

**ATTACHMENT C: TESTING AND MONITORING PLAN**  
**40 CFR 146.90**  
**CTV VI**

**Document Version History**

Version	Revision Date	File Name	Description of Change
1	7/31/2024	Att C - CTV VI TM_v1	Original Version

**1. Facility Information**

Facility Name: CTV VI

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Well location(s): **Claimed as PBI**

This Testing and Monitoring Plan describes how Carbon TerraVault Holdings, LLC (CTV) will monitor the CTV VI storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the wells are operating as planned, the carbon dioxide (CO<sub>2</sub>) 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<sub>2</sub> 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 **Attachment F: Emergency and Remedial Response Plan (Attachment F)**.

**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 in **Appendix 10**.

**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<sub>2</sub> 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<sub>2</sub> as injectate for the project. Notification will be sent to EPA prior to switching or adding CO<sub>2</sub> sources, at which time the sampling procedures can be reassessed.

### ***2.1 Sampling Location and Frequency***

CO<sub>2</sub> 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 quarterly after the start of injection.

CTV will increase the frequency and collect additional samples if both of the following occur:

- Significant changes in the chemical or physical characteristics of the CO<sub>2</sub> injectate occur, such as a change in the CO<sub>2</sub> injectate source.
- Facility or injector downtime is greater than 30 days.

### ***2.2 Analytical Parameters***

CTV will analyze the water content and the injectate 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<sub>2</sub> stream sampling will occur at the transfer point from the source and the discharge of the last compressor upstream of the injector. A sampling station will be installed to facilitate 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 Airborne Labs International, which is located at 22C World's Fair Drive, Somerset, New Jersey. 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 10**.

Chain of custody forms will accompany all samples that include 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)]**

As required by 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:

- 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<sub>2</sub> 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 **Table C-2**.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10-second sampling frequency and 30-second recording frequency for both active and shut-in periods. Monitoring of annulus fluid volume will be continuous with a 4-hour sampling frequency and a 24-hour recording frequency. 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 10**.

#### ***3.3 Calculation of Injection Volumes***

The mass of CO<sub>2</sub> injected into the Injection Zone will be calculated from the injection flow rate and CO<sub>2</sub> density. Density of CO<sub>2</sub> injected 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<sub>2</sub> enhanced oil recovery (EOR) applications to accurately model and match CO<sub>2</sub> 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 annulus 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) above injection pressure at the packer, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive pressure at surface. Any decrease in pressure or annular fluid level will be identified with the SCADA alarm system.

Failure to consistently maintain pressure 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 psi 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, 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 this section.

### **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<sub>2</sub> injectate to the injectors.

### **4.2    *Sample Description***

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO<sub>2</sub> 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. The wellbore materials of the injector wells exposed and in direct contact with injected CO<sub>2</sub> include corrosion-resistant alloy (CRA) casing below the packer and CRA tubing. These tubular materials will be included in the corrosion coupon monitoring and are presently 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 formations 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 intervals:

- Lowermost USDW: **Claimed as PBI** along with shallow alluvium above **Claimed as PBI**  
**Claimed as PBI**
- **Claimed as PBI** Between the confining layer **Claimed as PBI** and **Claimed as PBI**  
**Claimed as PBI**

#### 5.1 **Claimed as PBI** (Lowermost USDW)

CTV will monitor the lowermost USDW in the **Claimed as PBI**. 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 (e.g., increased CO<sub>2</sub> concentration). Based on having groundwater less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS), the proposed monitoring zone is a USDW. However, the water supply wells in the AoR are completed at shallower depths. Monitoring of the lowermost USDW is more protective than monitoring the freshwater aquifers because impacts would occur in the lowermost USDW before the fresh water aquifers. USDW monitoring well locations are shown on **Figure C-1**.

Prior to injection, an updated baseline analysis will be completed for the USDW monitoring wells. Future results will be compared against these baseline results for significant changes or anomalies. In particular, pH will be monitored as a key indicator of CO<sub>2</sub> presence.

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

- **Claimed as PBI** monitoring indicates increased pressure due to CO<sub>2</sub> injection.
- Lowermost USDW aquifer pressure or composition changes due to CO<sub>2</sub> injection.

## 5.2 **Claimed as PBI** (*Dissipation Zone*)

The Dissipation Zone has permeable sands and is observed between the Confining Zone and the lowermost USDW with the capacity to dissipate CO<sub>2</sub> injectate. The Dissipation Zone will be monitored continuously for pressure and temperature changes. Leakage from the Injection Zone to the Dissipation Zone will result in changes to the pressure and temperature of the Dissipation Zone. The Dissipation Zone is the first porous interval above the Injection Zone.

