ATTACHMENT C: TESTING AND MONITORING PLAN
40 CFR 146.90
CTV II

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Version History

File Name	Version	Date	Description of Change
Att C – Testing & Monitoring plan	1	5/3/2022	Original submission for CTV II project
Att C – Testing & Monitoring plan V2	2	12/5/2022	Updated for expanded CTV II project
Att C – Testing & Monitoring plan V2.1	2.1	2/2/2023	Updated to address EPA request
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Facility Information

Facility Name: CTV II

Facility Contact: William Chessum/Technical Manager
(562) 999-8380/William.chessum@crc.com

Well Location(s): Union Island Gas Field, San Joaquin County, CA
37.868/-121.420

1. Introduction

This Testing and Monitoring Plan describes how Carbon TerraVault Holdings, LLC (CTV) will monitor the CTV II storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the wells are operating as planned, that the carbon dioxide (CO_2) plume and pressure front are moving as predicted, and that there is no endangerment to underground sources of drinking water (USDWs). In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting 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.

1.1 Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided as **Appendix 11**.

1.2 Reporting Procedures

CTV will report the results of all testing and monitoring activities to the U.S. Environmental Protection Agency (EPA) in compliance with the requirements under 40 CFR 146.91.

2. Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV 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). Samples will be collected and analyzed quarterly, starting three months after the start of injection and every three months thereafter.

CTV is evaluating several sources of CO_2 as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

2.1 Sampling Location and Frequency

CO_2 injectate samples will be taken at the transfer point from the source and between the final compression stage and the wellhead. Sampling will take place three months after the date of authorization of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

- Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source
- Facility or injector downtime is greater than 30 days

2.2 Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in **Table C-1** using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

2.3 Sampling Methods

CO_2 stream sampling will occur at the discharge of the last compressor upstream of the injector. A sampling station will be installed to facilitate the collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

2.4 Laboratory to be Used/Chain of Custody and Analysis Procedures

Samples will be sent to and analysis will be conducted by a state certified laboratory. The current plan is to use Eurofins TestAmerica (Eurofins), which is located at 880 Riverside Parkway in Sacramento, California. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in Table 3 of **Appendix 11**.

Eurofins has a chain of custody procedure that includes the following.

- Sample date

- Sample description
- Sample type
- Relinquished by and received by signature
- Sampler name
- Location information

3. Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor the following as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b):

- Injection pressure, rate, and volume
- The pressure on the annulus between the tubing and the long string casing
- The annulus fluid volume added
- The temperature of the CO_2 stream

3.1 Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in **Table C-2** 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.

Monitoring for the parameters except for annulus fluid volume will be continuous, with a 10-second sampling and 30-second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

3.2 Injection Rate and Pressure Monitoring

Injection pressure, temperature, and flow rate will be continuously monitored and recorded by the CTV Central Command Facility (CCF). The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure of 90 percent of the injection zone's fracture pressure. Pressure and temperature gauges will be calibrated as shown in Table 6 of **Appendix 11**. In the event of any unexpected pressure or temperature deviations, the system will deliver alarms to indicate that there is an issue, and CTV will take the appropriate steps as defined in the Injection Well Monitoring Equipment Failure section of **Attachment F: Emergency and Remedial Response Plan** (**Attachment F**) to ensure that the injector resumes operating within acceptable injection rate and pressure ranges.

3.3 Calculation of Injection Volumes

The volume of CO_2 injected into the Winters Formation will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Winters Formation will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 enhanced oil recovery (EOR) applications to accurately model and match CO_2 pressure-volume-temperature (PVT) properties over a wide range of temperatures and pressures.

3.4 Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive and incompressible aqueous packer fluid. The casing-tubing annulus for injection wells will be maintained on average with 100 pounds per square inch (psi) at surface, as stated in the injection well operating procedure documents (**Appendix 4**). Monitoring wells will be operated with 100 psi positive annular pressure at surface. Any decrease in pressure less than 100 psi or annular fluid level will be identified with the supervisory control and data acquisition (SCADA) alarming system.

Failure to maintain pressure consistently above 100 psi could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1,000 psi and cannot be explained by operational conditions.

4. Corrosion Monitoring [40 CFR 146.90(c)]

CTV will monitor well materials during the operation period for loss of mass, change in thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description in the following subsections.

4.1 Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors. The baseline mass of a corrosion coupon is recorded at installation. Subsequent measurements are relative to the baseline mass.

4.2 Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are exposed to CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in **Table C-3** will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For injector wells Sonol Securities 1-A, Sonol Securities 3, and Pool B2, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the corrosion-resistant alloy (CRA) tubing. These casing materials will be included in the corrosion coupon monitoring and are currently included in **Table C-3**. General construction materials for pipeline, tubing, and wellhead are shown in **Table C-3**. Construction materials will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

4.3 Sample Handling and Measurement

Upon collection, the coupons will be sent to a laboratory and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to EPA per 40 CFR 146.91 (a)(7). A detected corrosion rate of greater than 0.3 mil per year (mil/yr) will initiate consultation with EPA. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mil/yr. CTV will continually update the corrosion monitoring plan as data are acquired.

