WELL CONSTRUCTION PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Project Manager
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Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_345C-36R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_345C-36R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_345C-36R_V3	3	1/10/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – COP Details_345C-36R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 3/2023
Attachment G – COP Details_345C-36R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

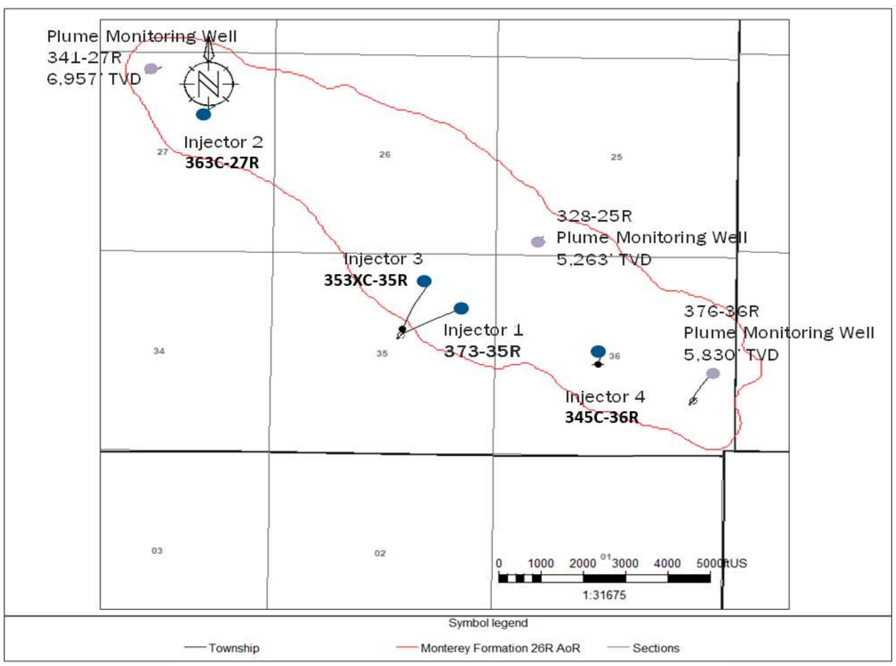


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 3 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long string	14' - 5600' 5600' - 6000'	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	5700' - 7980'	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

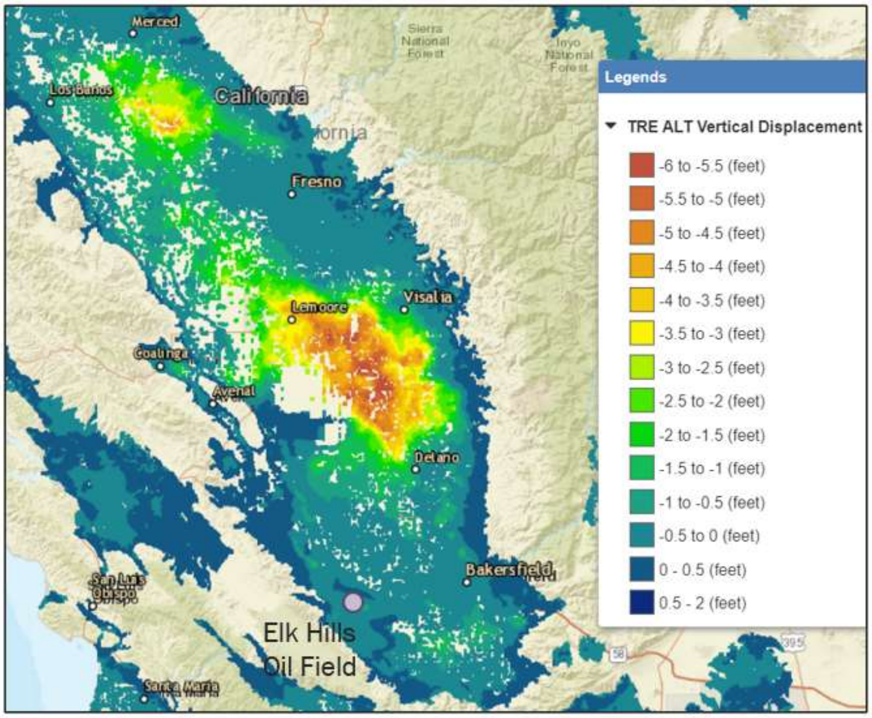


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 2: Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	5,700	4.5	4.00	11.6	L-80 CRA	Premium	7,780	6,350

Table 3: Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	5,700	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 345C-36R with a surface shut-off valve at the wellhead and not a down-hole device.

Pre-Injection Testing Plan

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120’ during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 345C-36R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log. The mechanical integrity testing procedures are described in the Testing and Monitoring document.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

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. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. 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 or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

<u>Objectives for Pre-Operational Testing</u>

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the reviews. This information is summarized below (along with the planned tests that will address each data need that was described in the initial permit application materials submitted in November 2021) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c) and 146.87.

Regional Geology and Geologic Structure

• Perform pressure build-up testing (anticipated testing method: pressure build-up test).

• Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

• Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

• Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

• Determine if there are any heterogeneities within the Monterey 26R injection zone that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; planned and completed core, log, and seismic analysis).

CO2 Stream Compatibility with Subsurface Fluids and Minerals

• Confirm the composition and water content of the CO2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses, benchtop studies).

• Confirm that the properties of the CO2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).

• Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of the geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

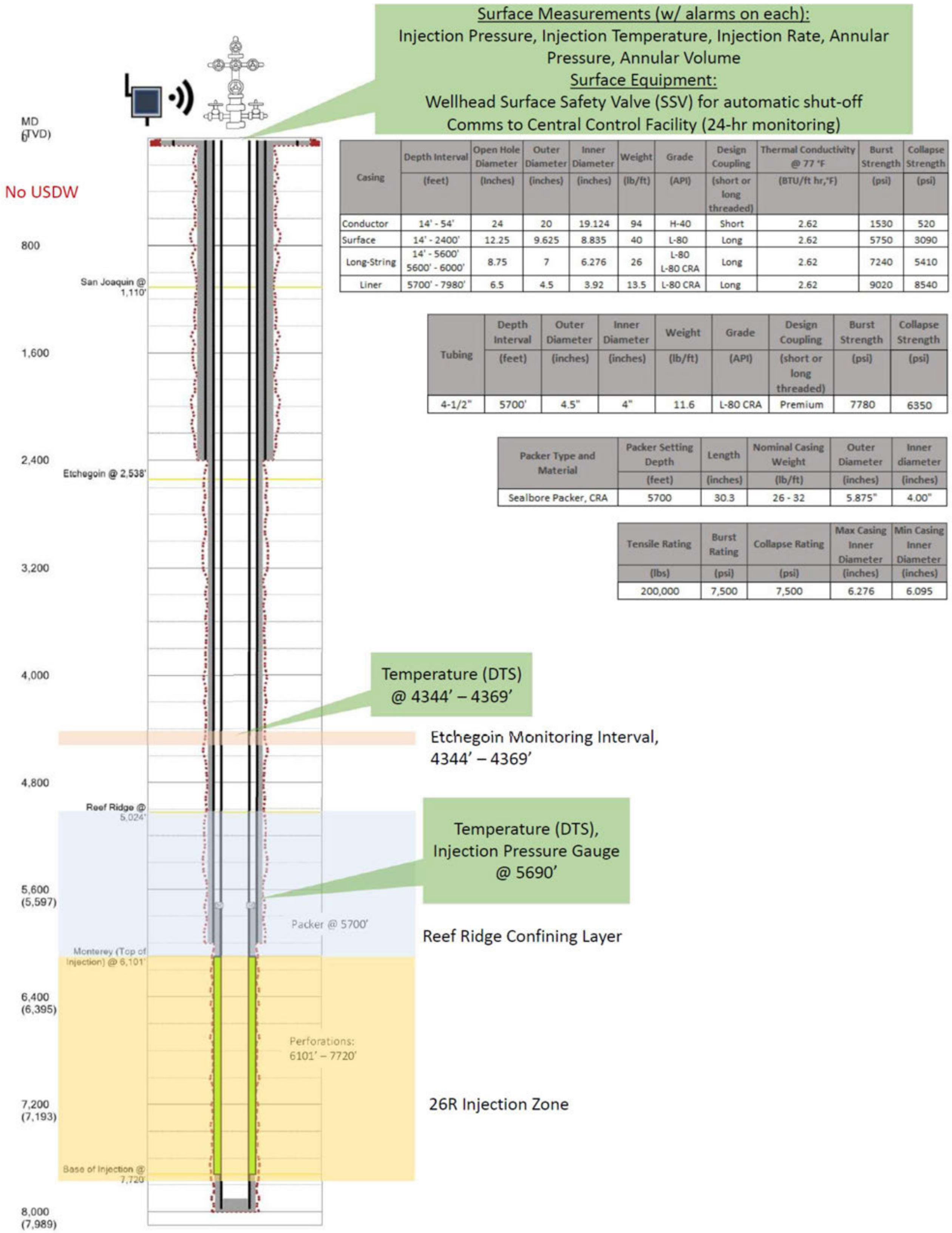
• Collect baseline pressure data in the Etchegoin Formation to support upward confinement between the Monterey and shallower formations (anticipated testing method: pressure build-up test).

• Determine the porosity and permeability of the Reef Ridge Shale at the location of each of the 26R project wells (anticipated testing methods: core and log data during well drilling).

• Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

• Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).



Casing	Depth Interval (feet)	Open Hole Diameter (Inches)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Thermal Conductivity @ 77 °F (BTU/ft hr,°F)	Burst Strength (psi)	Collapse Strength (psi)
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Tubing	Depth Interval (feet)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Burst Strength (psi)	Collapse Strength (psi)
4-1/2"	5700'	4.5"	4"	11.6	L-80 CRA	Premium	7780	6350

Packer Type and Material	Packer Setting Depth (feet)	Length (inches)	Nominal Casing Weight (lb/ft)	Outer Diameter (inches)	Inner diameter (inches)
Sealbore Packer, CRA	5700	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max Casing Inner Diameter (inches)	Min Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Figure 3: Injection Well 345C-36R, CO_2 Injection Schematic

WELL PLUGGING PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name:	Elk Hills 26R Storage Project
Facility Contact:	Travis Hurst / Project Manager 28590 Highway 119 Tupman, CA 93276 (661) 342-2409 / Travis.Hurst@crc.com
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Attachment G – COP Details_345C-36R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 3/2023
Attachment D – Well Plugging Plan_345C-36R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

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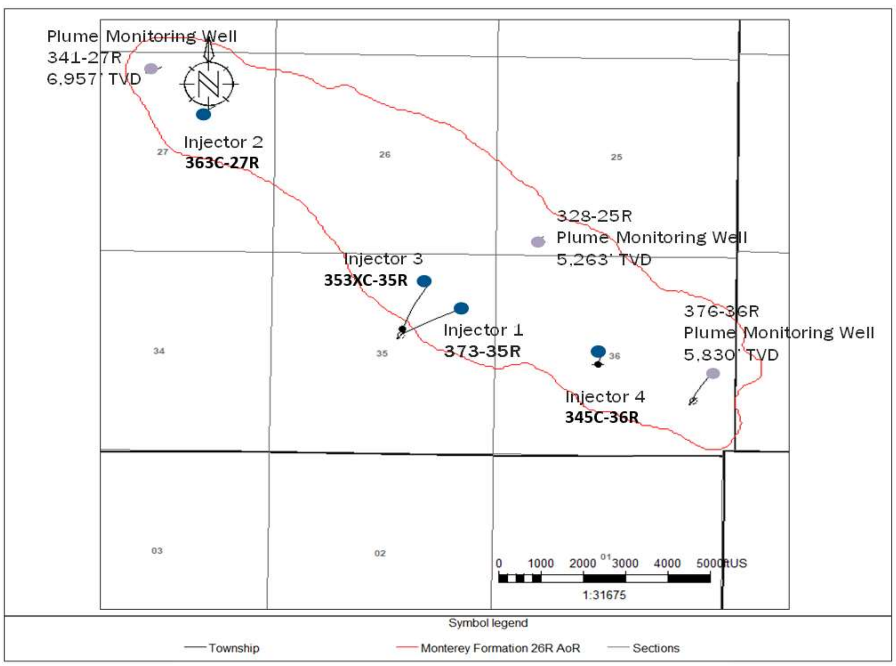

Figure 1: Map showing the location of injection wells and monitoring wells.

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Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The planned external MIT method will be a temperature log or other approved external MIT (Table 1) and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Table 1: 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

Information on Plugs

CTV will use the materials and methods noted in Table 2 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 2, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 2: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	3.92	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	7900	2563	1135	39
Sacks of cement to be used (each plug)	168	24	24	5
Slurry volume to be pumped (bbl)	34.41	4.92	4.92	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	5600	2438	1010	14
Bottom of plug (ft)	7900	2563	1135	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or CT Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5' below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

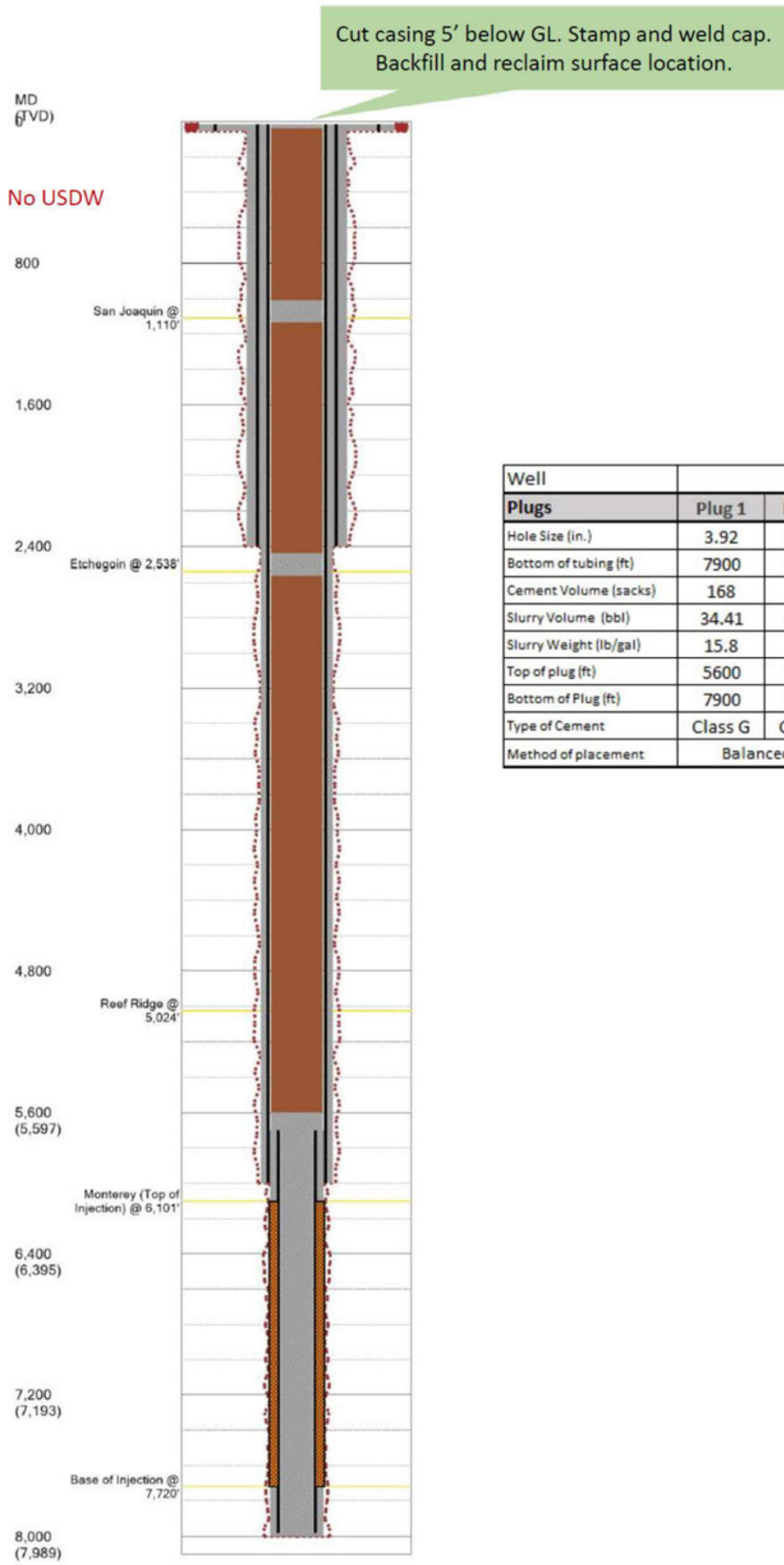
CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits.

In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

  - In 26R, this interval would be located at the top of the San Joaquin formation.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.



Well	345C-36R			
Plugs	Plug 1	Plug 2	Plug 3	Plug 4
Hole Size (in.)	3.92	6.276	6.276	6.276
Bottom of tubing (ft)	7900	2563	1135	39
Cement Volume (sacks)	168	24	24	5
Slurry Volume (bbl)	34.41	4.92	4.92	1.02
Slurry Weight (lb/gal)	15.8	15.8	15.8	15.8
Top of plug (ft)	5600	2438	1010	14
Bottom of Plug (ft)	7900	2563	1135	39
Type of Cement	Class G	Class G	Class G	Class G
Method of placement	Balanced Plug, Retainer, or CT Plug			

Figure 2: Injection Well 345C-36R, Abandonment Schematic

ATTACHMENT C: TESTING AND MONITORING PLAN – 345C-36R
40 CFR 146.90

Elk Hills 26R Storage Project

Facility Information

Facility Name: Elk Hills 26R Storage Project
345C-36R

Facility Contact: Travis Hurst / CCS Project Manager
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Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Comments
Attachment C – TM 345C-36R	1	09/30/2023	
Attachment C – TM 345C-36R	2	12/05/2023	Addition of air monitoring.

The Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills 26R storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. 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 AoR re-evaluations 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.

Quality Assurance Procedures

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

Reporting Procedures

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

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 date of authorization of injection and every three months thereafter.

The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area.

CO_2 injectate from these sources has been incorporated into Table 1 for injectate sampling. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken for each injection source and between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter. Sampling process will follow the procedures below.

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

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and
2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

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

Table 1. Summary of analytical parameters for CO_2 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_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry
Water Vapor	ISBT 3.0

Sampling Methods

Stream sampling will occur for each required CO2 analysis and in the last compressor station prior to being sent to 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.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 4.

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

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

For each required CO_2 analysis, CTV will report the time each sample was taken, a tabulation of all CO_2 stream analyses (including any quality assurance/quality control samples), an interpretation of the results, any identified changes and explanation of any data gaps.

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 injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the Appendix_26R - Injection & Monitoring Well Schematics document.

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.

Table 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 345C-36R: 5690'(MD) 353X-35R: 6390' (MD) 363-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
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 Gauge	Surface Downhole 345C-36R: 5690'(MD) 353XC-35R: 6390' (MD) 363C-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

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

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. 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 annually 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. Pressure and temperature gauges will be calibrated annually. Table 6 of the QASP provides operating range and precision specifications.

Calculation of Injection Volume and Mass

The volume and mass of CO_2 injected into the Monterey Formation 26R will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation 26R 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 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

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 brine with corrosion inhibitor. The casing-tubing annulus pressure for injection wells 373-35R, 345C-36R, 353XC-35R, 363C-27R will be maintained with at least 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently 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 1000 psi and cannot be explained by operational conditions.

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 below.

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.

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_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For well 373-35R, 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 CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction 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.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 steel (373-35R injection well) K-55 steel (341-27R, 328-25R monitoring wells) Chrome alloy consistent with final well construction for new drill wells
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab 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 the EPA as per 40 CFR 146.91 (a)(7). Table 5 of the QASP document provides detection limit/range and precision.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and condition of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone.

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. Figure 1 shows the location of 355X-26R and the shallow groundwater monitoring well. The well is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 4,063' – 4,087' MD in 355X-26R.

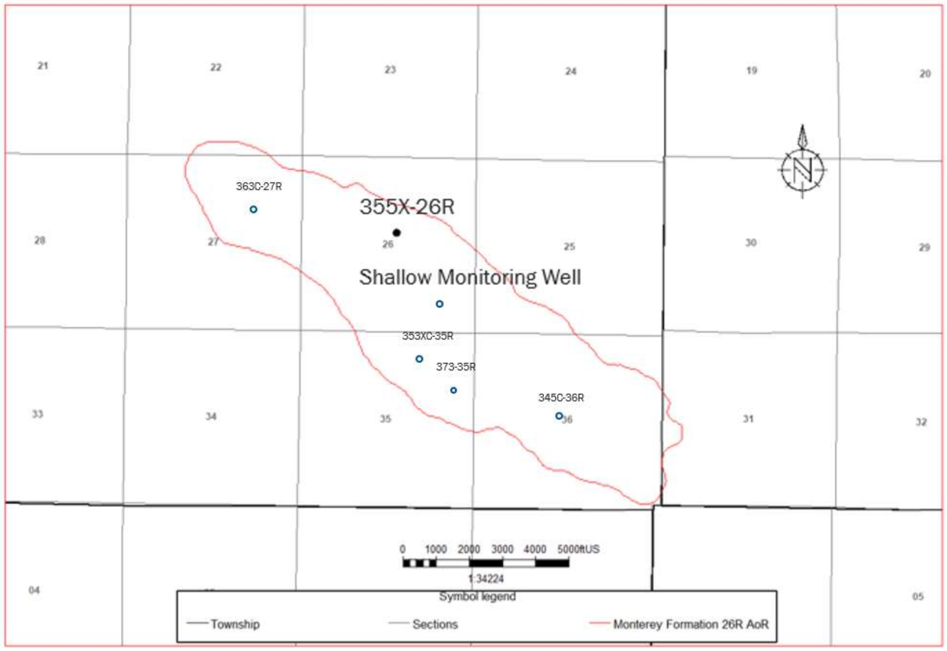

Figure 1: Above confining zone monitoring wells.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure and decrease in temperature of the Etchegoin. Additionally, potential leakage will create compositional changes detectable with fluid sampling and geochemical monitoring. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The Upper Tulare is unsaturated in the AoR. The Upper Tulare Formation will be monitored between 400' – 450' MD in the shallow monitoring well that will be drilled specifically for this project.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

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

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation 26R CO_2 injection.

2. Upper Tulare Formation pressure or composition changes due to Monterey Formation 26R CO_2 injection.

Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400' - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400' - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400' - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

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

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, approximately 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

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 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).

Standard Annular Pressure Testing (SAPT)

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 one-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 1000 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. Table 6 provides information on the frequency and test pressures for injection and monitoring wells within the project.

Table 6. Internal MIT requirements

<table>
<tr><th>Monitoring Activity</th><th>Data Collection Location(s)</th><th>Spatial Coverage or Depth</th><th>Frequency (Baseline)</th><th>Frequency (Injection Phase)</th><th>Frequency (Post-Injection Phase)</th><th>Maximum Injection Pressure (psi)</th><th>Test Pressure (psi)</th></tr>
<tr><td rowspan="6">Standard Annular Pressure Test (SAPT)</td><td>373-35R[1]</td><td rowspan="6">Casing/tubing annulus from surface to packer</td><td rowspan="6">Once, upon initial installation</td><td rowspan="6">Any time packer is replaced or reset</td><td rowspan="4">Not Applicable</td><td>1992</td><td>2092</td></tr>
<tr><td>345C-36R[1]</td><td>1888</td><td>1988</td></tr>
<tr><td>363C-27R[1]</td><td>2020</td><td>2120</td></tr>
<tr><td>353XC-35R[1]</td><td>1997</td><td>2097</td></tr>
<tr><td>355X-26R[2]</td><td rowspan="2">Any time packer is replaced or reset</td><td>--</td><td>1000</td></tr>
<tr><td>341-27R[3]
328-25R[3]
376-36R[3]</td><td>--</td><td>1000</td></tr>
</table>

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)	
Annular Pressure	373-35R[1] 345C-36R[1] 353XC-35R[1] 363C-27R[1]	Wellhead	Continuous	Continuous	Not Applicable	--		-
	355X-26R[2] 341-27R[3] 328-25R[3] 376-36R[3]				Continuous			-

[1] CO2 injection well
[2] Above Zone monitoring well
[3] Injection Zone monitoring well

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% 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% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the 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.

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.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

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 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize 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 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.

Since 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 utilized, or DTS may be proposed for EPA Director approval for monitoring well MIT.

Table 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

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 utilize 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 the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

    b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

    c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

    d. 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.

    e. 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.

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 Realtime, 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.

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 be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warm back 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 is 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.

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:

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

    b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

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. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "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.

Pressure Fall-Off Testing

Pressure falloff 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 Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

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. Bottomhole 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% 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 falloff 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 Falloff Testing Requirements document.

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).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted 26R reservoir. These 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. 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.

Based on the Base case model, the CO2 plume is expected to arrive at the monitoring well locations at approximately the – 7th year of injection for 376-25R, 8th year of injection for 328-25R and the 9th year of injection for 341-27R.

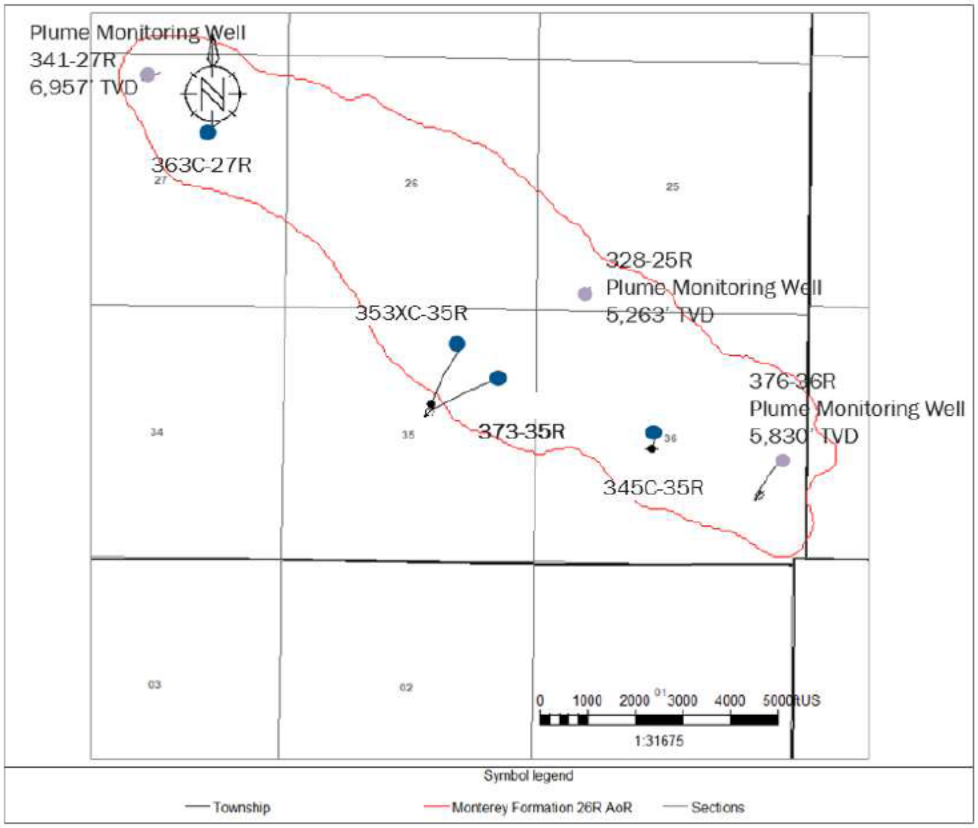

Figure 2: Monterey Formation 26R sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.

Table 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 9. Detection limits, precisions, and quality control requirements for these methods are presented in Table 3 of the QASP.

Table 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)	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Formation 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Once	Quarterly	Annual
		Pressure		6910' MD	Baseline	Continuous	Continuous
		Temperature		6910' MD	Baseline	Continuous	Continuous
		Fluid Sampling	328-25R	5268' - 5800' MD	Once	Quarterly	Annual

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
	Monterey Formation 26R	Pressure		5188' MD	Baseline	Continuous	Continuous
		Temperature		5188' MD	Baseline	Continuous	Continuous
	Monterey Formation 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Once	Quarterly	Annual
		Pressure		5760' MD	Baseline	Continuous	Continuous
		Temperature		5760' MD	Baseline	Continuous	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Baseline	Every year from start of injection	Every 5 years
			328-25R	5268' - 5800' MD			
			376-36R	5832' - 6815' MD			

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, 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 9.

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

As discussed in the AoR and Corrective Action Plan, 72% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and formation fluid 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 year during the injection phase.

CTV does not plan to conduct VSP monitoring for the depleted 26R oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Pressure Front Monitoring Location and Frequency

The aerial extent of plume development in the Monterey Formation 26R reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 3.

