Elk Hills A1-A2 and 26R CO_2 Subpart RR Monitoring, Reporting, and Verification Plan

Version Date: 11/29/2023

1 Contents

Overview

The Elk Hills Oil Field (EHOF), covering 75 square miles, was discovered in 1911 and has produced over 2 billion barrels of oil equivalent (BOE), making it one of the most productive fields in the United States. California Resources Corporation (CRC) and Carbon TerraVault (CTV; a CRC wholly owned subsidiary), owns 100% of the surface, mineral, and pore space rights at the EHOF.

CTV intends to inject and store a measurable quantity of carbon dioxide (CO_2) in subsurface geologic formations at the EHOF, for a term of 27 years referred to as the "Specified Period." During the Specified Period, CO_2 will be injected from anthropogenic sources such as the Elk Hills 550 megawatt (MW) natural gas combined cycle power plant (EHPP), bio-diesel refineries, and other sources in the EHOF area.

The CO_2 will be injected into the Monterey Formation A1-A2 and 26R reservoirs for dedicated geologic storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO_2 sequestration. Class VI applications have been submitted for the A1-A2 and 26R reservoir.

This EHOF monitoring, reporting, and verification (MRV) plan is based on decades of subsurface characterization and simulation of the targeted Monterey Formation. This empirically driven analysis indicates that the natural geologic seal that overlays the entire EHOF, known as the Reef Ridge shale, will provide a physical trap that will permanently prevent injected CO_2 from migrating to the surface.

This MRV plan documents the following in accordance with 40 CFR 98.440-449 (Subpart RR):

- Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA), Identification of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways,
- Strategy for detecting and quantifying any surface leakage of CO_2,
- Strategy for establishing the expected baselines for monitoring CO_2 surface leakage,
- Summary of considerations for calculating EHOF-specific variables for the mass balance equation, and
- Proposed date to begin collecting data for calculating total CO_2 sequestered.

1 Facility Information

i. Reporter number – 582061

ii. Existing wells in the EHOF including production, injection, and monitoring wells are permitted by California Geologic Energy Management Division (CalGEM) through California Public Resources Code Division 3.[1]

iii. Wells injecting CO_2 for geologic storage will be permitted with the United States Environmental Protection Agency (EPA) Underground Injection Control (UIC) program for Class VI injection.

[1] Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

iv. Wells in the EHOF are identified by name, American Petroleum Institute (API) number, status, and type. The list of wells as of March 2023 associated with the geologic storage projects is included in Appendix 11.5. Any new wells or changes to wells will be indicated in the annual report.

2 Project Description

The EHOF is one of the largest oil and natural gas fields in the United States, with production from multiple vertically stacked reservoirs. Turbidite sand deposits of the Miocene Monterey Formation will serve as the injection targets in two separate anticlinal structures, Northwest Stevens (NWS) and 31S (Figures 1a, 1b).

Numerous aspects of the geology, facilities, equipment, and operational procedures for A1-A2 and 26R are consistent throughout the field. As such, one MRV report will satisfy the 26R and A1-A2 reservoirs as shown in Table 1. The A1-A2 and 26R reservoir and well locations within the field are shown in Figure 1a.

Structure	Reservoir	Sequestration Type	Number of Injectors
31S	26R	Geologic : Class VI	4
NWS	A1-A2	Geologic : Class VI	2

Table 1: Reservoirs within the EHOF and sequestration type.

2.1 Project Characteristics

The potential CO_2 stored over the project duration is up to 48 million metric tons (refer to Table 2 for breakdown). For accounting purposes, the amount stored is the difference between the amount injected less any CO_2 that i) leaks to the surface, or ii) is released through surface equipment leakage or malfunction. Actual amounts stored during the Specified Period of reporting will be calculated as described in Section 7 of this MRV Plan.

2.2 Environmental Setting

The project site for this MRV plan is the EHOF, located in the San Joaquin Basin, California (Figure 2).

2.2.1 Geology of Elk Hills Oil Field

The EHOF is located 20 miles southwest of Bakersfield in western Kern County, producing oil and gas from several vertically stacked reservoirs formed in the Tertiary period (65 million to 2 million years ago). Of the more than 24,000 feet (ft) of sediment deposited, the most prolific reservoir is the Miocene epoch Monterey Formation that is the target CO_2 sequestration reservoir.

Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. These layers have been folded, resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (during the Oligocene and Miocene epochs). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals makes the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

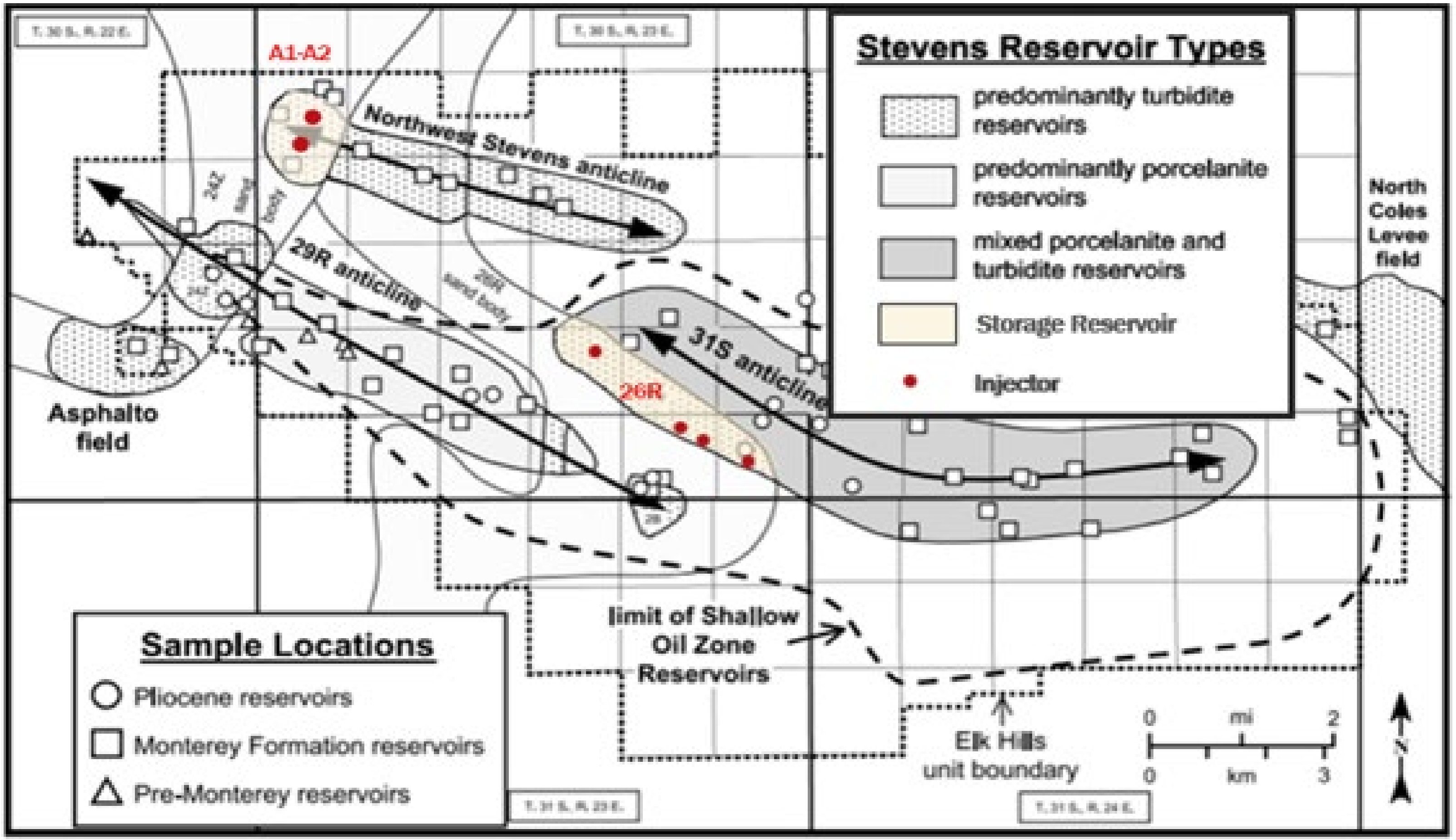

Figure 1a: EHOF map of injection target and injection well locations.

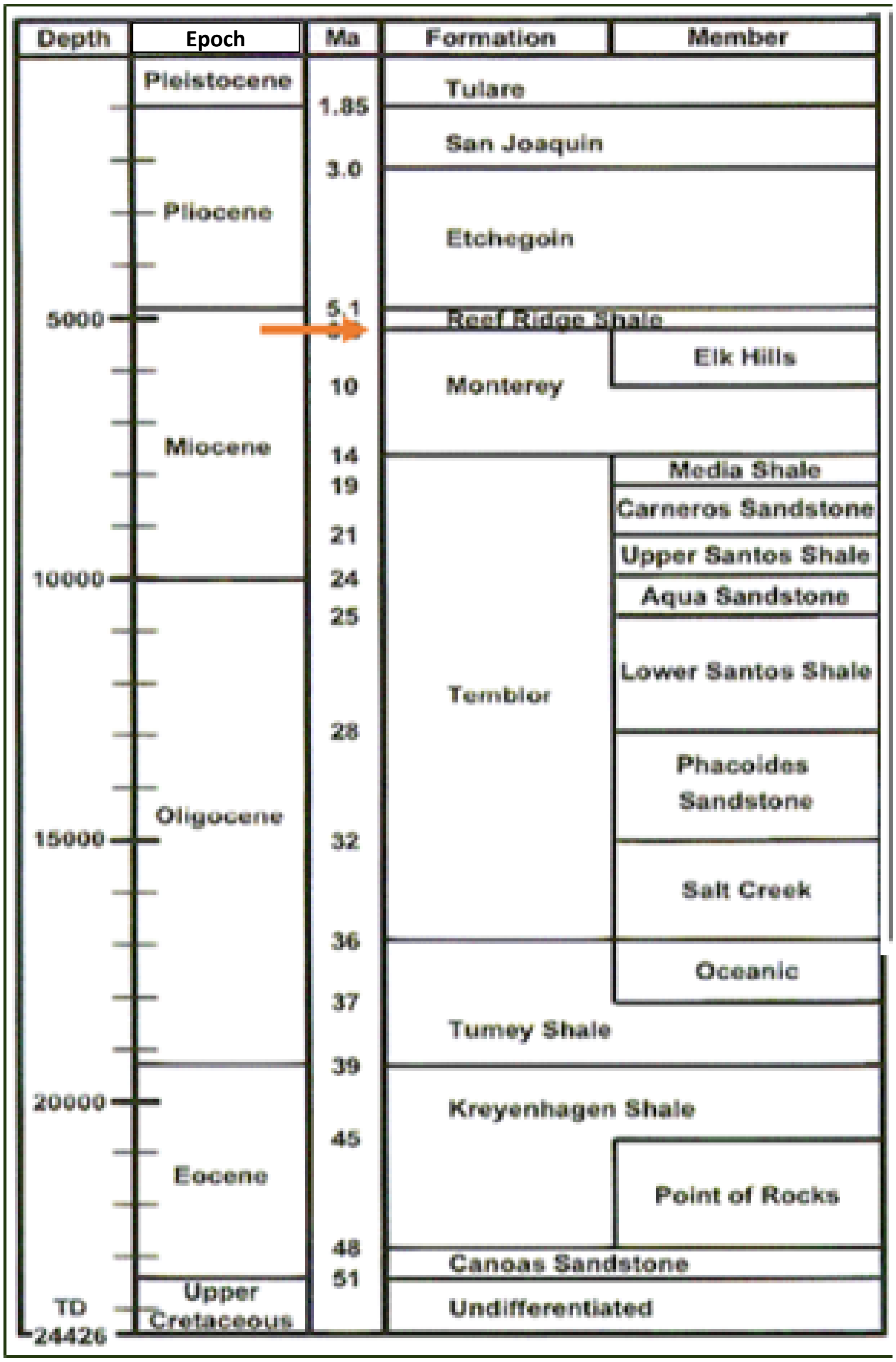

Figure 1b: EHOF stratigraphic column.

