ATTACHMENT E

TESTING AND MONITORING PLAN [40 CFR 146.90]

1. FACILITY INFORMATION

Facility Name: Aera CCS

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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°32'41.1707"N	119°47'52.2726"W

This Testing and Monitoring Plan (TMP) describes how Aera Energy LLC (Aera) will monitor the Aera CCS site pursuant to 40 Code of Federal Regulations (CFR) 146.90. In addition to demonstrating 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), the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (ERRP, **Attachment I**).

2. OVERALL STRATEGY AND APPROACH FOR TESTING AND MONITORING

The Aera CCS site TMP and development and 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) within the AoR and extends far beyond the AoR. The confining zone fractures are very limited and do not harm macroscopic sealing capacity of the layer. Larger 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 considered to be potential USDWs over a portion of the area within the Area of Interest (AoI) 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) is present (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 and fiber-optic distributed acoustic sensing (DAS). Pressure, temperature, and acoustic monitoring will provide early detection of parameters outside of the predicted model and operations limits. Each injection well will be tested annually for external mechanical integrity and undergo a pressure fall-off test every five years.

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, pulsed neutron logging, and distributed temperature sensors (DTS). The pressure front will be monitored directly at wells 1-28N, 39-26N, and 27-1N. Wells 1-28N and 25-26N will be monitored for potential changes in groundwater quality and geochemistry above the injection zone in the Agua Sandstone, which directly overlies the primary confining layer.

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. A microseismic monitoring network will be used to monitor for microseismic events at or above magnitude 1.0 in real time. 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 and periodic well logging, mechanical integrity testing, and groundwater fluid and CO_2 stream fluid 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.

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.

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 1** using the methods listed.

Table 1. 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	USGS Techniques and Methods 5-D4. GC with dual-inlet 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 1**.

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 at 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

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 Underground Injection Control (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 mechanical integrity failure.

4.1 <u>Monitoring Location and Frequency</u>

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 2**.

Table 2. 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]
Acoustic	DAS	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 2** 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 2** 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 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 well construction that are expected to be in contact with the CO_2 stream. The materials are listed in **Table 3** below. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 3. List of Equipment Coupons with Materials of Construction

Equipment Coupon	Material of Construction
Long-String Casing (0-6000 ft)	L80
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. 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. 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 monitoring in the sandstone unit directly overlying the injection zone to allow for early detection of potential leakage from the injection zone. The groundwater monitoring wells will be located on Aera property.

Monitoring will be conducted in the following sandstone unit:

- Agua Sandstone (approximately 6,500 to 8,250 feet true vertical depth [ft TVD]) – zone immediately above the primary confining layer (Lower Santos Shale).

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

6.1 Monitoring Location and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone. The locations of the proposed monitoring wells, 1-28N and 25-26N, 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 Sandstone, which directly overlies the primary confining layer.

Monitoring in the Agua Sandstone will include pulsed neutron logging, pressure and temperature monitoring, and fluid sampling. 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 CO_2. 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 Sandstone. 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. Fluid in the Agua Sandstone 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. Significant abnormalities or changes will be used to evaluate sequestration efficacy and if additional sampling events may be warranted.

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

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[1,2]
Agua Sandstone (approximately 6,500-8,250 ft TVD)	Fluid sampling	Installed monitoring wells 1-28N and 25-26N	Northern half of injection area	Baseline: Once prior to first injection. During injection: annually
	Temperature and Pressure Monitoring	Installed monitoring wells 1-28N and 25-26N	Vertical distribution within well casings (based upon geophysical data indicating most transmissive interval within the perforation)	Continuous
	Pulsed neutron	Installed monitoring wells 1-28N and 25-26N	Pulsed neutron log generated during well installation	Baseline: Once prior to first injection During injection: annually.

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.

6.2 Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods. 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 groundwater quality analytical parameters may be updated.

Groundwater sampling data will be compared to baseline data to identify changing conditions in the subsurface. 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. Summary of Analytical and Field Parameters for Groundwater Samples

Parameters	Analytical Methods
Agua Sandstone	
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 or similar
Anions (chloride, sulfate, sulfide, bromide, fluoride, nitrate)	EPA Method 300.0/300.1 or similar; SM 4500 for sulfide
Dissolved gases - CO_2 - CH_4 - O_2 - H_2S (field)	 RSK-175M RSK-175M SM 4500 OG or RSK-175M 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 150.1/SM4500-H+B EPA Method 120.1 Thermocouple
Hardness	SM 2340C
Turbidity	SM 2130B
Specific gravity	SM2710F
Water density	SM2710F
Dissolved inorganic carbon isotopes ($\delta^{13}C$)	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 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 6** periodically during the injection phase to demonstrate external mechanical integrity as required at 146.89(c) and 146.90.

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 6** 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 6. Annual External Mechanical Integrity Tests (MITs)

Test Description	Location
Temperature	Conventional wireline well log or DTS
Acoustic	Conventional wireline noise log or distributed acoustic sensing (DAS)
Oxygen Activation	Conventional wireline well log

7.2 Testing Details

Aera will run at least one of the tests in **Table 6** 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 observation wells. The following general procedure will be followed for these logs:

- Notify the UIC Program Director of the logging schedule at least 30 days prior to logging, per 40 CFR 146.87(f).
- Move in and rig up wireline logging unit. Assemble the temperature, oxygen activation, or noise logging tools.
- Rig up wireline pressure control equipment and test for leaks.
- Run in the hole with tools to plug back total depth and log to surface per industry-cased hole logging standards.
- Recover tools and rig down.
- Interpret log results.
- As required in 40 CFR 146.88(f), if there is an indication of a loss of mechanical integrity:
    - 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; and
    - Notify the UIC Program Director when injection can be expected to resume.
- If mechanical integrity is confirmed, 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).