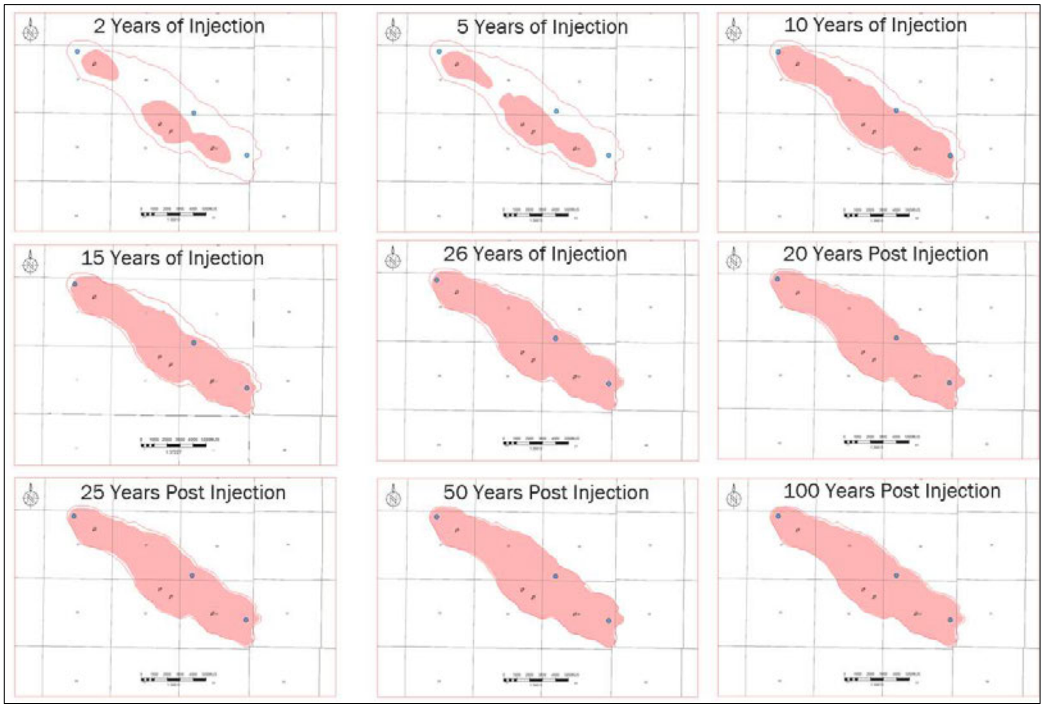

Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.

Monitoring well 328-25R pressure development based on computational modeling is shown in Figure 4. The average pore volume reservoir pressure stabilizes 1 year after the end of injection. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

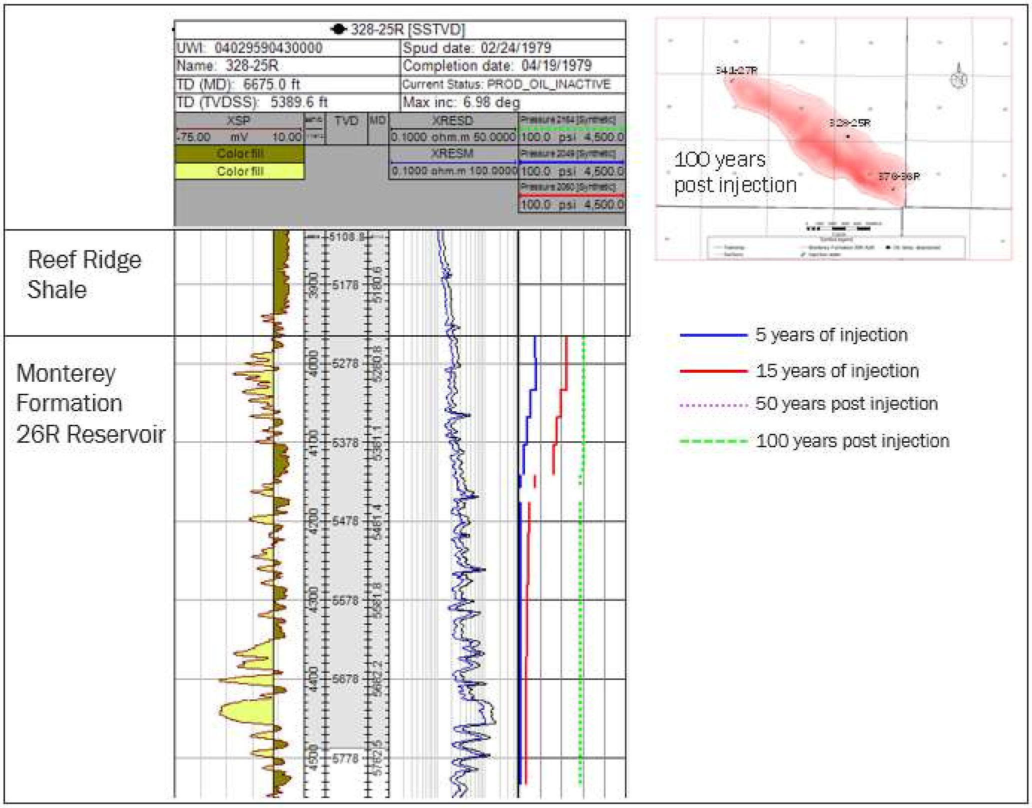

Figure 4: Monitoring well 328-25R showing the pressure increase through time from the computational modeling results.

Pressure Front Monitoring Details

Direct pressure monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 341-27R, 328-25R and 376-36R. The depleted Monterey Formation 26R oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post-injection. 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.

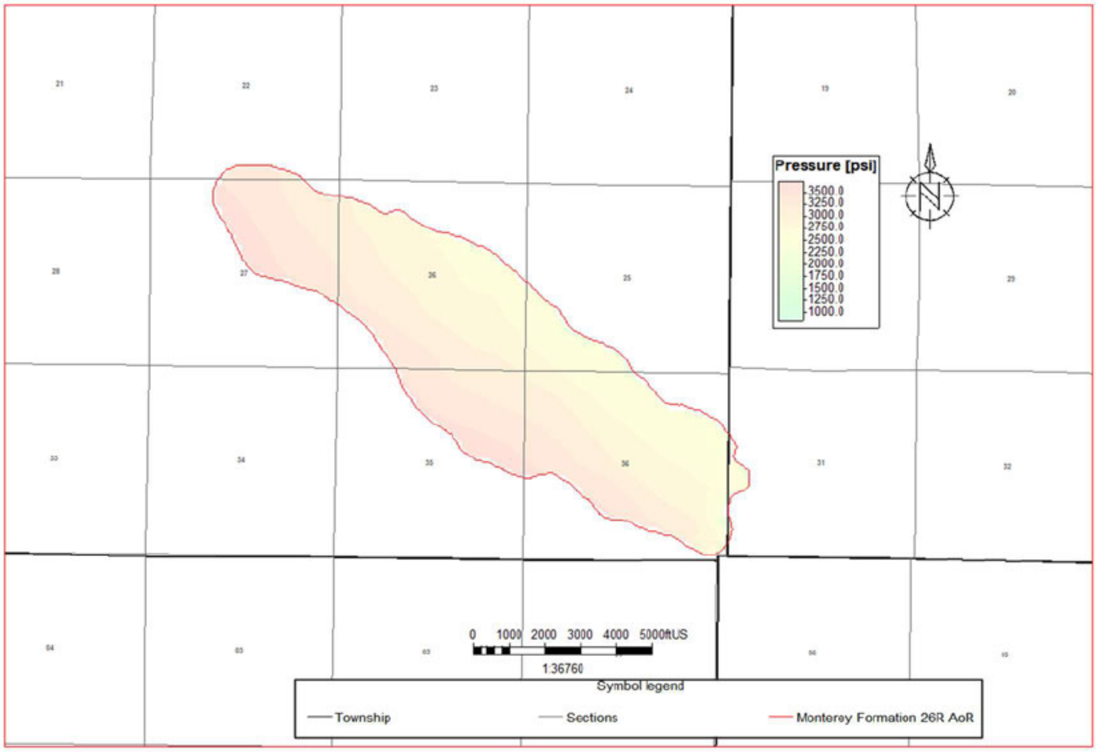

Figure 5: Monterey Formation 26R pressure 50 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

The modeled pressure increases at monitoring well 328-25R are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 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. Downhole gauge specifications are provided in Table 8 of the QASP document.

Table 10. 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)]	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
DIRECT MONITORING	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Baseline	Continuous
		Temperature			Baseline	Continuous

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. 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.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 6)
- Borehole sensors have been deployed (depths shown in Figure 6) 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

Baseline Analysis:

The monitoring network has been installed to collect seismicity data to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This 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_2 injection.

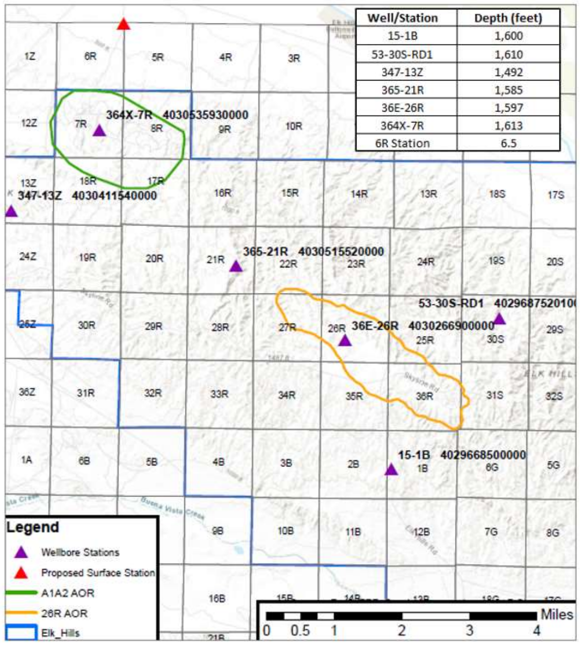

Figure 6: Elk Hills seismic monitoring network station location and depth of geophone sensors.

Monitoring Analysis:

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

- Waveform data to be 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 (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Surface Air Monitoring

Surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines will be conducted.

Continuous Monitoring of AOR

Broad aerial surface air monitoring will be conducted with eddy covariance towers. Eddy covariance towers are a widely used micrometeorological technique for direct high-speed measurements of the transport of gases, are a recommended component of CCS project surface air monitoring.

Each eddy covariance tower will consist of a solar-powered 3-dimensional sonic anemometer and open-path gas analyzer installed on a stationary tower and will be installed downwind of the prevailing wind direction from potential gas sources. Annual average prevailing wind direction in the vicinity is from the northwest. Proposed tower locations are displayed on Figure 7. Locations were chosen to be downwind (southeast) of the injection wells and surface expression of the simulated CO_2 plumes, to be in locally high topographic locations given the hilly terrain in the project vicinity, and in a location with access for equipment installation and servicing.

Monitoring equipment will be installed at a height of approximately 5 meters (33 feet). In general, the upwind distance represented by the tower height can be determined by the 1:100 rule; in this case with a 5-meter tower height the majority of measured flux will come from an oval-shaped area from near the tower to 500 meters (1,640 feet) upwind.

Gas emission rate is calculated from air density, vertical wind speed, and dry CO_2 mole fraction. Air density fluctuation is assumed to be negligible, wind speed will be measured with the sonic anemometer and CO_2 mole fraction with the gas analyzer. The sonic anemometer will be Campbell Scientific CSAT3 or equivalent, and CO_2 gas analyzer will be LI-COR Biosciences LI-7500A or equivalent. The gas analyzer will be positioned at or slightly below the sonic anemometer level, with a separation distance less than 20 centimeters. Vibration will be minimized by the use of several guy wires attached at the middle of the tower.

Manual cleaning of the gas analyzer will be performed on an as-needed basis when anomalous readings or excessive zero-drift in the data is observed. Factory calibration is assumed to be stable for at least several years and will be checked once per every six months as a precaution.

Data processing will be conducted and will be presented as hourly-averaged CO_2 concentrations and gas emission rates. Detection of anomalous and increasing CO_2 concentrations will lead to eddy covariance tower equipment testing and CARB consultation.

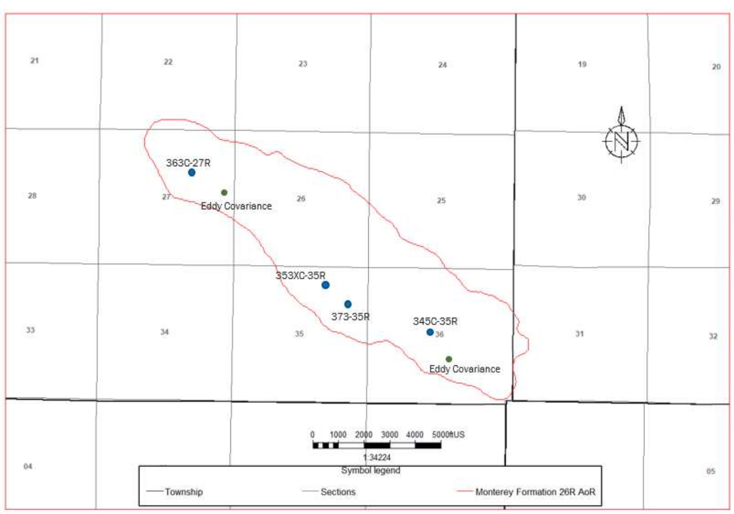

Figure 7: Location of Eddy Covariance monitoring.

Continuous Equipment Monitoring

Surface components of the injection system, including the flowlines and wellheads, will be monitored using equipment that will monitor for elevated CO_2. This leak detection equipment will be integrated with automated warning systems that notify the control center at the central facility, giving the operator the ability to remotely close the valves in the event of an anomalous reading. The central facility uses a SCADA software system to implement operational control decisions on a real-time basis throughout the project to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Monitoring Summary

This proposed monitoring program meets the goals of 40 CFR 146.90(g) by capturing continuous direct measurements of pressure and temperature in the storage reservoir (in-zone), Etchegoin (above zone) and USDW across key points of the AOR, in addition to frequent fluid samples and PNL to track the progress and confinement of the CO_2 plume. This data will also calibrate the dynamic model to predict plume front movement and pressure increase. In addition, the high resolution seismic monitoring network will provide a wide area measurement to indirectly monitor for pressure increase in-zone and above, that can be used in conjunction with the data from the monitoring wells to confirm confinement.

Direct:

The three in-zone monitoring wells are located close to the edges of the AOR, up-dip of the injectors, and thus in the flow direction of the less buoyant injected CO_2. The wells will be continuously measuring pressure and temperature at these locations. The continuous signals of pressure change in the reservoir will be used to update and calibrate the dynamic model and identify any major deviations from the predicted behavior of the reservoir. The continuous temperature measurements will provide data for the arrival of CO_2 at these locations.

In addition to the USDW and Etchegoin monitoring wells, the in-zone monitoring wells will provide confirmation of the confinement of CO_2 to the injection zone by also continuously measuring temperature changes in the Etchegoin and USDW (via DTS). Periodic fluid sampling at these locations will confirm the continuous pressure and temperature data, by providing measurements of CO_2 concentration in the reservoir that can further calibrate the dynamic model. Thus, the direct measurements for the injection zone through these wells will provide adequate special coverage of the development of the plume and pressure front, which can also improve the accuracy of the dynamic model predictions.

The two centrally located monitoring wells in the Etchegoin formation and USDW will continuously measure pressure and temperature in their respective zones, thus providing continuous direct measurements to assess the confinement of the injected CO_2. In addition, the continuous temperature measurements at these two locations, combined with the temperature measurement covering the Etchegoin and USDW at the three in-zone monitoring wells will provide adequate spatial coverage across the AOR to evaluate confinement of CO_2 in the storage reservoir.

Indirect:

PNL at the three in-zone monitoring wells will provide indirect measurement of gas saturation and CO_2 concentration in the injection zone, which will track the progress and confinement of the plume and further calibrate the dynamic model.

The seismic monitoring network will provide an indirect measurement of the pressure increase in the injection zone, the Etchegoin and the USDW. The seismic monitoring network will be sufficient to resolve events greater than 0 magnitude, with a 1,000 ft vertical resolution at the injection depths and above, giving us the ability to differentiate between events in the injection zone versus events in the shallower Etchegoin or USDW. This provides an indirect way to monitor for pressure increases in-zone or above zone via seismic events that could be triggered from pressure changes due to CO_2 injection or fluid migration.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

U.S. ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT

DRAFT PERMIT

CLASS VI INJECTION WELL

Permit Number: R9UIC-CA6-FY22-1.2

Well Name: 345C-36R

Issued to:

Carbon TerraVault JV Storage Company Sub 1, LLC

Table of Contents

<u>LIST OF ATTACHMENTS</u>

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 9
75 Hawthorne St.
San Francisco, CA 94105-3901

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS VI

Permit Number: R9UIC-CA6-FY22-1.2
Facility Name: CTV 1: Elk Hills 26R

Pursuant to the Safe Drinking Water Act and Underground Injection Control regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 124, 144, 146, and 147,

Carbon TerraVault JV Storage Company Sub 1, LLC of Tupman, CA

hereinafter, the permittee, is hereby authorized to construct and operate a Class VI injection well located in the State of California, Kern County, T 30 S, R 23 E of Mount Diablo Base Meridian, Section 36, 35° 16' 30.3383" N, 119° 27' 27.7825" W, as part of the Elk Hills 26R Carbon Dioxide Storage Project. The well will inject a carbon dioxide stream (carbon dioxide is also called CO_2 in the attachments to this permit) sourced initially from the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). All three initial carbon dioxide sources are to be located within the Elk Hills oil field. The permittee may request to inject carbon dioxide from additional emission sources in the future, subject to review and approval by EPA, as described in Section N of this permit. The permittee stated in their application that potential future sources of carbon dioxide may include: post combustion capture from the Elk Hills power plant, renewable fuel plants, post combustion capture from steam generators, other power plants, and industrial sources. The carbon dioxide stream, as characterized in the permit application and the administrative record, shall be a liquid, supercritical fluid, or gas. Injection is authorized into the Monterey Formation at a depth of approximately 6,000 feet below ground surface upon the express condition that the permittee meet the restrictions set forth herein. The designated confining zone for this injection is the Reef Ridge Shale Formation.

Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, directs federal agencies, to the greatest extent practical and permitted by law, to identify and address, as appropriate, disproportionate, and adverse human health or environmental impacts on people of color and low-income populations. See Exec. Order No. 12898, 59 Fed. Reg. 7629 (Feb. 11, 1994). Recently, Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All*, supplemented this direction. See Exec. Order No. 14096, 88 Fed. Reg. 25251 (Apr. 21, 2023). As part of the decision-making process for this permit, EPA considered these executive orders and EPA's Environmental Justice Guidance for UIC Class VI Permitting and Primacy (Aug. 17, 2023). EPA's evaluation and consideration of environmental justice for this permit is described in EPA's Fact Sheet.

This permit is for the construction and operation of one Class VI injection well (well name 345C-36R); three other wells at the Elk Hills 26R Carbon Dioxide Storage Project are authorized under separate Class VI permits (Permit Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4). Injection shall not commence until the operator has received written authorization from the Director of the Water Division of EPA Region 9, in accordance with Section S of this permit.

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit as enforceable conditions:

- A: Summary of Operating Requirements;
- B: Area of Review and Corrective Action Plan;
- C: Testing and Monitoring Plan;
- D: Well Plugging Plan;
- E: Post-injection Site Care and Site Closure Plan;
- F: Emergency and Remedial Response Plan;
- G: Construction Details;
- H: Financial Assurance Demonstration; and
- I: Stimulation Program.

This permit shall become effective on [Insert date], and shall remain in full force and effect during the operating life of the well and the post-injection site care period until site closure is authorized and completed, unless this permit is revoked and reissued, terminated, or modified pursuant to 40 CFR 144.39, 144.40, or 144.41. This permit shall also remain in effect upon delegation of primary enforcement responsibility of the UIC program for Class VI wells to the State of California until such time as the State issues its own permit to the permittee or the State chooses to adopt this permit as a State permit. The permit will expire in one year, if the permittee fails to commence construction on the well, unless a written request in electronic format for an extension of this one-year period has been approved by the Director. The permittee may request an expiration date sooner than the one-year period, provided no construction on the well has commenced. At least every five years from the effective date specified above, the permittee must re-evaluate the Area of Review and comply with 40 CFR 146.84(e). If results from the re-evaluated Area of Review are different from what is predicted in Attachment B of this permit, EPA may require the permittee to update the permit and the attachments.

Signed and Dated: ______________________

DRAFT

____

[Insert Name of signing official]
[Insert Title, Office/Division]

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is authorized to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs) or any unauthorized zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a). Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA.

Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this permit, nor compliance with its terms, shall be construed to relieve the permittee of any duties under applicable State or local laws or regulations that are not preempted or superseded by the Federal SDWA Underground Injection Control (UIC) program.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination –** The Director of the Water Division of Region 9 of the U.S. Environmental Protection Agency (EPA), hereinafter, the Director, may, for cause or upon request from any interested person, including the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. **Minor Modifications –** Upon the consent of the permittee, the Director may modify this permit to make the corrections or allowances for minor changes in the permitted activity as listed in 40 CFR 144.41. Any permit modification not processed as a minor modification under 40 CFR 144.41 must be made for cause, and with part 124 draft permit and public notice as required in 40 CFR 144.39.

3. **Transfer of Permits** – This permit is not transferable to any person except in accordance with 40 CFR 144.38(a) and Section O(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR part 2 (Public Information) and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim must be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2.

E. DEFINITION

All terms used in this permit shall have the meaning set forth in the SDWA and Underground Injection Control regulations specified at 40 CFR parts 124, 144, 146, and 147. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Duty to Comply** – The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. **Duty to Reapply** – If the permittee wishes to continue an activity regulated by this permit after the expiration or termination of this permit, the permittee must apply for and obtain a new permit.

3. **Penalties for Violations of Permit Conditions** – Any person who violates a permit requirement is subject to civil penalties and other enforcement action under the SDWA. Any person who willfully violates permit conditions may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

4. **Need to Halt or Reduce Activity Not a Defense –** It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. **Duty to Mitigate** – The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. **Proper Operation and Maintenance** – The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. **Duty to Provide Information** – The permittee shall furnish to the Director in an electronic format, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit or the UIC regulations. The permittee shall also furnish to the Director, upon request within a time specified, electronic copies of records required to be kept by this permit.

8. **Inspection and Entry** – The permittee shall allow the Director or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are kept under the conditions of this permit;

   (c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

   (d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

9. **Signatory Requirements** – All reports or other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with 40 CFR 144.32.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The permittee shall maintain and comply with the approved Area of Review and Corrective Action Plan (Attachment B of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.84.

2. As delineated in Attachment B, 157 wellbores within the AoR require plugging because the wellbores penetrate the injection zone or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are required to be properly plugged and abandoned prior to authorization of carbon dioxide injection.

3. At least sixty (60) days prior to commencing corrective action, the permittee shall submit procedures for performing corrective action on the identified deficient wells within the AoR and not commence any corrective action until the procedures are approved by the Director.

   (a) As corrective action activities are completed, the permittee shall provide periodic updates, including plugging reports, to the Director.

   (b) Corrective action on all deficient wells in the AoR must be complete, and approved in writing by EPA, before the permittee may commence injection pursuant to Section Q(3) of this permit.

4. At a fixed frequency of every five years, or more frequently when monitoring and operational conditions warrant, the permittee must reevaluate the area of review and perform any necessary corrective action in the manner specified in 40 CFR 146.84. The first reevaluation shall be completed no later than 5 years from the effective date of this permit unless the Director requests an earlier reevaluation. After conducting an AoR reevaluation, the permittee shall update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

5. Following each AoR reevaluation, the permittee shall submit the resultant information (i.e., the completed reevaluation analysis, along with either a revised AoR and Corrective Action Plan or a demonstration that the reevaluation analysis determined no revised Plan is needed) in an electronic format to the Director for review and approval. If a revised AoR and Corrective Action Plan is submitted and approved by the Director, the revised Plan becomes an enforceable condition of this permit.

6. To ensure permit activities do not increase environmental impacts, resource needs, and public health risks in already overburdened communities, along with the submittal of a

revised AoR and Corrective Action Plan, the permittee shall submit an updated EJScreen analysis that incorporates the revised AoR boundary.

H. FINANCIAL RESPONSIBILITY

1. **Financial Responsibility** – The permittee shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The permittee must maintain financial responsibility until site closure is authorized from the director as described in Section Q of this permit. Compliance with the financial responsibility requirements, including the applicable duration, described in this permit shall not relieve the permittee from complying with any other applicable Federal, State, and local financial responsibility requirements that are not preempted or superseded by the Federal SDWA UIC program.

   The financial instrument(s) must be sufficient to cover the cost of:

   (a) Corrective action (that meets the requirements of 40 CFR 146.84);

   (b) Injection well plugging (that meets the requirements of 40 CFR 146.92);

   (c) Post injection site care and site closure (that meets the requirements of 40 CFR (146.93) and;

   (d) Emergency and remedial response (that meets the requirements of 40 CFR 146.94).

   The permittee submitted a letter of credit, with a standby trust agreement, to cover financial assurance for items 1(a), (b), and (c) and submitted a certificate of insurance with details about a third-party insurance policy it will secure to cover financial assurance for 1(d). The EPA-approved financial assurance mechanisms are found in Attachment H and in the administrative record of this permit.

   The total initial cost estimates for these activities to be covered by the approved financial assurance mechanisms is $33,672,785. This amount covers all four Class VI injection well permits for the Elk Hills 26R CO_2 Storage Project.

2. **Cost Estimate Updates** – During the active life of the geologic sequestration project, the permittee must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format. The permittee must also provide to the Director written updates in an electronic format of adjustments to the cost estimate within 60 days of any amendments to the Project Plans included as Attachments B – F of this permit, which address items (a) through (d) in Section H(1) of this permit.

3. **Notification** –

(a) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the permittee, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase.

(b) Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the permittee has submitted a justification for the reduced cost estimate and received written approval from the Director. For requested reductions in the face amount of a financial instrument, the Director may provide notice to the public of the proposed reduction, prior to finalizing approval of the reduction.

(c) The permittee must notify the Director by certified mail and in an electronic format of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action or Emergency and Remedial Response.

(i) If the permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the permittee must notify the Director by certified mail and in an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the permittee as debtor, within 10 days after commencement of the proceeding.

(ii) A permittee who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

4. **<u>Establishing Other Coverage</u>** – The permittee must establish other financial assurance or liability coverage acceptable to the Director, within 60 days of the occurrence of the events in Section H(2) or H(3) of this permit.

I. CONSTRUCTION

1. **<u>Siting</u>** – The permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at 40 CFR 146.83.

2. **<u>Casing and Cementing</u>** – Casing and cement or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may

be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must prevent the movement of fluids into or between USDWs for the expected life of the well in accordance with 40 CFR 146.86. The casing and cement used in the construction of this well are shown in Attachment G of this permit and in the administrative record for this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

3. **<u>Tubing and Packer Specifications</u>** – Tubing and packer materials used in the construction of the well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The permittee shall inject only through tubing with a packer set within the long string casing at a point within or below the confining zone immediately above the injection zone. The tubing and packer used in the well are represented in engineering drawings contained in Attachment G of this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

J. PRE-INJECTION TESTING

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at 40 CFR 146.87. This testing shall provide data sufficient to address the pre-operational testing objectives identified in Attachment G of this permit, including:

   (a) Logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

   (i) Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);

   (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);

   (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);

   (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); and

   (v) Any alternative methods that are required by or approved by the Director pursuant to 40 CFR 146.87(a)(5).

   (b) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of 40 CFR 146.87(b);

(c) Records of the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of 40 CFR 146.87(c);

(d) Tests to provide information about the injection and confining zones, including calculated fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of 40 CFR 146.87(d); and

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 CFR 146.87(e), including:

(i) A pressure fall-off test; and

(ii) A pumping test or injectivity tests.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for logging and testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee must provide the Director or their representative with the opportunity to witness all logging, sampling, and testing required under this Section.

K. OPERATIONS

1. **Injection Fluids/Carbon Dioxide Sources –** The permittee will capture carbon dioxide from multiple sources during the life of the permit for injection into the Class VI well. Three initial sources of carbon dioxide are approved sources for injection: the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). The permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by EPA, as described in Section N of this permit.

2. **Injection Pressure Limitation** – The permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure limit is listed in Attachment A.

3. **Stimulation Program** – Pursuant to requirements at 40 CFR 146.82(a)(9), all stimulation programs proposed by the permittee must be approved by the Director as a permit modification and incorporated into Attachment I of this permit.

4. **Additional Injection Limitation** – No injectate other than that which has been analyzed and approved by the Director under this permit in accordance with Section N of this permit shall be injected except fluids used for rework, and well tests as approved by the Director.

5. **Annulus Fluid** – The permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

6. **Annulus/Tubing Pressure Differential** – Except during workovers or times of annulus maintenance, the permittee must maintain on the annulus a pressure that exceeds the operating injection pressure as specified in Attachment A of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

7. **Automatic Alarms and Automatic Shut-off System** –

   (a) The permittee must:

   (i) Install, continuously operate, and maintain an automatic alarm and an automatic shut-off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

   (ii) Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

   (iii) Establish well-specific thresholds for activating the shut-off system and submit a revised Attachment A to the Director prior to the Director authorizing injection.

   (b) Testing under this Section must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or his or her representative unless the Director authorizes an unwitnessed test in advance. The permittee must provide notice in an electronic format 30 days prior to running the test and must provide the Director or their representative the opportunity to attend. The test must be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

8. **Precautions to Prevent Well Blowouts** – At all times, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall

follow procedures such as those below to assure that a backflow or blowout does not occur:

(a) Limit the temperature and/or corrosivity of the injectate; and

(b) Develop procedures necessary to assure that pressure imbalances do not occur.

9. **Circumstances Under Which Injection Must Cease** –

Injection shall cease when any of the following circumstances arise:

(a) Failure of the well to pass a mechanical integrity test;

(b) A loss of mechanical integrity during operation;

(c) The automatic alarm or automatic shut-off system is triggered;

(d) A significant unexpected change in the annulus or injection pressure;

(e) The Director determines that the well lacks mechanical integrity; or

(f) The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Director determines that injection should cease.