5. Above Confining Zone Monitoring

CTV 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). Monitoring above the confining zone will include the following:

- Undifferentiated non-marine: lowermost USDW aquifer
- Mokelumne River Formation: between the confining layer and USDW

5.1 Undifferentiated Non-Marine Monitoring

CTV will monitor the lowermost USDW in the undifferentiated non-marine sediments. Monitoring will include pressure, temperature, and fluid sampling. Leakage to the lowermost USDW would increase the aquifer pressure and change the composition of the formation water (increased CO_2 concentration). Based on having groundwater with total dissolved solids (TDS) concentrations less than 10,000 parts per million (ppm), the proposed monitoring zone is a USDW. However, the water supply wells in the AoR are completed at much shallower depths that are above the base of fresh water, which is at about 600 feet measured depth (MD). Monitoring of the lowermost USDW is more protective than monitoring the fresh water aquifers because impacts would occur in the lowermost USDW before the fresh water aquifers.

The locations of groundwater monitoring wells are often based on the local groundwater gradient. There are very few groundwater supply wells in this area because there is a plentiful supply of surface water. Therefore, groundwater gradient maps do not show any water level elevations in this area. Thus, groundwater gradients are not expected to be significant due to the lack of pumping. The locations of the monitoring well is planned to be centrally located above the plume. The monitoring well is located near the injection wells and potential conduits.

Additional groundwater monitoring wells will be drilled to assess and monitor the lowermost USDW if the following occurs:

- Mokelumne River Formation monitoring well indicates increased pressure due to CO_2 injection in Winters Formation.
- Undifferentiated Non-marine lowermost USDW aquifer pressure or composition changes due to Winters Formation CO_2 injection.

5.2 Mokelumne River Formation Monitoring

The Mokelumne River Formation zone between the confining zone and Upper Markley will dissipate any CO_2 injectate that could potentially migrate upward through the confining zone. The Mokelumne River Formation will be monitored continuously for pressure and temperature changes and quarterly via fluid sampling within a continuous sand. Leakage from the Winters Formation to the Mokelumne River Formation will increase the reservoir pressure and decrease the temperature of the Mokelumne River Formation. This is the first porous interval above the sequestration reservoir.

The Mokelumne River Formation is continuous across the AoR. As such, Sonol Securities 2 and Phillips Yamada Bros 1 (**Figure C-1**) will adequately monitor for pressure and temperature changes. Prior to injection, baseline water analysis will be acquired for the Mokelumne River Formation monitoring zone.

5.3 Monitoring Methods, Location, and Frequency

Table C-4 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone. **Figure C-1** shows the monitoring well locations with respect to the AoR.

5.4 Analytical Parameters

Table C-5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in Table 3 of **Appendix 11**.

5.5 Sampling Methods

Samples will be collected using the following procedures:

- Depth and elevation measurements for water level taken.

- Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
- Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
- Samples preserved and sent to lab as per chain of custody procedure.
- Closure of well.

5.6 Laboratory to be Used/Chain of Custody Procedures

Samples will be sent to and analysis conducted by a state certified laboratory. The current plan is to use Eurofins TestAmerica (Eurofins) at 880 Riverside Parkway in Sacramento, California. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in Table 3 of **Appendix 11**.

Eurofins has a chain of custody procedure that includes the following.

- Sample date
- Sample description
- Sample type
- Relinquished by and received by signature
- Sampler name
- Location information

5.7 Data Interpretation

Consistent with the EPA *Class VI Testing and Monitoring Guidance*, trends indicative of potential fluid leakage are listed below. If two or more of these trends (as compared to baseline data) are noted over a period of three or more sampling events CTV will initiate further coordination with EPA to assess the potential for fluid leakage above the confining zone.

- Changing TDS: An increasing TDS trend may indicate that native brines have migrated from the injection zone, or an intervening zone, into the monitored zone. A change in the overall TDS trend may indicate fluid exchange between adjacent formations.
- Changing signature of major cations and anions: A change in the signature of dissolved ground water constituents in the monitored zone as compared to that of the injection zone or confining zone may indicate leakage. The anion/cation signature may be evaluated through the construction and use of ion diagrams, including piper and stiff diagrams.
- Increasing CO_2 concentration: An increase in the concentration of dissolved CO_2 may indicate leakage of the dissolved-phase plume into the monitoring zone. Increasing CO_2 concentrations may also be observed due to other factors, including increasing groundwater

recharge. These other factors may be evaluated to ascertain if the observed increasing CO_2 concentrations are due to migration from the injection zone.

- Decreasing pH: A decreasing pH trend may indicate migration of carbonic acid and other fluids into the monitoring zone. Similar to increasing CO_2 concentrations, other factors may be evaluated that would cause an observed decrease in pH.
- Increasing concentration of injectate impurities: An increase in the concentration of any impurities in the injectate may be indicative of injectate migration into the monitoring zone.
- Increasing concentration of leached constituents: The presence of CO_2 may leach certain inorganics from the formation matrix due to lowered pH (**Appendix 3**). Increasing trends may be indicative of fluid migration.
- Increased reservoir pressure and/or static water levels.

6. Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a standard annular pressure test (SAPT) will be performed. The injection and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b) and are summarized in **Table C-6**.

6.1 Standard Annular Pressure Testing

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.
2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.
4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.
5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least 1-minute intervals.
6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1,000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure (i.e., 900 psi), the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director.

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3 percent of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3 percent of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will use an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

6.2 Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in real-time based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

These data will be provided in the semiannual report to demonstrate ongoing internal mechanical integrity.

7. External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 40 CFR 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

7.1 Testing Methods

Table C-7 shows testing methods that may be used for MIT on injection and monitoring wells associated with this project. CTV will use an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While distributed temperature sensing (DTS) may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Because temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. Instead, another approved method under 40 CFR 146.89(c) may be used, or DTS may be proposed for EPA Director approval for monitoring well MIT.

