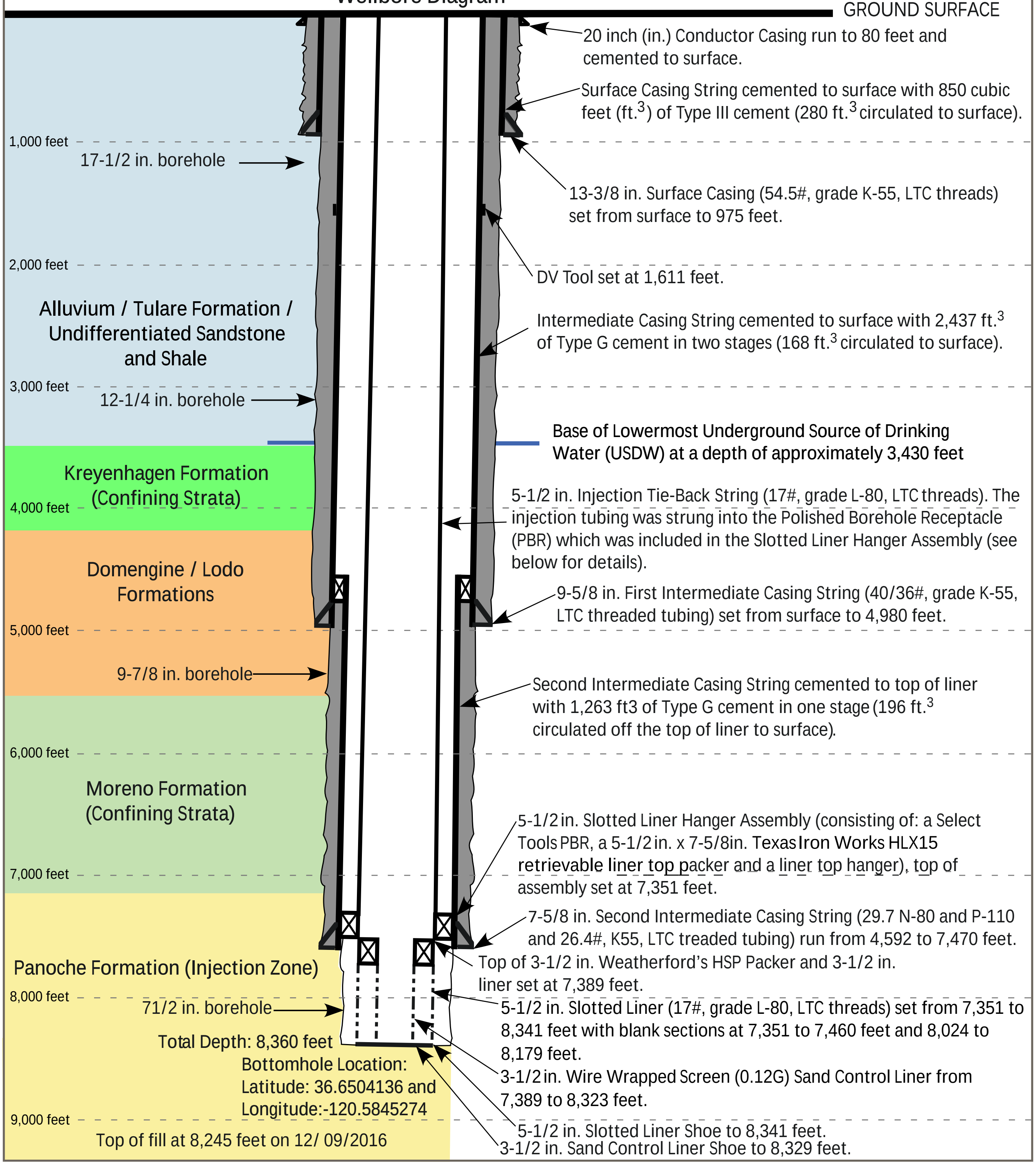
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.650645 and
Longitude:-120.5838281

Spud: September 26, 2008 Final Drilling Rig (Kenai #5)
Report: December 17, 2008 Final Completion Rig (Rival #9)
URS Completion Report: February 19, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =13 feet (ft.) above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 10/20/2020

Panoche Energy Center
Well IW2

FIGURE M-2

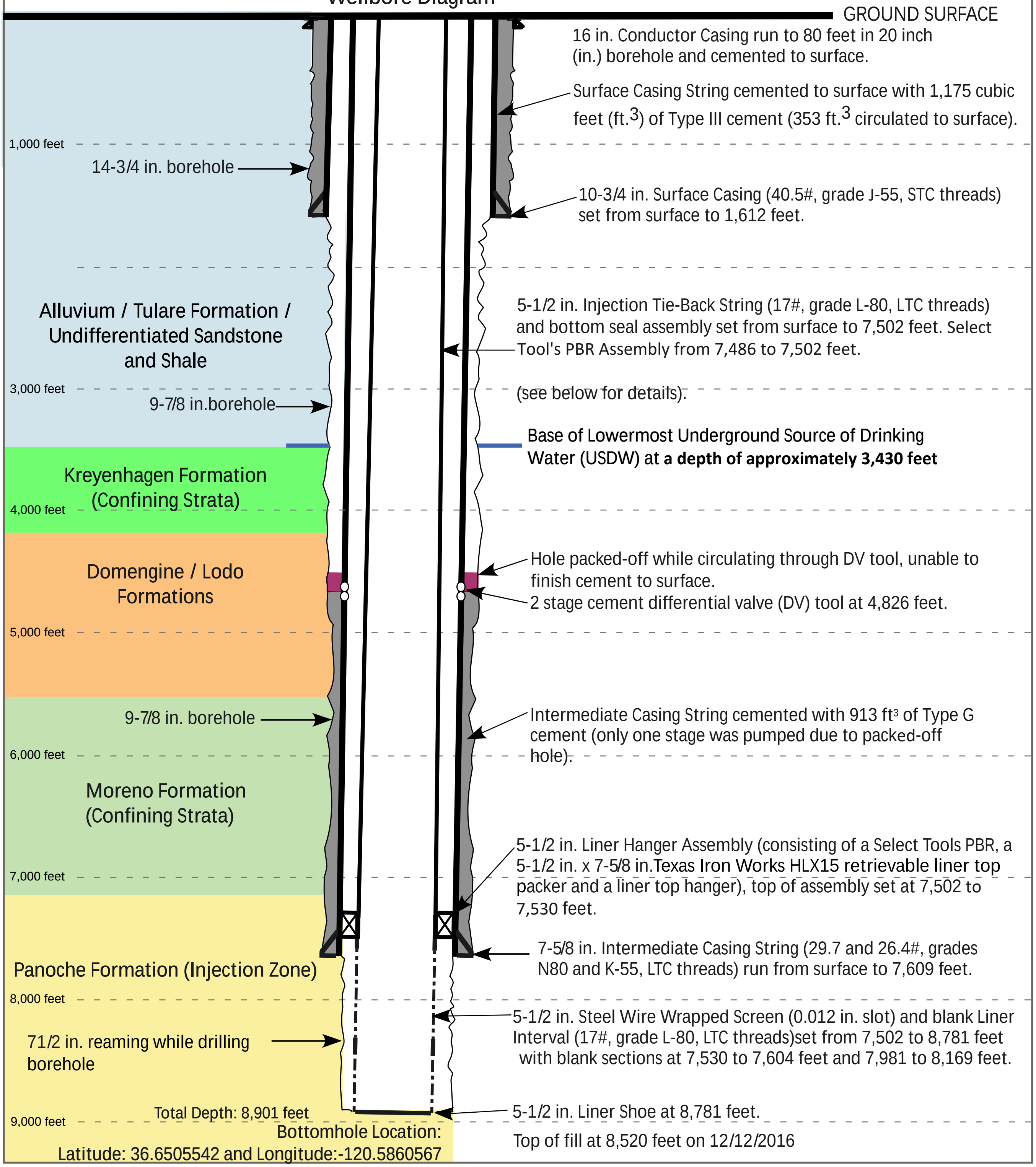
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.650588 and
Longitude:-120.5849399