10. **Approaches for Ceasing Injection** –

(a) The permittee must shut-in the well by gradual reduction in the injection pressure as outlined in Attachment A of this permit; or

(b) The permittee must immediately cease injection and shut-in the well as outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

L. MECHANICAL INTEGRITY

1. **Standards** – Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. To meet these requirements, mechanical integrity tests/demonstrations must be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. To conduct testing without an EPA representative, the following procedures must be followed.

(a) The permittee must submit prior notification in an electronic format within the time period specified in Section L(3) of this permit and if EPA informs the permittee that no

EPA representative is available this must be documented in the approved plan and testing report. The permittee must receive permission from the Director to proceed;

(b) The test must be performed in accordance with the Testing and Monitoring Plan (Attachment C of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest; and

(c) A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

2. **Mechanical Integrity Testing** – The permittee shall conduct a casing inspection log and mechanical integrity testing as follows:

(a) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate internal mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A pressure test with liquid or gas; and

(ii) A casing inspection log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(b) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A tracer survey such as an oxygen activation log; or

(ii) A temperature or noise log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(c) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee must continuously monitor injection pressure, injection rate, injection volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume as specified in 40 CFR 146.88(e) and 146.89(b).

(d) At least once per year, the permittee must perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89(c):

(i) An Administrator-approved tracer survey such as an oxygen-activation log; or

(ii) A temperature or noise log. The Director may require such tests whenever the well is worked over; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(e) After any workover that may compromise the internal mechanical integrity of the well, the well shall be tested by means of a pressure test approved by the Director and the well must pass the test to demonstrate mechanical integrity.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in the Injection Well Plugging Plan and that meets the requirements of 40 CFR 146.92(a).

(g) The Director may require the use of any other tests to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator pursuant to requirements at 40 CFR 146.89(e).

3. **<u>Prior Notice and Reporting</u>** –

(a) The permittee shall notify the Director in an electronic format of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Director, a shorter time period may be allowed.

(b) Reports of mechanical integrity demonstrations which include logs must include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within the time period specified in Section O(4) of this permit.

4. **<u>Gauge and Meter Calibration</u>** – The permittee shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test. Pressure gauge resolution shall be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Director prior to the test.

5. **<u>Loss of Mechanical Integrity</u>** –

(a) If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee must:

(i) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

(ii) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, implement the Emergency and Remedial Response Plan (Attachment F of this permit);

(iii) Follow the reporting requirements as directed in Section O of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) After receiving written approval to resume injection, notify the Director in an electronic format when injection is expected to resume.

(b) If a shutdown (*i.e.,* down-hole or at the surface) is triggered, the permittee must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required indicates that the well may be lacking mechanical integrity, the permittee must take the actions listed above in Section L(5)(a)(i) through (v).

(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity Testing on Request From Director** – The permittee shall demonstrate mechanical integrity at any time upon written notice from the Director.

M. TESTING AND MONITORING

1. **Testing and Monitoring Plan** –

(a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan (Attachment C of this permit) and with the requirements at 40 CFR 144.51(j), 146.88(e), and 146.90. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit must be submitted to the Director in an electronic format for approval at least 30 days prior to the test. In performing all testing and monitoring under this permit, the permittee must follow the procedures approved by the Director.

If the permittee is unable to follow the EPA-approved procedures, then, the permittee must contact the Director at least 30 days prior to testing to discuss options, if any are feasible. When the test report is submitted, a full explanation must be provided as to why any approved procedures were not followed. If the approved procedures were not followed, EPA may take an appropriate action, including but not limited to, requiring the permittee to re-run the test.

(b) The permittee must update the Testing and Monitoring Plan as required at 40 CFR 146.90 (j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(2) of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of monitoring wells or newly permitted injection wells within the AoR, or when required by the Director.

(c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis** – The permittee shall analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(a).

3. **Continuous Monitoring** – The permittee shall maintain continuous monitoring devices and use them to monitor injection pressure, flow rate, volume, the pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature. This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(b). The permittee shall maintain for EPA's inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

4. **Corrosion Monitoring** – The permittee shall perform corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with 40 CFR 146.90(c) to ensure that the well components meet the minimum standards for material strength and performance set forth in 40 CFR 146.86(b).

5. **Ground Water Quality Monitoring** – The permittee shall monitor ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones. This monitoring shall be performed for the parameters identified in the Testing and Monitoring Plan at the

locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(d).

6. **External Mechanical Integrity Testing** – The permittee shall demonstrate external mechanical integrity as described in the Testing and Monitoring Plan and Section L of this permit to meet the requirements of 40 CFR 146.90(e).

7. **Pressure Fall-Off Test** – The permittee shall conduct a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f).

8. **Plume and Pressure Front Tracking** –The permittee shall track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) as described in the Testing and Monitoring Plan.

   (a) The permittee shall use direct methods to track the position of the carbon dioxide plume and the pressure front in the injection zone as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(1).

   (b) The permittee shall use indirect methods to track the position of the carbon dioxide plume and pressure front as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(2).

   (c) If any indirect monitoring performed under Section M(8)(b) of this Permit detects increased pressure above the confining zone or other unanticipated results, the permittee shall increase the frequency of geochemical sampling under Section M(8)(a) to monthly sampling.

   (d) If data collection performed under Section M(8)(a) and M(8)(b) of this permit detects increased pressure above the confining zone or other unanticipated results the Director may require installation of additional monitoring wells.

9. **Surface Air and/or Soil Gas Monitoring** –

   (a) The permittee shall conduct any surface air monitoring or soil gas monitoring required by the Director to detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(h).

   (b) Any surface air monitoring or soil gas monitoring described in the Testing and Monitoring Plan of this Permit must not conflict with air monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting, and Verification (MRV) plan under 40 CFR part 98, Subpart RR, monitoring required for California's Low-Carbon Fuel Standard program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

10. **Leak Detection Monitoring** -

(a) The permittee shall conduct any leak detection monitoring at the wellhead required by the Director to ensure injection well integrity and detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan.

(b) Any leak detection monitoring described in the Testing and Monitoring Plan of this Permit should be consistent with EPA's document "Leak Detection and Repair – A Best Practices Guide" (October 2007), and must not conflict with leak detection monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting and Verification (MRV) plan under 40 CFR part 98, subpart RR, monitoring required for California's Low-Carbon Fuel Standard program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

11. **Additional Monitoring** – If required by the Director as provided in 40 CFR 146.90(i), the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 40 CFR 146.86(a). This monitoring shall be performed as described in a modification to the Testing and Monitoring Plan.

N. INJECTION OF CARBON DIOXIDE FROM ADDITIONAL SOURCES

1. The permittee must receive written approval from the Director before injecting carbon dioxide from a source that is not fully described in Attachment B of this permit. Carbon dioxide from additional sources will not be approved if the Director determines that the carbon dioxide stream from the proposed additional source is incompatible, or will adversely interact, with the injection well material, injection formation, or confining zone.

2. Proposed additional sources of carbon dioxide will be evaluated by EPA to determine if the additional source is approvable, and if so, whether its addition requires a major permit modification or a minor permit modification.

(a) Conditions that will result in a major permit modification include, but are not limited to, if the proposed additional source of carbon dioxide meets any of the following:

i. The addition of the proposed carbon dioxide source would increase the injection volume or injection pressure above the amount authorized in this permit; or

ii. The proposed additional carbon dioxide source is determined to have a chemical composition outside of the range of injectate compositions listed in Attachment B of this permit, or

iii. The addition of the proposed carbon dioxide source would interfere with the operation of the facility or its ability to meet conditions described in the permit; or

iv. The addition of the proposed carbon dioxide source would result in a material and substantial alteration or addition to the permitted Class VI injection activity which justifies the application of permit conditions that are different or absent in the existing permit; or

v. The Director determines that addition of the proposed carbon dioxide source does not meet criteria for a minor permit modification.

3. In proposing an additional source of carbon dioxide for the Director's approval, the permittee shall provide the Director with the following information:

(a) The analytical parameters of the proposed additional carbon dioxide stream from the proposed source as described in the Testing and Monitoring Plan of this permit;

(b) A description of the industry in which the proposed additional carbon dioxide stream will be produced from;

(c) The name and address of the proposed additional carbon dioxide source;

(d) An evaluation of the impact the proposed carbon dioxide source (the creation, capture, and transportation of carbon dioxide) will have on criteria pollutant and hazardous air pollutant emissions in the area; and

(e) An assessment of the compatibility of the carbon dioxide stream with subsurface fluids and minerals, and assurance that the construction materials of the injection wells and other wells that may encounter the injected plume are still compatible (e.g., will not corrode over time due to the chemical interactions).

4. All proposed additional sources of carbon dioxide will require pre-approval by Kern County Planning and Natural Resources Department, and any necessary mitigation measures pursuant to an approved Conditional Use Permit and Environmental Impact Report.

5. The public shall be notified within 30 days when a proposed additional carbon dioxide source is submitted to EPA for review.

6. The public shall be notified 30 days before the injection of an EPA-approved additional

carbon dioxide stream is injected.

O. REPORTING AND RECORDKEEPING

1. **Electronic Reporting** – Electronic reports, submittals, notifications, and records made and maintained by the permittee under this permit must be in an electronic format approved by EPA. The permittee shall electronically submit all required reports to the Director at:

   https://epa.velo.pnnl.gov/operators

2. **Semi-Annual Reports** – The permittee shall submit semi-annual reports containing:

   (a) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

   (b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;

   (c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

   (d) A description of any event which triggers the shut-off systems required in Section K(6) of this permit pursuant to 40 CFR 146.88(e), and the response taken;

   (e) The monthly volume or mass of the carbon dioxide stream injected over the reporting period and the volume or mass injected cumulatively over the life of the project;

   (f) Monthly annulus fluid volume added or produced; and

   (g) Results of the continuous monitoring required in Section M(3), including:

      (i) A tabulation of: (1) daily maximum injection pressure; (2) daily minimum annulus pressure; (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure; (4) daily volume; (5) daily maximum flow rate; and (6) average annulus tank fluid level; and

      (ii) Graph(s) of the continuous monitoring as required in Section M(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and

   (h) Results of any additional monitoring identified in the Testing and Monitoring Plan and described in Section M of this permit.

3. **24-Hour Reporting** –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment or any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:

(i) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iii) Any triggering of the shut-off system required in Section K(6) of this permit (i.e., down-hole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

(b) A written submission shall be provided to the Director in an electronic format within five days of the time the permittee becomes aware of the circumstances described in Section O(3)(a) of this permit. The submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit); and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

4. **Reports on Well Tests and Workovers** – The permittee shall report, within 30 days, the results of:

(a) Periodic tests of mechanical integrity;

(b) Any well workover, including stimulation;

(c) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit.

5. **Advance Notice Reporting** –

   (a) **Well Tests** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.

   (b) **Planned Changes** – The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid and, as specified in Section N of this Permit, an analysis of any additional source of carbon dioxide, shall be submitted to the Director for review and written approval at least 60 days prior to injection; this approval may result in a permit modification.

   (c) **Anticipated Noncompliance** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

6. **Additional Reports** –

   (a) **Compliance Schedules** – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 30 days following each schedule date.

   (b) **Transfer of Permits** – This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

   (c) **Other Noncompliance** – The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section O(3)(b) of this permit.

   (d) **Other Information** – When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such facts or corrected information in an electronic format within 10 days in accordance with 40 CFR 144.51(l)(8).

(e) **Report on Permit Review** – Within 30 days from the effective date of this permit, the permittee shall certify to the Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

7. Records –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(d) The retention periods specified in Section O(7)(a) through (c) of this permit may be extended by request of the Director at any time. The permittee shall continue to retain records after the retention period specified in Section O(7)(a) through (c) of this permit or any requested extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) The name(s) of the individual(s) who performed the sampling or measurements;

(iii) A precise description of both sampling methodology and the handling of samples;

(iv) The date(s) analyses were performed;

(v) The name(s) of the individual(s) who performed the analyses;

(vi) The analytical techniques or methods used; and

(vii) The results of such analyses.

P. PUBLIC AVAILABILITY OF MONITORING AND COMPLIANCE DATA

1. The permittee shall develop and maintain a publicly accessible website with all available monitoring data collected under this Permit. The website must be accessible to persons with disabilities and compliant with Section 508, and it shall include:

   (a) Semi-annual monitoring reports and data;

   (b) An executive summary (in both English and Spanish) that interprets the Semi-annual monitoring reports and data;

   (c) Real-time display of data collected for any Surface Air/Soil Gas Monitoring required under Section M(9) and Leak Detection Monitoring required under Section M(10) of this Permit; and

   (d) Notification of any permit non-compliance on a quarterly basis, including the steps taken to resolve the non-compliance, and any actions taken to prevent a re-occurrence of the non-compliance.

Q. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

1. **<u>Well Plugging Plan</u>** – The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment D of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.92.

2. **<u>Revision of Well Plugging Plan</u>** – If the permittee finds it necessary to change the Well Plugging Plan (Attachment D of this permit), a revised plan shall be submitted in an electronic format to the Director for written approval. Any amendments to the Well Plugging Plan must be approved by the Director, must be incorporated into the permit and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41.

3. **<u>Notice of Plugging and Abandonment</u>** – The permittee must notify the Director in writing in an electronic format pursuant to 40 CFR 146.92(c), at least 60 days before plugging, conversion or abandonment of a well. At the discretion of the Director, a shorter notice period may be allowed.

4. **<u>Plugging and Abandonment Approval and Report</u>** –

   (a) The permittee must receive written approval of the Director before plugging the well and shall plug and abandon the well in accordance with 40 CFR 146.92, as provided in the Well Plugging Plan (Attachment D of this permit).

   (b) Within 60 days after plugging, the permittee must submit in an electronic format a plugging report to the Director. The report must be certified as accurate by the permittee and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for 10 years following site closure. The report must include:

(i) A statement that the well was plugged in accordance with the Well Plugging Plan previously approved by the Director (Attachment D of this permit); or

(ii) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger USDWs, the permittee shall re-plug the well as required by the Director.

5. **Temporary Abandonment** – If the permittee ceases injection into the well for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, 40 CFR 144.52 (a)(6), and 40 CFR 146.92, or make a demonstration of non-endangerment of this well while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well will be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements according to the frequencies outlined in the permit.

6. **Post-Injection Site Care and Site Closure Plan** –

(a) The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan (Attachment E of this permit), which meets the requirements of 40 CFR 146.93 and is an enforceable condition of this permit. The permittee shall:

(i) Upon cessation of injection, either submit in an electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

(ii) At any time during the life of the project, the permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval. The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information at 40 CFR 146.93(c)(1).

(b) The permittee shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered, as specified in the Post-Injection Site Care and Site Closure Plan and in 40 CFR 146.90, and 40 CFR 146.93, including:

(i) Ground water quality monitoring;

(ii) Tracking the position of the carbon dioxide plume and pressure front including direct pressure monitoring and geochemical plume monitoring and the use of indirect methods;

(iii) Any other required monitoring, e.g., soil gas and/or surface air monitoring described in the Post-Injection Site Care and Site Closure Plan;

(iv) The permittee shall submit in an electronic format the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan; and

(v) The permittee shall continue to conduct post-injection site monitoring for at least 50 years or for the duration of any alternative timeframe approved pursuant to 40 CFR 146.93(c) and the Post-Injection Site Care and Site Closure Plan.

(c) The post-injection monitoring must continue until the project no longer poses an endangerment to USDWs and the demonstration pursuant to 40 CFR 146.93(b)(2) and as described in Section Q(6)(d) of this permit is approved by the Director.

(d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section Q(5)(b) of this permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b)(3). The Director reserves the right to amend the post-injection site monitoring requirements (including extending the monitoring period) if the carbon dioxide plume and the associated pressure front have not stabilized or there is a concern that USDWs are being endangered.

(e) The permittee shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment E of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachment E of this permit – the Post-Injection Site Care and Site Closure Plan – in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report must include the information specified at 40 CFR 146.93(f).

(h) The permittee shall record a notation on the deed to the facility property or any other document that is normally examined during a title search that will in perpetuity provide any potential purchaser of the property the following information:

(i) The fact that land has been used to sequester carbon dioxide;

(ii) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and

(iii) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(i) The permittee shall retain for 10 years following site closure an electronic copy of the site closure report, records collected during the post-injection site care period, and any other records required under 40 CFR 146.91(f)(4). The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

R. EMERGENCY AND REMEDIAL RESPONSE

1. The Emergency and Remedial Response Plan describes actions the permittee must take to address movement of the injection or formation fluids, including surface leaks of carbon dioxide or other contaminants, that may cause an endangerment to a USDW or public health during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment F of this permit), which is an enforceable condition of this permit, and with 40 CFR 146.94.

   Prior to the Director authorizing injection, the permittee shall revise the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers, including any contracts or access agreements with local emergency response authorities, to perform the actions outlined in the Emergency and Remedial Response Plan, and shall confirm that any required payments were made to Kern County Planning and Natural Resources Department, as required by the approved Conditional Use Permits, for transfer to the Kern County Fire Department for equipment and training specific to the detection and control of emergency situations caused by the release of carbon dioxide.

2. If the permittee obtains evidence that the injected carbon dioxide or associated pressure front may cause endangerment to a USDW or public health, the permittee must:

   (a) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

   (b) Take all steps reasonably necessary to identify and characterize any release;

   (c) Notify the Director within 24 hours; and

   (d) Implement the Emergency and Remedial Response Plan (Attachment F of this permit) approved by the Director.

3. At least every five years, or more frequently when monitoring and operational conditions warrant, the permittee shall review and update the Emergency and Remedial Response Plan as required at 40 CFR 146.94(d) or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of injection wells, or when required by the Director.

4. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

S. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program and a demonstration that all pre-operational testing objectives have been met as specified in Section J of this permit and in 40 CFR 146.87 are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the well has been demonstrated in accordance with 40 CFR 146.89(a)(1) and (2), and in accordance with Section L(1) through (3) of this permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment B of this permit in accordance with 40 CFR 146.84;

4. All requirements at 40 CFR 146.82(c) have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, Testing and Monitoring, Well

Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. The permittee has submitted the results of an analysis of the physical and chemical characteristic of the carbon dioxide stream for all analytical parameters identified in the Testing and Monitoring Plan (Attachment C of this Permit).

6. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with 40 CFR 146.86 and Section I of this permit;

7. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of this permit;

8. The Director has approved demonstration of the alarm system and shut-off system under Section K(6) of this permit;

9. The Permittee has revised the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers in order to perform the actions outlined in the Emergency and Remedial Response Plan;

10. The Director has approved the publicly accessible website required under Section P of this permit; and

11. The Director has given written authorization to commence injection.

ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by 40 CFR parts 144 and 146. The permittee shall comply with these conditions and adhere to these plans as approved by the Director, as follows:

A. **SUMMARY OF OPERATING REQUIREMENTS**

B. **AREA OF REVIEW AND CORRECTIVE ACTION PLAN**

C. **TESTING AND MONITORING PLAN**

D. **WELL PLUGGING PLAN**

E. **POST-INJECTION SITE CARE AND SITE CLOSURE PLAN**

F. **EMERGENCY AND REMEDIAL RESPONSE PLAN**

G. **CONSTRUCTION DETAILS**

H. **FINANCIAL ASSURANCE DEMONSTRATION**

I. **STIMULATION PROGRAM**

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Elk Hills 26R Storage Project

Facility Information

Facility name:	Elk Hills 26R Storage Project 345C-36R
Well location:	Elk Hills Oil Field, Kern County, CA 35°16'30.3383"N / 6126575.64 119°27'27.7825"W / 2289589.31

Table 1. Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE
Maximum Injection Pressure - Surface	1888 psi
Maximum Injection Pressure - Bottomhole	3847 psi
Annulus Pressure	3074 psi
Annulus Pressure/Tubing Differential	300 psi
Maximum CO_2 Injection Rate	25 mmscfpd

There will be continuous monitoring of injection pressure, rate and annulus pressure for the injector, as described in the well Construction, Operation and Plugging details (COP) document for 345C-36R.

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined: using the fracture gradient of 0.701psi/ft obtained from Fracture stimulation data obtained from well 388-26R in the 26R reservoir multiplied by 0.9, per 40 CFR 146.88(a).

Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), the permittee will reduce CO_2 injection at a rate of 165 tons per day over a 6 day period to ensure protection of health, safety, and the environment. This procedure applies to routine shutdowns and to “gradual shutdowns” described in the Emergency and Remedial Response plan. (Procedures that address immediately shutting in the well are in the Emergency and Remedial Response Plan of this permit.)

Table 2. Class VI Injection Well Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
CO_2 stream characterization	Semi-annually
Injection pressure, injection rate, injection volume, pressure on the annulus, and annulus fluid level	Semi-annually
Corrosion monitoring	Semi-annually
External MITs	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Table 3. Class VI Project Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment B - AoR_CA	1	01/11/21
Attachment B - AoR_CA	2	05/31/22
Attachment B - AoR_CA	3	12/21/22
Attachment B - AoR_CA	4	05/14/2023
Attachment B – AoR_CA	5	6/23/2023

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase

- Liquid and gas relative permeability
- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.

2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

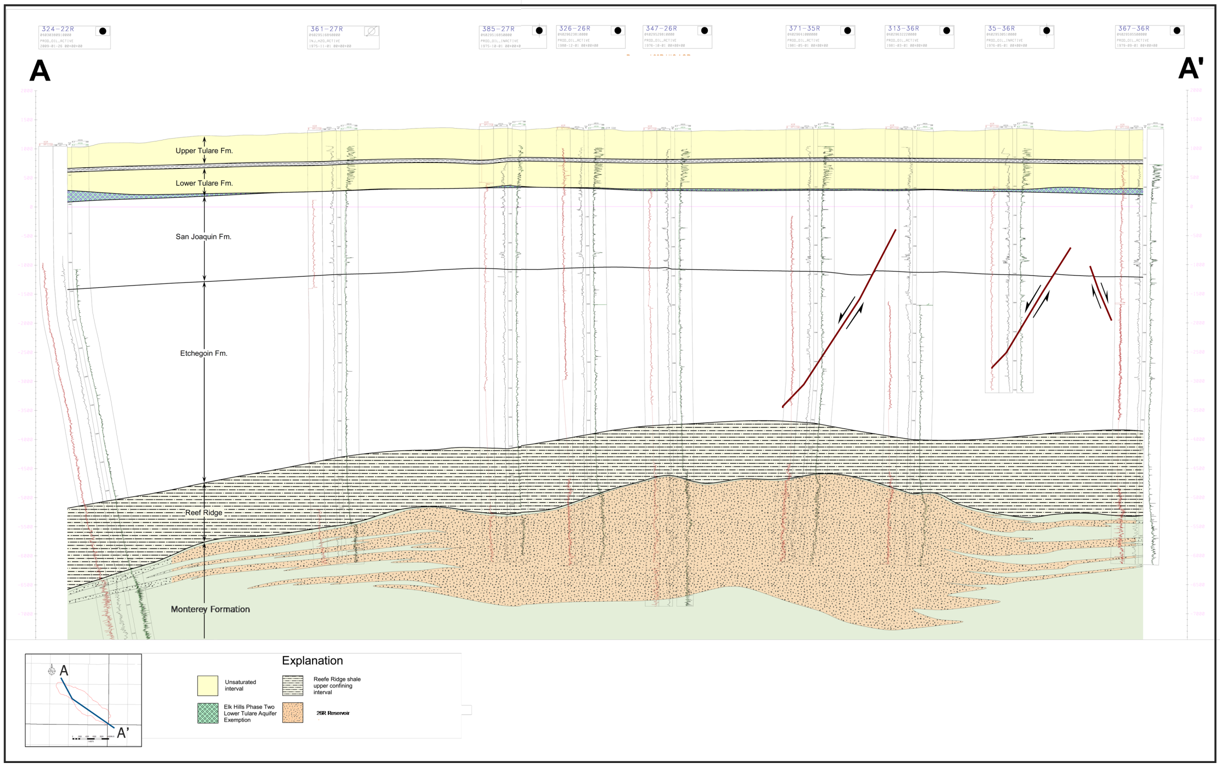
1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



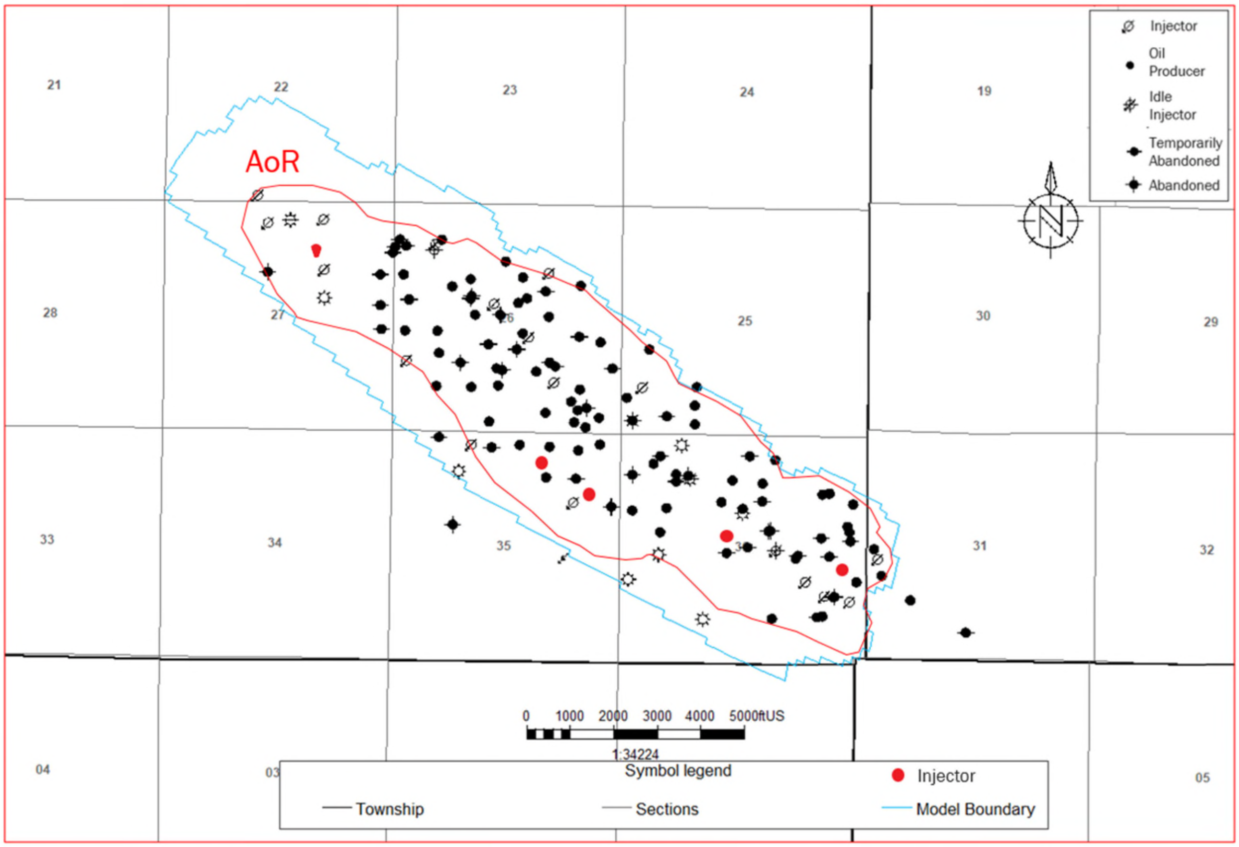
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2. The lateral dimensions and vertical thickness of the geomodel were chosen to capture the maximum extent of the mapped 26R reservoir. Well logs from the wells shown in Figure 2 were used to map the extent and delineate the edges of the reservoir where the reservoir sands pinchout or transition to shale. The total grid dimensions were chosen to adequately capture the reservoir properties and heterogeneity, while at the same time maintaining computational efficiency.

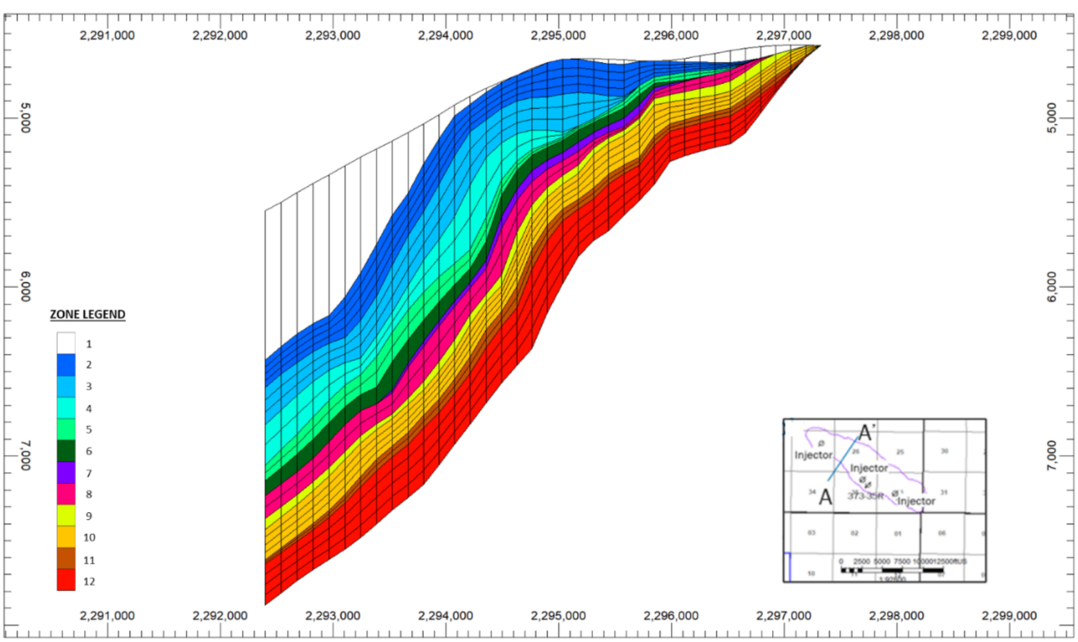
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Each of the 12 zones is a mappable sand and were modeled separately to ensure stationarity of the geostatistical model. With a data driven geostatistical model, the model can discretize the reservoir into multiple zones. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir showing the 12 zones, and the 27 layers. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Figure 4A shows how the log derived porosity compares to the upscaled model (synthetic) porosity for 363-27R (track five with log derived in black and the Upscaled model / synthetic porosity in blue). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4B) that is dependent on porosity and clay volume.