7.1.1 Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will use the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.
2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.
3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.
4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to EPA. The printed or digital log should have the following:
   - The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.
   - Vertical depth scale of the log should be 1 or 2 inches per 100 feet to match lithology logs.
   - Horizontal temperature scale should be no more than 1°F per inch spacing.
   - 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.
   - The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

A baseline temperature survey will be pulled while injecting at a constant rate and subsequent surveys pulled through time, post shut-in. The premise of temperature logging is that the wellbore fluid should warm back to a (constant) geothermal temperature gradient over time. Depending on the fluid profile behind pipe, the temperature could increase or decrease due to a hole in the casing. Any temperature anomalies will be analyzed to determine if it could be indicative of a failure in casing integrity. If analysis is inconclusive, additional surveys would be prescribed.

7.1.2 Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in real-time, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.
2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.
4. Start injection and record the temperature profile for 6 hours.
5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

7.1.3 Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will likely be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warmback can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in real-time. If dense-phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data are superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

7.1.4 Description of Noise Logging

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. Noise logging may 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 top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.
3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. 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.
5. 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:
   - The base of the lowermost bleed-off zone above the injection interval and
   - The base of the lowermost USDW.
6. Additional measurements may be made to pinpoint depths at which noise is produced.

7.1.5 Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, 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 may 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 (GR) log and casing collar locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. The GR 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 and less than 13⅜ 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 "no vertical 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 feet above the injection 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 immediately above the injection interval.
8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.
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 up hole or downhole as necessary at no more than 50-foot intervals and take stationary readings to determine the area of fluid migration.

8. Pressure Fall-Off Testing

Pressure fall-off tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests once prior to injection operations and during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Fall-off Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut-in. The injection pressure will be high enough to produce a pressure decrease upon shut-in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.
2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottom-hole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10-second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A, which provides 0.5 percent accuracy.
3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.
4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real-time because of the surface readout capabilities of the pressure gauges, and can therefore ensure a complete and adequate test before restarting injection.
5. Interference testing may be conducted at the conclusion of the fall-off test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut-in well.
6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry-standard methodologies. Anomalies that are identified from the interpretation will be investigated.
7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Fall-off Testing Requirements document.

9. Carbon Dioxide Plume and Pressure Front Tracking

CTV 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).

9.1 Plume Monitoring Location and Frequency

Figure C-1 shows the location of the wells that will monitor the targeted Winters zone (Yamada Brothers 2, Sonol Securities 4, M-1, and M-3) and east fault block zone (M-2). East fault block zone monitoring well M-2 will be used for pressure front monitoring. Remaining wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. If CTV detects evidence of USDW endangerment, CTV will implement the Emergency and Remedial Response Plan. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation per **Attachment B**.

Table C-8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in **Table C-9**. Quality assurance procedures for these methods are presented in Section B of **Appendix 11**.

9.2 Plume Monitoring Details

Fluid sampling, pressure, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but, more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in **Table C-9**.

The DTS from the monitoring wells will provide continuous temperature from packer to surface.

As discussed in **Attachment B**, 86 percent of the post-shut-in injected CO_2 will remain as super-critical 100 years after injection. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

The pulse neutron spectral carbon-oxygen logging technique has numerous applications for subsurface characterization, including time-lapse reservoir saturation monitoring. As a nuclear logging device with a relatively shallow depth of investigation, near wellbore conditions and proper calibration of the equipment prior to wireline deployment are essential for collecting accurate data and subsurface measurements. The standard operating procedure of the selected

PNL tool's manufacturer will be followed in the field. A generalized procedure for a PNL run is as follows:

1. Pre-Logging Preparation
   - Well Integrity: Confirm integrity of the wellbore and casing.
   - Confirm Run Details: Verify logging depths and scope of work.
   - Reservoir Parameters: Review the reservoir properties (e.g., lithology, porosity, permeability) of the formations of interest.
   - Tool Calibration: Ensure the tool is calibrated properly for accurate data and results. Thermal absorbers such as chlorine in brine increase the sensitivity of the PNL tool towards CO_2. Verify proper calibration to connate reservoir salinity and geochemical properties of drilling mud.
2. Logging Procedure
   - Tool Deployment: Lower the pulse neutron tool into the wellbore and position the tool string at the base of the target depth range.
   - Neutron Source Activation: Activate the neutron source to emit neutrons into the formation.
   - Gamma Ray Detection: The tool detects gamma rays emitted as neutrons interact with the formation. Log signature responses vary based on the fluid type encountered (CO_2, water, etc.) and geochemical properties of the logged formation.
   - Fluid Differentiation: The PNL tool differentiates CO_2 from other fluids by analyzing the energy spectrum of the gamma ray emissions. Due to its low hydrogen content, CO_2 produces a distinctive response compared to water.
   - CO_2 Saturation Assessment: Based on the neutron flux and gamma ray data, the tool calculates CO_2 saturation by measuring the hydrogen content in the formation and applying fluid identification models.
3. Post-Logging Data Processing
   - Data Review: Inspect the data for depth inaccuracies, signs of tool malfunctions, and verify the overall quality of the data. Relog any intervals that need relogging.
   - Interpretation: Use logging results to monitor and interpret CO_2 distribution in the aquifer. Use in conjunction with other well data (e.g., other logs & seismic data) for further validation.