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 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. One or more pressure gauges will record the pressure either downhole, at or near the wellhead or both downhole and at the wellhead. Each 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 0 to 3,000-psi range while the downhole gauge will cover the 0 to 8,000 psi range. Exact gauges specifications 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.

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). Annual fluid sampling and pulsed neutron logging, paired with continuous measurements of injection zone temperature and pressure within three monitoring wells will provide a robust mechanism for tracking the extent of the CO_2 plume and the presence or absence of elevated pressures. Pulsed neutron logs performed every three years at injection well sites will provide additional confirmation of CO_2 plume and pressure front extent.

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 through 8** show the predicted evolution of the CO_2 plume and pressure front after 1, 2, 3, 7, 10 and 100 years of injection.

9.1 Plume Monitoring Location and Frequency

Table 7 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 presented in **Table 8**.

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

9.2 Plume Monitoring Details

9.2.1 Direct Methods

Fluid Sampling

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 8**.

Table 7. 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	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	27-1N	Entire Wellbore	Continuous

Table 8. Summary of Analytical and Field Parameters for Fluid Sampling in the Injection Zone

Parameter	Analytical Method(s)
Carbon dioxide (CO_2)	ISBT 2.0. Chemical absorption with Zahm and Nagel Purity Tester. Precision: 0.05% @ 99.9% (% v/v)
Moisture (water vapor, H_2O)	ISBT 3.0. Electrometric moisture analyzer. Measurement range: 0-100 ppm. v/v. Precision: 5-10% @ 10 ppm v/v
Oxygen (O_2), Nitrogen (N_2), and Argon (Ar)	ISBT 4.0. Gas Chromatograph (GC) with discharge ionization detector (DID). Measurement range: 0-100 ppm. v/v. Precision: 5-10% @ 30 ppm v/v Could detect H_2, Ar, N_2, CH_4, and CO if present in the CO_2 injectate
Hydrogen (H_2)	ASTM D1945-14. GC with thermal conductivity detector (TCD). Detection range: 0.01-10 mol.%
Carbon monoxide (CO)	ISBT 5.0. GC with pulsed discharge ionization detector (PDID). Measurement range: 0-50 ppm. v/v. Precision: 5-10% @ 10 ppm v/v; 10-20% @ levels below 10 ppm
Oxides of nitrogen (NO_x)	ISBT 7.0. Colorimetric tubes able to detect NO and NO_2. Measurement range: 0.2-10 ppm. v/v. Precision: 5-30% of full scale
Ammonia (NH_3)	ISBT 6.0. Ammonia-specific colorimetric detector tube. Measurement range: 0.5-5 ppm. v/v. Precision 5-30% of full scale
Total hydrocarbons (THC)	ISBT 10.0. GC with flame ionization detector (FID). Measurement range: 0-100 ppm. v/v. Precision: 1-2% @ 20 ppm v/v; 2-5% @ < 1 ppm THC include alkanes, alkenes, alkynes, olefins, alcohols, aromatic hydrocarbons, ethers, aldehydes, and ketones
Methane (CH_4)	ISBT 10.1. GC/FID. Measurement range: 0-100 ppm. v/v. Precision: 2.5-5% @ 20 ppm v/v; 5-10% @ < 1 ppm Alternative: ASTM D1945-14. GC/TCD. Detection range: 0.01 to 100 mol.%
Aromatic hydrocarbons	ISBT 12.0. GC with photoionization detector (PID). Measurement range: 0-0.20 ppm. v/v. Precision: 5-10% @ 0.020 ppm v/v; 10-20% @ < 0.010 ppm Aromatic HCs include toluene, ethylbenzene, m-xylene, p-xylene, and o-xylene
Total sulfur (TS)	ISBT 13.0. GC with sulfur chemiluminescent detector (SCD). Measurement range: 0-5 ppm. v/v. Precision: 5-10% @ 0.10 ppm v/v TS include sulfides (including H_2S), disulfides, mercaptans, and SO_2 Apply ISBT 14.0 if SO_2 level is expected to exceed 1 ppm
Sulfur dioxide	ISBT 14.0. GC/SCD. Measurement range: 0-5 ppm. v/v. Precision: 5-10% @ 0.10 ppm v/v
Hydrogen sulfide (H_2S)	ASTM D1945-14. GC/TCD. Detection range: 0.3 - 30 mol.%
Ethanol (C_2H_6O)	EPA Method 8260B. GC/MS
^{13}C isotope	USGS Techniques and Methods 5-D4. GC with dual-inlet isotope ratio mass spectrometry (GC-IRMS)

9.2.2 Indirect Methods

Distributed Temperature Sensing

Distributed temperature sensing allows for continuous temperature profiles over the installed depth rather than measurements at fixed points. DTS will be utilized from the surface to the tubing packer in the injection well to continuously provide accurate temperatures profiles of the injection stream. 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 also be installed in the 64 Zone monitoring wells to identify temperature changes that may indicate the CO_2 plume's arrival at that location.

Pulsed Neutron Logging

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.

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	Pressure Gauge	1-28N	Distributed measurement to ~8,450 ft MD	Continuous
64 Zone	Pressure Gauge	39-26N	Distributed measurement to ~8,243 ft MD	Continuous
64 Zone	Pressure Gauge	27-1N	Distributed measurement to ~8,278 ft MD	Continuous

9.4 Other Monitoring

9.4.1 Microseismic Monitoring

A microseismic monitoring network will be utilized to detect microseismic events at or above magnitude 1.0 in real time. This network may consist of 3C geophones, DAS fiber-optic cable, and/or 3C surface seismic stations.

9.4.2 Network Design

Network modeling will be used to determine the optimum placement of the downhole and surface elements of the passive microseismic network, and to demonstrate that the required event thresholds can be captured [Printz et al., 2022].

9.4.3 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 in real time through the injection phase and into the post-injection period. Monitoring will begin at least one month prior to injection to establish the microseismic baseline.

Table 10. Summary of Passive Seismic Monitoring System

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Other Monitoring				
Multiple	Passive seismic	Borehole and/or surface seismic stations	The passive seismic monitoring system will have the ability to detect seismic events over M1.0 within the AoR.	Continuous

10. REFERENCES

Environmental Protection Agency Region IX (EPA). 2019. *Underground Injection Control Program, Aquifer Exemption Record of Decision North Belridge Oil Field – Tulare Formation.* 7 June.

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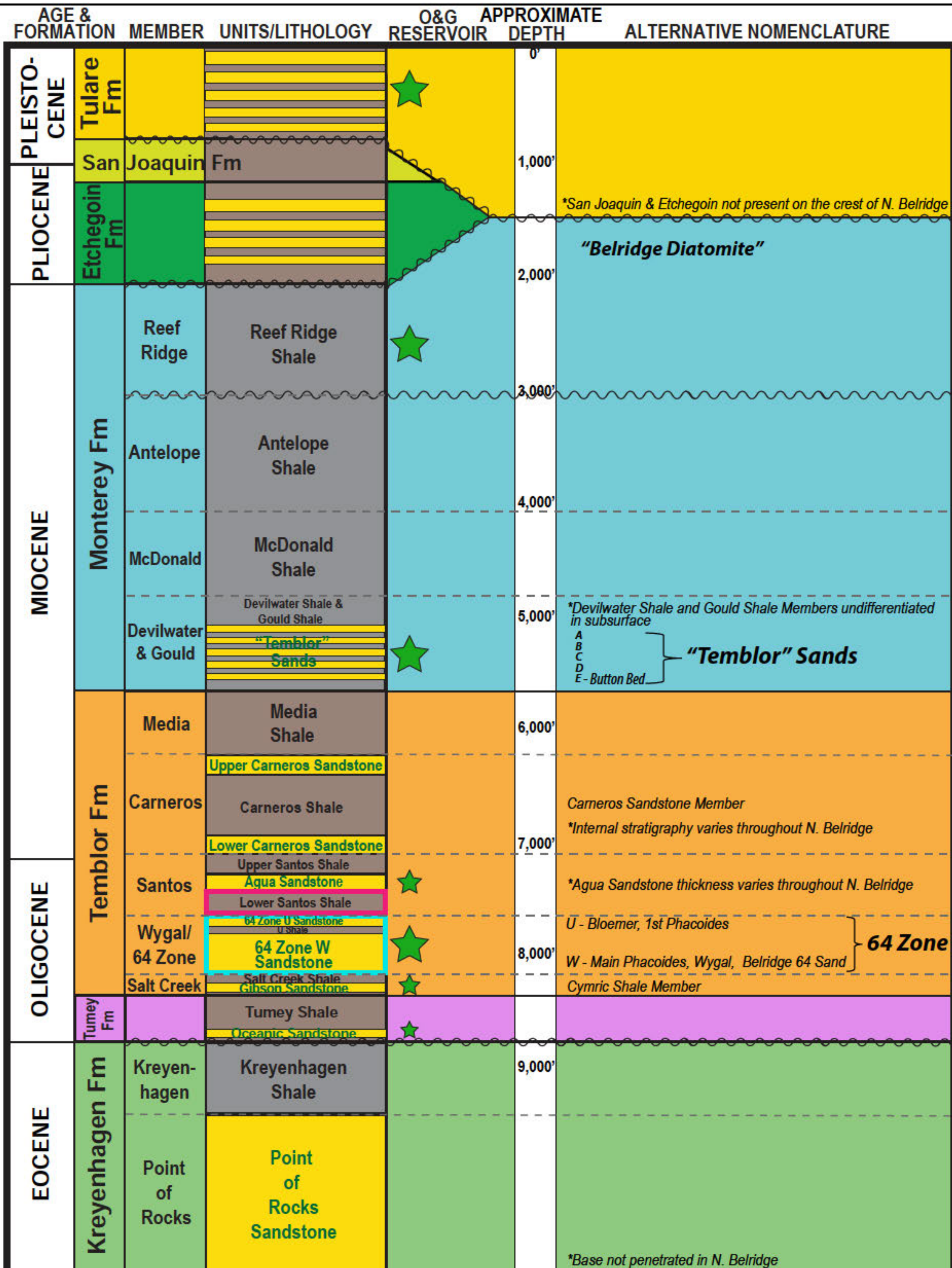
Wood Environmental and Infrastructure Solutions, Inc. 2021. *2021 Annual Post Closure Maintenance and Monitoring Report* – Former North Surface Impoundments, North Belridge Oil Field, Kern County, California, GeoTracker Site Global ID: SL0602993186. 16 December.

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

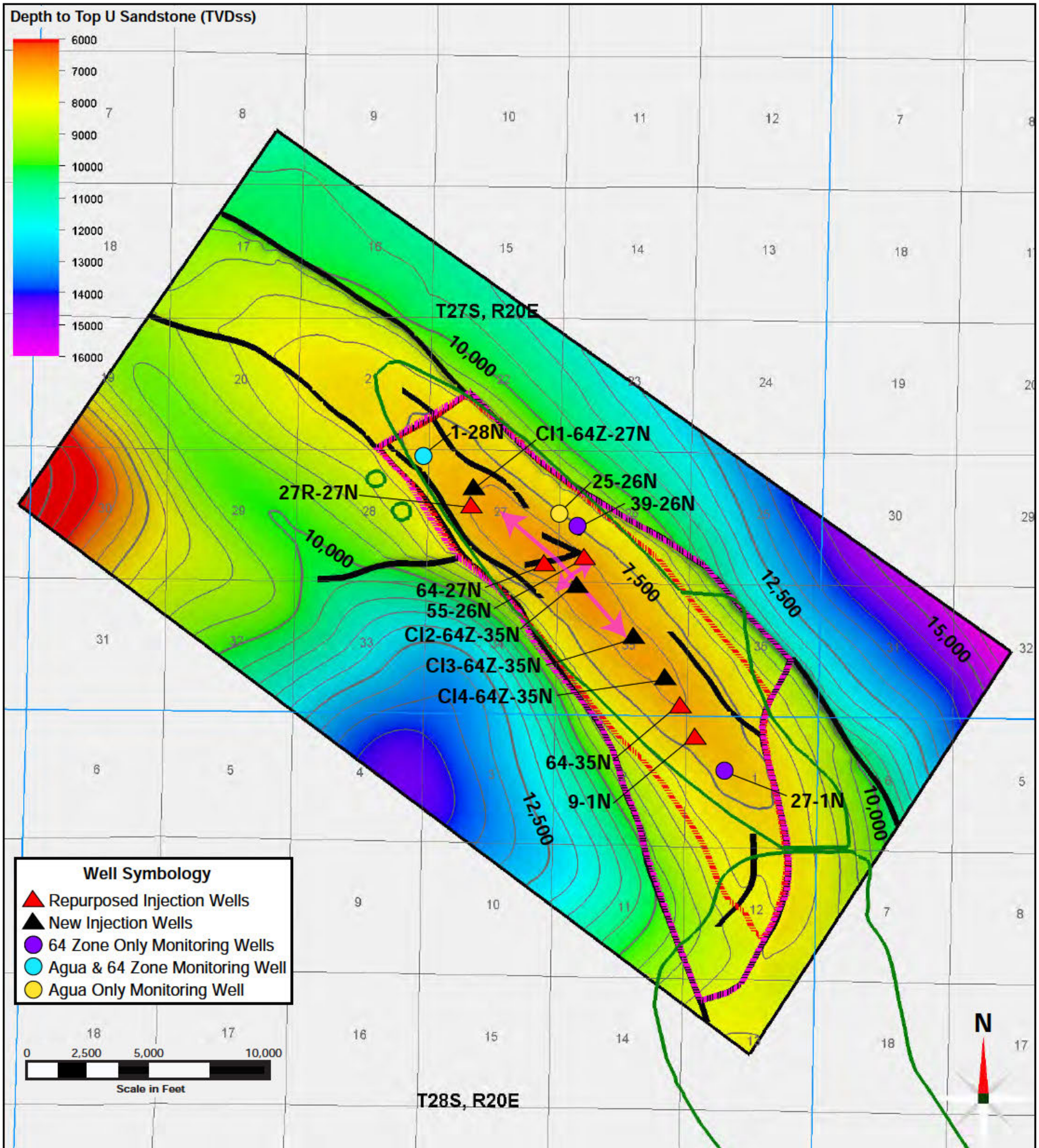
North Belridge Stratigraphic Column

North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

Aera CCS	December 2022	Figure 1

\\santabarbara-01\GIS\Aera Belridge CCUS\Projects\Section 2.1 Regional Geology\Figure 2.1-9_North_Belridge_Stratigraphic_Column_revised



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.

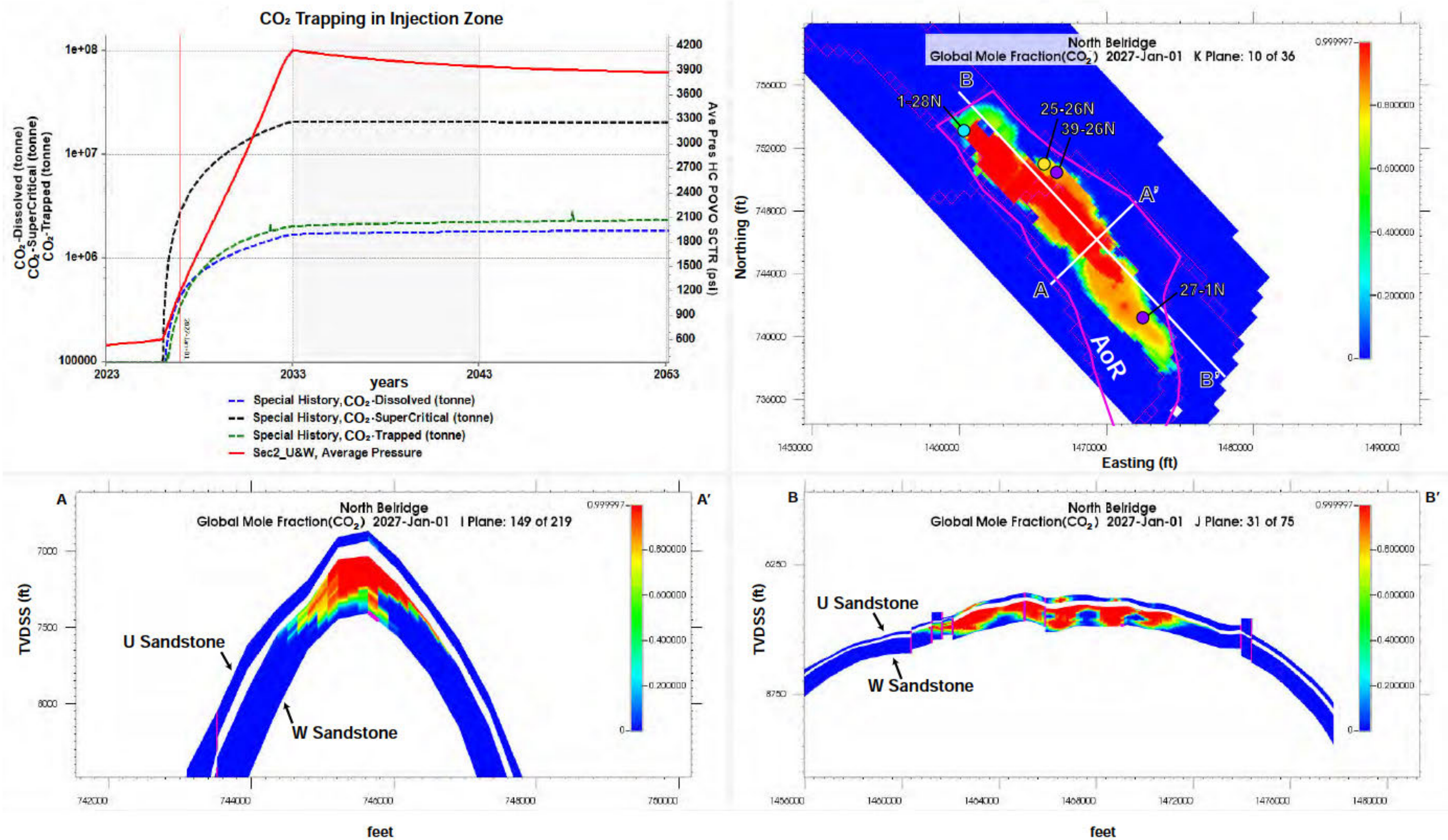
Location Map of Repurposed and New Wells
North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

Aera CCS | December 2022

Figure 2

C:\Geosyntec\Aera Belridge CCUS Project - General\A. Technical\Maps, Cross Sections, and Shapefiles\Structure Maps\Illustrator\Figure 5-1 Location Map of Repurposed and New Wells.ai



Legend

Monitoring Wells

- 64 Zone Only
- Agua & 64 Zone
- Agua Only

Explanation:

CO_2 - Carbon dioxide
psi - Pounds per square inch
ft - feet
TVDSS (ft) - True vertical depth sub sea (ft)
HC POVO SCTR - Hydrocarbon pore volume

Modeled Plume Timeline - 2027

North Belridge Oil Field
Western Kern County
California

AERA

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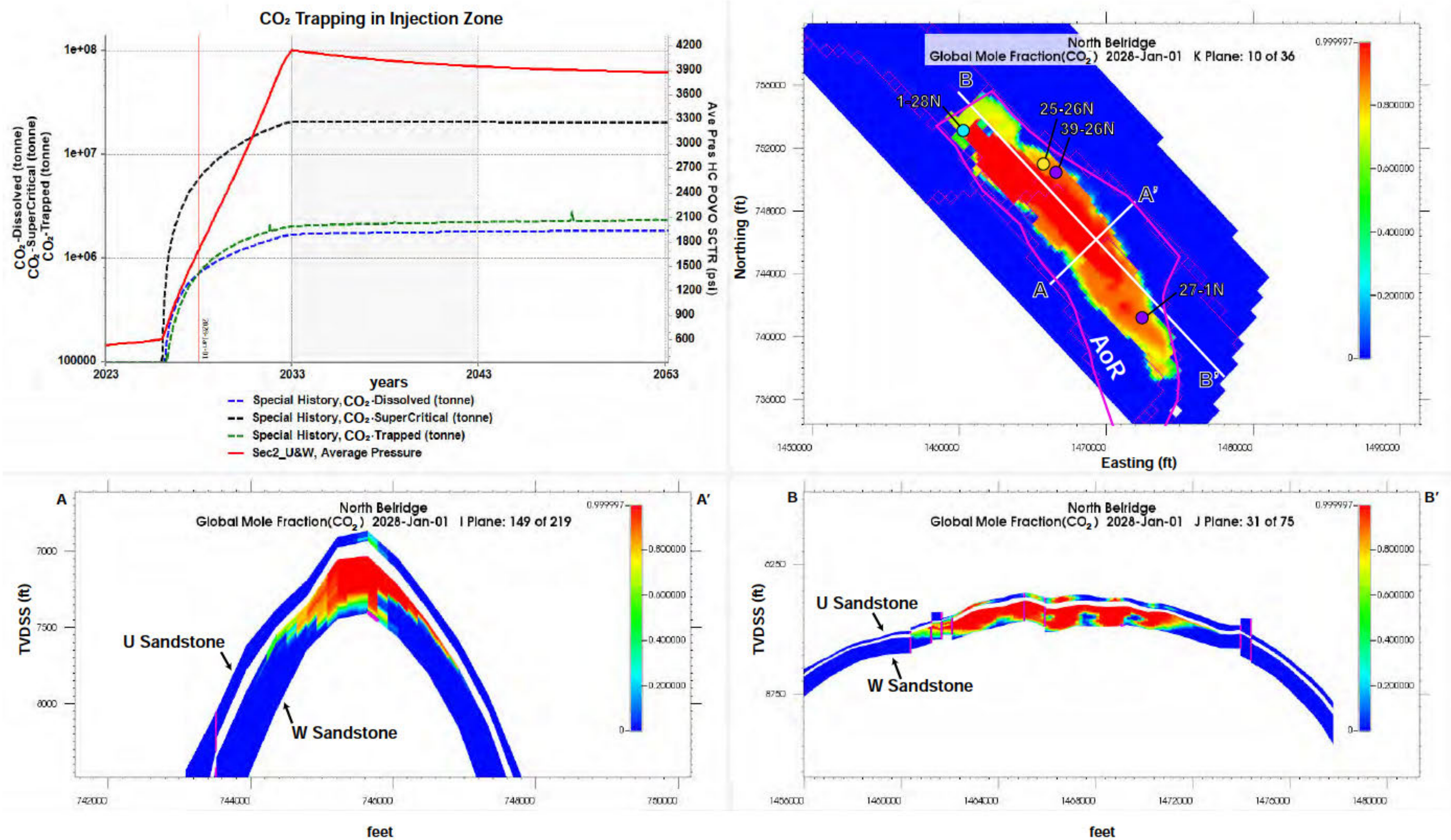
Figure 3



Legend

Monitoring Wells

- 64 Zone Only
- Agua & 64 Zone
- Agua Only

Explanation:

CO_2 - Carbon dioxide
psi - Pounds per square inch
ft - feet
TVDSS (ft) - True vertical depth sub sea (ft)
HC POVO SCTR - Hydrocarbon pore volume