Figure 4A: Log derived and Model Upscaled (Synthetic porosity) for 363-27R (track five with log derived in black and the Upscaled model synthetic in blue).

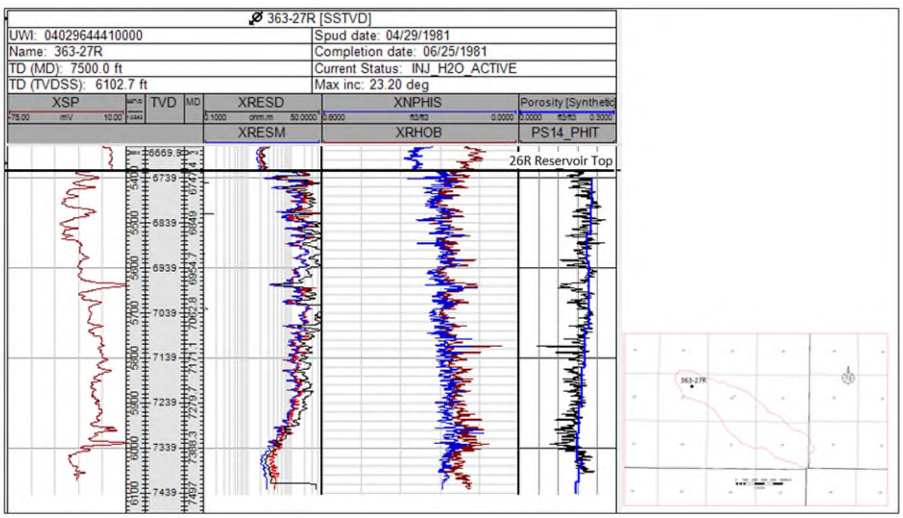


Figure 5B: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

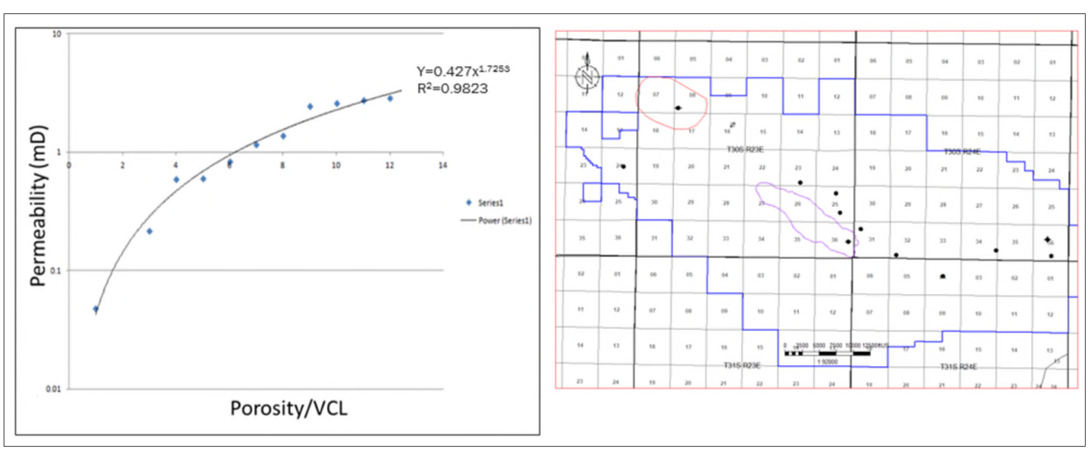


Figure 6: Monterey Formation 26R sands porosity and permeability distribution in the static model.

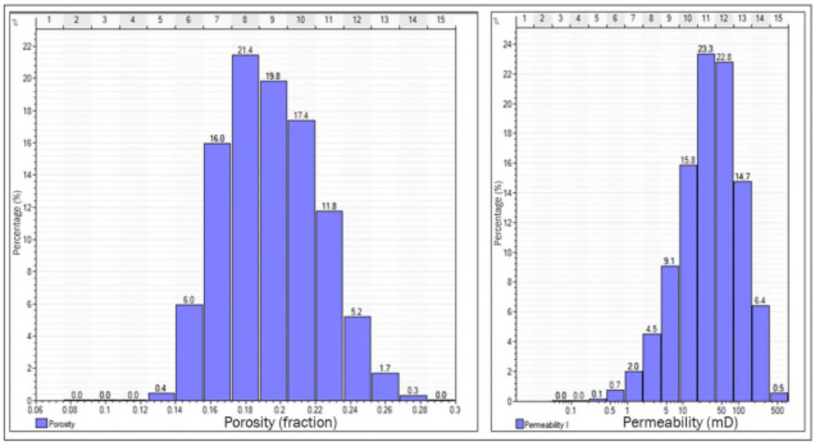
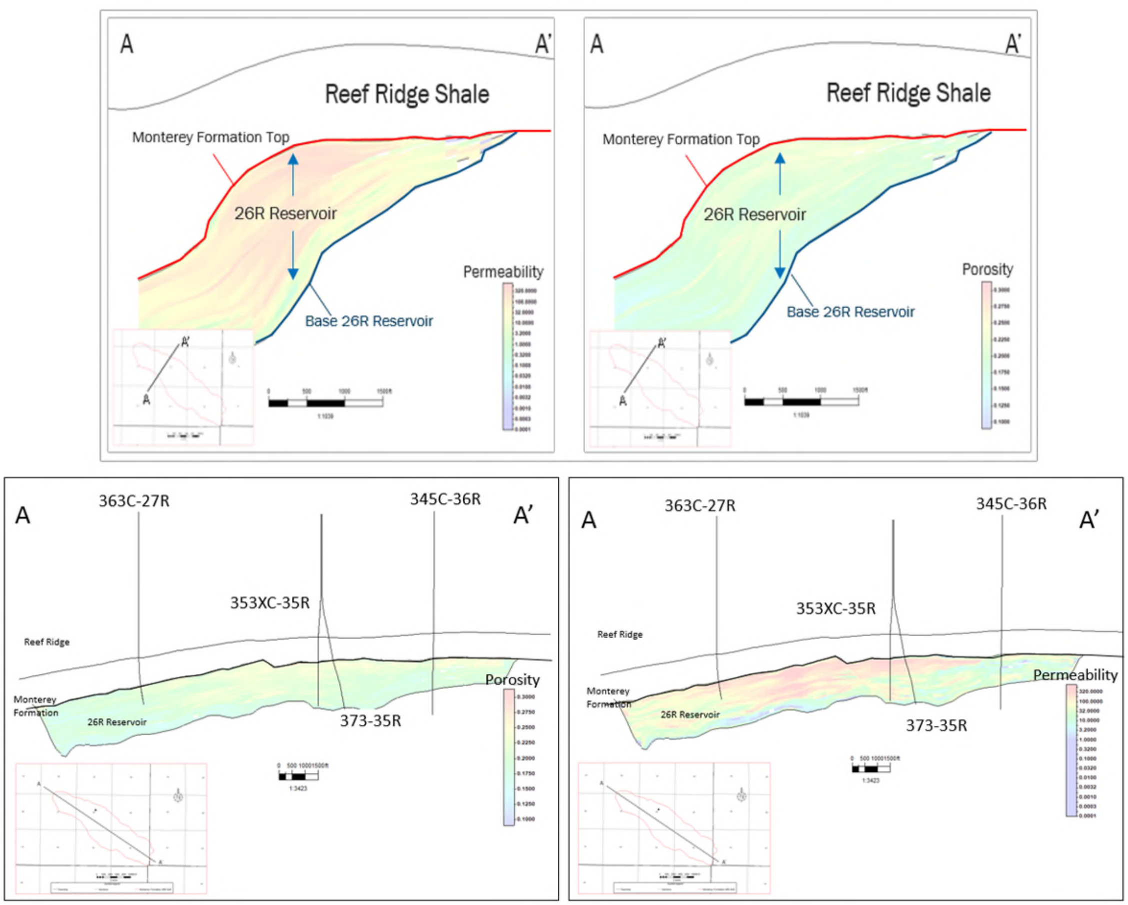


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands in the static model. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 7: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



A variable permeability anisotropy was included in the model, with a Vertical permeability (kv) to horizontal permeability (kh) ratio which ranged from 0.0001 to 1, with a log mean of value of 0.01. The permeability anisotropy was arrived at by upscaling log derived permeability, and then distributing the upscaled log data across the model domain. The log data was upscaled using an arithmetic mean to represent the horizontal permeability, and a harmonic mean to represent the vertical permeability.

Constitutive Relationships and Other Rock Properties

The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

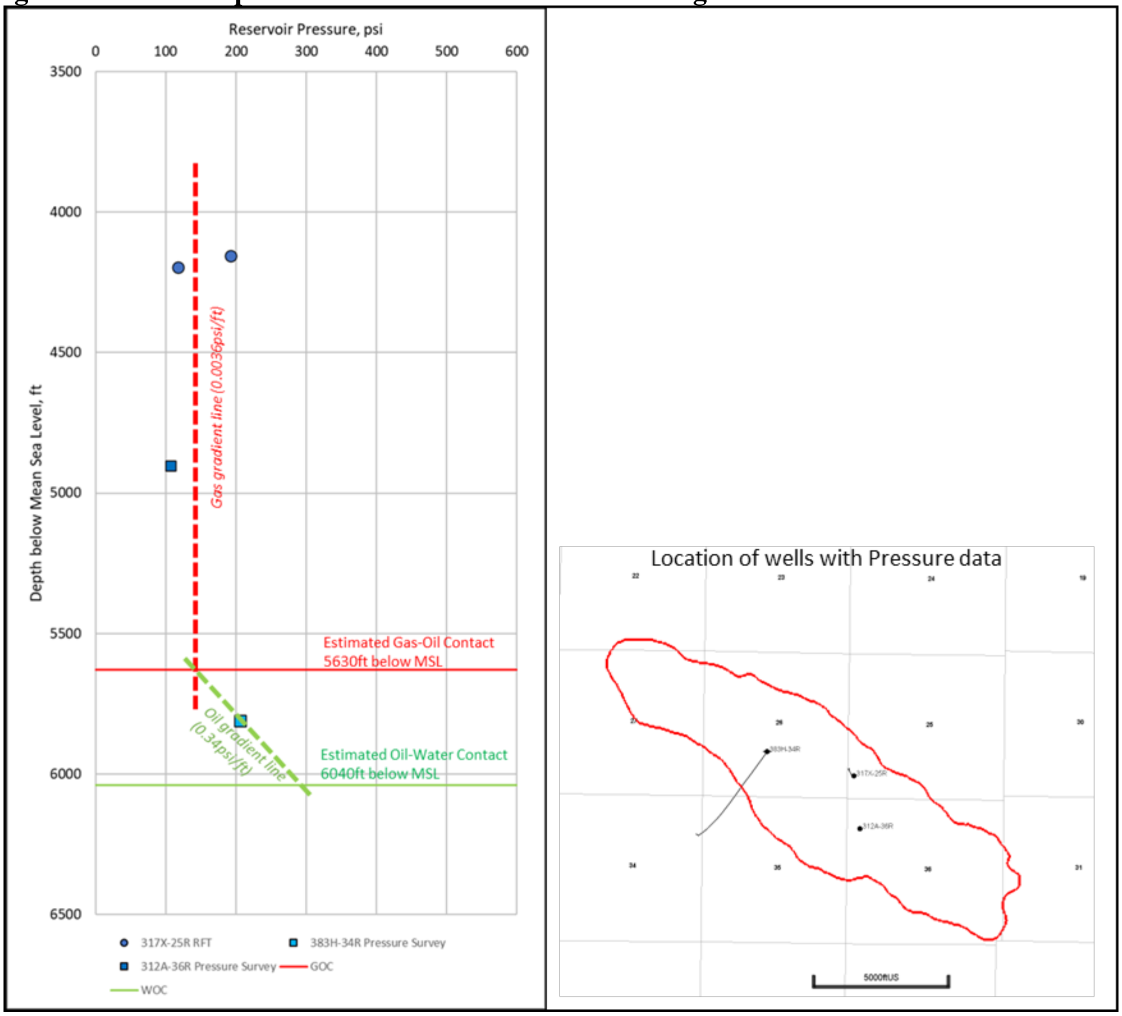
The saturations for the Gas, Oil and Water in the Gas Cap and Oil Band portions of the reservoir were determined using a Material Balance approach. The Pore Volume, discovery fluid contacts, pressure history, cumulative production and injection data for the reservoir, and the PVT properties of the fluids were used to estimate a current average oil, water, and gas saturation for the hydrocarbon portion of the 26R reservoir. These average saturations and estimates of remaining oil in place were used to iterate to a current oil-water and gas-oil contact in the computational model and the CMG GEM simulation model was initialized using the relative permeability curves, capillary pressure curves and current estimate of reservoir pressure.

The most recent data used to help validate the estimated gas-oil contact was pressure data gathered between 2006-2015. The pressure profile from this data was used to help estimate a gas contact of ~5630ft below MSL, using a gas gradient (0.0036psi/ft) and an oil gradient of 0.34psi/ft (see Figure 7). As there has not been evidence of an active aquifer following the blow down of the reservoir, the water contact is estimated to be at or near the original contact of ~6040ft below MSL, which was determined based on well logs obtained during the initial characterization of the reservoir in the 1950's.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs, pressure data, material balance and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

Figure 7 : Pressure profile in the 26R reservoir indicating a Gas-Oil contact of ~5630ft MSL

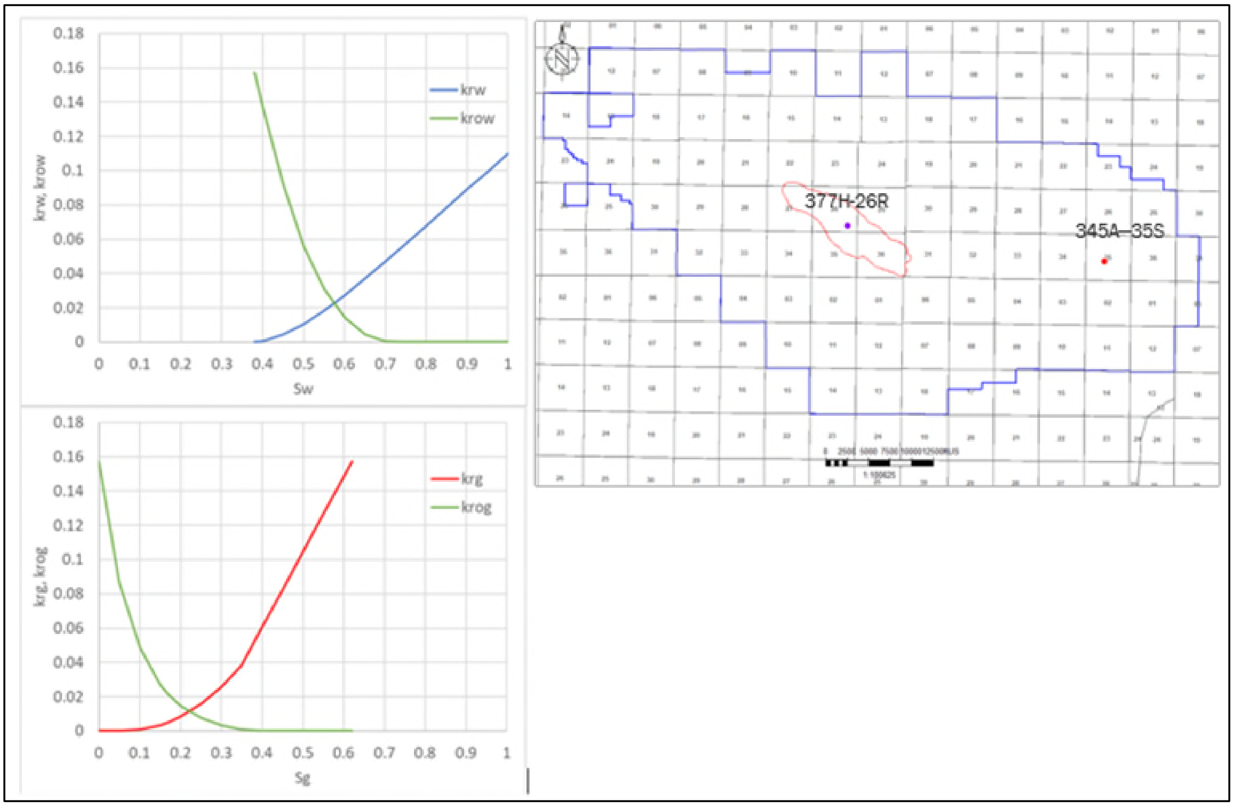


With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of saturation.

Where,
krg – relative permeability of Gas in a Gas–Oil system
krog – relative permeability of Oil in a Gas–Oil system
krow – relative permeability of Oil in an Oil-Water system
krw – relative permeability of Water in an Oil-Water system

Data acquired from Special Core Analyses (SCAL) determines these relationships. The geomodel modelled two rock types – sand and shale, but for the simulation a single sand rock type was modeled with the shale facies cells being treated as inactive cells. Core obtained from well 377H-26R in the 26R reservoir and equivalent Monterey Formation sandstone from well 345A-35S in the Elk Hills reservoir were used to generate the relative permeability relationships for the sand facies. The data was normalized with respect to air permeability using end point scaling and a single Corey relative permeability fit was generated. Figure 8 shows the relative permeability curves used in the computational modeling and Figure 9 shows the relative permeability data from wells 377H-26R and 345A-35S in tabular form.

Figure 8: Relative permeability curves for krg-krog and krw-krow used in the computational model study and wells locations for data used to develop the curves.



The functional form of the relative permeability curves are -

$krw = krwiro * ((Sw - Swcrit)/(1.0 - Swcrit - Soirw))^{Nw}$

$krow= krocw * ((So - Sorw)/(1.0 - Swcon - Sorw))^{Now}$

$krog=krogcg*((Sl - Sorg - Swcon)/(1.0 - Sgcon - Sorg - Swcon))^{Nog}$

$krg =krgcl *((Sg - Sgcrit)/(1.0 - Sgcrit - Soirg - Swcon))^{Ng}$

With the parameters for the curve being -

Swcon - Endpoint Saturation: Connate Water = 0.38

Swcrit - Endpoint Saturation: Critical Water = 0.38

Soirw - Endpoint Saturation: Irreducible Oil for Water-Oil = 0.2

Sorw - Endpoint Saturation: Residual Oil for Water-Oil = 0.22

Soirg - Endpoint Saturation: Irreducible Oil for Gas-Liquid = 0.21

Sorg - Endpoint Saturation: Residual Oil for Gas-Liquid = 0.22

Sgcon - Endpoint Saturation: Connate Gas = 0

Sgcrit - Endpoint Saturation: Critical Gas = 0.05

krocw - Kro at Connate Water = 1

krwiro - Krw at Irreducible Oil = 0.43
krgcl - Krg at Connate Liquid = 0.4
krogcg - Krog at Connate Gas = 1
Nw = 1.3
Now = 3
Nog = 3.8
Ng = 2.5

The end point relative permeabilities of the curves were then scaled by a factor of 0.1547 using Oil to Air permeability ratio from well 345A-35S, so that the curves would be in reference to air permeability, which was used in the simulation model.

Figure 9: Monterey formation relative permeability data from wells 345A-35S and 377H-26R

Well: 345A-35S						
Sample Depth, feet:	**7161.80**					
Permeability to Air, md:		**99.1**				
Porosity, fraction:		**0.221**				
Initial Water Saturation, fraction:		**0.380**				
Effective Oil Permeability at Swi, md:		**15.6**				
Oil to Air Permeability ratio		**0.1574**				
**** Relative to the effective permeability to oil at initial water saturation***						
Water Displacing Oil				**Gas Displacing Oil**		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.380	**0.000**	**1.000**		**0.000**	-	**1.000**
0.436	**0.026**	**0.662**		**0.184**	**0.002**	**0.109**
0.460	**0.053**	**0.525**		**0.198**	**0.005**	**0.093**
0.510	**0.108**	**0.324**		**0.226**	**0.014**	**0.069**
0.557	**0.176**	**0.176**		**0.269**	**0.040**	**0.040**
0.645	**0.328**	**0.033**		**0.334**	**0.106**	**0.010**
0.803	**0.615**	-		**0.405**	**0.195**	-

Well: 377H-26R						
Sample Depth, feet :		**5972.8**		**6015.9**		
Permeability to Air, md :		**100.0**		**286**		
Porosity, fraction :		**0.186**		**0.213**		
Initial Water saturation, fraction		**0.234**		**0.219**		
*** Relative to the effective permeability to oil at initial water saturation**						
Water Displacing Oil				**Gas Displacing Oil**		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.234	0.000	1.000		0.000	0.000	1.000
0.286	0.034	0.851		0.133	0.011	0.332
0.313	0.045	0.764		0.162	0.017	0.252
0.377	0.069	0.541		0.198	0.029	0.170
0.461	0.098	0.292		0.226	0.041	0.131
0.523	0.121	0.147		0.259	0.059	0.091
0.568	0.141	0.070		0.285	0.082	0.070
0.590	0.152	0.040		0.309	0.101	0.051
0.606	0.163	0.025		0.342	0.134	0.035
0.620	0.168	0.018		0.369	0.175	0.022
0.644	0.182	0.009		0.394	0.221	0.015
0.649	0.187	0.006		0.411	0.249	0.011
0.667	0.195	0.003		0.432	0.279	0.007
0.685	0.205	0.001		0.486	0.406	
0.694	0.213					

Mineralization

Based on previous studies on reactive transport modeling and geochemical reactions in CCS applications have shown that the amount of CO2 predicted to be trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special report on Carbon Dioxide Capture and Storage) for sandstone reservoirs. In addition, due to the fairly low salinity of the Formation water, stable mineralogy and minor expected on the AoR, reactive transport was not included as a part of the compositional simulation modeling at this time for computational efficiency.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 10) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 10) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

3. The 26R reservoir pinches out in the updip and lateral portions of the reservoir, and transitions to shale as shown in Figure 1.

Pressure data obtained while drilling wells in the AoR shows the pressure isolation of the 26R reservoir from the overlying Etchegoin Formation and the Lower Monterey Formation. Figure 11 shows the pressure data obtained for the formations, and location of these wells within the AoR.

Additional pressure data will be gathered and provided to the EPA during the pre-operational testing phase when all production operations in the reservoir have ceased, to confirm the historical understanding.

Figure 10: Monterey Formation 26R production and injection data.

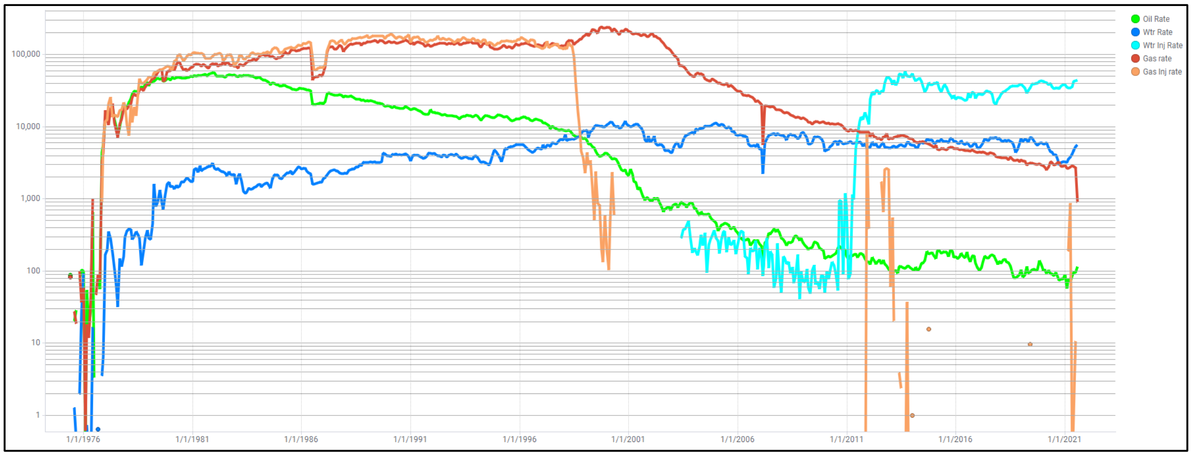
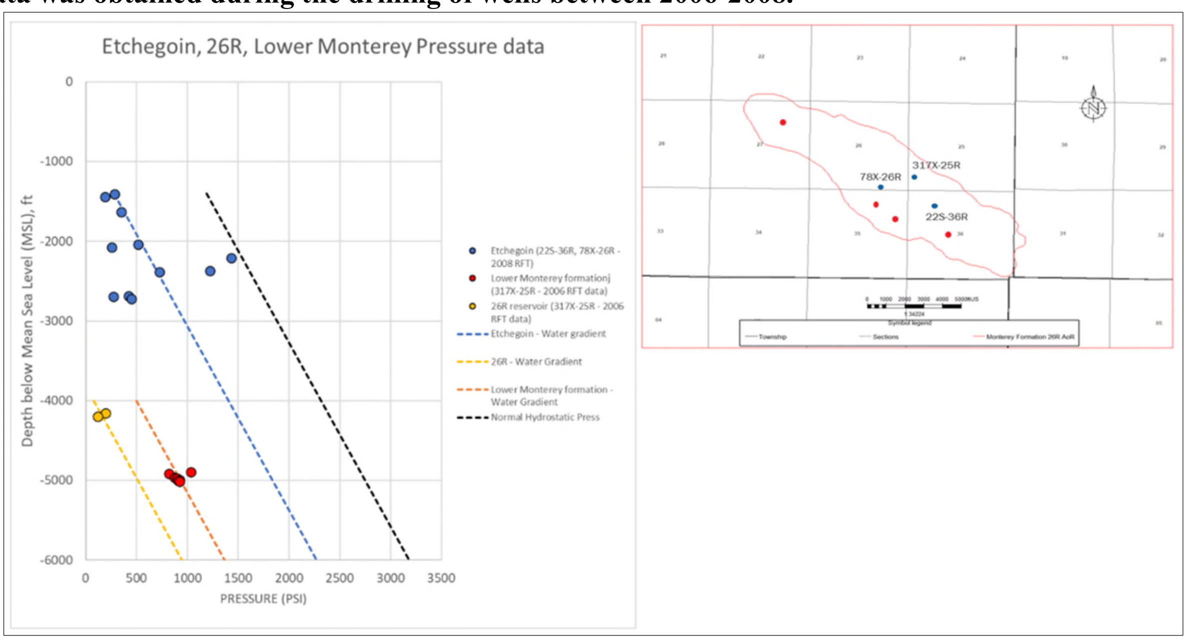


Figure 11: Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4. Depths in the Table 4 are depths below Mean Sea Level (MSL), which is used as the reference elevation.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft, below Mean Sea Level)	Data Source
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Location (global coordinates)	35.1634 N 119.2824W	35.2743 N 119.4577 W	35.3768 N 119.4732 W	35.2779 N 119.4535 W
Model coordinates (ft) X Y	6121906 2290081	6126556 2289316	6121940 2290248	6117204 2295938
No. of perforated intervals	13	25	11	12
Perforated interval (ft TVD / MD) Top Bottom	6807 / 7086 7109 / 7426	6097 / 6101 7710 / 7720	6625 / 6810 8373 / 8545	6698 / 6731 8124 / 8216
Production Casing diameter (in.)	4.5”	4.5”	4.5”	4.5”
Planned injection period Start End	1/1/2025 9/1/2051	1/1/2025 9/1/2051	1/1/2025 9/1/2051	1/1/2025 9/1/2051
Injection duration (years)	27	27	27	27
Injection rate (t/day)*	993	993	993	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

A fracture gradient of 0.701 psi/ft is expected for the 26R reservoir. This is based on fracture stimulation performed on well 388-26R in the 26R reservoir.

CTV will ensure that the injection pressure is below 90% of the fracture pressure as calculated at the top perforation for each injector. The maximum allowable subsurface wellbore injection pressure for the 4 injectors in the project is shown below in Table 6.

Table 6. Injection pressure details.

Injection Pressure Details	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Fracture Gradient (psi/ft)	0.701	0.701	0.701	0.701
Maximum allowable downhole injection pressure (90% of fracture pressure), psi	4294	3847	4180	4226
Elevation corresponding to maximum allowable bottomhole pressure (ft, TVD / MD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Elevation of top of the perforated interval (ft, TVD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Planned bottom hole injection pressure at top of perforations (psi)	4060	3555	3787	3558
Planned bottom hole injection gradient at top of perforations (psi/ft)	0.596	0.583	0.572	0.531

Proposed Carbon Dioxide Stream

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area

CTV expects the CO_2 stream to be sampled at the transfer point from the source and analyzed according to the analytical methods described in the QASP document and the Attachment C – Testing and Monitoring plan document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

For the purposes of Geochemical modeling, CO2 Plume modeling, and Well design, two major types of Injectate compositions were considered based on the source.