9.3 Pressure-Front Monitoring Location and Frequency

The areal extent of plume development in the Winters reservoir will reach close to the AoR boundaries early in the injection phase. Because the reservoir is pressure depleted, injected CO_2 will quickly fill the available pore space. Monitoring well locations with respect to plume development through time are shown in **Figures C-2a and C-2b** for the two modeled injectate compositions. Injectate compositions are detailed in Section 7.2 of **Attachment A**.

Table C-10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Quality assurance procedures for these methods are presented in Section B of **Appendix 11**.

Monitoring well M-2 will primarily be used to monitor leakage across the Stockton Arch Fault, and is not expected to encounter CO_2. Measurements on this well will be limited to pressure and temperature at the initiation of the project. Should these measurements indicate signs of leakage, further diagnosis and fluid sampling will be initiated. Signs of leakage will include a statistically significant increasing (at 95 percent confidence) pressure and/or decreasing temperature trend over a period of three to six months that constitute at least a 10 percent change over baseline conditions.

9.4 Pressure-Front Monitoring Details

Direct pressure monitoring in and around the AoR will be achieved through installation of pressure gauges in monitoring wells M-1, M-2, M-3, Yamada Brothers 2 and Sonol Securities 4. The depleted Winters Formation gas reservoir will be repressurized to 90 percent of initial/discovery pressure of the reservoir. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

10. Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the AoR. This network will be implemented to monitor seismic activity near the project site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment. The seismometers will be able to detect events with a magnitude 0 to 0.5 and will be installed one year prior to injection to provide baseline seismicity. In addition, CTV will monitor the Northern California Earthquake Data Center (NCEDC) network for seismic events. Historical seismicity within the area will be accounted for in the baseline assessment.

Specifications of the network are as follows:

- Sensor locations to be determined in the field (borehole and/or near surface) with high-sensitivity three-component geophones
- Borehole sensors will be deployed deeper than 1,500 feet to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events $>M_w$ 0.0.

10.1 Baseline Analysis

The monitoring network will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the NCEDC will be reviewed to assist in establishing the baseline. These data will help establish historical natural seismic event depth, magnitude, and frequency to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

10.2 Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data transmitted near real-time via cellular modem or other wireless means and archived in a database
- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby existing broadband seismometers and strong motion accelerometers of the NCEDC. The EPA Director will be notified of seismic activity per **Attachment F**.

10.3 Network Design

A preliminary monitoring network design is provided in **Figure C-3**. This design includes the repurposing of four wells in the routine abandonment list, along with the addition of three new shallow borehole wells to provide coverage throughout the AoR. In this case, the repurposed wells will be plugged and abandoned in the injection zone and confining zone per EPA requirements, with cement plugs being set to approximately 1,500 feet, where a three-component geophone will be installed on top of that plug. The shallow borehole wells will be new drills between 100 and 300 feet drilled specifically to install individual three-component geophones. This preliminary design is subject to change due to shallow borehole location determinations, wellbores to be used, and final number of stations. A final design will meet the specifications listed above and provide full AoR coverage. Working with our contractor, this current design will meet the specifications and analyses detailed above.