Spud: December 19, 2008 Final Drilling Rig (Kenai #5)
Report: January 17, 2008 Final Completion Rig (Rival #9)
Report: January 29, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =13 feet (ft.) above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 11/05/2020

Panoche Energy Center Well IW3

FIGURE M-3

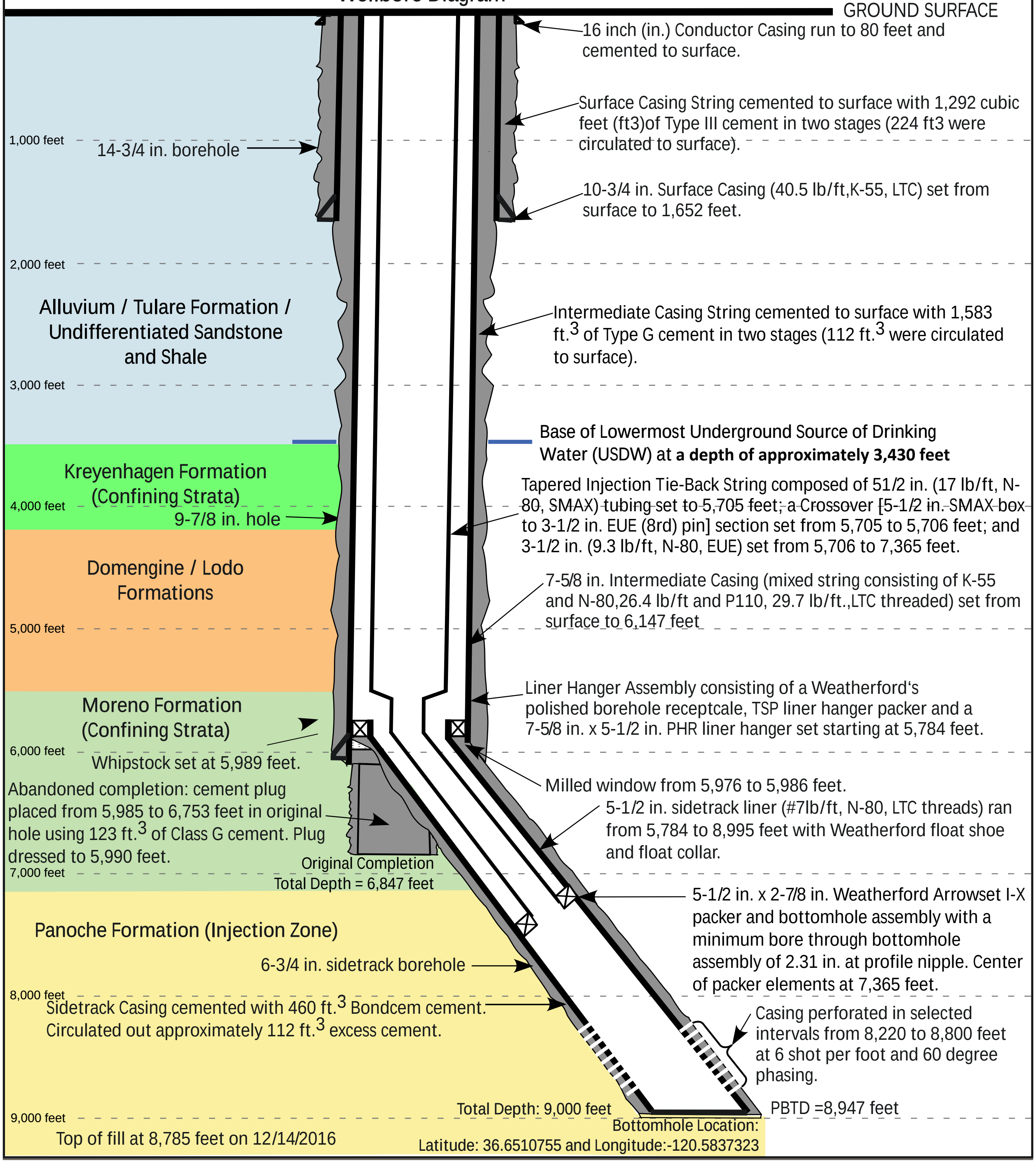
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.6506313 and
Longitude:-120.5833801

Spud: April 30, 2009
Final Original Hole Drilling Rig Report : May 25, 2009
Start of Well Deepening Sidetrack: October 19, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth = 19 feet (ft.) above Ground Surface (KB =427 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2018

Panoche Energy Center
Well IW4

FIGURE M-4

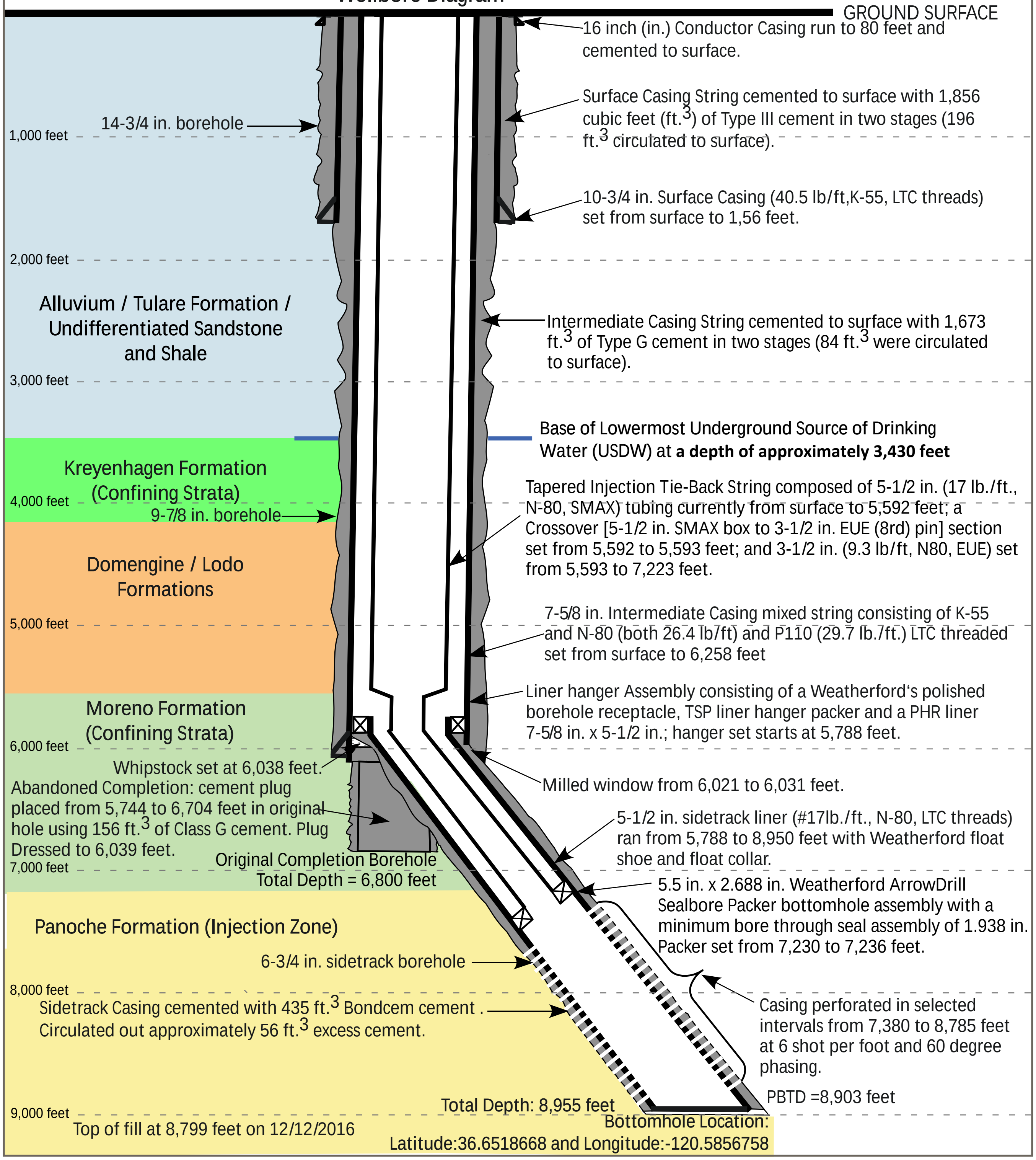
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/ State: Fresno / California

Wellhead Location:
Latitude: 36.6509366 and
Longitude:-120.585846

Spud: May 6, 2009
Final Original Hole Drilling Rig Report: June 4, 2009
Start of Well Deepening Sidetrack: October 20, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 410 feet above Mean Sea level (MSL)
Rig Kelly busing (KB) depth =19 feet (ft.) above Ground Surface (KB =429 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

Wellbore Diagram



UPDATED BY HALEY & ALDRICH, INC AND WEEGAR-EIDE & ASSOCIATES, LLC ON 12/18/2017

Appendix C

EPA Reporting Forms

UIC Permit R9UIC-CA1-FY17-2R

EPA Reporting Forms List

Form 7520-7: Application to Transfer Permit

Form 7520-8: Quarterly Injection Well Monitoring Report

Form 7520-18: Completion Report for Injection Wells

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-FY17-2R

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.

<u>Radioactive Baseline Survey</u>

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).

<u>Radioactive Tracer Depth Drive Survey</u>

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-FY17-2R

EPA Region 9
UIC PRESSURE FALLOFF REQUIREMENTS

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

August 8, 2002

TABLE OF CONTENTS

APPENDIX

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 Evironmental 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 <u>and any offset wells</u>.
    - 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, rvb/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

1. SPE Textbook Series No. 1, "Well Testing," 1982, W. John Lee
2. SPE Monograph 5, "Advances in Well Test Analysis," 1977, Robert Earlougher, Jr.
3. SPE Monograph 1, "Pressure Buildup and Flow Tests in Wells," 1967, C.S. Matthews and D.G. Russell
4. "Well Test Interpretation In Bounded Reservoirs," Hart's Petroleum Engineer International, Spivey, and Lee, November 1997
5. "Derivative of Pressure: Application to Bounded Reservoir Interpretation," SPE Paper 15861, Proano, Lilley, 1986
6. "Well Test Analysis," Sabet, 1991
7. "Pressure Transient Analysis," Stanislav and Kabir, 1990
8. "Well Testing: Interpretation Methods," Bourdarot, 1996
9. "A New Method To Account For Producing Time Effects When Drawdown Type Curves Are Used To Analyze Pressure Buildup And Other Test Data," SPE Paper 9289, Agarwal, 1980
10. "Modern Well Test Analysis – A Computer-Aided Approach," Roland N. Horne, 1990
11. Exxon Monograph, "Well Testing in Heterogeneous Formations," Tatiana Streltsova, 1987
12. EPA Region 6 Falloff Guidelines
13. "Practical Pressure Gauge Specification Considerations In Practical Well Testing," SPE Paper No. 22752, Veneruso, Ehlig-Economides, and Petitjean, 1991

14. “Guidelines Simplify Well Test Interpretation,” Oil and Gas Journal, Ehlig-Economides, Hegeman, and Vik, July 18, 1994
15. Oryx Energy Company, Practical Pressure Transient Testing, G. Lichtenberger and K. Johnson, April 1990 (Internal document)
16. Pressure-Transient Test Design in Tight Gas Formations, SPE Paper 17088, W.J. Lee, October 1987
17. “Radius-of-Drainage and Stabilization-Time Equations,” Oil and Gas Journal, H.K. Van Poollen, Sept 14, 1964
18. “Effects of Permeability Anisotropy and Layering On Well Test Interpretation,” Hart’s Petroleum Engineer International, Spivey, Aly, and Lee, February 1998
19. “Three Key Elements Necessary for Successful Testing,” Oil and Gas Journal, Ehlig-Economides, Hegeman, Clark, July 25, 1994
20. “Introduction to Applied Well Test Interpretation,” Hart’s Petroleum Engineer International, Spivey, and Lee, August 1997
21. “Recent Developments In Well Test Analysis,” Hart’s Petroleum Engineer International, Stewart, August 1997
22. “Fundamentals of Type Curve Analysis,” Hart’s Petroleum Engineer International, Spivey, and Lee, September 1997
23. “Identifying Flow Regimes In Pressure Transient Tests,” Hart’s Petroleum Engineer International, Spivey and Lee, October 1997
24. “Selecting a Reservoir Model For Well Test Interpretation,” Hart’s Petroleum Engineer International, Spivey, Ayers, Pursell,and Lee, December 1997
27. “Use of Pressure Derivative in Well-Test Interpretation,” SPE Paper 12777, SPE Formation Evaluation Journal, Bourdet, Ayoub, and Pirard, June 1989
28. “A New Set of Type Curves Simplifies Well Test Analysis,” World Oil, Bourdet, Whittle, Douglas, and Pirard, May 1983

APPENDIX

Pressure Gauge Usage and Selection

<u>Usage</u>

- 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.

<u>Selection</u>

- 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

<u>General Operational Considerations</u>

- 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:

   $$C = V_w \cdot c_{waste}$$ where, V_w is the total wellbore volume, bbls
   c_{waste} is the compressibility of the injectate, psi^{-1}

   b. Well goes on a vacuum:

   $$C = \frac{V_u}{\dfrac{\rho \cdot g}{144 \cdot g_c}}$$ where, V_u is the wellbore volume per unit length, bbls/ft
   ρ is the injectate density, psi/ft
   g and g_c 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:

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

   b. Falloff period:

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

   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:

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

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:

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

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.

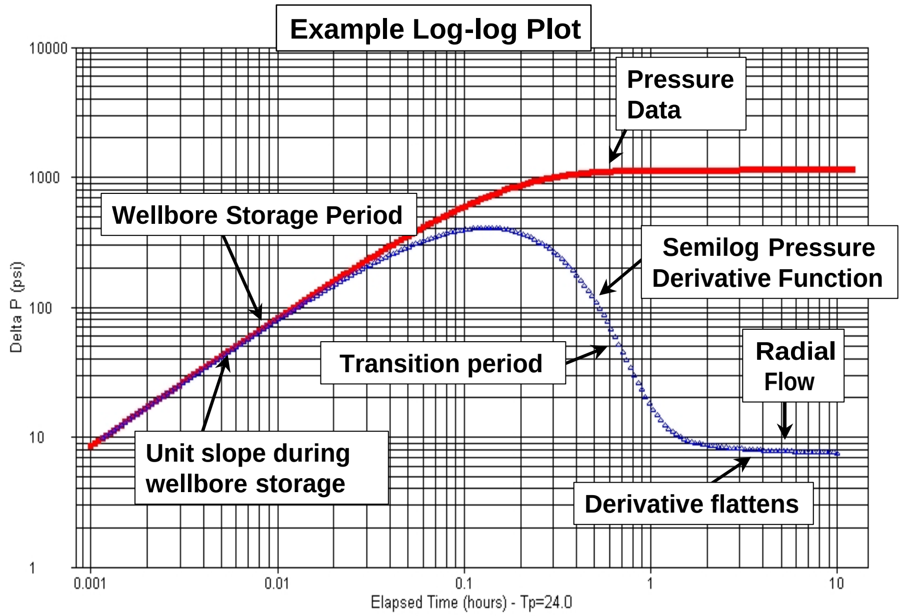
- X **Falloff tests conducted in highly transmissive reservoirs** may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for 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 the flow regimes present in the welltest.

An example log-log 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:

Flow Regime	Semilog Derivative Pattern
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. Psuedo-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 tranmissibility 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.

<u>Determination of the Appropriate Time Function for the Semilog Plot</u>

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 **<u>MDH plot</u>** 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 **<u>Horner plot</u>** 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 **<u>Agarwal equivalent time plot</u>** 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:

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

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:

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

where, s = skin factor, dimensionless

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

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

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

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

where, t_w= time to exit waste front, hrs
$V_{waste\ injected}$ = 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.

- 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

- 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.

- 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

- 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.

- 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.

- 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-FY17-2R

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-FY17-2R

FIGURE Q-1

Plug and Abandonment Plan

Panoche Energy Center
Well IW1

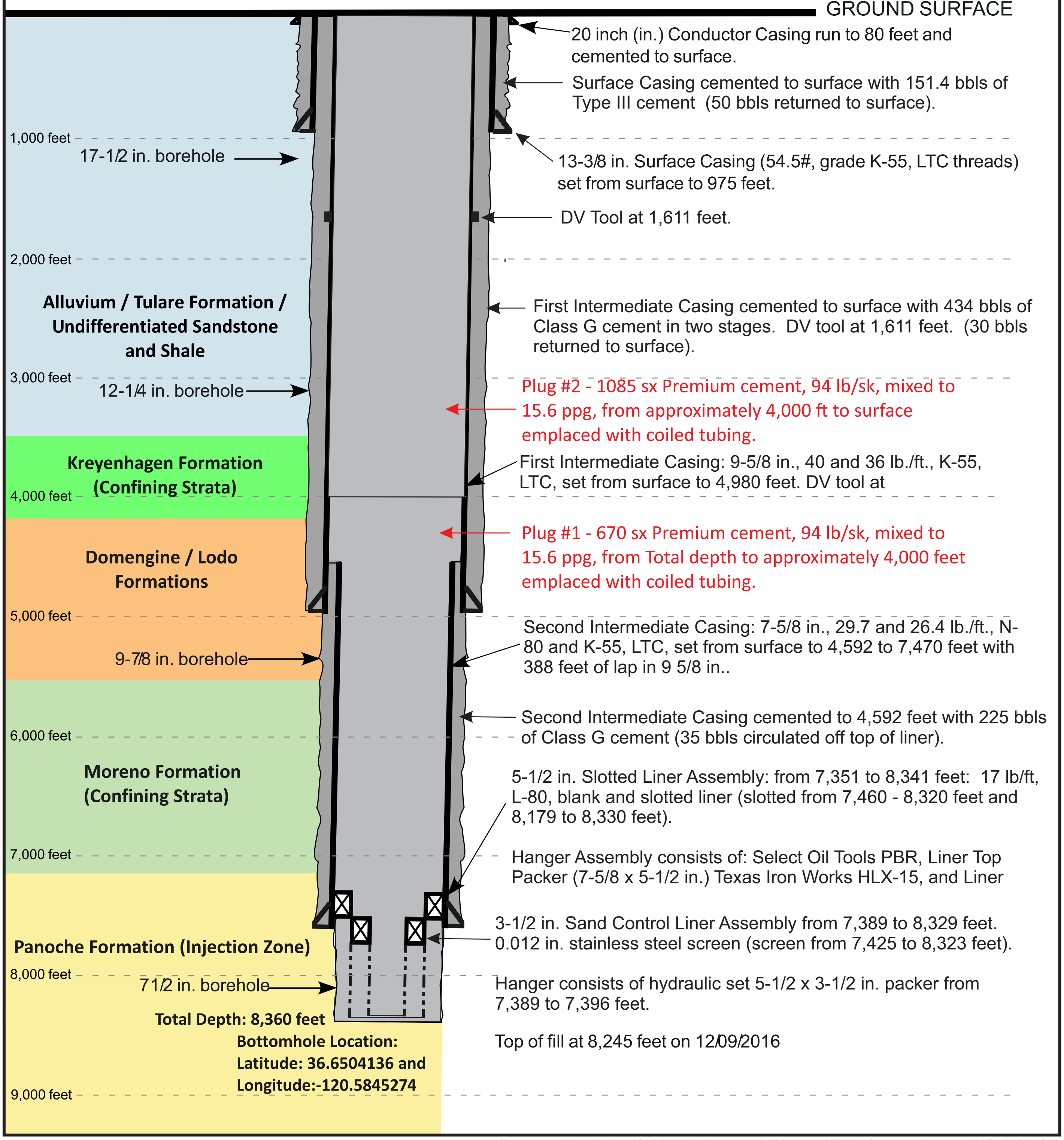
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.650645 and
Longitude:-120.5838281

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION

Spud: September 26, 2008 Final Drilling Rig (Kenai #5)
Report: December 17, 2008 Final Completion Rig (Rival #9)
URS Completion Report: February 19, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-1

IW1 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 220 bbls to kill tubing & 510 bbls to kill well with tubing removed)
4	e.	Rig up for laying down injection tubing. Kill injection tubing.
	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW1* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 185 bbls or approximately 670 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW1* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 306 bbls or approximately 1085 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	p.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

Panoche Energy Center
Well IW2

FIGURE Q-2
Plug and Abandonment Plan

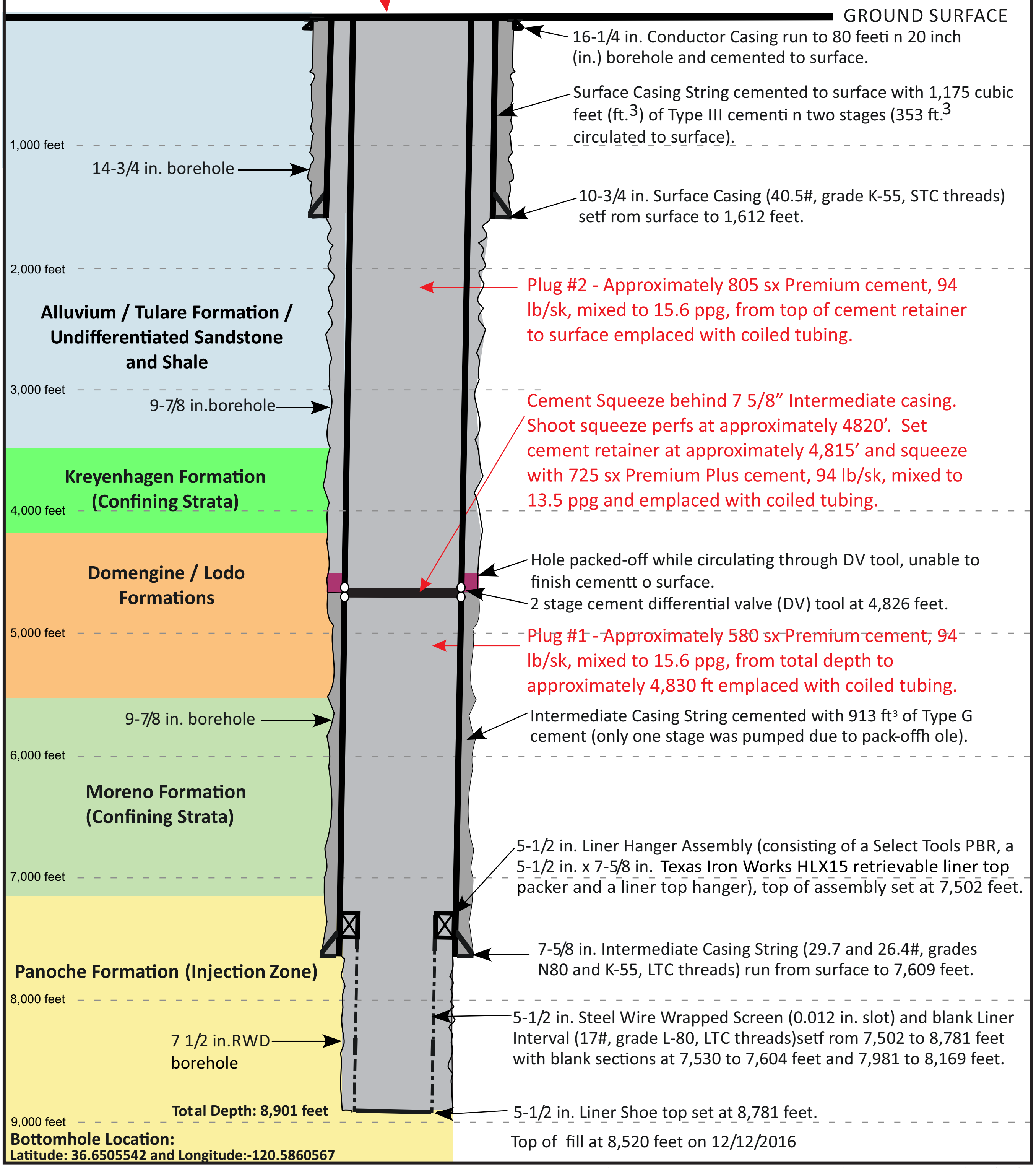
EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.650588 and
Longitude:-120.5849399

Spud: December 19, 2008 Final Drilling Rig (Kenai #5)
Report: January 17, 2008 Final Completion Rig (Rival #9)
Report: January 29, 2009

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =421 ft. MSL)
(All depths listed below are referenced to a depth below KB.)

