ATTACHMENT E

TESTING AND MONITORING PLAN [40 CFR 146.90]

1. FACILITY INFORMATION

Facility Name: CarbonFrontier

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Well Information:

Well Number	County, State	Latitude	Longitude
CI1-64Z-27N	Kern County, CA	35°33'9.4877"N	119°48'26.3702"W
CI2-64Z-35N	Kern County, CA	35°32'32.6713"N	119°47'37.0682"W
CI3-64Z-35N	Kern County, CA	35°32'11.6457"N	119°47'7.5912"W
CI4-64Z-35N	Kern County, CA	35°31'55.4154"N	119°46'51.7864"W
27R-27N	Kern County, CA	35°33'2.4280"N	119°48'28.6103"W
55-26N	Kern County, CA	35°32'43.2520"N	119°47'32.7755"W
64-35N	Kern County, CA	35°31'44.3600"N	119°46'44.9788"W
9-1N	Kern County, CA	35°31'31.6480"N	119°46'37.0154"W
64-27N	Kern County, CA	35°32'38.0979"N	119°47'54.6576"W

Version History

File Name	Version	Date	Description of Change
Attachment E – Aera CCS Testing and Monitoring Plan.pdf	1	January 19, 2023	Original document
Attachment E – CarbonFrontier Testing and Monitoring Plan V2 04182024.pdf	2	April 18, 2024	Revisions made based on additional monitoring well and design of seismicity monitoring network
Attachment E – CarbonFrontier Testing and Monitoring Plan V3 10152024.pdf	3	October 15, 2024	Revisions made based on EPA Technical Review comments from September 12, 2024

This Testing and Monitoring Plan (TMP) describes how Aera Energy LLC (Aera) will monitor the CarbonFrontier site pursuant to Title 40 of the Code of Federal Regulations (CFR) 146.90. In addition, the TMP will be used to confirm that that the wells are operating as planned, the carbon dioxide (CO_2) plume and pressure front are moving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDWs). Monitoring data will also be used to validate and update the geological and reservoir models used to predict the CO_2 plume extent and to support Area of Review (AoR) reevaluations and non-endangerment demonstrations.

Aera will review and submit any amendments to the TMP no less than every 5 years in order to incorporate monitoring data, operational data, and AoR reevaluations, in accordance with 40 CFR 146.90(j). Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (ERRP, **Attachment I**).

2. OVERALL STRATEGY AND APPROACH FOR TESTING AND MONITORING

The CarbonFrontier TMP and the monitoring, verification, and accounting (MVA) program detailed in the Quality Assurance and Surveillance Plan (QASP) will be used to demonstrate safe underground storage of injected CO_2 and USDW non-endangerment.

An AoR delineation model was constructed using a comprehensive data set as further described in **Section 2** of the Application Narrative and **Attachment B**. The proposed injection site is characterized by a porous and permeable injection zone, the 64 Zone Sandstones, overlain by a laterally continuous and impermeable confining layer, the Santos Shale Member, both of which are folded to form a broad anticline. The Santos Shale Member has an average true vertical thickness of approximately 200 feet (ft) and extends far beyond the AoR. The confining zone fractures are very limited and do not affect the macroscopic sealing capacity of the layer. Faults exist but available data suggests that these faults do not transmit fluids or pressure. Log and core analysis data display a difference of at least two orders magnitude in permeability between the 64 Zone Sandstones and the Upper Santos and Lower Santos shales. Overall, the site data indicate that the fluids will be confined to the 64 Zone Sandstones.

The Alluvium and Tulare formation (Fm) are potential USDWs over a portion of the area within the AoR that is outside the aquifer exemption boundary (for the Tulare Fm), and/or where groundwater with total dissolved solids (TDS) concentrations less than 10,000 milligrams per liter (mg/L) may exist (for the Alluvium and outside of the Tulare Fm exempt area). The injection zone is separated from these potential USDWs by numerous confining layers at depth. The injection zone is on average 7,250 ft true vertical depth (TVD) below the Tulare Fm across the North Belridge oil field anticline; whereas, the Alluvium, where present, is separated from the injection zone by a vertical distance of approximately 8,000 ft. The potential risks of CO_2 injection on groundwater quality in the potential USDWs are minimal due to: the limited aerial extent of the potential USDWs; numerous confining units (at the base of the Alluvium, within the Tulare Fm, and in deeper formations); the structural geometry of the North Belridge oil field anticline and injection zone; and the vertical distance separating the potential USDWs from the injection zone.

The injection wells will have continuous monitoring through pressure and temperature gauges. Pressure and temperature monitoring will enable immediate detection of deviations outside the operational limits. The injectate will be analyzed for fluid composition to verify geochemical composition and potential reaction with reservoir constituents. Each injection well will be tested annually for external mechanical integrity and undergo a pressure fall-off test every five years.

Subsurface monitoring will consist of CO_2 plume and pressure front monitoring, groundwater monitoring, and seismicity monitoring. Monitoring wells 1-28N, 39-26N, and 27-1N will be used to monitor the CO_2 plume through direct and indirect methods, including fluid sampling of the injection zone, pulsed neutron logging, and distributed temperature sensing (DTS). The pressure front will be monitored directly at wells 1-28N, 39-26N, and 27-1N. Monitoring wells 1-28N and 25-26N will be monitored for potential changes in fluid geochemistry above the injection zone in the Agua Sandstone, which is the first permeable interval above the injection zone, directly overlying the primary confining layer. These wells will also be analyzed by pulsed neutron logging in the Agua Sandstone for potential CO_2 leakage. Monitoring well 35X-27N will be used for fluid sampling and pressure monitoring in the Lower Carneros Sandstone, which overlies the secondary confining layer.

A microseismic monitoring network, in conjunction with the California Integrated Seismic Network, will be used to monitor for microseismic events at or above magnitude 1.0. Estimates of earthquake shaking potential prepared by the California Geological Survey (CGS) and United States Geological Survey (USGS) indicate that the AoR is located in an area of moderate seismic risk; however, while there are active faults within the region that have the potential to produce significant sharking, none are expected to induce subsurface ruptures within the AoR. All of the faults that are present within the AOI are interpreted to be inactive. The ERRP (**Attachment I**) provides details on the appropriate response actions.

This TMP and the **QASP** details the continuous pressure and temperature monitoring of the injection and monitoring wells in addition to periodic well logging, mechanical integrity testing, and subsurface fluid and CO_2 stream analysis used to demonstrate safe operation and storage of the injected CO_2. This TMP and **QASP** will provide early detection of operational or well integrity issues and demonstrate USDW non-endangerment. A summary of the testing and monitoring strategies to be conducted is given in **Table 1**.

2.1 Quality Assurance Procedures

A **QASP** for the testing and monitoring activities, required pursuant to 146.90(k), is provided as **Appendix A** to this TMP.

2.2 Reporting Procedures

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

Table 1: Summary of Testing and Monitoring Activities

Activity	Location(s)	Method	Pre-Injection Frequency	Injection Frequency	PISC Frequency	Analytical Technique	Lab/Custody	Purpose
CO_2 stream analysis	After compression and processing and before injection wellheads	Direct sampling	Once	Quarterly	N/A	Chemical analysis	California certified lab	Monitor injectate
Injection rate and volume	Before wellhead	Flow meter	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injectate rate and volume
Injection temperature/ pressure	Before wellhead	Temperature/ pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injectate temperature, pressure, and well integrity
Annular pressure	Wellhead	Pressure gauge	N/A	Continuous	None	Direct measurement	N/A	Monitor annular pressure and well integrity
Downhole pressure/ temperature	Injection wells	Downhole gauge and DTS	Continuous	Continuous	None	Direct measurement	N/A	Monitor reservoir pressure/injection temperature/well integrity
	Monitoring wells	Downhole gauge and DTS	Continuous	Continuous	Quarterly	Direct measurement	N/A	Monitor reservoir pressure/injection temperature/well integrity
Internal mechanical integrity	Injection wells and Monitoring wells	Annulus pressure test via annulus pressure gauge	Once	Every five years	None	Direct measurement	N/A	Monitor internal mechanical integrity of wellbore
External mechanical integrity	Injection wells	Temperature log, acoustic log, or oxygen activation log	Once	Annual	Once, prior to plugging	Physical analysis	N/A	Monitor external mechanical integrity
	Monitoring wells	Temperature log, acoustic log, or oxygen activation log	Once	As needed	As needed	Physical analysis	N/A	Monitor external mechanical integrity
	Injection wells	Ultrasonic casing/ cement log	Once	As needed	None	Physical analysis	N/A	Monitor well integrity
Corrosion monitoring	After compression	Coupon	Once	Quarterly	None	Physical analysis	N/A	Monitor well integrity
Pressure fall-off testing	Injection wells	Pressure gauge	Once	Every 5 years	None	Direct Measurement	N/A	Monitor well and reservoir integrity