Figures

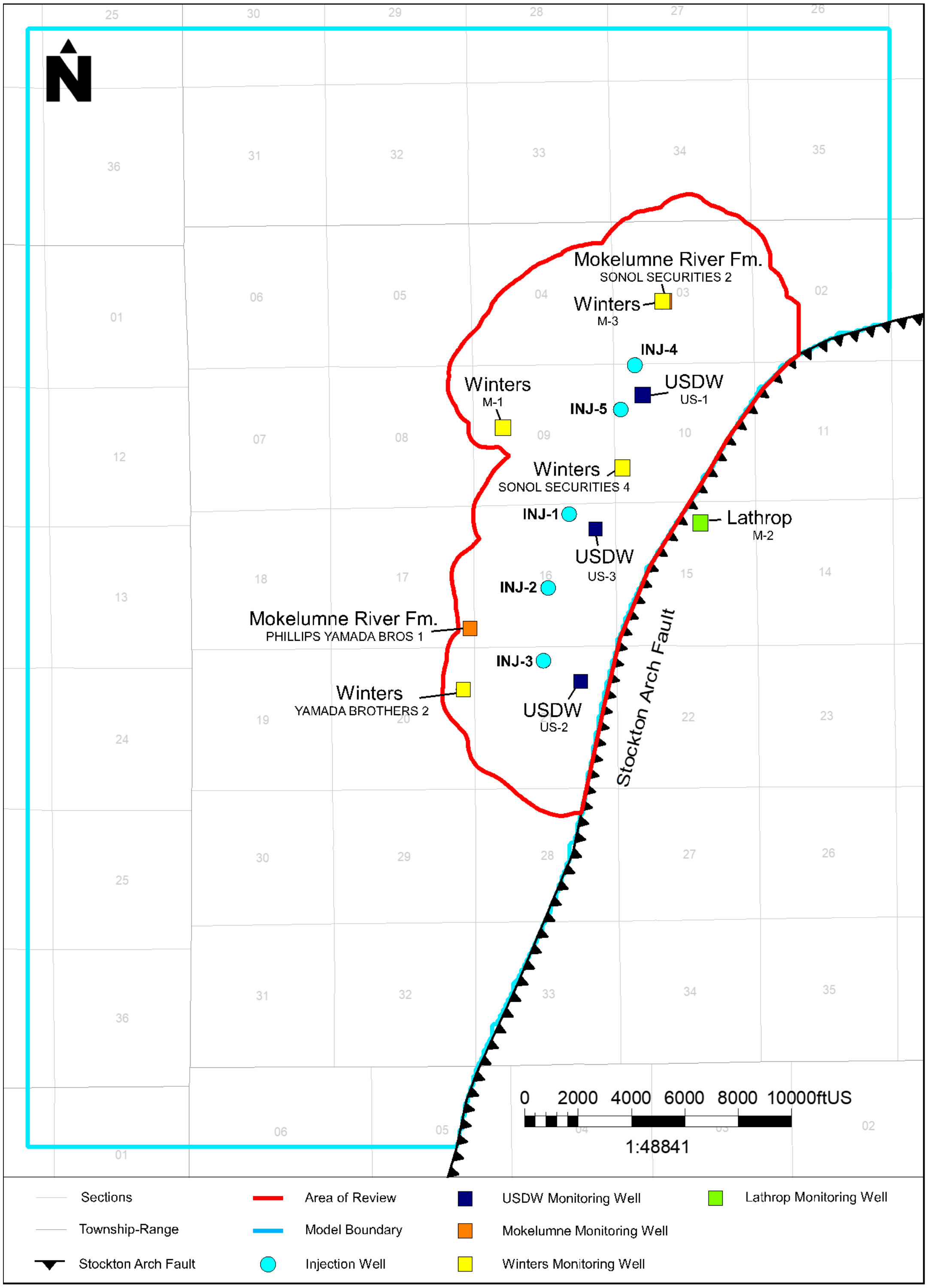

Figure C-1. Map showing the locations of monitoring wells.

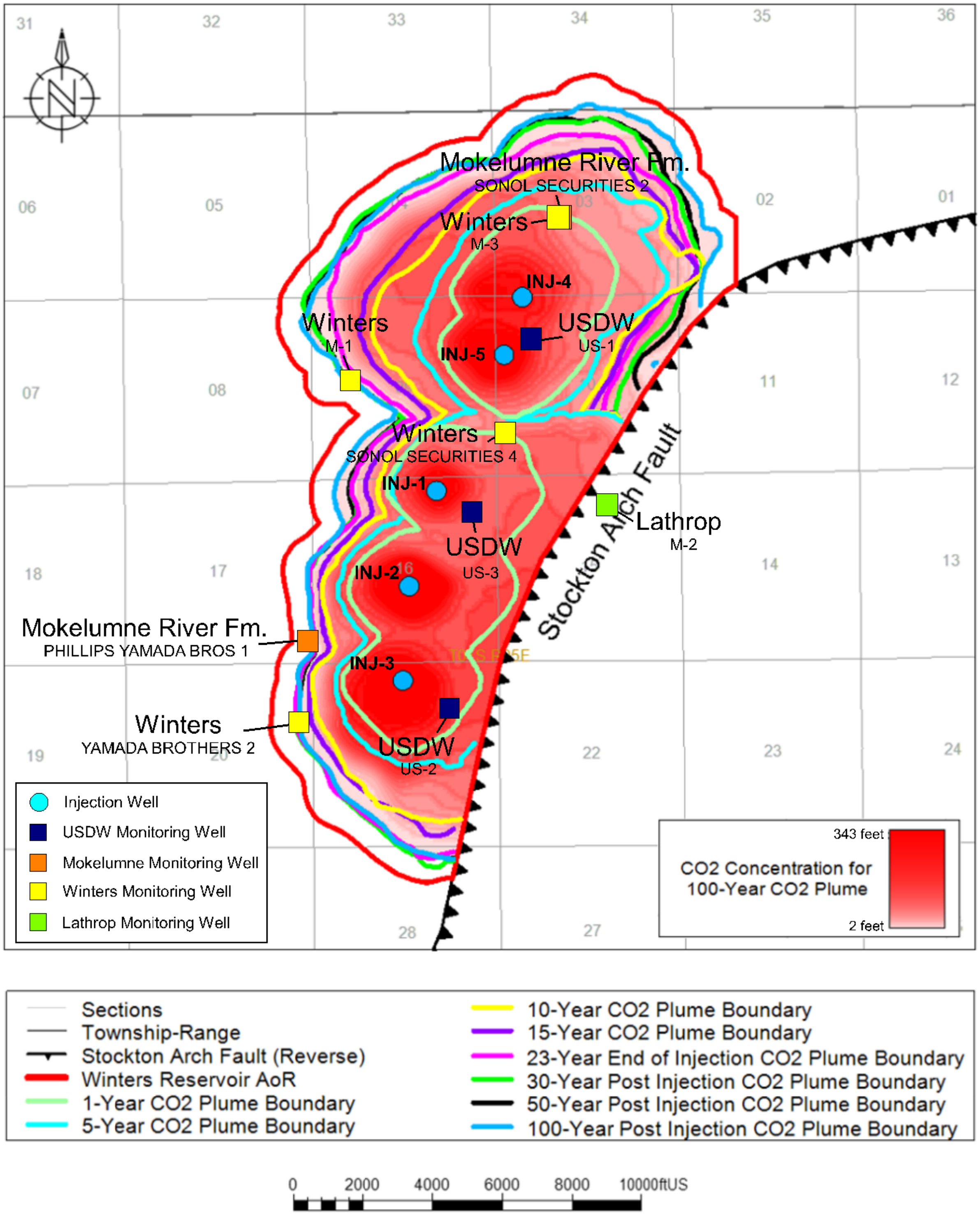

Figure C-2a. Map showing monitoring well locations and Injectate 1 plume development through time from computational model.

