TESTING AND MONITORING PLAN

40 CFR 146.90

SUTTER DECARBONIZATION PROJECT

1.0 Facility Information

Facility name: Sutter Energy Center
[redacted]

Facility contact: [redacted]

Well location: Robbins, Sutter County, CA
[redacted]

This Testing and Monitoring Plan describes how [redacted] will monitor the Sutter Decarbonization Project 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 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.

2.0 Overall Strategy and Approach for Testing and Monitoring

This project proposes development of three lateral CO_2 injection wells in Sutter County, California. Figure 1 provides a plan view of the Area of Review (AoR). The AoR and Corrective Action Plan discuss the technical basis for determination of the AoR and how monitoring data will be used to re-evaluate the AoR during the injection phases of the project [40 CFR 146.84 (e)]. Data from characterization of existing wells [redacted] in the proximity of the proposed site were used to develop the static earth model (SEM) and perform multi-phase flow modeling (See Narrative). The results of the modeling and simulations are the basis for determining the AoR and these were used to develop the Testing and Monitoring Plan. An additional stratigraphic test well is planned to the south of the proposed injectors (CarbonSAFE Phase II). The AoR as well as the Testing and Monitoring Plan will be re-evaluated upon completion and testing of this well if new data obtained from the wells significantly change model predictions and the delineated AoR. This would also trigger development of a modified Testing and Monitoring Plan. Furthermore, additional data from drilling and testing of the injection wells may further trigger AoR re-evaluation and modifications to the Testing and Monitoring Plan. All such modifications will be made in consultation with and approval of the UIC Program Director.

The storage reservoir, Starkey Clean Sand, is approximately [redacted] at the project site based on characterization work and the static model. The project involves directionally drilling the wells targeting a porous and permeable unit within the lower third of the formation for injection of CO_2. The unit shows a coarsening-upward channel facies in a progradational setting. The primary Confining Zone for the storage complex is the Capay Shale Formation that is more than [redacted] within the AoR and should serve as a barrier to upward fluid migration. This also acts as the last sealing unit before the shallower USDW formations. Finally, Winters Formation below the Starkey massive sand, also referred to regionally as the "Delta Shale", acts as the lower confining seal below the injection zone. [redacted] These phased step-outs in monitoring will allow [redacted] to assess the movement of the pressure front as well as validate and update the dynamic reservoir model for the injection site.

[redacted]

Figure 1: Sutter Decarbonization Project delineated Area of Review (black). Various injection and monitoring wells as proposed are identified.

Up to [redacted] legacy oil/ gas wells have been identified as potential leakage risks and they may potentially require remediation as identified in the Corrective Action Plan. The Testing and Monitoring Plan has been developed to identify and reduce risks associated with CO_2 injection into the subsurface. Goals of the monitoring strategy include:

1. Meet the regulatory requirements of 40 CFR 146.90.
2. Protect underground sources of drinking water (USDW).

3. Ensure that each injection well is operating as planned.
4. Ensure that each injection well is maintained as planned.
5. Provide data to validate and calibrate the geological and dynamic models used to predict the distribution of CO_2 within the injection zone.
6. Support AoR re-evaluations over the course of the project.

The Testing and Monitoring Plan will utilize direct and indirect monitoring technologies that will monitor:

1. Injectate composition to demonstrate that it is consistent with the permit 40 CFR 146.90(a)
2. Corrosion of well materials and components [40 CFR 146.90(c)]
3. Determine whether CO_2 or brine has migrated above the Confining Zone, ACZ [40 CFR 146.90(d)]
4. USDW groundwater quality [40 CFR 146.95(f)(3)(i)]
5. Well integrity over the injection phase of the project [40 CFR 146.89(c) and 146.90]
6. Near well-bore environment using pressure falloff testing [40 CFR 146.90(f)]
7. Development of the CO_2 plume and pressure front in the storage formation over time [40 CFR 146.90(g)]

Injection operations will be monitored using a range of techniques and methods as required by 40 CFR 146.88(e) and 146.90(b). Injection operations are discussed in more detail in Narrative Section. Continuous recording devices will monitor wellhead injection pressure, temperature, and flow rate [40 CFR 146.90 (b)]. A flow meter (Coriolis or orifice) will be installed on the injection line at surface.

The annular pressure between the tubing and the injection casing strings and the annular fluid volumes will be monitored on a continuous basis [40 CFR 146.90 (b)]. This data will be linked to operational control to record the operations data, control injection rates, or initiate system shutdown, if needed. The operator can also use the system to adjust the volume of annular fluid, and thereby pressure, within the annular space to meet the operational and regulatory objectives. Pressure and temperature will be measured continuously using pressure gauges to establish a wellhead-to-packer pressure correlation. This correlation can be used to calculate the injection pressure at the reservoir (perforated interval) at any time using the wellhead and downhole pressure data. The reservoir pressures and temperatures will also be used to calculate the injection volumes, which will be used to update the computational models at regular intervals throughout the injection phase of the project (AoR and Corrective Action Plan).

Pre-operational logging and testing (See Narrative) will establish baseline mechanical integrity of the injection wells. External mechanical integrity will be monitored continuously using distributed temperature sensors (DTS) mounted to the exterior of the injection well casing and cemented into place. External mechanical integrity will be confirmed through annual logging and compared back to baseline logging data to identify deflections which could indicate fluid flow behind the casing [40 CFR 146.90 (e)]. Annual testing will include temperature logging (DTS and/ or wireline), oxygen activation logging, or noise logging for MIT with emphasis on evaluation of distributed temperature data from DTS.

Well installations within the target injection zone include [redacted] and [redacted] monitoring wells to start with. Additional monitoring wells will be added under a phased approach. Monitoring wells will be used to evaluate the plume and pressure front development in the injection zone, and to ensure containment and protection of USDWs. The injection wells and IZM wells will be used for wireline logging and will be equipped with gauges and instrumentation to measure pressure (downhole gauge) and temperature (DTS & downhole gauge). These wells will provide DTS data along the length of the well from above the perforated interval to the surface. The IZM wells will be utilized for fluid sampling (fluid sampling will be discontinued once there is CO_2 breakthrough at the well in question). ACZ monitoring wells will be used to monitor the lowermost USDW formations above the Capay seal. These wells will be used for fluid sampling and will be equipped with pressure and temperature gauges as well.

A summary of the monitoring well type and well ID is shown in Table 1. Proposed well locations are shown in Figure 1.

Table 1. Sutter Decarbonization Project well summary

[redacted]

Note 1: Additional IZM wells will be added in a phased approach.

All monitoring locations are either on [redacted] or partner properties or will be accessible through property access agreements with the necessary landowners. Additional monitoring, including annular pressure monitoring for the injection wells and corrosion monitoring, are discussed in detail as part of this plan.

[redacted] has been operating in Sutter County for more than 20 years with proven ability to work with local landowners and public entities to obtain access to surface and subsurface areas for activities related to the project. Consequently, [redacted] can obtain access for monitoring, and corrective actions (if they are necessary) in the future. The OWNER may acquire, by lease or purchase, additional land parcel areas and surface entry rights for the injection, monitoring, and surface and sub-surface infrastructure. Monitoring well locations could change but only to the extent that they retain their monitoring intent as described in the Testing and Monitoring Plan (QASP). Monitoring locations will also consider access routes that minimize property damage, crop loss, and property owner inconvenience. And to assure safe access to each location.

The Testing and Monitoring Plan will be adaptive over time in that the plan can be adjusted to respond:

1. As project risks evolve over the course of the project.
2. If significant differences between the monitoring data and dynamic simulation predictions are identified.
3. If monitoring indicates anomalous results related to well integrity or the loss of containment.

Table 2 presents the general schedule and spatial extent for the monitoring activities in the baseline and injection phases of the project based on the current understanding of the site. The monitoring program will follow the Testing and Monitoring plan to establish that CO_2 injection is occurring in a stable and predictable manner. If, however, anomalous results are identified in the monitoring data, changes to the monitoring schedule or methods may be required. Changes to the Testing and Monitoring Plan will be made in consultation with the UIC Program Director [40 CFR 146.90 (j)].

Table 2. Testing and monitoring activities summary for the Sutter Decarbonization Project.

[redacted]

[redacted]

Note 1: In-zone fluid sampling will be discontinued once CO_2 breakthrough occurs at the IZM well.
Note 2: Test frequency for isotope analysis depends on the frequency of associated fluid sampling program.
Note 3: Based on observed conditions in the repeat survey, time-lapse 2D surveys may be substituted as agreed with the UIC Program Director.
Note 4: Baseline passive seismic monitoring survey will be continuous post deployment.
Note 5: Soil gas monitoring program will be added to the testing and monitoring program based on new information from stratigraphic well and updated AoR.

Sampling frequencies during the injection period, for the Sutter Decarbonization Project Testing and Monitoring Plan, are defined as follows:

1. Quarterly sampling and testing will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection and every 3 months thereafter, unless otherwise noted.
2. Semi-annual sampling will take place by the following dates each year: 6 months after the date of authorization of injection and 12 months after the date of authorization of injection and every 6 months thereafter, unless otherwise noted.
3. Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year and every year thereafter, unless otherwise noted. Annual logging will take place up to 45 days before the anniversary date of authorization of injection each year and every year thereafter, unless otherwise noted.

2.1 Quality assurance procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the QASP plan document.

2.2 Reporting procedures

[redacted] will report the results of all testing and monitoring activities to EPA in compliance with the requirements under 40 CFR 146.91.

3.0 Carbon Dioxide Stream Analysis

Pre-injection (baseline) samples will be collected and analyzed to demonstrate that the CO_2 stream and as required by 40 CFR 146.82(a)(7), (9), (10), and 146.88, meets permit requirements. [redacted] 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).

The detection of carbon isotopes ($\delta^{13}C$) in the injected CO_2 is useful in tracing the movement of CO_2 in the injection reservoir. The $\delta^{13}C$ composition of CO_2 in the gas samples is dependent on the source of CO_2 and isotope analysis will be used as a way of attributing observed CO_2 and its migration within the AoR.

3.1 Sampling location and frequency

CO_2 stream sampling will be immediately downstream of the injection flow meter upstream of the injector wellhead. A baseline sample will be collected and analyzed prior to the start of injection. Routine sampling will take place quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection. Sampling the stream on a quarterly basis should be sufficient to yield data representative of the CO_2 injection stream characteristics in the context of this project. If any known changes to the CO_2 stream occur, sampling protocol will be adequately modified with approval from UIC Program Director. [redacted] will follow a quarterly data review process where the observed compositions will be compared against the baseline collected at the start of injection period.

3.2 Analytical parameters

[redacted] will analyze the CO_2 for the constituents identified in Table 3 using the methods listed. This list was developed based on the currently known chemical characteristics of the CO_2 stream. Additional constituents may be included if there are known changes to the stream composition. The UIC Project Director will be notified 60 days in advance of any such changes.

Table 3. Summary of analytical parameters for CO_2 stream.

[redacted]

Note 1: An equivalent method may be employed with the prior approval of UIC Program Director. GC: Gas Chromatography, MS: Mass Spectroscopy, PID: Photoionization Detector.

If at any time this continuous monitoring reveals a substantive change from baseline levels for the CO_2 stream process [redacted] troubleshooting will begin to determine the root cause of the CO_2 quality deviation. If required, CO_2 will be diverted to atmosphere and injection activities will be paused.

3.3 Sampling methods

A sampling station will be used to draw representative samples into a container that will be sealed and sent to the authorized laboratory for analysis. Samples containers will be tagged with unique sample identification number and sampling date.

3.4 Laboratory to be used/chain of custody and analysis procedures

Samples will be analyzed by an approved laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photoionization techniques. The sample chain-of-custody procedures described in Section B.3.e of the QASP will be employed. The sample integrity will be documented through maintenance of a sampling record and documented Chain of Custody. The laboratory will provide, upon request, documentation of instrument calibration. The laboratory report will include the analytical results as well as reporting detection limits established for each method.

4.0 Continuous Recording of Operational Parameters

[redacted] will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required at 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

4.1 Monitoring location and frequency

[redacted] will perform the activities identified in Table 4 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table and are valid for both active injection periods as well as during shut-in periods.

Table 4. Sampling devices, locations, and frequencies for continuous monitoring.

[redacted]

Note 1: 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 1 minute and save this value in memory.
Note 2: Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). Following the same example above, the data from the injection pressure transducer might be recorded to a hard drive once every 5 minutes. This can be an average of the sampled readings over the previous 5-minute recording interval, or the maximum (or minimum, as appropriate) value identified over that recording interval.

Above-ground pressure and temperature instruments shall be calibrated over the full operational range at least annually using ANSI or other recognized standards. In lieu of removing the injection tubing, downhole gauges will demonstrate accuracy by using a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Pressure transducers shall have a drift stability of less than 2 pounds per square inch (psi) over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least once per minute. Temperature sensors will be accurate to within one degree Celsius. DTS sampling rate will be at least once every 2 minutes.

Flow will be monitored with a mass flowmeter at the wellhead. The flow meter will be either an orifice meter with flow computer or a Coriolis meter. The meter will be calibrated using accepted standards and be accurate to within ± 0.1 percent. The meter will be calibrated for the entire expected range of flow rates.

4.2 Monitoring details

[redacted] will monitor injection operations using a process control system, as presented below. For remote instrumentation installed at the wellhead, data will be transmitted back to the process control system via a secure data transmission system that allows for continuous monitoring and alarming to the operator. Loss of communication with the remote monitoring equipment will be alarmed to the operator as well.

The Surface Facility Equipment & Control System will limit maximum flow to approximately [redacted], and/or limit the well head pressure to about [redacted] for injection wells [redacted], respectively, which corresponds to the regulatory requirement to not exceed [redacted] of the injection zone's fracture pressure (Well Construction Plan). All injection operations will be continuously monitored and controlled by the [redacted] operations staff using the distributed process control system. This system will continuously monitor, control, record, and will alarm and shutdown if specified control parameters exceed their normal operating range. More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate will have continuous electronic monitoring with signals transmitted back to a master control system. [redacted] supervisors and operators will have the capability to monitor the status of the entire system from the distributed control center.

4.2 Calculation of injection volumes

Flow rate is measured on a mass basis (kg/hr). The downhole pressure and temperature data will be used to perform the injectate density calculation. The volume of carbon dioxide injected will be calculated from the mass flow rate obtained from the mass flow meter installed on the injection line. The mass flow rate will be divided by density and multiplied by injection time to determine the volume injected. Density will be calculated using the correlation developed by Ouyang (2011). The correlation uses the temperature and pressure data collected to determine the carbon dioxide density. The density correlation is given by:

$$\rho = A_0 + A_1 \times P + A_2 \times P^2 + A_3 \times P^3 + A_4 \times P^4$$

where ρ is the density, P is the pressure in psi, and A are coefficients determined by the equations:

$$A_i = b_{i0} + b_{i1} \times T + b_{i2} \times T^2 + b_{i3} \times T^3 + b_{i4} \times T^4$$

T is the temperature in degrees Celsius and b coefficients are presented in Table 3 and Table 4 below.

Table 5. Injection volume calculation b coefficients, pressure [redacted].

[redacted]

[redacted]

Table 6. Injection volume calculation b coefficients, pressure [redacted].

[redacted]

The final volume basis will be calculated as follows:

$$Volume\ basis\ (m^3/hr) = Mass\ basis\ (kg/hr)/density(kg/m^3)$$

4.3 Continuous monitoring of annular pressure

[redacted] will use the procedures below to monitor annular pressure. This procedure will be used to limit any unpermitted fluid movement into or out of the annulus:

1. The annulus between the tubing and the long string of casing will be filled with brine. The brine will have a specific gravity of [redacted] and a density of [redacted] The hydrostatic gradient is [redacted] The brine will contain a corrosion inhibitor. The final values are subject to change based upon actual conditions at the injection site.
2. The surface annulus pressure will be kept at a minimum of [redacted] during injection. The final values are subject to change based upon actual conditions at the injection site.
3. During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least [redacted] between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer set at [redacted]. The final values are subject to change based upon actual conditions at the injection site including depth of drilling and packer setting depths.
4. The pressure within the annular space, over the interval above the packer to the confining layer, will be always greater than the pressure of the injection zone formation.
5. The pressure in the annular space directly above the packer will be maintained at least [redacted] higher than the adjacent tubing pressure during injection.

The annular monitoring system would broadly consist of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using either compressed nitrogen or CO_2. The annulus pressure will be maintained between approximately [redacted] and monitored by control system gauges. The annulus head tank pressure will be controlled by pressure regulators–one set of regulators to maintain pressure above [redacted] by adding compressed nitrogen or CO_2 and the other to relieve pressure above [redacted] by venting gas off the annulus head tank. During workovers, the annulus pressure can go below [redacted]. The final pressure range values are subject to change based upon actual conditions at the injection site including depth of drilling and packer setting depths.

Any changes to the composition of annular fluid or pressure limits will be reported to the UIC Program Director as appropriate. If system communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours or twice per shift for both wellhead surface pressure and annulus pressure and will record hard copies of the data until communication is restored. Average annular pressure and annulus tank fluid level will be recorded daily. The volume of fluid added or removed from the system will be recorded.

4.4 Casing-tubing pressure monitoring

During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time by [redacted]. Surface pressure of the casing-tubing annulus is anticipated to be from [redacted]. As detailed in the Emergency and Remedial Response Plan, significant changes in the casing-tubing annular pressure attributed to well mechanical integrity will be notified and investigated appropriately.

5.0 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), [redacted] 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. [redacted] will monitor corrosion using corrosion coupon method and collect samples according to the description below.

5.1 Monitoring location and frequency

For the first two years, corrosion monitoring will occur quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection. Monitoring frequency will be semi-annual thereafter. There are no plans to monitor the coupons based on injection volumes. If the coupons show evidence of corrosion, the injection well can be assessed for signs of corrosion using well logging techniques such as multi-finger caliper logging or an ultrasonic casing evaluation tool.

While not anticipated, additional monitoring location(s) may be required if other sources of CO_2 are delivered to the injection wells via additional pipeline(s). The Director will be notified 60 days in advance of any such changes. The sampling and analytical program will be modified as needed to meet the requirements of 40 CFR 146.90(c).

5.2 Sample description

Samples of material used in the construction of the compression equipment, pipeline, and injection well, which come into contact with the CO_2 stream, will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. Samples will consist of those items listed in Table 7. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 7. List of equipment with material of construction.

[redacted]

5.3 Monitoring details

5.3.1 Sample exposure

Each sample will be attached to an individual holder and then inserted in a flow-through pipe arrangement (Figure 3). The corrosion monitoring system will be located downstream of all process compression/ dehydration/ pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high-pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore, this location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.

5.3.2 Sample handling and monitoring

The coupons will be handled and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). Upon removal, coupons will be inspected visually for evidence of corrosion (e.g., pitting). The coupons will be photographed, visually inspected with a minimum of 10× power, dimensionally measured (to within 0.0001 inch), and weighed (to within 0.0001 gm). Corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

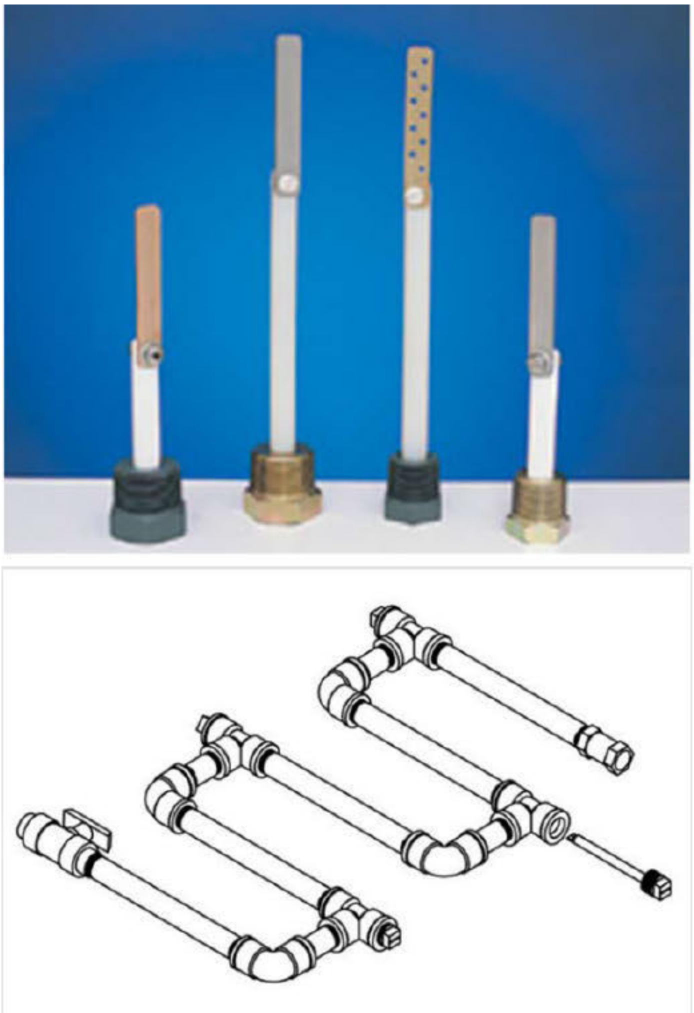

Figure 2 Fixed coupon holders for strip coupons (top) and Flow through coupon rack arrangement schematic (bottom).

5.4 Casing, tubing, and Cement integrity inspection

Casing and tubing will also be evaluated periodically for corrosion throughout the life of the injection well by running casing inspection (wireline) logs. The frequency of running these tubing and casing inspection logs will be determined based on site-specific parameters and well performance during the first two years of operation. Wireline tools are lowered into the well to measure properties of the well tubulars that indicate corrosion. Mechanical, electromagnetic, and/or ultrasonic tools will be used to monitor well corrosion (Table 8). These tools, or comparable tools from alternate vendors, will be used to monitor the condition of well tubing and casing.

Table 8. Examples of wireline tools for monitoring corrosion of casing and tubing.

[redacted]

[redacted]

Note 1: Schlumberger Ltd.
Note 2: Baker Hughes, Inc.

Mechanical casing evaluation tools, referred to as calipers, have multiple “fingers” that measure the inner diameter of the tubular as the tool is raised or lowered through the well. Modern-day calipers have several fingers and are capable of recording information measured by each finger so that the data can be used to produce highly detailed 3D images of the well. An example of a standard caliper tool is Schlumberger’s Multifinger Imaging Tool. This tool is available in multiple sizes to accommodate various sizes of well tubing and casing.
Ultrasonic tools are capable of measuring wall thickness in addition to the inner diameter (radius) of the well tubular. Consequently, these tools can also provide information about the outer surface of the casing or tubing. Examples of ultrasonic tools include Schlumberger’s Ultrasonic Casing Imager (UCI) and Ultrasonic Imager (USI). The USI can be used for cement evaluation as well.
Electromagnetic tools, such as Baker Hughes’ High-Resolution Vertilog, can distinguish between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated. These tools can provide mapped (circumferential) images with high resolution such that pitting depths, due to corrosion, can often be accurately measured.
Mechanical caliper tools are excellent casing/tubing evaluation tools for internal macro-scale features of the casing/tubing string. Ultrasonic tools, such as the USI, can further refine the scale of feature detection and can evaluate cement condition. However, electromagnetic tools offer the most sensitive means for casing/tubing corrosion detection. When conducting casing inspection logging, both an ultrasonic and an electromagnetic tool will be run to assess casing corrosion conditions (the ultrasonic tool will also be run to provide information on cement corrosion).

6.0 Above Confining Zone Monitoring

[redacted] 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).

The groundwater monitoring plan focuses on the following zones:

1. Laguna Formation, which is the source of local drinking water.
2. Lowermost USDW (LUSDW) Formation – directly above the confining zone.

6.1 Monitoring location and frequency

[redacted] ACZ monitoring wells will be used to monitor the LUSDW, the aquifer immediately above the confining layer. The purpose is to monitor whether there is CO_2 or brine migration past the Capay confining layer of the storage formation. The wells will be utilized for pressure and temperature monitoring as well as periodic fluid sampling. If monitoring data indicates that CO_2 has migrated out of the primary storage formation, it will trigger external well integrity testing of the injection well and the deep IZM wells [redacted]. It may also trigger an emergency response action described in the Emergency and Remedial Response Plan.

[redacted]

Figure 3. Location of water wells and existing oil & gas wells within AoR.

To meet the requirements at 40 CFR 146.95(f)(3)(i), [redacted] will also monitor groundwater quality, geochemical changes, and pressure in the LUSDW. The USDW monitoring program will meet the requirements of 40 CFR 146.90 (d) and will include baseline groundwater samples to characterize variations in water quality within the AoR prior to the start of CO_2 injection. Once injection phase of the project begins, the analytical results will be compared to the baseline results for indication of CO_2 or brine migration into the USDW. If indications of CO_2 or brine are found in the USDW, it will trigger the emergency response actions found in the Emergency and Remedial Response Plan.