Activity	Location(s)	Method	Pre-Injection Frequency	Injection Frequency	PISC Frequency	Analytical Technique	Lab/Custody	Purpose
Geochemistry monitoring	Monitoring wells: Agua Sandstone (I-28N, 25-26N); Lower Carneros Sandstone (35X-27N)	Fluid sampling	Once	Annually	Every two years	Chemical analysis	California certified lab	Monitor for CO_2 leakage
CO_2 plume tracking	Monitoring wells: 64 Zone (I-28N, 39-26N, 27-1N)	Fluid sampling	Once	Annually	Every two years	Direct Measurement	California certified lab	Directly monitor CO_2 plume migration
	Monitoring wells: 64 Zone (I-28N, 39-26N, 27-1N)	Pulsed neutron wireline log	Once	Quarterly until plume identified, then annually	Every two years	Indirect measurement	N/A	Indirectly monitor CO_2 plume migration
	Monitoring wells: Agua Sandstone (I-28N, 25-26N, 27-1N)	Pulsed neutron wireline log	Once	Annually	Every two years	Indirect measurement	N/A	Monitor for CO_2 leakage
Pressure front tracking	Monitoring wells: 64 zone (I-28N, 39-26N, 27-1N); Agua Sandstone (I-28N, 25-26N); Lower Carneros Sandstone (35X-27N)	Pressure gauge	Continuously	Continuously	Quarterly	Direct Measurement	N/A	Monitor pressure front migration
Seismic activity monitoring	AoR and within 1 mile radius of injection wells	Seismometer network	Continuous	Continuous	None	Indirect measurement	N/A	Monitor natural and induced seismic activity of magnitude 0.5-1.0 and greater for reservoir, well, facility, and pipeline integrity
	Within 1 mile radius of injection wells	California Integrated Seismic Network	Continuous	Continuous	Continuous	Indirect measurement	N/A	Monitor seismic activity of magnitude 2.7 or greater for reservoir, well, facility, and pipeline integrity

3D: three dimensional
DAS: distributed acoustic sensing
DTS: distributed temperature sensing
N/A: not applicable
PISC: post-injection site care

3. CARBON DIOXIDE STREAM ANALYSIS [40 CFR 146.90(A)]

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

3.1 Sampling Location and Frequency

Sampling will take place quarterly each year starting from 3 months, 6 months, 9 months, and 12 months after the date of commencement/injection. The collected samples will be analyzed by an analytical laboratory.

Prior to the commencement of injection, Aera will conduct a pre-injection analysis of the CO_2 injection stream with samples collected from monitoring points upstream of CO_2 injection wellheads. Aera will submit these data to EPA as part of the permit application requirements [146.82(a)(7)(iv)].

The proposed CO_2 stream will be sourced from a mixture of Aera's planned CO_2 capture facilities, located in the adjacent South Belridge oil field, and from third-party suppliers, received by pipeline or truck. These streams will be tested and reported to EPA according to the requirements of 40 CFR 146.82(a)(7)(iv). The proposed CO_2 streams are discussed in more detail in **Sections 1 and 7** of the Application Narrative.

3.2 Analytical Parameters

Aera will analyze the CO_2 stream for the constituents identified in **Table 2** using the methods listed.

Table 2: Summary of Analytical Parameters for CO_2 Stream

Parameter	Analytical Method(s)
Carbon dioxide (CO_2)	ASTM D1945-14 (2019). Gas Chromatography (GC) with thermal conductivity detector (TCD)
Moisture (water vapor, H_2O)	ISBT 3.0. Electrometric moisture analyzer
Oxygen (O_2), Nitrogen (N_2)	ASTM D1945-14 (2019). GC/TCD
Argon (Ar)	ISBT 4.0. GC with discharge ionization detector (DID) for Ar
Hydrogen (H_2)	ASTM D1945-14 (2019). GC/TCD
Carbon monoxide (CO)	ISBT 5.0. GC with pulsed discharge ionization detector (PDID)
Oxides of nitrogen (NO_x)	ISBT 7.0. Colorimetric tubes, able to detect NO and NO_2
Ammonia (NH_3)	ISBT 6.0. Ammonia-specific colorimetric detector tube
Total hydrocarbons (THC)	ISBT 10.0. GC with flame ionization detector (FID)
Methane (CH_4)	ASTM D1945-14 (2019). GC/TCD
Aromatic hydrocarbons	ISBT 12.0. GC with photoionization detector (PID)
Total sulfur (TS)	ISBT 13.0. GC with sulfur chemiluminescent detector (SCD) Apply ISBT 14.0 if SO_2 level is expected to exceed 1 ppm
Sulfur dioxide	ISBT 14.0. GC/SCD
Hydrogen sulfide (H_2S)	ASTM D1945-14 (2019). GC/TCD
Ethanol (C_2H_6O)	EPA Method 8260B. GC with mass spectroscopy (MS)
^{13}C isotope	Industry Best Practices (Dunn and Carter, 2018). GC with isotope ratio mass spectrometry (GC-IRMS)

3.3 Sampling Methods

Samples will be collected and prepared based on recommendations of the analytical methods included in **Table 2**.

Sample containers will be labeled with durable labels and indelible markings. A unique sample identification number, sample description, sampling date, location, personnel, and their signatures will be recorded on each sample container. Please refer to **Section 2.3** of the **QASP**. for further details.

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

Samples will be analyzed by California-certified laboratories using standard method-specific procedures. Selected laboratories, methods, and detection limits are listed in the **QASP**, along with the required chain of custody procedures.

Chain of custody information will include sampling date, sample description, type of sample, sampler name, location of sampling, methods for analysis, preservatives in the sample container, requested turnaround time for sample results, and the names and signatures of the people relinquishing and receiving the sample(s). A separate laboratory will be contracted to perform the carbon ^{13} isotope analysis. Details of the sample chain of custody and the analysis procedures are included in the **QASP** document.

4. CONTINUOUS RECORDING OF OPERATIONAL PARAMETERS [40 CFR 146.88(E)(1), 146.89(B) AND 146.90(B)]

Aera 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).

Safety valves and system equipment will be installed and operated following American Petroleum Institute Recommended Practice 14B. Biannual testing of surface and subsurface safety valves will be conducted to document their ability to hold pressure. Aera has standard operating procedures to function-test surface safety valves in existing facilities. The surface safety valves, also known as emergency shutdown valves, will be calibrated every 6 months to document their ability to hold pressure. Aera will conduct a function test of the master valve and associated wellhead pipeline isolation valves by fully opening and closing the valves on an annual basis. In addition, Aera will demonstrate valves can hold pressure by conducting an annual leak test using pressure gauges installed on either side of the valves.

Aera will use its existing supervisory control and data acquisition (SCADA) system to monitor equipment, rapidly identify issues that require repairs, and automatically initiate shut-in by a fail-safe actuated gate valve if a critical parameter is exceeded. In addition, Aera's Integrated Operating Control Center (IOCC) is staffed continuously by trained operators to monitor alarms and wells. If there is a triggered alarm, the IOCC will be able to shut-in injection immediately. An operator can then be dispatched to the well site to troubleshoot the alarm and perform needed repairs. If

Aera finds a surface or subsurface safety valve inoperable, injection will be shut-in and repairs will be made within 90 days. If an extension of 90 days is needed, a request for approval will be sent to the Underground Injection Control (UIC) Program Director.