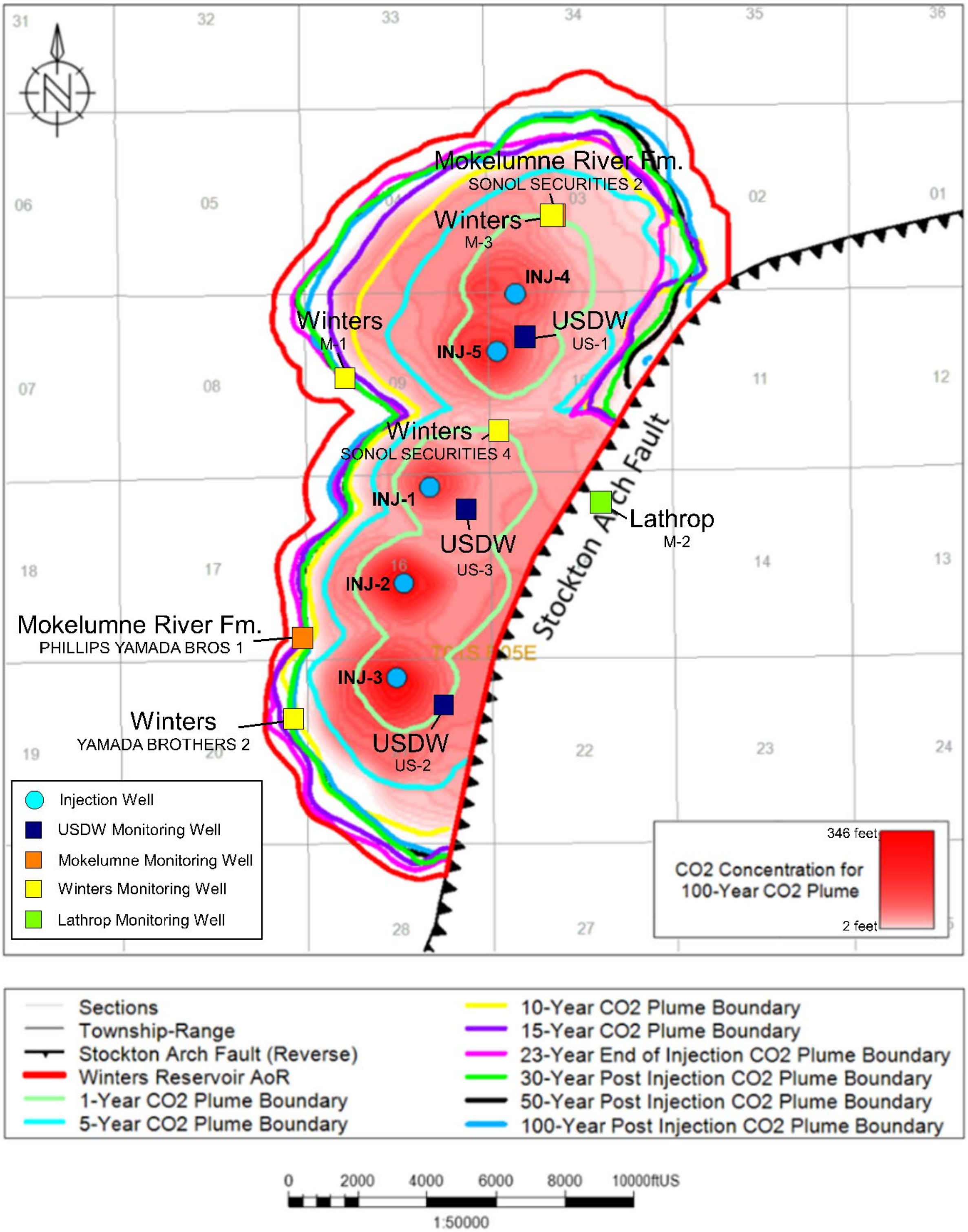

Figure C-2b. Map showing monitoring well locations and Injectate 2 plume development through time from computational model.