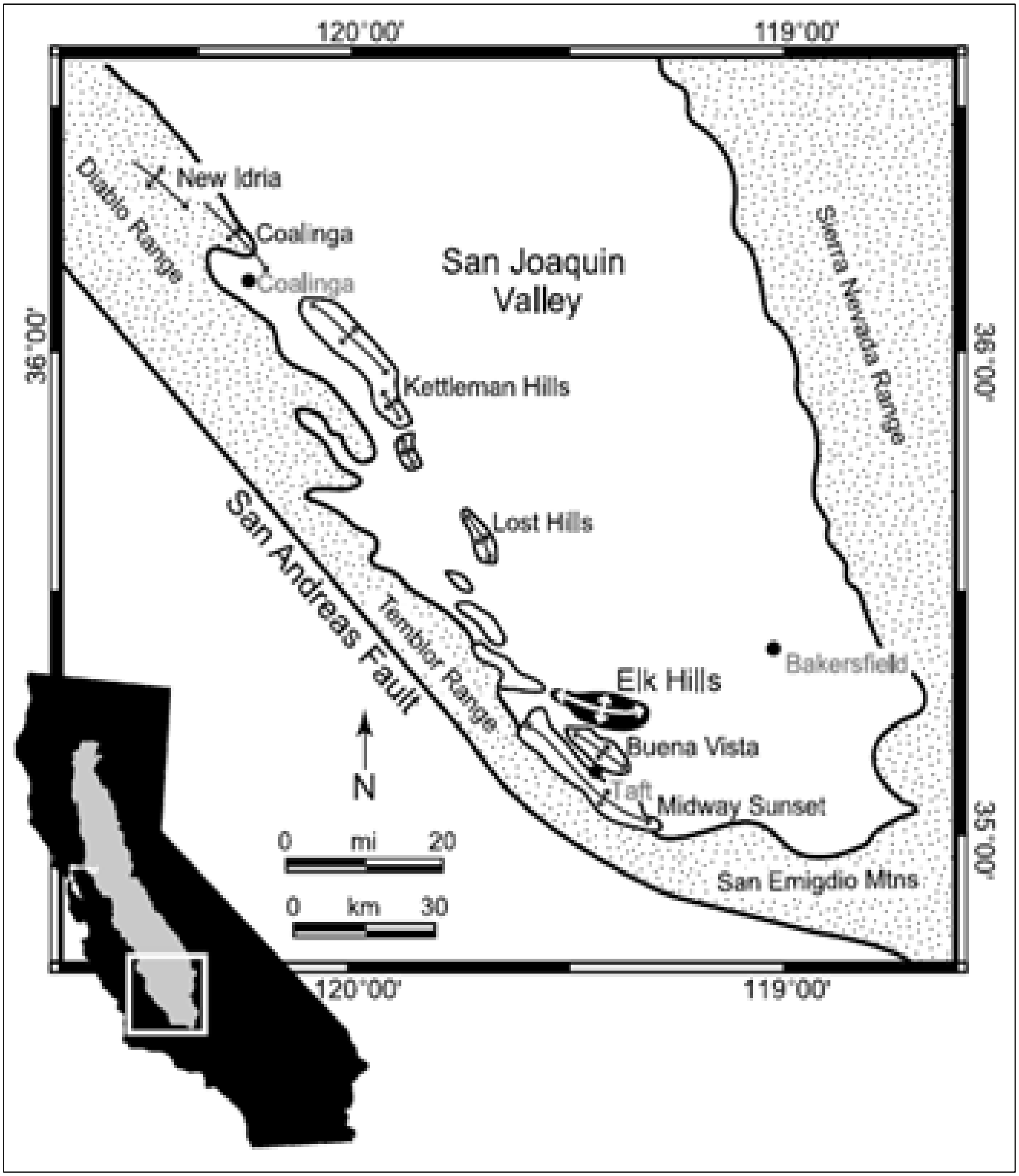

Figure 2: Location of Elk Hills Oil Field, San Joaquin Basin, California.

Following its deposition, Monterey Formation sediments were buried under more than 750 ft of impermeable silty and sandy shale that comprise the confining Reef Ridge shale. The Reef Ridge shale serves as the primary confining layer over the Monterey because it effectively seals underlying fluids from the overlying formations. Above the Reef Ridge lies several alternating sand-shale sequences of the Pliocene Etchegoin and San Joaquin Formations and Pleistocene Tulare Formation. These formations are highlighted in the cross-section in Figure 3.

As indicated in Figure 1a, the 31S and NWS structures represent structural highs, or anticlines, within the EHOF. The elevated areas form a natural trap for oil and gas that migrated from below over millions of years. Once trapped at these high points, the oil and gas has remained in place. In the case of the EHOF, the oil and gas has been trapped in the reservoir for more than 6 million years.

Based on physical site characterization and analysis of historic operating records from the Monterey Formation, there is sufficient reservoir capacity and flow properties to inject and store the entire volume of CO_2 proposed as determined by computational modeling (Table 2).

	Volume (million metric tons)
A1-A2 geologic storage	10
26R geologic storage	38
Total storage capacity	48

Table 2: Calculation of cumulative net fluid volume produced for the Monterey Formation sequestration reservoir.

Stored CO_2 will be contained securely within the EHOF Monterey Formation as demonstrated by 1) preservation of hydrocarbon accumulations over geologic time; 2) subsequent water and gas injection operations; 3) competency of the Reef Ridge confining zone over millions of years and throughout decades of primary and secondary operations; and 4) ample storage capacity of the A1-A2 and 26R reservoir. Confinement within the project area and in the reservoir will be ensured by limiting the pressure of the reservoir post-injection at or below the initial pressure of the reservoir at time of discovery.

2.2.2 Elk Hills Oil Field Operational History

McJannet (1996) reports on the early operating history of EHOF. By Executive Order, in 1912 President Taft designated the area surrounding EHOF as a naval oil reserve. Intended to ensure a secure supply of fuel for the Navy's oil-burning ships, the Executive Order defined "Naval Petroleum Reserve No. 1" (NPR-1). In 1977, President Carter signed the U.S. Department of Energy (DOE) Organization Act which transferred NPR-1 to the DOE. Nearly 20 years later, the DOE was directed to sell the assets of NPR-1. Occidental Petroleum ("Occidental") provided a winning bid of $3.65 billion, and on February 10, 1998, Occidental took over official ownership and operation of EHOF. In December 2014, Occidental Petroleum spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC.

The EHOF unit boundary is shown in orange below in Figure 4.

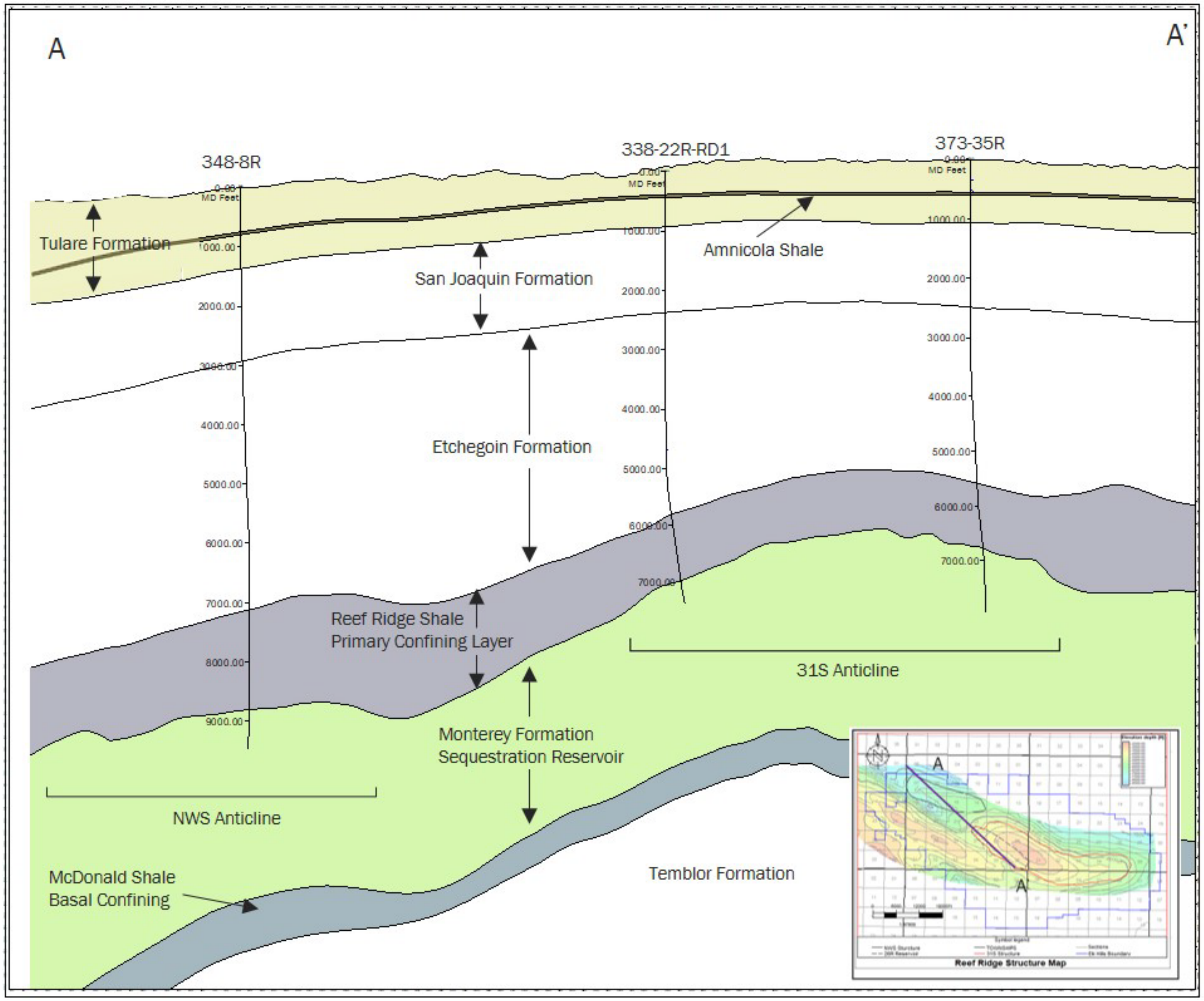

Figure 3: Stratigraphic schematic highlighting the NWS and 31S anticlines.

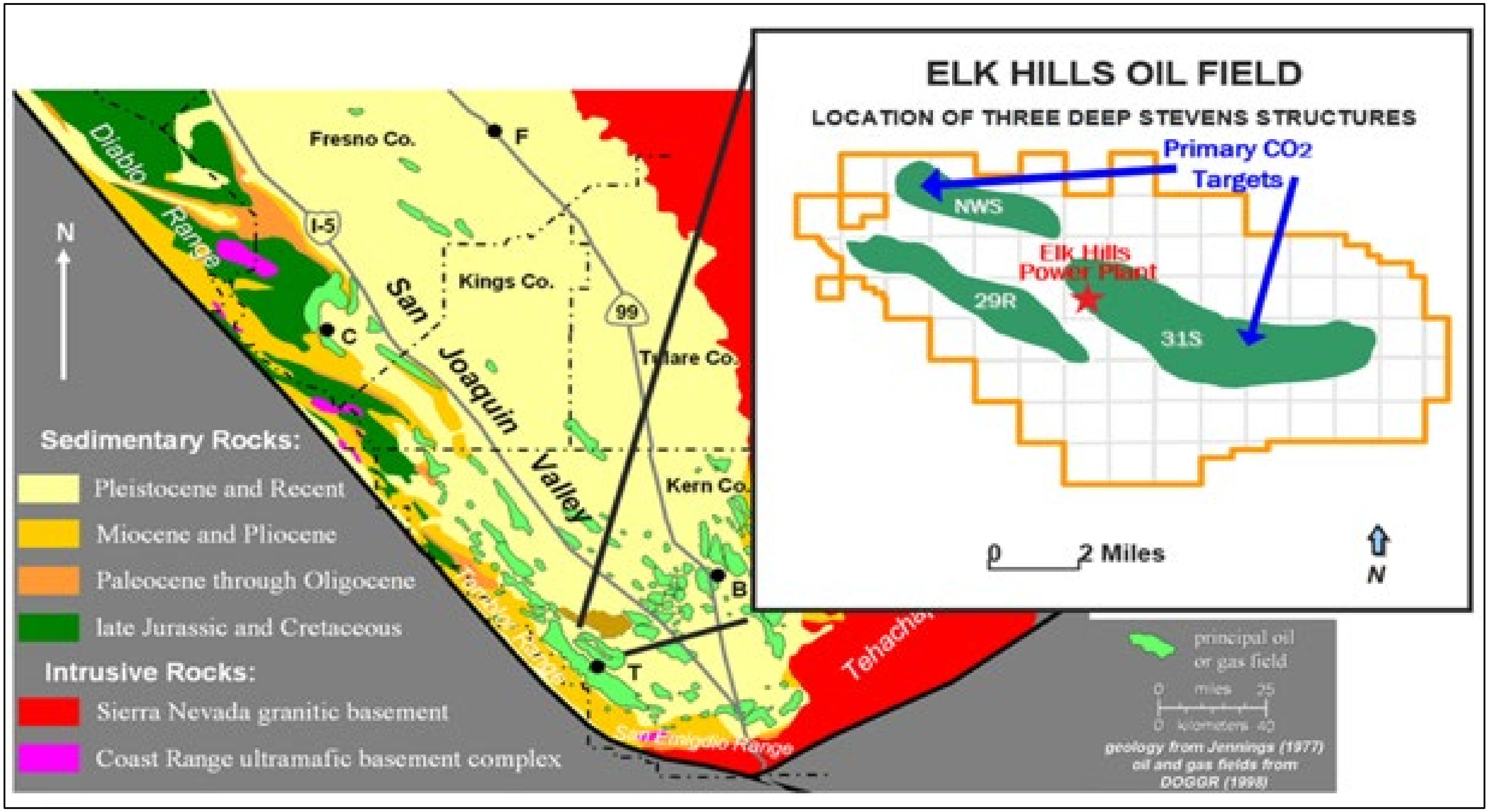

Figure 4: Location of Elk Hills Oil Field within San Joaquin Basin, California.