In compliance with 40 CFR 146.89(b), Aera will begin continuous monitoring of operational parameters by conducting an initial annulus pressure test on each injection and monitoring well to establish internal mechanical integrity prior to the start of CO_2 injection. Although exact procedures for specific wells will vary based on conditions and equipment at the location and below surface, in general, Aera will use the procedure below for conducting each annulus pressure test:

- Notify the UIC Program Director in writing 30 days in advance of the annulus pressure test, in compliance with 40 CFR 146.91(d)(3).
- Fill the tubing/casing annulus to surface with corrosion inhibited packer fluid.
- Rig up the pump truck and connect to the tubing/casing annulus at surface.
- Increase pressure on the tubing/casing annulus to the injection maximum allowable surface injection pressure and mechanically isolate the annulus.
- Hold pressure for 30 minutes. Capture test data on a pressure recording chart and in a data file with a reading at least once/minute.
- Less than a 3% drop or 3% build in pressure from the initial pressure shall constitute a successful annulus pressure test.
- Bleed off pressure, shut in the tubing/casing annulus. Rig down the pump truck.
- If the test is successful, report the results to the UIC Program Director within 30 days, as per 40 CFR 146.91(b)(1).
- If the test is unsuccessful, report the results to the UIC Program Director within 24 hours, as per 40 CFR 146.91(c)(4) and commence an investigation to evaluate the cause of the test failure.
  - In the event that a loss of mechanical integrity is discovered, as per 40 CFR 146.88(f), Aera will:
    - Cease injection.
    - Take the steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone.
    - Notify the UIC Program Director within 24 hours.
    - Restore and demonstrate mechanical integrity to the satisfaction of the UIC Program Director prior to resuming injection.

4.1 Monitoring Location and Frequency

Following the initial annulus pressure test, as required under 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b), Aera will continuously monitor and record operational parameters at each injection well including surface and downhole injection pressure, injection rate and volume, surface and downhole temperature, surface and downhole pressure on the annulus between the tubing and long string casing, and the annulus fluid volume as detailed in **Table 3**.

Table 3: Sampling Devices, Locations, and Frequencies for Continuous Monitoring

Test Description	Device(s)	Location	Minimum Sampling Frequency[a]	Min. Recording Frequency[b]
Injection Pressure	Direct Measurement by Pressure Gauge	Surface and downhole	Continuous	Continuous [c]
Injection Rate	Flowmeter	Surface	Continuous	Continuous [c]
Injection Volume	Calculated	Surface	Continuous	Continuous [c]
Annulus Pressure	Direct Measurement by Pressure Gauge	Surface and Above Packer	Continuous	Continuous [c]
Annulus Fluid Volume	Direct Measurement of Fluid Added	Surface	As Required [d]	As Required [d]
CO_2 Stream Temperature	Temperature Gauge	Surface	Continuous	Continuous [c]
Temperature	DTS	Surface and Downhole	Continuous	Continuous [c]

Notes:

[a] 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 2 seconds and save this value in memory.

[b] 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.

[c] This can be the average of the sampled readings over the period, or maximum or minimum, as appropriate.

[d] Fluid volume added or removed to maintain annular pressure will be recorded on the date performed and submitted to the regulatory authority.

4.2 Monitoring Details

Calibration standards, precision, and tolerances for the instruments in **Table 3** will meet or exceed accepted industry standards. Formulas used for calculation of parameters and conversion factors will be provided by the equipment supplier and will comply with accepted industry standards for the specific equipment and be appropriately adjusted for the CO_2 stream and composition parameters.

Data collected from the activities detailed in **Table 3** will be stored in Aera's surveillance system starting prior to the beginning of CO_2 injection so that baseline values, averages, and trends can be established for the parameters at each well. After the start of CO_2 injection, trends will be continuously monitored on each well and compared to prior trends so that changes can be quickly recognized. Total injection rates and volumes into injection wells will be analyzed relative to total CO_2 supplied for injection from surface facilities.

Well by well data trends that are steady and predictable, and in accordance with both CO_2 volumes supplied for injection and expected reservoir pressure increases from injection, will suggest the presence of satisfactory mechanical integrity. Rapid changes in parameters such as annulus pressure, fluid added to the annulus, and injection rate, or unexpected trends in these data, may provide cause for an investigation of mechanical integrity.

In the event that a loss of mechanical integrity is discovered, as per 40 CFR 146.88(f), Aera will:

1. Cease injection.
2. Take the steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone.
3. Notify the UIC Program Director within 24 hours.
4. Restore and demonstrate mechanical integrity to the satisfaction of the UIC Program Director prior to resuming injection.

5. CORROSION MONITORING

In compliance with 40 CFR 146.90(c), Aera will monitor injection and monitoring well materials during the injection 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. Aera will use the corrosion coupon method, as per 40 CFR 146.90(c)(1) and collect and evaluate samples according to the description below.

5.1 Monitoring Location and Frequency

Coupon samples will be attached to individual holders and inserted into a corrosion monitoring flow-through loop that is connected to the main CO_2 transport pipeline. Aera will place the loop in a location downstream of the process compression/dehydration/pumping equipment and upstream of wellheads. A parallel stream of high-pressure CO_2 will be routed from the main CO_2 transport pipeline through this corrosion monitoring loop and then back into a lower pressure point upstream in the system. The corrosion monitoring loop will operate when injection is active. No other equipment will act on the CO_2 past this point; therefore, this location will provide representative exposure of the coupon samples to the CO_2 composition, temperature, and pressure that will be incurred at wellheads and below surface. The holders and location of the system will be included in the pipeline design and will allow for continual injection during sample removal.

Aera will conduct initial baseline evaluations of corrosion coupon samples upon authorization to inject, and then quarterly following the start of injection, as per 40 CFR 146.90(c). An additional evaluation of coupons will occur within 30 days after any stop in injection, followed by a return to the quarterly monitoring schedule. If the CO_2 injection rate changes significantly, Aera will adjust the monitoring frequency to demonstrate sufficient characterization of well construction materials.

5.2 Sample Description

Corrosion coupon samples will consist of the same materials used in injection and monitoring well construction that are expected to be in contact with the CO_2 stream. The materials are listed in **Table 4**. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 4: List of Equipment Coupons with Materials of Construction

Equipment Coupon	Material of Construction for Injection and Monitoring Wells
Long-String Casing (~6000ft – 8000 ft)	Modified 13Cr110
Liner (~7700ft – 8500ft)	Modified 13Cr95
Injection Tubing	Modified 13Cr80
Wellhead	Flow wetted surfaces are expected to consist of F6NM in CO_2 Injection wells and F22 with Alloy 625 Clad in monitoring wells
Packer	Alloy 718 or equivalent for packers and EPDM Elastomers

5.3 Monitoring Details

The coupons will be handled and assessed for corrosion using the ASTM International (ASTM) G1-03 1999 standard for preparing, cleaning, and evaluating corrosion test specimens. The coupons will be photographed, visually inspected with a minimum of 10× power, dimensionally measured (to within 0.0001 in.) and weighed (to within 0.0001 gm). An ongoing record of the appearance, dimension, and weight, of each respective coupon sample will be maintained showing changes from previous evaluations. Rates and trends of corrosion will be determined for each respective sample, and changes in rates and trends will be noted. Rates and trends will be compared to the predicted rates estimated during corrosion modeling, as described in **Section 5.2.9.1** of the Application Narrative. The corrosion modeling showed that the proposed Modified 13Cr will corrode at a rate of 1.34 milli-inches per year (mpy) during injection and 3.73 mpy during times when the well is shut in for maintenance. Based upon the upper end of the predicted corrosion rates, a corrosion rate of greater than 3.7 mils/year will initiate consultation with the regulatory agencies. As warranted based on observed coupon corrosion rates, Aera may conduct additional downhole tests in wells, only as needed, for comparison and to demonstrate continual mechanical integrity.

5.3.1 Additional Downhole Corrosion Tests

An initial casing inspection log will be run prior to commencing injection operations as per 40 CFR 146.87(a)(4)(iv) and will provide baseline casing wall thickness measurements to which future logs will be compared. These logs will be run on both injection and monitoring wells. Subsequent casing inspection logs will be run as warranted based on observed coupon corrosion rates and trends or as required by the UIC Program Director, as per CFR 146.89(d) and 146.90(e). Aera will provide written notification to the UIC Program Director at least 30 days of prior to running these logs, as per 40 CFR 146.87(f). Casing inspection log measurement showing a wall thickness reduction greater than 20 percent from the initial log will be evaluated and may warrant corrective action.

6. ABOVE CONFINING ZONE MONITORING

Aera will monitor groundwater quality for potential geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

Aera will conduct pressure, temperature, and pulsed neutron logging along with fluid composition monitoring in the sandstone units directly overlying the primary confining unit and the secondary confining unit. This testing will allow for early detection of potential leakage from the injection zone. The monitoring wells will be located on Aera property.

The two sandstone units in which monitoring will be conducted are as follows:

- Agua Sandstone, approximately 7,500 to 7,800 ft TVD: permeable zone immediately above the primary confining layer (Lower Santos Shale)
- Lower Carneros Sandstone, approximately 6,550 to 7,150 ft TVD: permeable zone directly above the secondary confining layer (Upper Santos Shale)

A generalized stratigraphic column for the North Belridge oil field is depicted in **Figure 1**.

6.1 Monitoring Location and Frequency

Table 5 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone. The locations of the project monitoring wells are shown in **Figure 2**. These wells are located to allow for early detection of potential leakage from the injection zone into the permeable Agua or Lower Carneros Sandstones, which directly overlie the primary and secondary confining layers, respectively.

Pulsed neutron logging will be used to understand the porosity of different sections of the monitoring zone and to monitor for the presence of fluids and potential CO_2 leakage. The saturation will be used to quantify the amount of CO_2 leaking through the primary confining layer, with the location used to identify a potential pathway of the leakage and what corrective actions may be necessary.

Pressure and temperature will be monitored continuously to identify indicators of potential leakage from the injection zone to the monitoring zone. An increase in pressure and decrease of temperature in the monitoring zone may indicate leakage of CO_2 or other displaced gases and/or reservoir fluids from the injection zone into the Agua or Lower Carneros Sandstones. Because pressures in the monitoring zone are expected to be generally stable, variations from baseline identified through fluid sampling and analysis may provide an additional indicator of potential leakage of CO_2 or displacement of reservoir fluids into the monitoring zones. While the 64 zone monitoring wells will not be perforated in the Agua Sandstone or Lower Carneros Sandstone formations, these wells will have DTS fiber installed for continuous temperature monitoring along the wellbores. Section 9.2.2 describes DTS in further detail.

Fluid will be analyzed for geochemical properties (CO_2 concentrations, pH, and metal ions) to detect potential leakage from the injection zone as evidenced by increases in CO_2 or metals concentrations due to increased acidity during injection. While changes are not anticipated, as the project progresses and the CO_2 plume migrates within the AoR, data will be analyzed to evaluate if additional monitoring is warranted.

Baseline monitoring will be conducted prior to injection to establish conditions against which to compare future monitoring data. A numerical database will be used to establish statistical bounds of each analytical parameter for comparison of the baseline to injection period data. Significant abnormalities or changes will be used to evaluate sequestration efficacy and if additional sampling events may be warranted. Abnormalities suggestive of leakage could include increased TDS, change in cation and/or anion signature(s), increase in CO_2 concentrations, pH changes, or changes in dissolved metal concentrations.

Table 5: Monitoring of Fluid Composition and Geochemical Changes Above the Confining Zone

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[1,2]
Agua Sandstone (approximately 7,500-7,800 ft TVD)	Fluid sampling	Monitoring wells 1-28N and 25-26N	Northern half of injection area	Baseline: Once prior to first injection. During injection: annually
	Temperature (DTS) and Pressure Monitoring	Monitoring wells 1-28N and 25-26N	Above injection zone	Continuous
	Temperature (DTS) Monitoring	Monitoring wells 39-26N and 27-1N	Along wellbore	Continuous
	Pulsed neutron logging	Monitoring wells 1-28N, 25-26N, and 27-1N	Along wellbore	Baseline: Once prior to first injection During injection: annually
Lower Carneros Sandstone (approximately 6,550–7,150 ft MD)	Fluid sampling	Monitoring well 35X-27N	Above injection zone	Baseline: Once prior to first injection During injection: annually
	Pressure	Monitoring well 35X-27N	Above injection zone	Continuous

Notes:
1. Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.
2. Logging will take place up to 45 days before the anniversary date of authorization of injection each year.
MD: measured depth

6.2 Analytical Parameters

Table 6 identifies the parameters to be monitored and the analytical methods. Fluid sampling is planned to include an extensive set of chemical parameters to establish aqueous geochemical data. Parameters will include selected constituents that:

- Have primary and secondary EPA drinking water maximum contaminant levels;
- Are the most responsive to interaction with CO_2 or brine;

- Are needed for quality control; and
- May be needed for geochemical modeling.

If new information or updates to the geochemical modeling based on pre-operational testing identifies additional subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of subsurface fluid analytical parameters may be updated.

Information regarding the detection limit/range, precision, and quality control requirements for fluid analysis is provided in the **QASP Table 5**.

Table 6: Summary of Analytical and Field Parameters for Fluid Sampling

Parameters	Analytical Methods
Cations/metals (aluminum, barium, calcium, manganese, sodium, potassium, iron, arsenic, magnesium, silica, cadmium, chromium, copper, lead, selenium, titanium, zinc)	EPA Method 200.7/200.8
Anions (chloride, sulfate, sulfide, bromide, fluoride, nitrate)	EPA Method 300.0/300.1; SM 4500-S^{2-}-D for sulfide
Dissolved gases - CO_2 - CH_4 - O_2 - H_2S (field)	 RSK-175 RSK-175 SM 4500 OG or RSK-175 Field
Total dissolved solids	EPA Method 160.1/SM 2540 C
Alkalinity	SM 2320 B/EPA Method 310.1
Field measurements: - pH - Specific conductance - Temperature	 EPA Method 150.2/SM4500-H+B EPA Method 120.1 Thermocouple
Hardness	SM 2340C
Turbidity	SM 2130B
Specific gravity	SM2710F
Water density	SM2710F
Dissolved inorganic carbon isotopes ($\delta^{13}C$)	Industry best practices for isotope ratio mass spectrometry

6.3 Sampling Methods

Sampling will be performed in accordance with the **QASP**. Samples will be handled and shipped to the selected analytical laboratory under standard chain-of-custody procedures, detailed in the **QASP** and in the following section.

6.4 Laboratory to be Used/Chain of Custody Procedures

Samples will be analyzed by California-certified laboratories using standard method-specific procedures. Selected laboratories, methods, and detection limits are listed in the **QASP**, along with required chain of custody procedures.

Chain of custody information will include sampling date, sample description, type of sample, sampler name, location of sampling, methods for analysis, preservatives in the sample container, requested turnaround time for sample results, and the names and signatures of the people relinquishing and receiving the sample(s).

6.5 Surface Air and/or Soil Gas Monitoring

Pursuant to 40 CFR 146.90 (h)(1) through (3), surface air monitoring and/or soil gas monitoring may be required by the EPA for Class VI wells based on potential endangerment to USDWs within the AoR. There is little potential for USDW endangerment within the AoR for numerous reasons (**Section 2.7** of the Application Narrative) which include an aquifer exemption for portions of the North Belridge oil field [EPA, 2019], groundwater TDS concentrations exceeding the 10,000 mg/L threshold to be considered a USDW in parts of the Alluvium [Wood Environmental and Infrastructure Solutions, Inc., 2021], and where there is groundwater within the Alluvium with TDS potentially less than 10,000 mg/L, there are multiple confining layers and low risk for communication with the injection zone. In the portions of the AoR where there is no aquifer exemption and TDS concentrations in groundwater are unknown, if groundwater occurs within the Tulare Fm and/or Alluvium, it is considered a potential USDW; however, the potential for endangerment caused by CO_2 injection is still low due to the anticlinal geometry, presence of multiple confining units, and the limited extent of these potential USDWs.

If the results of planned pre-operational testing identify significant uncertainties about the geologic setting, EPA may mandate surface air and/or soil gas monitoring be conducted under 40 CFR 146.90; if this occurs, Aera will comply with these requirements. Class VI injection wells are also subject to Subpart RR of the EPA Greenhouse Gas (GHG) Reporting Program. This rule requires facilities to develop and implement an MRV plan that is site specific and details the maximum monitoring area (MMA), active monitoring area (AMA), potential leakage pathways, strategies for detecting and quantifying leakage, and general information on CO_2 received for injection. Aera will comply with these requirements by developing and implementing an EPA-approved MRV plan.

7. EXTERNAL MECHANICAL INTEGRITY TESTING

Aera will conduct at least one of the tests presented in **Table 7** annually during the injection phase to demonstrate external mechanical integrity as required at 146.89(c) and 146.90(e).

7.1 Testing Location and Frequency

To demonstrate the external mechanical integrity of the CO_2 injection wells, Aera will conduct at least one of the tests presented in **Table 7** annually during the injection phase, as required in 146.89(c) and 146.90(e). External mechanical integrity tests will be also performed on monitoring wells if irregularities are observed in continuous measurements of the surface tubing and annulus pressure or during routine logging, testing, and sampling programs.

Table 7: Annual External Mechanical Integrity Tests (MITs)

Test Description	Location
Temperature	Conventional wireline well log or DTS along wellbore
Acoustic	Conventional wireline noise log
Oxygen Activation	Conventional wireline well log

7.2 Testing Details

Aera will run at least one of the tests in **Table 7** every year, within 45 days of the respective anniversary date of the start of injection on each CO_2 injection well, and as warranted on monitoring wells. Aera will notify the UIC Program Director of the logging schedule at least 30 days prior to logging, per 40 CFR 146.87(f).

As required in 40 CFR 146.88(f), if there is an indication of a loss of mechanical integrity, Aera will perform the following:

- Cease injection.
- Take the steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone.
- Notify the UIC Program Director within 24 hours.
- Restore and demonstrate mechanical integrity to the satisfaction of the UIC Program Director prior to resuming.
- Notify the UIC Program Director when injection can be expected to resume.

If mechanical integrity is confirmed, Aera will prepare and submit a report on the interpreted logging results to the UIC Program Director within 30 days, as required in 40 CFR 146.91(b).

The following procedures will be followed for the selected mechanical integrity test.

7.2.1 Temperature Logging with Wireline

Aera will use the following procedures and comply with EPA guidance to ensure testing requirements are achieved:

1. Stabilize injection for 24 hours prior to running the temperature log.
2. Run an initial temperature survey logging down from at least 200 ft above the base of the Confining Zone to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft per minute (ft/min), and the acceptable range is between 20 and 50 ft/min.
3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.
4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to

determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to EPA. The printed or digital log should have the following:
    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 inches per 100 ft to match lithology logs.
    c. Horizontal temperature scale should be no more than 1°F 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.

7.2.2 Temperature Logging using Distributed Temperature Sensing

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

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 injection well:

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

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

7.2.2.1 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 detect temperature changes along the wellbore if external mechanical integrity is compromised. DTS will be installed in monitoring wells, 1-28N, 39-26N, 25-26N and 27-1N.

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

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

7.2.3 Noise Logging

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

1. Move in and rig up an electrical logging unit with lubricator.
2. Run a noise survey from the base of the potential USDW to the deepest point reachable in the injection zone while injecting at a rate that allows for safe operations.
3. Make noise measurements at intervals of 100 ft 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 ft within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 ft through the first 50 ft above the injection interval and at intervals of 20 ft within the 100-foot intervals, containing the following:
    a. The base of the lowermost bleed-off zone above the injection interval
    b. The base of the lowermost potential USDW
    c. Additional measurements may be made to pinpoint depths at which noise is produced.

7.2.4 Oxygen Activation Logging

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

1. Move in and rig up an electrical logging unit with lubricator.
2. Conduct a baseline gamma ray (GR) log and casing collar locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma ray log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.
3. The OA log shall be used only for casing diameters of greater than $1\frac{11}{16}$ inches and less than $13\frac{3}{8}$ inches.
4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.
5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a “no vertical flow behind the casing” section of the well to ensure accurate, repeatable tool response and for measuring background counts.
6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 ft 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 potential 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 potential USDW.

If flow is indicated by the OA log at a location, move uphole or downhole as necessary at no more than 50-foot intervals and take stationary readings to determine the area of fluid migration.

8. PRESSURE FALL-OFF TESTING

Aera will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

8.1 Testing Location and Frequency

A pressure fall-off test will be conducted on each operational Class VI injection well, at least once every 5 years throughout the injection phase of the project. Results of pressure fall-off tests will be submitted to UIC Program Director electronically within 30 days of the test [40 CFR 146.91(e) and 146.91(b)(3)]. Aera will follow guidance of the EPA Region 9 UIC Pressure Fall-Off Testing Guideline document.

Aera will conduct pressure fall-off testing according to the procedure below.

8.2 Testing Details

A pressure fall-off test is composed of a period of injection followed by a period of shut-in. Aera will hold and record a constant injection rate while maintaining as stable operating conditions as practically possible prior to the test shut-in period. The injection will then be shut in instantaneously at the wellhead or as near the wellhead as feasible. Pressure gauge will be of type that meets or exceeds American Society of Mechanical Engineers B 40.1 Class 1A (1% accuracy across full range). The surface pressure gauge will cover the range of 0 to 3,000 pounds per square inch (psi), while the downhole gauge will cover the 0 to 8,000 psi range. Gauge specifications are provided in the **QASP** (**Section 1.4.7**) and will be included in each test report. Overall, measures will be taken to acquire test data of sufficient quality, over sufficient time periods, to enable clear interpretation of the test results and an evaluation of the near-wellbore formation properties.

The following procedure will be followed:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.
2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottom-hole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10-second intervals, which is sufficient and appropriate for pressure-transient analysis.
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 injection well will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real-time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.
5. Interference testing may be conducted at the conclusion of the fall-off test to demonstrate communication between the wells. The injection rate of the offset injection well would be increased or decreased multiple times to create pressure pulses that can be observed by the shut-in well.
6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry-standard methodologies. Anomalies that are identified from the interpretation will be investigated.
7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semiannual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Fall-Off Testing Guideline.

9. CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING

Aera will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g). As shown below, the plan and schedule are designed to monitor the free-phase CO_2 plume location, thickness, and saturation; track the pressure development within the AoR over time; validate computational modeling results; and demonstrate the operations are not leading to elevated CO_2 or brine leakage or seismic risks.

Annual fluid sampling, pulsed neutron logging, and continuous measurements of injection zone temperature and pressure within four monitoring wells will provide a robust mechanism for tracking the extent of the CO_2 plume and the presence or absence of elevated pressures.

Monitoring well locations were selected based on simulated plume and pressure front migration and are in locations to validate the simulation results with the monitoring plan outlined below. **Figures 3 and 4** show the predicted evolution of the CO_2 plume and pressure front, respectively, during and following injection.

9.1 Plume Monitoring Location and Frequency

Table 8 presents the methods that Aera will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies Aera will employ. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are the same as for above confining zone monitoring and are presented in **Table 6**.

Quality assurance procedures for these methods are presented in **Section 1.4** of the **QASP**.

Table 8: CO_2 Plume Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Plume Monitoring				
64 Zone	Fluid sampling	1-28N	1 Point Location: ~8,029 - 8,358 ft MD	Annual
64 Zone	Fluid sampling	39-26N	1 Point Location: ~7,975 - 8,243 ft MD	Annual
64 Zone	Fluid sampling	27-1N	1 Point Location: ~8,001 - 8,302 ft MD	Annual
Indirect Plume Monitoring				
64 Zone	Pulsed neutron logging	1-28N	Survey log: ~7,505 - 8,450 ft MD	Quarterly until plume identified, then annual
64 Zone	Pulsed neutron logging	39-26N	Survey log: ~7,667–8,300 ft MD	Quarterly until plume identified, then annual
64 Zone	Pulsed neutron logging	27-1N	Survey log: ~7,594 - 8,278 ft MD	Quarterly until plume identified, then annual
64 Zone	DTS	1-28N	Entire Wellbore	Continuous
64 Zone	DTS	39-26N	Entire Wellbore	Continuous
64 Zone	DTS	27-1N	Entire Wellbore	Continuous

9.2 <u>Plume Monitoring Details</u>

9.2.1 Direct Methods

<u>Fluid Sampling</u>

The primary method for direct plume monitoring will be fluid sampling from the injection zone to detect changes from baseline values, indicative of the CO^2 plume's presence. Samples will be collected annually, up to 45 days before the anniversary date of authorization of injection each year. The parameters to be analyzed as part of the fluid sampling in the target injection zone and the analytical methods are presented in Table 6.

9.2.2 Indirect Methods

<u>Distributed Temperature Sensing</u>

Distributed temperature sensing allows for continuous temperature profiles over the installed depth rather than measurements at fixed points The continuous temperature data can be analyzed to provide information about the specific depths that the CO_2 enters the formation. Abnormal temperature profiles may indicate mechanical integrity concerns or unexpected leakage of CO_2. DTS will be installed in the 64 Zone monitoring wells, 1-28N, 39-26N, and 27-1N, to identify temperature changes that may indicate the CO_2 plume's arrival at that location. DTS will also be installed in the Agua sandstone monitoring well 26-25N and used in the 64 Zone monitoring wells to evaluate temperature changes above the injection zone.

<u>Pulsed Neutron Logging</u>

The CO_2 plume location will be tracked using pulsed neutron logging that will provide high-resolution vertical data around the wellbore of each monitoring well. The saturation of CO_2 in the target formation will be estimated by measuring the die-away time of a short neutron pulse. The die-away time is a function of the porosity and the fluid types in the rock. Pulsed neutron log accuracy and calibration are discussed in the **QASP** (**Section 1.4.7**).

An initial pulsed neutron log will be performed before the CO_2 plume reaches the monitoring well and will serve as a baseline that future measurements will be compared against. Increases in CO_2 saturation relative to baseline may indicate that the plume has reached the monitoring well. These data will be used in reevaluations of the AoR (**Attachment B**).

9.3 Pressure-Front Monitoring Location and Frequency

9.3.1 Distributed Pressure Sensing

Aera will deploy pressure gauges in each monitoring well to continuously monitor reservoir pressure and detect the position of the pressure front. **Table 9** presents the methods that Aera will use to monitor the position of the pressure front, including the activities, locations, and their frequencies. Seismicity monitoring will also provide indirect monitoring of the pressure front. See **Section 9.4** for details on the seismicity monitoring network.

Quality assurance procedures for these methods are presented in **Section 1.4.7** of the **QASP**.

Table 9: Pressure Front Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
64 Zone	DTS/Pressure Gauge	1-28N	Distributed measurement to ~8,450 ft MD	Continuous
64 Zone	DTS/Pressure Gauge	39-26N	Distributed measurement to ~8,243 ft MD	Continuous
64 Zone	DTS/Pressure Gauge	27-1N	Distributed measurement to ~8,278 ft MD	Continuous

9.4 Seismicity Monitoring

Aera intends to monitor seismicity with a network of shallow borehole seismometers in the AoR with potential surface seismometers for location verification. This network will be implemented to monitor seismic activity near the project site. The seismometers will be able to detect events with a magnitude 0.5 to 1.0 and above and will be installed at least one year prior to injection to provide baseline seismicity. Additionally, the California Integrated Seismic Network will be monitored continuously for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of one mile of injection operations from commencement of injection activity to its completion. Aera will respond to seismic events with an epicenter in the AoR in accordance with the Seismic Response System for seismic events >M1.0 established in the Emergency and Remedial Response Plan (**Attachment I).** A summary of the seismic monitoring locations and frequencies is given in **Table 10**. 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.

9.4.1 Network Design

Sensor locations will be determined following evaluation. At least three borehole seismometers will be installed in offset wells within the AoR with two potential surface stations outside of the AoR to provide location verification. The sensors will have high-sensitivity 3-component geophones. The systems will be designed with capability of detecting and locating events of magnitude 0.5 to 1.0 and above. A velocity model will be derived from nearby vertical seismic profiles (VSPs), sonic well logs, and check shots.

Monitoring will begin at least one year prior to injection to establish an understanding of the baseline seismic activity within the area of the project. Historical data from the California Integrated Seismic Network will be reviewed to assist in establishing the baseline. 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.

9.4.2 Network Operation

After design, the microseismic network will be installed and tested. After testing is completed, the network will be operational to monitor for microseismic events continuously during baseline and injection operations. Waveform data will be transmitted in near real-time via cellular modem or other wireless means and archived in a database. Event notification will be automatically sent to required personnel to ensure compliance with the Emergency and Remedial Response Plan (**Attachment I**).

Table 10: Summary of Passive Seismic Monitoring System

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Multiple	Seismic events of magnitude 0.5-1.0 and above	Shallow borehole seismometers within offset wells in AoR	AoR, within 1-mile radius of injection wells	Continuous
Multiple	Seismic events over magnitude 2.7	California Integrated Seismic Network	AoR, within 1-mile radius of injection wells	Continuous

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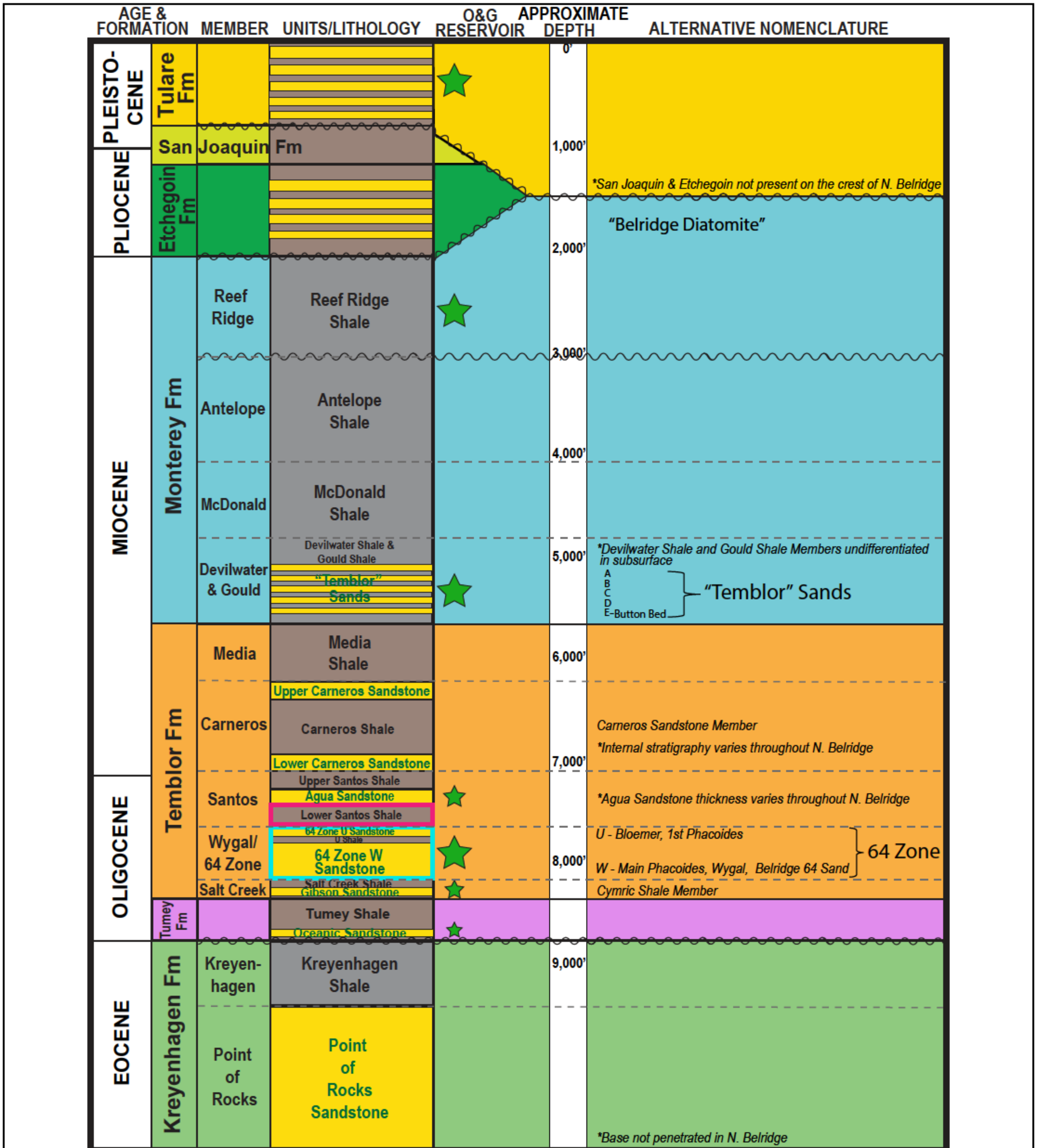
Figures