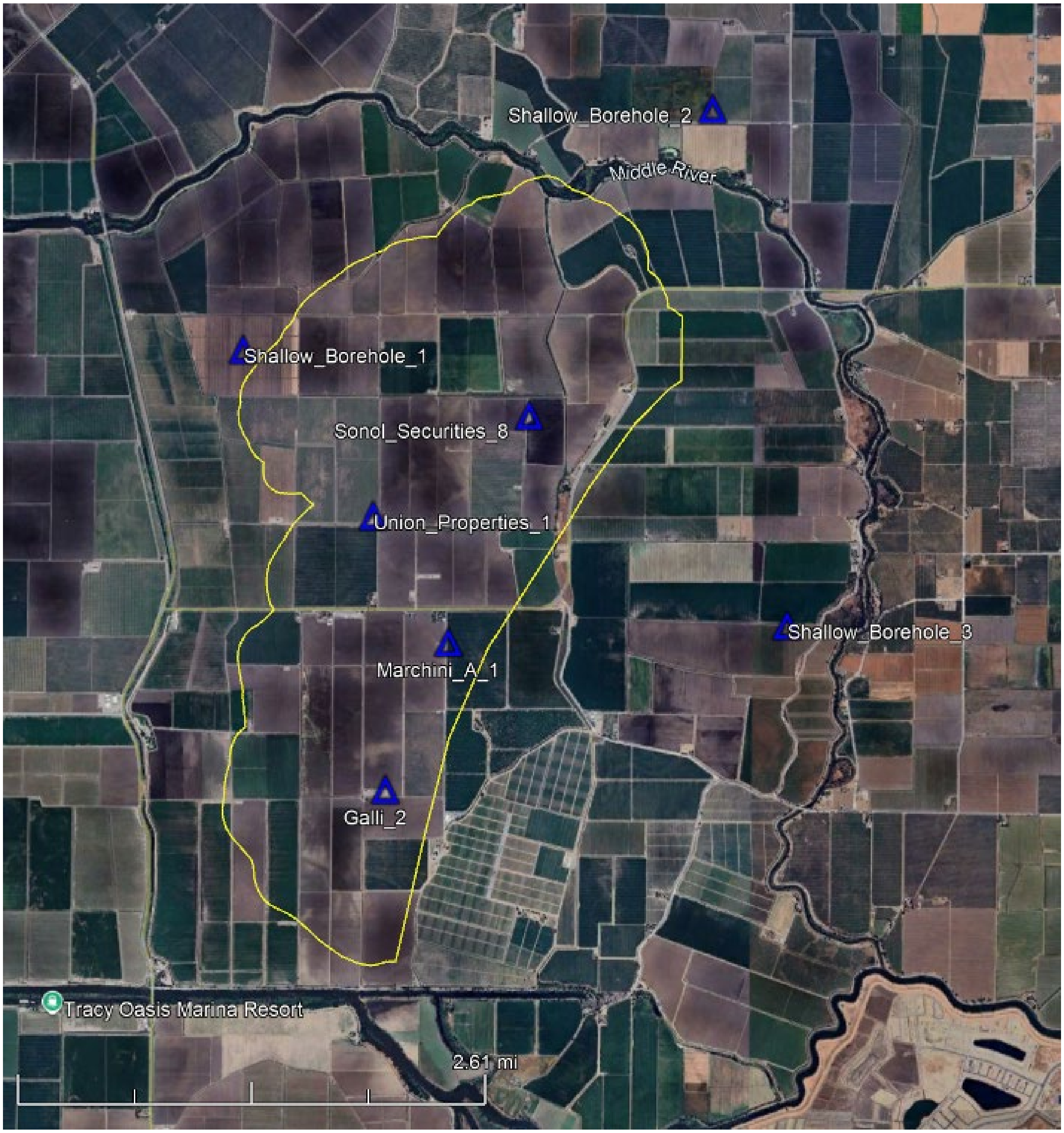

Figure C-3. Preliminary design for the seismicity monitoring network. The four named wells are wells that are to be abandoned as part of the routine abandonment list and re-purposed for seismicity monitoring. Shallow borehole locations would be newly drilled locations.

Tables

Table C-1. Analytical Parameters for CO_2 Stream.

Parameter	Analytical Method(s)
Oxygen, argon, and hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Water vapor	ISBT 3.0
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of nitrogen	ISBT 7.0 Colorimetric
Methane, ethane, ethylene	ISBT 10.1 (FID)
Hydrogen sulfide, sulfur dioxide, sulfur trioxide [a]	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
$\delta^{13}C$	Isotope ratio mass spectrometry

[a] Sulfur trioxide included if a component of the injectate stream.

Table C-2. Sampling Devices, Locations, and Frequencies for Continuous Monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface, Downhole: UI-INJ-1: 9,860’ (MD) UI-INJ-2: 9,880’ (MD) UI-INJ-3: 9,800’ (MD) UI-INJ-4: 9,580’ (MD) UI-INJ-5: 9,565’ (MD)	10 seconds	30 seconds
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Sensor	Surface, Downhole: UI-INJ-1: 9,860’ (MD) UI-INJ-2: 9,880’ (MD) UI-INJ-3: 9,800’ (MD) UI-INJ-4: 9,580’ (MD) UI-INJ-5: 9,565’ (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

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.

TableC-3. List of Equipment Coupons with Material of Construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 Carbon Steel L-80 CRA
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Table C-4. Monitoring of Groundwater Quality and Geochemical Changes Above the Confining Zone.

Target Formation	Monitoring Activity	Device	Monitoring Location(s)	Spatial Coverage or Depth	Frequency (Injection Phase)
Undifferentiated non-marine	Fluid Sampling	Pump	USDW Monitoring wells: USDW-1 USDW-2 USDW-3	USDW Monitoring wells: 2,105–2,147 feet MD/VD 2,141–2,183 feet MD/VD 2,122–2,164 feet MD/VD	Quarterly
	Pressure	Pressure Gauge			Continuous
	Temperature	Temperature Sensor			Continuous
	Temperature	Fiberoptic cable (DTS)	Injection Zone Monitoring wells: SONOL SECURITIES 4 M-1 YAMADA BROTHERS 2 M-3	Injection Zone Monitoring wells: 2,320-2,340 feet MD/VD 2,380-2,400 feet MD/VD 2,430-2,450 feet MD/VD 2,330-2,350 feet MD/VD	Continuous
Mokelumne River Formation	Fluid Sampling	Sampling Device	Above Confining Zone Monitoring Wells: SONOL SECURITIES 2 PHILLIPS YAMADA BROS 1	Above Confining Zone Monitoring Wells: 5,731–5,792 feet MD/VD 6,265–6,317 feet MD/VD	Quarterly
	Pressure	Pressure Gauge			Continuous
	Temperature	Temperature Sensor			Continuous
	Temperature	Fiber optic cable (DTS)	Injection Zone Monitoring wells: SONOL SECURITIES 4 M-1 M-3 YAMADA BROTHERS 2	Injection Zone Monitoring wells: 4,200–4,280 feet MD/VD 5,860–5,950 feet MD/VD 5,510–5,600 feet MD/VD	Continuous

Note: The minimum sampling and recording frequency for above confining zone pressure and temperature data during active injection is 5 hours.