Development History

Selected primary drilling in the Monterey Formation began in the early 1940s, with concerted drilling and production operations commencing with the DOE's oversight in the late 1970s. To support reservoir pressure and maximize the oil recovery factor, extensive water and gas injection has occurred.

A successful CO_2 injection pilot was implemented in the Monterey Formation in 2005. Data from the four-month pilot confirmed the formation as an attractive target for CO_2 sequestration. This project assessed how much oil could be mobilized from the conventional sand reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be produced. Production performance and data collected before, during, and after the pilot operations showed that Monterey Formation reservoirs selected are ideal for CO_2 sequestration.

In addition, past development of the shallow Etchegoin Formation oil reservoirs and Monterey Formation has created a large pressure differential across the Reef Ridge shale, further demonstrating the lack of communication between the reservoirs.

2.3 Description of Facilities and Injection Process

A simplified flow diagram of surface facilities can be seen in Figure 5. This includes facilities outside the scope of the MRV including CO_2 source(s), and the subsequent metering locations between the MRV scope and those facilities. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The subsequent parts of this section will review each of the following:

- CO_2 source,
- CO_2 distribution and injection, and
- Wells in the Class VI defined area of review (AoR) penetrating the Reef Ridge shale.

Facilities associated with dedicated geologic sequestration will be relatively simple as field production and re-compression process flows are unnecessary.

2.3.1 CO_2 Source

CTV plans to construct a carbon capture and sequestration (CCS) "hub" project (i.e., a project that captures CO_2 from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC-permitted injection well). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 metric tons per annum), with additional potential CO_2 from the EHPP, direct air capture (DAC), renewable diesel refineries, and/or other sources in the area.

All CO_2 sources will have custody-transfer metering to ensure accurate accounting of both the mass rate and impurities in the CO_2 stream. Anticipated hydrogen sulfide (H_2S) concentration in the injectate is 0.001 to 0.014%.

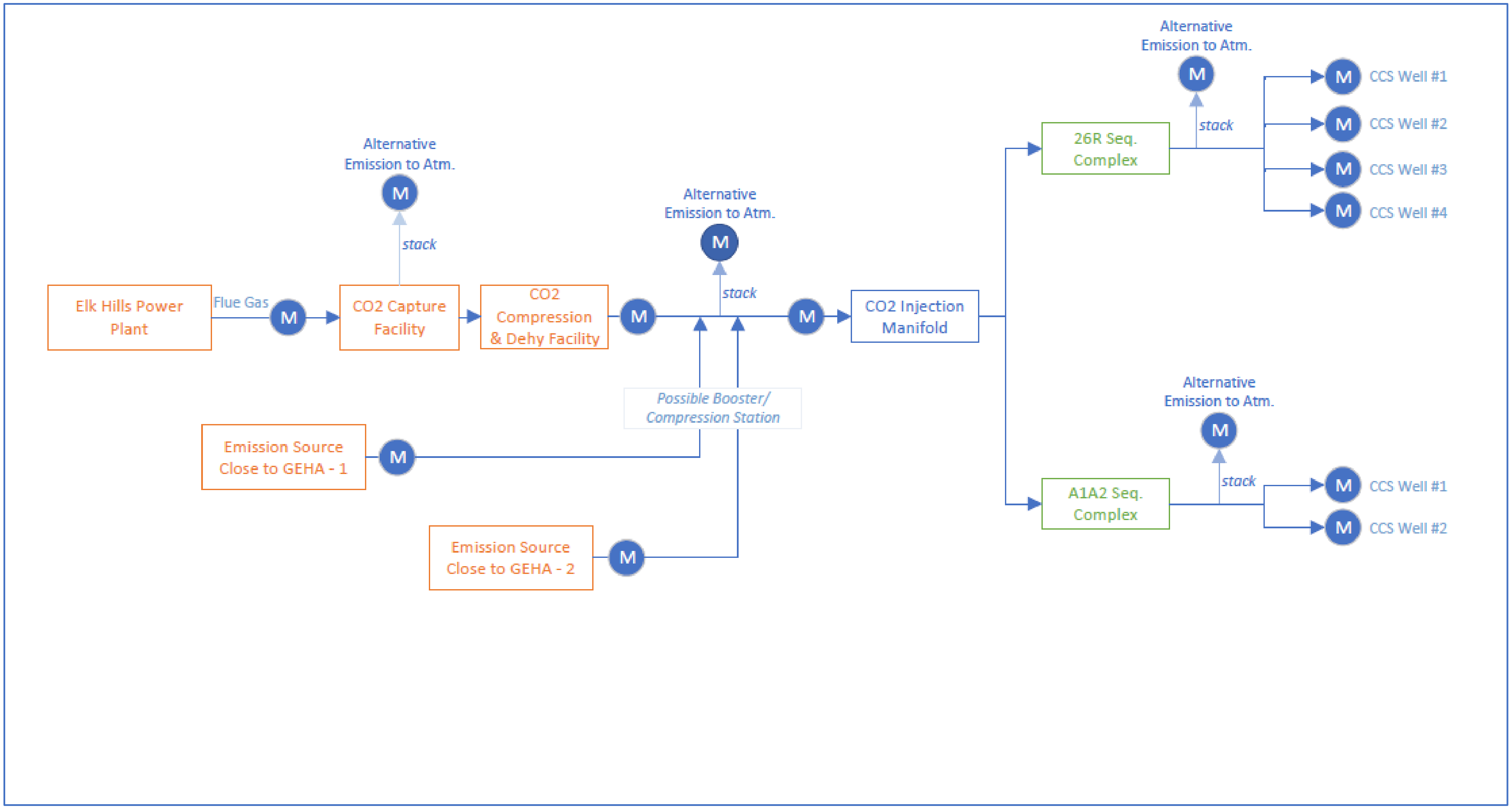

Figure 5: Facilities flow diagram for Carbon TerraVault carbon capture and sequestration project. Blue "M" symbols denote meter locations.

2.3.2 CO_2 Distribution and Injection

CO_2 from the sources previously discussed will be distributed throughout the field through a combination of new and existing infrastructure. This distribution infrastructure will allow CO_2 to be injected into CO_2 wells completed within the Monterey Formation at A1-A2 and 26R.

Each CO_2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure.

2.3.3 Wells in the AoR Penetrating the Reef Ridge Shale

CalGEM regulations govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields (other than UIC Class VI CO_2 injection wells that are regulated by the EPA UIC program). Current CalGEM rules require, among other provisions, the following conditions.

- Fluids must be constrained in the strata in which they are encountered.
- Activities governed by the regulations cannot result in the pollution of subsurface or surface waters.
- Wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata in which they are encountered into strata with oil and gas, or into subsurface and surface waters.
- Operators must file a completion report including basic electric log (e.g., a density, sonic, or resistivity log acquired from the wellbore).
- Wells must follow plugging procedures that require advance approval from CalGEM and allow consideration of the suitability of the cement based on the use of the well, location and setting of plugs.

Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM at time of drilling and as part of the existing Class II UIC permit applications. Wells penetrating the Reef Ridge confining layer and storage reservoir are shown in Figure 6, and are listed in Table 3 categorized in groups that relate to the well status for each reservoir.

Completion Date	A1-A2 Reservoir Count	26R Reservoir Count
Oil and gas producing wells	79	145
Class II injection/disposal wells	32	22
Observation wells	0	2
Plugged and abandoned	39	35
TOTAL	**150**	**204**

Table 3: Wells penetrating Reef Ridge shale for each reservoir by status.

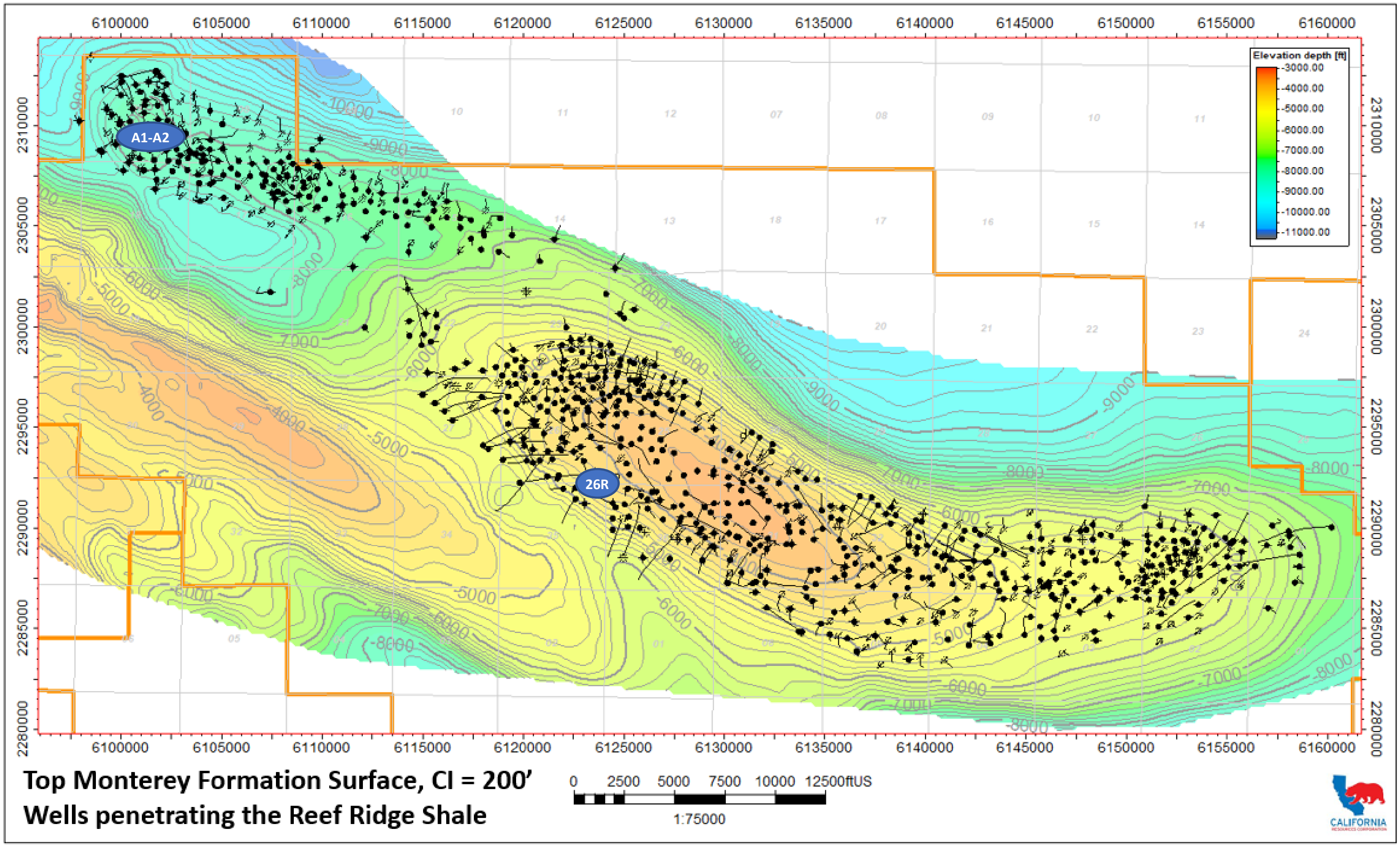

Figure 6: Wells penetrating the Reef Ridge shale. Project locations are shown at blue ovals.

Wells that penetrate the Reef Ridge shale (Table 3) were drilled between 1948 and 2014. Corrective action assessment of existing wellbores for the Class VI applications included the generation and detailed review of wellbore/casing diagrams for each well from CalGEM records. Information used in the review included depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top-of-cement determination supported the review for annular isolation.

Existing wellbores within the project areas will, where necessary and as approved by the UIC Director in the Class VI permit, be pressure tested, abandoned, re-abandoned, or have a technical demonstration of adequate zonal confinement. Corrective action will occur prior to the commencement of CO_2 injection or on an approved phased schedule after CO_2 injection commences if conditions allow.

Project injection and monitoring wells are listed in Section 11.5. Well workover crews are on-call to maintain active wells and to respond to any wellbore issues that arise. Incidents are detected by monitoring changes in the surface pressure of injection wells and by conducting Mechanical Integrity Tests (MITs) that include, but are not limited to, Radioactive Tracer Surveys (RTSs) and Standard Annular Pressure Tests (SAPTs).

All existing oil and gas wells, including both injection and production wells are regulated by CalGEM under Public Resources Code Division 3.

2.4 Reservoir Modeling

Numerical reservoir simulation is used for many purposes, including optimizing reservoir management, forecasting hydrocarbon and water production, predicting the behavior of injected fluids such as $CO_{2,}$ and assessing CO_2 plume development and confinement.

2.4.1 Reservoir Model for Operational Design and Economic Evaluation

Reservoir modeling workflow begins with the development of a three-dimensional (3-D) representation of the subsurface geology ("static model"). Static model development leverages all available well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces and faults (if present) into a geocellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. CRC used Schlumberger Petrel, an industry-standard geocellular modeling software, to build and maintain the EHOF static model.

The static model becomes "dynamic" in the reservoir simulator with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon phase,
- Liquid and gas relative permeability,
- Capillary pressure data, and
- Fluid injection and/or extraction rates.

2.4.2 Performance Prediction

One objective of the simulation models is to develop an injection plan that maximizes CO_2 storage and minimizes associated costs. The injection plan includes injection wells and appropriate injection rate and pressure for each well that adheres to regulatory requirements.

2.4.3 Plume Model for CO_2 Storage Capacity, Containment, and Predicted Plume Migration

Full-field plume models confirm reservoir capacity and CO_2 containment within the 26R and A1-A2 reservoir. These models were built using a dynamic reservoir simulation application known as the Equation-of-State (EOS) Compositional Simulator (GEM), developed by Computer Modelling Group Ltd. (CMG). Figure 7 shows the results of the modeling for the 26R and A1-A2 storage reservoir. The plume models were used to evaluate: (1) the quantity of CO_2 stored for geological sequestration, and (2) the lateral movement of CO_2 to define the MMA and demonstrate vertical confinement by the Reef Ridge shale.

2.4.4 Geomechanical Modeling of Reef Ridge Shale

In addition to the plume models, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock. This model was used to assess the pressure at which the Reef Ridge shale would shear through tensile failure.

The plume modeling effort confirms the Monterey Formation's ability to permanently store the planned project CO_2 volumes under the Reef Ridge shale over the project's life. The results of the plume models are discussed in greater detail below.

3 Delineation of Monitoring Area and Timeframes

3.1 Maximum Monitoring Area

The MMA is defined in 40 CFR 98.449 as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data as described above, was used to predict the size and location of the plume, as well as understand how the plume migrates over time.

The MMA, shown by the blue line Figure 8 , is defined by the extent of the CO_2 plume at 100 years post-injection for geologic sequestration plus one-half mile.

3.2 Active Monitoring Area

The AMA boundary was established by superimposing two areas (40 CFR 98.449):

- Area #1: The area projected to contain the free phase CO_2 plume at the end of year *t*, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one- half mile.
- Area #2: The area projected to contain the free phase CO_2 plume at the end of year *t* + 5.

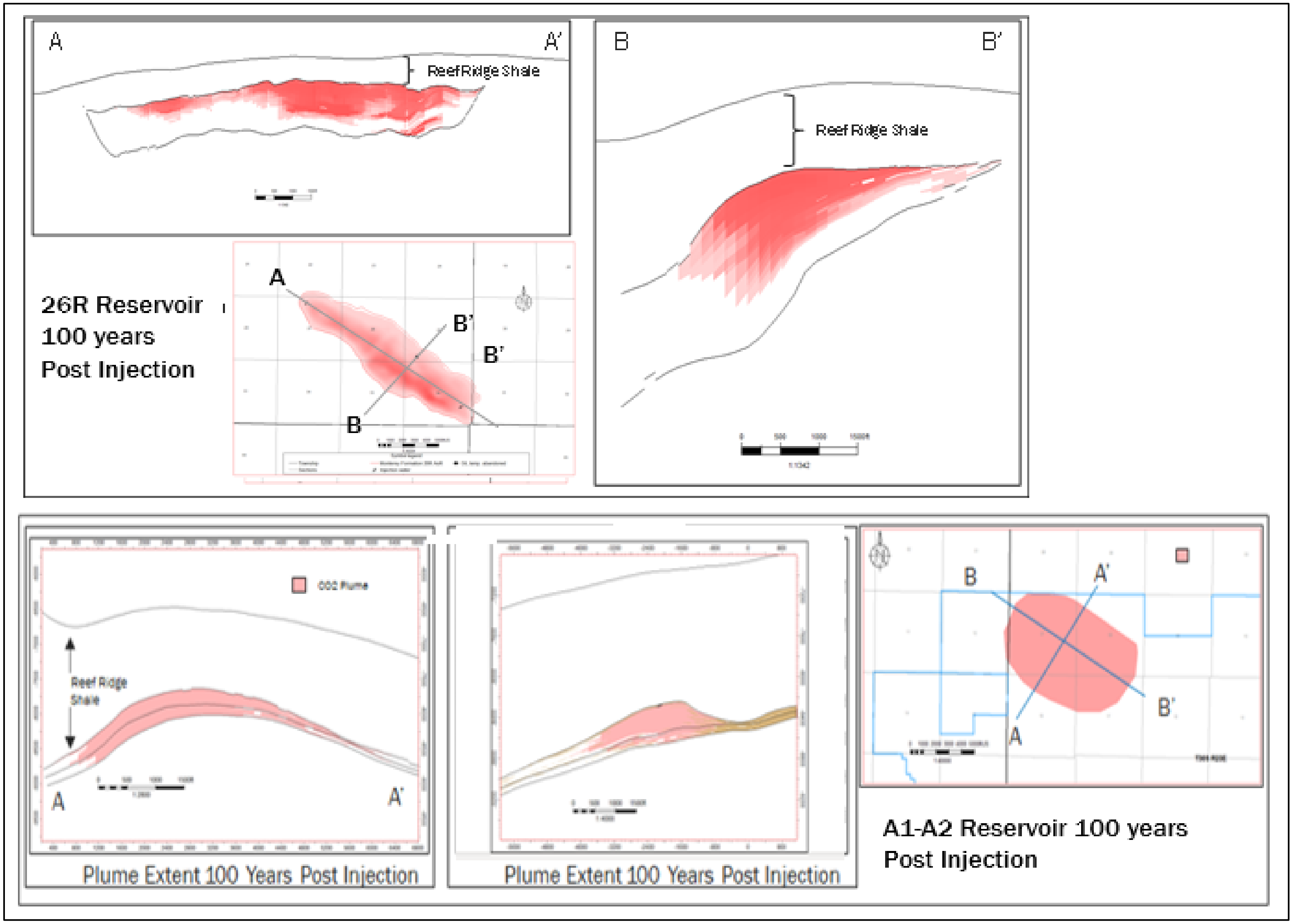

Figure 7: CO_2 plume modeling results.

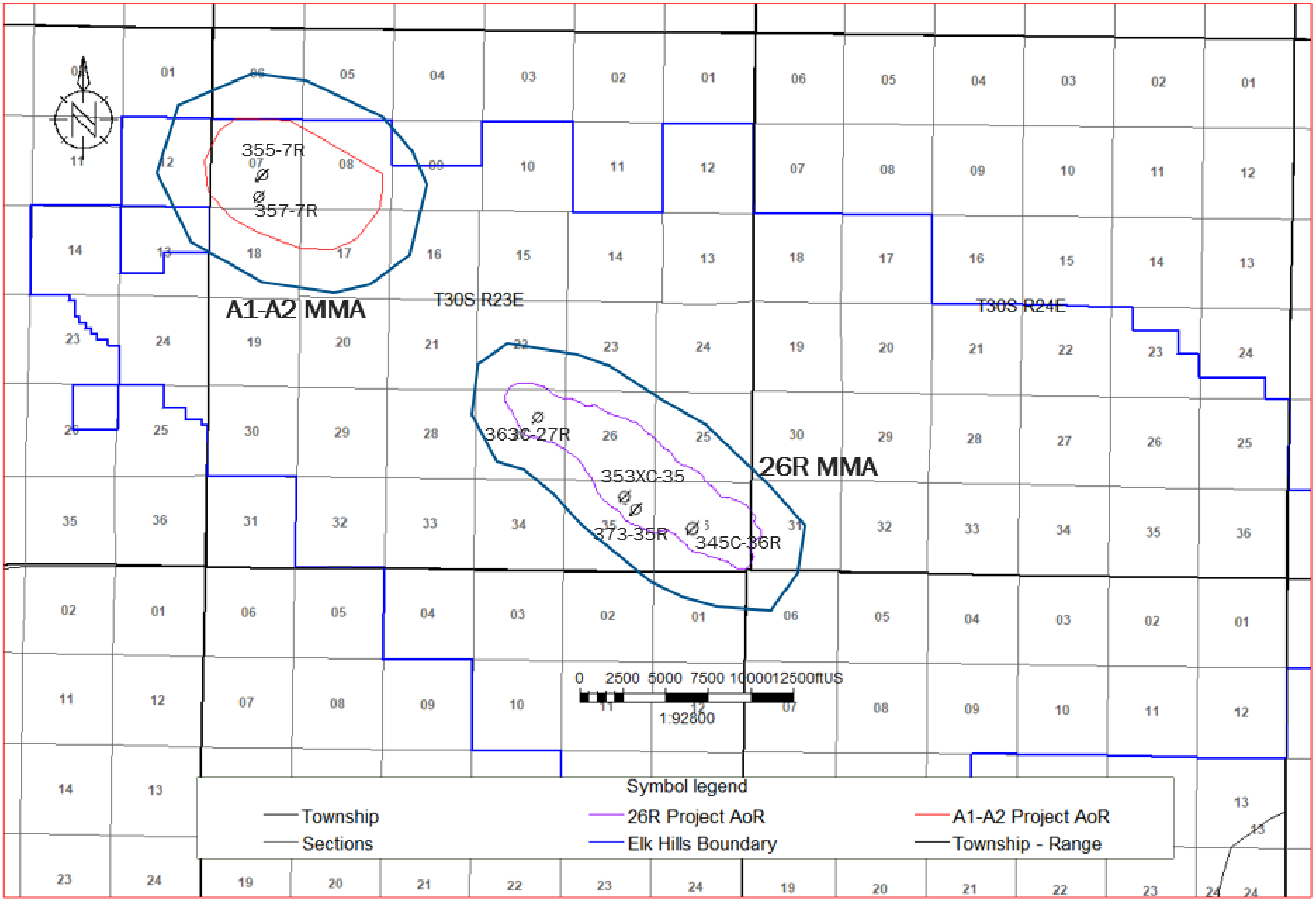

Figure 8: Injector well locations, EPA AoR (final CO_2 plume boundaries; orange and purple lines) and AMA - MMA (blue line). Scale bar units are feet.

The A1-A2 and 26R reservoirs are depleted and CO_2 is predicted to reach the edges of the reservoir within the first two to three years of injection (see Figures 9a, 9b). For this reason the area projected to contain free phase CO_2 is similar during the majority of the Specified Period.

The AMA boundary was determined for the time period ("*t*") corresponding to three years after the end of injection (30 years after the beginning of injection). Area #1, above, was taken as the plume area plus an all-around buffer zone of one-half mile. Area #2 is smaller or equal in all directions for both projects than Area #1, and therefore the final AMA was defined as Area #1 (Figure 8).

CTV has established one AMA boundary for 30 years and does not anticipate any expansion of the monitoring area under 40 CFR 98.448. Given the definitions used to define the MMA and AMA, AMA is also functionally equivalent to the MMA. Instituting monitoring throughout the entire MMA boundary for the Specified Period provides maximum operational flexibility. The absence of through-going faults or fractures confirms the competency of the Reef Ridge to preserve hydrocarbons within the Monterey Formation and to contain the CO_2.

3.3 Monitoring Timeframe

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted when a demonstration that current monitoring and model(s) show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within two to three years after injection for the Specified Period ceases based on predictive modeling supported by monitoring data.

4 Evaluation of Potential Pathways for Leakage to the Surface

4.1 Introduction

In the more than 100 years of the EHOF's development, the reservoir has been studied and documented extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface. The following potential pathways are reviewed:

- Existing wellbores,
- Faults and fractures,
- Natural and induced seismic activity,
- Previous operations,
- Pipeline/surface equipment,
- Lateral migration outside the EHOF,
- Drilling through the CO_2 area, and
- Diffuse leakage through the seal.

Section 4.10 summarizes how CRC and CTV will monitor CO_2 leakage from various pathways and describes the response to various leakage scenarios. In addition, Section 5 describes how CRC and CTV will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-12). Any incidents that result in CO_2 leakage up the wellbore and into the atmosphere will be quantified as described in Section 7.

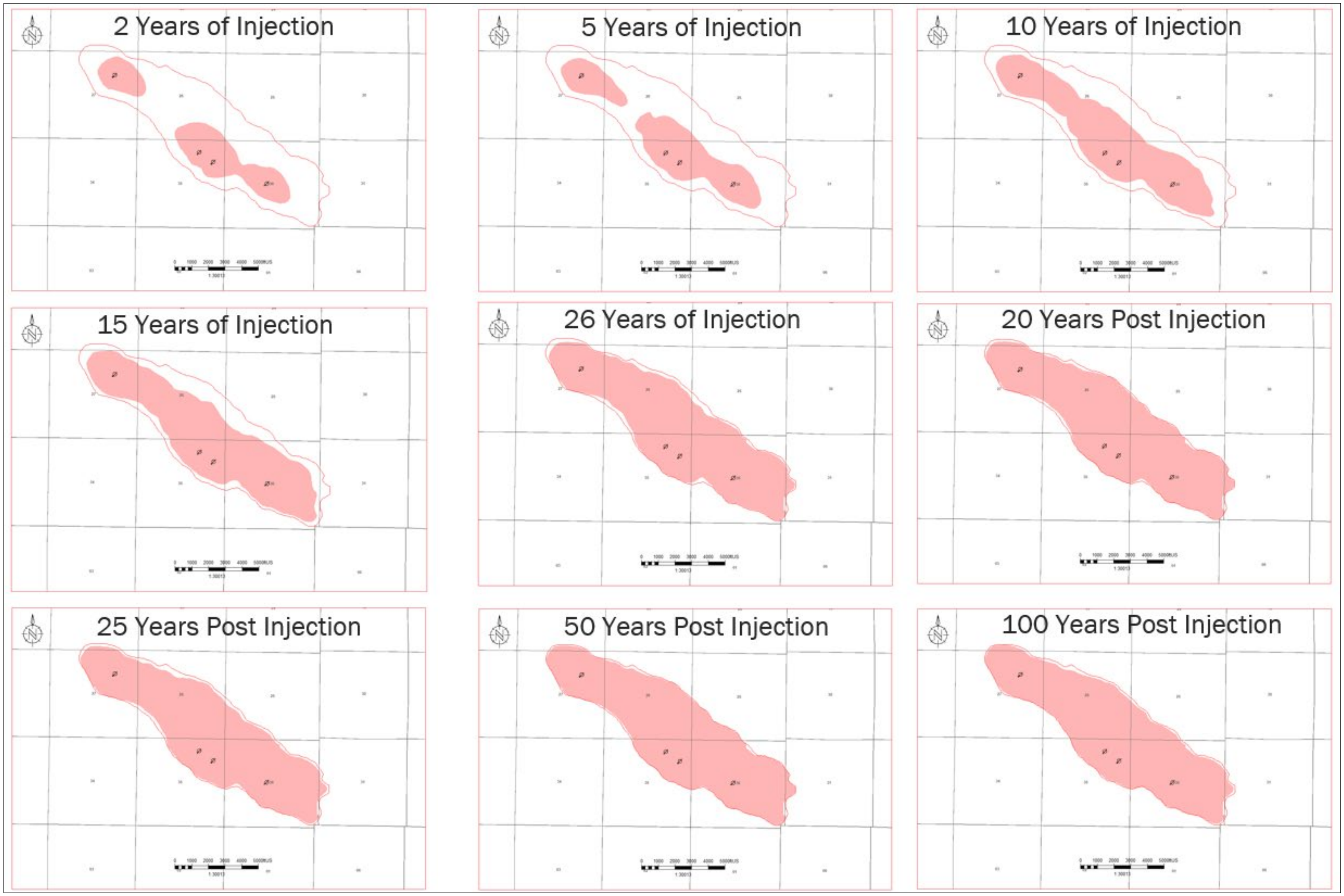

Figure 9a: Plan view showing modeled plume development through time, 26R project.

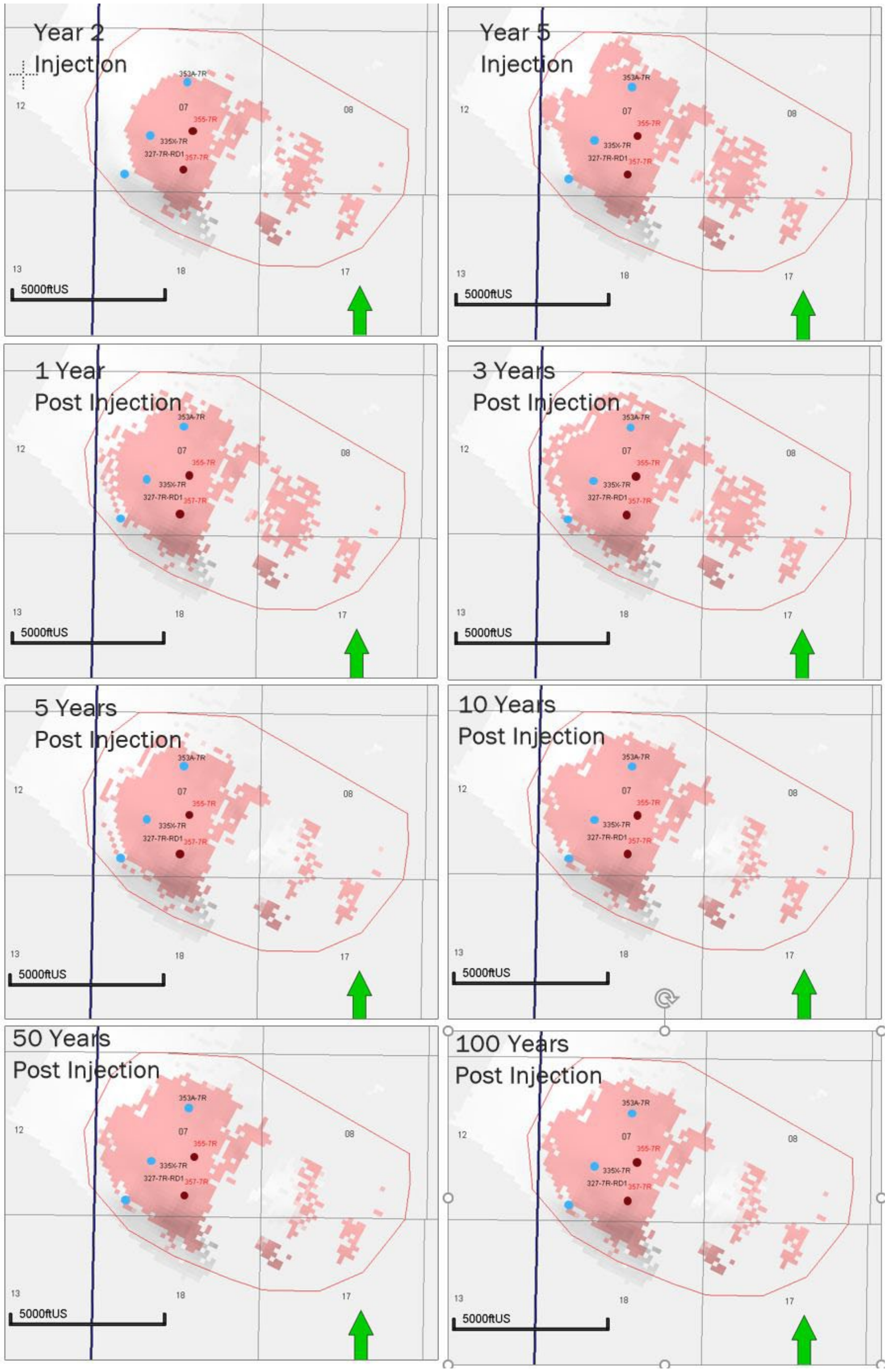

Figure 9b: Plan view showing modeled plume development through time, A1-A2 project (model layer 15). Red dots ae the injectors, Blue dots are monitoring wells.

4.2 Existing Wellbores

Leakage through existing wellbores is possible at the EHOF. However, that is mitigated by adhering to regulatory requirements for well drilling and testing; implementing best practices developed through extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment. Wells penetrating the Reef Ridge confining shale and sequestration reservoir are described in Section 2.3.3.

LIKELIHOOD: As discussed in Section 2.3.3, regulations governing the EHOF require that wells be completed and operated so that fluids are contained in the strata in which they are encountered. For this reason likelihood of leakage is considered low.

TIMING: Risk of leakage at each specific existing wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which is towards the end of the project injection time period.

MAGNITUDE: Leakage mass is predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Continual and routine monitoring and maintenance of wellbores and site operations is critical to ensure confinement in the following ways.

1. Injection well pressure is monitored continuously throughout the EHOF using a supervisory control and data acquisition (SCADA) system. Pressure and rate sensors on the injection wells are programmed to alarm and notify operations personnel when encountering values that significantly deviate from set target ranges. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed.

2. Experience gained over time allows for a strategic approach to well maintenance and workovers; workover crews are onsite for this purpose. For example, the well classifications by age and construction method inform planning for monitoring and updating wells. All available information, including pattern performance and well characteristics, is used to determine well maintenance schedules.

3. A corrosion protection program for CO_2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHOF. In line with industry standard operations and EPA Class VI requirements for CCS, downhole equipment and the interior and exterior of wellbores will be protected using special materials (e.g., fiberglass tubing, corrosion-resistant cements, nickel-plated packers, corrosion-resistant packer fluids), and procedures will be performed to prevent and monitor for corrosion (e.g., packer placement, use of annular leakage detection devices, cement bond logs, pressure tests). These measures and procedures are typically included in the injection orders filed with CalGEM and the EPA UIC program. Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

4. MIT requirements implemented by CalGEM and/or EPA UIC (as applicable) will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform to existing regulations and permit conditions. All active injection wells undergo MIT before

injection, after any workover or per time periods specified in the UIC approval. Operators are required to use a pressure recorder and pressure gauge for the tests. For CalGEM regulated wells, operator's field representative must sign the pressure recorder chart and submit it with the MIT form to CalGEM. The casing-tubing annulus must be tested to maximum anticipated surface pressure (MASP) for a specified duration and with an allowable pressure loss specified in the regulations. CalGEM or EPA UIC may also approve alternative pressure monitoring programs with varying requirements at their discretion.

If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180 days and re-tested, or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

5. Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any given day, there are approximately 40 personnel in the field. Leaking CO_2 is very cold and leads to formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and to safely remedy the issue. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in Section 5.

6. Corrective Action assessment performed pursuant to the Class VI regulation includes the generation and detailed review of wellbore/casing diagrams for each well in the project area. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of cement determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface. For each well determined to require additional plugging CTV has provided the plugging procedure that will be used to abandon wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. The planned plugging procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, CRC and CTV conclude that it will mitigate CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur by use of local surface air monitoring in the vicinity of the leaking wellbore.

4.3 Faults and Fractures

There are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow. First, the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Oil, and to a greater extent gas, migrates upward over time because both are less dense than the brine found in rock formations. Places where oil and gas remain trapped in the deep subsurface over millions of years, as is the case in the EHOF, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

While developing the EHOF, a seismic survey was conducted to characterize the formations and provide information for the reservoir models used for development planning. Initial interpretations of the 3-D seismic survey were based on a conventional pre-stack time migration volume. In 2019, the 3-D seismic survey was reprocessed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 10 displays the location and extent of four faults that helped to form these anticlines beginning in the Middle Miocene, 16 million years ago (Callaway and Rennie, 1991). These faults have remained inactive for millions of years since. Offsetting the 31S and NWS structures are the 1R, 2R, and 3R high-angle reverse faults that are oriented NW-SE. The faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge shale confining layer.

Lastly, the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures. Over 1.4 billion barrels of water and 1,237 billion standard cubic feet (Bcf) of gas have been injected into the NWS and 31S structures with no reservoir confinement issues. In fact, it is the absence of faults and fractures in the Reef Ridge shale that makes the Monterey Formation such a strong candidate for water injection operations and enables field operators to maintain effective control over the injection and production processes.

LIKELIHOOD: Because there are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow the likelihood of leakage is considered negligible.

TIMING: No faults are present that provide a potential pathway; therefore leakage is not expected via this pathway over the entire duration of the project.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Leakage via faults, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1.

4.4 Natural or Induced Seismicity

Based on published data and over 100 years of operational experience, there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. This is due, in part, to the thickness, ductility, and predominance of clay in the primary confining layer Reef Ridge shale.

No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

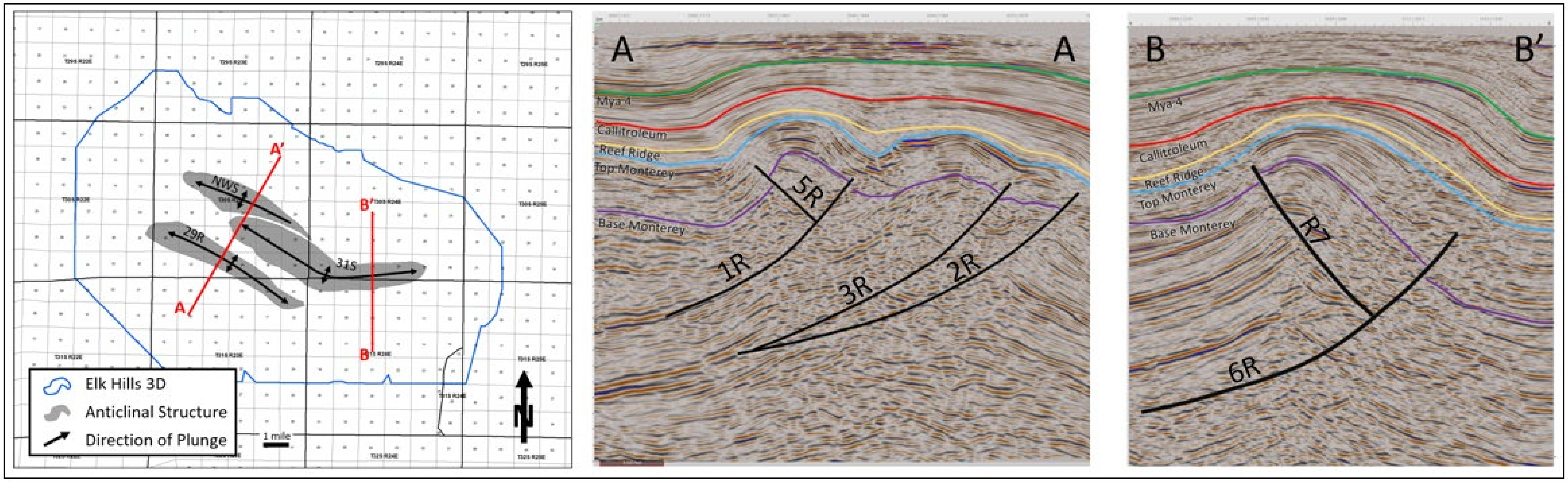

Figure 10: Outline of EHOF 3-D survey and seismic intersections across 31S and NWS structures.

Historical seismic events from 1932 to present are available from the Southern California Earthquake Data Center (SCEDC). Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1-A2 and 26R MMA. In addition, there have only been eleven earthquakes with a magnitude of 5.0 or greater within a 30-mile buffer around the EHOF administrative boundary (Figure 11). There have been 518 earthquakes with a magnitude between 3 and 5 within the 30-mile EHOF buffer. The average depth of the earthquakes with magnitude greater than 3 is 4.5 miles, while the storage reservoirs are one mile below surface.

LIKELIHOOD: Induced seismicity will be mitigated operationally by the following:

1. Injection pressure will be monitored continuously and will be lower than the failure pressure of the confining Reef Ridge shale.
2. Reservoir pressure will be at or beneath the discovery pressure.
3. Seismometers will be installed at the surface to detect seismicity induced by injection operations.

Adherence to these mitigation measures will ensure that likelihood of induced seismicity is low.

TIMING: Risk of induced seismicity is highest when operating pressures are greatest at the end of the injection time period. Risk of natural seismicity is not anticipated to change during the Specified Period.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Induced seismicity monitoring with seismometers, as described in Section 5.1.

4.5 Previous Operations

All of the existing wells at the EHOF have been permitted through CalGEM (and predecessor California agencies) under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details, and injection-production history of each well.

CTV has assessed internal databases as well as CalGEM information to identify and confirm wells within the project area. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Therefore, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the development history of the reservoir that includes injection of water and gas.

Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

LIKELIHOOD: This operational experience has verified that there are no unknown wells within the EHOF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells as discussed above. Over many years, the EHOF has been continuously checked for the presence of old, unknown wells throughout the EHOF. These practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management. For these reasons risk of leakage via this pathway is considered low.

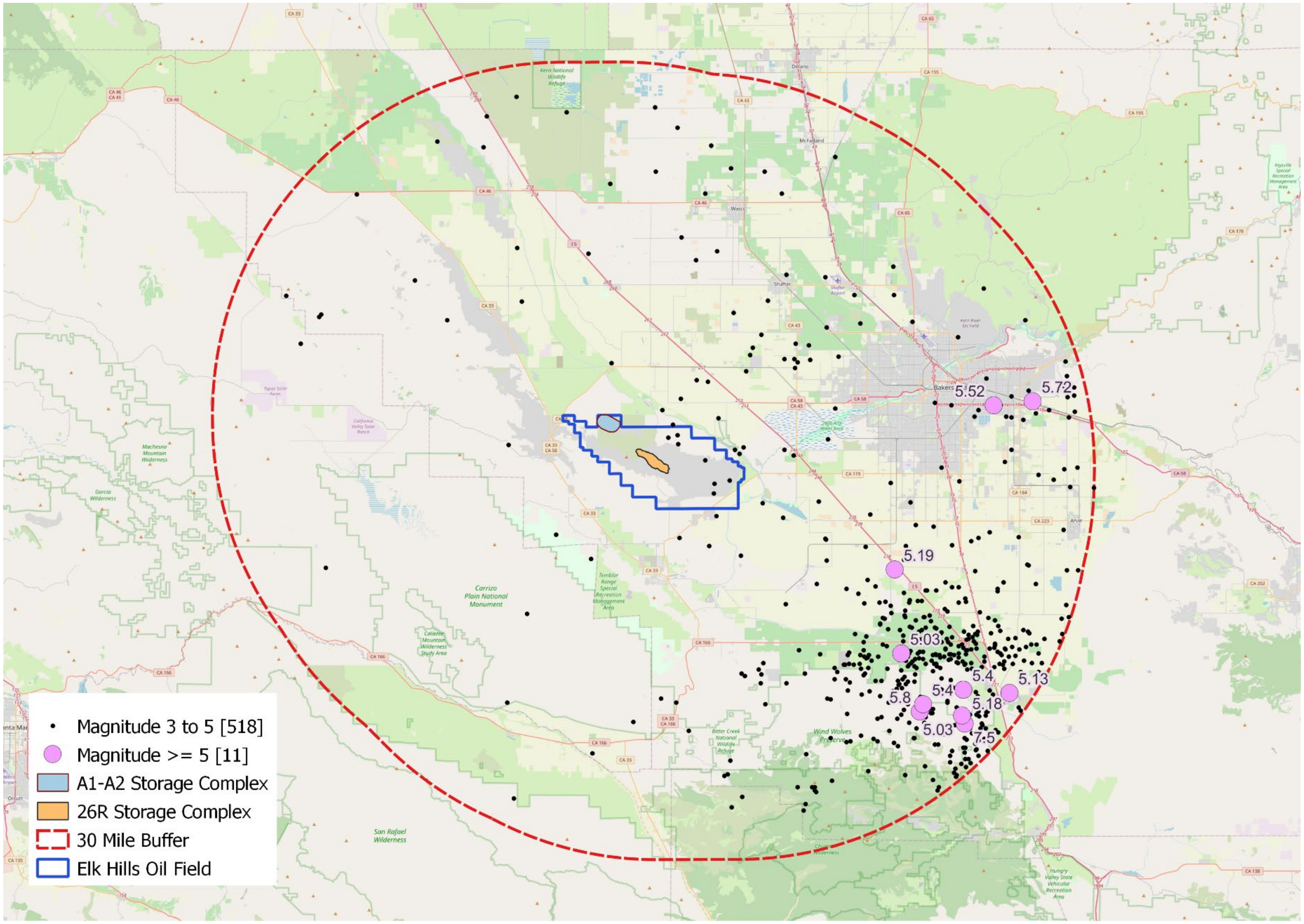

Figure 11: Earthquakes in the San Joaquin Basin with a magnitude greater than 3. Note: only 11 earthquakes have occurred within a 30-mile buffer around the EHOF administrative boundary. Earthquake data from SCEDC.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest that will be at the end of the injection period.

MAGNITUDE: Leakage mass is predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Leakage via abandoned wells, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1. Additional monitoring is discussed in Section 4.2.

4.6 Pipeline/Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2. Unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO_2 injection projects.

CO_2 delivery to the complex will comply with all applicable regulations, including as pipeline regulations are updated in the future as applicable. Instrumentation will be installed on pipelines and facilities that allows the 24/7 operations staff at the Central Control Facility (CCF) to monitor the process and potentially spot leaks. Furthermore, frequent and routine visual inspections of surface facilities by field staff will provide an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner.

LIKELIHOOD: Compliance with applicable regulations, as described above, ensures that likelihood of leakage via this pathway is low.

TIMING: Leakage risk via this pathway will be similar over the project time period.

MAGNITUDE: Should leakage be detected from pipeline or surface equipment, the mass of released CO_2 will be quantified following the requirements of 40 CFR 98.230-238 (Subpart W) of EPA's Greenhouse Gas Reporting Program (GHGRP).

MONITORING: Routine field inspection and remote monitoring will be conducted to detect any potential leakage from pipelines and surface facilities.

4.7 Lateral Migration

It is highly improbable that injected CO_2 will migrate downdip and laterally outside the EHOF because of the buoyant properties of supercritical CO_2, the nature of the geologic structure, and the planned injection approach. The strategy to minimize the lateral migration risk is to ensure that the CO_2 plume and surrounding fluids will be at or below the initial reservoir pressure at time of discovery.

LIKELIHOOD: Leakage via this pathway is not anticipated.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Geophysical monitoring conducted as approved in the Class VI permit will track the extent of CO_2 plume and ensure that there is not lateral migration outside of the AoR.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the Reef Ridge confining zone and into the Monterey Formation may occur.

LIKELIHOOD: The possibility of this activity creating a leakage pathway is extremely low for three reasons: 1) Future well drilling would be regulated by CalGEM (oil and gas wells) or EPA UIC (Class VI injection wells) and will therefore be subject to requirements that fluids be contained in strata in which they are encountered; 2) as sole operators and owners of the EHOF, CRC and CTV control placement and timing of new drilling operations; and 3) there are no oil and gas targets beneath the Monterey Formation.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest during future time periods if drilling through the Reef Ridge confining zone were to occur.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Ongoing regulation of all drilling activities by CalGEM and/or EPA will ensure future monitoring of drilling activities. See additional monitoring discussion in Section 4.2.

4.9 Leakage Through the Seal

Diffuse leakage through Reef Ridge confining layer is highly unlikely. The presence of gas caps trapped over millions of years confirms that the seal has been secure for millions of years. Leaking through the seal is mitigated by ensuring that post-injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The injection monitoring program referenced in Section 2.3.2 and detailed in Section 5 assures that no breach of the seal will be created.

Further, if CO_2 were to migrate through the Reef Ridge, it would migrate vertically until it encountered and was trapped by any of the additional shallower interbedded shales of the Etchegoin, San Joaquin, and Tulare Formations (more than 5,000 ft of vertical section; see Figure 3).

LIKELIHOOD: Diffuse leakage through Reef Ridge confining layer is highly unlikely.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest at the end of the injection period when pressures are highest. In addition the relative amount of CO_2 in the supercritical phase will decrease over time post-injection as CO_2 dissolves into the brine reducing leakage risk.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Leakage, if it were to occur, would be subject to detection from monitoring wells in zones above sequestration reservoir, as described in Section 5.1.

4.10 Monitoring, Response and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include routine issues such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment, and unique events such as induced fractures.

Table 4 summarizes some of these potential leakage scenarios, monitoring activities designed to detect those leaks, standard response, and other applicable regulatory programs requiring similar reporting.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing leak	Routine field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days	CalGEM or EPA UIC
Wellhead leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well-kill procedures; shut-in offset injectors prior to drilling	CalGEM or EPA UIC
Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM or EPA UIC
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut-in injectors near faults	EPA UIC
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	EPA UIC
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut-in injectors near seismic event	EPA UIC

Table 4: Response plan for CO_2 leakage or loss.

Section 5.1 discusses the approaches envisioned for quantifying the mass of leaked CO_2. In the event leakage occurs, CRC and CTV plan to determine the most appropriate methods for quantifying the mass leaked and will report it as required as part of the annual Subpart RR submission.

Any mass of CO_2 detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR 98.230-238 (Subpart W) or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection. As indicated in Sections 5.1 and 7, leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in the electronic environmental documentation and reporting system. Repairs requiring a work order will be documented in the electronic equipment maintenance system and well work historian. If the scope of repair work requires permitting through CalGEM or EPA UIC, a subsequent operations summary report will be provided under the conditions of the applicable permit.

4.11 Summary

The structure and stratigraphy of the Monterey Formation in the EHOF is ideally suited for injection and CO_2 storage. The CO_2 injection zone stratigraphy is porous, permeable, and very thick, providing ample capacity for long-term CO_2 storage. The overlying Reef Ridge shale forms an effective seal for Monterey Formation sequestration (see Figure 3). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, the potential threat of significant leakage is extremely low.

Risk of release is further reduced by the prudent operational strategy of limiting the pressure of the reservoir post-injection to at or below the initial pressure of the reservoir at time of discovery.

5 Monitoring and Considerations for Calculating Site-specific Variables

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

Existing operations are centrally monitored and controlled by the extensive and sophisticated CCF. The CCF uses a SCADA software system to implement operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Flow rates, pressures, gas composition, and other data will be collected at key points and stored in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow response and reporting protocols when the system delivers notifications that data exceed predetermined statistically acceptable limits. The data can be accessed for immediate analysis.

Figure 5 identifies the meters that will be used to evaluate, monitor, and report on the injection project and associated plume migration described earlier in Section 2.3. A similar metering system is already installed throughout the EHOF.

As indicated in Figure 5, a custody-transfer meter will be installed at the CO_2 sources. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are accurate for purposes of commercial transactions. All meter and composition data will be recorded.

Metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously, and will feed data directly to the CCF. In the oil and gas industry, the accepted level of custody-transfer meter accuracy is 0.25% or better, and the meters are calibrated every 60 to 90 days. A third party is frequently used to calibrate these meters, and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO_2 compositions. For these streams, flow rate is the most important control parameter. Operations flow meters are used to determine the flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. Flow meters are also used—comparing aggregate data to individual meter data—to provide a cross-check on actual operational performance.

Developing a CO_2 mass balance on multi-phase, multi-component process streams is best accomplished using custody-transfer meters rather than multiple operations meters. As noted above, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will affect any in-field meter reading.

Many meters have some form of automatic adjustment for some of these factors, others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same mass of flow and gas composition.

Table 5 summarizes the CO_2 injection monitoring strategy. Figure 12 shows the location of monitoring wells.

Monitoring Activity	Frequency/Location
MIT (Internal and External)	Annual
SAPT	Initially; any time the packer is replaced or reset
Injection rate, pressure, and temperature	Continuous
Seismicity	Induced seismicity monitoring via seismometers
Underground sources of drinking water (USDWs) and reservoirs between USDWs and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition, and periodic cased-hole logs
Stream analysis	Continuous
Corrosion monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment
Sequestration reservoir monitoring	Dedicated wells monitoring sequestration reservoir with pressure, temperature, fluid composition, and periodic cased hole logs

Table 5: Injection monitoring strategy summary.

5.1.2 CO_2 Received

A custody-transfer meter will be used at the CO_2 source(s) to continuously measure the mass and composition of CO_2 received. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

5.1.3 CO_2 Injected into the Subsurface

Injected CO_2 associated with geologic sequestration will be calculated using the flow meter mass at the operations/composition meter at the outlet of the recompression facilities (RCFs) and the custody-transfer meter at the CO_2 off-take points.

5.1.4 CO_2 Produced, Entrained in Products, and Recycled

No CO_2 will be produced or entrained in products or recycled.

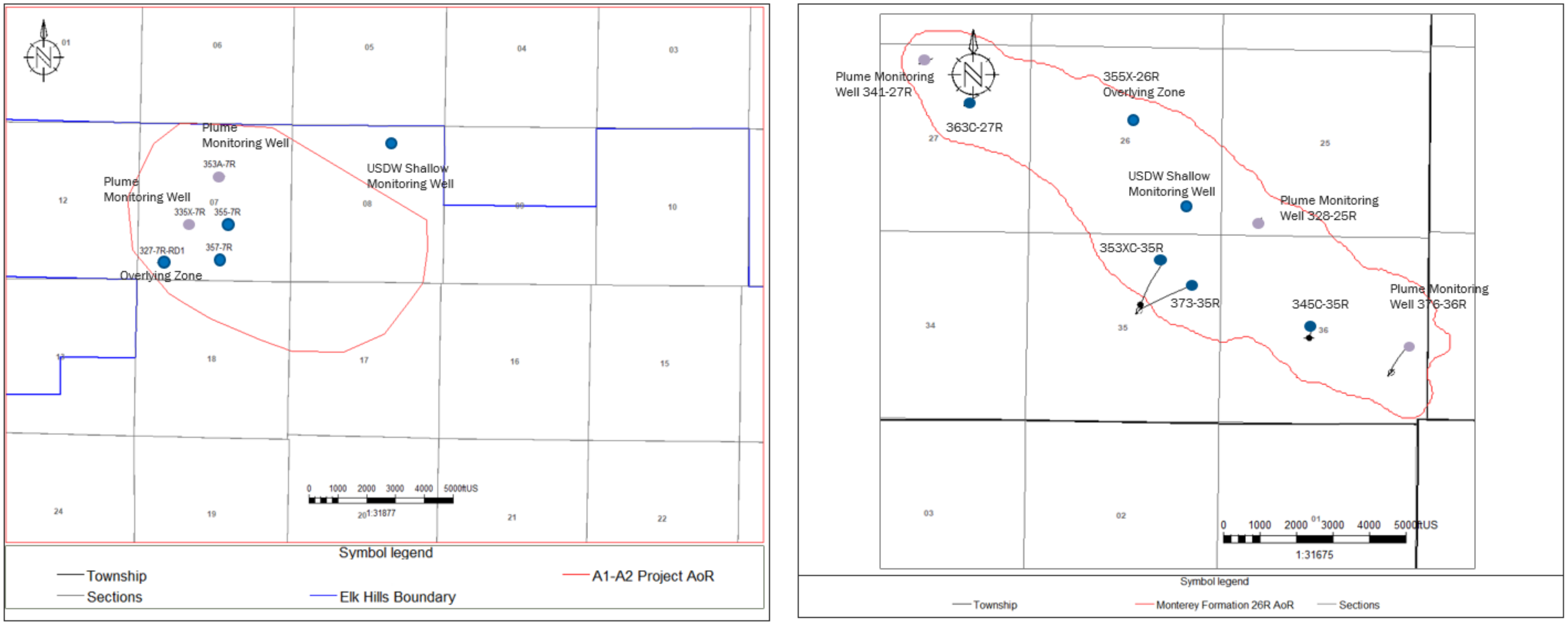

Figure 12: Map showing monitoring well locations.

5.1.5 CO_2 Emitted by Surface Leakage

40 CFR 98.230-238 (Subpart W) is used to estimate surface leaks from equipment at the EHOF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition an event-driven process will be used to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. Reporting will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double-counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet the following two objectives in accordance with the leakage risk assessment in Section 4: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the mass of CO_2 leaked to the surface. Injection Wells

Injection well pressure, temperature, and injection rate will be monitored continuously. If injection pressure or rate measurements are beyond the specified set-points determined for each injector, a data flag is automatically triggered and field personnel will investigate and resolve the problem. These excursions will be reviewed by well-management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or another minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and internal support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in the work order management system. This record will enable the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leak mass. Depending on specific circumstances, these determinations may rely on engineering estimates.

Monitoring of Wellbores

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a two-part visual inspection process will be employed in the general area of the EHOF to detect unexpected releases from wellbores. First, field personnel will visit the surface facilities on a routine basis. Inspections may include tank volumes, equipment status and reliability, lube oil levels, pressures and flow rates in the facility, and valve leaks. Field personnel inspections will also check that injectors are on the proper schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, data collected by personal CO_2 gas monitors (ToxiRAE Pro CO_2 or equivalent), which will always be worn by field personnel, will be a last method to detect leakage from wellbores. The monitor's sensor range is 0 to 50,000 parts per million (ppm) and resolution is 100 ppm. The monitor alarm setting will be established to alert workers to a CO_2 concentration exceeding 1,000 ppm or a lower value. If an alarm is triggered, the first response will be to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for greenhouse gas (GHG) reporting. Targeted point-source surface air monitoring will be conducted in the event of detected wellbore leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

Other Potential Leakage at the Surface

Routine visual inspections at surface are used to detect significant loss of CO_2 to the surface. Field personnel visit manned surface facilities daily to conduct visual inspection. Inspections may include review of equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper schedule, and conducting a general observation of the facility for visible CO_2 or fluid line leaks. If problems are detected, field personnel would investigate and, if maintenance is required, generate a work order in the maintenance system which is tracked through completion. In addition to these visual inspections, CRC and CTV will use the results of the personal gas monitors as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, a work order will be generated in the work order management system. The work order will describe the appropriate corrective action and be used to track completion of the maintenance action. The work order will also serve as the basis for tracking the event for GHG reporting and quantifying any CO_2 emissions. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.6 Monitoring for Potential Leakage from the Injection/Production Zone

Monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir, and the USDW. Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage. Measured increase in CO_2 in groundwater above the Storage Complex will be used to develop groundwater isoconcentration maps and quantify CO_2 leakage rates.

Monitoring well locations are shown on Figure 12, and monitoring wells are listed in Appendix 11.5. Monitoring well details including depth and chemistry monitoring parameters are listed in Appendix 11.6. Monitoring well data collection procedures will be consistent with protocols listed in the Class VI permit application.

5.1.7 Seismicity Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole. This network will be implemented to monitor seismic activity near the project site, and will consist of passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- Seven sensor locations (borehole and near surface) with high-sensitivity 3-component geophones.
- Borehole sensors will be deployed deeper than 1,500’ to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events greater than moment magnitude scale (M_w) 0.0.

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously. Waveform data will be transmitted near real-time via cellular modem or other wireless means and archived in a database. Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network.

The Class VI permit application describes actions that will be taken in the event of detected seismic events, based on the magnitude and frequency of seismic activity. In the event of a seismic event greater than M_w 2.0 and local report and confirmation of damage, an investigation will be conducted to determine of CO_2 leakage has occurred. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.8 CO_2 Emitted from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment Located Between the Injection Flow Meter and the Injection Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment and vented CO_2 as required under 40 CFR 98.230-238 (Subpart W).

5.2 To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, CRC and CTV intend to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the EHOF. After the end of the Specified Period, CRC and CTV anticipate that it will submit a request to discontinue monitoring and reporting. The request will demonstrate that the amount of CO_2 reported under 40 CFR 98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, CRC and CTV will be able to support the request with years of data collected during the Specified Period as well as two to three (or more, if needed) years of data collected after the end of the Specified Period. This demonstration will provide the information necessary for the EPA UIC Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (injection) over the monitoring period,
- An assessment of the CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the mass of stored CO_2 to the surface,
- A demonstration that there has been no significant leakage of CO_2, and
- An evaluation of reservoir pressure in the EHOF that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6 Determination of Baselines

Automatic data systems will be used to identify and investigate deviations from expected performance that could indicate CO_2 leakage. These data systems are used primarily for operational control and monitoring, and as such, are set to capture more information than is necessary for reporting in the Annual

Subpart RR Report. Necessary system guidelines will be developed to capture the information that is relevant to identify CO_2 leakage. A description of the approach to collecting this information is given below.

6.1 Visual Inspections

As field personnel conduct routine inspections, work orders are generated in the electronic system for maintenance activities that cannot be immediately addressed. Methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation. The responsible party will be provided in the monitoring plan, as required under 40 CFR 98.3(g) (Subpart A). The Annual Subpart RR Report will include an estimate of the amount of CO_2 leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

6.2 Personal Gas Monitors

CO_2 gas monitors will be worn by all field personnel (ToxiRAE Pro CO_2 or equivalent; sensor range 0 to 50,000 ppm and resolution of 100 ppm). The monitor alarm setting will be established to alert workers to a CO_2 concentration exceeding 1,000 ppm or a lower value. Any monitor alarm will trigger an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, it would be quantified, and mitigating actions determined accordingly. The person responsible for MRV documentation will receive notice of all incidents where gas is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

6.3 Monitoring Wells

Baseline data will be collected from each monitoring well during well construction in order to provide a baseline. Baseline data will be collected on sequestration zone fluid chemistry and pressure, and above confining zone water chemistry and pressure at monitoring well locations. Data will be acquired that is characteristic of the subsurface after showing data stabilization. Quarterly fluid sampling and continuous pressure/temperature monitoring will be conducted at groundwater monitoring wells above the confining zone during the baseline period. In the injection zone fluid chemistry sampling will occur once at each location and temperature/pressure will be monitored continuously during the baseline period.

6.4 Seismic Baseline

The seismic monitoring network (Section 5.1.7) will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

6.5 Injection Rates, Pressures, and Mass

Target injection rates and pressures will be developed for each injector, based on the results of ongoing modeling and permitted limits. High and low set-points are programmed into the controllers, and flags whenever statistically significant deviations from the targeted ranges are identified. The set-points are designed to be conservative. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7 Determination of Sequestration Mass Using Mass Balance Equations

The following sections describe how each element of the mass-balance equation (Equation RR-12) will be calculated.

7.1 Mass of CO_2 Received

CRC and CTV will use Equation RR-1 as indicated in 40 CFR 98.443 to calculate the mass of CO_2 received from each custody-transfer meter immediately downstream of the source(s).

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \quad \text{(Eq. RR-1)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).
$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).
$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction)
p = Quarter of the year.
r = Receiving flow meter.

Given CRC and CTV's method of receiving CO_2 and requirements of 40 CFR 98.444(a):

- All delivery to EHOF is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation
- Quarterly CO_2 concentration will be taken from the gas measurement database

CRC and CTV will sum to total mass of CO_2 Received using Equation RR-3 in 40 CFR 98.443:

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \quad \text{(Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 for flow meter r.

r = Receiving flow meter.

7.2 Mass of CO_2 Injected into the Subsurface

Mass of CO_2 injected into the subsurface at EHOF at each injection well will be calculated with Equation RR-4:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \text{ (Eq. RR-4)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

Aggregated injection at all injection wells will be calculated with Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$$

where:

CO_2. = Total annual CO_2 mass injected (metric tons) through all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

u = Flow meter.

7.3 Mass of CO_2 Emitted by Equipment Leakage

CRC and CTV will calculate and report the total annual mass of CO_2 emitted by equipment leakage using an approach that is tailored to specific leakage events and relies on 40 CFR 98.230-238 (Subpart W) equipment leakage reports. As described in Sections 4 and 5.1, the operators are prepared to address the potential for leakage in a variety of settings. Estimates of the amount of equipment leakage will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

7.4 Mass of CO_2 Emitted by Surface Leakage

The process for quantifying surface leakage will entail using best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are discussed in Section 5.1. In the event leakage to the surface occurs, the quantify and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the mass leaked as reported in the Annual Subpart RR Report. Further, the Subpart W report and results from any event-driven quantification will be made to assure that surface leaks are not double-counted.

Equation RR-10 in 40 CFR 98.443 will be used to calculate and report the mass of CO_2 emitted by surface leakage:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \text{ (Eq. RR-10)}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.
$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year
x = Leakage pathway.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Equation RR-12 in 40 CFR 98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the reporting year as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2\,FI} \text{ (Eq. RR-12)}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W

Figure 5 illustrates that CO_2 supplied for geological storage will be metered between the CO_2 source and the injection meter.

7.6 Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual mass obtained using RR-12 in 40 CFR 98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

8 MRV Plan Implementation Schedule

It is anticipated that this MRV plan will be implemented as early as first quarter (Q1) 2025 pending appropriate permit approvals and an available CO_2 source, or within 90 days of EPA approval, whichever occurs later. Other facility GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. As described in Section 3.3 above, it is anticipated that that the MRV program will be in effect during the Specified Period, during which time the project will ensure long-term containment of a measurable quantity of CO_2 in subsurface geologic formations at the EHOF and that the project will be operated in a manner not expected to result in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be made and submission with a request to discontinue reporting under this MRV plan (see 40 CFR 98.441(b)(2)(ii)).

9 Quality Assurance Program

9.1 Monitoring QA/QC

As indicated in Section 7, the requirements of 40 CFR 98.444 (a) – (d) in the discussion of mass balance equations have been incorporated. These include the following provisions.

CO_2 Received and Injected

The quarterly flow rate of CO_2 received is measured at the receiving custody-transfer meters.

CO_2 emissions from equipment leaks and vented emissions of CO_2

These amounts are measured in conformance with the monitoring and QA/QC requirements specified in 40 CFR 98.230-238 (Subpart W).

Flow meter provisions

The flow meters used to generate data for the mass balance equations in Section 7 are:

- Operated continuously except as necessary for maintenance and calibration,
- Operated using the calibration and accuracy requirements in 40 CFR 98.3(i),
- Operated in conformance with API standards, and
- Traceable by the National Institute of Standards and Technology (NIST).

9.2 Missing Data Procedures

In the event data needed for the mass balance equations cannot be collected, procedures in 40 CFR 98.445 for estimating missing data will be used as follows:

- A quarterly flow rate of CO_2 received that is missing would be estimated using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in 40 CFR 98.230-238 (Subpart W) would be followed.

9.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters, the MRV plan will be revised and submitted to the EPA UIC Administrator within 180 days as required in 40 CFR 98.448(d).

10 Records Retention

The record retention requirements specified by 40 CFR 98.3(g) will be followed. In addition, the requirements in 40 CFR 98.447 will be followed by maintenance of the following records for at least three years:

- Quarterly records of CO_2 received, operating temperature and pressure, and concentration of these streams,
- Quarterly records of injected CO_2 including flow rate, operating temperature and pressure, and concentration of these streams,
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways,
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, and
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

These data will be collected as generated and aggregated as required for reporting purposes.

11 Appendices

11.1 Conversion Factors

If needed, CO_2 volumes will be reported at standard conditions of temperature and pressure as defined by the California Air Resources Board (CARB): 60° F and 14.7 pounds per square inch absolute (psia)[2].

To convert these volumes into metric tons, a density is calculated using the Span and Wagner EOS as recommended by the EPA and using the database of thermodynamic properties developed by NIST, available at http://webbook.nist.gov/chemistry/fluid/.

The conversion factor 5.29×10^{-2} metric ton per thousand cubic feet (MT/Mcf) has been used throughout to convert volumes to metric tons.

[2] See California Code of Regulations Title 17 Section 95102 (General Requirements of Greenhouse Gas Reporting, Definitions)

11.2 Acronyms

3-D – three-dimensional
AGA – American Gas Association
AMA – active monitoring area
AoR – area of review
API – American Petroleum Institute
Bcf – billion standard cubic feet
BOE - barrel of oil equivalent
CalGEM – California Geologic Energy Management Division
CARB – California Air Resources Board
CCF – Central Control Facility
CCS – carbon capture and sequestration
CDMG – California Division of Mines and Geology
CMG - Computer Modeling Group Ltd.
CO_2 – carbon dioxide
CRC - California Resources Corporation
CTV - Carbon TerraVault
DAC – direct air capture
DOE – U.S. Department of Energy
EHOF – Elk Hills Oil Field
EHPP – Elk Hills Power Plant
EOS - equation of state
EPA – U.S. Environmental Protection Agency
GEM – geochemical equation compositional model
GHG – greenhouse gas
GHGRP -- Greenhouse Gas Reporting Program
GPA – Gas Processors Association
H_2S – Hydrogen sulfide
MASP - maximum anticipated surface pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MRV –monitoring, reporting, and verification
MT/Mcf – metric ton per thousand cubic feet
MW - megawatt
NIST -- National Institute of Standards and Technology
NWS – Northwest Stevens
ppm – parts per million
RTS – radioactive tracer survey
RCF – recompression facility
SAPT – standard annual pressure test
SCADA – supervisory control and data acquisition
SCEDC – Southern California Earthquake Data Center

UIC – underground injection control
USDW – underground source of drinking water
VSPs – vertical seismic profiles

11.3 References

Callaway, D.C. and E.W. Rennie, Jr. 1991. *San Joaquin Basin, California*, in Gluskoter, H.J., D.D.Rice, and R.B. Taylor, eds. Economic geology, U.S.: Boulder, Colorado. Geological Society of America. The Geology of North America, v. P-2: 417-430.

McJannet, G.S. 1996. *General Overview of the Elk Hills Field*. Society of Petroleum Engineers. doi:10.2118/35670-MS.

11.4 Glossary of Terms

This glossary describes some of the technical terms as they are used in this MRV plan. For additional glossaries please see the U.S. EPA Glossary of UIC Terms (http://water.epa.gov/type/groundwater/uic/glossary.cfm), and the Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/).

Anticline – an arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form excellent hydrocarbon traps, particularly in folds that have rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Contain/containment –the effect of keeping fluids located within in a specified portion of a geologic formation.

Dip – the angle of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or *updip*, and heavy fluids will tend to move down the dip, or *downdip*. Moving higher up structure is moving updip. Moving lower is downdip. Perpendicular to dip is *strike*. Moving perpendicular along a constant depth is moving along strike.

Downdip – see *dip*.

Flooding pattern – also known as an injection pattern; the geometric arrangement of production and injection wells to sweep oil efficiently and effectively from a reservoir.

Formation – a body of rock that is sufficiently distinctive and continuous that it can be mapped.

Injectivity – the ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Infill drilling – the drilling of additional wells within existing patterns. These additional wells decrease average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, shifting flow paths lead to increased sweep to areas where greater hydrocarbon saturations remain.

Permeability – the measure of a rock's ability to transmit fluids. Rocks that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed-grain size, with smaller, fewer, or less-interconnected pores.

Phase – a region of space throughout which all physical properties of a material are uniform. Fluids that don't mix segregate themselves into phases. Oil, for example, does not mix with water and forms a separate phase.

Pore space – see *porosity*.

Porosity – the fraction of a rock that is not occupied by solid grains or minerals. All rocks have spaces between rock crystals or grains that is available to be filled with a fluid, such as water, oil, or gas. This space is called *pore space*.

Primary recovery – the first stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive, or gravity drainage, displaces hydrocarbons from the reservoir into the wellbore and up to surface. Initially, the reservoir pressure is higher than the bottom-hole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to surface. However, as the reservoir pressure declines because of production, so does the differential pressure. To reduce the bottom-hole pressure or increase the differential pressure to increase hydrocarbon production, it is necessary to implement an artificial lift system, such as a rod pump, an electrical submersible pump, or a gas-lift installation. Production using artificial lift is considered primary recovery. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economic, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically 10%-12% for oil reservoirs. Primary recovery is also called *primary production*.

Saturation – the fraction of pore space occupied by a given fluid. Oil saturation, for example, is the fraction of pore space occupied by oil.

Seal – a geologic layer (or multiple layers) of impermeable rock that serves as a barrier to prevent fluids from moving upwards to the surface.

Secondary recovery – the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are immiscible gas injection and waterflooding.

Sedimentary rocks – rocks formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity, or precipitation from solution. There are three main types of rocks: igneous, metamorphic, and sedimentary.

Stratigraphic section – a sequence of layers of rocks in the order they were deposited.

Strike – see *dip.*

Updip – see *dip.*

11.5 Well List

The following tables present the well name and well type for the project.

26R Project Wells

Injectors	363C-27R 353XC-35R 373-35R 345C-35R	
Monitoring wells	341-27R	Plume monitoring
	328-25R	Plume monitoring
	374-36R	Plume monitoring
	355X-26R	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

A1-A2 Project Wells

Injectors	355-7R 357-7R	
Monitoring wells	353A-7R	Plume monitoring
	335X-7R	Plume monitoring
	327-7R-RD1	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

11.6 Monitoring Well Details

26R Project monitoring of ground water quality and geochemical changes above the confining zone.

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

A1-A2 Project monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD/VD	Baseline, Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD/VD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD/VD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD/VD 961' MD/VD 854' MD/VD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD 3780' - 3932' VD	Baseline, Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' 3850' - 3990' (all MD/VD)	Continuous

Summary of analytical and field parameters for groundwater samples above the confining zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO_3, SO_4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH_4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
$\delta 13C$	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

11.7 Summary of Key Regulations Referenced in MRV Plan

Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).