Figures Index



Legend

- ★ Significant Oil and Gas Producing Unit
- Injection Zone
- Primary Confining Zone
- Unconformity
- Formation Boundary
- Member Boundary

Lithology

- Mudstone
- Sandstone
- Siliceous Mudstone

Explanation

O&G - Oil and Gas
Fm - Formation
N. - North

North Belridge Stratigraphic Column

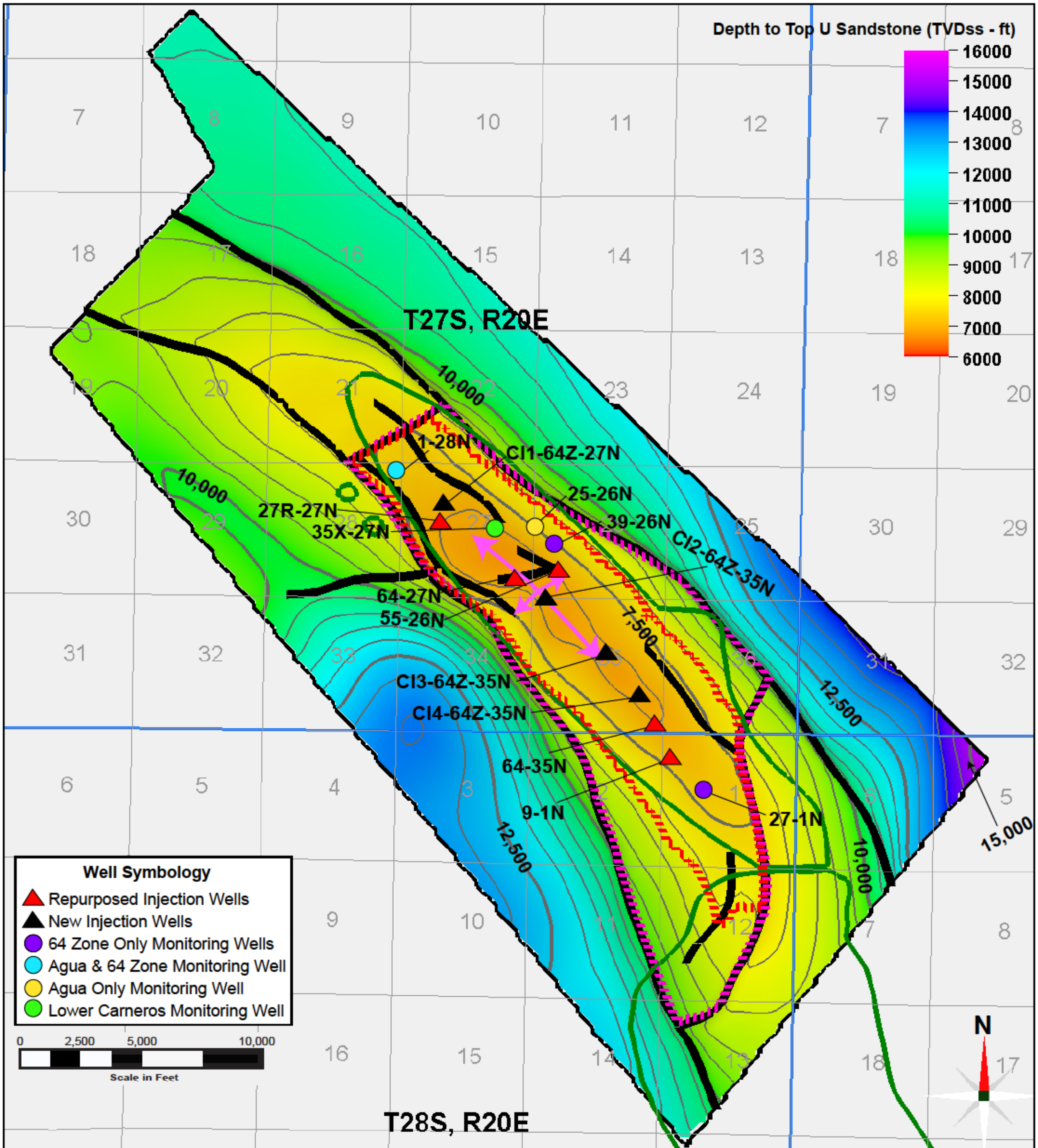
North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

Figure

1

CarbonFrontier | April 2024



Legend:

- Area of Interest
- Township/Range Boundaries
- Section Boundaries
- 1973/74 Oil Field Boundaries
- Fault Traces
- Elevation Contours (500 ft CI)
- Area of Review
- Modeled CO_2 Plume Extent
- Anticline Axis

Explanation:

ft - feet
TVDss - true vertical depth sub sea (ft)
CI - contour interval
CO_2 - carbon dioxide

Notes:

Surface artifacts due to interpolation across faults and structural model grid.

Location Map of Repurposed and New Wells

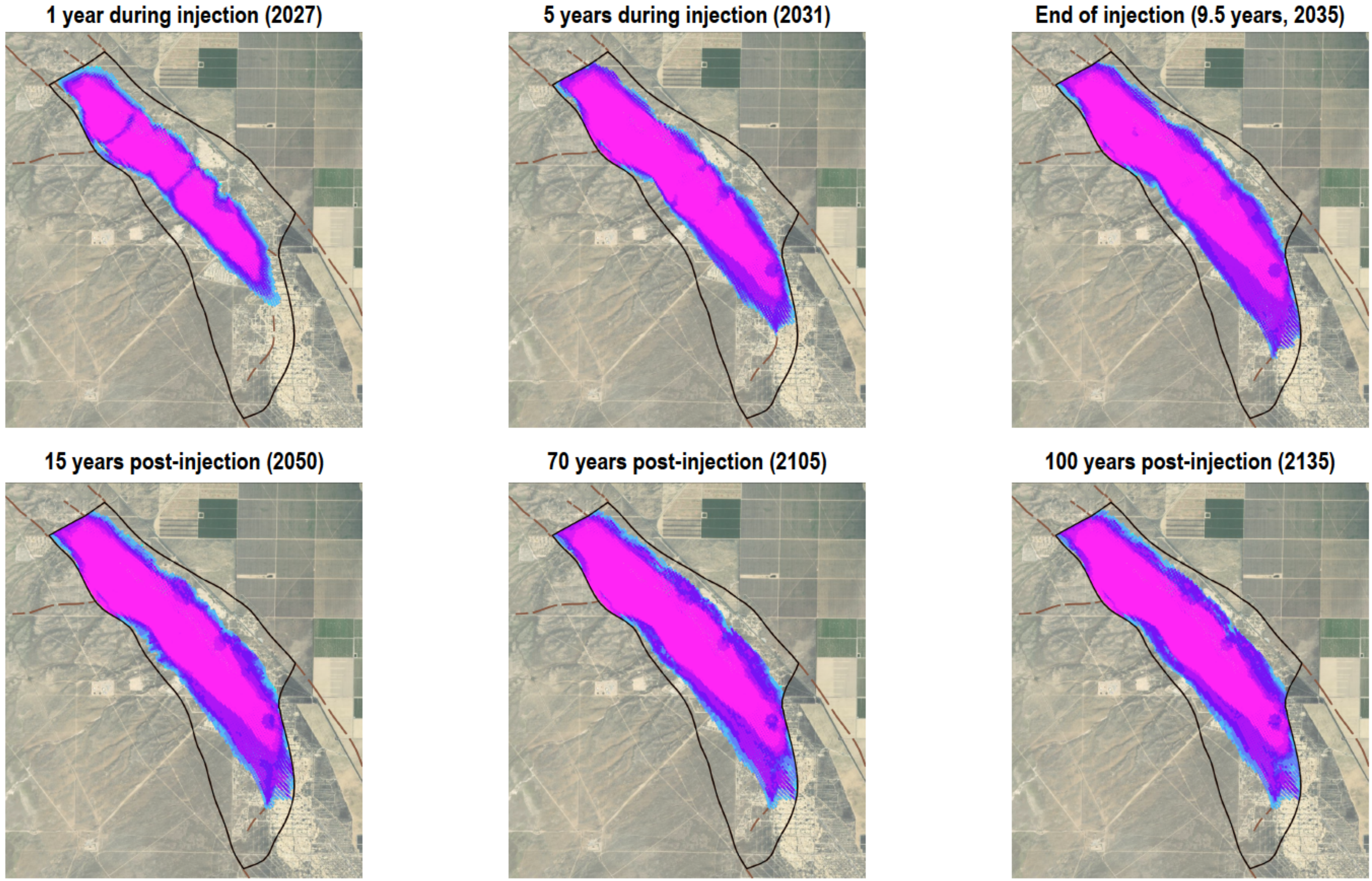
North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

CarbonFrontier | October 2024

Figure 2

Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAResponse202409\i_Illustrator\Attachment E\E_ Fig-2 Location Map of Repurposed & New Wells.ai



Legend:

Area of Review Boundary

Faults are projected from Top U-Sandstone

N

Notes:

The CO_2 plume is shown as a percent value of CO_2 saturation in the pore space, which is the sum of all phases (free-phase, dissolved phase in water, dissolved phase in oil, and residual) for all cells in the model at the respective time. The saturations are shown in map view by presenting the maximum value for all depths of the Area of Review. The Area of Review Boundary is defined as the maximum extent of the CO_2 plume and the pressure front.

Explanation:

CO_2 - Carbon Dioxide

1 10 20 30 40 50 60 68

CO_2 Saturation (%)

0 10,000 Feet

Evolution of CO_2 Plume Map View

North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

Figure 3

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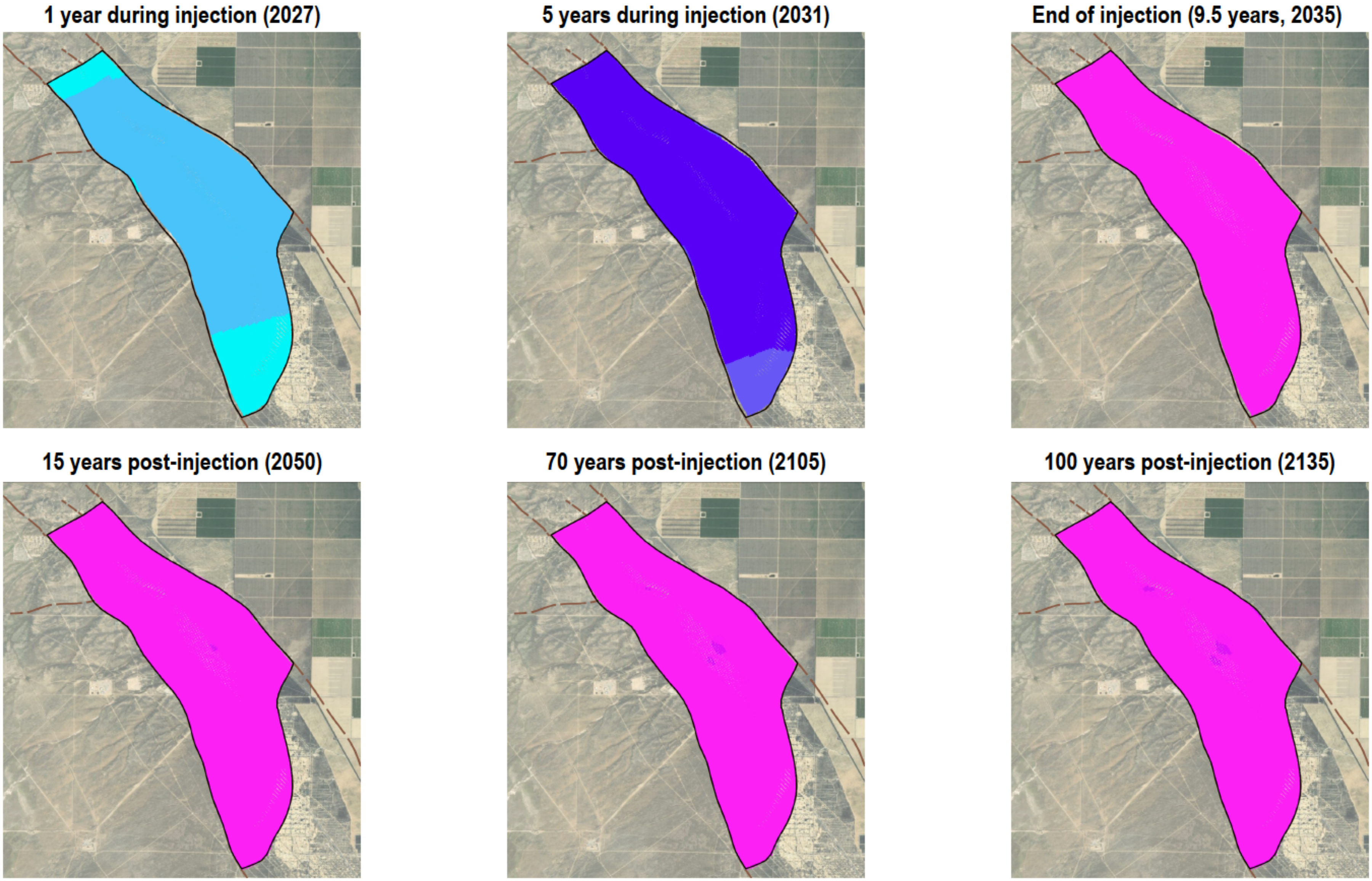
Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAProactive2024\i_Illustrator\Attachment E\E_ Fig-3 Map View CO_2 Saturation Distribution.ai



Legend:

Area of Review Boundary

Faults projected from Top U-Sandstone

25 1,000 1,500 2,000 2,500 3,000 3,500 4,000 4,350

Pressure Differential (psi)

Notes:
Showing maximum pressure Increment at each X/Y cell for all depths.

0 10,000 Feet

N

Evolution of Pressure Differential Map View

North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

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Figure 4

Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAProactive2024\i_Illustrator\Attachment E\E_ Fig-4 Map View Modeled Pressure Differential.ai

Appendix A

Quality Assurance and Surveillance Plan

The Quality Assurance and Surveillance Plan (QASP) is attached separately.