Table C-5. Analytical and Field Parameters for Water Samples from the USDW Monitoring Well and the Mokelumne River Formation Monitoring Well.

Parameters	Analytical Methods
Undifferentiated Non-marine- Lowermost USDW	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	EPA 200.7 Rev 4.4, EPA 200.8 Rev 5.4
Cations (Ca, Fe, K, Mg, Na, Si)	EPA 200.7 Rev 4.4
Anions (Br, Cl, F, NO_3, SO_4)	EPA Method 300.0 Rev 2.1
Dissolved CO_2	EPA 1631; SM 4500 CO2 D
$\delta^{13}C$	Isotope ratio mass spectrometry
Hydrogen sulfide	SM4500 S2 H and S2 D
Oxygen, argon, and hydrogen	Chromatographic analysis
Total dissolved solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Table C-6. Internal MIT Requirements

Monitoring Activity	Target Zone	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)
Standard Annular Pressure Test (SAPT)	Injection Wells	UI-INJ-1 UI-INJ-2 UI-INJ-3 UI-INJ-4 UI-INJ-5	Casing/tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	2,532 2,538 2,639 2,596 2,599	2,632 2,638 2,739 2,696 2,699
	Above Zone Monitoring Wells	SONOL SECURITIES 2 PHILLIPS YAMADA BROS 1				Any time packer is replaced or reset	—	1,000
	Injection Zone Monitoring Wells	SONOL SECURITIES 4 M-3 M-1 PHILLIPS YAMADA 2					—	1,000
	Eastern fault block Monitoring Well	M-2					—	1,000
Annular Pressure	Injection and Monitoring Wells	UI-INJ-1 UI-INJ-2 UI-INJ-3 UI_INJ-4 UI_INJ-5 SONOL SECURITIES 4 M-1 M-2 M-3 PHILLIPS YAMADA 2	Wellhead	Continuous	Continuous	Not applicable	—	—

Table C-7. External Mechanical Integrity Testing Methods.

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Table C-8. Plume Monitoring Activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth (feet MD)	Frequency (Baseline)	Frequency (Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] DIRECT MONITORING	Winters	Fluid Sampling	SONOL SECURITIES 4	9,661–9,733	Once	Quarterly
		Pressure		9,560	Baseline	Continuous
		Temperature		9,560	Baseline	Continuous
	Winters	Fluid Sampling	M-1	10,025–10,225	Once	Quarterly
		Pressure		9,910	Baseline	Continuous
		Temperature		9,910	Baseline	Continuous
	Winters	Fluid Sampling	YAMADA BROTHERS 2	10,003–10,326	Once	Quarterly
		Pressure		9,935	Baseline	Continuous
		Temperature		9,935	Baseline	Continuous
	Winters	Fluid Sampling	M-3	9,591-9,810	Once	Quarterly
		Pressure		9,570	Baseline	Continuous
		Temperature		9,570	Baseline	Continuous
	Lathrop Sands (East Fault Block)	Fluid Sampling	M-2	9,209-9,309	Once	Confirmation sampling based on T/P
		Pressure		9,170	Baseline	Continuous
		Temperature		9,170	Baseline	Continuous
Plume Monitoring [40 CFR 146.90(g)] INDIRECT MONITORING	Winters	Pulsed Neutron Log	SONOL SECURITIES 4	9,661–9,733	Baseline	Every 2 years from start of injection
			M-1	10,025–10,225		
			YAMADA BROTHERS 2	10,003–10,326		
			M-3	9,591-9,810		

Table C-9. Analytical and Field Parameters for Fluid Sampling in the Injection Zone

Parameters	Analytical Methods
Winters Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO_3, SO_4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
$\delta^{13}C$	Isotope ratio mass spectrometry
Hydrogen sulfide	ISBT 14.0 (GC/SCD)
Oxygen, argon, and hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total dissolved solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Table C-10. Pressure-Front Monitoring Activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth (feet MD)	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] DIRECT MONITORING	Winters	Pressure	SONOL SECURITIES 4	9,661–9,733	Baseline	Continuous
		Temperature			Baseline	Continuous
	Winters	Pressure	M-1	10,025–10,225	Baseline	Continuous
		Temperature			Baseline	Continuous
	Winters	Pressure	YAMADA BROTHERS 2	10,003–10,326	Baseline	Continuous
		Temperature			Baseline	Continuous
	Winters	Pressure	M-3	9,591–9,810	Baseline	Continuous
		Temperature			Baseline	Continuous
	Lathrop Sands (East Fault Block)	Pressure	M-2	9,209–9,309	Baseline	Continuous
		Temperature			Baseline	Continuous
Pressure-Front Monitoring [40 CFR 146.90(g)] INDIRECT MONITORING	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous