San Joaquin Renewables
Class VI Permit Application
Testing and Monitoring Plan

Prepared for

San Joaquin Renewables LLC
McFarland, California

Submitted to

U.S. Environmental Protection Agency Region 9
San Francisco, California

Prepared by

DBS&A
Daniel B. Stephens & Associates, Inc.

a Geo-Logic Company

43 Randolph Road, #129
Silver Spring, Maryland 20904
www.dbstephens.com

Project # DB19.1252.SS

September 7, 2022

TESTING AND MONITORING PLAN
40 CFR 146.90

SAN JOAQUIN RENEWABLES

1. Facility Information

Facility name: San Joaquin Renewables
Injection Well: SJR-I1

Facility contact: T.J. Paskach, Ph.D.
1521 West F Ave, Nevada, IA 50201
515-292-1200 x121/tpaskach@frontlinebioenergy.com

Well location: McFarland, Kern County, California
35.688330, -119.276642

This Testing and Monitoring Plan describes how San Joaquin Renewables (SJR) will monitor the site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

2. Overall Strategy and Approach for Testing and Monitoring

This Testing and Monitoring Plan is a component of the SJR application to the U.S. Environmental Protection Agency Region 9 (U.S. EPA) for an Underground Injection Control (UIC) Class VI permit for a planned facility located in McFarland, California. This plan is one of several separate documents submitted to the U.S. EPA Geologic Sequestration Data Tool (GSDT), and includes required information regarding planned testing and monitoring activities. Numerical modeling used to define the areas of anticipated carbon dioxide migration and the AoR are described in the Area of Review and Corrective Action Plan. Geologic analyses that underpin the conceptual model used in the AoR numerical modeling is primarily described in the narrative permit application report. Updating of the computational model is not a plume tracking method, but is a verification process.

The permit application and associated documents were prepared by a team including Daniel B. Stephens & Associates, Inc. (DBS&A), Driltek, Finsterle Geoconsulting, Keystone Diversified Energy, Inc. (KDEI), and Best Core Services.

2.1. Quality assurance procedures

A Quality Assurance and Surveillance Plan (QASP) for monitoring activities described in this report is included as Appendix A.

2.2. Reporting procedures

SJR will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR 146.91. Data will be submitted in electronic format. In addition, SJR will notify the EPA Director at least 30 days prior to conducting any testing.

3. Carbon Dioxide Stream Analysis

SJR will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

Anticipated injectate composition is presented in the narrative permit application report. The injectate is predicted to be 98.7-percent carbon dioxide by mass, with less than one percent of methane, benzene, ethane, and nitrogen making up the composition to 99.9-percent by mass.

The facility will have an in-house laboratory that will monitor injectate quality at least on a monthly basis, and often on a weekly or daily basis. In addition, on a quarterly basis the facility will collect a sample of the injectate for third-party laboratory analysis. Third-party samples will be extracted from a sample point just upstream of the wellhead via a valve and permitted to decompress into a gaseous phase within a sample holder for analysis by one of the methods described below. Standard methods will be used to calculate chemical and physical properties at in situ pressure and temperature from the results of analysis of the decompressed samples (U.S. EPA, 2013). Annulus pressure will be set at 50 psi for monitoring. The annulus/tubing differential will equal the injection pressure on the tubing less the annulus pressure (50 psig).

Third-party samples will be analyzed for the following using the analytical methods indicated (or equivalent with prior U.S. EPA approval):

- Carbon dioxide purity (ASTM E1747)
- Total sulfur (International Society of Beverage Technologists [ISBT] 14.0 or ASTM D3246)
- Hydrogen sulfide (ISBT 14.0 or ASTM D1945/D6228)
- Nitrogen (ISBT 4.0 or ASTM D1945)
- Total Hydrocarbons (ISBT 10.0 or ASTM D1945)
- Methane (ISBT 10.1 or ASTM D1945)
- Water Vapor (ISBT 3.0 CH)

- Ammonia (ISBT 6.0 DT)
- Oxygen (ISBT 4.0 GC/DID)
- Carbon Monoxide (ISBT 5.0 or ISBT 4.0)
- Oxides of Nitrogen (ISBT 7.0 Colorimetric)

All sample containers will be labeled with a unique sample identification number indicating the date of sample collection, and will be submitted under chain-of-custody protocols to an off-site third party laboratory for analysis.

Carbon dioxide injectate analyses will be submitted in semi-annual reports, including a list of all chemical analyses, original third-party laboratory reports, chain-of-custody forms, tabular results including in-house laboratory and third-party laboratory results, description of sampling activities, data interpretation, and identification of data gaps.

4. Continuous Recording of Operational Parameters

Continuous recording devices will be installed to monitor injection pressure, rate, and volume in the injection well. Injection and monitoring well schematics are provided in Appendix B. Continuous monitoring will include (also see Table 1):

- Gas flow control valves, backpressure and check valves to be installed on the wellhead and flow lines to ensure injection to individual completion zones.
- Temperature and pressure gauges at the surface (calibrated over the full operational range annually).
- Coriolis mass flowmeter located at the wellhead or transfer pipeline at the facility prior to the wellhead. The flowmeter will be calibrated using standard methods to within 0.1 percent over the entire expected range of flow rates.
- Surface telemetry of pressure, temperature and injection rates.
- Downhole fiber optics for monitoring of completion zone pressure and temperature by interval.
- Pressure gauge to monitor pressure on the annulus between the tubing and long-string casing to verify internal mechanical integrity.
- Downhole density calculation based on measured pressure and temperature (e.g., Ouyang, 2011).
- Volume-based flow rate will be calculated based on the mass-based flow rate and the downhole density.

Injection rate data will be submitted to the U.S. EPA in semi-annual reports. Semi-annual reports will include electronic data submission of all raw data, tabular data of all flow rate measurements, monthly average flow rate, monthly maximum and minimum values, total monthly injected volume, cumulative volume over the lifetime of the project, flagging of any flow rate exceedances, and identification of data gaps.

Table 1. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and downhole	30 seconds	2 minutes
Injection rate	Flowmeter	Surface	30 seconds	2 minutes
Injection volume	Calculated	Surface	30 seconds	2 minutes
Annular pressure	Pressure Gauge	Surface	30 seconds	2 minutes
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface and downhole	30 seconds	2 minutes

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

5. Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), SJR will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

Well corrosion monitoring will be conducted to ensure wellbore mechanical integrity over the life of the project. Corrosion will be assessed quarterly using the corrosion coupon method. Coupons representative of the long string casing, injection tubing and wellhead materials, based on the materials used for the injection well, will be installed in a flow-through pipe arrangement directly upstream of the wellhead. Coupon corrosion will be evaluated based on ASTM G1-03 or National Association of Engineers (NACE) TM01-69 including photographs, dimensional measurement and weighing.

An integrity concern would be identified from a measured corrosion rate of more than one mils per year (mpy; equal to a thousandth of an inch) per the EPA Testing and Monitoring Guidance (U.S. EPA, 2013).

Corrosion monitoring will also include casing inspection logs using one or more of the following methods if requested by the UIC Program Director and/or as triggered by an integrity concern based on corrosion coupon monitoring:

- Ultrasonic imaging log to gauge casing inside and outside roughness and thickness, casing to cement bond.
- Multi-finger caliper to evaluate inner metal loss.
- Electromagnetic flux log to evaluate total metal loss.
- Downhole video if necessary to identify casing problems where other logs may be ambiguous.

Casing inspection logging procedures will be consistent with U.S. EPA (2013) and references therein.

Semi-annual reports will include the results of corrosion monitoring, including a narrative description of all corrosion monitoring activities, corrosion coupon measurement results in tabular form including all historical results, photographs of corrosion coupons, all casing inspection logs and interpretations, and identification of any data gaps.

6. Groundwater Quality Monitoring

SJR will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). Groundwater quality monitoring will be conducted above the primary confining zone (Freeman Jewett formation) and within USDWs in the vicinity. Should any of the USDW wells be plugged by their owners, SJR will notify U.S. EPA and identify whether additional monitoring wells are needed and revise the plan if necessary. In addition, the results of formation water quality analyses conducted during drilling of the injection and monitoring wells will be used to confirm the appropriateness of the analytes selected for subsequent water quality analyses. Water quality sampling/analysis will be performed in accordance with the QASP (Appendix A).

6.1. Above Confining Zone Monitoring

One dedicated monitoring well (ACZ well) will be installed at the SJR property in the vicinity of the injection well that will be screened in the first formation overlying the confining zone that has a sufficient permeability to support collection and analysis of ground water samples (Olcese Formation Sandstone). Pressure increase within the Vedder formation is greatest at the injection well; therefore this location represents the maximum risk of vertical fluid leakage. In addition, separate-phase carbon dioxide is predicted to extend only to the direct vicinity of the project site. Figure 1a displays the planned location of the ACZ monitoring well relative to simulated carbon dioxide saturation at various times during and after injection, and Figure 1b displays the monitoring well locations overlaid with the maximum pressure increase (see the AoR and Corrective Action Plan).

The ACZ well will be screened within the Olcese Formation, which occurs from approximately 6,625 to 7,095 feet below ground surface (ft bgs) at the SJR site. Per U.S. EPA guidance the perforated interval will be in the lower parts of the Olcese, closer to the Freeman Jewett formation (perforated approximately 7,045 to 7,095 ft bgs pending verification of stratigraphy upon drilling of the injection well). The ACZ monitoring well will be drilled and constructed according to U.S. EPA (2013) specifications.

The ACZ will be fitted with a continuous pressure gauge in order to monitor increases in pressure that may indicate fluid leakage. In addition, fluid samples will be collected quarterly during the injection phase for the following per U.S. EPA (2013) protocols:

- Carbon dioxide (ASTM D513-16)
- Dissolved metals (EPA 200.7, Rev. 4.4; 200.8, Rev. 5.4; 200.9, Rev. 2.2.)
- Total dissolved solids (ASTM D5907-18)
- Major anions (EPA 300.0))(Br^-, Cl^-, F^-, NO^-, NO_3^-, SO_2^4)
- Major cations (EPA 6020 [Feb 2007 version])(Al, Sb, As, Ba, Be, B, Cd, Ca, Cr, Co, Cu, Fe, Pb, Mg, Mn, Mo, Ni, K, Se, Sr, Ag, Na, Sn, Ti, Tl, V and Zn)
- Mercury (EPA 7470)
- pH, temperature, specific conductivity (calibrated field meter/flow-through cell)(documentation to be retained indicating reference standards are not out of date).
- Dissolved oxygen (calibrated field meter/flow-through cell)
- Hydrogen sulfide (Hach® 2537800 Hydrogen Sulfide field Test Kit, Model HS-C)(24-hour holding time)
- Alkalinity (SM 2320B)
- Dissolved methane (RSK-175 gas chromatography)

At least three sets of baseline water-quality samples will be collected upon installation of the ACZ monitoring well and prior to injection, spanning a period of at least six weeks. Baseline pressure will also be monitored continuously for a period of at least six weeks prior to injection.

Samples will be collected after the well has been purged sufficiently that field parameters (e.g., pH, temperature, specific conductivity) have stabilized. Samples will be collected in bottles provided by a third-party laboratory, and will be submitted under chain-of-custody protocols to the laboratory. Quality assurance/quality control (QA/QC) samples will include one field duplicate, one equipment rinsate/blank, one matrix spike (where needed based on the analytical method) and one trip blank.

6.2. USDW Monitoring

Several groundwater production wells located within the vicinity of the project are routinely monitored for groundwater level and water quality as a component of compliance with the California Sustainable Groundwater Management Act (SGMA). The project vicinity coincides with the Southern San Joaquin Municipal Utility District (SSJMUD) Management Area, which is located within the larger Kern County groundwater subbasin (GEI, 2019). Figure 2 presents an overlay of the AoR, SSJMUD, and groundwater wells identified for monitoring under SGMA. Information regarding each of these wells is reproduced from GEI (2019) in Appendix C. Wells are owned by the City of Delano, the City of McFarland, and private parties. All supply wells in the vicinity, including these designated wells for monitoring, are screened within USDWs overlying the SJR project site. SSJMUD monitors each of these wells for water-quality data (GEI, 2019). Additional well construction for USDW monitoring wells will be requested from SSJMUD and/or obtained from well investigations (e.g., tagging the bottomhole depth), and provided to U.S. EPA when available.

SJR will seek to enter into a memorandum of understanding (MOU) with SSJMUD to (1) gain access to water-quality data obtained from each of the monitoring wells in their network within the vicinity as shown on Figure 2; and (2) if needed in order to obtain necessary water-quality parameters, obtain access to the wells for periodic direct sampling. SSJMUD wells within the project vicinity that will be sampled include Delano Well 14, McFarland Taylor Well, SSJMUD-23, SSJMUD-42, SSJMUD-53 and SSJMUD-14.

SJR will seek to collect the following data on a semi-annual basis:

- Carbon dioxide (ASTM D513-16)
- Dissolved metals (EPA 200.7, Rev. 4.4; 200.8, Rev. 5.4; 200.9, Rev. 2.2.)
- Total dissolved solids (ASTM D5907-18)
- Major anions (EPA 300.0))(Br^-, Cl^-, F^-, NO^-, NO_3^-, SO_2^4)
- Major cations (EPA 6020 [Feb 2007 version])(Al, Sb, As, Ba, Be, B, Cd, Ca, Cr, Co, Cu, Fe, Pb, Mg, Mn, Mo, Ni, K, Se, Sr, Ag, Na, Sn, Ti, Tl, V and Zn)
- Mercury (EPA 7470)
- pH, temperature, specific conductivity (calibrated field meter/flow-through cell)(documentation to be retained indicating reference standards are not out of date).
- Dissolved oxygen (calibrated field meter/flow-through cell)
- Hydrogen sulfide (Hach® 2537800 Hydrogen Sulfide field Test Kit, Model HS-C)(24-hour holding time)
- Alkalinity (SM 2320B)

- Dissolved methane (RSK-175 gas chromatography)

All data, including original laboratory reports and field notes, will be obtained from SSJMUD if possible. If SJR needs to collect samples independently, samples will be collected after the well has been purged sufficiently that field parameters (e.g., pH, temperature, specific conductivity) have stabilized. Samples will be collected in bottles provided by a third-party laboratory, and will be submitted under chain-of-custody protocols to the laboratory. Quality assurance/quality control (QA/QC) samples will include one field duplicate, one equipment rinsate/blank, one matrix spike (where needed based on the analytical method) and one trip blank.

6.3. Data Interpretation and Reporting

SJR will maintain an electronic database of all monitoring results, that will record date of sample collection, resulting sample concentrations, analysis date, analytical detection limit, and any QA/QC flags.

All groundwater quality data will be subjected to standard quality review prior to data interpretation per Standard Methods (1999). Data quality evaluation will include calculation of the cation-anion balance (CAB) with the following acceptable criteria:

- Anion Sum (meq/L) 0 – 3.0, Acceptable Difference = 0.2 meq/L
- Anion Sum (meq/L) 3.0 – 10.0, Acceptable Difference = 2%
- Anion Sum (meq/L) 10 – 800, Acceptable Difference = 5%

Charge balance error will also be calculated for analyses where the anion sum is greater than 800 meq/L, with the limit of accepting an analysis by the charge balance error calculation being 5%. A final check will include comparison of measured and calculated TDS, and the ratio of measured to calculated TDS should be within 1.0 to 1.2 (Standard Methods, 1999).

SJR will evaluate all groundwater quality monitoring data against baseline samples collected prior to injection for any indication of fluid leakage, including:

- Increasing TDS
- Changing major cation/anion signature, as displayed on standard Piper and Stiff diagrams
- Increasing carbon dioxide concentration
- Decreasing pH
- Increasing concentration of dissolved metals, which (along with other indications listed above), may indicate leaching of certain inorganics from the formation due to lowered pH

Groundwater quality monitoring results will be reported to U.S. EPA in semi-annual reports and in an electronic format, including the most recent water-quality database including all recent and historical results, complete original laboratory reports, data interpretation including time series charts, Piper and Stiff diagrams, narrative explanation of all sampling activities, data quality evaluation, calibration records for field meters, and identification of data gaps.

7. External Mechanical Integrity Testing

SJR will conduct at least one of the tests presented in Table 2 at the injection well and IZ and ACZ monitoring wells periodically during the injection phase to verify external MI as required at 146.89(c) and 146.90.

7.1. Testing location and frequency

MITs will be performed annually, up to 45 days before the anniversary date of authorization of injection each year. In addition, a deviation of +/- 25psi in annular pressure from the 50psi set point will trigger a mechanical integrity investigation for cause. If pressure drops or increases, it will be returned to its operating pressure and monitored to verify integrity. If the deviation continues, mechanical integrity will be verified. A wider range of pressure variation will be observed after an interruption in injection or well intervention or until the well stabilizes.

Table 2. MITs.

Test Description	Location
Temperature Log	Wireline log along wellbore
Oxygen Activation Log	Wireline log along wellbore

7.2. Testing details

Temperature and/or OALs will be conducted according to U.S. EPA (2013) specifications. Temperature logging procedures per U.S. EPA Region IX are provided in Appendix D. Temperature logs will be conducted with dedicated fiber optics for monitoring of completion zone pressure and temperature by interval by the following procedure:

- Upon well installation collect a baseline temperature profile representative of the natural geothermal gradient
- During operation record temperature profile for at least six hours prior to shutting in the well
- Stop injection and record temperature profile for approximately 36 hours.
- During the shut-in period, the temperature within the well bore will typically change toward static geothermal conditions. If there has been a leak of fluid out of the well, the temperature within the well bore at this location will change to a lesser degree and be measured as an anomaly because the temperature of the surrounding formation will have been modified by the leaking fluid (U.S. EPA, 2013).

OALs will be conducted only if necessary to resolve temperature logging results and further assess mechanical integrity if temperature logging results indicate potential failure. OAL procedures are provided in Appendix D.

All external MIT results will be submitted to U.S. EPA in an electronic format within 30 days of the completion of each test. MIT reports will include charts and/or tabular results of each log including a comparison of the temperature profile during injection, during the shut-in over various time periods, and the background geothermal gradient, and a description of each test including date and time of test and well shut in.

8. Pressure Fall-Off Testing

SJR will perform pressure fall-off tests (PFOTs) during the injection phase as described below to meet the requirements of 40 CFR 146.90(f). U.S. EPA PFOT guidelines that will be followed are provided in Appendix E. Upon initial completion of the injection well, a pressure fall-off test and injectivity test will be conducted to verify the fracture gradient and pressure for maximum allowable injection pressure, and a test will be repeated every five years to confirm reservoir and well conditions.

Pressure fall-off testing will include ceasing injection (shutting in the well at the wellhead) and monitoring pressure decay within the well. Continuous pressure measurements will be conducted with dedicated downhole fiber optics for monitoring of completion zone pressure and temperature by interval. A secondary pressure gauge will also be deployed during the test for verification. The shut-in period will be at least four days, or longer if needed to reach a straight-line of pressure decay on a semi-log plot.

Pressure readings and temperature within the well during the test will be plotted as a function of time prior to and during the test, including log-log and semi-log diagnostic plots. Observations of anomalous pressure decay at greater rates than previous tests may indicate a number of scenarios such as changes in relative permeability, the effects of well stimulation procedures, or leakage of fluid (U.S. EPA, 2002). The Site TOUGH numerical model will also be used to interpret the test results by adjusting model parameters to fit the observed decay curve and assess the resulting permeability.

Pressure fall-off test results will be submitted electronically to U.S. EPA within 30 days of the completion of each test in a tabular format, including a description of the test (date, duration), bottomhole pressure and temperature at specified depth(s), records of all gauges, raw data in a tabular format, injection rates and pressure prior to the test, diagnostic plots, plots of TOUGH modeling compared to pressure fall-off tests and changes to any TOUGH model parameters if necessary, calculated parameter values (permeability, transmissivity, skin factor), and identification of data gaps.

9. Carbon Dioxide Plume and Pressure Front Tracking

SJR will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

As required by the Class VI rule, plume and pressure-front tracking within the Vedder formation will include the following:

- Direct pressure monitoring within the injection well and a monitoring well that will be installed within the Vedder formation

- Indirect geophysical monitoring (surface seismic) on a repeated basis within the area of projected carbon dioxide migration

- Computational modeling that is updated to incorporate monitoring results (computational modeling methodology is discussed in the AoR and Corrective Action Plan).

Pressure will be monitored directly within the injection well as discussed in Section 4, above. In addition, a monitoring well will be installed updip of the project in order to track pressure increases in the vicinity and ensure that pressure increase is similar to model projections. Figure 1a displays the planned location of the Injection-Zone (IZ) monitoring well (35.692503, -119.242309). The IZ monitoring well will be perforated exclusively within the Vedder formation, which is approximately 6,672 ft bgs at this location. Final perforated interval will be determined based on updated stratigraphy obtained during monitoring well drilling. The IZ monitoring well will be fitted with a downhole transducer for continuous pressure measurement.

Figure 3 presents the simulated pressure changes at the IZ monitoring well location during the lifetime of the project based on the project TOUGH numerical model. Pressure measurements at the IZ well and injection well will be compared to corresponding model-simulated pressure profiles to confirm that pressure increases within the Vedder formation are not greater than simulated. Pressure monitoring data will be submitted to U.S. EPA in semi-annual reports, including raw pressure data, transducer calibration logs, time-series graphs of measured pressure versus model-simulated predictions, and identification of data gaps.

Indirect plume monitoring will include time-lapse three-dimensional surface seismic surveys covering the entire extent of the area anticipated to be subject to carbon dioxide migration. Figure 1a displays the anticipated seismic area overlaid with model simulated extent of carbon dioxide during the lifetime of the project. The anticipated area for seismic surveys is approximately six square miles. The 3D seismic survey will be conducted prior to injection (baseline), and at years 2, 5 and 10 during the injection phase. Seismic methods will be consistent with U.S. EPA (2013) including ensuring that the exact same methodology is used in repeat surveys. The second seismic survey will be completed prior to the initial AoR reevaluation. SJR will also include monitoring for seismic events via existing state- or USGS-operated seismic monitoring networks to afford an opportunity to respond to any events that could affect the injection/monitoring wells.

Surface-seismic results will provide an indication of whether supercritical-phase carbon dioxide is present in any given location, but does not generally provide an estimate of carbon dioxide saturation. Plan-view maps of survey results will be compared to model-predicted carbon dioxide extent as shown in Figure 1a. Geophysical survey results will be submitted to U.S. EPA in semi-annual reports following the survey event, including a detailed independent report by the geophysical contractor of all survey methods, map(s) showing all survey equipment positions, date/time of all survey data collection, near surface conditions during the test, raw seismic data and interpreted diagrams, maps showing the location of the carbon dioxide plume, and maps comparing the carbon dioxide plume progression over time to model simulated projections. All geophysical surveys and reporting will be overseen by a California Registered Professional Geophysicist.

References

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United States Environmental Protection Agency (U.S. EPA), 2002. EPA Region 6 UIC Pressure Falloff Testing Guideline, Third Revision (August 8, 2002).

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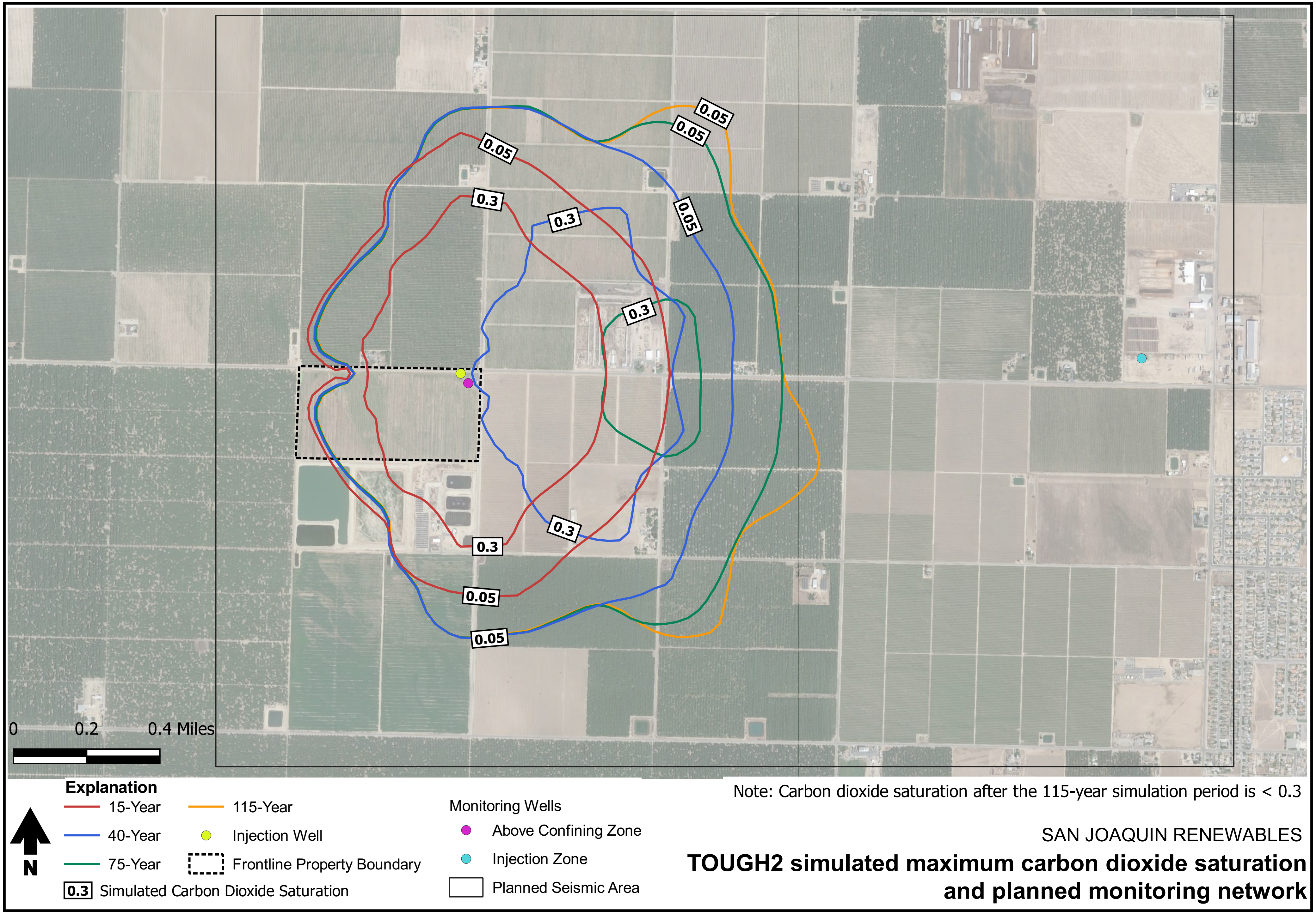
Figures

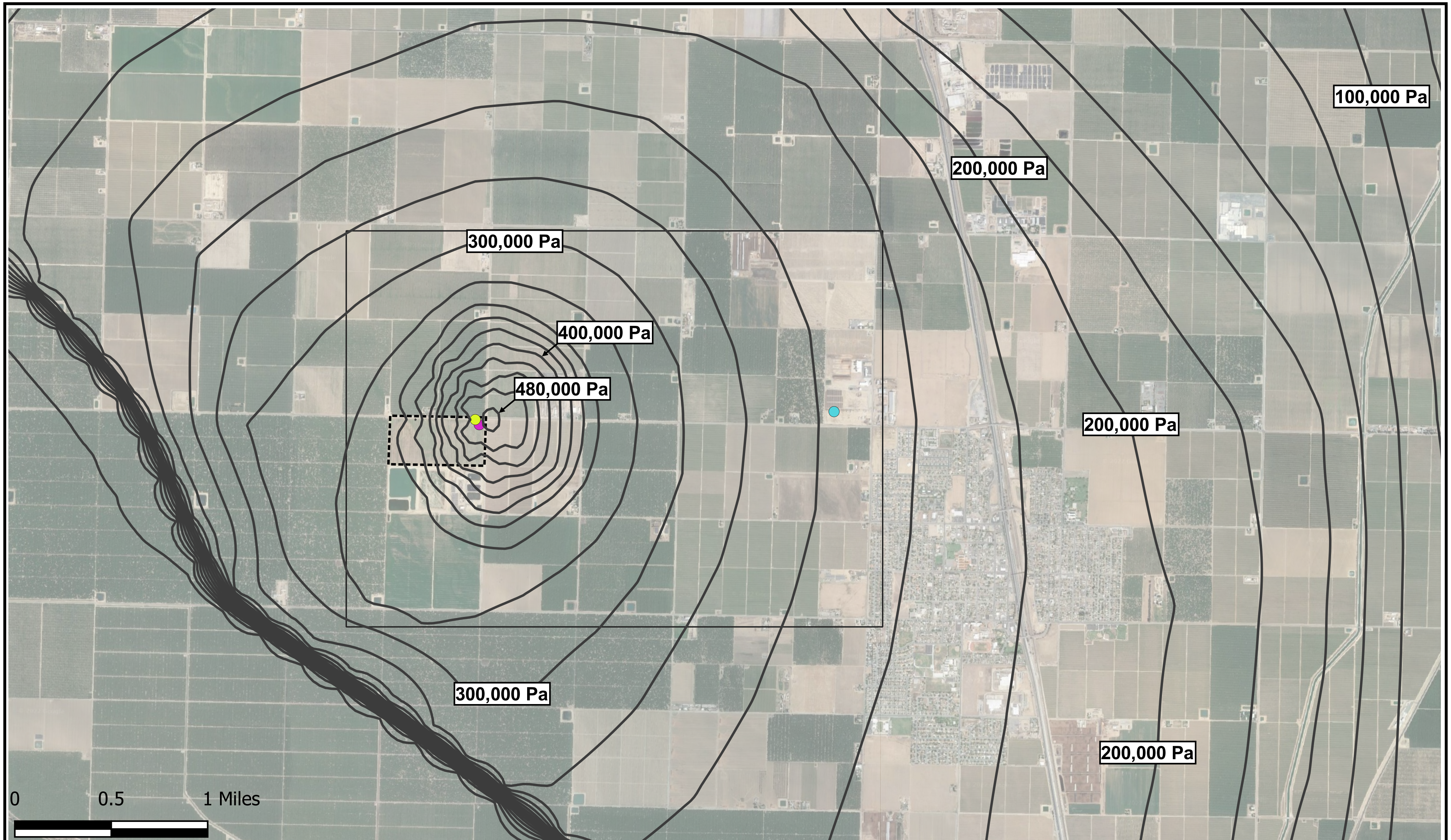


SAN JOAQUIN RENEWABLES

TOUGH2 simulated maximum carbon dioxide saturation and planned monitoring network

09/14/2021 JN DB19.1252

Figure 1a



Explanation

Frontline Property Boundary

Monitoring Wells

Above Confining Zone

Injection Zone

Injection Well

Planned Seismic Area

Maximum Pressure Increase, 20,000 Pa interval

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TOUGH2 simulated maximum overpressure (15 years) and planned monitoring network

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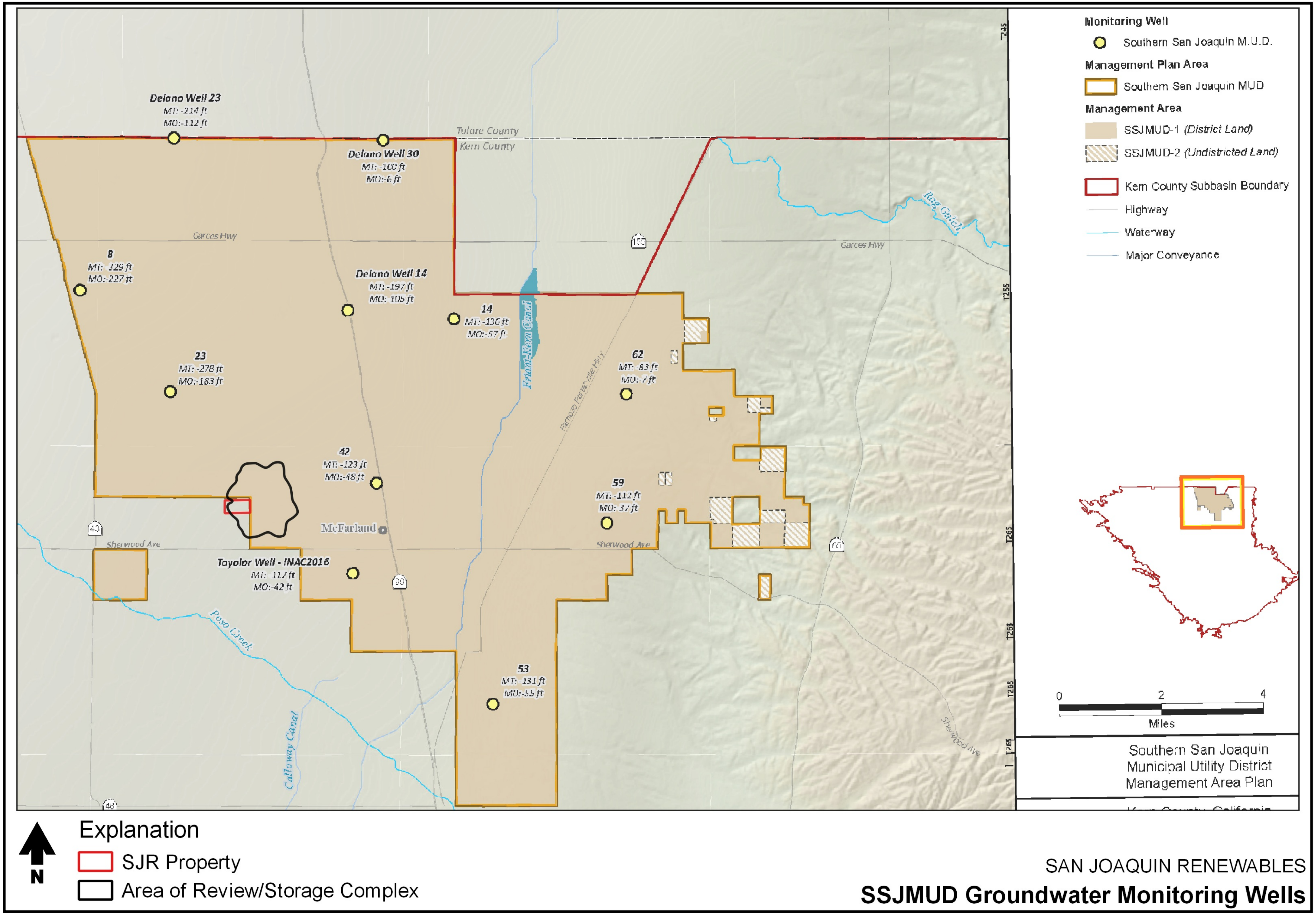

SAN JOAQUIN RENEWABLES

SSJMUD Groundwater Monitoring Wells

Figure 2

09/01/2022 JN DB19.1252

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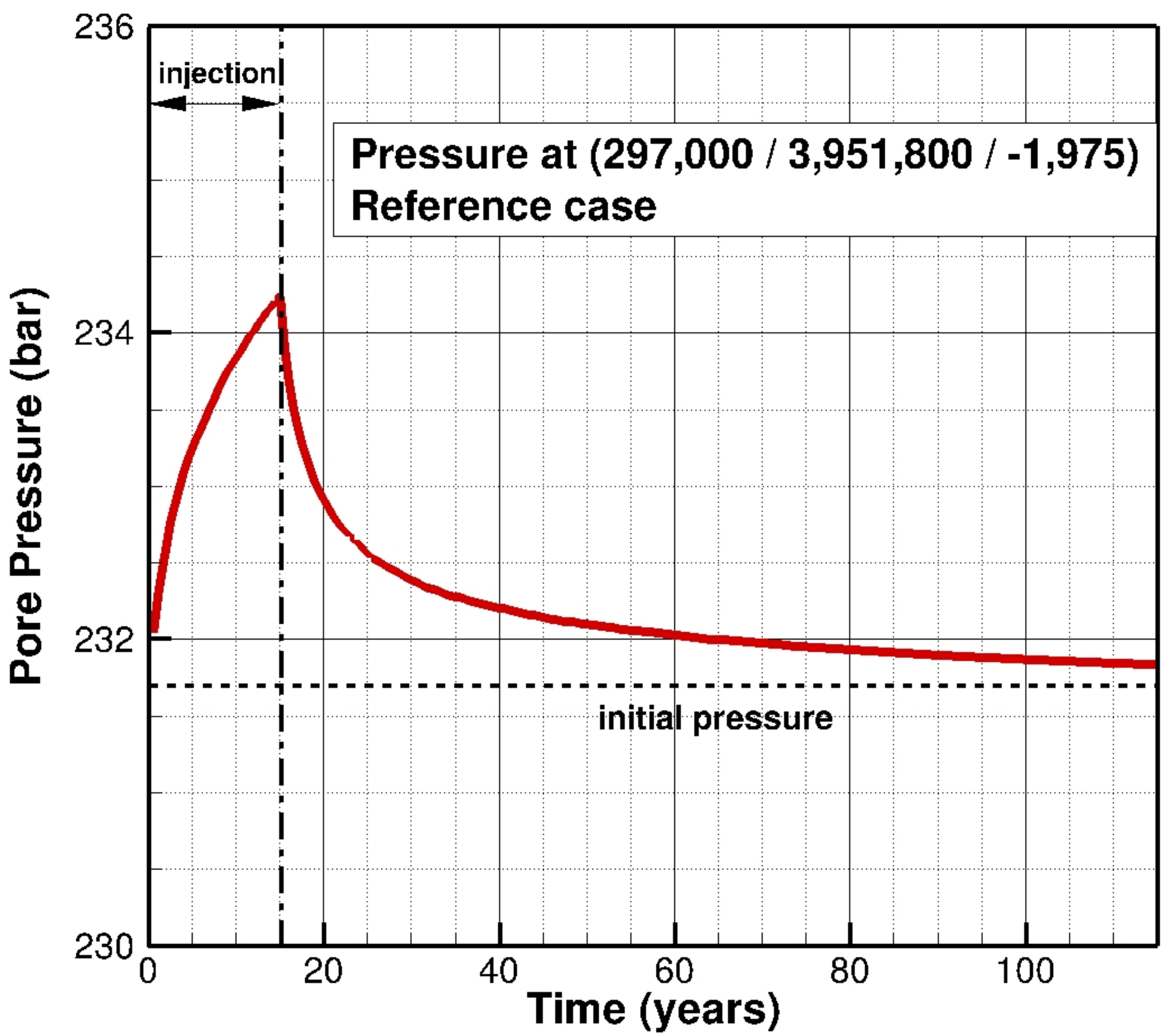

SAN JOAQUIN RENEWABLES

Simulated Pressure Profile at Pressure-Front Tracking Well Location, Vedder Formation

Appendix A: QASP

San Joaquin Renewables Class VI Permit Application Quality Assurance and Surveillance Plan

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December 22, 2021

Table of Contents

List of Attachments

1. Introduction and Background

This Quality Assurance and Surveillance Plan (QASP) is a component of the San Joaquin Renewables, LLC (SJR) application to the U.S. Environmental Protection Agency Region 9 (U.S. EPA) for an Underground Injection Control (UIC) Class VI permit for the proposed San Joaquin Renewables (SJR) facility near McFarland, California. This plan is one of several separate documents submitted to the U.S. EPA Geologic Sequestration Data Tool (GSDT) and includes required information regarding quality assurance tasks and methodology associated with planned testing and monitoring activities. Daniel B. Stephens & Associates, Inc. (DBS&A) prepared this QASP per 40 CFR 146.90(k) and United States Environmental Protection Agency (EPA) guidance (EPA, 2012).

2. Project/Task Description

As described in the testing and monitoring plan (DBS&A, 2021), the project includes the following primary field tasks listed below:

- Injectate stream analysis (laboratory sample analysis)
- Injection well pressure, rate, and volume monitoring (wellhead and in-situ monitoring instruments [screen interval] with downhole logging)
- Injection well casing corrosion monitoring (laboratory sample analysis and downhole logging)
- Injection well mechanical integrity testing (downhole logging)
- Groundwater quality monitoring (in-situ monitoring instruments [screen interval] and laboratory sample analysis)
- Geophysical (seismic) surveying (plume tracking of CO2 saturation)

3. Quality Assurance Objectives and Criteria

The quality assurance (QA) objectives and criteria are outlined below for each project task as applicable.

3.1 Data Generation and Acquisition

Data measurement and generation will be completed by external fixed commercial laboratories and by field instrumentation (dedicated in-line; downhole in-situ; downhole [wireline] logging; or portable instruments). The SJR facility will operate and maintain its own onsite fixed laboratory for routine injectate analyses while commercial laboratory analyses will be contracted for periodic QA checks against the onsite laboratory performance. QA procedures for data generation and acquisition are described below.

3.1.1 Laboratory Management

Specialized off-site fixed laboratories will operate under their facility-specific QA manual for the analytical services provided by that laboratory. Injectate stream analysis will be provided by TRI Air Testing (Round Rick, Texas) (or equivalent). Groundwater sample analysis will be provided by Eurofins Calcience in Garden Grove, California (or equivalent). Corrosion coupon testing analysis and/or American Society of Testing Materials (ASTM) analyses will be conducted by Zalco Laboratories Inc. in Bakersfield, California (or equivalent). Each laboratory will be required to maintain the appropriate certification and accreditation for each analytical service that is provided. The SJR facility will operate and maintain its own onsite fixed laboratory for routine injectate analyses. Laboratory analytical methods are specified in Section 3.1.4.

3.1.2 Field Instrumentation

Field instrumentation, including downhole logging tools, will be utilized for a variety of project measurements such as wellhead injection pressure (P), temperature (T), rate and volume; injected mass (flowmeter); in-situ groundwater pH, P, T, specific conductivity, dissolved oxygen (DO) and dissolved carbon dioxide; and well casing corrosion parameters.

Per U.S. EPA guidance the perforated interval of the above-confining zone (ACZ) well will be screened in the lower Olcese formation approximately 7,045 to 7,095 ft bgs (50-foot well screen interval) pending verification of stratigraphy upon drilling of the injection well. The IZ monitoring well will be perforated exclusively within the Vedder formation, which is approximately 6,672 ft bgs at this location pending verification of stratigraphy upon drilling. The IZ monitoring well will be fitted with a downhole transducer for continuous pressure measurement such as an ESI Hispec®HI5000 (Attachment A).

Field instrumentation will be installed or operated downhole, at the wellhead, or integrated in-line. A specialty vendor (i.e. Schlumberger®, Probe® or Horiba®) will be contracted to provide the instrumentation and assist with suitability analysis, customization (if needed), installation, calibration and maintenance where possible. Specialty geophysical survey instrumentation and equipment will also be used for 3D seismic survey data collection and analysis (CO2 plume tracking).

Each dedicated field instrument will be procured new from an authorized manufacturer or manufacturer's representative and maintained for dedicated project use. Each instrument will be calibrated, installed and maintained according to the frequency and methodology of the manufacturer's guidelines, specifications and requirements. Any instrumentation determined to be out of calibration will be immediately taken out of service and replaced. As a result, select stand-by replacement units will be procured and maintained for immediate project use. Instrumentation will be registered with the manufacturer in order to maintain correspondence regarding possible unit upgrades, modifications, or product recalls.

As possible, portable and fixed instrumentation will be installed and/or operated in a redundant manner, that is, duplicate instrumentation will be installed in series or parallel in order to evaluate and verify the precision of real-time measurements. Duplicate field instruments will be procured and deployed during routine measurements as possible. Each portable or fixed unit will be individually numbered and labeled so each measurement is assigned to a specific individual instrument.

Portable field instruments will be maintained in a dedicated, access-restricted (locked) and secure location between project measurement events and returned to storage after each use (including locked field vehicle storage). The storage unit or vehicle will be moisture and temperature-controlled as required for each instrument. Portable equipment will be deployed to a field task assignment with a sign-out/sign-in (return) sheet documenting the technician, date, and project use/location. Only properly trained staff will be permitted to operate portable field instrumentation. Rental equipment procurement and deployment (i.e. geophysical survey equipment or others) will be completed a noted above where applicable.

The manufacturer registration, documents and specifications such as model number, unit number, factory calibration, and factory registration will be maintained in the master project files. Operational manuals will be maintained in the master project files with a copy maintained with instruments in the field.

Field measurements will be redundantly conducted in duplicate or triplicate as possible with competing instruments to promote consistent and representative measurements.

Example specification sheets for in-situ and wireline logging instruments are included in Attachment A. Comparable in-line instrumentation upstream of the wellhead (pre-injection) is anticipated to be installed for injection P, T and injection rate. Downhole in-situ instrumentation may be installed within the ACZ and injection zone (IZ) monitoring well screen intervals for in-situ groundwater P, T, DO, specific conductivity (i.e. Probe® KPerm™ Multi-Drop Piezo Downhole Gauge) and, if a sensor is available, dissolved CO2. Downhole monitoring well instrumentation must be rated for the anticipated elevated water pressure at approximately 10,000 feet of water column depth.

Downhole logging tools are anticipated to be deployed by wireline for downhole P and T (to complement in-situ data), mechanical integrity testing, and well casing corrosion analysis (to supplement corrosion coupon testing). Downhole logging tools will be utilized for mechanical integrity testing prior to injection, and annually, using downhole P/T logging instrumentation. If needed to resolve or complement T logging data, a downhole oxygen activation (water flow) logging tool such as the Probe® Reservoir Analysis Sonde Sigma HD (pulsed neutron tool) may also be deployed.

Downhole logging tools will be utilized for corrosion monitoring on a semi-annual basis as follows:

- Ultrasonic imaging log (or equivalent) to gauge casing inside and outside roughness and thickness, casing to cement bond.
- Multi-finger caliper to evaluate inner metal loss.
- Electromagnetic flux log to evaluate total metal loss.
- Downhole video if necessary to identify casing problems where other logs may be ambiguous.

The following instrumentation (or equivalent) provided by Probe® (or an equivalent vendor) will be evaluated for applicability and modified or customized as needed for the corrosion parameters listed above (Attachment A):

- Radii® Cement Bond Tool
- Promac™40 Multi-arm Caliper Tool
- IQ™ Magnetic Properties Tool

Wellhead cellular telemetry (Hach Claros® or equivalent) will be installed to enable web-based real-time remote monitoring of downhole in-situ instrumentation. A reputable, established, and reliable commercial vendor will be identified to install and maintain this system.

3.1.3 Field Sampling Methods

Field sampling methodology is not applicable to in-stream, in-line, downhole logging or downhole in-situ dedicated instrumentation or geophysical surveying. Field sampling methods are specified below for:

- Injectate stream sampling
- Groundwater sampling
- Well casing corrosion testing

3.1.3.1 Injectate Stream Sampling

Injectate stream quality will be sampled for third-party fixed laboratory analysis as a quality check of the on-site fixed laboratory analyses. The carbon dioxide stream ahead of the injection well will be collected directly into specified sample containers without any required pre-sample in-line purging. An in-line sampling valve will be installed as needed to facilitate routine sampling. Samples will be extracted upstream of the wellhead and may be allowed to decompress into the vapor phase within a sample container for analysis. Samples can be also collected as liquified compressed gas or gaseous (vapor) samples as needed according to analytical laboratory specifications. Laboratory analytes and methods are presented in Section 3.1.4.

3.1.3.2 Groundwater Sampling

Groundwater sampling will be conducted in the above confining zone (ACZ) well installed at the SJR property. Per U.S. EPA guidance the perforated interval of the ACZ well will be in the lower Olcese formation approximately 7,045 to 7,095 ft bgs (50-foot well screen interval) pending verification of stratigraphy upon drilling of the injection well. ACZ well groundwater sampling will be conducted using passive diffusion bag (PDB) samplers or a discrete-depth sleeve sampler (Hydrasleeve® or equivalent). PDB or sleeve samplers will be verified in advance for suitability and performance at the well screen depth. A wireline system with a timed discrete-zone sampling device (e.g., Probe® Kuster® sampler or similar) (Attachment B) capable of collecting an in-situ sample from a specified depth interval may also be deployed for in-situ groundwater sampling.

In-situ water quality parameters pH, specific conductivity, temperature and dissolved oxygen (DO) and carbon dioxide (if feasible) will be monitored with dedicated in-situ instrumentation installed within the well screen interval during well construction (Section 3.1.2).

Groundwater sampling will also be conducted in underground sources of drinking water (USDW) wells (potable supply wells) in the project vicinity. These wells are already routinely sampled and SJR will seek permission to collect additional sample volume during routine sampling events to be conducted by Southern San Joaquin Municipal Utility District (SSJMUD). SJR will evaluate the SSJMUD sampling methods going forward and request accommodation for specific parameters (such as in-situ carbon dioxide) if needed. Laboratory analytes and methods are presented in Section 3.1.4.

3.1.3.3 Well Casing Corrosion Testing

Field well casing corrosion testing will be conducted according to the methods specified in ASTM G1-03 or National Association of Engineers (NACE) International TM-01-69 (or an approved equivalent) that are tailored to the field environment in-line and upstream of the injection wellhead. The testing will be conducted in a systematic, repeatable field procedure fully documented to provide for independent QA review and verification at any step in the procedure. Duplicate and redundant testing will be conducted at least at a frequency of 10 percent.

All calculations will be independently checked and confirmed and each analysis will be cross-checked for compliance with the approved methodology. Written documentation will provide a record of the QA review. Laboratory analytes and methods are presented in Section 3.1.4.

3.1.4 Laboratory Analytical Methods

The parameters and analytical laboratory methods for injectate stream analysis are listed below:

- Total sulfur (International Society of Beverage Technologists [ISBT] 14.0 or ASTM D3246)
- Hydrogen sulfide (ISBT 14.0 or ASTM D1945/D6228)
- Nitrogen (ISBT 4.0) or ASTM D1945)
- Total Hydrocarbons (ISBT 10.0 or ASTM D1945)
- Methane (ISBT 10.1 or ASTM D1945)
- Carbon dioxide purity (liquid) (ASTM E1747 or ASTM D1945)

The parameters and analytical laboratory methods for groundwater sampling are listed below:

- Carbon dioxide (in-situ dissolved) (ASTM D513 or similar)
- Dissolved metals (EPA 200.8/200.9/7010 or similar) (laboratory filtered)
- Total dissolved solids (ASTM D5907 or similar)
- Major anions (EPA 300.1 or similar)
- Major cations (EPA 6020A/6020C/700B or similar)
- pH, temperature, DO, specific conductivity (calibrated in-situ instrument or portable meter)

The methodology for well casing corrosion sampling is listed below:

- ASTM G1-03 Corrosion or Corrosion Coupon by National Association of Engineers (NACE) International TM-01-69.

Sample containers, preservatives, reporting limits, and holding times are presented in Attachment C.

3.1.5 Quality Control Samples

Quality control (QC) sampling will consist of field quality control samples and laboratory quality control samples. Field quality control samples will consist of field duplicate samples collected at a frequency of 10 percent. Field equipment rinsate blanks or sample shipment trip blanks are not applicable for the groundwater analyte list proposed for this project (Section 3.1.3).

Laboratory QC samples include laboratory duplicates, laboratory control samples, and matrix-spike/matrix spike duplicates as specified by the analytical methodology for each parameter.

3.1.6 Sample Handling and Custody

Field samples will be collected directly into specified containers provided by the laboratory for each analysis. Samples will be uniquely labeled with date, time, and location and listed onto a standard laboratory chain-of-custody (COC) form. The COC form will double as the sample collection log. Samples will be secured into a water-resistant and temperature-controlled sample shuttles (coolers) along with appropriate container cushioning to avoid potential container breakage. Sample coolers will also contain packaged ice, dry ice, or manufactured ice (blue ice) as needed for temperature control as specified for each sample analysis. Onsite refrigerators with temperature control may also be used if available in preparation for packaging and offsite shipment to the laboratory.

COC documentation will be maintained with each sample cooler during sample collection and storage. Custody of sample cooler(s) is defined as within one’s continual view or within a locked vehicle or locked storage area. Sample custody will be continually maintained and controlled between personnel with each transfer documented in the COC form. Laboratory shipments may be completed by commercial carrier as needed with proper shipment documentation and COC control.

3.1.7 Data Management and Reporting

SJR or a designated contractor will systematically compile and maintain project data and records as they are generated. Data will be electronic where possible and backed up on tape and held on secure servers. Data will be managed in a centralized electronic data management system. Electronic servers will be routinely maintained, updated, and backed-up to ensure the long-term preservation of project data and records. Project data and records includes field forms, analytical laboratory reports, instrument and equipment procurement records, calibration records, instrument manuals, analytical methodology, and related project information.

Calculations will be independently checked and confirmed and each analysis will be cross-checked for compliance with the approved methodology. Written documentation will provide a record of periodic QA reviews.

3.2 Measurement Performance and Acceptance Criteria

3.2.1 Field Instrumentation

Field instrumentation will be installed, calibrated and maintained according to the manufacturer's requirements and specifications. Only data measurements within the design range of the instrumentation will be accepted for project use.

3.2.2 Laboratory Reporting Limits

Laboratory reporting limits (RLs) are specified by the EPA, ASTM, or NACE analytical methodology and the laboratory performing the specified designated analysis. RLs will be specified in advance and only data within the specified range will be accepted for project use. In the event RLs are exceeded an assessment of the exceedance will allow for correction in the sampling or analytical methodology for subsequent analyses. Anticipated RLs are presented in Attachment C.

3.2.3 Data Validation and Usability

Laboratory reports will be comprehensively reviewed for accuracy and completeness regarding requested samples, methods, and RLs. QA blanks and duplicate data will be compared to original field sample data for comparability. An external commercial data validation service may be employed as needed to complete a systematic validation review and approval in order to formalize data usability. Rejected or qualified data, if any, will be clearly marked in reporting documents.

References

ASTM International, 2015. ASTM D3246-15, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, 100 Barr Harbor Drive, PO Box C700, West Conshohocken, Pennsylvania, January 15.

ASTM International, 2017. ASTM G1-03 (17), Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens, 100 Barr Harbor Drive, PO Box C700, West Conshohocken, Pennsylvania, November 1.

ASTM International, 2019. ASTM D6228-19, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, 100 Barr Harbor Drive, PO Box C700, West Conshohocken, Pennsylvania, April 1.

ASTM International, 2019. ASTM D1945-14 (19), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, 100 Barr Harbor Drive, PO Box C700, West Conshohocken, Pennsylvania, December 1.

ASTM International, 2019. ASTM E1747-95 (19), Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications, 100 Barr Harbor Drive, PO Box C700, West Conshohocken, Pennsylvania, December 1.

Daniel B. Stephens & Associates, Inc. (DBS&A), 2021. San Joaquin Renewables, Class VI Permit Application, Testing and Monitoring Plan, prepared for San Joaquin Renewables LLC, McFarland, California, October 13.

EPA, 2012. Geologic Sequestration of Carbon Dioxide, Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance. EPA 816-R-11-017, Office of Water (4606M), Washington, D.C., August 12.

National Association of Engineers (NACE) International/ASTM International, 2021. Standard Guide for Laboratory Immersion Corrosion Testing of Metals, NACE TM-01-69.

Attachment A

Hispec® HI5000

Downhole Pressure Transmitter

- Compact design
- NACE certified materials
- Silicon-on-sapphire sensor technology for outstanding stability
- High temperature up to 392 °F (200°C)
- High pressures up to 29,000 psi (2000 bar)
- All-welded and sealed construction for use in harsh and corrosive environments

ESI SILICON-ON-SAPPHIRE TECHNOLOGY SOS

RoHS 2011/65/EU

CE

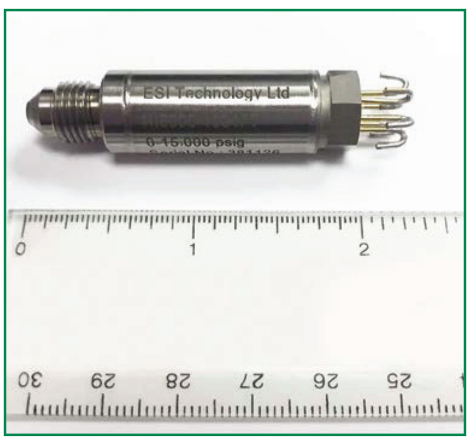
Description

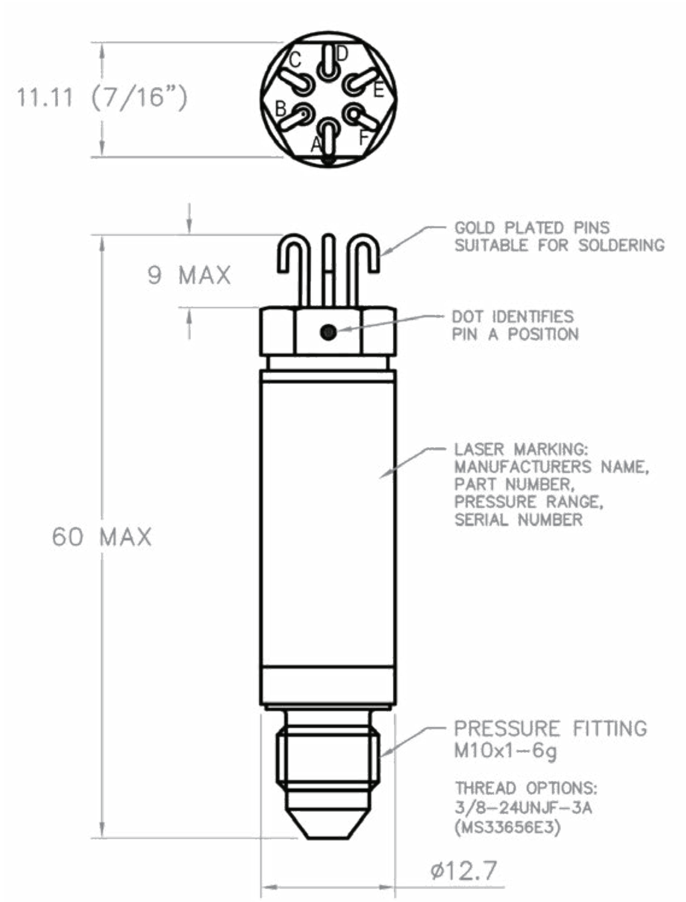
The HI5000 transmitter, for downhole applications, is highly compact with a maximum length of 58mm.

The tough, corrosion-resistant design, using NACE certified materials, makes installation easy in challenging environments. The sensor is designed to withstand high shock and vibration inputs in high temperature applications which require accuracy, stability and long term performance of downhole pressure monitoring.

Dimensions

(in mm)





ELECTRICAL CONNECTION

PIN	Designation
A	+ Excitation
B	+ Signal
C	- Signal
D	- Excitation
E	RTD
F	RTD

Technical Data

Type	HI5000
Sensor Technology:	Silicon-on-Sapphire
Pressure Range:	See Table 1
Proof Pressure:	See Table 1
Burst Pressure:	See Table 1
Excitation:	3-10 VDC (5 VDC Nominal)
Input Resistance:	4000Ω ±1000Ω
Output Resistance:	4000Ω ±1000Ω
Output at zero pressure over the calibrated pressure range:	±8.0 mV/V
Full scale sensitivity (span) over the calibrated temperature range:	10-20 mV/V Nominal
Operating Temperature Range:	-40°F to +392°F (-40°C to +200°C)
Calibrated Temperature Range:	75°F to +356°F (+24°C to +180°C)
Non-linearity & Hysteresis Combined:	±0.150 % of span maximum (Best Fit Straight Line method)
Total Error Band (Non-linearity, Hysteresis & Thermal Effects):	± 0.20% of span, serial number specific polynomial model P(T,mV) provided for all input pressures and temperatures over the calibration range
Pressure Media:	Any compatible with NACE approved Titanium grade 5 and BT9 alloys (other materials available. Contact sales)
Weight:	20g maximum (less than 1 oz.)
Process Connection Thread:	3/8-24UNJF as per MS33656-E3
Insulation resistance:	All connections pins together to case: 100 MΩ minimum at 50 VDC
Platinum Resistance Temperature Detector (RTD):	0°C, 1000Ω ±0.06% to IEC 751 Class A, Alpha = 0.00385 nominal
Recommended Installation Torque:	125 to 150 in-lb (14-17 Nm)
Calibration Data:	The calibration certificate supplied with each unit includes the coefficients for a 5th order polynomial calibration model

Table 1

MODEL NUMBER	PRESSURE RANGE [BARSG]	PROOF PRESSURE	BURST PRESSURE
HI5000-0400	0-400	200%	300%
HI5000-0600	0-600	200%	300%
HI5000-1000	0-1000	150%	200%
HI5000-1500	0-1500	110%	150%

DISCLAIMER : ESI Technology Ltd operates a policy of continuous product development. We reserve the right to change specification without prior notice. All products manufactured by ESI Technology Ltd are calibrated using precision calibration equipment, traceable to national measurement standards.

KPERM™ MULTI-DROP PIEZO DOWNHOLE GAUGE

SKU: MP203-030-406
Categories: Advanced Monitoring, Downhole Gauges, Downhole Instrumentation, KPerm™, Kuster®, Well Monitoring

PRODUCT DESCRIPTION

Probe Multi-Drop Gauges are based on our field proven permanent piezo gauge technology. Up to 6 gauges can be run on a single TEC cable conductor. All gauges continuously provide accurate pressure and temperature data to surface, where it is displayed real-time via a single surface readout. The gauges are internally and externally E-beam welded, and designed for maximum shock and vibration resistance to enhance reliability and performance.

Ratings & Dimensions

Max temperature	257° (125°/ 302°F (150°C)
Pressure Range	3kpsi, 5kpsi, 10kpsi & 15kpsi
Outer diameter	1.19 in (30.2 mm)
Length	19.0 in (482 mm)
Weight	3.5 lbs (1.59 kgs)
Materials	Nitronic 50 or 718 Inconel NACE MRO 175

Hardware Characteristics

Transducer type	Piezo resistive
Acquisition mode	Surface Readout Panel (SRO)

Pressure Measurements

Pressure Range	3kpsi, 5kpsi, 10kpsi & 15kpsi
Sampling Rate	1 sps
Resolution	0.0003% F.S.
Accuracy	0.024% F.S. or 0.05% F.S.
Drift	< 3 psi / year

Temperature Measurements

Max temperature	302°F (150°C)

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Resolution	0.005% F.S.
Accuracy	± 1°C

Electrical Specification

Data Output	Continuous data stream - MODBUS 485
Interface	KPerm SRO
Operating Voltage	24Vdc
Operating Current	12 – 34 mA
Max Number of Gauges	6

Version Control: 2021.12.14

On-line specifications are for REFERENCE ONLY and subject to change without notice. DO NOT USE FOR FIELD OPERATIONS.

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RESERVOIR ANALYSIS SONDE SIGMA - HD - 1 11/16 IN.

SKU: RAS003
Categories: Cased Hole Wireline, Formation Evaluation, HD Platform™, Pulsed Neutron, RAS

PRODUCT DESCRIPTION

The RAS003 is a multi-detector pulsed neutron tool for measuring reservoir saturation using Sigma techniques. The sonde features an array of three Sodium Iodide (NaI) detectors. The Sigma measurement is based on the near and far spacings, the long spacing is sensitive to porosity and gas saturation.

The tool also operates in Oxygen Activation mode to determine water phase velocity (Water-Flow mode) and can be combined with up to four Gamma Ray-CCL (GCL) tools for this application.

The RAS003 is an HD platform tool, and as such can be run in combination with other HD tools such as Spectral Gamma, RADii, ProMAC and Production Logging tools.

Ratings & Dimensions

Diameter	1.69 in (43.0 mm)
Length	140.7 in (3573.0 mm)
Weight	51.0 lb (23.0 kg)
Max temperature	320°F (160°C)
Max pressure	15,000 psi (103.4 mPa)
Measure Points	Near: 80.0 in (2032.0 mm) Far: 87.0 in (2210.0 mm) Long: 95.0 in (2413.0 mm)
Materials	Corrosion resistant materials used throughout

Hardware Characteristics

Source Type	3 detector array	
Sensor Type	Sodium Iodide (NaI) detectors	
Acquisition Mode	Real-time with TCU	Memory with MLT

Measurements

Type	Sigma, Oxygen Activation, Inelastic Gas

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IQ™ MAGNETIC PROPERTIES TOOL - PTX - 2 3/4 IN.

SKU: 050-CI275-0001
Categories: Cased Hole Wireline, Electro-Magnetic Thickness, iQ, PTX, Well Integrity

PRODUCT DESCRIPTION

The 4-segment receiver of the iQ™ Magnetic Properties Tool (PTX) measures the casing in 90° sections (quadrants). The tool produces a magnetic field that opposes the primary field casing attenuation and phase shift. The magnitude of the measured phase shift is a function of the electrical conductivity, magnetic permeability and metal thickness of the field being measured. Multiple coil spacing and frequencies control the depth of investigation and measure the electromagnetic properties of the casing, that yield a quantitative casing thickness and internal diameter measurements.

Ratings & Dimensions

Max Temperature	350°F (177°C)
Maximum Pressure	20,000 psi (138 MPa)
Outer Diameter	2.75 in (69.85 mm)
Length	75.0 in (1905.0 mm)
Weight	70.0 lb (31.75 kg)
Csg/Tbg OD	Min: 3.5 in (89.0 mm) Max: 7.0 in (178.0 mm)
Tensile Strength	**Tension:** 15,000 lb **Compression:** 15,000 lb
Measure Points	**Casing Thickness:** 24.5 in (639 mm) **Dift'l Thickness:** 32.7 in (828 mm) **Caliper:** 25.0 in (635 mm)

Borehole Conditions

Tool Positioning	Centralized
Logging Speed	**Recommended:** 30 ft (9.1 m) /min **Max:** 60ft (318.2 m) /min

Hardware Characteristics

Source Type:	Single and multi frequency AC coils Azimuthal thickness gauge with quadrant sensitivity
Sensor Type	Multi-frequency caliper and casing properties 3-axis accelerometer for tool orientation
Connections	E-Line 'GO' Type

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Combinability	GR, CCL, MAC, Radii Bond Tool

Electrical Specification

Current	+ 45 mA @ 130V

Measurements

	Casing Thickness	Casing Caliper
Principle	Remote-field EC	Near-field EC
Range	0 to 1.50 in	3.50 to 7.00 in
Azimuthal Resolution	4 sectors	NA
Vertical Resolution	1.56 in	1.00 in
Sensitivity	1% (2 inch through-hole)	1%
Accuracy	±1%	
Primary Curves	Casing & differential thickness	Casing ID
Secondary Curves	3-axis accelerometer, internal temperature, casing electrical properties	

Calibration

Primary & Wellsite	Sections of API casing in different weights

Version Control: 2021.12.16

On-line specifications are for REFERENCE ONLY and subject to change without notice. DO NOT USE FOR FIELD OPERATIONS.

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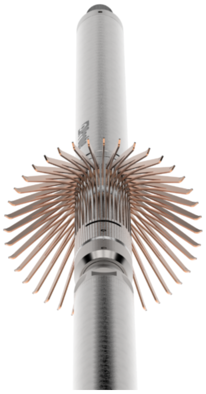
PROMAC™ 40 | MULTI-ARM CALIPER TOOL - HD - 2 3/4 IN.



SKU: 050-MAC40-1100
Categories: Caliper, Cased Hole Wireline, HD Platform™, Multi-Arm Calipers, ProMAC, Well Integrity

PRODUCT DESCRIPTION

The latest generation ProMAC™ series 40-arm caliper tool incorporates a series of mechanical, electrical and electronic design features that greatly increase tool accuracy, reliability, maintainability and overall cost efficiency.

Ratings & Dimensions

Max Temperature	350°F (177°C)
Max Pressure	20,000 psi (138 MPa)
Diameter	2.75 in (69.9 mm)
Length	63.66 in (1,617 mm)
Weight	66 lb (29.9 kg)
Tensile Strength	**Connection:** 15,000 lbF **Body:** 20,000 lbF
Measure Points	**Caliper:** 33.85 in (860 mm) from bottom of tool
	Inclination: 52.4 in (1331 mm) from bottom of tool
Materials	Corrosion resistant materials used throughout

Hardware Characteristics

Sensor Type	**Inclinometer:** 3-axis accelerometer
	Caliper: Differential Variable Reluctance Transducer
Combinability	All HD tools: GR, CCL, iQ, RADii, RAS, PLT
Tool Positioning	Centralized
Acquisition Mode	SRO w/ TCU Mem w/ MLT

Electrical Specification

Voltage	**SRO**	50V DC
	Memory	19.2V DC
Current	**SRO**	40mA(log) 100mA(opening)
	Memory	104mA(log) 260mA(opening)

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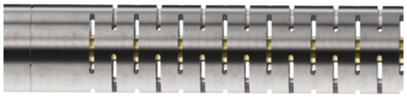
RADII® CEMENT BOND TOOL - HD - 2 3/4 IN.



SKU: 050-RB275-1000
Categories: Cased Hole Wireline, Cement Evaluation, HD Platform™, RADii, Well Integrity

PRODUCT DESCRIPTION

The medium diameter RADii® HD Segmented Cement Bond Tool uses a single ceramic transmitter, an eight segment receiver at 3 ft. and a single receiver at 5 ft. spacing. The segmented receiver generates a cement map which enables identification of cement channeling while the single receiver generates the traditional cement bond log (CBL) and a variable-density log (VDL).

Ratings & Dimensions

Max Temperature	350°F (177°C)
Maximum Pressure	15,000 psi (103.42 MPa)
Outer Diameter	2.75 in (69.85 mm)
Length	8.73 ft (2.66 m)
Weight	93 lb (42.18 kg)
Min Csg/Tbg OD	4.5 in (115.0 mm)
Max Csg/Tbg OD	11.6 in (295.0 mm)
Tensile Strength	**Tension:** 50,000 lb **Compression:** 35,000 lb
Materials	SST
Measure Points	**Amplitude, TT:** 4.3 ft (1.3 m) **VDL, Signature:** 3.3 ft (1.0 m)

Borehole Conditions

Borehole Fluids	Salt, Fresh and Oil
Tool Positioning	Centralized with one each centralizer above and below

Hardware Characteristics

Source Type:	One piezoelectric crystal fired at 20 kHz, 50 msec intervals
Sensor Type	**Omni Receiver:** One 20 kHz piezoelectric **Radial Receiver:** One 8 segment 20 kHz piezoelectric
Connections	**Top:** GOI box **Bottom:** GOI pin
Combinability	GR, CCL, ProMac, iQ, Temperature

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Acquisition Mode	SRO w/ TCU	Mem w/ MLT

Electrical Specification

Current	45 mA @ 130V

Version Control: 2021.11.16

On-line specifications are for REFERENCE ONLY and subject to change without notice. DO NOT USE FOR FIELD OPERATIONS.

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Attachment B

Kuster Flow Through Sampler (FTS)

Product Reference: 11700-100

Probe
powered by ingenuity

The Kuster Flow Through Sampler (FTS) is a device for obtaining fluid samples from a producing well.

The sample chamber is lowered into the well with open valves on each end, allowing well fluids to pass freely through the chamber. At an interval programmed on the surface, the valves close, trapping the fluid. The sampler can then be removed from the well. The sample contained in the chamber will remain in the same state as it was in the well. The pressure will not be changed. The sample can then be removed from the sampler and transferred to a container suitable for storage.

The instrument consists of a sample chamber with a spring-loaded valve on each end. A latching mechanism connects the valves together and holds them open. Above the chamber, there is a clock to program the closing time, and a ball operated tripping mechanism to release the valves. The lower end has a removable bull nose with ports to allow the fluid to enter. At the top, there is a rope socket for attaching the wireline.

SPECIFICATIONS - KUSTER FLOW THROUGH SAMPLER (FTS)

Outside diameter (O.D.)	1 1/2"	3.81 cm	**Seal Material**	VITON
Length	87"	2.20 m	**Material**	17-4 PH/SS Monel
			PH	2, 9-9
Operating Environment:			**Salinity**	300,000 ppm
Maximum Pressure	10,000 psi	68.9 MPa		
Maximum Temperature	450 °F	232.2 °C	**Miscellaneous:**	
Capacity	600 cc		Clocks	Programmable for 1, 2, 5 and 6 hours
			Transfer Method	Manual bleed-off

RELATED PRODUCTS

- 18600-XXX Carrying Case
- 18600-XXX Field Tool Kit
- 18600-XXX Spare parts kit

Note: Description and specifications are subject to change without notice.

At Probe, we design, manufacture and service specialized modular downhole tools and systems. Our tools are used in formation evaluation, well integrity assessment and well productivity determination across the global energy industry.

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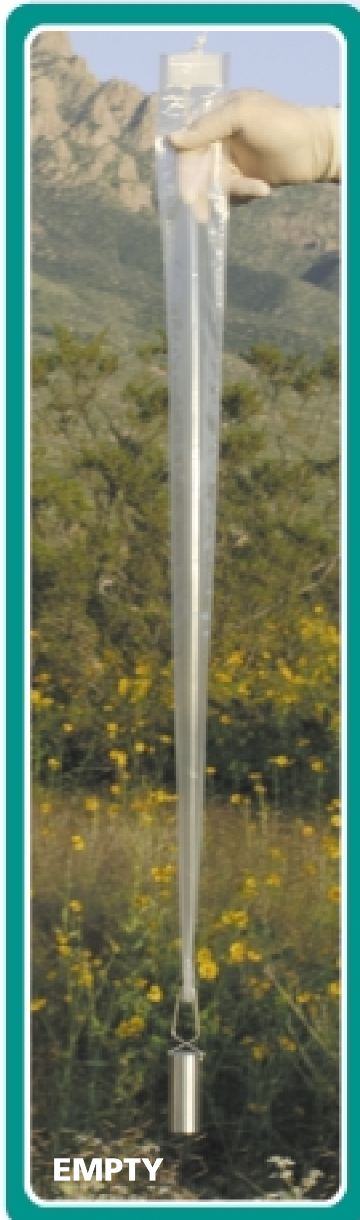
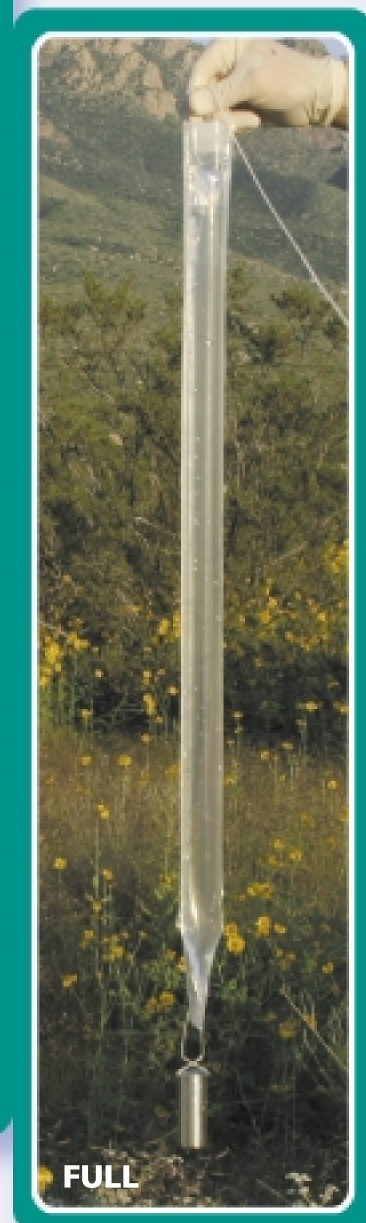
HYDRASleeve

US Patents No. 6,481,300; No. 6,837,120; No. 9,726,013 others pending

NO PURGE GROUND WATER SAMPLER

By more effectively sampling groundwater, especially in low-yield wells, the new HydraSleeve "No Purge" ground water sampler can cut field sampling costs in half! The low-cost, disposable HydraSleeve captures a "core" of water from any discrete interval in the screened portion of the well with no change in water level and minimal disturbance to the water column. HydraSleeve is sealed except during sample collection, then re-seals itself, assuring that a representative sample is recovered. The low-profile HydraSleeve can be fabricated in various sizes to match well and sampling requirements. HydraSleeve makes ground water sampling a simple, three-step operation.





FEATURES:

EFFECTIVE
- Sample for ALL compounds
- Best sampler for slow recharge wells
- Repeatable sampling method
- Lower turbidity than purge and sample
- Slim cross section minimizes disturbance

INEXPENSIVE
- Reduces field sampling costs by 50% - 80%
- No purge water disposal
- No expensive equipment

FAST
- Collect samples in less than 15 minutes
- Cuts total field time by half or more
- No decontamination

EASY TO USE
- No training or special tools required
- Small, convenient and simple shipping

USES
- Long term ground water monitoring
- Sample low-yield wells
- Determine dissolved containment fraction
- Sample crooked or constricted wells
- Vertically define contaminant concentrations

Simple by Design

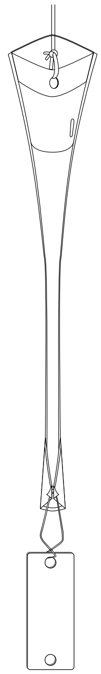
www.hydrasleeve.com

2007 Glass Road • Las Cruces, New Mexico 88005 • Phone:1.575.523.5799 • **1.800.996.2225** • info@hydrasleeve.com

HOW IT WORKS

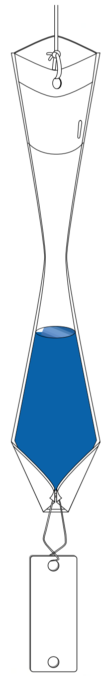
ONE

Placing Sampler
HydraSleeve is lowered into place and positioned in the well screen. Water pressure keeps bag collapsed and check valve closed, preventing water from entering sampler. Well is allowed to return to equilibrium.



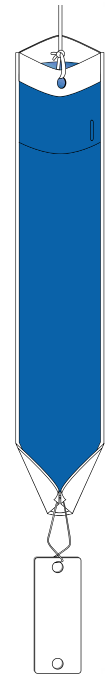
TWO

Sample Collection
HydraSleeve fills when the check valve is moved upward faster than 1 fps. It fills by continuous upward movement. When moving upward, the check valve opens and fluid flows into the bag. There is no change in well water level and minimum sample agitation during collection.



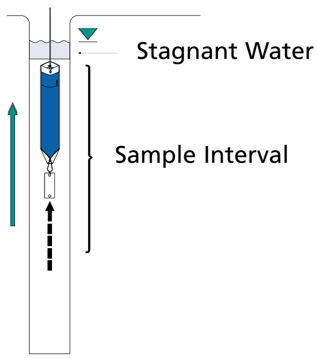
THREE

Sample Retrieval
Flexible bag is full and check valve closed. Sampler is recovered without entry of extraneous, over-lying fluids. Note: Several HydraSleeves may be stacked on the suspension cable for vertical profiling.

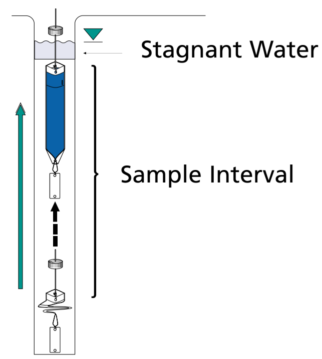


METHODS OF SAMPLING WITH THE HYDRASLEEVE

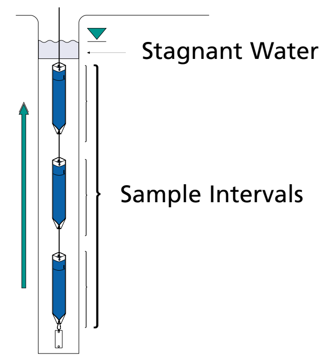
Continuous Pull – Bottom Weight



Continuous Pull – Top Weight



Vertical Profiling Multiple Samplers



HydraSleeve Specifications

	2-inch Fits 2-inch and larger wells	**4-inch** Fits 4-inch and larger wells
General Specifications		
Sample Sleeve Layflat Width	2.5 inches	4 inches
Filled Sample Sleeve Diameter	1.5 inches	2.6 inches
Total Volume for 30-inch HydraSleeve	650 ml	1250 ml
Sampler Tensile Strength	25-35 lb	25-35 lb
Standard Sample Sleeve Material	Virgin 4 mil PE	Virgin 4 mil PE
Volume Displaced		
8 oz. SS weight	25 ml	25 ml
30-inch Empty Sleeve (approx.)	30 ml	70 ml
Total, 8 oz. Weight and 30-inch Empty Sleeve (approx.)	**55 ml**	**95 ml**
(optional) 16 oz. Top Weight	25 ml	25 ml
Sample Collection		
Single Pull Distance to Fill @ 1-2 fps	30 inches (length of sampler)	30 inches (length of sampler)

(HydraSleeve available in custom sizes to maximize volume.)

EON Products, Inc.

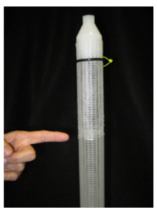
Your source for
Sampling, Measuring,
& Monitoring
Solutions

www.eonpro.com

Passive Diffusion Sampling for VOCs, SVOCs, Metals, Inorganics, Ions

Passive Diffusion Bag Samplers (PDBs) have been used worldwide to collect groundwater samples for Volatile Organic Compounds (VOCs) in groundwater since 1998. Lab and field case studies demonstrate that PDBs produce accurate sample concentrations and provide cost savings of 50 to 80% compared to low-flow and volume purge. PDBs also allow for discrete interval sampling and a reduced carbon footprint compared to pumping and bailing.

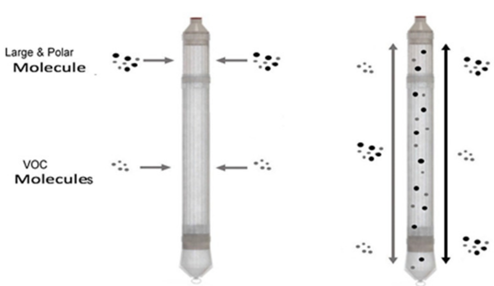
Expanding the List of Analytes Sampled By PDBs



Until now, the reliable and economical use of passive diffusion sampling has been limited to non-polar VOCs because large or polar molecules and ions cannot pass through the polyethylene membrane into the sampler. EON's Dual-Membrane Passive Diffusion (DMPDB) sampler operates under *the same principles as the well established PDB sampling,* using two semi-permeable membranes in a single sampler, to capture an expanded list of compounds.

What is the Principle?

Two separate semi-permeable membranes are aligned in series to form a tubular sample chamber. The sampler is filled with de-ionized water and lowered into the well screen intercepting groundwater flow. When the surrounding groundwater contains molecules that are not in the sampler, a concentration gradient drives the molecules in the groundwater to diffuse through the membrane pores into the sampler. The bottom membrane, having smaller pores, allows diffusion of VOCs from the surrounding groundwater into the sampler but does not allow water molecules to pass. The upper membrane, with larger pores, allows diffusion of large or polar molecules into the sampler.



Molecules that enter the sampler through either membrane diffuse throughout the water inside of the sampler until dynamic equilibrium is reached within the sampler and with the surrounding groundwater. When the sampler is retrieved, water in the top membrane leaves the sampler through the large pores, while the lower chamber serves as a reservoir and retains the thoroughly diffused sample until discharged for analysis.

Benefits

- **Reduce cost of sample acquisition by 50-80%**
- **Sample Volume up to 650 ml per sampler**
- **Depth Discrete Interval Sampling**
- **Also Sample for 1,4 Dioxane & PFAS**
- **Virtually NO Investigation Derived Waste Water (IDW)**

Is the Dual Membrane PDB a Proven Sampling Method?
Yes. The Dual-Membrane PDB sampler (DMPDB) was developed by combining the functionality of passive sampling devices that were evaluated by the ITRC Passive Sampling Team in the mid 2000's and found effective for sampling a wide range of compounds. Each of the methods performed well but some were not user friendly or did not produce adequate sample volume or were too expensive to commercialize. The DMPDB enables sampling for a wide range of compounds in a simple and effective way using the passive diffusion technology developed by the U.S.G.S. Since its initial use by the USEPA, the DMPDB has undergone extensive laboratory bench testing, followed by field use, validating the DMPDB's effectiveness at producing samples that represent concentrations of contaminants in surrounding groundwater fluid.

Bench-tests were performed using the DMPDBs to sample for a variety of analytes including; VOCs, Metals, Ions, and compounds of emerging concern such as 1,4 dioxane and PFAS. A large sample chamber representing a well, was spiked with compounds of interest, DMPDB samplers were installed, and the chamber sealed. The samplers were left in place for adequate time (about three weeks) to allow for the diffusion process to come to equilibration. Control samples were then taken from the fluid in the chamber surrounding the samplers. Next, the samplers were removed, and the contents discharged to laboratory bottles and sent to a certified lab for analysis. The resulting data from the DMPDB samples shows high correlation with the analyte concentrations from the control samples representing the water in the chamber, affirming diffusion sampling, using the Dual Membrane Passive Diffusion Sampler, produces accurate concentrations for a wide range of compounds.

In 2014 & 2015 the USEPA Region VI performed multiple, side by side field evaluations of the Dual-Membrane PDB on 2 sites manage. After the evaluation the DMPDB was adopted to replace the expensive and time consuming low-flow sampling for metals and ions on those sites. Hexavalent chromium was one of the key metals of concern and the results from Dual-Membrane sampler were in line with long term trends and with the side by side low flow results.

In 2016 and 2017 the Dual-Membrane PDB was evaluated for specific VOC compounds and a range of metals by the USGS and a private consultant at a U.S. Air Force base. The USGS used the samplers in wells that were over 1,000 feet deep and the results favorably compared to bailed samples. The private consultant sampled wells that were 300 to over 500 ft deep and obtained VOC and metals data that were consistent with the data taken using submersible pumps and the low flow method. The resulting data comparisons enabled the site to remove the troublesome low-flow pumps and tedious deep-well bailing and adopt passive sampling using the Dual-Membrane Passive Diffusion Sampler.

The Dual-Membrane Passive Diffusion Sampler has also been evaluated and adopted at private commercial sites, based on successful side by side comparisons with more costly sampling methods including low-flow pumping and bailing.

How Are They Deployed?
Like PDBs, the Dual-Membrane PDB sampler is installed on a re-usable weighted suspension tether, secured to the underside of the well cap.

Want to Know More about Passive Sampling?
Since EON first commercialized the PDB in 1998, we have been the leader in passive sampling. Contact EON by email: sales@eonpro.com or phone: 800-474-2490 / 770-978-9971

Attachment C

Daniel B. Stephens & Associates, Inc.

TRI Analytical Methods

Analyte	Analysis Method	Level of Accuracy	Level of Precision	Minimum Detection Limit	Maximum Detection Limit
Carbon Monoxide	Gas Chromatography with catalytic conversion then flame ion detector or pulse discharge ionization detector	5% or ± 0.5 ppm, whichever is greater	±3%	0.5 ppm (FID) 0.1 ppm (PDID)	99.999% (PDID)
Carbon Dioxide	Gas Chromatography with catalytic conversion then flame ion detector or pulse discharge ionization detector	5% or ± 5 ppm, whichever is greater	±3%	20 ppm (FID) 0.1 ppm (PDID)	99.999% (PDID)
Methane	Gas Chromatography with flame ion detector or pulse discharge ionization detector	5% or ± 1 ppm, whichever is greater	±3%	1 ppm (FID) 0.1 with (PDID)	99.999% (PDID)
Total Gaseous Hydrocarbons	Gas Chromatography with flame ionization detector	5% or ± 1 ppm, whichever is greater	±5%	1 ppm	2,000 ppm
Helium	Gas Chromatograph with pulse discharge ionization detector	2% or ± 0.1 ppm, whichever is greater	±2%	0.1 ppm	99.999% (PDID)
Hydrogen	Gas Chromatography with thermal conductivity detector or pulse discharge ionization detector	2% or ± 0.1 ppm, whichever is greater	±2% (TCD & PDID)	0.5%(TCD) 0.1ppm (PDID	99.999% (PDID)
Oxygen	Gas Chromatography with thermal conductivity detector or pulse discharge ionization detector	± 2% of concentration or 0.5% absolute whichever is greater	±2% (TCD & PDID)	0.5%(TCD) 0.1ppm (PDID)	99.999% (PDID)
Nitrogen	Gas Chromatography with thermal conductivity detector or pulse discharge ionization detector	± 2% of concentration or 0.5% absolute whichever is greater	±2% (TCD & PDID)	0.5%(TCD) 0.1ppm (PDID)	99.999% (PDID)
Condensed Hydrocarbons (Oil Mist and Particulates)	Standard Gravimetric, with hexane extraction for oil mist if results are within 90% of specification	± 0.1 mg/m3	±1%	0.01 mg/m^3 (less on request)	Varies
Moisture Dewpoint	Color indicator tube with critical orifice to measure air flow	± 4°F at -65°F ±30%	±30%	-95°F(-70°C)	20°F(-6°C)
Moisture ppmv	Color indicator tube with critical orifice to measure air flow	± 8 ppm at 24 ppm ±30%	±30%	2 ppm	3500 ppm

TRI Air Testing, Inc. ● 1801 Central Commerce Ct. Bldg. #2 ● Round Rock, TX 78664
(512) 263-0498 ● www.airtesting.com

AIR TESTING

TRI Analytical Methods

Analyte	Analysis Method	Level of Accuracy	Level of Precision	Minimum Detection Limit	Maximum Detection Limit
Nitrous Oxide	Gas Chromatograph with catalytic converter followed by flame ionization detector	± 0.5% or 5000 ppm ±30%	±2%	5000 ppm	99.5%
Nitrogen Dioxide	Color indicator tube with critical orifice to measure air flow	±30%	±20%	0.1 ppm	1.0 ppm
Sulphur Dioxide	Color indicator tube with critical orifice to measure air flow	±30%	±20%	0.1 ppm	3 ppm
Hydrocarbon Panel Identification (C1-C13 species)	Gas Chromatograph with mass selective detector	±10%	±10%	0.3 ppm	Varies
Halogenated Solvents (Freon TF, 111-Trichloroethane, and others)	Gas Chromatography with electron capture detector	±10%	±10%	0.01 ppm	10 ppm
Halogenated Hydrocarbons (Freon TF, 111-Trichloroethane, and others)	Gas Chromatography with electron capture detector	±10%	±10%	0.1 ppm	Varies
Execution of ISO 8573 OIL Vapor Method	Gas Chromatography with mass selective detector	±10%	±10%	1 ppm or 0.002 mg/m^3	Varies
Particle Counting and Sizing	Laser Particle Counter 3100	±10%	±10%	0.3 micron	25.0 micron
Particle Counting and Sizing	Laser Particle Counter 1100	±10%	±10%	0.1 micron	1.0 micron

Jason Vandagriff

Jason Vandagriff, Laboratory Director

Eurofins Calscience LLC
7440 Lincoln Way
Garden Grove, CA 92841

Prepared for:
John Dodge
Daniel B. Stephens & Associates Inc.
3150 Bristol Street
Suite 210
Costa Mesa, CA 92626
JDodge@Geo-Logic.com

Prepared by	Schwartz, Eydie
Date	12/28/2021
Expiration Date	6/17/2022
Est. Start Date	12/17/2021

Project: EPA Water Samples ***Quote Number: 57009720 - 1***

Water

Matrix	Method	Test Description	Analyte	RL	MDL	Units
Water	RSK-175	RSK-175 CO2	Carbon dioxide	5.00	2.78	ug/L

Matrix	Method	Test Description	Analyte	RL	MDL	Units
Water	200.8	Total Metals 23 compounds (Includes Ca, Na, K, Mg)	Aluminum	0.0500	0.0106	mg/L
			Antimony	0.00100	0.000500	mg/L
			Arsenic	0.00100	0.000630	mg/L
			Barium	0.00100	0.000160	mg/L
			Beryllium	0.00100	0.000210	mg/L
			Cadmium	0.00100	0.000980	mg/L
			Calcium	0.100	0.0366	mg/L
			Chromium	0.00100	0.000580	mg/L
			Cobalt	0.00100	0.000170	mg/L
			Copper	0.00100	0.000610	mg/L
			Iron	0.0500	0.0222	mg/L
			Lead	0.00100	0.000190	mg/L
			Magnesium	0.0500	0.0170	mg/L
			Manganese	0.00100	0.000440	mg/L
			Nickel	0.00100	0.000540	mg/L
			Potassium	0.0500	0.0257	mg/L
			Selenium	0.00100	0.000780	mg/L
			Silver	0.00100	0.000280	mg/L
			Sodium	0.100	0.0397	mg/L
			Thallium	0.00100	0.000180	mg/L
			Vanadium	0.00100	0.000200	mg/L
			Zinc	0.00500	0.00347	mg/L

Matrix	Method	Test Description	Analyte	RL	MDL	Units
Water	200.8	Dissloved Metals 23 compounds (Includes Ca, Na, K, Mg)	Aluminum	0.0500	0.0106	mg/L
			Antimony	0.00100	0.000500	mg/L
			Arsenic	0.00100	0.000630	mg/L
			Barium	0.00100	0.000160	mg/L
			Beryllium	0.00100	0.000210	mg/L
			Cadmium	0.00100	0.000980	mg/L
			Calcium	0.100	0.0366	mg/L
			Chromium	0.00100	0.000580	mg/L
			Cobalt	0.00100	0.000170	mg/L
			Copper	0.00100	0.000610	mg/L
			Iron	0.0500	0.0222	mg/L
			Lead	0.00100	0.000190	mg/L
			Magnesium	0.0500	0.0170	mg/L
			Manganese	0.00100	0.000440	mg/L

Eurofins Calscience LLC
7440 Lincoln Way
Garden Grove, CA 92841

Prepared for:

John Dodge
Daniel B. Stephens & Associates Inc.
3150 Bristol Street
Suite 210
Costa Mesa, CA 92626
JDodge@Geo-Logic.com

Prepared by	Schwartz, Eydie
Date	12/28/2021
Expiration Date	6/17/2022
Est. Start Date	12/17/2021

Project: EPA Water Samples ***Quote Number: 57009720 - 1***

Water

Matrix	Method	Test Description	Analyte	RL	MDL	Units
Continued						
			Nickel	0.00100	0.000540	mg/L
			Potassium	0.0500	0.0257	mg/L
			Selenium	0.00100	0.000780	mg/L
			Silver	0.00100	0.000280	mg/L
			Sodium	0.100	0.0397	mg/L
			Thallium	0.00100	0.000180	mg/L
			Vanadium	0.00100	0.000200	mg/L
			Zinc	0.00500	0.00347	mg/L
Water	SM 2540C	Total Dissolved Solids	Total Dissolved Solids	1.00	0.870	mg/L
Water	300.0	Br, Cl, F, SO4	Bromide	0.100	0.0410	mg/L
			Chloride	1.00	0.359	mg/L
			Fluoride	0.100	0.0460	mg/L
			Sulfate	1.00	0.237	mg/L
Water	300.0	NO2, NO3, o-PO4	Nitrite as N	0.100	0.0180	mg/L
			Nitrate as N	0.100	0.0240	mg/L
			Orthophosphate as P	0.100	0.0760	mg/L
Water	SM 2320B	Alkalinity - All Forms	Alkalinity, Total (As CaCO3)	5.00	2.18	mg/L
			Bicarbonate (as CaCO3)	5.00	2.18	mg/L
			Carbonate (as CaCO3)	5.00	2.18	mg/L
			Hydroxide (as CaCO3)	5.00	2.18	mg/L

Eurofins Calscience LLC
7440 Lincoln Way
Garden Grove, CA 92841

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Daniel B. Stephens & Associates Inc.
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JDodge@Geo-Logic.com

Prepared by	Schwartz, Eydie
Date	12/28/2021
Expiration Date	6/17/2022
Est. Start Date	12/17/2021

Project: EPA Water Samples ***Quote Number: 57009720 - 1***

Analytical Sample Information

Analysis / Method	Matrix	Preservative	Client Sub List Desc / Container	Volume Required	Holding Time
Alkalinity			Alkalinity - All Forms		
2320B	Water	None	Plastic 250ml - unpreserved	200 mL	14 Days
Anions, Ion Chromatography			Br, Cl, F, SO4		
300_ORGFM_28D	Water	None	Plastic 250ml - unpreserved	10 mL	28 Days
Anions, Ion Chromatography			NO2, NO3, o-PO4		
300_ORGFMS	Water	None	Plastic 250ml - unpreserved	10 mL	48 Hours
Dissolved Gases (GC)			RSK-175 CO2		
RSK_175_CO2	Water	None	Voa Vial 40ml - unpreserved	80 mL	7 Days
Metals (ICP/MS)			Dissloved Metals 23 compounds (Includes Ca, Na, K, Mg)		
200.8	Water	None	Plastic 250ml - unpreserved	100 mL	IMMEDIATELY
Metals (ICP/MS)			Total Metals 23 compounds (Includes Ca, Na, K, Mg)		
200.8	Water	Nitric Acid	Plastic 250ml - with Nitric Acid	50 mL	180 Days
Solids, Total Dissolved (TDS)			Total Dissolved Solids		
2540C_Calcd	Water	None	Plastic 250ml - unpreserved	50 mL	7 Days

Hold Times listed above represent the minimum allotted time between sampling and lab extraction, prep or analysis.

Multiple analyses may be consolidated into fewer containers. Please contact your Project Manager for clarification when requesting sample containers.

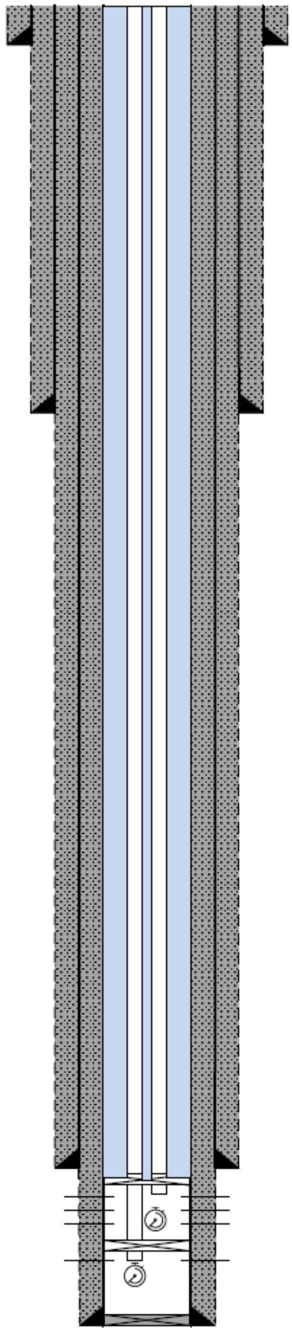
Except for some special tests, all samples should be kept cold at 6 degrees C.

Appendix B: Well Schematics

Proposed Wellbore Schematic

CO2 Injection Well
Two Injection Zones, Two Strings
Short String: Pyramid Hill + Vedder 1 + Vedder 2
Long String: Vedder 3

Frontline BioEnergy

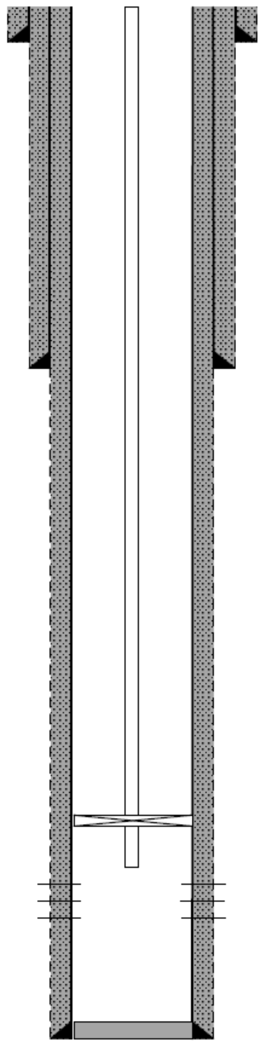
Geo Marker	INCL/TVD	Hole		Casing & Perf	Details
				Depths are MD	
		26"		20" 94# J-55 BTC Csg @ 250'	20" Csg cmt'd @ 250'-Surf w/ 489 CF cmt
		17-1/2"			
BFW @ ~1750'					
USDW @ ~2495'				13-3/8" 61# J-55 BTC Csg @ 2600'	13-3/" Csg cmt'd @ 2600'-Surf w/ 2377 CF cmt
		12-1/4"			
					9-5/8" Csg cmt'd @ 7700'-Surf w/ 3207 CF cmt
					Hydraulic set packer @ 7725' Packer fluid: water with corrosion inhibiters 2-3/8" Short string @ 7750'
				9-5/8" 53.5# N-80 LTC Csg @ 7700'	Pressure/Temperature gauge installed externally on long string at 7770' for V1/V2 monitoring
Pyramid Hills @ 7775' Vedder 1 @ 7789' Vedder 2 @ 8040'				Perforated @ 7775'-7789' (PH), 7789'-7900' (V1), 8040'-8132' (V2)	Wireline set packer @ 8120' 2-3/8" Long string @ 8150'
Vedder 3 @ 8167' Vedder 4 @ 8344'		8-1/2"		Perforated @ 8167'-8255' (V3)	Pressure/Temperature gauge installed on long string at 8150' for V3/V4 monitoring
		TD @ 8700'		7" 29# L-80 13 CR Csg @ 8700'	7" Csg cmt'd @ 8700'-Surf w/ 1166 CF cmt

Creator & Date: JAP 8/23/2022

Proposed Wellbore Schematic

Injection Monitoring Well
Above Confining Zone

Frontline BioEnergy

Geo Marker	INCL/TVD	Hole		Casing & Perf	Details
				*Depths are MD*	
		26"		20" 94# J-55 BTC Csg @ 250'	20" Csg cmt'd @ 250'-Surf w/ 489 CF cmt
				9-5/8" 53.5# N-80 LTC Csg @ 7700'	9-5/8" Csg cmt'd @ 2600'-Surf w/ 814 CF cmt
BFW @ ~1750'		12-1/4"			
USDW @ ~2495'					
Confining Zone: Olcese @ 6625'					
		8-1/2"			
				7" 29# N-80 Csg @ 7700'	7" Csg cmt'd @ 7700'-Surf w/ 985 CF cmt
				Perforated @ 7045-7095'	Hydraulic set packer @ 6995' 2-3/8" tubing string @ 7725'
		TD @ 7700'			
Pyramid Hills @ 7775'					

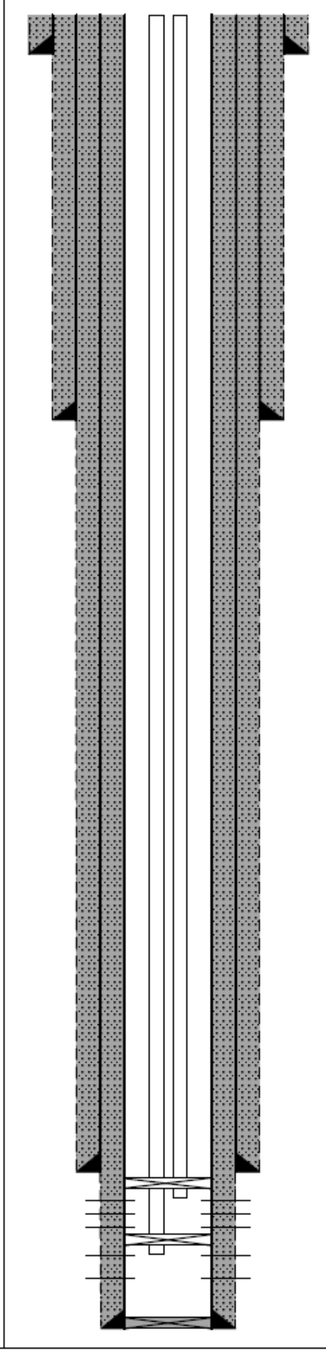
Creator & Date: JAP 8-12-2022

Proposed Wellbore Schematic

Injection Zone Monitoring Welll
Two Monitor Zones, Two Strings
Short String: Pyramid Hill + Vedder 1 + Vedder 2
Long String: Vedder 3 + Vedder 4

Frontline BioEnergy

Geo Marker	INCL/TVD	Hole		Casing & Perf	Details
				Depths are MD	
		26"		20" 94# J-55 BTC Csg @ 250'	20" Csg cmt'd @ 250'-Surf w/ 489 CF cement
		17-1/2"			
USDW @ ~2521'					
				13-3/8" 61# J-55 BTC Csg @ 2600'	13-3/8" Csg cmt'd @ 2600'-Surf w/ 1806 CF cement
Etchegoin @ 2951' Miocene @ 4291' Santa-Margarita @ 4921' Round Mtn @ 5632'					
Confining Zone: Olcese @ 5790'		12-1/4"			
Freeman-Jewett @ 6322'					
				9-5/8" 53.5# N-80 LTC Csg @ 6800'	9-5/8" Csg cmt'd @ 6800'-Surf w/ 2222 CF cement
Pyramid Hills @ 6819' Vedder 1 @ 6825' Vedder 1A @ 6918' Vedder 2 @ 7154' Vedder 3 @ 7254' Vedder 4 @ 7415' Walker @ 7431'		8-1/2"		Perforated @ 6819-6825' (PH), 6825-6918' (V1), 7154-7235' (V2) Perforated @ 7256-7415' (V3), 7415-7431' (V4)	Hydraulic set packer @ 6800' Short string @ 6815' Wireline set packer @ 7240' Long string @ 7251'
		TD @ 7500'		7" 29# L-80 13Cr Csg @ 7500'	7" Csg cmt'd @ 7500'-Surf w/ 973 CF cement



Creator & Date: JAP 9/8/2022

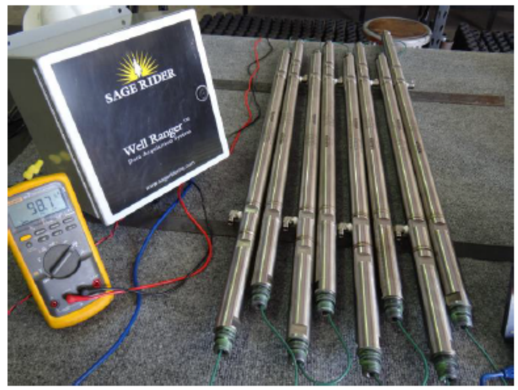
Example downhole and surface gauges:

RANGER
GAUGE SYSTEMS

Downhole ***In-Line*** Digital Quartz Pressure/Temperature Probe

Ranger Permanent Hybrid Digital Addressable Surface Read Out (DASRO) Gauge

The Ranger® DASRO gauge is a Quartz Digital Addressable Surface Read Out Pressure/Temperature Probe based on a resonating quartz sensor with digital signal transmission and addressing ability for multiple gauge deployment on a single line. Additionally, the DASRO has a cablehead on each end to allow in-line installation without need for a "Y" block. The internal gauge electronics consists of two custom microelectronic circuits that are hermetically sealed. Each gauge has a pre-assigned digital address for multiple unit operation on the same signal conductor. Fault protection current limiting is included for both the gauge electronics and the primary line.



FEATURES

- **Two leak-testable cable-heads for in-line operation**
- **Dual built in current limiting assures that no one gauge can draw excessive current and that upstream readings are still available with a downstream line fault.**
- **Complete double redundancy for all cable current limiting circuit components. This feature, together with a built in automatic reset on power-up, allows the cable current limit function to continue to operate if one limiting channel should fail open. This protects against loss of communication with downstream gauges, due to a current limit component failure.**
- **No CPU or memory for reliable, long term, high temperature operation. Configuration data and addresses are permanent**
- **High reliability and quality due to hermetically sealed custom hybrid circuits. This type of circuit construction is a MUST for sustained, high-temperature, operation**
- **Hybrid circuits are fully tested and qualified per MIL-883E, Method 1010.7 Test Condition B**
- **Includes level two reliability testing to yield long operating life required for permanent applications**
- **Metal to metal seals, Swagelok® pressure fittings and welded Nitronic 50HS® housing construction throughout results in no elastomers**
- **Optional Inconel 718 pressure housings are available for very aggressive well environments.**
- **Integral quartz temperature sensor**
- **Pre-assigned address for multiple unit operation on the same single conductor**
- **1024 address capability assures that gauges will have unique addresses**
- **Low power consumption 250mW (typical)**

Specifications

Ranger DASRO gauge specifications are determined in accordance with the ANSI/ISA-S51.1-1979, American National Standard, "Process Instrumentation Terminology".

Pressure Sensor
Thickness shear mode quartz resonator (with INCONEL® isolation bellows)

Total System Pressure Accuracy
±0.02% of full scale including linearity, hysteresis and repeatability over calibrated temperature range

Pressure Repeatability
≤0.01% of full scale

Pressure Resolution
0.01 psi or better

Temperature Sensor
Quartz resonator

Temperature Accuracy
±0.5°C (±0.9°F) within calibrated temperature range. Pressure accuracy is independent of indicated temperature accuracy.

Temperature Resolution
0.005°C (0.01°F)

Standard Calibrated Temperature Ranges
25°C to 125°C (77°F to 257°F)
25°C to 150°C (77°F to 302°F)
25°C to 175°C (77°F to 347°F)
25°C to 200°C (77°F to 392°F)

Operating Temperature Range
-20°C to 200°C (-4°F to 392°F)

Sample Rate
Complete pressure and temperature transmission in approximately one-second intervals

Operating and Calibrated Pressure Ranges
0 - 344.75 Bars (atm - 5,000 psia)
0 - 689.50 Bars (atm - 10,000 psia)
0 - 1103.20 Bars (atm - 16,000 psia)
0 - 1378.95 Bars (atm - 20,000 psia) - Optional

Dimensions (OD x L)
32.5mm x 81.3cm (1.281" x 46.5")

Weight
4.76 kg (10.5 lbs.)

Pressure Housing Wetted Material
Nitronic 50HS®

Sensor Wetted Materials
INCONEL® 600/625/718

Requirements of Conductor Cable
Single conductor coaxial cable with low conductor resistance. The maximum DC loop resistance is determined by the number of gauges on one line and the surface power supply. Can be up to 500 ohms with a capacitance of up to 1 ufd for a single unit installation and using a 30 volt surface power supply.

Reliability Testing Levels

- Level II (Basic for all units)
  -20 °C Test to confirm fully and correct operation (Not calibrated)
  Calibration and testing to full temperature and pressure ratings
  15-day burn-in at full pressure and temperature calibrated ranges
  Current protection testing at room and full temperature
  Gauge shock and vibration testing
  Final QC inspection

DASRO Configurations / Model Numbers

Dual Cable Head SIDE pressure inlet	(Model No: 68**xx**D DASRO) – Same length
Single Cable Head SIDE pressure inlet	(Model No: 68**x**1D DASRO) – Same length
Single Cable Head BOTTOM pressure inlet	(Model No: 62**xx**D DASRO) – Shorter
Dual Gauge Dual Cable Head SIDE pressure inlets (two)	(Model No: 68**x**2D DASRO) – Longer
Dual Gauge Single Cable Head SIDE pressure inlets (two)	(Model No: 68**x**4D DASRO) – Longer
Single FOT Cable Head BOTTOM pressure inlet	(Model No: 62**x**3D DASRO) – Special length
Single Cable Head ¾" OD BOTTOM pressure inlet	(Model No: 42**xx**C DASRO) – Shorter
Dual Cable Head 1.00" OD SIDE pressure inlet	(Model No: 108**xx**A DASRO)

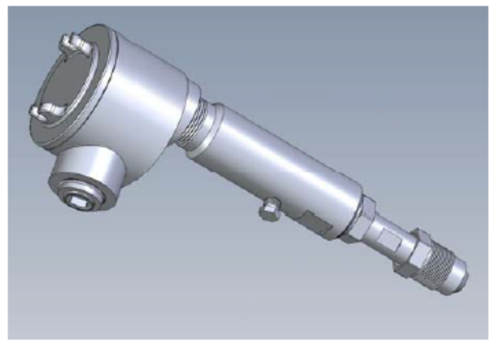
"x" or "xx" = Denotes calibrated temperature range. Example: A 175C calibrated gauge 68xxB = 6875B, 68x1B = 6871B, 62xxB = 6275B, 68x2B = 6872B, 62x3B = 6273B or 42xxB=4275B

RANGER
GAUGE SYSTEMS

Surface Ranger Gauge Wellhead Outlet

Ranger Gauge Wellhead Outlet for ¼” Outside Diameter 316SS TEC Cable

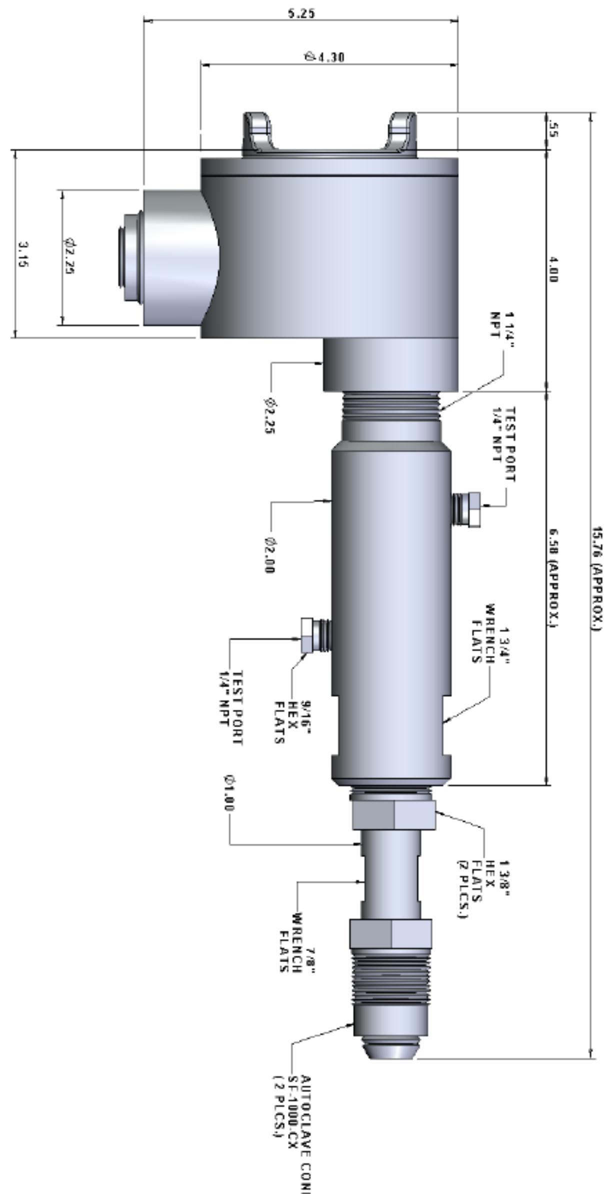
The standard Ranger® Wellhead Outlet is a durable, trustable and sleek way to terminate the downhole TEC line at the surface. It’s constructed with certified materials to sustain long periods of operations and different weather conditions as per current standards mentioned below. The Ranger Wellhead Outlet is divided in two major assemblies, the electrical junction box and the pressure isolation assembly or “body”. The electrical junction box is provided with cable pigtails for easy installation to the surface box.



FEATURES

- **The use of a high pressure feed-through guarantees pressure isolation and electrical connection to the TEC line**
- **Electrical junction box pre-wired with all needed connections. The spring-contact is also pre-wired including the proper Teflon insulator and electrical boot to help prevent disconnections and electrical shorts**
- **All wires are 16 or 18 AWG with Teflon insulation for longer durability**
- **The junction box has a terminal block with screw terminals for easy re-wiring if needed**
- **Simple Lightning Protection for the TEC line is included. This protection is built into the terminal block and helps prevent an over voltage surge to the downhole gauges like the one caused by a nearby lightning strike**
- **Earth grounding is provided internally through a threaded connection to the junction box body to help prevent electrical shock**
- **Leak-testable pressure isolation body. Two ¼” NPT ports are provided on the body’s side in order to perform a pressure test for leaks and monitor the high pressure housing permanently if required. Plugs are also provided with the unit**
- **Autoclave® type connections are provided for both ends of the exit nipple to the WHO body. Proper torque values are supplied**
- **Metal to metal seal assures free maintenance. Front, rear ferrules and jam nut are included for the ¼” TEC cable**
- **1 ¼” NPT or ¾” NPT (reducer) connections are available for the electrical conduits**
- **A crimp style spring contact and custom made insulator are provided for the TEC end. TEC dimensional preparation is supplied for a good mechanical engagement**
- **There is no need for jumpers, manual connections or splices on the TEC end. The spring contact takes care of the electrical connection to the feed-through with a simple push-in motion**

Specifications



Junction Box
- 2 Inlets
- 1 ¼" or ¾" NPT (reducer) inlet thread
- Box material – Feraloy iron alloy
- Cover material – Copper-free aluminum
- Compliance:
    - NEC/CEC:
        - Class I, Division 1 & 2, Groups C, D
        - Class II, Division 1, Groups E, F, G
        - Class II, Division 2, Groups F, G
        - Class III
    - UL Standard: 886
    - ANSI Standard: C33.27
    - CSA Standard: C22.2 No. 30
    - NEMA/EEMAC 3, 4
- Neoprene "O" ring standard to meet NEMA 4 requirements
- Explosion proof
- Dust-Ignition proof
- Raintight
- Wet Locations

Operating Temperature Range
-40°C to 70°C (-40°F to 158°F)

Standard Operating Pressure Ranges
0 - 1379 Bars (0 - 20,000 psi). Wellhead Body and Nipple only.

Dimensions (OD x L)
Varies x 40cm (Varies x 15.75")

Pressure Housing and Nipple Material
316 SS

Optional
- Different inlet configuration could be available upon request
- Longer nipple available upon request

Made in USA

SageWatch™
Surface Surveillance System

The **SageWatch™ Surface Surveillance System** Is a low-power multi-sensor monitoring system designed for gathering real-time pressure and temperature readings directly at the wellhead. The SageWatch™ system has the ability to be monitor up to 16 gauges on a single data acquisition unit. Once installed, pressure and temperature data is continuously transmitted to the data acquisition unit and can be accessed locally or wirelessly via any typical field SCADA type system.

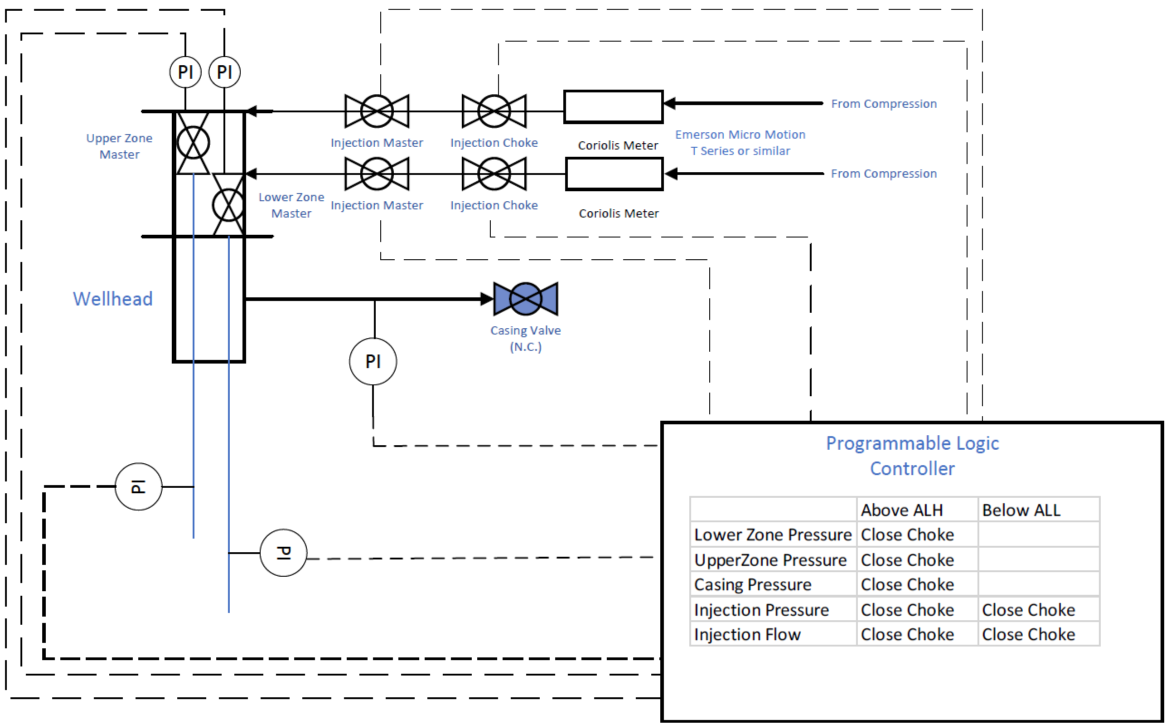
Benefits of this system include:

- Real-time pressure and temperature monitoring
- Multiple Sensors connected to a single Data Acquisition Unit
- Safety Rating - Ex ia IIB T4 Ga; IS CL I, DIV 1, GRP C and D T4 Class I, Zone 0, AEx ia IIB T4 Ga
- Utilizes Silicon-Sapphire sensors
- Data is transmitted to remote facility or corporate office

Measurement Method	**Piezo Transducer**
Pressure Rating	15,000 psi
Temperature Rating	392 deg F (200 deg C)
Pressure Resolution	0.05 psi
Temperature Resolution	0.01 deg C
Pressure Accuracy	+/- 0.03% of Calibration
Temperature Accuracy	+/- 1 deg C
Data Polling	1 Sample/Second

For more information contact us at info@sageriderinc.com

C02 Injection



	Above ALH	Below ALL
Lower Zone Pressure	Close Choke	
UpperZone Pressure	Close Choke	
Casing Pressure	Close Choke	
Injection Pressure	Close Choke	Close Choke
Injection Flow	Close Choke	Close Choke

PI = Pressure Indicator

Appendix C: USDW Monitoring Wells from SSJMUD

Table 4-3. SSJMUD Water Level and Water Quality Monitoring Network

Well No.	DMS ID	T-R-S	Latitude	Longitude	GSE (ft MSL)	RP Elev. (ft MSL)	Coord Source	Monitoring Type	Owner	Management Area Plan Well Monitoring Status	To be replaced	Management Area Plan Parameters Type	Year Constructed	Borehole Depth (ft)	Well Depth (ft)	Perforated Interval (ft)	Annular Seal (ft)	Casing Diameter (in)	Aquifer Zone
Delano Well 14	--	25S-25E-23H	35.742	-119.242	308		City of Delano	Supply Well	Municipal	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
Delano Well 23	--	25S-25E-05C	35.790	-119.303	264		City of Delano	Supply Well	Municipal	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
Delano Well 30	--	25S-25E-01B	35.790	-119.231	338		City of Delano	Supply Well	Municipal	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
McFarland Taylor Ave. Well	--	26S-25E-13E	35.667	-119.240	359		City of McFarland	Supply Well	Municipal	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
SSJMUD Well 8	--	25S-24E-13P2	35.74702	-119.336	265	259	District	Supply Well	Private	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
SSJMUD Well 14	--	25S-26E-19J1	35.73948	-119.205	354	351	District	Supply Well	Private	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
SSJMUD Well 23	--	25S-25E-29R2	35.7185	-119.304	294	292	District	Supply Well	Private	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
SSJMUD Well 42	--	25S-26E-01P2	35.69295	-119.232	342	338	District	Supply Well	Private	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
SSJMUD Well 53	--	26S-26E-32	35.63068	-119.191	433	430	District	Supply Well	Private	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
SSJMUD Well 59	--	26S-26E-10	35.682	-119.152	513	512	District	Supply Well	Private	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production
SSJMUD Well 62	--	25S-26E-26	35.71837	-119.145	474	472	District	Supply Well	Private	Interim	Yes	WL and WQ	--	--	--	--	--	--	Main Production

Appendix D: MIT Procedures

https://archive.epa.gov/region9/water/archive/web/pdf/appendixetemplogreqs.pdf

APPENDIX E – TEMPERATURE LOGGING PROCEDURES
U.S.E.P.A. REGION IX

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid Mechanical Integrity Test ("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.

1. With the printed log, provide also raw data for both logging runs (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 12 hours for running the initial temperature log, followed by a second log, a minimum of 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 20 and 50 ft. 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 1 or 2 in. per 100 ft. 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:
      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 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 10,000 ppm Total Dissolved Solids ("TDS") and is further defined in 40 CFR §144.3.

US EPA ARCHIVE DOCUMENT

DETERMINATION OF THE MECHANICAL INTEGRITY OF INJECTION WELLS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5 -- UNDERGROUND INJECTION CONTROL (UIC) BRANCH
REGIONAL GUIDANCE #5

Revised February, 2008

INDEX

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5 -- UNDERGROUND INJECTION CONTROL (UIC) SECTION
REGIONAL GUIDANCE #5

DETERMINATION OF THE MECHANICAL INTEGRITY OF INJECTION WELLS

Revised February, 2008

1 ISSUE

Demonstrations of mechanical integrity (MI) are the most common means of demonstrating that there is no movement of fluids into or between underground sources of drinking water (USDWs) associated with injection wells. Although relatively simple in theory, MI tests (MITs) must be conducted so that their validity as well as their outcome is evident. The Underground Injection Control (UIC) Branch of the Water Division in Region 5, United States Environmental Protection Agency (USEPA), as the authority in matters of MI in Region 5, should establish guidelines which will assist operators and regulators of injection wells in Region 5 subject to demonstrations of MI to conduct those demonstrations such that the results will be useful.

2 PURPOSE OF GUIDANCE

The guidelines were developed by the UIC Branch of Region 5 USEPA, to assist owner/operators of injection wells in Region 5 to demonstrate MI. Procedures varying from these guidelines may be accepted if first approved by the Director of the USEPA.

Pursuant to 40 C.F.R. &sect 146.8(a) "an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing, or packer; and (2) there is no significant fluid movement into an USDW through vertical channels adjacent to the injection well bore". The absence of significant leaks is demonstrated through the use of tests which have been approved for that purpose by the Administrator (MI tests). The methods presently accepted for establishing MI pursuant to 40 C.F.R. &sect 146.8(a)(1) [part 1] of MI for wells operating in states in which the UIC Branch implements the UIC regulations, include: 1) the standard annulus pressure test (SAPT), 2) the standard annulus monitoring test (SAMT), 3) the radioactive tracer survey (RTS), and for certain Class III wells: the water-brine interface test (W-BIT. Other methods, including the Ada pressure test(AT) and the cementing pressure/single point resistivity test, are approved for national use under certain circumstances, but are not used in Region 5. In addition, the dual completion monitoring test (DCMT) is used by a few wells in Michigan and Indiana although interim approval has expired. The procedures for this test are under review. Accepted methods for demonstrating MI pursuant to 40 C.F.R. &sect 146.8(a)(2) [part 2] include: 1) the results of a temperature log, 2) noise log, 3) oxygen activation log, 4) the re.sults of a radioactive tracer survey (RTS) (when the injection zone is separated from the lowermost USDW by a single confining layer), or 5) for all Class II wells and for Class III wells in which the casing precludes the use of logging techniques, cementing records demonstrating the presence of adequate cementto prevent fluid migration into USDWs pursuant to 40 C.F.R. &sect 146.8(c)(2) and (c)(3) respectively. Demonstrations of both part 1 and part 2 of MI must be made before injection can be authorized.

The procedures which are recommended in the attachments to this document will, in most cases, result in development of valid data which Region 5 will be able to interpret with confidence. Deviations from these procedures may result in anomalies which will complicate or even invalidate test results. If the recommended test results do not result in definitive information, any anomalies noted should be investigated immediately, including re-doing the tests. Results which provide demonstrations of MI are the purpose of this guidance, but adherence to guidance may not ensure development of acceptable results in all cases. In such cases, mere adherence to guidance does not absolve the operator from the requirement to demonstrate MI. In cases in which there is doubt about the certainty of outcomes, reference to and comparison with previous tests can often be used to clarify the test results. In this vein, comparison of tests through time, especially the comparison of temperature and radioactive tracer logs can make interpretation easier and make progressive change apparent. In all cases, operators should submit proposed testing procedures to the UIC Branch's Direct Implementation (DI) Section for approval before the testing is done. This can prevent misunderstandings and possible retesting.

3 DISCUSSION

3.1 Mechanical Integrity Pursuant to 40 C.F.R. &sect 146.8(a)(1)

There are a limited number of means by which part 1 of MI (the absence of significant leaks in tubing, casing, and packer) may be demonstrated. Therefore, little discussion of the relative merits of the various tests is necessary.

3.1.1 The Standard Annulus Pressure Test (SAPT)
The SAPT is the most common means used to demonstrate part 1 of MI. This test is based on the principle that a pressure applied to fluids filling a sealed vessel will persist. A well's annulus system, though closed to transfer of matter, is not closed to energy transfer because it is not isolated from transfer of heat from its surroundings, therefore an allowance for small pressure changes is necessary. The test provides an immediate demonstration of whether or not leaks, detectable by these means, exist. A discussion of and procedures for the SAPT are outlined in Attachment 1.

3.1.2 The Standard Annulus Monitoring Test (SAMT)
Pursuant to 40 C.F.R. &sect 146.8(b), monitoring of the annulus pressure is an approved method for establishing part 1 of MI for all wells. Annulus pressure monitoring for Class I wells required at &sect 146.13(b)(2) to verify the maintenance of a minimum pressure differential is not the SAMT, because changes in pressure due to loss of annulus liquid are attenuated by the presence of a gas blanket which is replenished as pressure decreases. If annulus monitoring is used to demonstrate MI, an initial SAPT is required. Annulus monitoring may continue throughout the life of the well or the operator may choose, at any time, to conduct a SAPT every five years and after well reworks (on rule authorized Class II wells and on permitted wells if the particular UIC permit allows it), thereby discontinuing the SAMT. A discussion of the merits and procedures for the SAMT is provided in Attachment 2.

3.1.3 The Radioactive Tracer Survey (RTS)
On September 18, 1987, the USEPA published a Federal Register (FR) notice at 35324 et seq. FR 52, No. 181, giving interim approval for the use of the RTS as an alternative MIT. In a FR Notice at 46837 et seq. FR 52, No. 237 on December 10, 1987, the USEPA announced final approval of the RTS as a demonstration of part 1 and 2 (as limited), and provided clarifications and additional information based on comments received and the use of the test during the interim approval period. A discussion of and procedures for conducting the RTS as a demonstration of part 1 of MI in Region 5 are outlined in Attachment 3.

3.1.4 Water-Brine Interface Test (W-BIT)
On January 10, 1992, approval of the W-BIT was announced in the Federal Register at 1109 et seq FR 57, No. 7. The test is valid only for Class III wells and only when construction and operating conditions make testing with the SAPT impractical. Although there are no special recommendations applicable in Region 5, additional explanation of the basis for the test is provided in Attachment 4, and a full description of the procedures for conducting the W-BIT is available in the above referenced FR Notice.

3.1.5 Ada Pressure Test
The Ada test is a variant of the SAPT. It is used to test wells which have perforations above the injection zone. It can be used to test the integrity of the casing above the perforations. To conduct the test gas pressure is used to depress the liquid level to a point just above the perforations. The

pressure is measured over a period of time. If the pressure change is less than the established limit, the well has mechanical integrity.

3.1.6 Water-in-Annulus Test (WIAT)

The WIAT was announced at 14678 et seq 54 FR No. 19 on April 12, 1989, for existing Class II wells for enhanced oil recovery in the counties in which the Bradford oil field is located in New York and Pennsylvania. Approval of the test was extended to similar wells in the Redhaw oil field in Ashland County, Ohio. The test is used for wells which are constructed without long string casing. The level of water near the top of the annulus between the surface casing, which protects all USDWs, and the injection tubing which is set on a formation packer and may have some cement on the top of the packer, is observed under specified conditions. The presence and nature of relatively small leaks can be determined.

3.2 Mechanical Integrity Pursuant to 40 C.F.R. &sect 146.8(a)(2)

Owner/operators have a choice of a number of methods for demonstrating that wells have part 2 of MI (no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore). The conditions under which these tests can be used to best effect differ significantly; therefore, a listing of relative advantages and disadvantages of the various options is provided in the attachments concerning each of the approved methods for demonstrating part 2 of MI.

3.2.1 Temperature Logs (TL)

Temperature logs are a very versatile and sensitive means of identifying fluids which have moved along channels adjacent to the well bore. In addition to demonstrations of part 2 of MI, temperature logs can be used to monitor fluid movement through the confining zone adjacent to the well bore and can often locate small casing leaks. To be effective for demonstrations of MI, there must be adequate time available for short-term temperature effects along the well bore to dissipate. Background information and general procedures for running t emperature logs are provided in Attachment 5.

3.2.2 Noise Logs (NL)

The use of noise logs is based on the observation that flow behind the casing in the well bore will, at some points, be turbulent. Turbulent flow causes noise which may travel for significant distances along the well bore. Noise logs are appropriate where it is impractical for injection operations to be suspended for the length of time needed to allow temperature stabilization to proceed to the point at which a temperature log can be run with good results. They can also be used to locate some tubing or casing leaks. Background information and procedures for using noise logs to demonstrate part 2 of MI are found in Attachment 6.

3.2.3 Oxygen Activation Method (OAL)

On February 1, 1991, the USEPA published a FR Notice (FRN)granting final approval, effective March 4, 1991, for use of the oxygen activation method or log (OAL) as a means of demonstrating part 2 of MI. Details of the operation and conditions under which the OAL can be used can be found at 4063 et seq. FR 56, No. 22 which is included in this guidance as Attachment 7.

3.2.4 Radioactive Tracer Survey

The same FRNs which describe how the RTS can be used for demonstrating part 1 of MI also describe its use for demonstrating part 2 of MI. This method may be used only where there is only a single confining formation separating the lowermost USDW from the injection zone with no aquifers within it. Additional requirements and limitations of the RTS are described in the previously mentioned FR Notices (See III.C.). The use of the RTS as a means of demonstrating part 2 of MI is described in Attachment 8.

3.2.5 Cement Records

The most common demonstration of part 2 of MI for Class II wells is based on cementing records. Demonstrations of MI for Class III wells can also be based on cementing records if the configuration of wells prevents the use of logging methods. If records show that casings are cemented in a way which will prevent the movement of liquids into or between USDWs, the well has part 2 of MI. A discussion of the use of cementing records is provided in Attachment 9.

3.3 Additional Mechanical Integrity Tests

Other alternative MITs will be added to this guidance if approved by the Administrator of the EPA for use in Region 5. In order for a test to be approved, it must be submitted to the Water Division Director in Region 5 with all supporting evidence. If the proposal is approved by the Director, then it will be submitted to the Administrator, and will be evaluated by the national UIC Technical Workgroup which will evaluate its effectiveness. If approved by the Administrator, the approval and any limitations placed on the test will be promulgated in the Federal Register. In addition, specific procedures outlined in this guidance may be modified after additional data are obtained or to accommodate a particular type of well construction. National UIC Guidances #15 and #34 include information relating to approval of alternate methods of testing mechanical integrity.

3.4 Tests which are not MI Tests but are Specifically Required by Regulation

3.4.1 Radioactive Tracer Survey
The regulations at 40 C.F.R. 146.68(d)(2) require annual demonstrations of the integrity of cement at the top of the injection interval in Class I hazardous-waste injection wells. The RTS is more often used for that purpose than to demonstrate either part 1 or 2 of MI. The procedures for demonstrating cement integrity using the RTS are presented in Attachment 10*.

3.4.2 Casing Inspection Logs (CIL)
The regulations at 40 C.F.R. 146.68(d)(4)require periodic monitoring of change in casing thickness for Class I wells injecting hazardous wastes. The procedures for running the logs and presentation of the results are set by the logging company. Because the standards adopted by the logging companies are appropriate, no additional information is provided for running casing inspection logs.

4 CONDUCTING TESTS WITHOUT A REPRESENTATIVE OF THE USEPA

It is, and has been, the policy of Region 5 to witness mechanical integrity testing to the extent practicable. Tests for which a mechanical or third-party record is produced may be conducted without an Agency witness when it proves impossible to resolve scheduling conflicts with both the USEPA contract inspectors and the Regional technical staff.

In order to conduct testing without an USEPA representative the following procedures should be followed:

1. The owner/operator must submit proposed procedures including the information that no USEPA representative is available, and receive permission from the DI Section of the UIC Branch to proceed;
2. The test must be documented using either a mechanical device which records the value of the parameter of interest, or by a service company job record;
3. A report of the testing including all data available at the conclusion of the test and a certification of accuracy which is signed by an authorized representative of the company must be submitted to the DI Section within 10 c alendar days of the completion of testing; and
4. A final report, including any additional interpretation necessary for evaluation of the testing, must be submitted prior to or with the next regularly scheduled monitoring report or as required under the appropriate permit for the injection well.

NOTE: Pursuant to &sect 146.8(f) of the UIC regulations, Region 5 may, at any time, require a test witnessed by a USEPA representative to verify the results of an unwitnessed test. This is possible if results are ambiguous or if documentation is lacking.

5 ACTIONS TO BE TAKEN IN THE EVENT OF A FAILURE TO DEMONSTRATE MI OR LOSS OF MI DURING OPERATIONS

If upon investigation, the well appears to be lacking MI, the operator should cease injection immediately and attempt to mitigate any environmental effects of the loss of MI. The Director may allow up to 48 hours of injection if necessary to allow for a smooth shut down of operations. Pursuant to 144.28(b) or 144.51(l)(6), owners/operators are required to report any known loss of MI which might endanger health or the environment to Region 5 within 24 hours. To report a failure, operators may call Region 5 at (312) 353-4148; during nonbusiness hours a message can be left on the voice mail system. Also, pursuant to 144.28(b) or 144.51(l)(6) a written submission shall be prepared and sent to Region 5 within five days of the time the operator becomes aware of a loss of MI.

Injection into wells which have lost MI can be resumed only after a letter authorizing injection is received from the Director. The Director will prepare such a letter only if: 1) the well is repaired, a report detailing the means used to effect the repair is submitted, and MI is demonstrated or 2) the owner/operator demonstrates, by means acceptable to the Director, an absence of flow into or between USDWs pursuant to 40 C.F.R. &sect 144.28(f)(4) or 40 C.F.R. 144.51(q)(3). As an alternative, the well can be plugged in accordance with 40 C.F.R. &sect 146.10. The plugging procedures must remove any threat posed by the absence of MI. If the failure is of part 1 of MI, this is usually accomplished through cementing the leaking portion. If the failure is of part 2 the means required to eliminate the fluid movement might be more demanding.

Falsification of MI testing is a violation of 18 USC &sect 1001 and violators may be subject to criminal penalties.

ATTACHMENT 1
STANDARD ANNULUS PRESSURE TEST (SAPT)

1 Basis

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted, undiminished, throughout the vessel. This fact is the basis for the selection of the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. To fully test the well bore, the pressure applied to the annulus system must be transmitted through the entire well bore. Therefore, no mechanical plug may be placed above the packer in any well subject to testing by means of the SAPT.

Because the annulus system is not an isolated system (e.g. it transmits energy, but not matter), the measured pressure applied may not be constant through time. The temperatures along the well bore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding rock. When the well is shut in part of the well bore may cool and part may become warmer. As this happens, the liquid in the annulus contracts or expands. Because liquids are only very slightly compressible, it is very unlikely that the pressure will appear to remain absolutely stable either while the well is shut in or being used for injection.

2 Advantages and Disadvantages of the SAPT

<u>Advantages of the SAPT</u>
1. Easy to interpret
2. Inexpensive to perform

<u>Disadvantage of the SAPT</u>
Provides a demonstration at a single point in time

3 Equipment and Forms

Pressure measurements must be made using a gauge which can be read with sufficient accuracy to identify pressure change which would result in failure of the test and to record accurate intervening values required per the procedures in Part D below. If the test pressure is 300 pounds per square inch, gauge (psig), then the gauge face should be marked in increments of 5 pounds per square inch (psi) or less. A gauge measuring injection pressure should be available.

The "Annulus Pressure Test" form (Attachment 11) is used to record SAPTs. Pressure measurements at intervals through the test period and the signature of an authorized witness are essential for acceptance. The most recent record of calibration for the gauge used for the MI test must be submitted along with the Annulus Pressure Test form. If authorization has been granted to conduct the test without a USEPA witness, the mechanical record of the test must be submitted as well.

4 Procedure for the SAPT:

To properly conduct the SAPT:

1. The tubing/casing annulus (annulus) must be completely filled with liquid (variations must be approved by Region 5). Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test. This may be achieved by filling the annulus with liquid and either ceasing injection or maintaining stabilized injection (i.e., continuous injection at a constant rate and constant injection fluid temperature) before and through the test;

   No unapproved substances may be added to the annulus liquid. Use of any substance which might affect the outcome of testing may constitute falsification of the test procedure, invalidate the test, and may subject the owner/operator to civil or criminal prosecution;
2. After stabilization, the annuluses of Class II wells should be pressurized to a surface pressure of no less than 300 psig. The annuluses of Class I wells should be pressurized to the greater of 300 psig or a pressure which exceeds the maximum allowable injection pressure by 100 psi, unless an alternate pressure is approved by Region 5. A positive pressure differential between the pressure in the annular space and the injection tubing pressure of at least 100 psi should be maintained throughout the entire annulus (from the top of the packer to the surface) of all Class I and II wells. Specific gravity differences between liquids in the annulus and the tubing should be accounted for when determining the appropriate test pressure. Following pressurization, the annular system must be isolated from the source of pressure and the sealpot (if present) by a closed valve. If not inconvenient, the connection to the pressure source should be disconnected entirely;
3. The annulus system must remain isolated for a period of no less than 30 minutes for Class II, III, and V wells. The isolation must be maintained for one hour for Class I wells. During the period of isolation measurements of pressure should be made at ten-minute intervals; and
4. After the SAPT test period has been completed, the valve to the annulus should be opened and liquid returns from the annulus observed and measured. This may be done by allowing liquid to flow into a sealpot assembly and measuring the volume of the returns or by opening a valve and catching the liquid flowback in a container. The volume of annulus liquid returns recovered is proportional to the volume of the annulus and the amount of pressurization. The liquid return test can serve as an indication as to whether the full length of the annulus has been tested. As an alternative, the amount of liquid needed to increase the pressure can be measured. If the entire length of the annulus, from the wellhead to the packer, set at the approved depth, is not tested, then the test is void.

5 Interpretation

The interpretation and confirmation of the SAPT include:

1. Comparison of the pressure change through the test period to 3% of the test pressure (0.03 X test pressure). If the annulus test pressure changes by this amount or more (gain or loss), the well has failed to demonstrate MI (for all wells), and operation may constitute a violation

of the UIC regulations. If the annulus test pressure changes by less than 3 percent (gain or loss) over the test period, the well has demonstrated MI, pursuant to 40 C.F.R. &sect 146.8(a)(1); and

2. Evaluation of the amount of liquid returned. If less than a cup of liquid is returned, the annulus may be blocked at a shallow depth. In the past criminal charges have been brought as a result of investigations inspired by the observation that very little liquid was returned. The owing formula can be used to find how much liquid should be returned:

   $dV = (P_t - P_f) \times V_f \times h \times 0.0000032$

   where:
   dV = the amount returned, gals;
   P_t = the pressure used to test the annulus, psi;
   P_f = annulus pressure after depressurization, psi;
   V_f = the volume of one foot of the annulus from
   Halliburton table 221-B, gals;
   h = length of the annulus, ft; and
   0.0000032 gal/gal/psi = the compressibility of water.

   The result is the number of gallons of liquid which should be returned. It is also the amount of liquid needed to pressurize the annulus to the test pressure once the annulus is filled with liquid. For a small annulus which might be typical of a Class II well (4-1/2 inch, 11.6 lb/ft. casing and 2-3/8 inch tubing, pressurized to 300 psi), just under one half gallon of liquid should be returned for each 1,000 feet of depth to the packer. If several gallons of liquid are returned, it is fairly certain that the entire length of the casing and tubing have been tested.

ATTACHMENT 2
STANDARD ANNULUS MONITORING TEST (SAMT)

1 Basis

The SAMT is essentially a continuing SAPT; however, interpretation is complicated by operational effects, principally: 1) injection tubing expansion or contraction as a result of injection pressure changes and 2) well bore temperature changes associated with a) starting or stopping injection or b) daily and seasonal changes of injectate temperature. To eliminate additional complexities, the regulations now require that the pressure be greater than atmospheric pressure.

This means that the annulus pressure should be raised to some pressure and the annulus should then be sealed. The pressure will change in response to temperature changes or even pressure changes in the injection tubing. Allowing for some seasonal variation, the range of temperature change should be consistent. In the event of a casing leak opposite a permeable zone, the pressure will normally fall, probably to zero and, if not, the range of pressure change will be much diminished because the aquifer with which the leak communicates will buffer volumetric changes in the annulus. In the event of a tubing or packer leak, the annulus pressure will track injection pressure. These two pressures will probably not be equal because of pressure loss due to friction in the injection tubing and density differences.

Region 5 Class I UIC permits require that a positive pressure differential be maintained between the annulus and injection tubing in Class I wells. The purpose of this requirement is to ensure that any leak in the injection tubing will result in an inward leak so that the injectate will not leak into the annulus. This is an important safeguard when the injectate is corrosive or very dangerous. Compliance with this requirement is not equivalent to use of SAMT if the pressure is artificially maintained through the addition of gas to a seal pot.

Unless any leak will result in an unimpeded pressure change, leaks might not be evident. To enhance the value of maintaining a positive pressure differential, Region 5 permits require volume measurement of all liquid additions and subtractions from the annulus systems of Class I wells. The results of these measurements are accumulated and a continuing need to add or remove fluid to maintain a set pressure is evidence of a leak in the well, although not necessarily an absence of MI. When a loss becomes evident, the Director may require a SAPT to confirm MI. If the well demonstrates MI, the Director may allow continued use if the leak does not cause violation of any UIC regulation.

2 Advantages and Disadvantages of the SAMT

Advantages

1. Provides a continuous demonstration of MI
2. Inexpensive for simple annulus systems
3. Easy to interpret for simple annulus systems

Disadvantages

Is difficult or impossible to interpret for wells with annulus pressure maintenance systems

3 Equipment and Forms

In order to make determinations quickly and simply, measurements of both the annulus and injection pressures should be made. Operators of Class I wells must use either an analog chart recorder or electronic equipment recording in a digital format at short intervals. Class II operators must record these pressure measurements at a frequency set by permit conditions. Other arrangements are possible, but must be established as permit conditions.

There is no set form for reporting the results of the SAMT. Each operator using the SAMT proposes a monthly reporting form to the DI Section. To effectively use the SAMT, the form must list not only the annulus pressure as measured at least once in any 24 hour period, but also the injection pressure measured at the same time. In addition, information about the injection rate, the temperature of the injection fluid, and the injection pressure may be useful. Changes in any of these parameters can affect the annulus pressure.

4 Procedure for the SAMT:

For Class I wells and other wells having a sealpot assembly and pressure maintenance the operator must:

1. Establish a positive pressure differential between the annulus and injection tubing sufficient to avoid changes which impinge on the required pressure differential (most Class I permits require at least a 100 psi pressure differential);
2. Isolate the annulus from any source of pressure maintenance;
3. Perform an SAPT, recording pressure at ten-minute intervals. If the pressure change is less than 3% in 30 minutes for Class II and III wells or 3% in 60 minutes for Class I wells, the test is passed and the SAMT begins;
4. Report the results of near-continuous measurements of annulus pressure and injection pressure in tabular and graphical formats along with tabulations of injection rate and pressure and injectate temperature as required by permit; and
5. Report the volume (in gallons) of any liquid added to or removed from the well's annulus system.

For wells not using a sealpot assembly the operator must:

1. Establish a pressure greater than atmospheric on the casing/tubing annulus;
2. Isolate the annulus from any source of pressure maintenance;

3. Perform an SAPT, recording pressure at ten-minute intervals. If the pressure change is less than 3% in 30 minutes for Class II or III wells or 60 minutes for Class I wells, the test is passed and the SAMT begins;
4. Report the results of periodic measurements of annulus and injection pressures and conditions under which pressure measurements are made, e.g. injecting or not injecting, and approximate injectate temperature; and
5. Report the volume (in gallons) of liquid added to or removed from the well's annulus system.

After any well failure, MI must be confirmed using the SAPT before resuming the SAMT.

5 Interpretation

The standard used for evaluating SAMT demonstrations is the same as that used for the SAPT, i.e., 3% pressure loss in either 30 or 60 minutes. However, it is only possible to apply this standard when external factors which might affect the annulus pressure are stable and a change in annulus pressure is established. Otherwise, liquid property changes occurring in response to change in ambient conditions make determination of a leak-induced pressure change impossible.

To provide an effective, real-time demonstration of MI, frequent inspection of pressure records is needed. This review should focus on the pressure in the annulus relative to: 1) atmospheric pressure, 2) the injection pressure measured at the surface, and 3) pressure in aquifers along the well bore. The following occurrences may indicate a loss of MI:

5.1 For wells with injection pressure greater than the annulus pressure

1. Annulus pressure increases and tracks injection pressure - probable tubing or packer leak;
2. Annulus pressure decreases:
    a. and goes to near zero - probable casing leak;
    b. stabilizes and returns to normal behavior - possible packer slip;
3. Annulus pressure is very stable regardless of injection - probable deep casing leak in well with light annulus liquid;
4. Annulus pressure fluctuates - probable temperature effects due to operational effects of injectate temperature changes;

5.2 For wells with injection pressure greater than zero but less than annulus pressure

1. Annulus pressure increases - if the well is deep, penetrates high pressure zones, and the annulus liquid is light it may indicate a deep casing leak, possibly due to an increase in injectate temperature;
2. Annulus pressure decreases:
    a. to near zero and/or becomes very stable - probable deep casing leak in well with lighter annulus liquid;
    b. and tracks injection pressure - probable tubing leak;
    c. stabilizes, and resumes normal behavior - could be a decrease in average injectate temperature or packer slip;
3. Annulus pressure fluctuates - probable temperature effects due to operational effects of injectate temperature changes;

5.3 <u>For wells which inject on a vacuum</u>

1. Annulus pressure decreases - could be either a casing, tubing, or packer leak;
2. Annulus pressure increases: and
    a. stabilizes - if the well is deep, penetrates high pressure zones, and the annulus liquid is light it may indicate a deep casing leak;
    b. begins to behave normally at a higher pressure - possibly due to an increase in injectate temperature.

In the event that a loss of MI is suspected an SAPT should be performed to ensure that the well has MI. If the SAPT confirms MI, then the operator may resume the use of the SAMT.

ATTACHMENT 3
RADIOACTIVE TRACER SURVEY (RTS)
FOR DEMONSTRATION OF 146.8(a)(1)

1 Basis

During injection, radioactive (RA) tracers can be added to injected liquids at a point above the interval to be checked for leaks. The RA material will mix with a portion of the injectate so that a slug of RA injectate passes through the section of the well to be tested. Any leak of the mixed injectate will be marked with some RA tracer. The leaked tracer material may be traced using a detector device on a wire line. The movement of the leaked tracer material is unlikely to keep pace with the movement of the slug of marked injectate which continues down the well and will be identifiable.

When tracer material is observed to split, the movement of the portion which appears to have separated should be carefully traced. The most accurate way to do this is by positioning the detector ahead of the moving tracer and observing its passage. When the tracer fails to arrive at the detector, the upper limit of movement is fixed. This method is superior to chasing the slug because it appears to be more sensitive and the record does not distort the shape of the slug as a result of tool movement. However, great care is needed to identify small increases in gamma ray activity.

2 Advantages and Disadvantages of the Radioactive Tracer Survey

<u>Advantage</u>
Locates the depth of the leak within the well bore

<u>Disadvantages</u>

1. Expensive relative to SAPT
2. Approved testing methods always require injection. Velocity shots used for the location of very small leaks may be used without injection, but require long periods of investigation

3 Equipment and Reporting Forms

The equipment required is readily available. In the past, almost any company engaged in geophysical logging was able to conduct RA tracer surveys. Some companies have discontinued the service due to restrictions imposed on the handling of RA material. The equipment consists of a sonde (tool) which is lowered into the well on a cable which allows transmission of data from the tool to receivers in a winch/instrument truck on the surface. The tool consists of an injector stage, one or more gamma radiation detector devices, and a collar locator.

The relative positions of the injector and detectors are variable. If only one detector is used, it must be located below the ejector. If more than one is used, it is common and advantageous for one detector to be located above the ejector. Three detectors are sometimes used with two being below the detector. This allows very accurate measurement of the speed of the injectate to be made. It also simplifies the location of the upward limit of leaking by eliminating some repositioning of the tool.

The purpose of the collar locator is to pinpoint the location of leaks in reference to permanent markers. This may also be done by means of correlation to a gamma ray trace which is scaled to show lithologic effects. Using a collar locator immediately lets the analyst know whether an identified leak is at a collar, while using a gamma ray correlation log clarifies the stratigraphic location of the leak.

The RA tracer is usually Iodine 131, because of its short (eight day) half life. Other tracers may be used for special applications. In any case, the tracer material used must be anionic to minimize its molecular attraction to well and rock materials.

In addition to the log of the test as presented bythe service company which performed the test, the digital data from which the log was produced must also be submitted. Information which is helpful to interpretation should be reocrded on the log form, including: 1) a schematic drawing or description of the configuration of the tool, 2) the injection rate, 3) the time at the beginning and end of each logging run, and 4) the time at which any peak is recorded. It is also helpful to use time markers on the logs to accurately fix the times at which changes in radioactivity are recorded.

We request that logging engineers review the information sheet which will be returned to permittees along with approval of procedures so that they will provide the informatiion needed to fully interpret the logs. The information sheets need not be filled out and returned.

Further testing may be necessary if possible migration out of an authorized injection interval is noted. This may include a series of time drives and slug chases to determine the extent of the leak or channel.

4 Procedures for Running the Radioactive Tracer Survey (RTS) as a Demonstration of Part 1 of MI

The demonstration can be effective for locating leaks in both the tubing and the casing. However, the RTS is useful for demonstrating an absence of leaks only in tubing strings through which the tracer material may flow. A demonstration that there are no leaks in the tubing requires that steps 1 through 8 listed below be followed. To test the casing, the tubing may be removed and the same steps followed, or the packer may be unseated and the method used to check cement integrity, described in Attachment 10, may be followed.

Testing is always conducted while injecting, and the operator should ensure that adequate water can be supplied for the test. The injection rate may be governed by the ability of the winch operator to track the RA slug as it moves downward. However, the injection rate should be as close to the maximum injection rate as practical. The following practices usually result in interpretable results:

1. Ensure that there is a significant pressure differential across the tubing wall to be tested. If the tubing is to be tested, special permission may be needed to perform the test with excess pressure in the tubing, because permits may require a positive pressure differential within the annulus. Although introduction of tracer material into the annulus can allow testing while maintaining a positive pressure differential, testing within the range of USDWs defeats the purpose of the positive pressure differential, because a casing leak would allow a release of radioactive material into an USDW. Further, practical difficulties make testing with the tracer in the annulus a complex operation;
2. Set the gamma ray (GR) detector sensitivity so that lithologic effects are just identifiable, usually 25 to 50 counts per second per inch. This ensures maximum sensitivity to leaked RA material. Noisy logs are much more difficult to interpret;
3. Make a background GR log over the interval to be tested before any RA material is introduced into the well;
4. Record measurements over a period of three to five minutes with the tool stationary at two points which are representative of the extremes of natural radiation within the interval to be tested. This will allow the interpreter to observe the effects of natural variations of GR emission on the record;
5. Release a slug of RA material above the interval to be tested. The greater the intensity of radioactivity of the slug the more resolution the method will have. Deflections caused by the slug should be 50 times greater than those caused by lithologic effects;
6. Follow the slug with the logging tool or make repeated passes upward through the slug as it moves down the well. Any increase in radioactivity which remains behind the slug should be investigated by supplementary passes through the interval as needed to determine whether

it is a result of material adhering to the tubing or of a leak. All logging should be done at a single logging speed which is appropriate for the injection rate to allow quantitative measurements of deflections to be evaluated

7. If repeated passes are used, the logs resulting from the slug-tracking exercise should overlap so that the return of radioactivity to the level which existed before the slug's passing is demonstrated for the entire length of the section of the well being tested. The logs of all passes should be presented as a composite log on a common depth track. If means to differentiate the log traces are available no other presentation is required. If the traces cannot be differentiated on the composite log, they should also be presented individually;
8. After any ejection, the slug should be followed until it has moved below the interval being tested. If the slug splits, both slug portions must be accounted for. This can be accomplished by concentrating first on the upward moving portion, and resuming tracking of the downward moving slug after the upward moving slug is tracked to its final destination; and
9. After completion of the passes, a final log should be made through the entire tested interval to check for residual radioactivity which might be associated with exit of tracer material from the well bore.

If the tubing has been removed from the well and the casing is being tested, leaked RA material will exit the well bore into a porous, permeable zone or fracture or move along the well bore to a porous, permeable zone or fracture. The movement of the tracer should be followed and the depth at which it exits the well bore recorded.

Leaks in the casing can be located with the tubing in the well by monitoring for upward movement at the base of the tubing with the packer released, as described in Attachment 8. Except in the unlikely case that the pressure in the aquifer with which a leak allows communication is higher than the injection pressure at the same depth less the friction loss from the leak to the end of the tubing, an absence of upward movement when the top of the annulus is sealed, means that there is no leak in the casing. However extreme care must be taken to ensure that upward movement will be identified. A release of a longer- period slug may increase the strength of the upward moving slug. Any upward movement of RA tracer will continue until the tracer reaches the leak and exits the well bore.

If the operator wishes, the portions of the injection interval which accept waste may be determined by making more frequent passes while the slug is within the injection interval. The sensitivity may be reset so that the log trace remains on scale.

5 Interpretation

1. Where a measurable amount of RA tracer material leaks from the tubing, it will be observed as a small area of increased radioactivity after the slug has passed;
2. If an area of elevated radioactivity is observed, additional runs should clarify what becomes of the RA material responsible. This will demonstrate whether only the tubing is leaking, or both the tubing and casing lack integrity. In most cases, if a well's casing has integrity but a tubing leak exists, pressure equalization and cessation of leaking will occur until a change in injection pressure allows the leak to resume. This is why it is important to ensure a pressure differential between the injection tubing and annulus.

   If annulus pressure is lower than injection pressure and both the tubing and casing are leaking, any tracer material that leaks out of the tubing will generally move toward and out through the casing leak. This is because the annulus pressure normally will be higher than the hydrostatic pressures within adjacent formations at all depths.

   If only the tubing is leaking, the tracer material will remain near the leak, spreading slowly both up and down from the leak location.

   Adherence of tracer material to the tubing can be differentiated from a tubing leak because any material adhering to the tubing will eventually be washed away with no movement evident.

If no evidence of leaking is observed, the well has demonstrated part 1 of MI. Be aware that demonstrations of MI using the RTS will be examined very closely, and any conditions which threaten the ability to interpret them accurately must be removed.

ATTACHMENT 4
WATER-BRINE INTERFACE TEST (W-BIT)

1 Basis

The water-brine interface test is based on:

1. The differences in liquid pressure gradients of the brine filling salt solution mining caverns and fresh water;
2. Pressurization of the cavern resulting from salt-solution mining; and
3. Pascal's Law, the transmission of pressure throughout a closed vessel.

The strategy governing the test is that a decrease in wellhead pressure will be observed in the event of loss of a fluid of lower density filling a standpipe open to a reservoir filled with a fluid of higher density. In practice, this situation is produced by:

1. Flushing the well to be tested with sufficient fresh water to dissolve any salt precipitated on the interior of the casing;
2. Withdrawing water until cavern brine is brought to the surface; and
3. Depressing the cavern brine to the base of the well casing by the injection of a volume of fresh water sufficient to fill the casing to within 25 feet of the casing shoe.

Because the cavern is pressurized sufficiently to cause the heavy brine to flow to the surface, the pressure within the well filled with fresh water is greater than the hydrostatic pressures in any aquifer through which the well passes. Therefore, any leak will allow fresh water to flow outward, to be replaced by dense brine flowing into the well from the cavern. Because the liquid pressure gradient of the brine from the cavern which replaces the leaked fresh water is greater than that of the freshwater, less pressure is transmitted from the cavern upward through the well to the well head.

It has been found that pressure within the cavern is not constant. To avoid the possibility that this variation might mask any change due to leakage, a reference well is used. This well, which is often the tubing within the well being tested, is filled with a static fluid column. If there is a leak in either the tubing or the casing, fresh water will be lost from the annulus. While the rate of leakage into the tubing is likely to be less than would be leakage from the casing, due to a lower pressure differential, particularly if the leak is near the base of the casing, the resultant emplacement of fresh water into the tubing will increase the wellhead pressure so that the effect is doubled.

The loss of one foot of annulus liquid during the W-BIT will cause a wellhead pressure reduction of approximately 0.11 psi:

$dP = dL \times (0.433 \text{ psi/ft.} - SG_c \times 0.433)$

$-0.11 \text{ psi} = 1 \text{ ft.} \times (0.433 \text{ psi/ft.} - 1.25 \times 0.433 \text{ psi/ft.})$,

where:
dP = pressure change resulting from fluid loss,
0.433 psi/ft. = pressure gradient of fresh water (SG = 1.0),
and
SG_c = specific gravity of cavern fluid = 1.25,

while the loss of one foot of pressurized annulus liquid from an annulus 1,000 feet in length will cause a loss of 312.5 psi:

dP = dV/V/0.0000032 ft./ft./psi

-312.5 psi = -1 ft./1000 ft./0.0000032 ft./ft/psi.

where:
dP = pressure change,
dV = volume leaked = -1 ft.,
V = annulus volume = 1000 ft., and
0.0000032 ft./ft./psi = the compressibility of water.

The test must be run for a longer period than the SAPT and measurements must be much more accurate to compensate for the lesser pressure change associated with leaked volume.

2 Advantages and Disadvantages

Advantages

1. Does not require removal of tubing and installation of a packer for wells used for injection and withdrawal of liquids;
2. Inexpensive for simple annulus systems.

Disadvantages

1. The W-BIT is approved only for Class III wells which cannot be tested by means of the SAPT
2. Requires use of a deadweight pressure gauge, which may be expensive to acquire;
3. Requires a 36-hour interval between initial and final pressure measurements.

3 Equipment and Forms

A dead weight pressure gauges and an operator trained in its use are needed. A convenient worksheet has been developed by members of the Salt Institute.

4 Procedures

The UIC Branch has not identified any common errors in conducting the W-BIT, and we believe that no additional guidance is needed beyond that provided in the Federal Register notices announcing its approval. A schematic drawing of the well construction must be submitted with a description of the proposed test procedures.

5 Interpretation

The calculations which are part of the test result in the calculation of a rate of pressure change. If this pressure change is less than 0.05 psi/hr., then the test demonstrates the MI of the tested well. If the rate of change is more than the standard, the well lacks MI.

ATTACHMENT 5
TEMPERATURE LOG (TL)

1 Basis

In almost every case, an aquifer into which water has flowed in the recent past is heated or cooled because the earth's temperature increases steadily with depth. This makes it unlikely that the water moving into a reservoir is the same temperature as that which is displaced. Given sensors of sufficient sensitivity, the change in temperature is identifiable. In addition, the zone from which the water came is likely to be identifiable if flow is continuing. Temperature logs can also confirm that there is no flow of injectate through the rock surrounding the well bore and often will identify small casing leaks.

During injection the ability of the injectate flowing through the well to maintain its own temperature dominates all other effects so that, for the purpose of establishing MI, the well must be shut in during temperature logging. The principal requirement for running temperature logs is that the well be shut in long enough so that temperature effects related to well construction can dissipate, leaving a relatively simple temperature profile. Experience has shown that 36 hours is usually sufficient in Region 5.

In new wells, baseline temperature logs should be made as long as possible after drilling the well, but before injection begins, because temperature effects due to circulation of drilling fluid will persist for several weeks after drilling is completed and infiltration of drilling fluids causes temperature anomalies which may persist for several months. A;though these anomalies can makr permeable zones, the existence of a temperature log which reflects the natural geothermal gradient can be of great value in assisting later analyses and for understanding other geophysical effects.

2 Advantages and Disadvantages of Temperature Logging

Advantages:

1. Continuous log with high vertical resolution
2. The most sensitive indicator of part 2 of MI
3. In addition to fluid movement within the well bore, fluid migration through the confining layers may be identified
4. Water-filled porosity can be determined if sufficient information is available
5. Injection pressure need not be maintained to ensure identification of well bore flow near the injection interval
6. Flow need not be occurring at the time of logging for its effects to be identifiable
7. Low cost per single survey covering entire well bore

Disadvantages:

1. Gas entry may be marked by cooling, but movement and exit may be obscure
2. Interpretation for complete understanding requires a greater degree of expertise than other logging methods
3. Fluid-filled well bore through interval to be tested may be required
4. Well must be shut in long enough to remove most construction and near-well bore effects

3 Equipment and Reporting Forms

The temperature logging tool is a wireline sonde operated from a winch truck. Temperature logging tools contain circuitry which responds to temperature change by changing resistance to current flow. The response is linear and temperature logs can distinguish very small changes in temperatures. Calibration of logging tools is often poor because the effects they are normally expected to measure have importance as relative rather than absolute values, although correct absolute temperatures also have value for other purposes. To be effective, temperature logging tools must have good thermal coupling to the borehole environment, which means that they are not generally useful in air-filled holes. Sampling is done at short intervals as the sonde is lowered into the well, so that a record of the entire well bore is produced. Because the tool does not react to temperature change instantaneously and the tool is continuously moving, the measured temperature changes lag actual wellbore temperature changes by a consistent amount. The more slowly the tool moves, the closer are the measured temperatures to actual temperatures. If the tool speed is erratic, the recorded temperature profile will also be irregular. Despite the possible inaccuracies due to poor calibration and tool response time, the absolute values recorded can generally be compared with some confidence.

A reporting form has been developed to accompany the log to assure that other information useful for interpretation is submitted. Alternatively, all the information requested on the reporting form can be placed on the log. This includes: average and amximum logging speed, time since the last injection, temperature of the liquid most recently injected (average temperatures for the most recent year, month, and day) and calibration information. If there are frequent changes in the temperature of the injectate or if process changes have caused a significant change in the temperature of the injectate, it is very important to record the average temperatures of the injectate before existing logs were made and the date of the change in injectate temperature and the volume of liquid injected before and since that time. In the case of Class III wells, it is important to note whether the well was last used for injection or production.

The scaling of logs is a matter of importance. Features of significance are emphasized by compressing the depth scale and expanding the temperature scale. A depth scale of one or two inches per 100 feet, and a temperature scale of one inch to two degrees Fahrenheit are appropriate in almost every case.

If multiple logs are run while shut in, they should be displayed on the same axes (depth scale) for comparison. To avoid confusion, it may be necessary to reduce the temperature scale, but reducing it to less than four degrees per inch should be done only when necessary to avoid superimposing logging traces which cannot then be followed.

Gamma ray logs must be run simultaneously with the temperature log. Gamma ray logs provide depth control and important information about the rock types along the well bore. The digital logging data must also be submitted. We request submission of data collected at intervals of one foot. More frequent readings increase the volume of data, but increased resolution serves no purpose.

4 Procedures for Running the Temperature Log

The following steps should be followed for effective temperature logging:

1. Shut well in for sufficient time for temperature effects resulting from well construction features to dissipate. This typically requires at least 36 hours in Region 5. If 36 hours prior to logging are not available, proof that sufficient time has elapsed can be demonstrated by comparison with another log of a well at the same site. The second log may have been made previously or a second log may be made six hours after the first;
2. Calibrate the log if at all possible. This can be done by comparing measurements made using the tool in any two liquids to the known temperatures of those liquids. For instance, both a thermometer and the thermistor to be used for the logging may be used to measure the temperature of water at ambient conditions and a bucket of ice water. Even a single measurement made in a well-mixed bucket of ice water may be very helpful;
3. Log the well from the surface downward, lowering the tool at a rate of no more than 30 feet per minute. The 30 feet per minute limitation is a practical balance between the tool response time and normal time constraints, slower speeds provide increasing detail. Time coding of the log, either a tick or gap in the log grid at one minute intervals or a logging-speed trace, should be used to confirm the tool speed;
4. If the well has not been shut in for at least 36 hours before the log is run, comparison with either a second log run six hours before the time the log of record is started or a log from another well at the same site showing no anomalies should be available to demonstrate normal patterns of temperature change.

5. The log data on a disc in either LAS or ASCII format is needed for ease of interpretation. A gamma ray log, made at the time of logging, or from a previous logging, and correlated to the temperature data is needed for accurate interpretation.

5 Interpretation

Confirm the validity of the log at the well site by comparing two logs made at the same site. When lithology and injectate characteristics are similar, then thermal effects along the well bore should also be very similar. After the temperature effects caused by casing joints, packers, well diameter, casing string differences, and cement have dissipated, the temperature profiles should be similar, although not identical. If construction features are evident, a longer shut-in period is probably needed.

Identification of flow is based on relative differences between logs of nearby wells if such logs exist. Although the gradients may be quite different as a result of differing injection history, their relative positions should be obviously consistent. Lithologic effects which show up on one log should show up similarly in other wells at the same site. Failure of logs made at the same site under conditions which should result in thermal stability to compare coherently constitutes an anomaly.

If there are no logs suitable for comparison, then deviations from a predictable geothermal gradient, modified by the effects of injection, are anomalies. These may take the form of a nearly constant temperature between reservoir strata. When more than one log is run, these anomalies are likely to grow (be left behind) as the profile returns toward the natural geothermal while relative differences between the traces elsewhere decrease. In addition areas with active flow will reach a stable temperature more quickly than other areas. If the movement is not related to injection, this temperature should be that of the natural geothermal gradient at the depth of the source reservoir.

If there are anomalies, a failure of MI may be indicated. In such a case, an additional new log may be necessary to show whether forms apparent on the log just made are evolving toward the forms established on the log from another well. Comparison of these two new logs should show increasing parallelism along the cased well bore, if not, then there may be flow along a channel adjacent to the well bore. If this flow results in the movement of liquid into or between USDWs, then the well does not have part 2 of MI. If the well is used to inject hazardous wastes and flow results in movement of fluid from the injection zone into the confining zone, then a release from the solid waste management unit is indicated. In the event that there are unresolved anomalies which might indicate an absence of part 2 of MI, another approved method must be used to confirm the absence of flow into or between USDWs.

Depending on the nature of the liquid movement, radioactive tracer, noise, oxygen activation, or other logs approved by the Region may be used to further define the nature of the fluid movement.

Identification of flow behind the casing is always made from long-term shut-in logs. The resolution of long-term shut-in logs for identifying the presence of flow is greater than that of logs made during injection. The temperature gradient within a well which has been injecting for some time is very shallow. The temperature at the injection zone may be only a few degrees different from that at the surface. The presence of a flow behind the casing will result in a fractional change in this gradient which will be proportional to the ratio of the flow rates within and outside the tubing. Therefore, only a rather substantial flow can be identified using logs made during injection.

ATTACHMENT 6
NOISE LOG (NL)

1 Basis

Channels along well bores are very rarely uniform. When flow is occurring, irregularities in channel cross section usually result in generation of some turbulence which occurs in audible ranges. Sonic energy travels for considerable distances through solids, allowing sensitive microphones to detect the effects of turbulent fluid flow at considerable distances. Different types of turbulence result in sounds having different frequencies. Single phase turbulence results in low frequency sounds, while two phase turbulence usually results in high frequency sounds. High pass filters are used to determine the intensity of detected noise within various frequency ranges.

2 Advantages and Disadvantages of Noise Logs

Advantages:

1. Relative to oxygen activation log, it is practical to increase vertical resolution by increasing spacing density
2. Can identify flow of gas and differentiate it from liquid flow
3. Relative to temperature logs, cannot be used to demonstrate confinement

Disadvantages:

1. Can identify only turbulent flow
2. Relative to temperature logs, cannot be used to demonstrate confinement
3. Requires liquid in well bore through the interval to be tested
4. Injection pressure must be maintained to ensure identification of fluid flow near the injection zone
5. Actual logging time and cost are usually greater than for temperature logging

3 Equipment and Forms

Noise logging tools are wireline tools which are essentially sensitive microphones. Sampling is done in a stationary mode and the time required at each station is approximately 3-4 minutes. Any sounds detected are transmitted to recorders which measure the amount (loudness) of sonic energy received over a period of time. A cumulative measure of the sound energy which has been received is recorded.

Sonic energy travels considerable distances through solids so sampling can be done in a reconnaissance mode, with additional stations run where increases in energy are detected so that exact locations of conditions which cause sonic events can be found. Sonic logs are similar to temperature logs in that they are much more effective in liquid-filled holes because of improved coupling.

The log is the only form which must be submitted. When the level of sound is low, a linear scale is used, and when there are intervals with higher sound, a logarithmic form is used. Either is acceptable. The vertical scale should be small, one or two inches per 100 feet. In addition to the graphical log, a tabulation of sound energy is normally included on the log form and it should also be submitted.

4 Procedure for Producing the Noise Log:

Noise logging may be carried out while injection is occurring in many wells because flow restriction caused by the logging tool is often insufficient to cause turbulence. It is especially desirable to log while injecting when looking for flow resulting from pressure increase near the top of the injection zone. If ambient noise while injecting is greater than 10 mv, injection should be halted. Logging procedures should include the following steps:

1. Make noise measurements at intervals of 100 feet to create a log on a coarse grid;

2. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels;
3. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing: 1) the base of the lowermost bleed-off zone above the injectioninterval, 2) the base of the lowermost USDW, and 3) in the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval;
4. Additional measurements may be made to pinpoint depths at which noise is produced; and
5. Use a vertical scale of 1 or 2 inches per 100 feet.

5 Interpretation

The interpretation of noise logs for the purpose of demonstrating part 2 of MI is quite straightforward. The following steps are used:

1. Determine the base noise level in the well (dead well level);
2. Identify departures from this level. An increase in noise near the surface due to equipment operating at the surface is to be expected in many situations;
3. Attempt to determine the extent of any movement, this may be difficult when there are few flow constrictions;
4. If flow is into or between USDWs, a lack of mechanical integrity is indicated. If flow is from the injection zone of a hazardous-waste disposal well into or above the confining zone, failure of containment is indicated.

If the log measurements are ambiguous, the determination should be confirmed using another method.

ATTACHMENT 7
OXYGEN ACTIVATION METHOD

1 Basis

The oxygen activation method is based on the ability of the tool to convert oxygen into Nitrogen 16 (N16) within a short distance of the tool. This is accomplished by emitting high energy neutrons from the tool's neutron source. N16 is an unstable isotope of nitrogen which is referred to as activated oxygen. The half life of activated oxygen is just 7.13 seconds, and the release of gamma rays as the activated oxygen decays into oxygen can be measured. If the tool is stationary and oxygen is activated, detectors placed near the activator device will detect increased gamma radiation. The intensity of the additional radiation will be inversely proportional to the square of the distance of the activated oxygen from the detector. Much of the oxygen near the tool occurs in water. If water containing activated oxygen moves, the measured intensity of radiation will be greater if the slug of activated oxygen moves closer to the detector, and less if it moves away. By comparison of intensity of gamma radiation measured as a result of activation at two detectors, the direction and velocity of water movement can be determined. Studies under controlled conditions have shown that water velocities between two and 120 feet per minute can be measured.

2 Advantages and Disadvantages

<u>Advantages:</u>

1. Interpretation is a simple comparison of a calculated velocity to a minimum velocity which the tool is able to identify reliably
2. Relative to temperature logs, little or no shut-in time is required
3. Does not require a liquid-filled well bore
4. Numerical result eliminates the need for qualitative interpretation

<u>Disadvantages:</u>

1. Can identify flow in a broad, but fixed, velocity range
2. Has a very small range of investigation, smaller than very large well bores

3. Cannot be used to demonstrate the absence of liquid movement through confining layers
4. It is not practical to increase vertical resolution by increasing spacing density
5. Calibration errors may affect tool accuracy, perhaps accounting for false positive indications
6. History includes false positives and missed MIT failures confirmed by one or more other tools
7. Injection pressure must be maintained to ensure identification of fluid flow near the injection zone
8. Actual logging time and cost are usually greater than for other logs

3 Equipment and Forms

The equipment consists of a wireline sonde containing a high- energy neutron generator and gamma ray detectors. By spacing several detectors at increasing distances from the oxygen activation area interpretational accuracy is increased. Although the oxygen which is activated may be present in water which may be moving along the well bore, oxygen is also present in rock and cement. Some of this oxygen is also activated, and its decay products become background radiation which must be accounted for in order to reach a valid measurement of the movement of activated atoms in the fluid passing along the well bore.

The need to account for oxygen which is not in flowing water can be addressed in either of two ways: 1) by making calibration measurements in a representative area of the well bore in which there is thought to be no flow behind the casing, or 2) by extending the measurement period at each station beyond the time during which the activated oxygen in flowing water has been carried away. The rate of decay indicated by the late measurements is used to calculate the theoretical levels of gamma radiation which would have been measured if there were no water movement. The difference between the calculated and measured values is assumed to be the effect of the decay of activated oxygen carried to the vicinity of the detectors as part of moving water.

The first method is used by Western Atlas and the second by Schlumberger. These are the only companies which provide oxygen activation logging service in Region 5.

4 Procedures for Running the Oxygen Activation Log (OAL):

All measurements should be taken for periods of at least five minutes with the well injecting at the maximum normal rate. A total of at least 15 minutes measurement time is required at each station. This total time may be accumulated in one, two, or three episodes. If open-hole caliper logs are available, care should be taken to obtain all readings at depths where the well bore is in gauge. The method for obtaining measurements shall conform to optimum procedures contained in the operator's manual for the tool being used. The following steps are recommended for demonstrating part 2 of MI using the OAL:

1. Secure a log for lithology determination. If no such log is available, run a gamma ray-neutron log to identify porous intervals;
2. If required for tool calibration, background checks will be run with no injection occurring in an interval where no flow is thought to occur. Background calibration should be run for each interval of varying well construction;
3. Take measurements at stations at least 10 feet above the open injection interval;
4. Take measurements at the top of the confining zone and at two or three formation changes between the confining zone and the base of the USDW;
5. Take measurements within 50 feet below the base of each USDW, within 50 feet of the top of the first underlying aquifer, and at least one measurement between these two points;
6. If anomalies are found, additional readings, including readings made while the well is injecting if the original measurements were made while not injecting, or not injecting if the original measurements were made while injecting, should be made above and below the depth of the anomaly to confirm the anomalous reading and discover the extent of fluid movement; and
7. If flow is indicated, another log may be used to confirm the measurement and define the extent of flow. The choice for the confirmation log should be based on all wellbore and

environmental factors, and the tool choice must be approved by Region 5 prior to commencing testing operations.

5 Interpretation

A ratio of the short-spaced flow indicator result to standard deviation of 3-4:1 indicates flow. Indicated water-flow velocities should be in excess of two feet per minute, lower values should be viewed with skepticism. Velocities near and above two feet per minute have been measured at several depths at several sites in Region 5 and other logs did not indicate flow. In some cases the occurrences were repeatable, at least during the period of one logging episode. Although the cause of the false measurements is not known, it is assumed that the logging tool was not properly calibrated for the interval being tested.

To minimize false positives, it is recommended that all measurements be confirmed at several nearby depths and/or measurements be taken under a minimum of 3 varying injection rates, i.e.: 75%, 50%, and 25% of maximum permitted injection rates. Before costly measures are taken to remedy problems, their existence should be confirmed using another approved log.

ATTACHMENT 8
RADIOACTIVE TRACER SURVEYS
FOR DEMONSTRATING PART 2 OF MI

1 Basis

Acceptance of the test as a means for demonstrating part 2 of MI is limited to those wells where there is no aquifer between the injection zone and the base of the lowermost USDW and where there is no significant water quality difference between individual USDWs.

The basis of the test is that flow will follow the well bore upward if the cement seal is poor at and above the base of the casing for open-hole completions or above the uppermost perforation for perforated completions. If the cement at the top of the injection interval is sound and there is no movement upward along the casing at that point, it is assumed that there is no alternate conduit which might allow injected liquids to reach the well bore at a shallower depth and then travel upward through either an uncemented or ineffectively cemented well bore. The analyst is primarily concerned with identifying the uppermost depth at which tracer material can be seen to be moving within and then exiting the well bore.

2 Advantages and Disadvantages

Advantages:

1. Can be run with the well injecting

Disadvantages:

1. Only valid for part 2 when there are no aquifers between the base of the casing and the base of the lowermost USDW and no significant differences between quality of the USDWs
2. Cannot be used to determine interformational flow where the tracer material cannot be introduced into the flow stream outside the casing

3 Equipment and Forms

These are identical to those described for the RTS in Attachment 3.

4 Procedures for Running the Radioactive Tracer Survey (RTS)as a Demonstration of Part 2 of MI

The demonstration of mechanical integrity requires that the packer be seated or the tubing be removed from the well.

Three different test methods are usually employed at each instance of testing: 1) slug tracking, 2) stationary testing, and 3) comparison of logs run before and after the other testing methods are used. Either slug tracking or the stationary tests are adequate tests, but the comparison of logs run before and after the injection is only supplementary, and its use is in identifying the intervals along the well bore where RA material has adhered to the walls as it exited the well bore.

4.1 Recommended procedures for the use of the slug tracking method are:

1. Inject at the maximum rate used for injection unless it is impossible for the tool can be effectively used at that rate. Otherwise inject at the maximum rate at which the winch operator can track the slug;
2. Release a slug of RA tracer far enough above the base of the casing or perforations to allow it to be logged within the casing at least once;
3. Drop the tool down through the slug and then log upward through the slug;
4. Drop the tool down to within 20 feet below the top of the perforations or base of the casing (or tubing tailpipe, if that is lower). Hold the tool at that point until the slug reaches it. As soon as the slug is detected, begin to log upward so that the logging tool passes the top of perforations or the base of the deeper of the casing or tubing just after the slug has passed the same point. This helps to ensure that any upward movement is detected;
5. Drop the tool below the slug, but no more than 50 feet below the perforations/casing/tubing if a split was observed during the previous logging run, and again log upward;
6. Continue making passes to show the upward movement of the slug as long as it is measurable;
7. The procedure (Steps 1 though 6) should be repeated until the highest point to which injectate moved upward is identifiable; and
8. If any slugs are seen to split, the tracer material remaining after all of the planned testing is done should be ejected just above the casing shoe and the resulting slug followed upward as far as possible.

4.2 Recommended procedures for the use of the stationary method are:

1. Injection should be at the maximum rate used to inject waste. The slug of RA material should be ejected some distance above the depth at which the stationary test will be made in order to eliminate electrical effects associated with the ejection which sometimes mask or distort the detection of the downward moving slug. The greater deflection caused by the slug, the better. However, the length of the ejection should not be over a few seconds to avoid producing a long slug.
2. With at least two detectors, one above and one below the ejector, recording in time drive, position the logging tool with the lower detector four feet above the top of the perforations or the deeper of the base of the casing or tubing. When used with slug tracking, position the upper detector about two feet above the highest point reached by the tracked slug;

   The use of at least two detectors has two important advantages: 1) it allows the test to be, in effect, run at two or more depths and may cut the time required to run a test which completely defines the upward distance a slug travels and, more importantly, 2) confirms the direction of travel of any RA material observed after the slug is ejected. Often ejectors leak a small amount of tracer. The direction of movement of extraneous slugs passing by a single detector cannot be determined and may confuse interpretation.

   The scaling should allow the easy calculation of time period and deflections should not be smeared out over so much paper that they are difficult to identify. The time scale should not be compressed so much that determining the time, to at least the minute, at which the increase in radioactivity begins is questionable;
3. The tool is run in time drive for a period sufficient to allow the RA material to reach the perforations, casing shoe, or end of the tailpipe and travel upward to the detectors assuming upward movement at a rate of no more than two feet per minute;

4. If upward moving RA material is detected, following the detection of the slug at the top detector, move the tool upward a short distance and again record in time drive until the RA material is detected. Record the times at which the RA material reaches the detectors to help evaluate how far the detectors should be moved;
5. Continue to monitor the upward movement of the slug until the limit of upward movement is reached. The limit can be considered to be the elevation of a detector which did not record passage of the slug after allowing travel time of two minutes per foot from the point of last detection.

4.3 Recommendations for producing the logs before and after testing are:

1. The log should cover the interval between at least 100 feet below the bottom of the deeper of the casing or tailpipe depth and 200 feet above the shallower of the casing or tailpipe depth.
2. A gamma ray log should be on hand to ensure that the new log reflects background conditions. Occasionally tool leaks cause anomalous results which can be avoided simply by repeating the logging.
3. A presentation including both logs on the same depth scale is helpful. The traces must be coded so as to be clearly identifiable.
4. The log data on disk should be submitted. Having these data allow us to plot various combinations of logging runs at scales which show us what we think we need to see.

5 Interpretation

Each of the three testing methods is interpreted individually.

5.1 The slug tracking records are evaluated by:

1. Reviewing the statistical check performed before testing began to check the sensitivity of the log display, check to be sure the scaling used for the logging is the same as was used for the statistical check;
2. Checking the deflection caused by the slug within the tubing or casing. It should be at least 50 times greater than that caused by lithological background;
3. Checking to see if a slug split occurred at the base of the tubing or casing. Identify any increases of radioactivity along the well bore above the base of the tubing or casing;
4. Evaluating the slug split for upward movement. Turbulence at the base of the tubing often causes some tracer to remain. If only a slow dissipation of the resulting hot spot, with no upward movement, is observed, the split has no significance;
5. If the tubing extends below the casing, upward movement to the base of the casing commonly occurs, this also has no environmental significance;
6. If movement above the base of the casing occurs, its extent must be very carefully determined and recorded. It is not uncommon or of concern if there is some limited movement, particularly where the base of the casing is within a porous, permeable interval. The extent of upward movement should be compared with previous measurements to confirm that the cement seal is not deteriorating.

5.2 The stationary tests are evaluated by:

1. Checking the strength of the slug, often the detector cannot react quickly enough to measure the entire distance of the deflection. The deflection should appear sharp if the total deflection is not measured;
2. Checking the record from the lower detector to see if any increase occurred after the initial passage of the slug;
3. If a second increase in radiation was detected, check the record from the upper detector (above the ejector) to check whether an increase occurred at that detector before the detection of the slug by the lower detector, if so, the detection may be due to an extraneous slug, previously ejected, moving downward past the tool;
4. If no increase in radiation is detected by the upper detector, then the tracer exited the well bore between the lower detector and the upper detector. The maximum upward movement identified through this test is the elevation of the upper detector;
5. If an increase in gamma ray radiation is detected by the upper detector after the detection by the lower detector, the tool should have been moved upward so that the slug had the

opportunity to pass both of the detectors again. If so, repeat steps 2, 3, and 4 until the maximum upward extent of movement of the tracer is established. This depth should be recorded and compared with that for the slug tracking and tests conducted in previous years;

5.3 To evaluate the logs run before and after all other tests are performed:

1. The logs should be printed overlain on the same depth scale. If not, on a light table, light box or back-lighted window, overlay the initial log above the final log. Focus on the interval just above the top of the injection interval;
2.
3. After matching depth and/or collar log features, check to be sure that the gamma ray traces overlay. If they do not, shift one log to the left or right until they generally overlay;
4. Identify regions in which the final log indicates apparent increased radiation. If the magnitude of the increased radiation is greater than the statistical variation, then radioactive tracer material has probably adhered to either the well construction materials or the borehole walls where the waste exited the well bore; and
5. Try to relate all instances of increased radiation above the casing shoe to the results of the previous testing. If unexplained occurrences persist, the results of a recent part 2 MI test should be carefully reviewed to see if upward movement is indicated.

5.4 The result of the testing should be determination of a depth above which no upward movement occurs. The result should be at or below the casing shoe. If it is above the casing shoe, the extent should be tracked and significance determined.

ATTACHMENT 9
CEMENTING RECORDS

1 Basis

A very small span of sound cement surrounding the casing will prevent movement between the well bore and the casing or between casings.

The use of cementing records as a demonstration of part 2 of MI is limited to all Class II wells and those Class III wells in which the nature of the construction precludes the use of temperature or noise logs. The cementing records must indicate that cement is present along the well bore between the injection zone and the base of the lowermost USDW.

2 Advantages and Disadvantages

<u>Advantages:</u>

1. Usually based on existing information
2. A one-time demonstration

<u>Disadvantages:</u>

1. This is an indirect demonstration. The presence of cement does not assure us that it is sound
2. If paper records are not available, they cannot be reconstructed
3. Either the CBL or CET requires that the well bore be water filled to the upper limit of the logged interval

3 Equipment and Forms

1. Forms of Cementing Records
   Cementing records include any acceptable records containing information which allows the calculation of cement placement behind the casings of wells. Cementing records may include

cement bond logs, cement evaluation logs, and temperature logs which give evidence of the location and/or quality of cement along well bores. The most reliable cementing records are job reports from cementing companies, but any records of construction containing information about the placement of cement may be acceptable. Either the original or copies of t hese cementing records must be submitted.

2. Cement Bond and Cement Evaluation Logs

   Cement bond logs (CBLs) use sonic attenuation and travel time to determine whether casing is cemented or free. The more cement which is bonded to casing, the greater will be the attenuation of sounds transmitted along the casing. The Cement Evaluation Tool (CET) operates on a principle similar to the CBL except that the tool uses many sound transmitters and receptors to evaluate the cement in various sectors of the well bore. Instead of an average bond index accounting for the entire circumference of the well bore, the log can identify poor bonding in single 60o segments. This increases the ability to confirm the presence of channels tremendously.

   The logs should include a gamma ray curve, casing collar log, acoustic amplitude and travel time curves, and CBLs should include an acoustic variable density log (VDL). The left hand track should contain the gamma ray and casing collar log. The right hand tracks should contain the acoustic amplitude and travel-time curves in track 2 and the acoustic VDL in track 3. CETs include a graphical depiction of the cemented area of the well bore in track 3. If available, a shop calibration record should be attached. The surface pressure under which the log was run should be noted on the log form.

   In new wells, the cement should be allowed to set for at least 72 hours before logging.

4 Procedures for Recording the Cement Bond Log (CBL) or Logs made Using Cement Evaluation Tool (CET)

1. Centralize the tool. Be sure that the part of the hole to be logged is liquid filled. Calibrate the tool;
2. Record the amplitude and travel time measured by the short- spaced receiver in the fixed gate mode;
3. Run the CBL over the entire cemented length of the casing and through at least two joints of the uncemented portion, if any;
4. Check the travel time. If intervals are found having four microseconds less than travel time in free pipe, check the tool centralization and relog the well if necessary;
5. If the log indicates poor bond, the log can be run under pressure to eliminate any micro-annulus effect. The pressure used should be minimal to prevent enlargement of the micro-annulus. Often reproduction of the pressure used during cement setting is sufficient. For Class I wells (although cement logs are occasionally required at Class I sites, they are not a demonstration of part 2 of MI) pressurizing to the normal annulus pressure may be sufficient to eliminate the micro- annulus; and
6. Check the tool calibration. If significant tool drift has occurred, relog the well with the back-up tool.

5 Interpretation

1. Interpretation of records

   Most cement records document the volume of cement emplaced between the casing and the well bore. For demonstrations of MI for Class II wells, the records must indicate that cement was emplaced at locations which will prevent upward movement from the injection zone. For demonstrations of MI for Class III wells, the records must indicate that cement was emplaced at locations which will prevent upward movement from the injection zone and into or between USDWs.
2. Interpretation of CBLs

   The log is examined to identify the location of cement along the casing. Only a few feet of sound cement are required to prevent flow along the well bore, but in most cases making judgements about the adequacy of a few feet of cement will not be required because there will be more than 10 feet of cement indicated to be sound, or there will be no indications of sound cement in critical areas. If an initial cement bond log does not indicate the presence of cement, often a second log will be run with pressure on the casing. This may show cement while the earlier log does not. In this case, a microannulus has developed due to past expansion of the casing while it was pressurized during operations or testing. It is sometimes necessary to pressurize the casing above the highest pressure to which it has been subjected. The presence of a microannulus does not indicate a lack of part 2 of MI. Microannuli are very minute. By definition, while they may allow the passage of gas but not liquids.

If there is a question about the adequacy of cement to prevent the movement of liquids into USDWs, then one of the previously described logs, pre-approved by Region 5, should be utilized to demonstrate MI.

ATTACHMENT 10
RADIOACTIVE TRACER SURVEYS FOR
THE INTEGRITY OF CEMENT AT THE TOP OF THE INJECTION INTERVAL

1 Basis

The basis of the use of the RTS for confirming the integrity of the cement at the top of the injection interval is identical to that of demonstrating part 2 of MI. In fact, if there are no aquifers above the injection interval from which the waters might degrade any USDW, the demonstration of cement integrity becomes a demonstration of part 2 of MI.

2 Advantages and Disadvantages

This test is required annually for Class I wells which are used to inject hazardous waste; there is no alternative test. The logs used to demonstrate part 2 of MI may also make a similar demonstration, but such a demonstration cannot be substituted for the RTS for this purpose. Because there is no alternative, and the advantages and disadvantages of the log have been previously listed in Attachment 8, they are not listed here.

3 Equipment and Forms

These are identical to the equipment and forms listed in Attachment 3 for the RTS.

4 Procedures

The procedures for using the RTS to confirm the integrity of cement are identical to those used for the demonstration of part 2 of MI.

5 Interpretation

The interpretation of the RTS used for confirming the integrity of cement is similar to that for demonstrating part 2. If any upward movement is observed, it becomes critical to determine the exact amount of upward movement. The upper limits of upward movement are recorded and compared from year to year to check for any increase.

Appendix E: PFOT Procedures

EPA Region 9
UIC PRESSURE FALLOFF REQUIREMENTS

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

Third Revision

August 8, 2002

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https://archive.epa.gov/region9/water/archive/web/pdf/falloff-testing-guidlines.pdf

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REQUIREMENTS

UIC PRESSURE FALLOFF TESTING GUIDELINE
Third Revision
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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 **<u>tests</u>** must be conducted annually. The time **<u>interval</u>** 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 **<u>report</u>** 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 **<u>report</u>** 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 **<u>falloff test report</u>** 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 <u>in addition</u> 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 <u>all</u> 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

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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

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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

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- 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 <u>at the wellhead</u> 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

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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.

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APPENDIX

Pressure Gauge Usage and Selection

Usage

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

Selection

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

Test Design

General Operational Considerations

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

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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

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- 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:

   $$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot g_c}}$$

   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:

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

   b. Falloff period:

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

   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

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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.

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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)

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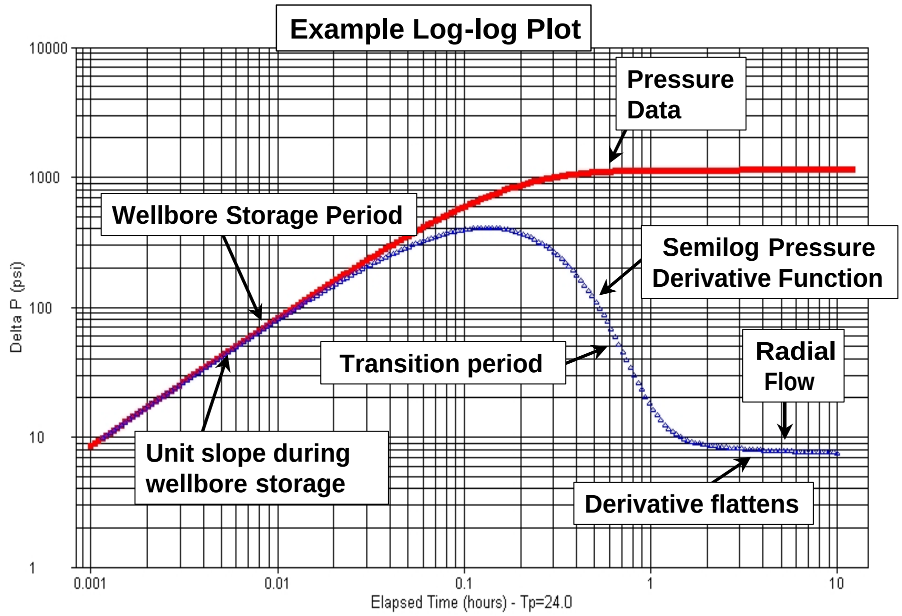
Log-log Diagnostic Plot

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.

- **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

- **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

- **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

- **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

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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

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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.

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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.

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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

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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

- The radius of investigation, r_i, is the distance the pressure transient has moved into a formation following a rate change in a well.

- 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).

- 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.

  - 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

- The effective wellbore radius relates the wellbore radius and skin factor to show the effects of skin on wellbore size and consequently, injectivity.

  - The effective wellbore radius is calculated from the following:

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

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

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Reservoir Injection Pressure Corrected for Skin Effects

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

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

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

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

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

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

Determination of the Appropriate Fluid Viscosity

X If the wastestream and formation fluid have similar viscosities, this process is not necessary.

X This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/\mu)_w$, and formation fluid, $(k/\mu)_f$. Depending on when the test reaches radial flow, these cases with extreme mobility differences could cause the derivative curve to change and level to another value. Eliminating alternative geologic causes, such as a sealing fault, multiple layers, dual porosity, etc., leads to the interpretation that this change may represent the boundary of the two fluid banks.

X First assume that the pressure transients were propagating through the formation fluid during the radial flow portion of the test, and then verify if this assumption is correct. This is generally a good strategy except for a few facilities with exceptionally long injection histories, and consequently, large waste plumes. The time for the pressure transient to exit the waste front is calculated. This time is then identified on both the log-log and semilog plots. The radial flow period is then compared to this time.

X The radial distance to the waste front can then be estimated volumetrically using the following equation:

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

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

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

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

Use of Computer Software

X To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.

X All data should be submitted on a CD-ROM with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the CD, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

X After analyzing any test, always look at the results to see if they "make sense" based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.

X If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.

X Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data

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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.

- 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.

- 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.

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