Pulsed neutron logging will be the standard indirect monitoring technique used in these wells. This log detects leaks by measuring changes in the capture cross-section of the fluids and gasses in the pore space of the rock using a wireline tool that emits neutrons which are slowed to a thermal velocity through elastic and inelastic collisions with the nuclei of the environment's elements and ultimately captured. These interactions are sensitive to fluid type and saturation changes in the formation and in the casing-formation annulus. Therefore, pulsed neutron measurements can be used to monitor the formation fluids as well as identify mechanical integrity problems. Figure 4 shows the project area and the location of proposed ACZ monitoring wells and planned deep monitoring wells. In addition, existing water wells will be identified and used for routine groundwater monitoring with final wells TBD based on site conditions and local access. Figure 4 highlights the available water wells within the AoR.

Table 9 and Table 10 show the planned monitoring methods, locations, and frequencies for groundwater quality monitoring above the confining zone. In addition, [redacted] will also monitor the injection zone (Starkey Clean Sand) to track the CO_2 plume and pressure front as described under "Carbon Dioxide Plume and Pressure Front Tracking". Table 11 identifies the sampling and recording frequencies of various pressure and temperature transducers associated with the injection and monitoring wells.

[redacted]

Note 2: Quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.
Note 3: Semi-annual sampling will be performed each year by: 6 months after the date of authorization of injection and 12 months after the date of authorization of injection.
Note 4: Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.
Note 5: Continuous monitoring is described in Table 4 of this plan.
Note 6: Additional monitoring wells will be added in a phased approach.

[redacted]

Note 1: Baseline sampling and analysis will be completed before injection is authorized.
Note 2: Logging will take place up to 45 days before the anniversary date of authorization of injection every year or will be alternatively scheduled with the prior approval of the UIC Program Director.

[redacted]

example, a recording device might sample a pressure transducer monitoring injection pressure once every 1 minute and save this value in memory.
Note 2: Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). Following the same example above, the data from the injection pressure transducer might be recorded to a hard drive once every 5 minutes. This can be an average of the sampled readings over the previous 5-minute recording interval, or the maximum (or minimum, as appropriate) value identified over that recording interval.

Note 3: DTS sampling frequency varies, and minimum specifications are identified in Table 4.

6.2 Analytical parameters

Table 12 identifies the parameters to be monitored and the analytical methods [redacted] will employ for ground water samples collected from ACZ monitoring wells.

Table 12. ACZ summary of analytical and field parameters for ground water samples.

[redacted]

Additional above injection zone monitoring locations will be added to the monitoring program depending on the injection behavior and reservoir response during the first two years of injection and with approval of UIC Program Director.

6.2.1 Sampling methods

Sampling will be performed as described in Section B.2 of the QASP; this section of the QASP describes the groundwater sampling methods to be employed, including sampling SOPs (Section B.2.a/b), and sample preservation (Section B.2.g).

6.2.2 Laboratory to be used/chain of custody procedures

A qualified, commercial laboratory will be selected to provide analytical services in accordance with the methods and standards included here and in the QASP. Sample handling and custody will be performed as described in Section B.3 of the QASP. Quality control will be ensured using the methods described in Section B.5 of the QASP.

7.0 External Mechanical Integrity Testing

[redacted]. will conduct at least one of the tests presented in Table 13 periodically during the injection phase to verify external mechanical integrity 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 or alternatively scheduled with the prior approval of the UIC Program Director.

Table 13. MITs

[redacted]

7.2 Testing details

7.2.1 Temperature dogging

Temperature logging detects leaks by measuring temperature anomalies due to fluid movement adjacent to the well bore. Fluid leaks from the wellbore are typically a different temperature compared to native fluids. Temperature logs are run after the well has been shut-in long enough for temperature effects to dissipate, leaving a relatively simple temperature profile (typically ~36 hours). While the absolute gradients may differ due to injection history, the relative profiles should be consistent. If there has been a leak of fluid out of the well, there may be an anomalous heating or cooling effect as compared to the baseline or another log. Gradient variation due to lithologic changes are expected. Note that to be effective, temperature logging tools must have good thermal coupling to the borehole environment. Depending on phase of CO_2 in the well, this may require that the wellbore be displaced with water or brine and thermally stabilized prior to running the logging tools. Distributed fiber sensing or electric wireline deployed temperature measurement devices can be used and should be of sufficient resolution and sufficiently calibrated to detect changes.

7.2.2 Temperature logging using wireline

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to the Capay Formation. Bottom hole pressure data near the packer will also be provided. The following procedures, will be employed for temperature logging:

The well should be in a state of injection for at least 6 hours prior to commencing operations to cool injection zones.

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a temperature survey from the top of the confining formation (or higher) to the deepest point reachable in the injection well while injecting at a rate that allows for safe operations. Should operational constraints or safety concerns not allow for a logging pass while injecting, an acceptable, alternate plan is to stop injecting immediately prior to the first logging pass.
3. Stop injection, pull tool back to shallow depth, wait 1 hour.
4. Run a temperature survey over the same interval as step 2.
5. Pull tool back to shallow depth and wait 2 hours.
6. Run a temperature survey over the same interval as step 2.

7. Pull tool back to shallow depth and wait 2 hours.
8. Run a temperature survey over the same interval as step 2.
9. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the topmost section of the log, additional logging runs over ahigher interval will be required to find the top of migration.
10. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours,over the same interval as step 2.
11. Rig down the logging equipment.
12. Data interpretation involves comparing the time-lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity, i.e., tubingleak or movement of fluid behind the casing. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline profile. Fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. Any identified anomaly versus the baseline would indicate a test failure.

7.2.3 Temperature logging using DTS fiber optic line

The injection well will be equipped with a DTS fiber optic temperature monitoring system that can monitor the injection well's annular temperature along the length of the tubing string till the top of injection zone. The DTS line is used for real-time temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. This approach provides the simplest and preferred testing methodology for demonstration of mechanical integrity that will be employed for the well. However, in case of fiber failure, the temperature survey will have to be performed via a wireline or an alternate method will be employed. The procedure for using the DTS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphiczone.
2. During injection operation, record the temperature profile for 6 hours prior to shutting in the well.
3. Stop injection and record temperature profile for 6 hours.
4. Evaluate data to determine if additional cooling time is needed for interpretation.
5. Start injection and record temperature profile for 6 hours.
6. Data interpretation involves comparing the time-lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity, i.e., tubingleak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a pre-set frequency in real-time. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline profile. Any identified anomaly versus the baseline would indicate a test failure. This data can be continuously monitored to provide real-time MIT surveillance making this technology superior to wireline temperature logging.