Modeled Plume Timeline - 2028

North Belridge Oil Field
Western Kern County
California

AERA

Figure 4

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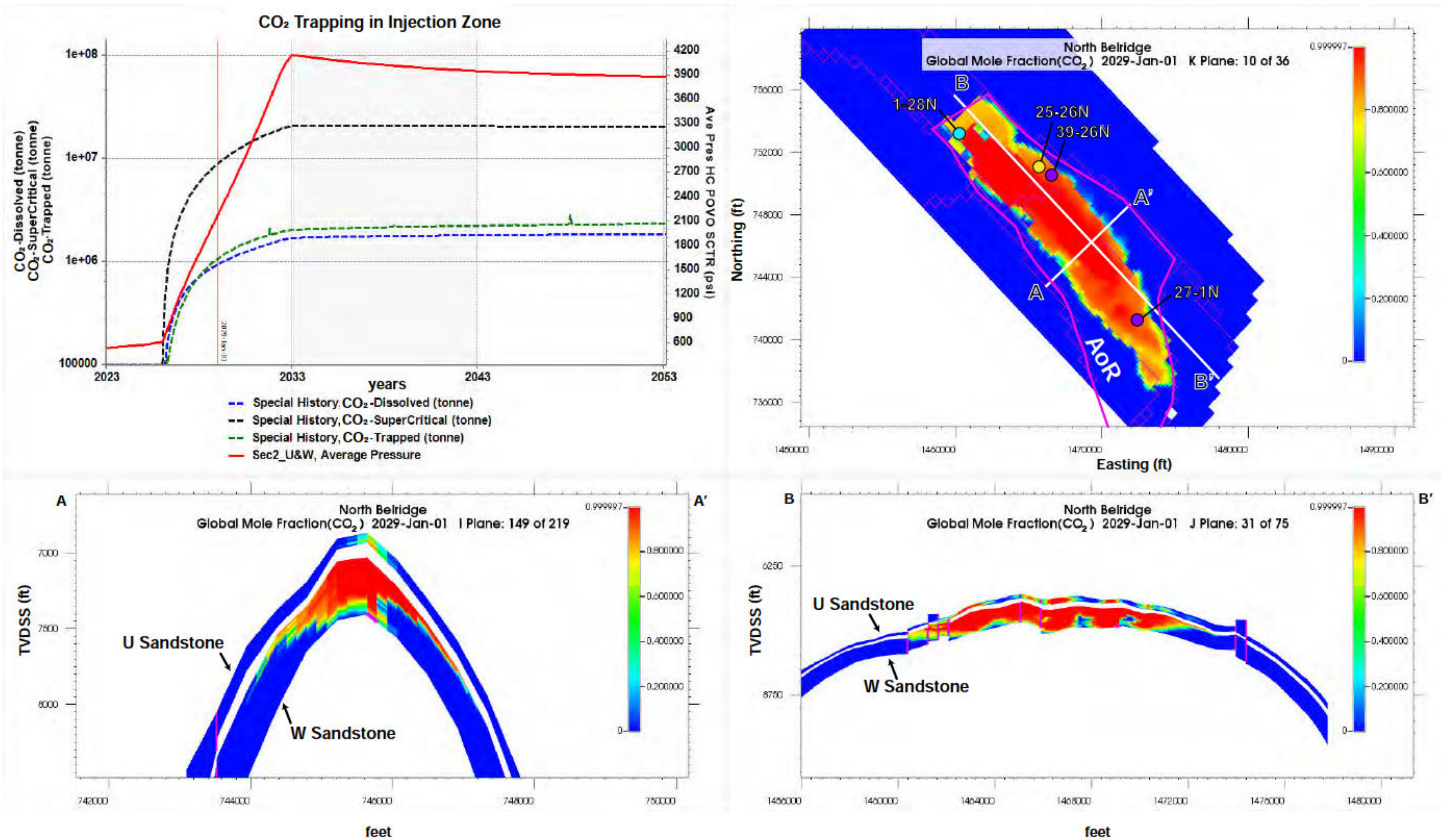

Legend

Monitoring Wells

- 64 Zone Only
- Agua & 64 Zone
- Agua Only

Explanation:

CO_2 - Carbon dioxide
psi - Pounds per square inch
ft - feet
TVDSS (ft) - True vertical depth sub sea (ft)
HC POVO SCTR - Hydrocarbon pore volume

Modeled Plume Timeline - 2029

North Belridge Oil Field
Western Kern County
California

AERA

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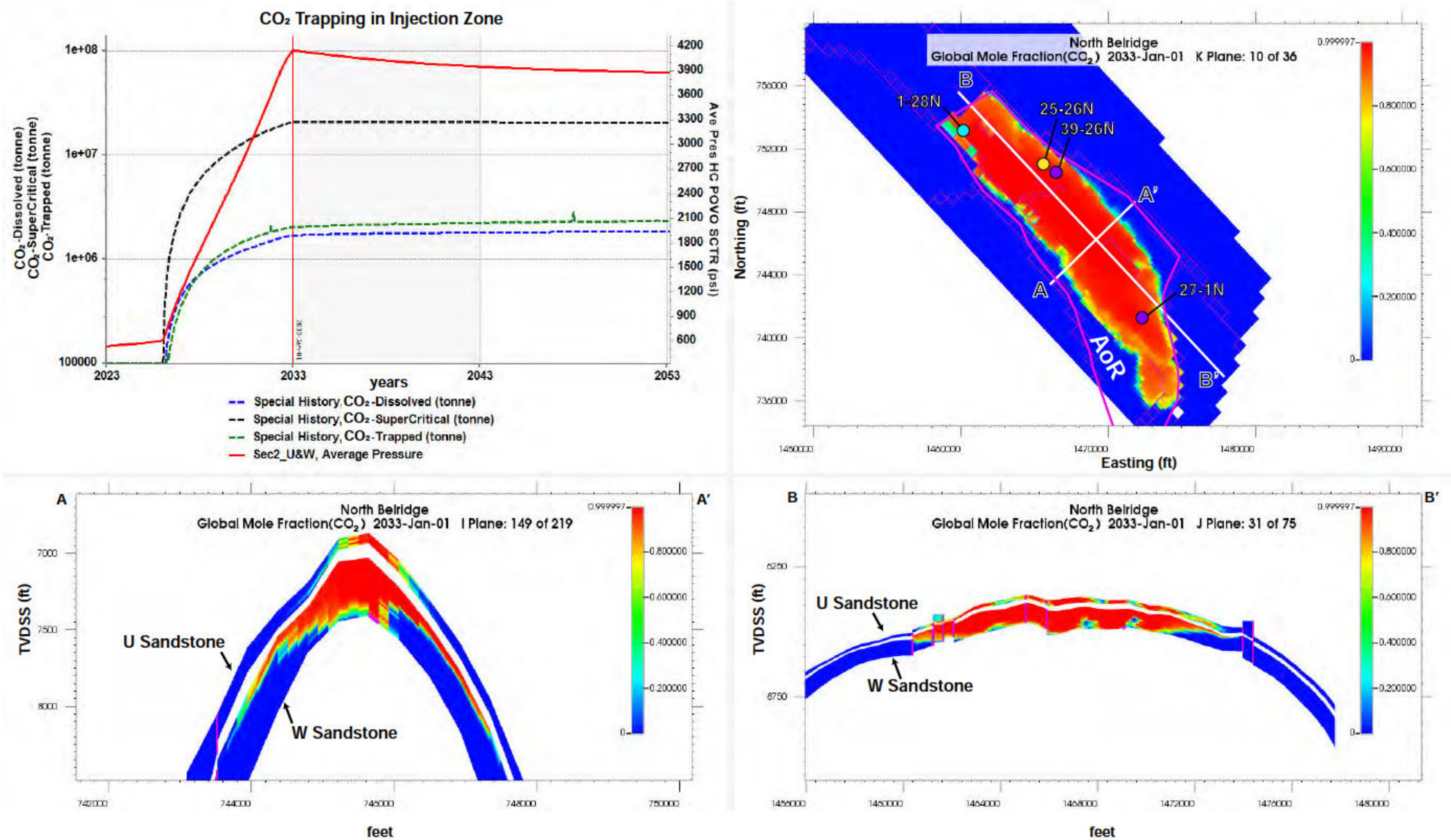
Figure 5



Legend

Monitoring Wells

- 64 Zone Only
- Agua & 64 Zone
- Agua Only

Explanation:

CO_2 - Carbon dioxide
psi - Pounds per square inch
ft - feet
TVDSS (ft) - True vertical depth sub sea (ft)
HC POVO SCTR - Hydrocarbon pore volume

Modeled Plume Timeline - 2033

North Belridge Oil Field
Western Kern County
California

AERA

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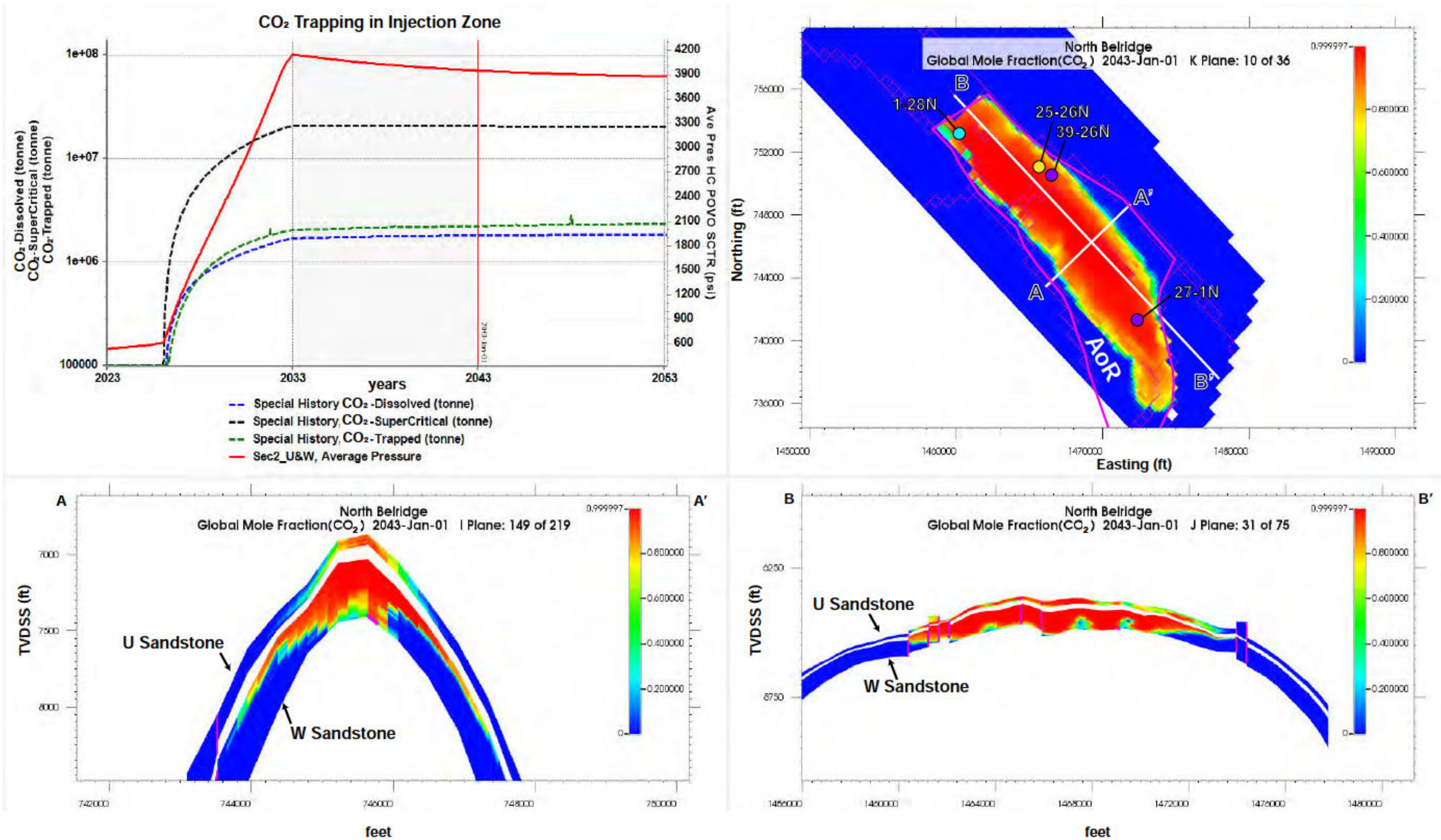
Figure 6



Legend

Monitoring Wells

- 64 Zone Only
- Agua & 64 Zone
- Agua Only

Explanation:

CO_2 - Carbon dioxide
psi - Pounds per square inch
ft - feet
TVDSS (ft) - True vertical depth sub sea (ft)
HC POVO SCTR - Hydrocarbon pore volume

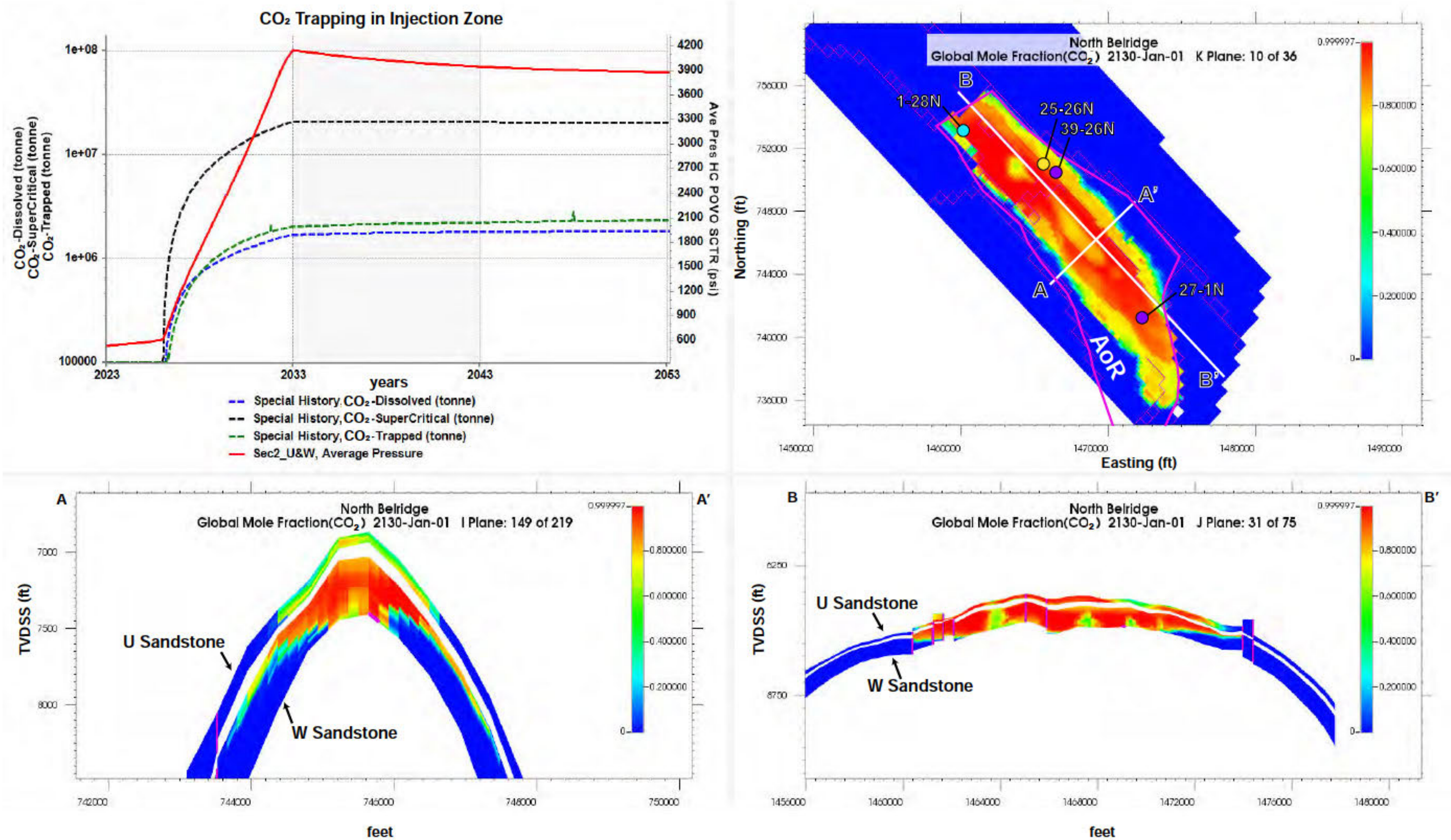
Modeled Plume Timeline - 2043

North Belridge Oil Field
Western Kern County
California

AERA

Aera CCS | December 2022

Figure 7



Legend

Monitoring Wells

- 64 Zone Only
- Agua & 64 Zone
- Agua Only

Explanation:

CO_2 - Carbon dioxide
psi - Pounds per square inch
ft - feet
TVDSS (ft) - True vertical depth sub sea (ft)
HC POVO SCTR - Hydrocarbon pore volume

Modeled Plume Timeline - 2130

North Belridge Oil Field
Western Kern County
California

Aera CCS | December 2022

Figure 8

Appendix A

Quality Assurance and Surveillance Plan

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