The Dissipation Zone is continuous across the AoR. External pressure and temperature gauges and fiberoptic cable at intervals corresponding to the Dissipation Zone within Injection Zone monitoring wells and injection wells (**Figure C-1**) will adequately monitor for pressure and temperature changes.

## 5.3 *Monitoring 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 location for 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 10**.

## 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) in Paloma, 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 10**.

Chain of custody forms including the following information will accompany all samples:

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

## **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**.

In-zone monitoring wells **Claimed as PBI** will be configured with distributed temperature sensing (DTS), pressure, and temperature gauges external to the casing per **Appendix 5**. Tubing and packers are not required for these monitoring wells. The process for standard casing pressure testing (SCPT) and continuous monitoring of casing pressure will follow the same protocols described in Sections 7.1 and 7.2 for the annulus.

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

### **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 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.

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) exceeds 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 that 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 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 wells will record continuous annular pressure such that internal mechanical integrity can be confirmed in real-time based on the interpretation of these 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 (MIT) 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<sub>2</sub> 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 EPA for approval.

Because temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, the monitoring wells cannot be tested for external MIT. Additionally, injecting fluid such as H<sub>2</sub>O or CO<sub>2</sub> 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.

### **7.2 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 Confining Zone 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 feet per minute (ft/min), and the acceptable range is between 20 and 50 ft/min.

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<sub>2</sub> 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.

### **7.3 Description of Temperature Logging using Distributed Temperature Sensing**

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 along the length of the wellbore. 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 MIT. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes 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.

#### **7.4 *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 and on the outside of the casing on injection-zone monitoring wells. 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 this method 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<sub>2</sub> were to breach the Injection Zone and migrate upward, the warmer CO<sub>2</sub> would cause a discernible temperature anomaly. If the CO<sub>2</sub> 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.

#### **7.5 *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 millivolts (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 base of the USDW to the deepest point reachable in the Injection Zone 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
  - ◇ The base of the lowermost USDW
  - ◇ Additional measurements may be made to pinpoint depths at which noise is produced.

### **7.6 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. Oxygen activation (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. 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  $1\frac{11}{16}$  inches and less than  $13\frac{3}{8}$  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 “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 uphole 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 on each injector 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 prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. 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 that 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 semiannual 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 CO<sub>2</sub> 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 CO<sub>2</sub> plume directly in the targeted Injection Zone. These wells will actively monitor the development of the CO<sub>2</sub> plume upon the initiation of injection. If the plume development is not consistent with computational modeling results, CTV will assess whether additional plume monitoring is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan (**Attachment B**).

**Table C-8** presents the methods that CTV will use to monitor the position of the CO<sub>2</sub> plume, including the activities, locations, and frequencies.

### **9.2 Plume Monitoring Details**

Pressure and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on the position of the plume front. Monitoring well locations with respect to plume development through time are shown in **Figure C-2**.

The DTS from the two Injection Zone monitoring wells will provide continuous temperature along the wellbore.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO<sub>2</sub> saturation changes through time. Prior to injection, a PNL will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

### **9.3 Pressure Monitoring Location and Frequency**

**Table C-9** presents the methods that CTV will use to monitor injection-zone pressure, including the activities, locations, and frequencies CTV will employ. Quality assurance procedures for these methods are presented in Section B of **Appendix 10**.

### **9.4 Pressure Monitoring Details**

Direct pressure monitoring of the plume will be achieved through installation of externally mounted pressure gauges in monitoring wells **Claimed as PBI** 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/or 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<sub>2</sub> containment. The seismometers will be able to detect events with a magnitude 0 to 0.5 and above and will be installed at least 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.
- A velocity model will be derived from nearby 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 in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO<sub>2</sub> 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 USGS/ Northern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

**Appendix: Quality Assurance and Surveillance Plan**

See **Appendix 10**.



## Figures

# Claimed as PBI



**Figure C-1. Locations of Injection and Monitoring Wells.**

# Claimed as PBI

**Figure C-2. Injection Zone Plume Development through Time.** Figure shows 1-year, 5-year, 10-year, 30-year (end of injection), 50-year, and 100-year post-injection.