CUT CASING OFF 3 FEET BELOW SURFACE AND PLACE STEEL PLATE WITH WELL IDENTIFICATION INFORMATION



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-2

IW2 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 225 bbls to kill tubing & 385 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW2* through 2-inch coiled tubing from PBTD to approximately 4,830 ft. Plug to consists of approximately 175 bbls or approximately 630 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Rig up wireline and shoot approximately 5 feet of perforations at 4,820 ft. for squeeze cementing of 7 5/8-inch longstring casing.
	o.	POOH with perforating guns and run in hole with 7 5/8-inch cement retainer to set at approximately 4,805 feet.
	p.	Run in hole with coiled tubing and sting into retainer. Open backside and squeeze cement 7 5/8-inch x 9 7/8-inch hole and 7 5/8-inch x 10 3/4-inch casing with 725 sx premium cement mixed to 13.5 ppg as per squeeze cementing program for IW2*. Unsting from retainer and leave 20 feet of cement on top of retainer and reverse clean. Pull out of hole and wait on cement to cure.
8	q.	Rig up wireline and run CBL on squeezed interval.
	r.	Run in hole with CT to bottom.
	s.	Pump second plug per cementing program for IW2* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 224 bbls or approximately 805 sx premium cement.
	t.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
9	u.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	v.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	w.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

Panoche Energy Center
Well IW3

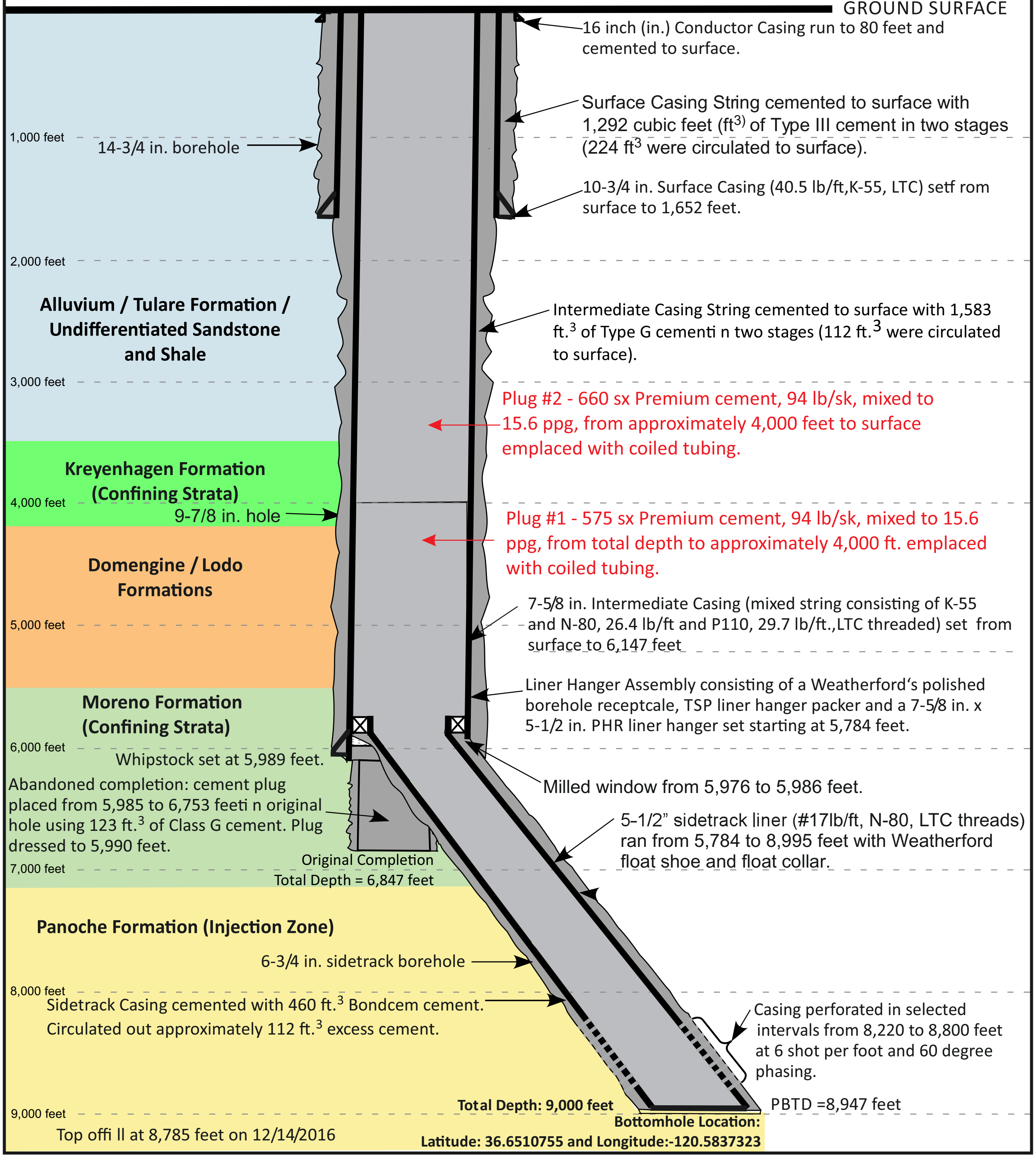
FIGURE Q-3
Plug and Abandonment Plan

EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.6506313 and
Longitude:-120.5833801

Spud: April 30, 2009
Final Original Hole Drilling Rig Report : May 25, 2009
Start of Well Deepening Sidetrack: October 19, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 408 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =427 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-3

IW3 Proposed Plugging Program

Day	Task	Task Description
1	a.	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	b.	Move in and rig up Wireline and perform MIT testing to include 1) Temperature Survey, 2) Static Bottomhole Pressure Measurement, and 3) Radioactive Tracer Survey.
3	c.	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 184 bbls to kill tubing & 346 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	f.	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5 x 3.5-inch injection tie-back string and lay out to pipe racks.
5	i.	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	k.	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW3* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 159 bbls or approximately 575 sx premium cement. Wait appropriate amount of time for plug to cure.
7	m.	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	Pump second plug per cementing program for IW3* through 2-inch coiled tubing from top of first plug to surface. Plug to consists of approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	p.	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

Panoche Energy Center
Well IW4

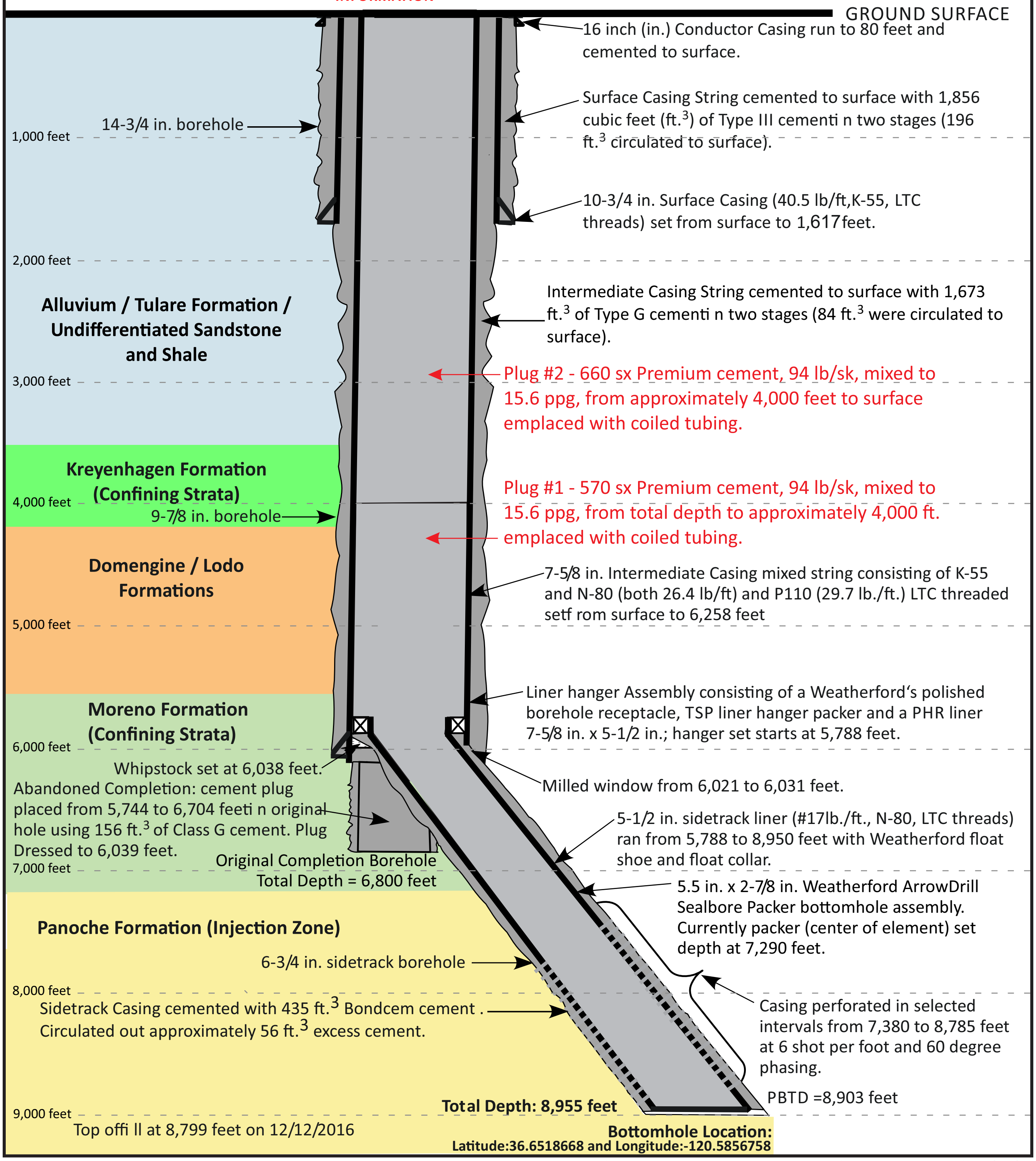
FIGURE Q-4
Plug and Abandonment Plan

EPA UIC Permit # CA10600001
Operator: Panoche Energy Center, LLC
Location: Section Sec 5 T15S R13E
County/State: Fresno/ California

Wellhead Location:
Latitude: 36.6509366 and
Longitude:-120.585846

Spud: May 6, 2009
Final Original Hole Drilling Rig Report: June 4, 2009
Start of Well Deepening Sidetrack: October 20, 2011
Final Well Deepening Report: May 15, 2012

Surface Elevation: 410 feet above Mean Sea level (MSL)
Rig kelly bushing (KB) depth = 13 feet above Ground Surface (KB =429 ft. MSL)
(All depths listed below are referenced to a depth below KB.)



Prepared by Haley & Aldrich, Inc. and Weegar-Eide & Associates, LLC 11/12/18

TABLE Q-4

IW4 Proposed Plugging Program

Day	Task	Task Description
1	**a.**	Move in frac tanks and accessories and fill with plant makeup water for well flush and final mechanical integrity testing (MIT).
2	**b.**	Radioactive Tracer Survey.
3	**c.**	Mobilize workover rig to well location. Rig up workover rig, rig pump, circulating tank, and pipe racks for Plugging Operations.
	d.	Receive necessary volume of weighted workover fluid to kill well (approximately 182 bbls to kill tubing & 346 bbls to kill well with tubing removed)
	e.	Rig up for laying down injection tubing. Kill injection tubing.
4	**f.**	Remove injection tree, spear tubing, strip over and test BOP, pull seal assembly.
	g.	Lay out landing joint. Rig up lay down machine for injection tubing. Re-kill well if necessary
	h.	Pull 5.5 x 3.5-inch injection tie-back string and lay out to pipe racks.
5	**i.**	Rig down and move out workover rig and ancillary equipment.
	j.	Run Casing Inspection Log as per 40 CFR 146.69.d.4 from maximum safe depth to surface.
6	**k.**	Move-in and rig up 2-inch coiled tubing, pumping unit, and cement transports.
	j.	Run CT to bottom. If significant wellbore fill is indicated, attempt to circulate fill out and wash down to total plugback depth.
	l.	Pump first plug per cementing program for IW4* through 2-inch coiled tubing from PBTD to approximately 4,000 ft. Plug to consists of approximately 158 bbls or approximately 570 sx premium cement. Wait appropriate amount of time for plug to cure.
7	**m.**	Run in hole with coiled tubing. Tag top of cement plug. Shut-in BOP and pressure test plug to confirm integrity.
	n.	approximately 185 bbls or approximately 660 sx premium cement.
	o.	Rig down and move out coiled tubing, pumping unit, and transports. Let cement cure.
8	**p.**	Cutoff casing 3 feet below ground level and weld steel plate on top with well identification information as required by CDOGGR rules.
	q.	Load out and return remaining rental equipment (e.g. frac tanks, forklift, etc..). Secure location.
	r.	Within 60 days of completion submit final plugging report and EPA form 7520-14 in accordance with 40 CFR 144.51.p.

* Cementing Program and Cost Estimate included in Exhibit Q

APPENDIX H

Operating Data

UIC Permit R9UIC-CA1-FY17-2R

ATTACHMENT H – OPERATING DATA

PERMIT REQUIREMENTS

As stated in U.S. Environmental Protection Agency (USEPA) Form 7520-6, Attachment H requires the applicant to submit the following proposed "operating data for each well (including all those to be covered by area permits):

(1) average and maximum daily rate and volume of the fluids to be injected;

(2) average and maximum injection pressure;

(3) nature of annulus fluid;

(4) for Class I wells, source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids."

AVERAGE AND MAXIMUM FLUID INJECTION RATES, VOLUMES, AND OPERATING PRESSURE

As described in Attachment P, all quarterly data can be found in the Quarterly Injection monitoring reports (tables and raw data spreadsheets) and in the Annual Monitoring Reports (USEPA Form 7520-11) submitted to USEPA for the last 10 years (See Exhibits folder on compact disc). A summary of an example set of consecutive four quarters of submitted operating data, including the average and maximum injection rate, daily volume of injectate, and injection pressure, are presented for each injection well in Table H-1. As the wells operate on an intermittent basis (only a few hours at a time) and thus, injection rates are presented in gallons per minute (gpm) as measure just during these injection periods rather than daily rates.

As described in Attachment K and previously discussed in Attachment A, the construction of the enhanced wastewater system (EWS) caused a decrease in wastewater injection at the Panoche Energy Center (PEC) facility starting in June 2016 (Haley & Aldrich, 2016). As a result, the anticipated wastewater injection rate is expected to be less between 2018 and 2027 than the wastewater injection rate that occurred between 2009 and 2016. Therefore, the data shown in Table H-1 was aggregated from the four most recent quarters of monitoring data (Haley & Aldrich, 2016, Haley & Aldrich, 2017a, Haley & Aldrich, 2017b, Haley & Aldrich, 2017c).

Maximum historic recorded daily injection volumes for each well are as follows: 144,039 gallons in IW1 during August 2013; 172,041 gallons in IW2 during September 2014; 155,147 gallons in IW3 during July 2013; and 164,002 gallons in IW4 during October 2014 (Haley & Aldrich, 2013b, Haley & Aldrich, 2014b, Haley & Aldrich, 2014c). While it is anticipated that future injection rates will be significantly lower most of the time due to the installation of the EWS, similar maximum daily injection volumes may occur when the EWS maintenance is required during a high electricity demand season. Therefore, we propose that the maximum daily injection volumes for the next permit period are set to be the same as the previous historic daily maximums. Similarly, the highest historical daily average volumes and maximum daily injection rates for individual wells reported in the quarterly reports are used as the proposed future values. The proposed average daily injection rates are estimated by the ratios of the proposed maximum daily volumes (in gallons) to 1,440 minutes; these estimates represent potential daily average rates that may occur when the EWS maintenance is required during a high electricity demand season.

Based on Attachment I, the proposed maximum injection pressures at well head are 2,478 pounds per square inch (psi) for IW1, IW3, and IW4; and 2,416 psi for IW2. The proposed average injection pressure at well head is 2,065 psi based on the historical maximum injection pressure for all wells. Note that the current injection pressure is limited by the capability of injection pumps (approximately 2,000 psi). The injection pumps can be upgraded to have the capability of performing injection at around 2,400 psi at well head.

The proposed average and maximum injection pressures, as well as the proposed average and maximum daily rate and volume of the fluids to be injected, are summarized in Table H-2.

NATURE OF ANNULUS FLUID

The annular fluid used in wells IW1 and IW2 consists of Amber Chemical's corrosion inhibitor packer fluid, which is composed of sodium bisulfite with a bio-filming amine (URS, 2009a; URS, 2009b). On 21 May 2013, IW3 was topped off with 10 pounds per gallon (ppg) inhibited fluid, and a packer was set in-place during the re-installation of injection tubing after fracture stimulation of this well (Haley & Aldrich, 2013a). On 16 June 2014, during the well repair of IW4, approximately 150 barrels (bbls) of 10.5 ppg calcium chloride inhibited with Geo Drilling Fluids, Inc.'s Amberguard COS and CAP was emplaced down the backside of the injection tube prior to setting the tubing sting packer (Haley & Aldrich, 2014a).

INJECTION FLUID CHARACTERISTICS

When it became operational, PEC performed a hazardous waste determination of the injection fluids on 28 April 2009, per the requirements of Code of Federal Regulations Title 40 (40 CFR) §262.11. The results of that determination indicated that the injection fluids did not meet the definition of hazardous waste as defined in 40 CFR §146.3 and §261. In addition, PEC performed a new hazardous waste injectate determination in the third quarter of 2016, per the above listed requirements and according to Section C, paragraph 1(b)(ii) of the Underground Injection Control (UIC) Permit, once an on-demand wastewater treatment system became operational and began contributing to the combined injectate flow. This Hazardous Waste Determination document concludes that the injectate still does not meet the definition of hazardous waste as defined in 40 CFR §146.3 and §261 and demonstrates that PEC continues to comply with the injection fluid limitations as required by Section C, paragraph 5(a) of the current UIC Permit. The Hazardous Waste Determination document prepared by PEC is presented as Appendix C of the Third Quarter 2016 Injection Monitoring Report (Haley & Aldrich, 2016).

In accordance with the Permit, injection fluid is analyzed on a quarterly basis (See Attachment P for details). The injection fluids for wells IW1 through IW4 originate from the same wastewater storage tank. Therefore, a single sample of injection fluid (a composite of all the wells) is collected and analyzed. A summary of the past four quarters of analytical results for injection fluids is presented in Table H-3. This time frame (previous four quarters) was selected because, as described above, the EWS system is in operation and the future injectate is expected to closely match the analytical results from the last four quarters.

References

1. Haley & Aldrich, Inc. (Haley & Aldrich). 2013a. IW3 Fracture Stimulation Report and Request to Operate Well IW3, Class 1 Nonhazardous Waste Injection Wells, UIC Permit Number CA10600001, Panoche Energy Center, LLC, Fresno County, California. July.

2. Haley & Aldrich. 2013b. Third Quarter 2013 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

3. Haley & Aldrich. 2014a. Second Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

4. Haley & Aldrich. 2014b. Third Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

5. Haley & Aldrich. 2014c. Fourth Quarter 2014 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

6. Haley & Aldrich. 2016. Third Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

7. Haley & Aldrich. 2017a. Fourth Quarter 2016 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

8. Haley & Aldrich. 2017b. First Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

9. Haley & Aldrich. 2017c. Second Quarter 2017 Monitoring Report, Class 1 Nonhazardous Waste Injection Wells, UIC Permit CA 10600001, Panoche Energy Center, LLC, West Panoche Road, Firebaugh, California.

10. URS. 2009a. Well Completion Report – UIC Well IW1, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California. March.

11. URS. 2009b. Well Completion Report – UIC Well IW2, Panoche Energy Center, UIC Permit No. CA10600001, Firebaugh, Fresno County, California.

TABLES

TABLE H-1
INJECTION WELL OPERATIONAL DATA
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Month	IW1						IW2						IW3						IW4					
	Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)		Daily Injection Volume (gal)		Well Head Injection Pressure (psig)		Injection Rate (gpm)	
	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum
July, 2016	17,698.0	90,730.0	1,856.6	1,993.4	104.0	156.0	19,472.4	108,765.0	1,849.7	1,994.3	140.2	234.9	7,910.9	52,917.0	1,840.7	1,913.3	88.6	179.6	5,298.5	70,769.0	1,814.9	1,935.9	134.6	162.8
August, 2016	27,265.3	87,759.0	1,889.1	2,004.8	99.1	145.1	28,235.3	88,500.0	1,885.9	1,993.4	132.0	186.6	13,983.4	42,859.0	1,893.7	1,949.7	82.0	111.8	--	--	--	--	--	--
September, 2016	6,709.2	46,000.0	1,837.6	1,922.2	103.8	143.9	13,915.4	129,051.0	1,862.1	2,001.2	140.5	253.1	7,266.0	71,004.0	1,887.2	1,998.0	89.5	150.2	11,598.9	59,125.0	1,857.4	1,953.3	150.4	230.7
October, 2016	5,994.1	107,000.0	1,885.1	1,998.6	106.3	147.5	11,792.6	113,046.0	1,862.8	1,997.7	143.3	186.7	5,510.1	32,101.0	1,878.1	1,978.3	90.0	124.4	10,302.0	61,830.0	1,867.8	1,977.4	145.6	203.3
November, 2016	2,367.6	31,110.0	1,849.7	1,955.6	112.7	131.9	7,888.2	56,495.0	1,873.3	1,979.9	143.5	204.6	3,991.0	33,940.0	1,870.4	1,976.9	94.3	130.3	5,474.0	58,842.0	1,852.7	1,909.6	142.4	163.9
November, 2016	7,311.0	93,612.0	1,885.6	1,972.8	106.6	234.7	7,792.3	102,000.0	1,779.2	1,977.1	125.9	199.4	6,130.9	67,002.0	1,923.3	1,978.3	87.2	111.8	6,157.8	49,913.0	1,895.1	1,977.1	143.3	181.9
January, 2017	5,987.9	45,472.0	1,879.6	1,989.5	101.6	178.0	13,849.9	62,445.0	1,906.5	1,999.3	134.3	166.0	4,359.7	21,170.0	1,899.5	1,991.3	96.0	135.9	16,041.7	65,650.0	1,922.9	1,996.6	141.4	206.9
February, 2017	2,440.9	33,221.0	1,942.6	1,989.7	118.5	139.5	6,202.1	42,502.0	1,931.6	1,977.4	144.0	197.8	--	--	--	--	--	--	9,677.9	47,244.0	1,952.4	1,992.2	146.0	186.3
March, 2017	1,859.1	39,582.0	1,860.0	1,902.1	103.4	126.3	7,898.2	43,213.0	1,907.2	1,988.8	146.8	251.3	--	--	--	--	--	--	8,994.0	44,583.0	1,930.7	1,998.0	143.6	182.5
April, 2017	5,963.4	33,000.0	1,884.7	1,981.0	99.6	121.6	9,839.6	54,463.0	1,891.9	1,984.0	139.0	174.2	2,353.6	21,768.0	1,859.1	1,897.7	103.4	151.2	10,779.5	61,731.0	1,903.4	1,991.5	140.3	161.3
May, 2017	4,888.6	37,627.0	1,855.7	1,968.4	98.8	139.2	7,713.9	34,002.0	1,857.0	1,969.6	140.6	200.1	1,762.3	33,009.0	1,949.5	1,991.3	104.8	117.2	12,133.0	41,989.0	1,908.8	1,990.9	141.6	168.1
June, 2017	13,922.5	71,285.0	1,856.0	1,958.1	74.2	141.6	25,292.4	97,581.0	1,879.6	2,000.7	113.7	172.5	5,803.4	44,981.0	1,867.8	1,919.0	89.6	122.3	27,859.0	97,792.0	1,898.9	1,998.6	121.3	170.3
Historical Operating Parameters (12-month average, 12-month maximum)	8,534.0	107,000.0	1,873.5	2,004.8	102.4	234.7	13,324.4	129,051.0	1,873.9	2,001.2	137.0	253.1	5,907.1	71,004.0	1,886.9	1,998.0	92.5	179.6	11,301.5	97,792.0	1,891.4	1,998.6	141.0	230.7

Abbreviations:
-- = not applicable
gal = gallons
gpm = gallons per minute

TABLE H-2
PROPOSED INJECTION PRESSURES, RATES, AND VOLUMES
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Operation Parameter		Proposed Quantity			
		IW1	IW2	IW3	IW4
Injection Pressure (psi)	Average	2,065	2,065	2,065	2,065
	Maximum	2,478	2,416	2,478	2,478
Injection Rate (gpm)	Average	98	119	108	114
	Maximum	240	224	181	253
Daily Volume (gallons)	Average	7,808	149,555	99,458	123,890
	Maximum	141,039	172,041	155,147	164,002

Operation Parameter		Rationale fofr Proposed Quantity			
		IW1	IW2	IW3	Iw4
Injection Pressure (psi)	Average	Historical Maximum Pressure			
	Maximum	See Attachment I			
Injection Rate (gpm)	Average	Based on maximum daily volume (÷1440)			
	Maximum*	2Q-2016	2Q-2016	4Q-2014	3Q-2014
Daily Volume (gallons)	Average*	3Q-2015	3Q-2015	3Q-2013	3Q-2015
	Maximum*	3Q-2013	3Q-2014	3Q-2013	3Q-2015

Notes:
* = based on the historical values reported in a quarterly report (2Q2016 = second quarter 2016 monitoring report)
gpm = gallons per minute
psi = pounds per square inch

TABLE H-3
LABORATORY ANALYTICAL RESULTS FOR INJECTION FLUIDS
PANOCHE ENERGY CENTER, LLC
FRESNO COUNTY, CALIFORNIA

Sample Date:		17-Aug-16	9-Dec-16	1-Mar-17	12-May-17
	Units	Results	Results	Results	Results
Physical/Chemical Properties					
pH	pH Units	8.0	7.4 J	7.3 J[1]	7.2 J [1]
Specific Conductivity	µmhos/cm @ 25°C[1]	13,000	9,900	14,000	15,000
Specific Gravity	@ 60/60°F[2]	1.008	1.0054	1.0107	1.011
Density	g/mL @ 60°F[3]	1.007	1.0054	1.0097	1.01
Viscosity	cSt @ 100°F[4]	0.7	0.71	1.1	0.76
Total Dissolved Solid	mg/L[5]	8,900	5,400	10,000	8,300
Total Suspended Solid	mg/L	17	21	32	22
Turbidity	NTU[6]	0.31	2.7	7.4	0.86
Alkalinity, as $CaCO_3$[7]	mg/L	410	270	280	260
Inorganic Analytes - Cations/Metals					
Aluminum	mg/L	< 0.050	< 0.050	< 0.050[9]	< 0.050[9]
Antimony	mg/L	< 0.0020	< 0.0040	< 0.0040	< 0.0020
Arsenic	mg/L	0.190	0.079	0.150	0.210
Barium	mg/L	0.019	0.019	0.037	0.021
Beryllium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Cadmium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Calcium	mg/L	37	61	18	15
Chromium	mg/L	< 0.010	< 0.020	< 0.020	0.010
Cobalt	mg/L	0.011	0.32	0.081	0.087
Copper	mg/L	0.041	0.050	0.200	0.130
Fluoride	mg/L	2.2	1.6	2.3	2.7
Iron	mg/L	0.60	3.1	23	1.9
Lead	mg/L	< 0.0050	< 0.010	< 0.002	< 0.001
Magnesium	mg/L	14	21	5.2	7.2
Manganese	mg/L	0.023	0.054	0.29	0.029
Mercury	mg/L	< 0.00020 J	< 0.0010	< 0.0002	< 0.0002
Molybdenum	mg/L	0.490	0.44	0.390	0.650
Nickel	mg/L	< 0.010	< 0.020	0.020	0.010
Phosphorus	mg/L	1.2	0.79	1.9	0.59
Potassium	mg/L	25	100	70	50
Selenium	mg/L	0.180	0.084	0.079	0.150
Silica (SiO_2)[9], total	mg/L	180	150	170	180
Silica (SiO_2), dissolved	mg/L	190	140	150	180
Silver	mg/L	< 0.010	< 0.020	< 0.020	< 0.010
Sodium	mg/L	3,900	2,600	3,900	4,900
Strontium	mg/L	0.500	0.70	0.660	0.460
Thallium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010 UJ [14]
Thorium	mg/L	< 0.00050	< 0.00050	< 0.00050	< 0.00050
Uranium	mg/L	< 0.0010	< 0.0020	< 0.0020	< 0.0010
Vanadium	mg/L	0.013	< 0.0060	< 0.0060	0.010
Zinc	mg/L	0.067	0.160	< 0.100	0.058
Inorganic Analytes - Anions					
Bicarbonate, as $CaCO_3$	mg/L	410	270	280	260
Carbonate, as $CaCO_3$	mg/L	< 3.0	< 3.0	< 3.0	< 3.0
Hydroxide, as $CaCO_3$	mg/L	< 3.0	< 3.0	< 3.0	< 3.0
Chloride	mg/L	810	650	1,100	940
Sulfate, as SO_4[10]	mg/L	4,900	3,900	6,400	6,500
Nitrate, as NO_3[11]	mg/L	< 20	< 1.0	< 50	< 100
Orthophosphate, as P [12]	mg/L	< 4.0	< 0.20	< 10	< 20
Mass Balance					
Anions	meq/L[13]	130	110	170	170
Cations	meq/L	170	120	170	220
Non-Ionic Analytes					
Biochemical Oxygen Demand	mg/L	2.0	47 J	17 J	8.0
Detected Organic Analytes					
Acetone	mg/L	0.022	0.035	0.080	0.064
Dibromomethane	mg/L	< 0.00050	0.0086	0.0026	0.0022
Dibromochloromethane	mg/L	< 0.00050	0.0014	< 0.00050	0.0011
Bromoform	mg/L	0.0086	0.057	0.015	< 0.00050

Notes:
µmhos/cm @ 25°C = micromhos per centimeter at 25 degrees Celsius
g/mL @ 60°F = grams per milliliter at standadization temperture in degrees Fahrenheit
meq/L = milliequivalents per liter
mg/L = milligrams per liter
@ 60/60°F = standardization temperature in degrees Fahrenheit
< = not detected at or above the reporting limit shown
$CaCO_3$ = calcium carbonate
cSt @ 100°F = centistokes at 100 degrees Fahrenheit
NO_3 = nitrate
NTU = nephelometric turbidity units
P = phosphorus
SiO_2 = silicon dioxide
SO_4 = sulfate