- Injectate 1: is a potential injectate stream composition from a Direct Air Capture (DAC) or a Pre-Combustion source (such as the Lone Cypress blue hydrogen facility) or a Post-Combustion source (such as a gas fired power plant or steam generator) where N2 will likely be the major impurity.
- Injectate 2: is a potential injectate stream composition from a Biofuel Capture source (such as a Biodiesel plant) or an Oil & Gas Refinery or Natural Gas processing facilities (such as CO2 capture from the feed gas to the Elk Hills Power plan stated above) where light end Hydrocarbons (Methane, Ethane) will be the major impurity.

Design studies for CO2 capture at the planned Lone Cypress facility and design studies for CO2 capture from feed gas to the Elk Hills power plant were incorporated into the two injectate compositions shown in Table 7, in addition to preliminary injectate specifications provided by other potential sources and from literature studies.

Table 7 : Injectate compositions

Component	**Injectate 1**	**Injectate 2**
	Mass%	**Mass%**
CO2	99.213%	99.884%
H2	0.051%	0.006%
N2	0.643%	0.001%
H2O	0.021%	0.000%
CO	0.029%	0.001%
Ar	0.031%	0.000%
O2	0.004%	0.000%
SO2+SO3	0.003%	0.000%
H2S	0.001%	0.014%
CH4	0.004%	0.039%
NOx	0.002%	0.000%
NH3	0.000%	0.000%
C2H6	0.000%	0.053%
Ethylene	0.000%	0.002%
Total	**100.00%**	**100.00%**

For geochemical and plume modeling scenarios, these injectate compositions were simplified to a 4-component system, shown in Table 8. The 4 component simplified compositions cover 99.9% by mass of Injectate 1 & 2 and cover particular impurities of concern (H2S and SO2). The estimated properties of the injectates at downhole conditions are specified in Table 9

Table 8: Simplified 4 component composition for Injectate 1 and Injectate 2

Injectate 1	
Component	**mass%**
CO2	99.213%
N2	0.643%
SO2+SO3	0.003%
H2S	0.001%

Injectate 2	
Component	**mass%**
CO2	99.884%
CH4	0.039%
C2H6	0.053%
H2S	0.014%

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This will be ensured by maintaining a water specification limit <25 lb/mmscf for the injectates, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Injectate will be sampled and analyzed as part of the pre-operational testing, to confirm that it is consistent with the well design, Plume modeling and Geochemical modeling assumptions.

Computational Modeling Results

Predictions of System Behavior

The base simulation case was run for a 127 year period, covering 27 years of injection and 100 years of post injection. The simulated injection storage capacity is 38MMT taking the reservoir from current reservoir conditions to initial discovery pressure of 3,250 psi. A 100% CO2 injectate stream was assumed for the base case simulation studies. Additionally, scenarios were also run for the two injectates (Injectate 1 and Injectate 2) detailed in the "Proposed Carbon Dioxide Stream" section. Minimal difference in results was seen between the cases. Table 9 summarizes the expected CO2 injectate properties at reservoir conditions over the life of the project.

Table 9: CO2 injectate properties at reservoir conditions

Injectate property	100% CO2	Injectate 1	Injectate 2
Viscosity, cp	0.019-0.044	0.019-0.043	0.019-0.045
Density, kg/m3	16.6-544.8	16.5-543.5	1.035-545.8
Salinity, ppm	NA	NA	NA
Compressibility factor, Z	0.97-0.59	0.97-0.59	0.97-0.59

The following maps (Figure 12) and cross-sections (Figure 13) show the computational modeling results and development of the CO_2 plume at multiple time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. The CO2 plume grows rapidly within the first 15 years of injection with majority of the CO2 going into the higher quality upper portion of the 26R reservoir and being controlled by the structure of the reservoir and the closed updip boundary. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The CO2 plume reaches its maximum vertical and lateral extent 20 years after the end of injection. The vertical and lateral extent of the CO2 plume predicted by the model aligns well with estimated discovery Oil-Water contacts of the reservoir and the vertical and lateral extent of the reservoir. The extent of the CO2 plume is slightly deeper than discovery fluid contacts in a few areas of the model likely due to gas override during injection and dissolution of the CO2 into the aqueous and oleic phases at the edge of the plume. The CO2 plume is largely stabilized 20 years after the end of injection, with little to no movement of the supercritical phase CO2 seen past this date.

The pressure front (defining as >10psi change from pressure at start of injection) in the reservoir reaches the vertical and areal boundaries of the model 6 years after the start of injection. The pressure in the reservoir reaches its peak at the end of injection. The reservoir pressure stabilizes fairly immediately in the reservoir with end of injection, and < 5psi/year change is expected in the first year after the end of injection. Figure 14 shows the average pore volume pressure vs time.

Figure 12A: Plan view showing the CO2 plume development through time. Plume is at its greatest extent at 20 years post injection.

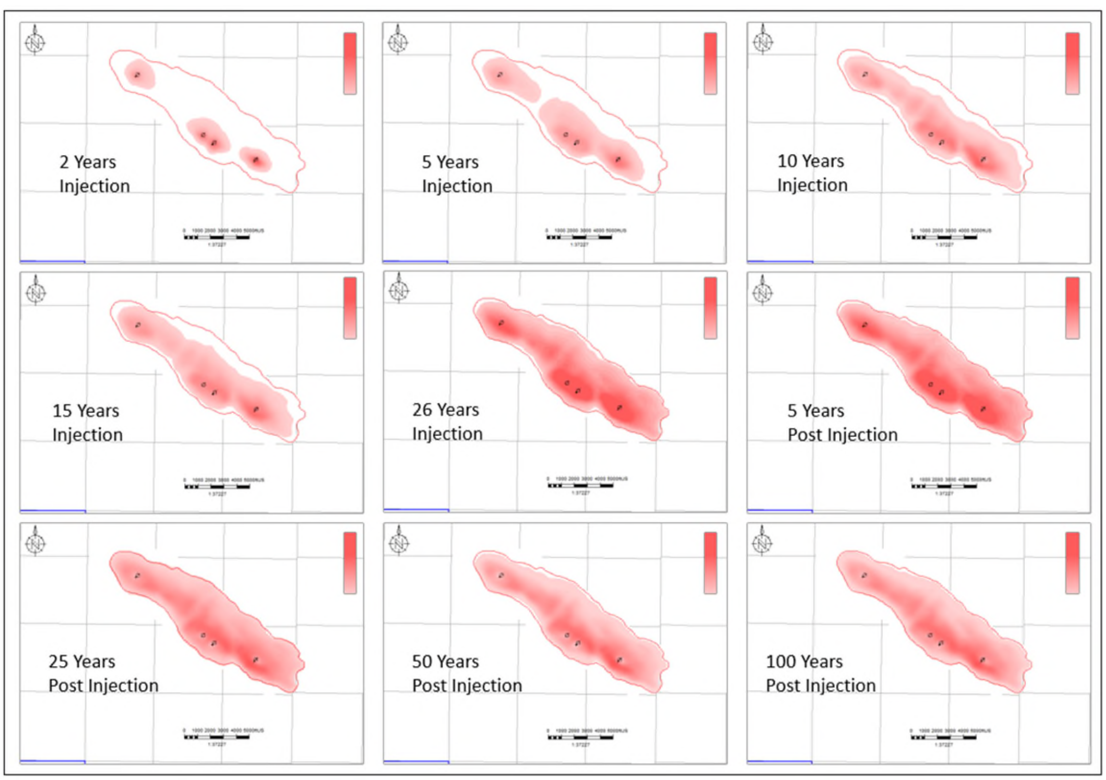


Figure 12B: Plan view showing the gas extent through time. Maps scaled so as to present Gas saturation over a nomial baseline

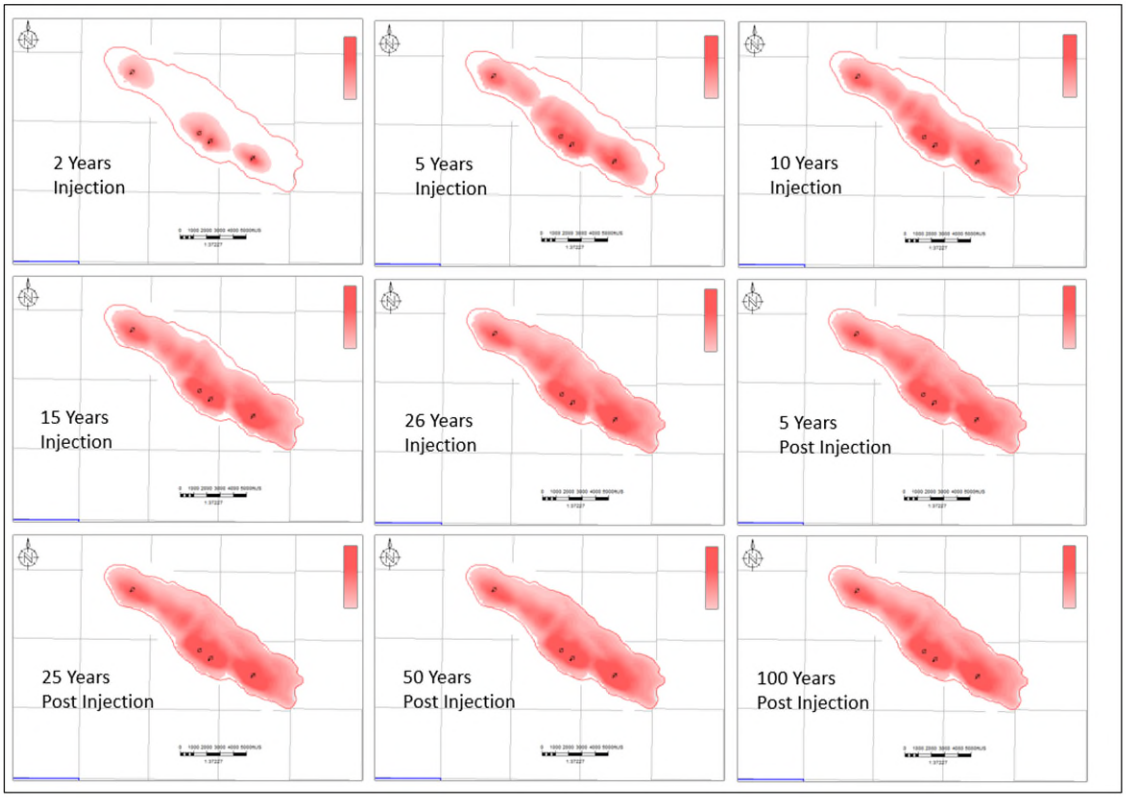


Figure 13A Cross-sections showing the CO2 plume development through varying times during the project.

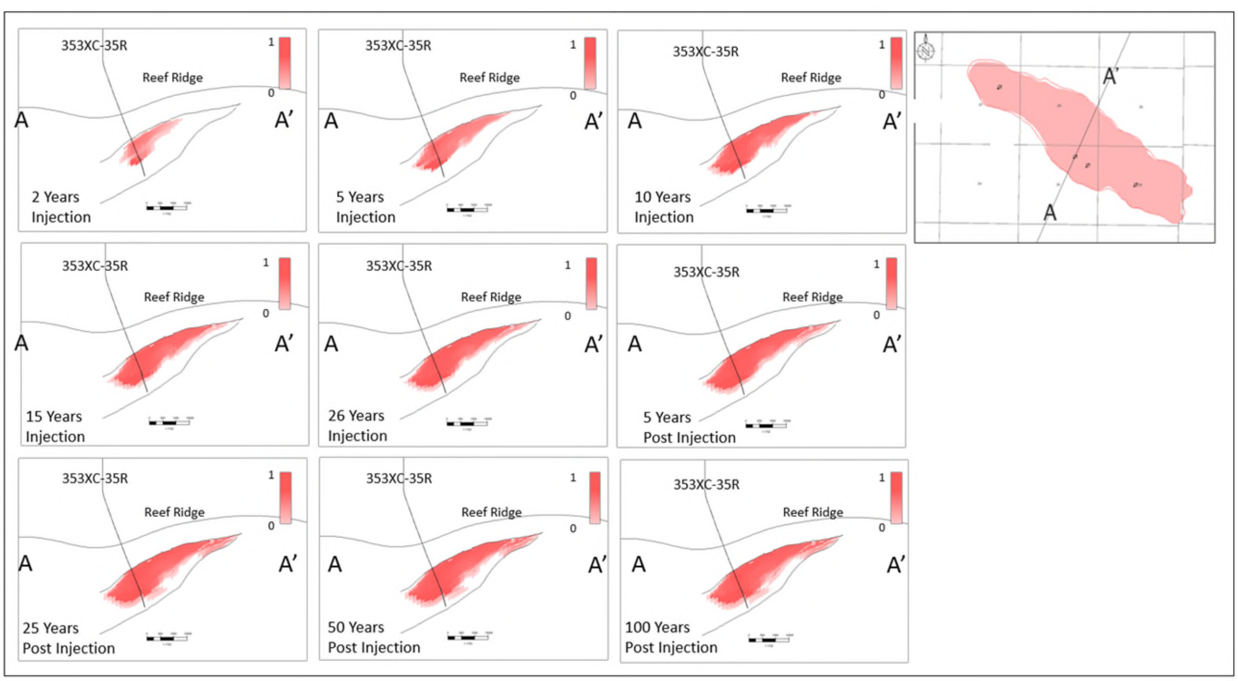


Figure 13B: Cross-sections showing the gas extent through varying times during the project. Maps scaled so as to present Gas saturation over a nomial baseline

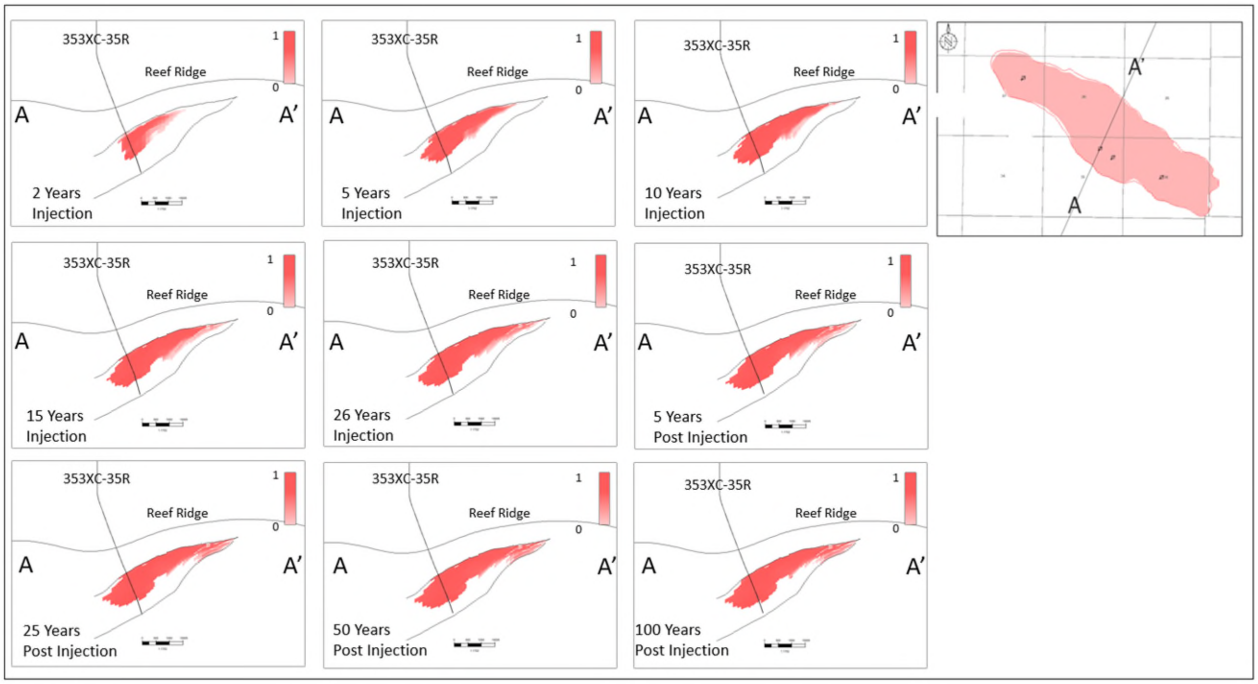
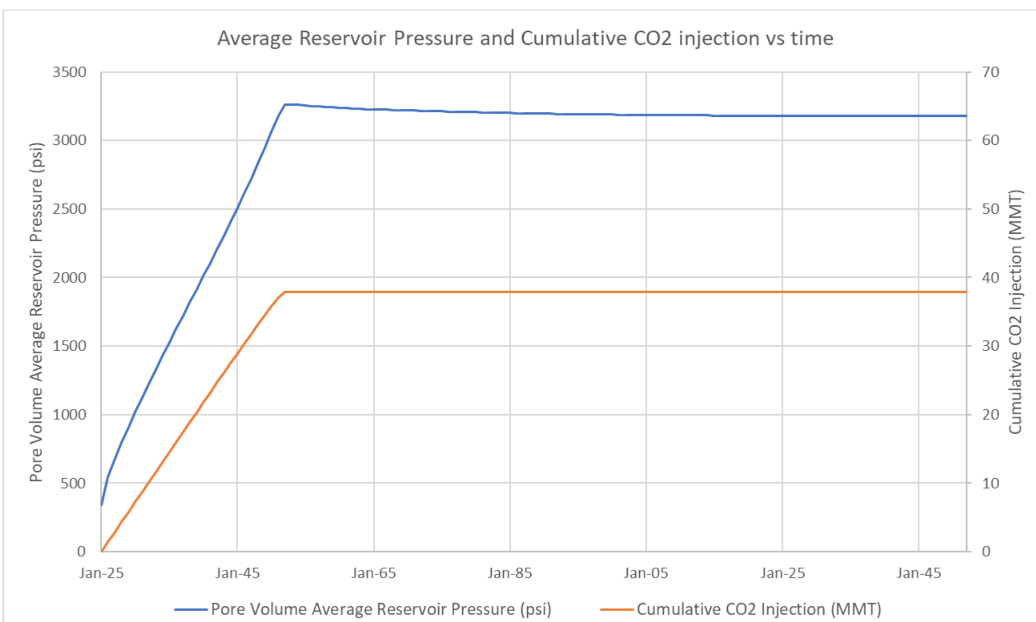
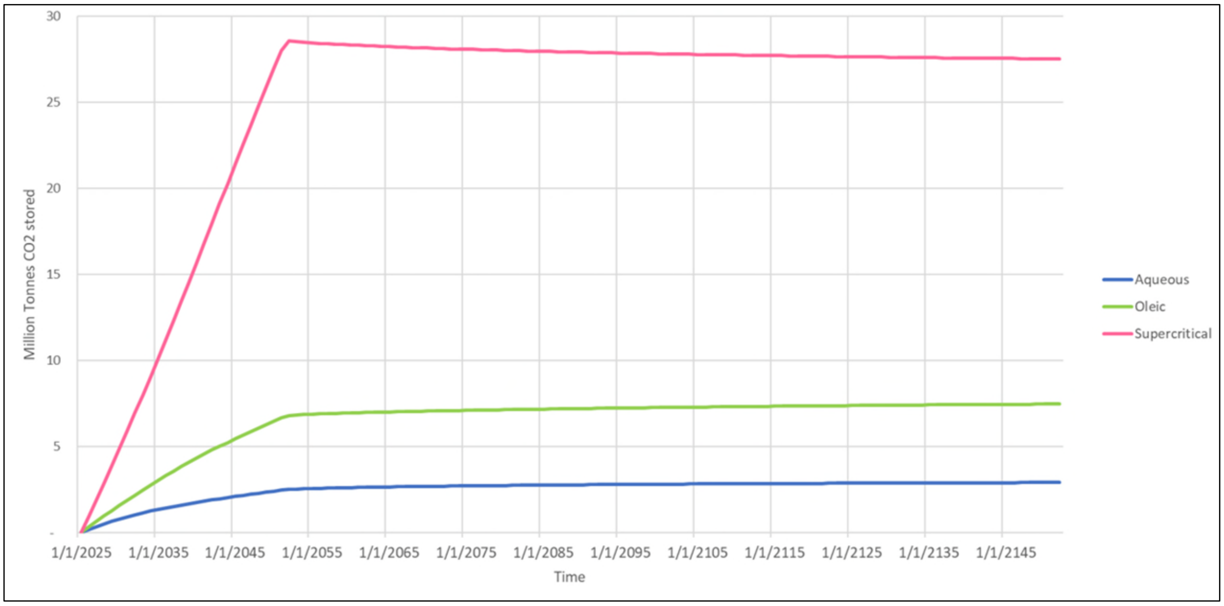


Figure 14: Average Reservoir pressure and cumulative CO2 injection versus time plot



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 15 shows the cumulative storage for each of the mechanisms.

Figure 15: Storage mechanism through time for the 26R reservoir.



CO_2 Injectate Composition effect on Plume and AoR modeling

The Plume model developed in the Computer Modeling Group (CMG) GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO2 injectate case. The cumulative volume of injectate for all 3 cases was the same.

The CO2 plume for Injectate 1 and Injectate 2 (detailed in the "Proposed Carbon Dioxide stream" section in this document) is consistent with the plume outline for 100% CO2 injectate (Figure 16), which was defined by a 0.03 global CO2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 16. The wells that fall within the CO2 plume are the same for all 3 cases.

Additionally, the average Pore Volume pressure was plotted for the 3 cases and there was minimal difference seen between the cases, as shown in Figure 17.

In summary, there is minimal effect of the minor components on the CO2 plume shape and the AoR boundary, for the proposed injectate compositions. As such, CTV's Plume and AoR modeling for Corrective Action assessment is adequate. CTV will confirm that the properties of the injectate are consistent with the model inputs at pre-operational injectate sampling. In addition, the AoR will be reviewed as per the Reevaluation Schedule and Criteria section.

Figure 16: CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Green) and 100% CO2 Cases (Red). Larger Red outline is the model boundary. There are Minimal difference in AoR boundaries between the 3 cases

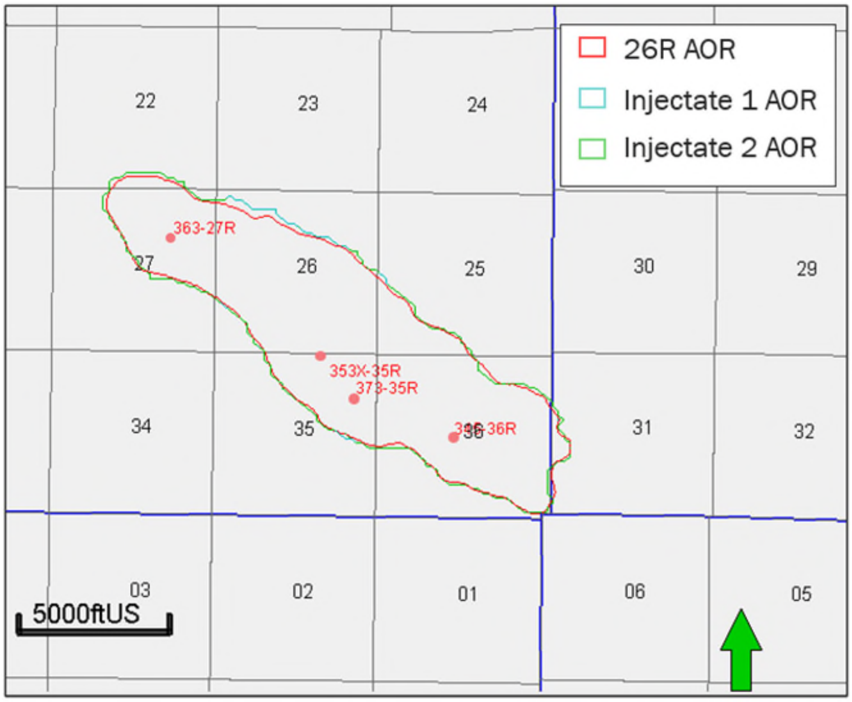
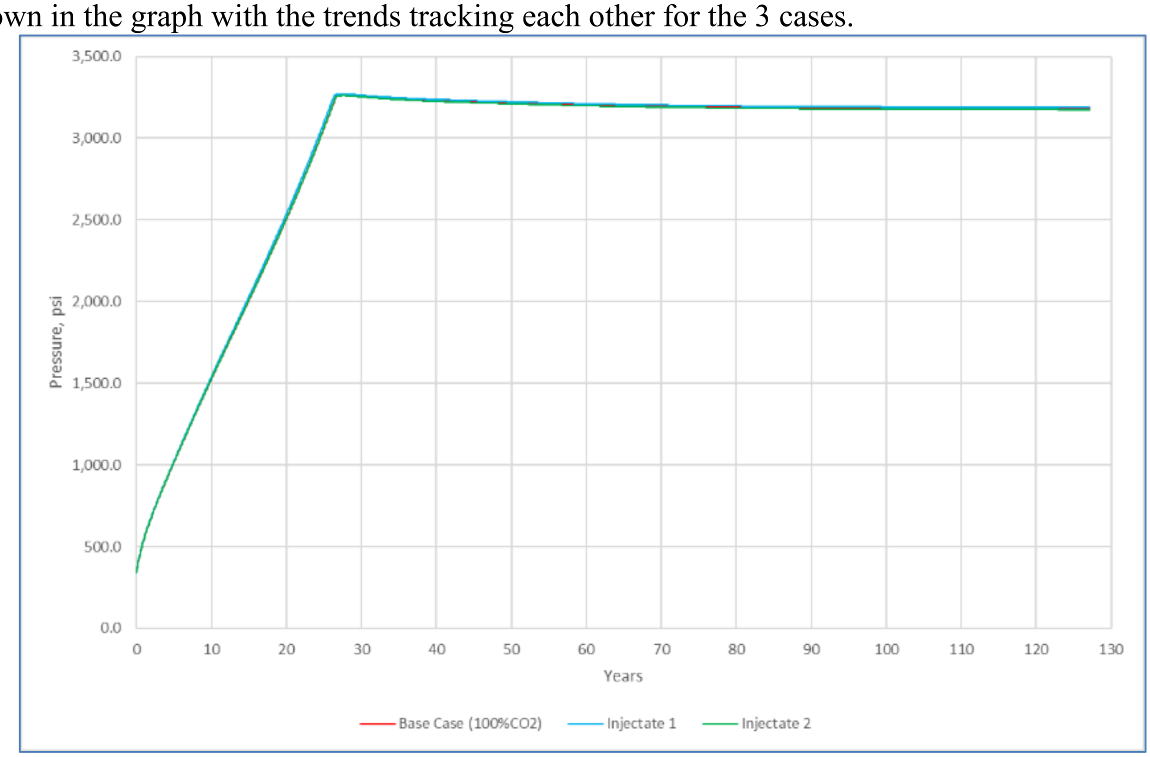


Figure 17: Average reservoir pressure vs time for Injectate 1 (Light blue), Injectate 2 (Green) and base 100% CO2 (Red) cases. Minimal difference in pressure trends between the 3 cases as shown in the graph with the trends tracking each other for the 3 cases.



Model Calibration, Sensitivies and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables. Due to ongoing water injection in the 26R reservoir, sensitivities were run to test the effect of higher reservoir pressure and higher water saturation in the Oil band and Gas cap to see if there would be significant impacts to the storage volume and AoR boundaries.

Sensitivities were also run varying major geomodel inputs into the simulation model (Porosity, Permeability, NTG) and varying the Grid XY dimensions, cell thickness, local grid refinement around injectors, and temperature effects to see if there was a significant change to the storage amount and AoR boundary. Although there was some effect to the total CO2 storage for the different cases, there was minimal change to the maximum extent of the CO2 plume. The porosity, permeability and NTG uncertainty were further modeled stochastically to understand their effect and is discussed in the next section.

- Cell thickness sensitivity case was run by reducing the cell thickness in the overall grid to an average of 18ft. The results of this finer cell thickness model, compared favorably to the Base case model with a < 2% increase in predicted CO2 storage capacity and minimal change to the plume extent.

- The local grid refinement case was run with a finer grid spacing in the 5Acre region around the injector location, with the X-Y grid dimensions reduced to 19ft by 15ft in that region. The results of this case also compared favorably against the base case, with the predicted maximum bottom hole pressure at the injector locations being within 0.5% of the Base Case.

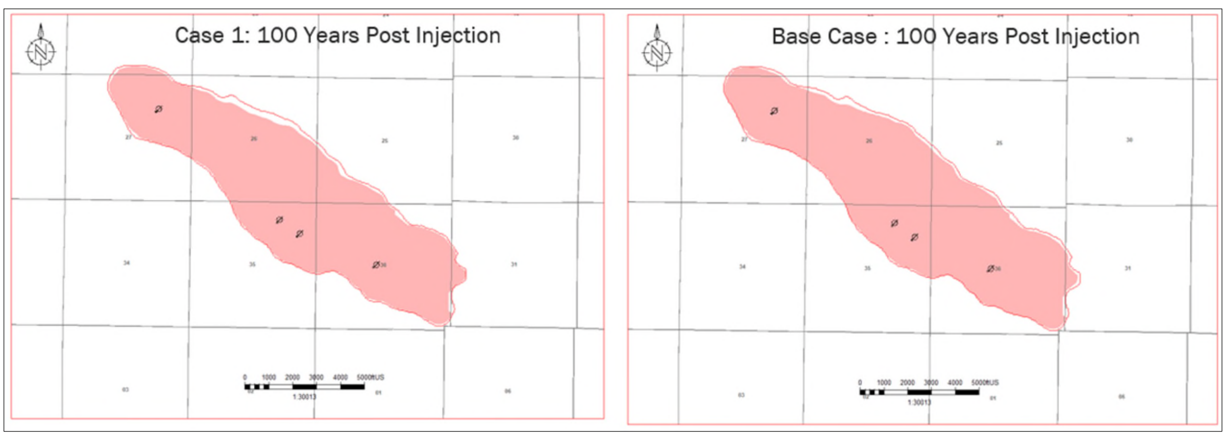
- The Base case model was initialized using a uniform average temperature of 210^{o} F (based on idle well temperature surveys run on wells in the area between 2008 – 2014) and with no thermal effect modeling in the reservoir. A sensitivity case was run using GEM's thermal option to model heat balance and gauge if modeling temperature change in the reservoir with CO2 injection was necessary. The results indicated minimal effect on the system behavior with < 2% change in CO2 storage capacity, and < 2% deviation in reservoir pressure trends.

Table 10 summarizes the sensitivity cases run and their effect on storage volume and the AoR boundary. Figure 18 compares the CO2 plume extent for Case 1 against the Base Case.

Table 10: Summary of sensitivity cases

Case #	Sensitivity Case	Storage Volume effect	AoR boundary effect
1	Pressure : Gas cap pressure increased to 300psi	Decreased volume	Minimal effect to AoR
2	Pressure : Gas cap pressure increased to 500psi	Decreased volume	Minimal effect to AoR
3	Saturation: Higher water saturation in Oil band and Gas cap	Decreased volume	Minimal effect to AoR
4	Porosity: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
5	Porosity: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
6	Permeability: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
7	Permeability: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
8	NTG: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
9	Grid Dimensions: reduced grid XY dimensions to 95 ft x 75ft	No effect	Minimal effect to AoR
10	Cell Thickness: Reduced average cell thickness in Gas cap to 18ft	Increased volume	Minimal effect to AoR
11	Local grid refinement around Injectors: reduced grid X-Y dimension to 19ft x 15ft in 5Acre area around injectors	No effect	Minimal effect to AoR
12	Temperature effect: model was run with GEM's thermal option	Minimal change	Minimal effect to AoR

Figure 18: CO2 plume extent for layer 2 comparing Base Case against Pressure and Saturation sensitivity cases.



These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

Stochastic analysis of effect of Reservoir parameters

A stochastic analysis was carried out using the reservoir parameters – Porosity, permeability, Net to Gross (NTG) ratio and kv-kh ratio. An upper and lower bound of the grid property was entered (directly or using multipliers), along with a distribution (see Table 11) in CMG's CMOST module to generate a set of 50 cases using the Latin Hypercube sampling method. All cases were run with the same bottom hole pressure control on the injectors, and with the same condition of ceasing injection once the reservoir had been brought back up to initial conditions. Although the stochastic analysis showed a range of storage capacity, the P50 estimate was 37MMT, with a P10 of 30MMT and a P90 of 44MMT.

Table 11: Parameters and distributions used for Stochastic analysis

Parameters	Parameter/ Multiplier	Parameter / Multiplier range	Distribution type	Description
Porosity	Multiplier	0.78 - 1.22	Normal distribution	Multiplier range used to have grid mean value range of 0.14 - 0.22
Permeability	Multiplier	0.3 - 3	Log Normal distribution	Multiplier range used to have grid mean value range of ~15 - 150md
Net to Gross ratio (NTG)	Multiplier	0.9 - 1.1	Uniform distribution	A uniform distribution uncertainty of +-10% applied
kv-kh ratio	Parameter	0.001 - 0.2	Log Normal distribution	A kv-kh ratio of 0.001 to 0.2 applied over the entire grid

AoR Delineation

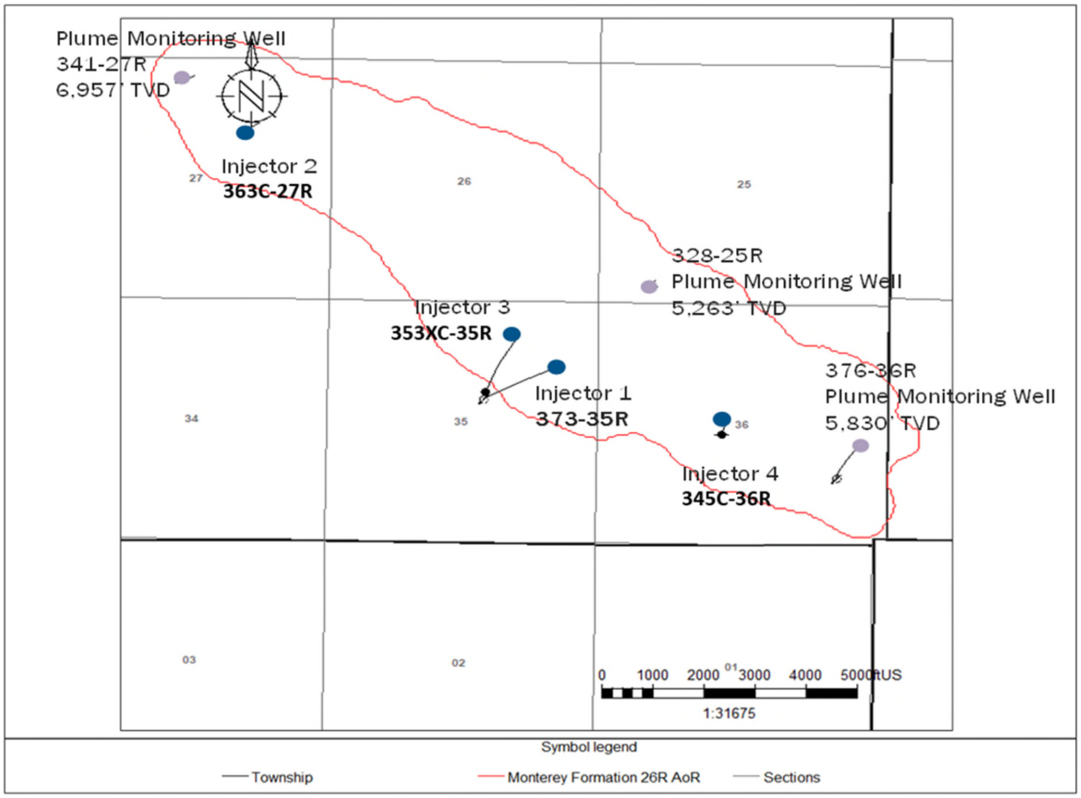
The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. A Global Mole Fraction cut off of 0.03 was used to delineate the plume boundary. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.
Figure 19 shows the AoR, injectors and offset monitoring wells. All wells that are currently operating in the 26R reservoir will cease operations, and wells not associated with the project will be abandoned prior to injection so as to eliminate interference with the AoR delineation and re-establish the confining layer. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 19: Map showing the location of injection wells and plume monitoring wells.



<u>Corrective Action</u>

The review of all wells within the AoR to determine the need for corrective action is a requirement of 40 CFR 146.84(c).

Tabulation of Wells within the AoR

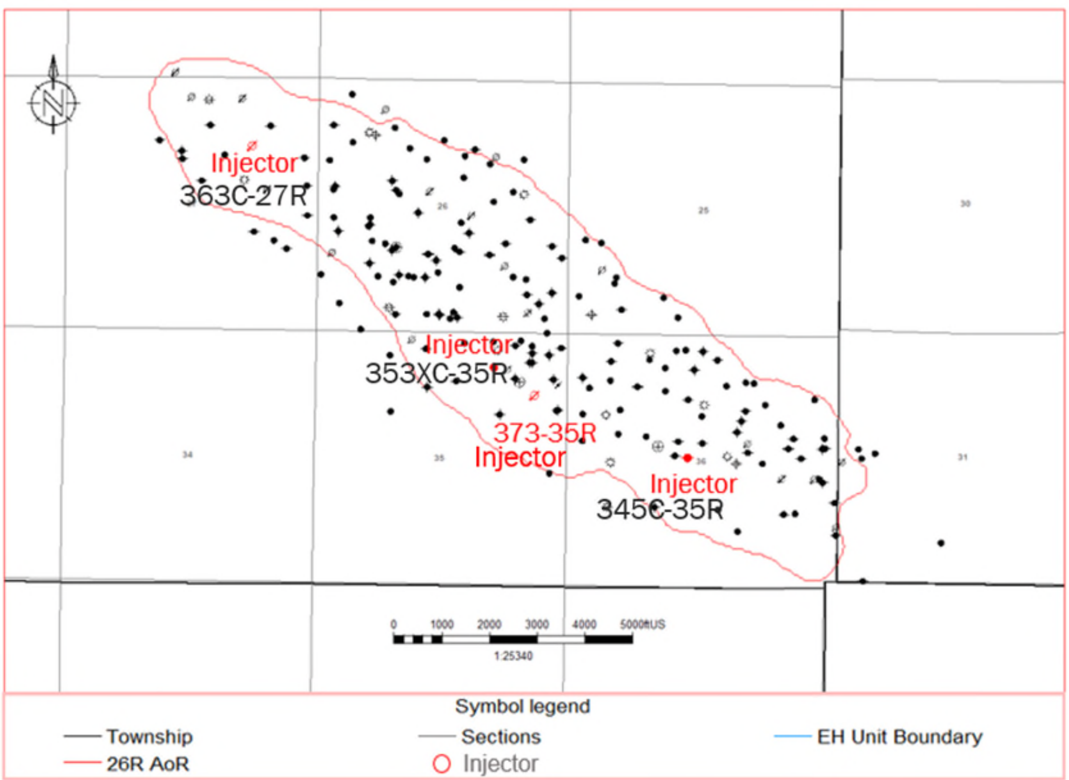
Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 12 is a summary of the AoR wells by type. Figure 20 displays the AoR wells' surface locations in map view. *Appendix: Well Table with Corrective Action Assessment* lists the wells individually and provides a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion, as required in 40 CFR 146.84 (c)(2). Additionally the table identifies pre-operational requirements and the corrective action assessment for each wellbore.

Table 12: Wellbores in the AoR by Well Type

Well Type	Count
Oil & Gas Producing Wells	145
Class II Injection/Disposal Wells	22
Pressure Observation wells	2
Plugged back	35
Total	**204**

Figure 20: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Corrective Action Assessment Methodology

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021, and the results of the review are incorporated into the assessment.

The corrective action assessment includes the generation and detailed review of wellbore/casing diagrams for each well in the AoR. The results of the assessment are included in the *Appendix: Well Table with Corrective Action Assessment*. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

A well in the AoR is a penetration of the Monterey Formation and/or Reef Ridge Shale that may have multiple wellbores resulting from sidetracking the well. CTV tracks wells at the “wellhead” level using API-10 and at the “wellbore” level using API-12 such that a single well may have multiple wellbores, and each wellbore may or may not penetrate the AoR. The assessment of all penetrations was conducted by evaluating all wellbores, and the summary data provided refers to wellbore penetrations.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Wells Penetrating the Confining Zone

Of the 204 wellbores penetrating the Reef Ridge formation (Table 13), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injector. Of the remaining, 157 wellbores require plugging because the wellbores penetrate the injection zone and/or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are not known to be deficient and are not known to require corrective action. The wells will be abandoned prior to CO_2 injection under the asset retirement obligation plan (ARO) to reduce abandonment liability at Elk Hills. 35 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore.

Table 13: Wellbores to be abandoned prior to injection

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	157

Monterey Formation 26R Isolation

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment prior to injection and implementation of a robust ongoing monitoring program, the CO_2 injected will be confined to the Monterey Formation 26R reservoir.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be pressure tested, abandoned, re-abandoned, monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, if conditions allow. Additional evaluation during pre-operational testing will inform the suitability and isolation of wells proposed for use in the project as injectors and monitoring wells. Diagnostics may also be performed, if necessary, to complement abandonment operations. Although no wellbores have been identified for corrective action and no corrective action schedule is required, if additional evaluation efforts result in the identification of wellbores that require corrective action, CTV will notify the EPA and communicate a corrective action plan and schedule.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation reservoir that are not related to well integrity.

b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a deviation greater than +-10% from the Base Case.

c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

   a. The presence of faults near the confining zone that indicates propagation into the confining zone.

   b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event.

ATTACHMENT C: TESTING AND MONITORING PLAN – 345C-36R
40 CFR 146.90

Elk Hills 26R Storage Project

Facility Information

Facility Name: Elk Hills 26R Storage Project
345C-36R

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119

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Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Comments
Attachment C – TM 345C-36R	1	09/30/2023	
Attachment C – TM 345C-36R	2	12/05/2023	Addition of air monitoring.

The Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills 26R storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. 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 AoR re-evaluations 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.

Quality Assurance Procedures

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

Reporting Procedures

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

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 date of authorization of injection and every three months thereafter.

The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area.

CO_2 injectate from these sources has been incorporated into Table 1 for injectate sampling. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken for each injection source and between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter. Sampling process will follow the procedures below.

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

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and
2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

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

Table 1. Summary of analytical parameters for CO_2 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_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry
Water Vapor	ISBT 3.0

Sampling Methods

Stream sampling will occur for each required CO2 analysis and in the last compressor station prior to being sent to 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.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 4.

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

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

For each required CO_2 analysis, CTV will report the time each sample was taken, a tabulation of all CO_2 stream analyses (including any quality assurance/quality control samples), an interpretation of the results, any identified changes and explanation of any data gaps.

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 injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the Appendix_26R - Injection & Monitoring Well Schematics document.

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.

Table 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 345C-36R: 5690'(MD) 353X-35R: 6390' (MD) 363-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
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 Gauge	Surface Downhole 345C-36R: 5690'(MD) 353XC-35R: 6390' (MD) 363C-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

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

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. 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 annually 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. Pressure and temperature gauges will be calibrated annually. Table 6 of the QASP provides operating range and precision specifications.

Calculation of Injection Volume and Mass

The volume and mass of CO_2 injected into the Monterey Formation 26R will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation 26R 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 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

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 brine with corrosion inhibitor. The casing-tubing annulus pressure for injection wells 373-35R, 345C-36R, 353XC-35R, 363C-27R will be maintained with at least 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently 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 1000 psi and cannot be explained by operational conditions.

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 below.

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.

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_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For well 373-35R, 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 CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction 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.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 steel (373-35R injection well) K-55 steel (341-27R, 328-25R monitoring wells) Chrome alloy consistent with final well construction for new drill wells
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab 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 the EPA as per 40 CFR 146.91 (a)(7). Table 5 of the QASP document provides detection limit/range and precision.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and condition of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone.

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. Figure 1 shows the location of 355X-26R and the shallow groundwater monitoring well. The well is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 4,063’ – 4,087’ MD in 355X-26R.

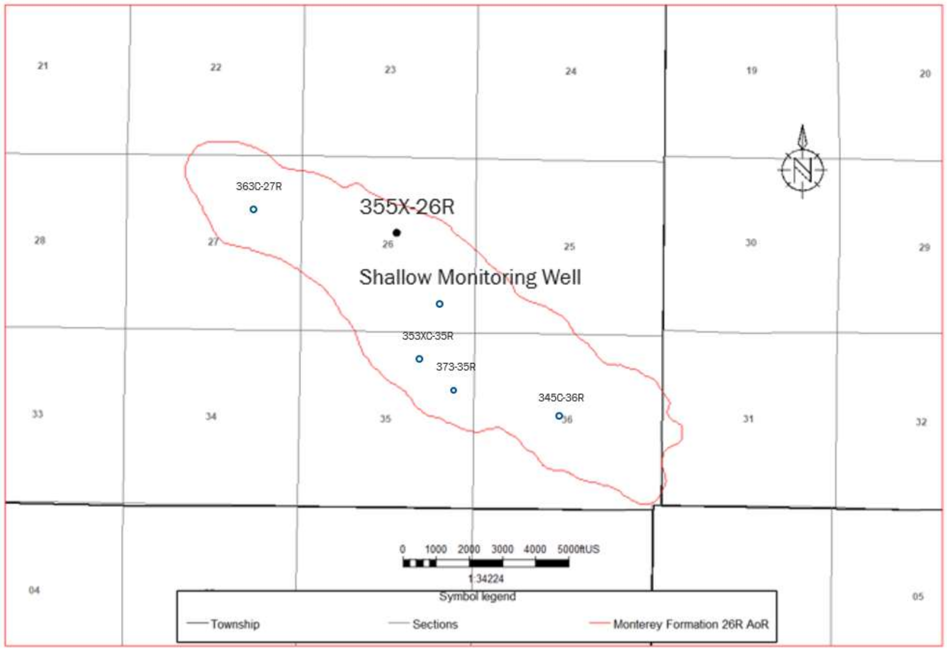


Figure 1: Above confining zone monitoring wells.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure and decrease in temperature of the Etchegoin. Additionally, potential leakage will create compositional changes detectable with fluid sampling and geochemical monitoring. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The Upper Tulare is unsaturated in the AoR. The Upper Tulare Formation will be monitored between 400' – 450' MD in the shallow monitoring well that will be drilled specifically for this project.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

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

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation 26R CO_2 injection.

2. Upper Tulare Formation pressure or composition changes due to Monterey Formation 26R CO_2 injection.

Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

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

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, approximately 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

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 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).

Standard Annular Pressure Testing (SAPT)

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 one-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 1000 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. Table 6 provides information on the frequency and test pressures for injection and monitoring wells within the project.

Table 6. Internal MIT requirements

<table>
<tr><th>Monitoring Activity</th><th>Data Collection Location(s)</th><th>Spatial Coverage or Depth</th><th>Frequency (Baseline)</th><th>Frequency (Injection Phase)</th><th>Frequency (Post-Injection Phase)</th><th>Maximum Injection Pressure (psi)</th><th>Test Pressure (psi)</th></tr>
<tr><td rowspan="6">Standard Annular Pressure Test (SAPT)</td><td>373-35R[1]</td><td rowspan="6">Casing/tubing annulus from surface to packer</td><td rowspan="6">Once, upon initial installation</td><td rowspan="6">Any time packer is replaced or reset</td><td rowspan="4">Not Applicable</td><td>1992</td><td>2092</td></tr>
<tr><td>345C-36R[1]</td><td>1888</td><td>1988</td></tr>
<tr><td>363C-27R[1]</td><td>2020</td><td>2120</td></tr>
<tr><td>353XC-35R[1]</td><td>1997</td><td>2097</td></tr>
<tr><td>355X-26R[2]</td><td rowspan="2">Any time packer is replaced or reset</td><td>--</td><td>1000</td></tr>
<tr><td>341-27R[3]
328-25R[3]
376-36R[3]</td><td>--</td><td>1000</td></tr>
</table>

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)	
Annular Pressure	373-35R[1] 345C-36R[1] 353XC-35R[1] 363C-27R[1]	Wellhead	Continuous	Continuous	Not Applicable	--		- -
	355X-26R[2] 341-27R[3] 328-25R[3] 376-36R[3]				Continuous			

[1] CO2 injection well
[2] Above Zone monitoring well
[3] Injection Zone monitoring well

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% 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% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the 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.

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.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

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 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize 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 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.

Since 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 utilized, or DTS may be proposed for EPA Director approval for monitoring well MIT.

Table 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

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 utilize 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 the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

    b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

    c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

    d. 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.

    e. 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.

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 Realtime, 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.

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 be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warm back 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 is 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.

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

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. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.
3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.
4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "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.

Pressure Fall-Off Testing

Pressure falloff 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 Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

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. Bottomhole 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% 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 falloff 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 Falloff Testing Requirements document.

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).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted 26R reservoir. These 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. 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.

Based on the Base case model, the CO2 plume is expected to arrive at the monitoring well locations at approximately the – 7th year of injection for 376-25R, 8th year of injection for 328-25R and the 9th year of injection for 341-27R.

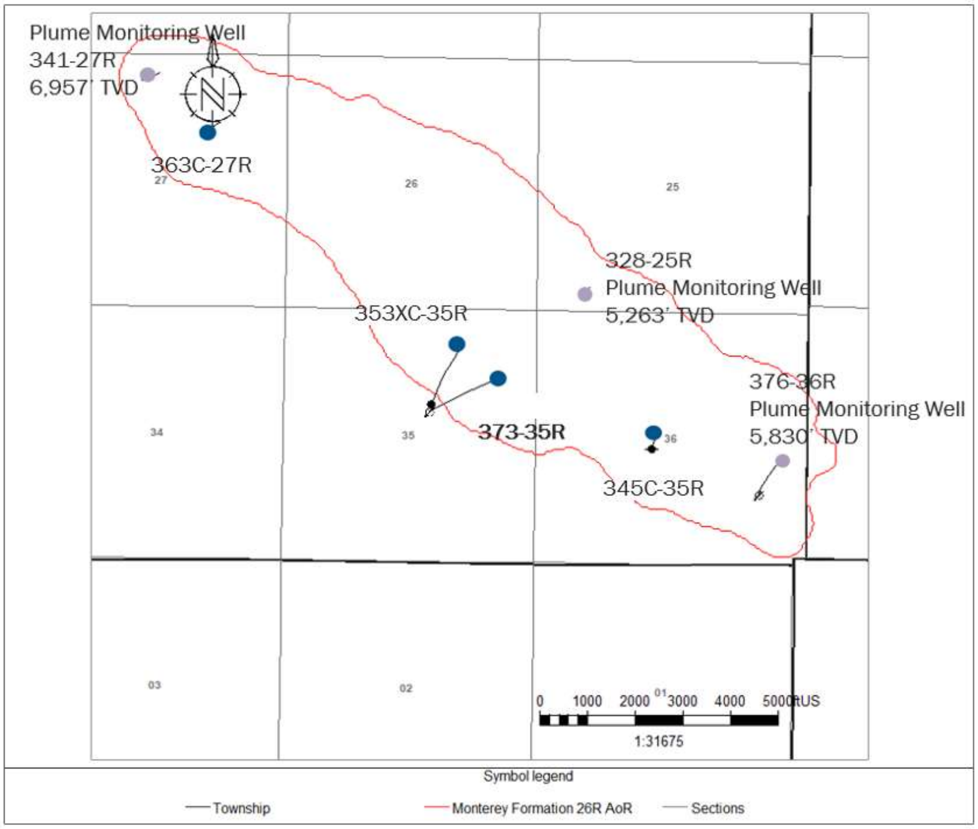


Figure 2: Monterey Formation 26R sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.

Table 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 9. Detection limits, precisions, and quality control requirements for these methods are presented in Table 3 of the QASP.

Table 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)	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Formation 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Once	Quarterly	Annual
		Pressure		6910' MD	Baseline	Continuous	Continuous
		Temperature		6910' MD	Baseline	Continuous	Continuous
		Fluid Sampling	328-25R	5268' - 5800' MD	Once	Quarterly	Annual

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
	Monterey Formation 26R	Pressure		5188' MD	Baseline	Continuous	Continuous
		Temperature		5188' MD	Baseline	Continuous	Continuous
	Monterey Formation 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Once	Quarterly	Annual
		Pressure		5760' MD	Baseline	Continuous	Continuous
		Temperature		5760' MD	Baseline	Continuous	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Baseline	Every year from start of injection	Every 5 years
			328-25R	5268' - 5800' MD			
			376-36R	5832' - 6815' MD			

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	**Analytical Methods**
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, 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 9.

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

As discussed in the AoR and Corrective Action Plan, 72% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and formation fluid 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 year during the injection phase.

CTV does not plan to conduct VSP monitoring for the depleted 26R oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Pressure Front Monitoring Location and Frequency

The aerial extent of plume development in the Monterey Formation 26R reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 3.

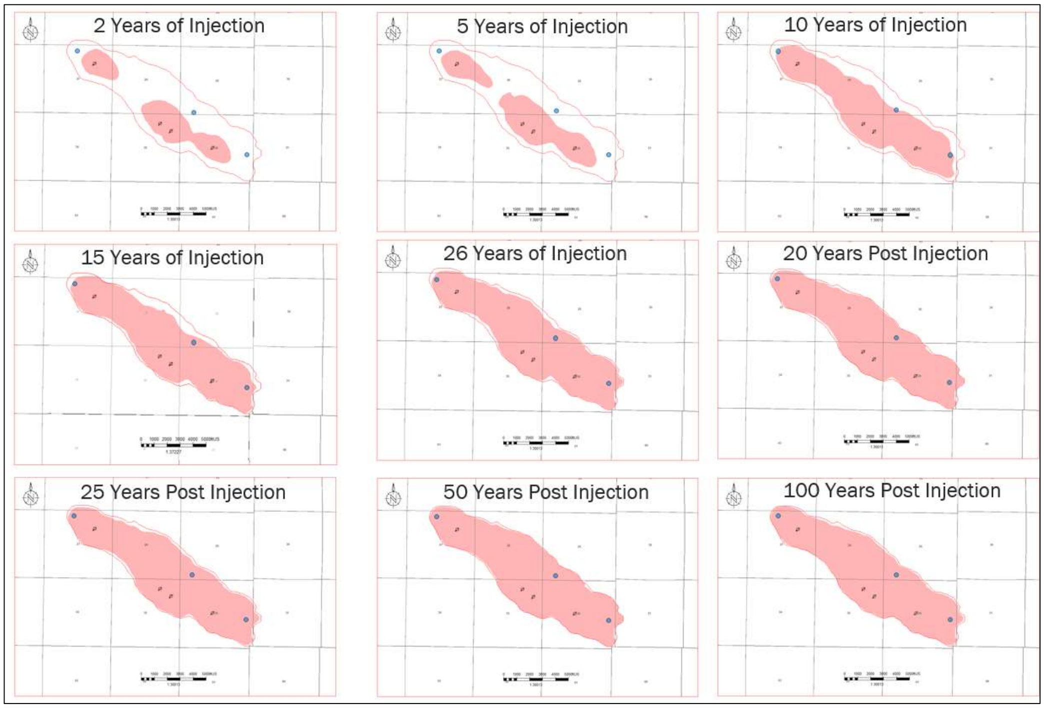


Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.

Monitoring well 328-25R pressure development based on computational modeling is shown in Figure 4. The average pore volume reservoir pressure stabilizes 1 year after the end of injection. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

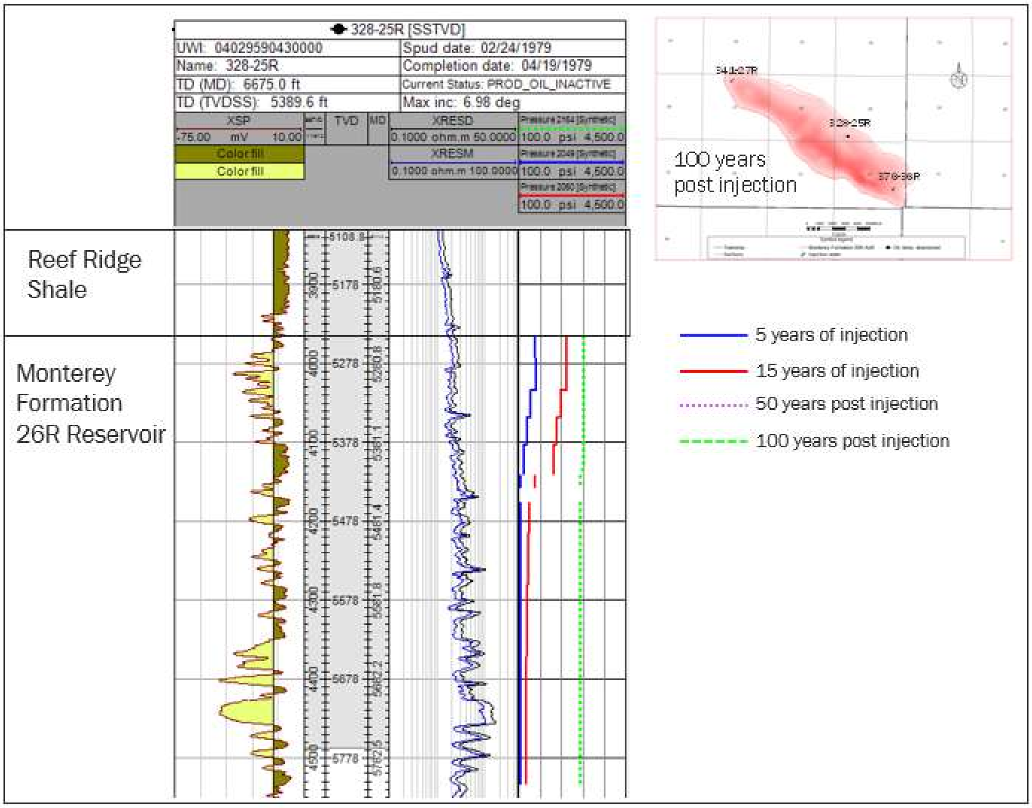


Figure 4: Monitoring well 328-25R showing the pressure increase through time from the computational modeling results.

Pressure Front Monitoring Details

Direct pressure monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 341-27R, 328-25R and 376-36R. The depleted Monterey Formation 26R oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post-injection. 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.

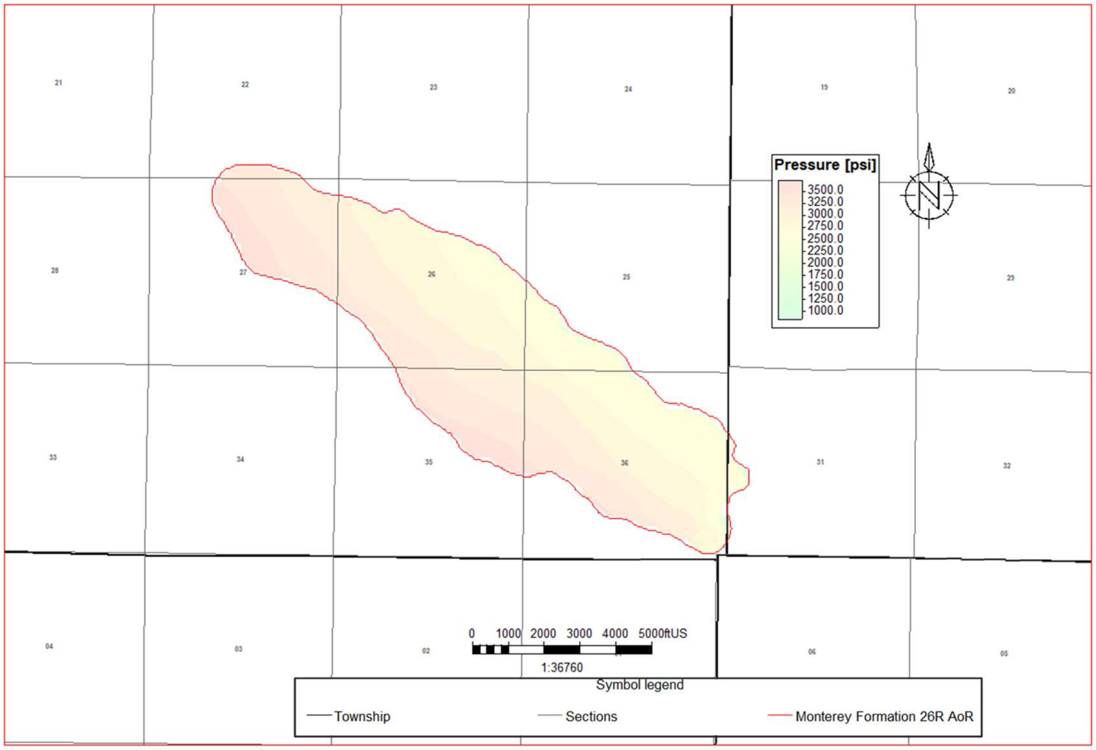


Figure 5: Monterey Formation 26R pressure 50 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

The modeled pressure increases at monitoring well 328-25R are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 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. Downhole gauge specifications are provided in Table 8 of the QASP document.

Table 10. 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**	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Baseline	Continuous
		Temperature			Baseline	Continuous

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. 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.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 6)
- Borehole sensors have been deployed (depths shown in Figure 6) 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

Baseline Analysis:

The monitoring network has been installed to collect seismicity data to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This 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_2 injection.

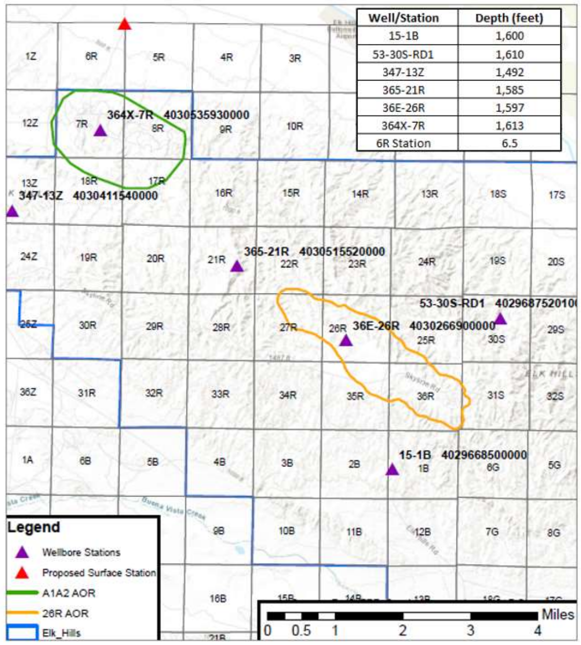


Figure 6: Elk Hills seismic monitoring network station location and depth of geophone sensors.

Monitoring Analysis:

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

- Waveform data to be 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 (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

<u>Surface Air Monitoring</u>

Surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines will be conducted.

Continuous Monitoring of AOR

Broad aerial surface air monitoring will be conducted with eddy covariance towers. Eddy covariance towers are a widely used micrometeorological technique for direct high-speed measurements of the transport of gases, are a recommended component of CCS project surface air monitoring.

Each eddy covariance tower will consist of a solar-powered 3-dimensional sonic anemometer and open-path gas analyzer installed on a stationary tower and will be installed downwind of the prevailing wind direction from potential gas sources. Annual average prevailing wind direction in the vicinity is from the northwest. Proposed tower locations are displayed on Figure 7. Locations were chosen to be downwind (southeast) of the injection wells and surface expression of the simulated CO_2 plumes, to be in locally high topographic locations given the hilly terrain in the project vicinity, and in a location with access for equipment installation and servicing.

Monitoring equipment will be installed at a height of approximately 5 meters (33 feet). In general, the upwind distance represented by the tower height can be determined by the 1:100 rule; in this case with a 5-meter tower height the majority of measured flux will come from an oval-shaped area from near the tower to 500 meters (1,640 feet) upwind.

Gas emission rate is calculated from air density, vertical wind speed, and dry CO_2 mole fraction. Air density fluctuation is assumed to be negligible, wind speed will be measured with the sonic anemometer and CO_2 mole fraction with the gas analyzer. The sonic anemometer will be Campbell Scientific CSAT3 or equivalent, and CO_2 gas analyzer will be LI-COR Biosciences LI-7500A or equivalent. The gas analyzer will be positioned at or slightly below the sonic anemometer level, with a separation distance less than 20 centimeters. Vibration will be minimized by the use of several guy wires attached at the middle of the tower.

Manual cleaning of the gas analyzer will be performed on an as-needed basis when anomalous readings or excessive zero-drift in the data is observed. Factory calibration is assumed to be stable for at least several years and will be checked once per every six months as a precaution.

Data processing will be conducted and will be presented as hourly-averaged CO_2 concentrations and gas emission rates. Detection of anomalous and increasing CO_2 concentrations will lead to eddy covariance tower equipment testing and CARB consultation.

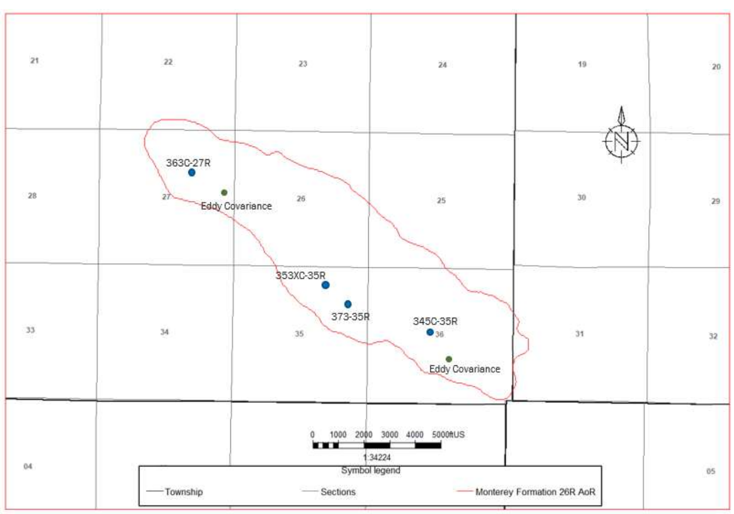


Figure 7: Location of Eddy Covariance monitoring.

Continuous Equipment Monitoring

Surface components of the injection system, including the flowlines and wellheads, will be monitored using equipment that will monitor for elevated CO_2. This leak detection equipment will be integrated with automated warning systems that notify the control center at the central facility, giving the operator the ability to remotely close the valves in the event of an anomalous reading. The central facility uses a SCADA software system to implement operational control decisions on a real-time basis throughout the project to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Monitoring Summary

This proposed monitoring program meets the goals of 40 CFR 146.90(g) by capturing continuous direct measurements of pressure and temperature in the storage reservoir (in-zone), Etchegoin (above zone) and USDW across key points of the AOR, in addition to frequent fluid samples and PNL to track the progress and confinement of the CO_2 plume. This data will also calibrate the dynamic model to predict plume front movement and pressure increase. In addition, the high resolution seismic monitoring network will provide a wide area measurement to indirectly monitor for pressure increase in-zone and above, that can be used in conjunction with the data from the monitoring wells to confirm confinement.

Direct:

The three in-zone monitoring wells are located close to the edges of the AOR, up-dip of the injectors, and thus in the flow direction of the less buoyant injected CO_2. The wells will be continuously measuring pressure and temperature at these locations. The continuous signals of pressure change in the reservoir will be used to update and calibrate the dynamic model and identify any major deviations from the predicted behavior of the reservoir. The continuous temperature measurements will provide data for the arrival of CO_2 at these locations.

In addition to the USDW and Etchegoin monitoring wells, the in-zone monitoring wells will provide confirmation of the confinement of CO_2 to the injection zone by also continuously measuring temperature changes in the Etchegoin and USDW (via DTS). Periodic fluid sampling at these locations will confirm the continuous pressure and temperature data, by providing measurements of CO_2 concentration in the reservoir that can further calibrate the dynamic model. Thus, the direct measurements for the injection zone through these wells will provide adequate special coverage of the development of the plume and pressure front, which can also improve the accuracy of the dynamic model predictions.

The two centrally located monitoring wells in the Etchegoin formation and USDW will continuously measure pressure and temperature in their respective zones, thus providing continuous direct measurements to assess the confinement of the injected CO_2. In addition, the continuous temperature measurements at these two locations, combined with the temperature measurement covering the Etchegoin and USDW at the three in-zone monitoring wells will provide adequate spatial coverage across the AOR to evaluate confinement of CO_2 in the storage reservoir.

Indirect:

PNL at the three in-zone monitoring wells will provide indirect measurement of gas saturation and CO_2 concentration in the injection zone, which will track the progress and confinement of the plume and further calibrate the dynamic model.

The seismic monitoring network will provide an indirect measurement of the pressure increase in the injection zone, the Etchegoin and the USDW. The seismic monitoring network will be sufficient to resolve events greater than 0 magnitude, with a 1,000 ft vertical resolution at the injection depths and above, giving us the ability to differentiate between events in the injection zone versus events in the shallower Etchegoin or USDW. This provides an indirect way to monitor for pressure increases in-zone or above zone via seismic events that could be triggered from pressure changes due to CO_2 injection or fluid migration.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

WELL PLUGGING PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_345C-36R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_345C-36R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_345C-36R_V3	3	1/10/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – COP Details_345C-36R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 3/2023
Attachment D – Well Plugging Plan_345C-36R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

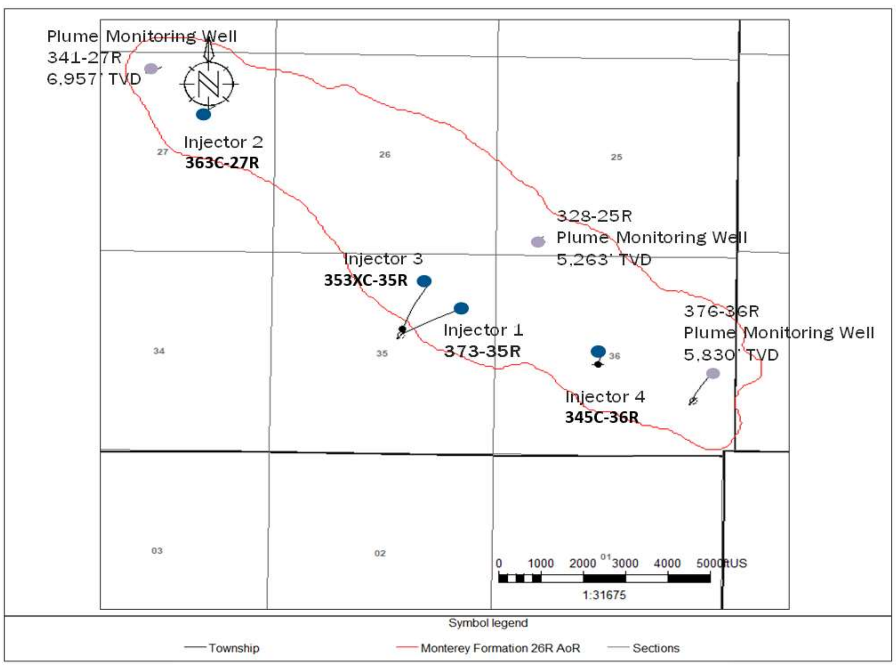


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 2 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The planned external MIT method will be a temperature log or other approved external MIT (Table 1) and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Table 1: 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

Information on Plugs

CTV will use the materials and methods noted in Table 2 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 2, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 2: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	3.92	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	7900	2563	1135	39
Sacks of cement to be used (each plug)	168	24	24	5
Slurry volume to be pumped (bbl)	34.41	4.92	4.92	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	5600	2438	1010	14
Bottom of plug (ft)	7900	2563	1135	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or CT Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5' below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):

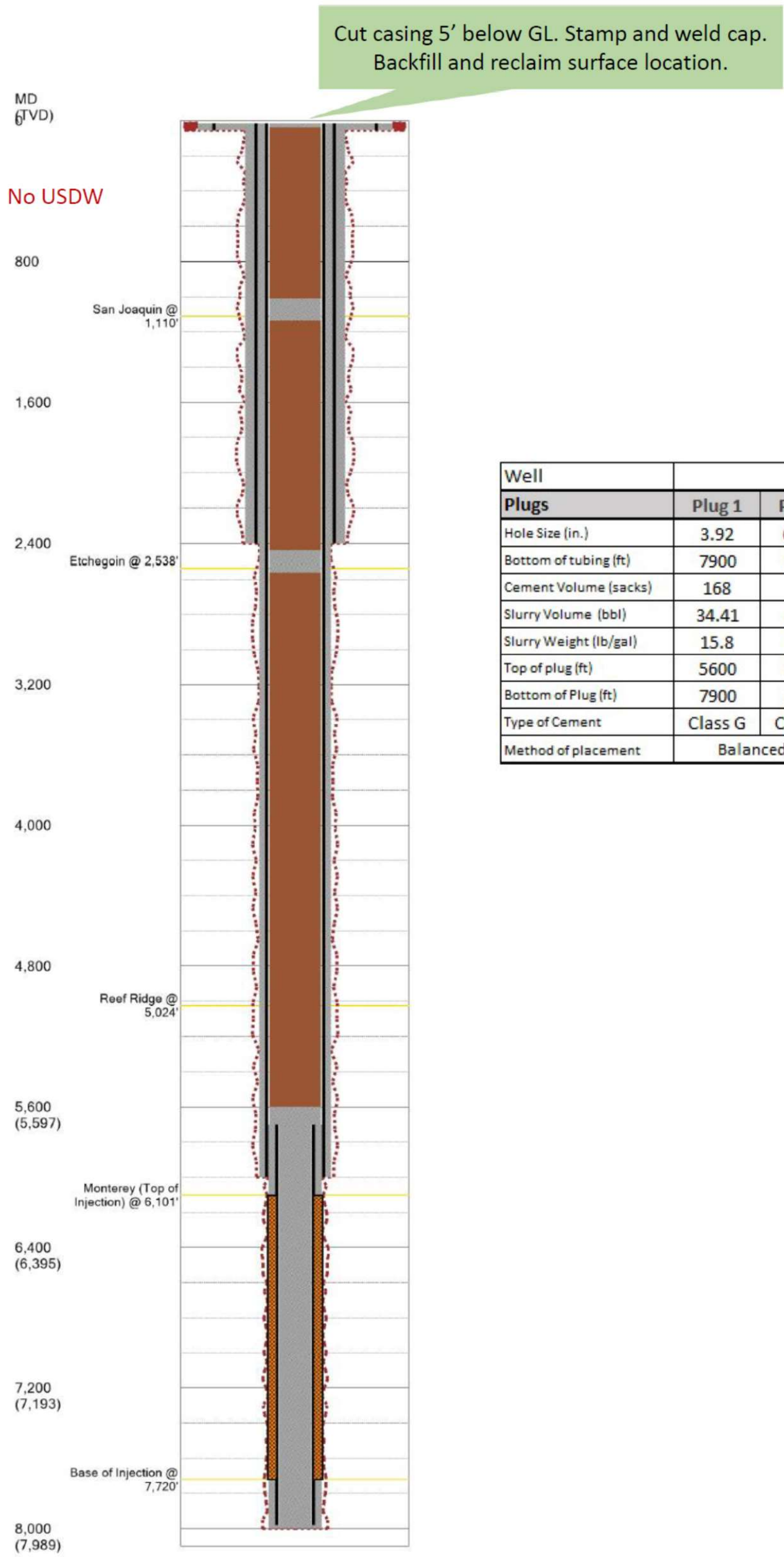
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits.

In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

  - In 26R, this interval would be located at the top of the San Joaquin formation.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.



Well	345C-36R			
Plugs	**Plug 1**	**Plug 2**	**Plug 3**	**Plug 4**
Hole Size (in.)	3.92	6.276	6.276	6.276
Bottom of tubing (ft)	7900	2563	1135	39
Cement Volume (sacks)	168	24	24	5
Slurry Volume (bbl)	34.41	4.92	4.92	1.02
Slurry Weight (lb/gal)	15.8	15.8	15.8	15.8
Top of plug (ft)	5600	2438	1010	14
Bottom of Plug (ft)	7900	2563	1135	39
Type of Cement	Class G	Class G	Class G	Class G
Method of placement	Balanced Plug, Retainer, or CT Plug			

Figure 2: Injection Well 345C-36R, Abandonment Schematic

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

CTV I Elk Hills 26R Project

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment E -PISC_SC	1	01/11/21
Attachment E -PISC_SC V2	2	05/31/22
Attachment E -PISC_SC V3	3	12/21/22

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize within one year after injection ceases. Injection limits will be based on the fracture pressure of the Monterey Formation 26R reservoir and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

Discussion

The Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation 26R storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Figure 1 shows the pressure of the Monterey Formation 26R reservoir through time from computational modeling.

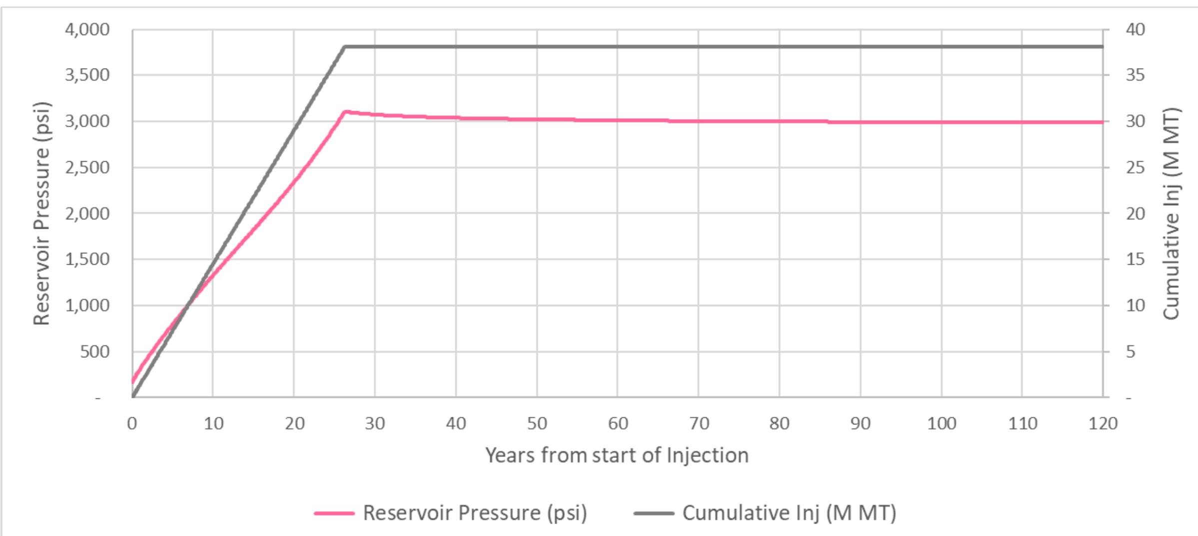


Figure 1: Reservoir pressure and Cumulative injection.

Pressure after 50 and 100 years post-injection are the same in monitoring well 328-25R (Figure 2) indicating plume stabilization. The low water saturation within the Monterey Formation 26R storage reservoir results in 72% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

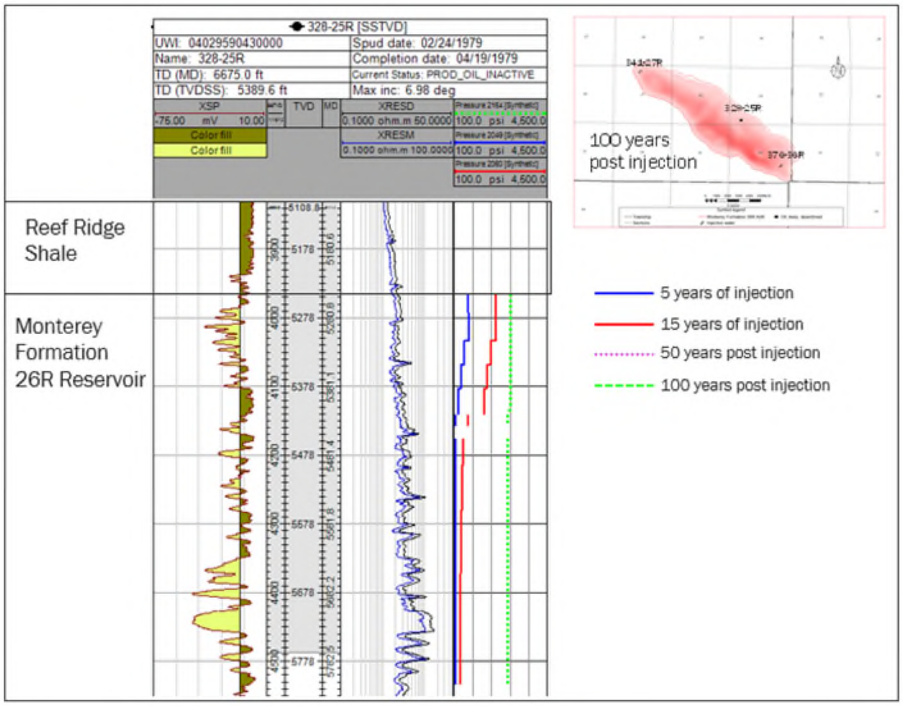


Figure 2: Pressure at the 328-25R monitoring well. Pressure after 50 and 100 years post-injection are the same indicating plume stabilization.

Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

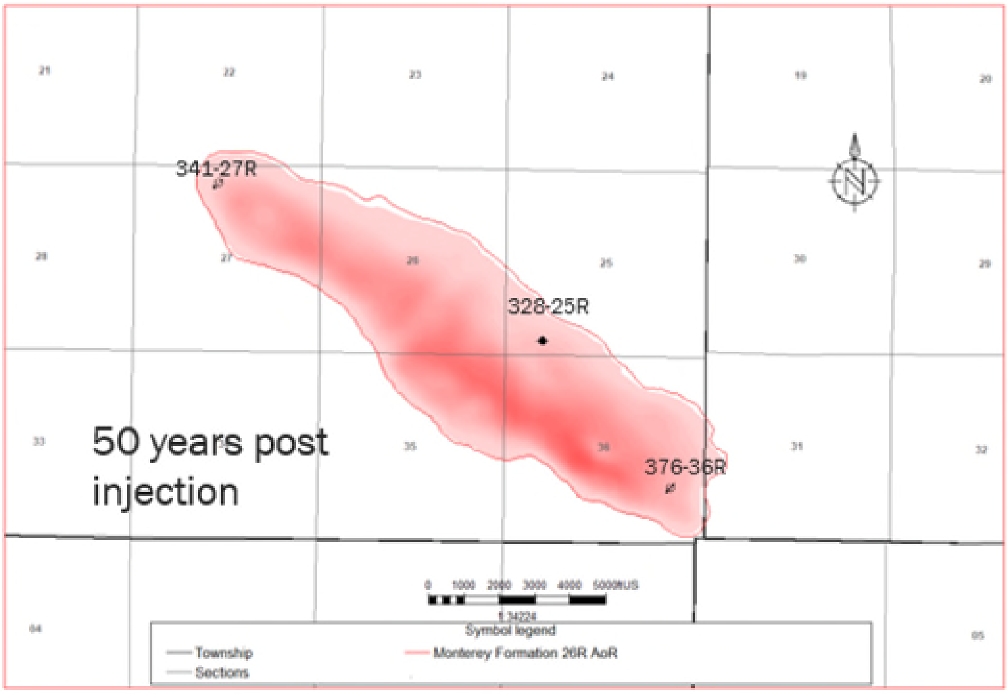


Figure 3: Map of the predicted extent of the CO_2 plume post-injection after 50 years with plume monitoring well locations . The pressure of the 26R reservoir will be at or beneath the initial pressure at the time of discovery.

Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include pressure monitoring and fluid composition monitoring in the storage reservoir and reservoirs above the injection zone. Post-injection monitoring, as described in the following sections, will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days of the anniversary date of final injection, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

The Testing and Monitoring Plan describes the monitoring strategies within the injection zone, above the injection zone, and within the USDW-containing reservoir. In addition to monitoring the zones above the injection zone for stabilized pressure and absence of CO2, the injection zone will be monitored for pressure stabilization as the best method to confirm confinement within the storage reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

The Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Throughout the AoR there is no USDW groundwater but a zone of unsaturated sands in the Upper Tulare. A shallow groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed annually for indicators of CO_2 movement into the formation.

CTV own the mineral rights for the Monterey Formation 26R reservoir. Surface access is guaranteed for the life of the project as CTV is a wholly owned subsidiary of California Resources Corporation, owner of the surface rights.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ. Figure 4 shows the monitoring well locations. Table 3 shows the sampling and recording frequencies for continuous pressure monitoring in the shallow monitoring well. The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation monitoring, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Post-Injection)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	400’- 450' MD/VD	Annual
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’- 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’- 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	800' - 1100' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Annual
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' MD/VD 4788' - 4811' MD/VD 4205' - 4226' MD/VD	Continuous

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, FE, K, Mg, Na, Si)	ICP-OEC EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
pH	EPA 150.1
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

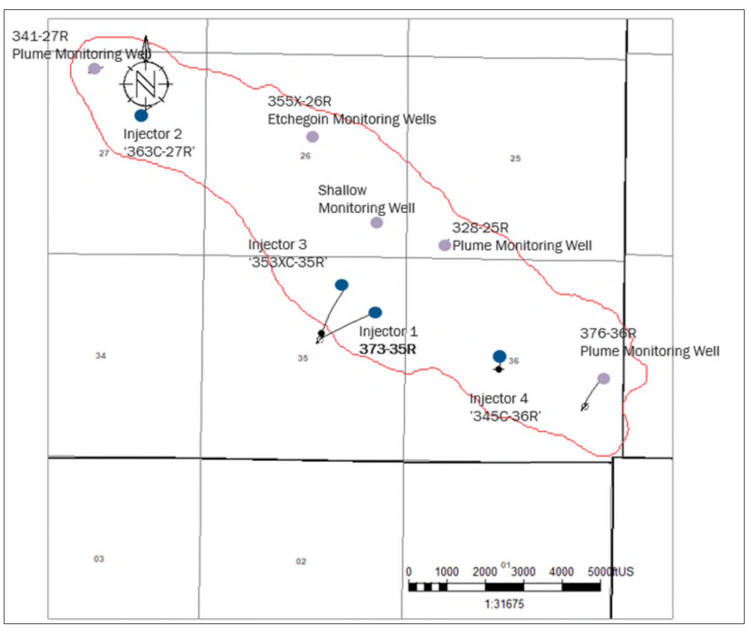


Figure 4: Map showing AoR and well locations for monitoring.

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	Shallow Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	Shallow Monitoring Well	12 hours	12 hours

Notes:

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

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the associated increase in pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation 26R (and associated analytical methods) are presented in Table 2.

Table 4. Post-injection phase plume monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Annual
		Pressure		6910' MD	Continuous
		Temperature		6910' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	328-25R	5268' - 5800' MD	Annual
		Pressure		5188' MD	Continuous
		Temperature		5188' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Annual

		Pressure		5760' MD	Continuous
		Temperature		5760' MD	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Every 5 years
			328-25R	5268' - 5800' MD	
			376-36R	5832' - 6815' MD	

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na and Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO_3, and SO_4)	Ion Chromatography: EPA Method 300.0
Dissolved CO_2	Coulometric Titration ASTM D513-11
Dissolved CH_4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
$\delta^{13}C$	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
pH (field)	EPA 150.1
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Fluid sampling will be performed as described in B.1. of the QASP. Sample handling and custody will be performed as described in B.3. of the QASP. Quality Control will be ensured using the methods described in B.5. of the QASP.

CTV will employ indirect and direct methods to monitor the pressure front. Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies. Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the three Monterey Formation 26R monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro-seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in map view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Continuous
		Temperature			Continuous
Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Continuous

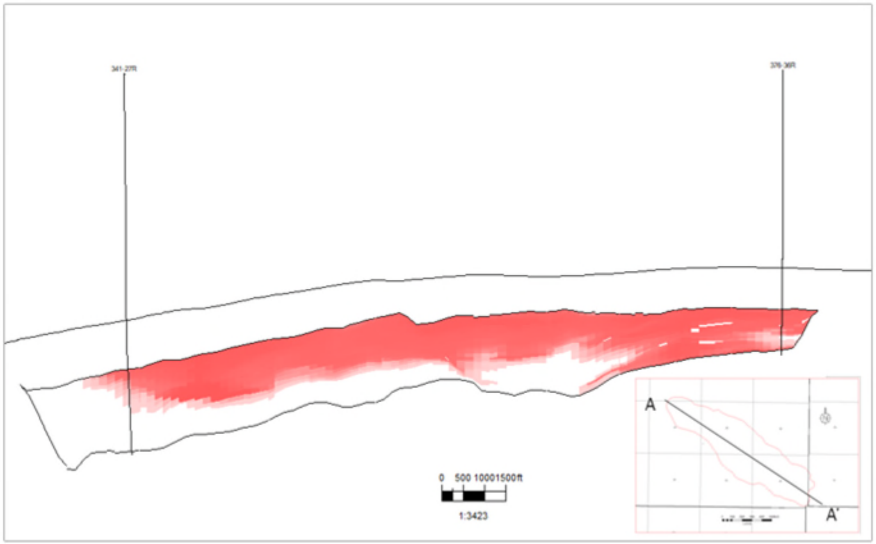


Figure 5: Cross-section showing plume CO2 plume 100 years post injection and 341-27R and 376-36R monitoring wells for post-injection monitoring.

Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria [40 CFR 143.93(b)(2) or (3)]

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director.

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,

2. Dates of all monitoring events,

3. Changes to the monitoring program over time,

4. An explanation of all monitoring information that has existed at the site,

5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and

6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO2 leakage over the project timeframe,

2. the accuracy of the model to predict and represent the storage reservoir, and

3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW

Site Closure Plan [40 CFR 146.93(e)]

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA. A site closure report will be prepared and submitted within 90 days following site closure supported by the following.

1. Verification of injector and monitoring well plugging,
2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2)
3. Composition and volume of the injected CO_2, and
4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO_2 sequestration, the period of injection and the volume of CO_2 injected,
2. The formation that the fluid was injected, and
3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

CTV I: Elk Hills 26R Project

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment F -ERR Plan	1	01/11/21
Attachment F -ERR Plan	2	05/31/22
Attachment F -ERR Plan	3	12/10/22

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.

3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in the individual Well Construction, Operating and Plugging details (COP) documents) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the CTV I Elk Hills 26R Project that may be affected as a result of an emergency event at the project site include:

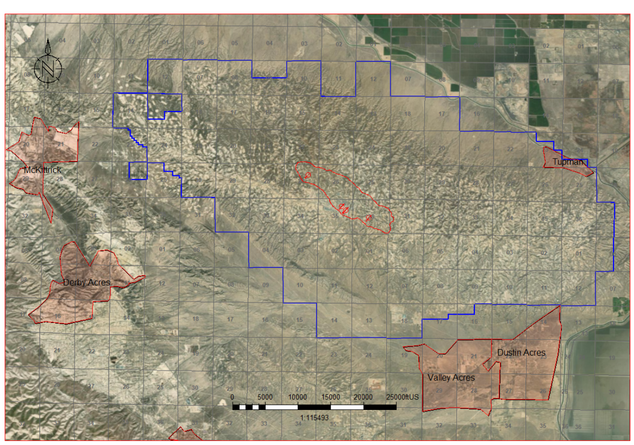
1. Elk Hills oil and gas production resources not associated with the CTV I Elk Hills 26R Project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the CTV I Elk Hills 26R Project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest census designated area is Valley Acres, 3.6 miles from the AoR. The population was 527 at the 2010 U.S. Census.

Infrastructure in the vicinity of the CTV I Elk Hills 26R Project that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CRC that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.36 miles from the census designated area of Valley Acres.



Potential Risk Scenarios

The following events related to the CTV I Elk Hills 26R Project that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- Potential Brine or CO2 Leakage to a USDW;
- A natural disaster (e.g. tornado, lightning strike); or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/Post-Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Preform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.

- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Perform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well or Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills 26R Storage site.

- Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
    - Verify whether contamination has occurred via handheld CO_2 monitors.
    - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.
- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
    - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) movement out of the injection zone or CO_2 leakage into a USDW. This may be identified through elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO2 leakage into a USDW. For example, a pressure increase of 50 PSI (not tied to seasonal changes) or a pH of 1.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits are 0.001 PSI for the pressure gauge and 0.2 for pH.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
  - Initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities.
  - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
    - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
    - Remediate unacceptable impacts to the affected USDW.
  - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
  - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or “pump and treat” to aerate CO_2-laden water).
  - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
  - If there is a well integrity issue perform MITs, refer to the Mechanical Integrity Failure scenario.

- If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. Natural disasters (e.g. tornado or lightning strike) may disturb surface and/or subsurface facilities.

Severity: Minor to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
    - Communicate with CTV personnel and local authorities to initiate evacuation procedures (if necessary).
    - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.

    - Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred.
    - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities. Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

<u>Induced or Natural Seismic Event</u>

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills 26R site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Minor to Major

Timing of event: Injection / post injection

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

<table>
<tr><th>Operating State</th><th>Threshold Condition[1,2]</th><th>Response Action[3]</th></tr>
<tr><td>Green</td><td>Seismic events less than or equal to M1.5</td><td>1. Continue normal operation within permitted levels.
2. Document the event in semiannual reports to the EPA.</td></tr>
<tr><td>Yellow</td><td>Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0</td><td>1. Continue normal operation within permitted levels.
2. Initiate gradual shutdown of the injection wells if it is determined appropriate.
3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event.
4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.
5. Document the event in semiannual reports to the EPA.</td></tr>
<tr><td rowspan="2">Orange</td><td>Seismic event greater than M1.5 and local observation or felt report</td><td rowspan="2">1. Continue normal operation within permitted levels.
2. Initiate gradual shutdown of the injection wells if it is determined appropriate.
3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event.
4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well.
5. Report findings to the UIC Program Director and perform corrective actions.
6. Document the event in semiannual reports to the EPA</td></tr>
<tr><td>Seismic event greater than M2.0 and no felt report</td></tr>
</table>

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] “Felt report” and “local observation and report” refer to events confirmed by local reports of felt ground motion or reported on the USGS “Did You Feel It?” reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual shutdown of the injection wells if it is determined appropriate. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected or endangerment, or CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan for all injection wells. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination or endangerment is detected, or CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	Phone Number
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the “no amendment necessary” determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

Carbon Dioxide Hazards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercise and drills simulating potential emergency situations.

WELL CONSTRUCTION PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_345C-36R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_345C-36R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_345C-36R_V3	3	1/10/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – COP Details_345C-36R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 3/2023
Attachment G – COP Details_345C-36R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

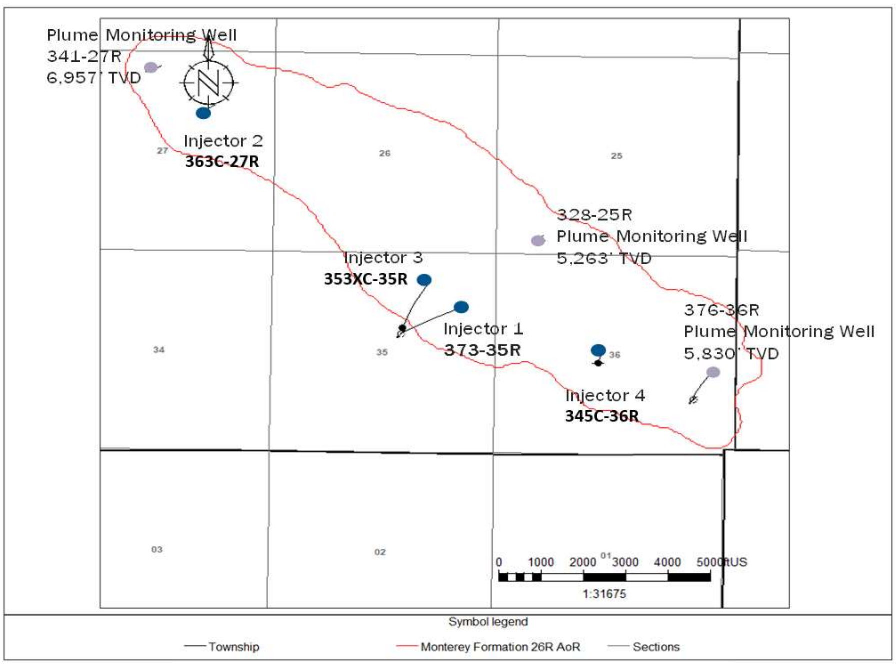


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 3 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long string	14' - 5600' 5600' - 6000'	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	5700' - 7980'	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

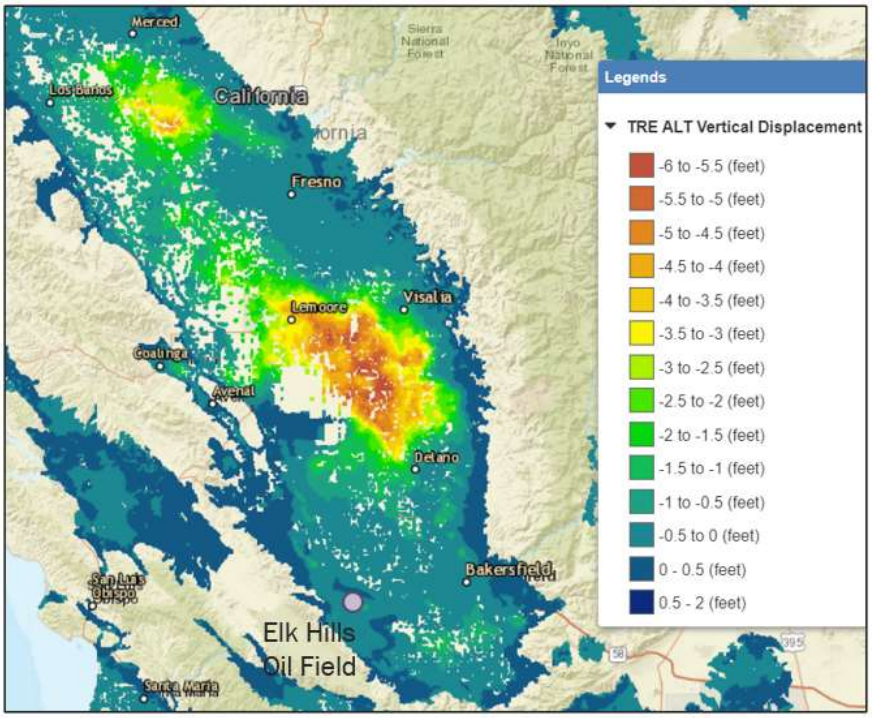


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 2: Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	5,700	4.5	4.00	11.6	L-80 CRA	Premium	7,780	6,350

Table 3: Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	5,700	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 345C-36R with a surface shut-off valve at the wellhead and not a down-hole device.

<u>Pre-Injection Testing Plan</u>

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120' during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 345C-36R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log. The mechanical integrity testing procedures are described in the Testing and Monitoring document.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

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. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. 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 or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

<u>Objectives for Pre-Operational Testing</u>

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the reviews. This information is summarized below (along with the planned tests that will address each data need that was described in the initial permit application materials submitted in November 2021) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c) and 146.87.

Regional Geology and Geologic Structure

• Perform pressure build-up testing (anticipated testing method: pressure build-up test).

• Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data
• Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

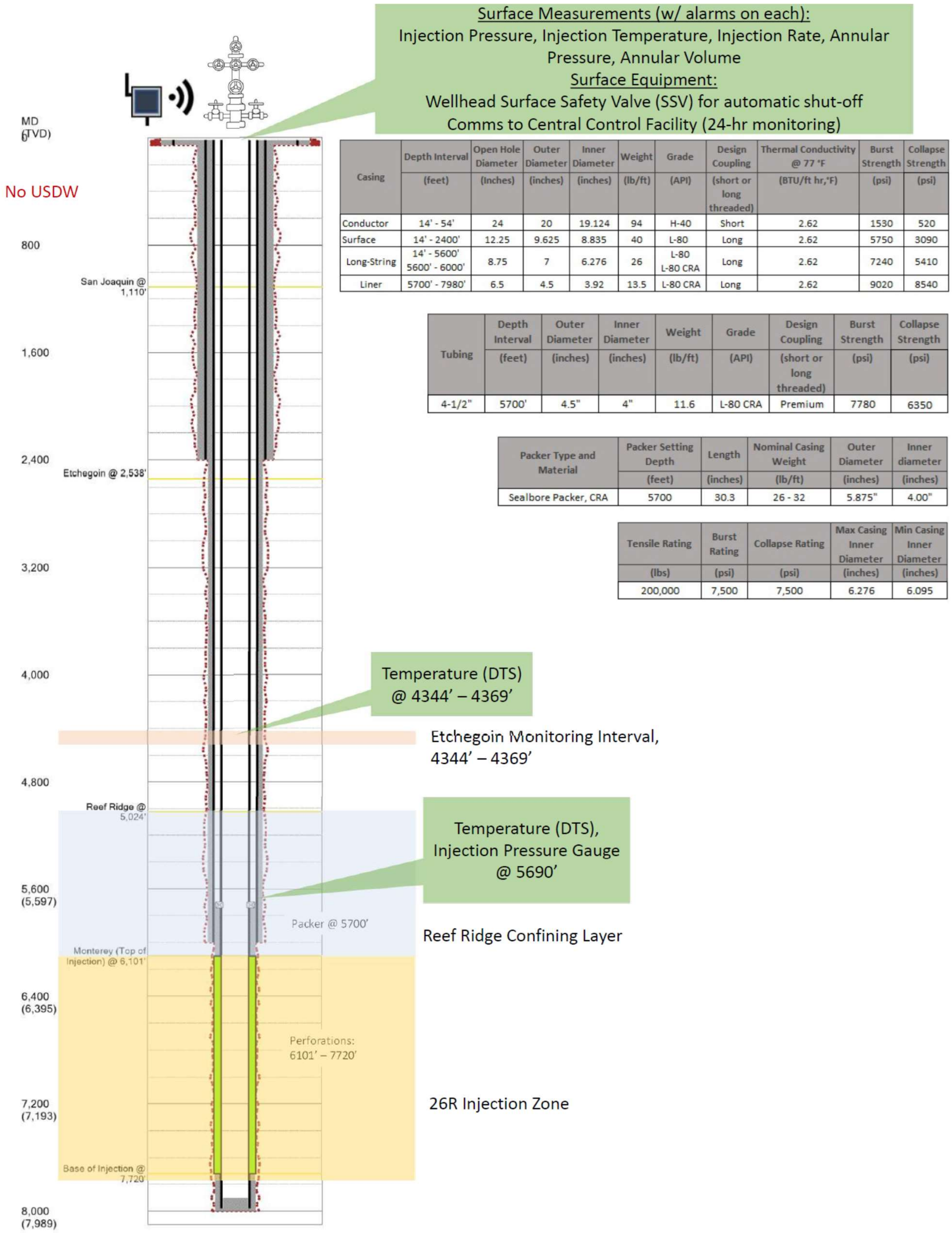
Seismic History and Seismic Risk
• Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones
• Determine if there are any heterogeneities within the Monterey 26R injection zone that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; planned and completed core, log, and seismic analysis).

CO2 Stream Compatibility with Subsurface Fluids and Minerals
• Confirm the composition and water content of the CO2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses, benchtop studies).
• Confirm that the properties of the CO2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).
• Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of the geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity
• Collect baseline pressure data in the Etchegoin Formation to support upward confinement between the Monterey and shallower formations (anticipated testing method: pressure build-up test).
• Determine the porosity and permeability of the Reef Ridge Shale at the location of each of the 26R project wells (anticipated testing methods: core and log data during well drilling).
• Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction
• Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).



Casing	Depth Interval (feet)	Open Hole Diameter (Inches)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Thermal Conductivity @ 77 °F (BTU/ft hr,°F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	24	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	12.25	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long-String	14' - 5600' 5600' - 6000'	8.75	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	5700' - 7980'	6.5	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Tubing	Depth Interval (feet)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Burst Strength (psi)	Collapse Strength (psi)
4-1/2"	5700'	4.5"	4"	11.6	L-80 CRA	Premium	7780	6350

Packer Type and Material	Packer Setting Depth (feet)	Length (inches)	Nominal Casing Weight (lb/ft)	Outer Diameter (inches)	Inner diameter (inches)
Sealbore Packer, CRA	5700	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max Casing Inner Diameter (inches)	Min Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Figure 3: Injection Well 345C-36R, CO_2 Injection Schematic

ATTACHMENT H: FINANCIAL ASSURANCE DEMONSTRATION
40 CFR 146.85

CTV I: Elk Hills 26R Project

Document Version History

Version	Revision Date	File Name	Description of Change
1	9/29/2023	Att H_Financial Responsibility_26R	Compilation of financial responsibility documents in one attachment

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Financial Instruments

Carbon TerraVault (CTV) is providing financial responsibility information pursuant to 40 CFR 146.85. CTV is using the following financial instruments:

- Letter of Credit to cover the costs of corrective action, injection well plugging, post-injection site care, and site closure.
- Certificate of Insurance to cover costs of emergency and remedial response

The estimated costs of each of these activities, as provided by CTV, are presented in Table 1.

CTV has provided financial assurance for Emergency and Remedial Response by procuring an environmental insurance policy. If needed the limits will be re-determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills 26R project environmental insurance policy covers all emergency and remedial response activities arising from the assets. The selected insurance carrier has issued a financial assurance certificate in compliance with state and federal regulations that is provided below.

Table 1. Cost Estimates for Activities to be Covered by Financial Responsibility.

Activity	Instrument	Total Cost ($)
Corrective Action	Letter of Credit	111,320
Plugging Injection Wells	Letter of Credit	1,197,840
Post-Injection Site Care	Letter of Credit	6,790,750
Site Closure	Letter of Credit	994,750
Emergency and Remedial Response	Certificate of Insurance	24,578,125

The following supporting information is provided below to satisfy Financial Responsibility requirements:

- Daniel B. Stephens & Associates, Inc. (DBS&A) third party cost estimate
- Deutsche Bank AG Irrevocable Standby Letter of Credit
- Irrevocable Standby Letter of Credit Notification Letter
- Bank of New York Mellon Standby Trust
- Letter of Credit Cost Estimate and Funding Value Summary
- Ascot Certificate of Insurance
- Insurance Endorsement
- Financial Strength Demonstration

DBS&A THIRD PARTY COST ESTIMATE

CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

COST ESTIMATE

CTV I 26R

Carbon TerraVault (CTV) had the following cost estimate prepared by third party contractor, Daniel B. Stephens & Associates, Inc., completed on 9/5/2023.

Table 1. Financial Responsibility Cost Summary

Activity	Estimated Cost		Reference
Corrective Action	$	111,320	Table 2
Injection Well Abandonment	$	1,197,840	Table 3
Post-Injection Site Care	$	6,790,750	Table 4
Site Closure	$	994,750	Table 5
Emergency and Remedial Response	$	24,578,125	Table 6
Total	**$**	**33,672,785**	

All values in 2022 dollars

Table 2. Costs, Corrective Action Total

Activity	Unit		Unit Cost	Total	Reference
Revise Numerical Model	400	hrs	$ 220	$ 88,000	-
Review CalGEM Well Database	40	hrs	$ 220	$ 8,800	-
Plug Deficient Wells	0	wells	-	$ -	A
Project Management	1	each		$ 14,520	B
			Total	**$ 111,320**	

Notes

A: Per Attachment B, as required wells will be abandoned prior to injection as part of asset retirement obligations

B: 15% of project costs

Table 3. Costs, Injection Well Abandonment

Location	Unit Cost		Depth (ft)	Cost	Reference
Injector 4 345C-36R	30	$/ft	8,680	$ 260,400	A
Injector 1 373-35R	30	$/ft	8,680	$ 260,400	A
Injector 3 353XC-35R	30	$/ft	8,680	$ 260,400	A
Injector 2 363C-27R	30	$/ft	8,680	$ 260,400	A
Documentation, project management	1	each	-	$ 156,240	B
			TOTAL	**$ 1,197,840**	

Notes

A: Abandonment costs from Driltek, 2021; well construction from Attachment G 'Injection Well 1 353XC-35R', Table

B: 15% of project costs

Table 4. Post Injection Site Care Costs

Activity	Unit		Events, 50 years	Unit Cost	Total	Reference
USDW geochemical monitoring/fluid sampling	1	well	50	$ 6,000	$ 300,000	A
Above Confining zone geochemical, pressure monitoring	1	well	50	$ 5,600	$ 280,000	A
Injection zone geochemical, pressure monitoring	3	well	50	$ 5,600	$ 840,000	A
Monitoring well O&M, Above confining zone	1	well	3	$ 30,000	$ 90,000	B
Injection zone monitoring well O&M	3	wells	10	$ 84,000	$ 2,520,000	-
Indirect Plume Monitoring (Pulsed neutron)	1	survey	10	$ 37,500	$ 375,000	C
Mechanical Integrity Test, Injection zone	3	well	10	$ 50,000	$ 1,500,000	B
Reporting/Project Management	1	each	-	$ 885,750	$ 885,750	D
				Total	**$ 6,790,750**	

Notes:

A: Assumes 1 geochemical monitoring event per year per well and continuous pressure monitoring with automated gage; shallow groundwater well have a higher testing cost than the other monitoring wells due to the potential time required to obtain a stabilized sample from a reservoir with low water deliverability.

B: Patrick Engineering, 2013; assumes $2,000 base cost + $4.25/ft (+12%)

C: Zaluski et al., 2016; assumes 8 well survey (inflation adjusted); technology and frequency from PISC plan Table 4

D: 15% of project costs

Assumes:

1 USDW Monitoring Well (exempt or unsaturated)

1 Above Confining Zone Monitoring Well

3 Injection Zone Monitoring Wells

4 Injection wells

Table 5. Costs, Site Closure

Activity	Unit		Unit Cost	Total	Reference
Non-endangerment report	1	each	$ 45,000	$ 45,000	-
Injection zone monitoring well plugging	3	wells	$ 200,000	$ 600,000	A
Above-confining zone monitoring well plugging	1	wells	$ 170,000	$ 170,000	A
USDW Monitoring well plugging	1	well	$ 50,000	$ 50,000	
Plugging documentation, project management	1	each		$ 129,750	B
			Total	**$ 994,750**	

Notes

A: Abandonment costs from Driltek, 2021

B: 15% of project costs

Assumes:

1 USDW Monitoring Well (exempt or unsaturated)

1 Above Confining Zone Monitoring Well

3 Injection Zone Monitoring Wells

4 injection wells

Table 6. Emergency Response

Groundwater Contamination Causal Investigation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,381,875	$ 1,381,875	B
Monitoring wells, depth 1,000 ft	5	well	$ 385,000	$ 1,925,000	A
Monitoring wells, depth 5,000 ft	3	well	$ 1,925,000	$ 5,775,000	A
Abandoned well investigation	51	well	$ 27,500	$ 1,402,500	D
Former Injection Well Investigation	4	well	$ 27,500	$ 110,000	-
Reporting/Project Management	1	each	$ 921,250	$ 921,250	C
Total				**$ 11,515,625**	

Groundwater Contamination Remediation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,567,500	$ 1,567,500	B
Pumping well, depth 1,000 ft	4	well	$ 350,000	$ 1,400,000	A
Pumping well, depth 5,000 ft	4	well	$ 1,925,000	$ 7,700,000	A
Groundwater extraction	1	year	$ 300,000	$ 300,000	-
Above-ground CO_2 removal (aeration)	1	unit	$ 150,000	$ 150,000	-
Former injection well repair	4	well	$ 225,000	$ 900,000	-
Reporting/Project Management	1	each	$ 1,045,000	$ 1,045,000	C
Total				**$ 13,062,500**	

Total, Causal Investigation and Remediation	**$ 24,578,125**

Notes

A: Assumes $385/ft for permitting, installation, field oversight, logging drilling, and waste

B: 15% of project costs

C: 10% of project costs separate from Planning/permitting

D: Assumes 25% of wellbores penetrating Reef Ridge Formation, Attachment B Table 9

References

Driltek, 2021: Personal communication with Driltek regarding well abandonment costs, California

Patrick Engineering, 2013: Third Party Cost Estimate for FutureGen Alliance UIC Class VI Permit Application

Zaluski et al., 2016. Monitoring technology ranking methodology for CO2-EOR sites using the Weyburn-Midale Field as a case study, IJGGC v.54, p.466 - 478

DEUTSCHE BANK AG IRREVOCABLE STANDBY LETTER OF CREDIT

Deutsche Bank

Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor

[redacted]

Deutsche Bank

Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor
New York, NY 10019

[redacted]

Very truly yours,
Deutsche Bank AG
New York Branch

[Signature(s) and title(s) of official(s) of issuing institution]

IRREVOCABLE STANDBY LETTER OF CREDIT NOTIFICATION LETTER

September 6, 2023

United States Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, D.C. 20460
Attention: UIC Program Director

Re: EPA Identification Number: _______________.

Dear UIC Program Director,

At our direction, effective _________, Deutsche Bank AG New York Branch issued a $____________ Irrevocable Standby Letter of Credit No. ____________ in your favor.

The Irrevocable Standby Letter of Credit was issued to meet the non-emergency response financial assurance requirements associated with the Elk Hills 26R Storage Project located at 28590 Highway 119, Tupman, CA 93276.

BANK OF NEW YORK MELLON STANDBY TRUST

Trust Agreement

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

LETTER OF CREDIT COST ESTIMATE AND FUNDING VALUE SUMMARY

Schedule A

Facility	Cost Estimate		
	Corrective action	Injection well plugging	Post injection site care and site closure
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	$111,320.00	$1,197,840.00	$7,785,500.00

Schedule B

Facility	Funding Value for Activities
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	Irrevocable Standby Letter of Credit No. [839BGC2300XXX] issued by Deutsche Bank AG New York Branch in the amount of [$9,094,660.00].

ASCOT CERTIFICATE OF INSURANCE

V. Certificate of Insurance

A certificate of insurance, as specified in this chapter, may be worded as follows, except that instructions in brackets are to be replaced with the relevant information and the brackets deleted:

Certificate of Insurance for [emergency and remedial response]

Name and Address of Insured (herein called the "insured"): Carbon TerraVault 1 LLC 1 World Trade Center, Suite 1500, Long Beach, CA 90831

Name and Address of Insurer (herein called the "insurer"): Ascot Specialty Insurance Company; 55 West 46th Street, 26th Floor, New York, New York 10036

Injection Wells covered: [list for each well: The EPA Identification Number, name, address, and the amount of insurance for [emergency and remedial response] (these amounts for all injection wells covered must total the face amount shown below).]

Underground Injection Control Class VI Permit Application Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.2, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4

Face Amount: $25,000,000
Policy Number: ENPU2310001018-01
Effective Date: 05/18/2023

The insurer hereby certifies that it has issued to the Insured the policy of insurance identified above to provide financial assurance for [emergency and remedial response] for the injection wells identified above. The Insurer further warrants that such policy conforms in all respects with the requirements for the fulfillment of [emergency and remedial response] obligations described at 40 CFR 146.94, respectively, as applicable and as such regulations were constituted on the date shown immediately below. It is agreed that any provision of the policy inconsistent with such regulations is hereby amended to eliminate such inconsistency.

The insurer may cancel the policy only for failure to pay the premium and by sending notice of cancellation by certified mail to the owner or operator and to the UIC Program Director for the area in which the injection well(s) is (are) located. EPA requires that cancellation not become final for 120 days beginning on the date of receipt of the notice of cancellation by the UIC Program Director, as evidenced by the return receipts.

Whenever requested by the UIC Program Director, the Insurer agrees to furnish to the UIC Program Director a duplicate original of the policy listed above, including all endorsements thereon.

[Authorized signature of Insurer]
[Name of person signing]
[Title of person signing]

Ted Mavraganis
Senior Vice President

[Signature of witness or notary:]
[Date]

08/31/2023

INSURANCE ENDORSEMENT

[redacted]

[redacted]

FINANCIAL STRENGTH DEMONSTRATION

Under 40 CFR 146.85(a)(6)(ii), EPA requires that the owner or operator submit proof of the third party's financial strength. EPA recommends that the owner or operator submit the third party's credit rating or, if the Director determines that the credit rating alone does not sufficiently meet the financial strength requirement, submit the third party's credit rating plus its most recent bond rating and calculated financial ratios. EPA recommends that owners or operators demonstrate that third party providers have a credit rating in the top four categories from either Standard & Poor's or Moody's (i.e., AAA, AA, A, or BBB for Standard & Poor's and Aaa, Aa, A, or Baa for Moody's)

Bank of New York Mellon:

- Standard and Poor's rating: AA-

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Bank of New York Mellon (The)

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULATORY IDENTIFIERS	CREDITWATCH/ OUTLOOK	CREDITWATCH/ OUTLOOK DATE
Local Currency LT	AA- Regulatory Disclosures	29-Nov-2011	28-Sep-2022	EE|UKE	Stable	11-Jun-2013

Deutsche Bank AG New York Branch:

- Standard and Poor's rating: A-

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Deutsche Bank AG

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULATORY IDENTIFIERS	CREDITWATCH/ OUTLOOK	CREDITWATCH/ OUTLOOK DATE
Local Currency LT	A- Regulatory Disclosures	09-Nov-2021	17-May-2023	EE|UK	Positive	17-May-2023

ATTACHMENT I: STIMULATION PLAN

Elk Hills 26R Storage Project

Facility Information

Facility name:	CTV I Elk Hills 26R Project 357-7R and 355-7R
Facility contact:	Travis Hurst / CCS Project Manager 28590 Highway 119 Tupman, CA 93276 (661) 342-2409 / Travis.Hurst@crc.com
Well location:	Elk Hills Oil Field, Kern County, CA

Version History

File Name	Version	Date	Description of Change
Att I – Stimulation Plan_v1	1	05/31/22	Original document

Stimulation Plan

The need for stimulation to enhance the injectivity potential of the Monterey Formation 26R reservoir is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 9 for review and approval prior to conducting any stimulation.