## Tables

**Table C-1. Summary of Analytical Parameters for CO<sub>2</sub> Stream**

Parameter	Analytical Method(s)
Oxygen, argon, and hydrogen	ISBT 4.0 (GC/DID) GC/TCD
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 and sulfur dioxide	ISBT 14.0 (GC/SCD)
CO <sub>2</sub> purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ <sup>13</sup> C	Isotope ratio mass spectrometry

**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 and Downhole; Claimed as PBI	10 seconds	30 seconds
Injection rate	Flowmeter	Surface (all injection wells)	10 seconds	30 seconds
Injection volume	Calculated	Surface (all injection wells)	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface (all injection wells and USDW monitoring wells)	10 seconds	30 seconds
Casing pressure	Pressure Gauge	Surface (all injection-zone monitoring wells)	10 seconds	30 seconds
Annulus fluid volume		Surface (all injection wells)	4 hours	24 hours
Temperature	Temperature Sensor	Surface and Downhole; Claimed as PBI	10 seconds	30 seconds
Temperature	Fiberoptic Cable (DTS)	Along wellbore to packer (all injection wells)	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.

**Table C-3. List of Equipment Coupons with Material of Construction**

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

**Table C-4. Monitoring Above the Confining Zone**

Target Formation	Monitoring Activity	Device	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Injection Phase)
USDW	Fluid Sampling	Pump	Claimed as PBI		Quarterly
	Pressure	Pressure Gauge	Claimed as PBI		Continuous
	Temperature	Temperature Sensor	Claimed as PBI		Continuous
	Temperature	Fiberoptic cable (DTS)	Claimed as PBI		Continuous
Claimed as PBI	Pressure	External Pressure Gauge	Claimed as PBI		Continuous
	Temperature	External Temperature Sensor	Claimed as PBI		Continuous
	Temperature	Fiberoptic cable (DTS)	Claimed as PBI		Continuous



**Table C-5. Analytical and Field Parameters for Groundwater Samples from Monitoring Wells**

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, 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 <sub>3</sub> , SO <sub>4</sub> )	EPA Method 300.0 Rev 2.1
Dissolved CO <sub>2</sub>	EPA 1631; SM 4500 CO <sub>2</sub> D
δ <sup>13</sup> C	Isotope ratio mass spectrometry
Hydrogen sulfide	SM4500 S <sub>2</sub> H and S <sub>2</sub> D
Oxygen, argon, and hydrogen	Chromatographic analysis
Total dissolved solids	Gravimetry; Method 2540 C
Alkalinity	SM 2320 B
pH (field)	EPA 150.1
Specific conductance (field)	SM 2510 B
Temperature (field)	Thermocouple
Dissolved oxygen (field)	Electrode, 4500-O G-2016

**Table C-6. Internal mechanical integrity testing requirements**

Monitoring Activity	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)	Claimed as PBI	Casing, tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	1,714	1,814
						1,646	1,746
	Claimed as PBI					1,670	1,770
						2,833	2,933
						2,778	2,878
						2,778	2,878
	Claimed as PBI					3,147	3,247
Standard Casing Pressure Test (SCPT)	In-Zone Monitoring Wells: Claimed as PBI	Wellbore from surface to TD		Casing pressure = 90% last SCPT		—	1,000 1,000
Annular Pressure	All Injection and USDW Monitoring Wells	Wellhead	Continuous	Continuous	Not Applicable	—	—
Casing Pressure	In-Zone Monitoring Wells: Claimed as PBI	Wellhead	Continuous	Continuous	Not Applicable	—	—
Fluid Sampling	All Injection and USDW Monitoring Wells	Wellhead	Baseline	Quarterly	Annual	—	—

**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	Frequency (Baseline)	Frequency (Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] Direct Monitoring	Claimed as PBI [REDACTED]	Pressure	Claimed as PBI [REDACTED]	[REDACTED]	Baseline	Continuous
		Temperature		Claimed as PBI [REDACTED]	Baseline	Continuous
	Claimed as PBI [REDACTED]	Pressure	Claimed as PBI [REDACTED]	[REDACTED]	Baseline	Continuous
		Temperature		Claimed as PBI [REDACTED]	Baseline	Continuous
Plume Monitoring [40 CFR 146.90(g)] Indirect Monitoring	Claimed as PBI [REDACTED]	Pulsed Neutron Log	Claimed as PBI [REDACTED]	[REDACTED]	Baseline	Every 2 years from start of injection
			Claimed as PBI [REDACTED]	[REDACTED]		

**Table C-9. Pressure-Front Monitoring Activities**

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] Direct Monitoring	Claimed as PBI [REDACTED]	Pressure	Claimed as PBI [REDACTED]	[REDACTED]	Baseline	Continuous
		Temperature			Baseline	Continuous
	Claimed as PBI [REDACTED]	Pressure	Claimed as PBI [REDACTED]	[REDACTED]	Baseline	Continuous
		Temperature			Baseline	Continuous
Pressure-Front Monitoring Indirect Monitoring	All Formations	Seismicity	Seismic Monitoring Network	Full AoR	Baseline	Continuous