7.2.4 Noise logging

A wireline tool is deployed which uses sensitive microphones to detect noise due to flow behind the casing. The sounds are recorded in different frequency ranges at ~100' depth intervals for approximately three to five minutes. If anomalies are detected the depth intervals are shortened to better locate the anomaly. When the level of sound is low, a linear scale is used for reporting noise logs, and, when there are intervals with higher sound, a logarithmic scale is used. Departures from baseline noise levels in the log indicate an anomaly. Ambient noise while injecting that produces a signal greater than 10 mV may indicate leakage or require further investigation.

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to the primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging will be carried out while injection is occurring. If ambient noise is greater than 10 mV, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a noise survey from the top of the confining formation (or higher) to the deepest point reachable in the injection well while injecting at a rate that allows for safe operations.
3. Make noise measurements at intervals of 100 ft to create a log on a coarse grid.
4. If anomalies are evident on the coarse log, construct a finer grid by making noisemeasurements at intervals of 20 ft within the coarse intervals containing high noise levels.
5. Make noise measurements at intervals of 10 ft through the first 50 ft above the injection interval and at intervals of 20 ft within the 100-ft intervals containing:

   The base of the lowermost bleed-off zone above the injection interval and

6. The base of the lowermost USDW.
7. Additional measurements may be made to pinpoint depths at which noise is produced.
8. Use a vertical scale of 1 or 2 inches per 100 ft.
9. Rig down the logging equipment.
10. Interpret the data as follows: Determine the base noise level in the well (dead well level).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. Any significant noise anomaly above the baseline indicates a test failure. Determine the extent of fluid movement; flow into or between USDWs indicates a lack of mechanical integrity; flow from the injection zone into or above the confining zone indicates a failure ofcontainment.

7.2.4 Oxygen activation (OA) logging

A wireline tool is deployed to activate oxygen by emitting high-energy neutrons from a neutron source. The activated isotopes emit gamma radiation which is measured by the wireline tool. Gamma-ray measurements are used to calculate water flow direction and velocity. If water flow outside of the casing is detected it could indicate the potential loss of external mechanical integrity.

To minimize false positives, a calibration will be performed, and measurements will be confirmed at several nearby depths and/or under a minimum of three varying injection rates.

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging will be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.
2. Conduct a baseline Gamma-Ray Log and casing collar locator log from the top of theinjection zone to the surface prior to taking the stationary readings with the OA tool. (Gamma-Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.
3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches andless than 13-3/8 inches.
4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.
5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a “novertical flow behind the casing” section of the well to ensure accurate, repeatable tool response and for measuring background counts.
6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 ft above theinjection interval so that turbulence does not affect the readings.
7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediatelyabove the injection interval.
8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confiningzone.
9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.
10. If flow is indicated by the OA log at a location, move uphole or downhole as necessary atno more than 50-foot intervals and take stationary readings to determine the area of fluid migration.
11. Interpret the data: Identification of differences in the activated water’s measured gammaray count-rate profile versus the expected count-rate profile for a static environment. Differences between the measured and expected may indicate flow in the annulus or behind the casing. Any identified differences versus the expected profile would indicate a test failure. The flow velocity is determined by measuring the time that the activated water passes a detector.

If there are unresolved temperature anomalies that cannot be explained, i.e., a potential mechanical integrity failure indication, additional logging may be necessary to show whether a failure is indeed occurring at the injection well. Depending on nature of the suspected CO_2 movement, specific tests will be selected with approval from the UIC Program Director.

7.3 Continuous monitoring and leak detection

Apart from permanently installed DTS fiberoptic temperature monitoring system, the injection well will have continuous annular pressure monitoring at the surface as well as injection pressure monitoring within the reservoir proximate to the location of the packer which can be additionally used to identify potential leaks.

The Standard Annulus Pressure Test (SAPT) can be used to demonstrate the absence of significant leaks in tubing, casing, and packer. This test is based on the principle that a pressure applied to fluids filling a sealed bore 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, and therefore, an allowance for small pressure changes is necessary. The test provides a quick indication of whether leaks, detectable by these means, exist. The interpretation and confirmation of the SAPT includes,

1. Comparison of the pressure change through the test period to 3% of the test pressure (0.03 × test pressure).
2. If the annulus test pressure changes by this amount or more (gain or loss), the well has failed to demonstrate mechanical integrity, and operation may constitute a violation of the UIC regulations.
3. If the annulus test pressure changes by less than 3 percent (gain or loss) over the test period, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1).

SAPT will be performed as required based on the well conditions and consistent with approved and accepted guidance and regulations [40 CFR 146.89 (a)]. For example, an APT will be performed following emergency shut-in due to a high or low annulus pressure alarms should the cause of the alarm not be easily correlated to a changes in temperature from DTS monitoring.

8.0 Pressure Falloff Testing

[redacted] will perform pressure falloff tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f). Pressure falloff tests are required to demonstrate integrity and to measure formation properties in the vicinity of the injection well (e.g., transmissivity).

Baseline pressure falloff tests (PFO) will be conducted as described in the Pre-Operational Testing Plan. During the injection phase of the project, a PFO will be conducted within 45 days of the 4-year anniversary of start of injection and within 45 days of the 4-year anniversary of previous pressure test subsequently. Alternatively, a PFO may be conducted in the interim periods if a significant degradation in injectivity is observed. A final PFO will also be conducted at the cessation of the injection into each of the injector wells.

The objective of the PFO testing is to periodically monitor for changes in the near well bore environment that would impact injectivity or cause injection pressures to increase (US EPA, 2013). The formation characteristics obtained through the PFO testing will be compared to the results from previous tests to identify changes over time, and they will be used to calibrate the computational models and carry out remedial operations deemed necessary. Finally, if an anomalous pressure drop occurs during the PFO, it may indicate an issue with well integrity (US EPA, 2013).

8.1 Testing location and frequency

Pressure falloff testing will be performed in each well:

1. As part of pre-operational testing (baseline)
2. During Injection Operations:
    - After every 4 years and,
    - At end of injection period

8.2 Testing details

A pressure falloff test has a period of injection followed by a period of no-injection or shut-in. Normal injection using the stream of CO_2 captured from the [redacted] facility will be used during the injection period preceding the shut-in portion of the falloff tests. Prior to the falloff test the normal injection rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased as necessary. Injection will have occurred for four years prior to this test, but there may have been injection interruptions due to operations or other testing activities. At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in injection period and subsequent analysis.

This data will be measured using a surface readout downhole gauge so a final decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition, or a pressure gauge will be conveyed via wire line (e-line).

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at ten second intervals or less for the entire test.

The time needed to reach radial flow during the injectivity, and falloff portions of the test will be pre-evaluated prior to the test. This is accomplished by reviewing previous well tests, if available, simulating the test using measured or estimated reservoir and well completion parameters, calculating the time to the beginning of radial flow using the empirically-based equations provided in EPA Region 9 falloff testing guideline (https://archive.epa.gov/region9/water-/archive/web/pdf/falloff-testing-guidlines.pdf), and allowing adequate time beyond the beginning of radial flow to observe radial flow so that a well-developed semi log 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. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because surface readout gauges will be used, the shut-in duration can be determined in real-time. Quantitative analysis of the measured data will be used to estimate formation characteristics, including transmissivity, permeability, and a skin factor. The measured parameters will be compared to those used in site computational modeling and AoR delineation.

A report containing the pressure falloff data and interpretation, including the reservoir ambient pressure, will be submitted within 90 days of the test. Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure falloff test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (0.5% accuracy across full range). Wellhead pressure gauge range will be at least 0-5,000 psi. Downhole gauge range will be at least 0-10,000 psi.

9.0 Carbon Dioxide Plume and Pressure Front Tracking

[redacted]

Figure 4. Predicted CO_2 plume front evolution after year [redacted] (left column), year [redacted] (middle column) and year [redacted] (right column).

[redacted] 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).

Evolution of the plume front in the injection zone, and through injection operations, is summarized in Figure 5; predicted pressure profiles of the bottom-hole pressure at the injection wells are shown in Figure 6.

[redacted]

Figure 5. Pressure profiles of injection wells during injection as well as PISC period.

Accurate AoR delineation will require accurately estimating critical pressures at the injection site. This requires solid understanding of initial pressures in the injection zone, and at the base of lowermost USDW zone. In addition, accurate estimates of brine densities are also necessary. The critical pressure will be simulated after the stratigraphic well (CarbonSAFE Phase II) is drilled and the well data becomes available. The updated simulation results will then be used to re-evaluate the AoR and update various plans, including the Testing and Monitoring Plan as necessary. In zone monitoring will be phased with five IZM wells proposed for the site. These include the [redacted] wells to start with and wells [redacted] and [redacted] wells to be added later. These wells are outlined in Figure 1. While the tentative locations for the three additional IZM wells is highlighted, the exact location will be evaluated after three years of injection operations, or after [redacted] of CO_2 injection, whichever occurs first. The location of any new monitoring wells will be based on data from the initial monitoring wells, stratigraphic test well (CarbonSAFE Phase II) and, if available, the results of the first time-lapse 3D seismic survey. As shown in Figure 7, the CO2 plume is not projected to extend beyond the first two planned IZM wells [redacted] through the first three years of injection. Figure 8, Figure 9 and Figure 10 show the modeled plume front at three year intervals till the end of the injection phase. The subsequent IZM well locations will be proposed to the UIC Program Director following completion of the updated dynamic model and installed with his concurrence.

[redacted]

Figure 6. Modeled CO_2 plume location after [redacted] years of injection.

[redacted]

Figure 7. Modeled CO_2 plume location after [redacted] years of injection.

[redacted]

Figure 8. Modeled CO_2 plume location after [redacted] years of injection.

[redacted]

Figure 9. Modeled CO_2 plume location at the end of injection phase.

Pressure and temperature sensors in the IZM wells will be used to measure pressure and temperature variations within the storage formation in the pre-operational, injection, and post-injection phases of the project [40 CFR 146.90 (g)]. Note that the subsequent IZM wells, if any, will begin continuous pressure and temperature monitoring upon their completion. The gauges will record the data that will be retrieved and reviewed monthly. Additional detail regarding the gauges is included in the QASP. The IZM wells also will be used to collect fluid samples from the storage formation to monitor for changes in the water chemistry over time and verify when the leading edge of the CO_2 plume reaches the IZM wells. Once there is CO_2 breakthrough, fluid sampling will be discontinued in that IZM well.

[redacted]

Figure 10. USGS Seismic Monitoring Stations in Proximity of the Project Site.

Indirect techniques will be used to monitor the development of the CO_2 plume and the associated pressure front through the injection and post injection project phases [40 CFR 146.90 (g)]. Time-lapse 3D surface seismic data will be used to qualitatively monitor the CO_2 plume distribution and calibrate the computational modeling results over time. The time-lapse 3D surface seismic data will also be used to verify CO_2 containment within the storage formation. In addition, passive seismic monitoring system will be designed and deployed to detect events over M1.0 within the AoR. These sensors will complement the USGS real time monitoring stations in general proximity of the Sutter Decarbonization Project Site (Figure 11). Passive seismic surveying is particularly useful in monitoring the overall plume extent as well as avoiding any potential reactivation of the Willows Fault system to the [redacted]t of the injection wells and an active seismicity area identified as Dunnigan Hills towards the [redacted] of the injection wells. The exact configuration and array design are TBD at this stage.

Pulsed neutron measurements can be used to monitor the formation fluids as well as identify mechanical integrity problems. The pulsed neutron Sigma (Σ) is the thermal neutron capture cross-section or the rate at which thermal neutrons are captured by the formation matrix and fluids. The capture cross-section can be used to detect fluid changes behind the casing over time to verify the well external mechanical integrity. Open hole wireline logs for lithologic definition and baseline pulsed neutron logs are key inputs to this type of monitoring.

Pulsed neutron (sigma mode)/RST logs will be acquired in the injection and IZM wells to identify the saturation of CO_2 close to the well bores and the stratigraphic intervals that may contain CO_2. This monitoring activity also will be used to examine for the presence of CO_2 above the confining zone as has been discussed previously in "Above Confining Zone Monitoring" section. The pressure and pulsed neutron log data will be used to calibrate the dynamic simulation during the injection and post-injection phases of the project.

9.1 Plume monitoring location and frequency

Table 14 presents the methods that [redacted] will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies [redacted] will employ. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 8. Quality assurance procedures for these methods are presented in B.5 of the QASP.

Table 14. Direct and indirect CO_2 plume monitoring activities.

[redacted]

Note 1: Baseline monitoring will be completed before injection is authorized.
Note 2: Annual monitoring will be performed up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.
Note 3: Logging surveys will take place up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.
Note 4: Seismic surveys will be performed in the 4th quarter before or the 1st quarter of the calendar year shown or alternatively scheduled with the prior approval of the UIC Program Director.
Note 5: Additional monitoring wells will be added in a phased approach.

Formation logging of the injection zone will take place annually during the injection phase within 45 days of the anniversary date of authorization of the injection. 3D seismic surveys will be conducted once after 4 years, and after 8 years from the anniversary date of authorization of the injection (Table 14). Based on observed conditions in the repeat survey, time-lapse 2D surveys may be substituted as agreed with the UIC Director. Additionally, more frequent seismic surveys may be conducted if significant deviations in the tracked plume are observed when compared to the baseline or updated dynamic modeling results. Finally, DTS fibers will be deployed in the IZM wells and used as a continuous tracking tool for plume front arrival detection and tracking at the monitoring locations.

9.2 Plume monitoring details

As summarized in Table 14, [redacted] will utilize a combination of direct and indirect methods to detect, track and monitor the CO_2 plume. Direct CO_2 plume monitoring method will involve downhole sampling, retrieval, and analysis of formation fluid samples (vendor TBD) at fixed-point location within every IZM well to monitor the absence or presence of the CO_2 within the injection reservoir (Starkey Clean Sand within the Starkey Storage Complex). The above-zone wells will be used to monitor formation fluids within the first permeable rock immediately overlying the caprock ("Above Confining Zone Monitoring" section). Fluid sampling will involve the use of slimline reservoir fluid samplers. The parameters to be analyzed as part of fluid sampling and analytical methods to be used are presented in Table 15.

[redacted] will utilize several indirect methods to monitor and track CO_2 plume development (summarized in Table 14). Indirect CO_2 plume monitoring techniques to be deployed are Pulse Neutron Capture/Reservoir Saturation Logging (PNC/RST Logging), and time lapse 3D/ 2D reflection seismic surveys. PNC wireline tools will be run to monitor CO_2 and brine saturations within formation of interest. A PNC/RST log will be run prior to injection to establish baseline conditions and will then be re-run every year during the injection phase. This data will compliment seismic data and confirm CO_2 containment within the reservoir. Please refer to Table 8 in section A.4 of the QASP for PNC/RST logging tool product specifications and quality control procedures. Time lapse 3D surface seismic monitoring will be used to map the lateral and vertical extent of the plume front and its evolution in time. Seismic modeling and inversion workflows will be used delineate the pressure and saturation anomalies within the area of interest.

Table 15. Summary of analytical and field parameters for fluid sampling in the injection zone.

[redacted]

9.3 Pressure-front monitoring location and frequency

Table 16 presents the methods that [redacted] will use to monitor the position of the pressure front, including the activities, locations, and frequencies [redacted] will employ. Quality assurance procedures for these methods are presented in A.4 of the QASP.

As summarized in Table 16, [redacted] will utilize direct monitoring of pressure and temperature to detect the CO_2 pressure front. This will involve the deployment of electronic downhole pressure-temperature (P/T) gauges (Quartz P/T gauge, vendor TBD) at fixed-point locations within every in-zone and above-zone monitoring well to monitor the absence or presence of the CO_2 within the injection reservoir and above the caprock (Capay Formation). In addition, injection wells will be monitored for pressure and temperature in the injection zone. IZM wells will be monitored for pressure and temperature in three zones: Sacramento Shale Formation just below the injection layer, top of the Starkey SS unit in the injection interval, and at the top of the Starkey Formation, i.e., just below the Capay seal unit. Measurements in these three zones allow for insights into the pressure propagation in 3 dimensions as well as a direct measurement of temperature for reference. The ACZ monitoring wells will measure pressure and temperature in the first permeable rock immediately overlying the caprock (LUSDW). Early detection of out-of-zone CO_2 and/or brine will be achieved using pressure and temperature measurements below the Capay Formation and based on quarterly fluid sampling discussed earlier. All downhole gauges will be comprised of a corrosion resistant chrome alloy and will continuously record formation pressure and temperature from fixed-point locations. Refer to Section A.4 of the QASP for P/T gauge product specifications and quality control procedures. Recording frequencies have already been identified earlier in Table 11 ("Above Confining Zone Monitoring" section).

9.4 Pressure-front monitoring details

[redacted] will directly monitor the presence of the elevated pressure front by deploying several electronic downhole pressure-temperature (P/T) gauges (Quartz P/T gauge with vendor TBD) within every completion interval within injection, IZM and ACZ monitoring wells to monitor the absence or presence of the CO_2 within the Starkey Storage Complex and other critical geological units. [redacted] may also deploy bottom-hole gauges comprised of similar materials within terminal depth locations of each well to monitor pressure conditions at the fixed-point interval. Table 16 highlights the direct pressure front monitoring methods which are planned as part of this monitoring plan.

Comparison of observed and simulated arrival responses (PNC/ Pressure-Temperature gauges) at the in-zone well locations will continue throughout the life of the project and will be used to calibrate and verify the dynamic reservoir model, while improving its predictive capability for assessing the long-term environmental impacts of any observed loss of CO_2 containment.

The phased five monitoring well network is sufficient to provide spatial and temporal resolution of the plume and pressure development within the multi-well CCS system to be operated by [redacted] under this project.

Table 16. Pressure-front monitoring activities.

[redacted]

[redacted]

Note 1: Additional monitoring wells will be added in a phased approach.

10.0 Soil Gas Monitoring/Other Testing and Monitoring

The up dip towards the Willow's Fault from the injection zone could cause a possible upward migration of the CO_2 plume. To verify the integrity of USDW on the upthrown side of the fault, [redacted] may carry out additional soil gas monitoring in this area with exact sampling locations and frequency TBD based on site conditions. Table 17 highlights the proposed soil gas monitoring plan.

Table 17. Additional soil gas monitoring plan.

[redacted]

11.0 References

1. U.S. Environmental Protection Agency, 2013. *Geologic Sequestration of Carbon Dioxide – Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance.*
2. Ouyang 2011. *New Correlations for Predicting the Density and Viscosity of Supercritical Carbon Dioxide Under Conditions Expected in Carbon Capture and Sequestration Operations.* The Open Petroleum Engineering Journal, 2011, 4, 13-21.